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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Energy+Environmental Economics

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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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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.

- <u>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.</u> 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.

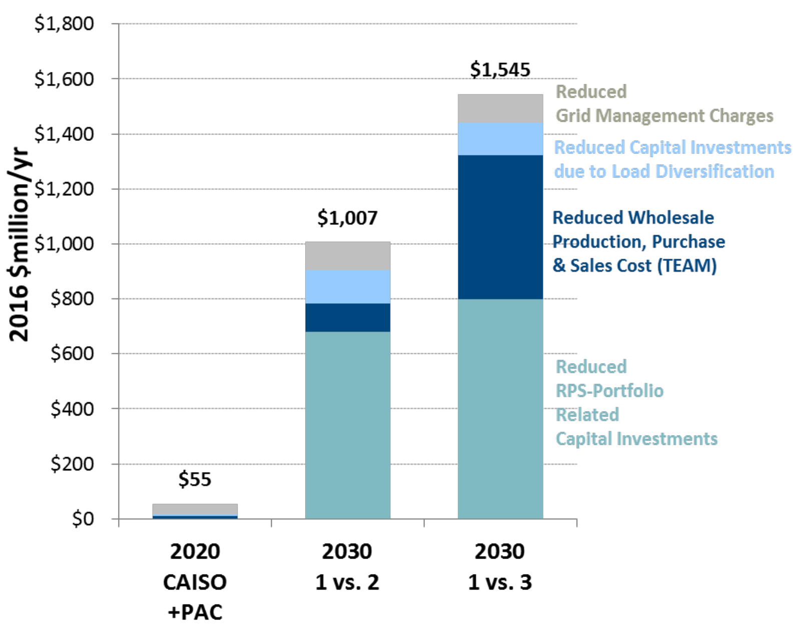
The key findings of the SB 350 analysis with respect to California ratepayer impact, greenhouse gas and other emissions, economic and environmental impacts, and impacts on disadvantaged communities are as follows:

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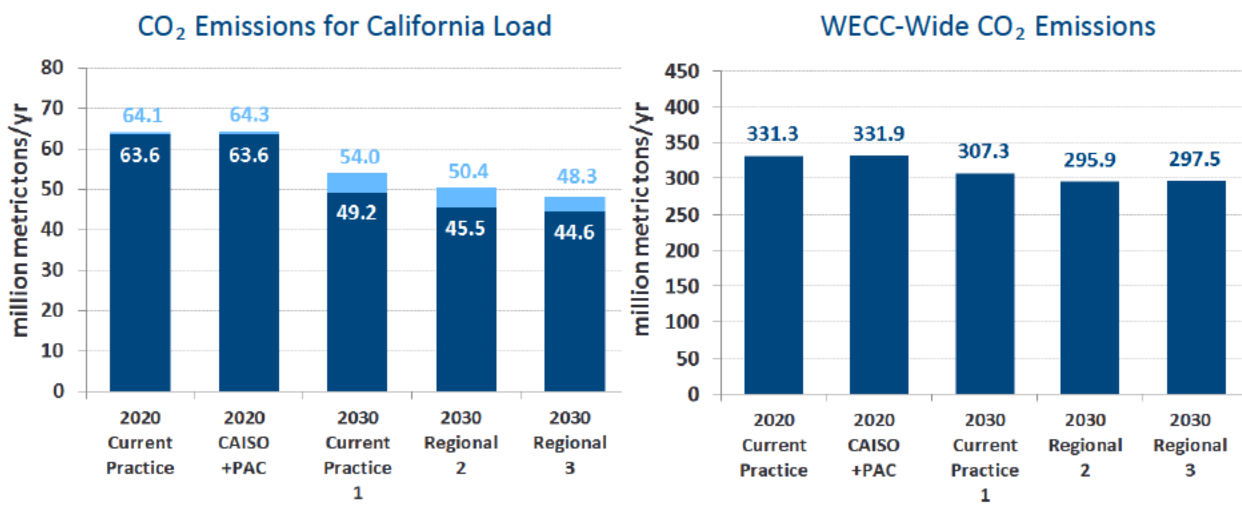
[10] Note that the emissions results presented in this final report differ slightly from preliminary results presented on May 24, 2016; all cases were updated to: (1) include CO_2 emissions during plant starts and (2) exclude wheeling-through transactions in California emissions accounting.

[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.

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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

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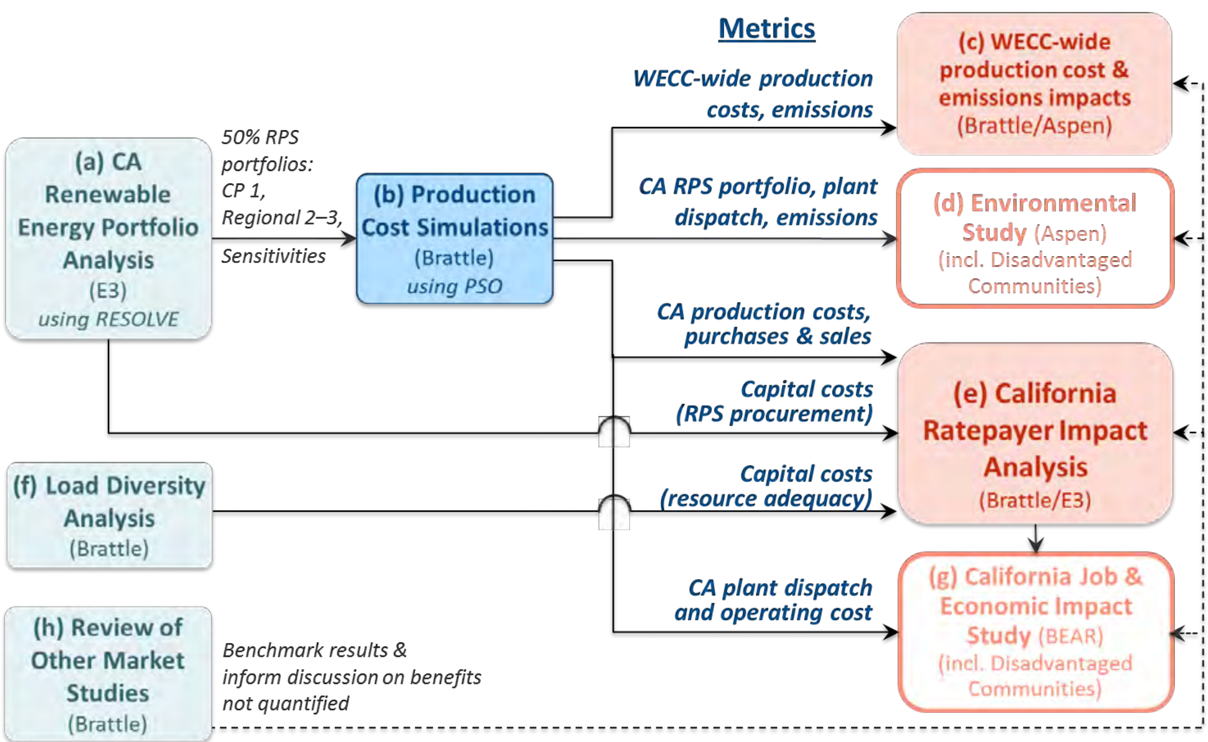
18 Specifically, the PMAs being excluded for the analysis are Bonneville Power Administration ("BPA") and Western Area Power Administration ("WAPA")—Colorado-Missouri Region, Lower Colorado Region and Upper Great Plains West. WAPA's Sierra Nevada Region is included in the Balancing Area of North California 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.

[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.

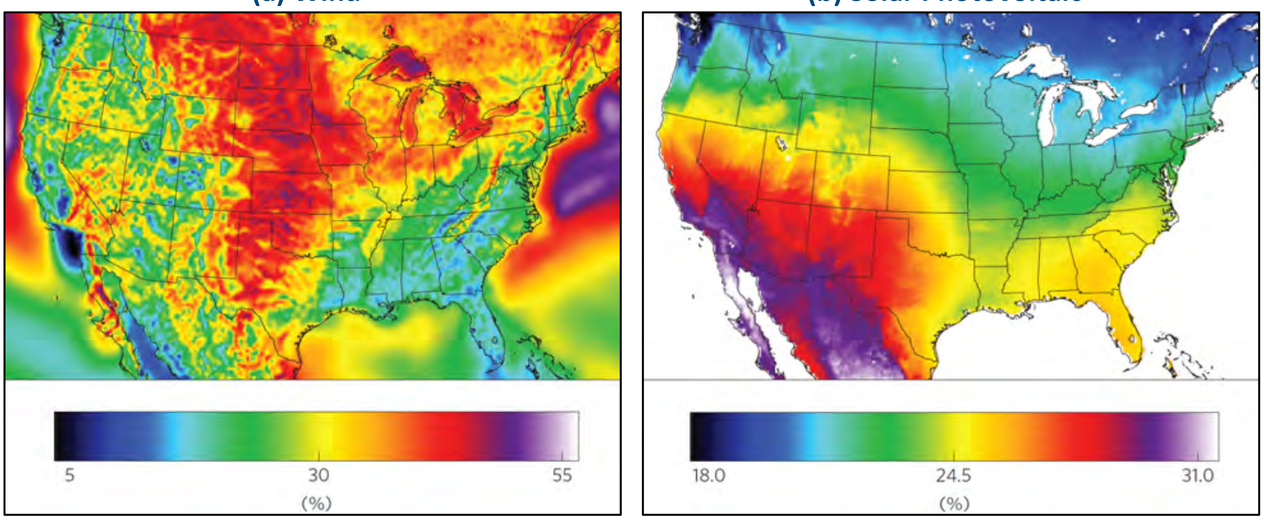
D. PORTFOLIOS TO MEET CALIFORNIA'S 50% RENEWABLE PORTFOLIO STANDARD

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.

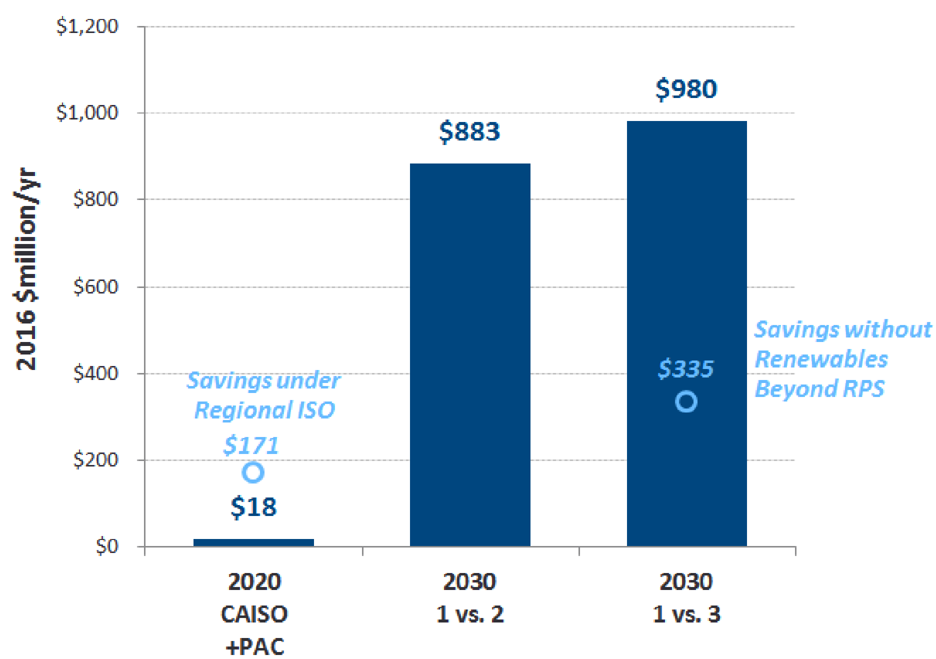
The five baseline scenarios reflect a 2020 and 2030 western wholesale electricity market with and without expanded ISO market operations, as described in Section I.B above. In the 2020 Current Practice and 2030 Current Practice 1 scenarios, we simulate a wholesale market that operates similarly to today's, 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.

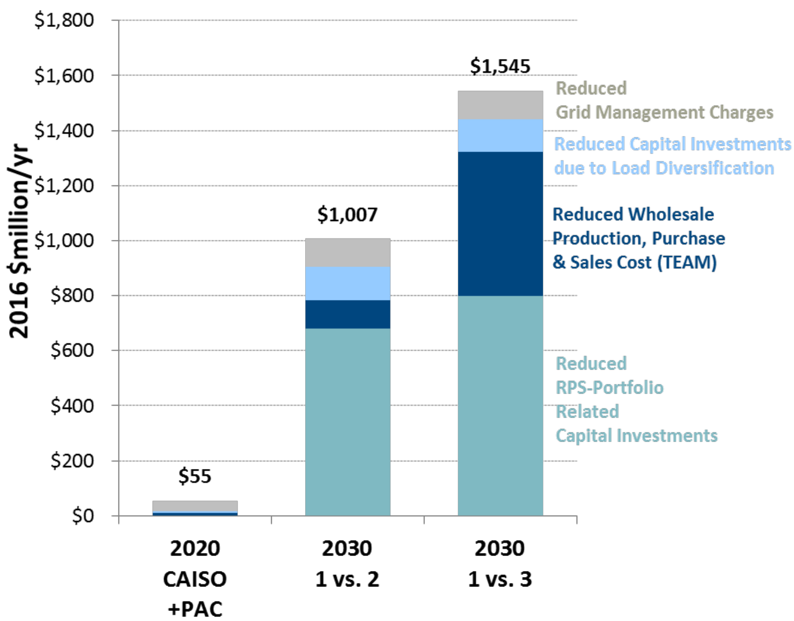
1. Overall Impact on California Ratepayers

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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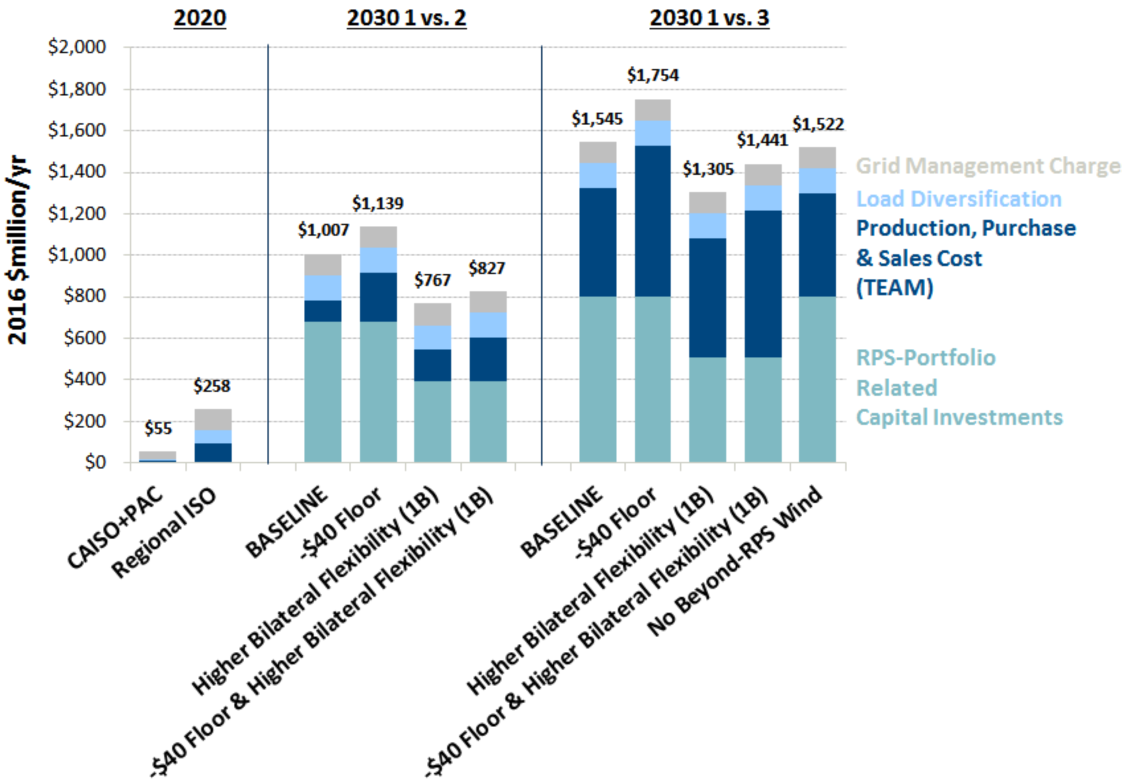
[34] Negative prices are already being experienced during real-time operations in the CAISO footprint. For example, 7% of all 5-minute real-time pricing intervals have experienced negative prices during the first quarter of 2016, reaching 14% of all pricing intervals in March 2016 due to high solar generation 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).

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.

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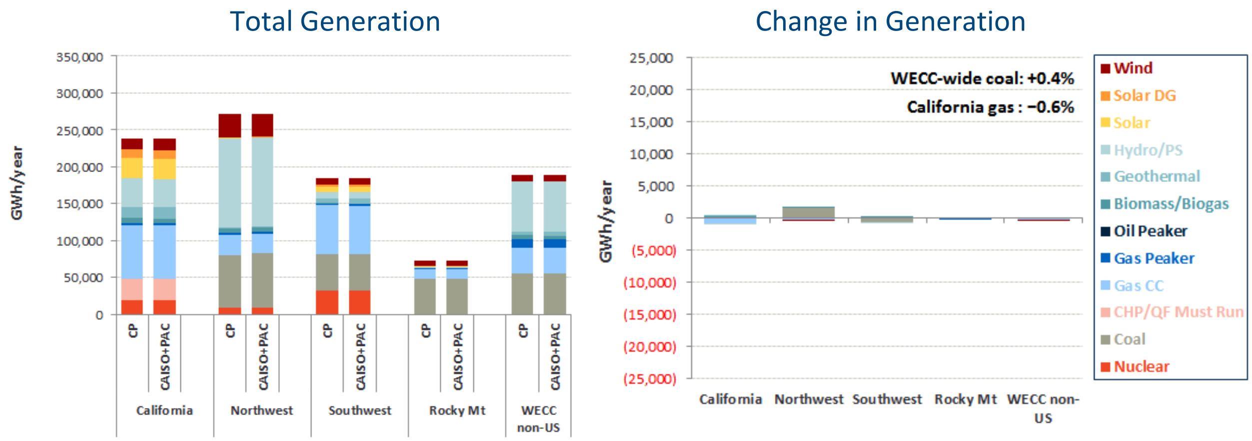
36 The production cost model does track unit-specific NOx and SO_2 emissions. However, as with most or all production cost models there are some limitations to interpreting absolute levels of unit-specific air emissions as explained in footnote 23.

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

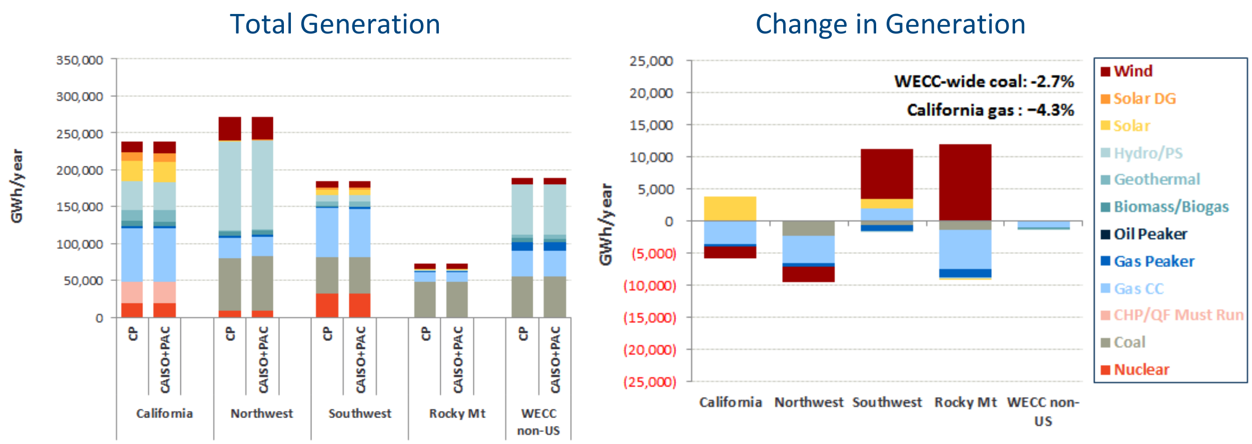
38 This study is focused on the changes in emissions associated with the deployment and the operational use of the power generation resources, and, accordingly, this study assesses the effects of regional market on those uses. To the extent that less natural gas is used for electricity production due 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

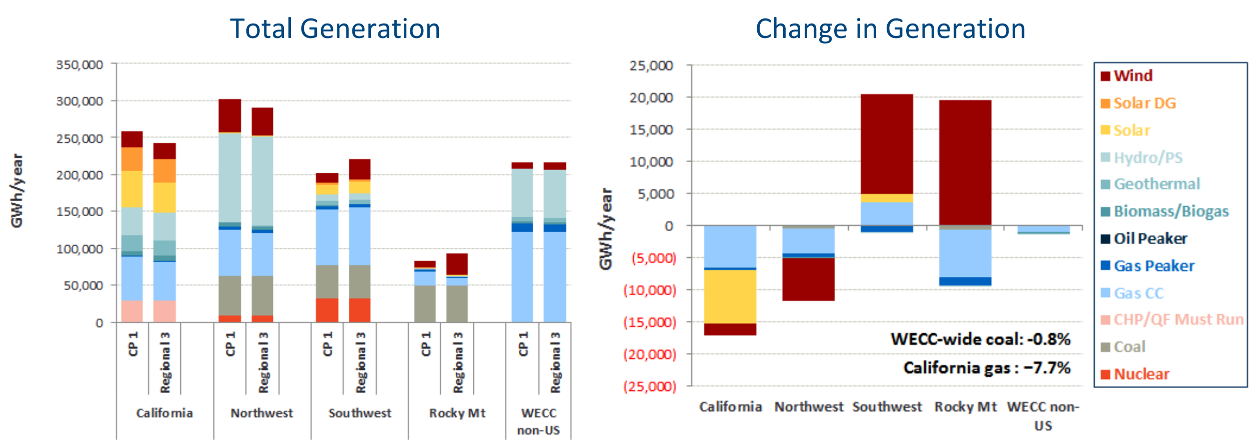
(a) 2020 Current Practice versus CAISO+PAC



(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

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[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.*

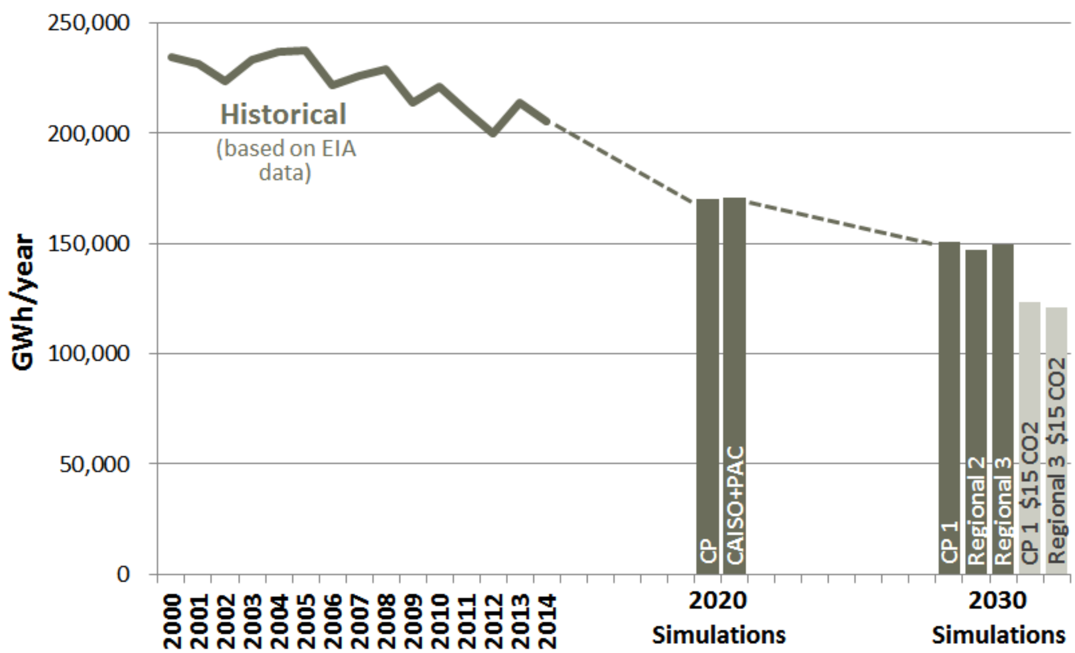
44 Gavin Blade, "SPP CEO: Regionalization, transmission help push renewables penetration near 50%," UtilityDive, May 26, 2016.

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



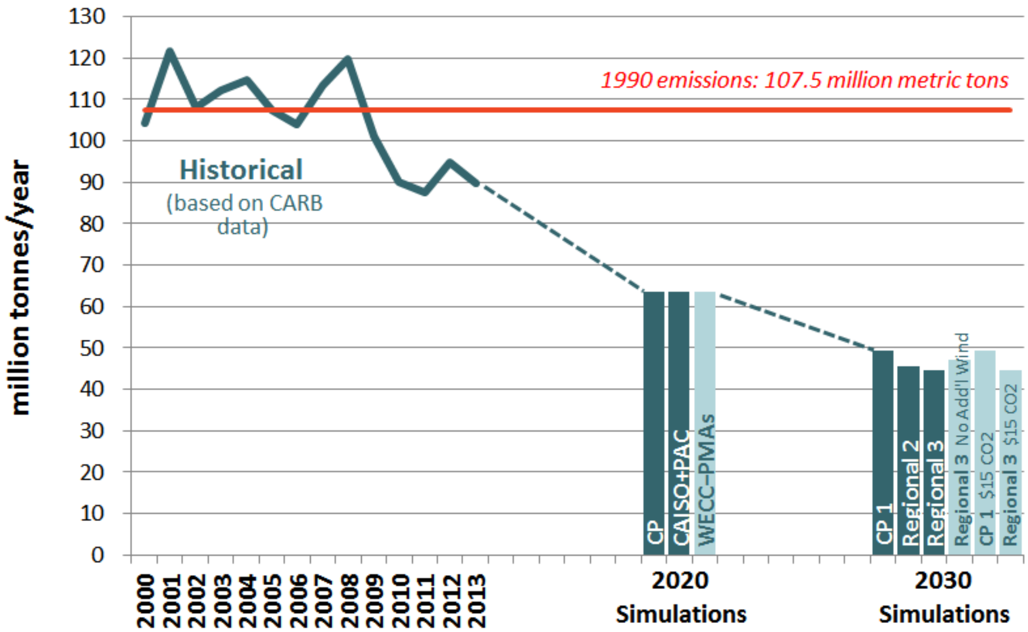
Despite the pressures on coal-fired plants created by expanding renewable generation in a regional market, the primary drivers of changes in the overall output of coal plants likely are the relative prices of fuel (coal versus natural gas) and environmental regulations. As discussed above, we did not 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]

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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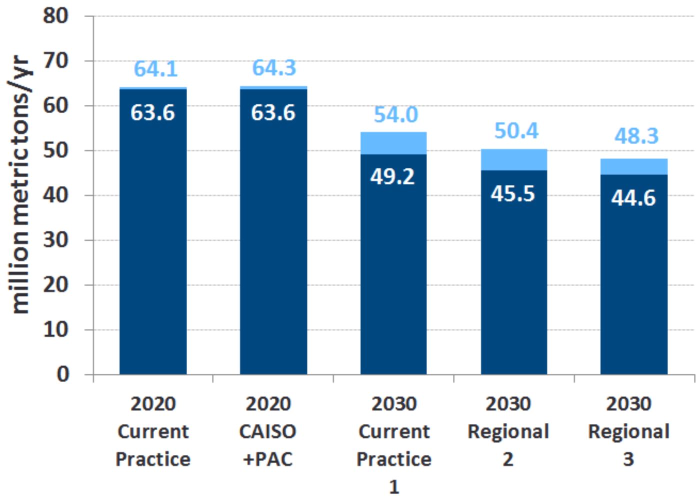
Figure 13: Simulated California Electric Sector CO_2 Emissions



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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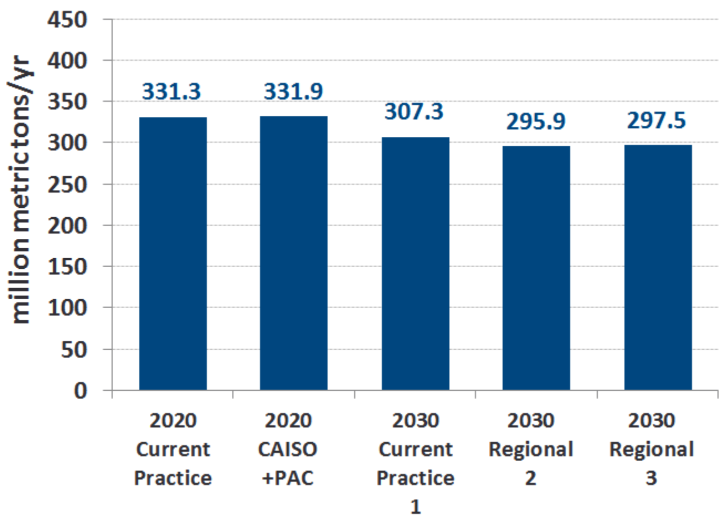
in simulated 2020 CO_2 emissions to be *de minimus*. Even if a portion of the simulated slight increase were realized in the near term, it would be very small compared to the much more significant long-term CO_2 emission reduction across the WECC, including the long-term emissions benefits of a regional 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 <u>proxy</u> 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.

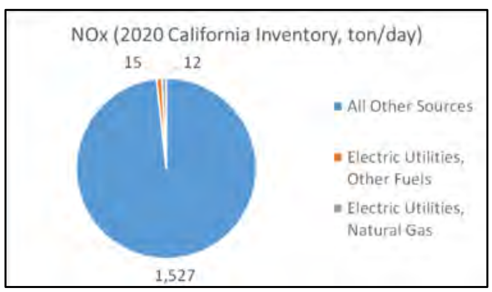
In a separate sensitivity analysis, Regional 3 without renewables beyond RPS results in a slight 0.6% increase in the dispatch of California's in-state natural gas–fired fleet compared to Current Practice 1. But this sensitivity would still avoid some of the excess startup emissions that would occur 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

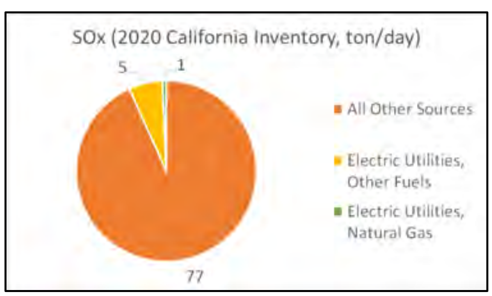
The analysis of NOx, SO_2, and PM2.5 emissions for 2030 shows that a Regional ISO-operated market would decrease these emissions from the electricity sector, both in California and in the rest of WECC. However, the results for 2020 showed a slight increase in these emissions for the rest of WECC due 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

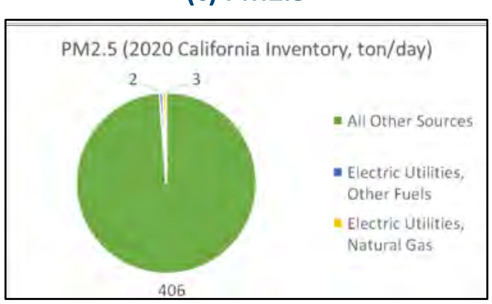
(a) NOx



(b) SOx



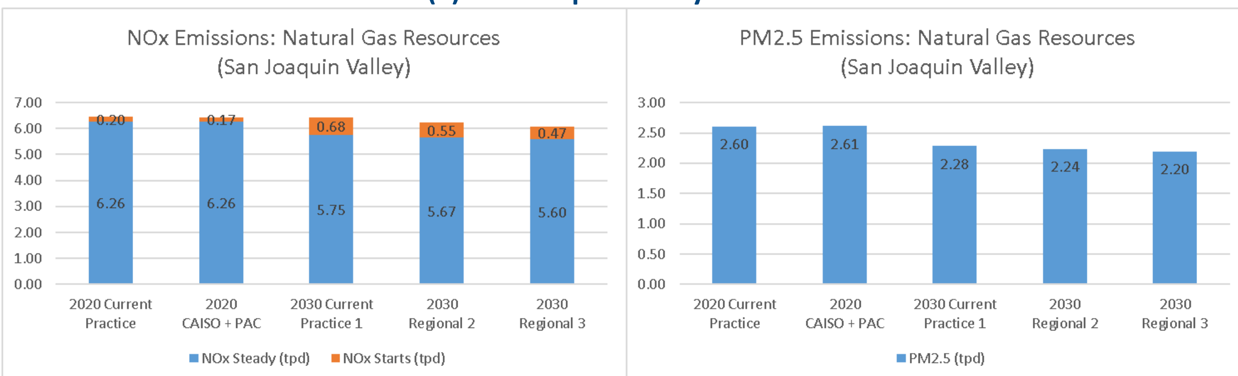
(c) PM2.5



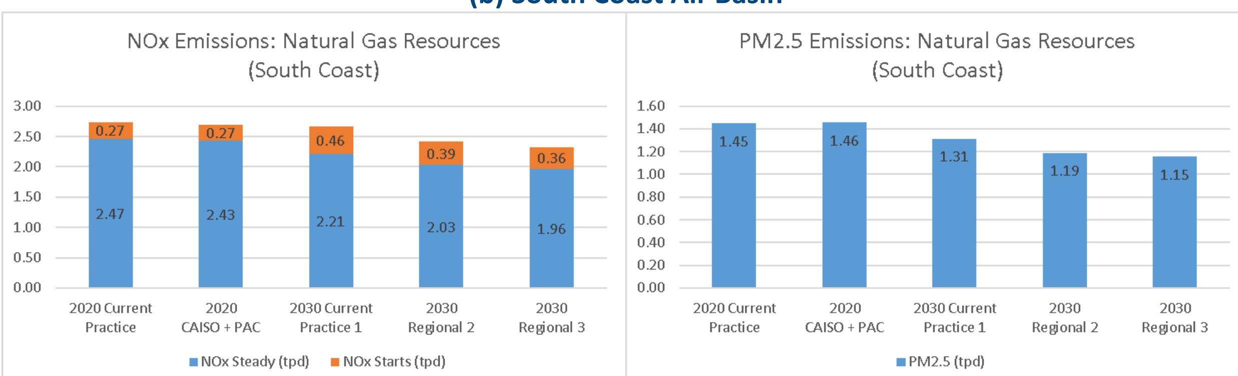
In California, a regional market is projected to reduce NOx and PM2.5 emissions in the persistent non-attainment areas of the San Joaquin Valley, South Coast, and Mojave Desert air basins. In addition, emissions in the Salton Sea air basin (which has relatively low emissions in any scenario) drop to 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

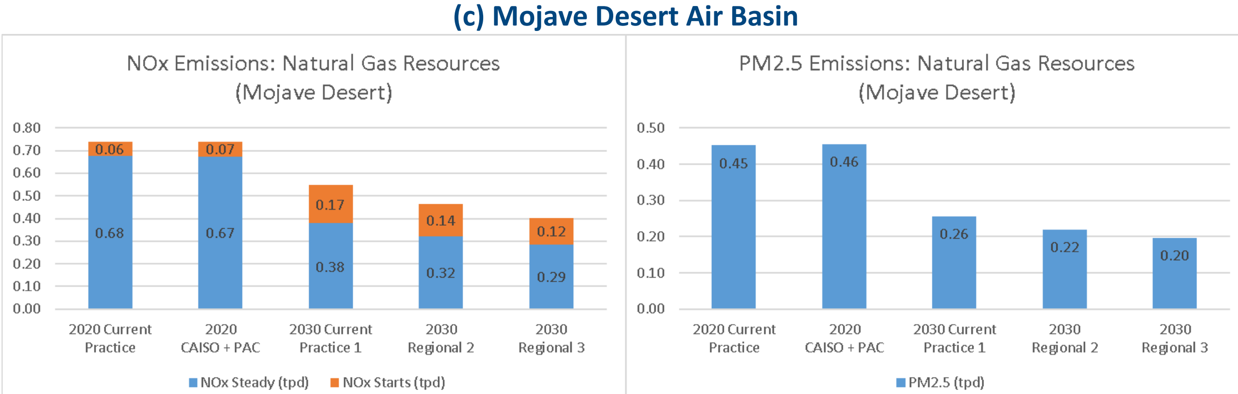
(a) San Joaquin Valley Air Basin



(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.

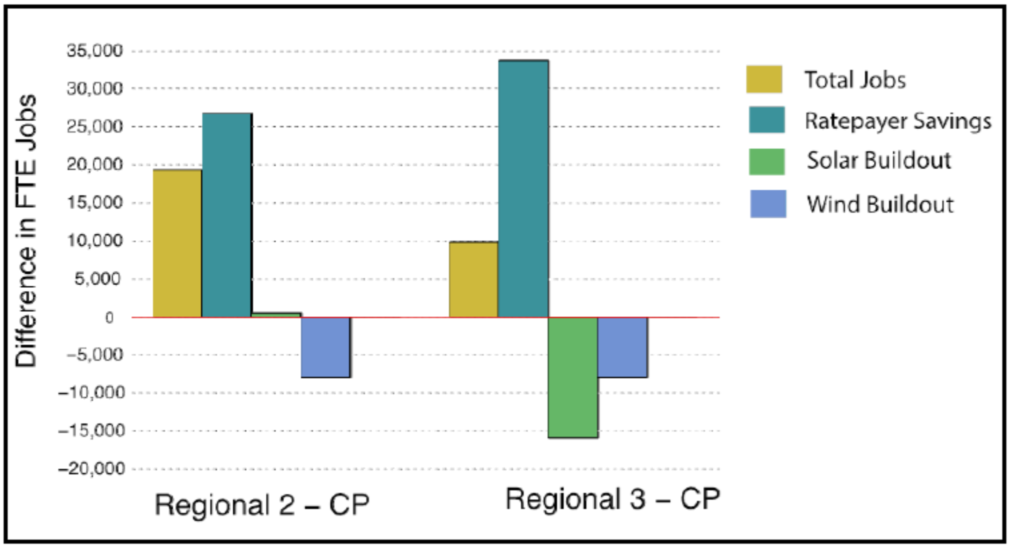
Figure 17: Overall Impacts on the California Economy
Change Relative to Current Practice 1 ($B)

	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.

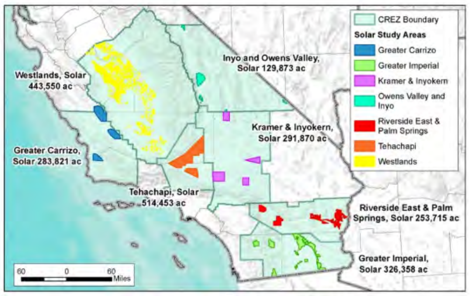
Figure 19: Resource Zones in California for Portfolios and Environmental Study

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.

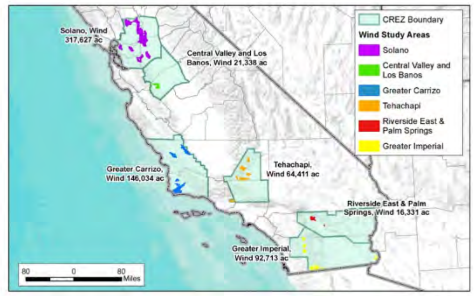
The environmental study starts with the renewable portfolios, which are drawn from coarsely-defined geographies inside California by the RESOLVE model based on estimates of location-specific resource development costs, resource development potential, and resource performance (*e.g.*, capacity factors). 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

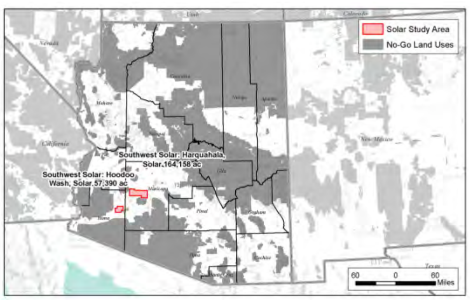
(a) California Solar



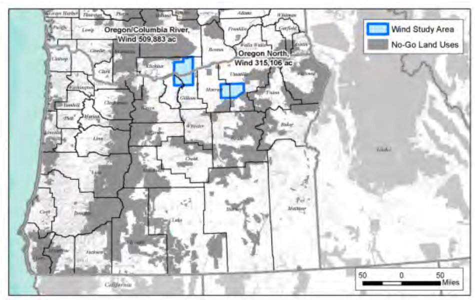
(b) California Wind



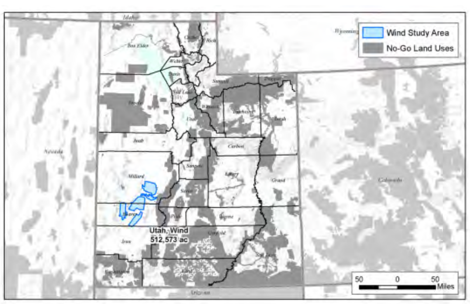
(c) Southwest Solar



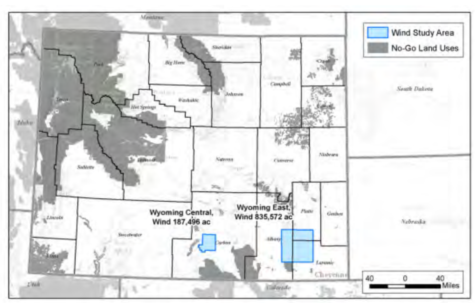
(d) Northwest Wind



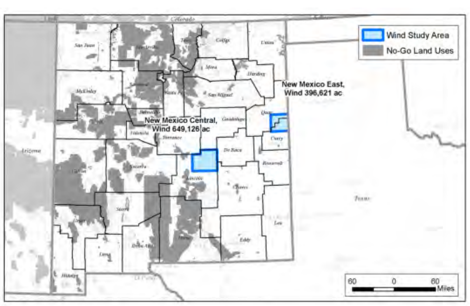
(e) Utah Wind



(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.

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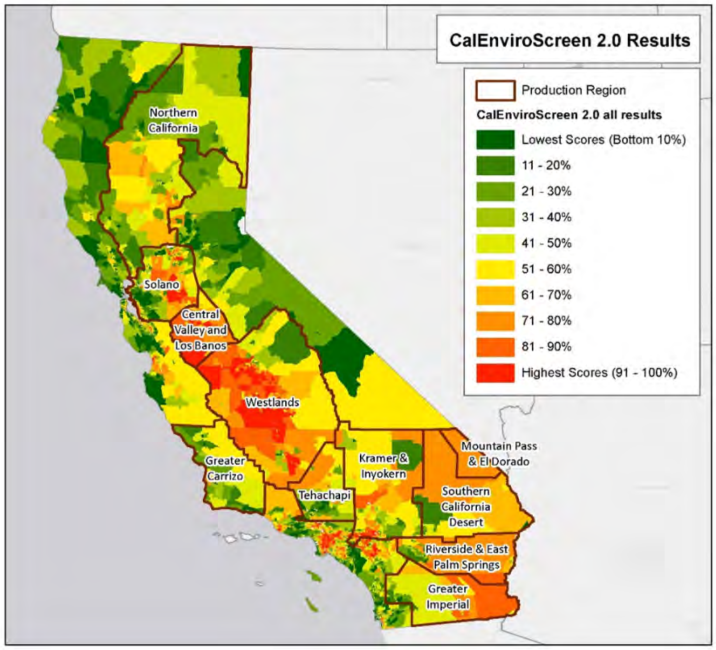
[54] NREL (2011). A review of Operational Water Consumption and Withdrawal Factors for Electricity Generating Technologies. Available at: http://www.nrel.gov/docs/fy11osti/50900.pdf.

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

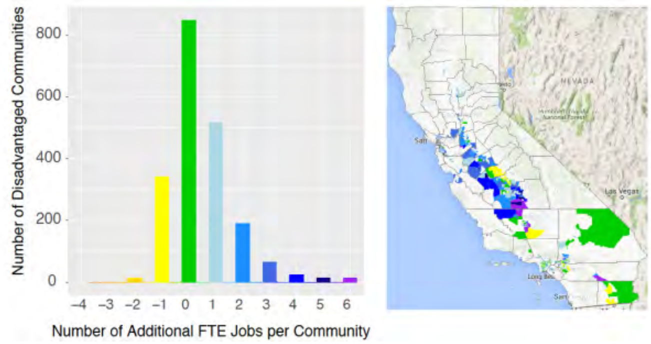


As part of the California economic and job impact analysis, the results are mapped to the CalEnviroScreen 2.0 scores at the census tract level. That way, one can distinguish results for disadvantaged and other communities.

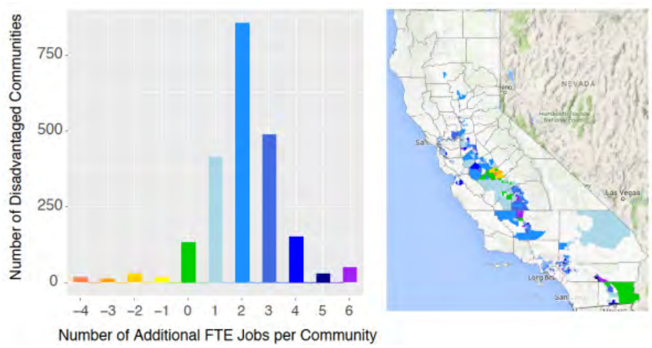
From a job and economic impact perspective, a regional market creates more jobs and more income in many disadvantaged communities, as shown in Figure 21. Real income increases by about $180 to $340 per year, and net jobs increase by 800 to 2,800 between 2020 and 2030. Because the disadvantaged communities 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

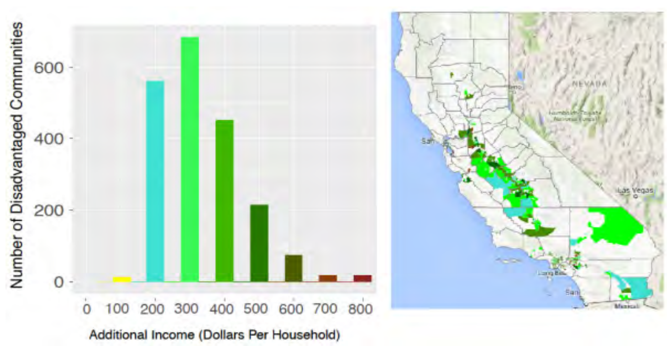
Employment Impacts: Regional 3 Minus Current Practice 1



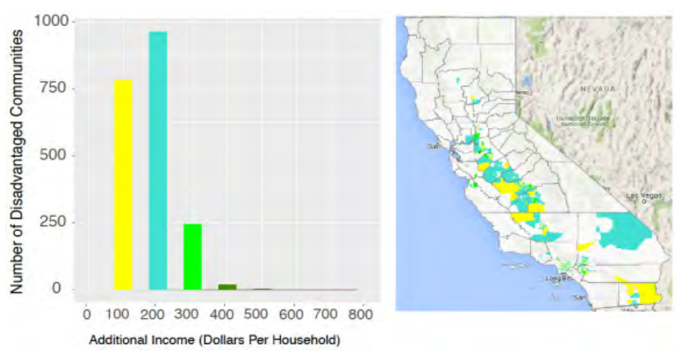
Employment Impacts: Regional 2 Minus Current Practice 1



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;

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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.

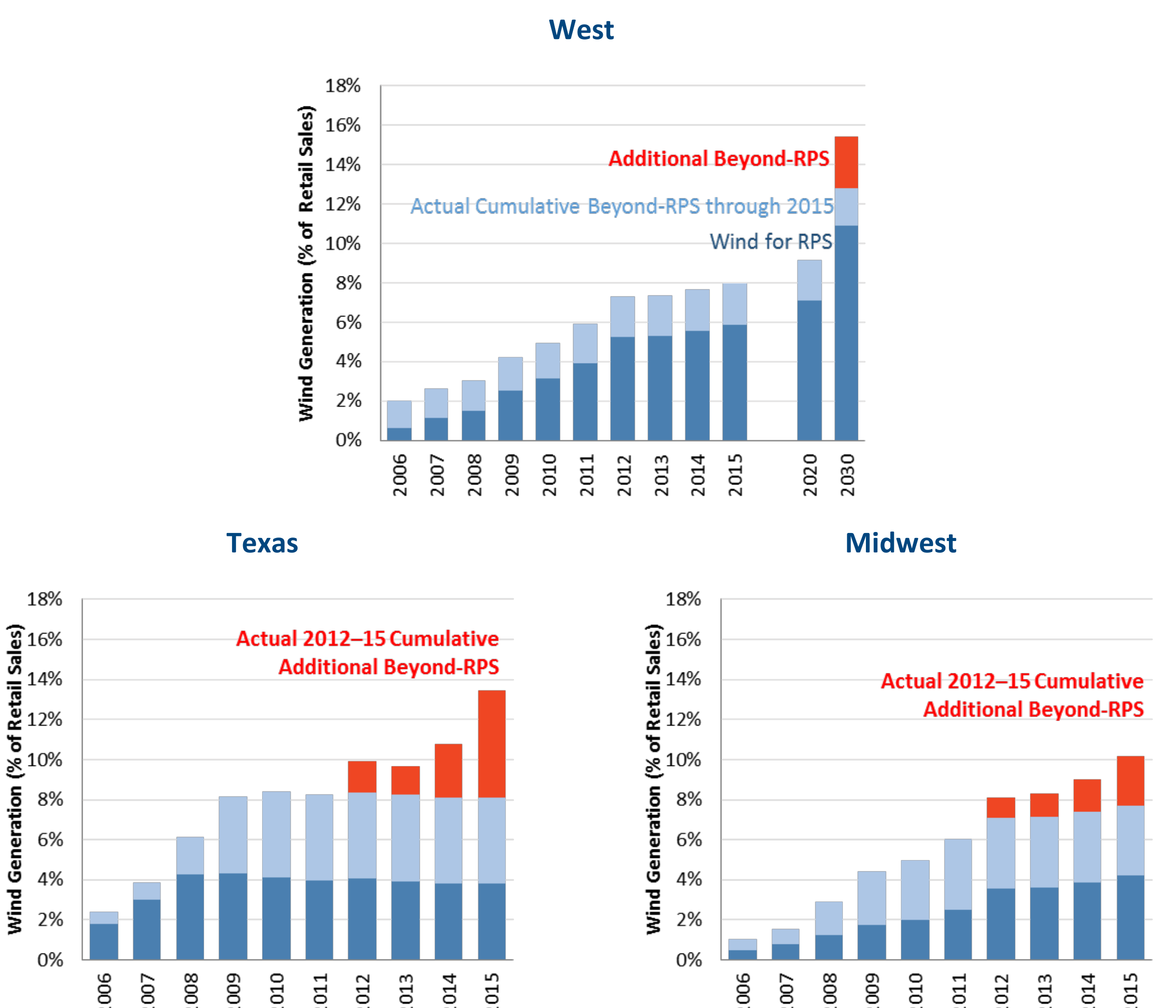
The reduction of integration and balancing costs faced by renewable resources facilitates a more rapid development and growth of renewable generation in the regional footprint, including accelerated renewable development beyond the western states' RPS requirements.

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

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Berkeley Economic Advising and Research

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

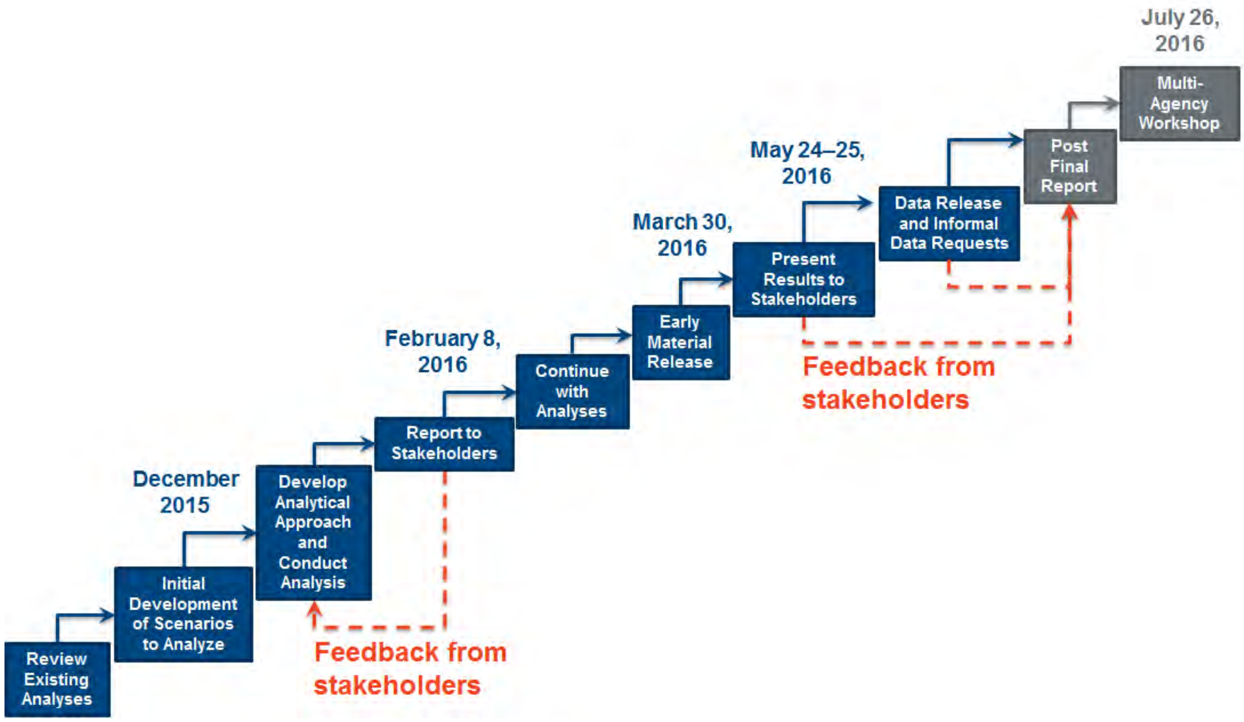
The SB 350 study efforts include a stakeholder process, by which the study team provides study assumptions, methodology, results, and detailed descriptions of all of the relevant metrics used in the analyses. The stakeholder process began with the study team presenting initial ideas about the approach 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

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 III: Table of Contents

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

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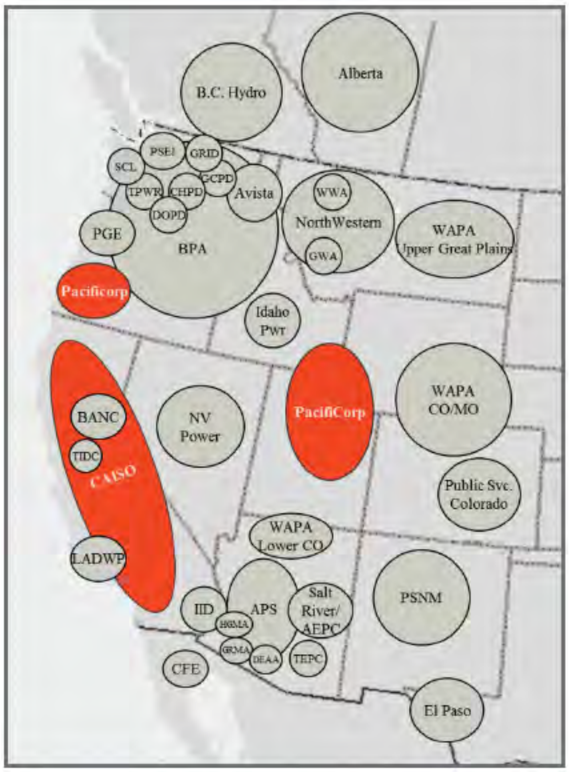
3 A Participating Transmission Owner turns over operational control of their transmission system and their balancing area is' subsumed within the CAISO balancing area.

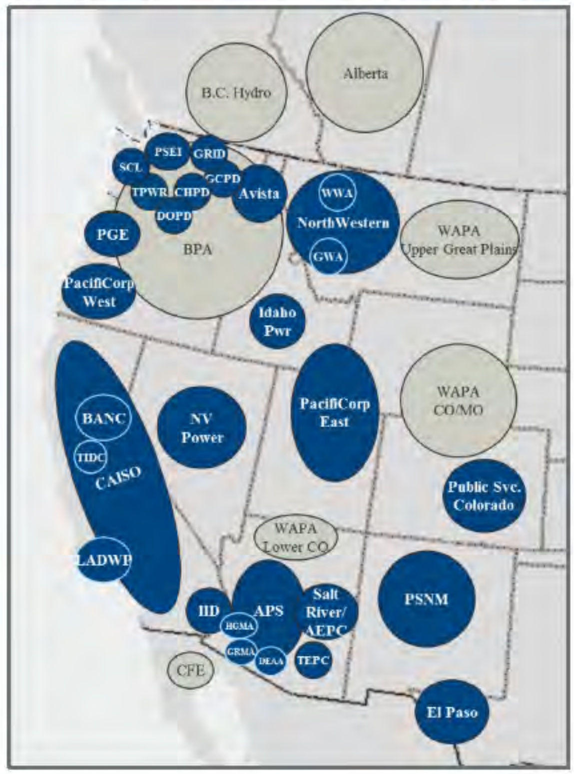
and how many entities would join by 2030, which would join after 2030, and which would not join until later (or not at all).

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

[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.

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)	Analytical Scope (Tool): Production Costs and Emissions (PSO)	Analytical Scope (Tool): 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

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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; $N	$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:

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

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

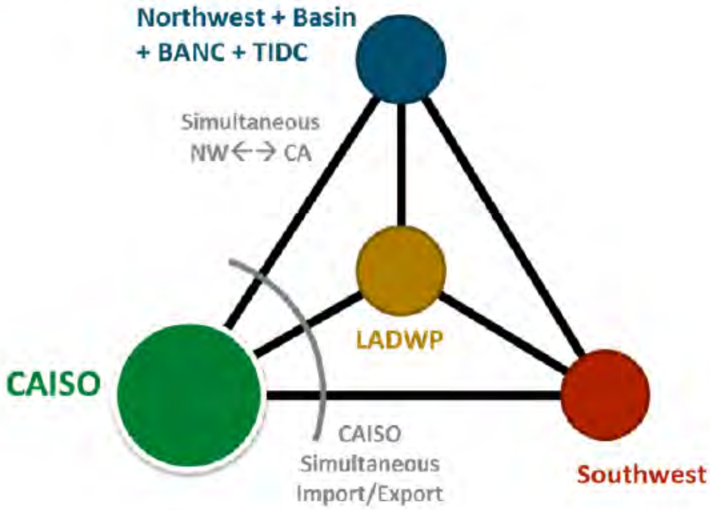


Table 8. Flow constraints between zones and simultaneous flow constraints (negative numbers reflect flows in opposite direction).

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

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

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

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.

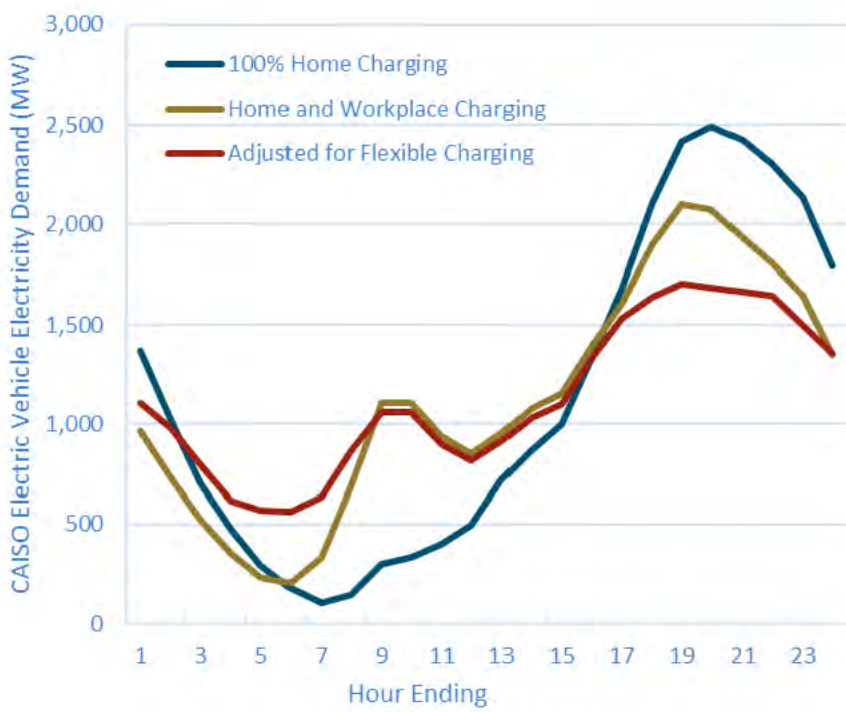
Table 10. Hourly load shape adjustment (MW) due to time-of-use rates in ISO in the month of January for the years 2015, 2020, 2025 and 2030.

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

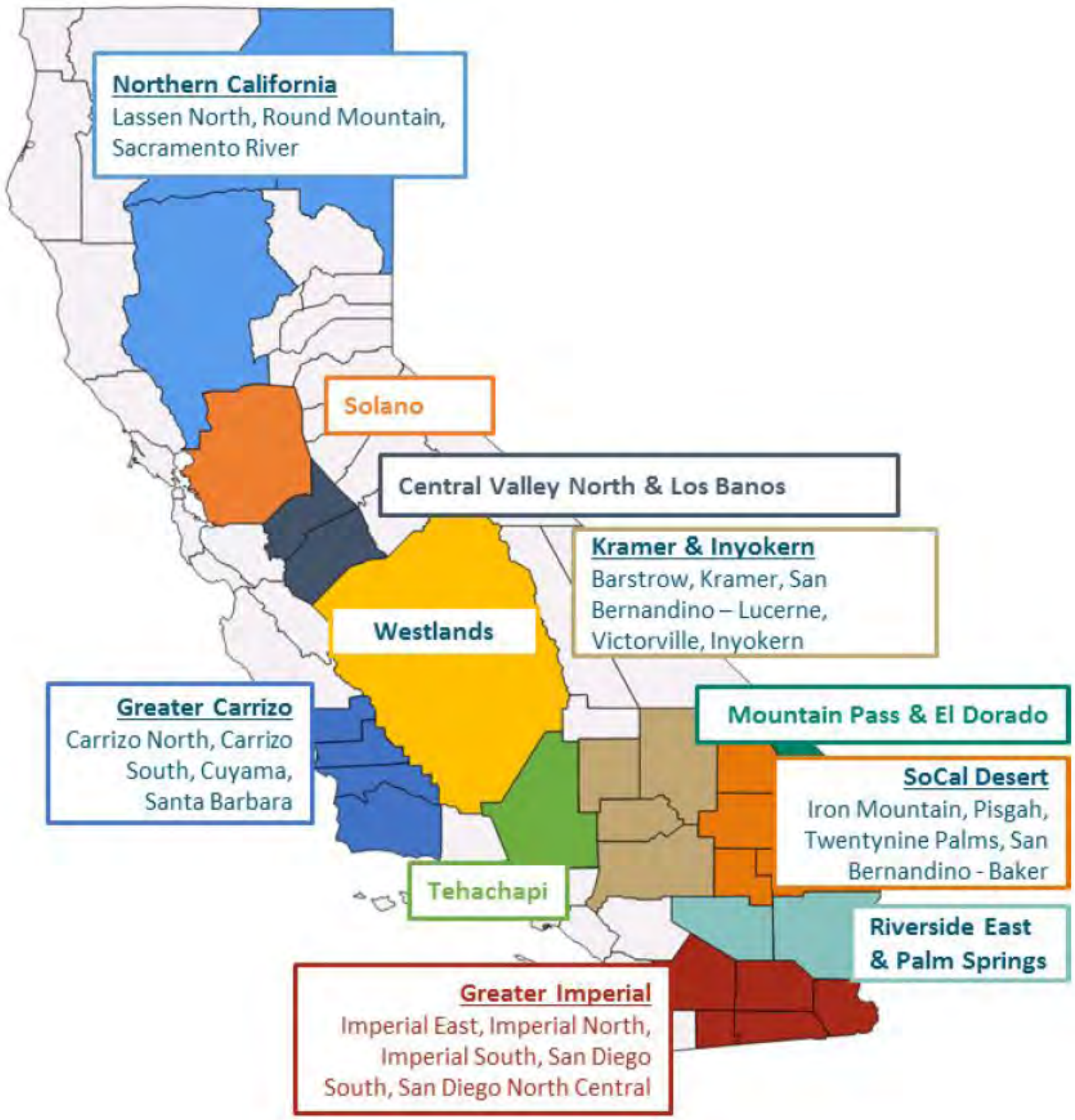


Table 14. California renewable potential considered in RESOLVE (additional to existing renewables)

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.

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[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

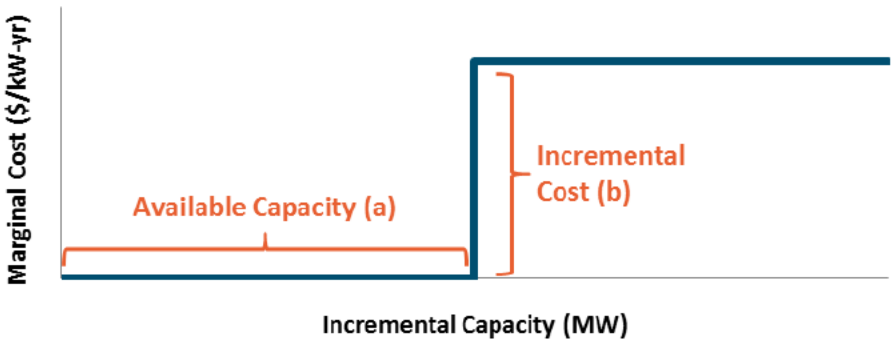

Table 17. Availability of energy only capacity and cost of transmission upgrades in California zones.

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
New Mexico Wind	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
New Mexico Wind	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)
Wyoming Wind	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

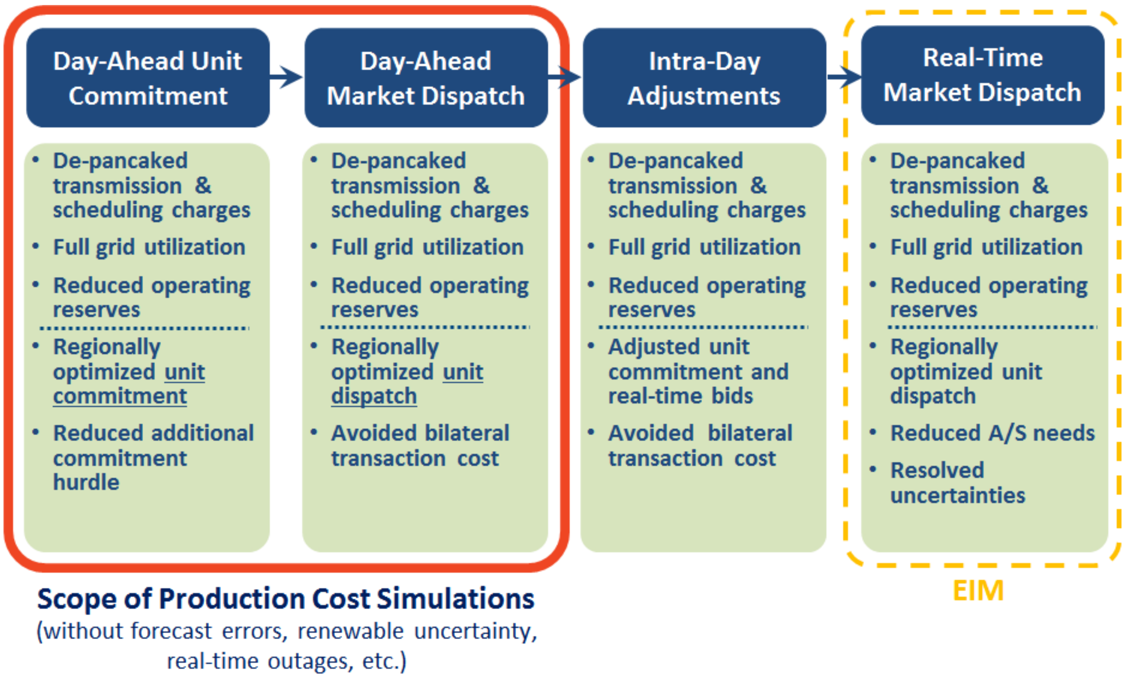
	Cycle	Description
Cycle 1	Marginal Losses	Calculates marginal loss factors
Cycle 2	Unit Commitment	Makes commitment decisions based on the up/down time and the magnitude of minimum generation amount for different types of generation resources (longer for baseload and older gas-fired combined-cycles and 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

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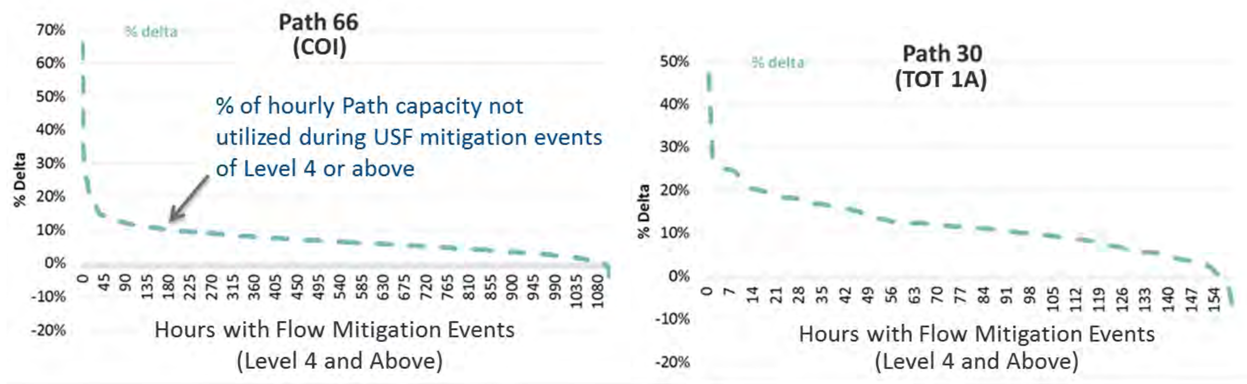
4 See https://www.nrdc.org/experts/carl-zichella/count-all-benefits-regional-expansion

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.

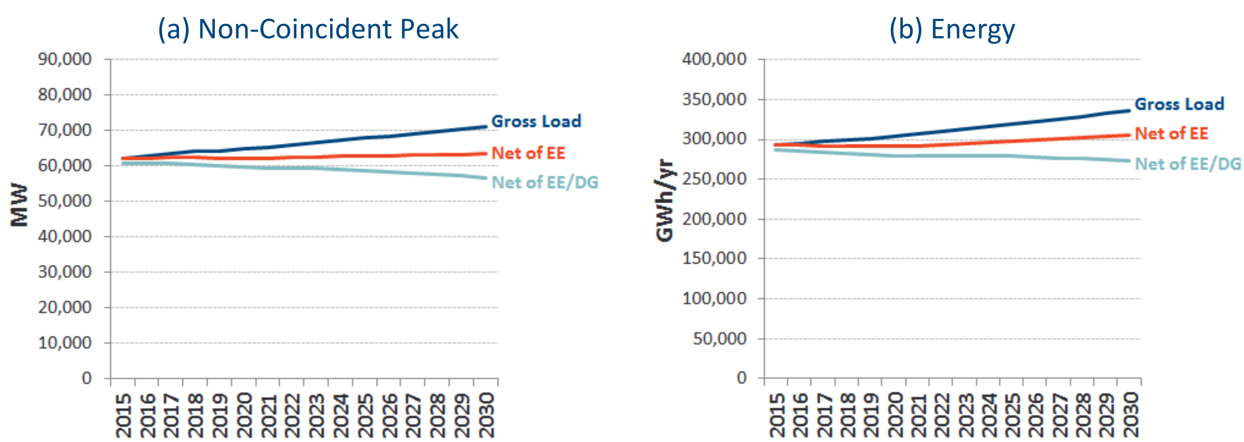
8 Specifically, these materials can be found here: https://www.caiso.com/informed/Pages/RegionalEnergyMarket/BenefitsofaRegionalEnergyMarket.aspx Last accessed in July 2016.

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

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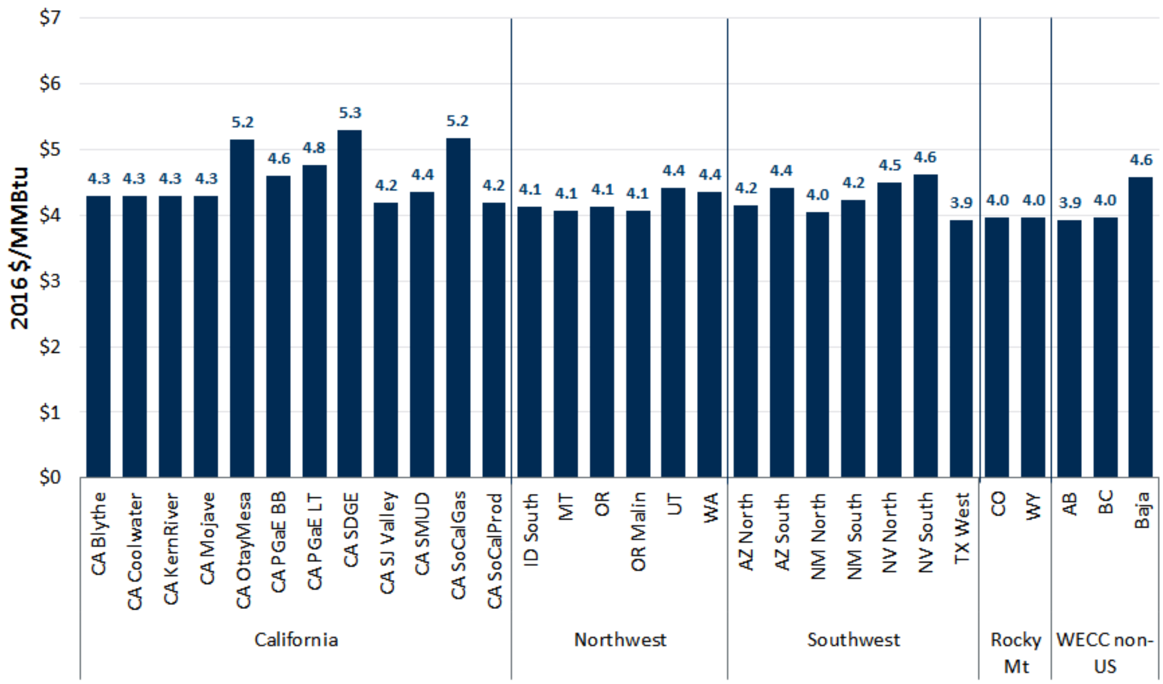
[11] CEC, "WECC Gas Hub Burner Tip Price Estimates using 2015 IEPR Natural Gas Estimates," January 2016, available at: http://docketpublic.energy.ca.gov/PublicDocuments/15-IEPR-03/TN210495_20160222T143214_WECC_Gas_Hub_Burner_Tip_Price_Estimates_using_2015_IEPR_Natural.xls

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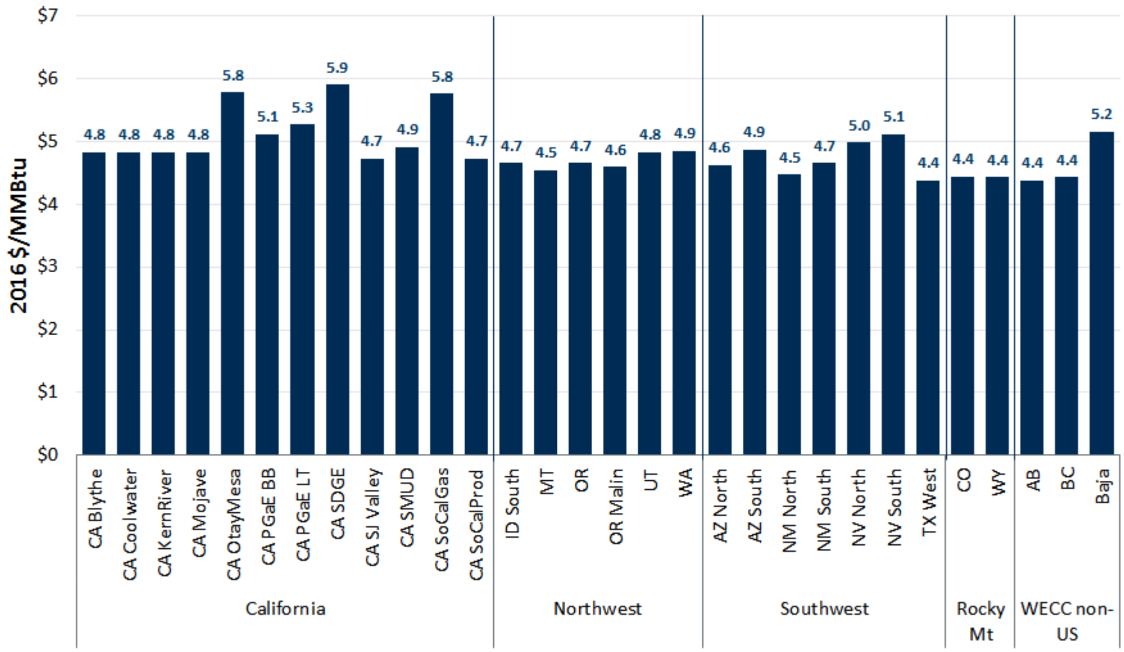
12 For details on CEC's methodology, please see Staff report "Estimating Natural Gas Burner Tip Prices for California and the Western United States", November 2014, available at: http://www.energy.ca.gov/2014publications/CEC-200-2014-008

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

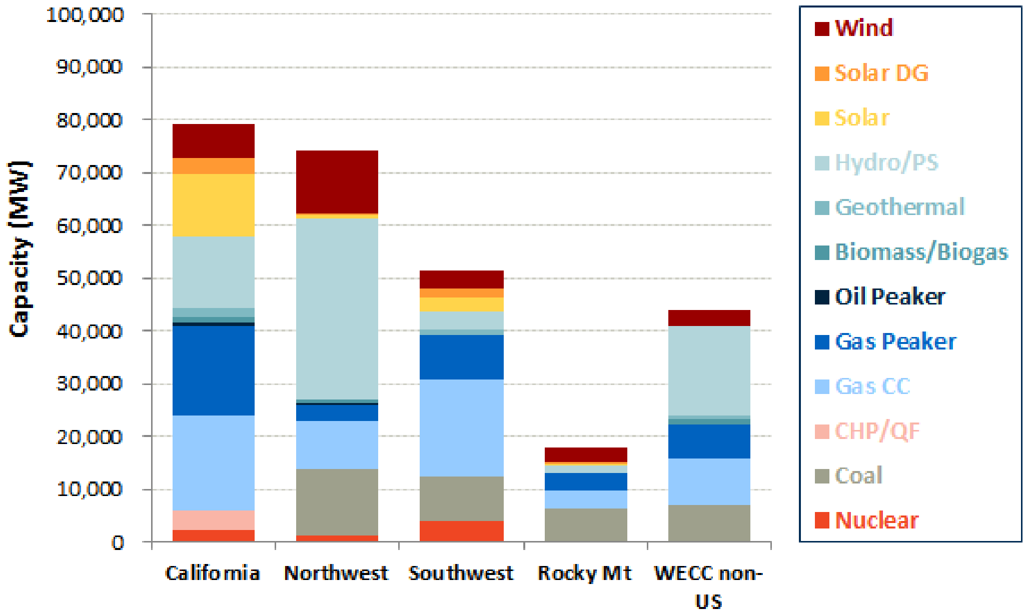
Coal Price Region	Price 2016$/MMBtu
Alberta	$1.57
Arizona	$2.50
California South	$1.83
Colorado East	$2.25
Colorado West	$2.24
Idaho	$1.22
Montana	$1.39
New Mexico	$2.30
Nevada	$3.26
Pacific Northwest	$2.73
Utah	$2.01
Wyoming East	$1.56
Wyoming Powder River Basin	$0.99
Wyoming Southwest	$2.16

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



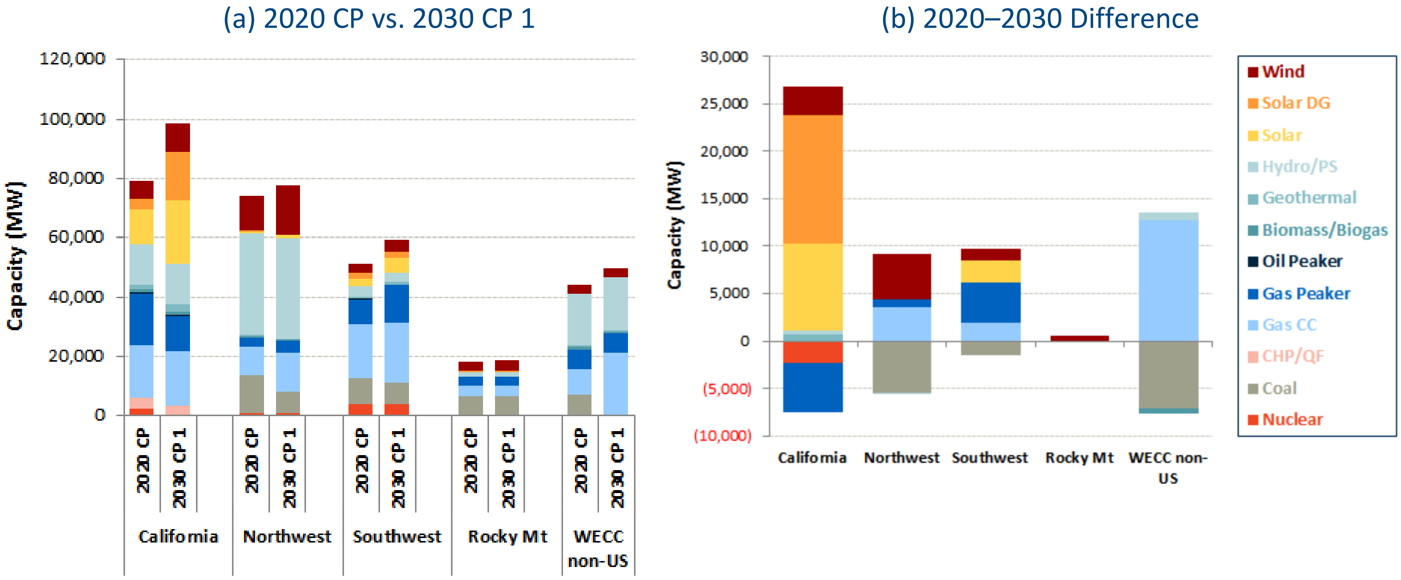
Note: The graphic reflects maximum capacity for renewable resources and summer capacity for conventional resources.

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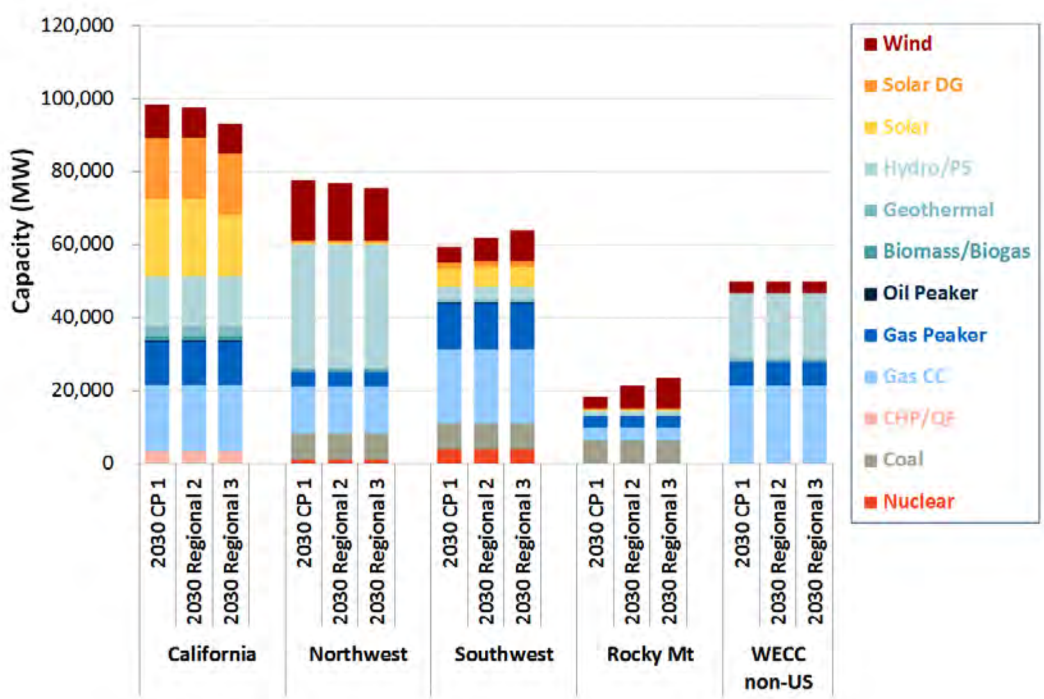
13 Pacific Gas & Electric Company has announced that they will retire Diablo Canyon by the end of its existing nuclear operating license in 2024.

- 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.

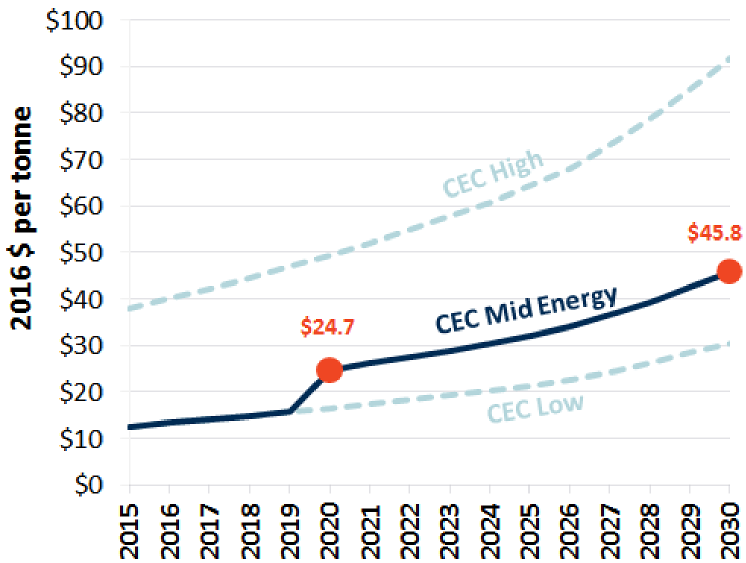
4. Greenhouse Gas Emission Prices

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-

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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).

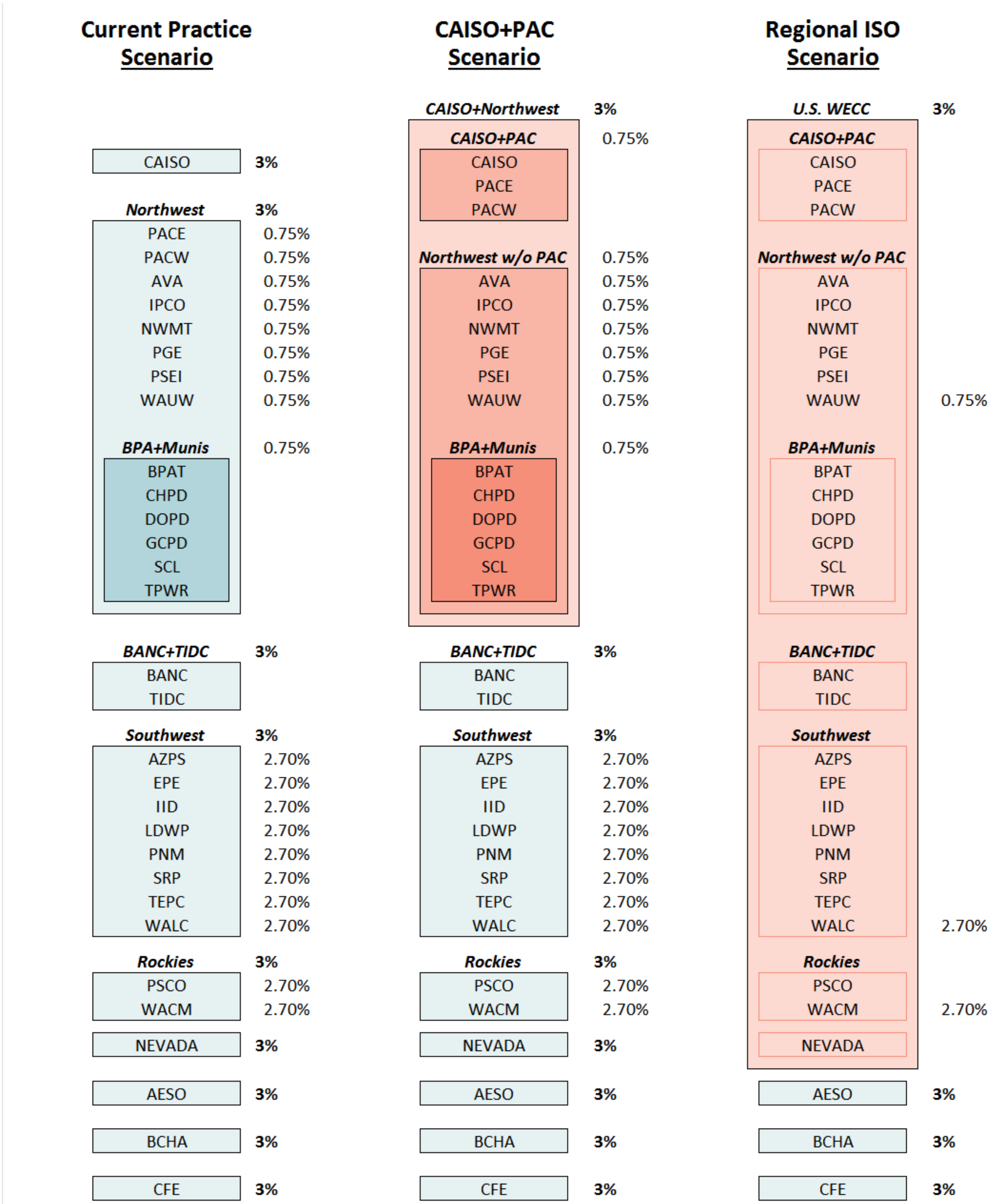
In the CAISO+PAC and Regional ISO scenarios, we expanded and combined the reserve sharing groups assuming the sharing arrangements that exist under the Current Practice scenarios would continue to exist within a regional market in addition to the new sharing arrangements that would emerge as a result 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

[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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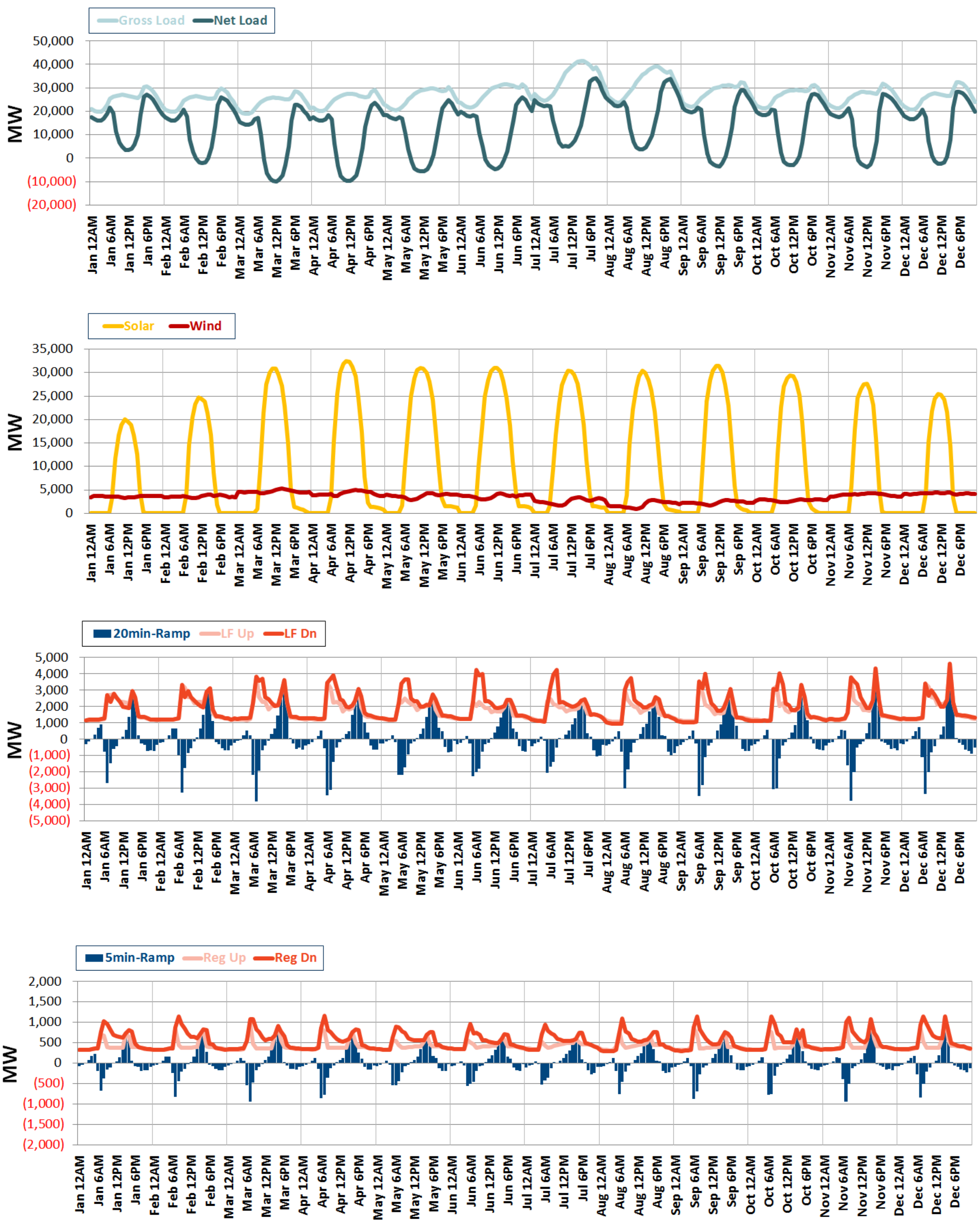
[23] *Id.*

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

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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)

		2020 All Cases		2030 Current Practice, Regional 2		2030 Regional 3	
WECC Path Name		**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

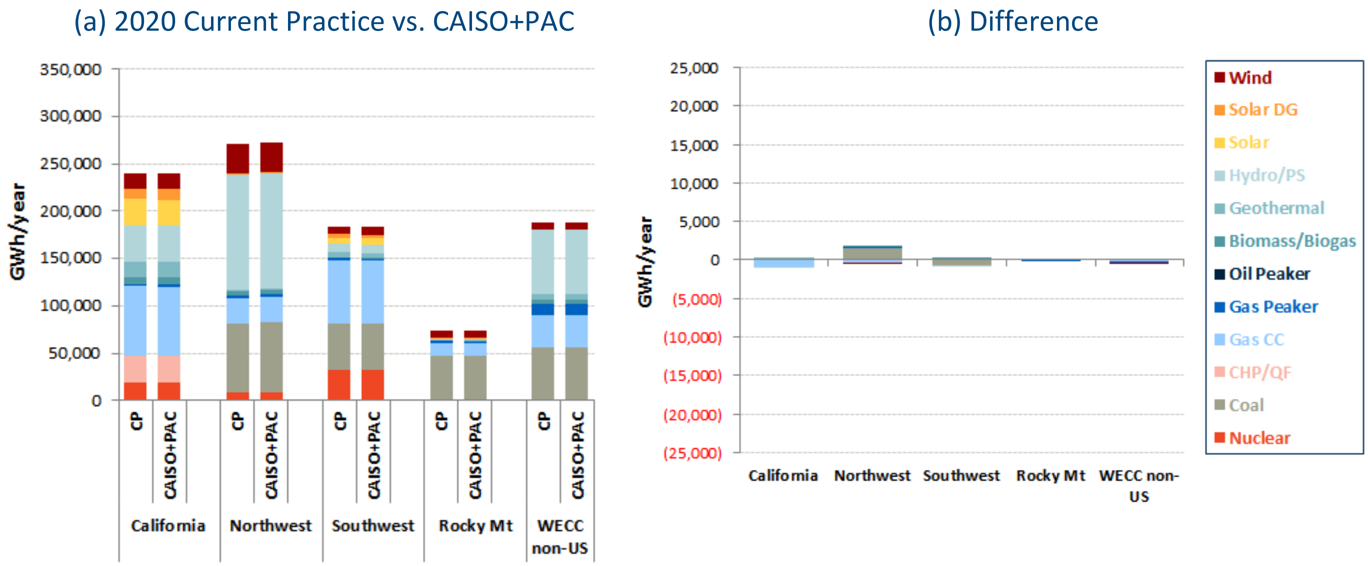
a. Generation Output

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.

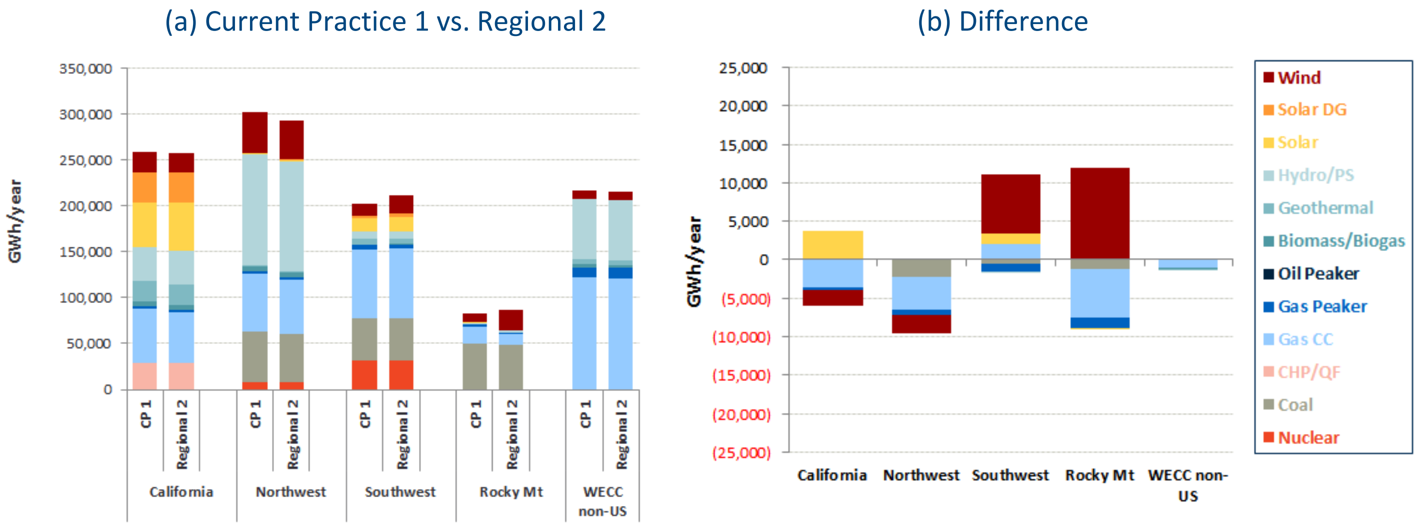
It is important to note that the impact on 2020 coal dispatch is overstated due to the generic natural gas-based CO_2 hurdle rate applied to all market imports into California. Contrary to the hurdles that would actually be imposed, this simplification artificially advantages coal units in the market 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



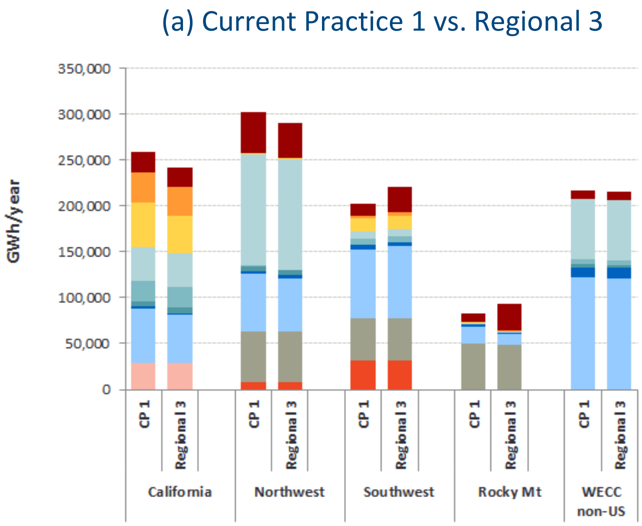
With the larger regional footprint covering all of the U.S. WECC without the PMAs the 2030 simulations show more significant shifts in generation patterns. Figure 27 shows the impact of the expanded regional market on generation results under the Regional 2 scenario. Due to a re-optimized renewable portfolio 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



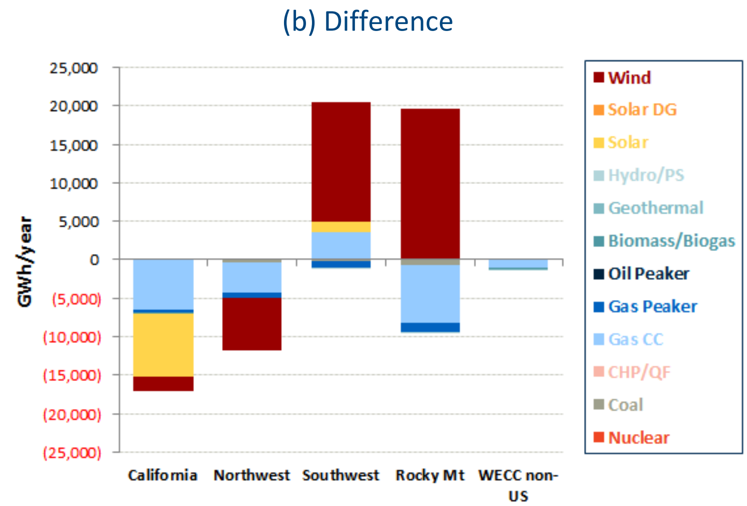


Figure 29 compares simulated natural gas-fired generation in California against historical data. Increased amounts of renewables added to meet state's RPS result in the decline of gas generation by about 12% in 2020 and 25–30% in 2030 compared to the recent historical levels (except 2011, which was a wet hydro year both in California and WECC-wide).

Figure 29: Simulated vs. Historical Natural Gas-Fired Generation in California

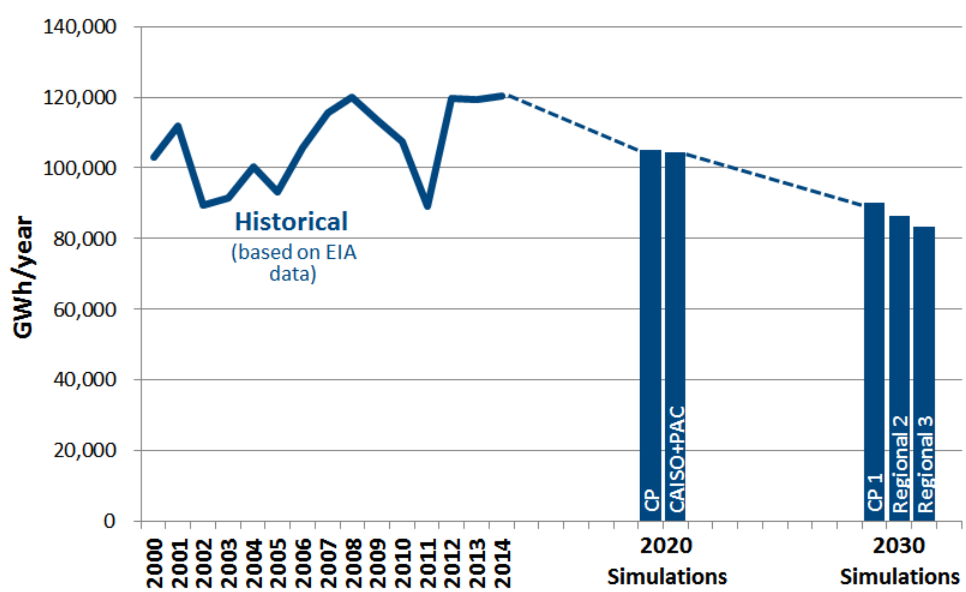
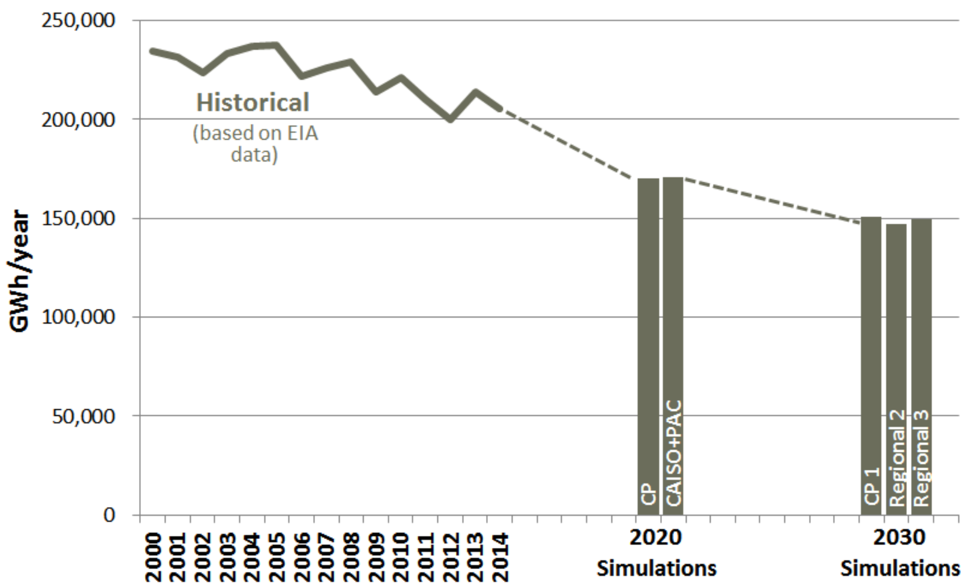


Figure 30 compares simulated coal-fired generation in the U.S. WECC against historical data. With retiring coal plants and the addition of renewables, the coal dispatch in 2020 is projected to decrease substantially by about 17% from recent historical levels; by 2030, it is projected to have decreased 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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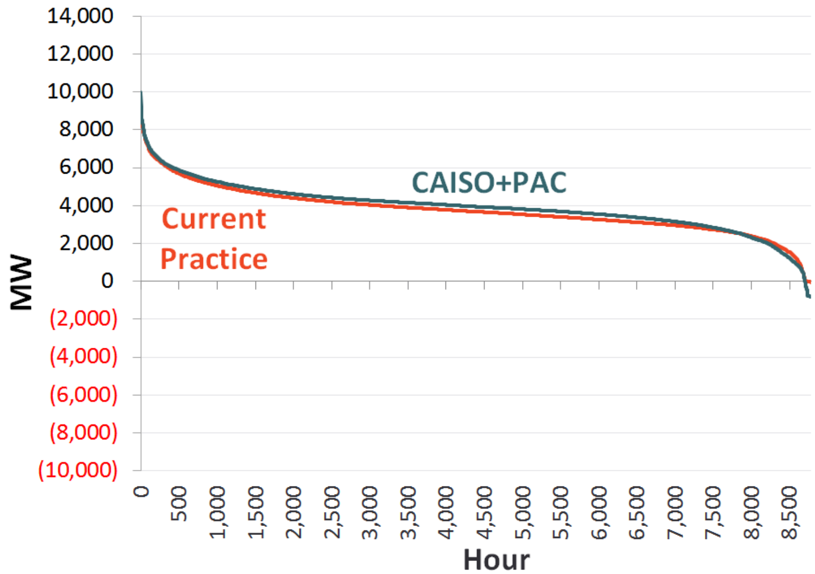
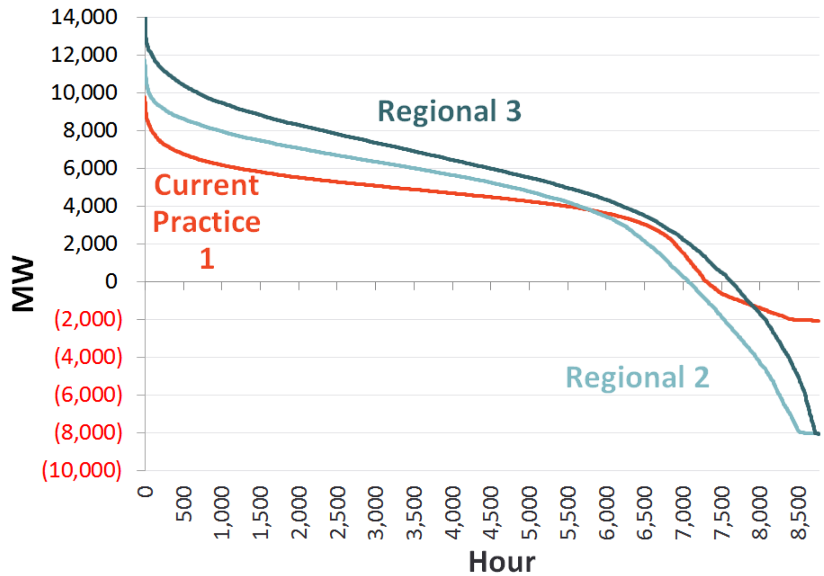
28 For example, as shown in Section 2.e below and discussed in Volume I of this report, the impact of even a modest $15/tonne CO_2 price in the rest of WECC would reduce coal dispatch by around 20%, while the differences across Current Practice, CAISO+PAC, and expanded Regional ISO scenarios are limited 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)

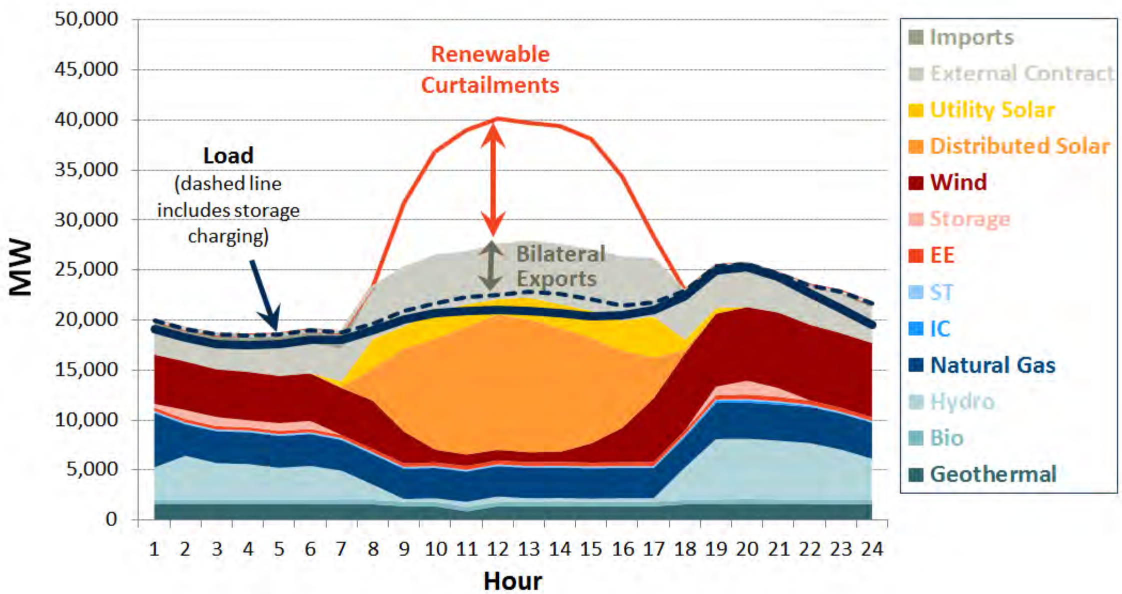


Figure 34 below shows the simulated amounts of renewable energy curtailments in California across the three baseline scenarios and compares the results between the PSO and RESOLVE models. More limited bilateral export ability in the Current Practice 1 scenario (assuming all 3,000–4,000 MW of existing 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.

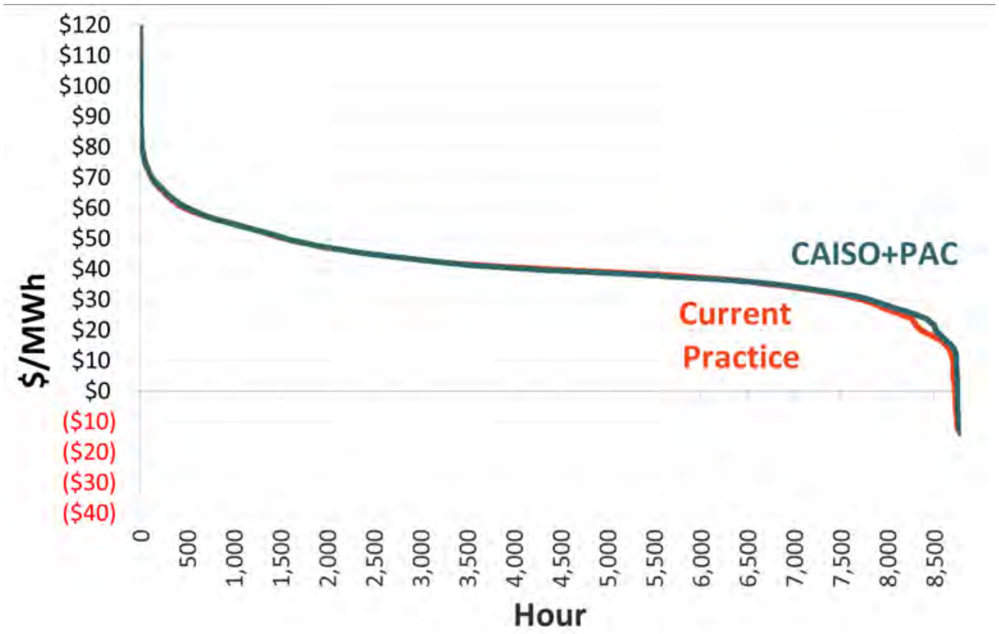
It is important to note that both PSO and RESOLVE will likely understate the full magnitudes of renewable curtailments since they simulate market outcomes deterministically (equivalent to a day-ahead market) without taking into account the real-time uncertainties and day-ahead forecasting errors for 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.

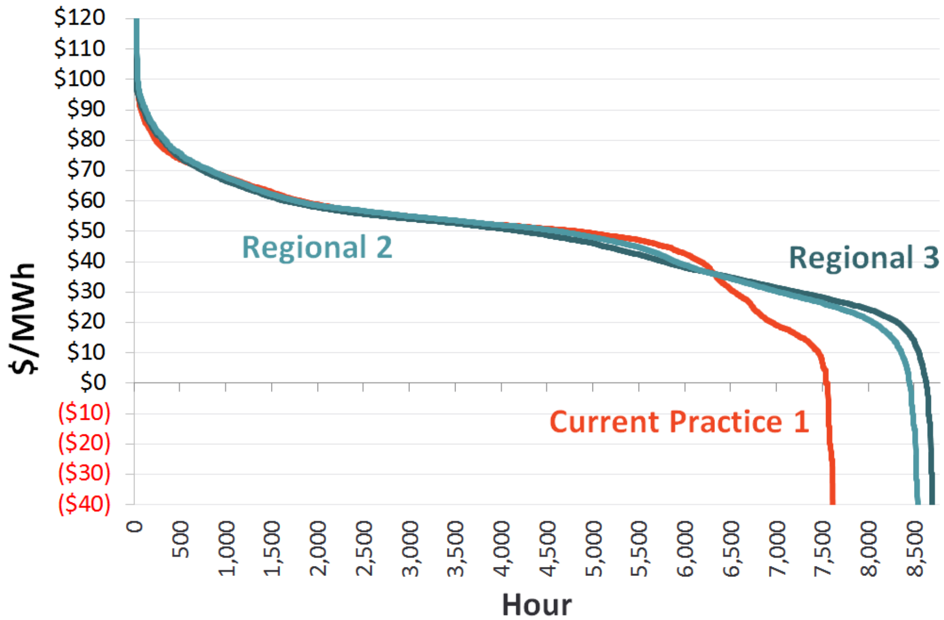
Figure 35 displays the 2020 hourly load-weighted LMPs in CAISO sorted from highest to lowest. There is very little movement in prices between the Current Practice and CAISO+PAC scenarios, which is consistent with the small changes observed in generation dispatch due to the limited scope of regionalization.

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

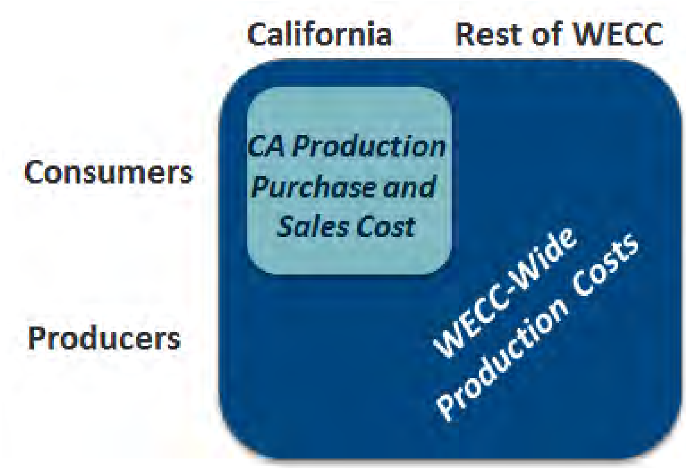
Does not include societal benefits of emission reductions or incremental investment costs associated with additional renewables facilitated by the regional market in 2030 Scenarios 2 and 3.

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.

(−) **<u>Revenues from market sales</u>** 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).

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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.

[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.

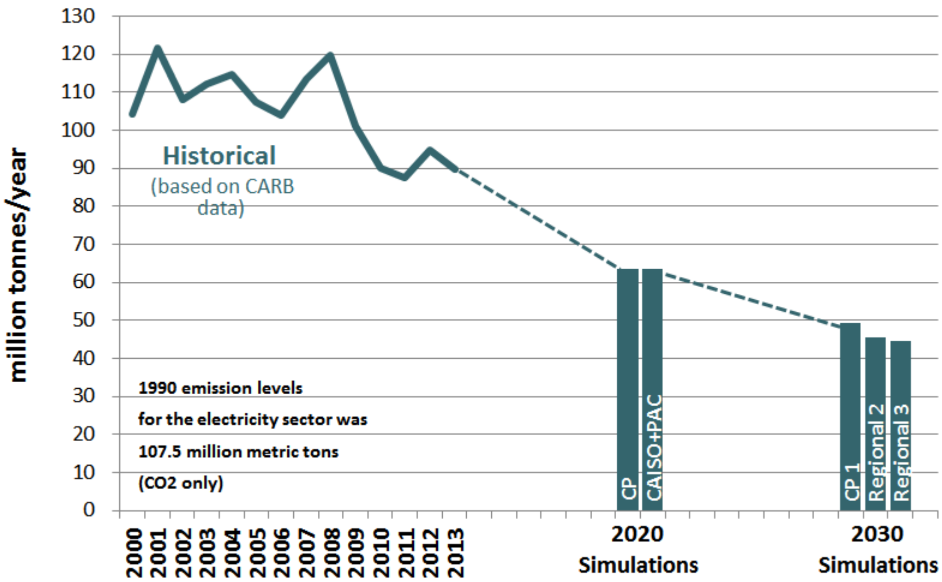
Figure 42: Summary of Annual California and WECC-Wide CO_2 Emissions

	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)		(3.7)	(4.6)
		(0.1%)		(7.6%)	(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		(11.4)	(9.8)
		0.2%		(3.7%)	(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

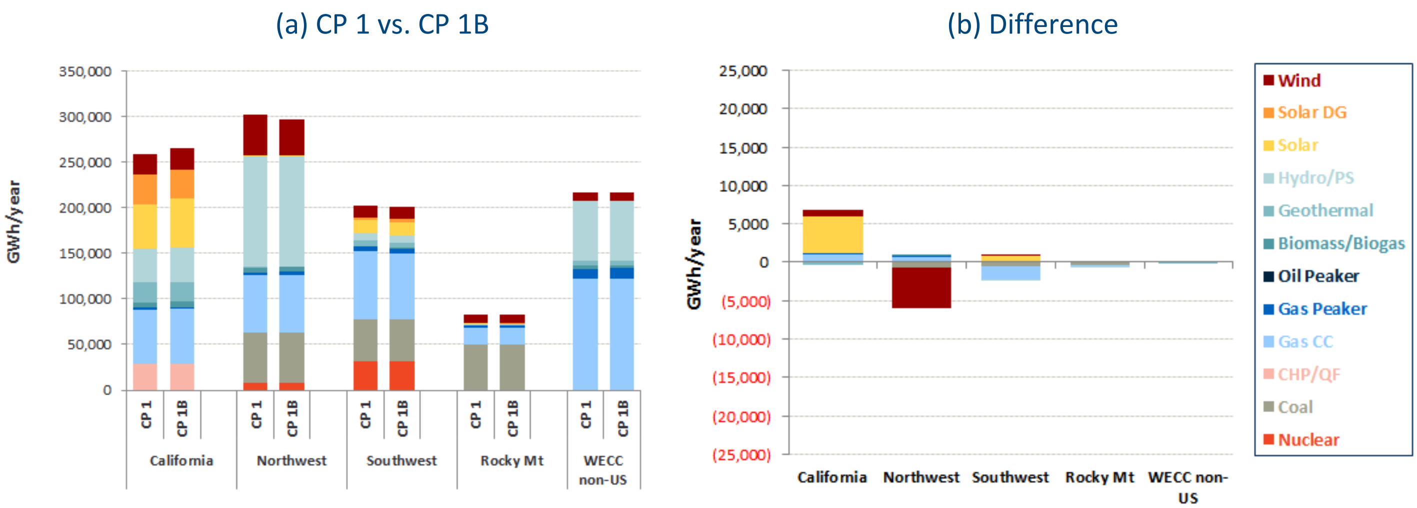
In the 2030 Current Practice 1B Sensitivity, we assumed that bilateral markets have higher flexibility to manage oversupply conditions, absent a Regional ISO. This case was requested by stakeholders following the February 8, 2016 stakeholder workshop. In response, the study team included this case as 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

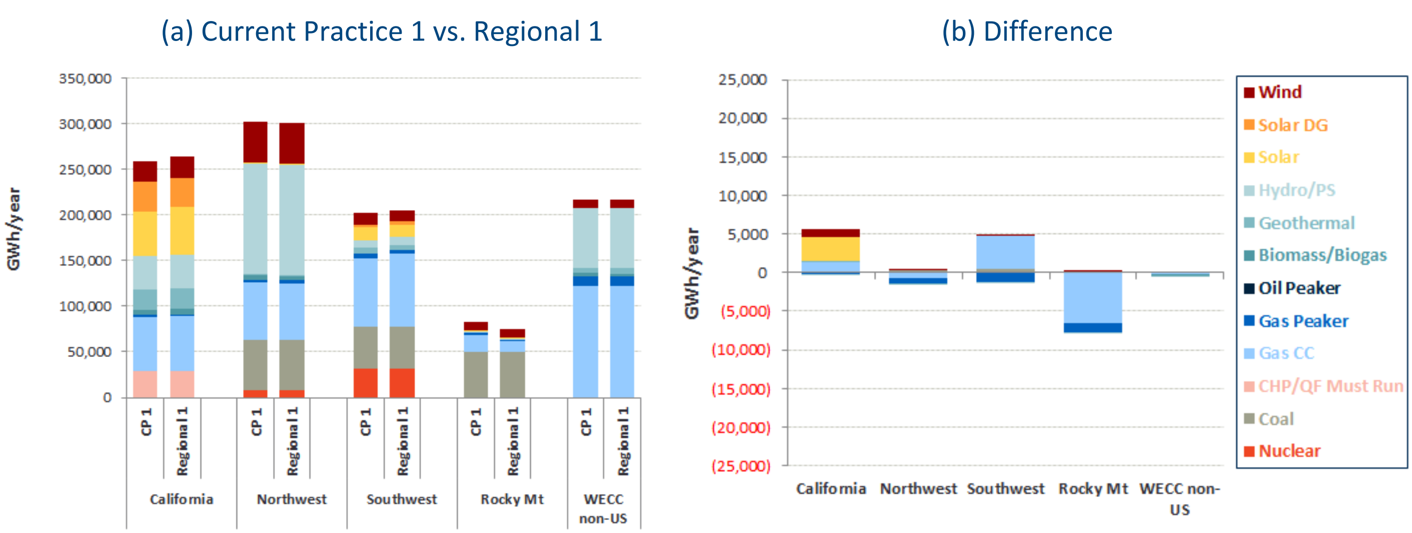


Figure 50 summarizes the 2030 production costs and CO_2 emissions impacts for the Regional ISO 1 sensitivity and the Current Practice 1 baseline scenario. With fewer curtailments and higher renewable output, the 2030 regional market simulated in this sensitivity is estimated to provide WECC-wide production 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

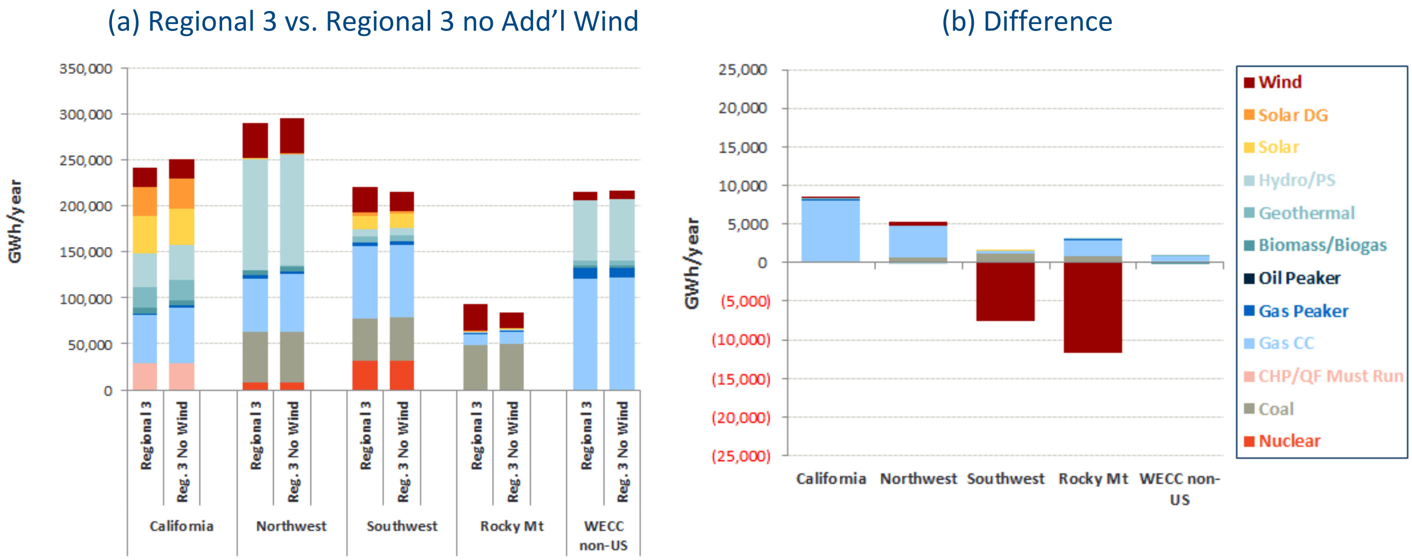
	2030 Current Practice 1	2030 Regional ISO 1
CA In-State	46.2	46.4
CA Imports Contracted	6.2	5.3
CA Imports Generic	1.7	2.8
CA Exports Generic	(4.8)	(7.5)
CA Emissions for Load	**49.2**	**47.0**
Impact of Regionalization		(2.2)
		(4.5%)
WECC TOTAL	**307.3**	**304.4**
Impact of Regionalization		(2.9)
		(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

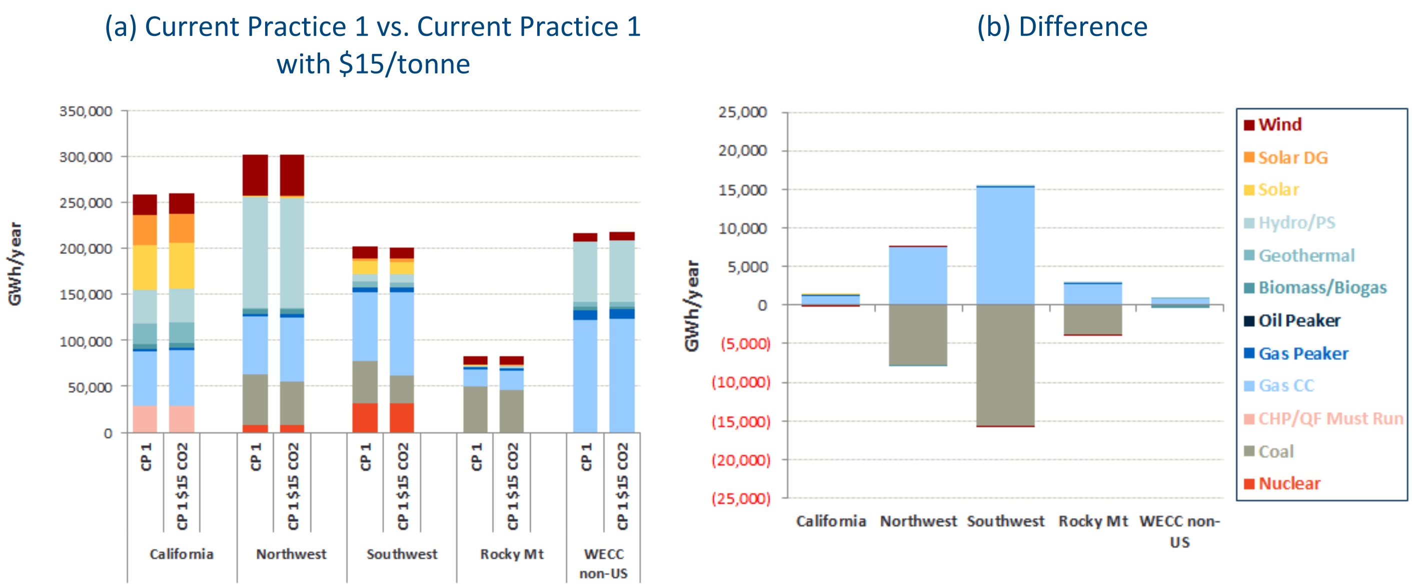


Figure 56 summarizes the production cost savings and CO_2 emissions impacts of the regional market for a $15/ton CO_2 price applied to the rest of WECC in both Current Practice 1 and Regional 3 scenarios. The estimated WECC-wide production cost savings of the regional market are $971 million (4.9%), 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.

Senate Bill 350 Study

Volume VI: Load Diversity Analysis

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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

Volume VI: Table of Contents

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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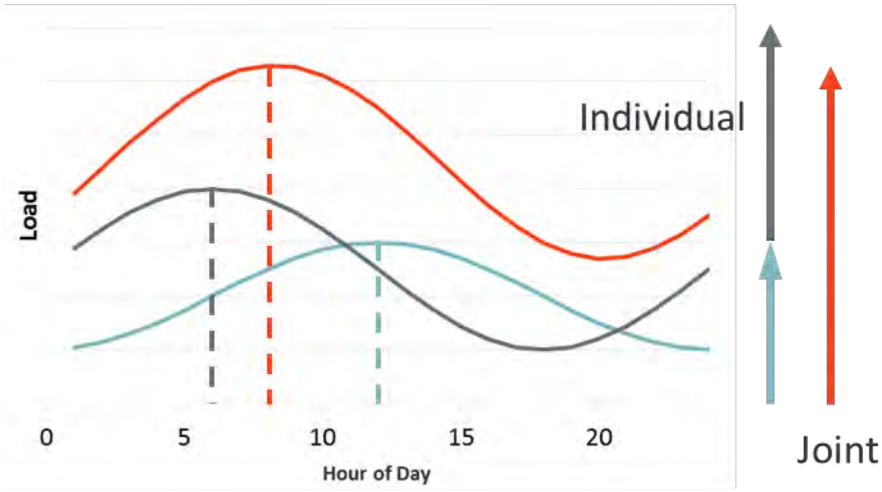
1 Energy + Environmental Economics, "Regional Coordination in the West: Benefits of PacifiCorp and California ISO Integration," October 2015. Available at: http://www.caiso.com/informed/Pages/RegionalEnergyMarket/BenefitsofaRegionalEnergyMarket.aspx

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

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

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[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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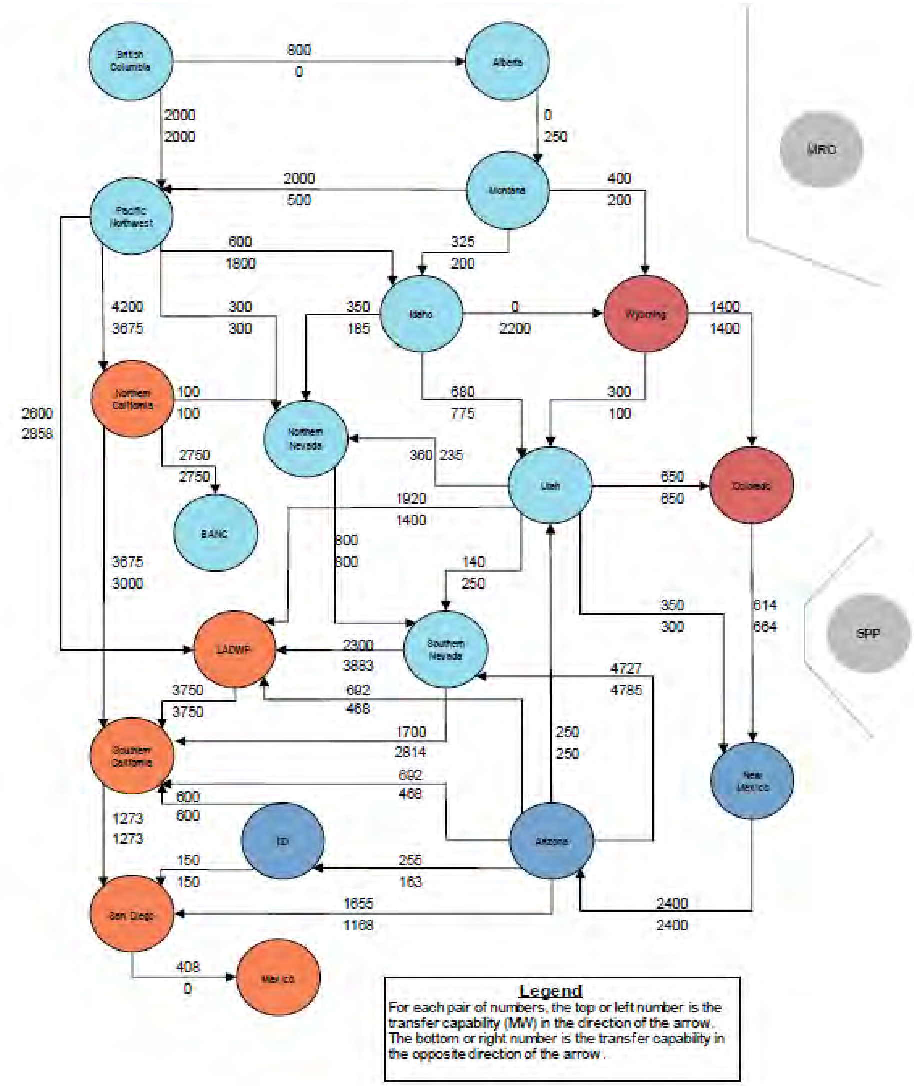
[21] WECC Staff, "Loads and Resources Methods and Assumptions," November 2015, Table 4, Available at: https://www.wecc.biz/ReliabilityAssessment

[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

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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.

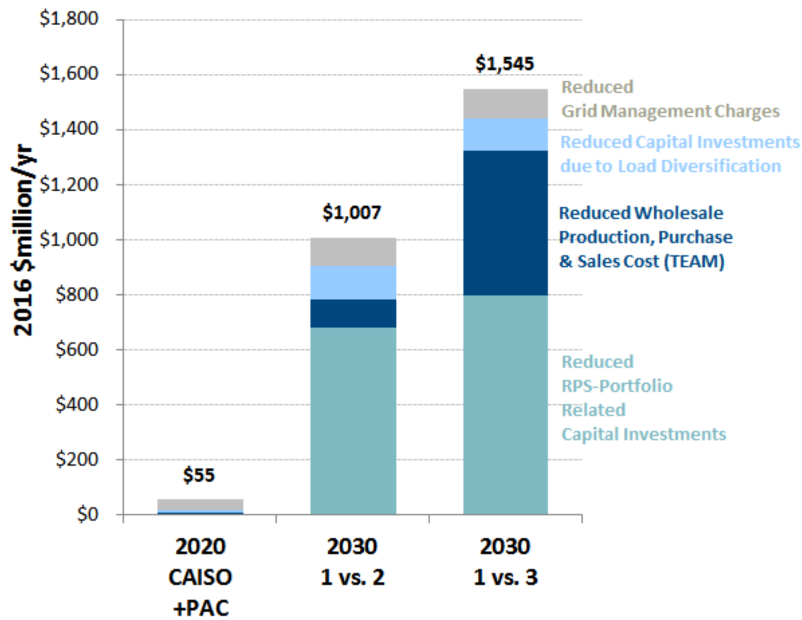
The expansion of the CAISO into a larger regional market would also affect the allocation of existing transmission costs and new transmission investments, both of which will depend on how those allocations are negotiated as a part of the regional market design. For the purpose of this study, we have 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.

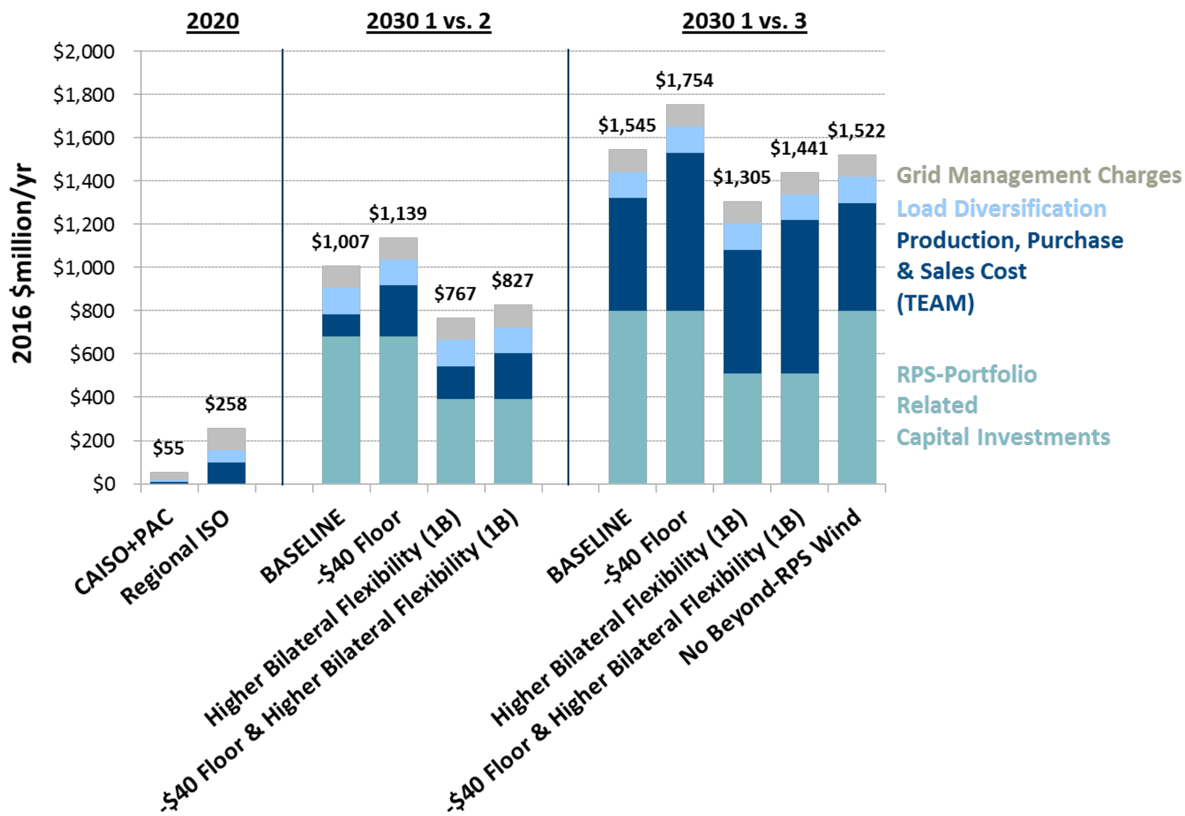
- **"Low Willingness to Buy in Bilateral Market"** sensitivity captures the impact of negative energy prices during oversupply and renewable curtailment conditions. The baseline simulations assume power is sold at no less than $0/MWh suggesting that California would give power away for free. Accordingly, 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:

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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Senate Bill 350 Study

Volume VIII: Economic Impact Analysis

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BEAR

Senate Bill 350 Study

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

List of Report Volumes

Volume VIII.

SB 350 Study: Economic Model & Impacts

Final Report

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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 or regional entity (Regional ISO). SB 350, in part, specifically requires an evaluation of how regionalization would impact the creation or retention of jobs and other benefits to the California economy. Understanding these economic impacts is an integral part of the policy making process, and as a result Berkeley Economic Advising and Research (BEAR) has been engaged to model these impacts. This report is Volume VIII of XII of an overall study in response to SB 350's legislative requirements.

The BEAR dynamic economic forecasting model was used to evaluate California's long-term growth prospects from developing a Regional ISO. Results are generated for 3 primary scenarios and 1 sensitivity scenario across 3 time periods. Current Practice (CP) refers to business as usual renewables procurement to meet California's 50% Renewable Portfolio Standard by 2030 (50% RPS), the CAISO footprint as-is, and a 2,000 MW limit on net bilateral sales from CAISO entities. Two regionalization scenarios were compared to Current Practice. Regional 2 examines a regional market with business as usual renewables procurement and a regional ISO that includes most of U.S. WECC. Regional 3 examines a regional market with more out-of-state renewables procurement and a regional ISO that includes most of U.S. WECC. The study considers a sensitivity to the Current Practice scenario where the limit on net bilateral sales from CAISO entities is increased to 8,000 MW.

As an initial baseline we provide evidence-based support that California's higher Renewable Portfolio Standard ("RPS") (50% by 2030) will provide a wide range of benefits to California households and enterprises. Across all scenarios, including the Current Practice scenario, we project higher statewide gross product, real output, state revenue, and employment. By 2030, we estimate there will be an additional 90,000 – 110,000 statewide jobs created from the 50% RPS policy goal depending on scenario analyzed. Furthermore, we find that reduced energy rates will lead to increase household income across every scenario, ensuring that an increased RPS will provide a stream of benefits to all Californians.

While these findings offer support that a clean energy future is beneficial to the California economy, there are important differences between the scenarios that are worth noting. Most notably, we find that regionalization (scenarios Regional 2 and Regional 3) offers the most benefits to California in terms of job creation and income gains. Specifically, we find that regionalization can create 9,900 (Regional 3) to 19,300 (Regional 2) more jobs than the Current Practice scenario in 2030. Furthermore, the more affordable energy from regionalization offers further stimulus for the state economy, creating jobs that increase community real incomes by the equivalent of $290 (Regional 2) to $550 (Regional 3) per household in 2030.

Although there will be less jobs from renewable buildout created in the regionalization scenarios due to the lower renewable capacity investments within California, we find that efficiency gains and the associated ratepayer savings will spur induced jobs through increased spending on services and consumption. Consequently, the net employment impacts from regionalization are positive. This finding is significant as these jobs are often "invisible" in the sense they are not directly captured or advocated for by the renewable buildout. However, these jobs are equally as important, and arguably more so, as they allow increased discretionary spending among lower socio-economic groups, and spur job creation across the entire state. Indeed, we find that hundreds of disadvantaged communities stand to receive significant job creation and income gains. As these communities are the most at-risk and underrepresented, our findings demonstrate that a regional renewable energy market will benefit all of California. The results for disadvantaged communities are discussed in Volume X of the SB 350 study.

Table of Contents

I. Introduction

Comparing scenarios, we find that a regional energy market in 2030 (Regional 2 and Regional 3) can create 9,900 – 19,400 more jobs than the Current Practice (CP 1), primarily through making electricity more affordable and the associated induced job effects from these savings. Specifically, the increased affordable energy from regionalization is expected to produce a higher statewide household real disposable income of $300 - $550 per household in 2030.

Although Current Practice will see the most jobs directly linked to the large in-state renewable buildout requirements from 33% to 50%, a regional market in California can help the state balance both ratepayer savings and renewable buildout job creation. Indeed, we find that the regional market with California-focused procurement (Regional 2) offers the highest impact on statewide output and employment compared to Current Practice 1 and Regional 3[1].

The balance of this section of the SB350 report is organized as follows: Sections 2 and 3 provide background information and details the methodological approach used for this analysis; Section 4 presents our main findings of state-wide impacts across scenarios[2]; and Section 5 provides conclusions.

II. Previous Literature

A. Estimating Impacts

As explained in E3's report (Volume IV), regionalization could have a significant impact on the location and characteristics of new renewable generation resources developed by California to meet its 50% Renewable Portfolio Standard ("RPS") by 2030. Investments of this magnitude will have a material effect on the state's economy. However, estimating the economic impacts of the different investment scenarios is complicated as there are several economic drivers of income and job dynamics. In general, these drivers can be classified under one of three groups:

1. Power Capacity Investment – These are the economic impacts associated with the direct build out of new renewable generation. This includes both direct jobs working on the construction of the facility and operations, as well as indirect supply chain related jobs. There are also induced effects through increased household income from related jobs supporting the renewable generation buildout(?).
2. Infrastructure Investment – Increased renewable buildout also requires a related investment in infrastructure, such as new or upgraded transmission, to ensure the

[1] As discussed later in the section, a Current Practice sensitivity case (Scenario 1B) that assumes high bilateral exports absent a regional market produced the greatest employment impact but is very unlikely to materialize in practice due to the challenges of exporting large amounts of renewables under the current market structure.

[2] More details on disadvantaged community effects are also presented in Volume 10.

new generation reliably connects to the grid. This associated increase in infrastructure produces a variety of direct, indirect, and induced jobs.
3. Income/expenditure effects of electricity rate reductions – The implementation of the 50% RPS will affect electricity rates, resulting in a change in discretionary income. The associated expenditure effects of this change will impacts jobs across the entire economy through different spending patterns.

Adding further complexity to the estimation challenge is the fact that the income and job growth across all of these drivers will occur through a combination of effects:
1. Direct Effects – This is the increased economic activity in response to direct spending (either investment or consumption) on capacity buildout (e.g. jobs associated with the direct renewable buildout such as construction or operations).
2. Indirect Effects – This is the economic activity in enterprises linked by supply chains to directly affected sectors (e.g. suppliers of input components and raw materials)
3. Induced Effects – Demand from rising household income (e.g. spending by employed of directly and indirectly affected firms or from ratepayer savings).

Of particular interest are the induced effects as they are often the largest driver of job creation, but can be challenging to quantify. As a result, a model that does not accurately reflect these subtleties nor captures the entire supply chain of California will produce biased results.

B. Previous Studies

There have been a few previous studies that consider how renewable energy contributes to job creation in California. The majority of these studies are based on voluntary survey results and offer past assessments of existing projects within the state.

The California Advanced Energy Employment Survey is a publication-based on a survey of more than 2,000 companies in California. The survey reports some 431,800 jobs in the advanced energy economy in 2014. However, the majority of jobs (70%) are captured in the energy efficiency sector. If we strictly consider the advanced electricity generation sector, the report finds 95,000 employed in this sector, with the majority working in solar generation (~73,000). The report makes no distinction between those who work in utility-scale solar versus rooftop solar. Utility-scale wind generation was estimated to employ an additional 3,270 workers.

Two recent reports from the Donald Vial Center on Employment in the Green Economy (which is affiliated with the Berkeley Labor Center) have studied how renewable energy contributes to job growth. The first, "Environmental and Economic Benefits of Building Solar in California," by Peter Philips (2014) considers the employment effects of building 4,250 MW of utility-scale solar powered facilities over the previous five years. This report offers a useful comparison to this SB350 report as it focuses on utility-scale solar and relies on actual industry data.

Phillips (2014) finds that an estimated 10,200 construction job-years[3] were created during the rapid expansion of utility-scale solar generation facilities from 2010–2014. On average, these jobs paid $78,000 per year and offered health and pension benefits. Additionally, 136 permanent operations and maintenance job-years were created and are expected to last the lifetime of these facilities paying $69,000 a year on average with benefits. There were also an estimated 1,600 job-years created in the supply chain to perform other new business activities associated with construction. Finally, the newly-created jobs boosted consumer spending, resulting in an additional 3,700 jobs-years to meet the increased consumer demand. In total, this suggests an estimated 15,000 job-years were created from some 1,350 MW of increased solar generation capacity constructed in the timeframe of 2010–2014.

The Philips (2014) study methodology is largely based on a review of existing literature. First, he identifies the electricity generation capacity of new utility-scale solar projects that were built or under construction between 2010 and 2014. Next, using four other studies, Philips takes the average number of job-years, supply chain multipliers, income, and pension benefits per MW installed from three large PV projects in central and southern California.[4] He then multiplies the total number of estimated MW by the number of job-years (or other variable) per MW to obtain the estimates given above.

The second report from the Donald Vial Center is, "Job Impacts of California's Existing and Proposed Renewables Portfolio Standard," by Betony Jones, Peter Philips, and Carol Zabin (2015). This study considers both the historical job creation for California's renewable energy investments between 2003 and 2014 and forecasts estimates for jobs from 2015 to 2030 to meet the 50% RPS. Their study includes other sources of renewables outside of solar (such as wind), but does not include jobs created from renewable self-generation, which does not count towards the 50% RPS directly. They also do not report on jobs in operations and maintenance of these new plants as the authors argue that they are much smaller in quantity, and are unlikely to change significantly from the transition from conventional to renewable sources. Finally, the authors do not consider the jobs required for new transmission infrastructure or increased energy storage, both of which are likely needed to achieve the 50% RPS goal.

Jones et al. consider both the historical creation of jobs in the timeframe 2003 – 2014 as well as forecasting jobs creation in 2015 – 2030. Much like Philips (2014), the authors' first start with the total amount of renewable energy capacity that was built between 2003 and 2014, as well as estimates needed to achieve 50% RPS by 2030. The authors find that from

[3] Jobs here mean job-years, or 2,080 hours of work. Construction workers are often rotated off jobs to get experience in other types of construction over the course of a year, and therefore one job year may be spread across two or more workers. In contrast, the study's estimated 136 operations and maintenance jobs each represent 25 job-years, with each job lasting the expected lifetime of a newly-built solar electrical generation facility.

[4] The reports are: Stephen F. Hamilton, Darin Smith and Tepa Banda, "Economic Impact to San Luis Obispo County of the California Valley Solar Ranch," Appendix 14B, December, 2010; Stephen F. Hamilton, Mark Berkman and Michelle Tran, "Economic and Fiscal Impacts of the Topaz Solar Farm," March, 2011; Aspen Group, "Socioeconomic and Fiscal Impacts of the California Valley Solar Ranch and Topaz Solar Farm Projects on San Luis Obispo County," January, 2011. Mark Berkman and Wesley Ahlgren, "Economic and Fiscal Impacts of the Desert Sunlight Solar Farm," The Brattle Group (private communication with the author).

2003 – 2014, California added some 7,000 MW of in-state capacity and is projected to need an additional 30,600 – 37,400 MW of additional capacity to meet the 50% RPS.

The authors use the JEDI model to then provide a historical estimate of the number of jobs created and forecast future jobs. They find that in 2003 – 2014 about 52,000 direct job-years were created due to the construction of renewable energy plants. This includes both labor-based jobs and professional services. Including both the related indirect jobs (from inputs) and induced jobs (from increased consumer spending in the service sector) this estimate stretches to 130,000 total job-years. Note that these estimates are gross, rather than net.

For the period from 2015 – 2030, the authors find that increasing the RPS to 50% by 2030 would create an additional 354,000 (low scenario) to 429,000 (high scenario) direct construction job-years. Including both indirect and induced jobs, this number becomes an estimated 879,000 to 1,067,000 job-years by 2030. In terms of permanent jobs instead of job years, these numbers represent some 23,600 to 28,600 direct full-time construction jobs and about 58,600 to 71,100 *total* full-time jobs from 2015 – 2030. It should be noted that these numbers represent "cumulative jobs" across the 2015 – 2030 period, a somewhat ambiguous aggregation of differences form reference employment levels over 15 years. In more concrete terms, annual average job creation and the increase in the standing labor force by 2030 are less than 10% of these cumulative numbers.

The authors concede that their estimates likely overstate the amount of jobs created. They compare their results to their co-author Philips' study from 2014 and find that JEDI overestimates direct jobs per MW, especially for solar which Philips (2014) has industry data for. For example, Philips (2014) estimates approximately 2.4 direct jobs per MW, while Jones et al. (2015) estimate 5.8 direct jobs per MW. Therefore, they conclude that the JEDI model is best used for comparisons between alternative scenarios and technology mixes than for absolute job numbers.

III. Model and Methodology

A. BEAR Model Description

The BEAR model is a dynamic economic forecasting model for evaluating long-term growth prospects for California (Roland-Holst, 2015). The model is an advanced policy simulation tool that models demand, supply, and resource allocation across the California economy, estimating economic outcomes annually over the period 2015–2030. This kind of Computable General Equilibrium ("CGE") model is a state-of-the-art economic forecasting tool, using a system of equations and detailed economic data that simulate price-directed interactions between firms and households in commodity and factor markets. The role of government, capital markets, and other trading partners are also included, with varying degrees of detail, to close the model and account for economy-wide resource allocation, production, and income determination.

BEAR is calibrated to a 2013 dataset of the California economy and it includes highly disaggregated representation of firm, household, employment, government, and trade behavior (Table 1). The model's 2015 - 2030 baseline is calibrated to the California Department of Finance economic and demographic projections. The model's baseline is recalibrated to incorporate the new data whenever new projections are released.

Table 1: BEAR 2013 - Current Structure

1.	195 production activities
2.	195 commodities (includes trade and transport margins)
3.	15 factors of production
4.	22 labor categories
5.	Capital
6.	Land
7.	Natural capital
8.	10 Household types, defined by income decile
9.	Enterprises
10.	Federal Government (7 fiscal accounts)
11.	State Government (27 fiscal accounts)
12.	Local Government (11 fiscal accounts)
13.	Consolidated capital account
14.	External Trade Account

For the SB 350 study the BEAR model was aggregated to 60 economic sectors (Table 2). The electric power sector was disaggregated by 8 generation types in order to be consistent with the portfolios generated by the RESOLVE and PSO models.

Table 2: 60 Sector BEAR Model Aggregation

Label	Description	Label	Description
A01Agric	Agriculture	A31Aluminm	Aluminum production and related manufacturing
A02Cattle	Livestock	A32Machnry	Machinery manufacturing
A03Dairy	Dairy cattle and milk production	A33AirCon	Major appliance manufacturing
A04Forest	Forestry, forest products, and timber tract production	A34MfgComp	Computer and related component manufacturing
A05OilGas	Oil and gas extraction	A35SemiCon	Semiconductor and related component manufacturing
A06OthPrim	Other mining activities	A36ElecApp	Electrical appliance manufacturing
A07EleHyd	Electric power generation- Hydro	A37Autos	Automobile manufacturing
A08EleFF	Electric power generation- Fossil	A38OthVeh	Other vehicle and component manufacturing
A09EleNuc	Electric power generation- Nuclear	A39AeroMfg	Aerospace, railroad, ship, and related component manufacturing
A10EleSol	Electric power generation- Solar	A40OthInd	Other manufacturings
A11EleWind	Electric power generation- Wind	A41WhlTrad	Wholesale trade
A12EleGeo	Electric power generation- Geothermal	A42RetVeh	Retail- vehicles
A13EleBio	Electric power generation- Biomass	A43AirTrns	Air transportation
A14EleOth	Electric power generation- All other	A44GndTrns	Rail and pipeline transportation
A15DistElec	Electric power transmission and distribution	A45WatTrns	Water transportation
A16DistGas	Natural gas distribution	A46TrkTrns	Truck transportation
A17DistOth	Other utilities	A47PubTrns	Transit and ground passenger transportation
A18ConRes	Construction- Residential	A48RetAppl	Apparel and other related retail
A19ConNRes	Construction- NonResidential	A49RetGen	Other retail
A20ConPow	Construction- Power and communications	A50InfCom	Information and communication services
A21ConRd	Construction- Highways and roads	A51FinServ	Financial services
A22FoodPrc	Food processing	A52OthProf	Other professional services
A23TxtAprl	Textile and apparel manufacturing	A53BusServ	Business services
A24WoodPlp	Wood product manufacturing	A54WstServ	Waste services
A25PapPrnt	Paper manufacturing and printing	A55Educatn	Education services
A26OilRef	Petroleum products manufacturing	A56Medicin	Medical services
A27Chemicl	Chemical manufacturing	A57Recratn	Recreation services
A28Pharma	Pharmaceutical and medicine manufacturing	A58HotRest	Hotels and restaurants
A29Cement	Cement and concrete product manufacturing	A59OthPrSv	Other private services
A30Metal	Ferrous and nonferrous metal production and metal fabrication	A60GovtSv	Government services

B. Scenarios

The BEAR model produces results at the state level. Results are generated for 3 primary scenarios and 1 sensitivity scenario across 3 time periods. The scenarios are:

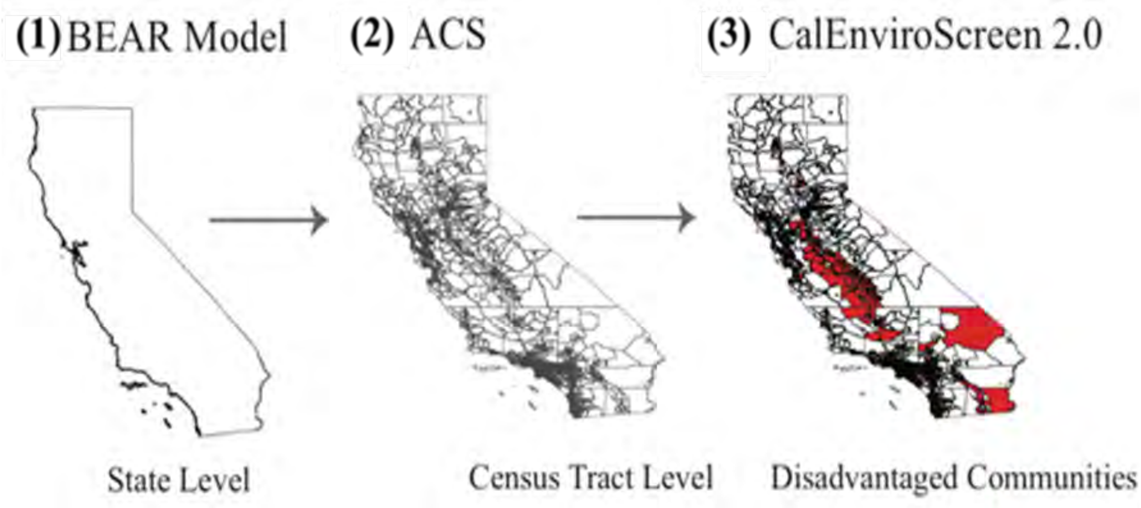
- Current Practice 1: Current Practice Procurement, CAISO operations, 2,000MW export limit
- Regional 2: Current Practice Procurement, WECC-wide operations, 8,000 MW export limit
- Regional 3: WECC-wide Procurement, WECC-wide operations, 8,000 MW export limit
- Sensitivity 1b: Current Practice Procurement, CAISO operations, 8,000MW export limit

The reporting years for the economic study are: 2020, 2025, and 2030.

C. Disaggregation

The process of estimating economic impacts on disadvantaged communities is carried out in several steps. This assessment technique leverages available data to downscale state level estimates to the census tract level conforming to disadvantaged community definitions. Detailed descriptions of each step are presented below.

Figure 1: Downscaling Results to Identify Impacts of Disadvantaged Communities



1. Step 1 – Census Tracts

State-wide results produced by the BEAR model are first disaggregated to individual census tracts. Complete data on economic activities are not available at the census tract level, so it is not possible to build Social Accounting Matrices (SAMs) for individual census tracts. Instead, we construct census tract shares of state level economic activity for select variables of interest, i.e. income by decile, sector of employment, and occupation. Census tract estimates of these values are derived from the American Communities Survey ("ACS")[5] using the 5-year averages covering the period 2008-2013.

Income

The ACS reports income by tax bracket, however, the BEAR model estimates impacts on income by decile. Consequently, tax brackets were converted to income decile according to the share of overlap in each category. The number of households in each income decile was calculated for each census tract. State level income estimates were then shared out across census tracts according to the number of households in each income decile in each census tract.

The income estimates are presented as community income per household in 2030. In order to estimate the *number of households* in each census tract in 2030 we use Department of Finance estimates of population growth by county. We assume that population growth within counties is constant across census tracts and that household size remains constant so population growth is equivalent to growth in households. Relying on these assumptions, we calculate household growth rates for each census tract and apply them to the current number of households in order to forecast the number of households in each census tract in 2030.

[5] http://factfinder.census.gov/

Jobs

Job estimates from the BEAR model measure total jobs by occupation. Jobs due to ratepayer impacts at the state level are calculated by netting out statewide total estimated direct jobs. Jobs by occupation resulting from ratepayer savings are then downscaled from state to census tract level according to the number of employees in each occupation in each census tract. Direct jobs are downscaled from the county to census tract level according to the number of employees in construction-based occupations in each census tract. Renewable buildout and ratepayer savings jobs are then summed to estimate total jobs in each census tract.

2. Step 2 – Disadvantaged Community Level

In the final step, we use CalEnviroScreen 2.0 ("CES")[6] to identify census tracts designated as disadvantaged communities. We define disadvantaged communities as census tracts in the top 25th percentile of CES scores. By this definition, there are 2,009 disadvantaged communities (census tracts) in California. Income and job estimates for the subset of census tracts meeting this condition are presented in Volume X of the SB 350 study.

IV. Results

Study results are presented below in two formats. Section 4.1 presents results comparing all scenarios to a hypothetical reference point that maintains the state's current 33% RPS. Section 4.2 fulfills the direct requirements of SB350 by isolating the specific impacts of regionalization.

A. Baseline Effects of Investment in 50% RPS

To better understand how California's future renewables investments could affect the state's economy and job creation we simulated a hypothetical reference point in which the state maintains its 33% RPS and does not expand to 50% by 2030. By first doing this we find strong evidence that regional electric power trading can benefit the California economy across a variety of indicators. Table 3 shows the percentage change from the reference scenario in 2030 for gross state product, real output, employment, state revenue, and real wage. The differences reported are estimated with respect to a reference scenario assuming no additional RPS investment from 2020. For Current Practice 1, we find increases ranging from 0.21% (state revenue) to 0.48% (real income).

[6] http://oehha.ca.gov/ej/pdf/CES2_0SHP.zip

Table 3: Baseline Impacts of Moving from 33% RPS to 50% RPS (Percent Change from Reference in 2030)

	Current Practice 1	Regional 2	Regional 3
Gross State Product	**0.32%**	**0.37%**	**0.35%**
Real Output	**0.35%**	**0.40%**	**0.39%**
Employment	**0.29%**	**0.35%**	**0.32%**
Real Income	**0.48%**	**0.53%**	**0.61%**
State Revenue	**0.21%**	**0.33%**	**0.34%**

Percent changes are useful in comparing the relative impacts between different scenarios, but do not give a clear idea to the size of these effects. To counter this, we also report our findings in terms of raw number in Table 4. These results illustrate the size of the impacts with Gross State Product increasing some $11.3 – $13 billion depending on the scenario. Real income is projected to increase the largest, ranging between $26.9 billion - $34.7 billion depending on scenario. In regards to jobs, we find an estimated increase of 90,000 new jobs in 2030 under Current Practice 1 to 110,000 new jobs under Regional 2.

Table 4: Baseline Impacts of Moving from 33% RPS to 50% RPS (Difference from Reference in 2030; 2015 $ Billions Unless Noted)

	Current Practice 1	Regional 2	Regional 3
Gross State Product	**11.298**	**12.987**	**12.467**
Real Output	**18.289**	**21.027**	**20.564**
Employment (,000 FTE)	**90.330**	**109.678**	**100.247**
Real Income	**26.853**	**30.970**	**34.747**
State Revenue	**6.082**	**6.669**	**7.663**

B. Impact of Regionalization

While these numbers are supportive that increasing to a 50% RPS is beneficial for the California economy, we are more interested in how this scenario compares to Regional 2 and Regional 3, which introduce WECC procurement and operations. In general, we find that some form of regionalization is more beneficial to the California economy, with more growth across every single indicator compared to Current Practice. Of the two regionalization scenarios, we find the most gains in Regional 2, due to both the lower electricity rates associated with regional operations as well as the comparatively larger build out in California compared to Regional 3.

1. Employment Impacts by Occupation

One of the salient features of the BEAR model is the ability to forecast employment impacts by occupation. In Figure 2 we present the employment impacts (relative to the 33% RPS reference scenario) by occupation across the different scenarios. Significant gains in employment span a variety of diverse sectors, signaling the large scope of indirect and induced effects from increasing the RPS. For example, while we find large increases in employment sectors readily associated with a large renewable build out such as construction, there are also large projected increases in sectors that are much less direct such as office support, sales and marketing, and food processing and preparation. In Figure 3 we compare how Current Practice 1 compares to the two different regionalization scenarios, Regional 2 and Regional 3. Here we find that job creation increases universally across all categories for Regional 2 compared to Current Practice 1, while Regional 3 shows some categories with less jobs created than Current Practice 1. This finding is important as although all scenarios stimulate job creation in California (as seen in Figure 2), there are some large differences between the regionalization scenarios in which occupations are affected.

Figure 2: Employment Impacts by Occupation (FTE Change from Reference in 2030)

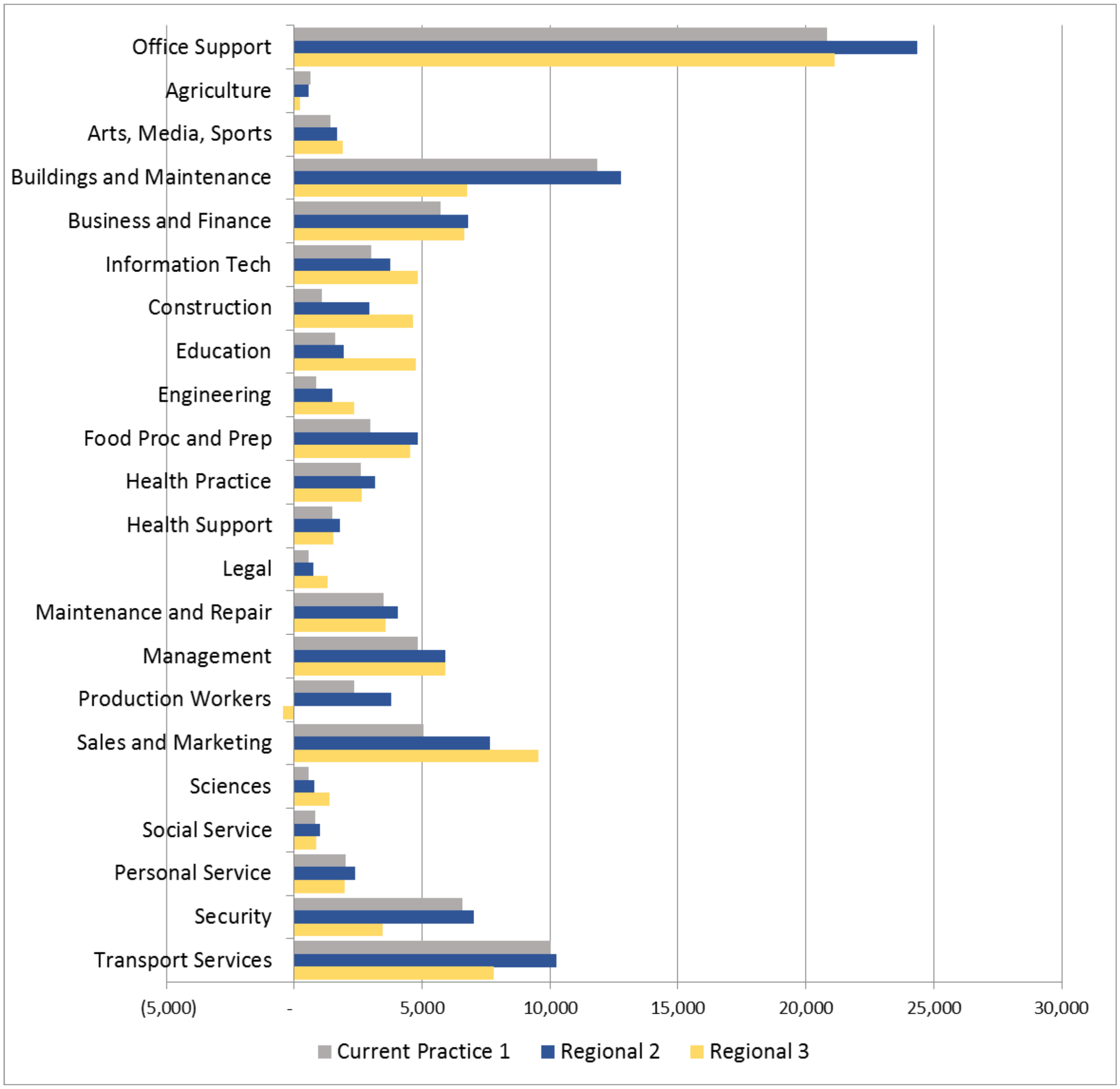
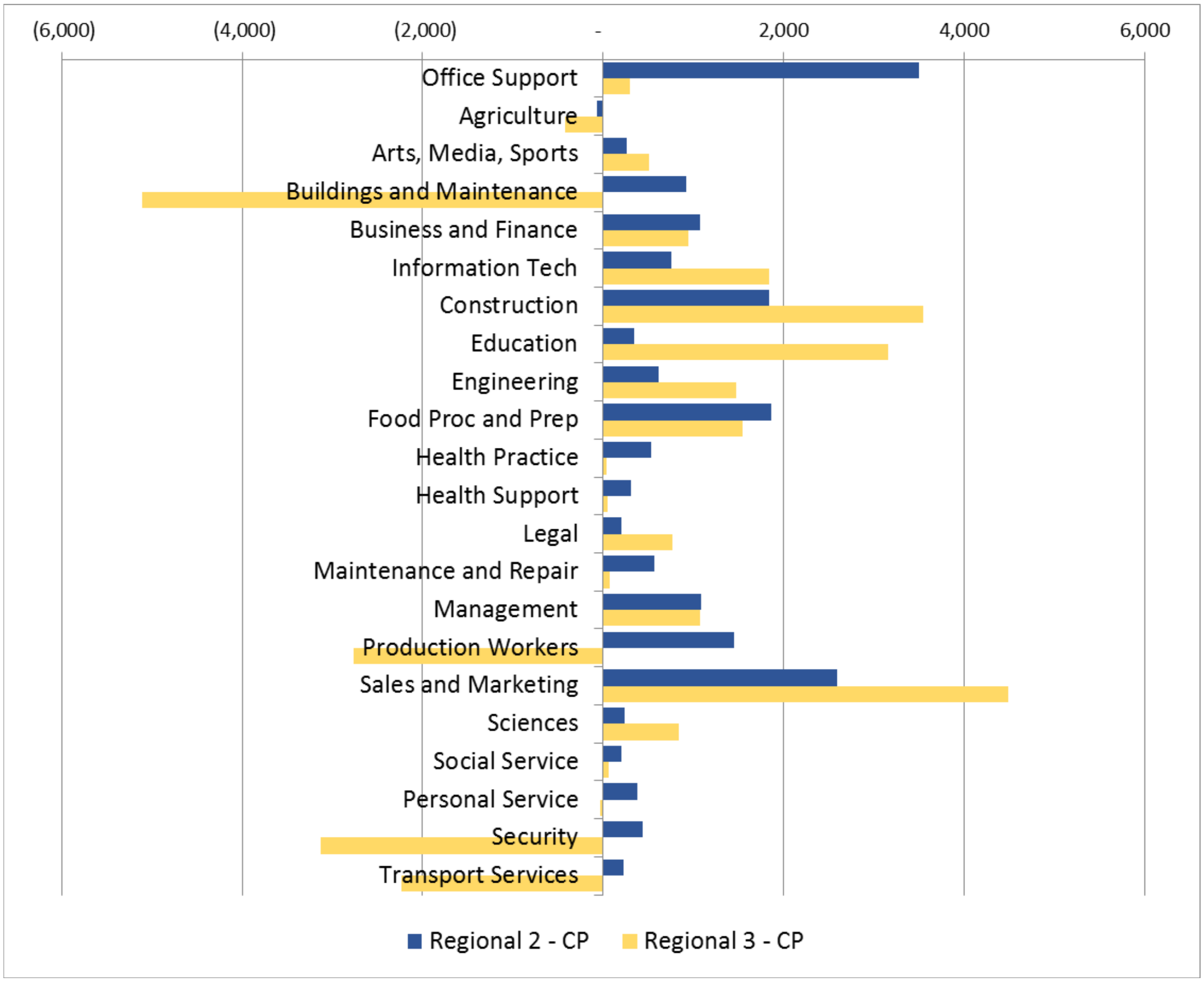


Figure 3: Employment Impacts by Occupation – Regionalization Comparison (FTE Change from Baseline in 2030)



For each of the occupation classes previously listed, job creation either occurs as a result of the renewable buildout or from ratepayer savings effects. In Figure 4 and Figure 5, we show the different job creation between scenarios for ratepayer savings induced jobs and jobs from the renewable buildout. Regional 2 produces the most jobs overall, with an increase of over 19,000 jobs compared to Current Practice 1. This large growth is led primarily from ratepayer savings induced jobs and increased renewable build in California. Comparing Current Practice 1 and Regional 3 we find that Regional 3 has an even larger increase in jobs generated by the ratepayer savings from reduced energy rates, but has less jobs overall compared to Regional 2 due to less renewable buildout job creation in solar from more out-of-state renewables procurement.

Figure 4: Statewide Jobs Created by 2030

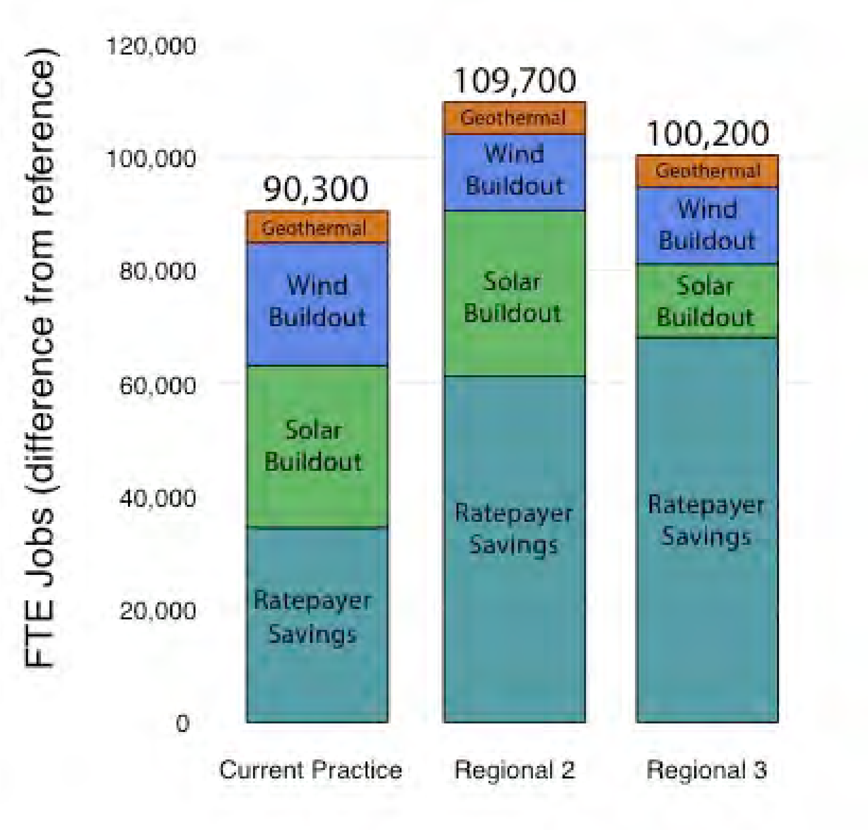
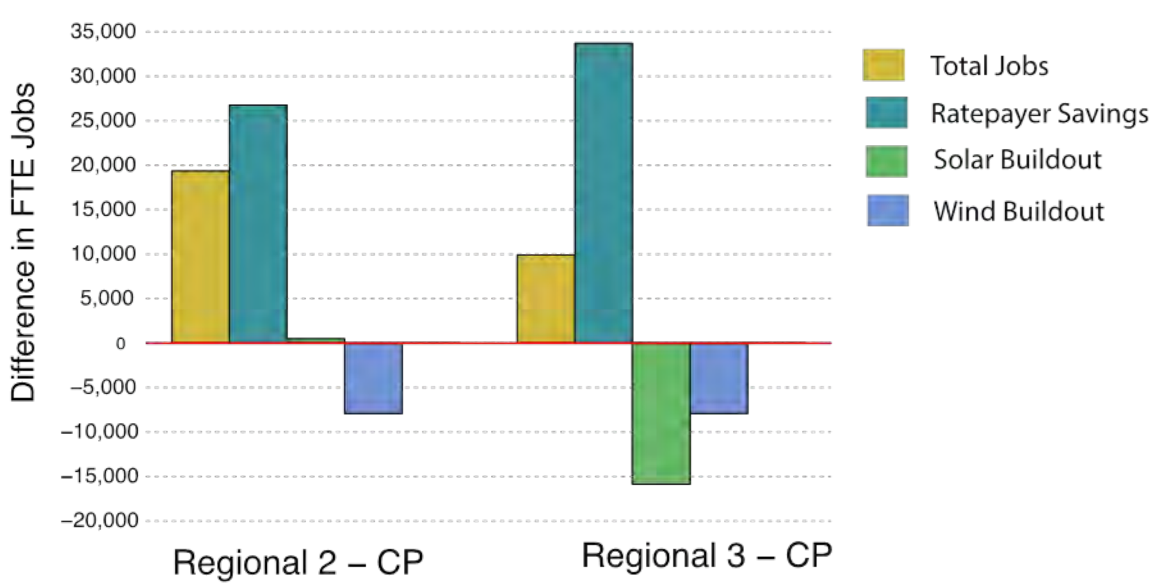


Figure 5: Difference in Statewide Jobs Created by 2030



2. Impacts by Income Decile

Another notable feature of the BEAR model is the ability to forecast results across income deciles. Given that the benefits from an increased renewable buildout will not be uniformly disturbed across the population, this feature of the model is particularly relevant for this study. The results for income impacts by decile are listed in Figure 6. In general, we find that the largest share of increases across income deciles occur in the middle and upper income deciles, with the largest projected increases occurring in decile 7, 8, and 9 under Regional 3. Consistent with our other results, we find the largest increases across all income groups in Regional 3. These results are reflective of the fact that more out-of-state procurement and Regional ISO operations in Regional 3 will produce the lowest energy rates among all scenarios, resulting in higher household income across all deciles.

The difference in statewide income across all deciles can be seen more clearly in Figure 7, which reports the difference in statewide income between Scenario 1 and Regional 2 and Regional 3. As seen in the figure, Regional 3 results in the largest income effect owing to the lower rates from full regionalization. Note however that these figures should not be interpreted as how much additional income each household in California will enjoy as a result of regionalization. Instead, those households that receive new jobs will receive the vast amount of new benefits, while other households will only see a small increase from ratepayer savings. Therefore, this figure is somewhat misleading as it averages out the benefits across all households, when in reality only a few will receive the majority of benefits. However as each utility has different rate classes and rate allocations, it is not feasible to do a rate allocation study for this detail of a study.

Figure 6: Household Real Income Impact by Decile (Percent Change from Reference in 2030)

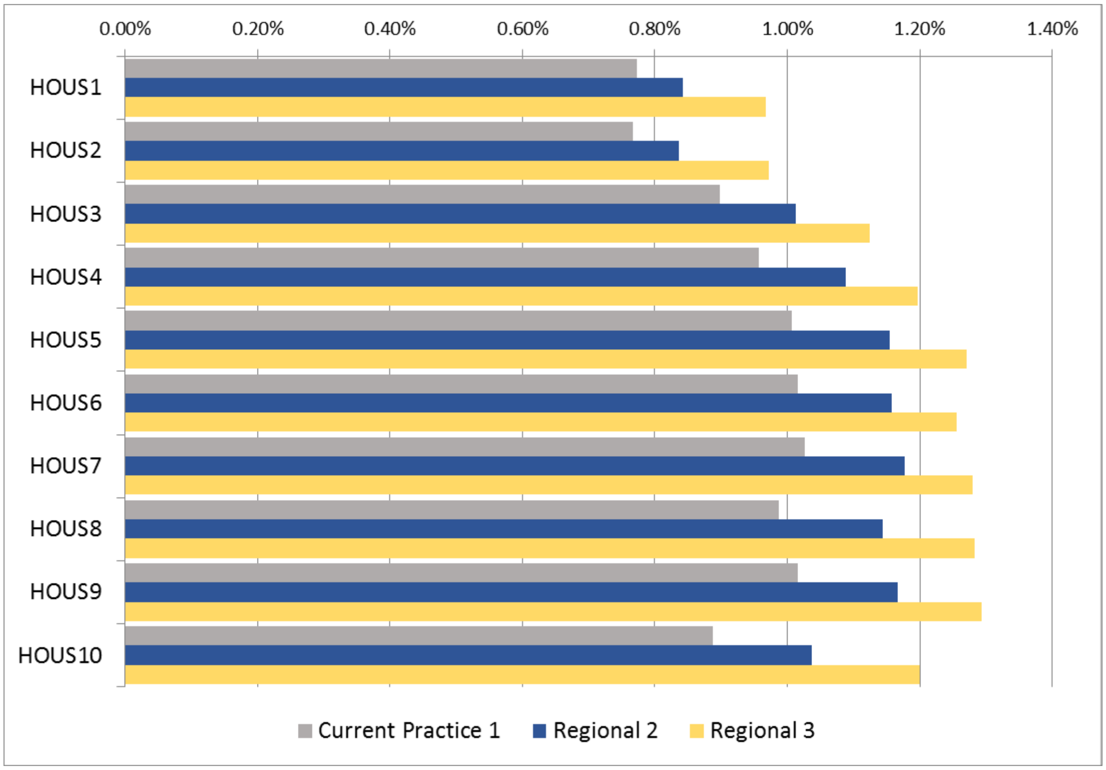
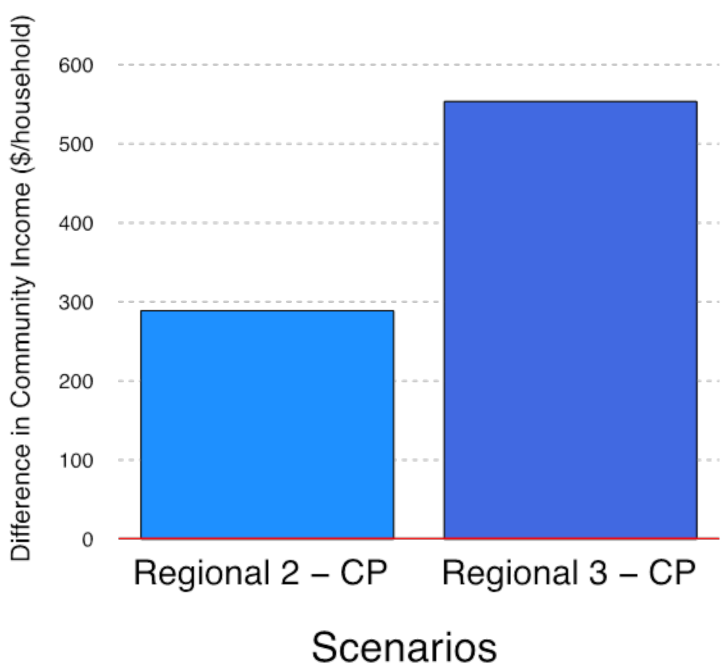


Figure 7: Difference in Statewide Income in Year 2030



3. Sensitivity Analysis

The economic analysis includes one sensitivity analysis that is identical to the Current Practice 1 scenario except with a higher limit on net bilateral sales from CAISO entities (8000MW vs. 2000MW). The statewide macroeconomic impacts for sensitivity 1B are shown in Table 5. The positive economic impacts compared to Current Practice 1 are due to the higher levels of investments in in-state wind and solar resources, combined with greater ratepayer savings due to the higher export capacity. The two regionalization scenarios result in moderately lower levels of employment growth compared to the sensitivity 1B scenario. Regional 2 results in 1,212 fewer jobs created and Regional 3 results in 9,432 fewer jobs created. Similar results are observed for gross state product and real output. Despite slightly lower ratepayer savings than the two regionalization scenarios, the greater in-state investments due to the renewable buildout generate more jobs and in-state economic activity. It is important to note that this sensitivity is an extreme bookend to isolate the benefits of a regional market holding the level of export capability constant. Achieving this level of export capability under the current market structure is extremely unlikely given the operational and market barriers that exist in the West. Nonetheless, the statewide macroeconomic impacts of this sensitivity are presented here for completeness.

Table 5: Macroeconomic Impacts for Sensitivity 1B in 2030 (2015 $ billions unless noted)

	1B – CP1	Regional 2 – 1B	Regional 3 – 1B
Gross State Product	**2.284**	**-0.595**	**-1.115**
Real Output	**3.607**	**-0.869**	**-1.332**
Employment (,000 FTE)	**20.560**	**-1.212**	**-9.432**
Real Income	**4.285**	**-0.168**	**3.609**
State Revenue	**0.792**	**-0.205**	**0.788**

V. Conclusion

Although we find that all renewables investment scenarios offer tremendous benefits to a wide group of occupations and income groups, regionalization offers benefits to the widest group of Californians. While this is an important finding on its own, the benefits of a regional market undoubtedly extend beyond California. Regionalization offers other states an opportunity to increase their own RPS providing both job creation and income benefits through ratepayer savings.

The foundation developed in this study could be used by others to assess what would demonstrate the scope of ratepayer benefits beyond California, and especially with respect to states who might opt in or out of a given regional framework. Our current findings are based on a variety of assumptions regarding the coordination and renewable buildout of other states, but they do not elucidate potential benefits that might recruit other states to the regional initiative. Such an exercise would be valuable for political sustainability, but also to facilitate more optimal regional trading and transmission integration for states considering joining the Regional ISO.

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Senate Bill 350 Study

Volume IX: Environmental Study

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Senate Bill 350 Study

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

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Environmental Study

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July 2016

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Executive Summary and Key Findings

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 "the environmental impacts in California and elsewhere." Aspen Environmental Group has been engaged to study these environmental impacts. This report is Volume IX of XII of an overall study in response to SB 350's legislative requirements.

A foundational assumption to our study is how regionalization could affect California's procurement of incremental future renewable resources to satisfy the state's 50% Renewable Portfolio Standard (RPS) by 2030. With a regional ISO, 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 <u>build less</u> renewable generation capacity to meet its 50% RPS. Additionally, regional operations and markets would give California <u>better access to lower-cost out-of-state resources</u> in wind- or solar-rich areas of the west. In particular, generating plants in the more wind-rich areas of the west use land more efficiently by producing more renewable energy per acre of land. California's renewable development footprint, therefore, could be shifted more out of state. The combination of less capacity built and the shift towards out-of-state development is a major driver of our key findings. We also consider expected changes in the operations of existing power plants both in state and out of state, and the resulting expected changes in water use, fuel burn, and emissions. Our findings, along with the findings in the SB 350 study's economic impact analysis (Volume VIII) and the analysis of the impact on California's disadvantaged communities (Volume X) reflect inherent tradeoffs to in-state versus out-of-state renewable development.

In 2020, we assume no incremental buildout of renewable resources or transmission beyond what is already planned to meet the state's 33% RPS by 2020. With limited regionalization in 2020, we also assume no incremental renewable energy development and no associated ground disturbance. Therefore, there would be no effects to land use or biological resources from the implementation of the limited regional market. However, there would be changes associated with how the wholesale electric system might respond to the limited regional market in 2020 (CAISO + PAC), in terms of changes to the operations of existing resources. These operational changes would have effects on water use and air emissions.

The 2020 results for water use and emissions are summarized as follows:

- By achieving a small decrease in fossil fuel use for electricity production in California, limited regionalization in 2020 results in a small but beneficial decrease in the electric power sector's use of water resources (water used by electricity generation decreases by 1.5% statewide).
- Limited regionalization in 2020 reduces air pollutant emissions from natural gas-fired electricity generation in California on average (decrease 0.5% to 1.2% statewide, depending on pollutant), depending on the dispatch of the fleet of natural gas–fired power plants. Certain air basins would experience slight increases in PM2.5 and SO_2 emissions (increase 0.4% in San Joaquin Valley and South Coast air basins and increase 0.7% in Mojave Desert air basin), but the San Joaquin Valley and South Coast air basins would experience greater benefits through decreases in NOx, which is a precursor to both ozone and PM2.5.

By 2030, a significant incremental renewable generation buildout would be required to satisfy California's 50% RPS under any scenario. This buildout would require developing land, which is associated with ground disturbance and environmental effects. Changes associated with how the wholesale electric system might respond to regionalization would also be a part of the 2030 scenarios. The potential changes in land use and potential impacts to biological resources depend on the geographic distribution of the portfolios modeled in the 2030 scenarios. With regionalization, we find that land use and the acreage required decreases in California by 42,600 acres in the Regional 2 scenario and by 73,100 acres in the Regional 3 scenario. Outside of California, land use decreases by 31,900 acres in Regional 2, and increases by at least 69,300 acres in Regional 3, largely due to assumed wind resource development. While the development footprint associated with 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 by the access roads and foundations for wind turbines while the remainder of the site may remain undisturbed and available for other uses. Under Scenario 3, additional land and acreage would be devoted to out-of-state transmission right-of-way to integrate the high-quality out-of-state renewable generation into the regional power system. Results for Regional 2 versus Regional 3 illustrate an inherent tradeoff of building renewables for RPS in state versus out of state.

The 2030 results for water use and emissions are summarized as follows:

- Scenarios Regional 2 and Regional 3 decrease the amount of water used by power plants statewide, when compared with Current Practice Scenario 1. By decreasing fossil fuel use for electricity production in California, regionalization results in a beneficial decrease in the electric power sector's use of California water resources (decrease by 4.0% to 9.7% statewide).
- Scenarios Regional 2 and Regional 3 decrease the emissions of NOx, PM2.5, and SO_2 from power plants statewide and also decrease these emissions in several air basins with nonattainment designations, because of the changed dispatch of the fleet of natural gas-fired power plants. In particular, the San Joaquin Valley, South Coast, Mojave Desert, and Salton Sea air basins experience decreased emissions of all pollutants when compared with Current Practice Scenario 1. Modeling for 2030 shows very small increases in PM2.5 and SO_2 emissions in certain other locations, namely the San Francisco Bay and North Central Coast air basins, although these other locations would experience greater benefits through decreases in NOx. Statewide, combustion-fired electric generation comprises a small portion or roughly 1% to 2% of California's average daily inventories of NOx and PM2.5; this means that the transformation into regional wholesale electricity market is likely to have a negligible impact on California's overall criteria air pollutant inventories.

The differences due to an expanded regional power market and the modeled portfolio and operational changes are summarized in Table ES-1.

Table ES-1. Summary of Environmental Study Key Findings

Study Topic	2020 CAISO + PAC Relative to Current Practice	2030 Regional 2 Relative to Current Practice Scenario 1	2030 Regional 3 Relative to Current Practice Scenario 1
Land Use and Acreage Required in California	No change	▪ Comparable impacts for solar ▪ More solar acreage (+1,400 ac) ▪ Fewer impacts for wind ▪ Less wind acreage (–44,000 ac)	▪ Fewest impacts for solar ▪ Lowest solar acreage (–29,000 ac) ▪ Fewer impacts for wind ▪ Less wind acreage (–44,000 ac)
Land Use and Acreage Required Outside California	No change	▪ More solar acreage (+3,500 ac) ▪ Impacts substantially similar except fewer impacts in Northwest (wind) ▪ Lowest wind acreage for RPS (–35,400 ac) ▪ Facilitates development beyond RPS (+200,000 ac, wind)	▪ More solar acreage (+3,500 ac) ▪ Impacts increase in Wyoming, New Mexico ▪ Fewest impacts in Northwest and Utah (wind) ▪ Most wind acreage for RPS (+65,800 ac) ▪ Adds acreage for out-of-state transmission for California RPS ▪ Facilitates development beyond RPS (+200,000 ac, wind)
Biological Resources in California	No change	▪ Impacts slightly increased from solar ▪ Fewer impacts from wind	▪ Fewest impacts from solar ▪ Fewer impacts from wind
Biological Resources Outside California	No change	▪ Increased avian mortality due to wind beyond RPS	▪ Fewest impacts in Northwest and Utah (wind) ▪ Most avian mortality for wind beyond RPS plus RPS portfolio wind ▪ Adds impacts of out-of-state transmission for California RPS
Water in California	▪ Slight decrease in water used for operation of generators	▪ Less water used during construction in high risk water areas ▪ Less water used for operation of generators	▪ Least water used during construction in high risk water areas ▪ Least water used for operation of generators
Water Outside California	▪ Slight increase in water used for operation of generators	▪ More water used during construction in high risk water areas ▪ Least water used for operation of generators	▪ Most water used during construction in high risk water areas ▪ Less water used for operation of generators
Air Emissions Changes in California	▪ Slight decrease in emissions	▪ Lower emissions of NOx (–6.5%) ▪ Lower emissions of PM2.5 and SO_2 (–4.0%)	▪ Lowest emissions of NOx (–10.2%) ▪ Lowest emissions of PM2.5 and SO_2 (–6.8%)
Air Emissions Changes Outside California	▪ Slight increase in emissions	▪ Lowest emissions of NOx (–1.9%) ▪ Lowest emissions of SO_2 (–0.9%)	▪ Lower emissions of NOx (–1.3%) ▪ Lower emissions of SO_2 (–0.2%)

Notes:
Solar acreage shown for site control and potential ground disturbance.
Wind acreage shown for site control; ground disturbance is less than 10% of acreage.

1. Introduction to Environmental Study

1.1 Background and Scope

California's Senate Bill No. 350 — the Clean Energy and Pollution Reduction Act of 2015 — (SB 350) requires the California Independent System Operator (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. Further, SB 350 requires the ISO to evaluation the environmental impacts in California and elsewhere due to regionalization. This environmental study depends on the scenario modeling and portfolio development efforts within the overall SB 350 study process, described below.

This environmental study does not consider all of the environmental resources or topics that could be impacted by regionalization and the associated renewable buildout, as might be within an environmental impact report, but rather it focuses on some of the most sensitive resources and where the changes resulting from regionalization would be most important. Some of these resources are addressed qualitatively, like land use and biological resources, and some are addressed quantitatively, like acreage, water use, and air emissions, depending on the type of data available. Electric sector greenhouse gas (GHG) emissions results are presented and discussed in Volume I and Volume V (Production Cost Analysis) of the SB 350 study.

The environmental study's treatment of renewable portfolios to meet California's 50% Renewable Portfolio Standard by 2030 (50% RPS), and the treatment of renewable study areas, recognizes that siting decisions are not made by the ISO. As such, the renewable portfolios themselves and the geographic definitions of the renewable study areas are not binding or reflective of any specific generation proposals.

1.2 Role of Environmental Study in SB 350 Study Process

This environmental study depends on the defined renewable portfolios and production cost simulations developed elsewhere within the overall SB 350 study process. Accordingly, the environmental study methodology and the analysis of environmental topics rely upon these two separate modeling efforts.

Renewable Portfolios. The SB 350 study process includes a Renewable Energy Portfolio Analysis (Volume IV) that identifies optimal renewable capacity additions to meet California's 50% RPS using the Renewable Energy Solutions (RESOLVE) model and a number of modeling assumptions discussed in Volume IV. The model defines renewable portfolios and identifies needs for new system infrastructure, such as regional transmission and flexible generating capacity. The environmental study uses the following information from the RESOLVE model:

- Locations of incremental new resources for California to achieve RPS goals by 2030, identifiable in terms of Competitive Renewable Energy Zone (CREZ) and selected development regions (outside of California) and renewable technology.
- Megawatt (MW) capacity and type of new added generation resources, including storage.
- New high-voltage transmission system additions to access and integrate out-of-state resources that would help meet California's 50% RPS.

Production Cost Simulation. The SB 350 study process also includes a Production Cost Analysis (Volume V) that identifies potential changes in the operation of existing generation facilities including retirements. The environmental study uses the following information from the production cost simulation in the analysis of scenarios:

- Locations of megawatt hours (MWh) produced and fuel consumed in million British Thermal Units (MMBtu) by generating unit, aggregated by California air basin.
- MWh produced and/or displaced by generation or transmission additions.
- Changes in fuel type(s) used and type of generating unit dispatched.
- Emissions of carbon dioxide (CO_2) and key criteria air pollutants (NOx and SO_2); although the analysis of electric sector greenhouse gas emissions is presented in the Production Cost Analysis (Volume V) since it is a direct output of the production cost simulations.

Environmental Study Process as Downstream from Sector Modeling. Table 1-1 illustrates the various inputs to the environmental study as they are derived from the wider SB 350 study process.

Table 1-1. Sector Modeling as Input to Environmental Study

Key Inputs	2020 Current Practice	2020 CAISO + PAC	2030 Current Practice Scenario 1	2030 Regional 2	2030 Regional 3
Renewable Portfolios ■ Incremental MW buildout for California by 2030	Already contracted	No change from 2020 CP	Portfolio 1 Incremental Buildout by 2030	Compare Buildout of Portfolio 2 to Current Practice 1	Compare Buildout of Portfolio 3 to Current Practice 1
Production Cost Simulations ■ Dispatch of generation in 2020 and 2030 ■ MWh, Unit starts ■ WECC-Wide emissions	2020 Environmental Baseline	Difference in 2020 CAISO + PAC relative to CP	2030 Environmental Baseline	Difference in 2030 Regional 2 relative to Current Practice 1	Difference in 2030 Regional 3 relative to Current Practice 1
Major Out-of-State Transmission Additions for California RPS	None	No change from 2020 CP	2030 Future Buildout	No change from 2030 Current Practice 1	Incremental transmission to deliver from Wyoming, New Mexico
Renewables Beyond RPS, Out-of-State	None	No change from 2020 CP	None	5,000 MW added	5,000 MW added

1.3 Environmental Study Approach

The geographic scope of the environmental study is set by SB 350 to include "environmental impacts in California and elsewhere," and for this environmental study, we take "elsewhere" to mean the area of the Western Interconnection. Within this extremely broad and environmentally diverse region, this study aims to narrow the focus to key zones or areas where possible.

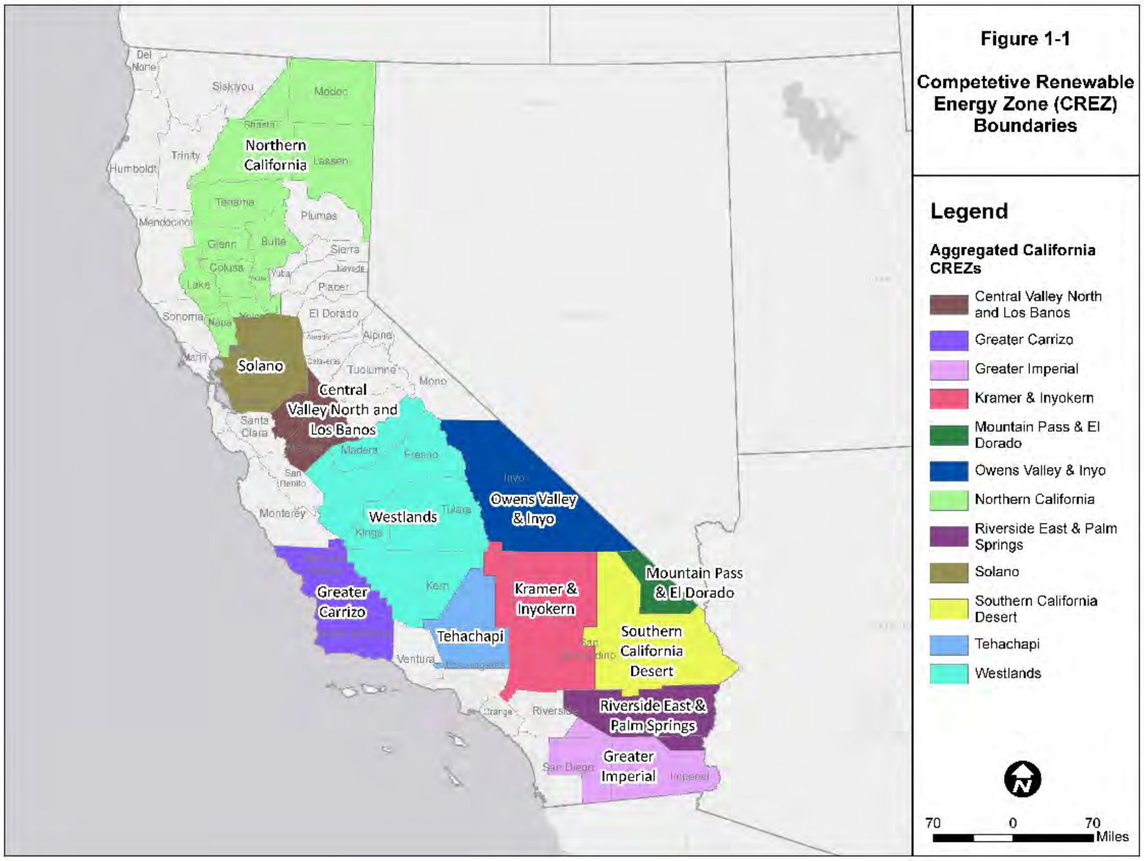
The environmental study process requires defining geographic areas to focus the analysis to areas that could reasonably accommodate the new buildout, establishing an understanding of the baseline conditions, and analyzing the potential environmental effects of regionalization including the renewable buildouts. The three steps used in the approach are described further as follows.

Step 1: Define Renewable Resource Study Areas

The environmental study authors have defined physical boundaries of "study areas" in order to limit the impact analysis presented in this study (as described in detail in Section 3). The areas represent the geographic areas that could reasonably supply the range of resources selected in the portfolios from RESOLVE. The analysis considers and identifies more than 20 study area locations across California and the rest of the west for new renewable resources, as selected by RESOLVE for the incremental buildout by 2030. The geographic scope for the buildout includes approximately 12 different CREZs in California, and renewable energy resources in the Southwest (Arizona), the Northwest (Oregon or Washington), Utah, Wyoming, and New Mexico.

The CREZ boundaries for California's renewable energy resources within the scope of the RESOLVE model and this environmental study are shown in Figure 1-1.

Figure 1-1. Competitive Renewable Energy Zone (CREZ) Boundaries



Step 2: Describe Baseline Conditions

For each environmental discipline, each renewable resource study area has been assessed to determine its existing natural resources and conditions. These conditions help define the potential level of concern or conflict for various environmental factors. The baseline conditions are quantified or categorized for relative sensitivity, where possible and where impaired conditions are known to occur. This allows the study to focus on specific sensitive environmental resources or locations of concern for each environmental topic.

Step 3: Analyze Potential Impacts of Regionalization

The environmental analysis considers regionalization including each renewable buildout as a potential expansion of today's infrastructure, which is projected to achieve the 33% RPS by 2020. The activities necessary to construct, install, and operate the different buildouts between 2020 and 2030 are described briefly in Section 2. However, the focus of this environmental study is to highlight the potential environmental differences that result from implementation of the "current practice" or Scenario 1 and potential "regionalization" scenarios.

This means that this study focuses on the changes between regionalization scenarios and the different portfolios to the extent that they would have different physical effects on the environment. Because the various portfolios rely on construction of generators in different locations and using different generation resources, the study identifies how regionalization changes the renewable buildout such that it would place or avoid development in locations known to be environmentally sensitive. Adverse effects may occur where the potential for collocation of the buildout and environmentally sensitive locations is highest.

New transmission outside of California is presented separately for the Regional 3 scenario. The environmental impacts of potential major transmission additions for California to achieve the 50% RPS are summarized (in Section 5) based on a review of several proposed transmission projects that have been the subject of previous environmental analysis by siting authorities and are similar to the transmission facilities that would be needed to implement the portfolio of the Regional 3 scenario.

2. Summary of Scenarios

2.1 Current Practice and Regional ISO Scenarios in 2020

The near-term 2020 scenarios include no incremental buildout of renewable energy beyond what is already planned to meet California's 33% RPS by 2020. Accordingly, limited regionalization in 2020 involves no incremental renewable energy development. There would be no incremental construction activities and no construction-related impacts to the environment. The limited regionalization in the 2020 scenario (CAISO + PAC) would cause changes in the operation of the existing system of generation.

2.2 Incremental Buildout by 2030

The scenarios for regionalization in 2030 include the following assumptions carried forward into the environmental analysis:

- No additional major transmission inside California would be needed to interconnect the incremental 50% RPS renewable energy buildout inside California.
- Incremental additions include geothermal (500 MW) and energy storage (at least 500 MW), which are common to all 2030 scenarios in California.
- Regional scenarios include renewable development beyond RPS facilitated by regional market (5,000 MW of wind) distributed as 3,000 MW in Wyoming and 2,000 MW in New Mexico. It is assumed that no additional transmission would be needed to facilitate these renewables beyond RPS. The environmental effects related to construction activities for these renewables are not considered in the analysis.
- Regional 3 includes additional transmission for California to access and integrate new wind resources in Wyoming and New Mexico.

The environmental analysis of 2030 scenarios starts by presuming construction of the renewable portfolios defined with the RESOLVE model. Where the RESOLVE model selects Renewable Energy Certificates (RECs) for procurement, this environmental study presumes incremental construction would occur. The incremental renewable buildout between 2020 and 2030 is presented in Table 2-1 for inside and outside California. Notable differences between the scenarios are described in subsequent text.

Table 2-1. Incremental Renewable Buildout for California by 2030 (MW)

Portfolio Composition	Current Practice Scenario 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
Out-of-State Solar	1,000	1,500	1,500
Out-of-State Wind	4,551	3,666	6,194
Total California New Capacity	11,101	10,204	5,840
Total Out-of-State New Capacity	5,551	5,166	7,694
Total New Renewable Capacity	16,652	15,370	13,534
Major Out-of-State Transmission Additions for California RPS?	No	No	Yes
Renewables Beyond RPS, Out of State	No	5,000	5,000

Source: Results from the RESOLVE model; adding renewable development beyond RPS facilitated by regional market.

Notes:
- All portfolios also include energy storage (batteries and/or pumped hydro);
- Incremental California geothermal located in Greater Imperial.

Incremental Buildout Inside California

The renewable portfolios as developed through the RESOLVE model reflect MW of renewable buildout by CREZ and technology for the entire state of California including both CAISO and non-CAISO utilities. The buildout for solar is presented in Table 2-2 and for wind is presented in Table 2-3.

Table 2-2. California Solar, Incremental Buildout Details (MW)

California Solar Portfolio	Current Practice Scenario 1	Regional 2	Regional 3
Greater Carrizo Solar	570	570	0
Greater Imperial Solar	923	923	512
Kramer and Inyokern Solar	375	375	375
Owens Valley Solar	578	578	305
Riverside East and Palm Springs Solar	331	1,984	0
Tehachapi Solar	2,500	2,500	1,761
Westlands Solar	2,323	873	486
Total California New Solar Capacity	7,601	7,804	3,440

Source: Results from the RESOLVE model.

Table 2-3. California Wind, Incremental Buildout Details (MW)

California Wind Portfolio	Current Practice Scenario 1	Regional 2	Regional 3
Central Valley North and Los Banos Wind	150	150	150
Greater Carrizo Wind	500	500	500
Greater Imperial Wind	400	400	400
Riverside East and Palm Springs Wind	500	0	0
Solano Wind	600	0	0
Tehachapi Wind	850	850	850
Total California New Wind Capacity	3,000	1,900	1,900

Source: Results from the RESOLVE model.

Current Practice (Scenario 1) emphasizes solar in Tehachapi, Westlands, and Imperial and distributes wind across six resource areas (3,000 MW), emphasizing Tehachapi and Solano. The Regional 2 buildout emphasizes solar in Riverside East & Palm Springs, Tehachapi, and Imperial and distributes wind across four resource areas (1,900 MW); there would be no incremental wind in the Riverside East and Solano CREZs. The Regional 3 buildout distributes solar across five resource areas with no incremental solar in Greater Carrizo and Riverside East; it also distributes wind across four resource areas (1,900 MW) and eliminates incremental wind in the Riverside East and Solano CREZs.

Incremental Buildout Out of State

The renewable portfolios also include the MW of renewable buildout outside California. The buildout for solar and wind is presented in Table 2-4.

Table 2-4. Out-of-State Solar and Wind, Incremental Buildout Details (MW)

Out-of-State Portfolio for California	Current Practice Scenario 1	Regional 2	Regional 3
Southwest Solar (Arizona)	1,000	1,500	1,500
Northwest Wind (Oregon)	2,447	1,562	318
Utah Wind	604	604	420
Wyoming Wind	500	500	2,495
New Mexico Wind	1,000	1,000	2,962
Total Out-of-State New Capacity	5,551	5,166	7,694
Major Out-of-State Transmission Additions for California RPS?	No	No	Yes
Renewables Beyond RPS, Out-of-State	No	5,000	5,000

Source: Results from the RESOLVE model; adding renewable development beyond RPS facilitated by regional market.

Outside of California, Current Practice (Scenario 1) emphasizes Northwest wind and uses existing transmission for Southwest solar and wind in Utah, Wyoming, and New Mexico. The Regional 2 buildout increases solar development in the Southwest and decreases Northwest wind. It uses existing transmission for Southwest solar and wind in Northwest, Utah, Wyoming, and New Mexico. The Regional 3 buildout has the greatest level of out-of-state resources overall emphasizing wind in Wyoming and New Mexico. It includes additional transmission for California to access this wind. Both regional scenarios create a market that facilitates renewable energy development beyond RPS (5,000 MW wind) distributed in Wyoming and New Mexico.

Differences between the Buildouts for 2030

The environmental analysis focuses on the environmental effects of regionalization rather than the effects of building out the portfolios themselves. Therefore, the relative construction-related environmental effects of the scenarios depend on the differences between the renewable buildout rather than the totals. These differences are presented in Table 2-5 for solar buildout in California, Table 2-6 for wind buildout in California, and Table 2-7 for renewable buildout out of state.

Table 2-5. California Solar, Differences Between Scenarios (MW)

California Solar Portfolio	Regional 2 minus Current Practice Scenario 1	Regional 3 minus Current Practice Scenario 1
Greater Carrizo Solar	0	–570
Greater Imperial Solar	0	–411
Kramer and Inyokern Solar	0	0
Owens Valley Solar	0	–273
Riverside East and Palm Springs Solar	1,653	–331
Tehachapi Solar	0	–739
Westlands Solar	–1,450	–1,837
Difference in California New Solar	203	–4,161

Source: Results from the RESOLVE model.

Table 2-6. California Wind, Differences Between Scenarios (MW)

California Wind Portfolio	Regional 2 minus Current Practice Scenario 1	Regional 3 minus Current Practice Scenario 1
Central Valley North and Los Banos Wind	0	0
Greater Carrizo Wind	0	0
Greater Imperial Wind	0	0
Riverside East and Palm Springs Wind	–500	–500
Solano Wind	–600	–600
Tehachapi Wind	0	0
Difference in California New Wind	–1,100	–1,100

Source: Results from the RESOLVE model.

Table 2-7. Out-of-State Solar and Wind, Differences Between Scenarios (MW)

Out-of-State Portfolio for California	Regional 2 minus Current Practice Scenario 1	Regional 3 minus Current Practice Scenario 1
Southwest Solar (Arizona)	500	500
Northwest Wind (Oregon)	–885	–2,129
Utah Wind	0	–184
Wyoming Wind	0	1,995
New Mexico Wind	0	1,962
Difference Out-of-State	–385	2,143
Major Out-of-State Transmission Additions for California RPS?	No	Yes
Renewables Beyond RPS, Out-of-State	5,000	5,000

Source: Results from the RESOLVE model; adding renewable development beyond RPS facilitated by regional market.

Major Out-of-State Transmission Additions for Regional 3

One regionalization scenario (Regional 3) adds incremental new transmission to access and integrate out-of-state resources to satisfy California's 50% RPS goals. To assess the environmental impacts of the new transmission, this environmental study describes the physical features and potential locations of representative transmission projects that could carry the Wyoming and New Mexico generation to the regional load. The projects that are analyzed in this environmental study were chosen for convenience as a significant amount of public information regarding potential impacts and costs is available. These projects are intended to merely represent a transmission solution that would be included with the Regional 3 scenario. The choice of the projects used in this analysis is for the sole purpose of assessing the benefits of a regional market over a range of plausible scenarios. This study is not promoting or advocating for a particular project.

The relevant transmission line proposals that are pending review or under review by siting authorities are listed in Table 2-8. The environmental impacts of these proposals are summarized in Section 5.

Table 2-8. Major Out-of-State Potential Transmission

Project	Voltage/ Configuration	Length	Permitting Status
PacifiCorp Gateway West (Segment D: Windstar to Populus Substation) for access to Wyoming wind at Hemingway in Idaho	230, 345 & 500 kV (1,500 MW capacity)	488 miles	BLM issued Record of Decision (ROD) on 11/14/13, except deferred decision in southwestern Idaho to perform additional environmental analysis of Morley Nelson Snake River Birds of Prey Conservation Area. Targeted online in 2019-2024.
PacifiCorp Energy Gateway South (Segment F) for access to Wyoming wind at Clover Substation in Mona, Utah	500 kV HVAC	~400 miles	BLM issued Draft EIS in February 2014 and announced Agency Preferred Alternative in December 2014, stating that it was moving forward with its analysis in the Final EIS. Targeted online in 2020-2024.
Anschutz Corporation TransWest Express for access to Wyoming wind at southern Nevada	600 kV HVDC (~3,000 MW capacity)	730 miles	BLM and Western Area Power Administration published Final EIS on 5/1/15.
Duke-American Transmission Company Zephyr Power for access to Wyoming wind at compressor air energy storage facility near Delta, Utah	500 kV HVDC (~2,100 to 3,000 MW capacity)	~500 to 800 miles (525 miles to energy storage, plus 490 miles of existing transmission to Los Angeles area)	Preliminary routing and pre-NEPA work by applicant. Applicant may submit a proposal to the Southern California Public Power Authority to supply the Los Angeles area with renewable energy and electricity storage. Targeted online by 2023.
SunZia Southwest Transmission Project for access to New Mexico wind from SunZia East to Pinal Central in Arizona	Two single-circuit 500 kV HVAC lines; or One single-circuit 500 kV HVAC and one single-circuit 500 kV HVDC line (~3,000 to 4,500 MW capacity)	515 miles	BLM issued ROD on 1/23/15. Targeted online by 2021.
Western Spirit Clean Line for access to New Mexico wind at northern Arizona	345 kV HVAC (~1,500 MW capacity)	~140 to 200 miles	Preferred and alternative routes being identified by Clean Line Energy Partners, LLC, and the New Mexico Renewable Energy Transmission Authority based on stakeholder input.

Source: BLM, 2014; BLM, 2013; BLM and USFS, 2013; BLM and Western, 2015; Clean Line Energy, 2013; DATC, 2014; Linares, 2015.

3. Renewable Resource Study Areas

This section describes the assumptions regarding the physical features of the portfolios and how the portfolios are treated by the environmental study. The primary effort is to define "study areas" or proxy locations for each renewable energy resource type within the incremental buildouts.

The purpose of defining study areas is to allow a focused look at the potential environmental effects of the buildouts. This study separately considers:

- In-State Renewable Resources (see Appendix 1)
- Out-of-State Renewable Resources (see Appendix 2)

It is important to note that despite use of study areas to allow focusing of the impact analysis, this environmental study is not site-specific, and it does not reflect or represent a siting study for any particular planned or conceptual construction project. Siting decisions are not made by the ISO. The boundaries of study areas are representative and are intended to include land areas large enough to accommodate the build-out of each plausible portfolio. The boundaries are tailored to avoid "no go" areas and to reflect location-specific constraints and previous planning processes, where known. The geographic definitions of the study areas are not binding or reflective of any specific generation proposals.

Additionally, California's renewable energy goals may be achieved by following many different paths. The SB 350 study presents plausible portfolios as possible renewable energy buildouts to demonstrate the impact of regionalization, but any future or actual buildout may or may not resemble these portfolios.

3.1 Defining Boundaries for Study Areas

This study uses physical boundaries to define study areas that represent geographic locations that could reasonably supply the resources that are selected by the RESOLVE model for the incremental buildout by 2030 for this SB 350 study.

3.1.1 Portfolios Output

Each portfolio from RESOLVE draws renewable energy resources for California and elsewhere from a range of locations and across a range of generation technologies. Portfolios represent different potential buildouts that may be completed before 2030 for California to achieve the 50% Renewable Portfolio Standard (RPS).

In California, RESOLVE builds the portfolios with a locational specificity within individual competitive renewable energy zones (CREZs). The geographic scope of the portfolios within California and the CREZ boundaries appear in Figure 1-1.

The term "CREZ" comes from the Renewable Energy Transmission Initiative (RETI) process, as originally presented in 2008, and the term remains in use by California's energy agencies. However, the boundaries of CREZs have changed over time as the scope and breadth of California's renewable energy planning efforts have changed and as developers have built capacity. In general, CREZs define boundaries of areas within which renewable resources and development potential is expected to be somewhat similar. CREZs have been defined for areas where renewable development is generally not prohibited and where generation resources exist. The RESOLVE model builds portfolios in terms of the Aggregated CREZ, which is a more coarsely-defined geographic area than the original CREZs. An

Aggregated CREZ may span multiple counties or substantial portions of counties. This environmental study uses the terms Aggregated CREZ and CREZ interchangeably.

For out-of-state resources available across the U.S. portion of the Western Interconnection, the RESOLVE model builds portfolios with a locational specificity in terms of the highest-quality wind or solar resources predominately based on availability and capacity factor, and relatively near transmission within the particular state.

Some stakeholders expressed a concern that portfolios may include “overbuilding” California resources. This concern is addressed in Volume IV (Renewable Energy Portfolio Analysis), which indicates that the RESOLVE model may produce renewable energy portfolios that include some overbuilding as necessary to overcome curtailed energy loss and still produce enough to meet the RPS target. This environmental study considers the buildout for each scenario as it is derived from the portfolio modeling effort. Accordingly, the impacts of overbuilding renewable capacity are included in the environmental study of each buildout.

3.2.2 Study Area Boundaries

The analysis started with definition of “study areas” within the larger regions drawn upon by RESOLVE. The study areas serve as proxy locations to focus the environmental review. At least one study area has been defined for each generation technology type per CREZ or resource zone selected by the portfolio analysis, in Volume IV (Renewable Energy Portfolio Analysis). These study areas are used to characterize the environmental setting and potential indicators of impacts within and adjacent to the study area boundaries.

Most study areas align with areas where siting generation has been historically successful, or within larger regions previously defined or considered viable for future siting. Boundaries of each study area have been tailored for this study so that the areas largely avoid areas of high environmental conflict and areas with greater development risk, because this environmental study need not consider the effects of developing in areas where siting of generation facilities is unlikely or not permitted.

Inside California, the starting point for definition of study areas was the CPUC’s RPS Calculator solar and wind potential areas as posted on DataBasin.[1] The RPS Calculator contains generic proxy polygons representing the best solar and wind resource areas for the state of California. The RPS wind potential areas were updated to eliminate any areas that are not currently available to wind development due to local or regional zoning or other planning restrictions. Within the RPS solar potential areas, study areas focused where solar projects would be technically viable (i.e., the slope and the insolation were adequate). Because the RPS Calculator solar potential areas are finely drawn, these areas were aggregated into larger, more uniform areas. The solar study areas were also defined to eliminate areas defined as incompatible with solar by existing renewable energy planning documents. The study areas were drawn to be of sufficient size and shape to provide flexibility for location of resources selected by RESOLVE. They also included diverse areas whenever possible to provide for a more comprehensive look at potential environmental effects of the portfolio buildout. Additional details on the methodology used in selecting the study area boundaries in California is presented in Appendix 1 to this environmental study.

Outside of California, the treatment of the study areas began with a review of the renewable resources as identified by the National Renewable Energy Laboratory. After identifying available resources, the

[1] CPUC RPS Calculator solar and wind potential areas can be found at: https://databasin.org/datasets/c4ddcb27f7d74e68b7dcdb19cc8dfe02 and https://databasin.org/datasets/64b8dab6dad34680baa6355851e1d9e0.

team identified study areas based on a review of existing operating projects, previous energy planning documents, proposed transmission interconnection options, and land availability. The areas were then tailored to avoid areas of high environmental impact and development risk. The treatment of each state's resource areas varied depending on information available. For example, in Utah, state-defined renewable energy zones were used, and in New Mexico large areas with good wind resources were identified based on locations of potential transmission projects. The methodology for selecting the study area boundaries for each state is presented in Appendix 2 to this environmental study.

Again, the treatment of portfolio components and the study areas in the environmental study recognizes that siting decisions are not made by the ISO, and that the geographic definitions of the study areas are not binding or reflective of any specific generation proposals. The study areas are merely plausible siting options selected solely for the purpose of this regional impact study.

3.2.3 Capturing Earlier Foundational Studies

The boundaries of the study areas have been drawn to incorporate results of previous regional and foundational studies, including the Desert Renewable Energy Conservation Plan (DRECP), County-level, and WECC efforts to identify the locations where siting could be expected to avoid or minimize environmental land use conflicts. The buildouts are assumed to generally adhere to these previously-documented zones and the mitigation practices defined in earlier studies, or enforced by siting authorities that have historically reviewed specific development proposals.

These previous and foundational studies include:

- Programmatic Environmental Impact Statement (EIS) for Solar Energy Development in Six Southwestern States (BLM, 2012)
- Draft DRECP and EIR/EIS (CEC [California Energy Commission], BLM, CDFW, USFWS 2014) and BLM Proposed LUPA and Final EIS (BLM, 2015)
- Renewable Energy Transmission Initiative (and RETI 2.0, ongoing)
- Solar and the San Joaquin Valley: Identification of Least Conflict Lands
- WECC Environmental Data Task Force data sets
- County renewable energy plans and ordinances
- Utah Renewable Energy Zones Task Force

Information on typical environmental impacts from renewable energy development and presented throughout this study was obtained from several sources, including:

- Programmatic EIS for Solar Energy Development in Six Southwestern States (BLM, 2012)
- Programmatic EIS on Wind Energy Development on BLM-Administered Lands in the Western United States (BLM, 2005)
- Programmatic EIS for Geothermal Leasing in the Western United States (BLM, 2008)
- Geothermal Power Plants – Minimizing Land Use and Impact (DOE, 2016)
- Draft DRECP and EIR/EIS (CEC [California Energy Commission], BLM, CDFW, USFWS 2014) and BLM Proposed LUPA and Final EIS (BLM, 2015)

3.2 Acreage Required by Buildouts

The limited regionalization of the 2020 CAISO + PAC scenario includes no incremental renewable energy development. No incremental acreage would be required, and no changes to construction-related activity would occur inside or outside of California.

Each 2030 portfolio to expand California's RPS from 33% to 50% requires new solar, wind, geothermal, and other resource development, and this would require land use conversion in each study zone. A portion of this land would have disturbance during construction.

The approximate area of land that would need to be dedicated to buildout of the renewable energy is estimated using acreage conversion factors (acres/MW). This study uses factors from the DRECP, which developed a set of fixed input assumptions regarding renewable energy development in the desert. During the DRECP process, the public was provided an opportunity to comment on acreages per MW for renewable development. The acreage conversion factor for wind falls within the range given in the NREL study, *Land-Use Requirements of Modern Wind Power Plants in the US* (2009). The factor for solar development is similar to those reflected by current trade publications and by the NREL study, *Land-Use Requirements for Solar Power Plants in the US* (2013). These factors were developed through the DRECP process (BLM, 2015) for renewable energy development in the California desert:

- Solar (PV): 7 acres/MW
- Wind: 40 acres/MW; 3 acres/MW of ground disturbance
- Geothermal: 6 acres/MW

Table 3-1 shows the acres required for each buildout under these assumptions.

Table 3-1. Approximate Acres Required for Incremental Buildout by 2030 (acres)

Resource Type	Current Practice Scenario 1	Regional 2	Regional 3	Difference: Regional 2 Relative to Current Practice Scenario 1	Difference: Regional 3 Relative to Current Practice Scenario 1
California Solar	53,200	54,600	24,100	1,400	–29,100
California Wind	120,000	76,000	76,000	–44,000	–44,000
California Geothermal	3,000	3,000	3,000	No change	No change
Out-of-State Solar	7,000	10,500	10,500	3,500	3,500
Out-of-State Wind	182,000	146,600	247,800	–35,400	65,800
Total Acreage in California	176,200	133,600	103,100	–42,600	–73,100
Total Acreage Out-of-State	189,000	157,100	258,300	–31,900	69,300
Major Out-of-State Transmission Additions for California RPS?	No	No	Yes	No change	Added
Renewables Beyond RPS, Out of State	No	200,000	200,000	200,000	200,000

Notes:
Solar acreage shown for site control and potential ground disturbance.
Wind acreage shown for site control; ground disturbance is less than 10% of acreage.
Common to all 2030 scenarios in California: Geothermal (500 MW); energy storage (min. 500 MW)
Regional scenarios include renewable development beyond RPS facilitated by regional market (5,000 MW wind) distributed in WY and NM.

To achieve the buildout capacity under Current Practice Scenario 1, approximately 176,200 acres in California and 189,000 acres outside of California are the total land and acreage required (Table 3-1). Less renewable generation capacity would have to be built with regionalization. This is because regionalization shifts development towards relatively higher-performing and lower-cost out-of-state resources. With renewables being better integrated into the system, the investments to satisfy the RPS would be more efficient; this tends to reduce the overall land use and acreage required.

Both scenarios of regionalization reduce the amount of land in California for wind (–44,000 acres), and scenario Regional 2 achieves the lowest amount of out-of-state acreage for wind (–35,400 acres for wind outside California compared with Current Practice Scenario 1). While Regional 3 involves a larger footprint of out-of-state acreage for wind (+65,800 acres compared with Current Practice Scenario 1), and the additional land devoted to out-of-state transmission right-of-way, only a modest portion of the acreage, usually less than 10 % would be disturbed by the access roads and foundations needed for installing the wind capacity. The remainder of the land within a typical wind site would remain undisturbed and available for other uses. Overall, with regionalization the land use and acreage required decreases in California by 42,600 acres in the Regional 2 scenario and by 73,100 acres in the Regional 3 scenario. Outside of California, a tradeoff between regional scenarios is more apparent; land use and acreage decreases by 31,900 acres in Regional 2 and increases by at least 69,300 acres in Regional 3 due to the emphasis on out-of-state wind in Regional 3.

4. Environmental Analysis by Discipline

This section presents discussions of impacts for land use, biological resources, water, and air emissions. Separately, Section 5 presents the impacts of out-of-state transmission that may be required for the Regional 3 scenario.

4.1 Land Use

This section describes potential land use impacts for the incremental renewable energy buildouts and the potential land use impacts of regionalization as compared with the current practice. The approach to the analysis relies upon a narrow set of baseline conditions that are treated as potential indicators or predictors of impacts, as listed in Table 4.1-1.

Table 4.1-1. Baseline Conditions and Indicators of Impacts, Land Use

Baseline condition of a study area	How are scenarios analyzed relative to the baseline?	Potential indicator of land use impact
Land Use		
Population density	Coincidence of incremental renewable energy buildout with areas of high population density	Land use compatibility
Existing land uses	Coincidence of incremental renewable energy buildout with areas of high-value agricultural uses	Land use compatibility
Proximity to excluded or protected land uses	Proximity of incremental renewable energy buildout to lands with excluded or protected uses, including natural or recreational areas and military installations	Land use compatibility and visual resources

Assumptions and Methodology for Land Use Analysis

This analysis reviews the relative compatibility of renewable energy development in light of existing land uses in the different study areas and the acreage required by the buildouts (Section 3), and then compares the scenarios. Population density, existing land uses, and proximity to protected lands are used to identify whether the renewable energy buildouts in a given study area may create a low, medium, or high degree of land use conflict.

The topic of cultural resources is addressed within this land use analysis; however, this study does not include an analysis of potential impacts to cultural resources. Establishing a definitive level of risk for impacts to cultural resources requires spatial datasets or area surveys for each area, and an analysis of data gaps, which are unavailable at the scale of this study.

Land Use Conversion and Incompatibilities

Population Density. It is assumed that a large-scale renewable energy development would be located on land that is vacant or largely undeveloped land, such as agricultural or open land. Open land may be previously disturbed. Development locations may include brownfield sites, where previous practices limit the development options. The study area boundaries exclude some areas to ensure that potential land use conflicts are not overstated; however, such conflicts can still occur within the study areas, and the potential for them to occur varies between study areas.

Population density indicates the number of people in a given geographic area, and population density is used as an indicator of relatively open or unoccupied lands. Higher density (greater number of persons per square mile or per acre) suggest that an area has less vacant or open land and a greater number of potentially affected people, while lower densities suggest the opposite. Density data were from 2012 (ArcGIS 2016). To characterize population density data, a density of 3.2 persons per square mile is equal to 1 person per 200 acres; 32 persons per square mile is equal to 1 person per 20 acres; and 640 persons per square mile is equal to a density of 1 person per acre. U.S. Census data apply uniformly across a census tract, however, population is not uniformly distributed across an area. Therefore, there are always areas within a census tract where the population is higher than the tract-wide average and areas where the density is lower than the average.

A low number of residents in an area indicates two things: there is likely to be more vacant or open land; and there are relatively fewer people to be potentially affected by development. Census tracts wholly or partially within a study area were identified and the population density per square mile of the tracts was determined using U.S. Census data. Three density ranges were identified to indicate a low, medium, or high potential for conflict. The ranges were based on persons per square mile, with density thresholds set at 5 persons or less (low), between 5 and 15 persons (medium), and more than 15 (high). To be able to qualitatively describe other potential population-related concerns, population centers in and near the study areas were identified based on visual inspection of online satellite photos and maps.

Existing Land Uses. The existing uses of land within the study areas were qualitatively assessed by examining satellite photos, to generally characterize if the land within a study area is substantially built out or is primarily open space (vacant or in agriculture). It is possible that brownfield areas exist within study areas and could be suitable sites for renewable projects, but this was not quantified or determined in the analysis of satellite photos.

The presence of active agriculture is a consideration because while it creates large areas with fewer biological concerns, it has become a land use type that may be attractive to large scale renewable energy development. In many areas where renewable energy facilities may locate, agriculture use could be absent, inactive, or could occur at a low intensity; common low-intensity uses include rangeland or land used for hay production. Other areas may have high-value crops, including agricultural uses that is actively irrigated. The agricultural uses of the study areas were determined by inspecting Google Earth aerial photography.

If an area is in agricultural use, this study considers whether the agricultural use is intensive (such as in orchards or cropland) or not intensive (such as pasture or rangeland). Rangeland is more likely to be compatible with the buildout than more intensively used agricultural areas. Rangeland generally creates a low degree of land use conflict (but has potential for greater impacts on biological resources), while more intensively use agricultural lands are likely to create a medium degree of conflict or incompatibility. Areas that are not agricultural but built-upon with urban/suburban development are likely to be incompatible with large-scale renewable generation.

Proximity to Excluded or Protected Areas. Excluded or protected land uses include areas valued for their natural or scenic conditions or for their particular uses or characteristics that may require isolation or separation from other uses. Protected land uses that occur in proximity to a study area are considered in two ways. Visual impacts are considered because renewable energy development, particularly wind development, may be visible over long distances. Energy facilities developed in proximity to protected land uses (e.g., wilderness areas, national and state parks, historic trails, scenic highways) may be visible from high-value natural or scenic areas, altering the view and adversely affecting a visitor's experience. Protected land uses were identified using mapped data from multiple BLM State Offices, the USFWS, and the USGS (BLM 2016a, BLM 2016b, BLM2014a, BLM2014b, BLM2013, BLM 2012b, USFWS 2016, USGS 2012).

Areas defined here as “excluded” include those where development would be prohibited because of existing functions and activities that may be adversely affected by the proximity of the renewable energy facility (e.g., military bases, ranges, and training areas).

Excluded and protected lands were identified and mapped to determine if they were within or near the renewable resource study areas. In areas protected because of their natural or scenic qualities, visitors have an expectation that they will experience undeveloped, natural settings in the protected area itself and that the views from these lands to nearby unprotected lands will not include substantial development. For military bases, ranges, test areas, and similar uses, the presence of certain types of development could pose safety risks or potentially interfere with operations.

With regard to visual impacts, the visual dominance of development within the landscape diminishes over distance, owing to naturally occurring haze (water vapor and dust) and the perceived muting of colors and shapes with increasing distance between the object and the viewer. Those study areas (or parts of study areas) that are less than 5 miles from a protected land use present a higher potential to create either visual or operational impact. Study areas located between 5 and 10 miles from a protected land use are likely to be at medium potential of impact. Study areas at distances greater than 10 miles have a low likelihood of impact. In practice, other factors and conditions in the landscape may reduce these visual effects. Examples of mitigating conditions include the nature of the protected land use itself, intervening topography, the number and locations of visitors, and the protected land use’s elevation and orientation relative to the study area.

Cultural Resources and Tribal Concerns

This study considered a range of possible approaches to studying the effects of regionalization on cultural resources. Establishing a definitive level of risk for impacts to cultural resources requires spatial datasets for each area or area surveys, and an analysis of data gaps, which are unavailable at the scale of this study. Therefore, the environmental study does not include an analysis of potential impacts to cultural resources or tribal concerns.

Study of potential impacts to cultural resources depends on availability of spatial datasets. The following are necessary for least-impact and cost efficient infrastructure planning:

- Spatial data related to tribal places of importance.
- Archaeological site data, including previously recorded prehistoric and historic resources.
- Locations of Districts and Landscapes listed in National and State Registers of Historic Places.
- Prehistoric bio-habitat, hydrology, and soils spatial data, critical to building site sensitivity models that can predict areas of low/medium/high risk for impacts.

All of the renewable resource study areas may be assumed to have moderate to high risk for archaeological and tribal resources. Additional planning considerations include:

- Densities of archaeological data vary across geographical areas.
- Some areas may not have been surveyed, and therefore generalization across those areas may yield an inaccurate understanding of risk.
- Analysis of data gaps is critical to the identification of feasible and efficient methods of gathering new data and/or predicting hypothetical data for modeling.
- Levels of tribal and public interest and/or concern are variable; 1-meter wide site can generate as much interest as a 1-mile long site.

- Interest may also reflect subjective and qualitative factors that are difficult to predict in the absence of focused cultural and tribal studies.

4.1.1 Regulatory Framework

Individual renewable energy facilities may be located wholly on land under a single jurisdiction or may be sited on land under multiple jurisdictions. If on lands under separate jurisdictions, the regulations administered by or applicable to the separate individual agencies having land use authority would apply to the portions of the development falling within their jurisdiction.

Federal Land Use Controls

At the federal level, land-use oriented regulations apply on lands under federal agency jurisdiction, including Bureau of Land Management and Forest Service lands. Typically, an existing land use plan would guide facility siting, or may require amendment to allow a proposed facility. Complementing federal land use regulations and plans are regulations relating to the protection of specific resources. These laws influence how and where a development may be located and operated, and what special requirements may be imposed based on site conditions. Examples of laws and regulations that apply to land use on federal lands include:

- The National Environmental Policy Act of 1969
- The Federal Land Policy and Management Act
- California Desert Protection Act
- Omnibus Public Land Management Act
- Wild and Scenic Rivers Act
- National Trails System Act
- The Bureau of Land Management (BLM) Manual 6320
- Energy Policy Act of 2005
- Executive Orders 13212, 13514, 3285, and 3285A1
- BLM Solar Energy Development Policy

Examples of resource-oriented federal acts that apply nationwide, and not just on federal lands, include:

- The Federal Endangered Species Act
- The Migratory Bird Treaty Act
- The Bald and Golden Eagle Protection Act of 1940, as amended
- The National Historic Preservation Act

State Land Use Controls and Siting Authorities

Each state has laws and regulations pertaining to land use and development. Generally, most land use decisions are made at the local level by county or municipal governments. Approvals may be required at the state level, at the local level, or both. The body having jurisdiction may vary depending on the size and type of facility, with facilities using particular technologies or being below a particular size threshold considered locally, while other technologies and larger facilities are considered at the state level, or through a combination of state and local decision making. As with federal resource protection regulations, states also have specific resource protection laws that affect the siting and operation of facilities.

Siting authority for renewable energy may be shared by various levels of government. In California, for example, thermal power plants of 50 MW or greater in capacity (including solar thermal and geothermal) are in the jurisdiction of the California Energy Commission (CEC); transmission additions by investor-owned utilities are subject to review by the California Public Utilities Commission (CPUC). Non-thermal solar (photovoltaic) and all wind energy development normally undergo review based on the land jurisdiction: locally at the county or municipal level for private land, or by BLM for its land.

Local Jurisdictions

If not preempted by state or federal authority, local regulations may affect whether and how renewable energy development occurs. Conditional use permits under local zoning, property line setback requirement and noise level restrictions, and similar regulations and ordinances are examples of requirements that may apply.

4.1.2 Baseline Conditions in Study Areas

This section presents the baseline land use conditions of the study areas in the order of the renewable energy resource types, as follows:

- Inside California Solar
- Inside California Wind
- Inside California Geothermal
- Out-of-State Solar
- Out-of-State Wind

These baseline conditions are summarized in Table 4.1-2 for solar areas and Table 4.1-3 for wind areas.

Table 4.1-2. Baseline Land Use for Solar Study Areas

Solar Study Area	Population Density *(Potential for Conflict)*	Agriculture Activity *(Potential to Result in Land Use Conversion)*	Proximity to Excluded or Protected Areas *(Potential Incompatibilities)*
Greater Carrizo	Low/Medium	Moderate	Medium
Greater Imperial	Low	Moderate	High
Kramer & Inyokern	Low	Moderate	High
Owens Valley and Inyo	Low	Low	High
Riverside East & Palm Springs	Medium/High	Moderate	High
Tehachapi	Medium	Low	High
Westlands	Medium	Extensive	Medium
Out-of-State Southwest Solar	Low	Low	Low

Table 4.1-3. Baseline Land Use for Wind Study Areas

Wind Study Area	Population Density *(Potential for Conflict)*	Agriculture Activity *(Potential to Result in Land Use Conversion)*	Proximity to Excluded or Protected Areas *(Potential Incompatibilities)*
Central Valley North and Los Banos	Medium	N/A	Low
Greater Carrizo	Medium	N/A	Medium
Greater Imperial	Medium	N/A	High
Riverside East & Palm Springs	Medium/High	N/A	Medium
Solano	High	N/A	High
Tehachapi	Medium	N/A	Medium
Out-of-State Northwest	Low	N/A	Low
Out-of-State Utah	Low	N/A	Low
Out-of-State Wyoming	Low	N/A	Low
Out-of-State New Mexico	Low	N/A	Low

Inside California Solar

Greater Carrizo Solar

The Greater Carrizo solar study area consists of three geographically separate parts. Two are in eastern San Luis Obispo County, in the greater Cholame Valley area of the Temblor Range and in the Carrizo Plain to the south. The third area is in northwestern Santa Barbara County, around Santa Maria and Orcutt.

- The Cholame Valley region consists of a series of valleys and coastal range mountains. A small amount of irrigated agriculture occurs, but most of the land is grassland with some oak woodland. South of this area is the Carrizo Plain, which is bisected by Highway 58 connecting Highway 101 and the San Joaquin Valley. While some irrigated agriculture occurs, most land is rangeland or vacant. Two large solar facilities are already located in the Carrizo Plain area. Most of the two areas have low to medium population density, ranging from 2.8 to 15 persons per square mile.
- The area around Santa Maria and Orcutt includes both developed urban land and extensive irrigated farmland. The central core of the area, along the Highway 101 corridor, is well populated, but east and west of this corridor are extensive agricultural lands, particularly to the east, where the census tract population density is 13.7 persons per square mile.

There are 6 protected land uses in or within 5 miles of the Greater Carrizo solar study area: 2 BLM Areas of Critical Environmental Concern; an Air Force Base; a National Forest; a National Monument; and a Wilderness area.

Greater Imperial Solar

The Greater Imperial Solar study area includes Imperial County and part of San Diego County. In Imperial County the major solar area includes the land east of Salton Sea and extends south to the Mexico border to the eastside of the agricultural land found here. Smaller solar development areas are found to the west of this agricultural area in Imperial County as well. Other portions of this study area are in eastern San Diego County, around Jacumba Hot Springs and Boulevard, Warner Springs, and Borrego Springs, respectively.

- In Imperial County, the solar study areas are largely in desert, outside of the extensive irrigated agricultural land that extends from the Salton Sea south to the Mexico border. These flat lands are either rangeland or vacant, with sparse vegetation. Population density is low, ranging from 0.2 to 5.8 persons per square mile, with most of the area at the low end of the range.
- The three areas in San Diego County are in census tracts with populations densities per square mile of 6.6 persons (Warner Springs area), 4.2 persons (Borrego Springs area), and 16.9 persons (Jacumba Hot Springs/Boulevard area). The Warner Springs area is southeast of Palomar Mountain in rolling terrain that is principally dry rangeland. The Borrego Springs area has a limited area of irrigated agriculture and a moderate density town, Borrego Springs, but most of the area is desert with sparse vegetation. The Jacumba Hot Springs/Boulevard area is along the Mexico Border and extends north past Interstate 8. The land primarily is shrubland and the terrain varies from flat to hilly.

There are 26 protected land uses in or within 5 miles of the Greater Imperial solar study area: 13 BLM Areas of Critical Environmental Concern; 7 military installations or areas; a National Forest; a National Wildlife Refuge; a State Park; and 3 Wilderness areas.

Kramer and Inyokern Solar

The Kramer and Inyokern solar study area consists of four parts: one in Searles Valley near the San Bernardino/Inyo county line, one near Newberry Springs on the north side of Interstate 40, one west of Highway 395 west of Victorville, and one in Lucerne Valley east of Victorville.

- The Searles Valley area is largely vacant flat land with sparse desert vegetation. It is within a census tract having a population density of 1.6 persons per square mile.
- The solar area east of Newberry Springs supports a limited amount of irrigated agriculture, but most of this flat landscape is sparsely vegetated desert. The area is in a census tract with a population is 0.5 persons per square mile.
- The area west of Highway 395 near Victorville is largely a desert landscape with scattered shrub vegetation. Most of the area's population is in developments near the intersection of Highways 395 and 18. The land to the north and west of the populated area is in a census tract having an overall population density of 29.1 persons per square mile.
- The Lucerne Valley area supports some irrigated agriculture, but much of the area is shrub covered desert, including some playas. The area includes portions of three census tracts having population densities ranging from 2.6 to 71.7 persons per square mile, with nearly half of this solar area in a tract with a density of 11.2 persons per square mile.

There are 23 protected land uses in or within 5 miles of the Kramer and Inyokern solar study area: 14 BLM Areas of Critical Environmental Concern; 3 military installations; 2 National Forests; 2 Research Natural Areas; and 3 Wilderness areas.

Owens Valley Solar

Three of the four Owens Valley solar study area locations are near Highway 395: one at the north end of Inyo County east of Bishop; one south of Lone Pine at Owens Lake; and one farther south in the Dunmovin and Coso Junction vicinity. The fourth area is to the east, on the Nevada border near Pahrump, Nevada.

- The area east of Bishop has limited irrigated agriculture and is mostly shrubby grassland in flat to rolling terrain. The population density in the two census tracts within which the area is located ranges from 4.3 to 8.8 persons per square mile.

- The Owens Lake area is in the former lakebed characterized by shrubland. The area south of Owens Lake (Dunmovin/Coso Junction vicinity) and the area south of Pahrump are flat desert shrubland. These three areas fall within the same census tract, which has a population density of 0.5 persons per square mile.

There are 23 protected land uses in or within 5 miles of the Owens Valley study area: 6 BLM Areas of Critical Environmental Concern; a military installation; a National Forest, and 14 Wilderness areas.

Riverside East and Palm Springs Solar

The Riverside East and Palm Springs solar study area includes two areas in the Palm Springs/Indio vicinity and several locations in the I-10 corridor extending from Desert Center east to Blythe and including the desert area around Blythe. In the Palm Springs/Indio vicinity, one area is primarily north of I-10, between Whitewater and Desert Hot Springs, the other is east and south of Indio in the Coachella Valley.

- The solar area that includes Desert Hot Springs is a mix of open desert and city development. Outside of the main developed part of Desert Hot Springs the desert landscape is divide into large residential parcels and smaller residential properties along widely spaced roads. Numerous energy-related facilities exist in the area, including solar farms, wind farms, transmission lines, and substations. In this solar area, the census tract having most desert has a population density of 83.5 persons per square mile.
- The Coachella Valley solar area is extensively developed over about half the area. The portion of the area on both sides of I-10 is largely desert, and east of Highway 86 is irrigated agriculture. These less developed parts of the solar area have a population density of 0.5 and 115.3 persons per square mile, respectively. The larger value results from the inclusion in the census tract of portions of Coachella and Thermal, as well as farmland.
- The solar areas in Eastern Riverside are in the less developed parts of the desert, with sparse shrub vegetation and little agricultural activity. Several solar facilities have been developed in the area. The population density in this part of Riverside County is 0.5 persons per square mile.

There are 26 protected land uses in or within 5 miles of the Riverside East and Palm Springs solar study area: 10 BLM Areas of Critical Environmental Concern; a National Forest; a National Monument; a National Park; a National Preserve; a State Park; and 11 Wilderness areas.

Tehachapi Solar

The Tehachapi solar study area is east of the Tehachapi Mountains and North of Los Padres National Forest and consists of two geographic areas.

- The larger area is in the desert between the Tehachapi Mountains and Edwards Air Force Base, extending north from about Neenach on Highway 138 to Cantil on Highway 14. There are small communities and rural residences in parts of the area. However, the overall population density is low. The four census tracts that comprise most of the area have densities of 5.6, 7.4, 8.1, and 37.3 persons per square mile.
- The second area is around the City of Lancaster and includes the city and surrounding region, extending south to Palmdale. Much of this area is built up, but large sections in the west and southeast remain open. The grid-based road pattern has a mix of open land, road front residential, and subdivisions that have leapfrogged from the cities. Irrigated agriculture is practiced in portions of the southeast quadrant of the area, where the lowest population density in the area occurs, at 9.8 persons per square mile. In the western portion of the area, several large solar fields have been

developed. In this area, the population density if 567.8 persons per square mile, which contrasts with the tract immediately north of this one that has a density of 48.8 persons per square mile.

There are 13 protected land uses in or within 5 miles of the Tehachapi solar study area: 6 BLM Areas of Critical Environmental Concern; 4 military reservations; a National Forest; and 2 State Parks.

Westlands Solar

The Westlands solar study area covers numerous small land parcels and a few very large parcels throughout southern San Joaquin Valley, from Madera and Fresno Counties south to the Tehachapi Mountains in Kern County. Many individual parcels are in or near populated areas, while others are in sparsely populated agricultural areas. The largest single contiguous area, representing well over half of the total Westlands solar area acreage, is in western Fresno and Kings Counties, east of Interstate 5. High concentrations of heavy metals, salts, and other chemicals in the soils here have adversely affected the quality of water draining from the area, resulting in the need to permanently retire some lands and discontinue irrigation. The population density in the four large census tracts covering much of this contiguous west valley area ranges from 7.1 to 26.1 persons per square mile, with most of the population in crossroad centers, farmsteads, and residences along road frontages.

There are 8 protected land uses in or within 5 miles of the entire Westlands solar study area: 6 BLM Areas of Critical Environmental Concern; a Naval Air Station; and a National Wildlife Refuge.

Inside California Wind

Central Valley North and Los Banos Wind

The Central Valley North and Los Banos wind study area straddles Interstate 5 east of the San Luis Reservoir. Most of the area is west of the Interstate, surrounding the O'Neill Forebay; here the flat to rolling terrain is used for rangeland or hay production. The portion of the area east of the freeway is mostly in irrigated agriculture. Several transmission lines traverse the area and a large solar farm has been developed near the National Cemetery west of the Interstate, and more are planned. The census tract in which nearly all of the area is located has a population density of 6.2 persons per square mile.

There are 4 protected land uses in or within 5 miles of the Central Valley North and Los Banos wind study area: the San Joaquin Valley National Cemetery; 2 State Parks; and a State Recreation Area.

Greater Carrizo Wind

The Greater Carrizo study area for wind includes areas with distinctly different characteristics in San Luis Obispo and Santa Barbara Counties. These areas include:

- The sparsely populated coastal plain and foothills north of San Simeon to about 4 miles south of the county line. The area is in a census tract where the population density is 7.4 persons per square mile and the land is predominately grassland with scattered woodlands in ravines and along drainages. Much of the area is visible for scenic Highway 1 (Cabrillo Highway)
- The coastal hills and mountains east of Atascadero and Santa Margarita, crossed by Highways 229 and 58. This area includes portions of two census tracts, with the population density ranging from 15 to 61 persons per square mile. The area is characterized by widely spaced rural roads and houses, with much of the land covered in oak woodlands and grassland. Views are limited by topography and vegetation.
- The Temblor Range west of the Carrizo Plain, South of Highway 41 and north of Highway 58 near the Kern County border. The area is in two census tracts, with population density ranging from 6 to 15.8

person per square mile. This area is drier than the wind resource areas nearer the coast, and is predominately hilly grassland.

- The coastal mountains east and south of Vandenberg AFB. The wind resource areas here are dispersed across four census tracts having population densities ranging between 14.1 and 60.6 persons per square mile. South of Lompoc to Gaviota, the landscape includes hill and ridge areas on both sides of scenic Highway 1. Inland, the wind resource areas are primarily on grass-covered ridgelines, with much of the intermountain flatlands in row crops and other forms of agriculture.

There are 9 protected land uses in or within 5 miles of the Greater Carrizo wind study area: a BLM Area of Critical Environmental Concern; a military reservation; a National Forest; a National Monument; 2 State parks; and 3 Wilderness Areas.

Greater Imperial Wind

The Greater Imperial wind study area is in four separate parts of eastern San Diego County: a mountainous area west of Holcomb Village and east of Anza-Borrego Desert State Park; a mountainous area south of Warner Springs and east of Highway 79; a mountainous area between Santa Ysabel and Julian; and the Mexico border region between Campo and the Imperial County line, primarily south of Interstate 8.

- The northern area is primarily rolling to steep terrain with dense shrub and tree growth. The flatter areas here are occupied by large-lot homesteads, small agricultural operations, and horse facilities. The area south of Warner Springs varies from flat to steep terrain. The flat lands are primarily rangeland, with the slopes and ridges primarily covered in grass and shrub growth. Trees are found along drainages between ridges. Population density in the census tract where both the northern and Warner Springs areas are located is 5 persons per square mile.
- In the Santa Ysabel and Julian area, flat lands and rolling topography are occupied by low density housing and grasslands, with some agriculture. Slopes and ridges tend to be grassland or mixed woodlands. The area is in two census tracts, with population density ranging from 5 to 43.2 persons per square mile. Based on the distribution of housing in the area, the overall density within the wind area is likely to be at the higher end of the range. Tribal land is not included in this study area.
- The wind area along the Mexican border overlaps to a large degree with the solar area in this area. The flat to rolling topography is covered primarily in shrub growth, with decreasing vegetation moving east toward Imperial County. Flatter and more accessible areas are often large-lot homesteads. The population density in this census tract is 15.9 persons per square mile.

There are 17 protected land uses in or within 5 miles of the Greater Imperial wind study area: 4 BLM Areas of Critical Environmental Concern; 2 military reservations; a National Forest; a National Wildlife Refuge; a Research Natural Area; 2 State Parks; and 6 Wilderness Areas.

Riverside East and Palm Springs Wind

The Riverside East and Palm Springs wind study area includes in two parts. The largest area is north of Thousand Palms, north of Interstate 10. A smaller area is east of Indio.

- The area north of Thousand Palms is mountainous interspersed with flat desert, and supports scattered desert shrub vegetation. Large lot residential properties are found in the flat lands at the northern part of the area. The larger wind area is in two census tracts with population densities ranging from 16 to 31.8 persons per square mile; however; this includes population centers within the census tract but outside the wind area.

- The small area east of Indio and north of Interstate 10 is primarily flat land with sparse desert shrub vegetation. The small area east of Indio is within a vast census tract with a density of 0.7 persons per square mile.

There are 8 protected land uses in or within 5 miles of the Riverside East and Palm Springs wind study area: 3 BLM Areas of Critical Environmental Concern; a National Forest; a National Preserve; a National Wildlife Refuge, 2 Wilderness Areas.

Solano Wind

The Solano wind study area includes a number of separate areas within a region roughly bounded by a triangle from San Francisco Bay northeast to Sacramento and south past Stockton, essentially an enlarged Delta area. Individual wind areas are designated in Yolo, Sacramento, Contra Costa, Alameda, and San Joaquin Counties. Large existing wind developments are found at Montezuma Hills in Solano County and Altamont Pass in Alameda County. The areas comprising the Solano wind study area are found in two topographic conditions: East Bay Hills and delta-valley. Near the bay, the wind areas are on ridges in the East Bay hills, including near Martinez, Concord-Antioch, and Livermore-Tracy. In the delta and Central Valley, the areas are in flat lands influenced by the wind flows between the Golden Gate and the valley.

- The areas in the East Bay hills are predominately along grassland ridges with trees occurring in inter-ridge valleys and on slopes. Many of these areas include public parkland and open space or are protected water supply reservoir watersheds. None of the census tracts for the wind areas in the hills in Contra Costa County have fewer than 100 persons per square mile; they range from 132 to well over 1,000 persons per square mile.
- The areas in the Yolo, Sacramento, and San Joaquin County portions of the San Joaquin and Sacramento River deltas are primarily flat farmland. In Yolo County, the areas are a mix of foothill grasslands and farmland. High value crops, including nuts and grapes, are produced in the region. Here the population density range is from 16.5 to 75.1 persons per square mile. The wind areas in Sacramento County range from 22.7 to 109.4 persons per square mile; in the Tracey area they range from 9.1 to 208.3 persons pes square mile.

There are 11 protected land uses in or within 5 miles of the extended Solano wind study area: a BLM Area of Critical Environmental Concern; 4 military installations; a National Historic Park; 3 National Wildlife Refuges; and 2 State Parks.

Tehachapi Wind

The Tehachapi wind study area is comprised of six geographic areas, five in Kern County and one small area in Ventura County.

- The Kern County areas are on the east side of the Tehachapi Mountains and in the adjacent desert. The mountainous areas have sharply defined ridges and are vegetated in shrubs. The flat desert areas have a moderate shrub cover, and some irrigated agriculture takes place. The population density in the mountainous areas ranges from 3.4 to 8.3 persons per square mile. In the desert areas, the population density ranges from 4.2 to 32.8 persons per square mile, with the higher density tract including residential areas north of Lancaster.
- The wind area in Ventura County is in the steep, shrub covered mountains north of Simi Valley and south of the Santa Clara River. While the mountains are very sparsely populated, the flatlands in the area are heavily populated. The wind area here includes portions of three census tracts with population density ranging from 228.8 to 469.7 persons per square mile.

There are 7 protected land uses in or within 5 miles of the Tehachapi wind study area: 4 BLM Areas of Critical Environmental Concern; a military installation; a National Forest; and a State Park.

Inside California Geothermal

Greater Imperial Geothermal

The geothermal study area in Imperial County is on lands near the south end of the Salton Sea, and in portions of the agricultural land extending south from the Salton Sea, including areas north of Calipatria, Brawley, and Imperial. The areas east and west of the Salton Sea are primarily desert, while the remaining areas are in irrigated agricultural land. The population density in the geothermal areas ranges from 5.4 to 128.7 persons per square mile, reflecting the variety of land uses, from open desert to farmland near urban areas.

There are 21 protected land uses in or within 5 miles of the Greater Imperial geothermal study area: 10 BLM Areas of Critical Environmental Concern; 8 military installations; a National Wildlife Refuge; a State Park; and a Wilderness Area

Out-of-State Solar

Southwest Solar (Arizona)

The two study areas for solar in southwest Arizona are in Maricopa and Yuma Counties.

- The Harquahala study area in Maricopa County is generally flat with sparse desert vegetation. Most of the land is open and uninhabited. However, some irrigated agriculture occurs in the far western portion the study area and along the Gila River in the eastern part of the study area. The primary built land uses are power plants and substations and their associated transmission lines. The area includes the large Palo Verde Nuclear Generating Station as well as conventional power plants, and nearly 2,000 acres of existing solar PV. The census tract that includes most of the Harquahala study area has a population density of 3.5 persons per square mile.
- The Hoodoo Wash area in Yuma County also is generally flat desert, with some areas in the western portion of the study area irrigated agriculture. An existing solar farm nearly 2,000 acres in extent is within the area, along with a substation and transmission lines. The census tract that includes the Hoodoo Wash study area has a density of 0.6 persons per square mile.

There are 5 protected land uses in or within 5 miles of the Southwest solar study area: a BLM Area of Critical Environmental Concern; a military range; and 3 Wilderness Areas.

Out-of-State Wind

Northwest Wind (Oregon)

The two study areas for wind in the Northwest are in the Columbia River vicinity. One, east of The Dalles, includes land in Klickitat County, Washington and Sherman and Gilliam Counties, Oregon, and is roughly bisected by the Columbia River. The second is in Umatilla and Morrow Counties, Oregon, on the Umatilla Plateau southwest of Pendleton and west and north of Umatilla National Forest

- The area centered on the river is hilly terrain with incised drainages and mesas; the vegetation mostly is grass and shrubland. Some areas are irrigated, and the land is used primarily for range and hay production. Rows of existing wind turbines are found along several ridgelines. The area is in portions of three census tracts, which range in density from 1.6 to 6.6 persons per square mile.

- The terrain in the Umatilla and Morrow Counties study area is in rolling to hilly grassland with a dendritic drainage pattern. Much of the land is used as unirrigated pasture. Within the study area the population density in the two census tracts that include most of the area are 1.8 and 1.9 persons per square mile, respectively.

There are 6 protected land uses in or within 5 miles of the Northwest wind study area: a BLM Area of Critical Environmental Concern; 2 National Forests; a National Wildlife Refuge; and 2 State Parks.

Utah Wind

The Utah wind study area consists of five separate areas in southwestern Utah, east of Interstate 15 in Millard and Beaver Counties.

- The desert landscape of the areas in Millard County is sparse shrubland with a dry hilly to mountainous terrain. Millard County has a population density of 2 persons per square mile
- The areas in Beaver County include a similar environment as is found in Millard County, however one area south of the community of Milford supports irrigated alfalfa cropland over about ¼ of the area. Beaver County has a population density of 3 persons per square mile.

There are 3 protected land uses in or within 5 miles of the Utah wind study area: 2 BLM Areas of Critical Environmental Concern and an Experimental National Forest.

Wyoming Wind

The two study areas for wind in Wyoming are in the southeast quadrant of the state. One is primarily in Laramie and Albany Counties in south-central Wyoming, and the other in Carbon County, near the southeast corner of the state. The south-central study area is south of Interstate 80 and Rawlins and is primarily rolling sagebrush steppe scrubland. Over 90percent of the county's farmland is pastureland. The population density in the study area ranges from 0.7 to 1.7 persons per square mile, with most of the area is the lower density census tract.

- The southeastern study area extends east and north of the City of Laramie and consists of foothills and mid-elevation scrublands. Agricultural units tend to be thousands of acres in size. Range grass, hay, and livestock production are the predominant uses. The population density in the three census tracts that include most of the area ranges from 0.5 to 5.5 persons per square mile.

There are 2 protected land uses in or within 5 miles of the Wyoming wind study area: a BLM Area of Critical Environmental Concern and a National Forest.

New Mexico Wind

The two study areas identified for wind in New Mexico are principally in Quay and Curry Counties, along the Texas border, and in Lincoln County, in west-central New Mexico

- The eastern most study area includes the proposed Tres Amigas "super substation" and transmission facilities. Tres Amigas has been granted the right to lease 14,400 acres (22.5 square miles) of land in Clovis by the New Mexico State Land Office for this system. Much of the study area is flat plains, but the northernmost part of the area includes the Caprock Escarpment, a transition between the level high plains and the rolling and incised terrain to the north. The predominant land use in the area is agriculture, with most of Quay County in pasture while Curry County is about equally divided between cropland and pasture. The two census tracts in the study area have population densities of 1.1 and 6.0 persons per square mile.

- The study area in Lincoln County includes the proposed endpoints for SunZia Southwest Transmission Project and the Centennial West Clean Line transmission project. Ranching is the dominant land use. The west-central study area is in two census tracts, with population densities of 0.8 and 2.1 persons per square mile; most of the area is in the lower density tract.

There are 3 protected land uses in or within 5 miles of the New Mexico wind study area: a BLM Area of Critical Environmental Concern and 2 National Forests.

4.1.3 Typical Land Use Impacts of the Buildouts

This section describes the land use impacts that would be common across the scenarios as a result of the incremental buildout of new solar, wind, and geothermal energy. Typical land use impacts associated with development of renewable energy and transmission facilities are categorized as either construction-related or related to operations, as follows:

- During construction activities, short-term impacts result from increased noise and air emissions (exhaust and dust), alterations in the visual landscape and presence of workers and equipment, or exposure to hazards or hazardous materials.
- During ongoing operations and maintenance activities, long-term impacts result from the conversion of existing land uses to a more industrial use and exclusion of alternative or planned land uses.

Note that the SB 350 environmental study is not site-specific and does not reflect or represent a siting study for any particular planned or conceptual construction project. Although environmental impacts are described in general, project-specific impacts can typically be managed through best management practices and mitigation through the siting processes and with review by the siting authorities. Conflicts in land use can often be avoided or reduced on a case by case basis during the state or local siting processes.

Construction Impacts in General

The impacts of construction on adjacent residential, commercial, recreational, and agriculture uses would be similar for solar, wind, geothermal and transmission. Impacts would include dust, noise, traffic, and similar 'nuisance' effects associated with vegetation removal, ground disturbance, and erecting facilities. For agriculture, off-site impacts could include: damage to equipment, crops, and livestock; competition for water resources; water and soil contamination; suppression of crop growth by fugitive dust; soil erosion; and the spread of weeds.

Visual changes due to utility-scale renewable facility and transmission development result from a range of activities, including:

- Disturbance of ground surface.
- Alteration or removal of vegetation and landforms.
- Introduction of structures (e.g., energy collection and generation units, buildings, towers, and ancillary facilities).
- Development of new or upgraded roads.
- New or upgraded utilities and/or rights-of-way (e.g., widening of rights-of-way, addition of transmission lines, and upgrading of transmission capacity).
- Presence and movement of workers, vehicles, and equipment.
- Visible emissions (e.g., dust and water vapor plumes).
- Reflectance, glare, and lighting.

Solar Construction

Large-scale solar generation facilities are normally located on flat to gently sloped or rolling terrain. Installation of large fields of solar arrays typically requires vegetation removal and grading to level the land under linear arrays and to develop access roads. For security, sites are usually fenced.

Solar project visual impacts vary based on the technology used, but they have a number of common features, including grading that creates color and texture contrasts between existing soil and vegetation conditions and the disturbed, unvegetated project footprint. Ground disturbance also creates opportunities for visible windblown dust clouds to occur. Numerous vehicles and pieces of equipment are needed to prepare the site and deliver and install the arrays during construction, resulting in visual effects associated with movement, dust, and the presence of the vehicles and equipment. Glint and glare from equipment and materials may occur during construction. Also, temporary structures may be erected for facilitate assembly and to provide site offices and storage.

Wind Construction

Utility-scale wind energy facilities can preclude certain types of land uses but allow for other compatible land uses to continue. Land disturbance includes creation of access roads and preparation of turbine sites, but does not require disturbing all of the land within the property. Because of the large amount of space between turbines, existing roads within a property may be use to access some turbines, reducing the need for new roads. Spur roads to individual towers would still be required. Agricultural uses could continue to occur during construction in areas not required for individual tower development, roads, or materials laydown.

For wind energy construction, large cranes and other equipment would be needed to prepare foundations and assemble and mount towers, nacelles (turbine housings), and rotors. This construction equipment and its laydown areas would be especially visible and prominent near the activity and from a middle distance (within 5 miles). Construction equipment would produce emissions and may create visible exhaust plumes. Glint and glare from equipment may occur. The disturbed footprint of individual turbines typically would be small, but for a field of turbines can be extensive.

Geothermal Construction

Large geothermal developments may also require large areas for development. Land would be disturbed for surface facilities, well pads, and pipelines between the surface facilities and well pads. Access roads also would be needed. In some cases, these projects may include directional drilling to access geothermal resources from adjacent properties. In addition, geothermal construction can include multiple wells in each well pad, which limits the area of disturbance (surface footprint) for well development.

Visual impacts during construction would include the presence of equipment and materials, vegetation removal and ground disturbance, dust, and glint and glare from equipment and materials.

Operational Impacts in General

The presence of solar and geothermal facilities eliminates potential alternative uses of the land such as residential, commercial, and recreational uses. With some exceptions, most agricultural uses within a utility-scale renewable energy site would be eliminated as well because of the acreage needed and the nature of the energy system's physical components. Wind and transmission development, in contrast, would eliminate agricultural use only within the footprints of turbines, poles, and associated infrastructure.

Typical activities associated with renewable energy developments include ongoing facility operations; dust suppression; equipment maintenance, repair, and replacement; and fire and fuel management. A facility would require the long-term use of tracts of land, converting land from its existing use and limiting alternative uses, and potentially disrupting or degrading adjacent land uses. This impact would be greatest for solar developments, which occupy large portions of a site, as they depend on large surface areas to capture solar energy.

The operation and maintenance of facilities could have some ongoing impacts on adjacent agricultural lands. The range of impacts are similar to those of construction and potentially include: damage to equipment, crops, and livestock from increased traffic on farm roads; competition for water resources; water and soil contamination; soil erosion; spread of weeds; and shading of crops.

The operation and maintenance of renewable energy facilities and related transmission lines and roads, and their associated rights-of-way, would have long-term adverse visual effects. Among these are land scarring, introduction of structural contrast and industrial elements into natural or minimally disturbed settings, view blockage, and skylining (silhouetting of project elements against the sky). Renewable energy facilities generally include both enclosed and open workspaces, exterior lighting around buildings, access roads, fencing, and parking areas. Built structures (buildings, piping, fencing, collector arrays, towers, etc.) would introduce industrial elements into the landscape and contrast with surrounding undisturbed areas in form, line, color, and texture. They also can block views and create skylining, depending on their height and location relative to the viewer. The need for security and safety lighting could contribute to light pollution in areas where night lighting is otherwise absent or minimal. Light impacts may include skyglow, off-site light trespass, and glare or reflection. Localized visible dust may be created by vehicles and equipment operating within the site or along a right-of-way or access road. Without proper disturbed soil management strategies, wind can mobilize dust and create visible plumes or clouds of dust.

Solar Operations

Once in operation, ongoing ground disturbance at solar facilities is not required, although periodic vegetation control and road repair may occur. Dedicating a site to solar development normally precludes most other land uses. However, in certain cases, a solar photovoltaic project can allow limited grazing activities or allow some wildlife movement. The extent to which a site could function as a wildlife corridor would depend on the nature of any fencing that might be required and whether particular small mammal species (especially kit foxes) could pass through the fenced property.

Photovoltaic facilities generally have lower visual impacts than solar-thermal technologies because of the comparatively low profile of the collector arrays and the lower reflectance of photovoltaic panels, as compared with mirrors used in other technologies. Operating photovoltaic facilities do not have steam turbines, cooling towers, or steam plumes and have few lights and a low level of onsite worker activity. Still, some panels can be reflective, especially when viewed from elevated locations or from certain angles or times of day, and can be visible for long distances (up to 20 miles). Power conversion units (inverters) associated with these facilities can also cause visual contrasts. Because photovoltaic facilities do not require the infrastructure of other solar technologies (e.g., towers, turbines, boilers), they are visually simpler, more uniform, and have lower visual contrast. All types of renewable energy facilities require a transmission lines to interconnect to the power grid.

Wind Operations

Operating wind turbines would be compatible with uninhabited land uses such as most agriculture. The area immediately around each turbine tower as well as access roads would be unavailable, but other land within the overall site could be available for agricultural use. Ranchers and farmers can continue the agricultural uses of the land (particularly grazing) while also leasing turbine sites to others or participating directly in wind projects, thereby increasing their income.

Wind energy project components are highly visible because of the large and very tall (over 300 feet) towers and rotating turbines that would be erected in areas where there may be few, if any, comparable tall structures. Night aviation safety lighting (blinking red lights and/or white strobe lights) are required by the FAA. Visibility and contrast would be heightened at locations where they these structures are sited along mesas or ridgelines, silhouetting them against the sky. Wind turbines may create visually incongruous “industrial” associations for viewers, particularly in predominantly natural landscapes. Their moving blades attract visual attention.

Depending on the time of day, the shadows of towers and moving turbine blades extend across the landscape. The direction and length of this effect vary with the relative position of the sun in various seasons and at different times of the day, with morning and evening producing the longest shadows. The regular periodic interruption of sunlight by rotating turbine blades may produce a strobe-like effect, flickering alternating light and shadow over the area where the shadow is cast. During the life of a wind facility, towers, nacelles, and rotor blades may need to be upgraded or replaced, creating visual impacts similar to the impacts occurring during initial tower construction and assembly.

Geothermal Operations

Depending on the location of well pads and surface facilities (including pipelines) some portions of geothermal sites may be available for limited agricultural grazing. However, because geothermal operations normally require extensive pipelines and active wells on the surface, and they are within a controlled site, relatively little land around project components is normally available for other uses.

Visual impacts associated with the operation and maintenance of geothermal energy facilities largely derive from ground disturbance and the visibility of industrial power plants, production and injection well pads, pipes, cooling towers, steam plumes, and transmission lines.

4.1.4 Land Use Impacts of Regionalization

The 2020 CAISO + PAC scenario includes no incremental renewable energy development beyond what is already planned to meet California’s 33% RPS by 2020. For limited regionalization in 2020, there would be no incremental construction activities, and no land use changes or adverse effects would occur in this scenario.

Each scenario of regionalization in 2030 requires an incremental buildout of new solar, wind, and geothermal energy facilities that will create environmental impacts in the vicinity of the renewable energy buildout. This section describes the locations of potential land use impacts related to each incremental buildout, inside California and elsewhere, to facilitate a comparison of the scenarios and identify the tradeoffs between in-state versus out-of-state development.

Incremental Buildout for Current Practice Scenario 1 by 2030

Inside California

Solar. Under Current Practice Scenario 1, the solar portfolio in California emphasizes:

- Areas having population densities ranging from low to medium/high, with most occurring in areas of medium density.
- Areas with low to extensive levels of agricultural activity.

- Areas within 5 miles of a medium to high number of excluded or protected areas.

Current Practice Scenario 1 includes 7,601 MW of incremental solar buildout inside California, requiring about 53,000 acres, or about 83 square miles. Over 60 percent of the total generation Current Practice 1 would be in two areas, Tehachapi and Westlands. The remaining 40 percent of the generation would be shared among five other resource areas. The Tehachapi solar area is traversed by Highways 14, 58, and 138. It surrounds the cities of Mojave and Lancaster and is north and west of Edwards AFB. Except for in Mojave and Lancaster and a few small towns and cities in the area, the population density is very low. The land is flat desert with sparse vegetation, with some small areas in irrigated agriculture.

A large contiguous part of the Westlands study area east of Interstate 5 in the southern San Joaquin Valley is primarily in agricultural uses or fallow; this part alone covers over 250,000 acres (390 square miles). The land is flat and the population density across the area is low to moderate, with population occurring primarily in scattered crossroad communities and along road frontages.

Given the overall low population density in the solar study areas, and the lack of widespread agriculture in most of the study areas, impacts on land use and agriculture are expected range from low to moderate. The Westlands area has more agriculture than the other solar study areas, but because of constraints imposed by water availability and extensive soil impairment, the area is less suitable for intensive farming than other regions of the San Joaquin Valley. Several solar projects already exist in this area and more are proposed. While several of the solar study areas are within 5 miles of several land uses considered to be protected (wilderness, recreation areas, National Parks, refuges, military installations, etc.) the low physical profile of solar components is expected to result in little or no adverse visual impact to these areas and to not represent a concern to most military operations.

Wind. Under Current Practice 1, the wind portfolio in California emphasizes:

- Areas having population densities ranging from low to high, with most occurring in areas of medium density.
- Areas within 5 miles of a medium to high number of excluded or protected areas.

Current Practice 1 includes 3,000 MW of incremental wind buildout inside California. This would require 120,000 acres (or just over 31 square miles), assuming 40 acres per MW. Actual ground disturbance would be about 3 acres per MW (the remainder of the land remains open and is needed for setbacks and for siting of individual turbines so as to not interfere with each other's wind flow).

The Riverside East and Palm Springs wind study area would be fully built-out with 500 MW in this scenario, and the Solano study area would include 600 MW. The Solano wind study area is one of the more problematic in terms of wind turbine visibility and potential conflicts with adjacent land uses. Many parts of the Solano study area are in or near parks and water supply watersheds, where turbines would not be allowed. Aside from Riverside East & Palm Springs and Solano study areas, the others are in remote locations where siting would be less problematic. Some are near wilderness areas and parks, but most areas are sufficiently large that it would be feasible to site turbines far from these protected land uses.

Geothermal. As with each scenario, Current Practice 1 includes 500 MW of incremental geothermal buildout. Assuming 6 acres per MW, this would require 3,000 acres, or about 4.6 square miles. Surface facilities (generation stations, pumps, cooling towers, pipelines, well pads) would occupy a portion of the area. Multiple injection and extraction wells can be directionally drilled from a single pad, reducing the number of pads needed and the length of pipelines. In the open desert landscape, pipelines could affect recreational cross country access, which would be restricted for safety. In agricultural land, building and well pads may occupy previously farmed land.

Out of State

Under Current Practice 1, the out-of-state resources would include 1,000 MW of solar in Arizona and 4,551 MW of wind from Oregon, Utah, Wyoming, and New Mexico, including new generation capacity and RECs. Together this capacity would require nearly 220,000 acres, or 343 square miles. These study areas have population densities as low or lower than areas in California, suggesting that fewer people would be affected by land use impacts, either in terms of compatibility and agricultural displacement, and frequency of views.

Solar. Under Current Practice 1, the solar portfolio out-of-state emphasizes:

- Areas having low population densities.
- Areas with low levels of agricultural activity.
- Areas within 5 miles of a low number of excluded or protected areas.

The Arizona solar study area is an open space where solar development would not displace any existing uses or conflict with any mining or agricultural uses. Generation and transmission infrastructure are established uses in the Arizona study area, especially in Maricopa County, and new solar facilities would be compatible with existing uses.

Wind. Under Current Practice 1, the wind portfolio out-of-state emphasizes:

- Areas having low population densities.
- Areas within 5 miles of a low number of excluded or protected areas.

The Oregon, Utah, Wyoming, and New Mexico study areas could each accommodate the levels of wind energy generation identified in the 2030 Portfolios. Based on the sparse population densities within the study areas, and the use of much of the land as open range or pasture land, it is expected that there would be sufficient available land for wind turbines that there would be no significant conflicts with existing land uses. Where wind turbines would be potentially visible to protected land uses, there is sufficient land to site turbines so as to increase the distance between the turbines and the protected land uses in order to reduce this impact.

Incremental Buildout for Regional 2 by 2030

Inside California

Solar. Under Regional 2, the solar portfolio in California emphasizes:

- Areas having population densities ranging from low to medium/high, with most occurring in areas of medium density.
- Areas with low to extensive levels of agricultural activity.
- Areas within 5 miles of a medium to high number of excluded or protected areas.

Regional 2 would include 7,804 MW of incremental solar buildout in California, except with more solar development in the Riverside East and Palm Springs solar area and less in Westlands when compared with Current Practice 1. Generation in the other areas would be the same under both Current Practice 1 and Regional 2. Solar facilities under Regional 2 would require development on about 55,000 acres of land, or about 85 square miles. Impacts would be similar to Current Practice 1 with less acreage required in Westlands and more required in Riverside East and Palm Springs. The overall acreage under both scenarios is the same.

Wind. Under Regional 2, the wind portfolio in California emphasizes:

- Areas having medium population densities.
- Areas within 5 miles of a medium to high number of excluded or protected areas.

Regional 2 would include about 36 percent less wind buildout in California than Current Practice 1 by having no new wind generation in either the Riverside East and Palm Springs wind study area or the Solano wind study area. This scenario would eliminate new wind facility impacts in these areas, both of which have substantially more population than the other wind areas and which have potential land use constraints, especially in the Solano wind study area.

Geothermal. Regional 2 is identical to Current Practice 1.

Out of State

Under Regional 2, out-of-state resources would be about 10 percent less than under Current Practice 1 overall. However, it would increase the solar generation and RECs from Arizona while decreasing wind from Oregon, and generation from the other three out-of-state areas would remain the same. The increase in solar buildout in Arizona would have minimal land use effects, as the population density is very low, and solar and other forms of energy infrastructure are already sited in the area.

Incremental Buildout for Regional 3 by 2030

Inside California

Solar. Under Regional 3, the solar portfolio in California emphasizes:

- Areas having low population densities.
- Areas with moderate levels of agricultural activity.
- Areas within 5 miles of high number of excluded or protected areas.

Regional 3 would involve development of solar inside California on about 24,000 acres of land, or about 38 square miles. This scenario would rely more heavily on renewable energy imports from out of state than other scenarios. Except in the Kramer and Inyokern solar area, which includes 375 MW of solar in each scenario, new solar development in other study areas would be reduced by 30 to 100 percent.

Because of its reduced level of generation, Regional 3 would have less potential impact in California than other scenarios. About half of the affected land under this scenario would be in the Tehachapi solar area, but the amount of land affected here would be 30 percent less than under the other scenarios.

Wind. Under Regional 3, the wind portfolio in California emphasizes:

- Areas having medium population densities.
- Areas within 5 miles of a low to high number of excluded or protected areas.

Regional 3 is identical to Regional 2 in terms of wind generation and potential land use impacts. This scenario would eliminate new wind facility impacts in the Palm Springs and Bay Delta areas (Solano study area), both of which have substantially more population than the other wind areas and which have potential land use constraints, especially in the Solano wind study area.

Geothermal. Regional 3 is identical to Current Practice 1.

Out of State

Regional 3 would increase out-of-state generation while decreasing California generation. Solar generation from Arizona would be the same under Regional 2 and 3. Northwest wind generation from Oregon would be much less, and Utah wind also would be less than in other scenarios. However, Wyoming and New Mexico generation would rise substantially, from 500 to 2,495 MW in Wyoming and from 1,000 to 2,962 MW in New Mexico. This additional wind generation would need to be supported by additional high-voltage transmission. While the amount of land needed for wind generation in Wyoming and New Mexico would increase in Regional 3, much of the land would still be available as rangeland.

Out-of-State Transmission Additions

Under Regional 3, it is assumed that major out-of-state transmission additions would be necessary to integrate renewable generation from Wyoming and New Mexico into the regional power system and for California to achieve 50% RPS. The land use considerations related to the construction and operation of the transmission expansions are summarized in Section 5.

4.1.5 Comparison of Scenarios for Land Use

The change from Current Practice into regional scenarios allows the following comparisons.

Inside California

- Decrease in potential solar buildout in areas with some potential for impact due to land use conversion or potential incompatibilities
- Decrease in potential wind buildout in areas with medium or higher potential for impact due to potential incompatibilities, notably Solano

Out of State

- Increase in potential solar and wind buildout in areas with relatively low potential for impact due to land use conversion or potential incompatibilities

Regional 2 Relative to Current Practice 1

- Increased renewables development would occur in out-of-state areas with less potential for conflicts (lower population densities, less agriculture, fewer excluded or protected areas within 5 miles) as compared to development in California.
- California would have a slight increase in solar development, but a substantial decrease in wind development (eliminating new wind development in Riverside East and Solano wind study areas).

Regional 3 Relative to Current Practice 1

- Increased renewables development would occur in out-of-state areas with less potential for conflicts (lower population densities, less agriculture, fewer excluded or protected areas within 5 miles) as compared to development in California.
- California would have a slight increase in solar development and would decrease development of solar in Westlands but increase it in Riverside East and Palm Springs
- A substantial decrease in wind development would occur (eliminating new wind development in Riverside East and Solano wind study areas).

4.2 Biological Resources

This section describes the potential impacts to biological resources for the incremental renewable energy buildouts and the potential biological impacts of regionalization as compared with the current practice. The approach to the analysis relies upon a narrow set of baseline conditions that are treated as potential indicators or predictors of impacts, as listed in Table 4.2-1.

Table 4.2-1. Baseline Conditions and Indicators of Impacts, Biological Resources

Baseline condition of a study area	How are scenarios analyzed relative to the baseline?	Potential indicator of biological resources impact
Biological Resources		
Sensitivity of crucial habitat	Coincidence of incremental renewable energy buildout with mapped critical habitat or known occurrences of listed species	Special-status species or habitat
Distribution of riparian and wetland habitat	Coincidence of incremental renewable energy buildout with mapped sensitive natural communities, including riparian habitat, wetlands, or other waters	Riparian habitat, wetlands or other waters
Sensitivity of large natural areas and landscape connectivity	Coincidence of incremental renewable energy buildout with established corridors	Wildlife corridors

Assumptions and Methodology for Biological Resources Analysis

This analysis describes the baseline conditions for biological resources, and acknowledges the limitations of available data and the need for site-specific studies at the time of project-specific siting review. In addition, this study identifies the areas and the locations with limited data availability. The background information in this section also summarizes applicable federal, state, and local regulations governing biological resources that would apply to future renewable energy buildouts.

Crucial Habitat Assessment Tool

The Crucial Habitat Assessment Tool (CHAT) is used as the basis for the biological resources analysis. The CHAT was developed by the Western Governors' Wildlife Council as a tool to aid large-scale planning efforts in the western states, and it launched in December 2013. The Western Association of Fish and Wildlife Agencies assumed responsibility of the CHAT in April 2015, and continues to manage it and ensure data are kept current.

State-specific information on priority species and habitat has been developed for nine western states; these include all states within the west-wide region of study in this analysis (California, Arizona, Oregon, Washington, New Mexico, and Wyoming). These data are incorporated into the CHAT model.

For each buildout, biological resources assessment may include maps showing the CHAT scores in each of the following CHAT model output categories. Data are not available in all of the following categories for all areas; each development scenario will report available rankings for that location with an emphasis on categories that are available in all areas and will also report those data that are unavailable.

- Crucial Habitat Rank
- Species of Concern
- Large Natural Areas
- Landscape Connectivity
- Riparian and Wetland Habitat Distribution

Maps would be accompanied by a description of overall habitat sensitivity (Crucial Habitat Rank) along with the specific resources that contribute to the scores (Species of Concern, Landscape Connectivity, etc.). CHAT data is presented in hexagons with a resolution of one square mile for most states, and California and Wyoming map crucial habitat in three-square-mile hexagons. Therefore, multiple CHAT mapping units lie within each study area.

The biological resources assessment includes a description of overall habitat sensitivity within each of the study areas and identifies subareas within each polygon that may be more or less sensitive than other locations within the development area. The narrative describes any particular concerns that may be identified by the CHAT tool, such as a high score for wildlife connectivity in one part of a study area.

Other Data Sources

The CHAT data, which provides relatively standardized aggregate data across the western U.S., is supplemented by state- and species-specific data that is used to provide more detailed information on the biological resources within each study area. Many of these data sets have been incorporated into the CHAT rankings. Where federally listed species or designated critical habitat are identified, the analysis will describe any applicable recovery plans for those species. The following lists those datasets that are considered, in addition to the CHAT model for each buildout area.

California – Wind and Solar

- Local and regional renewable planning and conservation efforts: Desert Renewable Energy Conservation Plan (sensitive biological resources modeling and range data), BLM’s Western Solar Energy Program, San Joaquin Valley Solar Assessment, County efforts
- California Natural Diversity Database species occurrence information
- USFWS critical habitat boundaries
- Audubon Important Bird Areas
- Recovery plans for federally listed species

Oregon and Columbia River Gorge in Washington – Wind

- Washington Department of Fish and Wildlife Priority Habitats and Species data
- USFWS raptor breeding survey results
- Audubon Important Bird Areas
- Recovery plans for federally listed species

Wyoming – Wind

- USFWS critical habitat boundaries
- Audubon Important Bird Areas
- Recovery plans for federally listed species

New Mexico – Wind

- USFWS critical habitat boundaries
- Audubon Important Bird Areas
- Recovery plans for federally listed species

Arizona – Solar

- USFWS critical habitat boundaries
- National Wetlands Inventory
- Recovery plans for federally listed species

For each of the study areas, the assessment of potentially adverse effects to biological and ecological resources considers whether the buildouts would be likely to:

- Adversely affect, either directly or through habitat modifications, any species identified as a candidate, sensitive, or special-status species in local or regional plans, policies, or regulations, or by the State or U.S. Fish and Wildlife Service; or
- Interfere with established wildlife corridors or impede the use of native wildlife nursery sites.

Environmental impact assessment documents for similar and proximate projects are reviewed for each study area to inform recommendations of steps that can be taken or the indicators that can be monitored, possibly through an ongoing adaptive management strategy, to mitigate potential environmental impacts. In addition, landscape-level renewable energy planning efforts such as the DRECP and BLM's Western Solar Energy Program overlap with several study areas in the buildouts. As applicable, the analysis summarizes impact avoidance, minimization, and mitigation strategies identified by those efforts.

4.2.1 Regulatory Framework

Federal Protection of Species and Habitat

Federal Endangered Species Act

The Endangered Species Act (ESA) establishes legal requirements for conservation of endangered and threatened species and the ecosystems upon which they depend. Administered by the U.S. Fish and Wildlife Service (USFWS). Under the ESA, the USFWS may designate critical habitat for listed species. Section 7 of the ESA requires federal agencies to consult with the USFWS to ensure that their actions are not likely to jeopardize listed threatened or endangered species, or cause destruction or adverse modification of critical habitat. Section 10 of the ESA requires similar consultation for non-federal applicants.

Migratory Bird Treaty Act

The Migratory Bird Treaty Act (MBTA) prohibits take of any migratory bird, including eggs or active nests, except as permitted by regulation (e.g., licensed hunting of waterfowl or upland game species). Under the MBTA, "migratory bird" is broadly defined as "any species or family of birds that live, reproduce or migrate within or across international borders at some point during their annual life cycle" and thus applies to most native bird species.

Bald and Golden Eagle Protection Act

The Bald and Golden Eagle Protection Act prohibits the take, possession, and commerce of bald eagles and golden eagles. Under this act and subsequent rules published by the USFWS, "take" may include actions that injure an eagle, or affect reproductive success (productivity) by substantially interfering with normal behavior or causing nest abandonment. The USFWS may authorize incidental take of bald and golden eagles for otherwise lawful activities.

Clean Water Act

The Clean Water Act (CWA) regulates the chemical, physical, and biological integrity of the nation's waters. Section 401 of the CWA requires that an applicant obtain State certification for discharge into waters of the United States. Section 404 of the CWA establishes a permit program, administered by the U.S. Army Corps of Engineers, to regulate the discharge of dredged or fill material into waters of the United States, including wetlands. Individual projects may qualify under "Nationwide General Permits," or may require project-specific "Individual Permits."

Protection of Wetlands (Executive Order 11990)

This Executive Order directs federal agencies to avoid to the extent possible the long- and short-term adverse impacts from the destruction or modification of wetlands, and to avoid direct or indirect support of new construction in wetlands wherever there is a practicable alternative.

Invasive Species (Executive Order 13112)

This Executive Order establishes the National Invasive Species Council and directs federal agencies to prevent the introduction of invasive species, provide for their control, and minimize the economic, ecological, and human health impacts caused by invasive species.

State Protection of Species and Habitat

California Endangered Species Act

The California ESA (CESA) prohibits take of State-listed threatened or endangered species, except as authorized by the California Department of Fish and Wildlife (CDFW). Authorization may be issued as an Incidental Take Permit or, for species listed under both the CESA and the federal ESA, through a Consistency Determination with the federal incidental take authorization.

Native Birds (California Fish and Game Code Sections 3503, 3503.5, and 3513)

This code section prohibits take, possession, or needless destruction of birds, nests, or eggs, except as otherwise provided by the code. Section 3513 provides for the adoption of the MBTA's provisions (above)

Desert Tortoise (California Fish and Game Code Section 5000)

This code section states that it is unlawful to sell, purchase, harm, take, possess, or transport any tortoise (*Gopherus* spp.) or parts thereof, or to shoot any projectile at a tortoise.

Fully Protected Designations (California Fish and Game Code Sections 3511, 4700, 5515, and 5050)

This code section designates 36 fish and wildlife species as "fully protected" from take, including hunting, harvesting, and other activities. The CDFW may only authorize take of designated fully protected species through a Natural Community Conservation Plan (NCCP).

Protected Furbearers (California Code of Regulations Title 14 Section 460)

This code section specifies that "[f]isher, marten, river otter, desert kit fox and red fox may not be taken at any time." The CDFW may permit capture or handing of these species for scientific research, but does not issue Incidental Take Permits for other purposes.

California Native Plant Protection Act (California Fish and Game Code Sections 1900-1913)

Prior to enactment of CESA and the federal ESA, California adopted the Native Plant Protection Act (NPPA), authorizing the California Fish and Game Commission to designate rare or endangered native plants, and requiring state agencies to use their authority to carry out programs to conserve these plants. CESA (above) generally replaces the NPPA for plants originally listed as endangered under the NPPA. However, plants listed as rare retain that designation, and take is regulated under provisions of the NPPA. The California Fish and Game Commission has adopted revisions to the NPPA to allow CDFW to issue incidental take authorization for listed rare plants, effective January 1, 2015.

California Desert Native Plants Act

This act protects California desert native plants from unlawful harvesting on both public and privately owned lands within Imperial, Kern, Los Angeles, Mono, Riverside, San Bernardino, and San Diego Counties. The following native plants, or any part thereof, may not be harvested, except under a permit issued by the commissioner or the sheriff of the county in which the native plants are growing: all species of the Agavaceae (century plants, nolinas, and yuccas); all species of the family Cactaceae; all species of the family Fouquieriaceae (ocotillo, candlewood); all species of the genus *Prosopis* (mesquites); all species of the genus *Cercidium* (palo verdes); catclaw acacia (*Acacia greggii*); desert holly (*Atriplex hymenelytra*); smoke tree (*Dalea spinosa*); and desert ironwood (*Olneya tesota*), both dead and alive. Plants that are listed as rare, endangered, or threatened by federal or State law or regulations are excluded.

Lake and Streambed Alteration Agreements (California Fish and Game Code Section 1600 1616)

Lake and Streambed Alteration Agreements (LSAAs) regulate projects that would divert, obstruct, or change the natural flow, bed, channel, or bank of a river, stream, or lake. Regulation is formalized in a LSAA, which generally includes measures to protect any fish or wildlife resources that may be substantially affected by a project.

Porter-Cologne Water Quality Control Act

This act regulates surface water and groundwater and assigns responsibility for implementing federal CWA Section 401 in California. It establishes the State Water Resources Control Board (SWRCB) and nine Regional Water Quality Control Boards (RWQCBs) to protect State waters.

Arizona Native Plant Law

The Arizona Native Plant Law (Title 3: Agriculture, Chapter 7: Arizona Native Plants), administered by the Arizona Department of Agriculture (AZDA) identifies five categories of protected plants in Arizona:

- Highly Safeguarded (essentially endangered species)
- Salvage Restricted (cacti, ocotillo, etc.)
- Export Restricted
- Salvage Assessed (the common desert trees)
- Harvest Restricted (firewood, bear grass, yucca)

These plants are protected by law and cannot be removed from any lands without a permit from the AZDA. This applies to plants that are owned by a private entity or managed by a government agency.

Arizona Game and Fish Department Regulations

Arizona State Statutes and Arizona Game and Fish Department Commission Policies have been established to conserve, protect, restore, and enhance fish and wildlife populations and their habitats. These statues and policies include, but are not limited to, restrictions on "take" of wildlife, prohibition of taking or harassing nesting birds, and restrictions on closing any state or federal lands to hunting or fishing.

Oregon Endangered Species Act - Threatened or Endangered Plants (ORS 603-073-0001-0110) and Wildlife (ORS 496.171-182)

The Oregon Endangered Species Act codified in the Oregon Revised Statutes (ORS) gives the Oregon Department of Agriculture responsibility for and jurisdiction over state-listed threatened and endangered plants, and the Oregon Department of Fish and Wildlife has responsibility and jurisdiction over state-listed threatened and endangered fish and wildlife. The Act requires Oregon's state agencies to develop management and protection programs for state-listed endangered species and to comply with Oregon Fish and Wildlife Commission's adopted guidelines for state-listed threatened species.

Oregon Noxious Weed Control Law (ORS 570.500-600)

This law directs the prevention and eradications of noxious weeds in Oregon, including the establishment of local Weed Districts to oversee education, eradication, and enforcement.

Oregon Wildflower Protection Law (ORS 564.020-040)

This law identifies native wildflowers that are regulated in Oregon, and identifies required permissions to dig up, cut, sell, export, etc., any of these wildflower species.

New Mexico Wildlife Conservation Act

This act provides definitions, legislative policies, and regulations for listing or delisting species in New Mexico, and identifies penalties for violating the Act.

New Mexico Noxious Weed Control Act

This act describes requirements for the establishment and duties of noxious weed control districts.

New Mexico Noxious Weed Management Act

This act directs the New Mexico Department of Agriculture to develop a list of noxious weeds in the state, identify methods of control for noxious weeds, and provide noxious weed education to the public.

Utah Wildlife Resources Code

This law includes a variety of statues including designation of all wildlife as property of the state unless held in private ownership, provisions on invasive species, regulation of taking of wildlife, and penalties for violations.

Utah Division of Wildlife Resources Administrative Rules

These rules are passed by the Utah Wildlife Board and provide regulations on take for a variety of wildlife species, hunting rules and regulations, wildlife control and depredation, and other wildlife-related topics.

Utah Noxious Weed Control Act

This act designates noxious weed species in Utah and governs their prevention and management within the state.

Wyoming Nongame Wildlife (Wyoming Game and Fish Commission Chapter 52)

These regulations govern take of nongame wildlife in Wyoming.

Wyoming Weed & Pest Control Act

This act requires designation of noxious weeds within the state and provides statewide legal authority to regulate and manage designated noxious weeds.

Desert Renewable Energy Conservation Plan (DRECP)

The DRECP is a Land Use Plan Amendment proposed by the BLM that would define protective land designations to protect specific desert ecosystems and would facilitating appropriate development of renewable energy projects in designated areas.

Examples of Other Major Local or Regional Conservation Planning Documents for California

- San Joaquin County Multi-Species HCP (MSHCP)
- Imperial Irrigation District HCP and NCCP
- Northeastern San Luis Obispo County HCP
- Santa Barbara MSHCP
- San Diego East County MSHCP
- Lower Colorado River MSHCP
- Metropolitan Bakersfield HCP
- Coachella Valley MSHCP
- East Fresno HCP
- South Sacramento HCP
- East Contra Costa County HCP and NCCP
- Bakersfield Regional HCP
- East Bay Regional Park District HCP and NCCP
- West Mojave HCP, applicable on BLM lands

4.2.2 Baseline Conditions in Study Areas

The Crucial Habitat Assessment Tool (CHAT) was used as the basis for the biological resources analysis because it provides relatively standardized aggregate data across the western U.S. The CHAT was developed by the Western Governors' Wildlife Council as a tool to aid large-scale planning efforts in the western states, and it launched in December 2013. The Western Association of Fish and Wildlife Agencies assumed responsibility of the CHAT in April 2015, and continues to manage it and ensure data are kept current.

State-specific information on priority species and habitat has been developed for nine western states; these include all states within the west-wide region of study in this analysis (California, Arizona, Oregon, Washington, New Mexico, and Wyoming). These data are incorporated into the CHAT model.

The top two most crucial ranks are considered here to identify the relative biological sensitivity of each study area. For each of the following descriptions of baseline conditions, the overall amount of area ranked as most crucial is reported, and the biological resources that contribute to sensitivity are described. Data that inform the sensitivity ranking of crucial habitat for each state varies but generally includes the following: distribution/presence of listed and other special-status species, presence of Important Bird Areas, designated critical habitat, riparian and wetland habitats and other sensitive habitats, migration and connectivity corridors, large natural areas, and species of economic and recreational importance.

Limitations. The datasets underlying this analysis exist at a variety of spatial and temporal scales, accuracies, and geographic scopes. Few of the datasets offer current, comprehensive coverage for each entire study area, which limits the power of the data to precisely define site-specific opportunities or constraints. Project-level datasets, local experts, field studies, and unpublished data would provide additional site-specific information to fully ascertain the biological resources present and the potential impacts of development of projects under each scenario.

Inside California Solar

Greater Carrizo Solar

Crucial Habitat. The top two most crucial ranks comprise 52 percent of the Greater Carrizo Solar Study Area (Figure 4.2-1). The most sensitive area is the portion of the study area north of Soda Lake. Sensitive biological resources in this study area include but are not limited to giant kangaroo rat (state and federally listed endangered), San Joaquin kit fox (state listed threatened and federally listed endangered), arroyo toad (federally listed endangered and California Species of Special Concern [CSSC]), longhorn fairy shrimp (federally listed endangered), vernal pool fairy shrimp (federally listed threatened), burrowing owl (CSSC), California red-legged frog (federally listed threatened and CSSC), California tiger salamander (state and federally listed threatened), vernal pool habitats, and migratory birds (particularly in coastal areas). A total of 59 sensitive species and habitat types are recorded in this study area, and additional resources are likely to be present and unrecorded.

Riparian and Wetland Habitats. The most significant riparian/wetland area in the Greater Carrizo Solar Study Area is the Sisquoc River corridor along the north and east boundaries of the portion of the study area near Santa Maria. In addition, multiple small drainages occur throughout the Cholame Hills. Riverine and wetland habitats are mapped in association with Cholame Creek in the Cholame Valley, and scattered agricultural ponds and likely vernal pools occur throughout the study area.

Large Natural Areas and Landscape Connectivity. Landscape connectivity and intactness in agricultural and grassland habitats is particularly important in this study area due to the presence of San Joaquin kit fox. This study area overlaps the Carrizo Plain Important Bird Area, a 162,000-acre area along the San Andreas Fault that supports roosting lesser sandhill cranes and breeding populations of golden eagle, northern harrier, burrowing owl, prairie falcon, Swainson's hawk, the canescens race of sage sparrow, and other listed and special-status birds. It represents one of the most significant swaths of protected lands in California, and is jointly managed by the BLM and several other public agencies and non-profits (Audubon, 2013).

Other Biological Sensitivity. Critical habitat for the following species occurs within the study area: California red-legged frog (federally listed threatened and CSSC), California tiger salamander (state and federally listed threatened), La Graciosa thistle (state listed threatened and federally listed endangered), longhorn fairy shrimp (federally listed endangered), vernal pool fairy shrimp, and steelhead (federally listed threatened).

Greater Imperial Solar

Crucial Habitat. The top two most crucial ranks comprise 44 percent of the Greater Imperial Solar Study Area (Figure 4.2-2). Sensitive biological resources in this study area include but are not limited to migratory birds at the Salton Sea, peninsular bighorn sheep (federally listed endangered, state-listed threatened, and fully protected in California), burrowing owl (CSSC), flat-tailed horned lizard (Candidate for state listing as threatened and CSSC), arroyo toad, desert pupfish (state and federally listed endangered), least Bell's vireo (state and federally listed endangered), southwestern willow flycatcher (state and federally listed endangered), Stephen's kangaroo rat (federally listed endangered and state-listed threatened), Yuma clapper rail (federally listed endangered, state-listed threatened and fully protected in California), and barefoot gecko (state-listed threatened). A total of 90 sensitive species and habitat types are recorded in this study area, and additional resources are likely to be present and unrecorded.

Riparian and Wetland Habitats. Significant riparian and wetland areas in this study area include the Salton Sea and surrounding wetlands, irrigation canals and stockponds in the agricultural areas around the Salton Sea, Lake Henshaw, the San Luis Rey River, Buena Vista Creek, Borrego Sink, and Tule Lake.

Large Natural Areas and Landscape Connectivity. The Imperial Valley, Salton Sea, San Diego Montane Forests, and San Luis Rey River Important Bird Areas overlap the Greater Imperial Solar Study Area. The southwestern and the eastern portions of this study area are also modeled as important wildlife movement corridors and intact landscape.

The Imperial Valley Important Bird Area lies between the Salton Sea and the U.S.-Mexico border, and is one of the premier wintering bird spots in the U.S. This area supports the largest California populations of several species, including 30-40 percent of the global population of wintering mountain plover, 70 percent of the burrowing owls in the state, and the only population of Gila woodpecker outside of the Colorado River in California. The Salton Sea Important Bird Area supports an exceptionally high bird diversity year-round, with some species regularly occurring here and nowhere else in the U.S. Approximately 30 percent of the North American breeding population of American white pelicans breeds here, one of the largest breeding populations of double-breasted cormorants occurs here, and about 40 percent of the U.S. population of Yuma clapper rails occur in marshes in this Important Bird Area. (Audubon, 2013)

The San Diego Montane Forests (San Diego Peaks) Important Bird Area encompasses high-elevation backcountry in San Diego County. Lake Cuyamaca and scattered grassy meadows attract a large number of birds. Several species occur here at the edge of their global ranges, including red-breasted sapsucker, white-headed woodpecker, and mountain chickadee. The San Luis Rey River Important Bird Area includes some of the most extensive riparian habitat in southern California. This important bird area supports one of three main nesting populations of southeastern willow flycatcher, and least Bell's vireo breeds here in significant numbers. (Audubon, 2013)

Other Biological Sensitivity. Several California Species of Special Concern are of particular conservation focus in Imperial County; these include the burrowing owl and flat-tailed horned lizard. Approximately two-thirds of the burrowing owl population in California occurs in agricultural areas in the Imperial Valley near the Salton Sea (BLM et al., 2014). There are three regional populations of flat-tailed horned lizard in California; two of these (representing the majority of the range in the state) occur in Imperial County. These are on the west side of the Salton Sea/Imperial Valley and on the east side of the Imperial Valley; both populations extend south into Mexico and overlap portions of the Greater Imperial Solar Study Area. Critical habitat for peninsular bighorn sheep and arroyo toad also occurs within the study area.

Kramer and Inyokern Solar

Crucial Habitat. The top two most crucial ranks comprise just 2 percent of the Kramer and Inyokern Study Area (Figure 4.2-3). Sensitive biological resources in this study area include but are not limited to desert tortoise (federally and state-listed threatened), Mohave ground squirrel (state-listed threatened), Cushenbury buckwheat (federally listed endangered), Mohave tui chub (state and federally listed endangered and fully protected in California), burrowing owl, golden eagle (fully protected in California), and desert bighorn sheep (fully protected in California). It is also within a migration route for Swainson's hawks (state listed threatened). A total of 28 sensitive species and habitat types are recorded in this study area, and additional resources are likely to be present and unrecorded (including Mohave ground squirrel and California condor).

Riparian and Wetland Habitats. The largest mapped wetland in this study area is Searles Lake, a primarily dry playa lake that supports variable amounts of water during and following rain events. It also contains several large wastewater ponds associated with mining. Other desert playas, including El Mirage Dry Lake near the community of El Mirage, Troy Dry Lake near Newberry Springs, and Lucerne Dry Lake in Lucerne Valley, also occur in the study area. Numerous dry desert washes, some very large, cross through the study area. The Mojave River does not intersect the study area but occurs less than 3 miles from the southwestern subarea and adjacent to the eastern subarea.

Large Natural Areas and Landscape Connectivity. The Mojave River corridor and the eastern portion of the study area in Lucerne Valley are identified as important areas for landscape intactness and wildlife corridors. North Mojave Dry Lakes Important Bird Area overlaps the study area, and encompasses the four dry lakes between Ridgecrest and Barstow in the northern Mojave Desert (China Lake, Searles Dry Lake, Koehn Dry Lake, and Harper Dry Lake). Several spring-fed wetlands and wastewater treatment areas occur here and attract a variety of birds including migrating waterfowl and shorebirds (Audubon, 2013).

Other Biological Sensitivity. Critical habitat for desert tortoise occurs in the study area.

Owens Valley Solar

Crucial Habitat. The top two most crucial ranks comprise 87 percent of the Owens Valley & Inyo Solar Study Area (Figure 4.2-4). Sensitive biological resources in this study area include but are not limited to least Bell's vireo, southwestern willow flycatcher, Owens pupfish (state and federally listed endangered and fully protected in California), Owens tui chub (state and federally listed endangered), burrowing owl, golden eagle, Mohave ground squirrel, northern leopard frog (CSSC), and a wide variety of rare plants. A total of 52 sensitive species and habitat types are recorded in this study area, and additional resources are likely to be present and unrecorded.

Riparian and Wetland Habitats. The most prominent wetland and riparian habitats in this study area are associated with the Owens River and Owens Lake. Dry desert washes are abundant throughout the study area, particularly in Stewart Valley near the Nevada border.

Large Natural Areas and Landscape Connectivity. The Owens Lake Important Bird Area is a 100-square mile alkali playa at the southern end of the Owns Valley. It is a major migratory stop-over site for shorebirds and waterfowl. (Audubon, 2013)

Other Biological Sensitivity. Critical habitat for Fish Slough milk-vetch occurs within the study area.

Riverside East and Palm Springs Solar

Crucial Habitat. The top two most crucial ranks comprise 30 percent of the Riverside East and Palm Springs Solar Study Area (Figure 4.2-5). Sensitive biological resources in this study area include but are not limited to migratory birds, desert washes, peninsular bighorn sheep, Coachella Valley milk-vetch (federally listed endangered), triple-ribbed milk-vetch (federally listed endangered), desert slender salamander (federally and state listed endangered), least Bell's vireo, elf owl (state-listed endangered), desert tortoise, Coachella Valley fringe-toed lizard (federally listed threatened and state-listed endangered), burrowing owl, and desert bighorn sheep. A total of 58 sensitive species and habitat types are recorded in this study area, and additional resources are likely to be present and unrecorded.

Riparian and Wetland Habitats. Dry desert washes are abundant in the study area, and include the Whitewater River in the Palm Springs area and McCoy Wash near Blythe. Palen Dry Lake is a playa that overlaps a portion of the eastern study area. The study area is within 2 miles of the Colorado River and its associated riparian and wetland habitats, and the eastern edge of the study area abuts the agricultural plain associated with the river.

Large Natural Areas and Landscape Connectivity. Although no designated Important Bird Areas overlap this study area, its proximity to the Colorado River and its location in the eastern California desert place it within migratory bird pathways. Landscape corridors are modeled along the Whitewater River in the Palm Springs area.

Other Biological Sensitivity. Critical habitat for Coachella Valley milk-vetch and desert tortoise occurs within the study area.

Tehachapi Solar

Crucial Habitat. The top two most crucial ranks comprise 13 percent of the Tehachapi Solar Study Area (Figure 4.2-6). Sensitive biological resources in this study area include but are not limited to migratory birds, least Bell's vireo, desert tortoise, spreading navarretia (federally listed threatened), burrowing owl, golden eagle, Mohave ground squirrel, tricolored blackbird (CSSC), and Swainson's hawk. A total of 39 sensitive species and habitat types are recorded in this study area, and additional resources are likely to be present and unrecorded.

Riparian and Wetland Habitats. Mapped habitats in this study area are primarily named and unnamed dry desert washes of varying size as well as playa lakes.

Large Natural Areas and Landscape Connectivity. The North Mojave Dry Lakes and Antelope Valley Important Bird Areas overlap the study area. The North Mojave Dry Lakes Important Bird Area encompasses the four dry lakes between Ridgecrest and Barstow in the northern Mojave Desert (China Lake, Searles Dry Lake, Koehn Dry Lake, and Harper Dry Lake). Several spring-fed wetlands and wastewater treatment areas occur here and attract a variety of birds including migrating waterfowl and shorebirds. The Antelope Valley (Lancaster) Important Bird Area supports one of the westernmost populations of LeConte's thrasher, and a wide variety of grassland birds and raptors winter here (Audubon, 2013).

Other Biological Sensitivity. Critical habitat for California condor occurs within the study area.

Westlands Solar

Crucial Habitat. The top two most crucial ranks comprise 5 percent of the Westlands Solar Study Area (Figure 4.2-7). Sensitive biological resources in this study area include but are not limited to San Joaquin kit fox, Buena Vista Lake ornate shew (federally listed endangered and CSSC), Fresno kangaroo rat (state and federally listed endangered), Tipton kangaroo rat (state and federally listed endangered), blunt-nosed leopard lizard (state and federally listed endangered and fully protected in California), giant garter snake (state and federally listed threatened), California tiger salamander, Bakersfield cactus (state and federally listed endangered), California jewelflower (state and federally listed endangered), hairy Orcutt grass (state and federally listed endangered), Kern mallow (federally listed endangered), palmate-bracted salty bird's-beak (state and federally listed endangered), San Joaquin woollythreads (federally listed endangered), San Joaquin adobe sunburst (federally listed threatened and state-listed endangered), least Bell's vireo, longhorn fairy shrimp (federally listed endangered), vernal pool fairy shrimp, western snowy plover (federally listed threatened and CSSC), western yellow-billed cuckoo (federally listed threatened and state-listed endangered), and burrowing owl. A total of 72 sensitive species and habitat types are recorded in this study area, and additional resources are likely to be present and unrecorded.

Riparian and Wetland Habitats. This study area supports primarily agricultural lands, and numerous stockponds and irrigation ditches occur. Natural waterways with associated wetlands and riparian habitats include the Kings River and various tributaries, the San Joaquin River, Ash Slough, Berenda Slough, Cottonwood Creek, Fresno Slough, and Cole Slough.

Large Natural Areas and Landscape Connectivity. No Important Bird Areas or landscape corridors are mapped within this study area; however, it is located within a broad migratory route for birds along the California coast.

Inside California Wind

Central Valley North and Los Banos Wind

Crucial Habitat. The top two most crucial ranks comprise 77 percent of the Central Valley North and Los Banos Wind Study Area (Figure 4.2-8). Sensitive biological resources in this study area include but are not limited to migratory birds at the San Luis Reservoir, blunt-nosed leopard lizard, San Joaquin kit fox, longhorn fairy shrimp, Swainson's hawk, and burrowing owl. A total of 6 sensitive species are recorded in this study area, and additional resources are likely to be present and unrecorded.

Riparian and Wetland Habitats. The most significant water bodies in and near this study area are the San Luis Reservoir and O'Neill Forebay.

Large Natural Areas and Landscape Connectivity. The area to the east and south of the O'Neill Forebay is an important movement corridor for San Joaquin kit fox and other grassland species.

Greater Carrizo Wind

Crucial Habitat. The top two most crucial ranks comprise 57 percent of the Greater Carrizo Wind Study Area (Figure 4.2-1). Sensitive biological resources contributing to the high crucial habitat ranks in this study area include giant kangaroo rat, San Joaquin kit fox, burrowing owl, arroyo toad, California red-legged frog, California tiger salamander, vernal pool fairy shrimp, longhorn fairy shrimp, southern California DPS of steelhead, Gaviota tarplant (state and federally listed endangered), Kern mallow, La Graciosa thistle, and migratory birds (particularly in coastal areas). There are also overwintering sites for monarch butterflies recorded in the study area. A total of 59 sensitive species and habitat types are recorded in this study area, and additional resources are likely to be present and unrecorded.

Riparian and Wetland Habitats. Numerous named and unnamed creeks with riparian habitats occur throughout this study area. A portion of the Santa Ynez River and its substantial riparian corridor cross the study area near Buellton. Several scattered agricultural ponds also occur.

Large Natural Areas and Landscape Connectivity. Landscape connectivity and intactness in agricultural and grassland habitats is particularly important in this study area due to the presence of San Joaquin kit fox in the northern area. The Santa Ynez Mountains contain important modeled landscape corridors. This study area overlaps the Santa Ynez River Valley Important Bird Area, which encompasses the intact riparian habitat between Highway 101 and the agricultural region west of Lompoc. This area supports a large population of southwestern willow flycatchers, and other special-status birds include least Bell's vireo, western yellow-billed cuckoo, golden eagle, and tricolored blackbird (Audubon, 2013).

Other Biological Sensitivity. Critical habitat for steelhead, tidewater goby, California red-legged frog, California tiger salamander, southwestern willow flycatcher, Gaviota tarplant, and Lompoc yerba santa occurs in the study area.

Greater Imperial Wind

Crucial Habitat. The top two most crucial ranks comprise 56 percent of the Greater Imperial Wind Study Area (Figure 4.2-2). Sensitive biological resources in this study area are generally the same as described for the Greater Imperial Solar Study Area, and include migratory birds at the Salton Sea, peninsular bighorn sheep, burrowing owl in the Salton Sea agricultural areas, and flat-tailed horned lizard east and west of the Imperial Valley, among other special-status species and sensitive habitats. A total of 96 sensitive species and habitat types are recorded in this study area, and additional resources are likely to be present and unrecorded.

Riparian and Wetland Habitats. The easternmost portion of this study area overlaps the Colorado River floodplain and associated wetlands and riparian habitat in the vicinity of the Mittry Lake State Wildlife Area. Other mapped areas include Buena Vista Creek, Campo Creek, Tule Creek, Tule Lake, Boundary Creek, and various small ponds near Julian.

Large Natural Areas and Landscape Connectivity. The San Diego Montane Forests, Lower Colorado River Valley, and Imperial Valley Important Bird Areas overlap portions of the study area. The San Diego Montane Forests (San Diego Peaks) Important Bird Area encompasses high-elevation backcountry in San Diego County. Lake Cuyamaca and scattered grassy meadows attract a large number of birds. Several species occur here at the edge of their global ranges, including red-breasted sapsucker, white-headed woodpecker, and mountain chickadee. The Lower Colorado River Valley Important Bird Area contains essential habitats for some of the most imperiled birds in the U.S. Wetlands and riparian thickets support breeding populations and provide migratory stopover and wintering habitat for species including elf owl, yellow-billed cuckoo, northern cardinal, Harris' hawk, and sandhill crane. The Imperial Valley Important Bird Area lies between the Salton Sea and the U.S.-Mexico border, and is one of the premier wintering bird spots in the U.S. This area supports the largest California populations of several species, including 30 to 40 percent of the global population of wintering mountain plover, 70 percent of the burrowing owls in the state, and the only population of Gila woodpecker outside of the Colorado River in California. (Audubon, 2013)

Other Biological Sensitivity. Critical habitat for the following species occurs within the study area: southwestern willow flycatcher, yellow-billed cuckoo, razorback sucker, Quino checkerspot butterfly, and peninsular bighorn sheep.

Riverside East and Palm Springs Wind

Crucial Habitat. The top two most crucial ranks comprise 55 percent of the Riverside East and Palm Springs Wind Study Area (Figure 4.2-5). Sensitive biological resources in this study area include but are not limited to migratory birds, Coachella Valley milk-vetch, triple-ribbed milk-vetch, Coachella Valley fringe-toed lizard, desert tortoise, southwestern willow flycatcher, desert pupfish, burrowing owl, and desert bighorn sheep. A total of 14 sensitive species and habitat types are recorded in this study area, and additional resources are likely to be present and unrecorded.

Riparian and Wetland Habitats. The Coachella Valley Preserve supports a desert oasis with a pond and extensive riparian habitat adjacent to the study area. Dry desert washes of various sizes cross through the study area.

Large Natural Areas and Landscape Connectivity. Although no designated Important Bird Areas overlap this study area, its proximity to the Coachella Valley Preserve and oasis indicates that it is likely within the movement area for a large number of birds.

Other Biological Sensitivity. Critical habitat for Coachella Valley fringe-toed lizard and Coachella Valley milk-vetch occurs within the study area.

Solano Wind

Crucial Habitat. The top two most crucial ranks comprise 73 percent of the Solano Wind Study Area (Figure 4.2-9). Sensitive biological resources in this study area include but are not limited to migratory birds at the Delta, longfin smelt (state-listed threatened and candidate for federal listing), Delta smelt (federally listed threatened and state-listed endangered), Central Valley DPS of steelhead (federally listed threatened), Valley elderberry longhorn beetle (federally listed threatened), vernal pool fairy shrimp, vernal pool tadpole shrimp (federally listed endangered), longhorn fairy shrimp, Alameda whipsnake (state and federally listed threatened), giant garter snake, California red-legged frog, California tiger salamander, San Joaquin kit fox, western snowy plover, western yellow-billed cuckoo, least Bell's vireo, and several listed plants. A total of 101 sensitive species and habitat types are recorded in this study area, and additional resources are likely to be present and unrecorded.

Riparian and Wetland Habitats. Extensive riparian corridors and wetlands occur throughout this study area, including the San Joaquin River and various tributaries, Suisan Bay, Putah Creek, Willow Slough, Babel Slough, North and South Mokelumne River and Old River. There is a broad wetland and vernal pool complex south of Saxon and west of the Sacramento River Deep Water Ship Channel.

Large Natural Areas and Landscape Connectivity. Several landscape corridors are modeled within this study area, including along the base of Rocky Ridge and the broad wetland and vernal pool complex south of Saxon and west of the Sacramento River Deep Water Ship Channel. The following Important Bird Areas overlap the study area: Yolo Bypass Area, Sacramento-San Joaquin Delta, Cosumnes River Watershed – Lower, Mount Hamilton Range, San Joaquin River – Lower, and Byron Area. These areas support freshwater and tidal marsh ecosystems, riparian, and grassland habitats that attract a high concentration and wide diversity of songbirds, shorebirds, waterfowl, and raptors. (Audubon, 2013)

Other Biological Sensitivity. Critical habitat for the following species overlaps the study area: Alameda whipsnake, California red-legged frog, Colusa grass, Contra Costa goldfields, large-flowered fiddleneck, Solano grass, vernal tidepool shrimp, Delta smelt, steelhead, and Chinook salmon.

Tehachapi Wind

Crucial Habitat. The top two most crucial ranks comprise 20 percent of the Tehachapi Wind Study Area (Figure 4.2-6). Sensitive biological resources in this study area include but are not limited to migratory birds, burrowing owl, golden eagle, and Swainson's hawk. A total of 30 sensitive species and habitat types are recorded in this study area, and additional resources are likely to be present and unrecorded.

Riparian and Wetland Habitats. A variety of named and unnamed drainages are mapped within the southern portion of this study area, and many support riparian habitat. Areas within the Antelope Valley support a variety of dry desert washes. Proctor Dry Lake lies within the study area in the Tehachapi Valley.

Large Natural Areas and Landscape Connectivity. The Southern Sierra Desert Canyons and Antelope Valley Important Bird Areas overlap this study area. The Southern Sierra Desert Canyons Important Bird Area includes one of interior California's most important segments of the Pacific Flyway migration corridor, and its canyons provide critical breeding and migratory stopover habitat to countless birds. The Antelope Valley (Lancaster) Important Bird Area supports one of the westernmost populations of LeConte's thrasher, and a wide variety of grassland birds and raptors winter here (Audubon, 2013).

Other Biological Sensitivity. Critical habitat for California condor and coastal California gnatcatcher occurs within the study area.

Inside California Geothermal

Greater Imperial Geothermal

Crucial Habitat. The top two most crucial ranks comprise 33 percent of the Greater Imperial Geothermal Study Area (Figure 4.2-2). Sensitive biological resources in this study area are the same as described for the Greater Imperial Solar Study Area, and include migratory birds at the Salton Sea, peninsular bighorn sheep in the Borrego Springs area, burrowing owl in the Salton Sea agricultural areas, and flat-tailed horned lizard east and west of the Imperial Valley, among other special-status species and sensitive habitats. A total of 48 sensitive species and habitat types are recorded in this study area, and additional resources are likely to be present and unrecorded.

Riparian and Wetland Habitats. Significant riparian and wetland areas in this study area include the Salton Sea and surrounding wetlands, and irrigation canals and stockponds in the agricultural areas around the Salton Sea.

Large Natural Areas and Landscape Connectivity. The Imperial Valley and Salton Sea Important Bird Areas overlap this study area. The eastern portion of this study area is also modeled as an important wildlife movement corridor and intact landscape.

The Imperial Valley Important Bird Area lies between the Salton Sea and the U.S.-Mexico border, and is one of the premier wintering bird spots in the U.S. This area supports the largest California populations of several species, including 30-40 percent of the global population of wintering mountain plover, 70 percent of the burrowing owls in the state, and the only population of Gila woodpecker outside of the Colorado River in California. The Salton Sea Important Bird Area supports an exceptionally high bird diversity year-round, with some species regularly occurring here and nowhere else in the U.S. Approximately 30 percent of the North American breeding population of American white pelicans breeds here, one of the largest breeding populations of double-breasted cormorants occurs here, and about 40 percent of the U.S. population of Yuma clapper rails occur in marshes in this Important Bird Area. (Audubon, 2013)

Other Biological Sensitivity. Critical habitat for peninsular bighorn sheep and arroyo toad occurs within the study area. Other sensitive biological resources are the same as described for the Greater Imperial Solar Study Area.

Out-of-State Solar

Southwest Solar (Arizona)

Crucial Habitat. The top two most crucial ranks comprise 2 percent of the Southwest Solar Study Area (Figure 4.2-10). The Arizona state CHAT ranking is driven by the presence of large natural areas, species of concern, species of economic and recreational importance, and wetland and riparian areas. Raw species occurrence data were not publically available for this study area, but were used by the state to develop Arizona's CHAT model.

Riparian and Wetland Habitats. The Gila River and Centennial Wash are major drainages with associated wetland and riparian habitats in the Harquahala area, and the Gila River and associated riparian corridor cross the southern portion of the Hoodoo Wash area. Numerous named and unnamed dry desert washes of varying sizes occur throughout the study area.

Large Natural Areas and Landscape Connectivity. The Lower Salt and Gila Riparian Ecosystem Important Bird Area overlaps this study area. This Important Bird Area includes portions of the Salt and Gila Rivers, which support a large and diverse fish population. In turn, the area attracts large numbers of a wide variety of fish-eating birds, including osprey, egrets, herons, cormorants, and bald eagles. Yuma clapper rails are widely distributed here, and reach the upstream limit of their distribution on the Gila River in this Important Bird Area (Audubon, 2013).

Other Biological Sensitivity. Critical habitat for the yellow-billed cuckoo occurs in the study area.

Out-of-State Wind

Northwest Wind (Oregon)

Crucial Habitat. The top two most crucial ranks comprise 31 percent of the Northwest Wind Study Area (Figure 4.2-11). The Oregon state CHAT ranking is driven by the presence of large natural areas, species of concern, freshwater integrity, landscape connectivity, wildlife corridors, natural vegetation communities, species of economic and recreational importance, and wetland and riparian areas. A total of 27 sensitive species and habitat types are recorded in this study area, and additional biological resources are likely to be present and unrecorded. Sensitive species in this study area include but are not limited to golden eagle, Washington ground squirrel (Candidate for federal listing), gray wolf (federally listed endangered), Swainson's hawk (Sensitive [Vulnerable] in Oregon), several sensitive invertebrates, and several rare plants.

Riparian and Wetland Habitats. The Columbia River, John Day River, and Rock Creek are major drainages that pass through the study area. Mapped drainages that may support riparian habitat in the Oregon North portion of the study area include Butter Creek and tributaries, Bear Creek, Owings Creek, and Birch Creek.

Large Natural Areas and Landscape Connectivity. Important modeled landscape corridors include the John Day River Corridor, Alkali Canyon, and the Coombs Canyon area. The Columbia Hills and Boardman Grasslands Important Bird Areas overlap the study area. The Columbia Hills Important Bird Area in Washington supports substantial populations of wintering and breeding raptors, including bald eagle, peregrine falcon, golden eagle, prairie falcon, and Swainson's hawk. Over 2,000 waterfowl have been recorded at the Swale Creek wetlands in winter. (Audubon, 2013)

The Boardman Grasslands Important Bird Area consists of two adjacent parcels, the Boardman Conservation Area and the Boardman Bombing Range. This Important Bird Area supports one of the largest remaining intact areas of native shrub-steppe and grassland ecosystems in Oregon. This site supports the largest known breeding populations in Oregon for grasshopper sparrow, long-billed curlew, and burrowing owl. (Audubon, 2013)

Other Biological Sensitivity. Critical habitat for steelhead, Chinook salmon, and bull trout occurs in the study area.

Utah Wind

Crucial Habitat. The top two most crucial ranks comprise 10 percent of the Utah Wind Study Area (Figure 4.2-12). The Utah state CHAT ranking is driven by the presence of large natural areas, sage grouse management areas, species of concern, National Hydrography Dataset results, and the National Wetlands Inventory results. A total of 18 sensitive species are recorded in this study area, and additional biological resources are likely to be present and unrecorded. Sensitive species in this study area include but are not limited to greater sage grouse, Utah prairie dog (federally listed threatened), kit fox, pygmy rabbit, spotted bat, Townsend's big-eared bat, least chub, bald eagle, burrowing owl, dark kangaroo mouse, and several rare plants.

Riparian and Wetland Habitats. The Beaver River, Wah Wah Wash, other named and unnamed dry desert washes, and scattered agricultural ponds are the primary mapped areas within the Utah Wind Study Area.

Large Natural Areas and Landscape Connectivity. No modeled large natural areas, landscape corridors, or Important Bird Areas occur within this study area.

Wyoming Wind

Crucial Habitat. The top two most crucial ranks comprise 31 percent of the Wyoming Wind Study Area (Figure 4.2-13). The Wyoming state CHAT ranking is driven by the presence of large natural areas, species of concern, species of economic and recreational importance, and wetland and riparian areas. Raw species occurrence data were not publically available for this study area, but were used by the state to develop Wyoming's CHAT model.

Riparian and Wetland Habitats. Riparian and wetland habitats in this study area include Sybille Creek, Mule Creek, Chugwater Creek, Spring Creek, Horse Creek, Lodgepole Creek, Farthing Reservoir, Richeau Creek, Bear Creek, Little Sage Creek, Sage Creek, Rasmussen Creek, Sage Creek Reservoir, Kindt Reservoir, and several other drainages and reservoirs. The Wyoming Central subarea is just west of the North Platte River and its associated riparian corridor.

Large Natural Areas and Landscape Connectivity. Most of study area is modeled as important large natural areas. The Laramie Plains Lakes Complex Important Bird Area overlaps the study area, and encompasses four discreet lake complexes and associated wetland areas within the Laramie Plains Basin. This Important Bird Area is an important migratory stopover for a variety of waterfowl, shorebirds, gulls, and waders. It provides breeding habitat for a number of species including one of the three American white pelican breeding populations in Wyoming, as well as black-crowned night heron, American bittern, white-faced ibis, American avocet, and California gull. (Audubon, 2013)

Other Biological Sensitivity. Critical habitat for the Colorado butterfly plant occurs in the study area. The study area is also within big game crucial range.

New Mexico Wind

Crucial Habitat. The top two most crucial ranks comprise 26 percent of the New Mexico Wind Study Area (Figure 4.2-14). The New Mexico state CHAT ranking is driven by the presence of large natural areas, species of concern, species of economic and recreational importance, wetland and riparian areas, natural vegetation communities, freshwater integrity, and wildlife corridors. Raw species occurrence data were not publically available for this study area, but were used by the state to develop New Mexico's CHAT model.

Riparian and Wetland Habitats. The Cola del Gallo Arroyo, Gallo Arroyo, and numerous dry desert washes of various sizes cross the study area. Scattered agricultural ponds occur in the eastern portion of the study area.

Large Natural Areas and Landscape Connectivity. Almost all of the New Mexico Central subarea is modeled as important large natural areas. The Clovis Playas and NM Lesser-Prairie Chicken Complex Important Bird Areas also overlap the study area. The Clovis Playas Important Bird Area consists of grasslands interspersed with agricultural lands at the eastern edge of New Mexico. It provides wintering habitat for a large number of waterfowl, and when playas are full it provides migratory stopover habitat for waterfowl and shorebirds. The NM Lesser Prairie-Chicken Complex Important Bird Area encompasses over 2 million acres in eastern New Mexico, including a number of properties managed specifically for lesser prairie-chicken. This area also supports other declining grassland species such as burrowing owl, scaled quail, Cassin's sparrow, and grasshopper sparrow. When full, the playa lake in this Important Bird Area can host thousands of migrating sandhill cranes. (Audubon, 2013)

Other Biological Sensitivity. Caprock Escarpment provides essential habitat for bats.

Figure 4.2-1. Crucial Habitat Greater Carrizo CREZ Study Areas

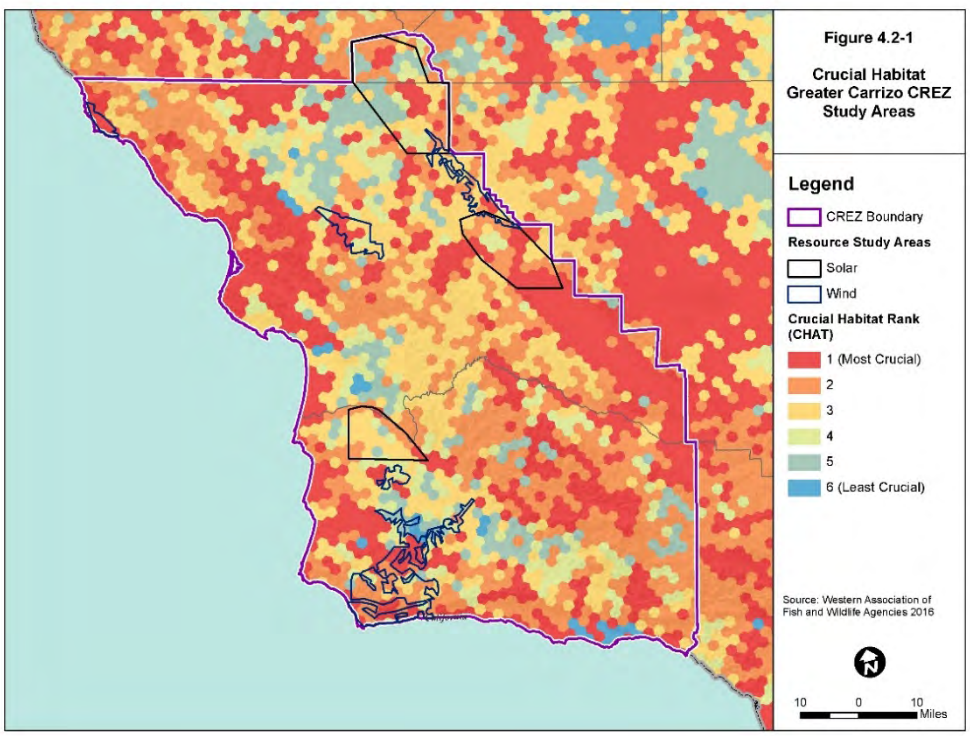


Figure 4.2-2. Crucial Habitat Greater Imperial CREZ Study Areas

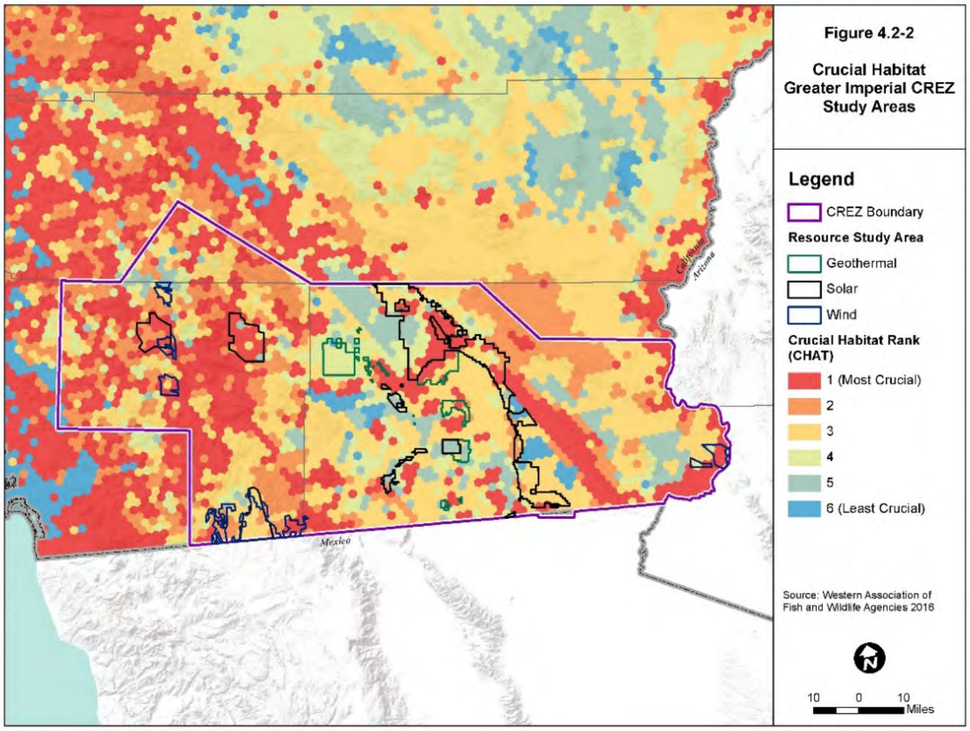


Figure 4.2-3. Crucial Habitat Kramer & Inyokern CREZ Study Areas

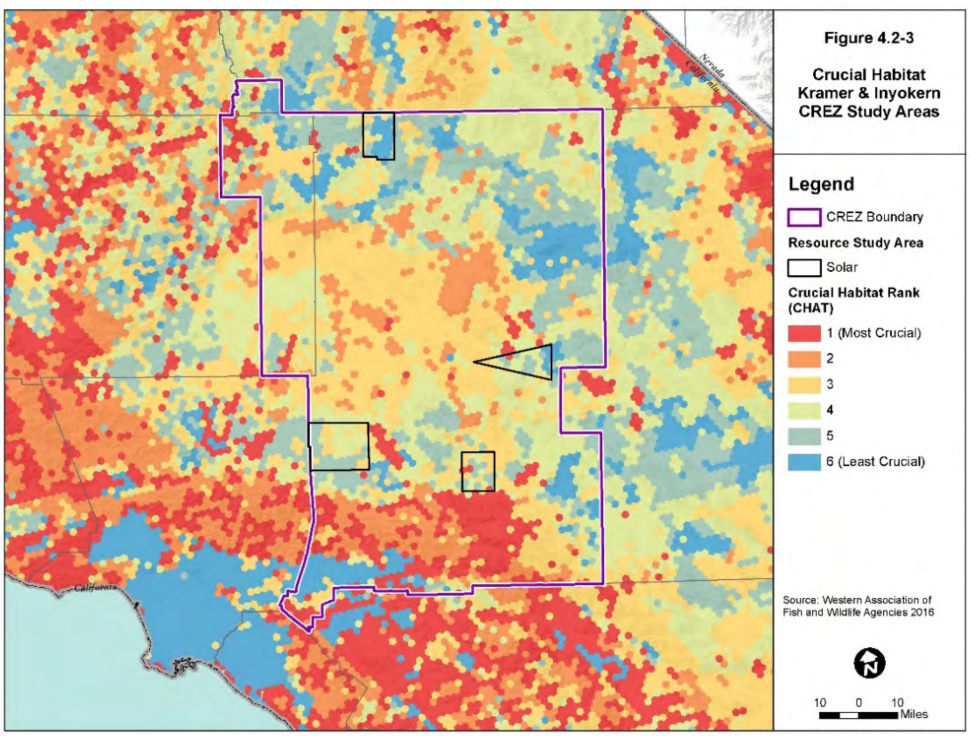


Figure 4.2-4. Crucial Habitat Owens Valley & Inyo CREZ Study Areas

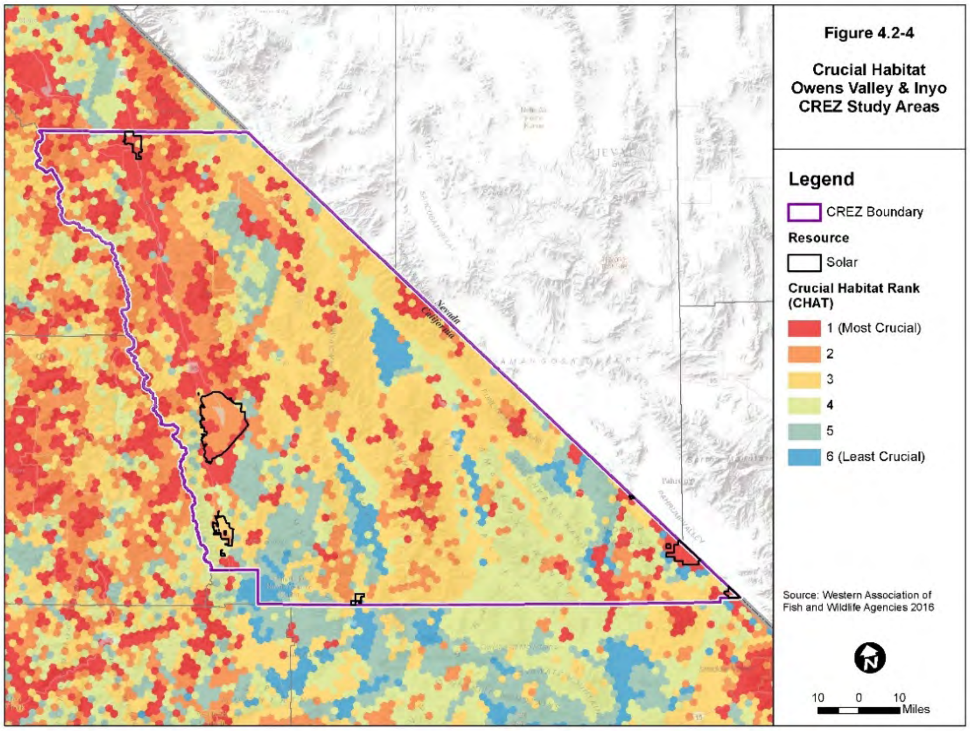


Figure 4.2-5. Crucial Habitat Riverside East & Palm Springs CREZ Study Areas

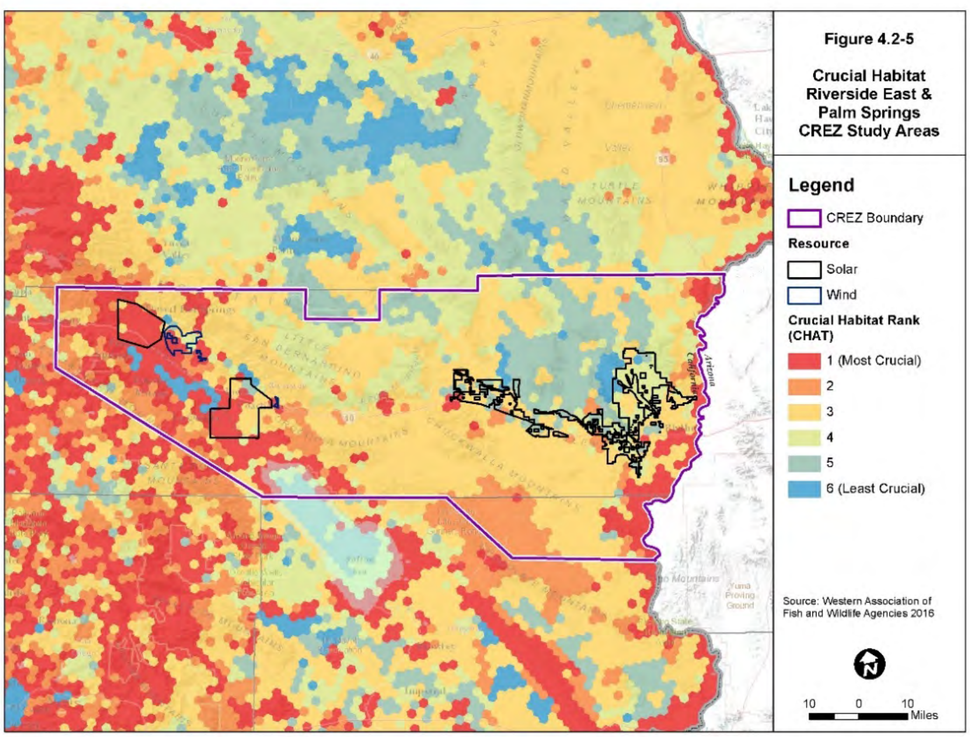


Figure 4.2-6. Crucial Habitat Tehachapi CREZ Study Areas

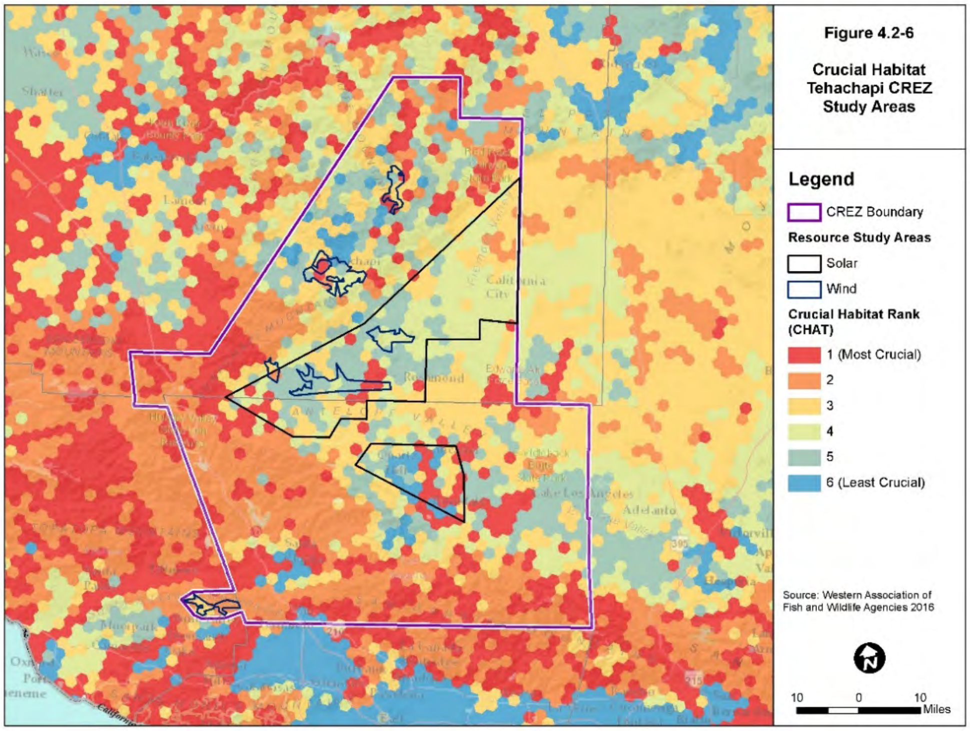


Figure 4.2-7. Crucial Habitat Westlands CREZ Study Areas

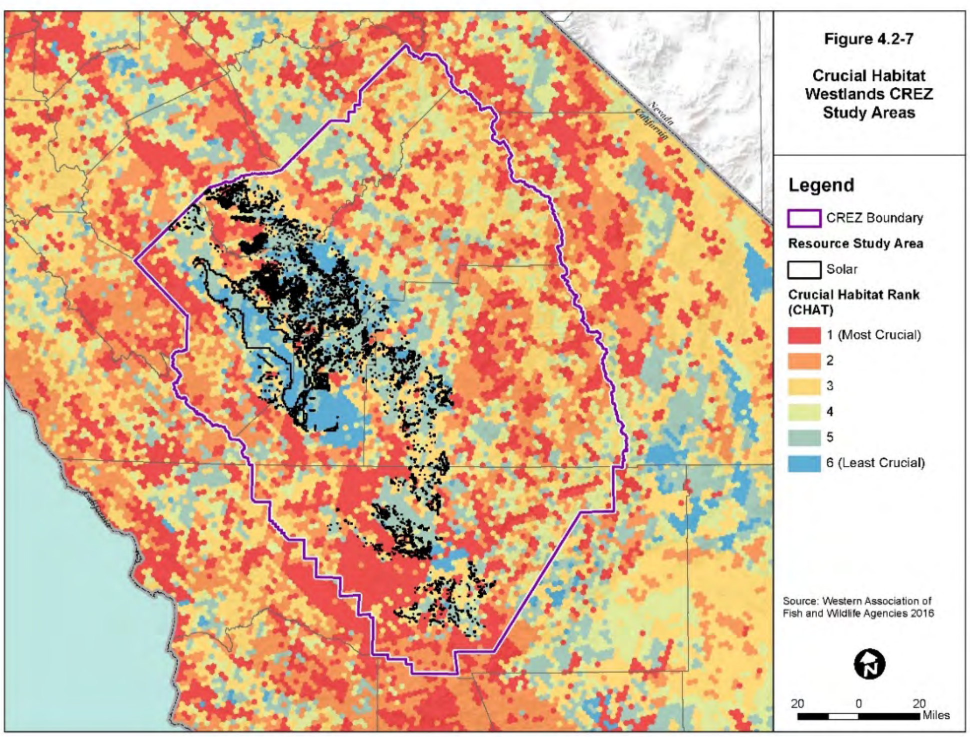


Figure 4.2-8. Crucial Habitat Central Valley North and Los Banos CREZ Study Areas

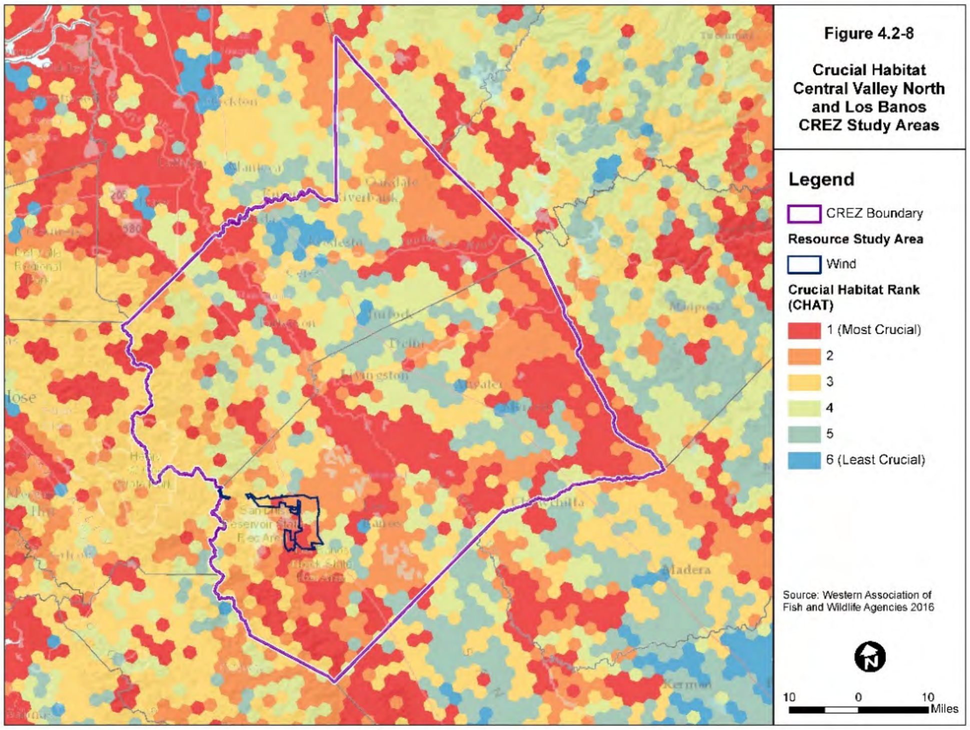


Figure 4.2-9. Crucial Habitat Solano CREZ Study Areas

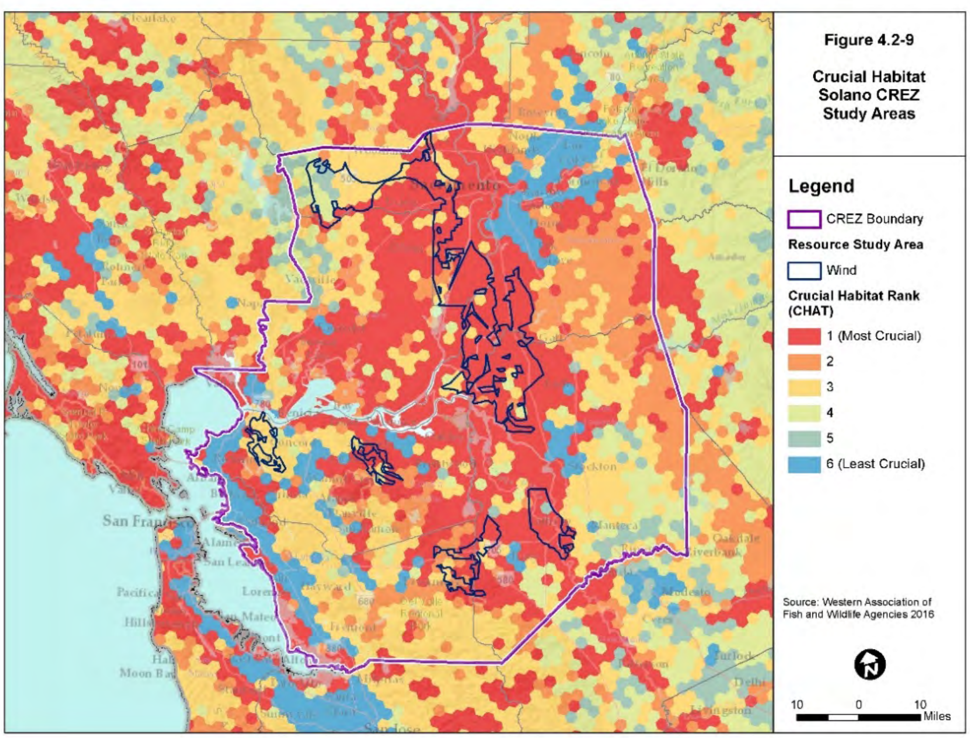


Figure 4.2-10. Crucial Habitat Arizona Solar Study Areas

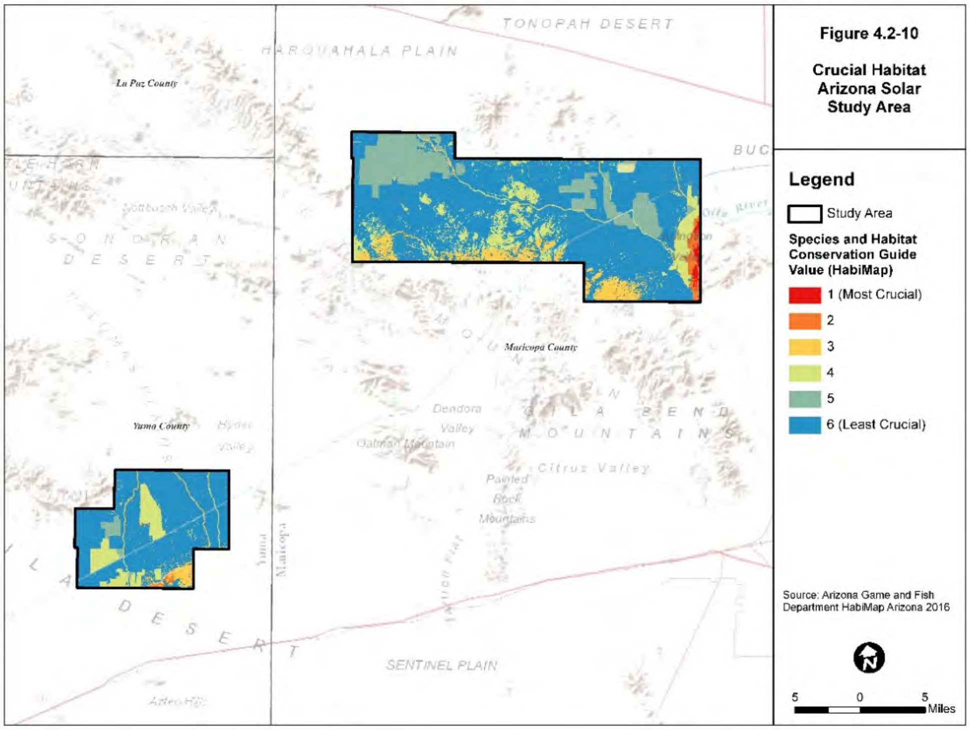


Figure 4.2-11. Crucial Habitat Oregon/Columbia River Wind Study Areas

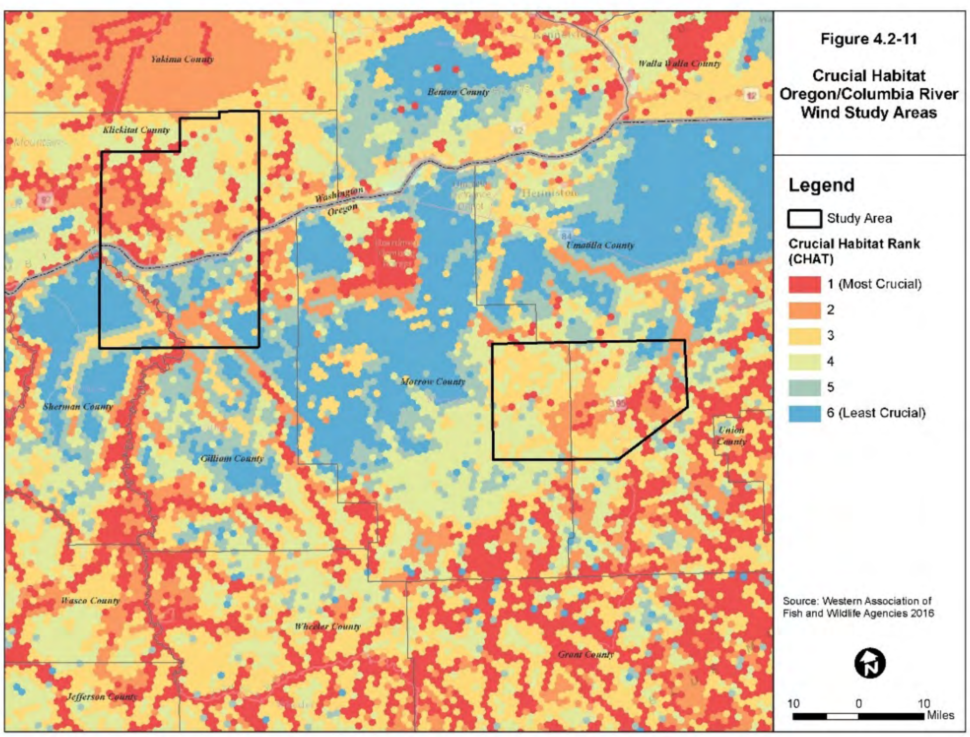


Figure 4.2-12. Crucial Habitat Utah Wind Study Areas

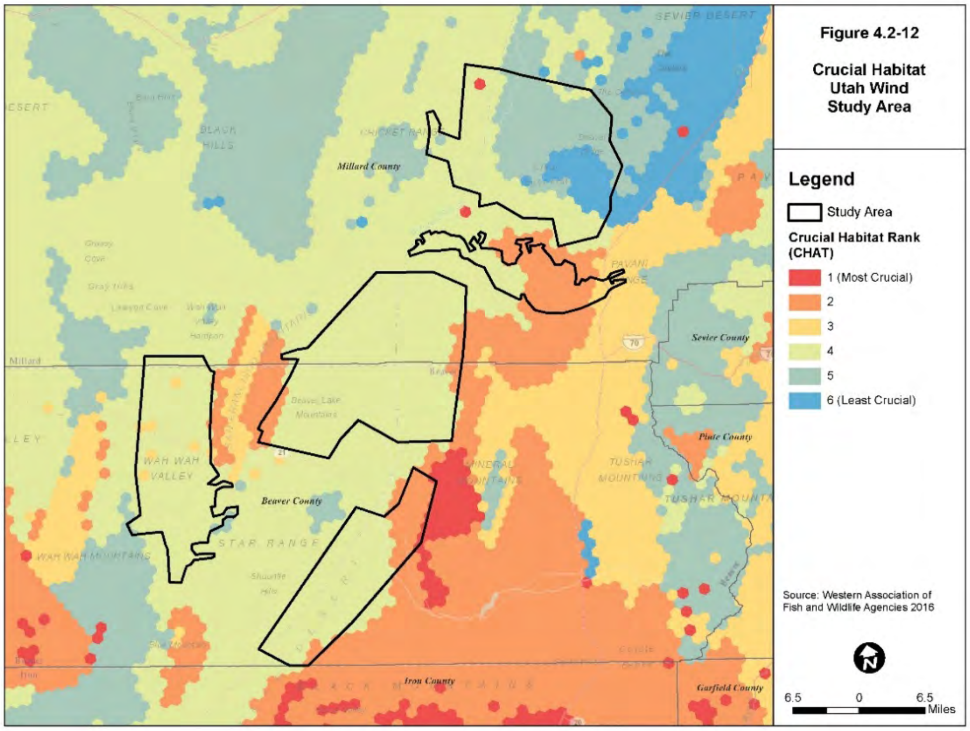


Figure 4.2-13. Crucial Habitat Wyoming Wind Study Areas

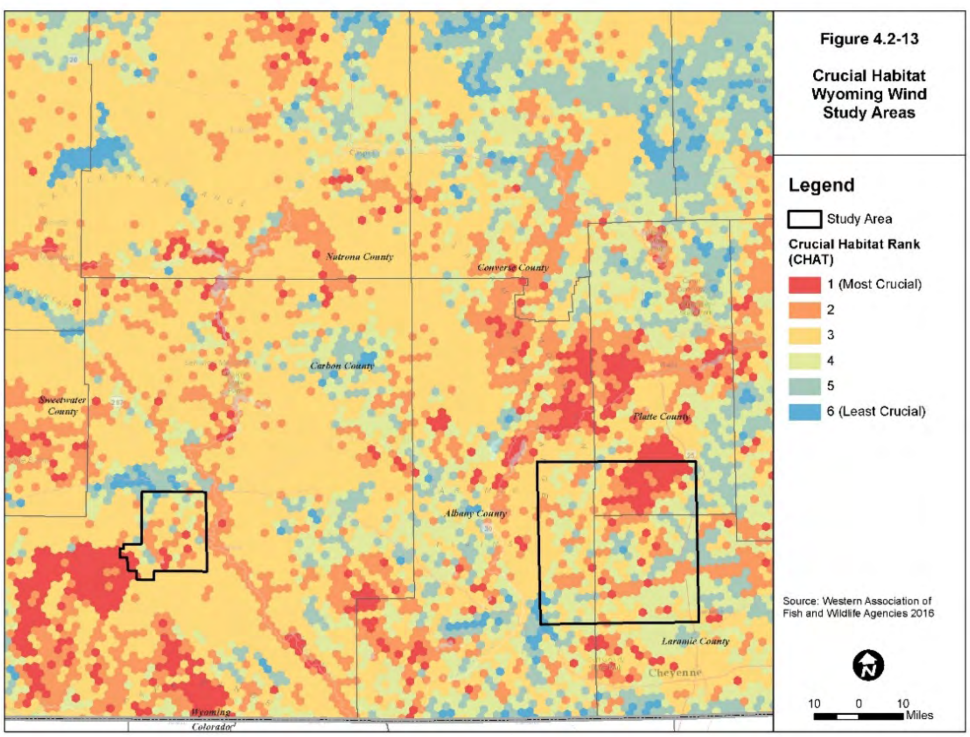
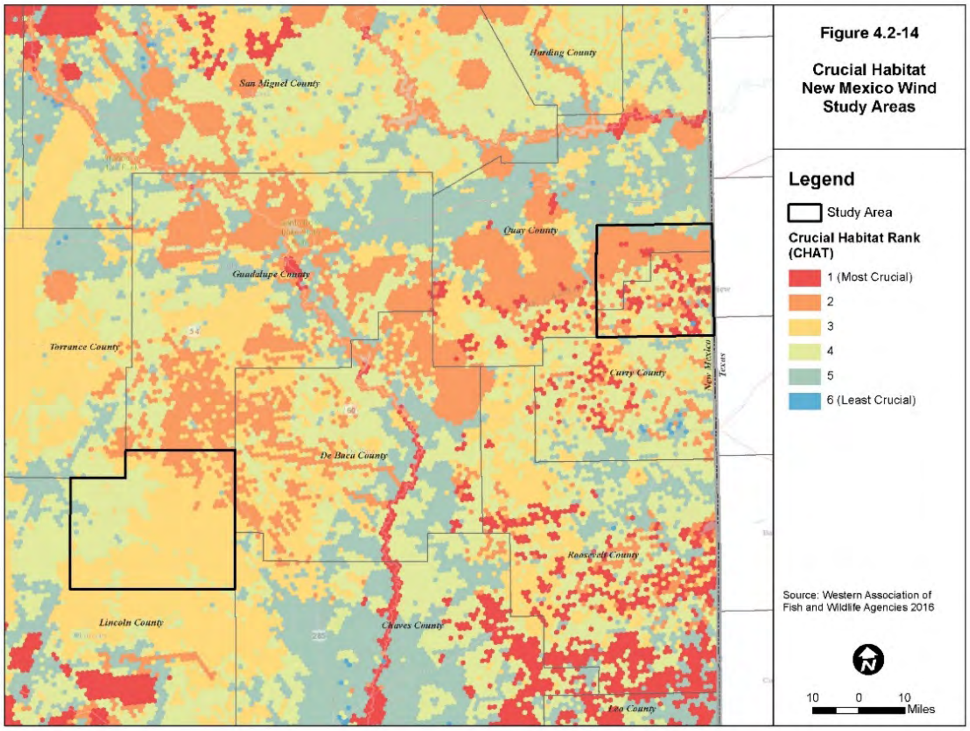


Figure 4.2-14. Crucial Habitat New Mexico Wind Study Areas



4.2.3 Typical Biological Resources Impacts of the Buildouts

The SB 350 environmental study describes environmental impacts in general; it is not site-specific and does not reflect or represent a siting study for any particular planned or conceptual construction project. Impacts to biological resources from large-scale renewable energy development may include habitat conversion, loss, degradation, or fragmentation, as well as through disturbance, injury, or mortality of plants or wildlife. Project-specific impacts would be avoided, minimized or compensated for, to the extent feasible, through site-specific configuration of project components as well as implementation of best management practices and mitigation as developed during the siting processes and required by the siting authorities with jurisdiction over affected biological resources. The impacts typical of construction and ongoing operations and maintenance activities are summarized in this section.

Construction Impacts in General

Buildout of the portfolios introduces some typical impacts to biological resources that may be caused by the construction activities for development of utility-scale renewable energy facilities. Renewable resource-specific impacts are explained in the subsections that follow. In general, typical construction-phase impacts are:

- **Habitat loss.** Conversion of habitat and fill of wetlands and other waters from installation of permanent facilities, including generation equipment, substations, transmission interconnections, and access roads. Cumulative effects throughout species range exacerbate impacts.

- **Habitat degradation.** Indirect damage to habitat from the establishment or expansion of noxious weeds and invasive species populations, sediment disposition or reduced water quality in aquatic habitats/wetlands, and reduced groundwater availability to groundwater-dependent vegetation communities.
- **Habitat fragmentation.** Large installations and roads may restrict wildlife movement, potentially reducing genetic diversity and interfering with migration. Cumulative effects throughout species range exacerbate impacts.
- **Disturbance, injury or mortality of special-status species.** Construction noise and human presence may disturb breeding wildlife and result in abandonment of eggs or young. Vehicles and equipment (including grading) may crush plants and wildlife or their burrows/dens.

Solar Construction

Construction of utility-scale solar facilities generally involves grading of large contiguous areas of land and typically results in extensive habitat loss. Restoration and revegetation of temporary disturbance areas in desert ecosystems can be difficult or impossible and damage to cryptobiotic crust of desert soils is particularly slow to recover, if ever.

Solar arrays can be configured to avoid sensitive biological resources (e.g., wetlands, watercourses, wildlife nursery sites, special-status plants and dense populations of small mammals) and to maintain wildlife movement corridors. Within fenced areas, native vegetation can exist between panels and continue to provide grassland foraging habitat in very limited cases; typically, vegetation is mowed or removed and the fenced facility is designed to deter larger wildlife (e.g., with exclusion fencing) to avoid possible injury to animals and damage to solar equipment and/or to facilitate movement of smaller mammals (e.g., kit fox).

Wind Construction

Habitat loss due to construction of wind energy systems does not typically occur in large contiguous areas and is normally isolated to wind turbine pads, ancillary buildings, substations, and access roads. Therefore, fragmentation is not usually severe; however, some species in wind resource areas (e.g., sage grouse) are particularly sensitive to the presence and use of equipment used for installing the infrastructure. Turbines can be configured to avoid sensitive terrestrial biological resources (e.g., wetlands, watercourses, wildlife nursery sites, special-status plants).

Geothermal Construction

Similar to wind construction, habitat loss resulting from geothermal construction does not typically occur in large contiguous areas and is normally isolated to surface facilities, well pads, pipelines, substations, and access roads. Therefore, fragmentation is not usually severe; however, some species in geothermal resource areas (e.g., peninsular bighorn sheep) are particularly sensitive to the presence and use of equipment used for installing the infrastructure. Wells can be clustered, which would expand the disturbance area at a particular well pad, but reduce total disturbance in the well field. Wells can also be configured to avoid sensitive biological resources (e.g., wetlands, watercourses, wildlife nursery sites, special-status plants), but directional drilling or trenching for pipeline installation would result in construction-phase disturbances.

Drilling requires large amounts of water, and local drawdown of water tables can have a direct effect on wetlands and groundwater flows, which can directly affect riparian vegetation or groundwater-dependent vegetation communities and associated wildlife. Sumps and pits used for storing excess geothermal fluids may be an attractant to wildlife that could result in physical injury or exposure to contaminants.

Drilling can take place up to 24 hours a day. Lighting and construction activity at night can be highly disruptive to wildlife and cause adverse alterations of behavior.

Operational Impacts in General

Buildout of the portfolios introduces some typical impacts to biological resources that may be caused by the operation of utility-scale renewable energy facilities. Renewable resource-specific impacts are explained in the subsections that follow. In general, typical operational impacts are:

- **Introduction of invasive species.** Habitat degradation from the establishment or expansion of noxious weeds and invasive species populations, including increased wildfire risk and changes to native species composition.
- **Predator subsidization.** Provision of additional food, water, nesting/bedding material that attracts predators (e.g., raven, coyote) and increases predation.
- **Disturbance, injury or mortality of special-status species.** Noise, night lighting, and human presence may disturb breeding wildlife, spread disease, and adversely alter wildlife behaviors. Maintenance vehicles and equipment may result in injury or mortality of wildlife along access roads or in unfenced areas of the facility.

Solar Operations

During operations, vehicles and equipment may be occasionally onsite to wash panels, maintain and inspect facilities, and mow vegetation to reduce fire risk. This could result in occasional temporary disturbance, injury or mortality of special-status species. Fencing must be maintained to ensure exclusion of larger wildlife, as necessary, but smaller special-status wildlife not excluded by fencing could be encountered inside or outside project boundaries along access roads.

Runoff water from washing solar panels or dust control could exacerbate the proliferation of invasive plants and attract wildlife if the arrays are unfenced. If groundwater is the water source, degradation of groundwater-dependent vegetation communities and impacts to associated wildlife could occur.

Wind Operations

The primary operational impact of wind energy facilities is bird and bat injury and mortality from collisions with turbines. Collision fatalities of some species, particularly those that are state or federally listed, can have a greater effect on local or regional populations and may affect migration behaviors.

Vehicles and equipment may be occasionally onsite to maintain and inspect facilities. This could result in occasional temporary disturbance, injury or mortality of special-status species.

Geothermal Operations

Vehicles and equipment may be occasionally onsite to maintain and inspect facilities and manage geothermal production waste. As geothermal developments are typically unfenced, this could result in occasional temporary disturbance, injury or mortality of special-status species.

Sumps and pits used for storing excess geothermal fluids may be an attractant to wildlife that could result in physical injury or exposure to contaminants.

4.2.4 Biological Resources Impacts of Regionalization

The 2020 CAISO + PAC scenario does not include any incremental renewable energy development. For limited regionalization in 2020, there would be no incremental construction activities; therefore, no adverse effects to biological resources would occur in this scenario.

Each scenario of regionalization in 2030 requires an incremental buildout of new solar, wind, and geothermal energy facilities, inside California and elsewhere, that will create environmental impacts in the vicinity of the renewable energy buildout. This section describes the potential impacts to biological resources for each incremental buildout to facilitate a comparison of the scenarios and identify the tradeoffs between in-state versus out-of-state development.

Incremental Buildout for Current Practice Scenario 1 by 2030

Inside California

Current Practice Scenario 1 emphasizes solar development in the Tehachapi and Westlands study areas, which account for 60 percent of total solar generation under this scenario (Tehachapi: 2,500 MW; Westlands: 2,323 MW), as shown in Section 2. These study areas also have low coverage of crucial habitat (Tehachapi: 13%, Westlands: 5%) and therefore have relatively low baseline biological resources sensitivity. In Tehachapi, solar development would primarily affect desert tortoise and Mohave ground squirrel, which are particularly sensitive to cumulative habitat loss and degradation. The Westlands study area is characterized by active and fallow agricultural land, which provides foraging habitat for various species including raptors; however, similar foraging habitat is widespread in the Central Valley. San Joaquin kit fox may move across the landscape through this study area, but fencing and facility design considerations could minimize any corridor constriction.

Wind generation would be distributed across six California study areas under Current Practice 1, with the greatest amount (28% of total or 850 MW) occurring in Tehachapi. The Tehachapi study area has the lowest crucial habitat coverage of the California wind study areas at 20 percent. Sensitive resources potentially affected by wind development in this study area include California condor, Swainson's hawk, golden eagles, and a diversity of birds at the Antelope Valley and Southern Sierra Desert Canyons Important Bird Areas, which include one of interior California's most important segments of the Pacific Flyway migration corridor. In general, impacts across the six wind study areas would be typical of those described in Section 4.2.3 and would include bird and bat injury and mortality from collisions with turbines. Collision impacts would be particularly severe in the Central Valley North/Los Banos and Solano study areas, which have high crucial habitat coverage (Central Valley North/Los Banos: 77%, Solano: 73%) attributable to their proximity to large water bodies that attract birds (Central Valley North/Los Banos: San Luis Reservoir, Solano: Sacramento-San Joaquin Delta).

Geothermal development would only occur in the Greater Imperial study area, which has 33% coverage of the highest crucial habitat ranks. Impacts would be typical of those described in Section 4.2.3.

Out of State

Current Practice 1 emphasizes wind development in the Northwest study area (44% of total or 2,447 MW) followed by wind development in New Mexico (18% of total or 1,000 MW). There is high potential for avian collision with turbines in the Northwest study area due to its proximity to the Columbia River and associated riparian habitat, which runs through the study area, as well as the Boardman Grasslands Important Bird Area, which supports one of the largest remaining intact areas of native shrub-steppe and grassland ecosystems in Oregon and the largest known breeding populations in Oregon for grasshopper sparrow, long-billed curlew, and burrowing owl. The New Mexico study area overlaps portions of the NM Lesser Prairie-Chicken Complex Important Bird Area. The federally threatened lesser prairie-chicken is highly sensitive to the presence of vertical infrastructure, including wind turbines, and cumulative effects of infrastructure development are the main threat to this species.

Under this scenario, most solar development would occur in the Southwest study area (18% of total or 1,000 MW), which has the lowest crucial habitat coverage of any study area (2%). Although not many sensitive biological resources occur in this study area, impacts to those present would be typical of those described in Section 4.2.3 and likely avoided or minimized by implementation of standard measures.

Incremental Buildout for Regional 2 by 2030

Inside California

Regional 2 would increase solar development in the Riverside East & Palm Springs study area, decrease solar development in Westlands, and eliminate incremental wind development in the Riverside East & Palm Springs and Solano study areas in comparison to Current Practice 1. A comparison of biological resources impacts from Regional 2 and Current Practice 1 for each California study area is presented in the Comparison of Scenarios in Section 4.2.5, in Table 4.2-2 (solar) and Table 4.2-3 (wind).

Regional 2 emphasizes solar development in the Riverside East & Palm Springs study area; this represents an increase of 1,653 MW in this study area in comparison to Current Practice 1, which assumes 331 MW. Accordingly, the severity of impacts to biological resources in the Riverside East & Palm Springs study area would increase. In particular, development would result in more habitat loss for several listed species and greater constriction of movement corridors for desert tortoise and bighorn sheep (peninsular and desert) than under Current Practice 1. Solar development in the Westlands study area would decrease by 1,450 MW in comparison to Current Practice 1; however, this study area has a low baseline sensitivity, so this reduction in development would not reduce any major impacts.

The elimination of incremental wind development in the Riverside East & Palm Springs and Solano study areas under Regional 2 would also eliminate impacts to biological resources in these study areas that would occur under Current Practice 1. Most importantly, bird and bat injury and mortality from collisions with turbines in the Solano study area in the highly-sensitive Sacramento-San Joaquin Delta would not occur.

Out of State

A comparison of biological resources impacts from Regional 2 and Current Practice 1 for each out-of-state study area is presented in the Comparison of Scenarios in Section 4.2.5, in Table 4.2-4.

Regional 2 would increase solar development in the Southwest study area by 500 MW in comparison to Current Practice 1. This would not substantially increase the severity of biological resource impacts in the Southwest study area given its low baseline sensitivity. However, wind development in the Northwest study area would decrease by 885 MW in this scenario. This study area has a relatively high baseline sensitivity due to the Columbia River and associated high-quality bird habitat; a decrease in wind development would result in a decrease in avian and bat mortality from turbine collisions.

Importantly, Regional 2 would greatly increase wind development in the Wyoming and New Mexico study areas by 2,000 MW and 3,000 MW, respectively, in comparison to Current Practice 1, due to renewable energy development facilitated by the regional market. These study areas have high baseline sensitivity attributable to the presence of Important Bird Areas. This increase in wind development would result in much greater impacts to birds and bats in comparison to Current Practice 1. Impacts to the lesser prairie-chicken in the New Mexico study area would be particularly severe.

Incremental Buildout for Regional 3 by 2030

Inside California

Regional 3 would eliminate incremental solar development in the Riverside East & Palm Springs and Carrizo study areas and decrease solar development in the Westlands, Tehachapi, Owens Valley and Greater Carrizo study areas in comparison to Current Practice 1. A comparison of biological resources impacts from Regional 3 and Current Practice 1 for each California study area is presented in the Comparison of Scenarios in Section 4.2.5, in Table 4.2-2 (solar) and Table 4.2-3 (wind).

Regional 3 would eliminate or reduce impacts to biological resources in all California solar study areas, except in the Kramer and Inyokern study area, where there would be no change in solar development between scenarios. The reduction of impacts in Owens Valley and Greater Imperial study areas are particularly notable given the relatively high baseline sensitivity of these study areas (crucial habitat coverage: Owens Valley – 87%, Greater Imperial – 44%), which is attributable to the occurrence of numerous listed species in these study areas.

With regard to wind development in California, Regional 3 is the same as Regional 2. Impacts to biological resources in the Riverside East & Palm Springs and Solano study areas that would occur under Current Practice 1 would be eliminated under Regional 3. Most importantly, bird and bat injury and mortality from collisions with turbines in the Solano study area in the highly-sensitive Sacramento-San Joaquin Delta would not occur.

Out of State

A comparison of biological resources impacts from Regional 3 and Current Practice 1 for each out-of-state study area is presented in the Comparison of Scenarios in Section 4.2.5, in Table 4.2-4.

As with Regional 2, Regional 3 would increase solar development in the Southwest study area by 500 MW in comparison to Current Practice 1. This would not substantially increase the severity of biological resource impacts in the Southwest study area given its low baseline sensitivity. However, wind development in the Northwest study area would decrease by 2,129 MW in comparison to Current Practice 1, which assumed 2,447 MW. This study area has a relatively high baseline sensitivity due to the Columbia River and associated high-quality bird habitat; this substantial decrease in wind development would result in a decrease in avian and bat mortality from turbine collisions in comparison to Current Practice 1.

Importantly, Regional 3 would immensely increase wind development in the Wyoming and New Mexico study areas by 3,995 MW and 4,962 MW, respectively, in comparison to Current Practice 1, due to renewable energy development facilitated by the regional market. This represents a nine-fold increase in Wyoming and six-fold increase in New Mexico in wind generation in these study areas in comparison to Current Practice 1. These study areas have high baseline sensitivity attributable to the presence of Important Bird Areas. This increase in wind development would result in much greater impacts to birds and bats in comparison to Current Practice 1. Impacts to the lesser prairie-chicken in the New Mexico study area would be particularly severe.

Out-of-State Transmission Additions

Under Regional 3, it is assumed that major out-of-state transmission additions would be necessary to integrate renewable generation from Wyoming and New Mexico into the regional power system and for California to achieve 50% RPS. The biological resources considerations related to the construction and operation of the potential transmission expansions are summarized in Section 5.

4.2.5 Comparison of Scenarios for Biological Resources

The change from Current Practice into regional scenarios allows the following comparisons.

Inside California

- Regional 2 exchanges potential impacts, by slightly increasing impacts to resources in Riverside East & Palm Springs (e.g., desert tortoise, bighorn sheep) and reducing impacts elsewhere
- Regional 2 and Regional 3 reduce impacts to avian resources (e.g., migratory birds) by eliminating wind in Riverside East & Palm Springs and Solano
- Regional 3 eliminates or reduces impacts to biological resources in all California solar study areas, except no change in Kramer and Inyokern (which is has relatively low baseline sensitivity).

Out of State

- Regional 2 and Regional 3 reduces impacts to avian resources (e.g., migratory birds) in Northwest wind area with a relatively high baseline sensitivity
- Regional 3 increases impacts to avian resources (e.g., migratory birds) in Wyoming and New Mexico due to wind for the California RPS
- Regional 2 and Regional 3 also increase impacts to avian resources (e.g., migratory birds) in Wyoming and New Mexico due to renewable energy development facilitated by the regional market (5,000 MW wind)

Important differences of the scenarios are described in the sections following the tables. The results of the comparison of scenarios are summarized in Table 4.2-2 for solar and Table 4.2-3 for wind areas inside California, and in Table 4.2-4 for renewable energy resources outside of California.

Table 4.2-2. Biological Resources, Comparison of Scenarios for California Solar Buildout

California Solar Study Areas	Coverage of Most Crucial Habitat Ranks	Difference: Regional 2 Relative to Current Practice 1	Difference: Regional 3 Relative to Current Practice 1
Greater Carrizo Solar	52%	No change	Impacts eliminated
Greater Imperial Solar	44%	No change	Impacts reduced
Kramer and Inyokern Solar	2%	No change	No change
Owens Valley Solar	87%	No change	Impacts slightly reduced
Riverside East and Palm Springs Solar	30%	Impacts increased	Impacts eliminated
Tehachapi Solar	13%	No change	Impacts reduced
Westlands Solar	5%	Impacts reduced	Impacts reduced

Table 4.2-3. Biological Resources, Comparison of Scenarios for California Wind Buildout

California Wind Study Areas	Coverage of Most Crucial Habitat Ranks	Difference: Regional 2 Relative to Current Practice 1	Difference: Regional 3 Relative to Current Practice 1
Central Valley North and Los Banos Wind	77%	No change	No change
Greater Carrizo Wind	57%	No change	No change
Greater Imperial Wind	56%	No change	No change
Riverside East and Palm Springs Wind	55%	Impacts eliminated	Impacts eliminated
Solano Wind	73%	Impacts eliminated	Impacts eliminated
Tehachapi Wind	20%	No change	No change

Table 4.2-4. Biological Resources, Comparison of Scenarios for Out-of-State Buildout

Out-of-State Solar & Wind Study Areas	Coverage of Most Crucial Habitat Ranks	Difference: Regional 2 Relative to Current Practice 1	Difference: Regional 3 Relative to Current Practice 1
Southwest Solar (Arizona)	2%	Impacts increased	Impacts increased
Northwest Wind (Oregon)	31%	Impacts reduced	Impacts reduced
Utah Wind	10%	No change	Impacts slightly reduced
Wyoming Wind	31%	Impacts greatly increased (beyond RPS)	Impacts greatly increased (beyond RPS plus RPS portfolio)
New Mexico Wind	26%	Impacts greatly increased (beyond RPS)	Impacts greatly increased (beyond RPS plus RPS portfolio)

Regional 2 Relative to Current Practice 1

Relative to Current Practice 1, in California, Regional 2 would result in increased habitat loss for several listed species and greater constriction of movement corridors for desert tortoise and bighorn sheep (peninsular and desert) in the Riverside East & Palm Springs study area from greater solar development and the elimination of bird and bat injury and mortality from collisions with turbines in the highly-sensitive Solano study area due to the elimination of wind development.

Regarding out-of-state biological resources impacts, relative to Current Practice 1, Regional 3 would decrease avian and bat mortality from turbine collisions in Northwest study area due to a reduction in wind development and greatly increase these impacts in the Wyoming and New Mexico study areas due to an increase in wind development for the California RPS and wind development facilitated by the regional market beyond RPS.

Regional 3 Relative to Current Practice 1

Relative to Current Practice 1, Regional 3 would eliminate or reduce impacts to biological resources in all California solar study areas, except in the Kramer and Inyokern study area (no change), which has relatively low baseline sensitivity. Regional 3 would also eliminate bird and bat injury and mortality from collisions with turbines in the highly-sensitive Solano study area due to the elimination of wind development.

Regarding out-of-state biological resources impacts, relative to Current Practice 1, Regional 3 would decrease avian and bat mortality from turbine collisions in Northwest study area due to a reduction in wind development and immensely increase these impacts in the Wyoming and New Mexico study areas due to an increase in wind development for the California RPS portfolio and wind development facilitated by the regional market beyond RPS.

4.3 Water

This section describes the potential impacts to water resources for each of the four buildouts. The approach to the analysis relies upon a narrow set of baseline conditions that are treated as potential indicators or predictors of impacts, as listed in Table 4.3-1.

Table 4.3-1. Baseline Conditions and Indicators of Impacts, Water Resources

Baseline condition of a study area	How are scenarios analyzed relative to the baseline?	Potential indicator of water impact
Water		
Level of groundwater basin overdraft	Coincidence of incremental renewable energy buildout with areas of substantially constrained groundwater availability	Water supply and water quality
Level of groundwater basin overdraft	Changes in fossil fuel generation by technologies that rely heavily on cooling water	Water supply

Assumptions and Methodology for Water Analysis

The water methodology considers the following issues:

- How the construction of the renewable buildout for each portfolio may affect Critically Overdrafted Groundwater Basins in California as defined by the California Department of Water Resources (CDWR)
- How the construction of renewable buildout for each portfolio may affect areas in low to medium, medium to high, and high water risk based on the World Resources Institute (WRI) risk characterization
- The water requirement for the operation of renewable and non-renewable resources under each of the PSO scenarios

Critically Overdrafted Groundwater Basins

The CDWR defines critically overdrafted groundwater basins as basins and subbasins in California in conditions of critical overdraft, resulting from seawater intrusion, land subsidence, groundwater depletion, and/or chronic lowering of groundwater levels. In this report, study areas are evaluated to define whether they would overlap areas of critically overdrafted groundwater basins. The study areas do not align completely with groundwater basin boundaries, and this analysis does not attempt to calculate how much water would be used from the basins.

Water Risk

The WRI published an *Aqueduct Water Risk Atlas,* which is a publicly available, global database and interactive tool that maps indicators of water-related risks. This tool provides an overall score of water risk that incorporates water quantity, water variability, water quality, public awareness of water issues, access to water, and ecosystem vulnerability. Because the data set covers the entire U.S., it allows for a comparison among the states that are included in the RESOLVE renewable portfolios.

In order to confirm the relevance of the WRI water risk assessment dataset, it has been compared to other U.S. reports, such as the United States Geological Survey (USGS) Groundwater Depletion in the United States (1900-2008) and NASA GRACE-Based monitoring tools.[2]

[2] See for example the GRACE-Based Surface Soil Moisture Drought Indicator, GRACE-based Ground Water Storage, and GRACE-Based Shallow Groundwater Drought Indicator.

The resource study areas were mapped using the WRI data to determine the percentage of each area that overlapped with low to medium, medium to high, or high water risk areas. This information was used to calculate the potential amount of water used for construction under each risk category. In order to calculate the amount of water used during construction, state-based estimates were developed (6 acre-feet per MW for construction in Arizona and 2 acre-feet per MW for construction in California). This data was take from the Sandia Report "Water Use and Supply Concerns for Utility-Scale Solar Projects in the Southwestern United States" (July 2013).[3] Wind turbine construction water use assumed at 0.4 acre-feet per MW[4]. Geothermal construction use assumed 1.4 acre-feet per MW for construction.[5]

It should be noted that the study areas are much larger than would be needed to develop the amount of energy assumed under each scenario. Therefore, while this analysis allows for comparison among the scenarios, more energy could be developed in any one of the risk areas than the calculations would indicate.

Operational Water Use

The production cost simulation model provided the changes in overall generation (in MWh) in the WECC under each of the scenarios. This information was used to define an estimated change in water consumption both inside and outside of California under each scenario. The model provides the MWh by technology (combined cycle, coal, geothermal, wind, etc.). The National Renewable Energy Laboratory's (NREL) *A review of Operational Water Consumption and Withdrawal Factors for Electricity Generating Technologies* (2011) provides water consumption factors for each type of electricity generation and was used to calculate the estimated water use under each scenario. The analysis uses the following consumption factors for renewable and conventional technologies (gallons per MWh):

■ Solar PV	26	■ Solar thermal	78
■ Wind	0	■ Geothermal flash technology	10
■ Geothermal binary technology	3,600	■ Natural gas combined cycle	198
■ Natural Gas steam turbine	826	■ Natural gas combustion turbine	0
■ Coal	687		

Water consumption factors[6] were used instead of water withdrawal factors[7] because they provide a better representation of the effect of energy on water use. The numbers presented in the NREL article were comparable to other reports regarding water use in energy. Nonetheless, due to solar technology advancements, some solar technologies may now use less than 26 gallons per MWh.

4.3.1 Regulatory Framework

The following is the regulatory framework for water in the study areas.

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[3] This report is available at: http://citeseerx.ist.psu.edu/viewdoc/download?doi=10.1.1.490.1952&rep=rep1&type=pdf.

[4] A discussion regarding the amount of water used during construction of wind turbines was not found. Instead, the authors reviewed several CEQA and NEPA documents for proposed wind projects to review how much water per MW was anticipated for use during construction.

[5] A discussion regarding the amount of water used during construction of geothermal projects was not found. The authors reviewed several CEQA document for proposed geothermal projects in the Imperial Valley to review how much water per MW was anticipated for use during construction.

[6] Water consumption is the portion of the total freshwater input that has become unavailable for reuse due to evaporative losses, incorporation into the produced energy, or transfer to another catchment or sea (Madani and Khatami, 2015).

[7] Water withdrawal is the total freshwater input into the energy production system (Madani and Khatami, 2015).

Federal Protection of Surface Water and Groundwater

Clean Water Act

The federal Clean Water Act (CWA 33 United States Code [U.S.C.] 1251 et seq.) requires that states set standards to protect water quality, including the regulation of stormwater and wastewater discharges during construction and operation of projects (Section 402). The CWA also establishes regulations and standards to protect wetlands and navigable waters (Section 404). The U.S. Army Corps of Engineers issues Section 404 permits for discharges of dredge or fill material. These permits cover discharges to waters of the United States, and are subject to Section 401 water quality federal license and permit certification. Section 401 certification is required if U.S. surface waters, including perennial and ephemeral drainages, streams, washes, ponds, pools, and wetlands, could be adversely impacted. The U.S. Army Corps of Engineers and, in California, a Regional Water Quality Control Board (RWQCB) can require that impacts to these waters be quantified and mitigated. Whenever a discharge is made to U.S. waters the RWQCB issues National Pollution Discharge Elimination System (NPDES) and Waste Discharge Requirement (WDR) permits. If a discharge is confined to California state waters only a WDR permit is required.

Reclamation Reform Act

Under the Reclamation Reform Act of 1982 (Public Law 97–2933; 96 Stat. 1261), the U.S. Bureau of Reclamation (USBR) manages, develops, and protects U.S. waters and related resources.

Safe Drinking Water Act

The Safe Drinking Water Act (42 U.S.C. 300[f] et seq.) establishes requirements and provisions for the Underground Injection Control Program. One way this law safeguards the public health is by protecting underground drinking water sources from injection well contamination. General provisions for the Underground Injection Control Program (including state primacy for the program) are described in Sections 1421 through 1426. The California Division of Oil, Gas, and Geothermal Resources has the authority to issue federal Class V Underground Injection Control permits for geothermal fluid injections.

Environmental Protection Agency Sole Source Aquifer Protection Program

The EPA Sole Source Aquifer Protection Program, established in Section 14245(e) of the Safe Drinking Water Act, requires that EPA review proposed federally assisted projects to determine their potential for aquifer contamination.

Colorado River Water Accounting Surface

Colorado River diversions are governed by the Colorado River Compact, signed in 1922, and by associated documents subsequently affirmed by the United States Supreme Court in Arizona v. California (547 U.S. 150 2006) (Consolidated Decree). Following the historical growth in water demand outside California, in 2001 the U.S. Department of the Interior (DOI) issued Interim Surplus Guidelines that define Lake Mead reservoir elevations below which California would not be able to use “surplus” water. The USBR monitors and accounts for all water use in areas with diversions from the Lower Colorado River.

State Protection of Surface Water and Groundwater

California Porter–Cologne Water Quality Control Act

California’s Porter–Cologne Water Quality Control Act, enacted in 1969 (Cal. Stats. 1969, Ch. 482), provides the legal basis for water quality regulation in California. It predates the CWA and regulates discharges to state waters. This law requires a Report of Waste Discharge for any discharge of waste (liquid, solid, or gaseous) to land or surface waters that may impair beneficial uses for surface or groundwater of the state. Waters of the state are more than just waters of the United States and include, for example, groundwater and some surface waters that do not meet the definition for waters of the United States. In addition, it prohibits waste discharges or the creation of water-related "nuisances," which are more broadly defined than the CWA definition of "pollutant." Discharges under the Porter–Cologne Act are permitted with waste discharge requirements and may be required even when the discharge is already permitted or exempt under the CWA.

California Water Quality, Supply and Infrastructure Improvement Act and Sustainable Groundwater Management Act

In 2014 the Water Quality, Supply and Infrastructure Improvement Act and the Sustainable Groundwater Management Act were signed into law. The Water Quality, Supply and Infrastructure Improvement Act includes funding for integrated regional water management, water recycling, groundwater sustainability, and watershed protection and ecosystem restoration. The Sustainable Groundwater Management Act provides for sustainable management of groundwater basins, establishes minimum standards for effective and continuous management of groundwater, avoids or minimizes impacts of land subsidence, increases groundwater storage and removes impediments to recharge, and improves data collection and understanding of groundwater resources and management. Sustainable groundwater management is defined as the management and use of groundwater in a manner that can be maintained during the planning and implementation horizon without causing undesirable results. The act requires local agencies to establish groundwater sustainability agencies and develop groundwater sustainability plans for groundwater basins or sub-basins that are designated as medium or high priority basins.

Arizona Groundwater Management Code

Arizona enacted the Ground Water Management Code in 1980 because of historic groundwater overdraft, where groundwater recharge is exceeded by discharge. The Code describes three main goals for the state regarding the management of groundwater: (1) controlling severe overdraft, (2) allocation of the limited water resources of the state, and (3) enhancement of the state's groundwater resources using water supply development. Arizona's groundwater management laws are separated using a three tier system based on the Code. The lowest level of management includes provisions that apply statewide, Irrigation Non-Expansion Areas (INAs) have an intermediate level of management, and Active Management Areas (AMAs) have the highest level of management with the most restrictions and provisions. There are currently five AMAs and three INAs in the state, each of which has its own specific rules and regulations regarding the appropriation of groundwater.

The ADWR has created guidelines regarding the appropriation of water for solar generating facilities, specifically detailing what information needs to be submitted for permit evaluation. The information required includes the proposed method of power generation, the proposed amount of water to be consumed, the point of diversion, and to what or whom the power is to be distributed. To secure water rights for a solar facility located within an AMA, the applicant must demonstrate that there is an "assured water supply" for the life of the project. The ADWR then makes a decision based on whether the proposed water right will be detrimental to public welfare and general conservation of water.

Arizona Underground Water Storage, Savings, and Replenishment Act

The Underground Water Storage, Savings, and Replenishment Act created the Arizona Water Banking Authority, which has two programs: (1) Underground Storage Facilities, which use excess Central Arizona Project (CAP) water, other surface water, or effluent to artificially recharge a groundwater aquifer, and

(2) Groundwater Savings Facilities, which provide water supplies (CAP water, other surface water or effluent) in lieu of using groundwater, allowing the groundwater to stay in storage and become "savings." The ADWR is in charge of the distribution of the program's waters as well as the evaluation of permits to store and recover their waters. To put this water to use, the ADWR must first award a recovery well permit. If a recovery well permit is submitted for use inside an AMA, a "hydrologic impact analysis" report may also need to be submitted.

Oregon Water Resources Department Chapter 690 Division 310

Under Oregon law, all water is publicly owned. With some exceptions, cities, farmers, factory owners and other users must obtain a permit or water right from the Water Resources Department to use water from any source — whether it is underground, or from lakes or streams. Landowners with water flowing past, through, or under their property do not automatically have the right to use that water without a permit from the Department.

Oregon Drinking Water Quality Act of 1981

The purpose of the act is to ensure that all Oregonians have safe drinking water, to provide a simple and effective regulatory program for drinking water systems; and to provide a means to improve inadequate drinking water systems.

Oregon Water Quality, Pollution Prevention Control

Oregon's Nonpoint Source Program is implemented by land use in order to address water quality issues on agricultural lands; state, private, or federal forest lands; or in urban areas. The goal of the program has been broadened to safeguard groundwater resources as well as surface water. The state has been divided into 21 watershed basins and 91 sub-basins. The state's permitting and assessment work has been aligned and prioritized according to these sub-basins. Forty-three local, state, and federal regulatory and non-regulatory programs address nonpoint source control and treatment.

Washington Surface Water Code

The 1917 Water Code was a comprehensive code that established a substantive and procedural system. An important element of the code is the provision for general adjudications of particular bodies of water, basins, or aquifers. Since 1917, no surface water may be appropriated without a permit. In considering permit applications, the State considers whether there is water available, if the application is for a beneficial use, will granting the application adversely affect existing water rights, and will granting the application be detrimental to the public interest.

Washington Ground Water Code

The Washington Legislature passed the Ground Water code in 1945. In general, this meant treating ground water like surface water for the purpose of obtaining permits for water rights. In 1973, the Legislature amended the definition of "ground water" to make it clear that the code covered all ground water.

Washington Water Resources Act of 1971

The Water Resources Act of 1971 set out general policy statements regarding water use in both surface and groundwater areas. It required the department to create a comprehensive state water resources program that would provide a process for making decisions on future water resource allocation and use. It listed beneficial uses and recognized allocation will be based generally on the securing of the maximum net benefits for the people of the state.

Utah Water Quality Act

Utah water law is governed under the doctrine of prior appropriation. The agency responsible for the regulation, appropriation, and distribution of the state's water is the Utah Division of Water Rights, headed by the State Engineer. Water rights are assessed regionally in one of the seven regional offices of the Utah Division of Water Rights. The Utah Division of Water Rights assesses proposed water right applications based on whether the proposed right will have available unappropriated water, whether the right will impair existing rights, and whether granting the proposed right will be detrimental to the public welfare.

Wyoming Water Statutes

In 1957 Wyoming enacted a comprehensive code for handling underground water. Those laws provided that wells for domestic and stock uses would have preferred rights over other groundwater uses even though they were still exempt from filing requirements, and that all other wells would need to be permitted by the State Engineer before construction could commence. The appointment of a Division Advisory Committee on groundwater matters was required for each of the four historic water divisions, and the State Engineer was directed to establish aquifer districts and sub-districts within those water divisions. In districts of sub-districts where concerns for the condition of an aquifer existed, the laws provided the designation of "critical areas" and the election of an advisory board to manage the concerns of that area.

This legislature was expanded in 1969 such that all groundwater wells, even previously exempted stock and domestic wells, required a permit from the State Engineer before drilling could be commenced. Domestic and stock water wells still had a preferred right over wells for other purposes, with the term "domestic" being well-described and conditioned.

New Mexico Water Statutes

Water law in New Mexico is governed under the doctrine of prior appropriation. All waters (both groundwater and surface water) are public and subject to appropriation by a legal entity with plans of beneficial use. A water right in New Mexico is a legal entity's right to appropriate water for a specific beneficial use and is defined by seven major elements: owner, point of diversion, place of use, purpose of use, priority date, amount of water, and periods of use. Water rights in New Mexico are administered through the Water Resources Allocation Program under the New Mexico Office of the State Engineer.

Under Title 19, Chapter 27 Part 1, a water use permit from State Engineer's Office is required to drill a well and to use the water. The two major exemptions from the permitting process are minimal domestic uses and wells deeper than 2500 feet.

New Mexico Ground Water Storage and Recovery Act

In 1999, the State legislature passed the Ground Water Storage and Recovery Act to save money through groundwater recharge, storage, and recovery, to reduce the rate of decline in aquifers, to promote conservation, to serve the public welfare, and to lead to more effective use of the State's water resources. It set production limits for ground water based on proportionate reduction, rate of withdrawal, and prevention of well interferences.

4.3.2 Baseline Conditions in Study Areas

Water use for development of energy can be surface water or groundwater. Surface water includes streams, rivers, lakes, and reservoirs. In California, renewable development would not use surface water during construction unless it were purchased through a management entity. Outside of California, it is possible that developers might use surface water for construction but they are more likely to use groundwater during construction.

Groundwater is a part of the hydrologic cycle and is recharged from deep percolation of rainfall, streamflow, and other sources. Groundwater discharges to streams, lakes or the ocean, where water evaporates, condenses to form clouds, and returns to the earth's surface as precipitation. In general, groundwater flows from areas of higher hydraulic head to low hydraulic head and takes the path of least resistance through sediments and rocks, such as those with relatively high permeability. At a regional scale, groundwater flows from recharge areas to discharge areas. Some groundwater pathways are shallow, short, and quick and some pathways may be very long, deep within a basin and prolonged. At a local scale, groundwater flow may be intercepted by a water supply well, where pumping creates drawdown and a cone of depression (low hydraulic head) around the well. A pumping well is an artificial point of discharge from the aquifer.

Inside California Solar

A groundwater basin — typically underlying a valley or coastal plain — contains one or more connected and interrelated aquifers and often represents a groundwater reservoir capable of providing substantial water supply. The CDWR has defined groundwater basins throughout California, designating 515 basins and subbasins.

Groundwater resources play a vital role in maintaining California's economic and environmental sustainability. During an average year, California's 515 alluvial groundwater basins and subbasins contribute approximately 38 percent toward the State's total water supply. During dry years, groundwater contributes up to 46 percent (or more) of the statewide annual supply, and serves as a critical buffer against the impacts of drought and climate change. Many municipal, agricultural, and disadvantaged communities rely on groundwater for up to 100 percent of their water supply needs. Groundwater extraction in excess of natural and managed recharge has caused historically-low groundwater elevations in many regions of California.

CDWR has a long-standing history of collecting and analyzing groundwater data, investigating and reporting groundwater conditions, implementing local groundwater assistance grants, encouraging integrated water management, and providing the technical expertise needed to improve statewide groundwater management practices. CDWR is responsible for characterizing California's groundwater basins through updates to Bulletin 118.

Groundwater balance describes the portion of the hydrologic cycle in a groundwater basin in terms of inflows, outflows, and change in storage. The basic equation is: Inflows – Outflows = Change in Storage. Under long-term natural conditions, groundwater basins remain basically full, change in storage is zero and inflows equal outflows. Under historical and current conditions in many California groundwater basins, the rate of groundwater pumping and consumption (e.g., evapotranspiration) has been much greater than the rate of recharge. Consequently, outflows are greater than inflows and the groundwater storage decreases. This is manifested by falling groundwater levels and often is accompanied in the long term by adverse impacts such as loss of well yields, land subsidence, water quality degradation, and other environmental impacts. This long-term adverse condition is called overdraft. In California, overdraft occurs in parts of the Central Valley, especially the Tulare Basin, and in some coastal and southern California basins with limited surface water supplies and intensive agriculture.

This report uses the *Aqueduct Water Risk Atlas,* to determine the overall score of water risk incorporating water quantity, water variability, water quality, public awareness of water issues, access to water, and ecosystem vulnerability. The risk categories within California are shown in Table 4.3-2.

Many locations in California experience either medium to high or high water risk. A discussion of the groundwater basins in California follows this table. This discussion explains the primary concerns in the California groundwater basins underlying the solar and wind study areas.

Table 4.3-2. California Water Risk Categories

	Low to Medium	Medium to High	High
Solar Study Areas			
Greater Carrizo Solar	0%	92%	8%
Greater Imperial Solar	38%	0%	62%
Kramer Inyokern Solar	39%	61%	0%
Owens Valley Solar	87%	0%	13%
Riverside East Palm Springs Solar	34%	25%	41%
Tehachapi Solar	27%	73%	0%
Westlands Solar	0%	8%	92%
Wind Study Areas			
Central Valley North Los Banos Wind	0%	100%	0%
Greater Carrizo Wind	0%	95%	5%
Greater Imperial Wind	50%	4%	46%
Riverside East Palm Springs Wind	0%	0%	100%
Solano Wind	51%	46%	3%
Tehachapi Wind	27%	49%	24%

In California, the CDWR publishes California's Groundwater Bulletin 118 that provides information regarding the groundwater quantity and quality for every groundwater basin and subbasin. Information regarding the basins and subbasins that underlie the locations of renewable energy resources selected by the RESOLVE model is summarized below. Bulletin 118 data for each basin is available through the Groundwater Information Center Interactive Map Application (CDWR, 2016).

Greater Carrizo Solar

Three groundwater basins underlie the Greater Carrizo solar study areas, the Santa Maria Valley Basin (3-12), the Paso Robles Area subbasin of the Salinas Valley Basin (3-4.06), and the Cholame Valley Basin (3-05). The Santa Maria Valley basin is an adjudicated groundwater basin. Court adjudications are a form of groundwater management where the groundwater rights of all the overliers and appropriators are determined by the court. The court also decides: (1) who the extractors are; (2) how much groundwater those well owners can extract; and (3) who the Watermaster will be to ensure that the basin is managed in accordance with the court's decree.

The Paso Robles Area subbasin is designated a critically overdrafted groundwater basin. It supplies water for 29 percent of San Luis Obispo County's population and an estimated 40 percent of the agriculture production in the county (San Luis Obispo County, 2011). Agricultural water use accounts for an estimated 67 percent of the pumping in the basin. Multiple groundwater studies indicated that the basin outflow, including groundwater pumping, would soon be greater than basin inflow, or recharge. The Paso Robles Groundwater Basin Management Plan was developed in 2011 to develop a common understanding of the groundwater issues and management opportunities in the Basin and identify and support projects such as conjunctive use, recycled wastewater, and demand management, which will improve groundwater management

Greater Imperial Solar

The Greater Imperial solar study area covers the Amos Valley (7-34), Imperial Valley Basin (7-30), East Salton Sea Basin (7-33), Ocotillo Clark Valley Basin (7-25), Borrego Valley Basin (7-24), and the Warner Valley basin (9-08). The water levels in these groundwater basins have generally declined since the mid-1900s. The Imperial Valley Basin recharge is primarily from irrigation return. Groundwater in the Imperial Valley Basin, the Ocotillo Clark Valley, and the Borrego Valley is poor, with high total dissolved solids.

The Borrego Valley Basin is designated a critically overdrafted groundwater basin. Groundwater is used for agricultural, recreational, and municipal purposes. Over time, groundwater withdrawal through pumping has exceeded the amount of water that has been replenished, causing groundwater-level declines of more than 100 feet in some parts of the basin. Continued pumping has resulted in an increase in pumping lifts, reduced well efficiency, dry wells, changes in water quality, and loss of natural groundwater discharge. Groundwater studies shows that little recharge is occurring under the current climatic conditions. (Faunt, *et al.*, 2015).

Kramer and Inyokern Solar

The Kramer and Inyokern solar study area covers the Searles Valley Basin (6-52), Caves Canyon Valley (6-38), the Lower Mojave River Valley (6-40), the Upper Mojave River Valley Basin (6-42), the El Mirage Valley Basin (6-43), Antelope Valley (6-44) and the Lucerne Valley Basin (7-19). Groundwater levels in portions of the El Mirage Valley and Lucerne Valley have declined significantly. There is evidence of subsidence from overdraft in Lucerne Valley. The Lower and Upper Mojave River Basins, Lucerne Valley Basins, and a portion of the Antelope Valley Basin are adjudicated.

The Lower Mojave River Valley Groundwater Basin underlies an elongate east-west valley, with the Mojave River flowing (occasionally) through the valley from the west across the Waterman fault and exiting the valley to the east through Afton Canyon. Groundwater levels in wells in the floodplain unit near the Mojave River tend to vary in concert with rainfall and runoff rates, whereas groundwater levels in the fan unit do not show significant changes due to local rainfall.

The Upper Mojave River Valley Groundwater Basin underlies an elongate north-south valley, with the Mojave River flowing (occasionally) through the valley from the San Bernardino Mountains on the south, northward into the Middle Mojave River Valley Groundwater Basin at the town of Helendale. Impacts to the basin include overdraft. Additionally, water quality impacts in basin including nitrates, inorganics, and fuel additives. There is a superfund site within basin.

Owens Valley Solar

The Owens Valley solar study area covers the Mesquite Valley (6-29), Owens Valley (6-12), Pahrump Valley (6-28), Rose Valley (6-56) and Searles Valley Basin (6-52). Both the Pahrump Valley and Mesquite Valley basins extent into Nevada. Water levels in the Pahrump Valley are generally declining and the State of Nevada Department of Water Resources has documented overdraft and subsidence conditions in this basin. Much of the groundwater in the Owens Valley is exported to Los Angeles, resulting in limited irrigated acres and domestic development. Impacts to the Mesquite Valley basin include declining water levels and locally high total dissolved solids in the southern portion of basin that makes the groundwater marginal to inferior for domestic uses.

Riverside East and Palm Springs Solar

The Riverside East and Palm Springs solar study area includes the Palo Verde Mesa Basin (7-39), the Chuckwalla Valley (7-5), and the Coachella Valley Indio (7-21.01), Mission Creek (7-21.02), and Desert Hot Springs (7-21.03) subbasins. The Palo Verde Mesa Basin has high concentrations of arsenic, selenium, fluoride, chloride, boron, sulfate, and total dissolved solids. The Chuckwalla Valley Basin has high concentrations of sulfate, chloride, fluoride, and total dissolved solids. The high boron and total dissolved solids concentrations and high sodium percentage impair groundwater for irrigation use. All subbasins of the Coachella Valley have some levels of concern, the Indio Subbasin has nitrates and salts due to the Colorado River imported water as well as local areas of elevated fluoride. The Mission Creek Subbasin has radiological and nitrate issues and high total dissolved solids and declining water levels have been documented in the Desert Hot Springs Subbasin.

Tehachapi Solar

The Tehachapi solar study area includes the Fremont Valley Basin (6-46) and the Antelope Valley (6-44). The Fremont Valley Basin has naturally high TDS locally and other constituents. Groundwater levels have shown significant decline throughout the basin. The Antelope Valley Basin is a closed basin where extractions likely exceed natural recharge. The basin is pending adjudication and has water reliability issues and subsidence.

Westlands Solar

The Westlands solar study area overlays the San Joaquin Valley Basin (5-22) which is surrounded on the west by the Coast Ranges, on the south by the San Emigdio and Tehachapi Mountains, on the east by the Sierra Nevada and on the north by the Sacramento-San Joaquin Delta and Sacramento Valley. The northern portion of the San Joaquin Valley drains toward the Delta by the San Joaquin River and its tributaries, the Fresno, Merced, Tuolumne, and Stanislaus Rivers. The southern portion of the valley is internally drained by the Kings, Kaweah, Tule, and Kern Rivers that flow into the Tulare drainage basin including the beds of the former Tulare, Buena Vista, and Kern Lakes.

The Westlands Solar area includes the Chowchilla Subbasin (5-22.05), Madera Subbasin (5-22.06), Delta-Mendota Subbasin (5-22.07), Kings Subbasin (5-22.08), Westside Subbasin (5-22.09), Pleasant Valley Subbasin (5-22.10), Kaweah Subbasin (5-22.11), Tulare Lake Subbasin (5-22.12), Tule Subbasin (5-22.13), and Kern County Subbasin (5-22.14). The primarily concern for the Westlands Solar area are overdraft, subsidence and water quality degradation. This entire area is an important agriculture region. The following subbasins are critically overdrafted basins:

- Chowchilla Subbasin (5-22.05)
- Madera Subbasin (5-22.06)
- Delta-Mendota Subbasin (5-22.07)
- Kings Subbasin (5-22.08)
- Westside Subbasin (5-22.09)
- Kaweah Subbasin (5-22.11)
- Tulare Lake Subbasin (5-22.12)
- Tule Subbasin (5-22.13)
- Kern County Subbasin (5-22.14)

Inside California Wind

Central Valley North and Los Banos Wind

The Central Valley North and Los Banos wind study area overlays the San Joaquin Valley Delta Mendota Subbasin (5-22.07). This subbasin is described under Westlands Solar.

Greater Carrizo Wind

The Greater Carrizo wind study area includes the Salinas Valley Basin (3-04.06), the Santa Maria Valley Basin (3-12), the San Antonio Creek Valley (3-14), the Santa Ynez River Valley Basin (3-15), Carrizo Plain (3-19), the San Carpoforo Valley (3-33), and the Arroyo de la Cruz Valley Basin (3-34). See the Greater Carrizo Solar area for details for the Salinas Valley Paso Robles Area subbasin and the Santa Maria Valley Basin.

The San Antonio Creek Valley and Santa Ynez River Basin have issues of concern that include overdraft and water quality degradation. The Carrizo Plain Groundwater Basin underlies a narrow northwest trending valley that lies between the Temblor Range on the east and the Caliente Range and San Juan Hills on the west. The valley has internal drainage to Soda Lake. The San Andreas fault zone passes through the valley. Few impacts to this groundwater basin have been identified. The San Carpoforo Valley and Arroyo de la Cruz Valley are very small basins adjacent to the Pacific Ocean. No impacts to these basins have been identified.

Greater Imperial Wind

The Greater Imperial wind study area includes the Yuma Valley Basin (7-36), the Jacumba Valley Basin (7-47), the Warner Valley Basin (9-8) and the Campo Valley Basin (9-28). See Greater Imperial Solar for details about the Warner Valley Basin.

The Yuma Valley groundwater basin underlies a southeast trending valley in southeast Imperial County. No impacts to groundwater quality for this valley were identified. The Jacumba Valley groundwater basin lies within the southeastern Peninsular Ranges. According to San Diego County documents, some wells are going reportedly dry; this basin is a small basin with no source of imported water. The Campo Valley groundwater basin underlies Campo Valley, which is approximately 40 miles east of the city of San Diego and adjacent to the Mexican border. The basin is listed by the EPA as a “Sole Source Aquifer”, meaning it supplies at least 50 percent of the drinking water for this area and there are no reasonably available alternative drinking water sources should it become contaminated.

Riverside East and Palm Springs Wind

The Riverside East and Palm Springs wind study area includes the Coachella Valley Basin: Indio (7-21.01), Mission Creek (7-21.02), and Desert Hot Springs (7-21.03) subbasins. See Riverside East and Palm Spring Solar for details about the subbasins.

Solano Wind

The Solano wind study area includes the Livermore Valley Basin (2-10), the Sacramento Valley: Solano (5-21.66), South American (5-21.65, Yolo (5-21.67) and Colusa (5-21.52) subbasins, and the San Joaquin Valley: Tracy (5-22.15), Eastern San Joaquin (5-22.01), and Cosumnes (5-22.16) subbasins. The Livermore Valley Basin lies about 40 miles east of San Francisco and 30 miles southwest of Stockton within a structural trough of the Diablo Range. The San Joaquin Valley Basin comprises the southernmost portion of the Great Valley Geomorphic Province of California. The Great Valley is a broad structural trough bounded by the tilted block of the Sierra Nevada on the east and the complexly folded and faulted Coast Ranges on the west. Areas of poor water quality exist throughout the basin. The Sacramento Valley: South American subbasin has seven sites with significant groundwater contamination, including three US EPA Superfund sites (Aerojet, Mather Field, and the Sacramento Army Depot). Groundwater quality in the Solano and Yolo subbasins is considered generally good. The San Joaquin Valley comprises the southernmost portion of the Great Valley Geomorphic Province of California. There is little published data about the groundwater budget for the Tracy subbasin. The Eastern San Joaquin subbasin has shown a fairly continuous decline in groundwater level in Eastern San Joaquin County and significant groundwater depressions are shown in some areas. As a result of overdraft poor quality groundwater has been migrating throughout the subbasin. This subbasin is a critically overdrafted groundwater basin.

Tehachapi Wind

The Tehachapi wind study area includes the Antelope Valley Basin (6-44), Fremont Valley Basin (6-46), Kelso Lander Valley Basin (6-69), Tehachapi Valley East Basin (6-45), and Tehachapi Valley West Basin (5-28). See Tehachapi Solar for details about the Antelope Valley and Fremont Valley Basins.

The Kelso Lander Valley Groundwater Basin is a small basin that underlies a northwest-trending valley in eastern Kern County. Little is known about the groundwater quantity in this basin, impairments to the groundwater quality include elevated levels of fluoride concentrations making it inferior for domestic use but appropriate for irrigation uses. Both the Tehachapi Valley East and West Basins are adjudicated basins under the Tehachapi-Cummings County Water District. An alluvial high (surface drainage divide) forms the boundary between these two basins. Runoff waters west of this divide flow to Tehachapi Creek northwest to the San Joaquin Valley. Surface drainage to the east of this divide either ponds in Proctor Dry lake or flows eastward down Cache Creek toward Freemont Valley. However, heavy pumping in areas south of Tehachapi and Monolith has altered the movement of groundwater due to the creation of a large pumping depression. Between the 1950s to the 1970s, the groundwater level decreased substantially. Since the start of basin adjudication in the early 1970's, groundwater levels have increased to those of the late 1940s when the overdraft problem became apparent. The groundwater quality of these basins has not be characterized.

Inside California Geothermal

Greater Imperial Geothermal

The Greater Imperial geothermal study area includes the Amos Valley (7-34), Imperial Valley Basin (7-30), East Salton Sea Basin (7-33), Ocotillo Clark Valley Basin (7-25), and West Salton Sea Basin (7-22). See Greater Imperial Solar for details about the Amos Valley, Imperial Valley, East Salton Sea, and Ocotillo Clark Valley Basins.

The West Salton Sea Groundwater Basin underlies a valley along the western shores of the Salton Sea in central Imperial County. Groundwater levels from one well in the northeast part of the basin close to Salton Sea show groundwater levels declined by about 64 feet in 1979 through 2000. The quality of the groundwater is marginal to poor for domestic and irrigation purposes because of elevated concentrations of fluoride, boron, and total dissolved solids.

Out-of-State Solar

As with California, this report uses the *Aqueduct Water Risk Atlas,* to determine the overall score of water risk. The risk categories out of state are shown in Table 4.3-3. A discussion of the groundwater basins out of state follows the table. This discussion explains the primary concerns in the groundwater basins underlying the solar and wind study areas.

Table 4.3-3. Out-of-State Water Risk Categories

	Low to Medium	Medium to High	High
Solar Study Areas			
Southwest Solar (Arizona)	0%	0%	100%
Wind Study Areas			
Oregon/Washington Wind	0%	100%	0%
Utah Wind	0%	99%	1%
Wyoming Wind	0%	86%	14%
New Mexico Wind	15%	15%	70%

Southwest Solar (Arizona)

The southwest solar study areas are located in the Lower Colorado River Water Planning District and the Active Management Area Planning Area. The Harquahala study area would be located on an Irrigation Non-Expansion Area. The Harquahala study area would be within the Lower Gila groundwater basin, the Harquahala basin, and the Phoenix groundwater basin. The Hoodoo Wash study area is located entirely within the Lower Gila groundwater basin.

The Lower Gila Basin has been impacted by irrigation pumping at some locations. Historically, cones of depression occurred in irrigated areas north of Hyder, east of Dateland, and in the Palomas Plain west of Hyder (ADWR, 2009). Irrigation water in the western part of the basin has created groundwater mounds in the floodplain aquifer. Colorado River water was brought to the area in 1952 and groundwater pumping for irrigation stopped. Groundwater quality in the western part of the basin, in the Gila River floodplain, is unsuitable for many uses due to elevated total dissolved solids and fluoride and arsenic (ADWR, 2009).

The Harquahala Basin has been impacted by agricultural pumping that caused severe overdraft from the 1950s through the mid-1980s, resulting in large water level declines and formation of a cone of depression (ADWR, 2009). Groundwater recharge is minimal. Introduction of water from the Central Arizona Project in the late 1980s replaced a significant volume of groundwater pumping allowing groundwater levels to rise. A portion of the Harquahala Basin was designated an Irrigation Non-Expansion Area in 1984. Groundwater quality is generally suitable for irrigation but may require treatment for drinking water standards due to elevated total dissolved solids, fluoride, and arsenic (ADWR, 2009).

The Harquahala solar study area is partially within the Phoenix groundwater basin in the Phoenix Active Management Area established pursuant to the 1980 Groundwater Management Act (ADWR, 2010). In several areas, groundwater flows have been altered by well pumping. Agriculture pumping had produced localized depressions by 1983 (ADWR, 2010). In the early 1990s and 2000s, water levels were stable or rose or declined slightly in the western part of the Management Area where the study zone is located. Groundwater quality is generally suitable for most uses, although specific industrial and other activities are present throughout the basin. A number of these activities are located near the Harquahala study area (ADWR, 2010: at Figure 8.1-10).

Out-of-State Wind

Northwest Wind (Oregon and Washington)

The Northwest Wind area is located within the Columbia Plateau, a wide basalt plateau between the Cascade Range and the Rocky Mountains that covers parts of Washington, Oregon, and Idaho. The Columbia River Gorge area falls within the Yakima Fold Belt structural region with the majority of the

Oregon North area within the Blue Mountains structural region (Vaccaro, *et al.*, 2015). A large quantity of the water used in this area is derived from local and imported surface-water sources although groundwater use is also substantial, with the Columbia Plateau aquifer system as the primary source (Konikow, 2013).

Groundwater levels in localized areas within the Plateau aquifer system have risen substantially in areas of high recharge from surface-water imports due to heavy irrigation and decreased in areas where surface-water is not imported and water use is high (Konikow, 2013). Water level rises occurred primary between the 1950s and 1960s, after which water level rises were balanced by water level declines and water level declines dominated the system after 1970 (Konikow, 2013).

Increasing demands for water for municipal, fisheries/ecosystems, agricultural, domestic, hydropower, and recreational uses must be met by additional groundwater withdrawals and (or) by changes in the way water resources are allocated and used throughout the hydrologic system. As of 2014, most surface-water resources in the study area were either over allocated or fully appropriated, especially during the dry summer season (Vaccaro, *et al.*, 2015).

Utah Wind

Groundwater in the Utah Wind Study Area occurs in unconsolidated deposits in the Lower Sevier River Watershed, Escalante Valley-Milford Area sub-basin, Escalante Valley-Black Rock Area sub-basin, Pahvant Valley Area sub-basin, and the Wah Wah Valley and Sevier Lake Area sub-basin. Unconsolidated basin fill deposits within the area are generally composed of clay and sand and recharge to the principal aquifer system is from infiltration of surface water, precipitation, and irrigation.

The Escalante Valley-Milford Area and Escalante Valley-Black Rock Area drainage basin includes the watersheds of Shoal Creek, Pinto Creek, and Little Pinto Creeks in the south, and the watershed of Cove Creek and the Beaver River in the north. Generally shallow groundwater conditions are prevalent within 5,000 to 10,000 feet of the Beaver River. Surface waters in the area are considered fully appropriated (UDWR, 2013). Most of the area is closed to new appropriations of groundwater except in the Black Rock Area where small, fixed time or temporary, and non-consumptive appropriations are allowed (UDWR, 2013).

Pahvant Valley, in southeastern Millard County, extends from the vicinity of McCornick in the north to Kanosh in the south, and from the Pahvant Range and Canyon Mountains on the east and northeast to a low basalt ridge known as The Cinders on the west. Groundwater drains west to the valley from the mountainous terrain to the east. Water levels have declined from 1985 to 2015 in all parts of the Pahvant Valley, primarily due to continued large withdrawals for irrigation (USGS, 2015). As of February 20, 2003, Pahvant Valley is closed to ground-water appropriations (UDWR, 2011).

The Wah Wah Valley and Sevier Lake Area is composed of two sub-basins, Wah Wah Valley and the area around Sevier Lake. The area includes several intermittent streams that flow from the surrounding mountains to the Wah Wah Valley Hardpan (a dry lake bed) or Sevier Lake (UDWR, 2014). The Utah State Engineer has not adjudicated the minimal number of established water rights and there is no state-administered water distribution system in this sub-basin (UDWR, 2014). Surface waters of the basin are generally considered to be fully appropriated, but there is likely unappropriated water available in the aquifer system.

Wyoming Wind

Both of the Wyoming wind study areas are underlain by the Platte River Basin. The Platte River Basin drainage basin covers approximately one quarter of the state in southeastern and central Wyoming.

Perennial streams receive a large percentage of their source waters from overland flow associated with snowmelt and rainfall that originate in semi-humid and humid mountainous headwater regions and persistent baseflow (Taucher, *et al.,* 2013). The basin encompasses the North Platte River and its headwater drainage system, and the northern part of the headwater drainage of the South Platte River (however, the South Platte River does not flow through Wyoming). The Platte River is the major tributary to the Missouri-Mississippi River Basin (Taucher, *et al.,* 2013).

Groundwater use in the state of Wyoming is managed by the Wyoming State Engineer's Office. The North Platte River basin has special conditions restricting new uses of water, including groundwater that is hydrologically connected to surface water (BLM, 2012). Water in the North Platte Basin has been fully appropriated, and these agreements effectively prevent the development of new uses with the exception of stock, domestic, and municipal uses (BLM, 2012). The State Engineer's Office has a process in place to protect the historic and current uses of groundwater that are in good standing with the agency. Current groundwater permittees/appropriators can file an interference complaint against other water users as outlined in the Groundwater Regulations and Instructions. These regulations prevent the pumping activity at a well from negatively impacting the pumping of water from nearby wells.

New Mexico Wind

The water supply in New Mexico is difficult to quantify because of high natural variability in the surface water supply; data limitations of groundwater; variation in yearly obligations of in-state and interstate delivery; the interrelationship between groundwater and streamflows; and the complication caused by groundwater quality, economic constraints, local land use regulations, and land ownership (BLM, 2010). The Office of the State Engineer and Interstate Stream Commission of New Mexico in the 2003 State Water Plan concluded that the water supply barely accommodates and has sometimes fallen short of existing demand, even during the unusually wet years of the 1980s and 1990s. During times of average water supply, the demand for water exceeds the supply (BLM, 2010).

The New Mexico central wind study area is underlain by the Roswell Artesian declared underground water basin. Water-producing zones in the carbonate aquifer rise stratigraphically from north to south and from west to east. Some wells may penetrate as many as five water-producing zones. Recharge occurs by direct infiltration of precipitation and by runoff from intermittent losing streams flowing eastward across a broad area east of the Sacramento Mountains. During the initial development of the artesian aquifer in the late 1800s, many wells flowed to the surface and high volume springs fed the Pecos River. Decades of intensive pumping caused substantial declines in hydraulic head in the aquifer, and by the mid-20th century it was estimated that withdrawals exceeded recharge. Most down-gradient flow is intercepted by irrigation wells in the Artesian Basin. Mineral content of the water rapidly increases in an eastward direction. The freshwater-saltwater interface migrates westward during periods of low rainfall. (USGS, 2012)

The New Mexico east wind study area is underlain by the Tucumcari and Curry County declared underground water basins. The High Plains aquifer is the primary source of water in the Curry County basin and consists of water bearing formations from the Ogallala Formation. Modeling studies and observed water declines indicate that large areas of this aquifer cannot sustain the amount of water currently withdrawn (OSE, 2010). Due to the limited groundwater, the High Plains aquifer within Curry County is closed to the filing of applications. Applications are considered on a case by case basis.

4.3.3 Typical Water Impacts of the Buildouts

Construction and operation of utility-scale renewable energy facilities under the buildout of the portfolios would introduce impacts to water resources. Resource-specific impacts are explained in the subsections that follow. In general, typical construction-phase impacts are:

- **Disruption of drainage patterns.** Land disturbing activities such as clearing and grading, road construction, or vegetation removal could disrupt drainage patterns, especially to stream channels. Stream disturbance can also alter and diminish riparian habitat and the wildlife that depends upon it.
- **Flooding**. Ground disturbances (e.g. paving) and renewable structures can impede or redirect flood flows. Flooding may cause environmental damage beyond facility sites and include erosion, sedimentation, and soil and water contamination from hazardous materials transport.
- **Water Quality Degradation.** During construction, hazardous materials, particularly oil-based and liquid chemical products, can spill and cause contamination to soils, surface water bodies, and groundwater.
- **Consumption of Water – Construction.** Installation of water supply wells and consumption of water during construction can affect groundwater levels and storage volumes. Water volumes used during the construction period, particularly for dust control, are relatively high but occur for a short duration.
- **Consumption of Water – Operation.** Changes in the overall operation of the portfolios could change the amount of water required for cooling renewable and non-renewable technologies. Different technologies require different amounts of water for cooling, with fossil fuel generation typically requiring more water than renewable energy.

Construction Impacts in General

Flooding, conditions that could worsen flooding, and impacts to other hydrologic surface water features and drainage patterns generally depend upon how widespread the land disturbance may be from renewable energy. The broader and more intensive the land disturbance, the greater the likelihood it could affect surface water and groundwater.

Solar Construction

Construction of utility-scale solar facilities generally convert large areas of land, requiring large amounts of grading and clearing of vegetation. Grading removes all vegetation, disturbs biological soil crust, and causes the greatest disturbance to surface water and drainage patterns. Disturbance to vegetation and surface soils changes infiltration and runoff, which in turn leads to greater potential for erosion, sedimentation, flooding, and water quality degradation. A number of existing regulations are designed to protect the water quality and reduce these effects, the primary one being the Clean Water Act. Under the Clean Water Act, any project disturbing more than 1 acre of land would be required to obtain a NPDES General Permit for Storm Water Discharges Associated with Construction Activity. Compliance with the NPDES would require a Storm Water Pollution Prevention Plan (SWPPP) that would describe Best Management Practices (BMPs) to prevent the acceleration of natural erosion and sedimentation rates and to reduce the risk of accidental spills and releases into the environment and specifically into surface water or groundwater.

The construction of utility-scale solar projects require water for dust control and engineering purposes. While the exact amount of water required would be determined on a case by case basis, this report assumes the use of 2.2 acre-feet (AF) per MW in California and 5.6 AF per MW in Arizona (Sandia, 2013). Groundwater extraction and consumption by renewable energy projects can cause groundwater levels to decline. Declining groundwater levels could have the following effects (BLM, 2015):

- Increase the needed pumping lift in wells, and gradually cause pumping rates to decrease and eventually cease altogether.
- Lower groundwater gradients and reduce groundwater discharge to springs, streams, rivers, and down-gradient hydraulically connected groundwater basins.
- Lessen the areal extent and vigor of wetland, riparian, or other groundwater-dependent vegetation areas or playas.
- Cause certain types of sediments (e.g., saturated clay units) to dewater and compress. This compression reduces their volume and can lower land surface elevations (land subsidence). This can potentially (1) cause damage to existing structures, roads, and pipelines; (2) reverse flow in sanitary sewer systems and water delivery canals; and (3) alter the magnitude and extent of flooding. This sediment compression can also permanently reduce aquifer storage capacity.

These types of effects are especially problematic in the southwestern United States where groundwater is typically limited. However, these effects would be short-term, during construction only. Other than California, all the states where the renewable portfolio would be constructed have regulations that require the developer to obtain a permit for the use of surface or groundwater. Such permits would consider the state of the groundwater basin or aquifer and ensure that the one-time use of water for construction would not affect the groundwater basin. In California, the effects of groundwater use would typically be considered and mitigated as necessary in the environmental permitting for the project under the California Environmental Quality Act or the National Environmental Policy Act.

Wind Construction

Construction of utility-scale wind facilities requires grading and clearing large areas of land, resulting in impacts similar to those described for solar construction. Wind facilities do not require these areas to be contiguous, grading is typically limited to wind turbine pads, ancillary buildings, substations, and access roads. While the grading and clearing would disrupt drainage patterns, the natural vegetation surrounding the grading would help stabilize soils and reduce the potential effects. Permit requirements, including a Stormwater Pollution Prevention Plan (SWPPP) and Best Management Practices (BMPs), would account for construction on steep slopes, frequently a requirement for wind projects.

Utility-scale wind projects require water for dust control and engineering purposes. While the exact amount of water required would be determined on a case by case basis, this report assumed 0.4 AF per MW. Groundwater extraction and consumption by renewable energy projects can cause groundwater levels to decline as described under solar construction.

Geothermal Construction

Construction of utility-scale geothermal facilities requires grading and clearing land for the geothermal well pads and access roads, resulting in impacts similar to those described for solar construction. Geothermal typically uses only a small amount of land for the well pads. While the grading and clearing would disrupt drainage patterns, the natural vegetation surrounding the well pads would help stabilize soils and reduce the potential effects. Permit requirements, including a SWPPP and BMPs, would further reduce effects.

Utility-scale geothermal projects require water for dust control, grading, drilling, and other uses. While the exact amount of water required would be determined on a case by case basis, this report assumed 1.4 AF per MW. Groundwater extraction and consumption by renewable energy projects can cause groundwater levels to decline as described under solar construction.

Operational Impacts in General

Project facilities, roads, and their surrounding environments can be flooded during operations and maintenance. Considering the large area required for many renewable energy projects, ephemeral streams may flow through the project areas, and drainage paths and processes are at risk of being altered. This can cause developed drainage systems to exceed their design capacities, which in turn could damage both the project and the environment, both on and off site (e.g., erosion, sedimentation, and contamination of soil and water by transport of project-related hazardous materials and wastes). Disturbance to streams can also alter and diminish riparian habitat.

Hazardous material and waste storage during operations and maintenance can be disturbed by stormwater and flooding if not properly contained, or if stormwater drainage facilities are not properly designed. These project-related activities can cause degradation and long-term adverse effects to water quality and the beneficial uses of surface waters and groundwater.

The operation of renewable and non-renewable facilities requires water, generally for cooling purposes but also for other uses such as panel cleaning. Regionalization would change the overall generation makeup in the WECC. As noted in the methodology, this information was used to generate an estimated change in water use both inside and outside of California.

Solar Operations

Groundwater consumption affects both groundwater levels and storage volumes. While the exact amount of water required for operations of a facility would be determined on a case by case basis, this report assumes the use of 26 gallons per MWh for solar PV and 78 gallons per MWh for solar thermal energy.

Wind Operations

Wind energy uses minimal amount of water during operations. While the exact amount of water required during operations would be determined on a case by case basis, the amount is anticipated to be minimal so this report does not calculate operational water use for wind energy.

Geothermal Operations

Geothermal plant operations may require substantial amounts of water for steam generation, cooling, and other industrial processes. While the exact amount of water required for operations of a geothermal facility would be determined on a case by case basis, this report assumes the use of 3,600 gallons per MWh for binary geothermal energy and 10 gallons per MWh for flash geothermal energy.

4.3.4 Water Impacts of Regionalization

The 2020 CAISO + PAC scenario includes no incremental renewable energy development so no construction effects would occur inside or outside of California.

Incremental Buildout for All Scenarios by 2030

Inside California

This report considers three factors pertaining to water use inside California. First it considers development in critically overdrafted groundwater basins, followed by construction in areas of different water risk factors, and finally it looks at water consumption during operations.

Construction of the 2030 renewable portfolios under any scenario would require a substantial amount of ground disturbance in California that could result in flooding, conditions that could worse flooding, and impacts to other hydrologic surface water features and drainage patterns. As noted above, this effect would be reduced through implementation of a SWPPP and BMPs required for all construction greater than one acre.

Critically Overdrafted Groundwater Basins

Development of the renewable portfolio under 2030 Current Practice 1 would require construction of solar and wind projects in the following study areas that overlap with critically overdrafted groundwater basins (see Figures 4.3-1 and 4.3-2):

- Greater Carrizo Solar
- Westlands Solar
- Solano Wind
- Greater Imperial Solar
- Greater Carrizo Wind
- Central Valley and Los Banos Wind

While it is possible that the development in these areas could avoid using water from the critically overdrafted groundwater basins, the basins underlie almost the entire Central Valley and Los Banos wind and Westlands solar areas. Construction of the renewable portfolios would increase the need for water from these basins. However, because neither wind nor solar require large amounts of water during operations, this effect would be short-term in nature. Water used for construction purposes could come from a variety of sources that would be determined on a case by case basis depending on the specific circumstances. If groundwater were not available, a project developer would likely work with a local water provider, for example the Westlands Water District, to ensure sufficient water is available for construction. Additionally, if the development of renewable energy were to displace a use, such as agriculture, that requires large amounts of water, it could result in a net benefit to the underlying groundwater basin. This type of benefit is most likely to occur in the Westlands solar study area due to the groundwater basin overdraft and the abundant agriculture in the region.

Figure 4.3-1. Solar Resource Study Areas and Critically Overdrafted Basins

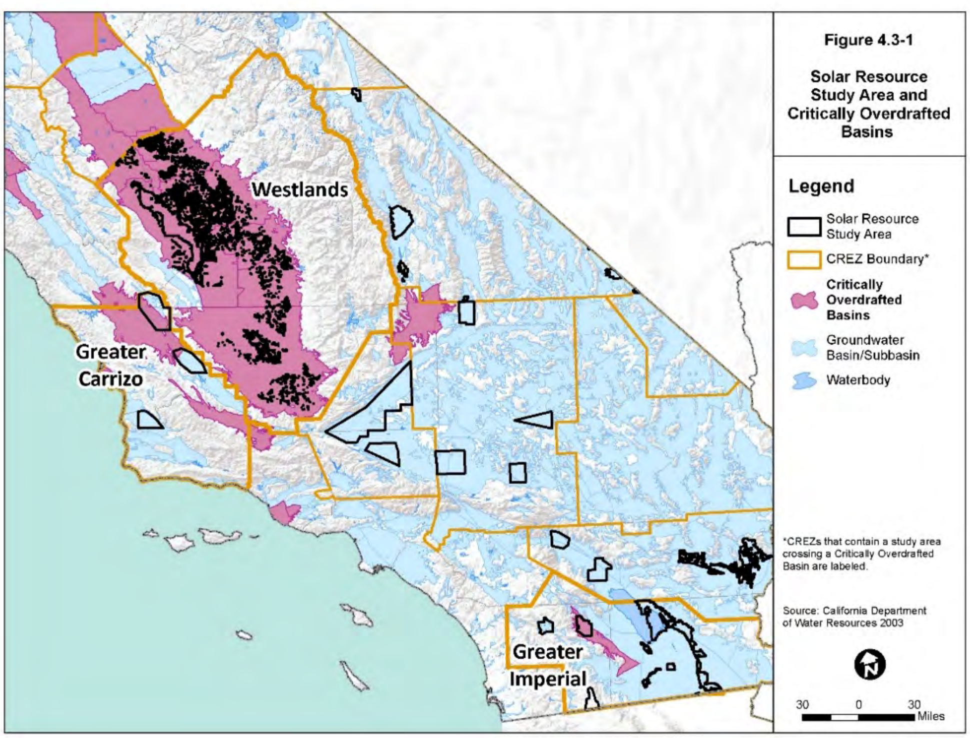
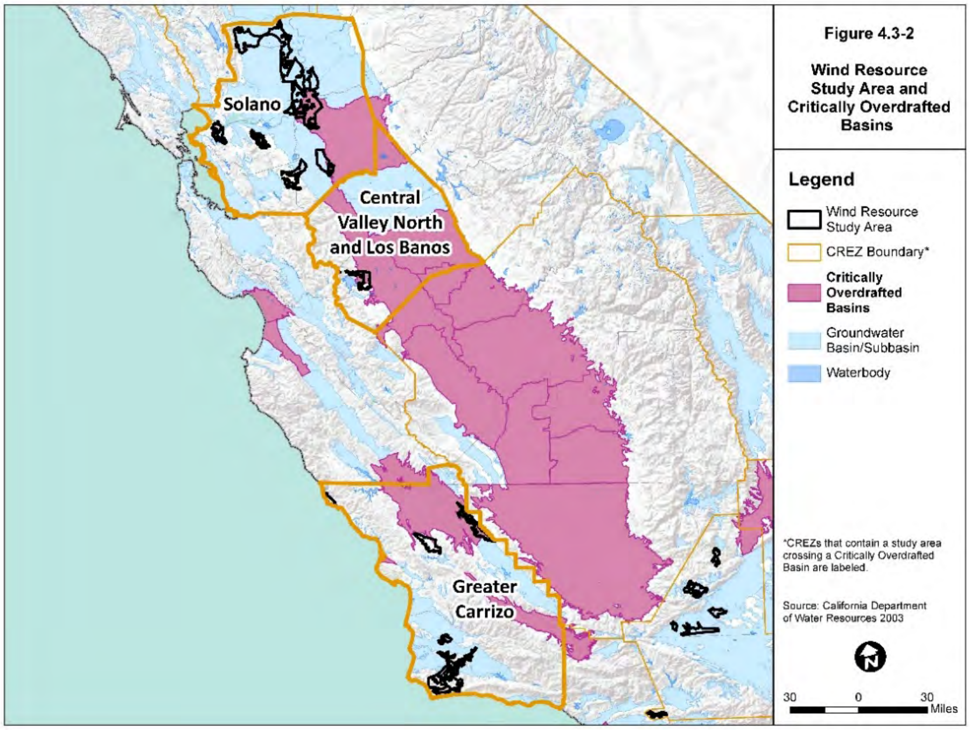


Figure 4.3-2. Wind Resource Study Areas and Critically Overdrafted Basins



The 2030 regionalization scenarios would reduce the construction water use in critically overdrafted groundwater basins as follows:

- All scenarios would reduce the amount of construction and associated water use in Westlands solar study area compared with the 2030 Current Practice 1.
- 2030 Regional 2 and 2030 Regional 3 (and the sensitivity scenario of Regional 3 without Beyond RPS generation) would reduce construction and associated water use in the Solano wind study area.
- 2030 Regional 3 would reduce construction in the Greater Carrizo and Greater Imperial study areas.

Construction in Areas of Water Risk

This study considers the use of water for construction in areas of different categories of water risk using the WRI risk atlas. Table 4.3-4 presents the acre feet of water required for construction of renewable energy in California under the different portfolios.

Table 4.3-4. Construction Water Use by Risk Category

Water Risk (acre feet)	2030 Current Practice 1	2030 Regional 2	2030 Regional 3
Low to Medium	4,364	5,512	2,646
Medium to High	7,019	7,580	3,984
High	7,562	5,871	2,467

Out of State

The analysis outside California does not consider specific groundwater basins as there is not a consistent dataset available to analyze. As such, it uses the WRI index to allow for consistent comparison for use of water during construction.

Construction in Areas of Water Risk

As with the analysis for inside California, Table 4.3-5 presents the acre feet of water required for construction of renewable energy outside California under the different portfolios.

Table 4.3-5. Construction Water Use by Risk Category Out of State

Water Risk (acre feet)	2030 Current Practice 1	2030 Regional 2	2030 Regional 3
Low to Medium	1,039	685	305
Medium to High	471	471	1,202
High	5,998	8,842	9,503

Out-of-State Transmission Additions

Under Regional 3, it is assumed that major out-of-state transmission additions would be necessary to integrate renewable generation from Wyoming and New Mexico into the regional power system and for California to achieve 50% RPS. The water resources considerations related to the construction and operation of the potential transmission expansions are summarized in Section 5.

Operational Impacts of Regionalization

Inside California

The production cost simulation model provided the changes in overall generation (in MWh) in the WECC under each of the 2020 and 2030 scenarios. This information was used to generate an estimated change in water consumption use inside California for each scenario. Table 4.3-6 presents the water use for operations of generators, excluding wind, which uses very little water, under the Current Practice and regionalization scenarios.

Table 4.3-6. Total Water Use for Energy Generation in California

Water Consumption by Technology (af)	2020 Current Practice	2020 CAISO + PAC	2030 Current Practice 1	2030 Regional 2	2030 Regional 3
Solar PV	1,859	1,859	3,540	3,836	2,881
Solar Thermal	1,041	1,041	1,039	1,040	1,040
Natural Gas Combined Cycle	50,240	49,371	41,486	39,309	37,504
Natural Gas Steam Turbine	3,195	3,195	2,710	2,658	2,601
ST Coal	163	162	0	0	0
Total (excluding Geothermal)	56,498	55,628	48,776	46,843	44,025
Geothermal	142,126	142,225	205,897	206,475	207,806
Impact of Regionalization (af)		–870		–1,933	–4,750
Impact of Regionalization (%)		*–1.5%*		*–4.0%*	*–9.7%*

The 2020 Current Practice scenario would use over 56,000 acre-feet of water inside California during operations excluding geothermal energy. Limited regionalization (2020 CAISO + PAC) would reduce the water use by 870 acre feet, facilitating a reduction in water use for electricity generation in California of 1.5%. Geothermal water use would remain constant.

Under 2030 Current Practice 1, an estimated 48,776 acre-feet of water would be used for energy generation for all resources excluding geothermal.[8] Geothermal production would use almost 206,000 acre-feet of water; however, geothermal water use can and frequently does include brine rather than potable water.[9] A small portion of potable water would likely be required for geothermal generation for make-up water. Regionalization by 2030 would reduce the water used for electricity generation in California by at least 4%.

Out of State

The production cost simulation model provided the changes in overall generation (in MWh) in the WECC under each of the 2020 and 2030 scenarios. This information was used to generate an estimated change in water consumption use outside California for each scenario. This water use is presented in Table 4.3-7 for all of the scenarios.

[8] According to the California Water Plan, Chapter 3, California Water Today, urban applied water use in 2010, which includes industrial water use such energy generation, was 8.3 million acre-feet (DWR, 2013). Compared to the overall water use in California, the amount of water used for energy generation is a very small amount.

[9] "Binary geothermal plants" use a closed-loop system such that 100 percent of the geothermal brine produced is injected back into the geothermal reservoir. Because the water is not used for other purposes, a brackish water supply is adequate for the cooling system. This is different from a "geothermal flash plant" where the condensed geothermal steam is used for the cooling water. Geothermal flash plants are used with higher temperature geothermal resources than binary geothermal plants.

Table 4.3-7. Total Water Use for Energy Generation Outside California

Water Use by Technology (af)	2020 Current Practice	2020 CAISO + PAC	2030 Current Practice 1	2030 Regional 2	2030 Regional 3
Solar PV	458	458	989	1,102	1,103
Solar Thermal	635	635	634	634	634
Combined Cycle	86,529	85,944	169,032	163,271	163,641
Steam Turbine	239	222	297	179	220
ST Coal	454,302	459,289	295,450	286,454	292,279
Total (excluding Geothermal)	542,163	546,548	466,401	451,640	457,877
Geothermal	149,913	149,916	140,805	140,261	140,334
Impact of Regionalization (af)		4,385		–14,761	–8,524
Impact of Regionalization (%)		*0.8%*		*–3.2%*	*–1.8%*

The 2020 Current Practice scenario would use 542,163 acre-feet of water outside California during operations excluding geothermal energy. Limited regionalization with CAISO + PAC would increase the water use by 4,385 acre feet, an increase in water use of 0.8%. Geothermal water use would remain constant.

Under 2030 Current Practice 1, an estimated 466,401 acre-feet of water would be used for energy generation for all resources excluding geothermal. Geothermal production would use approximately 140,805 acre-feet of water. Regionalization by 2030 would reduce the water used for electricity generation outside California by 1.8%.

4.3.5 Comparison of Scenarios for Water Resources

The change from Current Practice into regional scenarios allows the following comparisons.

Inside California

Section 4.3.4 lists the amount of water used for construction in areas of different categories of water risk in Table 4.3-4. Using this information, Table 4.3-8 lists the change in water use due to regionalization.

Table 4.3-8. Change in Construction Water Use by Risk Category in California

Water Risk (acre feet)	2030 Regional 2 Relative to Current Practice Scenario 1	2030 Regional 3 Relative to Current Practice Scenario 1
Low to Medium	1,148	–1,718
Medium to High	562	–3,035
High	–1,691	–5,095

As shown in Table 4.3-8, 2030 Current Practice 1 would require the most water for construction in areas designated as high risk. These scenarios, along with 2030 Regional 2, would use the most water for construction in areas designated as medium to high risk. 2030 Regional 3 would reduce the amount of water used for construction in all three categories because it reduces the amount of renewable energy built in California.

Table 4.3-9 highlights the change in water use for operations under the Current Practice and regionalization scenarios.

Table 4.3-9. Change in total Water Use for Energy Generation in California

Water Use	2020 CAISO + PAC Relative to Current Practice	2030 Regional 2 Relative to Current Practice Scenario 1	2030 Regional 3 Relative to Current Practice Scenario 1
Impact of Regionalization (af)	–870	–1,933	–4,750
Impact of Regionalization (%)	*–1.5%*	*–4.0%*	*–9.7%*

In the limited regionalization of 2020, water use by generators in California would decrease (–1.5%). Regionalization by 2030 would affect the operational water use as follows:

- 2030 Regional 2 would reduce water use by 1,933 acre feet, about 4%.
- 2030 Regional 3 would reduce water use by 4,750 acre feet, about 10%.

The amount of water used for geothermal energy remains relatively constant regardless of the scenario. Overall, the greatest reduction of water use compared to 2030 Current Practice 1 is for the 2030 Regional 3 which reduces water consumption by almost 10 percent.

Out of State

Section 4.3.4 lists the amount of water used for construction in areas of different categories of water risk in Table 4.3-5. Using this information, Table 4.3-10 lists the change in water use due to regionalization.

Table 4.3-10. Change in Construction Water Use by Risk Category Out of State

Water Risk (acre feet)	2030 Regional 2 Relative to Current Practice Scenario 1	2030 Regional 3 Relative to Current Practice Scenario 1
Low to Medium	–354	–734
Medium to High	0	731
High	2,844	3,504

As shown in Table 4.3-10, 2030 Current Practice 1 would require the least water for construction in areas designated as high risk. 2030 Regional 3 would increase the amount of water used for construction in medium to high and high risk categories as the amount of renewable energy built outside California would increase under this scenario.

Table 4.3.11 highlights the change in water use for operations under the Current Practice and regionalization scenarios.

Table 4.3-11. Change in Total Water Use for Generation Out of State

Water Use	2020 CAISO + PAC Relative to Current Practice	2030 Regional 2 Relative to Current Practice Scenario 1	2030 Regional 3 Relative to Current Practice Scenario 1
Impact of Regionalization (af)	4,385	–14,761	–8,524
Impact of Regionalization (%)	*0.8%*	*–3.2%*	*–1.8%*

In the limited regionalization of 2020, water use by generators outside of California would increase slightly (0.8%). Regionalization by 2030 would affect the out-of-state operational water use, relative to the scenario of 2030 Current Practice 1 as follows:

- 2030 Regional 2 would reduce water use by 14,761 acre feet, about 3%.
- 2030 Regional 3 would reduce water use by 8,524 acre feet, about 2%.

The amount of water used for geothermal energy remains relatively constant regardless of the scenario. Overall, the greatest reduction of water use compared to 2030 Current Practice 1 is for the 2030 Regional 2 which reduces water consumption outside California by over 3 percent.

4.4 Air Emissions

This section describes the potential impacts to air resources for each of the incremental renewable energy buildouts and the potential air emissions changes of a regional power market as compared with emissions from electricity generators in the current practice. The approach to the analysis relies upon a narrow set of baseline conditions that are treated as potential indicators or predictors of impacts, as listed in Table 4.4-1.

Table 4.4-1. Baseline Conditions and Indicators of Impacts, Air Resources

Baseline condition of a study area	How are scenarios analyzed relative to the baseline?	Potential indicator of air quality impact
Air Emissions		
Ozone levels	Changes in NOx emissions in designated nonattainment areas	Criteria air pollutant exposures and public health
Particulate matter levels	Changes in SO_2 and PM2.5 emissions from fossil fuel use in designated nonattainment areas	Criteria air pollutant exposures and public health

Assumptions and Methodology for Air Emissions Analysis

This portion of the environmental study explores the locations where changing emissions from fossil fuel generators may occur as a result of regionalization. The methodology focuses on the modeled changes in power plant operations, and how they may bring about a change in air emissions from these sources. Separate discussion is also provided regarding the incremental buildouts and how construction-related activities can locally influence air pollutant concentrations.

The production cost simulation modeling provides the changes in generator starts, generation output in terms of megawatt-hours (MWh), and fuel use by type of fuel and heat-input rate (MMBtu). These data are used as input the air emissions analysis as a way to estimate the changes in nitrogen oxides (NOx), PM2.5, and sulfur dioxide (SO_2). Greenhouse gas (GHG) emissions analysis and carbon dioxide (CO_2) rates are presented in the Production Cost Analysis (Volume V).

Our study methodology includes an estimate of the annual emissions on a unit-specific basis, for all units in the WECC-wide fleet, but our presentation shows aggregated emission for each geographical location. This means the results are aggregated temporally and geographically. The temporal result is for either the near-term (2020) or longer-term (2030) study year. This study aggregates the criteria air pollutant emissions results and totals the emissions rates for the California natural gas fleet emissions by air basin. Out of state, emissions from the remainder of the WECC-wide fleet are provided from PSO, for NOx and SO_2. The production cost model does track unit-specific NOx and SO_2 emissions. However, there are some limitations to interpreting absolute levels of unit-specific air emissions from the production cost model, since the model does not mimic the precise accounting of emissions rates or control equipment use.

Other important limitations and considerations relevant to the air emissions analysis include:

- 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.
- 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 greenhouse gases 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.
- For the purposes of the Disadvantaged Communities (DAC) analysis, the regional modeling output for generators in specific communities was examined at the air basin level. Emissions are summed up by air basins. The DAC results are based on these basin-wide totals, not emissions from specific power plants in or near DACs.
- 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 owner of the generator. 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.
- Emissions are presented for the annual periods of the two study years: the near-term (2020), and the longer-term (2030), with separate presentation of average emissions rates within the three months of the summer season, for consideration of the effects on ozone levels.
- The results do not use any generator specific permit limits, as those are specific to each source in each air district. Note that emissions changes from the fleet of existing stationary sources are required to be well within the limits allowed by the permitting authorities, depending on the permitted terms that apply to each generating unit. This study assumes that no existing source would need to change its permitted terms of operation. New fossil-fueled stationary sources are not contemplated by this study.

Approach to Estimating NOx Emissions

Review of production cost simulation results indicated that the dispatch could change with certain generating units running overnight to save cycling and startup costs. To quantify the effect that changing dispatch could have on NOx emissions, startup emissions are quantified separately from steady-state emissions. This is accomplished by adding a startup penalty ratio, which is the ratio of the increased emissions due to a startup to the emissions from the unit during one hour of full-load (steady state) operation.

The steady-state levels of NOx emissions from California's natural gas fleet were estimated based on a review of factors published by the CEC (CEC, 2015), as summarized in Table 4.4-2.

Table 4.4-2. California Natural Gas Fleet, Modeled Emission Factors

Generating Technology (subset)	NOx Steady (lb/MWh)	NOx due to Starts (lb/MW cap)	PM2.5 (lb/MMBtu)	SO_2 (lb/MMBtu)
Combined Cycle (Aero)	0.07	0.53	0.0066	0.0007
Combined Cycle (Industrial)	0.076	0.53	0.0066	0.0007
Combined Cycle (Single-Shaft)	0.07	0.53	0.0066	0.0007
Combustion Turbine (Aero)	0.099	0.79	0.0066	0.0007
Combustion Turbine (Industrial)	0.279	0.79	0.0066	0.0007
Internal Combustion Engine	0.5	0.79	0.01	0.0007
Steam Turbine, Boiler	0.15	0.84	0.0075	0.0007

Source: CEC, 2015; NREL, 2013.

The startup penalty ratio for NOx from the California natural gas fleet is based on the following points:

- NREL conducted a review of actual continuous emissions monitoring (CEM) data records and derived an approximation of a startup penalty for plants responding to the integration of solar and wind in WECC (NREL, 2012; NREL, 2013).
- The generation-weighted average WECC-wide shows that combined cycle natural gas–fired units emit about as much NOx during a startup as approximately 7 hours of full-load operation, and simple cycle units emit about as much NOx during a startup as approximately 3 hours of full operation; NREL also expressed these startup emissions per MW of unit capacity as 0.53 lb/MW for CC units and 0.79 lb/MW for CT units (NREL, 2013).
- Simple cycle configurations of combustion turbines start much more quickly and emit less excess NOx during each startup event, because of the nature of simple-cycle units having no secondary steam turbine or steam cycle as a part of the design (RMB, 2002; NREL, 2012; NREL, 2013).
- Unit-specific startup distinctions are not made in this environmental study in light of the consideration that startup performance characteristics of combined-cycle units vary tremendously, even when focusing on an identical make and model or units within one specific facility (RMB, 2002). Additionally, as portions of the emissions occur at uncontrolled rates, they are partially beyond the ability to regulate.
- Distinctions between hot starts and cold starts are not made here because the production cost simulations data were not developed to make that distinction.
- Increased NOx emissions due to partial load operations or hours of ramping are not quantified from an emissions perspective (although partial and full load efficiency was considered in the plant dispatch of the production cost simulations); during these hours, part load penalties may be around 30% and ramping penalties are less than 10% (NREL, 2012; NREL, 2013). Production cost simulation results indicate that regionalization would generally reduce the need for generation unit cycling. As such, the excess NOx emissions of partial loads and ramping would be more likely to occur in the baseline conditions, and not modeling the additional emissions likely results in a more conservative estimate of the emissions reductions achieved by a regional market.
- The penalty ratios published by NREL as a gauge of actual WECC-wide emissions are reasonable in light of air permit records reviewed for facilities in California's fleet, which contain permit limits at levels that are higher than the actual WECC-wide rate by a factor of two- to five-times. Permits always provide a safety margin above the anticipated actual emission rates; and California's natural gas-fired fleet is generally better controlled than the WECC-wide average.

The ratios for NOx startup emissions from combined cycle and simple cycle units are shown in Table 4.4-3.

Table 4.4-3. Startup Ratios for NOx from Natural Gas–Fired Units

Examples of NOx Limits	Location or Citation	Cumulative Startup Emissions (lb per event)	Full-Load Steady State (lb NOx/hr)	Startup Ratio (start / steady state hour)
Combined-Cycle Units (CC)				
Colusa 657 MW CC (permit amended 12/15/2015)	Colusa Co APCD	260 to 779	20.7	12.6 to 38
Gateway 530 MW CC (permit licensed in 2007)	BAAQMD	189 to 452	20	9.5 to 23
Los Medanos, 520 MW CC (permit amended 4/19/2004)	BAAQMD	240 to 600	20	12 to 30
La Paloma 1048 MW CC (permit amended 10/6/2004)	SJVAPCD	1200	69.2 (17.3 x 4)	17.3
Lodi Energy Center 294 MW CC (permit amended 8/27/2013)	SJVAPCD	160	15.5	10.3
Theoretical Example (GE 7FA CC)	(RMB, 2002)	275	24	11.5
Approximate WECC-wide CC (based on review of CEMs)	(NREL, 2012)	—	—	6.1
Approximate WECC-wide CC (based on review of CEMs)	(NREL, 2013)	Excess: 0.53 lb/MW	Typical CA CC: 0.08 lb/MWh (CEC, 2015)	6.6
Simple-Cycle Units (CT, CTG)				
TID Almond2 3 x 58 MW aero-CTG (permit licensed in 2010)	SJVAPCD	25	5.02	5.0
Approximate WECC-wide CT (based on review of CEMs)	(NREL, 2012)	—	—	1.8
Approximate WECC-wide CT (based on review of CEMs)	(NREL, 2013)	Excess: 0.79 lb/MW	Typical CA CT: 0.28 lb/MWh (CEC, 2015)	2.8

Sources: NREL, 2012; NREL, 2013; supplemented by a review of CEC siting case records.

Approach to Estimating PM2.5 Emissions

This study identifies the levels of PM2.5 emissions changes using emission factors typical of the nationwide fleet for each basic technology (U.S. EPA AP-42), as shown in Table 4.4-2. All natural gas–fired PM10 emissions are presumed to qualify as PM2.5. Although the typical particulate matter emission factors are known to be somewhat uncertain, they are well-established in documentation vetted by U.S. EPA, drawn from comparable measurement methods independent of combustion technology, and available on a heat-input basis (per MMBtu) rather than an energy-output basis, which helps to avoid biases that arise from different test methods and variations in the thermal efficiencies of generating units.

For natural gas generating units, the directly-emitted PM2.5 factors are:

- Internal combustion engines (4-stroke, lean burn): 0.01 lb/MMBtu (EPA AP-42, Ch. 3.2, 2000).
- Gas turbines, combined cycle and simple cycle configuration: 0.0066 lb/MMBtu (EPA AP-42, Ch. 3.1, 2000).
- Boilers and steam generators: 0.0075 lb/MMBtu (EPA AP-42, Ch. 1.4, 1998).

Coal-fired units emit particulate matter at a wide range of rates that varies depending on the unit-specific the firing method, configuration, and the post-combustion controls (e.g., these include electrostatic precipitators, baghouses, and scrubbers). Because very little coal firing occurs in California, and PM10 or

PM2.5 emission factors are not available for each unit-specific configuration in the west-wide PSO model, the SB 350 studies provide a review of the WECC-wide changes in terms fuel use, total generation, and changes in production from coal-fired units as presented in Volume I and in the Production Cost Analysis (Volume V).

Approach to Estimating SO_2 Emissions

This study identifies the levels of SO_2 emissions changes as sulfur oxides are an important precursor to PM2.5 formation. As with the study of PM2.5, the SO_2 results also focus on PM2.5 nonattainment areas and those air basins with the highest scoring disadvantaged communities.

Electric generating station fuel types across California include agricultural and wood waste, diesel, digester gas, distillate oil, landfill gas, municipal solid waste, process or refinery gas, and natural gas. The vast majority of the fossil fuel–fired generating capacity in California uses natural gas. California's pipeline quality natural gas has negligible sulfur, which limits sulfur compound emissions (CEC, 2003).

Sulfur dioxide emissions due to the natural gas portion of the fleet are calculated based on a mass balance of the very low total sulfur content of the gas being fully converted to SO_2 by the combustion process.

For California's natural gas–fired units, an SO_2 emission factor can be derived as:

- 0.0007 lb/MMBtu, based on a typical annual average sulfur content of 0.25 gr S/100 scf of natural gas.

4.4.1 Regulatory Framework

Federal and State-Level Air Quality Management

Federal Clean Air Act and Ambient Air Quality Standards

The federal Clean Air Act [42 USC Section 7401 et seq. (1970)] is the comprehensive federal law that regulates air emissions from stationary and mobile sources. The Clean Air Act gives U.S. EPA the responsibility for implementing nationwide programs for air pollution prevention and control. This entails defining the National Ambient Air Quality Standards and the efforts to attain these standards. National Ambient Air Quality Standards (NAAQS) and California Ambient Air Quality Standards (CAAQS) are planning standards that define the upper limits for airborne concentrations of pollutants. The criteria air pollutant standards are designed to protect the most sensitive individuals and ensure public health and welfare with a reasonable margin of safety.

Criteria Air Pollutants

The NAAQS and CAAQS are established for "criteria air pollutants." These are ozone, respirable particulate matter (PM10), fine particulate matter (PM2.5), carbon monoxide (CO), nitrogen dioxide (NO_2), sulfur dioxide (SO_2), and lead. Ozone is an example of a secondary pollutant that is not emitted directly from a source (*i.e.*, not a product of combustion), but it is formed in the atmosphere by chemical and photochemical reactions. Reactive organic gases (ROG), including volatile organic compounds (VOC), are regulated as precursors to ozone formation.

Each state must prepare an air quality control plan referred to as a State Implementation Plan (SIP), and each SIP must incorporate the control measures necessary to reduce air pollution in nonattainment areas. The SIP is periodically modified to reflect the latest emissions inventories, planning documents, and rules and regulations for the air basins. The U.S. EPA has responsibility to review each SIP to determine if implementation will achieve air quality goals. In California, air quality management and regulation is the shared responsibility of the California Air Resources Board (ARB) and local air quality management and air pollution control districts. Regardless of jurisdiction, stationary sources must operate in compliance with permit conditions set by the local air district in order to avoid creating a conflict with the SIP.

Toxic Air Contaminants and Hazardous Air Pollutants

Toxic air contaminants (TACs) are air pollutants that may lead to serious illness or increased mortality, even when present in relatively low concentrations. Potential human health effects of TACs include birth defects, neurological damage, cancer, and death. The Health and Safety Code defines a TAC as an air pollutant which may cause or contribute to an increase in mortality or serious illness, or which may pose a present or potential hazard to human health. There are almost 200 compounds designated in California regulations as TACs (17 CCR Sections 93000-93001). The list of TACs also includes the substances defined in federal statute as hazardous air pollutants (HAPs) pursuant to Section 112(b) of the federal Clean Air Act (42 USC Section 7412(b)).

4.4.2 Baseline Air Quality Conditions

California Nonattainment Areas

California is divided geographically into air basins for the purpose of managing the air resources on a regional basis. An air basin generally has similar meteorological and geographic conditions throughout. California is divided into 15 air basins.

California's urbanized areas and inland valleys cover the air basins with the most persistent air quality problems. The nonattainment areas with the most persistent air quality nonattainment conditions are shown in Table 4.4-4.

Table 4.4-4. California's Federal Nonattainment Areas

California Air Basin	Ozone Nonattainment Designation (8-hour NAAQS)	PM10 Nonattainment Designation (24-hour NAAQS)	PM2.5 Nonattainment Designation (24-hour NAAQS)
San Joaquin Valley	Extreme	Maintenance	Serious
South Coast	Extreme	Maintenance	Serious
Salton Sea	Severe (Riverside); Marginal (Imperial)	Serious	Moderate (Imperial)
North Central Coast	—	—	—
Mojave Desert	Severe (West Mojave Desert); Marginal (Eastern Kern)	Moderate; Serious (Eastern Kern)	—
Sacramento Valley	Severe (Sacramento metro)	Maintenance	Moderate (Sacramento metro)
San Francisco Bay Area	Marginal	—	Moderate
South Central Coast	Serious (Ventura); Marginal (Eastern San Luis Obispo)	—	—
San Diego	Marginal	—	—

Note: "—":Attains NAAQS.
Source: https://www3.epa.gov/region9/air/maps/index.html.

The federally-designated nonattainment areas are mapped for ozone in Figure 4.4-1 and for PM2.5 in Figure 4.4-2.

Figure 4.4-1. California's Federal Ozone Nonattainment Areas

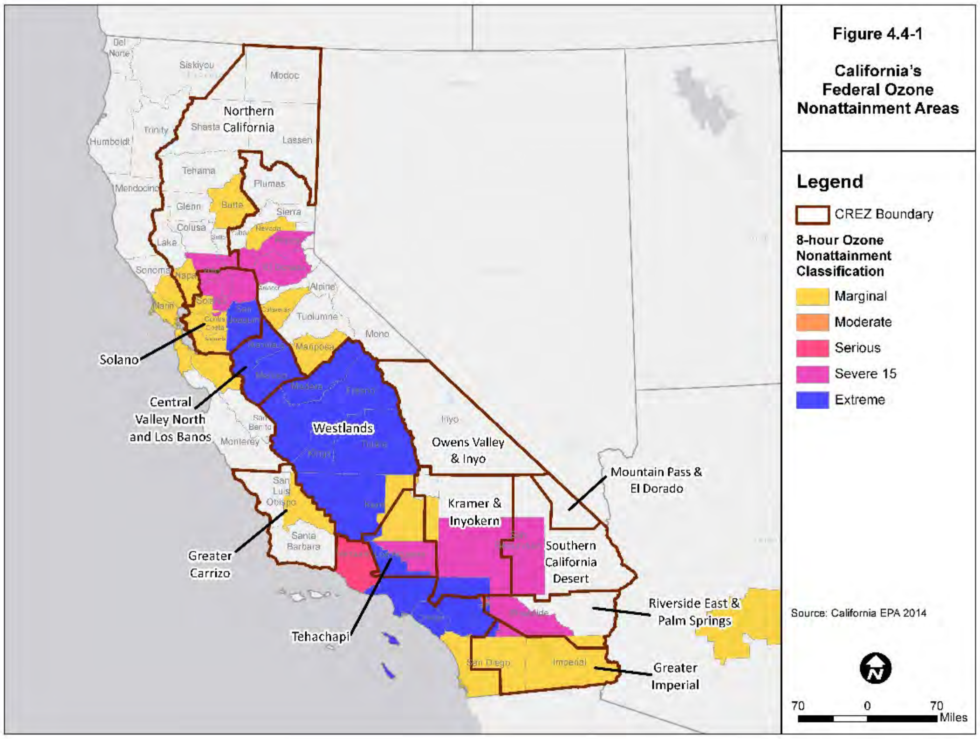
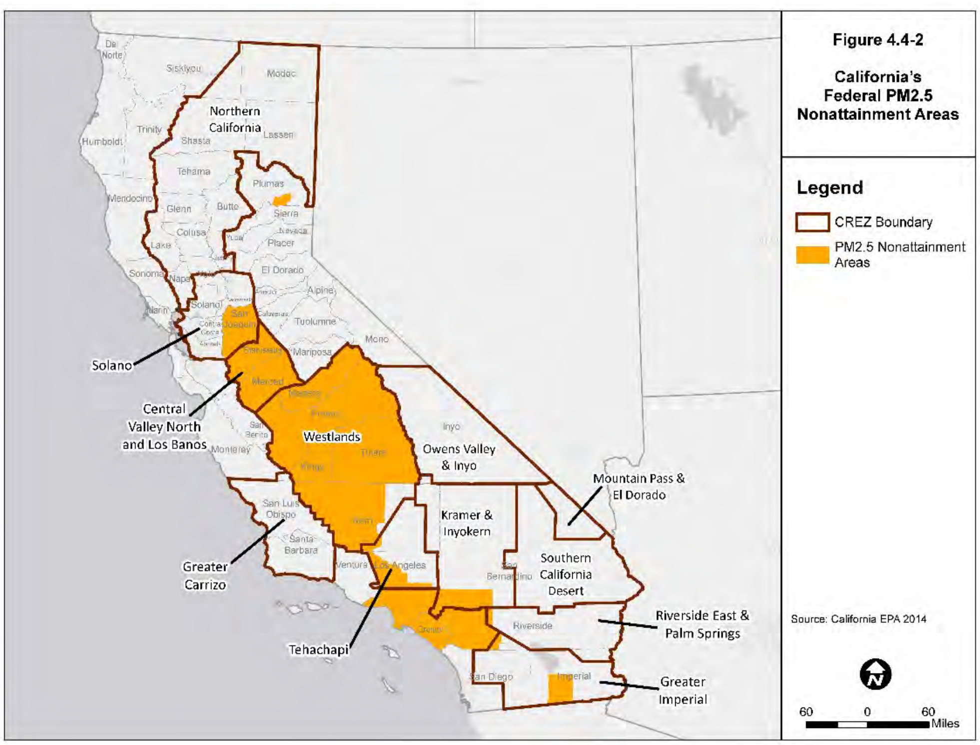


Figure 4.4-2. California's Federal PM2.5 Nonattainment Areas



Statewide Emissions from Electric Utilities

Emissions of criteria air pollutants are inventoried by ARB into stationary source subcategories, with all mobile sources and numerous area-wide sources treated separately. The stationary source category of Fuel Combustion, includes the emissions from all power plants, along with cogeneration facilities, and the combustion emissions from oil and gas production, refining, and other industrial, manufacturing, agricultural and service-sector sources. The combustion emissions from power plants (i.e., as stationary sources that produce electricity in California aside from cogeneration) are inventoried in a subcategory called Electric Utilities.

The ARB has a forecasting tool to estimate future-year criteria pollutant emissions, called California Emissions Projection Analysis Model (CEPAM). Table 4.4-5 shows the forecasted emissions of the 2020 California inventory across the entire state for all source categories, excluding natural sources. Statewide, combustion-fired electric generation comprises a small portion or roughly 1 to 2% of California's average daily inventories of NOx and PM2.5.

Table 4.4-5. California Statewide Emissions Inventory for 2020 (tons per day)

Source Categories	NOx	ROG	PM10	PM2.5	SOx
Area-wide Source Category	---	---	---	---	---
Miscellaneous Processes	73.8	265.9	1,258.2	278.3	6.4
Solvent Evaporation	0.0	364.2	0.0	0.0	0.0
Mobile Source Category	---	---	---	---	---
On-Road Motor Vehicles	544.8	220.2	67.8	31.5	5.5
Other Mobile Sources	643.3	285.7	35.7	32.6	15.4
Stationary Source Category	---	---	---	---	---
Industrial Processes	71.7	61.4	107.1	40.5	21.2
Petroleum Production and Marketing	4.4	127.8	1.8	1.6	4.4
Waste Disposal	4.6	42.1	1.8	0.8	1.5
Cleaning and Surface Coatings	0.3	166.8	3.2	3.1	0.2
Fuel Combustion	---	---	---	---	---
Food and Agricultural Processing	9.5	2.3	1.1	1.1	0.4
Manufacturing and Industrial	64.9	8.3	5.8	4.8	8.4
Oil and Gas Production (Combustion)	8.4	2.1	1.7	1.7	0.6
Other (Fuel Combustion)	13.5	0.9	2.1	0.5	0.4
Petroleum Refining (Combustion)	19.6	3.0	1.8	1.8	8.1
Service and Commercial	47.2	5.4	4.7	4.7	3.1
Cogeneration	20.6	2.5	3.5	3.2	1.4
Electric Utilities	---	---	---	---	---
Electric Utilities, Natural Gas	11.8	1.1	2.4	2.5	0.6
Electric Utilities, Other Fuels	15.0	1.3	3.1	2.5	5.0
Total, All Source Categories	1,553.4	1,560.8	1,502.0	411.2	82.4

Source: ARB Almanac Emission Projection Data (published in 2013); http://www.arb.ca.gov/ei/emissiondata.htm.

The ARB forecasts that emissions of criteria air pollutants (NOx, PM2.5, and SOx) from Electric Utilities statewide will remain steady or increase slightly from 2015 to 2020 and 2030. Table 4.4-6 shows the trend of historical and forecasted emissions for the portion of the electric utilities subcategory fired by natural gas in California.

Table 4.4-6. Statewide Inventory: Electric Utilities Subcategory, Natural Gas Only (tons per day)

Criteria Air Pollutant	2000	2005	2010	2012	2015	2020	2030
NOx	49.73	15.91	10.88	8.80	11.68	11.84	12.28
PM2.5	4.64	3.89	3.15	2.90	2.48	2.52	2.66
SOx	0.57	0.63	0.56	0.65	0.59	0.58	0.60

Source: ARB Almanac Emission Projection Data (published in 2013); http://www.arb.ca.gov/ei/emissiondata.htm.

4.4.3 Typical Air Quality Impacts of the Buildouts

This section describes the air quality impacts that would be common across the scenarios as a result of the incremental buildout of new solar, wind, and geothermal energy. Construction activities and operation of utility-scale renewable energy facilities under the buildout of the portfolios would introduce some localized air quality impacts by creating relatively minor levels of emissions, as summarized in this section.

Note that the SB 350 environmental study is not site-specific and does not reflect or represent a siting study for any particular planned or conceptual construction project. Although environmental impacts are described in general, project-specific impacts can typically be managed through best management practices and mitigation through the siting processes and with review by the siting authorities. Localized air quality impacts of construction activities can often be avoided or reduced on a case by case basis during the state or local siting processes.

Construction Impacts in General

Construction-phase air quality impacts are the result of the construction activities necessary to mobilize the workforce and equipment to install a given renewable energy development. These construction activities are similar for the incremental renewable energy buildouts across all scenarios. Therefore, these are the types of impacts that could occur on a community-scale for construction of renewable energy facilities and associated transmission interconnections. Because construction is limited in duration, the potential to create construction-related emissions essentially ends with the end of construction.

The typical construction-related air quality impacts are caused by fugitive dust from grading, vehicles driving on unpaved surfaces or roadways, and emissions from heavy-duty construction equipment and vehicles carrying construction materials and workers. These emissions occur during site development and preparation, transmission line development, and from building and roadway construction. The types of emissions would be the same for each renewable energy technology.

Construction activities may include mobilization, land clearing, earth moving, road construction, ground excavation, drilling and blasting, foundation construction, and installation activities. Heavy equipment used during site preparation would also include bulldozers, scrapers, trucks, cranes, rock drills, and possibly blasting equipment. These activities and equipment use would temporarily increase the amounts of particulate matter, including PM2.5, and precursors to particulate matter. Similarly, increased amounts of ozone precursors (VOCs and NOx) would occur from engine exhaust emissions, further exacerbating ozone nonattainment conditions.

Increased health risks would result for people exposed to excessive concentrations of dust, potentially including valley fever, and hazardous or toxic air pollutants routinely caused by gasoline and diesel-powered equipment. Diesel particulate matter is designated as a toxic air contaminant in California.

High levels of construction-phase emissions can exacerbate regional nonattainment conditions or expose sensitive receptors to substantial concentrations of hazardous or toxic air pollutants during project construction. Assessing the air quality impacts from construction emissions usually involves project-specific quantification of air pollutants emitted by construction activities for each phase of site development for each project.

Operational Impacts in General

Emissions are caused by operations and maintenance activities of the renewable energy buildout, through routine upkeep of the sites, security patrols, use of emergency generators, employee transportation, and vegetation removal. Dust emissions come from ground disturbance from access and spur road maintenance. Products of combustion are emitted by the use of natural gas, auxiliary heating of solar thermal technologies, and by the use of gasoline and diesel fuel for facility maintenance activities. Backup power supplies or fire water-pumping engines could also generate emissions if long-term operations and maintenance include diesel-powered emergency-use engines at substations and renewable energy facility sites.

Geothermal well-venting emissions include hydrogen sulfide (H_2S), carbon dioxide (CO_2), mercury, arsenic, and boron (when these compounds are contained in geothermal steam). H_2S is generally the primary pollutant of concern, and typically an air monitoring system is installed during geothermal field development. People exposed to high concentrations of H_2S or other hazardous or toxic air pollutants could experience adverse health effects, including cancer and non-cancer health risks; even at very low concentrations.

Producing electricity from the renewable energy resources displaces the need to produce electricity and the associated air contaminants from conventional fossil fuel–fired power generation facilities. These benefits would be felt at a regional or statewide level, but could also reduce the pollutant burden at the local level due to decreased emissions from conventional power generation facilities.

Reductions of SO_2 and NOx emissions and directly-emitted PM2.5 would yield health benefits. Sulfur oxides, which include SO_2, are precursors to PM2.5 formation in the ambient air, and NOx is a precursor to PM2.5 and ground-level ozone formation. As such, reductions of SO_2 and NOx can facilitate lower overall ambient concentrations of PM2.5 and ozone. Lower PM2.5 and ozone concentrations would generally reduce the exposure of persons to the adverse health effects and facilitate the associated human health benefits, such as avoided mortality and morbidity.

4.4.4 Air Emissions Impacts of Regionalization

The limited regionalization in the 2020 CAISO + PAC scenario includes no incremental renewable energy development so no incremental construction effects would occur inside or outside of California. Each scenario of regionalization in 2030 requires an incremental buildout of new solar, wind, and geothermal energy facilities that will create environmental impacts in the vicinity of the renewable energy buildout.

Incremental Buildout for All Scenarios by 2030

Inside California

Construction of the 2030 renewable portfolios under any scenario would require a substantial amount of ground disturbance and use of heavy-duty (diesel-powered) equipment that would be likely to create dust emissions and diesel exhaust emissions in California.

Nonattainment Areas and Construction-Related Emissions

Development of the renewable portfolio under 2030 Current Practice 1 would require construction of solar and wind projects in the following study areas that overlap with federally designated nonattainment areas (see Figures 4.4-1 and 4.4-2). The locations of the various renewable resource study areas are summarized in Table 4.4-7.

Table 4.4-7. Nonattainment Areas and California Study Areas

Federally-Designated Nonattainment Area	California Study Area
Mojave Desert Ozone Nonattainment Area	■ Tehachapi Wind and Solar ■ Kramer & Inyokern Solar
Sacramento Metropolitan Ozone Nonattainment Area	■ Solano Wind
Salton Sea Ozone Nonattainment Area	■ Riverside East & Palm Springs Solar and Wind ■ Greater Imperial Solar and Geothermal
San Diego County Ozone Nonattainment Area	■ Greater Imperial Wind
San Francisco Bay Area Ozone Nonattainment Area	■ Solano Wind
San Joaquin Valley Ozone and Particulate Matter Nonattainment Area	■ Westlands Solar ■ Solano Wind ■ Central Valley and Los Banos Wind
San Luis Obispo County Ozone Nonattainment Area	■ Greater Carrizo Solar and Wind

Although all scenarios include the incremental buildout, Current Practice 1 would emphasize solar in the Tehachapi, Westlands, and Greater Imperial areas, which are persistent nonattainment areas. The dust emissions and diesel exhaust emissions related to the buildout would temporarily increase the air pollutant burdens in these air basins.

When compared with 2030 Current Practice 1, the regional scenarios would reduce the construction emissions in California's nonattainment areas as follows:

- All regional scenarios would reduce the amount of construction and associated emissions in the San Joaquin Valley ozone and particulate matter nonattainment area (Westlands solar study area; Solano wind and Central Valley North and Los Banos wind study areas) compared with the 2030 Current Practice 1.
- 2030 Regional 3 would reduce construction and associated emissions in the Mojave Desert ozone nonattainment area (primarily in the Tehachapi solar study area).
- 2030 Regional 3 would reduce construction and associated emissions in the Salton Sea ozone nonattainment area (portions of the Riverside East & Palm Springs and Greater Imperial study areas).

Out of State

Wind and solar development out of state would involve certain amount of ground disturbance and use of heavy-duty equipment that depends on the relative incremental buildouts for California to achieve 50% RPS by 2030. Construction-phase emissions of ozone precursors and particulate matter would occur outside of California in the form of dust and diesel exhaust in the immediate vicinity of the buildout locations. A portion of the out-of-state buildout could occur in an ozone nonattainment area in Maricopa County Arizona, but all other out-of-state wind and solar buildout would avoid nonattainment areas. To the extent that regionalization could increase the buildout of the Southwest solar study area, construction-phase activities could temporarily increase the localized air pollutant concentrations in the Maricopa County ozone nonattainment area.

Out-of-State Transmission Additions

Under Regional 3, it is assumed that major out-of-state transmission additions would be necessary to integrate renewable generation from Wyoming and New Mexico into the regional power system and for California to achieve 50% RPS. Construction-phase emissions of ozone precursors and particulate matter would occur outside of California during the limited period of construction, and these would temporarily increase localized air pollutant concentrations in immediate vicinity of the activity. The potential transmission expansions are summarized in Section 5.

Operational Impacts of Regionalization

The production cost simulation model provided the changes in overall generation (in MWh) in the WECC under each of the 2020 and 2030 scenarios. This information was used to generate an estimated change in air emissions from the natural gas fleet inside California and out of state, or the remainder of the WECC, for each scenario. The changes in fossil fuel MWh production brought about by regionalization are almost exclusively an exchange between natural gas inside California and coal or natural gas outside California. Between 2020 and 2030, California natural gas dispatch by 2030 is modeled to be notably lower (-14% to -21%) than in the 2020 Current Practice scenario. Across this timeframe, out-of-state coal dispatch decreases and natural gas dispatch increases by 2030 when compared with the 2020 Current Practice scenario. Reductions in dispatch of the fossil fuel–fired units drive the emissions results presented in this section. Details on simulated dispatch results, including fuel use and fuel type trends, are presented in the Production Cost Analysis (Volume V).

Inside California

California's transition to achieving the RPS goals, including the incremental renewable buildout to 2030, relies partially upon the flexibility of California's existing fossil fuel–fired generators. The flexibility is reflected in the number of startups of the natural gas units, which would generally be more frequent in 2030 than in 2020.

Baseline forecasts of the California statewide emissions inventory (summarized in Table 4.4-6) indicate that emissions from natural gas-fired electric utilities statewide should remain steady or increase slightly between 2020 and 2030; however, the official forecast may not fully reflect current RPS goals. Between the time of California achieving the 33% RPS and achieving the 50% RPS by 2030, the retail demand for non-renewable and fossil fuel energy should continue to fall. Growth to serve California load is expected to come from renewable resources between 2020 and 2030, and the scenarios of this study include no new fossil fuel power plants. In sum, between 2020 and 2030, a decreasing amount of energy would be produced by California's fossil fuel fleet, and accordingly, overall criteria air pollutant emissions from California's generators would also decrease by 2030, even without regionalization.

Modeling of limited regionalization in 2020 (CAISO + PAC) indicates that the San Joaquin Valley and South Coast air basins could experience slightly increased PM2.5 and SO_2 emissions due to changes in natural gas–fired power plant dispatch, but these changes would occur in conjunction with a NOx decrease. By 2030, however, regionalization would decrease the emissions of NOx, PM2.5, and SO_2 from power plants statewide and in the air basins with persistent nonattainment conditions.

Tables 4.4-8, 4.4-9, and 4.4-10 present the modeled average daily air emissions rates for NOx, PM2.5, and SO_2, respectively, for the annual periods of 2020 and 2030 due the operation of California's natural gas–fired fleet under the Current Practice and regionalization scenarios.

Table 4.4-8. Modeled NOx Emissions Rates, California Natural Gas Fleet by Air Basin

Air Basin	2020 Current Practice (tons/day)	2020 CAISO + PAC (tons/day)	2030 Current Practice 1 (tons/day)	2030 Regional 2 (tons/day)	2030 Regional 3 (tons/day)
Mojave Desert	0.74	0.74	0.55	0.46	0.40
North Central Coast	0.41	0.41	0.47	0.46	0.46
North Coast	0.22	0.22	0.21	0.22	0.21
Sacramento Valley	1.30	1.27	1.35	1.21	1.13
Salton Sea	0.06	0.05	0.10	0.00	0.00
San Diego County	0.49	0.46	0.48	0.36	0.35
San Francisco Bay	2.63	2.58	2.75	2.67	2.51
San Joaquin Valley	6.46	6.43	6.44	6.22	6.06
South Central Coast	0.20	0.20	0.20	0.19	0.19
South Coast	2.74	2.70	2.67	2.42	2.33
Statewide Total	**15.24**	**15.06**	**15.21**	**14.23**	**13.66**
(% of All CA Sources)	*1.0%*	*1.0%*	*1.2%*	*1.2%*	*1.1%*
Impact of Regionalization		**–0.18**		**–0.99**	**–1.56**
(Relative to Current Practice)		*–1.2%*		*–6.5%*	*–10.2%*
Difference from 2020 Current Practice			**–0.03**	**–1.01**	**–1.58**
(Relative to 2020)			*–0.2%*	*–6.6%*	*–10.4%*

Table 4.4-9. Modeled PM2.5 Emissions Rates, California Natural Gas Fleet by Air Basin

Air Basin	2020 Current Practice (tons/day)	2020 CAISO + PAC (tons/day)	2030 Current Practice 1 (tons/day)	2030 Regional 2 (tons/day)	2030 Regional 3 (tons/day)
Mojave Desert	0.45	0.46	0.26	0.22	0.20
North Central Coast	0.24	0.24	0.25	0.25	0.25
North Coast	0.03	0.03	0.03	0.03	0.03
Sacramento Valley	0.88	0.87	0.80	0.74	0.70
Salton Sea	0.02	0.02	0.02	0.00	0.00
San Diego County	0.31	0.29	0.26	0.22	0.21
San Francisco Bay	1.64	1.61	1.45	1.52	1.46
San Joaquin Valley	2.60	2.61	2.28	2.24	2.20
South Central Coast	0.16	0.16	0.16	0.16	0.16
South Coast	1.45	1.46	1.31	1.19	1.15
Statewide Total	**7.78**	**7.75**	**6.82**	**6.55**	**6.36**
(% of All CA Sources)	*1.9%*	*1.9%*	*1.6%*	*1.5%*	*1.5%*
Impact of Regionalization		**–0.04**		**–0.27**	**–0.47**
(Relative to Current Practice)		*–0.5%*		*–4.0%*	*–6.8%*
Difference from 2020 Current Practice			**–0.96**	**–1.24**	**–1.43**
(Relative to 2020)			*–12.4%*	*–15.9%*	*–18.4%*

Table 4.4-10. Modeled SO_2 Emissions Rates, California Natural Gas Fleet by Air Basin

Air Basin	2020 Current Practice (tons/day)	2020 CAISO + PAC (tons/day)	2030 Current Practice 1 (tons/day)	2030 Regional 2 (tons/day)	2030 Regional 3 (tons/day)
Mojave Desert	0.05	0.05	0.03	0.02	0.02
North Central Coast	0.03	0.03	0.03	0.03	0.03
North Coast	0.00	0.00	0.00	0.00	0.00
Sacramento Valley	0.09	0.09	0.09	0.08	0.07
Salton Sea	0.00	0.00	0.00	0.00	0.00
San Diego County	0.03	0.03	0.03	0.02	0.02
San Francisco Bay	0.17	0.17	0.15	0.16	0.15
San Joaquin Valley	0.28	0.28	0.24	0.24	0.23
South Central Coast	0.02	0.02	0.02	0.02	0.02
South Coast	0.15	0.15	0.14	0.13	0.12
Statewide Total	**0.82**	**0.82**	**0.72**	**0.69**	**0.67**
(% of All CA Sources)	*1.0%*	*1.0%*	*0.8%*	*0.7%*	*0.7%*
Impact of Regionalization		**0.00**		**–0.03**	**–0.05**
(Relative to Current Practice)		*–0.5%*		*–4.0%*	*–6.8%*
Difference from 2020 Current Practice			**–0.10**	**–0.13**	**–0.15**
(Relative to 2020)			*–12.4%*	*–15.9%*	*–18.4%*

Managing ambient levels of ozone across California is a major focus of air quality management activity in many of California's air basins and in the SIP for the entire state. The planning period that is most relevant to the air basins with ozone nonattainment conditions generally spans the summertime months, and achieving reductions in NOx during those months is especially beneficial because NOx is a strong precursor to ground-level ozone along with being a PM2.5 precursor. To evaluate the potential impacts to ozone levels as a result of NOx emissions during summertime months (June, July, and August), the production simulation results for this three-month period were reviewed.

Table 4.4-11 presents the daily average modeled air emissions rates for NOx during the summer season from the natural gas fleet under the Current Practice and regionalization scenarios. Tables 4.4-12 and 4.4-13 show the summer season emissions rates for PM2.5 and SO_2, respectively. The results show that the two regionalization scenarios generally achieve similar levels of NOx emissions reductions in the summer season when compared with 2030 Current Practice 1.

Table 4.4-11. Modeled Summer Season NOx Emissions Rates, California Natural Gas Fleet

Air Basin	2020 Current Practice (tons/day)	2020 CAISO + PAC (tons/day)	2030 Current Practice 1 (tons/day)	2030 Regional 2 (tons/day)	2030 Regional 3 (tons/day)
Mojave Desert	0.86	0.89	0.69	0.61	0.60
North Central Coast	0.67	0.66	0.69	0.68	0.72
North Coast	0.23	0.24	0.23	0.23	0.24
Sacramento Valley	1.41	1.39	1.49	1.33	1.34
Salton Sea	0.07	0.06	0.10	0.00	0.00
San Diego County	0.70	0.67	0.65	0.53	0.55
San Francisco Bay	2.78	2.74	2.95	2.85	2.82
San Joaquin Valley	6.73	6.71	6.69	6.50	6.45

Table 4.4-11. Modeled Summer Season NOx Emissions Rates, California Natural Gas Fleet

Air Basin	2020 Current Practice (tons/day)	2020 CAISO + PAC (tons/day)	2030 Current Practice 1 (tons/day)	2030 Regional 2 (tons/day)	2030 Regional 3 (tons/day)
South Central Coast	0.20	0.20	0.20	0.20	0.20
South Coast	3.73	3.69	3.51	3.24	3.28
Statewide Total	**17.38**	**17.24**	**17.20**	**16.18**	**16.19**
Impact of Regionalization		**–0.14**		**–1.02**	**–1.01**
(Relative to Current Practice)		*–0.8%*		*–5.9%*	*–5.9%*
Difference from 2020 Current Practice			**–0.18**	**–1.20**	**–1.19**
(Relative to 2020)			*–1.0%*	*–6.9%*	*–6.9%*

Table 4.4-12. Modeled Summer Season PM2.5 Emissions Rates, California Natural Gas Fleet

Air Basin	2020 Current Practice (tons/day)	2020 CAISO + PAC (tons/day)	2030 Current Practice 1 (tons/day)	2030 Regional 2 (tons/day)	2030 Regional 3 (tons/day)
Mojave Desert	0.53	0.56	0.33	0.31	0.32
North Central Coast	0.41	0.40	0.33	0.35	0.39
North Coast	0.03	0.03	0.03	0.03	0.03
Sacramento Valley	0.94	0.94	0.88	0.83	0.84
Salton Sea	0.02	0.02	0.02	0.00	0.00
San Diego County	0.43	0.41	0.32	0.27	0.28
San Francisco Bay	1.74	1.72	1.61	1.68	1.68
San Joaquin Valley	2.72	2.73	2.40	2.40	2.42
South Central Coast	0.16	0.16	0.16	0.16	0.16
South Coast	1.85	1.85	1.59	1.45	1.47
Statewide Total	**8.82**	**8.83**	**7.67**	**7.48**	**7.57**
Impact of Regionalization		**0.00**		**–0.19**	**–0.10**
(Relative to Current Practice)		*0.0%*		*–2.5%*	*–1.3%*
Difference from 2020 Current Practice			**–1.15**	**–1.34**	**–1.25**
(Relative to 2020)			*-13.1%*	*-15.2%*	*-14.2%*

Table 4.4-13. Modeled Summer Season SO_2 Emissions Rates, California Natural Gas Fleet

Air Basin	2020 Current Practice (tons/day)	2020 CAISO + PAC (tons/day)	2030 Current Practice 1 (tons/day)	2030 Regional 2 (tons/day)	2030 Regional 3 (tons/day)
Mojave Desert	0.06	0.06	0.03	0.03	0.03
North Central Coast	0.04	0.04	0.04	0.04	0.04
North Coast	0.00	0.00	0.00	0.00	0.00
Sacramento Valley	0.10	0.10	0.09	0.09	0.09
Salton Sea	0.00	0.00	0.00	0.00	0.00
San Diego County	0.05	0.04	0.03	0.03	0.03
San Francisco Bay	0.18	0.18	0.17	0.18	0.18
San Joaquin Valley	0.29	0.29	0.25	0.25	0.26
South Central Coast	0.02	0.02	0.02	0.02	0.02

Table 4.4-13. Modeled Summer Season SO_2 Emissions Rates, California Natural Gas Fleet

Air Basin	2020 Current Practice (tons/day)	2020 CAISO + PAC (tons/day)	2030 Current Practice 1 (tons/day)	2030 Regional 2 (tons/day)	2030 Regional 3 (tons/day)
South Coast	0.20	0.20	0.17	0.15	0.16
Statewide Total	**0.93**	**0.93**	**0.81**	**0.79**	**0.80**
Impact of Regionalization		**0.00**		**–0.02**	**–0.01**
(Relative to Current Practice)		*0.0%*		*–2.4%*	*–1.3%*
Difference from 2020 Current Practice			**–0.12**	**–0.14**	**–0.13**
(Relative to 2020)			*–13.1%*	*–15.2%*	*-14.2%*

Out of State

In 2020 CAISO + PAC scenario, production simulation indicates a slight (+0.5%) increase in out-of-state coal use and a slight (-0.3%) decrease in out-of-state natural gas use. This slightly increases emissions from the WECC-wide fleet outside California when compared with 2020 Current Practice.

Air pollutant reductions outside of California by 2030 are driven by the transition away from coal. Between 2020 and 2030, out-of-state coal dispatch decreases and natural gas dispatch increases. This reduces emissions in all 2030 scenarios when compared with the 2020 conditions.

In 2030 Regional 2 and Regional 3, production simulation indicates overall reductions in out-of-state coal and natural gas use (-0.7% to -5.3%) when compared with 2030 Current Practice 1. The modeled emissions and changes in NOx and SO_2 emissions from the WECC fleet, excluding California sources, are shown in Table 4.4-14.

Table 4.4-14. Modeled Out-of-State Emissions Rates from Production Simulation

Criteria Air Pollutant	2020 Current Practice (tons/day)	2020 CAISO + PAC (tons/day)	2030 Current Practice 1 (tons/day)	2030 Regional 2 (tons/day)	2030 Regional 3 (tons/day)
NOx	1,522	1,533	1,166	1,143	1,150
Impact of Regionalization		**10**		**–23**	**–16**
(Relative to Current Practice)		*0.7%*		*–2.0%*	*–1.4%*
SO_2	1,509	1,527	1,113	1,102	1,110
Impact of Regionalization		**18**		**–11**	**–2**
(Relative to Current Practice)		*1.2%*		*–1.0%*	*–0.2%*

4.4.5 Comparison of Scenarios for Air Emissions

The change from Current Practice into regional scenarios allows the following comparisons.

Inside California

Modeling of limited regionalization in 2020 (CAISO + PAC) indicates that the San Joaquin Valley and South Coast air basins could experience slightly increased PM2.5 and SO_2 emissions due to changes in natural gas–fired power plant dispatch, but these changes would occur in conjunction with a NOx decrease. By 2030, however, regionalization would decrease the emissions of NOx, PM2.5, and SO_2 from power plants statewide and in the air basins with persistent nonattainment conditions.

Tables 4.4-15, 4.4-16, and 4.4-17 summarize the relative changes in criteria air pollutant emissions from the existing system of natural gas–fired generating units in California's air basins.

Table 4.4-15. NOx Emissions Changes, California Natural Gas Fleet by Air Basin

Air Basin	2020 CAISO + PAC Relative to Current Practice (% NOx)	2030 Regional 2 Relative to Current Practice Scenario 1 (% NOx)	2030 Regional 3 Relative to Current Practice Scenario 1 (% NOx)
Mojave Desert	0.2%	–15.6%	–26.8%
North Central Coast	–0.6%	–2.5%	–2.1%
North Coast	–0.3%	0.3%	–1.0%
Sacramento Valley	–2.6%	–9.7%	–16.2%
Salton Sea	–5.1%	–99.4%	–99.4%
San Diego County	–6.8%	–24.6%	–26.9%
San Francisco Bay	–1.7%	–3.0%	–8.7%
San Joaquin Valley	–0.5%	–3.3%	–5.8%
South Central Coast	–0.1%	–0.3%	–0.3%
South Coast	–1.4%	–9.2%	–12.8%
Difference Statewide NOx (California natural gas fleet)	**–1.2%**	**–6.5%**	**–10.2%**

Table 4.4-16. PM2.5 Emissions Changes, California Natural Gas Fleet by Air Basin

Air Basin	2020 CAISO + PAC Relative to Current Practice (% PM2.5)	2030 Regional 2 Relative to Current Practice Scenario 1 (% PM2.5)	2030 Regional 3 Relative to Current Practice Scenario 1 (% PM2.5)
Mojave Desert	0.7%	–14.2%	–23.3%
North Central Coast	–0.7%	0.3%	2.9%
North Coast	10.0%	–0.9%	–2.6%
Sacramento Valley	–1.3%	–8.5%	–12.6%
Salton Sea	–1.4%	–99.2%	–98.8%
San Diego County	–6.4%	–17.3%	–18.9%
San Francisco Bay	–1.4%	4.4%	0.1%
San Joaquin Valley	0.4%	–2.0%	–3.8%
South Central Coast	0.0%	0.0%	0.0%
South Coast	0.4%	–9.7%	–12.2%
Difference Statewide PM2.5 (California natural gas fleet)	**–0.5%**	**–4.0%**	**–6.8%**

Table 4.4-17. SO_2 Emissions Changes, California Natural Gas Fleet by Air Basin

Air Basin	2020 CAISO + PAC Relative to Current Practice (% SO_2)	2030 Regional 2 Relative to Current Practice Scenario 1 (% SO_2)	2030 Regional 3 Relative to Current Practice Scenario 1 (% SO_2)
Mojave Desert	0.7%	–14.2%	–23.3%
North Central Coast	–0.7%	0.3%	2.9%
North Coast	10.0%	–0.9%	–2.6%
Sacramento Valley	–1.3%	–8.6%	–12.7%
Salton Sea	–1.4%	–99.2%	–98.8%
San Diego County	–6.4%	–17.3%	–18.9%
San Francisco Bay	–1.4%	4.5%	0.1%
San Joaquin Valley	0.3%	–1.9%	–3.8%
South Central Coast	0.0%	0.0%	0.0%
South Coast	0.4%	–9.7%	–12.2%
Difference Statewide SO_2 (California natural gas fleet)	**–0.5%**	**–4.0%**	**–6.8%**

During the ozone management summer season, Table 4.4-18 summarizes the relative changes in NOx emissions from the existing system of natural gas–fired generating units in California's air basins. Tables 4.4-19 and 4.4-20 summarize the relative changes in PM2.5 and SO_2 within the summer season.

Table 4.4-18. Modeled Summer Season NOx Emissions Changes, California Natural Gas Fleet

Air Basin	2020 CAISO + PAC Relative to Current Practice (% NOx)	2030 Regional 2 Relative to Current Practice Scenario 1 (% NOx)	2030 Regional 3 Relative to Current Practice Scenario 1 (% NOx)
Mojave Desert	3.0%	-11.3%	-13.6%
North Central Coast	-1.3%	-1.4%	5.0%
North Coast	4.0%	-0.1%	1.5%
Sacramento Valley	-1.6%	-10.2%	-9.7%
Salton Sea	-13.2%	-98.4%	-98.0%
San Diego County	-4.3%	-17.4%	-15.7%
San Francisco Bay	-1.6%	-3.6%	-4.4%
San Joaquin Valley	-0.3%	-2.8%	-3.6%
South Central Coast	-0.5%	-0.8%	-0.7%
South Coast	-1.1%	-7.7%	-6.7%
Difference Statewide NOx (California natural gas fleet)	**–0.8%**	**–5.9%**	**–5.9%**

Table 4.4-19. Modeled Summer Season PM2.5 Emissions Changes, California Natural Gas Fleet

Air Basin	2020 CAISO + PAC Relative to Current Practice (% PM2.5)	2030 Regional 2 Relative to Current Practice Scenario 1 (% PM2.5)	2030 Regional 3 Relative to Current Practice Scenario 1 (% PM2.5)
Mojave Desert	4.5%	-5.5%	-3.9%
North Central Coast	-1.6%	5.1%	16.5%
North Coast	15.9%	-2.2%	-0.1%
Sacramento Valley	-0.5%	-5.4%	-4.6%
Salton Sea	-8.5%	-98.2%	-96.9%
San Diego County	-3.8%	-13.6%	-12.4%
San Francisco Bay	-0.8%	3.8%	3.8%
San Joaquin Valley	0.6%	0.1%	0.8%
South Central Coast	0.2%	0.0%	0.0%
South Coast	0.0%	-8.6%	-7.4%
Difference Statewide PM2.5 (California natural gas fleet)	**0.0%**	**–2.5%**	**–1.3%**

Table 4.4-20. Modeled Summer Season SO_2 Emissions Changes, California Natural Gas Fleet

Air Basin	2020 CAISO + PAC Relative to Current Practice (% SO_2)	2030 Regional 2 Relative to Current Practice Scenario 1 (% SO_2)	2030 Regional 3 Relative to Current Practice Scenario 1 (% SO_2)
Mojave Desert	4.5%	-5.5%	-3.9%
North Central Coast	-1.6%	5.1%	16.5%
North Coast	15.9%	-2.2%	-0.1%
Sacramento Valley	-0.5%	-5.5%	-4.6%
Salton Sea	-8.4%	-98.2%	-96.9%
San Diego County	-3.8%	-13.6%	-12.4%
San Francisco Bay	-0.8%	3.8%	3.8%
San Joaquin Valley	0.6%	0.1%	0.9%
South Central Coast	0.2%	0.0%	0.0%
South Coast	0.0%	-8.6%	-7.4%
Difference Statewide SO_2 (California natural gas fleet)	**0.0%**	**–2.4%**	**–1.3%**

Out of State

In the 2020 CAISO + PAC scenario, production simulation indicates a slight (+0.5%) increase in out-of-state coal use and a slight (-0.3%) decrease in out-of-state natural gas use, when compared with 2020 Current Practices, and this slightly increases emissions out of state (+0.7% for NOx and +1.2% for SO_2).

Regionalization by 2030 would affect the emissions from electricity generating units in the remainder of the Western Interconnection as follows:

- Regional 2 decreases NOx (-1.9%) and SO_2 (-0.9%) emissions out of state relative to 2030 Current Practice 1.

- Regional 3 decreases NOx (-1.3%) and SO_2 (-0.2%) emissions out of state relative to 2030 Current Practice 1.

4.5 Discussion of Sensitivities

Along with the primary scenarios of the SB 350 study, summarized in Section 2 (Summary of Scenarios), the study team tested how certain assumptions could affect the results through sensitivity analyses. The full range of sensitivity analyses is described within Volume III (Description of Scenarios and Sensitivities). The environmental study focuses on two of these sensitivities to illustrate potential differences in the buildout of the renewable resources by 2030 or the operational characteristics of generators.

The 2030 Current Practice 1B sensitivity (Sensitivity 1B) assumes a higher flexibility in bilateral markets with CAISO's net bilateral export capability increased from 2,000 MW to 8,000 MW. This sensitivity is characterized by a portfolio that includes a somewhat larger buildout of solar resources in California and less emphasis on out-of-state wind than in the 2030 Current Practice Scenario 1.

Additionally, a sensitivity for testing the 2030 Scenario 3 without renewables beyond RPS is also reviewed. The renewable buildout for this sensitivity is the same incremental renewable buildout as for 2030 Regional Scenario 3; the only change from Regional 3 was the overall generation in the WECC, which would not include 5,000 MW of added wind capacity distributed as 3,000 MW in Wyoming and 2,000 MW in New Mexico. As such, the sensitivity without the renewables beyond RPS is analyzed for potential changes in water use and air emissions from operation of the generators across the WECC. While this sensitivity removes the impacts of developing these presumed resources (5,000 MW), there would be no other difference in the impacts to land use or biological resources when compared with Regional 3 because this sensitivity has an identical buildout for satisfying RPS goals.

As with the analysis of all 2030 scenarios, the analysis of the Sensitivity 1B starts by presuming construction of the renewable portfolios defined through the use of the RESOLVE model. The incremental renewable buildout between 2020 and 2030 is presented in Table 4.5-1 for inside and outside California. Current Practice Scenario 1 is presented for comparison purposes.

Table 4.5-1. Incremental Renewable Buildout for Sensitivity 1B (MW)

Portfolio Composition	2030 Current Practice Scenario 1	2030 Sensitivity 1B
California Solar	7,601	8,279
California Wind	3,000	3,000
California Geothermal	500	500
Out-of-State Solar	1,000	1,272
Out-of-State Wind	4,551	2,551
Total California New Capacity	11,101	11,779
Total Out-of-State New Capacity	5,551	3,823
Total New Renewable Capacity	16,652	15,602
Major Out-of-State Transmission Additions for California RPS?	No	No
Renewables Beyond RPS, Out of State	No	No

Source: Results from the RESOLVE model; adding renewable development beyond RPS facilitated by regional market.
Notes:
- All portfolios also include energy storage (batteries and/or pumped hydro);
- Incremental California geothermal located in Greater Imperial.

Incremental Buildout Inside California

The renewable portfolios as developed through the RESOLVE model reflect MW of renewable buildout by CREZ and technology for the entire state of California including both CAISO and non-CAISO utilities. The buildout for solar is presented in Table 4.5-2 and for wind is presented in Table 4.5-3.

Table 4.5-2. California Solar, Incremental Buildout Details in Sensitivity 1B (MW)

California Solar Portfolio	2030 Current Practice Scenario 1	2030 Sensitivity 1B
Greater Carrizo Solar	570	570
Greater Imperial Solar	923	923
Kramer and Inyokern Solar	375	375
Owens Valley Solar	578	578
Riverside East and Palm Springs Solar	331	2,459
Tehachapi Solar	2,500	2,500
Westlands Solar	2,323	873
Total California New Solar Capacity	7,601	8,279

Source: Results from the RESOLVE model.

Table 4.5-3. California Wind, Incremental Buildout Details in Sensitivity 1B (MW)

California Wind Portfolio	2030 Current Practice Scenario 1	2030 Sensitivity 1B
Central Valley North and Los Banos Wind	150	150
Greater Carrizo Wind	500	500
Greater Imperial Wind	400	400
Riverside East and Palm Springs Wind	500	500
Solano Wind	600	600
Tehachapi Wind	850	850
Total California New Wind Capacity	3,000	3,000

Source: Results from the RESOLVE model.

Incremental Buildout Out of State

The renewable portfolios also include the MW of renewable buildout outside California. The buildout for solar and wind is presented in Table 4.5-4.

Table 4.5-4. Out-of-State Solar and Wind, Incremental Buildout Details in Sensitivity 1B (MW)

Out-of-State Portfolio for California	2030 Current Practice Scenario 1	2030 Sensitivity 1B
Southwest Solar (Arizona)	1,000	1,272
Northwest Wind (Oregon)	2,447	447
Utah Wind	604	604
Wyoming Wind	500	500
New Mexico Wind	1,000	1,000
Total Out-of-State New Capacity	5,551	3,823
Major Out-of-State Transmission Additions for California RPS?	No	No
Renewables Beyond RPS, Out-of-State	No	No

Source: Results from the RESOLVE model; adding renewable development beyond RPS facilitated by regional market.

4.5.1 Land Use Impacts of Sensitivity 1B

Inside California

Solar. Under Sensitivity 1B, the solar portfolio in California would be similar to the Current Practice Scenario 1, and would emphasize:

- Areas having population densities ranging from medium/high to low, with most occurring in areas of medium/high density.
- Areas with extensive to low levels of agricultural activity.
- Areas within 5 miles of a high to medium number of excluded or protected areas.

Sensitivity 1B would include 8,279 MW of California solar capacity, about 9 percent more than Scenario 1, with the increase occurring in the Riverside East and Palm Springs Solar area, while decreasing generation in Westlands. This scenario would require development on about 58,000 acres of land, or about 90 square miles. While projects would be located in all study areas, nearly 60 percent of the total used area under Sensitivity 1B would be in two study areas: Tehachapi and Riverside East and Palm Springs. The only difference between the buildout for Scenario 1 and Sensitivity 1B is a decrease in solar development in the Westlands area and an increase in the Riverside East and Palm Springs solar area. As described for Scenario 1, the Tehachapi solar area surrounds Lancaster, Mojave, and lands north and west of Edwards AFB. Except for in Lancaster and a few small towns in the area, the population density is very low. The land is flat desert with sparse vegetation, with some small areas of irrigated agriculture. The Riverside East and Palm Springs solar study area is a patchwork of lands located in two general areas: the lands west of Blythe to near Desert Center in eastern Riverside County, and in the Palm Springs area near Desert Hot Springs and between Indio and Thermal. The solar area's terrain is flat, sparsely vegetated desert with some areas of irrigated agriculture. Much of the area has a very low population density, except in urbanized areas in the vicinity of Palm Springs.

Impacts on land use and agriculture would be similar between Scenario 1 and Sensitivity 1B, except that there is a greater population density in the Palm Springs portion of the Riverside East and Palm Springs area as compared to the Westlands area. However, the population density in the eastern part of Riverside East between Blythe and Desert Center is extremely low. Less agricultural land would potentially be affected in Sensitivity 1B when compared with Scenario 1.

Wind. In terms of wind powered generation in California, Scenario 1 and Sensitivity 1B are identical and would have similar land use impacts.

Geothermal. Sensitivity 1B is identical to Scenario 1.

Out of State

Out of state, under Sensitivity 1B, solar generation would slightly increase in Arizona as compared to Scenario 1. This would partially offset a large reduction in wind generation in the Oregon area. Wind generation in Utah, Wyoming, and New Mexico would be the same as in Scenario 1. Overall, Sensitivity 1B would include nearly 30 percent less out-of-state buildout than Scenario 1. Impacts would be similar to those in Scenario 1, except there would be somewhat more land used in Arizona for solar, and the land needed in Oregon for wind generation would decrease notably.

4.5.2 Biological Resources Impacts of Sensitivity 1B

Inside California

Sensitivity 1B emphasizes solar in the Tehachapi (30% of total or 2,500 MW) and Riverside East & Palm Springs (29.7% of total or 2,459 MW) study areas. Impacts of solar development in the Tehachapi study area under Sensitivity 1B would the same as those described under Current Practice Scenario 1 as generation capacity would be the same. The Riverside East & Palm Springs has 30% coverage of the highest crucial habitat ranks. Development would result in habitat loss for several listed species and constriction of movement corridors for desert tortoise and bighorn sheep (peninsular and desert), which are also susceptible to cumulative effects of habitat fragmentation and associated population-level impacts of genetic isolation.

Impacts of wind and geothermal development under Sensitivity 1B would be the same as those described under Current Practice 1 as generation capacity across all study areas would be the same.

Out of State

Sensitivity 1B would use the fewest out-of-state resources when compared with other buildouts by 2030 with the most generation occurring in the Southwest solar study area and the New Mexico wind study area. Impacts in these study areas would be consistent with those described in Section 4.2.3 and under Current Practice Scenario 1 for these study areas as generation capacity would be similar.

4.5.3 Water Impacts of Sensitivity 1B and Sensitivity without Renewables Beyond RPS

Inside California

As with the primary scenarios and impacts described in Section4.3, this analysis considers three factors pertaining to water use inside California for Sensitivity 1B. First it considers development in critically overdrafted groundwater basins, followed by construction in areas of different water risk factors, and finally it looks at water consumption during operations.

Critically Overdrafted Groundwater Basins

Sensitivity 1B would reduce the construction water use in critically overdrafted groundwater basins as follows:

- It would reduce the amount of construction and associated water use in Westlands solar study area compared with the 2030 Current Practice 1.

Construction in Areas of Water Risk

Table 4.5--5 presents the acre feet of water required for construction of renewable energy in California under the sensitivity. Current Practice Scenario 1 is provided for comparison purposes. Sensitivity 1B would require more water in California in low to medium and medium to high risk areas and less water in areas of high risk.

Table 4.5-5. Construction Water Use by Risk Category for Sensitivity 1B

Water Risk (acre feet)	2030 Current Practice Scenario 1	2030 Sensitivity 1B
Low to Medium	4,364	6,000
Medium to High	7,019	7,959
High	7,562	6,518

Water Consumption during Operations

Table 4.5-6 presents the results of the operational water use for the sensitivity analyses for regionalization in 2030.

Table 4.5-6. Total Water Use for Energy Generation in California – Sensitivity Analyses

Water Consumption by Technology (af)	2030 Current Practice Scenario 1	2030 Sensitivity 1B	2030 Scenario 3 w/o Renewables Beyond RPS
Solar PV	3,540	3,926	2,883
Solar Thermal	1,039	1,040	1,040
Natural Gas Combined Cycle	41,486	42,105	42,382
Natural Gas Steam Turbine	2,710	2,715	2,721
ST Coal	0	0	0
Total (excluding Geothermal)	48,776	49,786	49,026
Geothermal	205,897	201,955	208,231
Change Relative to Current Practice 1 (af)		1,010	250
Change Relative to Current Practice 1 (%)		2.1%	0.5%

Under the sensitivity analyses in comparison with Current Practice Scenario 1, the following would occur inside California:

- 2030 Sensitivity 1B would increase water use for electricity generation by 1,010 acre feet, about 2%.
- 2030 Scenario 3 without renewables beyond RPS would increase water use by 250 acre feet, about 0.5%.

Out of State

Construction in Areas of Water Risk

As with the analysis for inside California, Table 4.5-7 presents the acre feet of water required for construction of renewable energy outside California under the different portfolios. Sensitivity 1B would require less water outside California in low to medium areas and more water in areas of high risk.

Table 4.5-7. Construction Water Use by Risk Category Out of State for Sensitivity 1B		
Water Risk (acre feet)	**2030 Current Practice Scenario 1**	**2030 Sensitivity 1B**
Low to Medium	1,039	239
Medium to High	471	471
High	5,998	7,546

Water Consumption during Operations

Table 4.5-8 presents the operational water use for the out-of-state electricity generation in the sensitivity analyses for regionalization in 2030.

Table 4.5-8. Total Water Use for Energy Generation Outside California – Sensitivity Analyses			
Water Consumption by Technology (af)	**2030 Current Practice Scenario 1**	**2030 Sensitivity 1B**	**2030 Scenario 3 w/o Renewables Beyond RPS**
Solar PV	989	1,049	1,108
Solar Thermal	634	634	634
Natural Gas Combined Cycle	169,032	168,420	210,437
Natural Gas Steam Turbine	297	353	215
ST Coal	295,450	292,391	297,832
Total (excluding Geothermal)	466,401	462,847	510,226
Geothermal	140,805	140,577	140,599
Change Relative to Current Practice 1 (af)		–3,554	1,442
Change Relative to Current Practice 1 (%)		–0.8%	0.3%

Under the sensitivity analyses in comparison with Current Practice Scenario 1, the following would occur outside California:

- 2030 Sensitivity 1B would reduce water use by 3,554 acre feet, about 1%.
- 2030 Scenario 3 without renewables beyond RPS would increase water use by 1,442 acre feet, about 0.3%.

4.5.4 Air Emissions Impacts of Sensitivity 1B and Sensitivity without Renewables Beyond RPS

Inside California

Tables 4.5-9, 4.5-10, and 4.5-11 present the modeled average daily air emissions rates for NOx, PM2.5, and SO_2, respectively, for the two sensitivity cases considered for 2030.

Table 4.5-9. Modeled Sensitivities NOx Emissions Rates, California Natural Gas Fleet by Air Basin			
Air Basin	**2030 Current Practice 1 (tons/day)**	**2030 Sensitivity 1B (tons/day)**	**2030 Scenario 3 w/o Renewables Beyond RPS (tons/day)**
Mojave Desert	0.55	0.55	0.51
North Central Coast	0.47	0.49	0.50
North Coast	0.21	0.22	0.22
Sacramento Valley	1.35	1.40	1.28

Table 4.5-9. Modeled Sensitivities NOx Emissions Rates, California Natural Gas Fleet by Air Basin

Air Basin	2030 Current Practice 1 (tons/day)	2030 Sensitivity 1B (tons/day)	2030 Scenario 3 w/o Renewables Beyond RPS (tons/day)
Salton Sea	0.10	0.09	0.00
San Diego County	0.48	0.51	0.43
San Francisco Bay	2.75	2.84	2.74
San Joaquin Valley	6.44	6.46	6.28
South Central Coast	0.20	0.20	0.19
South Coast	2.67	2.71	2.50
Statewide Total	**15.21**	**15.47**	**14.65**
(% of All CA Sources)	*1.2%*	*1.3%*	*1.2%*
Change Relative to Current Practice 1		**0.25**	**–0.56**
(Relative to Current Practice 1)		*1.7%*	*–3.7%*
Difference from 2020 Current Practice	**–0.03**	**0.23**	**–0.59**
(Relative to 2020)	*–0.2%*	*1.5%*	*–3.9%*

Table 4.5-10. Modeled Sensitivities PM2.5 Emissions Rates, California Natural Gas Fleet by Air Basin

Air Basin	2030 Current Practice 1 (tons/day)	2030 Sensitivity 1B (tons/day)	2030 Scenario 3 w/o Renewables Beyond RPS (tons/day)
Mojave Desert	0.26	0.26	0.25
North Central Coast	0.25	0.26	0.27
North Coast	0.03	0.03	0.03
Sacramento Valley	0.80	0.83	0.79
Salton Sea	0.02	0.02	0.00
San Diego County	0.26	0.27	0.24
San Francisco Bay	1.45	1.48	1.59
San Joaquin Valley	2.28	2.29	2.32
South Central Coast	0.16	0.16	0.16
South Coast	1.31	1.32	1.23
Statewide Total	**6.82**	**6.90**	**6.88**
(% of All CA Sources)	*1.6%*	*1.6%*	*1.6%*
Change Relative to Current Practice 1		**0.08**	**0.06**
(Relative to Current Practice 1)		*1.1%*	*0.9%*
Difference from 2020 Current Practice	**–0.96**	**–0.89**	**–0.90**
(Relative to 2020)	*–12.4%*	*–11.4%*	*–11.6%*

Table 4.5-11. Modeled Sensitivities SO_2 Emissions Rates, California Natural Gas Fleet by Air Basin

Air Basin	2030 Current Practice 1 (tons/day)	2030 Sensitivity 1B (tons/day)	2030 Scenario 3 w/o Renewables Beyond RPS (tons/day)
Mojave Desert	0.03	0.03	0.03
North Central Coast	0.03	0.03	0.03

Table 4.5-11. Modeled Sensitivities SO_2 Emissions Rates, California Natural Gas Fleet by Air Basin

Air Basin	2030 Current Practice 1 (tons/day)	2030 Sensitivity 1B (tons/day)	2030 Scenario 3 w/o Renewables Beyond RPS (tons/day)
North Coast	0.00	0.00	0.00
Sacramento Valley	0.09	0.09	0.08
Salton Sea	0.00	0.00	0.00
San Diego County	0.03	0.03	0.03
San Francisco Bay	0.15	0.16	0.17
San Joaquin Valley	0.24	0.24	0.25
South Central Coast	0.02	0.02	0.02
South Coast	0.14	0.14	0.13
Statewide Total	**0.72**	**0.73**	**0.73**
(% of All CA Sources)	*0.8%*	*0.8%*	*0.8%*
Change Relative to Current Practice 1		**0.01**	**0.01**
(Relative to Current Practice 1)		*1.1%*	*1.0%*
Difference from 2020 Current Practice	**–0.10**	**–0.09**	**–0.10**
(Relative to 2020)	*–12.4%*	*–11.4%*	*–11.6%*

Under the sensitivity analyses in comparison with Current Practice Scenario 1, the following would occur inside California:

- Emissions in California would increase slightly (1% to 2%) in Sensitivity 1B, as operation of California's natural gas fleet would slightly increase.
- 2030 Scenario 3 without renewables beyond RPS similarly results in a slight increase in operation of California's natural gas–fired fleet, but this scenario would avoid some of the excess startup emissions of NOx that would occur under the 2030 Current Practice Scenario 1.

Out of State

For the sensitivity analyses, the modeled emissions and changes in NOx and SO_2 emissions from the WECC fleet, excluding California sources, are shown in Table 4.5-12.

Table 4.5-12. Modeled Sensitivities Out-of-State Emissions Rates from Production Simulation

Criteria Air Pollutant	2030 Current Practice 1 (tons/day)	2030 Sensitivity 1B (tons/day)	2030 Scenario 3 w/o Renewables Beyond RPS (tons/day)
NOx	1,166	1,158	1,170
Change Relative to Current Practice 1		**–8**	**4**
(Relative to Current Practice 1)		*–0.7%*	*0.4%*
SO_2	1,113	1,104	1,126
Change Relative to Current Practice 1		**-9**	**14**
(Relative to Current Practice 1)		*–0.8%*	*1.2%*

Under the sensitivity analyses in comparison with Current Practice Scenario 1, the following would occur outside California:

- Emissions would decrease slightly (0.7% to 0.8%) in Sensitivity 1B, as operation of out-of-state generators would slightly decrease.

- 2030 Scenario 3 without renewables beyond RPS results in an increase in operation of out-of-state generators to replace the energy that would otherwise be provided by the renewable resources facilitated by the regional market, and subsequently, emissions outside California would increase slightly (0.4% to 1.2%).

5. Impacts of Out-of-State Transmission for Regional 3

The 2030 expanded regionalization scenario (Regional 3) includes construction and operation of major out-of-state transmission additions to integrate renewable generation from Wyoming and New Mexico into the regional power system and for California to achieve 50% RPS. This section summarizes the potential adverse environmental impacts that could be caused by transmission additions, depending on siting of the specific projects.

While no specific project is assumed to be developed, several proposals that could be used to import wind are currently in different stages of the permitting process, as summarized in Section 2 (Scenarios), in Table 2-8. Because it is assumed that transmission expansion would be necessary for California to achieve 50% RPS in the Regional 3 scenario, the environmental study anticipates that construction must be completed by 2030. The additional transmission identified here would built to support interconnecting renewables on to the high-voltage transmission system, but renewable resources for California would use only a portion of the added transmission capacity.

The analysis considers the following transmission line proposals (also listed in Table 2-8), that are pending review or under review by siting authorities:

- **Gateway West (Segment D)** for access to Wyoming wind at Hemingway in Idaho (PacifiCorp)
- **Gateway South (Segment F)** for access to Wyoming wind at Mona or Clover in Utah (PacifiCorp)
- **TransWest Express** for access to Wyoming wind at southern Nevada (TransWest Express LLC, subsidiary of the Anschutz Corporation and Western Area Power Administration)
- **Zephyr Power Transmission Project** for access to Wyoming wind at southern Nevada (Duke-American Transmission Company)
- **SunZia Southwest Transmission Project** for access to New Mexico wind from SunZia East to Pinal Central in Arizona (SunZia)
- **Western Spirit Clean Line** for access to New Mexico wind at northern Arizona (Clean Line Energy Partners)

5.1 Land Use and Biological Resources Considerations in Siting Major Transmission

The following land use and biological resources constraints have been generally identified as potential transmission routing constraints affecting access to Wyoming and New Mexico wind resources:

- National Forests
- Tribal Lands
- National Parks
- Historic Trails
- National Monuments
- National Wildlife Refuges
- Wilderness Areas and Wilderness Study Areas
- Areas of Critical Environmental Concern
- National Conservation Areas
- National Historic Landmarks and Sites
- Sage Grouse Habitat
- Desert Tortoise Habitat
- Department of Defense Areas
- Department of Energy Areas
- Inventoried Roadless Areas
- Wild and Scenic Rivers
- State-managed Lands
- Wetlands, Rivers, and Lakes
- Vegetation Cover
- Private Lands

The following discussion highlights some of the specific issues of environmental concern for construction of new transmission in each region.

Transmission for Wyoming Wind Resources by 2030

Four proposals could provide access to Wyoming wind resources: Gateway West (Segment D) Gateway South (Segment F), TransWest Express, and the Zephyr Power Transmission Project. Because these potential projects cross similar lands and have similar environmental constraints, the following discussion applies to all four.

- **Lands with Special Status**. The transmission lines would be routed to avoid or minimize impacts to sensitive areas and lands with special status, some of which may prohibit new transmission lines. Impacts from construction and operation to lands with special designations depend on the location of the crossing as well as the relevant and important values for which land was or is being proposed to be designated. Examples of areas with special management designations along these routes include:
  - BLM Areas of Critical Environmental Concern
  - BLM Wilderness & Wilderness Study Areas
  - United States Forest Service (USFS) Inventoried Roadless Areas & Unroaded/Undeveloped Areas
  - Conservation Easements
  - National Conservation Areas
  - National Monuments & Landmarks
  - National Wildlife Refuges
  - National Scenic & Historic Trails, and
  - State & federal parks
- **Visual Resources**. The transmission lines could modify viewsheds and alter landscape characteristics in areas, such as Flat Top Mountain, Wasatch Plateau, Reservation Ridge, Cherokee Historic Trail, Wyoming Highway 789 (a county-designated scenic drive), Dinosaur National Monument from the east entrance, Energy Loop Scenic Byway, and the Green River.
- **BLM and USFS Visual and Land Use Conformity**. Conformance with land use plans and BLM Visual Resource Management (VRM) Class Objectives, or consistency with USFS Visual Quality Objectives or Scenic Integrity Objectives could require amendments to several land use plans.
- **Sensitive Land Uses**. There are constraints and public concern in areas where the transmission lines would cross existing agricultural operations, grazing allotments, existing and authorized residential land uses, recreation facilities, and the Ioka cemetery.
- **Special Use Airspace Designations.** Routing is constrained by airspace/structure height restrictions around National Guard Orchard Training Area.
- **Wild Horses**. Transmission lines would cross nine herd management areas/herd areas and certain alignments could cause a potential hazard to BLM helicopters used during wild horse roundups.
- **Landslides and Ground Subsidence**. There are engineering constraints and a high risk of landslides in in areas of mountainous terrain. Electrical transmission lines have been impacted by ground stability hazards on the Wasatch Plateau.
- **Paleontological and Mineral Resources**. There are large number of geological formations known to produce fossils, as well as major mineral resources in the area that could be impacted by construction of the transmission lines.
- **Cumulative Impacts.** Numerous transmission lines are being proposed within already crowded transmission corridors.

Transmission for New Mexico Wind Resources by 2030

Two proposals could provide access to New Mexico wind resources: SunZia Southwest Transmission Project and the Western Spirit Clean Line project. The major issues facing these lines are the following:

- **Lands with Special Status**. The transmission lines would be routed to avoid or minimize impacts to sensitive areas and lands with special management status. Examples in the project area include:
  - Sevilleta and Bosque del Apache National Wildlife Refuges
  - Peloncillo Mountains and Rincon Mountains Wilderness Areas
  - BLM Hot Well Dunes Recreation Area
  - Stallion, Veranito, Presilla and Peloncillo Mountains Wilderness Study Areas
  - Johnson (Gordy's) Hill Special Recreation Management Area
  - Arizona National Scenic Trail and Buehman Canyon Trail
  - Rio Grande River crossing
- **Special Use Airspace Designations**. Transmission line routing is constrained by airspace/structure height restrictions around White Sands Missile Range.
- **Visual Resources**. The transmission lines could modify viewsheds and alter landscape characteristics to viewers on the lands listed above with special management designations and to travelers along several scenic byways in the area.
- **BLM Visual and Land Use Plan Conformity**. Conformance with land use plans and BLM VRM Class Objectives, would require amendments to the Socorro and Mimbres Resource Management Plans.
- **Sensitive Land Uses**. The areas are mostly rural, but there are constraints and public concern where the transmission lines would cross existing and authorized residential land uses, as well as where they would be located nearby to recreational facilities, such as the lands listed above with special status.
- **Other Federal Agencies**. Coordination and separate NEPA decisions by the Bureau of Indian Affairs and Bureau of Reclamation would be required to grant right-of-way crossings of canals or other facilities, such as the San Carlos Irrigation Project canal system and Reclamation lands along the Rio Grande and along the Central Arizona Project canal.

Transmission safety requirements may eliminate direct land use conflicts, because occupied land uses and high-voltage transmission lines cannot be co-located and safety requirements ensure adequate separation. Most existing agriculture can continue in and around transmission line rights of way, as the only disturbed area is individual tower footprints and, where needed, access roads. The visibility of transmission lines from protected uses is a potential issue, and this can sometimes be resolved by rerouting the lines around sensitive areas, using appropriate non-reflective materials, and micro-siting individual towers to reduce opportunities for skylining. Transmission lines also may need to be routed so as to avoid areas where they could pose an aviation hazard, such as around airports or military installations.

5.2 Cultural and Tribal Considerations in Siting Major Transmission

The following cultural and tribal resources impacts were identified for the transmission projects proposed to access Wyoming and New Mexico wind resources.

Transmission for Wyoming Wind Resources by 2030

- **National Scenic and Historic Trails**. The transmission line could cause significant adverse effects on historic properties for which visual setting is important, such as National Scenic and Historic Trails, including the Oregon, California, Mormon Pioneer, Pony Express, and Old Spanish National Historic Trails, as well as the Continental Divide National Scenic Trail.

- **Traditional Cultural Properties (TCPs)**. The transmission line would affect Native American TCPs and respected places, such as the Gypsum Cave TCP, which is held as sacred to the Nuwu (Paiute) people.
- **Tribal Land**. The transmission line would cross the Ute Indian Tribe of the Uintah and Ouray Reservation and would require Tribal approval.

Transmission for New Mexico Wind Resources by 2030

- **Cultural Landscape**. The transmission line would result in visual and cultural resource impacts to the Gran Quivira unit of the Salinas Pueblo Missions National Monument.
- **Archaeological Resources**. The transmission line could potentially impact seven known habitation sites and the McClellan Wash Archaeological District.
- **National Historic Trails**. The transmission line would cross the El Camino Real, Butterfield, Gila, Janos Copper, Zuñiga, Southern Pacific Mail, and General Cooke's Wagon Road/Mormon Battalion National Historic Trails.

5.3 Water Resources Consideration in Siting Major Transmission

All surface-disturbing activities have the potential to cause erosion that could result in adverse impacts to water resources. In addition, the following water-related impacts were identified for the major transmission projects proposed to access Wyoming and New Mexico wind resources.

Transmission for Wyoming Wind Resources by 2030

- **Floodplains**. There would likely be some locations where structures would be placed in floodplains, such as within the Bear River floodplain, which could negatively impact wetlands and riparian habitat and structures could be damaged by flooding.
- **Water Supply**. Any new water withdrawals in the watersheds of the Platte River, Utah Lake/Provo River, and Colorado River would require either participation in the recovery programs for those rivers (provided for in programmatic biological opinions for each) or a separate consultation with the USFWS.

Transmission for New Mexico Wind Resources by 2030

- **Floodplains**. There would likely be some locations where structures would be placed in floodplains, such as within the Rio Grande floodplain, which could negatively impact wetlands and riparian habitat and structures could be damaged by flooding.

6. Environmental Study Results

In 2020, we assume no incremental buildout of renewable resources or transmission beyond what is already planned to meet the state's 33% RPS by 2020. With limited regionalization in 2020, we also assume no incremental renewable energy development and no associated ground disturbance. Therefore, there would be no effects to land use or biological resources from the implementation of the limited regional market. However, there would be changes associated with how the wholesale electric system might respond to the limited regional market in 2020 (CAISO + PAC), in terms of changes to the operations of existing resources. These operational changes would have effects on water use and air emissions.

The 2020 results for water use and emissions are summarized as follows:

- By achieving a small decrease in fossil fuel use for electricity production in California, limited regionalization in 2020 results in a small but beneficial decrease in the electric power sector's use of water resources (water used by electricity generation decreases by 1.5% statewide).
- Limited regionalization in 2020 reduces air pollutant emissions from natural gas-fired electricity generation in California on average (decrease 0.5% to 1.2% statewide, depending on pollutant), depending on the dispatch of the fleet of natural gas–fired power plants. Certain air basins would experience slight increases in PM2.5 and SO_2 emissions (increase 0.4% in San Joaquin Valley and South Coast air basins and increase 0.7% in Mojave Desert air basin), but the San Joaquin Valley and South Coast air basins would experience greater benefits through decreases in NOx, which is a precursor to both ozone and PM2.5.

By 2030, a significant incremental renewable generation buildout would be required to satisfy California's 50% RPS under any scenario. This buildout would require developing land, which is associated with ground disturbance and environmental effects. Changes associated with how the wholesale electric system might respond to regionalization would also be a part of the 2030 scenarios. The potential changes in land use and potential impacts to biological resources depend on the geographic distribution of the portfolios modeled in the 2030 scenarios. With regionalization, we find that land use and the acreage required decreases in California by 42,600 acres in the Regional 2 scenario and by 73,100 acres in the Regional 3 scenario. Outside of California, land use decreases by 31,900 acres in Regional 2, and increases by at least 69,300 acres in Regional 3, largely due to assumed wind resource development. While the development footprint associated with 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 by the access roads and foundations for wind turbines while the remainder of the site may remain undisturbed and available for other uses. Under Scenario 3, additional land and acreage would be devoted to out-of-state transmission right-of-way to integrate the high-quality out-of-state renewable generation into the regional power system. Results for Regional 2 versus Regional 3 illustrate an inherent tradeoff of building renewables for RPS in state versus out of state.

The 2030 results for water use and emissions are summarized as follows:

- Scenarios Regional 2 and Regional 3 decrease the amount of water used by power plants statewide, when compared with Current Practice Scenario 1. By decreasing fossil fuel use for electricity production in California, regionalization results in a beneficial decrease in the electric power sector's use of California water resources (decrease by 4.0% to 9.7% statewide).
- Scenarios Regional 2 and Regional 3 decrease the emissions of NOx, PM2.5, and SO_2 from power plants statewide and also decrease these emissions in several air basins with nonattainment designations, because of the changed dispatch of the fleet of natural gas-fired power plants. In particular, the San

Joaquin Valley, South Coast, Mojave Desert, and Salton Sea air basins experience decreased emissions of all pollutants when compared with Current Practice Scenario 1. Modeling for 2030 shows very small increases in PM2.5 and SO_2 emissions in certain other locations, namely the San Francisco Bay and North Central Coast air basins, although these other locations would experience greater benefits through decreases in NOx. Statewide, combustion-fired electric generation comprises a small portion or roughly 1% to 2% of California's average daily inventories of NOx and PM2.5; this means that the transformation into regional wholesale electricity market is likely to have a negligible impact on California's overall criteria air pollutant inventories.

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Appendices

Appendix 1. Study Areas for In-State Renewable Resources

Appendix 2. Study Areas for Out-of-State Renewable Resources

Appendix 1: California Renewable Study Areas

RESOLVE Portfolios of Inside-California Resources

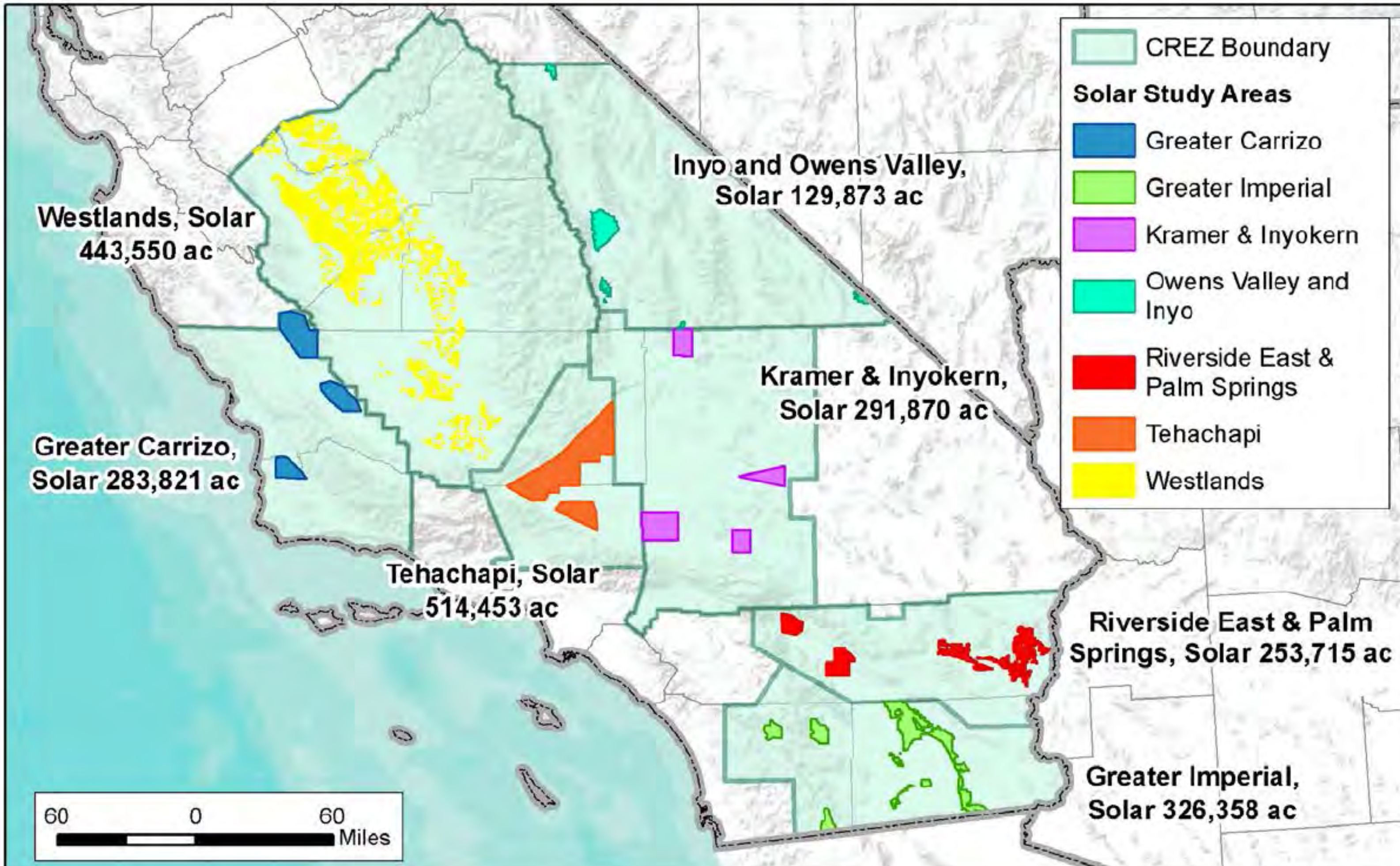
- This presents various "study areas" in Aggregated CREZs as proxy locations
- Need to focus environmental study on meaningful locations
- Need to cover the following potential resource regions in California:

– Greater Carrizo	Solar and Wind
– Central Valley North, Los Banos	Wind
– Greater Imperial	Solar, Wind and Geothermal
– Kramer, Inyokern	Solar
– Owens Valley, Inyo	Solar
– Riverside East, Palm Springs	Solar and Wind
– Solano	Wind
– Tehachapi	Solar and Wind
– Westlands	Solar

General Methodology - Solar

- Use RPS Calculator solar potential that avoids RETI Category 1 lands
- Review renewable resource and siting considerations
- Review local / state / federal renewable planning documents and processes
- Review existing and planned renewable projects to help determine viability
- Draft polygons of sufficient size / shape as proxy locations to facilitate study of portfolios
- Tailor polygons to eliminate clear “no go” areas within the boundaries (Protected Areas Data: National Parks, National Forest, BLM wilderness and ACECS, State Parks, and military)

Solar Overview



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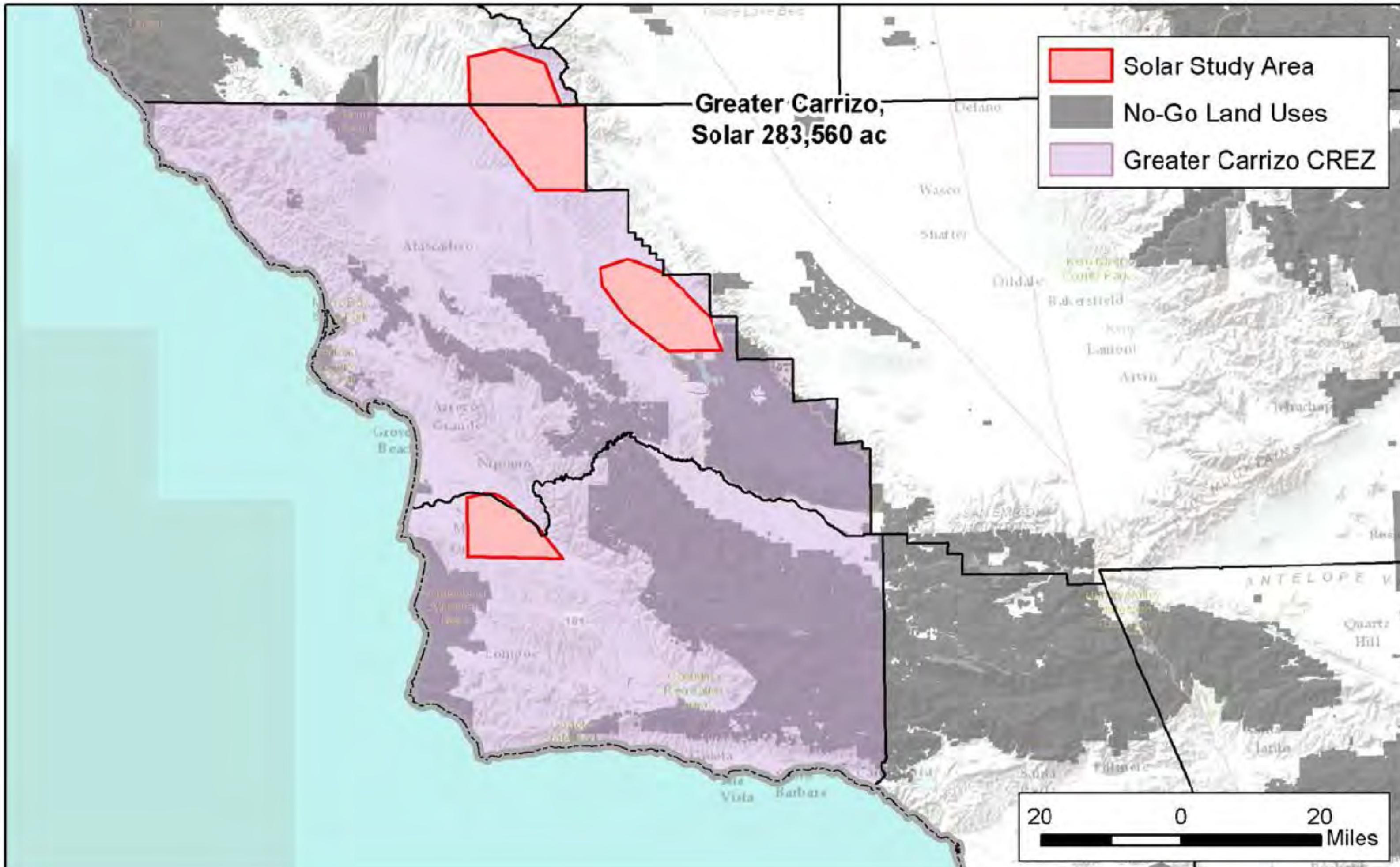
Greater Carrizo Solar, Overview

- Solar resource: throughout most of the CREZ
- Slope consideration: lots of rolling hills with some large valleys in eastern part of CREZ
- Existing successful large development: mainly in Carrizo Plains and California Flats
- Tailored three polygons of representative areas
  - California Flats: San Luis Obispo and Monterey counties
  - Carrizo Plain: San Luis Obispo County
  - Santa Maria: northern Santa Barbara County

Greater Carrizo Solar



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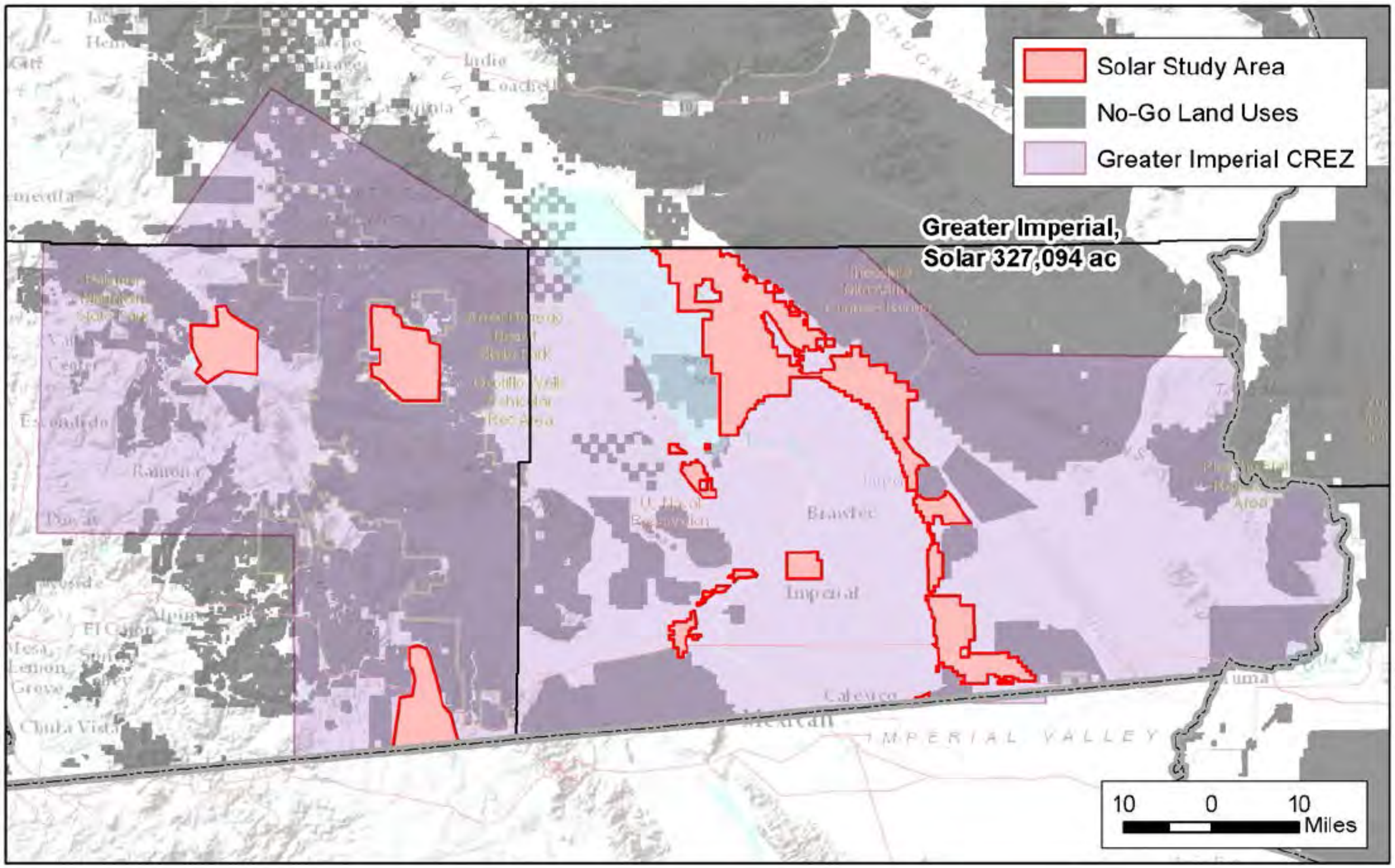
Greater Imperial Solar, Overview

- Solar resource: throughout all of the CREZ
- Slope consideration: lots of rocky hills in the western part of the CREZ
- Existing successful large development: mainly in Imperial Valley and Borrego Valley
- Used existing planning from DRECP and Imperial County General Plan
- Tailored four representative areas
  - Imperial Valley: DRECP DFAs and General Plan Energy Overlay
  - San Diego County: Boulevard, Borrego Springs, and Warner Springs

Greater Imperial Solar



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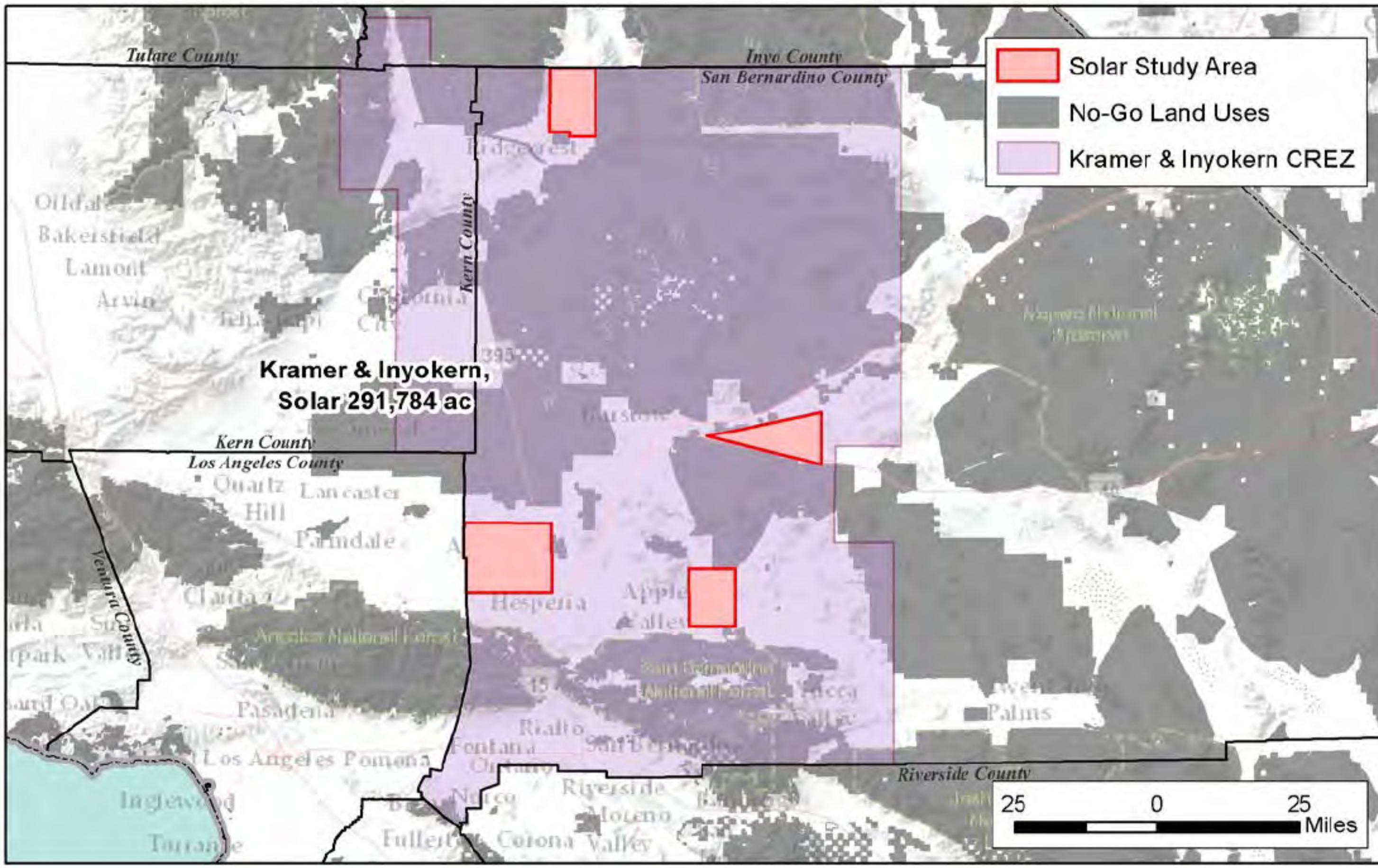
Kramer & Inyokern Solar, Overview

- Solar resource: covers entire CREZ
- Slope consideration: primarily flat valleys with some mountains
- Much of the CREZ is encumbered with land designations that prohibit solar (such as wilderness or ACECs / NLCS under the DRECP)
- Tailored four polygons covering a variety of representative areas
  - Searles Valley: DRECP Development Focus Area on BLM land
  - Barstow: private agriculture land
  - Lucerne Valley and Adelanto: rural residential / private undeveloped land

Kramer & Inyokern Solar



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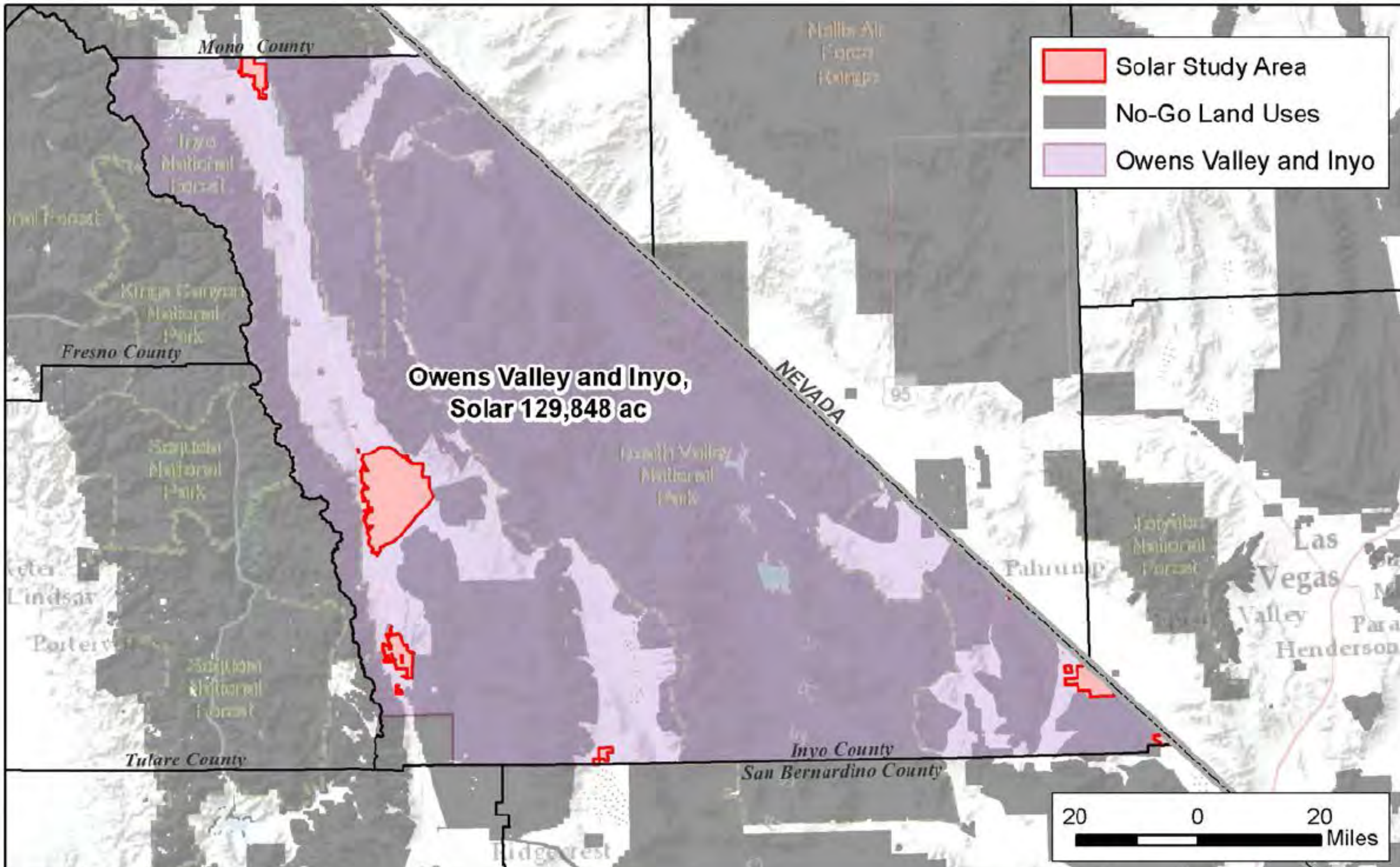
Owens Valley & Inyo Solar, Overview

- Solar resource: throughout all of the CREZ
- Slope consideration: majority of the CREZ is mountainous with a valley running through the western side and other smaller valleys
- No existing large development but some projects proposed in valleys
- Used existing planning from DRECP and Inyo County General Plan
- Tailored six representative areas
  - Owens Valley: DRECP DFAs and General Plan Solar Energy Development Areas
  - Eastern border: Solar Energy Development Areas near Nevada

Owens Valley & Inyo Solar



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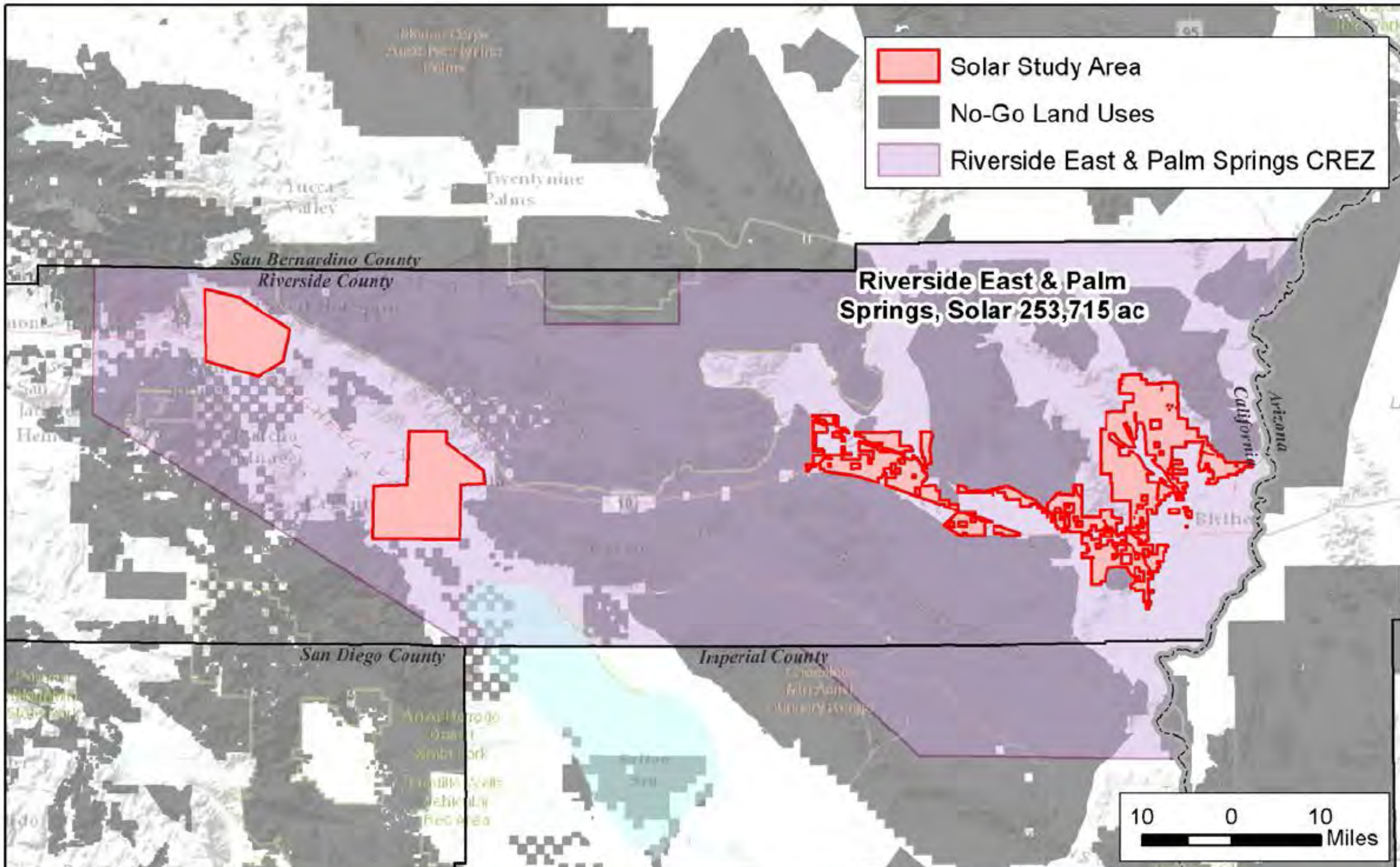
Riverside East & Palm Springs Solar, Overview

- Solar resource: abundant, most of the CREZ
- Slope consideration: many valleys surrounded by mountains
- Tailored three polygons to allow for flexibility for development (size and land use)
  - Eastern Riverside: used DRECP development focus area plus private land in Desert Center
  - Indio: private, agriculture land
  - Palm Springs region: private, undeveloped or existing infrastructure land

Riverside East & Palm Springs Solar



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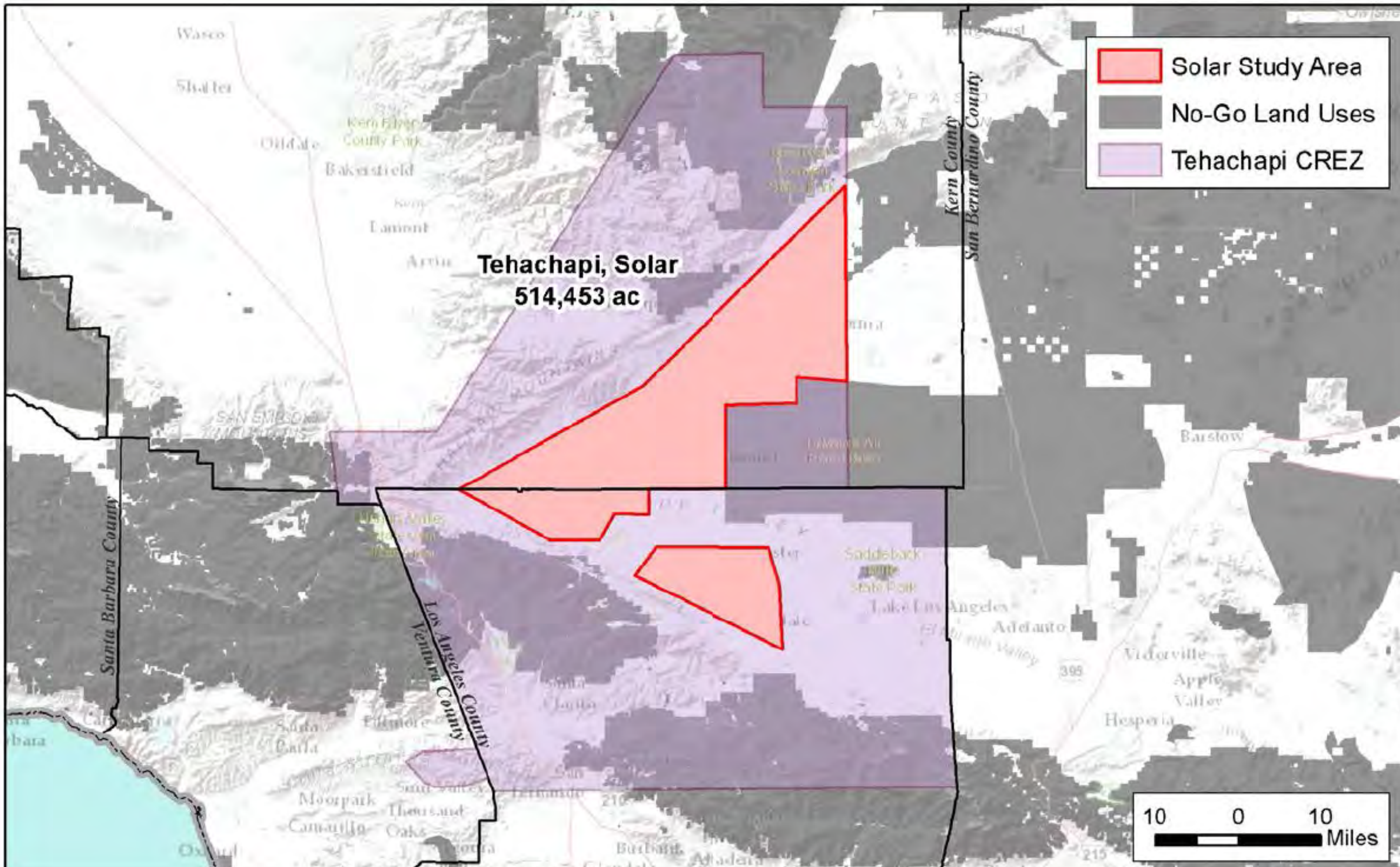
Tehachapi Solar, Overview

- Solar resource: covers entire CREZ
- Slope consideration: western part of CREZ has steep slopes
- Considered the Draft DRECP DFAs in Kern and Los Angeles County
- Incorporated the Los Angeles County Renewable Energy Ordinance exclusion areas
- Tailored three polygons with flexibility in terms of size and land use
  - Kern County: used DRECP draft development focus area / RPS solar layer
  - Los Angeles County (two polygons): private land, some agriculture

Tehachapi Solar



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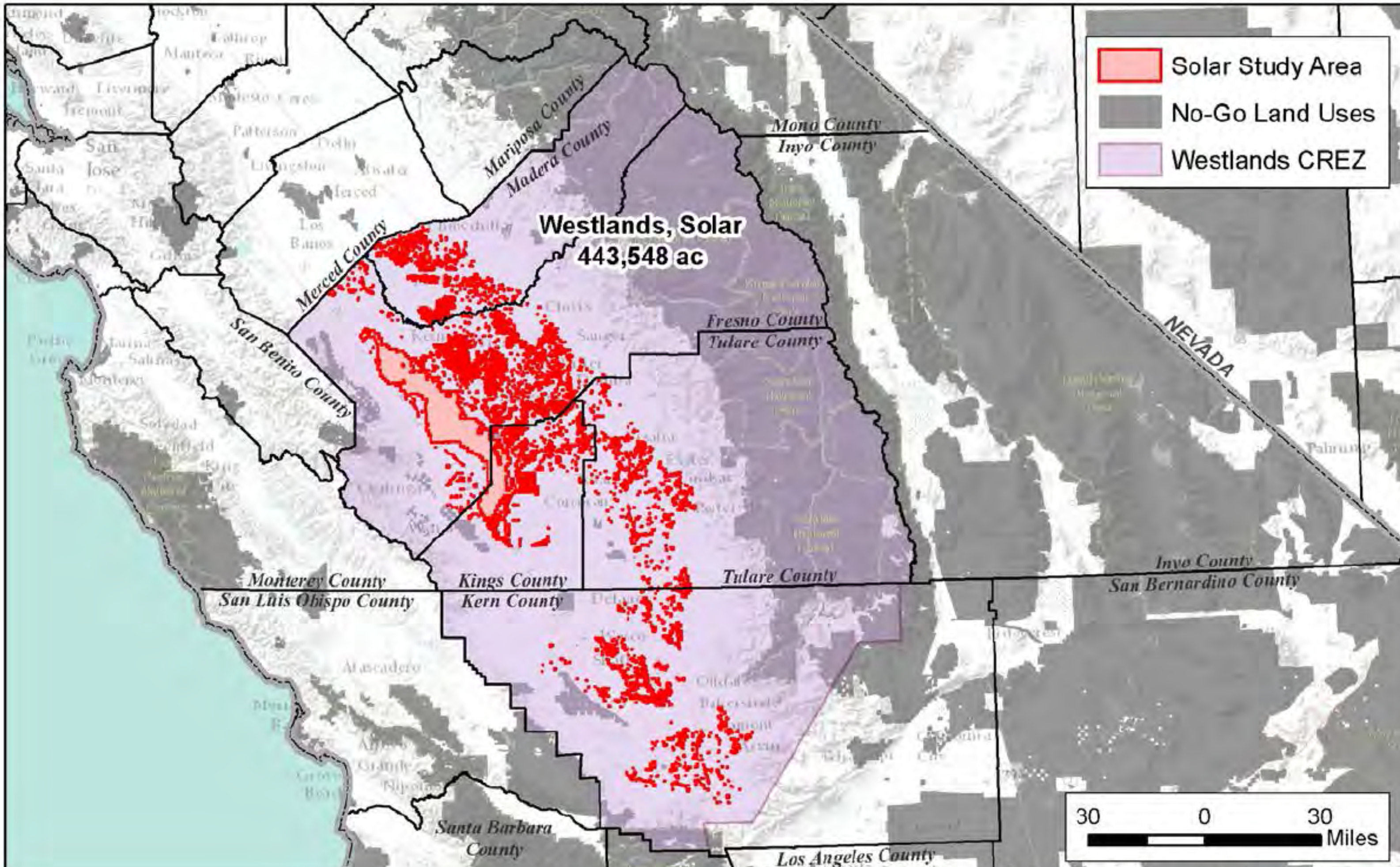
Westlands Solar, Overview

- Solar resource: covers the majority of the CREZ
- Slope consideration: valley is flat but surrounded by rolling hills on the eastern and western boundaries of the CREZ
- Use the San Joaquin Valley collaborative effort, including 3 categories from the “least-conflict lands”:
  - Priority least conflict
  - Least conflict
  - Potential least conflict

Westlands Solar



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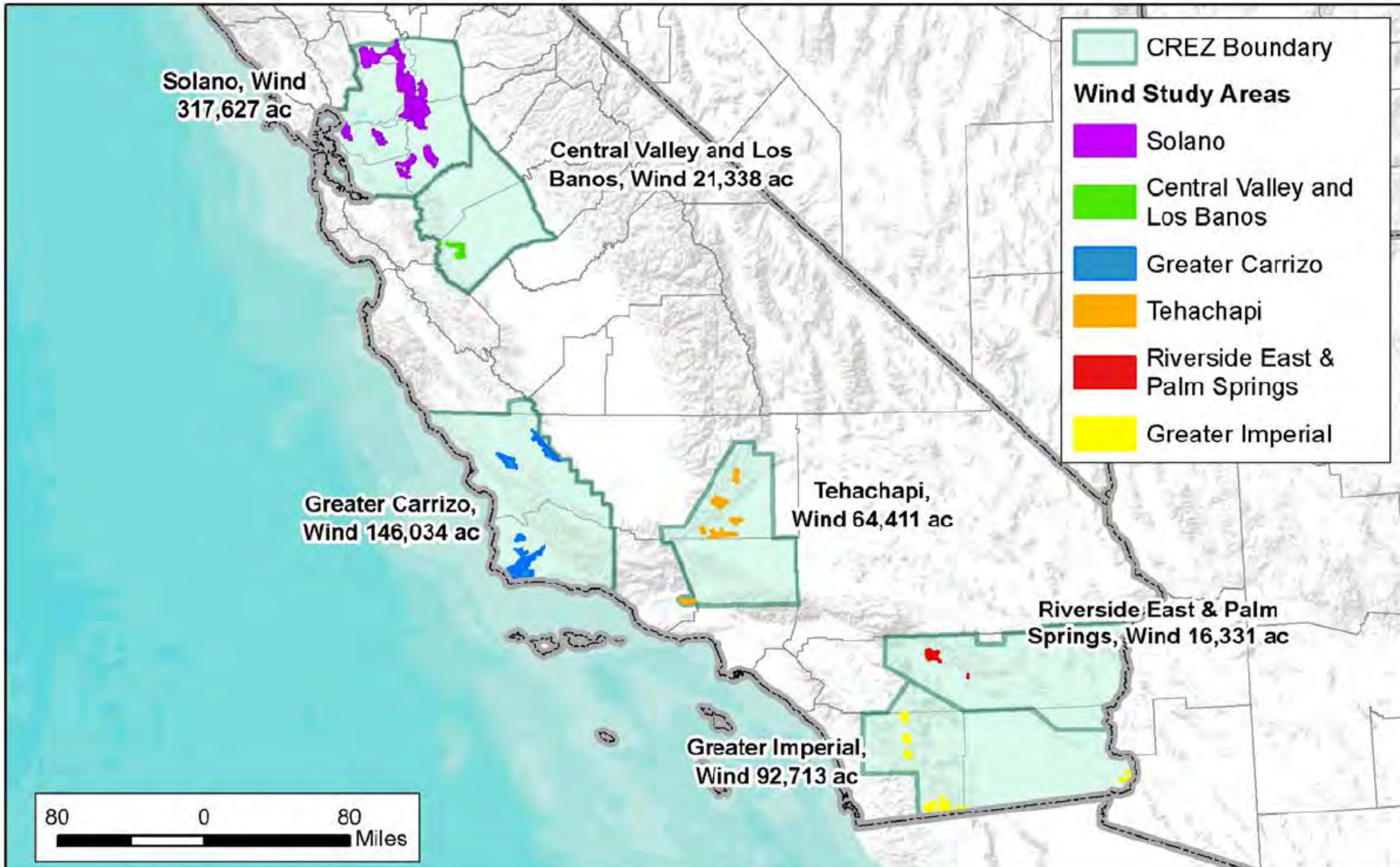
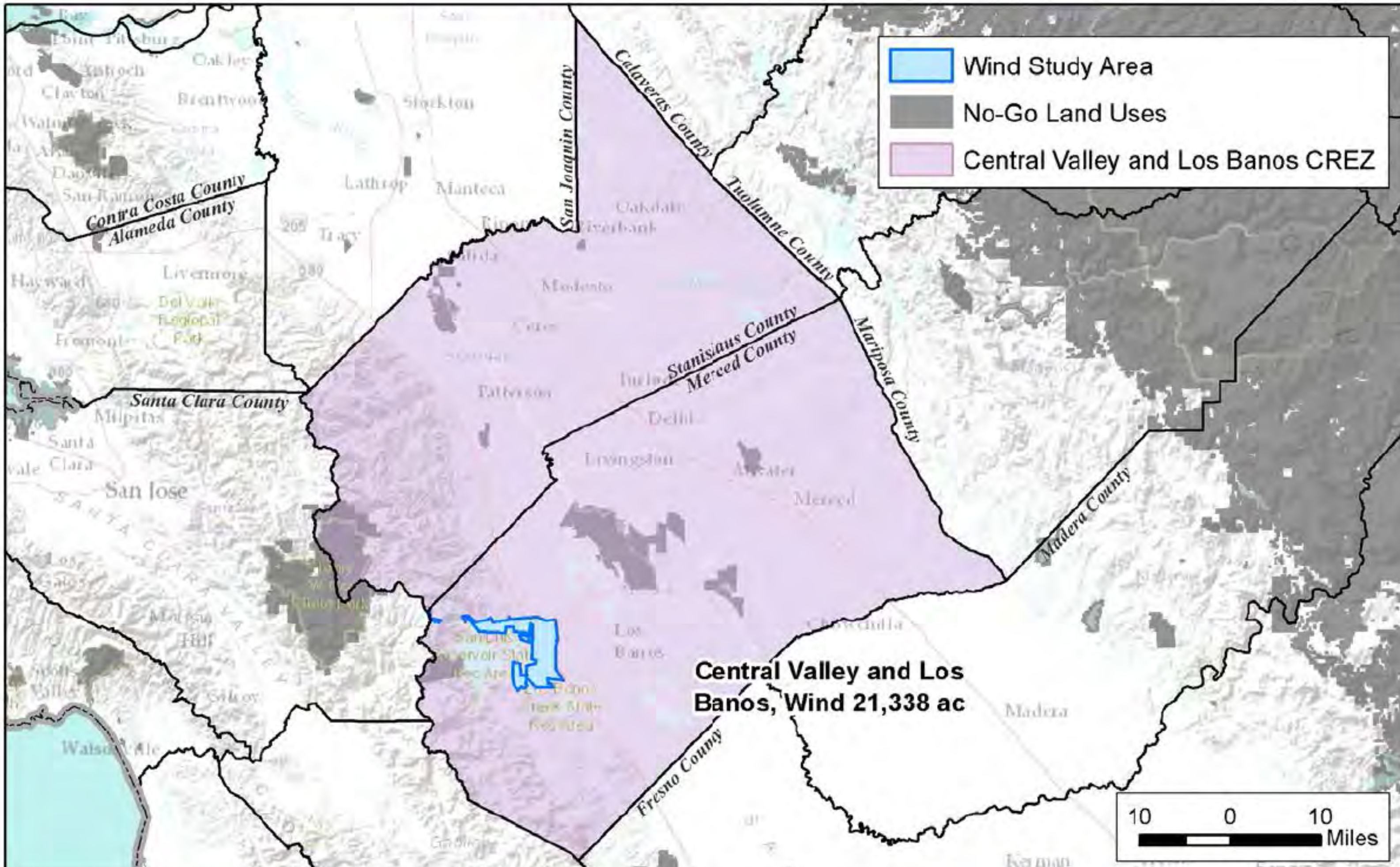
General Methodology – Wind and Geothermal

- Use RPS Calculator wind potential polygons
- Review local / state / federal renewable planning documents and processes and eliminated areas where wind is likely to be prohibited
  - Tehachapi CREZ: Los Angeles County prohibited wind within the county as part of the Renewable Energy Ordinance
  - Riverside East, Palm Springs and Greater Imperial CREZs: DRECP prohibits wind within ACEC and NLCS designations
  - All other CREZs use RPS Calculator polygons with no tailoring
- Review local and federal planning documents and included areas open to geothermal
  - Included DRECP DFAs
  - Included Imperial County renewable zoning ordinance overlay

Wind Overview



Central Valley North & Los Banos Wind



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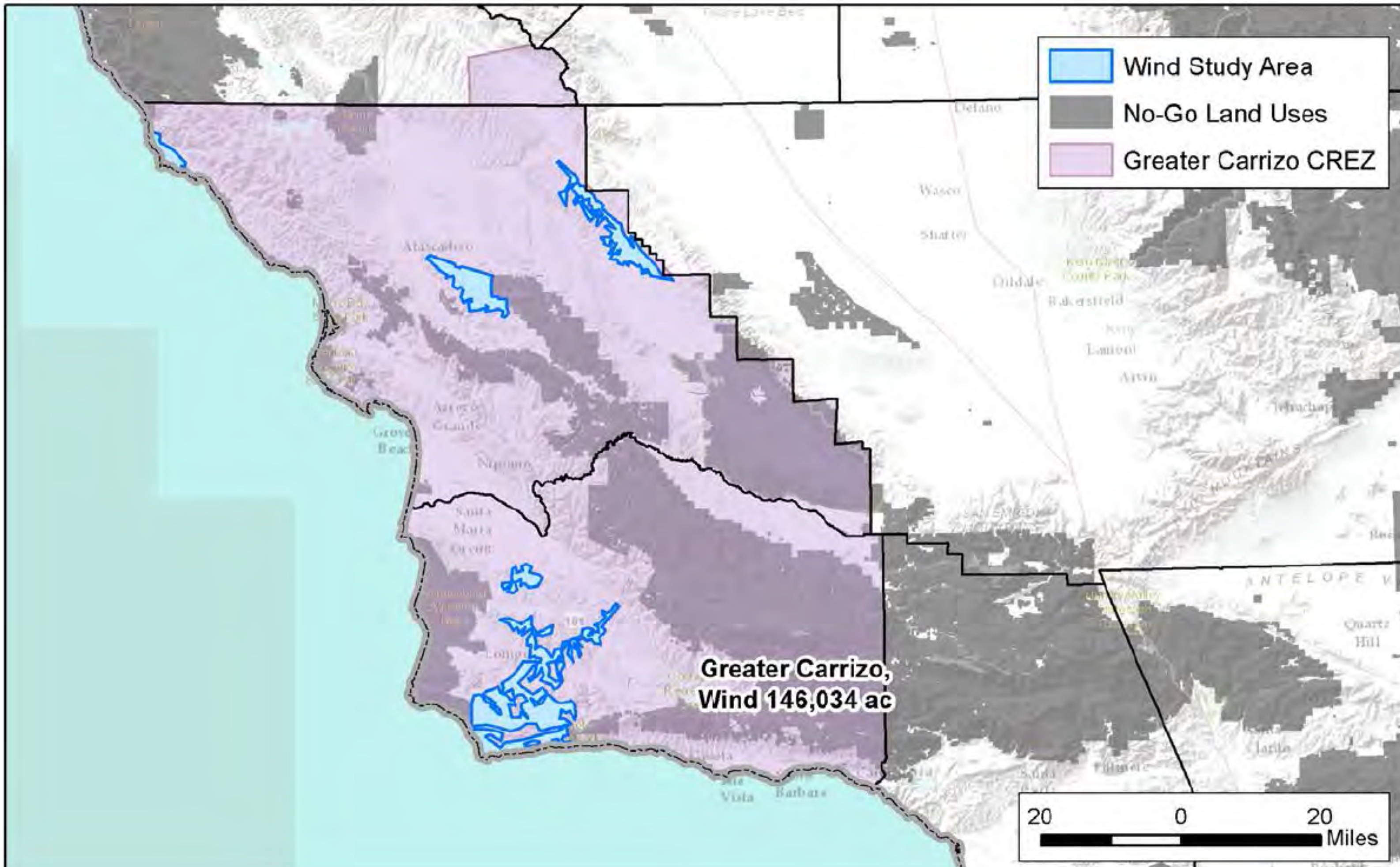
Greater Carrizo Wind



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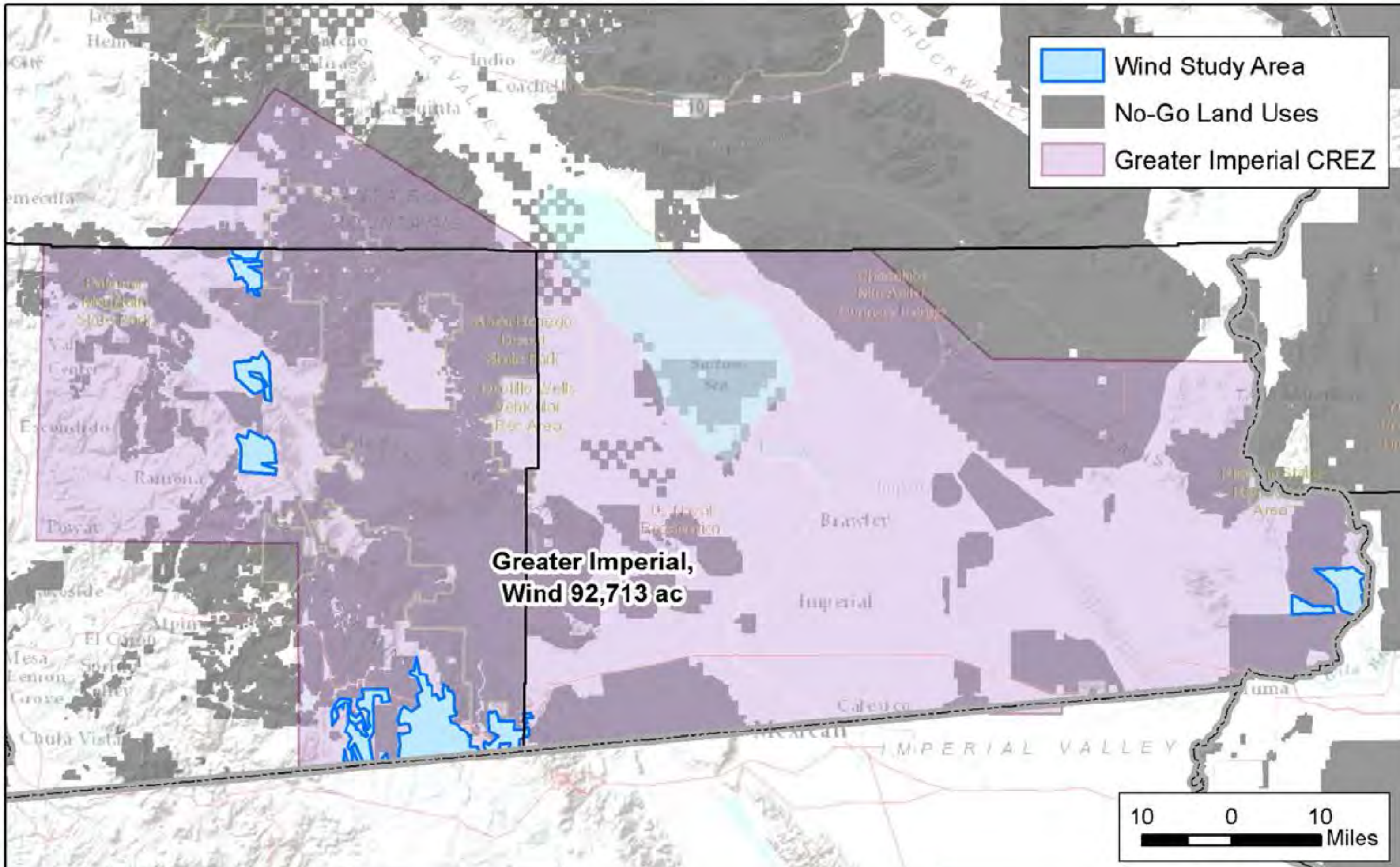
Greater Imperial Wind



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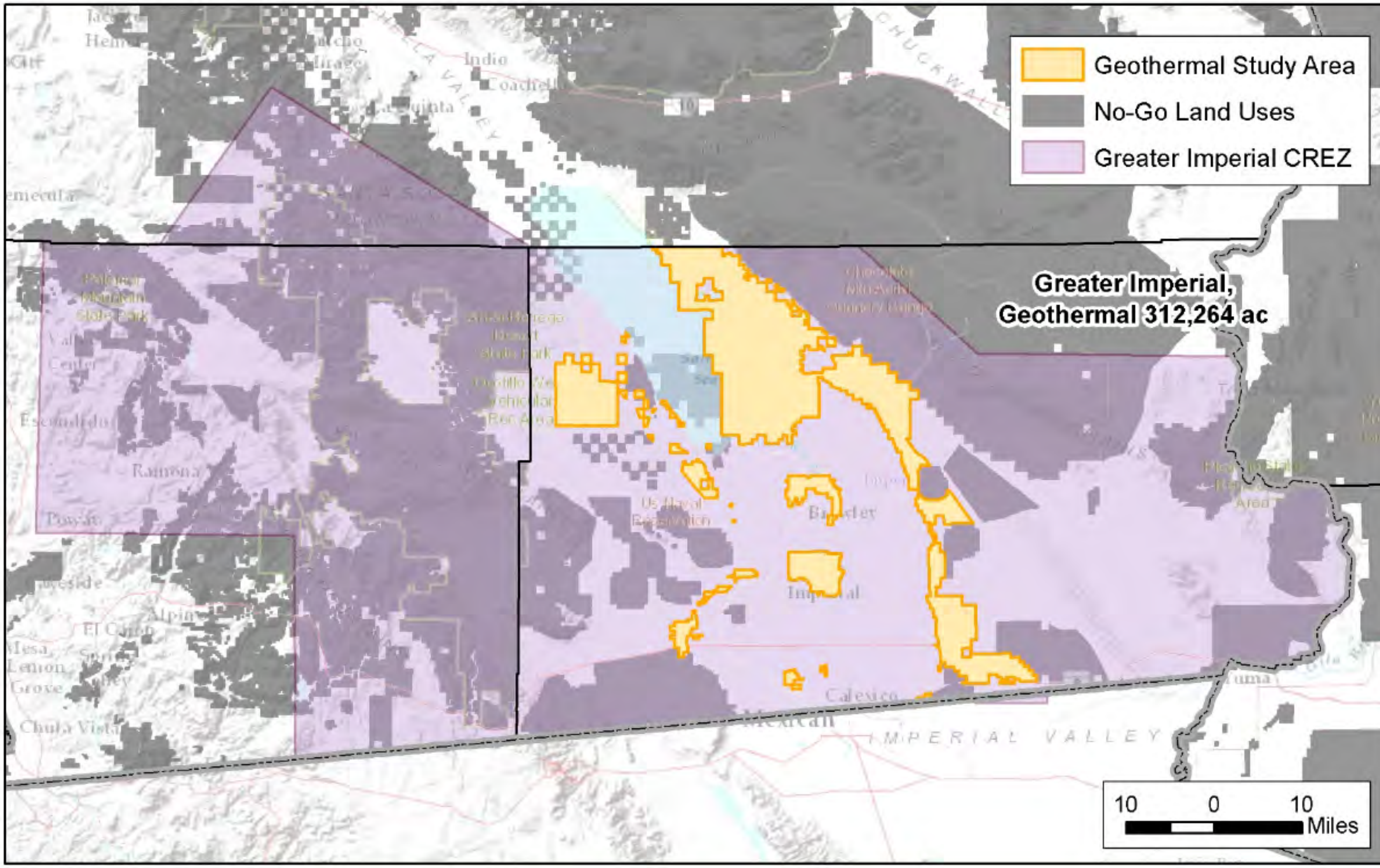
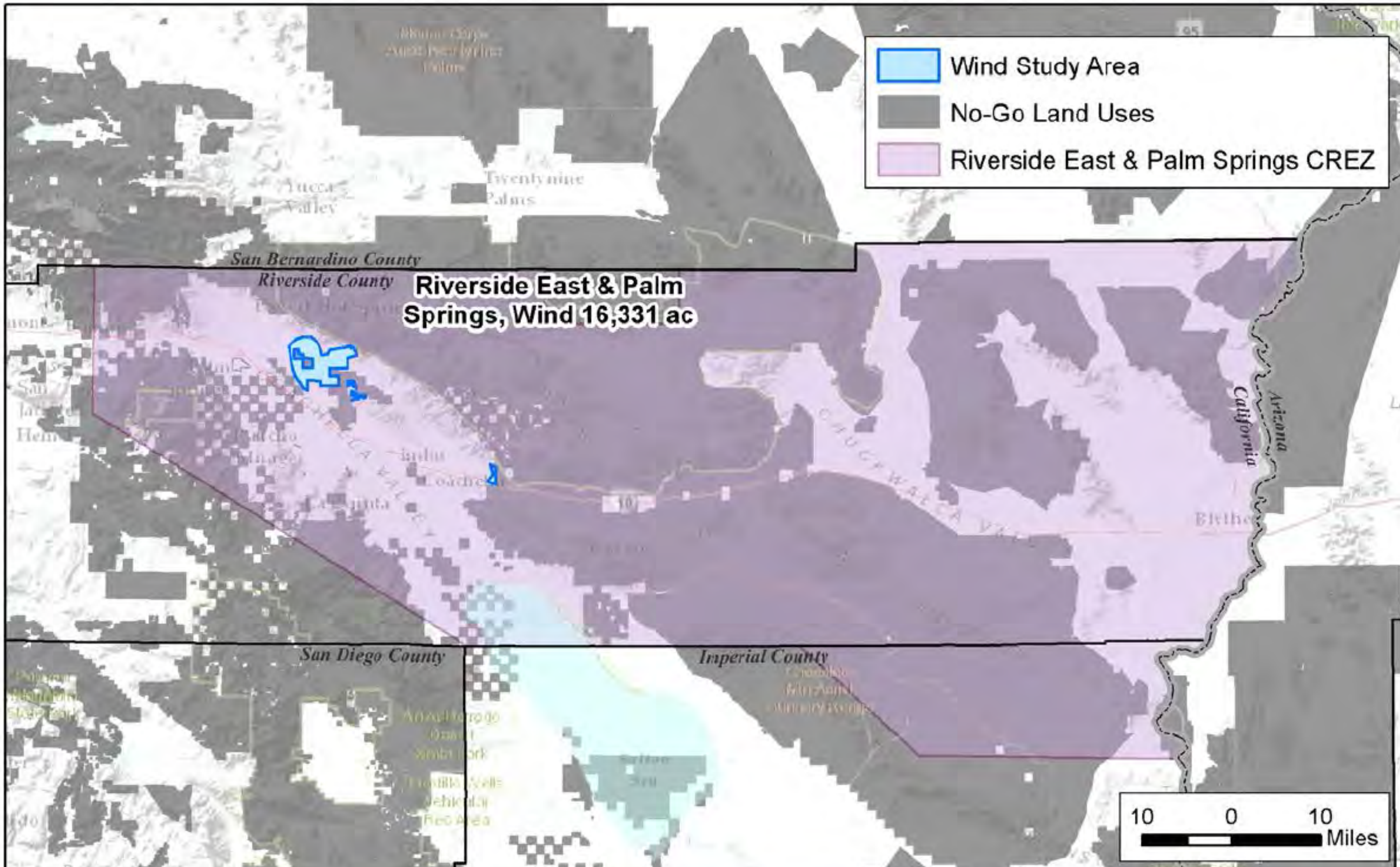
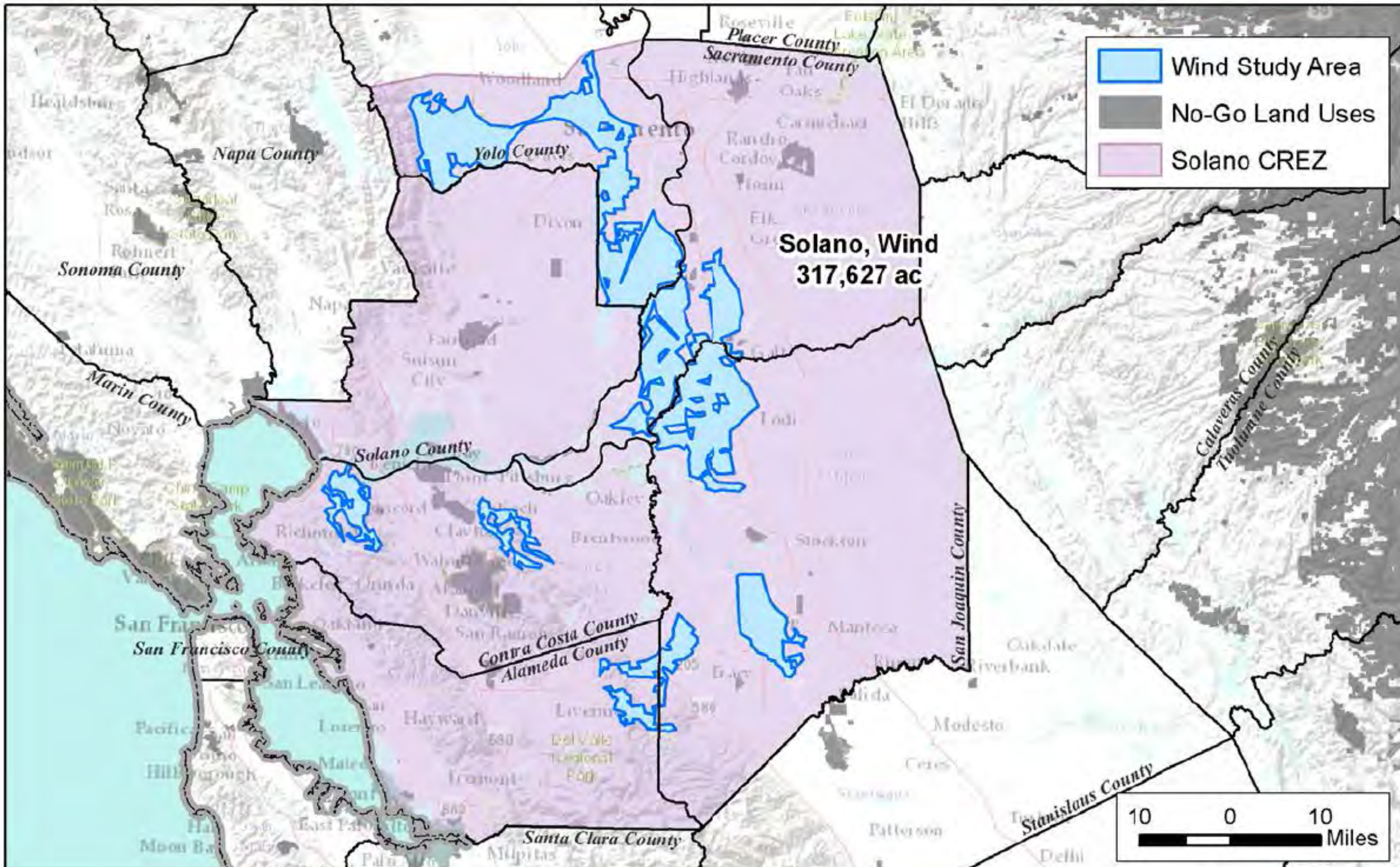
Greater Imperial Geothermal



Riverside East & Palm Springs Wind



Solano Wind



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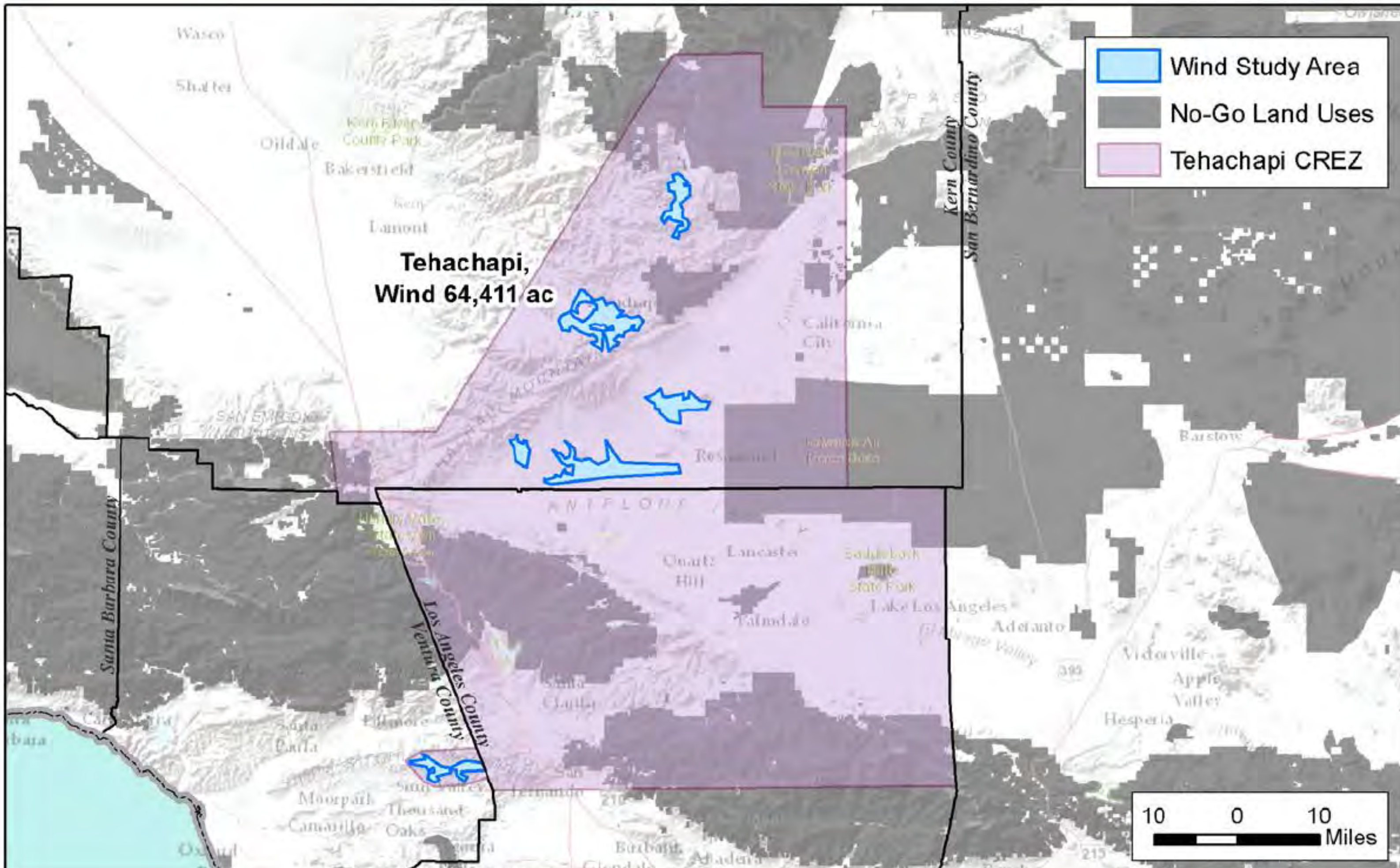
Tehachapi Wind



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Appendix 2: Out of State Renewable Study Areas

RESOLVE Portfolios include Out of State Resources

- This presents various "study areas" as proxy locations
- Need to focus environmental study on meaningful locations
- Need to cover five potential regions of Out of State Resources:
  - Southwest Solar (Arizona)
  - Northwest Wind (Oregon)
  - Utah Wind
  - Wyoming Wind
  - New Mexico Wind

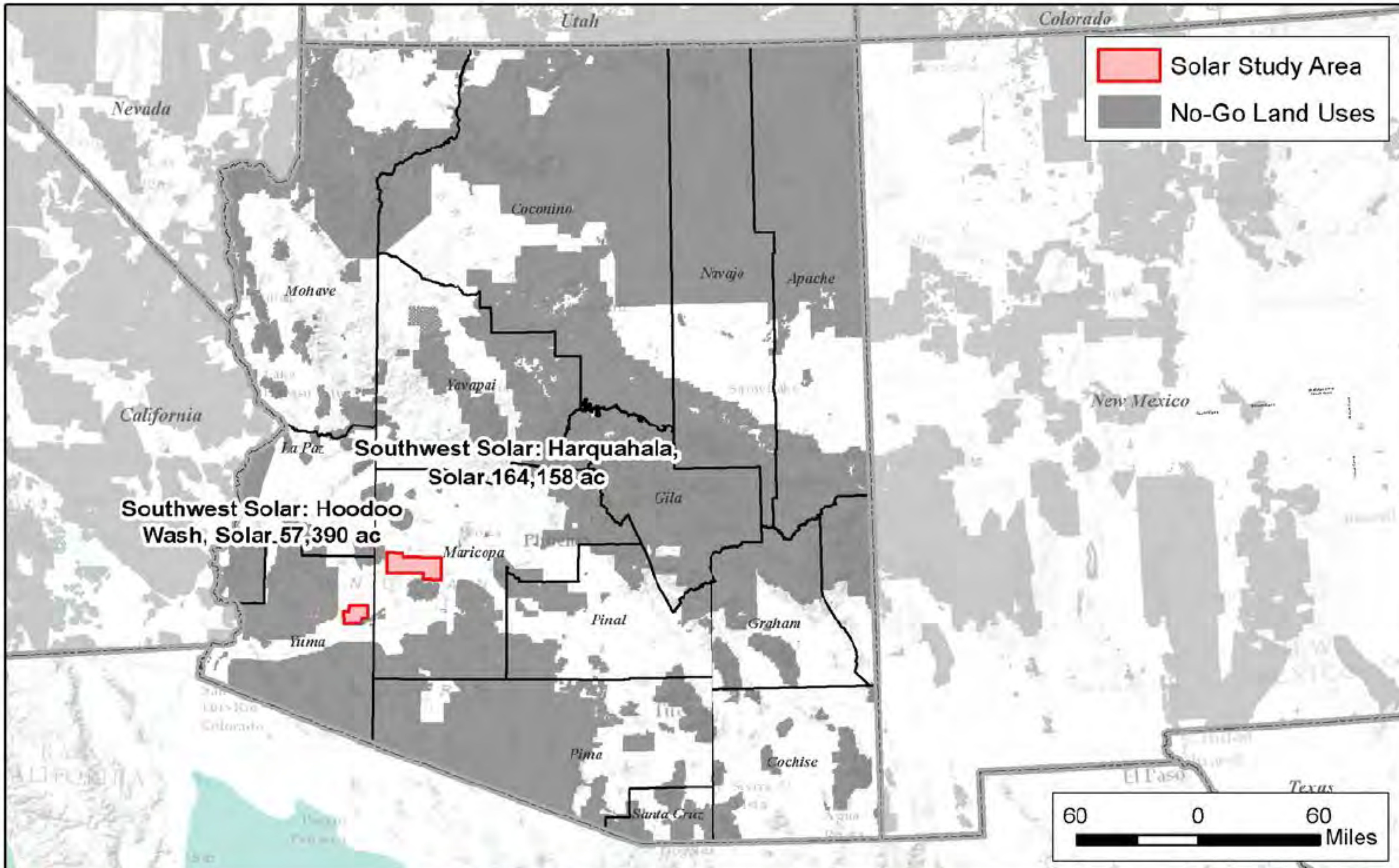
General Methodology

- Review renewable resource and siting considerations
- Review state / federal renewable planning documents and processes
- Review existing and planned transmission
- Review existing and planned renewable projects to help determine viability of renewable development
- Draft polygons of sufficient size / shape as proxy locations to facilitate study of portfolios
- Tailor polygons to eliminate clear “no go” areas within the boundaries (Protected Areas Data: National Parks, National Forest, BLM wilderness and ACECS, State Parks, and military)

Southwest Solar (Arizona), Overview

- Solar resource: abundant, most of the State
- Reviewed previous BLM Renewable Energy Development Areas
- Considered likely substation interconnection points, including:
  - Harquahala, Hassayampa, Delaney or Palo Verde Hub
  - Hoodoo Wash
- Tailored two polygons where either polygon could allow for more than 500 MW of solar energy with substantial flexibility

Arizona Solar, Overview



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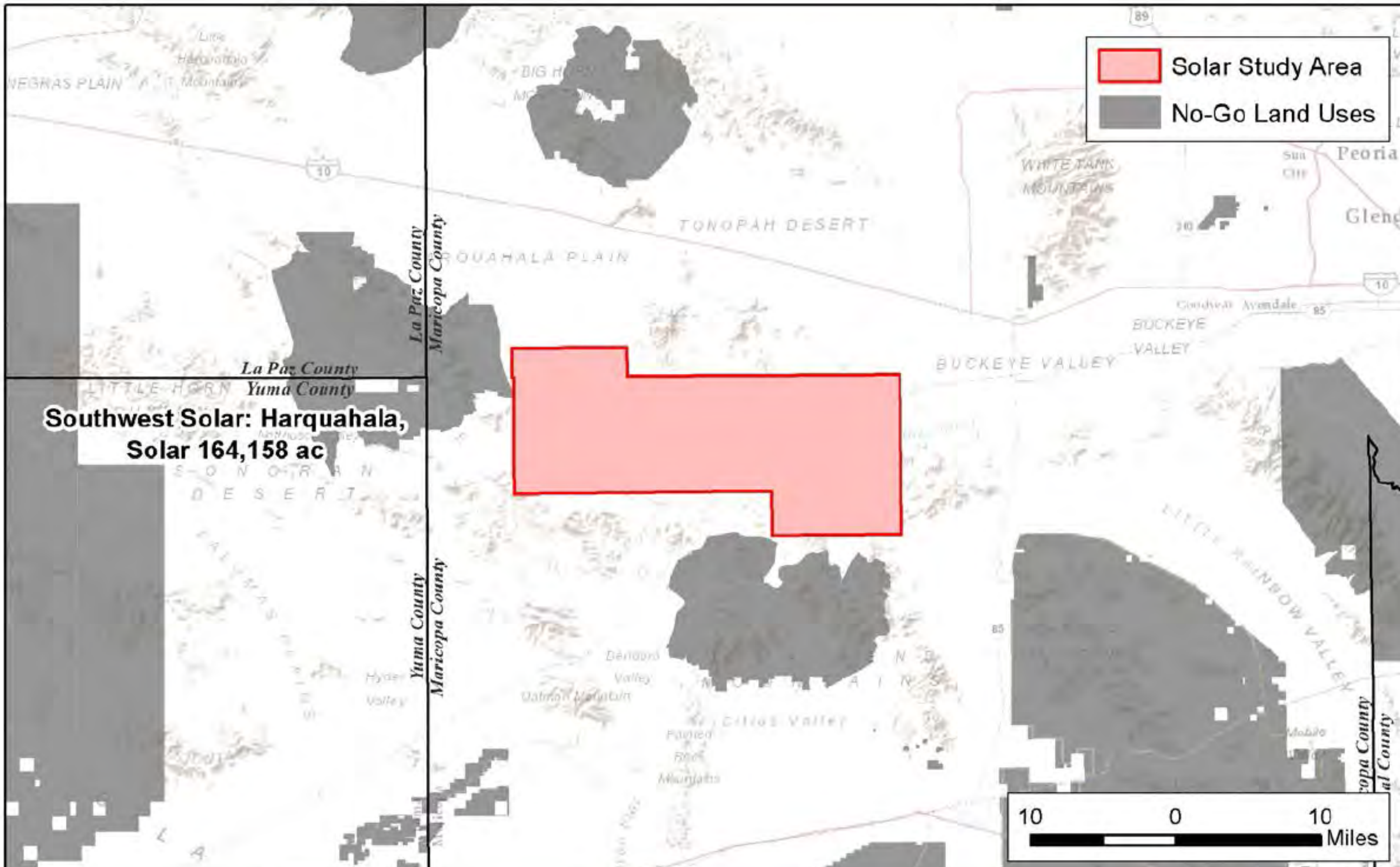
Arizona Harquahala



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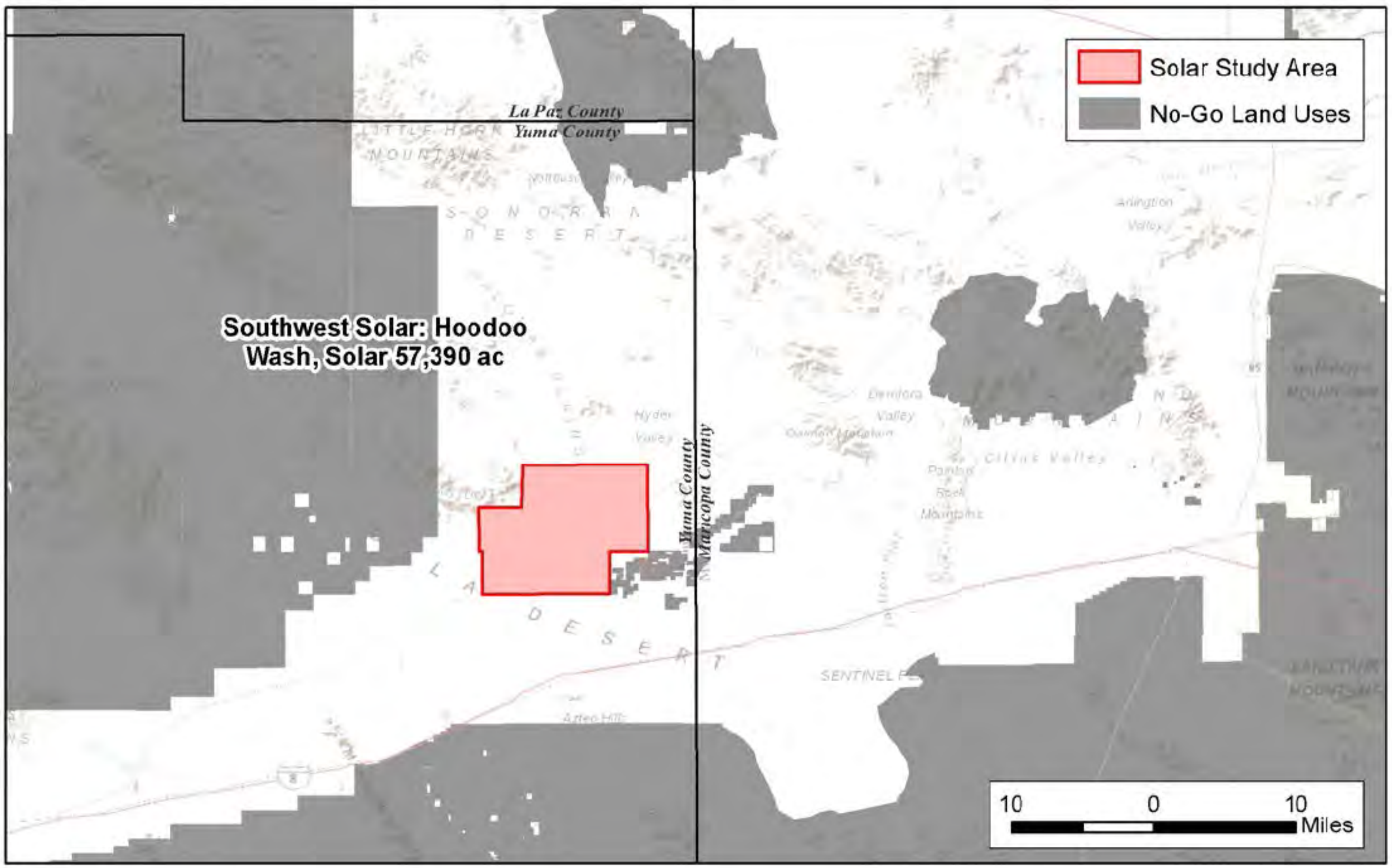
Arizona Hoodoo Wash



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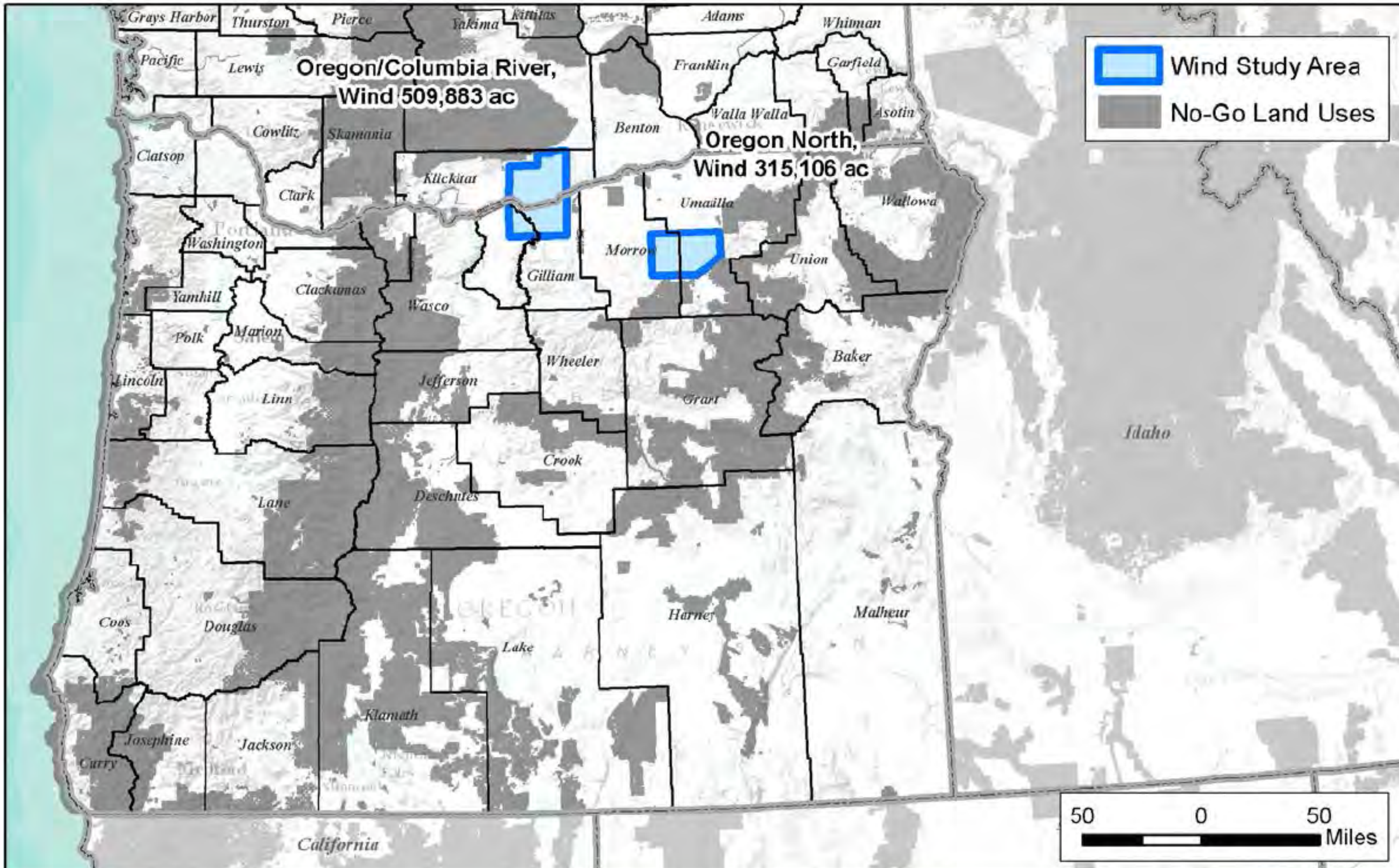
Northwest Wind (Oregon), Overview

- Wind resource: scant potential in south
- Existing successful development: mainly in Columbia Gorge
- Previous BLM planning document and earlier process regarding
  - Existing ROWs
  - Renewable Energy Development Challenges and Opportunities
- Tailored two polygons of representative areas
  - Oregon side of the Columbia Gorge, outside of existing sites
  - Southern Oregon BLM land, near existing wind testing ROWs and transmission

Oregon Wind, Overview



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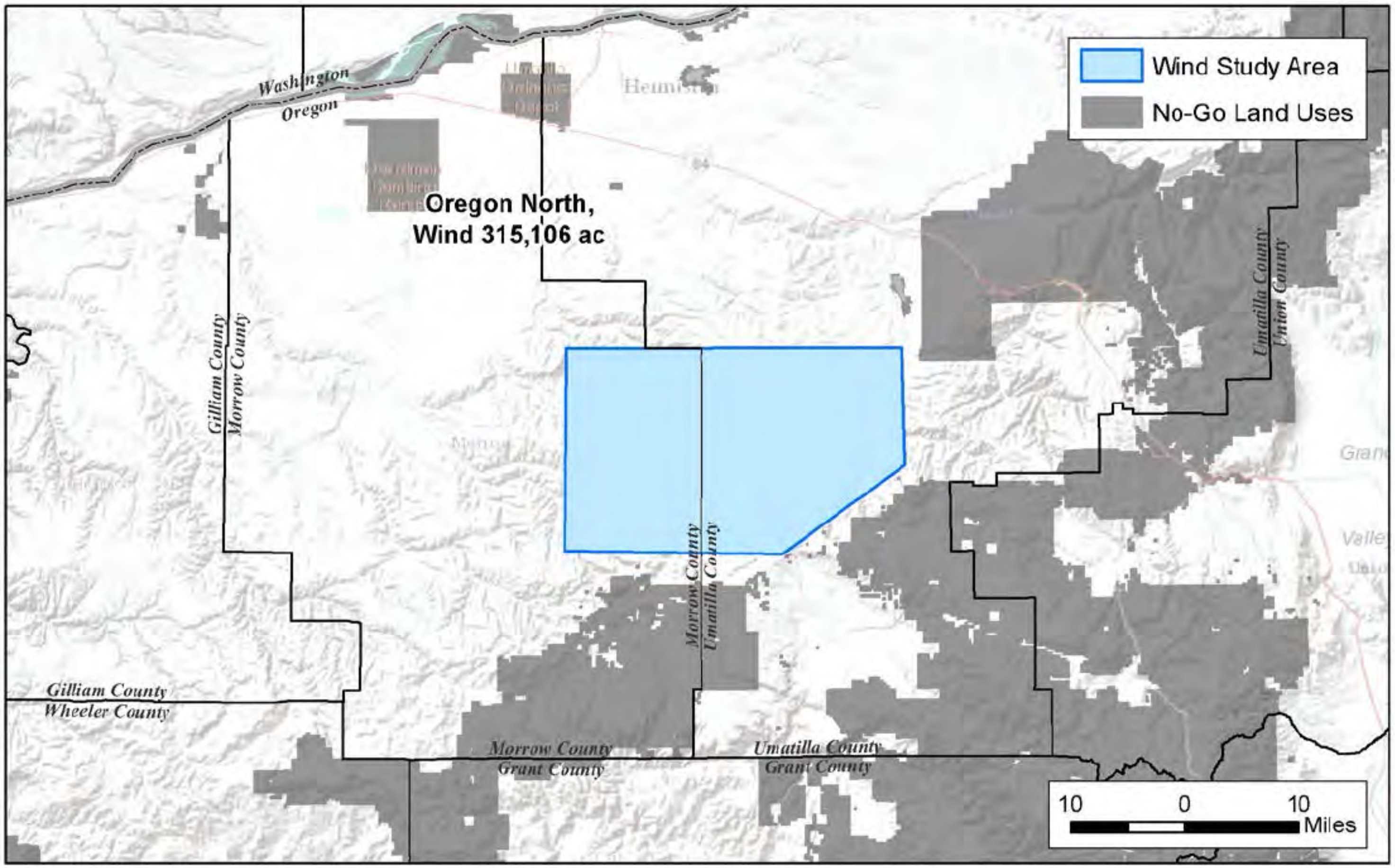
Oregon North



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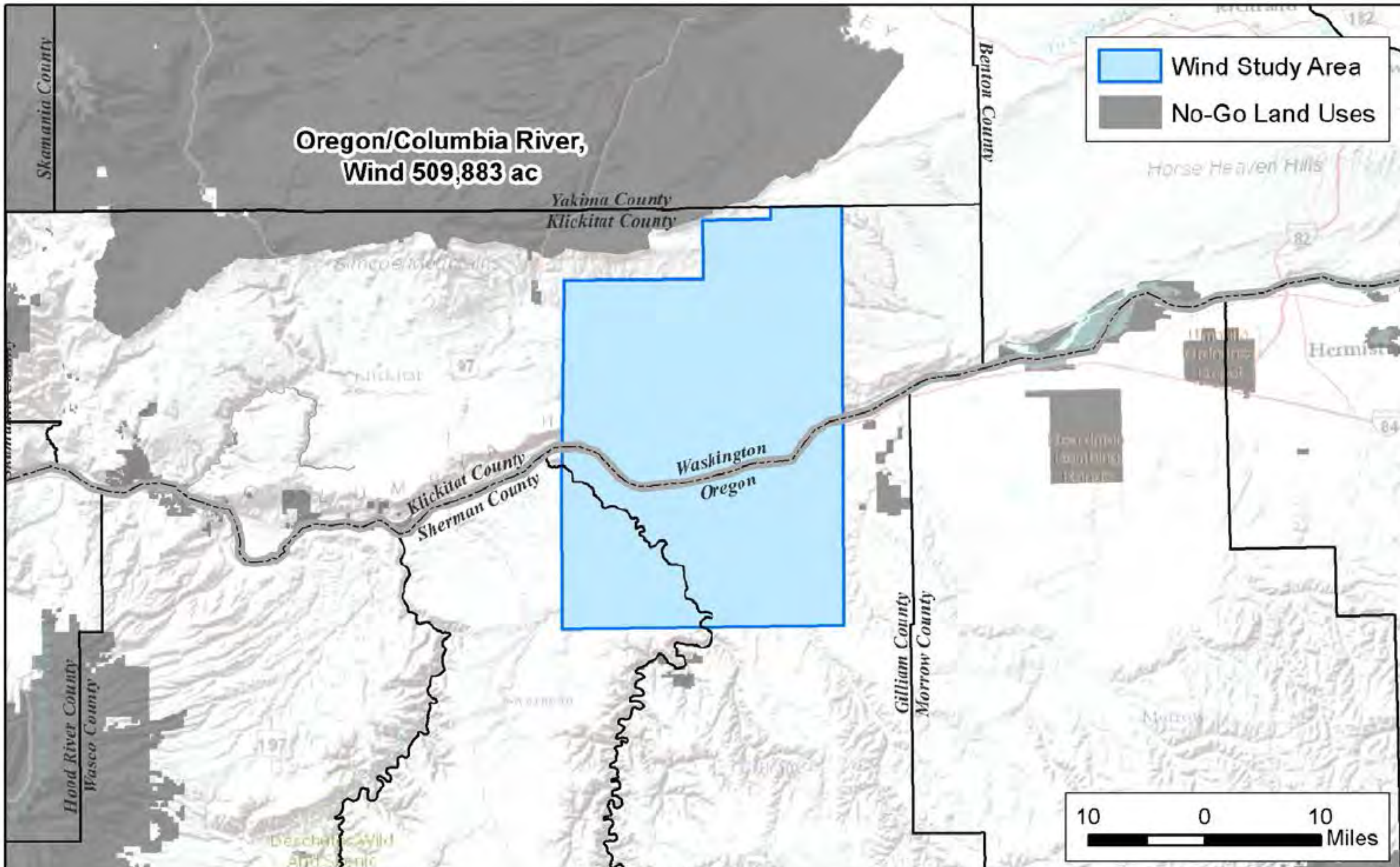
Columbia River Gorge



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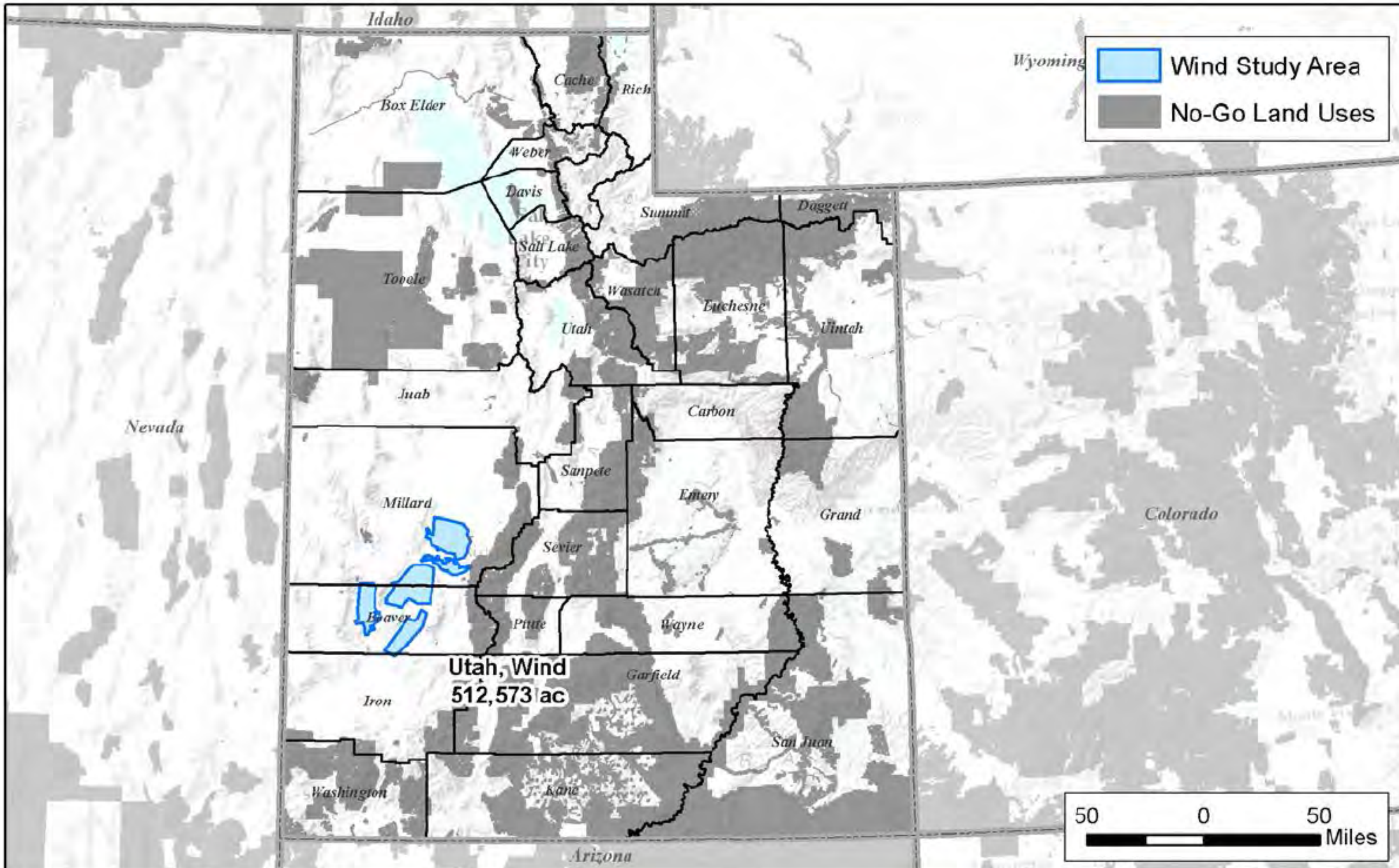
Utah Wind, Overview

- Wind resource: best resource covers western half of the State, south of the Great Salt Lake
- Utah governor commissioned a Utah Renewable Energy Zones task Force to identify areas where utility-scale energy could occur
- Zones screened out environmentally sensitive areas and military airspace and set parameters regarding development
- Use five clustered polygons that allow for more than 600 MW of wind with substantial flexibility
  - Locations are near the Wah Wah Valley and Cricket Range

Utah Wind, Overview



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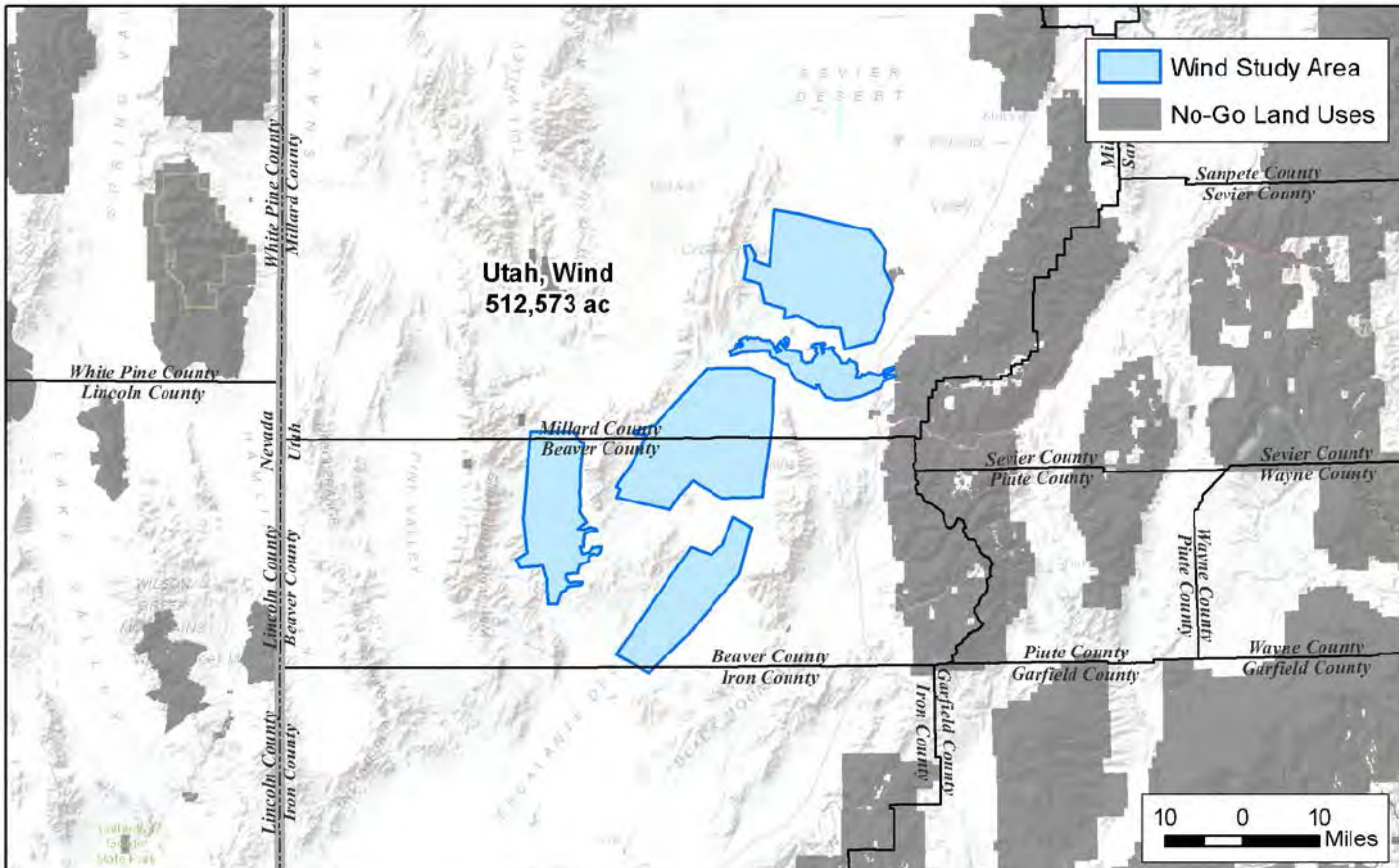
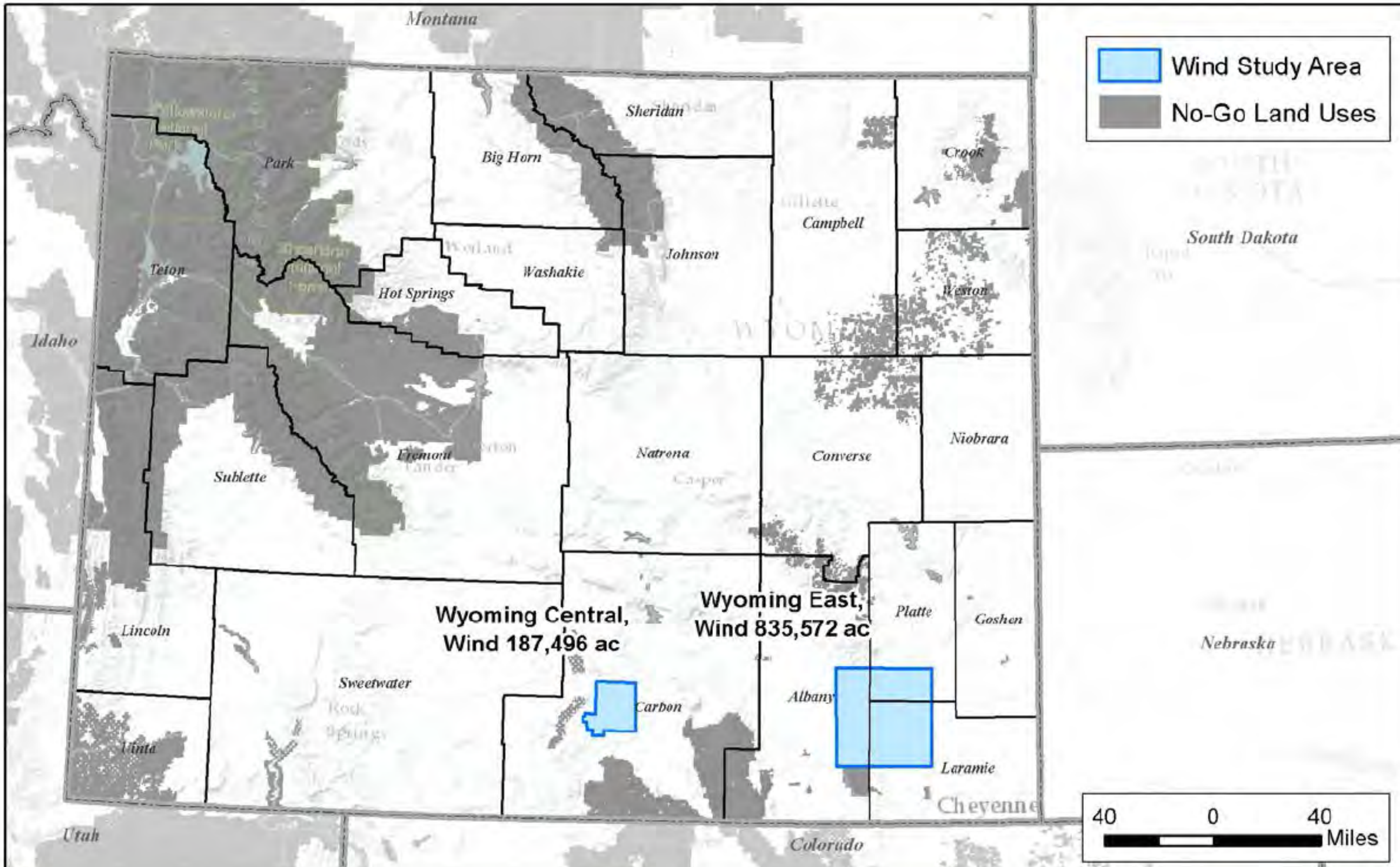
Utah Wind


Wind Study Area
No-Go Land Uses
Utah, Wind
512,573 ac
White Pine County
Lincoln County
Millard County
Beaver County
Iron County
Nevada
Utah
Sanpete County
Sevier County
Piute County
Wayne County
Garfield County
10 0 10
Miles

Wyoming Wind, Overview

- Wind resource: resource covers eastern two-thirds of State
- No specific state / federal renewable coordinated planning processes
- Two previously-documented transmission-driven wind projects:
  - Anschutz Corp., Sierra Madre/Chokecherry – 3,000 MW (EIS in 2012)
  - Duke, Windstar – 2,100 MW (proposed)
- Tailored two polygons where either polygon could allow for more than 2,495 MW of wind with substantial flexibility

Wyoming Wind, Overview



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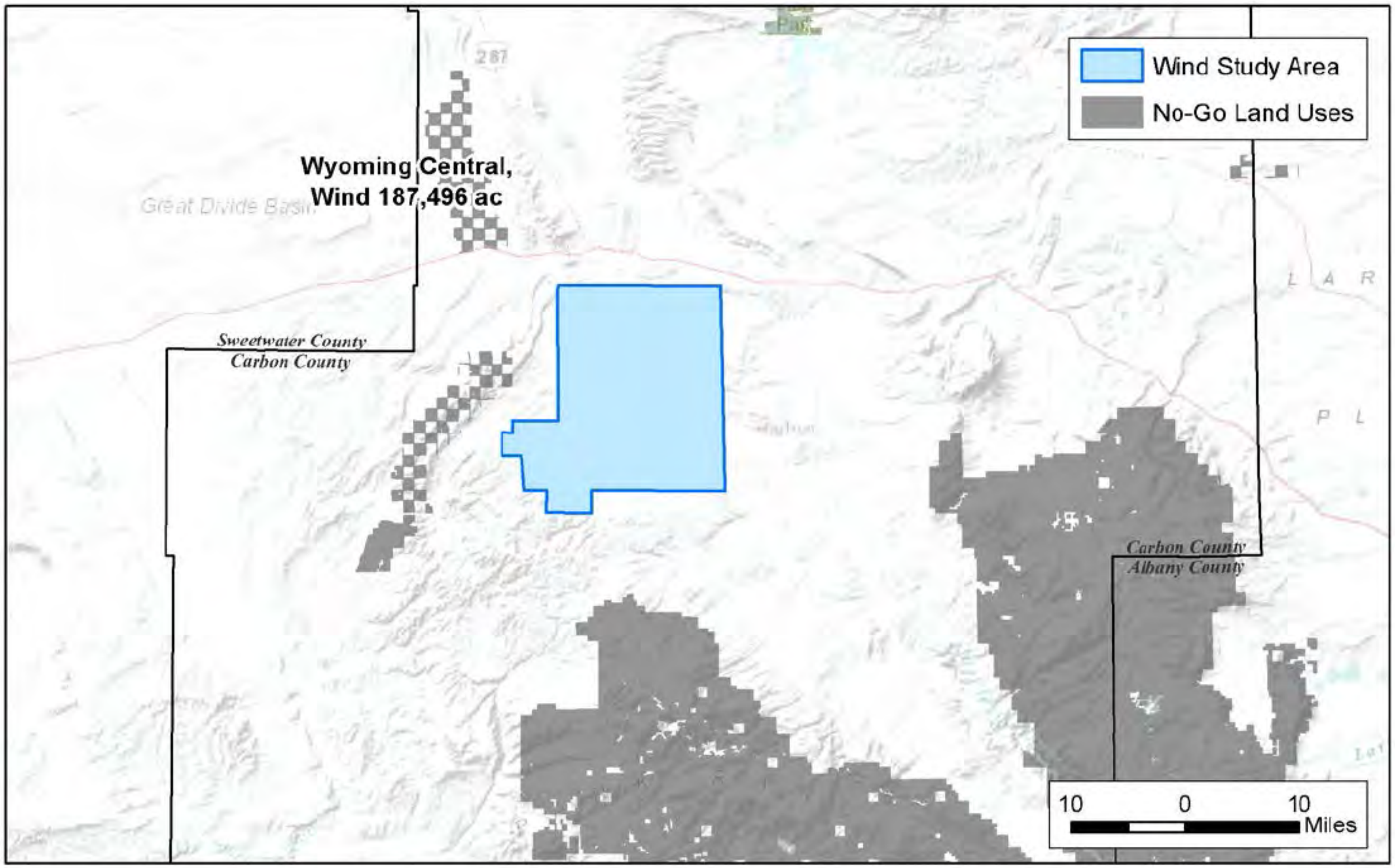
Wyoming Central



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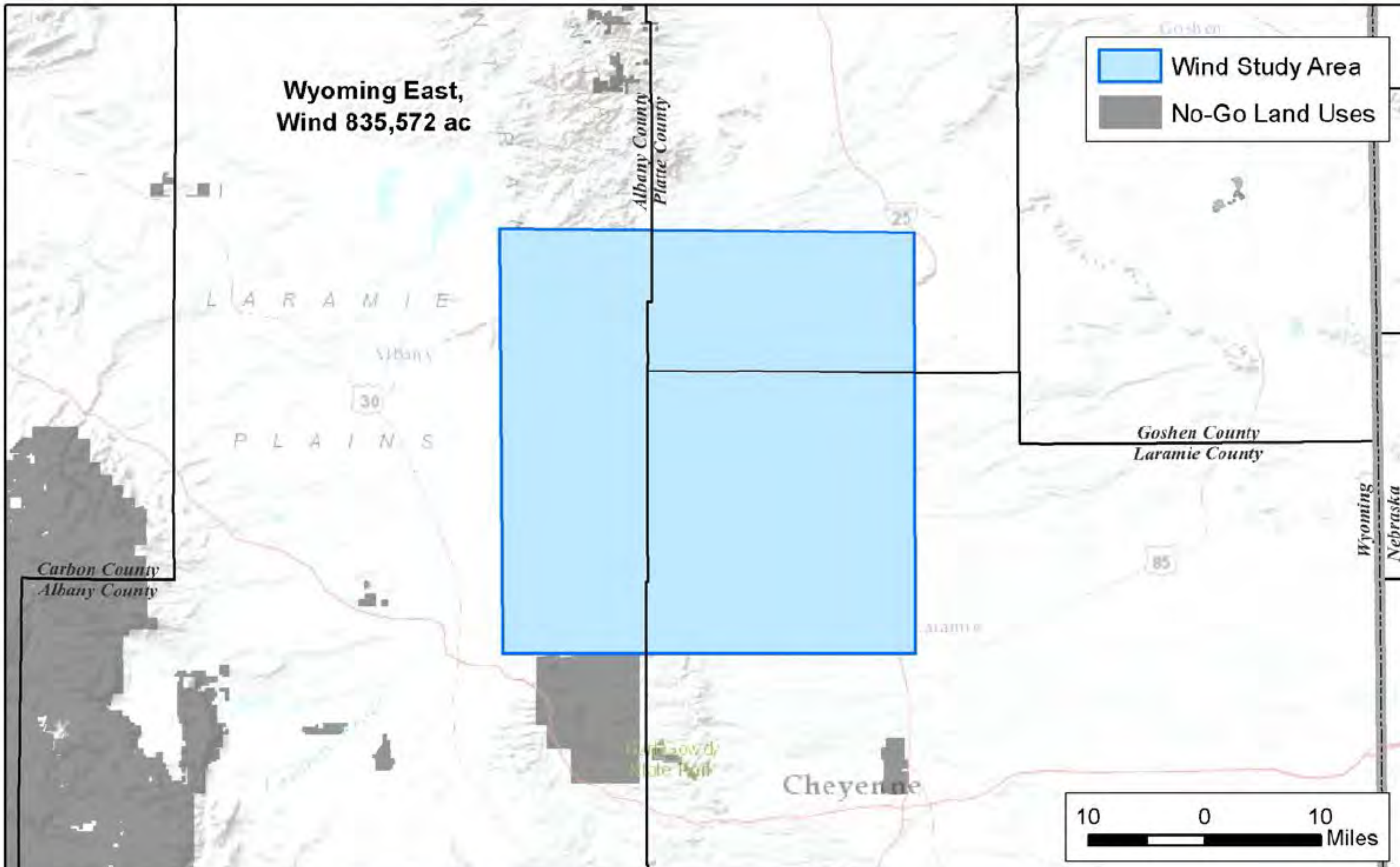
Wyoming East



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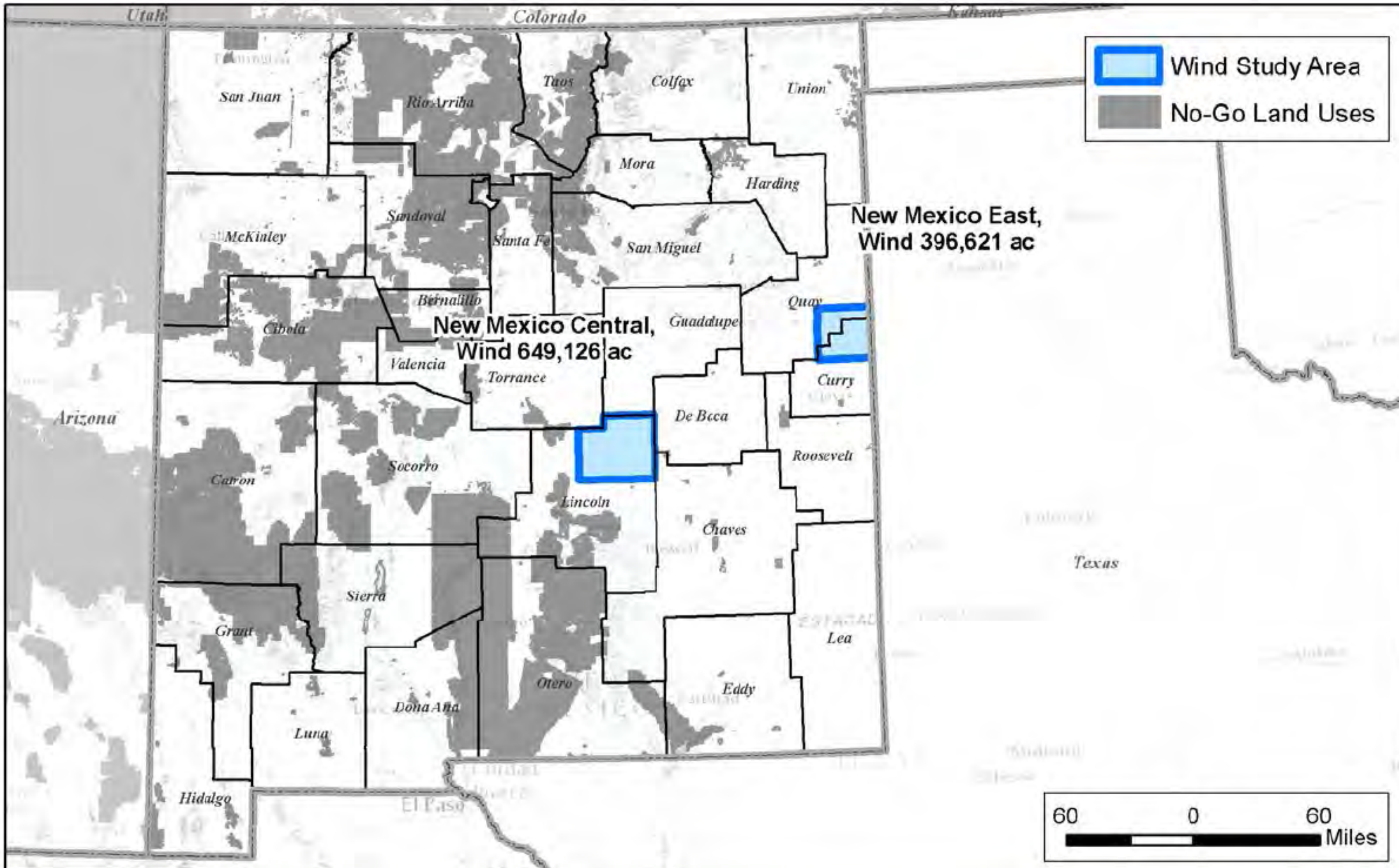
New Mexico Wind, Overview

- Wind resource: best resource covers eastern half of the State
- No specific state / federal renewable coordinated planning processes
- Tailored two polygons where either polygon could allow for more than 2,962 MW of wind with substantial flexibility
  - Central study area covering proposed endpoints for SunZia East and Centennial West Cleanline
  - Eastern study area centered around proposed Tres Amigas vicinity

New Mexico Wind, Overview



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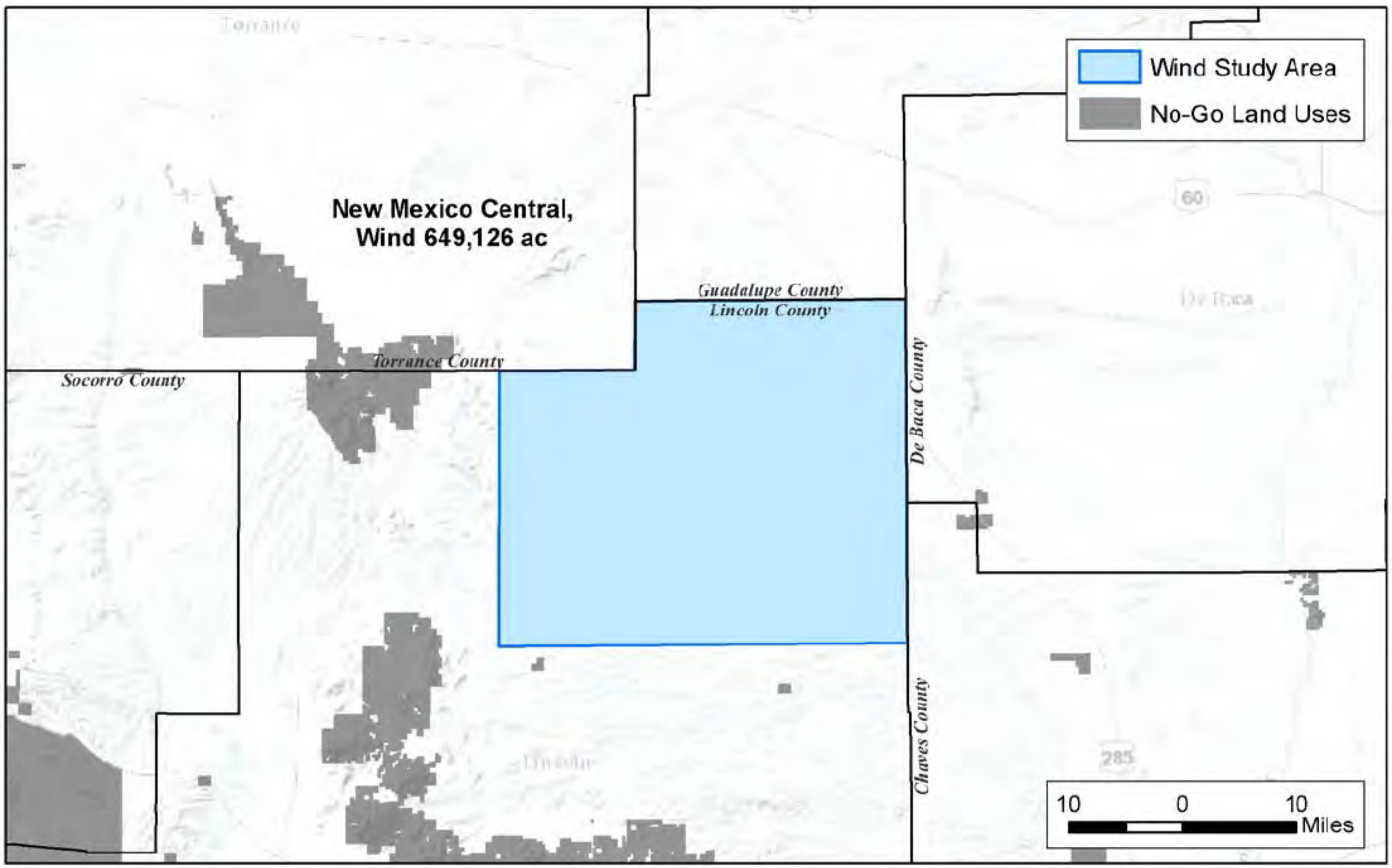
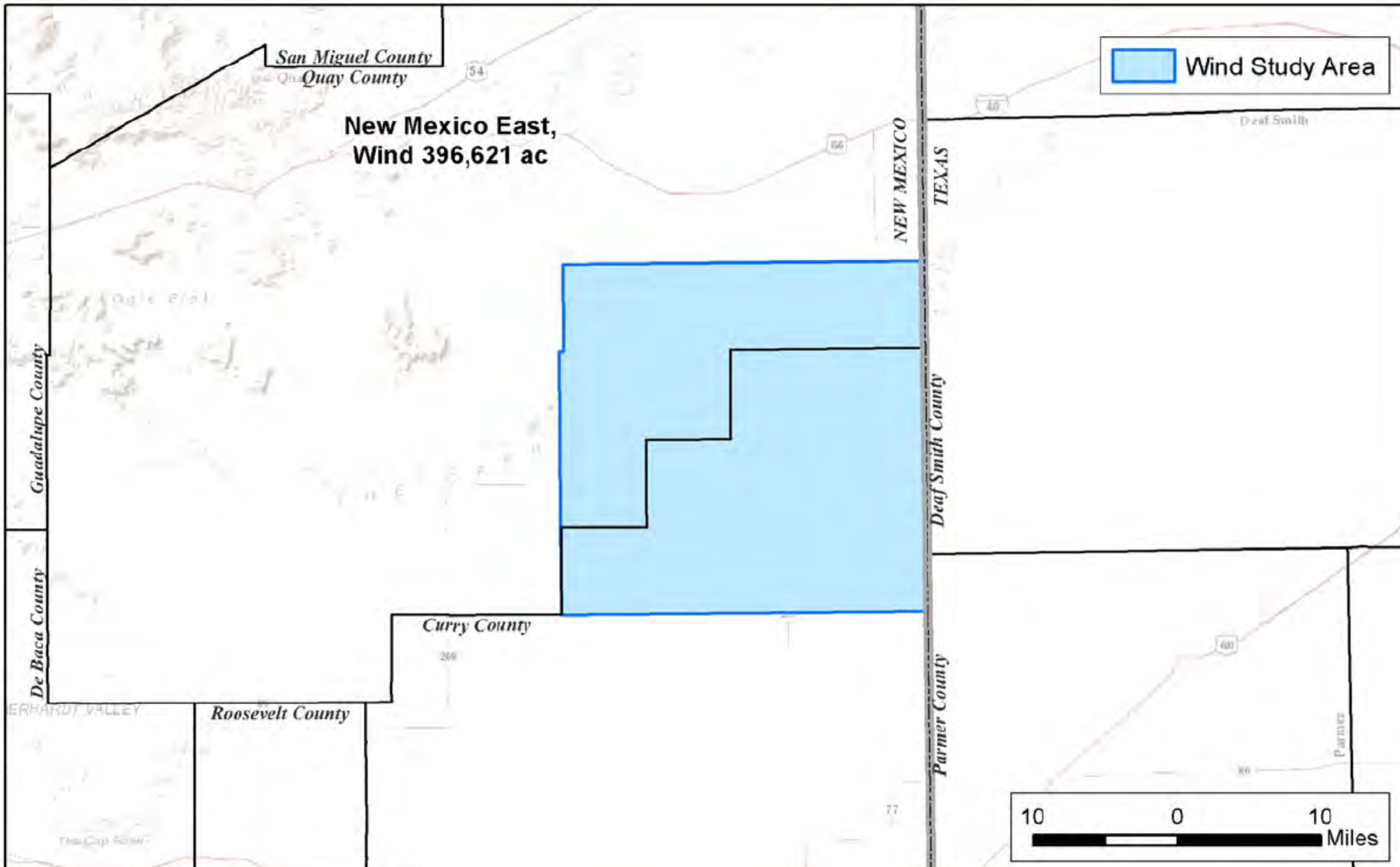
New Mexico Central



New Mexico East



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Volume X: Disadvantaged Community Impact Analysis

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California ISO

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Aspen Environmental Group

BEAR

Berkeley Economic Advising and Research

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Senate Bill 350 Study

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

List of Report Volumes

Senate Bill 350 Study

Volume X

Disadvantaged Community Impact Analysis

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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 "impacts in disadvantaged communities in California." Aspen Environmental Group and Berkeley Economic Advising and Research have been engaged to study these impacts. This report is Volume X of XII of an overall study in response to SB 350's legislative requirements.

This report begins by defining disadvantaged communities, identifies them by location, and presents environmental and economic assessments of energy policy impacts on them. Aspen Environmental Group conducted the environmental study, and Berkeley Economic Advising and Research (BEAR) conducted the economic assessment. More detailed information on methodologies and assumptions, and on impacts across the entire study region, including areas outside of disadvantaged communities, can be found in the Environmental Study (Volume IX) and in the Economic Impact Analysis (Volume VIII).

As discussed in detail below, the limited regionalization in 2020 causes no adverse environmental impact in California's disadvantaged communities and may result in small but beneficial environmental effects by generally reducing water use and NOx emissions. Modeling of the 2020 CAISO + PAC scenario indicates that the San Joaquin Valley and South Coast air basins could slightly increase PM2.5 and SO_2 emissions due to changes in the dispatch of natural gas-fired power plants, but these changes would occur in conjunction with a NOx decrease.

The most severely disadvantaged communities from an economic perspective lie in three regions: Los Angeles (56%), Central Valley (22%), and Inland Valley (13%). For these communities, there are economic benefits right from the start of regionalization in 2020. For 2030, the current practice results in a renewable buildout impacting seven solar resource areas and six different wind resource areas, including four that have a high level of concern for impacts to disadvantaged communities (Westlands; Central Valley North & Los Banos; Kramer & Inyokern; Greater Imperial). The Regional 2 and Regional 3 buildout by 2030 occurs across a smaller number of resource areas in California, when compared with Current Practice 1, although two buildout areas have a high level of concern for impacts to disadvantaged communities (Kramer & Inyokern; Greater Imperial). Thus with expanded regionalization and increased renewable buildout out of state, the impact to California's disadvantaged communities would decline. Regional 2 and Regional 3 both produce more jobs in 2030 in disadvantaged communities than Current Practice 1, arising primarily from job growth induced by ratepayer savings. The economic analysis also considers how income effects differ between disadvantaged and non-disadvantaged communities across scenarios. Once again the state trend with Regional 2 shows the largest increases in incomes and employment across both disadvantaged and non-disadvantaged communities.

1. Screening for Disadvantaged Communities - Overview

The methodology begins with an initial screening of California's disadvantaged communities through maps and tables. The study of disadvantaged communities is limited to California and does not consider out of state effects or out-of-state communities.

1.1 Definition of Disadvantaged Communities

The term "disadvantaged community" is associated with minority and low-income populations in several California laws (e.g., Safe Drinking Water Act, Affordable Housing and Sustainable Communities Program [Public Resources Code, Division 44, Part 1, Section 75200]). Additionally, in 2012 the California Legislature passed Senate Bill 535 (De León), regarding the Greenhouse Gas Reduction Fund, which required the California Environmental Protection Agency (CalEPA) to implement a more comprehensive approach to identifying disadvantaged communities in California through the use of public health and environmental hazard criteria in addition to socioeconomic data (CalEPA, 2014). Through this refined approach, the state definition of disadvantaged communities was expanded to include areas that are disproportionately impacted by environmental pollution and negative public health effects.

This study uses current California definitions and tools to define a disadvantaged community as an area that is:

- Disproportionately affected by environmental pollution and other hazards that can lead to negative public health effects, exposure, or environmental degradation; and/or
- Characterized by concentrations of people that are of low income, high unemployment, low levels of home ownership, high rent burden, sensitive health, or low levels of educational attainment.

1.2 Determination of Disadvantaged Communities

Implementing the provisions of SB 535 is a multi-agency effort among the California Environmental Protection Agency (CalEPA), the Office of Environmental Health Hazard Assessment (OEHHA), and the Air Resources Board (ARB) (ARB, 2016). In addition to targeting a statewide reduction of greenhouse gas emissions, SB 535 earmarked 25 percent of the Greenhouse Gas Reduction Fund for projects that provide a benefit to disadvantaged communities. The CalEPA was tasked with the responsibility for identifying disadvantaged communities for the purpose of SB 535. CalEPA developed CalEnviroScreen (California Communities Environmental Health Screening Tool) as a science-based tool for evaluating multiple pollutants and stressors in communities, and ultimately for identifying disadvantaged communities (CalEPA, 2014).

CalEnviroScreen uses existing environmental, public health, and socioeconomic data to develop indicators to create a screening score for communities across the state. An area with a high score would be expected to experience more severe environmental impacts than areas with low scores. CalEnviroScreen 2.0 (updated October 2014) uses a quantitative method to evaluate multiple pollution sources and stressors, and vulnerability to pollution, in California's approximately 8,000 U.S. Census Tracts. Using data from federal and state sources, the tool consists of indicators (Table 1) that are divided into two broad groups:

- Indicators for exposure and environmental effects comprise a Pollution Burden group; and
- Indicators for sensitive populations and socioeconomic factors comprise a Population Characteristics group.

Table 1. CalEnviroScreen Indicators Used for Identifying Disadvantaged Communities

Environmental Indicators: Pollution Burden (12)	▪ Ozone Levels ▪ Particulate Matter 2.5 Concentrations ▪ Diesel Particulate Matter Emissions ▪ Drinking Water Contaminants ▪ Pesticide Use ▪ Toxic Releases from Facilities ▪ Traffic Density ▪ Cleanup Sites ▪ Groundwater Threats ▪ Hazardous Waste Sites/Facilities ▪ Impaired Water Bodies ▪ Solid Waste Sites/Facilities
Demographic Indicators: Population Characteristics (7)	▪ Children/Elderly ▪ Asthma Emergency Departmental Visits ▪ Low Birth-Weight Births ▪ Educational Attainment ▪ Linguistic Isolation ▪ Poverty ▪ Unemployment

Source: CalEPA, 2014.

Census tracts are used as a geographic scale for identifying disadvantaged communities within California. For each census tract, CalEnviroScreen calculates an overall score by combining the individual indicator scores within each of the two groups (i.e., Pollution Burden and Population Characteristics), then multiplying the Pollution Burden and Population Characteristics scores to produce a final score.[1] Based on these final scores, the census tracts across the state are ranked relative to one another.

CalEnviroScreen Methodology

The CalEnviroScreen model is designed to use the 19 indicators shown in Table 1 that measure a community's exposure, environmental effects, sensitive population, and socioeconomic factors. Table 2 provides more detail on how each of these indicators is developed and the data sources used. As noted above, many of these data sources are California-specific, which provides a more relevant analysis when identifying disadvantaged communities within the state.

Table 2. CalEnviroScreen Indicators and Data Sources

Issue	Indicator	Data Source
Environmental Indicators (12)		
Air Quality: Ozone	Amount of the daily maximum 8-hour ozone concentration over the California 8-hour standard (0.070 ppm), averaged over three years (2009 to 2011)	▪ Air Monitoring Network, California Air Resources Board
Air Quality: Fine Particulate Matter (PM2.5)	Annual mean concentration of PM2.5 (average of quarterly means), over three years (2009-2011)	▪ Air Monitoring Network, California Air Resources Board

[1] The maximum score within each of the Pollution Burden and Pollution Characteristics groups is 10. The maximum CalEnviroScreen Score is 100.

Table 2. CalEnviroScreen Indicators and Data Sources

Issue	Indicator	Data Source
Diesel Particulate Matter	Spatial distribution of gridded diesel PM emissions from on-road and non-road sources for a 2010 summer day in July (kg/day)	▪ California Air Resources Board ▪ San Diego Association of Governments
Drinking Water Contaminants	Drinking water contaminant index for selected contaminants	▪ Public Water System Location Data (PICME Database), CDPH ▪ Safe Drinking Water Information System, U.S. EPA ▪ Water Quality Monitoring Database, CDPH ▪ Domestic Well Project, Groundwater Ambient Monitoring and Assessment (GAMA) Program, State Water Resources Control Board (SWRCB) ▪ Priority Basin Project, GAMA Program, SWRCB and U.S. Geological Survey
Pesticide Use	Total pounds of selected active pesticide ingredients (filtered for hazard and volatility) used in production-agriculture per square mile	▪ Pesticide Use Reporting, California Department of Pesticide Regulation
Toxic Releases from Facilities	Toxicity-weighted concentrations of modeled chemical releases to air from facility emissions and off-site incineration	▪ Risk Screening Environmental Indicators ▪ U.S. EPA Toxic Release Inventory
Traffic Density	Sum of traffic volumes adjusted by road segment length (vehicle-kilometers per hour) divided by total road length (kilometers) within 150 meters of the census tract boundary	▪ Environmental Health Investigations Branch, CDPH ▪ San Diego Association of Governments
Cleanup Sites	Sum of weighted sites within each census tract	▪ EnviroStor Cleanup Sites Database, Department of Toxic Substances Control (DTSC) ▪ US EPA, Region 9 NPL Sites (Superfund Sites) Polygons
Groundwater Threats	Sum of weighted scores for sites within each census tract	▪ GeoTracker Database, SWRCB
Hazardous Waste Generators and Facilities	Sum of weighted permitted hazardous waste facilities and hazardous waste generators within each census tract	▪ EnviroStor Hazardous Waste Facilities Database and Hazardous Waste Tracking System, DTSC
Impaired Water Bodies	Summed number of pollutants across all water bodies designated as impaired within the area	▪ 303(d) List of Impaired Water Bodies, SWRCB
Solid Waste Sites and Facilities	Sum of weighted solid waste sites and facilities	▪ Solid Waste Information System and Closed, Illegal, and Abandoned Disposal Sites Program, California Department of Resources Recycling and Recovery, CalRecycle

Table 2. CalEnviroScreen Indicators and Data Sources

Issue	Indicator	Data Source
▪ Population Characteristics (7)		
Age: Children and Elderly	Percent of population under age 10 or over age 65	▪ U.S. Census Bureau
Asthma	Spatially modeled, age-adjusted rate of emergency department (ED) visits for asthma per 10,000 (averaged over 2007-2009)	▪ California Office of Statewide Health Planning and Development (OSHPD) ▪ Environmental Health Investigations Branch, California Department of Public Health
Low Birth Weight Infants	Percent low birth weight, spatially modeled (averaged over 2006-2009)	▪ California Department of Public Health (CDPH)
Educational Attainment	Percent of the population over age 25 with less than a high school education (5-year estimate, 2008-2012)	▪ American Community Survey ▪ U.S. Census Bureau
Linguistic Isolation	Percentage of households in which no one age 14 and over speaks English "very well" or speaks English only	▪ American Community Survey ▪ U.S. Census Bureau
Poverty	Percent of the population living below two times the federal poverty level (5-year estimate, 2008-2012)	▪ American Community Survey ▪ U.S. Census Bureau
Unemployment	Percent of the population over the age of 16 that is unemployed and eligible for the labor force. Excludes retirees, students, homemakers, institutionalized persons except prisoners, those not looking for work, and military personnel on active duty (5-year estimate, 2008-2012)	▪ American Community Survey ▪ U.S. Census Bureau

Source: CalEPA and OEHHA, 2014.

For a census tract-level analysis, the 19 indicators are averaged into two groups (Pollution Burden and Population Characteristics) to generate a score for each group. Group scores are calculated as follows:

Pollution Burden Score. Pollution Burden scores for each census tract are derived from the average percentiles of the seven exposures indicators (ozone and PM2.5 concentrations, diesel PM emissions, drinking water contaminants, pesticide use, toxic releases from facilities, and traffic density) and the five environmental effects indicators (cleanup sites, impaired water bodies, groundwater threats, hazardous waste facilities and generators, and solid waste sites and facilities). Indicators from the environmental effects component are given half the weight of the indicators from the exposures component. The calculated average Pollution Burden score (average of the indicators) is divided by 10 and rounded to one decimal place for a Pollution Burden score ranging from 0.1 to 10.

Population Characteristics Score. Population Characteristics scores for each census tract are derived from the average percentiles for the three sensitive population indicators (children/elderly, low birth weight, and asthma) and the three socioeconomic factor indicators (educational attainment, linguistic isolation, and poverty). The calculated average percentile divided by 10 for a Population Characteristic score ranging from 0.1 to 10.

CalEnviroScreen Score and Maps

The CalEnviroScreen 2.0 model uses the following formula to calculate an overall CalEnviroScreen Score for a particular census tract:

(Pollution Burden) x (Populations Characteristics) = CalEnviroScreen Score

As demonstrated in the above formula, the CalEnviroScreen Score is calculated by multiplying the Pollution Burden score with the Populations Characteristics score. Since each of the two groups (i.e., Pollution Burden and Populations Characteristics) has a maximum score of 10, the maximum CalEnviroScreen Score is 100.

Additional considerations involved with the CalEnviroScreen system and scoring include:

- Geographic Resolution of Data: CalEnviroScreen 2.0 (utilized within this report) uses census tract boundary data for the 2010 Census obtained from the U.S. Census Bureau.
- Indicator Data Criteria: Data must be available statewide at the census tract level geographical unit or translatable to the census tract level; must be of sufficient quality; and must be complete, accurate, and current.
- Score Calculation Method for Pollution Burden and Population Characteristics Groups:
  - First, the percentiles for all the individual indicators in a group are averaged. Within the Pollution Burden Group, indicators from the environmental effects component are weighted half as much as indicators from the exposures component.[2] Thus, the score for the Pollution Burden category is a weighted average, with exposure indicators receiving twice the weight as environmental effects indicators.
  - Second, Pollution Burden and Population Characteristics percentile averages are scaled so that they have a maximum value of 10 and a possible range of 0 to 10. Each average is divided by the maximum value observed in the state and then multiplied by 10. The scaling ensures that the pollution component and population component contribute equally to the overall CalEnviroScreen score.

2. Disadvantaged Communities Identified

2.1 CalEnviroScreen Score and Maps

Using CalEnviroScreen, the disadvantaged census tracts within California have been identified. Because this tool is California-specific, it provides the following advantages for an in-state analysis:

- Use of census tracts[3] as the geographic scale allows for a reasonably precise screening of pollution burdens and vulnerabilities in specific communities.
- The tool reflects CalEPA's continued effort to enhance the current indicators by incorporating the most up-to-date information, as available.

[2] The contribution to possible pollutant burden from the environmental effects indicators is considered to be less than those from sources in the exposures indicators, and therefore a weighted average is used to calculate the total Pollution Burden.

[3] Census tracts generally have a population size between 1,200 and 8,000 people, with an optimum size of 4,000 people (approximately 1,500 housing units) (USCB, 2015).

Disadvantaged Communities Identified Statewide

Once CalEnviroScreen scores are calculated for each census tract, these tracts are ordered from highest to lowest, based on their overall score. After taking into consideration legislative direction, comparative markers of being disadvantaged and basic principles of fairness, CalEPA has decided on the use of a 25 percent threshold to identify disadvantaged communities (CalEPA, 2014). <u>All census tracts (and population within) ranked within the top 25 percentile are considered disadvantaged within a statewide context.</u>

CalEPA developed maps that show the percentiles for all the state's census tracts and that highlight the census tracts that are within the top 25 percent of communities. CalEnviroScreen scores within the top 25 percent, which are defined as disadvantaged communities, correspond to percentile as follows:

- Score of 7.51 to 8 represents 75 to 80%;
- Score of 8.1 to 9 represents 81 to 90% (population within this ranking is considered more sensitive than that ranked 75 to 80%); and
- Score of 9.1 to 10 represents 91 to 100% (population within this ranking is considered more sensitive than that ranked 75 to 90%).

Disadvantaged Communities Overlay Boundaries for SB 350 Study

In the maps and tables presented with this methodology overview, the locations of disadvantaged communities within the State of California appear, along with an overlay of the following three boundaries for comparison purposes:

- County boundaries.
- Air Basin boundaries. California is divided geographically into air basins for the purpose of managing the air resources of the state on a regional basis. An air basin generally has similar meteorological and geographic conditions throughout. California is currently divided into 15 air basins.
- Competitive Renewable Energy Zone (CREZ) boundaries. CREZ boundaries are established under the Renewable Energy Transmission Initiative (RETI) process and identify the best renewable resource locations to prioritize future transmission infrastructure development. An Aggregated CREZ is a coarsely-defined geography that can span multiple counties or substantial portions of counties.

Information is provided for the 25% highest-scoring census tracts within California, as these census tracts contain the population considered to be disadvantaged that could bear disproportionate impacts from energy infrastructure siting. Because the overlay boundaries encompass complete census tracts and portions of census tracts, to avoid double-counting population in partial tracts, the counted population and number of tracts considers the census tracts that are primarily within each of the boundaries. Accordingly, population data presented here includes some portion outside each overlay boundary.

Note that the scores for each area identified by CalEnviroScreen are the same underlay for each map in this overview, only the overlay of the different boundary types change here (i.e., County, Air Basin, and CREZ).

2.2 Disadvantaged Communities for the Environmental Analysis

Disadvantaged Communities in California by County

Figure 1 shows the distribution of the top 25% highest CalEnviroScreen scores across the counties in California. Table 3 (at the end of this section) provides data corresponding to the map, and shows the population levels in disadvantaged communities by county. As shown in Table 3, the counties with the highest percentages of population in disadvantaged communities are: Merced, Tulare, Fresno, Kings, Madera, Kern, Imperial, San Joaquin, Stanislaus, Los Angeles, and San Bernardino.

Disadvantaged Communities in California Air Basins

Figure 2 shows the distribution of the top 25% highest CalEnviroScreen scores across air basins in California. Table 4 (at the end of this section) provides data corresponding to the map, and shows the population levels in disadvantaged communities by air basin. As shown in Table 4, the San Joaquin Valley, South Coast, and Salton Sea air basins contain the highest percentages of population in disadvantaged communities.

Disadvantaged Communities in CREZs

Figure 3 shows the distribution of the top 25% highest CalEnviroScreen scores across the Aggregated CREZs in this overview. Table 5 (at the end of this section) provides data corresponding to the map, and shows the population levels in disadvantaged communities by CREZ. As shown in Table 5, the Westlands, Central Valley North & Los Banos, Mountain Pass & El Dorado, Kramer & Inyokern, and Greater Imperial CREZs contain the highest percentages of population in disadvantaged communities.

Figure 1. CalEnviroScreen 2.0 Scores by County

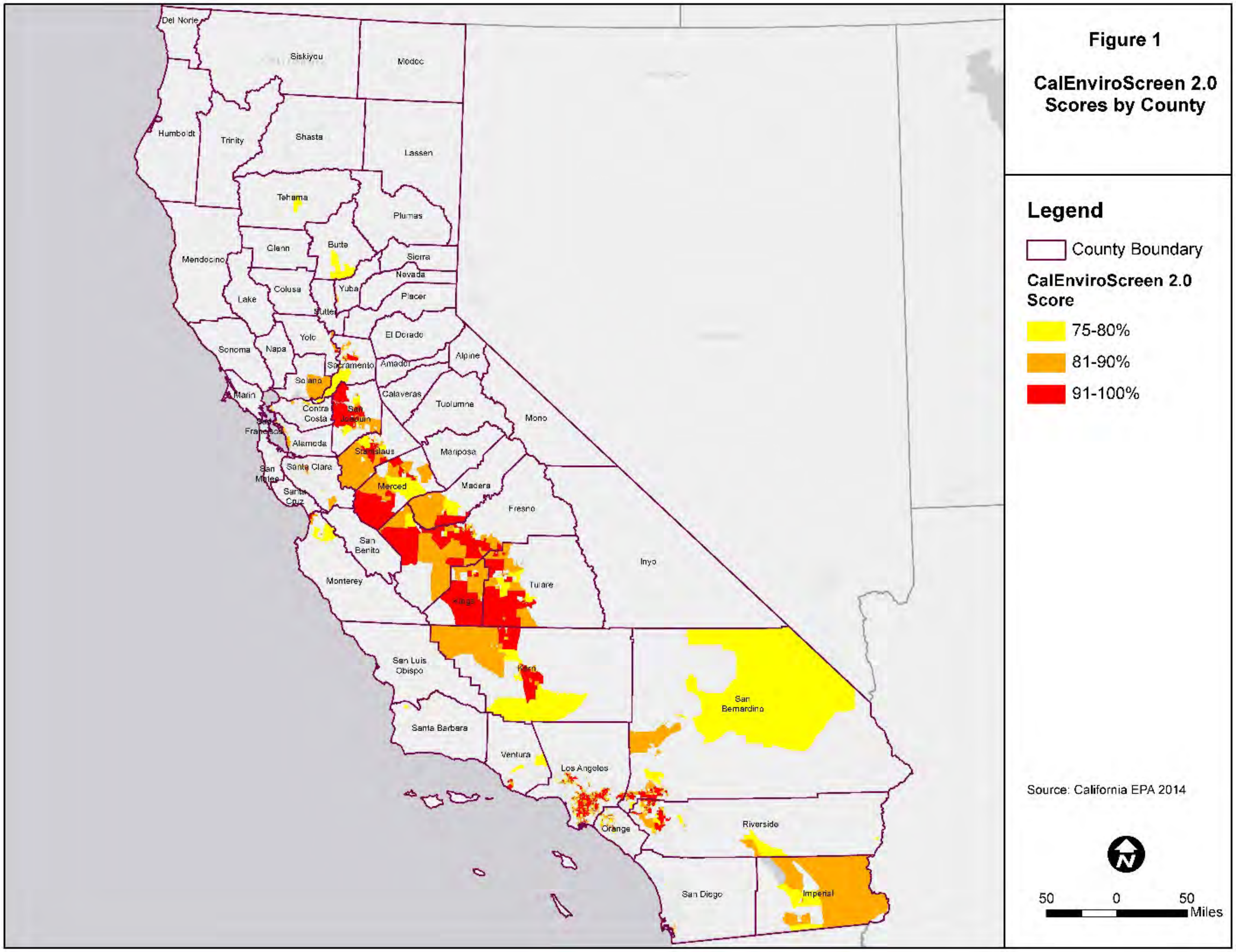


Figure 2. CalEnviroScreen 2.0 Scores by Air Basin

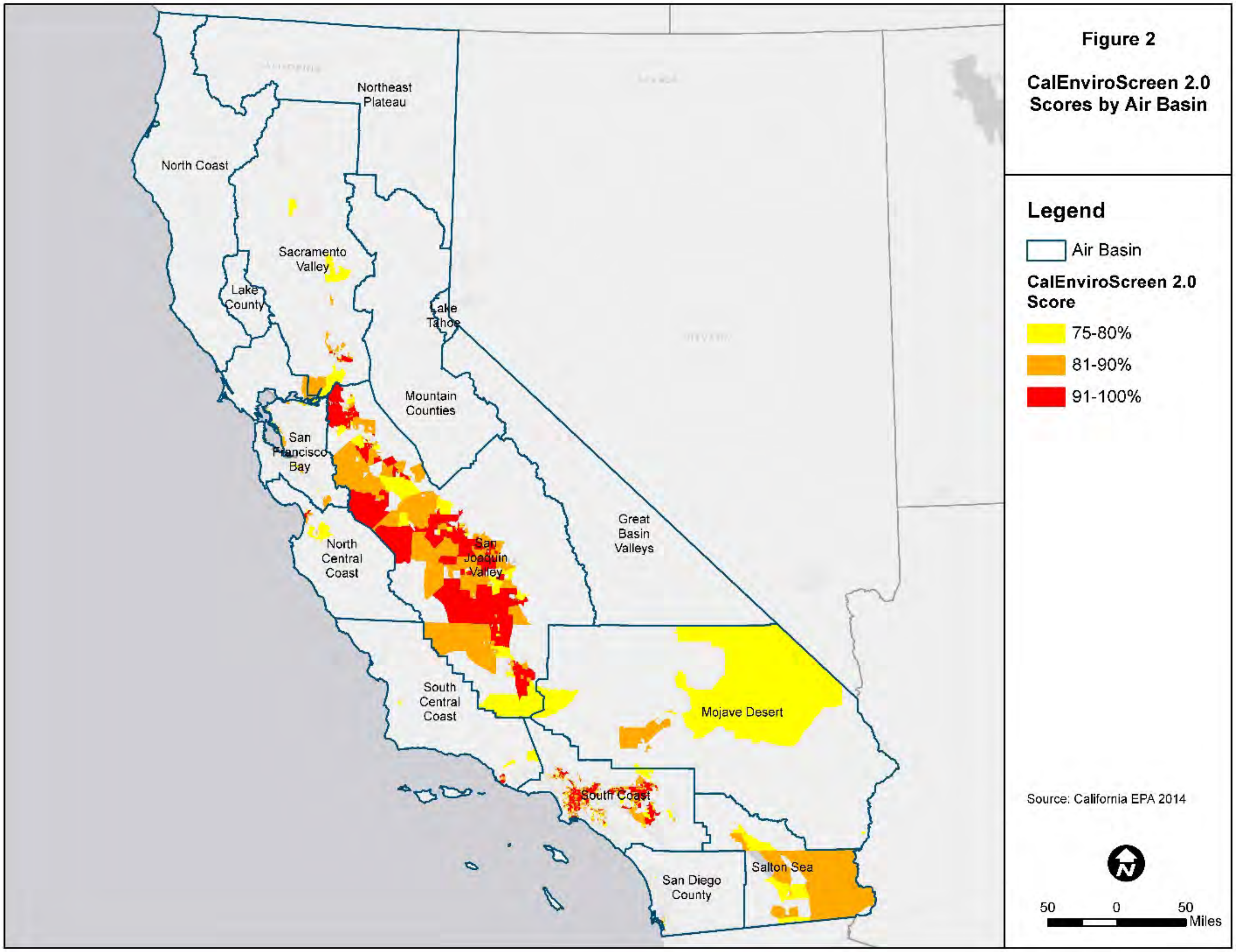


Figure 3. CalEnviroScreen 2.0 Scores by Aggregated CREZ

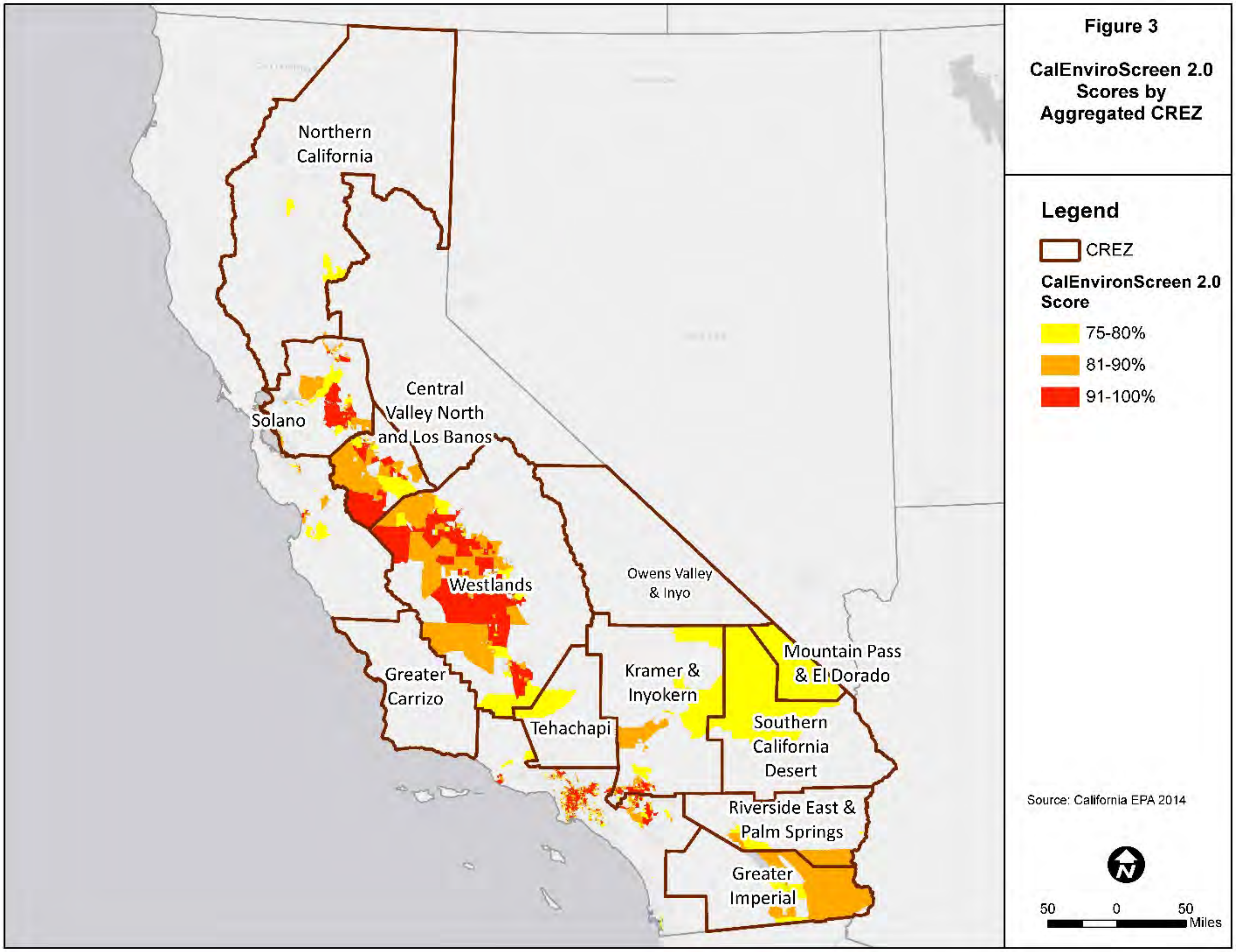


Table 3. CalEnviroScreen Scores by County

County	76-80% Highest Scores		81-90% Highest Scores		91-100% Highest Scores		County Totals (top 25% highest scoring areas)		Percentage of County Population within Disadvantaged Communities
	No. of Tracts	*Population*	*No. of Tracts*	*Population*	*No. of Tracts*	*Population*	*No. of Tracts*	*Population*	*Percentage*
Merced	5	27,944	17	97,544	14	62,152	36	187,640	73%
Fresno	14	70,293	36	172,204	81	386,223	131	628,720	68%
Tulare	7	43,448	26	123,002	17	110,769	50	277,219	63%
Madera	2	17,424	6	36,584	5	38,016	13	92,024	61%
Kern	18	97,718	24	128,416	31	202,271	73	428,405	51%
Stanislaus	10	51,793	20	92,520	20	98,543	50	242,856	47%
Los Angeles	163	674,588	408	1,762,569	447	1,910,843	1018	4,348,000	44%
San Joaquin	10	42,512	26	134,429	28	120,939	64	297,880	43%
San Bernardino	23	119,125	61	343,508	76	400,063	160	862,696	42%
Kings	2	8,795	7	28,136	5	25,887	14	62,818	41%
Imperial	6	33,152	7	36,482	—	—	13	69,634	40%
Riverside	30	145,317	32	175,004	42	207,530	104	527,851	24%
Orange	33	213,508	43	249,509	10	63,840	86	526,857	18%
Yuba	—	—	3	12,296	—	—	3	12,296	17%
Sacramento	15	67,461	19	92,340	9	36,788	43	196,589	14%
Contra Costa	13	68,018	10	53,186	—	—	23	121,204	12%
Yolo	1	4,922	1	7,702	1	5,397	3	18,021	9%
Monterey	3	15,783	3	15,139	1	4,518	7	35,440	9%
Alameda	15	55,909	16	62,896	1	5,547	32	124,352	8%
Tehama	1	4,112	—	—	—	—	1	4,112	6%
Santa Clara	7	29,476	13	67,357	3	8,771	23	105,604	6%
Butte	3	12,313	—	—	—	—	3	12,313	6%
Ventura	3	9,076	2	9,002	3	15,390	8	33,468	4%

Table 3. CalEnviroScreen Scores by County

County	76-80% Highest Scores		81-90% Highest Scores		91-100% Highest Scores		County Totals (top 25% highest scoring areas)		Percentage of County Population within Disadvantaged Communities
	No. of Tracts	*Population*	*No. of Tracts*	*Population*	*No. of Tracts*	*Population*	*No. of Tracts*	*Population*	*Percentage*
San Diego	8	40,549	14	60,614	4	15,432	26	116,595	4%
Santa Cruz	1	7,976	—	—	—	—	1	7,976	3%
Solano	1	2,962	1	8,423	—	—	2	11,385	3%
Santa Barbara	1	11,406	—	—	—	—	1	11,406	3%
San Mateo	1	7,510	1	7,327	—	—	2	14,837	2%
San Francisco	2	7,546	1	3,499	—	—	3	11,045	1%

Note: The counted population and number of tracts include the census tracts that are primarily within each boundary and may not include the population of the partial tracts in each overlay boundary.

Table 4. CalEnviroScreen Scores by Air Basin

Air Basin	76-80% Highest Scores		81-90% Highest Scores		91-100% Highest Scores		Air Basin Totals (top 25% highest scoring areas)		Percentage of Air Basin Population within Disadvantaged Communities
	No. of Tracts	*Population*	*No. of Tracts*	*Population*	*No. of Tracts*	*Population*	*No. of Tracts*	*Population*	*Percentage*
San Joaquin Valley	67	354,453	162	812,835	201	1,044,800	430	2,212,088	58%
South Coast	242	1,112,097	534	2,469,914	575	2,582,276	1,351	6,164,287	39%
Salton Sea	9	57,547	9	50,060	—	—	18	107,607	18%
Sacramento Valley	20	88,808	24	120,761	10	42,185	54	251,754	9%
Mojave Desert	5	21,520	8	47,098	—	—	13	68,618	7%
North Central Coast	4	23,759	3	15,139	1	4,518	8	43,416	6%
San Francisco Bay	39	171,421	40	190,815	4	14,318	83	376,554	5%
San Diego County	8	40,549	14	60,614	4	15,432	26	116,595	4%
South Central Coast	4	20,482	2	9,002	3	15,390	9	44,874	3%
Great Basin Valleys	—	—	—	—	—	—	0	0	0%

Note: The counted population and number of tracts include the census tracts that are primarily within each boundary and may not include the population of the partial tracts in each overlay boundary.

Table 5. CalEnviroScreen Scores by Aggregated CREZ

	76-80% Highest Scores		81-90% Highest Scores		91-100% Highest Scores		CREZ Totals (top 25% highest scoring areas)		Percentage of Population within CREZ within Disadvantaged Communities
Aggregated CREZ	***No. of Tracts***	***Population***	***No. of Tracts***	***Population***	***No. of Tracts***	***Population***	***No. of Tracts***	***Population***	***Percentage***
Westlands	42	232,204	99	488,342	139	763,166	280	1,483,712	62%
Central Valley N & Los Banos	15	79,737	37	190,064	34	160,695	86	430,496	56%
Kramer & Inyokern	22	115,279	61	343,508	76	400,063	159	858,850	42%
Greater Imperial	6	33,152	7	36,482	—	—	13	69,634	22%
Solano	55	241,784	72	355,526	39	168,671	166	765,981	15%
Riverside East & Palm Springs	4	27,736	2	13,578	—	—	6	41,314	9%
Southern California Desert	1	3,846	—	—	—	—	1	3,846	8%
Tehachapi	2	8,407	2	10,900	—	—	4	19,307	2%
Northern California	4	16,425	—	—	—	—	4	16,425	2%
Greater Carrizo	1	11,406	—	—	—	—	1	11,406	2%
Owens Valley & Inyo	—	—	—	—	—	—	0	0	0%

Note: The counted population and number of tracts include the census tracts that are primarily within each boundary and may not include the population of the partial tracts in each overlay boundary.

2.3 Disadvantaged Communities for the Economic Analysis

The economic and environmental analyses use the same criteria for identifying disadvantaged communities; however, the economic analysis uses an alternative aggregation methodology for reporting results. Disadvantaged communities are aggregated to nine multi-county economic regions (Table 6). 91% of California's disadvantaged communities fall within three economic regions: Los Angeles (56%), Central Valley (22%), and Inland Valley (13%).

Table 6. Disadvantaged Community Aggregation Used for Economic Analysis

Regions	Counties within Region	Percent of Disadvantaged Communities
Los Angeles	Los Angeles, Ventura, Orange	56%
Central Valley	San Joaquin, Stanislaus, Merced, Madera, Fresno, Kings, Tulare, Kern, Mariposa, Tuolumne, Calaveras, Amador	22%
Inland Valley	San Bernardino, Riverside	13%
Bay Area	San Francisco, Marin, Sonoma, Napa, Solano, Contra Costa, Alameda, Santa Clara, San Mateo	4%
Sacramento	El Dorado, Placer, Sacramento, Yolo, Sutter, Yuba	2.5%
San Diego and Imperial	San Diego, Imperial	2%
Central Coast	Monterey, San Luis Obispo, Santa Barbara, Santa Cruz, San Benito	<1%
North State	Del Norte, Siskiyou, Modoc, Humboldt, Trinity, Shasta, Lassen, Tehama, Plumas, Sierra, Nevada, Butte, Glenn, Colusa, Lake, Mendocino	<1%
Southern Sierra	Alpine, Mono, Inyo	None

Note: The nine economic region aggregation is taken from the following report by the California EPA Office of Environmental Health Hazard Assessment: Approaches to Identifying Disadvantaged Communities (2014).

3. Ranking of Disadvantaged Communities

Areas that have the greatest numbers of highest-scoring tracts according to CalEnviroScreen results are considered in this study to be the areas of greatest concern. The areas of greatest concern in this study are likely to have many census tracts in the highest-scoring decile, and the highest percentage of population in disadvantaged communities, as shown previously for the air basins (Table 4), the CREZs (Table 5), and Economic Regions (Table 6).

The geographic resolution of the environmental study is at the scale of air basins and CREZs, some of which include hundreds of census tracts defined as disadvantaged communities The number of census tracts that are disadvantaged communities, meaning those in the highest quartile of CalEnviroScreen scores (7.6-10), and the number of census tracts with the highest decile of CalEnviroScreen Scores (9.1-10) are used here to further focus the study on areas where highest-scoring tracts are most likely to occur. Any area that has more than 40% of census tracts the top quartile also in the top decile (i.e., more than 10 tracts in the top decile per every 25 tracts in the top quartile) is an area characterized with the highest-scoring tracts.

Table 7 lists the air basins with the number of tracts in the highest-scoring decile and fraction of disadvantaged communities that are the highest-scoring. Table 7 shows that the San Joaquin Valley and South Coast air basins have the greatest numbers of the highest-scoring disadvantaged communities.

On the basis of having a relatively high percentage of population in disadvantaged communities (Table 4), the top three air basins of greatest concern also include the Salton Sea air basin.

Table 7. Air Basins with the Highest-Scoring Disadvantaged Communities

Air Basin	Percentage of Air Basin Population within Disadvantaged Communities	CalEnviroScreen Scores between 7.6 and 10 (No. of Tracts in Top Quartile)	CalEnviroScreen Scores between 9.1 and 10 (No. of Tracts in Top Decile)	Highest-Scoring Areas (Top Decile divided by Top Quartile)
San Joaquin Valley	58%	430	201	47%
South Coast	39%	1,351	575	43%
South Central Coast	3%	9	3	33%
Sacramento Valley	9%	54	10	19%
San Diego County	4%	26	4	15%
North Central Coast	6%	8	1	13%
San Francisco Bay	5%	83	4	5%
Salton Sea	18%	18	0	0%
Mojave Desert	7%	13	0	0%

Note: The counted number of tracts considers the census tracts that are primarily within each boundary, shown also in Table 4.

Table 8 lists the CREZs with number of tracts in the highest-scoring decile and fraction of disadvantaged communities that are the highest-scoring. The top five CREZs of greatest concern include the Central Valley North & Los Banos and Greater Imperial CREZs, due to a relatively high percentage of population in disadvantaged communities; the Solano CREZ has a lower percentage of population in disadvantaged communities (Table 5). Table 8 shows that the Westlands and Kramer & Inyokern CREZs also have the greatest numbers of highest-scoring disadvantaged communities.

Table 8. CREZs with the Highest-Scoring Disadvantaged Communities

Aggregated CREZ	Percentage of Population within CREZ within Disadvantaged Communities	CalEnviroScreen Scores between 7.6 and 10 (No. of Tracts in Top Quartile)	CalEnviroScreen Scores between 9.1 and 10 (No. of Tracts in Top Decile)	Highest-Scoring Areas (Top Decile divided by Top Quartile)
Westlands	62%	280	139	50%
Kramer & Inyokern	42%	159	76	48%
Central Valley N & Los Banos	56%	86	34	40%
Solano	15%	166	39	23%
Greater Imperial	22%	13	0	0%
Riverside East & Palm Springs	9%	6	0	0%
Southern California Desert	8%	1	0	0%
Northern California	2%	4	0	0%
Tehachapi	2%	4	0	0%
Greater Carrizo	2%	1	0	0%

Note: The counted number of tracts considers the census tracts that are primarily within each boundary, shown also in Table 5.

Table 9 lists the nine economic regions with the number of disadvantaged communities the top decile and quartile of CalEnviroScreen scores; 91% of the disadvantaged communities are in Central Valley, Inland Valley, and Los Angeles. These are also the three economic regions with the greatest number of high-scoring disadvantaged communities.

Table 9. Economic Regions with the Highest-Scoring Disadvantaged Communities

Aggregated Economic Region	CalEnviroScreen Scores between 9.1 and 10 (No. of Tracts in Top Decile)	CalEnviroScreen Scores between 7.6 and 10 (No. of Tracts in Top Quartile)	Highest-Scoring Areas (Top Decile divided by Top Quartile)
Central Valley	201	431	47%
Inland Valley	118	264	45%
Los Angeles	460	1,112	41%
Sacramento	10	49	20%
Central Coast	1	9	11%
San Diego and Imperial	4	39	10%
Bay Area	4	85	5%
North State	0	4	0%
Southern Sierra	0	0	NA

In summary, the areas having the highest percentages of population in disadvantaged communities and the highest-scoring disadvantaged communities are:

- **Air Basins:** the San Joaquin Valley, South Coast, and Salton Sea air basins.
- **CREZs:** the Westlands, Central Valley North & Los Banos, Kramer & Inyokern, and Greater Imperial CREZs.
- **Economic Regions:** the Central Valley, Inland Valley, and Los Angeles economic regions.

4. Environmental Impacts in Disadvantaged Communities

For our environmental study of impacts in disadvantaged communities, we focus on whether the action of changing the California ISO into a regional market operator is likely to increase the environmental pollution burden on any disadvantaged community. Two criteria are used here to describe how the different regionalization scenarios can affect disadvantaged communities:

- First, because regionalization is likely to influence the preferred locations for the incremental renewable energy buildout to meet California's 50% Renewable Portfolio Standard (RPS), construction of the buildout and long-term operation of renewable energy facilities may create adverse community-scale effects depending on whether the buildout is located in a setting of disadvantaged communities. The impacts common to all portfolios and the incremental buildout to meet the RPS by 2030 are discussed in Section 4.1.
- Second, because regionalization is likely to cause changes in the operation of the existing system of generation, and because power production may consume water and create emissions of air pollutants, the regional differences in power production are reviewed for adverse effects in areas of disadvantaged communities. The operational impacts are summarized in Section 4.2.

The potential to increase the pollution burden in disadvantaged communities could occur:

- If the locations of the incremental renewable energy buildout shift to identified disadvantaged communities under regionalization.
- If the location of an adverse environmental impact shifts to an area that predominately includes disadvantaged communities under regionalization.

Because the specific locations of community-scale impacts depend on the locations of actual individual future projects, these impacts cannot be determined with certainty at this time. However, the discussion below presents the typical localized environmental impacts resulting from renewable energy and utility-scale transmission project construction and operation that could affect areas of disadvantaged communities.

Figures 4, 5, and 6 illustrate the relative capacity that would be added by each buildout and the locations of disadvantaged communities in their resource zones.

Figure 4. Disadvantaged Communities Focus Map 1

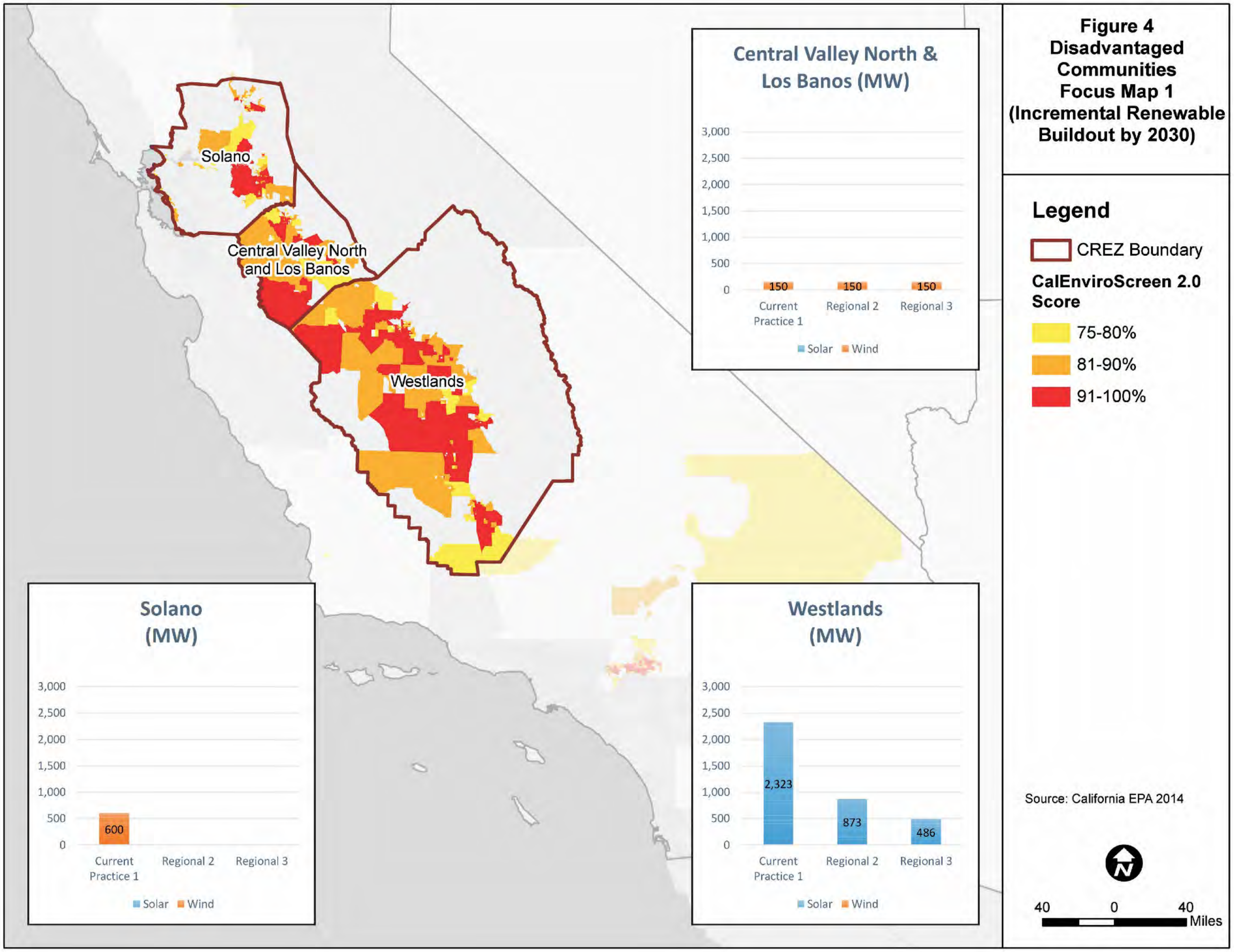


Figure 5. Disadvantaged Communities Focus Map 2

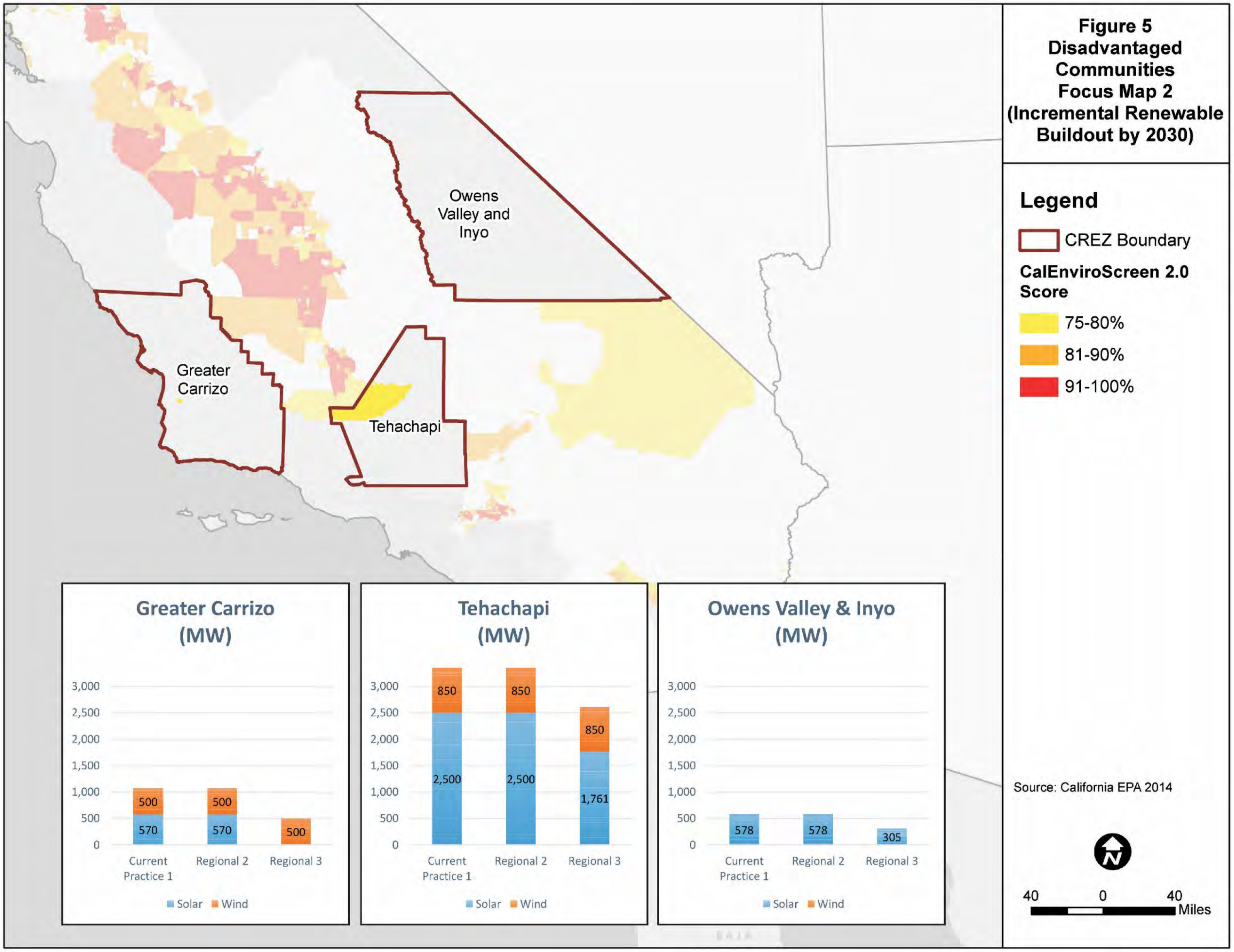
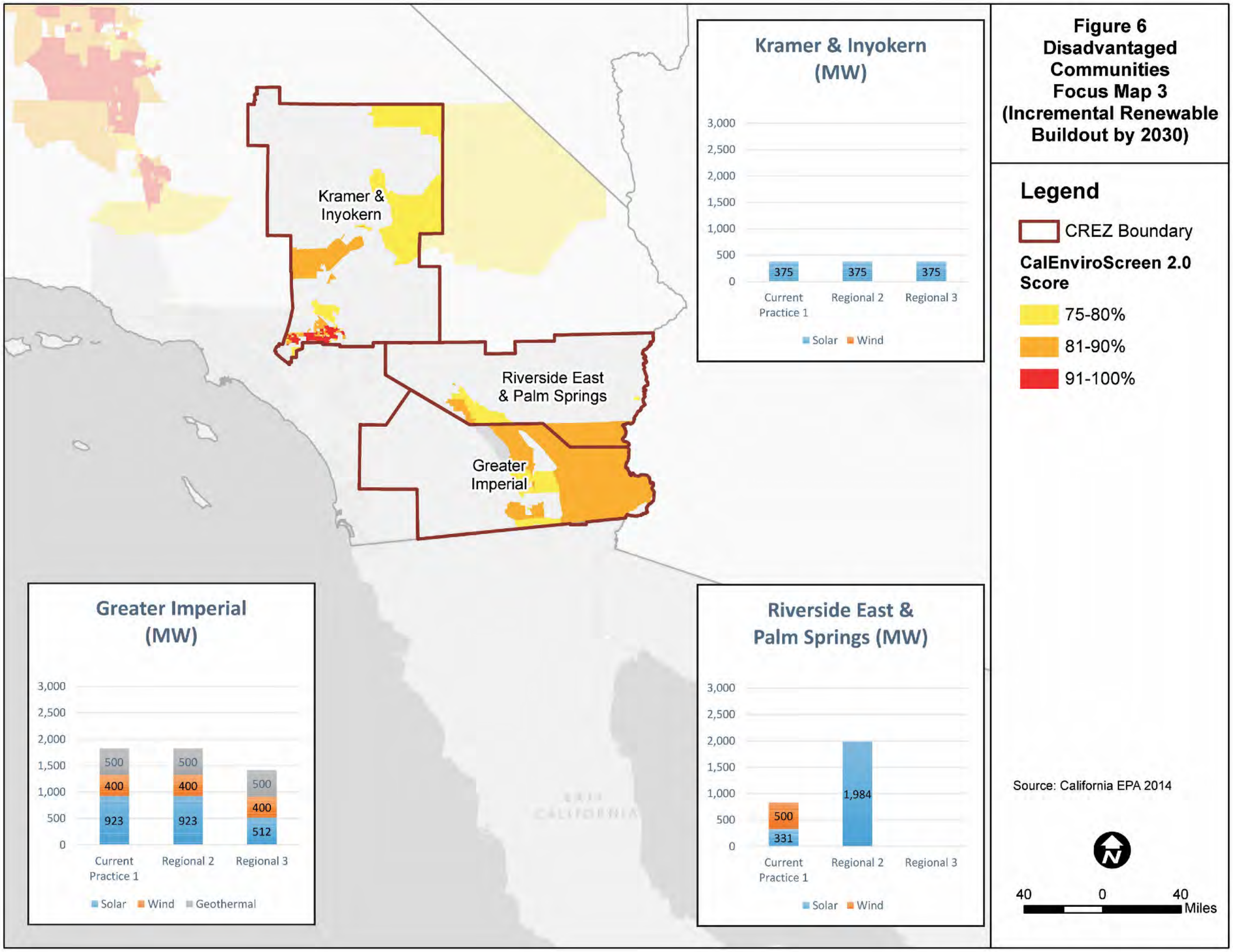


Figure 6. Disadvantaged Communities Focus Map 3



4.1 Typical Community-Scale Impacts of the Buildouts

This study of environmental impacts in disadvantaged communities considers how regionalization may influence the preferred locations for the incremental renewable energy buildout and how those locations may relate to disadvantaged communities. Because construction of the buildout and long-term operation of renewable energy facilities may create adverse community-scale effects depending on whether the buildout is located in a setting of disadvantaged communities, this section describes the environmental impacts that would be common across the scenarios as a result of the incremental buildout by 2030.

Note that the SB 350 environmental study is not site-specific and does not reflect or represent a siting study for any particular planned or conceptual construction project. Although environmental impacts are described in general, project-specific impacts can typically be managed through best management practices and mitigation, through the siting processes and with review by the siting authorities.

Construction Impacts in General

Common types of environmental impacts resulting from construction of large-scale renewable energy facilities or transmission infrastructure expansions could occur within disadvantaged communities depending on project-specific circumstances. These types of construction activities are similar for the incremental renewable energy buildouts in all scenarios. Therefore, the discussions below describe the types of impacts that could occur on a community-scale for construction of renewable energy facilities and associated transmission interconnections, with technology-specific unique or distinguishing aspects mentioned. Because construction is limited in duration, the potential to create construction-related environmental impacts essentially ends with the end of construction. These construction-phase impacts can typically be managed by siting authorities through best management practices and mitigation.

General types of construction impacts include:

- **Air Quality:** The typical construction-related air quality impacts are caused by fugitive dust from grading, vehicles driving on unpaved surfaces or roadways, and emissions from heavy-duty construction equipment and vehicles carrying construction materials and workers. These emissions occur during site development and preparation, transmission line development, and from building and roadway construction. The types of emissions would be the same for each renewable energy technology.

  Construction activities may include mobilization, land clearing, earth moving, road construction, ground excavation, drilling and blasting, foundation construction, and installation activities. Heavy equipment used during site preparation would also include bulldozers, scrapers, trucks, cranes, rock drills, and possibly blasting equipment. These activities and equipment use would temporarily increase the amounts of particulate matter, including PM2.5, and precursors to particulate matter. Similarly, increased amounts of ozone precursors (volatile organic compounds [VOCs] and nitrogen oxides [NOx]) would occur from engine exhaust emissions, further exacerbating ozone nonattainment conditions.

  Increased health risks would result for people exposed to excessive concentrations of dust, potentially including valley fever, and hazardous or toxic air pollutants routinely caused by gasoline and diesel-powered equipment. Diesel particulate matter is designated as a toxic air contaminant in California. High levels of construction-phase emissions can exacerbate regional nonattainment conditions or expose sensitive receptors to substantial concentrations of hazardous or toxic air pollutants during project construction. Assessing the air quality impacts from construction emissions usually involves project-specific quantification of air pollutants emitted by construction activities for each phase of site development for each project.

- **Noise:** Temporary construction noise typically occurs intermittently and varies depending on the nature or phase of construction (e.g., demolition and land clearing, grading and excavation, erection). Construction noise is localized and can create short term nuisances from the activities such as site preparation, trucks hauling material, concrete pouring, use of power tools, etc. Noise from heavy-duty equipment, including earthmovers, material handlers, and portable generators, can reach high levels for brief periods. Temporary noise impacts would be similar for all renewable energy types.
- **Traffic:** During construction of renewable energy and transmission facilities, workers commute to the project site over local roads, and shipments to and from the facilities are usually by truck. Rail transport to the closest intermodal facility for materials could also be used. The movement of persons, equipment, and materials to project sites during construction could cause a temporary decrease in the performance levels on local primary and secondary road networks.

  Wind turbine components are delivered in oversized or overweight loads, such as the rotor blades, which may be delivered as one piece, and nacelles, which contain massive drivetrain components and generators. Transporting these components typically requires permitting for movement of oversized loads and temporary road closures. In addition, the main cranes required for tower and turbine assembly typically also require a number of oversized or overweight shipments. The wind energy transportation requirements may cause temporary disruptions in surrounding communities.

Operational Impacts in General

General types of impacts that occur over the long-term operation of large-scale renewable energy facilities or transmission infrastructure expansions include:

- **Aesthetics:** The operation and maintenance of renewable energy facilities and associated transmission lines, roads, and rights-of-way would have long-term adverse visual effects due to visual intrusion of facilities introduced into landscapes. Among these are land scarring, introduction of structural contrast and industrial elements into natural settings, view blockage, and skylining (silhouetting of elements against the sky). Another impact common to renewable energy facilities is dust generated by vehicle movement within a site or along a right-of-way or access road. Without proper disturbed soil management strategies, wind can mobilize dust from project sites and create visible plumes or clouds of dust.

  Solar projects introduce geometric shapes and repeated linear elements into the visual environment. Utility-scale projects have a large footprint and are usually in open and relatively flat settings with little to no vegetative or other screening. Solar energy projects also vary in their visual impacts because of the different technologies employed. Furthermore, the level of impact can vary between urban and rural landscapes. While more viewers in urban areas see solar installations, the installations will typically create greater visual contrast in rural areas. Under certain viewing conditions, solar installations give rise to specular reflections (glint and glare) visible to stationary or moving observers from long distances, and can constitute a major source of visual impact. Glint and glare from photovoltaic facilities are typically lower than solar concentrating facilities using trough, power tower, and solar dish technologies that employ mirrors and lenses.

  Wind energy projects are usually highly visible because the vertical towers and rotating turbine blades need unobstructed access to the wind resource, usually best in areas where there are few, if any, comparable tall structures in strongly horizontal landscapes. Visual impacts associated with the operation and maintenance of geothermal energy projects largely derive from ground disturbance and the visibility of industrial power plants, wells, pipes, steam plumes, and transmission lines.

- **Air Quality:** Emissions are caused by operations and maintenance activities of the renewable energy buildout, through routine upkeep of the sites, security patrols, use of emergency generators, employee transportation, and vegetation removal. Dust emissions come from ground disturbance from access and spur road maintenance. Products of combustion are emitted by the use of natural gas, auxiliary heating of solar thermal technologies, and by the use of gasoline and diesel fuel for facility maintenance activities. Backup power supplies or fire water-pumping engines could also generate emissions if long-term operations and maintenance include diesel-powered emergency-use engines at substations and renewable energy facility sites.

  Geothermal well-venting emissions include hydrogen sulfide (H_2S), carbon dioxide (CO_2), mercury, arsenic, and boron (when these compounds are contained in geothermal steam). H_2S is generally the primary pollutant of concern, and typically an air monitoring system is installed during geothermal field development. People exposed to high concentrations of H_2S or other hazardous or toxic air pollutants could experience adverse health effects, including cancer and non-cancer health risks; even at very low concentrations.

- **Public Access:** The development of large undisturbed areas for renewable energy installations can result in long-term impacts by limiting the access to previously accessible public lands or limiting other development of these lands. Such limitations could both directly and indirectly affect local economies and populations, but effects depend on site-specific existing and potential use. Closures of open public lands may affect motorized access to historically available recreational destinations and areas and reduce new access to individual, commercial, and motor-dependent recreational destinations. Demand for motorized access, particularly in public backcountry areas on federal lands, may put additional pressure on the remaining backcountry areas to meet that demand. Such restrictions could also limit access to lands that could otherwise be used for farming or for other economic purposes, and lands with cultural, tribal, or religious significance.

- **Water Quality and Supply:** Operations and maintenance activities for the renewable energy buildout can introduce a small risk of groundwater contamination, interference with recharge, depletion of groundwater levels and storage, and other water quality impacts. Improper handling or containment of hazardous materials could disperse contaminants to soil and impact groundwater quality. Evaporation ponds may be required as part of cooling structures, and these may leak and possibly discharge brines and other contaminants to shallow groundwater. Groundwater consumption affects groundwater levels and storage volumes. Solar thermal and geothermal plant operations may require substantial amounts of water for steam generation, cooling, and other industrial processes; much less water is used for maintenance of photovoltaic facilities that may require cleaning. Similarly, the water used for operations and maintenance of wind energy systems would be limited to smaller volumes for operation, maintenance, cleaning activities, and possibly dust suppression.

- **Public Services:** Deployment of utility-scale renewable energy facilities can introduce new demands on the local public services of the host community and may also have implications in terms of local tax revenue. The need for new or expanded public services, including applicable performance objectives and service ratios, is strongly influenced by population levels. While development of renewable energy projects and transmission infrastructure could generate growth from new employment, in most areas, any population increase from new workers would likely be nominal compared to the existing population currently served by local public service providers, (e.g., fire, police, and schools). It should be noted that renewable projects sited on federal land may not generate property tax benefits to local communities when compared to those sited under a local jurisdiction.

Environmental Benefits

The construction and operation of large-scale renewable energy facilities may also provide environmental benefits, which can reduce preexisting burdens within disadvantaged communities. In general, the greatest beneficial impacts result from renewable energy facilities leading to a reduction or avoidance of the natural resources used by or emitted as a result of operating conventional power plants.

Regulatory precedent for identifying the environmental benefits of California's renewable energy buildout appears in SB X1-2, signed in 2011, that was reiterated in SB 350. According to SB X1-2 [specifically, in Pub. Util. Code § 399.13(a)(7)], procurement of renewable energy should give preference "to renewable energy projects that provide environmental and economic benefits to communities afflicted with poverty or high unemployment, or that suffer from high emission levels of toxic air contaminants, criteria air pollutants, and greenhouse gases."

General types of beneficial impacts that could occur from the incremental renewable energy buildout include:

- **Air Quality:** Producing electricity from the renewable energy resources displaces the need to produce electricity and the associated air contaminants from conventional fossil fuel-fired power generation facilities. While such benefits would be felt at a regional or statewide level, disadvantaged communities would be among those realizing reduced burden at the local level due to decreased emissions when compared to conventional power generation facilities.
- **Land Use:** While the deployment of large-scale renewable energy development is presumed to occur on land that is vacant or largely undeveloped, open land may be used that is previously disturbed. Rangeland and certain types of agriculture can be collocated with the wind buildout, and suitable solar buildout locations may include brownfield sites, where other development options are limited. In some instances, solar photovoltaic energy installations may be sited on degraded lands (landfills, brownfield sites, etc.), or co-located with other industrial uses. While these projects may introduce land scarring and some structural contrast and industrial elements, in developed areas, they can often be visually screened due to their relatively low profile (compared to wind energy or conventional power facilities). The siting of solar photovoltaic facilities on degraded lands could be considered a community benefit, as installations may: improve the value and aesthetics of underused sites; provide a buffer against land use incompatibilities in densely developed areas; and/or allow a fuller realization of value of other undisturbed or open lands with resource potential. Using degraded lands to site renewable energy can allow other lands with higher land use, resource, and visual potential to be preserved.
- **Water Supply:** The renewable energy buildout requires little water for operation. The buildout scenarios help to reduce the need for new conventional power plants. This could lead to a decrease in the amount of future water needed for electrical generation, resulting in reduced groundwater consumption, reclaimed water use (that could be utilized for agricultural use or groundwater recharge), and potable water use. While such benefits would be felt at a regional or statewide level, local disadvantaged communities would be among those benefiting from decreased water use by conventional power generation facilities because the water would remain available for agricultural and customer uses.
- **Socioeconomics:** The beneficial economic and tax base impacts in disadvantaged communities that occur during construction and operation of the renewable energy buildout are identified in Section 5, prepared by Berkeley Economic Advising and Research (BEAR).

4.2 Environmental Impacts of Regionalization in Disadvantaged Communities

The Environmental Study (Volume IX) describes the baseline environmental conditions and potential impacts across the entire study region including areas outside of disadvantaged communities. The study includes in-depth analysis of the setting and impacts to land use, biological resources, water, and air emissions. Our findings in the SB 350 environmental study reflect inherent tradeoffs to in-state versus out-of-state renewable development. From the methodologies and assumptions of the environmental study, this section describes the impacts on California's disadvantaged communities.

Our study methodology includes an estimate how power plants operate on a generating unit-specific basis, for all units in the WECC-wide fleet, but our presentation shows aggregated results for each geographical location. The presentation of operational impacts relies directly on the on the Production Cost Analysis (Volume V). However, there are some limitations to interpreting absolute levels of unit-specific operations and the subsequent air emissions from the production cost model, since the model does not mimic the precise accounting of emissions rates or air pollutant control equipment use.

Other important limitations and considerations relevant to the air emissions analysis include:

- 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.
- 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 greenhouse gases 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.
- For the purposes of the Disadvantaged Communities (DAC) analysis, the regional modeling output for generators in specific communities was examined at the air basin level. Emissions are summed up by air basins. The DAC results are based on these basin-wide totals, not emissions from specific power plants in or near DACs.
- 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 owner of the generator. 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.
- Emissions are presented for the annual periods of the two study years: the near-term (2020), and the longer-term (2030), with separate presentation of average emissions rates within the three months of the summer season, for consideration of the effects on ozone levels.
- The results do not use any generator specific permit limits, as those are specific to each source in each air district. Note that emissions changes from the fleet of existing stationary sources are required to be well within the limits allowed by the permitting authorities, depending on the permitted terms that apply to each generating unit. This study assumes that no existing source would need to change its permitted terms of operation. New fossil-fueled stationary sources are not contemplated by this study.

Environmental Impacts in Disadvantaged Communities in 2020

Of the five primary scenarios of the SB 350 studies, the near-term 2020 scenarios include no incremental buildout of California's renewable energy portfolio beyond what is already planned to meet the state's 33% RPS by 2020. As a result, limited regionalization in 2020 (CAISO + PAC) involves no incremental construction activities and no construction-related impacts to the environment. The 2020 scenarios may cause changes in the operation of the existing system of generation; the impacts associated with those changes are described in the following paragraphs and tables.

Operational Impacts of Limited Regionalization in 2020

The modeling and production cost simulation of limited regionalization scenarios reveal how operation of the existing system of generation may change. Changes in power production will result in changes in the consumption of water and creation of emissions of air pollutants. The production cost simulation for 2020 Current Practice versus the CAISO + PAC scenario shows that the operational changes in California's existing system of generation and primarily the fleet of natural gas fired power plants would be negligible in a limited regional market as compared with the 2020 Current Practice scenario. On average, power plants across California would operate slightly less, and power plants outside of California would operate slightly more (Production Cost Analysis, Volume V).

Some components of the existing system of generation are located in disadvantaged communities, and reducing the use of fossil fuel burned at these facilities will slightly reduce the baseline pollution burden of disadvantaged communities. The 2020 results for water use and emissions are summarized as follows:

- By achieving a small decrease in fossil fuel use for electricity production in California, regionalization results in a small but beneficial decrease in the electric power sector's use of water resources (water used by electricity generation decreases by 1.5% statewide). This may reduce the baseline stress on water bodies and water systems in disadvantaged communities.
- Limited regionalization in 2020 reduces emissions of air pollutant emissions in California on average (decrease 0.5% to 1.2% statewide, depending on pollutant), depending on the dispatch of the fleet of natural gas-fired power plants. Certain air basins that are of the greatest concern for disadvantaged communities would experience slight increases in PM2.5 and SO_2 emissions (increase 0.4% in San Joaquin Valley and South Coast air basins and increase 0.7% in Mojave Desert air basin), but the San Joaquin Valley and South Coast air basins would experience greater benefits through decreases in NOx, which is a precursor to both ozone and PM2.5.

The Environmental Study (Volume IX) shows these benefits of a limited regionalization in 2020 in greater detail. In conclusion, the limited regionalization causes no adverse environmental impact in California's disadvantaged communities and may result in small but beneficial environmental effects by generally reducing water use and NOx emissions. Modeling of the 2020 CAISO + PAC scenario indicates that the San Joaquin Valley and South Coast air basins could slightly increase PM2.5 and SO_2 emissions due to natural gas-fired power plants, but these changes would occur in conjunction with a NOx decrease.

Environmental Impacts in Disadvantaged Communities in 2030

Each scenario of regionalization in 2030 requires an incremental buildout of new solar, wind, geothermal and other energy facilities that will create environmental impacts in the vicinity of the renewable energy buildout. The locations of the incremental buildout in all scenarios are illustrated in Figures 4, 5, and 6. Incremental Buildout for Current Practice 1 by 2030

The buildout for Current Practice 1 by 2030 emphasizes incrementally more new solar generation in the Tehachapi, Westlands, and Greater Imperial CREZs. New wind power would predominately occur in Tehachapi and Solano, and new geothermal would be in Greater Imperial (in all scenarios). The Westlands CREZ in the San Joaquin Valley is one area of greatest concern for impacts to disadvantaged communities due to the high baseline level of pollution burden (e.g., poor air quality) and concentrations of sensitive populations (i.e., people with low incomes and high unemployment). The Central Valley North & Los Banos, Kramer & Inyokern, and Greater Imperial CREZs also contain high percentages of population in disadvantaged communities.

The environmental impacts of the incremental renewable energy buildout in disadvantaged communities include: the construction-related dust and equipment exhaust emissions, along with noise and traffic; the general impacts of long-term operation of renewable energy facilities, including the changes in aesthetics; and benefits that depend on site-specific circumstances. These are impacts common to all portfolios (Section 4.1).

The Current Practice 1 buildout by 2030 involves seven different solar resource areas and six different wind resource areas in California, including four areas that have a high level of concern for impacts to disadvantaged communities (Westlands; Central Valley North & Los Banos; Kramer & Inyokern; Greater Imperial). The disadvantaged communities in these areas are the most likely to experience some construction-related community-scale environmental impacts. Although the Tehachapi, Westlands, and Greater Imperial CREZs are emphasized in the renewable energy buildout in Current Practice 1, the Tehachapi CREZ does not contain high percentages of population in disadvantaged communities.

The Regional 2 buildout by 2030 emphasizes solar in the Riverside East & Palm Springs, Tehachapi, and Greater Imperial CREZs. These areas have lower fractions of population within disadvantaged communities than the Westlands CREZ, which would not be emphasized in this buildout. The environmental impacts of the incremental renewable energy buildout in disadvantaged communities include the impacts common to all portfolios (Section 4.1).

The Regional 2 buildout by 2030 occurs across a smaller number of resource areas in California, when compared with Current Practice 1, although two buildout areas have a high level of concern for impacts to disadvantaged communities (Kramer & Inyokern; Greater Imperial). In contrast with scenario Current Practice 1, which includes an emphasis on Westlands, the Tehachapi and Riverside East & Palm Springs CREZs emphasized in Regional 2 do not contain high percentages of population in disadvantaged communities. Accordingly, Regional 2 would be likely to avoid some construction-related community-scale environmental impacts in disadvantaged communities.
Incremental Buildout for Regional 3 by 2030

The Regional 3 buildout by 2030 includes the lowest level of development overall among all of the scenarios, and it has the lowest incremental capacity of additional renewable energy resources inside California. The environmental impacts of the incremental renewable energy buildout in disadvantaged communities include the impacts common to all portfolios (Section 4.1).

The Regional 3 buildout by 2030 occurs at a much lower intensity in California than in other scenarios, and only five different solar resource areas and four different wind resource areas in California are included. As with other scenarios, two buildout areas have a high level of concern for impacts to disadvantaged communities (Kramer & Inyokern; Greater Imperial). By emphasizing renewable energy resources outside of California, Regional 3 would be most likely to avoid construction-related community-scale environmental impacts in the state's disadvantaged communities.

Operational Impacts of Regionalization in 2030

The 2030 scenarios reveal that regionalization generally reduces the need to operate power plants inside California, and this reduces the consumption of water and emissions of air pollutants. The production cost simulation for 2030 Current Practice 1 versus the two regionalization scenarios shows that greater levels of reductions in use of California's existing system of generation and primarily the fleet of natural gas fired power plants occur with increasing regionalization. On average, power plants across California and also outside California would operate slightly less as regionalization decreases the use of fossil fuels (Production Cost Analysis, Volume V).

Portions of the existing system of generation are located in disadvantaged communities, and reducing the use of fossil fuel burned at these facilities will slightly reduce the baseline pollution burden of disadvantaged communities. The 2030 results for water use and emissions are summarized as follows:

- Scenarios Regional 2 and Regional 3 decrease the amount of water used by power plants statewide, when compared with Current Practice 1. By decreasing fossil fuel use for electricity production in California, regionalization results in a beneficial decrease in the electric power sector's use of water resources (decrease by 4.0% to 9.7% statewide). This may reduce the baseline stress on water bodies and water systems in disadvantaged communities.
- Scenarios Regional 2 and Regional 3 decrease the emissions of NOx, PM2.5, and SO_2 from power plants statewide and in the air basins of greatest concern for disadvantaged communities, depending on the dispatch of the fleet of natural gas-fired power plants. The San Joaquin Valley, South Coast, Mojave Desert, and Salton Sea air basins experience decreased emissions of all pollutants when compared with Current Practice 1. Certain other locations that are not the areas of greatest concern for disadvantaged communities would experience slight increases in PM2.5 and SO_2 emissions, although these other locations would experience greater benefits through decreases in NOx.

The Environmental Study (Volume IX) shows these benefits of 2030 regionalization in greater detail. In conclusion, the 2030 regionalization causes no adverse environmental impact in California's disadvantaged communities. The expanded scenario of Regional 3 shows the most beneficial environmental effects by achieving the greatest reductions in water use and emissions.

Review of Operational Water Use Impacts and Emissions Changes

This section reviews the results of the SB 350 Environmental Study to illustrate the operational changes in the existing system of generation. Because power production may consume water and create emissions of air pollutants, these results are summarized here based on the Environmental Study (Volume IX).

Table 10 summarizes how regionalization changes statewide water use for electricity production. [See Environmental Study (Volume IX)]

Table 10. Water Use for Electricity Production in California

Statewide	2020 CAISO + PAC Relative to Current Practice (% water use)	2030 Regional 2 Relative to Current Practice Scenario 1 (% water use)	2030 Regional 3 Relative to Current Practice Scenario 1 (% water use)
Difference Statewide Water Consumption (all generating technologies, excluding geothermal)	–1.5%	–4.0%	–9.7%

Source: Environmental Study (Volume IX).

Tables 11, 12, and 13 summarize the relative changes in criteria air pollutant emissions from the existing system of natural gas fired generating units in California's air basins, listed in the order of highest to lowest percentage of population in disadvantaged communities. [See Environmental Study (Volume IX)].

Table 11. NOx Emissions Changes, California Natural Gas Fleet by Air Basin

Air Basin	2020 CAISO + PAC Relative to Current Practice (% NOx)	2030 Regional 2 Relative to Current Practice Scenario 1 (% NOx)	2030 Regional 3 Relative to Current Practice Scenario 1 (% NOx)
San Joaquin Valley	**–0.5%**	**–3.3%**	**–5.8%**
South Coast	**–1.4%**	**–9.2%**	**–12.8%**
Salton Sea	**–5.1%**	**–99.4%**	**–99.4%**
North Central Coast	–0.6%	–2.5%	–2.1%
Mojave Desert	0.2%	–15.6%	–26.8%
Sacramento Valley	–2.6%	–9.7%	–16.2%
San Francisco Bay	–1.7%	–3.0%	–8.7%
South Central Coast	–0.1%	–0.3%	–0.3%
San Diego County	–6.8%	–24.6%	–26.9%
North Coast	–0.3%	0.3%	–1.0%
Difference Statewide NOx (California natural gas fleet)	**–1.2%**	**–6.5%**	**–10.2%**

Note: Bold indicates an air basin of greatest concern for disadvantaged communities.
Source: Environmental Study (Volume IX).

Table 12. PM2.5 Emissions Changes, California Natural Gas Fleet by Air Basin

Air Basin	2020 CAISO + PAC Relative to Current Practice (% PM2.5)	2030 Regional 2 Relative to Current Practice Scenario 1 (% PM2.5)	2030 Regional 3 Relative to Current Practice Scenario 1 (% PM2.5)
San Joaquin Valley	**0.4%**	**–2.0%**	**–3.8%**
South Coast	**0.4%**	**–9.7%**	**–12.2%**
Salton Sea	**–1.4%**	**–99.2%**	**–98.8%**
North Central Coast	–0.7%	0.3%	2.9%
Mojave Desert	0.7%	–14.2%	–23.3%
Sacramento Valley	–1.3%	–8.5%	–12.6%
San Francisco Bay	–1.4%	4.4%	0.1%
South Central Coast	0.0%	0.0%	0.0%
San Diego County	–6.4%	–17.3%	–18.9%
North Coast	10.0%	–0.9%	–2.6%
Difference Statewide PM2.5 (California natural gas fleet)	**–0.5%**	**–4.0%**	**–6.8%**

Note: Bold indicates an air basin of greatest concern for disadvantaged communities.
Source: Environmental Study (Volume IX).

Table 13. SO_2 Emissions Changes, California Natural Gas Fleet by Air Basin

Air Basin	2020 CAISO + PAC Relative to Current Practice (% SO_2)	2030 Regional 2 Relative to Current Practice Scenario 1 (% SO_2)	2030 Regional 3 Relative to Current Practice Scenario 1 (% SO_2)
San Joaquin Valley	**0.3%**	**–1.9%**	**–3.8%**
South Coast	**0.4%**	**–9.7%**	**–12.2%**
Salton Sea	**–1.4%**	**–99.2%**	**–98.8%**
North Central Coast	–0.7%	0.3%	2.9%
Mojave Desert	0.7%	–14.2%	–23.3%
Sacramento Valley	–1.3%	–8.6%	–12.7%
San Francisco Bay	–1.4%	4.5%	0.1%
South Central Coast	0.0%	0.0%	0.0%
San Diego County	–6.4%	–17.3%	–18.9%
North Coast	10.0%	–0.9%	–2.6%
Difference Statewide SO_2 (California natural gas fleet)	**–0.5%**	**–4.0%**	**–6.8%**

Note: **Bold** indicates an air basin of greatest concern for disadvantaged communities.
Source: Environmental Study (Volume IX).

Sensitivity Analysis

As with Current Practice Scenario 1, the Sensitivity 1B buildout by 2030 emphasizes a renewable energy procurement strategy that is in-state focused. The primary CREZs are Riverside East & Palm Springs, Tehachapi, and Greater Imperial CREZs, along with the Westlands CREZ to a lesser extent than Current Practice 1. The environmental impacts of the incremental renewable energy buildout in disadvantaged communities include the impacts common to all portfolios (Section 4.1).

The buildout for Sensitivity 1B, like Current Practice 1, involves seven different solar resource areas and six different wind resource areas in California, including four areas that have a high level of concern for impacts to disadvantaged communities (Westlands; Central Valley North & Los Banos; Kramer & Inyokern; Greater Imperial). However, the portfolio distribution of renewable energy buildout in Sensitivity 1B emphasizes the Tehachapi and Riverside East & Palm Springs CREZs more than Westlands. In contrast with scenario Current Practice 1, which includes an emphasis on Westlands, the Tehachapi and Riverside East & Palm Springs CREZs emphasized in Sensitivity 1B do not contain high percentages of population in disadvantaged communities.

Emissions of criteria air pollutants from California's natural gas-fired fleet of power plants are quantified in the Environmental Study (Volume IX) for two sensitivities analyses. Under the sensitivity analyses in comparison with Current Practice Scenario 1, the following would occur inside California:

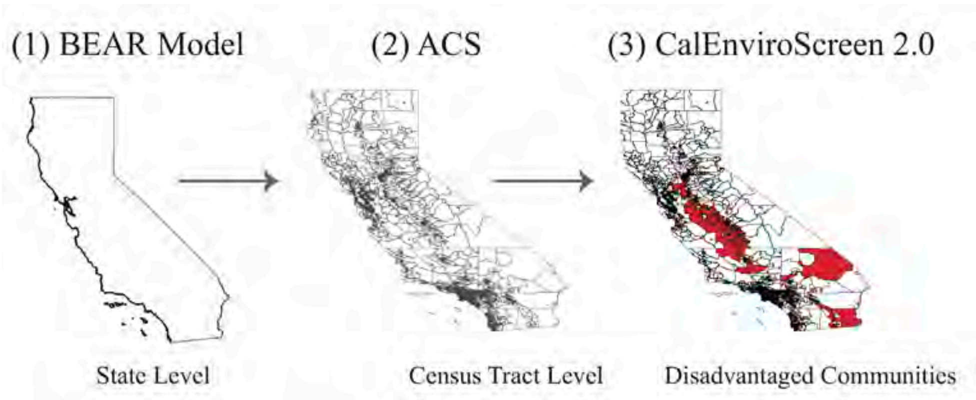
- Emissions in California would increase slightly (1% to 2%) in Sensitivity 1B, as operation of California's natural gas fleet would slightly increase, and this would slightly increase the emissions occurring within the air basins of greatest concern to disadvantaged communities, as illustrated in the Environmental Study (Volume IX).
- 2030 Scenario 3 without renewables beyond RPS similarly results in a slight increase in operation of California's natural gas–fired fleet, but this scenario would avoid some of the excess startup emissions of NOx that would occur under the 2030 Current Practice Scenario 1.

5. Economic Impact in Disadvantaged Communities

5.1 Methodology for Determining Economic Impacts in Disadvantaged Communities

The process of estimating economic impacts on disadvantaged communities is carried out in several steps. This assessment technique leverages available data to downscale state level estimates to the census tract level conforming to disadvantaged community definitions. Detailed descriptions of each step are presented below.

Figure 7. Downscaling Results to Identify Impacts in Disadvantaged Communities



Step 1 – Census Tracts

State-wide results produced by the BEAR model are first disaggregated across individual census tracts. Complete data on economic activities are not available at the census tract level, so it is not possible to build Social Accounting Matrices (SAMs) for individual census tracts. Instead, we construct census tract shares of state level economic activity for select variables of interest, i.e. income by decile, sector of employment, and occupation. Census tract estimates of these values are derived from the American Communities Survey (ACS)[4] using the 5-year averages covering the period 2008-2013.[5]

The ACS reports income by tax bracket, however, the BEAR model estimates impacts on income by decile. Consequently, tax brackets were converted to income deciles according to the share of overlap in each category. The number of households in each income decile was calculated for each census tract. State level income estimates were then shared out across census tracts according to the number of households in each income decile in each census tract.

The income estimates are presented as community income per household in 2030. Department of Finance estimates of population growth by county were used to estimate the *number of households* in each census tract to 2030. Population growth within counties is assumed to be constant across census tracts and household size is assumed to remain constant, so population growth is equivalent to growth in number of households. With these assumptions, household growth rates are calculated for each census tract and applied to the current number of households in order to forecast the number of households in each census tract in 2030.

[4] http://factfinder.census.gov/

[5] Base year economic accounts for the BEAR model are calibrated to 2013, the latest year for which complete California official economic statistics are currently available.

Job estimates from the BEAR model measure total Full Time Equivalent (FTE) employment by occupation. Indirect jobs at the state level are calculated by netting out statewide total estimated direct (investment target sector) jobs. Indirect jobs by occupation are then downscaled from state to census tract level according to the number of employees in each occupational category within each census tract. Direct jobs are downscaled from counties to census tracts according to the number of employees in construction-based occupations within each census tract. Direct and indirect jobs are then summed to estimate total jobs in each census tract. This allocation of jobs assumes local recruitment for investments in buildout, as well as local employment in activities responding to increased local demand.

Step 2 – Disadvantaged Community Level

In the final step, CalEnviroScreen 2.0 is used to identify census tracts designated as disadvantaged communities. Disadvantaged communities are defined as census tracts in the top 25th percentile of CES scores. By this definition, there are 2,009 disadvantaged communities (census tracts) in California. Income and job estimates for the subset of census tracts meeting this condition are presented in the results section.

5.2 Economic Impact Results

The economic results begin by decomposing our findings between disadvantaged and non-disadvantaged communities. Given that disadvantaged communities represent a quarter of all census tracts in California, it should be no surprise that the macroeconomic trends previously described also apply for disadvantaged communities. That being said, there are some small differences between impacts on disadvantaged and non- disadvantaged communities and these merit further discussion.

The first such results are illustrated in Figure 8, where we see that comparable job creation trends by type hold for disadvantaged communities versus non-disadvantaged communities. That is, Regional 2 and Regional 3 both produce more jobs in 2030 in disadvantaged communities than Current Practice 1. More robust job growth in the regional scenarios is driven primarily by ratepayer savings. The effect if this induced employment is more readily seen in Figure 9, which illustrates direct comparison between Current Practice 1, Regional 2, and Regional 3. Disadvantaged communities will experience relatively fewer direct jobs from renewable energy projects in either regionalization scenario compared to Current Practice 1, but the more widely distributed household benefits of ratepayer savings induce new job creation across occupations that more than offset this.[6] Similar effects are observed for non-disadvantaged communities, although the effects are less pronounced. This difference in jobs between disadvantaged and non-disadvantaged communities resulting from the renewable buildout depends upon the precise counties in which certain renewable development is expected to occur across the various scenarios. The key takeaway here is that, like the rest of the state, regionalization will not benefit the disadvantaged communities in terms of direct job creation as much as Current Practice, but instead disadvantaged communities will see benefits from the indirect effects from the supply chain or induced effects from lower energy rates.

The distinction can be quite important depending on the nature of jobs created by the renewable energy buildout. While the BEAR assessment identifies employment impacts spatially and in different occupations, we are looking at economic stimulus only in the time period considered (2015-2030). Direct

[6] The Regional 2 scenario actually calls for the largest solar build of all three scenarios and generates the greatest number of solar jobs (29,300 compared to 28,800 in Current Practice 1). However, the total number of additional jobs from the renewable buildout is less in Regional 2 compared to Current Practice 1 since there is considerably less wind energy development in Regional 2.

job stimulus will last as long as the renewable capacity buildout investments, while ratepayer savings can be expected to continue. Many of the investment-driven buildout jobs may be temporary, while those fueled by ratepayer savings will be sustained and support higher long term community income and expenditure. Moreover, the latter are widely dispersed across service sector employment, providing more diverse training and income earning opportunities.

Figure 8.
Job Creation Across Scenarios in Disadvantaged Communities and Non-Disadvantaged Communities

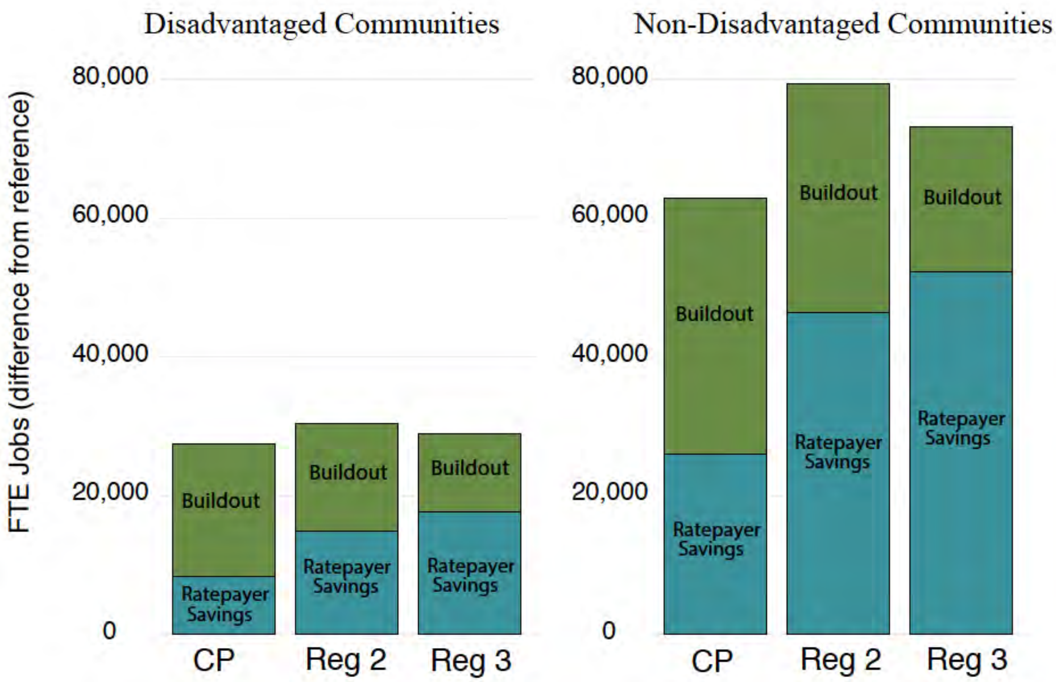
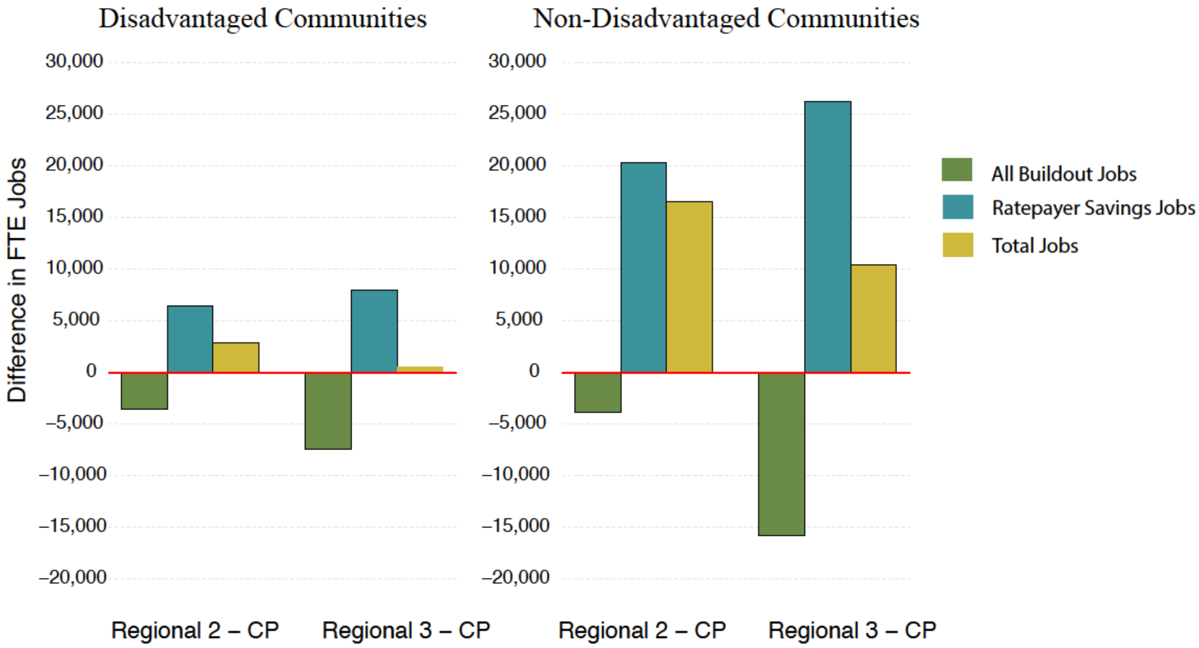
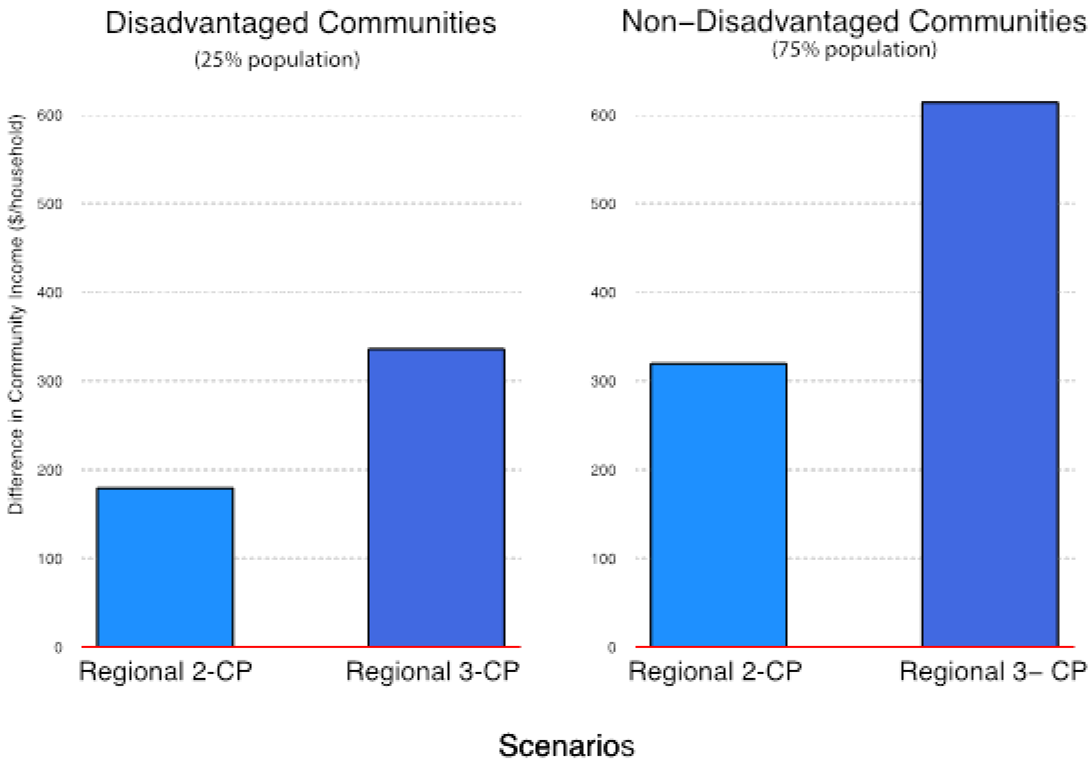


Figure 9.
Difference in Job Creation Across Scenarios in Disadvantaged Communities and Non-Disadvantaged Communities



Income effects also differ between disadvantaged communities and non-disadvantaged communities across scenarios, as shown in Figure 10. Once again the state trend remains the same with Regional 3 posting the largest increase in incomes across both disadvantaged communities and non-disadvantaged communities. Average income gains for disadvantaged communities are lower than non-disadvantaged communities, which is to be expected given that disadvantaged communities have lower average incomes in general. However, disadvantaged communities, which account for 25% of the State's census tracts, receive 31% and 35% of the total income benefits for Regional 2 and Regional 3, respectively. This result suggests that the income benefits accrue to disadvantaged communities in higher proportion than their population share.

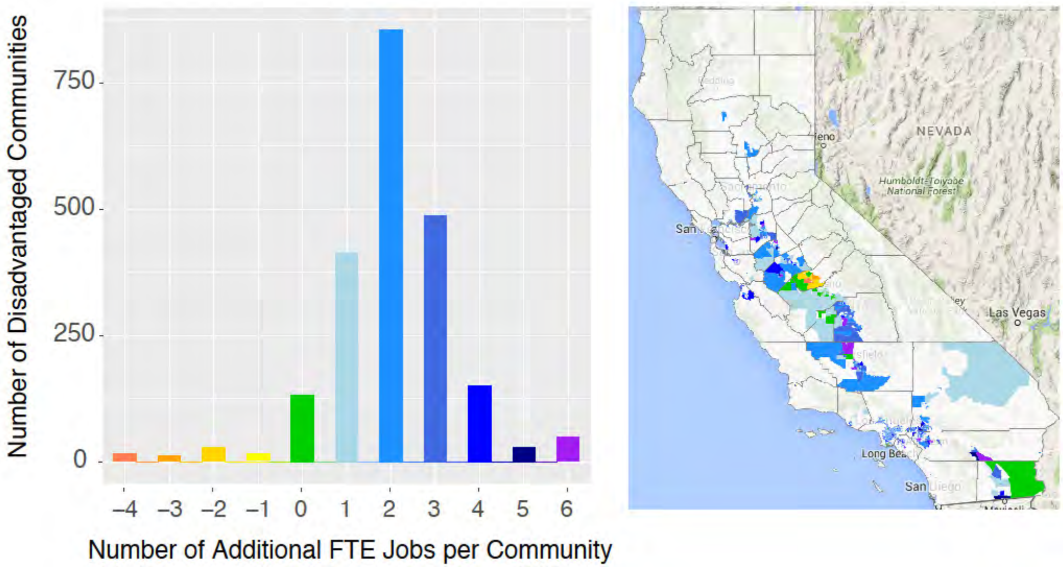
Figure 10.
Difference in Community Income Across Scenarios in Disadvantaged Communities and Non-Disadvantaged Communities



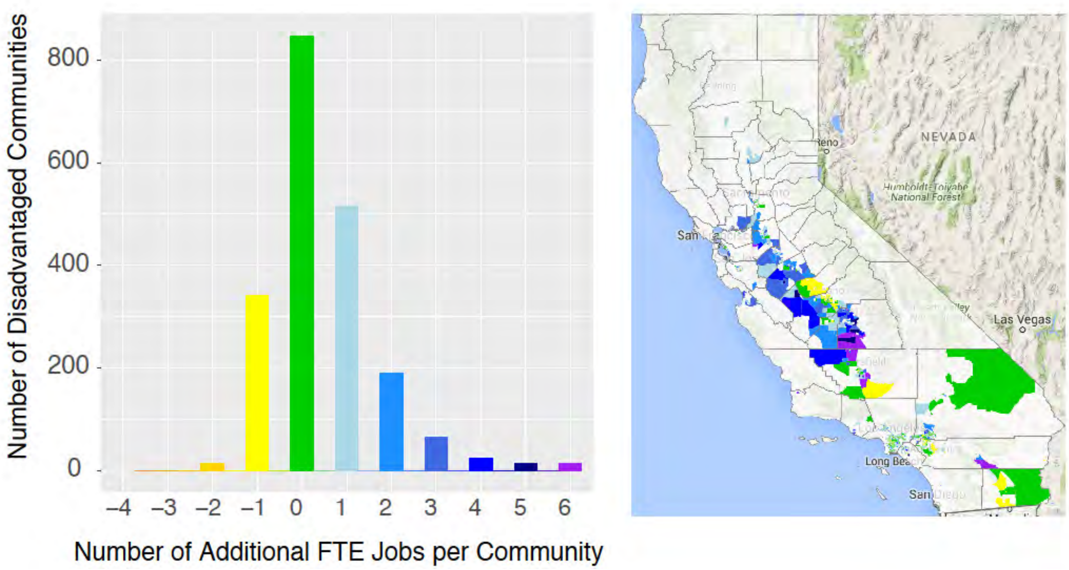
The disadvantaged communities results can also be represented with spatial detail, and the following figures represent the employment and income results for specific disadvantaged community regions. Figure 11 shows job creation results for all disadvantaged communities across California in 2030. The left panels show a count of the number of disadvantaged communities that are expected to have more or less jobs compared to Current Practice, and the right panels show the spatial distribution of employment effects.[7] This figure shows how majority of job creation will be concentrated in communities in the Central Valley and Los Angeles. Comparing Current Practice 1 to Regional 2 and Regional 3, we find that jobs across Regional 2 are more evenly dispersed among disadvantaged communities, while Regional 3 sees a higher concentration in specific disadvantaged communities. Moderately lower job growth is observed in several disadvantaged communities (primarily in the Central Valley) in both regional scenarios, compared to Current Practice 1, although the net employment impact for disadvantaged communities is positive.

[7] The term *community* refers to an individual disadvantaged community census tract.

Figure 11. Difference in FTE Jobs in Disadvantaged Communities
Scenario 2 vs. Current Practice



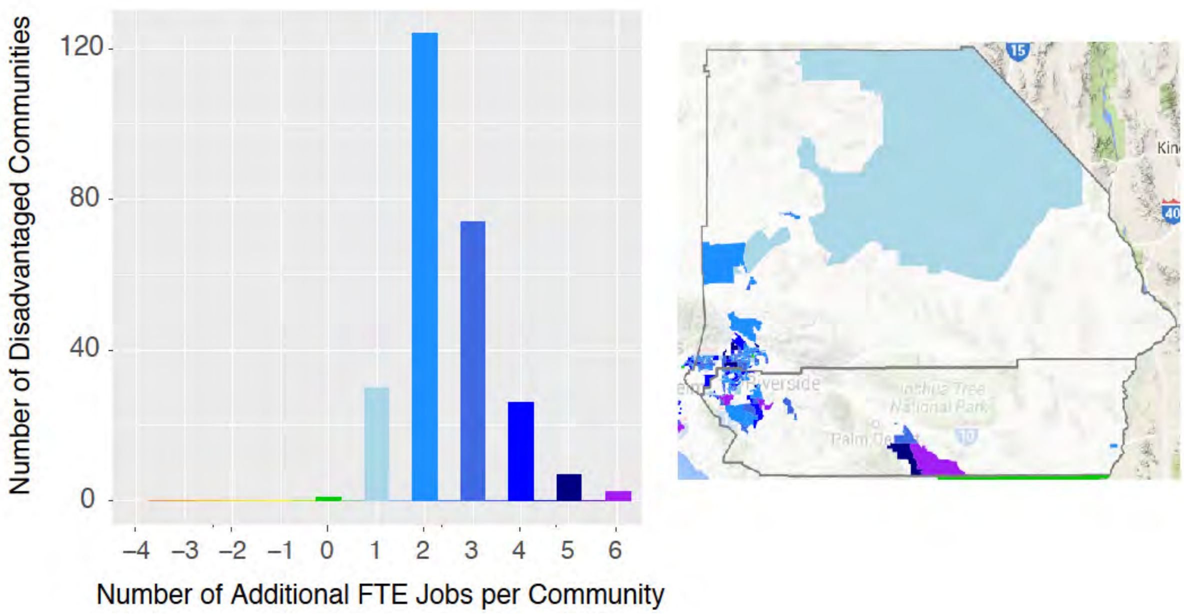
Scenario 3 vs. Current Practice



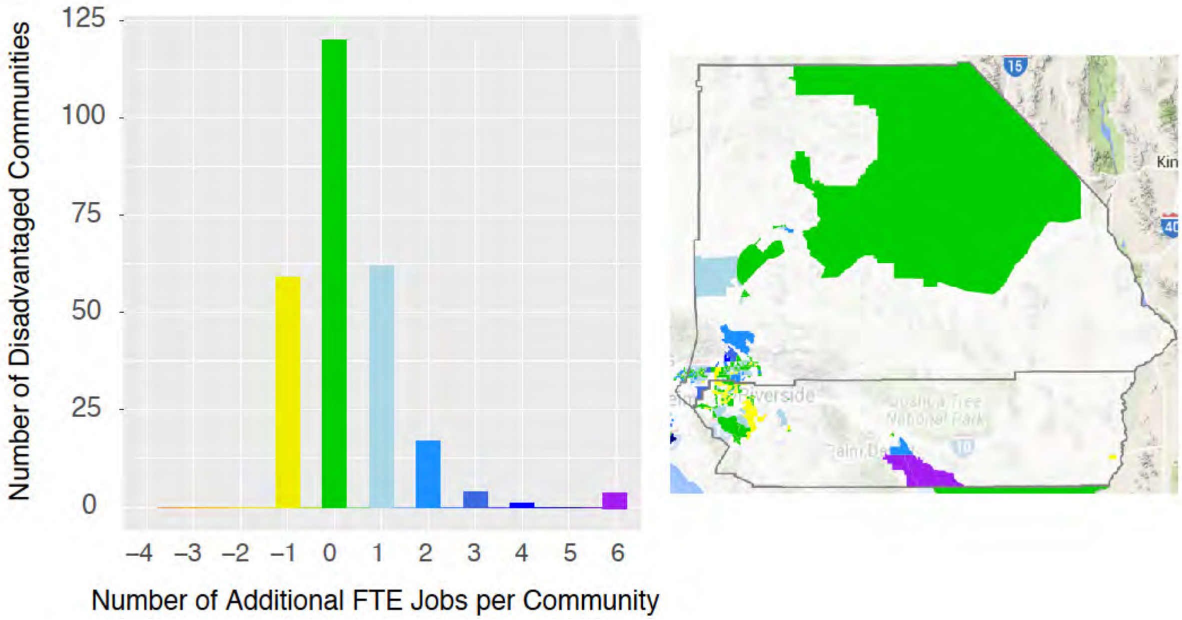
Employment and income results are presented below for three economic regions with the majority of disadvantaged communities: The Inland Valley, the Greater Los Angeles Area, and the Central Valley. Starting with the Inland Valley, Figure 12 shows that a regional market would have a positive impact on job creation. Regional 2 yields a greater number of jobs created from the renewable buildout than Current Practice (8,800 FTEs in Regional 2 vs. 6,200 FTEs in Current Practice), while also retaining the employment generated by considerable ratepayer savings. The net employment effect in Regional 2, compared to Current Practice, is positive job creation in all of Inland Valley's disadvantaged communities. Regional 3 shows more modest net jobs creation due to the fact that the total jobs created through ratepayer savings are only slightly greater than the fewer number of jobs created from the renewable buildout. In the Inland Valley renewable buildout, the Regional 3 scenario results in approximately 1,300 FTEs vs. the 6,200 FTEs created in the Current Practice Scenario. Approximately half of the disadvantaged communities in Regional 3, compared to Current Practice, received no additional jobs created. Approximately 60 disadvantaged communities are projected to have 1 less job in Regional 3 compared to Current Practice.

Figure 12. Difference in FTE Jobs in Disadvantaged Communities (Inland Valley)

Regional 2 – Current Practice



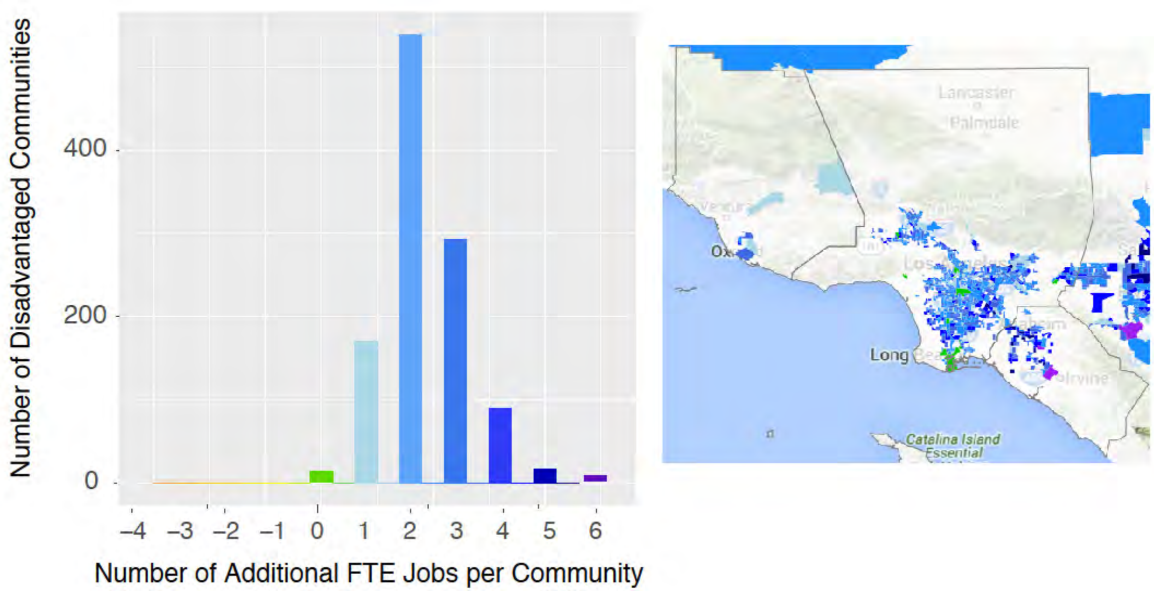
Regional 3 – Current Practice



Moving next to the Greater Los Angeles Area, Figure 13 shows positive employment impacts across for the vast majority of the region's 1,112 disadvantaged communities in Regional 2 and Regional 3. The region, which accounts for 56% of the state's disadvantaged communities, also accounts for most of the jobs creation resulting from regionalization. The job creation driven by a regional market is due primarily to the effect of ratepayer savings on economic activity in the region. Job creation is highest in the Regional 2 scenario, where disadvantaged communities receive both significant ratepayer savings and all of the buildout jobs attributed to Los Angeles and Ventura counties in the Current Practice scenarios. A small fraction of the disadvantaged communities that might benefit slightly more from the employment generated from the renewable buildout are projected to have one less job in Regional 3 compared to Current Practice.

Figure 13. Difference in FTE Jobs in Disadvantaged Communities (Greater Los Angeles)

Regional 2 – Current Practice



Regional 3 – Current Practice

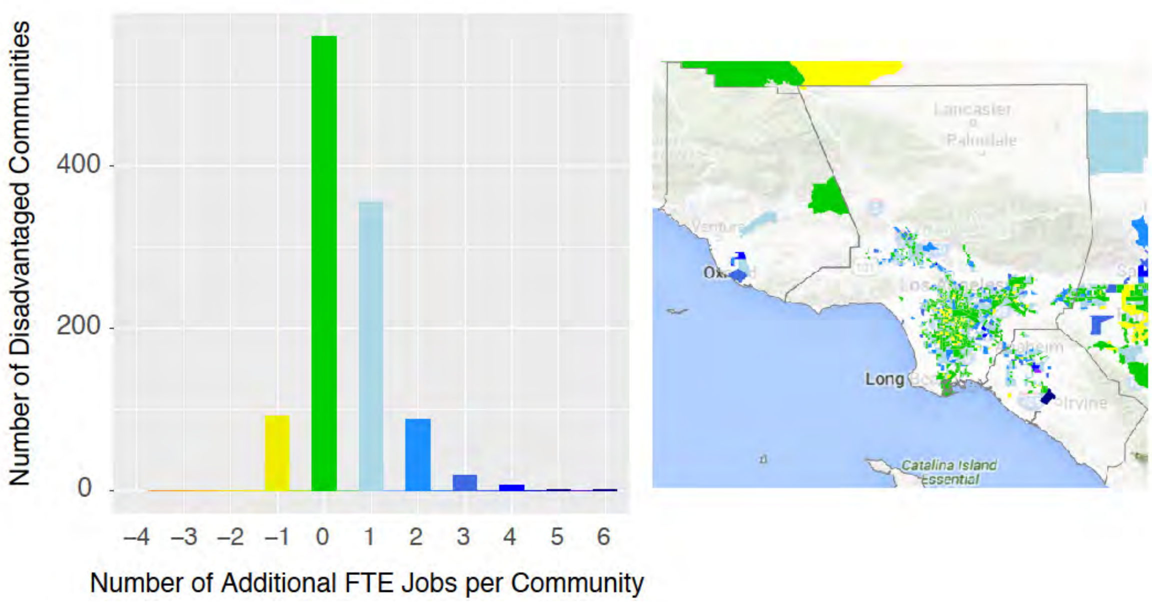
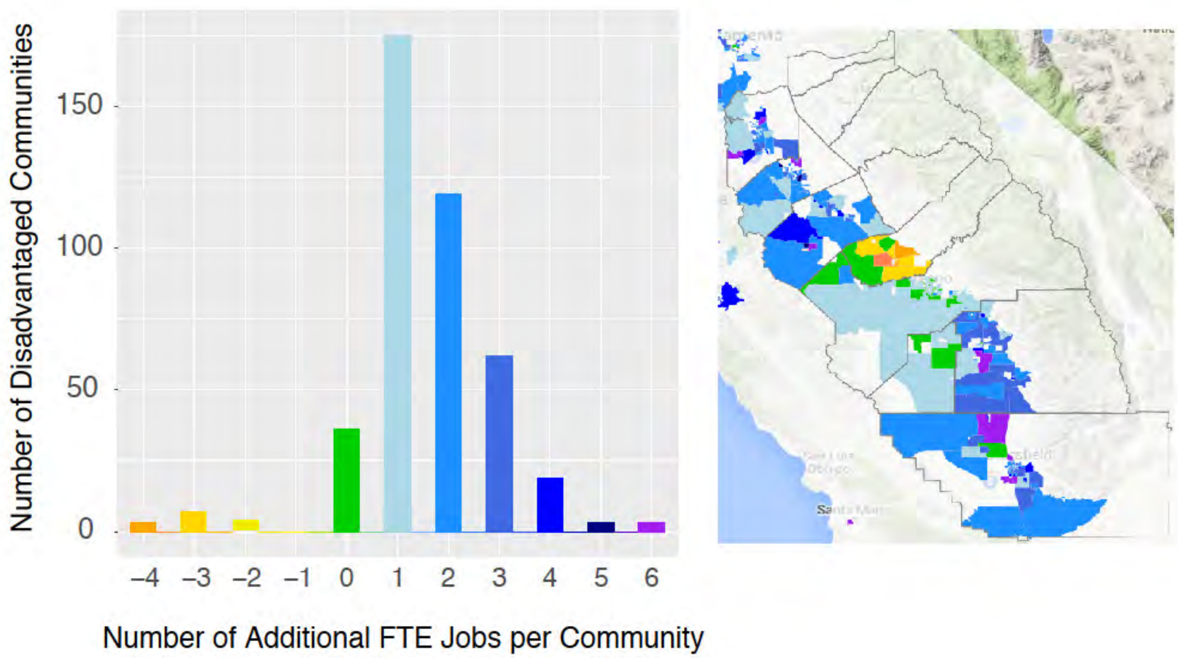


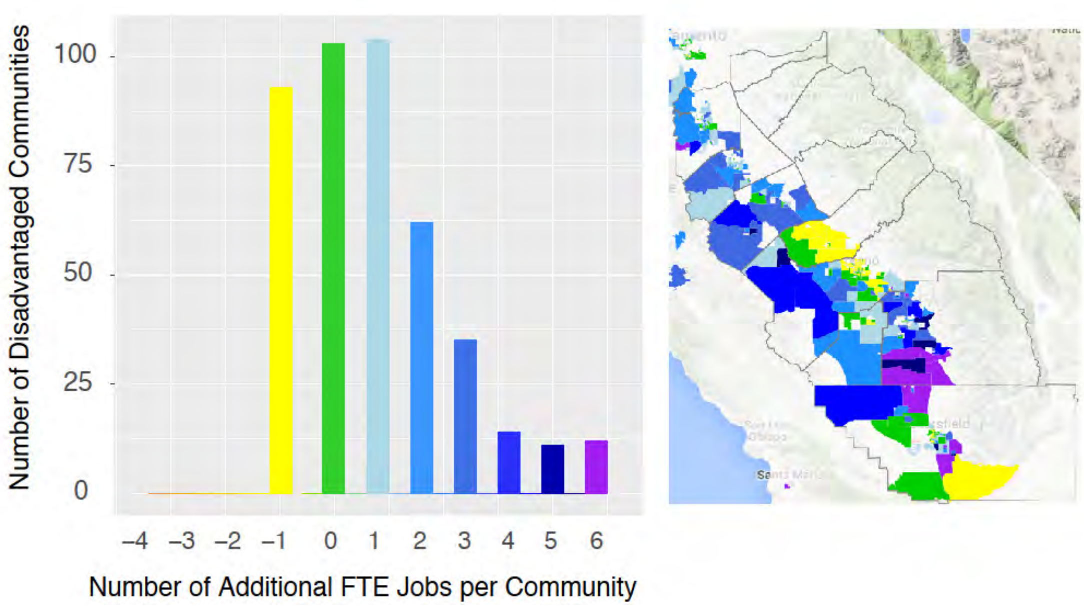
Figure 14 shows the employment impacts in the Central Valley's 431 disadvantaged communities. Both regional scenarios show positive employment effects in all disadvantaged communities, despite the fact that there are fewer jobs from the renewable buildout compared to Current Practice. There are 7,000 and 10,500 fewer renewable buildout jobs in the Central Valley for Regional 2 and Regional 3, respectively, compared to Current Practice. However, fewer additional renewable buildout jobs are more than offset by the employment generated through greater ratepayer savings. As shown in Figure 14 (left panel), the vast majority of the disadvantaged communities receive an additional 1-3 jobs.

Figure 14. Difference in FTE Jobs in Disadvantaged Communities (Central Valley)

Regional 2 – Current Practice

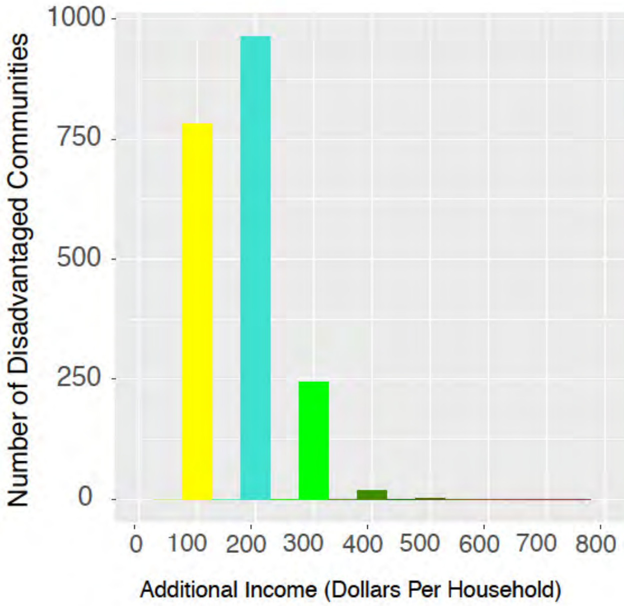


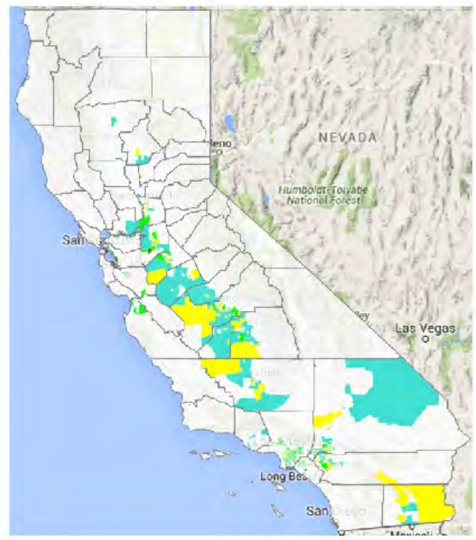
Regional 3 – Current Practice



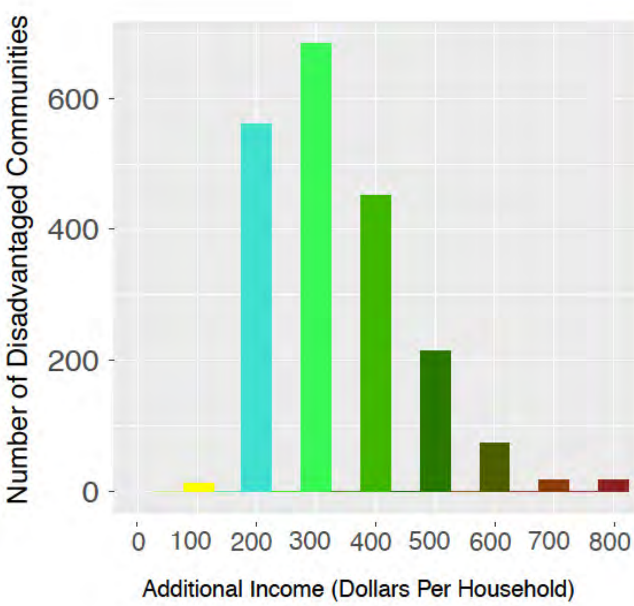
Turning next to differences in real income across the state level results show similar trends across comparison groups in Figure 15. The income effects are generally consistent with the employment effects described above in terms of the regional allocation of benefits from a regional market. The Central Valley region experiences the largest amounts of income benefits, although Inland Valley shows strong growth. Comparing Current Practice 1 to Regional 2 and Regional 3, we find that Regional 2 has a more even dispersion of income benefits, while Regional 3 sees a higher concentration in specific disadvantaged communities.

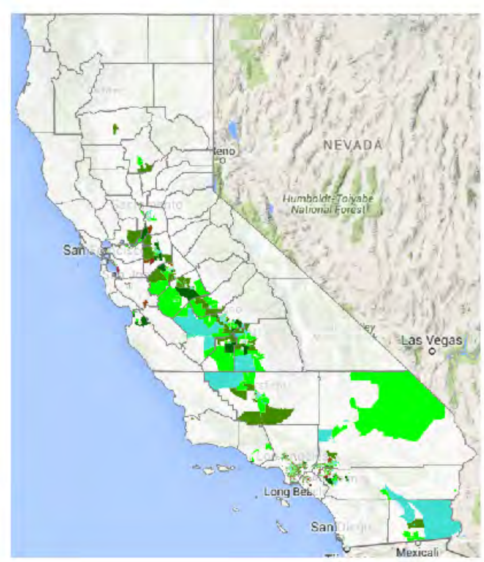
Figure 15. Differences in Disadvantaged Community Income
Scenario 2 vs. Current Practice





Scenario 3 vs. Current Practice

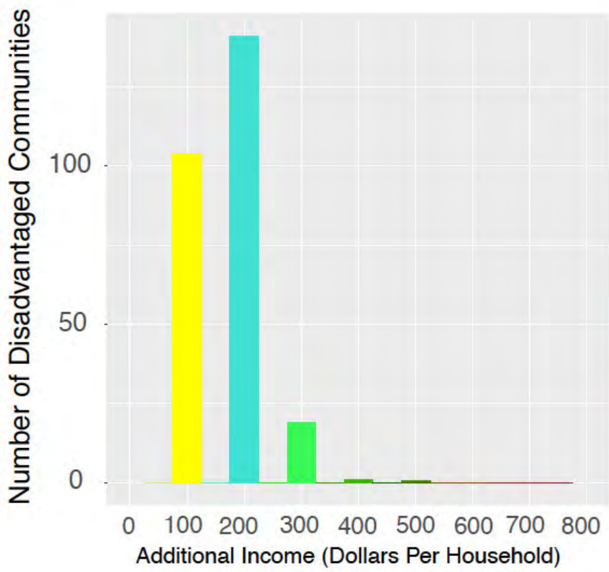


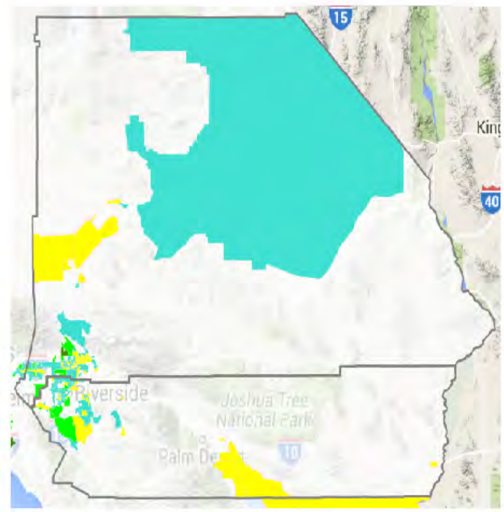


Similar to the employment results, the income results are also presented in a more disaggregated regional analysis. In Figure 16 we find the largest gains in income are expected in the communities around Riverside and San Bernardino, with the largest income effects in Regional 3. Figure 17 shows that the most concentrated income effects are in the communities near Long Beach. There are also large effects in the areas around the Orange County communities of Irving and Anaheim. Finally, both Oxnard and communities in western San Bernardino show significant income increases as well. Comparing scenarios, results show the largest income gains expected in Regional 3. Figure 18 shows results for the Central Valley, where a fairly even distribution of income effects are observed, with Regional 3 having the largest gains. The largest gains are in the communities near Los Banos, Merced, and south of Fresno. Jobs and income results for the remaining 5 economic regions with disadvantaged communities are shown in Annex A.

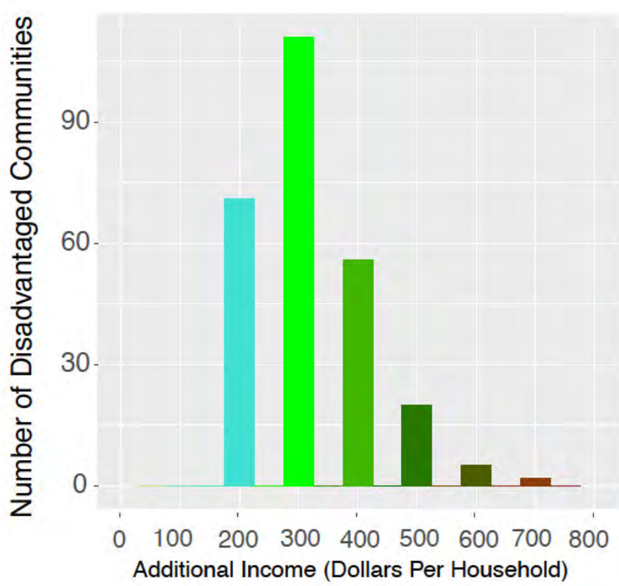
Figure 16. Differences in Disadvantaged Community Income – Inland Valley

Regional 2 – Current Practice





Regional 3 – Current Practice



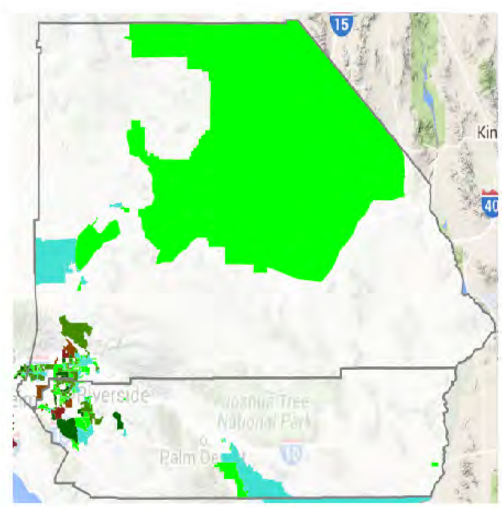
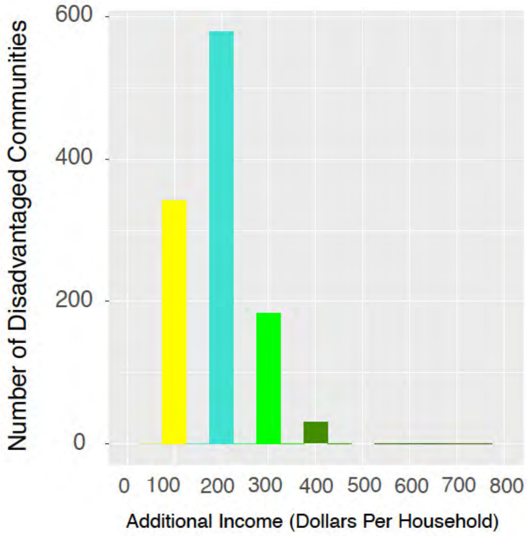
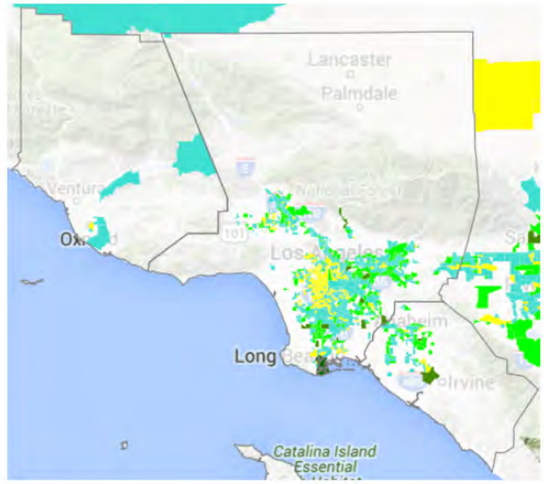


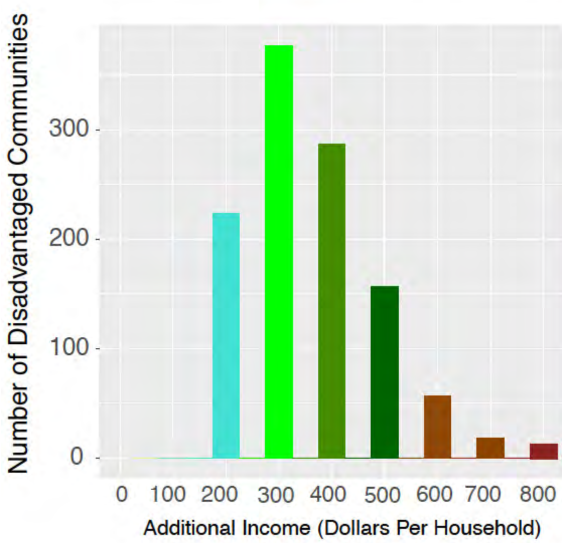
Figure 17. Differences in Disadvantaged Community Income – Greater Los Angeles

Regional 2 – Current Practice





Regional 3 – Current Practice



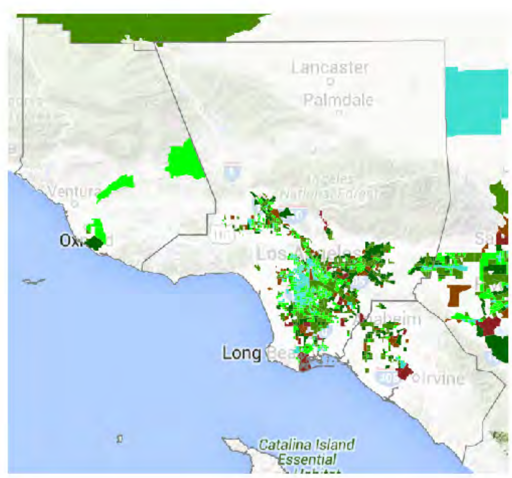
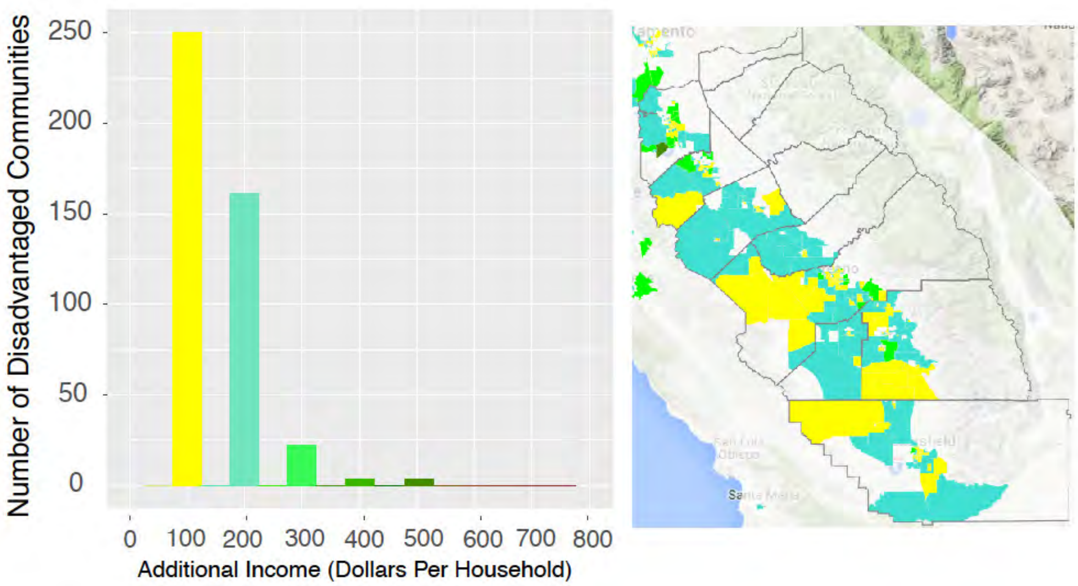
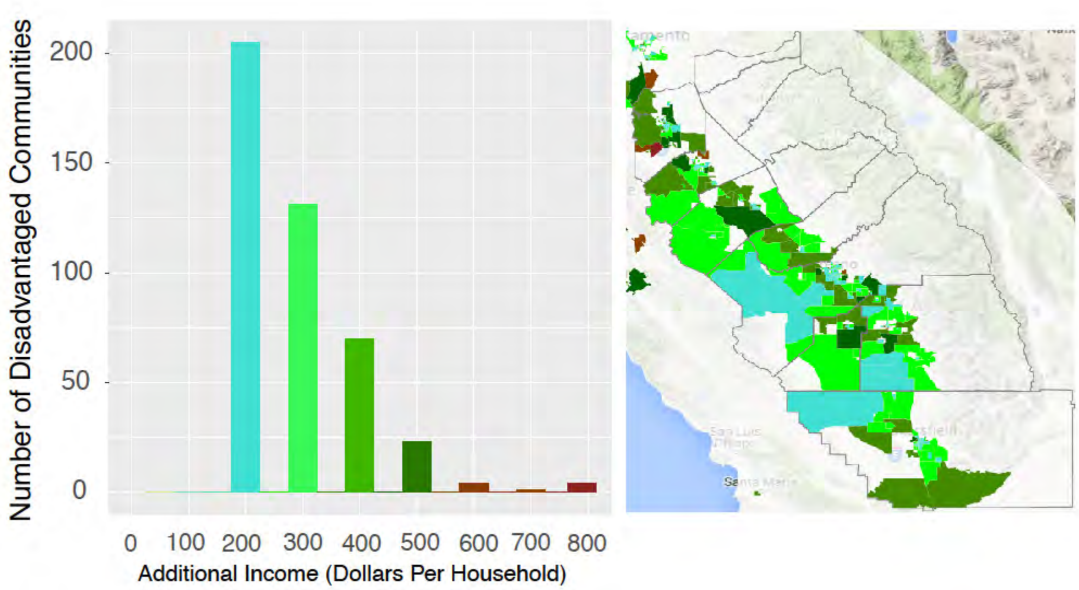


Figure 18. Differences in Disadvantaged Community Income – Central Valley

Regional 2 – Current Practice



Regional 3 – Current Practice



Sensitivity Analysis

The economic impact study for disadvantaged communities considered one sensitivity case. Scenario 1B is identical to the Current Practice scenario except with a higher export limit (8,000 MW vs 2,000 MW). As noted in Volume 8 of the study report, this sensitivity is considered to be a bookend for identifying the benefits attributable to a regional market. It is highly unlikely that achieving the export capability in Sensitivity 1B would be feasible in the absence of a regional market. However, these results are presented below for completeness.

Comparing the two regional scenarios to this alternative (1B) scenario suggests show that more disadvantaged community jobs would be created than in either regional scenario. Regional 2 results in 117 fewer jobs (0.01 jobs per thousand people) than Sensitivity 1B, and Regional 3 results in 2,100 fewer jobs (0.35 jobs per thousand people) than scenario 1B. These small net effects are due to the fact that the jobs created in disadvantaged communities from the greater ratepayer savings are slightly more than offset by lower job creation from renewable buildout in those communities.

Similar to the employment effects, income gains for Regional 2 are also less than the sensitivity 1B scenario ($15/HH lower income in Regional 2). Regional 3 income is actually higher than 1B by $140/HH. This result suggests that the income effects generated from ratepayer savings (which is greatest in Regional 3) are greater than the income effects generated by the renewable buildout. In other words, ratepayer savings, which is more dispersed across the economy, yields more salient multiplier effects than the localized impact of renewable capacity development. Indeed, the sensitivity comparison reminds us of the importance of distinguishing between sources of demand and job creation. Current Practice and 1B scenarios are largely investment driven, while household consumption is the primary demand driver when regionalization confers higher purchasing power on California households. The longevity of buildout or investment-driven employment is very uncertain, while ratepayer benefits are likely to be enduring. The latter, consumption expenditure by households across the state, is also likely to create more diverse and inclusive employment, with about 70% distributed across tertiary activities.

6. Summary of Key Conclusions

6.1 Environmental Analysis Conclusions

Regional 2 Relative to Current Practice Scenario 1

For California's disadvantaged communities, and generally inside California, Regional 2 results in:

- Fewer community-scale impacts from construction of the renewable buildout in California by emphasizing the Tehachapi and Riverside East & Palm Springs CREZs that do not contain high percentages of population in disadvantaged communities.
- Less water used in California because the fleet of natural gas fired power plants would operate less than in the Current Practice (Scenario 1), and this may reduce the baseline stress on water bodies and water systems in disadvantaged communities.
- Lower emissions from California power plants in air basins of greatest concern because the fleet of natural gas fired power plants would operate less than in the Current Practice (Scenario 1), and this decreases the emissions of NOx, PM2.5, and SO_2 in the air basins of greatest concern for disadvantaged communities.

Regional 3 Relative to Current Practice Scenario 1

For California's disadvantaged communities, and generally inside California, Regional 3 provides:

- Fewest community-scale impacts from construction of the renewable buildout in California by emphasizing renewable energy resources outside of California.
- Least amount of water used in California because the fleet of natural gas fired power plants would operate less than other scenarios, and this may reduce the baseline stress on water bodies and water systems in disadvantaged communities.

- Lowest emissions from California power plants in air basins of greatest concern because the fleet of natural gas fired power plants would operate less than other scenarios, and this decreases the emissions of NOx, PM2.5, and SO_2 in the air basins of greatest concern for disadvantaged communities.

6.2 Economic Analysis Conclusions

- Disadvantaged communities primarily benefit from a regional market and job creation induced by ratepayer savings, generating greater employment and income than the Current Practice.
- Employment effects: There is a tradeoff between the types of jobs in disadvantaged communities across the scenarios. Current Practice yields the greatest number of direct jobs from the renewable buildout, while induced employment from ratepayer savings in the regional scenarios is a more potent stimulus to these local economies. Regional 3 yields the fewest jobs from the renewable buildout, but more than offsets this with the greatest number of jobs created through ratepayer savings. Regional 2 creates the greatest number of jobs in disadvantaged communities by combining the employment benefits of in-state renewable capacity generation and high levels of induced employment from ratepayer savings.
- Income effects: The income effects in disadvantaged communities from a regional market largely mirror the net employment effects. Driven by a combination of more modest renewable development and the potent growth catalyst of ratepayer savings, regional markets deliver higher real incomes to disadvantaged communities. This is driven by the economic stimulus delivered by ratepayer savings, which more than offsets lower levels of direct job creation due to less ambitious in-state renewable energy development.
- The employment and income benefits accrue primarily to disadvantaged communities in three economic regions: Inland Valley, Los Angeles Area, and the Central Valley. These regions account for 91% of the State's disadvantaged communities. Economic benefits from ratepayer savings are estimated to be distributed across all disadvantaged communities. The employment gains and losses attributable to renewable buildout vary considerably across the State's disadvantaged communities, based on scenario and precise location of future renewable capacity development.

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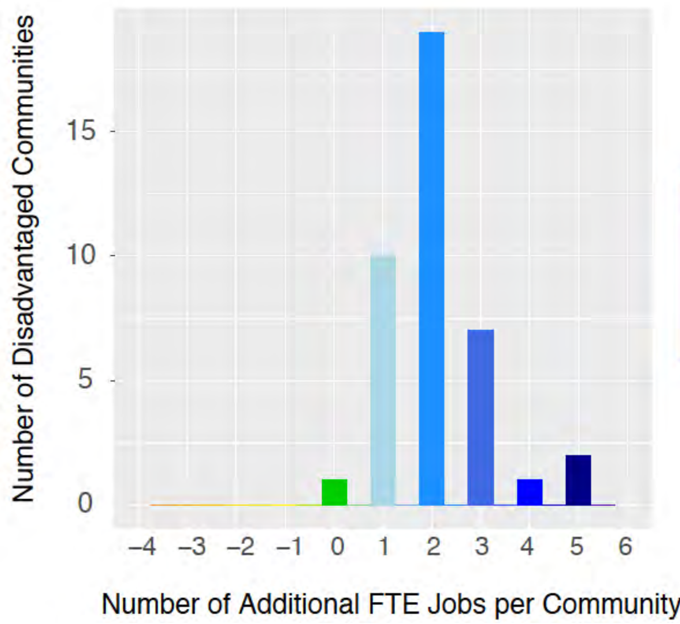
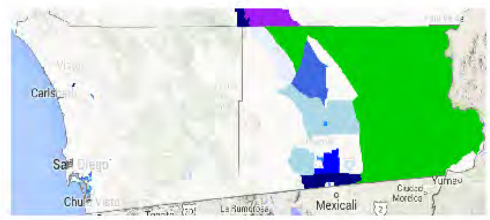
CalEPA (California Environmental Protection Agency) and OEHHA (Office of Environmental Health Hazard Assessment. 2014. Approaches to Identifying Disadvantaged Communities. [online]: http://www.arb.ca.gov/cc/capandtrade/auctionproceeds/workshops/calepa-approaches-to-identify-disadvantaged-communities-aug2014.pdf

8. Annex A: Disadvantaged Community Figures for Additional Economic Regions

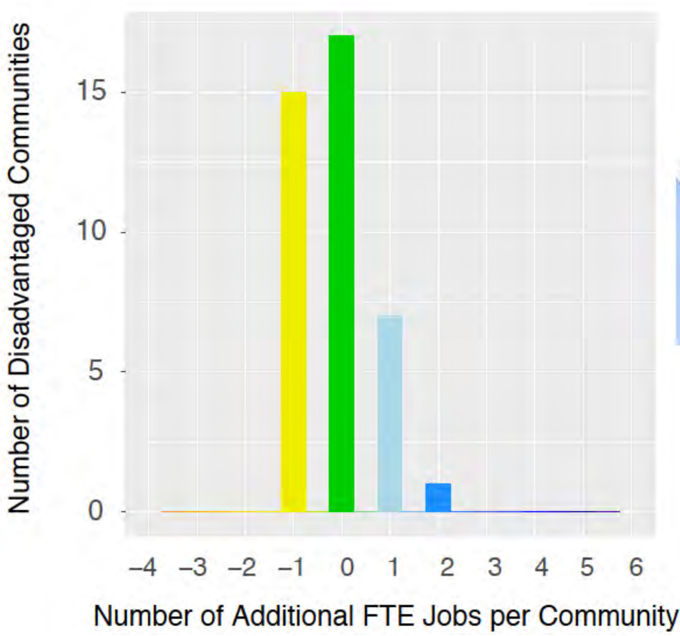
Figure A.1: Difference in Disadvantaged Community FTE Jobs (San Diego and Imperial)

Regional 2 – Current Practice





Regional 3 – Current Practice



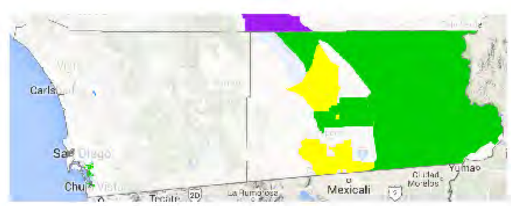
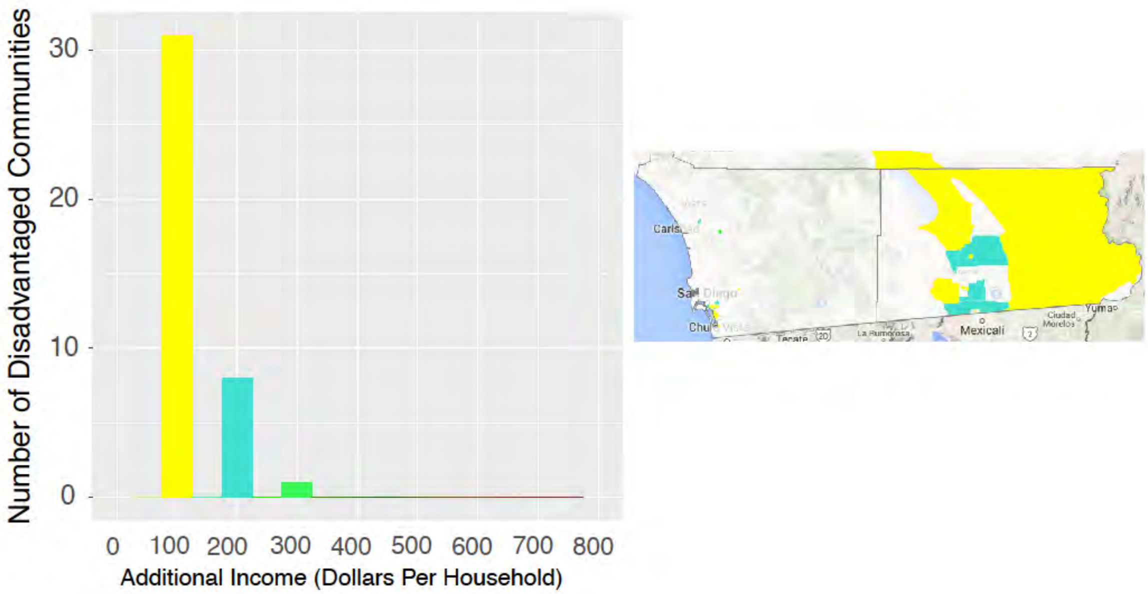


Figure A.2: Differences in Disadvantaged Community Income – San Diego and Imperial ($/hh)

Regional 2 – Current Practice



Regional 3 – Current Practice

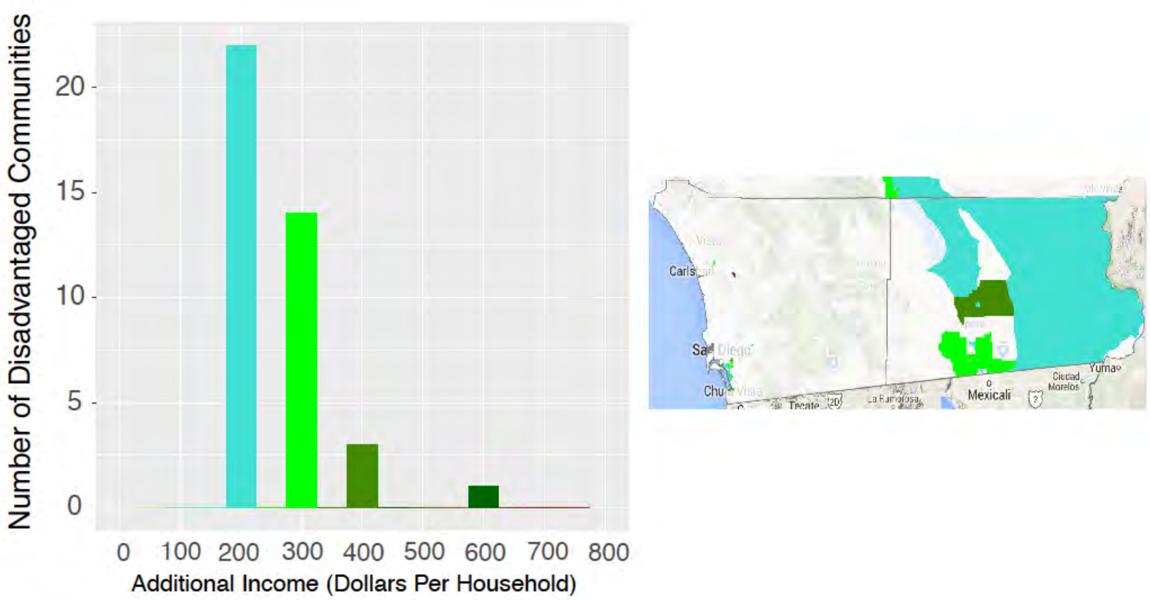
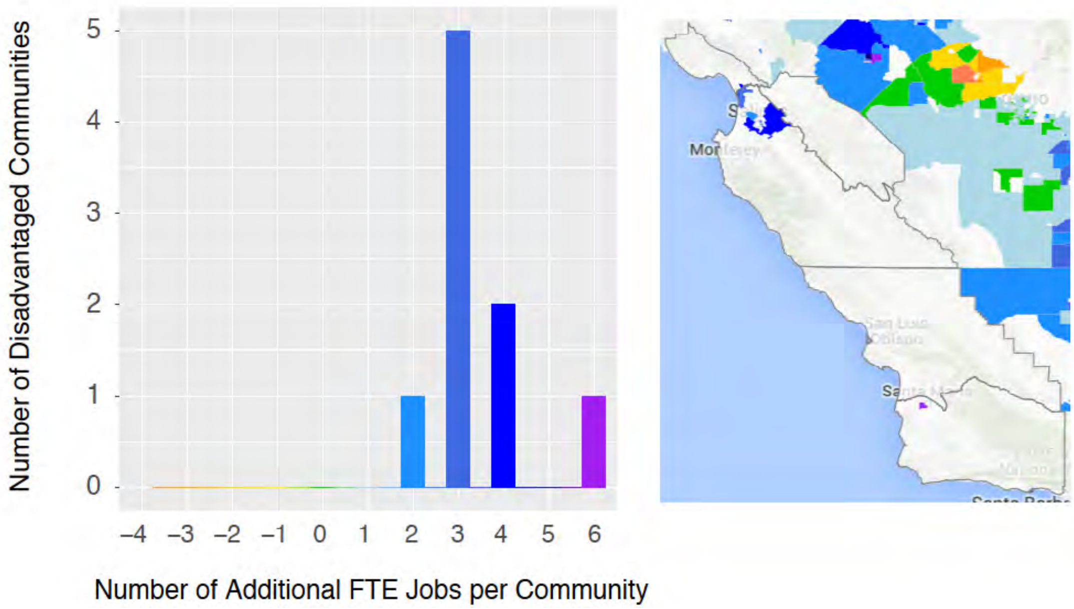


Figure A.3: Difference in Disadvantaged Community FTE Jobs (Central Coast)

Regional 2 – Current Practice



Regional 3 – Current Practice

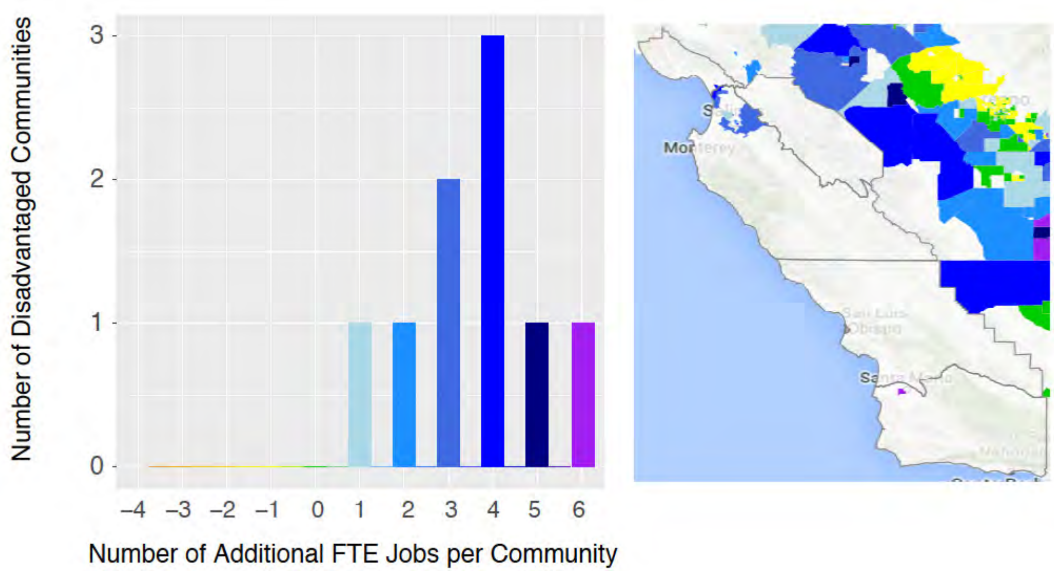
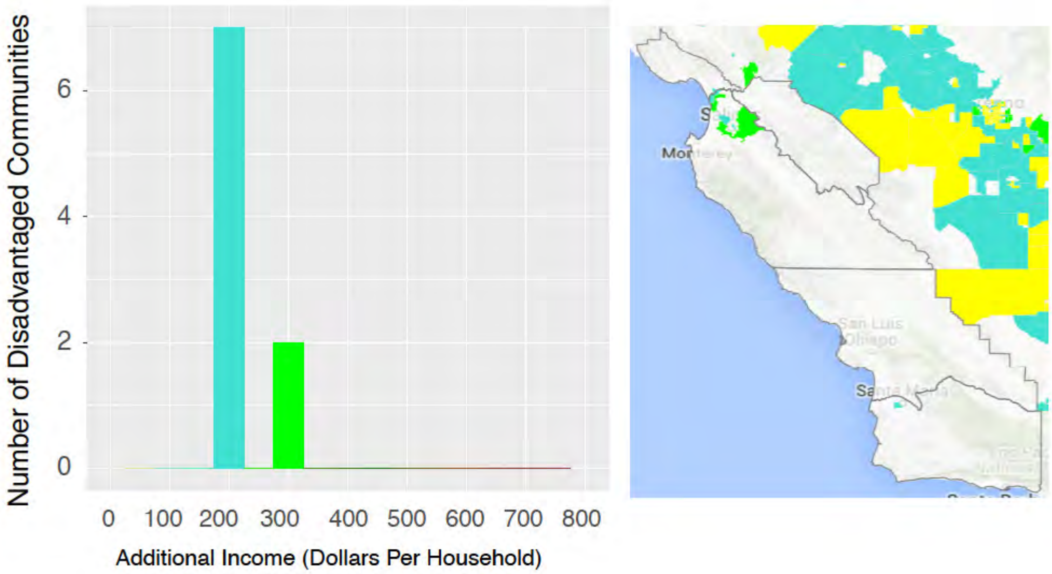


Figure A.4: Differences in Disadvantaged Community Income – Central Coast ($/hh)

Regional 2 – Current Practice



Regional 3 – Current Practice

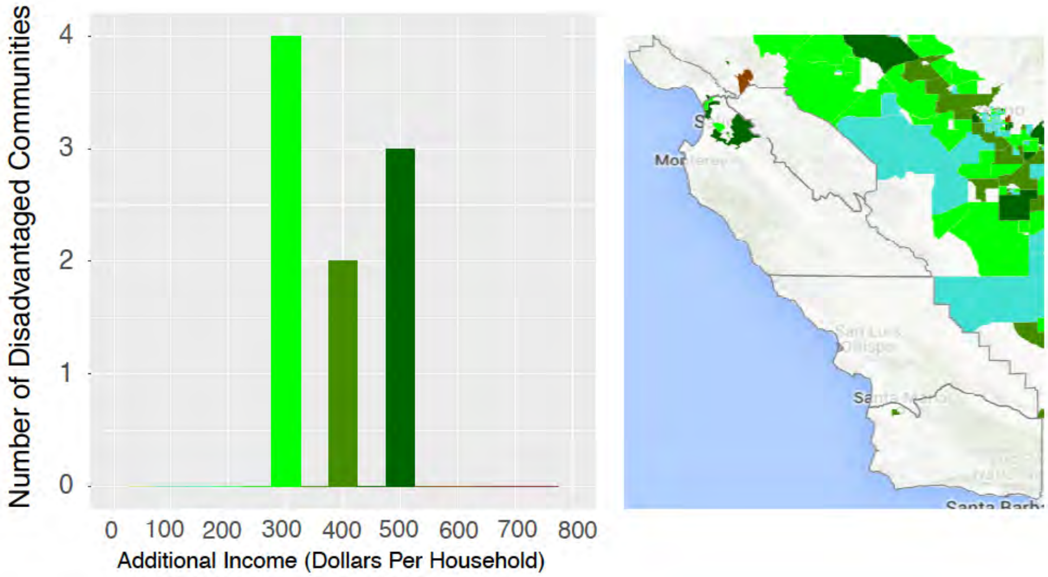
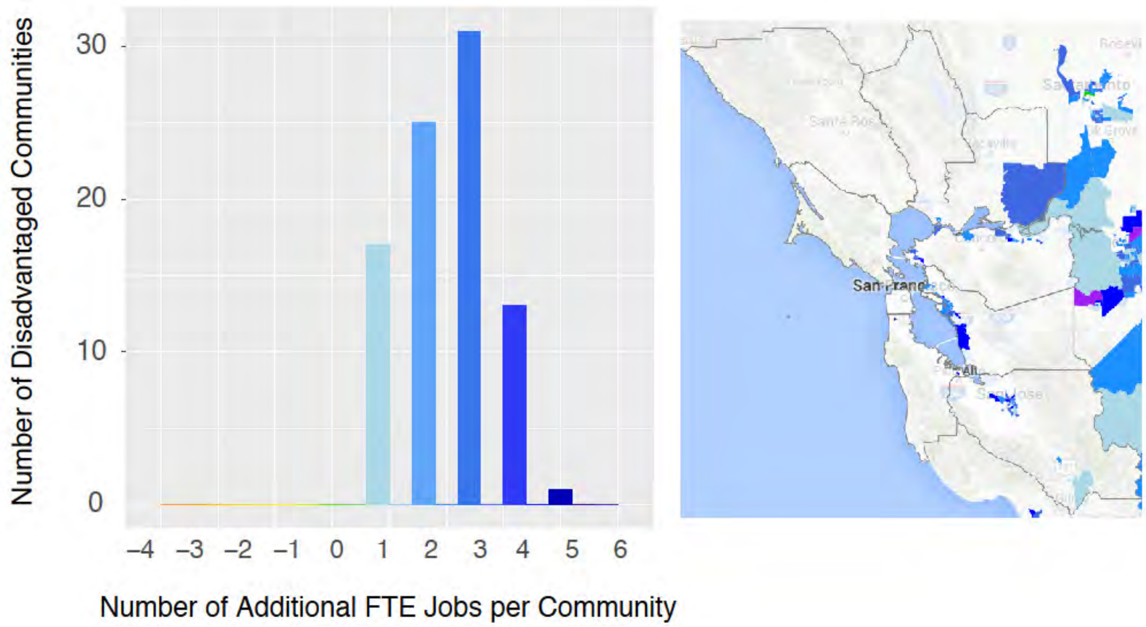


Figure A.5: Difference in Disadvantaged Community FTE Jobs (San Francisco Bay Area)

Regional 2 – Current Practice



Regional 3 – Current Practice

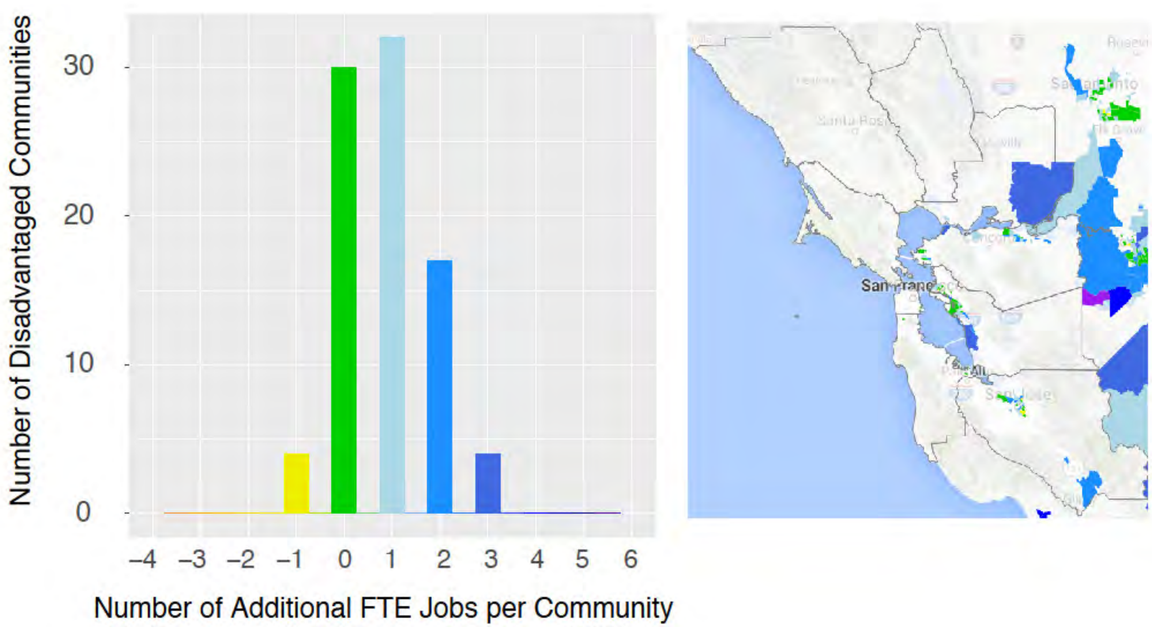
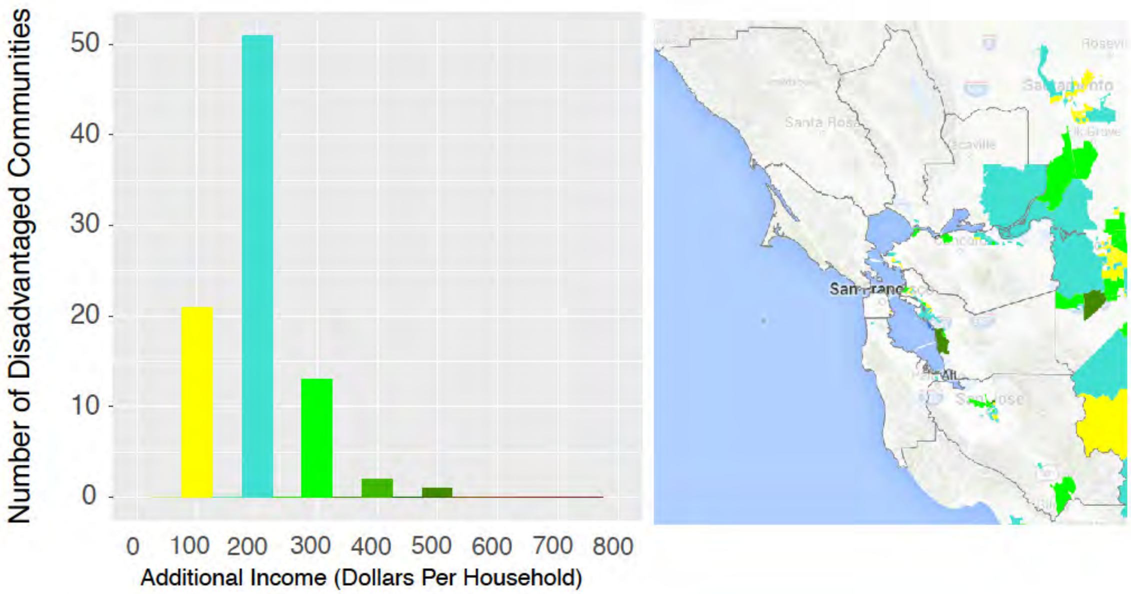


Figure A.6: Differences in Disadvantaged Community Income – San Francisco Bay Area ($/hh)

Regional 2 – Current Practice



Regional 3 – Current Practice

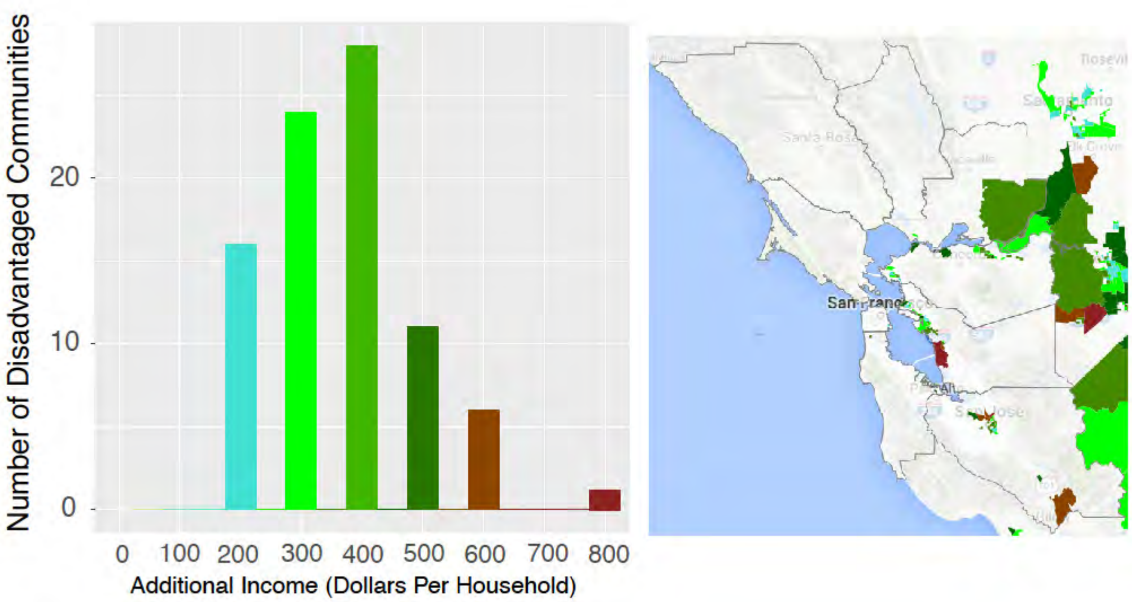
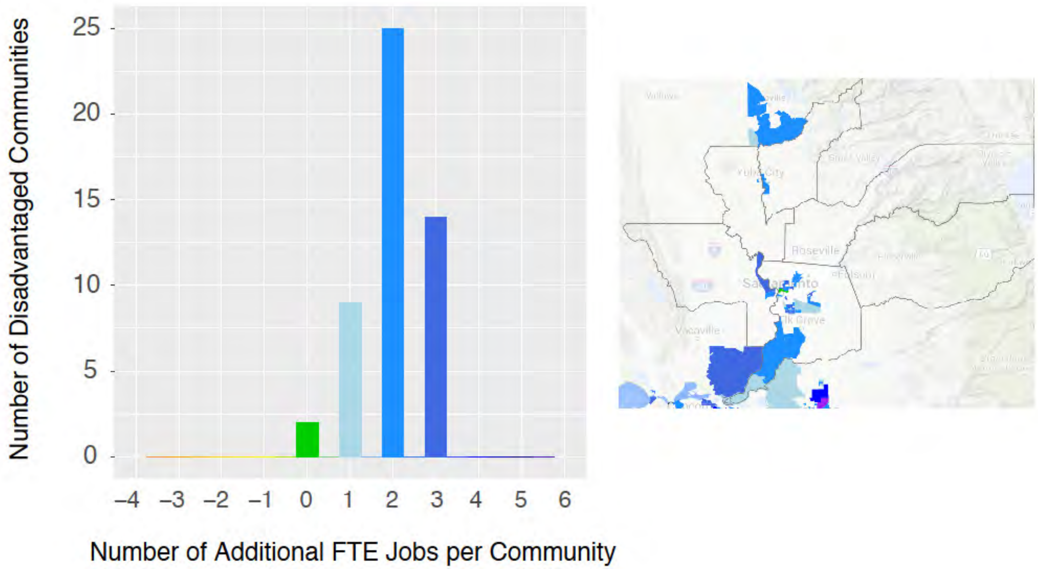


Figure A.7: Difference in Disadvantaged Community FTE Jobs (Sacramento Area)

Regional 2 – Current Practice



Regional 3 – Current Practice

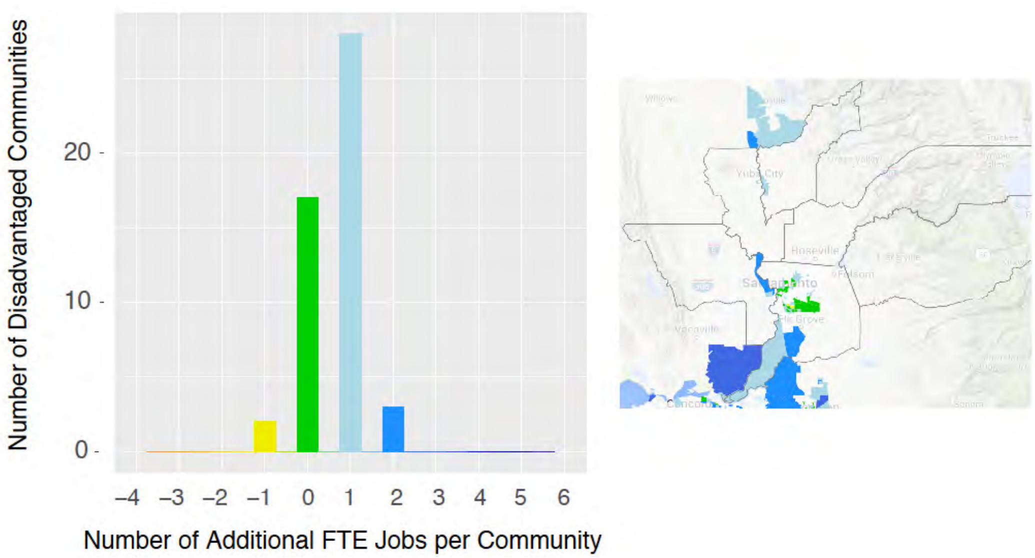
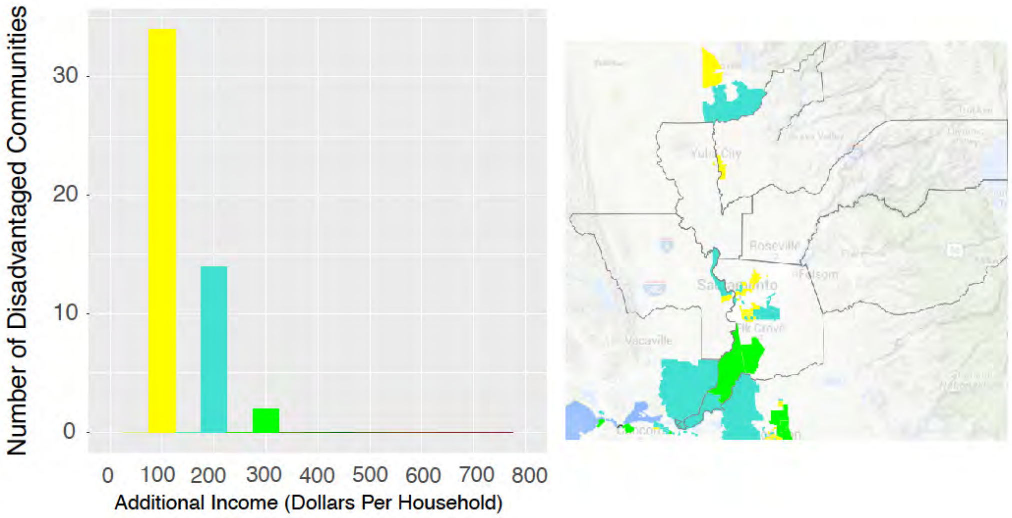


Figure A.8: Differences in Disadvantaged Community Income – Sacramento Area ($/hh)

Regional 2 – Current Practice



Regional 3 – Current Practice

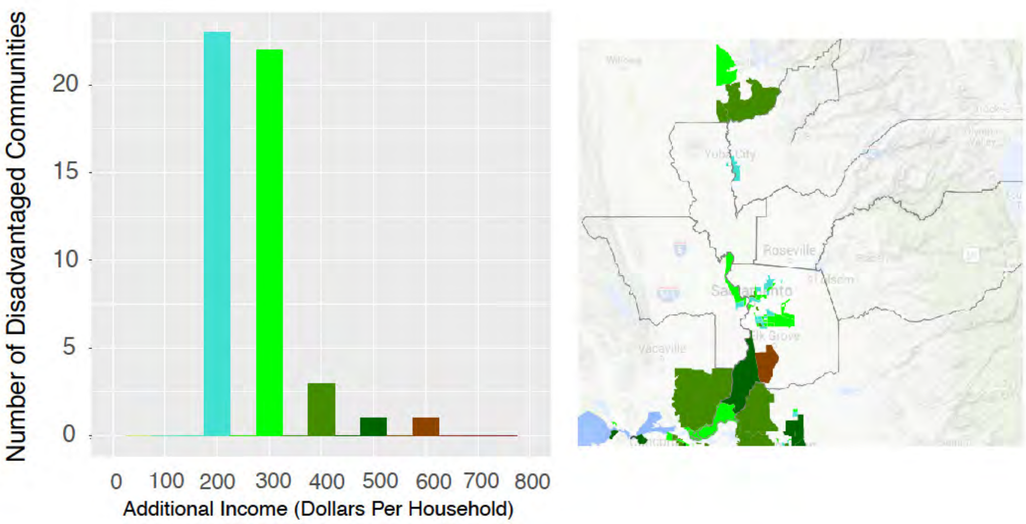
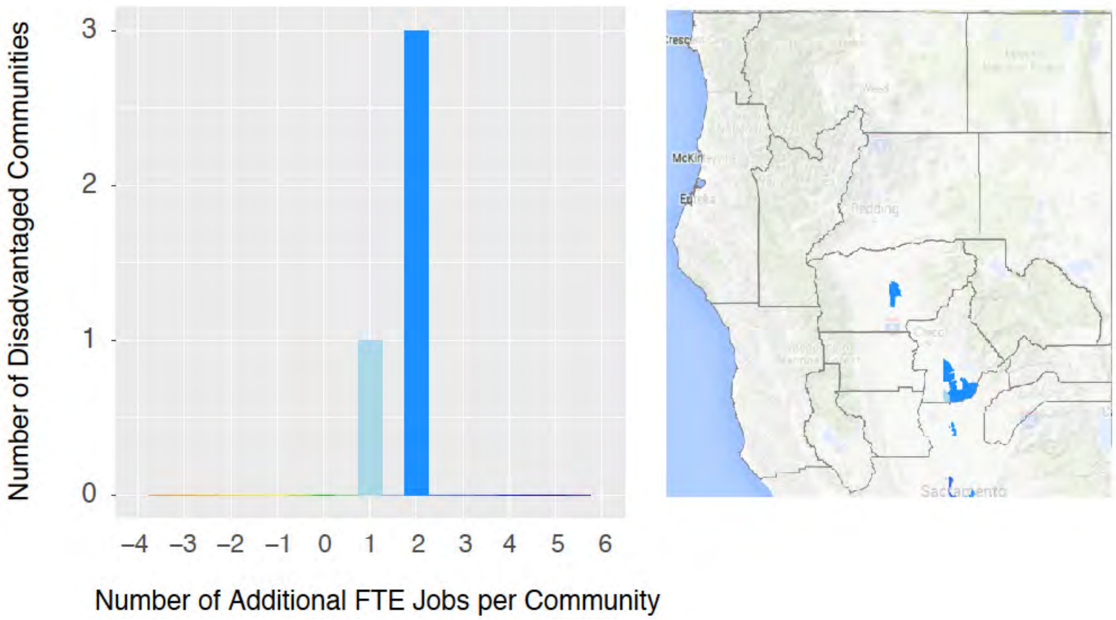


Figure A.9: Difference in Disadvantaged Community FTE Jobs (North State)

Regional 2 – Current Practice



Regional 3 – Current Practice

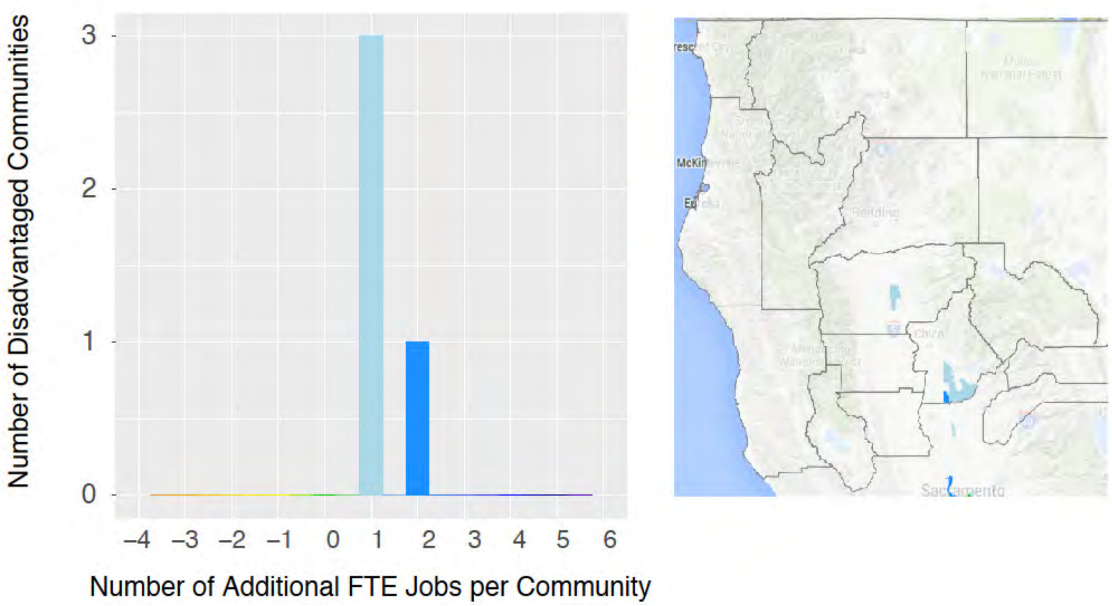
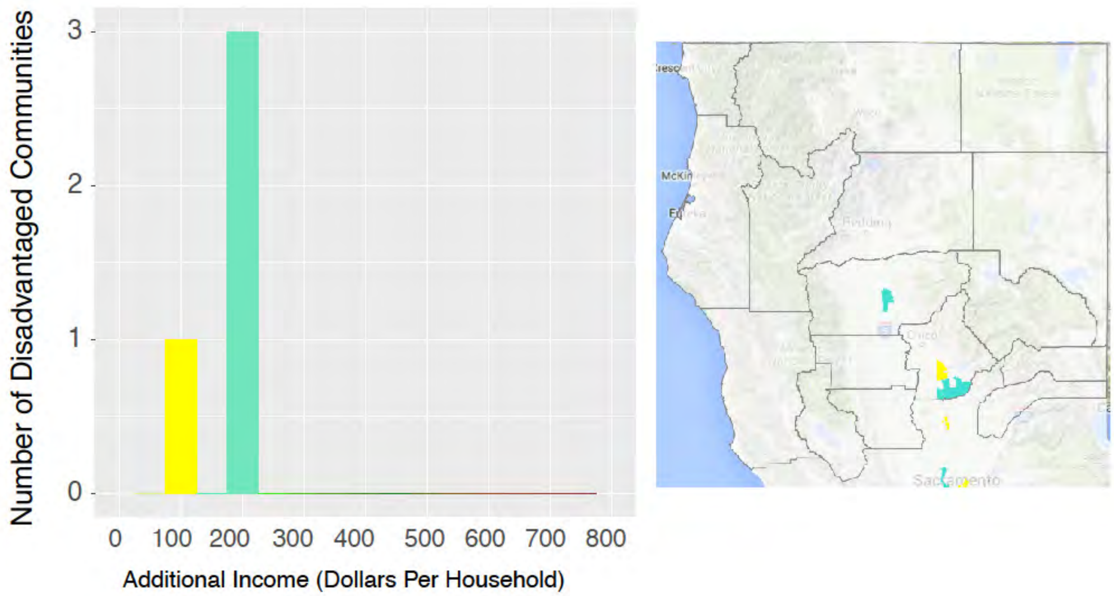
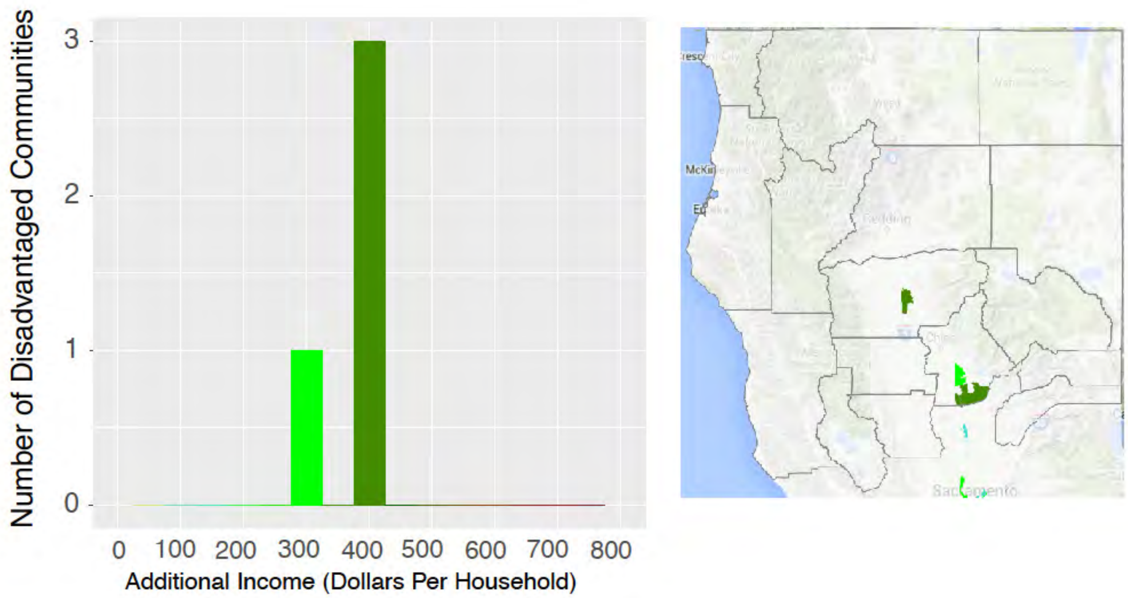


Figure A.10: Differences in Disadvantaged Community Income – North State ($/hh)

Regional 2 – Current Practice



Regional 3 – Current Practice



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Senate Bill 350 Study

Volume XI: Renewable Integration and Reliability Impacts

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

Volume XI: Table of Contents

Volume XI. Renewable Integration and Reliability Impacts

A. Introduction

As documented by industry experience and in a wide range of industry studies, regional market operations and planning will allow for the more cost effective and more reliable integration and balancing of intermittent renewable resources.[1] The benefits of operational efficiency, 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 Energy Imbalance Market ("EIM").[2]

A full "Day 2" regional market will magnify these EIM-related benefits by adding substantial additional 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 on both a day-ahead and intra-day basis; and (4) region-wide, co-optimized ancillary services markets for procurement of regulation reserves, procurement and deployment of operating reserves, and flexible capacity for load-following reserves. In addition to these operational benefits, an ISO-based regional market will also benefit from the integrated, region-wide operational, reliability, resource adequacy management, and transmission planning functions performed by an independent system operator ("ISO").

Covered in other parts of this report, key aspects of reliability and renewable integration benefits of a larger ISO-operated regional market already have been quantified in terms: (1) the load diversity analysis, which assesses how resource adequacy requirements can be met with less

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1 See discussion of existing studies in Volume XII of this report.

2 For example, for renewable integration benefits of the EIM refer to http://www.caiso.com/Pages/documentsbygroup.aspx?GroupID=5180B3C9-2B88-4678-B6AD-2A6B55CE8DEB for actual benefits and http://www.caiso.com/Pages/documentsbygroup.aspx?GroupID=7DF86332-C71D-44B7-836B-56181A694C8C for pre-operational benefit assessments.

For reliability benefits of the EIM see FERC's Staff Report, "Qualitative Assessment of Potential Reliability Benefits from a Western Energy Imbalance Market," February 26, 2013, Available http://www.caiso.com/Documents/QualitativeAssessment-PotentialReliabilityBenefits-WesternEnergyImbalanceMarket.pdf generating capacity (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).

However, the estimation of the benefits associated with reliability and renewable integration benefits captured in California ratepayer savings does not reflect other value 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.[3] 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.

B. INTEGRATION AND BALANCING OF RENEWABLE GENERATION

CAISO has undertaken a number of initiatives to improve the current market structure and improve renewable integration. Our future scenarios assume these measures are in place, even in the Current Practice scenarios, including:

- The creation and regional expansion of the Energy Imbalance Market;
- Ensuring sufficient flexible generation is made available in the CAISO market;
- Refining the markets for ancillary service needed to balance intermittent generation;
- Expanding the transmission system;

---

3 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.

- Introducing 15-minute scheduling on transmission interties with neighboring regions; and
- Facilitating the wholesale market integration of demand-side resource and storage.

In addition, all scenarios assume that a number of additional measures are in place by 2030:

- Time-of-use rates that encourage daytime use;
- 5 million electric vehicles by 2030 with near-universal access to workplace charging;
- 500 MW of pumped storage are developed in California;
- 500 MW of geothermal resources are manually added to California's renewable portfolio in all cases, which reduces renewable curtailment relative to a case with an equivalent quantity of solar;
- 5,000 MW of out-of-state renewable resources available to be selected on a least-cost basis;
- Unlimited storage available to be selected on a least-cost basis;
- Renewable resources are assumed to be fully dispatchable and capable of providing grid services such as operating reserves;
- Storage and hydro are assumed to be fully dispatchable and capable of providing grid services such as operating reserves and frequency response.

A larger regional ISO-operated wholesale power market will improve the integration and balancing of renewable resources by enabling:

- A single intra-hourly energy market for selling intermittent output that is integrated with optimal day-ahead commitment and pre-dispatch of the entire region's generating plants;
- Coordinated and centralized region-wide day-ahead and intra-day forecasting of renewable output to reduce balancing costs, improve congestion management, and reduce curtailments;
- Reduced system-wide operating and load following reserve requirements in a regional market because of larger-regional diversification of renewable generation variances and a more cost-effective combination of renewable resources and transmission;
- Lower-cost provision and deployment of regional operating and load following reserves through optimized security-constrained unit commitment and dispatch; and

- Lower integration-related investment needs through improved region-wide generation interconnection and transmission planning processes.

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."[4]

Compared to EIM, the broader regional market design further lowers the integration and balancing costs currently faced by many developers of renewable generation projects by additionally providing:

- A system-wide generation day-ahead unit commitment and dispatch over a broader region with a more diverse set of renewable and conventional resources
- 5-minute real-time pricing for all energy generated by both intermittent resources and the entire fleet of conventional resources in the regional market's footprint (which exceeds the scope of EIM dispatch);
- Availability of market-based ancillary services with lower-cost balancing options;
- Fewer renewable curtailments through improved region-wide forecasting, optimized unit commitment, and utilization of transmission infrastructure;
- Streamlined access to existing and new transmission to deliver low-cost renewables and one-stop shopping for generator interconnection requests and transmission planning service; in the entire region; Improved regional transmission planning to provide access to low-cost renewable areas within the regional footprint;
- Easier contracting for load-serving entities (including public power companies, cooperative utilities, municipal electric companies) as well as with commercial and industrial customers who do not currently have transmission access to the low-cost renewable generation areas within the region; and
- Improved financial hedging options through day-ahead markets, optimized congestion management, and congestion revenue rights, more transparent energy pricing, more

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

competitive access to a larger regional market, and improved access to more liquid trading hubs that offer longer-term forward contracting.

As discussed in more detail below, this reduction of integration and balancing costs faced by renewable generation developers or their contractual off-takers offered by regional ISO-operated markets reduces investment costs, thereby contributing to a more rapid development and growth of renewable generation in the regional footprint.

C. Facilitating The Development of Renewable Generation

Numerous existing studies show that ISO-operated regional markets facilitate renewable generation investment and, thus, a more rapid development and growth of renewable generating resources. Nationally, ISO-operated regional markets account for a disproportionate share of the nation-wide investment in renewables, which has been attributed to the improved integration of renewable resources in ISO-operated regional markets.[5]

For example, as of 2014 over 77% of wind generation capacity was installed in areas with regional electricity markets.[6] As shown in Figure 1, the seven states with the highest installed wind generating capacity are Texas, Iowa, California, Oklahoma, Illinois, Kansas, and Minnesota; they are all located in areas with ISO-operated wholesale power markets.[7]

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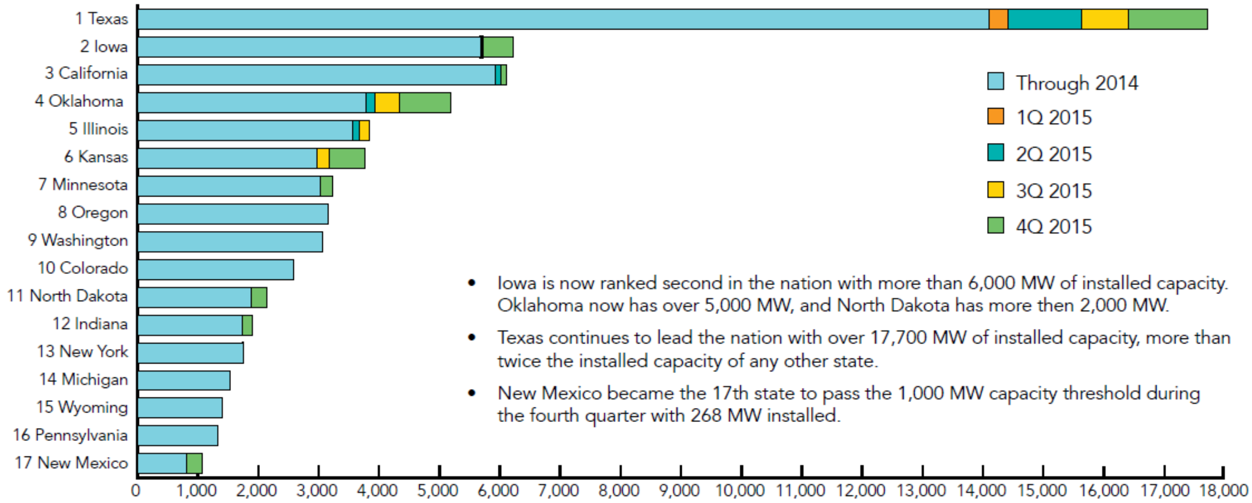
5 Hogan, W., "Electricity Wholesale Market Design in a Low Carbon Future", volume in Padilla, J. and Schmalensee, R., Harnessing Renewable Energy, p. 10, Available: https://www.hks.harvard.edu/fs/whogan/Hogan_Market_Design_012310.pdf

6 COMPETE, "RTO and ISO Markets are Essential to Meeting Our Nation's Economic, Energy and Environmental Challenges", 2014, pp. 3-4, Available: http://www.competecoalition.com/files/COMPETE%20RTO%20White%20Paper_December%202%202014%20FINAL.pdf

7 AWEA, "U.S. Wind Industry Fourth Quarter 2015 Market Report", American Wind Energy Association, January 2015, p. 14, Available: http://awea.files.cms-plus.com/FileDownloads/pdfs/4Q2015%20AWEA%20Market%20Report%20Public%20Version.pdf

Figure 1: Installed Wind Generation Capacity, End of 2015



* Source: http://awea.files.cms-plus.com/FileDownloads/pdfs/4Q2015%20AWEA%20Market%20Report%20Public%20Version.pdf

The fact that regional markets facilitate renewables integration has specifically been emphasized by developers and utilities. For example, MidAmerican stated when joining MISO that it was motivated in part by the ability of the market to provide ancillary services and facilitate integrating renewables.[8] Since joining MISO, MidAmerican has been able to greatly expand its (mostly voluntary) purchase and development of renewable resources, which are now expected to supply 58% of the utility's Iowa load by the end of 2016.[9]

As shown in Figure 2, in 2015, most of the country's wind generation additions were focused in the wind-rich areas of the Great Plains with regional wholesale power markets operated by ERCOT, SPP, and MISO. As also shown in Figure 2, significantly less development activity occurred in the similarly wind-rich areas of Wyoming, Colorado, and New Mexico without ISO-operated wholesale markets.

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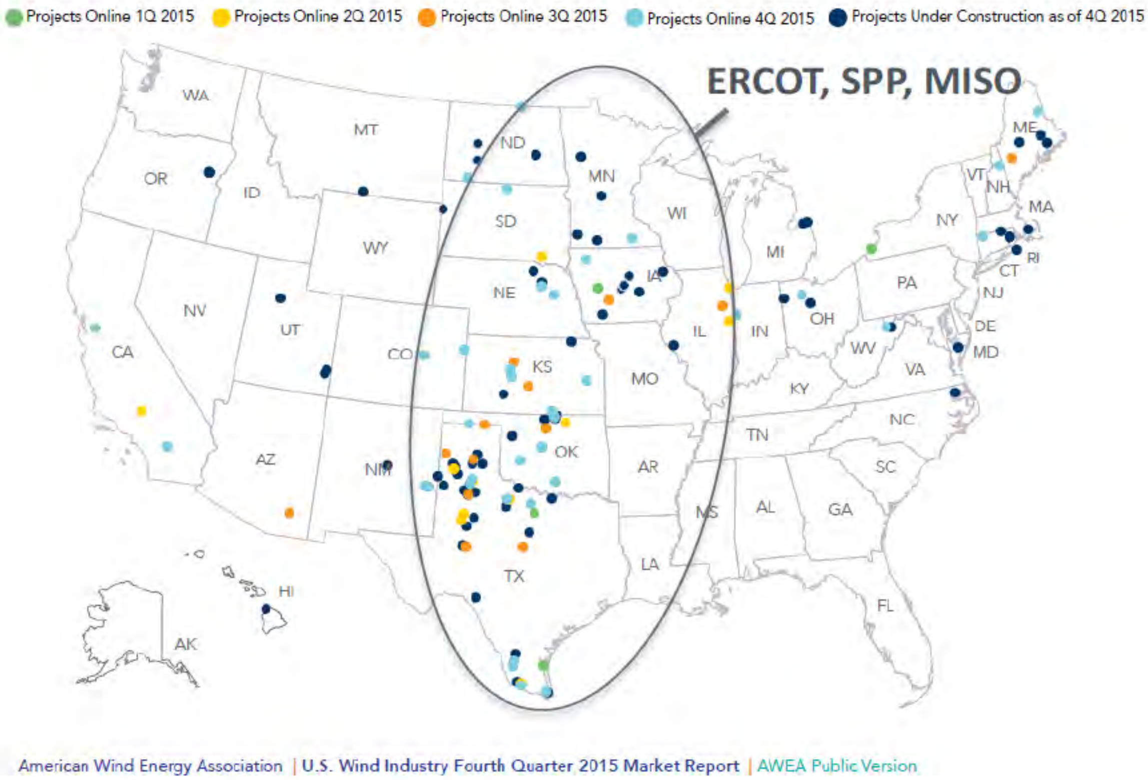
8 COMPETE, "RTO and ISO Markets are Essential to Meeting Our Nation's Economic, Energy and Environmental Challenges," 2014, pp. 3–4

9 These renewable energy purchases also allowed MidAmercian to retire 2,000 MW of coal plants. See Matyi and McGuirk, "2,000 MW of coal retired in the Midwest," *Mega Watt Daily*, April 15, 2016.

Figure 2: 2015 Wind Generation Additions and Projects under Construction



* Source: http://awea.files.cms-plus.com/FileDownloads/pdfs/4Q2015%20AWEA%20Market%20Report%20Public%20Version.pdf

The industry reports we reviewed summarize a range of factors by which ISO/RTO markets facilitate renewable development. These factors are summarized in Figure 3 and Figure 4 below. ISO/RTO markets improve transmission planning processes, allowing previously inaccessible renewable sites to be developed.[10,11] Features of ISO/RTO markets, such as 5-minute pricing, nodal pricing, and financial congestion hedging, enable further savings.[12] The larger geographic scale of ISO/RTO market footprints allows the development of renewable resources in lower-cost

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10 AWEA, "Green Power Superhighways: Building a Path to America's Clean Energy Future," American Wind Energy Association, 2009, Available: http://www.tresamigasllc.com/docs/2016_02_19_US_FOSG_GreenPowerSuperhighways.pdf

11 FERC-Regulated ISO/RTOs, "2010 ISO/RTO Metrics Report," 2010, Available: https://www.ferc.gov/industries/electric/indus-act/rto/metrics/summary-rto-metrics-report.pdf

12 FERC-Regulated ISO/RTOs, "2015 ISO/RTO Metrics Report," 2015, Available: http://www.pjm.com/%5CMedia%5Cdocuments%5Cferc%5Cfilings%5C2015%5C20151030-ad14-15-000-package.pdf

locations and reduces both the variability of renewable output due to geographic diversity and improves access to low-cost balancing resources.[13]

Figure 3: Summary of Studies Discussing How Regional Markets Facilitate Renewable Generation Development

Study	Finding
Brookings Clean Economy Study (2011)	• ISO/RTOs facilitate renewables through geographic diversity • ISO/RTOs also reduce barriers to expanding transmission capacity to allow additional renewables
AWEA Green Power Superhighways (2009)	• Markets that incentivize flexibility minimize the cost of integrating renewables • RTOs have been more effective in administering large balancing areas, using short scheduling intervals, and operating sophisticated energy markets
Hogan Markets In a Low Carbon Future (2010)	• Wind installations are disproportionately in RTO markets • Markets facilitate integration of low-carbon technology through improved granularity of pricing and dispatch
COMPETE Markets and Environmental Challenges (2014)	• Renewables developers are attracted to ISO/RTO markets due to transparency, fairness of rules, and geographic diversity
ISO/RTO Metrics Report (2015)	• ISO/RTOs facilitate renewables by establishing simple interconnection processes for new resources, providing access to spot markets, and allowing resources to take advantage of geographic diversity
IRC Increasing Renewables (2007)	• ISO/RTO markets facilitate renewables by having transparent pricing, highly granular dispatch, and geographic diversity

13 Muro, et al., "Sizing the Clean Economy: A National and Regional Green Jobs Assessment," The Brookings Institution, 2011, Available: http://www.brookings.edu/~/media/series/resources/0713_clean_economy.pdf

Figure 4: Summary of Factors by Which Regional Markets Facilitate Renewable Generation Development

Factor	Description
Improved Market Designs	Increased granularity in time (5-minute) and location (nodal) improves price signals and stimulates efficient transmission and generation investment Increased granularity increases the ability of prices to reflect avoided cost and improves dispatch of low carbon resources ISO/RTO markets provide a mechanisms for non-transmission owners (such as most renewables developers) to hedge against congestion RTO/ISO markets allow market participation by renewable resources by offering provide bid-based curtailments and providing ancillary services
Larger Markets	The larger geographic reach of ISO/RTO markets allows the development of renewable resources in lower-cost locations Allows a larger set of low-cost resources to provide balancing services for renewables Large footprints of ISO/RTO markets reduce balancing costs by taking advantage of the diversity of renewables output Liquidity of RTO spot markets further reduces the cost of addressing wind's variability and uncertainty compared to illiquid markets
Transparency, Open Access, and Fairness	Fair, transparent pricing rules give confidence to investors Markets reduce the potential for conflicts of interest in selecting new transmission projects and allocating the costs of these projects ISO/RTOs help promote Open Access to transmission, which is particularly important to the largely independent producers who develop renewables ISO/RTOs allow for market participation by all resources, including intermittent renewable resources

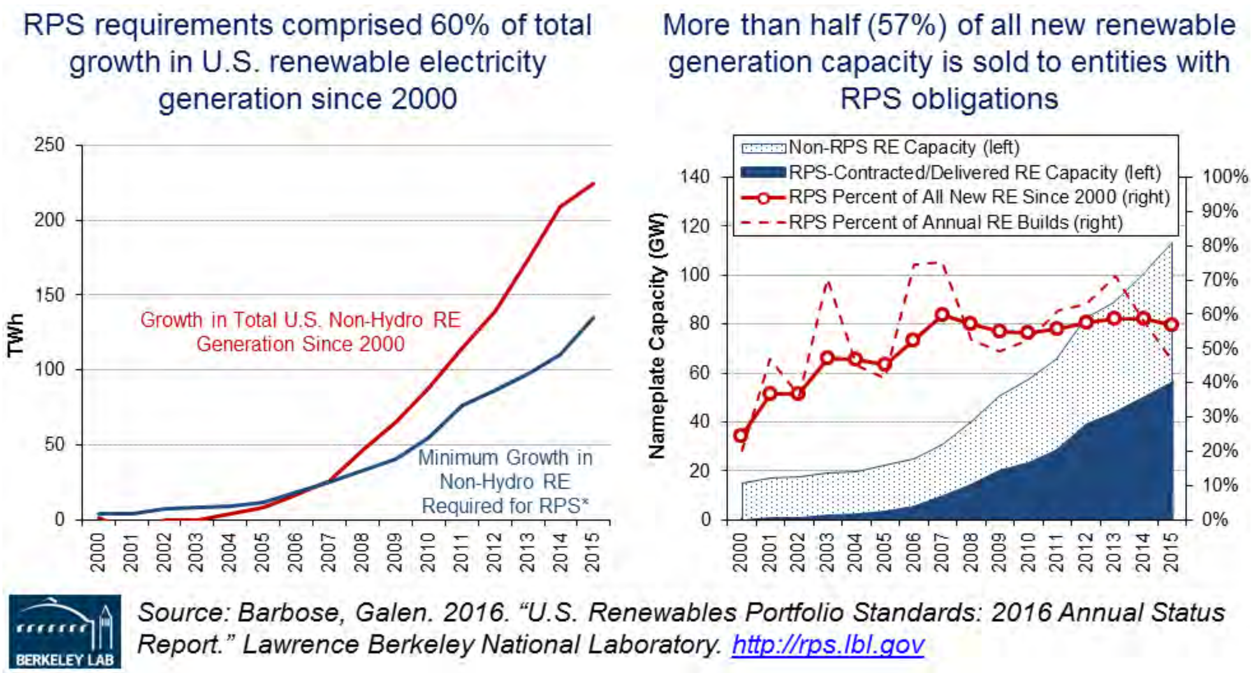
Finally, as summarized in the above tables, the transparency, fully open access to transmission, and fairness offered by independently operated RTOs provide increased confidence to investors in renewable generating plants. While ISO/RTOs support renewables penetration beyond the requirements of Renewable Portfolio Standards, they facilitate the implementation of the RPS itself. This observation is supported by the fact that most states with RPS are in regions with RTOs. Several U.S. ISO/RTOs support implementation of RPS by tracking generation and Renewable Energy Credits. This tracking is useful to market participants in meeting their RPS obligations and to states in monitoring compliance.[14]

[14] IRC, "Increasing Renewable Resources," ISO/RTO Council, 2007, p. 11, Available: http://www.consultkirby.com/files/IRC_Renewables_Report_101607_final.pdf

D. DEVELOPMENT OF RENEWABLE GENERATION BEYOND RPS REQUIREMENTS

In areas with access to low-cost renewable generation, regional markets have supported the development of renewable generating plants at levels well beyond RPS mandates. In fact, as shown in Figure 5, since 2000, RPS mandates have been responsible for only about 60% of the total development of non-hydro renewable generation nation-wide.[15]

Figure 5: Renewable Generation Investments for and beyond RPS Requirements



Based on data provided by Dr. Galen Barbose of the Laurence Berkeley National Laboratory (LBNL), most of the development of renewables beyond RPS requirements has occurred in ISO/RTO regions with low-cost wind resources. For example, since 2000, wind generation accounted for 80% of 44,000 MW of non-RPS-related renewable generation additions nationwide, and 80% of these non-RPS-related wind generation investments (over 28,000 MW) took place in six states (Texas, Iowa, Oklahoma, Kansas, Illinois, and Indiana), all of which are in ISO-operated market areas. In 2015 alone, 6,100 MW or 95% of all non-RPS-related wind

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15 Barbose, G., "U.S. Renewables Portfolio Standards: Overview of Status and Key Trends," Lawrence Berkeley National Laboratory, January 2016, p. 7, Available: https://emp.lbl.gov/sites/all/files/2016%20CESA%20Webinar%20Barbose.pdf

generation additions were located in just these six states with low-cost wind resources and ISO-operated regional markets.[16]

Particularly in Texas and the Great Plains portion of the Midwest—with regional power markets operated by ERCOT, SPP, and MISO—the penetration of wind generation has far exceeded RPS mandates. As shown in Figure 6, 72% of Texas' total 17,800 MW of wind generating capacity installed by the end of 2015 was unrelated to RPS mandates and 7,690 MW of these "beyond-RPS" wind plants have been added in the last five years. The output of these 7690 MW is equivalent to 6.9% of Texas retail load. Similarly, the LBNL data summarized in Figure 6 shows that more than 9,200 MW of wind generation were added in the Midwest (mostly western SPP and MISO) unrelated to RPS requirements over the last five years.[17] These 9,200 MW of wind generation additions are equivalent to serving more than 3% of total Midwestern retail load beyond RPS requirements.

Figure 6: Wind Generation Investments beyond RPS Requirements in Texas and the Midwest

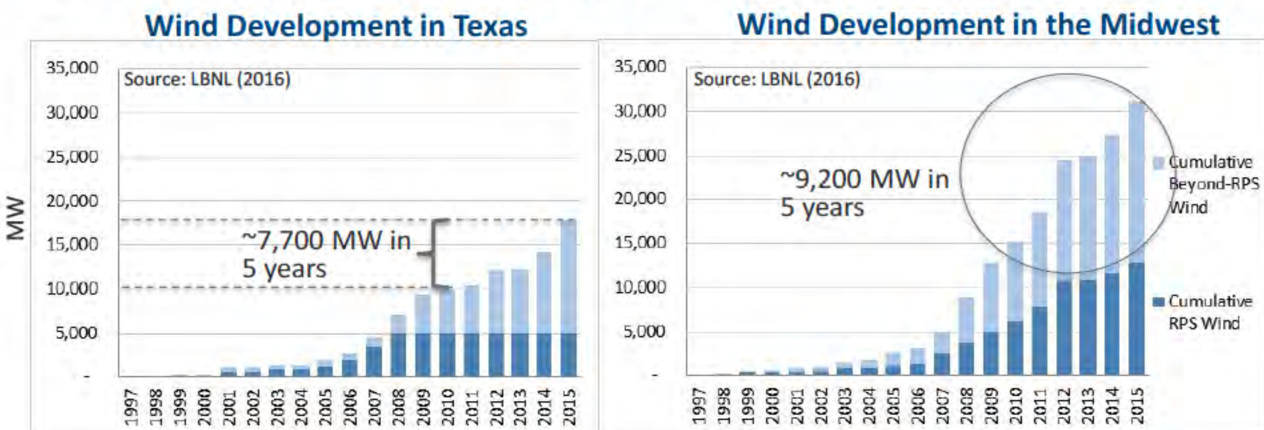


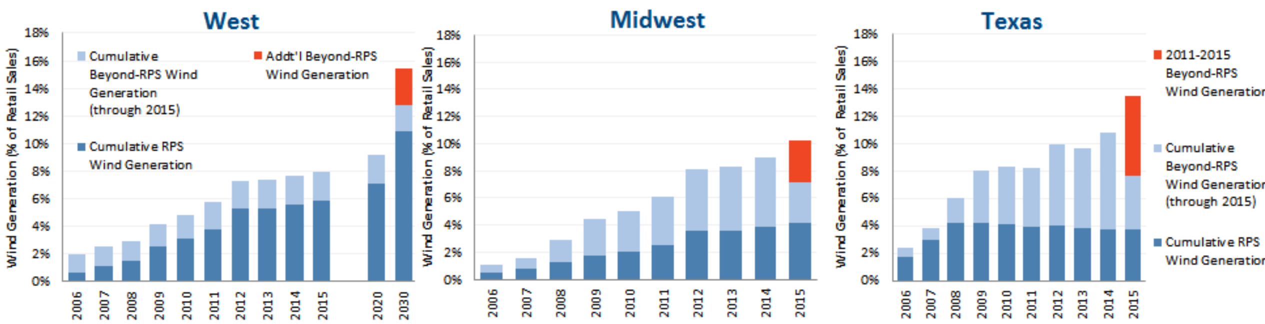
Figure 7 shows the amount of beyond-RPS wind added in Texas and the Midwest as a share of total retail load in these regions. As mentioned above, the 7,690 MW of wind unrelated to RPS that has been installed in Texas over the last five years represents 6.9% of Texas retail load. Similarly, the 9,200 MW of beyond-RPS wind installed in the Midwest over the same period represents 3% of retail load. Figure 7 also provides a benchmark for the 5,000 MW of additional beyond-RPS wind assumed to be developed between 2020 and 2030 in regional market scenarios of the SB350 study. This 5,000 MW of additional wind generation represents only 2.6% of the

16 Based on data provided by Dr. Galen Barbose of LBNL.

17 Based on data provided by Dr. Galen Barbose of LBNL.

regional market's 2030 retail load, a smaller share than the amount of beyond-RPS wind that has already been developed in Texas and the Midwest. This assumption is also discussed in more detail in Volume I of this report.

Figure 7: Wind Generation Development to meet RPS Requirements and Beyond
Historical (and simulated WECC future) in Regions with ISO-markets and Low-Cost Resources



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

Most of these wind generation investments beyond RPS mandates are supported by power purchase agreements ("PPAs") voluntarily signed by utilities, public power companies, and large commercial or industrial customers. However, the combination of transmission access, an improved wholesale market design, and liquid forward markets even allowed ERCOT to attract over 1,400 MW of pure "merchant" wind projects in 2014. Expanded transmission and the improved wholesale market design allowed ERCOT to reduce wind curtailments from 17% of generation in 2009 to 0.5% of generation in 2013, thereby increasing renewable energy generation without the need for new construction of renewable resources.[18]

The industry studies reviewed show that the drivers behind renewable generation development beyond RPS mandates fall into four distinct categories:

- **Voluntary PPAs by Investor-Owned Utilities in Excess of RPS Requirements.** While Investor Owned Utilities are often subject to RPS requirements, many utilities in areas

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18 Wiser, R. and Bolinger, M., "2014 Wind Technologies Market Report," Lawrence Berkeley National Laboratory, August 2015, pp. 38, 66, Available: http://energy.gov/sites/prod/files/2015/08/f25/2014-Wind-Technologies-Market-Report-8.7.pdf

"Merchant" projects are those whose electricity sales revenue is tied to short-term contracted and/or wholesale spot electricity market prices (with the resulting price risk commonly hedged over a 10- to 12-year period) rather than being locked in through a long-term PPA. (*Id.*, at 27) with access to low-cost wind generation have procured additional renewables for economic reasons. For example, because of MidAmerican's voluntary purchases and development of low cost wind resources, wind generation is projected to supply 58% of the utility's Iowa load by the end of 2016.[19]

- **Purchases by Public Power and Municipal Utilities Not Subject to RPS.** Public Power and Municipal Utilities, who are generally not subject to RPS requirements, have voluntarily contracted for significant amounts of renewable generation. For example, publicly-owned utilities were responsible for 15% of the renewable generation purchases in 2014.[20]
- **PPAs by Commercial and Industrial Customers.** Commercial and industrial electricity customers are increasingly opting to purchase renewable power through PPAs with renewable power developers. As discussed further below, in regional markets that can readily accept the energy produced by renewable generating resources, such PPAs with retail electricity customers are possible even in states without retail access. According to Renewable Choice Energy, 3,420 MW of voluntary PPAs for renewable energy were signed by commercial and industrial customers in 2015 (up from 1,615 MW in 2014 and 559 MW in 2013).[21,22]
- **Merchant Renewable Generation Development.** Merchant wind generation projects have been developed without a long term PPA. They often sell power into spot energy markets and may use multi-year financial hedges to support the financing of the generation investments. While utilities remain the largest purchaser of renewables, merchant wind installations reached 33% of the total renewable generation development in 2014.[23]

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19 These renewable energy purchases also allowed MidAmercian to retire 2,000 MW of coal plants. See Matyi and McGuirk, "2,000 MW of coal retired in the Midwest," MegaWatt Daily, April 15, 2016.

20 Wiser, R. and Bolinger, M., "2014 Wind Technologies Market Report," Lawrence Berkeley National Laboratory, August, 2015, p. 27

21 O'Shaughnessy, E. *et al.*, "Status and Trends in the U.S. Voluntary Green Power Market (2014 Data)," NREL, October, 2015, p. v., Available: http://www.nrel.gov/docs/fy16osti/65252.pdf

22 Powers, J. "The Rise of the Corporate Energy Buyer," Renewable Choice Energy, 2016, Available: http://www.renewablechoice.com/blog-corporate-energy-buyer/

23 Wiser, R. and Bolinger, M., "2014 Wind Technologies Market Report", Lawrence Berkeley National Laboratory, August 2015, p. 27, Available: http://energy.gov/sites/prod/files/2015/08/f25/2014-Wind-Technologies-Market-Report-8.7.pdf

Recently, several new mechanisms have emerged to enable voluntary purchases of renewable electricity. In some states, community choice aggregation programs allow municipalities to purchase renewable electricity on behalf of some or all of the customers in their jurisdictions. Community solar programs allow customers to directly support the construction of a solar facility while continuing to receive power from their local utility. Of particular interest, large commercial and industrial customers have increasingly been signing PPAs to procure renewable energy directly. Such PPAs are facilitated by organized markets.

According to NREL, "voluntary" renewable purchases by retail customers accounted for 26% of U.S. non-hydro renewables generation in 2014 (74 million MWh), an increase of 10% over 2013.[24] Such voluntary purchases could be executed in several ways. First in de-regulated states, customers may purchase renewable electricity from competitive suppliers. Second, in regulated states where no retail choice exists, utilities may procure renewable electricity and then sell it to their customers using green pricing programs or tariffs. Third, customers in any region can purchase "unbundled" Renewable Energy Credits (RECs) that are sold independently of the underlying renewable energy. And finally, customers can sign PPAs that financially support renewable generation investments whose energy is injected into the regional wholesale power market while customers continue to be served by their local utility through the utility's standard regulated retail service.

Commercial and industrial purchasers account for an increasingly large share of renewable PPAs and such retail purchases are increasing over time. Non-utility entities have been reported to account for over 50% of all wind PPAs in 2015.[25] The recently formed Renewable Energy Buyers Alliance (REBA), a collection of more than sixty companies interested in increasing purchases of renewable energy, set a goal of procuring 60,000 MW of new renewable generation in the U.S. by 2025.[26,27] Figure 8 shows aggregate commercial and industrial (C&I) PPA deals over time by counter-party.

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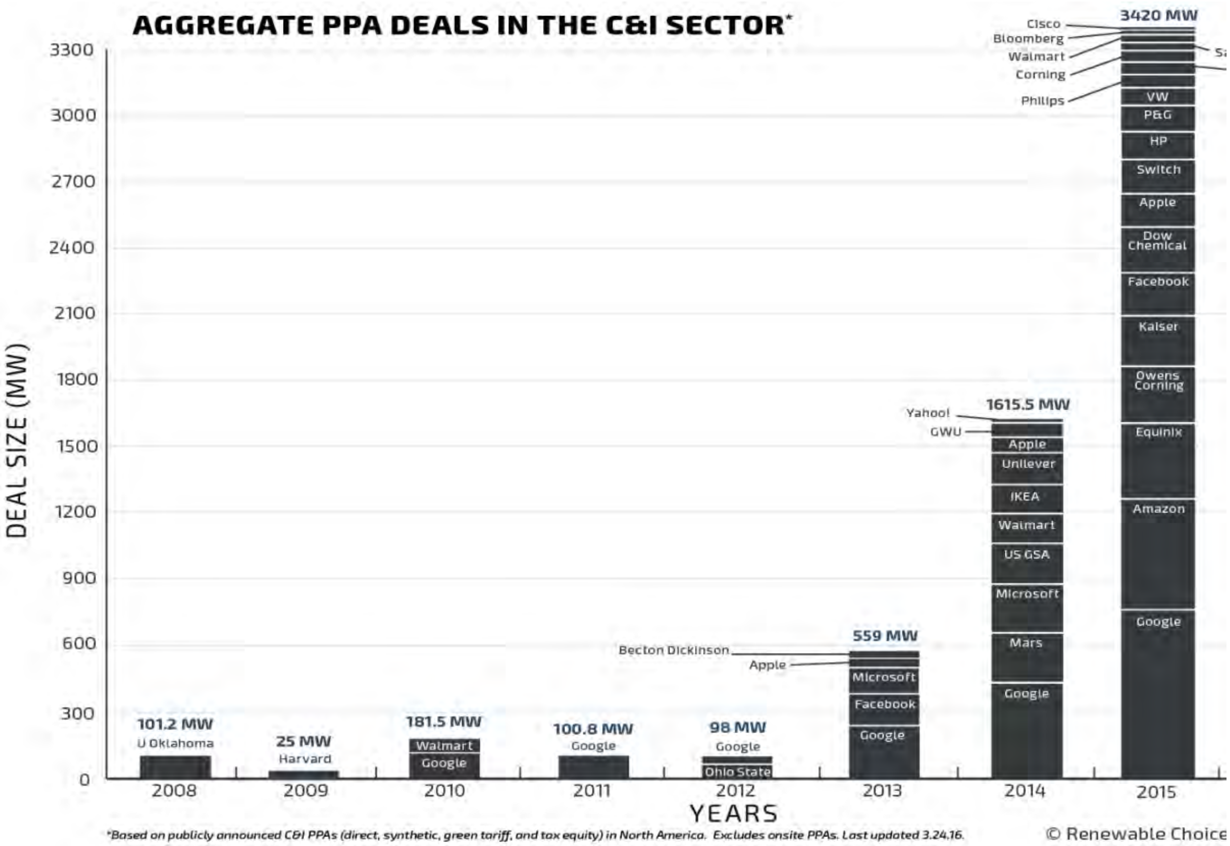
24 O'Shaughnessy, E. *et al.*, "Status and Trends in the U.S. Voluntary Green Power Market (2014 Data)," NREL, October, 2015, Available: http://www.nrel.gov/docs/fy16osti/65252.pdf

25 Copley, M. "Business coalition doubles down on corporate demand for renewables," SNL, May 13, 2016, Available: https://www.snl.com/InteractiveX/article.aspx?id=36493637&KPLT=2

26 WRI, "RELEASE: Renewable Energy Buyers Alliance Forms to Power the Corporate Movement to Renewable Energy," WRI Press Release, May 12, 2016, Available:

Continued on next page

Figure 8: Aggregate PPA deals with Commercial & Industrial Customers
(Reproduced from renewableenergychoice.com)



Source: http://www.renewablechoice.com/blog-corporate-energy-buyer/

See also: http://www.renewablechoice.com/blog-electricity-corporate-ppa-buyers/

Based on the authors of Figure 8, all PPAs shown on the chart involve long-term PPAs, for bundled off-site resource (not unbundled RECs), involve new construction, are mostly for wind generation (with some solar), and are generally (but not always) located in the same ISO market as the retail customers.

Continued from previous page

http://www.wri.org/news/2016/05/release-renewable-energy-buyers-alliance-forms-power-corporate-movement-renewable

27 WRI, "Corporate Renewable Energy Buyers' Principles: Increasing Access To Renewable Energy," December 2015, Available: http://www.wri.org/sites/default/files/Corporate_Renewable_Energy_Buyers_Principles.pdf

Google, one of the most active companies in this regard, states the following about its renewable power purchases:[28]

> Google's goal is 100% renewable power, and to date we've signed 16 contracts to purchase over 2.2 Gigawatts of clean energy…To achieve our goal, we're buying clean electricity directly from wind and solar farms around the world through Power Purchase Agreements (or PPAs), and we're additionally working with our utility partners to make more renewable energy available to us and others through renewable energy tariffs and bilateral contracts.
>
> We hold ourselves to the highest standards when purchasing clean power. First, our contracts must create new sources of green power on the grid. Second, we purchase renewable energy in the same grid regions from which we're withdrawing power. And third, we purchase "bundled" energy and RECs, meaning the same quantity of energy and RECs at the same time.

More recently, organized wholesale markets have been facilitating the development of renewable generating facilities through PPAs with commercial and industrial customers in the form of so-called Contracts for Differences ("CfD")—a novel mechanism allowing non-utility purchasers to access both the environmental and economic benefits of new renewables in states with or without retail access. In a CfD arrangement, customers obtain bundled RECs directly from the renewable generator, but leave their existing retail arrangement unchanged. Meanwhile, the renewable generator sells the PPA-related energy output into the local wholesale market at market rates. The customer and renewable generator then settle for the difference between the wholesale market price and the contract price. If the wholesale price is less than the contract price, the customer pays the renewable generator. If the wholesale price is higher than the contract price, the renewable generator pays the customer. The CfD arrangement provides a steady revenue stream for the renewable generator and allows the customer to hedge against electricity price risk while obtaining the environmental benefits of purchasing renewable generation in the wholesale power region in which they are located.

Figure 9 illustrates the concept. While such contracts have recently been used by Apple, Google, and Kaiser Permanente to execute renewable PPAs in California,[29] they are particularly

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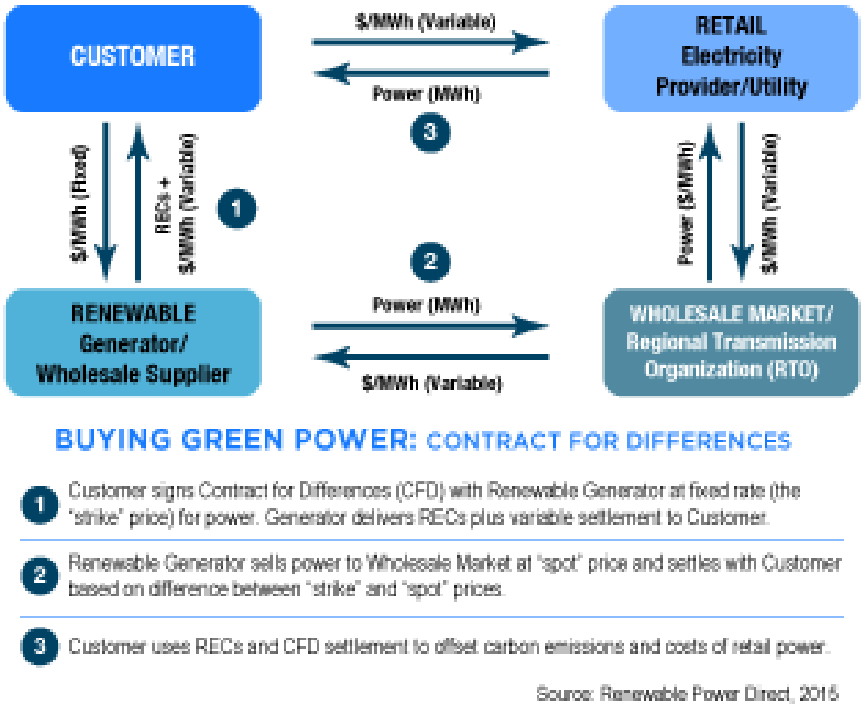
[28] See https://www.google.com/green/energy/use/#purchasing. Amazon's goals and approach are very similar: http://aws.amazon.com/about-aws/sustainability/

[29] Catasein, J. "A New Way for Companies to Go Green," Renewable Power Direct, February 27, 2015, Available: http://renewablepowerdirect.com/a-new-way-for-companies-to-go-green/

attractive in regional wholesale markets that provide access to the lower-cost renewable resources.

Figure 9: Renewable Purchases Using Contracts for Differences
(Reproduced from renewablepowerdirect.com)



Reproduced from: http://renewablepowerdirect.com/a-new-way-for-companies-to-go-green/

As the industry data discussed earlier shows, the majority of renewable generation developed beyond RPS requirements occurred in areas that offer both (1) low-cost renewable generating resources that make contracts economically attractive; and (2) ISO-operated regional wholesale power markets. Regional markets without access to low-cost renewable resources (such as CAISO, ISO-NE, NYISO, and PJM) show significantly less renewable development beyond RPS requirements.

E. Reliability Impacts

The quantitative analyses of ratepayer savings and environmental and economic impacts presented in this report focus on maintaining the existing level of reliability in a more cost-effective fashion. The estimated ratepayer impacts include only the following cost savings associated with meeting applicable planning and operational reliability standards:

- Lower generation investment costs from load diversity based on estimated market price for capacity. This does not capture the additional reliability value of any achieved higher reserve margins.
- Production cost savings associated with lower operating, regulation, and load-following reserve requirements and the reduced cost of providing these operating reserves due to reserve sharing and net load diversity.

This quantification of ratepayer benefits does not reflect the value of achieving more reliable region-wide system operations.

Expanding ISO operations to a larger regional footprint additionally offers significant reliability benefits to both California and the larger regional market area for several reasons. 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.[30] Expanding regional market operational practices consequently offers reliability benefits to (a) the expanded regional footprint which, 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 presented in Figure 10 (prepared by CAISO), even relative to the enhanced reliability benefits achieved by EIM, an ISO-operated, consolidated regional market and balancing area offers important additional reliability benefits.

As the table shows in significantly more detail, these enhanced regional reliability-related benefits include:

- Improved real-time awareness of system conditions[31];

30 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.

31 This would be complementary to the role of the reliability coordinator for the Western Interconnection (Peak Reliability) – a NERC registered entity responsible for providing provide situational awareness and real-time monitoring of the Reliability Coordinator (RC) Area within the Western Interconnection.

- 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;
- 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.

Figure 10: Reliability Benefits of Regional Market Operation, Compliance, and Planning

	Reliability Benefits of Regional Market Operation, Compliance, and Planning			Extent Achievable	
	Function	**Western Interconnection Operations/Standard Practice**	**Regional Operations/ISO Practice**	**EIM**	**Full Day-2 Market**
1	Locational 5-minute Real-Time (and Hourly Day-Ahead) Price Signals	Bilateral markets achieve reliability based on contractual rights and industry standards with little guidance from locational prices or focus on economic impacts	• ISO enhances reliability by informing all market participants on the state of grid conditions and market operations through locational electricity prices and the day-ahead and real-time posting of other key system information • As a reflection of actual real-time (and projected day-ahead) system conditions, market prices in the ISO energy market provides specific locational signals where more (or less) generation is needed to maintain reliabilty	Limited to real-time prices and conditions	Provides Day-Ahead and opportunity to converge prices reflective system conditions between markets and thus providing
2	Congestion Management	• Performed using WECC Unscheduled Flow Mitigation Procedure or internally developed operating procedure based on congestion management system • 30 – 60 minute response time	• Market-based congestion management that relies on a five minute security constrained economic dispatch to mitigate transmission congestion on a least-cost basis allows for more timely and efficient congestion management • Look Ahead Commitment Tool provides unit commitments, de-commitments, online extension recommendations for congestion management, and models near-real-time conditions to utilize resource capabilities • Simultaneous feasibility tests performed to capture transmission security constraints in DA market processes, while Real-time contingency analysis of Energy Management System provides real-time security constraints for real-time clearing and pricing	Limited to real-time condtions	Day-Ahead can anticipate and position system to avoid congestion in real-time based on the greater situtational awareness.
3	Unscheduled Flow Management	• Unscheduled flows are managed sub-optimally on a limited set of qualified paths	• A regional integration allows congestion management to more effectively manage unscheduled flows in the entire grid and also solve the related congestion	Limited to real-time condtions	Day-Ahead can anticipate and position system to avoid unscheduled flow. A broad region would elminate unscheduled flow because all flow would be managed by congestion management
4	Regional Unit Commitment	Decentralized unit commitment decisions without region-wide perspective and differing granularity can lead to inconsitencies and unintended reliability	Regional unit commitment to address footprint-wide reliability needs: • Advisory 2-day ahead process • Multi-day residual unit commitment (RUC) • Regional Reserve Requirements Calculation • Day-Ahead RUC • Intra-Day RUC • Ensure availability of flexible capacity	Limited to short-start resources	Incorporates all periods of unit commitment and can ensure commitment aligns with flexibility needs

	Reliability Benefits of Regional Market Operation, Compliance, and Planning			Extent Achievable	
	Function	Western Interconnection Operations/Standard Practice	Regional Operations/ISO Practice	EIM	Full Day-2 Market
5	Sytem Monitoring and Visualization	• Real-time monitoring using SCADA on a local area basis (Some has limited Real Time Contingency Analysis) • Use of standard vendor supplied displays • Operator interface of standard monitor display screen augmented with static map board (some has digital dynamic map board) • Ad-hoc and off-line voltage security analysis review	• Regional view/monitoring of the power system including: – A State Estimator - runs every 60 seconds – Contingency analysis of over 2000 contingencies every five minutes that is scallable to higher number of contingencies – 24-hour shift engineer coverage responsible for maintaining security application performance - Advanced real-time voltage stability and security application • Extended use of custom tools and displays to allow for faster analysis and better situational awareness • Large video wallboard (80 feet) that provides operators with live data reflecting the state of the power system and real-time market results • Real-time Voltage Stability Analysis Tool (VSAT) and Transmission Security Assessment Tool (TSAT), which allow comprehensive analyses of system operating conditions for predicting and preventing voltage insecurity and transient instability	Limited to real-time conditions and EIM footprint	Can monitor and visualize prior to real-time and thus respond to security conditons prior to real-time expanding solution options for secure operation over entier region.
6	Backup Capabilities	• Offline and/or scaled down backup facility • Significant time to bring backup facility up in the event a failover or failback is needed • Testing of failover process performed annually	• 24 x 7 staffed back-up control center • On-line back-up facility with full coverage of power system and market applications immediately available • Less than 30 minutes required for failover or failback for critical applications • Testing of failover process is performed quarterly for critical applications	Not covered because BA maintains its role	Consolidated back-up capablity
7	Operator Training	• Classroom training only (some has limited simulators) • Train to meet minimum NERC requirements • Five-person rotation (no training rotation) and some has six person rotation • Offline power system restoration procedure review	• Training methods include extensive use of full-dispatch training simulator • Training exceeds NERC requirements • Six-person rotation at key operator positions (allowing a training week during each cycle) • Annually conduct a regional "live" power system restoration drill that includes dozens of companies in the region	Not covered because BA maintains its role	Consolidated, consistency across region
8	Performance Monitoring	• Performance reviewed on a "post-event" basis • Operator call review on a "post-event" basis	• Daily review of operational performance including: – Frequent near-term performance feedback to operators and support personnel – Routine review of upcoming operational events • Standardized operator call review process • Feedback provided to each operator	Not covered because BA maintains its role	Consolidated, consistency across region
9	Procedure Updates	• Procedures updated on an ad-hoc, as-needed basis	• Annual procedure review conducted on all control room procedures • Routine drills including member participation conducted on capacity emergency procedures • Annual Emergency Operating Procedures training session with members, neigboring entities, and reliability coordinator	Not covered because BA maintains its role	Consolidated, consistency across region

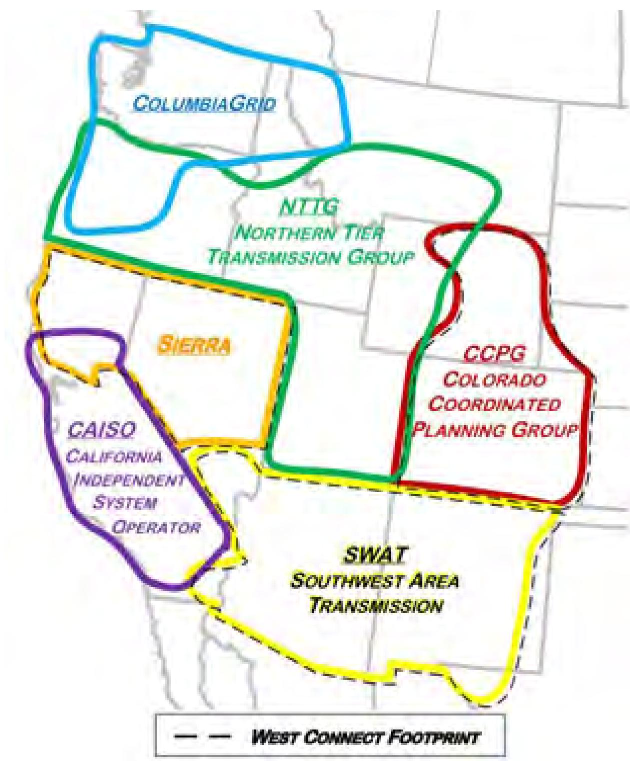
	Reliability Benefits of Regional Market Operation, Compliance, and Planning			Extent Achievable	
	Function	**Western Interconnection Operations/Standard Practice**	**Regional Operations/ISO Practice**	**EIM**	**Full Day-2 Market**
10	Standards Development	• Utilities are varied in their approach to standards engagement. • Many are "standards takers," relying on the good judgment of others in the industry to develop standards.	• By collaborating and participating in the standards creation, the ISO and its members can better manage the ultimate compliance responsibilities • ISO engages in several WECC/NERC drafting teams to actively manage the scope of standards development and to limit the number of changes required to MISO and stakeholders • ISO's integrated efforts lighten the workload on all members for a given level of input and control of the process	Not covered because BA maintains its role	Consolidated, consistency across region
11	NERC Compliance	• Many parties in the WECC region are responsible for managing NERC compliance • 30+ Interchange Authorities, Transmission Service Providers, Balancing Authorities (BA) • Several Planning Authorities • Individual Reserve Sharing Groups	• With ISO as a regional balancing authority, many compliance responsibilities are consolidated (and member responsibilities decreased) • Single regional Transmission Service Provider • Significantly fewer BAs and related compliance requirements • Fewer Planning Authorities • Consolidated Reserve Sharing Administrator • Centralization of some Transmission Operator Requirements • Allows members to avoid hiring compliance-dedicated staff or reduce existing compliance-driven staff to track these compliance-related issues	Not covered because BA maintains its role	Conssolidated, consistency across region
12	Regional Planning	• Planning by many individual utilities focused on local needs • Regional and interregional planning require complex coordination amont many utilities and planning groups	• Single regional view and planning can address reliability needs more accurately and consistently • Offers opportunities to find most efficient solutions across multiple transmission owners	Not covered because BA maintains its role	Consolidated, consistency across region
13	Fuel Diversity	• 38 WECC Balancing Areas with limited fuel diversity within many of the areas	• Regional market can mitigiate reliability risks associated with fuel supply risks (Gas, Hydro/Drought, Renewable Intermittency)	Limited to real-time and voluntary	More fully leverages diverstiy across region and market time frames
14	Long-term Investment Signals	Bilateral markets provide less granular price signals which can result in less efficient investment and placement of generation resources and transmission infrastructure	Price signals sent by the ISO's market provides investors in generation assets with more economic signals upon which they can anchor their forecasts for future wholesale prices and provide the basis for market driven investments	No real-time, too limited	Full leverages signals across regoin and market time frames leveraging regional resource adequacy opportunity

F. REGIONAL TRANSMISSION PLANNING

A larger ISO-operated regional market will offer improved regional transmission planning, from a reliability, economic congestion management, and renewable integration perspective. Transmission planning is currently undertaken in a coordinated but not integrated fashion by the CAISO and each of several sub-regional transmission planning groups in the West.

As shown in Figure 10, this planning process currently requires the coordination of utility planning efforts through four transmission planning groups: (1) CAISO; (2) WestConnect (and its three embedded sub-regions, Sierra, Southwest, and Colorado); (3) Northern Tier Transmission Group; and (4) Columbia Grid.

Figure 11: Western Sub-Regional Planning Groups



Source: http://www.westerngrid.net/western-sub-regional-planning/

Outside the CAISO, which employs a single integrated planning process, intra-regional planning within each of these planning sub-regions is conducted by aggregating individual transmission plans of the member utilities and conducting sub-regional studies to identify possible sub-regional transmission projects that are more effective than the projects proposed by the individual utilities. Planning of transmission projects that cross the boundaries of the individual sub-regions requires substantial and complex coordination across these individual planning groups, which employ their own (in many aspects unique) planning processes. This coordination is time consuming and challenging even under the coordination requirements under FERC Order No. 1000 on transmission planning and cost allocation.[32] The challenges of interregional planning are further magnified by the absence of a clear cost allocation framework for valuable interregional transmission projects.

In comparison, the more unified transmission planning process of an expanded regional ISO offers significant benefits and additional long-term value through the following features:

- A single, unified planning process and set of planning criteria that will apply to a larger regional footprint;
- ISO-market operations and price signals that allow for an enhanced focus on identifying valuable economic and public policy transmission projects (while maintaining reliability) that reduce overall system costs;
- Planning for a larger regional footprint that will facilitate regional access to and integration of renewable resources;
- Generator interconnection and repowering processes that are simplified because more power flows are internalized within the planning region and fewer individual planning will be affected by unscheduled loop flows;
- Fewer planning coordination challenges, enhanced regional planning visibility, and more consistent and unified regional planning tools in a regional footprint that includes a greater number of individual transmission owners;
- Streamlined cost allocation processes that facilitate development of valuable regional transmission projects; and
- Fewer interregional planning challenges related to "market seams" between small, individual planning areas.

32 See http://www.ferc.gov/industries/electric/indus-act/trans-plan/filings.asp

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THE Brattle GROUP

Senate Bill 350 Study

Volume XII: Review of Existing Regional Market Impact Studies

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

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Volume XII. Review of Existing Regional Market Impact Studies

A. Introduction

We reviewed a number of other studies that have estimated the benefits of organized regional electricity markets. While most other studies analyzed markets different from those projected for California and the West, they offer relevant information and helpful reference points. Many of these studies employ analytical frameworks similar to those used in this SB 350 study. Taken together, the studies show that the magnitude of benefits from regionalizing markets is generally consistent across various regions, circumstances, and time periods.

Some of the studies we reviewed analyzed circumstances similar to those explored in this SB 350 study. For example, the SPP Retrospective Study (2015) estimated the benefits of moving from an imbalance market similar to California's Energy Imbalance Market to a full Day-2 Market. This study is particularly relevant for SB 350 because SPP resembles WECC in other ways, albeit on a smaller scale. Much like WECC, SPP has a mix of natural gas, coal, and renewable generation with major load centers in one portion of the footprint (the southeast) and distant areas with low-cost renewable generation (the Great Plains). Additionally, the Basin/WAPA Study (2013) explored the benefit of regional market participation to public power entities similar to those found in WECC. The Entergy-MISO Study (2011) analyzed the benefits of the expansion of a regional market.

A few of the reviewed studies specifically focused on WECC and explored the benefits of improved regional market design and renewable integration. For example, and as discussed further below, the Low Carbon Grid Study (2016) simulated the WECC for a 2030 study year with very similar study assumptions, yielding very similar results for both California and the broader WECC region.

B. Market Integration Studies Reviewed

Figure 1 below summarizes the types of studies reviewed to provide background and reference levels for the analysis of the impacts that regional market integration and region-wide independent system operations would likely have on California and the surrounding regions.

Figure 1: Studies Reviewed

Study Type	Examples of Studies
Day-2 Market Studies Evaluate benefits of moving from de-pancaked transmission and energy imbalance market to full Day-2 market	SPP Retrospective (2015), SPP Prospective (2009), Navigant Markets Study (2009), Chan Efficiency Study (2012), MISO Value Proposition Report (2015), MISO Retrospective Study (2009), Wolak Nodal Study (2011), NYISO Plant Efficiency Study (2009), ERCOT Nodal Study (2014)
RTO Participation Studies Evaluate benefits and costs to a utility of joining an existing RTO	E3 PAC Integration Study (2015), Basin/WAPA Study (2013), Entergy-MISO Study (2011), Entergy SPP/MISO Cost-Benefit Analysis (2010), Mansur PJM Efficiency Study (2012)
Post Order 2000 RTO Studies Benefit-cost studies of forming RTOs that followed issuance of FERC Order 2000 in late 1999	LBNL Review Study (2005), RTO West Study (2002), National RTO Study (2002)
EIM Studies Evaluate the benefits of the Western EIM, or the benefits of a utility joining the EIM	WECC-Wide EIM (2011), APS-EIM (2015), PGE-EIM (2015), NV Energy-EIM (2014), Puget Sound-EIM (2014), PacifiCorp-EIM (2013)
European Market Integration Studies Evaluate the benefits of market integration in the European context	EPRG Integrating European Markets (2015), DNV-GL European Renewable Integration Study (2014)
Renewables Studies Studying the challenges of higher penetration of renewable resources	NREL/DOE WWSIS 2 (2013), Low Carbon Grid Study (2016), WGA Integration Study (2012), SPP Wind Integration (2016)
Markets-Based Renewables Studies Discussing the function of markets in facilitating renewables development beyond RPS requirements	Brookings Clean Economy Study (2011), AWEA Green Power Superhighways (2009), Hogan Markets In a Low Carbon Future (2010), COMPETE Markets and Environmental Challenges (2014), ISO/RTO Metrics Report (2015), IRC Increasing Renewables Study (2007), LBNL Wind Technologies Market Report (2015), NREL Voluntary Green Power (2015)

While the scopes and objectives of some of these studies differ markedly from the requirements under SB 350, most of them estimate the cost savings and price impacts of regional market integration. This provides a useful reference point for the ratepayer impact analyses required under SB 350. Additional industry studies were reviewed in the context of regional markets' facilitation of renewable generation developments. These studies and the related industry data is discussed in Volume XI of this report.

C. Most Prospective Regional Market Integration Studies Show Production Cost Savings Ranging from 1% to 3%

The transition to regional markets impacts both investment-related (fixed) costs and production-related (variable) costs. The impact of regional markets on variable production costs has been studied extensively in many analyses from both a prospective (*ex ante*, before the fact) and retrospective (*ex post*, after the fact) basis. The prospective studies we reviewed generally report production cost savings associated with transitioning to a regional market in the range of 1% to 3% of the system's total production costs. Note, however, that the magnitude of intermittent renewable generation present in the regions analyzed in most of these studies is well below the magnitude of existing and projected future renewable generation in California and the WECC.

These studies typically use production cost models to simulate a "Without Regional Market" (or "Smaller Regional Market") case to compare with a "With Regional Market" case. Savings are then estimated based on the difference between the two cases' production costs. The market design features that are simulated to represent the "Without Regional Market" and "With Regional Market" cases differ across the studies. The most common market design feature used to represent a "With Regional Market" case is to have a full "Day-2" market (consisting of integrated day-ahead energy, real-time energy, and ancillary services markets) in which the transmission charges are fully de-pancaked within the study region. The de-pancaking of transmission charges means that, within the regional market, energy transactions between the individual areas of the regional market are not subject to any variable transmission charges.[1]

Most of the production cost simulations do not incorporate uncertainties in load or generation between the time when conventional generation is committed (mostly on a day-ahead basis) and the real-time dispatch of these resources against load. A few of the studies differentiate between the day-ahead commitment time frame and the real-time market to capture the potential impact caused by unanticipated changes in load and generation between the two time frames. Some of the studies analyze the potential impact of more efficient utilization of the existing transmission system due to automated, security-constrained economic dispatch for the entire region. Collectively, these prospective studies embody a representative range of analytical approaches used to estimate production cost savings from regional market integration.

Figure 2 summarizes the features of the Regional Markets that are analyzed across various prospective studies and thereby represent the benefits that the various studies are able to capture through the production cost simulations. The last row in the figure shows the estimated production cost savings (as a percentage share of total production costs) reported by the studies.

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1 In other words, while loads pay for transmission at the withdrawal point, they can be served from any resource within the region without incurring additional, transaction-specific transmission charges.

Figure 2: Market Features and Production Cost Savings Captured in Prospective Market Integration Studies (expressed as a % of system production costs)

Market Design Features Captured in Production Cost Savings	National RTO (2002) [1]	LBNL Review (2005) [2]	RTO West (2002) [3]	SPP Prospective (2009) [4]	Basin/ WAPA (2013) [5]	Entergy-MISO (2011) [6]	E3 PAC Integration (2015) [7]
Transmission Charge De-Pancaking	✓	✓	✓	✓	✓	✓	✓
Day-Ahead Market	no	✓	no	✓	✓	✓	✓
Full Real-Time Imbalance Market	✓	Varies	✓		✓	✓	Varies
Ancillary Services Market	no	Varies	✓	✓	no		Varies
Improved Transmission Utilization	✓	Varies	✓	no	no	✓	Varies
Generator Efficiency and Availability Improvements	✓	Varies	no	no	no	no	Varies
% Reduction in Total Production Costs	0.3%–5%	<1% to 8%	Not Reported	1.3%–2.0%	0.9%–2.1%	3.4%–3.8%	1.6%–3.6%

Sources and Notes:

[1]: The range represents savings in the "Transmission Only" scenario (de-pancaked transmission charges and increased transmission capacity) on the low end and "RTO Policy" scenario (includes 6% efficiency and 2.5% availability improvement for fossil units) on the high end. This study used a single-stage dispatch model to estimate benefits. It did not model unit commitment.

[2]: This was a study review report. Studies in the review modeled different market designs. Inter-quartile range of reported savings was 1%–3%. Some of the reviewed studies reported other savings in addition to production cost (*e.g.*, congestion revenues).

[3]: Study did not provide baseline production costs, so % savings could not be calculated.

[4]: Total production cost savings over 2009–2016 time horizon with low end of range from across case I (DA market-only) and high end from case IIB (DA + AS markets).

[5]: WAPA 'Enhanced Adjusted Production Cost" savings of joining SPP as a percentage of "Standalone" LMP-based charges. Range reflects 2013–2020 savings.

[6]: Range reflects Entergy adjusted production cost savings of joining SPP and MISO as estimated using production cost simulation. Savings do not include spinning and regulation reserve savings estimated using MISO's Value Proposition methodology.

[7]: This was a study review. Studies in the review modeled different market designs.

Of the studies summarized in Figure 2, two represented a review of several other analyses. Specifically, the LBNL Review Study (2005) reviewed 11 RTO studies from the early 2000s. From those studies reviewed, LBNL found that the reported production cost savings ranged from less than 1% to 8% of total production costs, though most of the reviewed studies reported estimated production cost savings between 1% and 3%.[2] Further, the E3 PAC Integration Study (2015) surveyed several prior market integration studies and found that estimated production cost savings ranged from 1.6% to 3.6%.[3] Overall, these results show that the production cost benefits of regional market integration tend to range from 1% to 3%.

D. Limitations in the Analytical Approaches Used for Prospective Studies Tend to Underestimate the Benefits of Regional Markets

The prospective studies of regional markets' production cost savings commonly acknowledge that their analytical methodologies omit some of the benefits provided by regional markets. These studies generally underestimate benefits because they (1) do not capture the full production cost benefits of market integration, and (2) do not capture non-production cost related benefits. We first discuss common set limitations related to the deterministic approaches of the analyses and the fact that production cost simulations capture only fuel and other variable generation cost savings.

Most of the prospective studies reviewed put the estimated benefits into perspective by either (1) discussing limitations of their analytical framework which tend to understate the estimated production cost savings; or (2) discuss benefits beyond production cost savings that have not been quantified. We first summarize the types of production cost benefits that are not typically captured due to the limitations generally found in market simulation analyses. We later discuss the second set of limitations—that studies rarely estimate investment cost benefits, such as reductions in generation investments needed as a result of greater load and resource diversity across larger footprints.

Most prospective production cost studies tend to understate production cost savings due to one or more of the following limitations: (1) they simulate only normal system conditions; (2) they do not analyze the extent to which regional markets optimize the use of the existing grid; (3) they do not capture the impact of stronger incentives to improve plant efficiencies; and (4) they do not capture increased competition and improved market monitoring and mitigation. Regional markets additionally (5) improve system reliability, and (6) improve regional operational and system planning, which offers benefits not fully captured in production cost savings.

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[2] Eto and Hale (December 2005).

[3] Energy + Environmental Economics (October 2015)

1. Production Cost Simulations Typically Do Not Capture Cost Savings Associated with Non-Normal System Conditions

Most studies that rely on production cost models estimate savings only by simulating normal system conditions. This means that the simulated load generally is weather normalized without any potential large swings and differences in regional loads due to different weather conditions. In addition, transmission outages are not typically considered in the analyses. Both of these omissions were discussed in the Basin/WAPA study (2013). That study states that the production cost simulations used in its analysis will yield a conservative estimate of benefits because it does not address important aspects of actual market operations such as transmission outages, actual weather patterns that deviate from normal weather, and any load and generation uncertainties between day-ahead and real-time operations. Due to these limitations, simulation results will tend to underestimate the level of transmission congestion and the extent to which improved congestion management through a regional market with security-constrained economic dispatch can reduce overall production costs.

2. Markets Can Improve the Utilization of the Existing Transmission Grid by More than is Reflected in Production Cost Simulations

The RTO West Study (2002) suggests, but does not quantify, that an RTO would increase the effectively Available Transmission Capacity (ATC) over major transmission lines. The benefits associated with increased ATC are incremental to the production cost savings that result from de-pancaked transmission charges and region-wide security-constrained dispatch.[4] The Basin/WAPA study (2013) makes the qualitative point that—because congestion management based on point-to-point transmission reservations and the curtailment of scheduled transactions[5] is less efficient than how congestion is managed in production cost simulations—the savings associated with participation in an RTO would be underestimated.[6] Similarly, the Entergy SPP/MISO Cost-Benefit Analysis (2010) notes that the inefficiencies at the seam between the Entergy and the SPP systems in the "Not-Joint-RTO" case, if they were fully simulated, would increase the value of integration compared to model results.[7]

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4 Zobian, *et al.* (March 2002), at p. 49

5 Such curtailments are undertaking through "flow mitigation events" in the WECC and Transmission Loading Relief or "TLR" in the Eastern Interconnection.

6 Celebi, M., *et al.* (March 8, 2013), at p. 6

7 Charles River Associates and Resero Consulting (September 30, 2010).

The extent to which markets can utilize the existing grid more fully has been documented by analyzing how much of the available transmission capability remains unutilized in traditional bilateral markets. For example, an analysis of RTO market benefits by the U.S. Department of Energy (DOE) assumed that improved congestion management and internalization of power flows by ISOs result in a 5–10% increase in the effective transfer capabilities on transmission interfaces.[8] Similarly, a study of congestion management in MISO's "Day-1" market found that, during 2003, available flowgate capacities were underutilized by between 7.7% to 16.4% on average within MISO sub-regions during curtailment (so-called "TLR") events.[9] Our own analysis of unused capacity on WECC transmission paths during flow mitigation events similarly shows that between 5% and 25% of available transmission capabilities is left unutilized in the current bilateral market structure even at times when existing transactions are being curtailed.[10]

3. Production Cost Simulations Typically Do Not Capture Cost Savings Associated with Stronger Incentives to Improve the Efficiency and Availability of Power Plants

The stronger exposure to market forces of a regional market can lead to improvements in generator efficiency and availability. A number of studies have examined such efficiency improvements. As pointed out by the 2005 LBNL Review Study, operating within RTOs can create incentives for generators to invest in "enhancements or improvements to the efficiency" of existing generators.[11] The LBNL review noted that prospective studies typically do not capture such generator efficiency improvements because of the challenges of making assumptions about those efficiency improvements and benchmarking them against actual experiences.

An indication of possible plant efficiency gains is provided by several industry studies. For example, the Chan Efficiency Study (2012) used an econometric analysis to estimate the efficiency improvements in coal plants operated by investor-owned utilities over the period from 1991 through 2005 when restructuring policies were implemented and several regional

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8 U.S. Department of Energy, DOE/S-0138 (April 30, 2003), pp. 7–8 and 41–42.

9 McNamara, Ronald R., Docket ER04-691-000 (June 25, 2004), p. 14

10 See slide 167 of the CAISO stakeholder presentation, "Clean Energy and Pollution Reduction Act Senate Bill 350 Study: Preliminary Results," May 24, 2016, available at: https://www.caiso.com/Documents/Presentation-May24_2016-SenateBill350Study-PreliminaryResults.pdf

11 Eto and Hale (December, 2005), p. 40.

electricity markets were formed in the U.S. The study found that the efficiency of coal plants improved by 2%–3% in restructured states compared to non-restructured states.[12]

An increasing trend of power plant availability has been documented by various regional system operators as well. For example, the 2015 MISO Value Proposition report includes "Generator Availability Improvement" as a benefit of operating within the RTO and estimates its magnitude by using observed increases in availability since the start of market operations. The study found that availability improved by 1.5% from 2000 to 2014 and estimated associated annual savings of $210 million to $260 million per year. Other informal assessments, including ones conducted by the Electric Power Supply Association, NYISO, and Navigant, report increased power plant efficiency coincident with the introduction of markets.[13] The Navigant Markets Study (2009) reported that the availability of nuclear units operating in NYISO, MISO, and PJM had increased from 81% in 1996 (before regional markets were implemented) to 93% in 2007 (after Day-2 markets were established in all these regions.).

If these plant efficiency and availability gains materialize due to the increased transparency and competition of a regional market, the potential impacts on California and the rest of the WECC could be significant. While power plants in California are operating in such a market environment, the rest of the region is not. For example, the 2002 National RTO study evaluated a scenario featuring a 6% improvement in fossil generation efficiencies and a 2.5% increase in fossil unit availability. That study found that the assumed efficiency and availability improvements associated with market integration would reduce production cost by an additional 4.5%. While California generators are subject to strong market-based incentives, given California's dependence on imports, the state would benefit from the efficiency improvements across the WECC.

4. Organized Markets Can Increase Competition and Mitigate Uncompetitive Behavior, a Benefit Not Generally Captured by Market Simulations

Organized regional markets create price transparency in the wholesale market and thereby increase competition among generation and demand-side resources. The RTO West study (2002)

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12 Chan, *et al.* (August 2012).

13 Babcock, *et al.* (April 2009); EPSA (May, 2007).

notes that RTOs would reduce transaction costs, reduce overall production costs, and improve market liquidity.[14] Regional markets greatly facilitate the market monitoring of competitive behaviors and implementing mitigation practices. Anti-competitive practices tend to be less visible and more difficult to monitor and mitigate in a bilateral market construct.

Since production cost simulations typically represent existing systems as perfectly efficient systems without significant internal transactions costs (unless specifically added), the resulting comparisons commonly understate the potential competitive benefits of enlarging the regional markets. Production cost simulations generally assume fully competitive bidding behavior with bids reflecting true marginal costs. This does not capture the extent to which the additional competitive pressures and improved market monitoring that is present in larger-regional markets reduce bid-cost mark-ups and thus yield additional benefits.

5. Organized Markets Can Improve System Operating Reliability, a Benefit not Fully Captured by Production Cost Simulations

Region-wide coordinated outage planning, operations management, and real-time monitoring will improve system reliability. The value of such reliability improvements is not fully captured in the production cost simulations. Because of the challenges to fully reflect real-world conditions, the models typically simulate the region for normal system conditions, without transmission outages, and with perfect foresight of system conditions, generation outages, loads, and renewable generation levels. This will understate the benefits of a larger regional market and its ability to more efficiently and more quickly respond to forced outages, extreme events, and unexpected system conditions. The RTO West study (2002) notes that RTOs would improve reliability by allowing coordinated outage management, reducing failure propagation, improving outage restoration, voltage/frequency management, and loop/parallel path flow management,[15] but those benefits are above and beyond those captured by conventional analyses. Similarly, the LBNL Review study (2005) mentions that additional benefits (not usually quantified by prospective analyses) to forming RTOs include reliability benefits that stem from facilitating coordinated scheduling of maintenance outages, improving reserve procurement, and managing frequency and voltage in real time, and contingency response.[16]

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14 Zobian, *et al.* (March 2002), at p. 53

15 *Id.*, pp. 47-49.

16 Eto and Hale (December, 2005), p. 38.

6. Regional System Operations Improve System Planning

More coordinated regional planning and operations can increase the value of regional transmission investments and allow resources across larger footprints to be used more optimally. This can help the region meet its public policy goals at lower costs and simultaneously avoid redundant transmission projects that aim to meet similar needs in different areas within the large region. The RTO West study (2002) discusses that RTO-level transmission planning would "elevate the system planning process from a narrow focus on local or subregional needs to a broader focus on regional needs, thereby reducing the cost of transmission for the larger footprint."[17]

E. Retrospective Studies of Regional Market Integration Document Benefits Higher than those Estimated in Prospective Studies

Several studies evaluated the benefits of implementing a regional Day-2 market on an after-the-fact basis. Because the retrospective studies use actual market performance data, the analyses are more likely to capture impacts of market integration. By contrast, analyses conducted prospectively need to make assumptions about how the eventual operation of the market would perform relative to the status quo, which requires simulating complex bilateral markets or suboptimal coordination across operations and planning. Further, most prospective production cost studies do not or cannot estimate certain benefits (as discussed above), thus underestimating the overall production cost benefits of market integration (and before even considering any investment cost savings). Figure 3 describes the market features evaluated by each retrospective study as well as the savings reported by each one.

Three of the retrospective studies we reviewed focused on production cost savings. While one of these studies estimated only the incremental benefit of transitioning from a zonal to a nodal Day-2 market (Wolak Nodal Study 2011), the other two studies (MISO Retrospective Study 2009 and SPP Retrospective Study 2015) evaluated the benefits of transitioning from no centralized markets (*i.e.*, only bilateral transactions facing pancaked transmission charges), to full regional Day-2 markets (*i.e.*, de-pancaked transmission, nodal markets, and consolidated balancing areas). These latter two studies estimated the full production cost benefits of forming Day-2 markets and found notably larger production cost savings than the prospective studies we reviewed.

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[17] Zobian, *et al.* (March 2002), at p. 52

The 2009 MISO Retrospective Study used econometric methods to estimate achieved generation cost savings based on actual market performance.[18] The study found that MISO's transition from "no centralized market" to a region-wide Day-2 market produced a 4% reduction in production costs. The study separately estimated the benefits of (1) moving from a bilateral market with pancaked transmission charges, to a regionally de-pancaked but still bilateral "Day-1" market; and (2) additionally consolidating balancing areas and implementing a nodal Day-2 market design with regional day-ahead, real-time, and ancillary services markets. The analysis showed that 'more than half of the overall benefits (2.6% out of 4%) were attributable to the transition from MISO's Day-1 market to its current Day-2 market design.

Similarly, a 2015 SPP Retrospective study of its Day-2 market performance used actual market bid offers and real-time load to estimate the savings during the first year of SPP's "Integrated Marketplace."[19] The results documented an 8% reduction in production costs attributable to SPP's transition from purely bilateral markets with pancaked transmission charges to its current Day-2 market design. SPP evaluated separately (1) the benefits captured by its initial energy imbalance services (EIS) market with fully de-pancaked transmission rates; and (2) those provided incrementally by the consolidation of balancing areas and its implementation of a nodal Day-2 market design with day-ahead, real-time, and ancillary service markets. The SPP study found that, out of the 8% in total production cost savings from regional market integration, more than half (4.8%) is attributable to the transition from SPP's EIS imbalance market to the full Day-2 market design.[20] SPP resembles WECC (on a smaller scale) with a mix of natural gas, coal, and renewable generation, major load centers in one portion of the footprint (the southeast), and distant areas with low-cost renewable generation (the Great Plains).

The authors of the LBNL Review Study (2005) made a similar observation when they reviewed 11 prospective and retrospective market integration studies conducted in the early 2000s. They observed that retrospective studies would more accurately capture the value of RTO formation and discussed that many potentially much larger benefits (and costs) of RTO formation were not

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18 Reitzes, *et al.* (October 1, 2009).

19 Davis (April, 2015).

20 In contrast to the EIM, SPP's Energy Imbalance Service (EIS) market was a fully de-pancaked market (including bilateral transactions) and made use of all available transmission.

captured by prospective production cost modeling. They recommended that retrospective studies "should become the standard for assessing the impacts of FERC's policies."[21]

Two other retrospective studies more narrowly focused on the benefits of changing from a zonal Day-2 market to a nodal market design. The Wolak Nodal Study (2011) estimated production cost savings for the CAISO footprint to transition from a de-pancaked zonal market (with a bilateral day-ahead market, a real-time imbalance market, and an intra-zonal congestion management process) to a full nodal market with integrated day-ahead, real-time, and ancillary services markets. The study used econometric techniques to estimate improvements in the efficiency of the 258 natural gas power plants in the California ISO associated with the new nodal market design and found that the efficiency of these units increased by 2.5%—leading to a 2.1% reduction in the variable cost of CAISO generation (after controlling for changes in gas prices).

Similarly, the ERCOT Nodal Study (2014) estimated the effect of ERCOT's transition from a zonal market (with a bilateral day-ahead market) to a nodal market structure with integrated day-ahead, real-time, and ancillary-services markets. Using a regression analysis to control for changes in load, price caps, natural gas prices, and the treatment of congestion costs, the authors estimated that implementing the nodal market resulted in a 2% reduction in real-time energy prices.

The MISO Value Proposition (2015) is an annual assessment of the overall benefits to MISO market participants. Taking advantage of data from the operation of its markets, the study estimates a number of different benefits ranging from improved reliability, dispatch of energy, regulation, spinning reserves, wind integration, compliance, footprint diversity, generator availability improvement, and demand response integration. The most recent 2015 study reported annual net benefits (net of MISO operating costs) to market participants ranging from $2.1 billion to $3.0 billion per year.

The Mansur PJM Efficiency Study (2012) examined the expansion of the PJM footprint to include the AEP and Dayton control areas that occurred in October 2004. Prior to the expansion of the footprint, these regions had traded electricity via bilateral arrangements. However, the study authors observed that the more effective matching of buyers and sellers facilitated by

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[21] Eto and Hale (December, 2005), p. 37.

PJM's formal markets increased the volume of trade by a factor of three. Additionally, the authors found that the total gains from trade (*i.e.*, the total reduction in production costs compared to a scenario with no trading) were 48% ($163 million in the first year) higher under organized markets compared to bilateral markets.[22]

Figure 3 summarizes the results of the reviewed retrospective market integration studies. The studies report different savings metrics, although many focus on production cost savings. As shown, production cost savings range from 1.4% (for moving to a de-pancaked bilateral Day-1 market in MISO) to 8.0% (for moving from pancaked bilateral markets to consolidated balancing areas with nodal markets in SPP). Other retrospective studies reported decreased wholesale power prices, improved generating plant availability, and improved generating plant efficiencies (heat rates) associated with regional market integration.

22 Mansur and White (January, 2012).

Figure 3: Market Formation Benefits as Reported By Retrospective Studies

Study	Region	Metric	Savings
MISO Retrospective Study (2009)	MISO	Production Cost Savings	1.4% Implementing a regional, de-pancaked bilateral market + 2.6% Consolidating BAs and implementing nodal DA, RT, and AS markets = 4.0% Total
SPP IM Retrospective Study (2015)	SPP	Production Cost Savings	3.2% Implementing a de-pancaked regional imbalance energy market (EIS) + 4.8% Consolidating BAs and implementing nodal DA, RT, and AS markets Markets), = 8.0% Total
MISO Value Proposition Report (2015)	MISO	Reduced production costs, generation investment needs, wind integration cost; improved reliability; net of MISO costs	Total of $2.1–$3.0 Billion/year
Wolak Nodal Study (2011)	CAISO	Production cost savings	2.1% Moving from de-pancaked zonal Day-2 market to full nodal DA, RT, and AS markets
ERCOT Nodal Study (2014)	ERCOT	Wholesale power price reductions	2.0% Moving from de-pancaked zonal Day-2 market to full nodal DA, RT, and AS markets
Navigant Markets Study (2009)	PJM, MISO, and NYISO	Improved Availability of Nuclear Units and Heat Rates of Large Coal Units	Nuclear Unit Availability Increased from 81% to 93% and Large Coal Unit Heat Rates Improved by 9.4% from 1998 to 2007
Chan Efficiency Study (2012)	U.S.	Improved Heat Rates of Large Coal Units	2%–3% increase in restructured markets compared to non-restructured regions
NYISO Plant Efficiency Study (2009)	NYISO	Improved Heat Rates of Fossil Fueled Units	21% Improvement in market-wide heat rates from 1999 to 2008
Mansur PJM Efficiency Study (2012)	PJM	Gains from Trade	Gains from trade were 48% higher in an organized market compared to a bilateral market

F. In Addition to Reducing Production Costs, Regional Markets Can Reduce the Need for Generating Capacity and Associated Investment Costs

By diversifying load fluctuations across a larger region, market integration reduces the total generation capacity needed to meet regional peak demand and assure resource adequacy under adverse system conditions. This reduces the generation investment cost of ensuring resource adequacy. Several of the reviewed studies quantitatively estimated this benefit and several discuss the benefit in a qualitative manner. Figure 4 summarizes the capacity savings reported in three studies that made a detailed assessment of the load diversity capacity savings enabled by regional markets. The savings range from 0.6% of peak load (savings to CAISO of PacifiCorp joining a regional market) to 8% of peak load (savings to PacifiCorp of joining a regional market with CAISO). Several studies reported savings ranging from 6% to 8% of peak load.

Figure 4: Load Diversity Capacity Savings in Other Studies

Study	Reported Capacity Reduction (% of Peak Load)	Note
MISO 2015 Value Proposition[1]	**6%–7%**	Capacity savings to all MISO members of participating in the RTO market
Entergy-MISO(2011)[2]	**6%**	Capacity savings to Entergy of joining MISO
E3 PAC Integration (2015)[3]	**0.6% (ISO)** **8% (PAC)**	Capacity savings with an integrated market consisting of the California ISO (ISO) and PacifiCorp (PAC)

Sources and Notes:

1. MISO (January 21, 2016).
2. Entergy (May 12, 2011).
3. Energy + Environmental Economics (E3) (October, 2015).

In the MISO 2015 Value Proposition Report, a retrospective analysis, MISO estimates that the investment cost savings achieved by its members are equivalent to reducing the region's capacity requirements by 9,300 MW to 11,250 MW (6% to 7% of peak load), compared to balancing areas assuring resource adequacy individually in the absence of a regional market. The value of those savings is estimated at \$1.2–\$2.0 billion per year in the entire MISO market.[23]

The National RTO Study (2002) estimated the value of resource adequacy by assuming that RTO formation would reduce planning reserve margins across the country from 15% to 13%, with an associated reduction in generation capacity requirement of approximately 2%.[24] Translating these investment cost savings to annualized cost reductions, they are equivalent to an approximately 1.6%–2.5% additional decrease in total production costs.[25]

23 MISO (January 21, 2016).

24 ICF (February, 2002), p. 37

25 Because total investment costs are not available in most studies, we report investment cost savings as a percentage of total *production costs* in order to enable comparison across regions.

The Entergy-MISO Study (2011) applied the MISO resource adequacy framework to estimate the investment cost savings of joining the RTO. Entergy compared the reserve margin it required as a standalone entity (17%–20% over the study period) to the effective reserve margin of approximately 12% of its internal peak load that it would need to hold as a MISO member. The reduction in planning reserve margin reflects the load diversity benefit between the original MISO and Entergy systems. Entergy's estimated reduction in generating capacity needs was approximately 1,400 MW or 6% of Entergy's peak load.[26] Entergy estimated the value of such savings to be approximately $35/kW-year or $49 million per year, equivalent to an additional 1.3% reduction of total production costs. In 2015, after joining MISO, Entergy confirmed that the anticipated capacity savings had in fact been achieved.[27]

Similarly, the E3 PAC Integration study (2015) estimated the value of load diversity between PacifiCorp and CAISO by calculating coincidence factors between the loads of the two entities. The study determined that PacifiCorp's capacity needs would decrease by up to 900 MW (approximately 9.5% of PacifiCorp's peak load), but that the savings to PacifiCorp would be limited by the 776 MW of available transmission capacity from California when integrated with CAISO. The study estimated that PacifiCorp's' reduced generation capacity need of 776 MW represented approximately 8% of PacifiCorp's internal (non-coincident) peak load. Similarly, the estimated generation investment savings for the CAISO footprint are 284 MW, which represents approximately 0.6% of the CAISO's internal (non-coincident) peak.[28] The associated annual cost savings of $90 million/year are equivalent to approximately 0.5% of the total CAISO plus PacifiCorp annual production costs.

Load diversity benefits were discussed in the RTO West Study (2002) as well. While it did not estimate the value of generation-related investment cost savings, it recognized that "As the [participation in] RTO results in lower capacity requirements, benefits will be recognized in the long run through reduced need for additions to generating capacity."[29] Similarly, the

26 Entergy also performed a similar calculation for the case of joining SPP, which we do not report here.

27 Entergy (August, 2015).

28 Based on PacifiCorp and CAISO 2024 peak loads of 9,550 MW and 47,000 MW.

29 Zobian, *et al.* (March, 2002), p. 52.

Basin/WAPA Study (2013) noted that ISO-membership would have resource adequacy benefits in addition to the quantified production cost savings.[30]

G. MARKET INTEGRATION CAN IMPROVE ACCESS TO LOW-COST RENEWABLE RESOURCES AND REDUCE THE INVESTMENT COST OF MEETING RPS GOALS

In the context of ambitious renewable generation targets, gaining access to lower cost and higher-quality renewable resources through a regional market can significantly reduce the capital costs necessary to comply with those public policy goals. By enabling renewable generators to access a larger market, regional markets can reduce the need to curtail renewable generation output during times of high output, thus further reducing renewable capacity by avoiding the "over build" that would be necessary to offset the curtailed production.

Both MISO and SPP have shown that their larger footprints allow the regions to access lower-cost renewable energy resources to help meet various states' public policy goals. Specifically the high-capacity-factor wind resources in western MISO and SPP allowed the utilities and other buyers in the regions' footprint to access lower-cost renewable resources to meet their procurement preferences or requirements under the various states' RPS. In fact, the low cost and high quality of wind resources in the Great Plains means that these resources have (with the help of production tax credits) become competitive with conventional generation such that some utilities and other buyers are entering into renewable energy contracts well beyond those needed to comply with their states' RPS.

The LBNL Wind Technologies Market Report (2014) documents trends in wind installations and the cost of Power Purchase Agreements across the country and over time.[31] The report discusses that SPP's 2014 market integration and consolidation of its balancing areas helped the SPP states access the high-quality wind resources in the Great Plains. The report notes that the now completed Texas Competitive Renewable Energy Zones (CREZ) transmission projects will enable 18,500 MW of low-cost wind development in the state—much of which is constructed or under construction. Furthermore, the additional transmission and an improved regional market design helped to balance wind generation more effectively. ERCOT was able to reduce wind curtailments from 17% of total wind generation in 2009 to 1.2% in 2013. The reduced

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30 Celebi, *et al.* (March 8, 2013), p. 5.

31 Wiser and Bolinger (August, 2015).

curtailments mean that less renewable generating capacity is needed to produce a particular amount of renewable energy production.

Similarly, the E3 PAC Integration study (2015) included in its estimated market integration benefit the savings associated with California's ability to access lower-cost renewable resources in PacifiCorp's balancing areas. The authors found that the low-cost and high-quality Wyoming wind would allow California to reduce the cost of meeting its RPS requirements while providing resource diversification benefits. The study found that the annual value of accessing the lower-cost resource would be range from $150 to $750 million per year, the equivalent of 1%–4% of the combined region's total production costs.

Additionally, the E3 PAC Integration study (2015) estimated investment cost savings associated with reduced renewable generation curtailments. These investment cost savings are associated with avoiding the construction of renewable generation capacity that otherwise would be needed to make up for the curtailed renewable output. The study estimated the additional investment cost benefits of this "More Efficient Over-Generation Management" to range from $50 to $220 million/year, which is equivalent to approximately 0.3%–1.0% of the combined footprint's production costs.

The MISO Value Proposition (2015) likewise estimated the value of access to the higher-quality wind resource enabled by its regional market. MISO estimated the capacity cost savings of providing access to higher-quality resources by comparing the actual capital cost of developing wind in MISO to the cost of meeting state renewables mandates with lower-quality local wind resources. The value proposition deducts the incremental cost of transmission required to reach the low-cost wind resources from the estimated benefits, concluding that the regional market creates $316–$377 million/year in annual renewable capacity cost savings, a benefit the RTO labels "wind integration."

While the specific assumptions made in these analyses differ across the studies, they uniformly show that regional markets facilitate both the access to and integration of low-cost renewable resources, providing investment cost savings to the entire regional footprint. The studies find that is the case even after netting out the cost of transmission investments that may be associated with providing access to low-cost renewable resources in certain locations.

H. REGIONAL MARKETS REDUCE THE COST OF BALANCING VARIABLE RENEWABLE GENERATION OUTPUT

The geographic and resource diversity of renewables generation across large regional markets can significantly reduce the overall variability of generation and the quantity of flexible fossil generators and other resources needed to balance the system. In addition to this "quantity benefit," the ability to use the most economic flexible resources across the larger region to provide these balancing services reduces production costs even further.

Regional market integration increases the flexibility of the grid and its ability to "absorb" and "balance" renewable energy. Using this analogy, it is useful to examine how the CEERT/NREL Low Carbon Grid Study (2016) analyzed the value of a flexible grid for accommodating high renewable generation targets in western states. The CEERT/NREL study simulated increased flexibility by allowing WECC-wide resources to satisfy California's RPS, allowing the region's hydro facilities to provide ancillary services, and allowing California to meet more of its load with external resources. While the Low Carbon Grid Study did not specifically analyze the impacts of a regional market, the study's "increased flexibility" assumptions are fully consistent with the typo of increased flexibility that is provided by a regional ISO-operated market.

The Low Carbon Grid Study has many parallels with the SB 350 study. The CEERT/NREL study evaluated scenarios achieving a 50% reduction in carbon emission of the California electricity-sector by 2030. The study also evaluated scenarios with very high renewables penetrations (averaging 56% for supplying California loads) and additional energy efficiency. The CEERT/NREL study modeled the retirement of all California-contracted (out of state) coal plants in meeting the emissions reduction target. Additionally, the study considered additional sensitivity cases, for example, Dry Hydro, High Solar, and High WECC RPS.

Figure 5 shows annual electric sector CO_2 emissions in California and all of WECC in four of the scenarios presented in the Low Carbon Grid study: Baseline Enhanced (33% renewables with additional flexibility), Baseline Conventional (33% renewables with status quo flexibility), Target Enhanced (56% renewables with additional flexibility), and Target Conventional (56% renewables with status quo flexibility). In both the 33% Baseline and the 56% Target cases, enhanced flexibility reduced CO_2 emissions. Emissions assigned to imports actually increased with flexibility, but were offset by larger reductions in emissions from California gas generation. The emissions reductions due to enhanced flexibility were substantially larger in the 56% renewable scenarios.

Figure 5: Annual Carbon Accounting, in Million Metric Tons
Table 10 in the CEERT/NREL Low Carbon Grid Study (2016)

Scenario	CO_2 from CA gas generators	CO_2 assigned to imports and exports	CO_2 assigned to CA load	Change in assigned California CO_2 emissions compared to Baseline	Total WECC CO_2 emissions	Change in WECC CO_2 emissions compared to Baseline
Baseline Enhanced	67.7	6.7	74.4	-	380.9	-
Baseline Conventional	68.9	6.3	75.2	0.8	381.0	0.2
Target Enhanced	43.7	-2.5	41.1	-33.2	345.1	-35.8
Target Conventional	48.9	-3.9	45.0	-29.4	349.3	-32.4

Sources and Notes:

Brinkman, *et al* (January, 2016), Table 10.

Original notes:

Exports in this context include both net exports and specified imports that are not imported. This is zero-carbon energy that is sold out of state.

Total WECC emissions not only include the western United States but also parts of Mexico and Canada (Alberta and British Columbia).

Unspecified imports and exports are assumed to have a 0.432 MT/MWh carbon penalty (or credit). Unspecified imports from the Northwest have a penalty of 20% of 0.432 MT/MWh, which is consistent with the California Air Resources Board 2012 assumptions (CARB 2014) and the California ISO LTPP modeling (Liu 2014). CARB uses 0.022 MT/MWh for data year 2015.

In terms of costs, the study found that increasing grid flexibility through market integration reduced WECC-wide production costs by approximately $600 million/year (2.1% of total production costs) for the 56% California renewable requirement scenario, with $550 million in California savings related to the production, purchase, and sale of electricity for serving California loads. The WECC-wide production cost benefit of increased flexibility was $100 million/year for the 33% RPS scenario, demonstrating that savings are much higher in scenarios with high penetrations of renewables. The study found that increased flexibility reduced carbon emissions in California and in the rest of WECC. This shows that increasing system flexibility significantly reduces operating costs under a high renewables scenario while facilitating emissions reductions. Figure 6 summarizes the study's WECC-wide production cost savings and California emissions reductions of improved flexibility at renewables penetrations of 33% and 56%.

Figure 6: Production Cost Savings and Carbon Emissions Reductions of "Enhanced Flexibility" at 33% and 56% CA Renewables Penetrations

CEERT/NREL Low Carbon Grid Study (2016)

	Renewables Penetration	70% Import Requirement for CA RPS Resources	Limited Ancillary Services from Hydro	Minimum 25% Energy from Local Thermal and Hydro in CA BAs	Total WECC Production Cost ($ millions)	California CO_2 Emissions (million metric tons)
Baseline (33% CA RPS), Conventional Flexibility [1]	33%	✓	✓	✓	$33,760	75.2
Baseline (33% CA RPS), Enhanced Flexibility [2]	33%				$33,660	74.4
Estimated Production Cost Savings and CA emissions reductions of Regional Markets with 33% California Renewables as Difference between [1] Conventional Flexibility Case (as approximation of bilateral markets) and [2] Enhanced Flexibility Case (as approximation of an ISO-operated regional market)					***$100 0.3%***	***0.8 1%***
Target (56% CA renewables), Conventional Flexibility [3]	56%	✓	✓	✓	$29,430	45.0
Target (56% CA renewables), Partially Enhanced Flexibility [4]	*56%*		✓	✓	*$28,990*	*42.3*
Target (56% CA renewables), Enhanced Flexibility [5]	56%				$28,820	41.1
Estimated Production Cost Savings and CA emissions reductions of Regional Markets with 56% California Renewables as Difference between [3] Conventional Flexibility Case (as approximation of bilateral markets) and [5] Enhanced Flexibility Case (as approximation of an ISO-operated regional market)					***$610 2.1%***	***3.9 9%***

Sources and Notes: Results from selected scenarios in the CEERT/NREL Low Carbon Grid Study (2016). Renewables penetration for the non-California portion of WECC in the above scenarios was 16%. CO_2 emissions in the rest of the WECC (not shown in figure) also declined when flexibility improved in both the 33% and 56% renewables cases.

The Western Wind and Solar Integration Study No. 2 (NREL/DOE WWSIS-2 2013) similarly estimated the likely range of savings associated with a reduction in resource variability due to increased geographic diversity in wind and solar generation. The study quantified the resource variability before and after accounting for geographic diversity and found that diversity can dramatically decrease the collective resource variability thereby decreasing the amount of flexible resources needed to balance the system at high renewable deployment levels. The study found that aggregating distributed rooftop PV in southern California reduced variability (as measured by the coefficient of variation of hour-over-hour changes in output) from 4% to 3%

after approximately 3,000 MW were aggregated. The study found that wind variability dropped even faster—from 9% to 2% after approximately 2,000 MW were aggregated.

SPP's recent (2016) Wind Integration Study similarly evaluated the impacts of 30%–60% wind generation in the SPP footprint. The study did not attempt to quantify the wind integration value of its recently-implemented Day-2 market design, but highlighted several ways in which the market is already facilitating the integration of high levels of renewables. The study identified several enhancements that would allow very high penetrations to be achieved in the future and confirmed that the new transmission projects identified through the RTO's recent transmission planning process would be critical in providing access to the high-quality, low-cost wind resources located in the southwest portion of the footprint. It further determined that SPP has sufficient ramping capability to accommodate its projected growth in renewables generation (SPP experienced real-time wind generation equal to 40% of its system-wide load). SPP notes that, as more wind generation is added over the longer-term, the introduction of additional ancillary services may be necessary to provide added flexibility.

The Western Governors' Association's Renewable Integration Challenge study (WGA Integration Study 2012)[32] similarly discussed a number of options for facilitating the integration of renewables in the West. Several of the options include the operation of an integrated market across WECC. As explained in the study, a WECC-wide regional market would include the operation of sub-hourly dispatch and intra-hour scheduling, increased geographic diversity supported by new transmission, and increased reserve sharing—all of which would help to lower the cost of integrating renewable resources.

I. Benefits of Regional Market Integration are Confirmed by the European Experience with High Renewable Generation

The European experience is helpful in documenting the role of regional markets, particularly with respect to integrating increasing amounts of renewable generation. In Europe, the integration of renewable generation is seen as a key pillar to the region's broader energy and climate objectives in reducing emissions, improving security of supply, diversifying energy supplies, and improving Europe's industrial competitiveness. Many European countries have

32 Western Governors' Association (June, 2012).

high shares of renewable generation and ambitious goals to further increase renewable generation in the next decades.

Germany's share of renewable generation exceeds 30% on an annual basis and reached a high of 83% on August 23, 2015.[33] Because most of Germany's solar power generation is associated with distributed solar installations in southern Germany while most of Germany's wind generation is located in northern Germany and the North Sea, these locational differences create substantial north-south power flows through Germany and its neighboring countries[34] that require close coordination. Such issues are among the motivations for market-integration efforts, such as a European Union-wide "market coupling."[35]

The experience in Denmark serves as another illustration of managing high renewables penetration.[36] In January 2014, wind generation provided 62% of Denmark's monthly power demand, with that share reaching 105% on January 19, 2014. The ability to manage this level of renewable power generation operationally has been attributed primarily to Denmark's strong integration with the neighboring grids of Europe, including the well-developed region-wide Nord Pool markets (Nordic and Baltic day-ahead and intraday markets). Through Nord Pool, Denmark is part of a large market with significant resource diversity (including hydro resources in Sweden and Norway), which means Denmark can buy freely from, and sell power to, its neighbors in order to balance its high renewable generation levels.

The DNV-GL European Renewable Integration Study[37] (2014) finds that having a regional market has become increasingly important to support the integration of higher levels of renewable generation due to its ability to increase system flexibility and security of supply through the exchange of energy between the regional submarkets. This reduces the overall amount of conventional generation capacity required in the system—thereby reducing total system-wide costs.

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33 Graichen, Kleiner, and Podewils (January 7, 2016).

34 Weixin Zha, Marke Strzelecki (July, 2015).

35 Baritaud and Volk (2014).

36 Martinot and White (January, 2015).

37 DNV-GL (June 12, 2014).

Similarly, the EPRG European Market Integration study (2015) evaluated potential savings from integrating the existing country-level electricity markets.[38] The proposed single European market platform, known as Euphemia, would lead to increased utilization of and price convergence across international transmission interties. The proposal would couple the country-level European markets at the day-ahead, intraday, and real-time horizons. (Day-ahead coupling has already been implemented.) The study estimated that the benefits of market coupling were approximately €3.3 billion per year, equivalent to 2% of the total value of wholesale electricity. Approximately one-third of these benefits were estimated to be achieved by day-ahead integration, intraday integration, and region-wide real-time balancing.

In addition to the direct economic impact of reducing price divergence across interties, the study qualitatively discussed some of the value of coordinated European markets. These included pressures to reduce costs and innovate, improved liquidity in markets, and potentially reduced environmental impact. Additionally, increased coordination should lead to increased reliability.

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38 Newbery, Strbac, and Viehoff (February, 2015J).

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