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2015 IEPR

INTEGRATED ENERGY POLICY REPORT

CALIFORNIA ENERGY COMMISSION
EDMUND G. BROWN JR., GOVERNOR
CEC-100-2015-001-CMF



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Program Manager

Heather Raitt

Primary Authors

Aniss Bahreinian

Stephanie Bailey

Jim Bartridge

Martha Brook

Guido Franco

Angela Gould

Judy Grau

Mike Jaske

Chris Kavalec

Suzanne Korosec

Rachel MacDonald

Chris Marxen

Jim McKinney

Ean O'Neill

Gordon Schremp

Charles Smith

ACKNOWLEDGEMENTS

Al Alvarado	Pablo Gutierrez	Bill Pennington
Grace Anderson	Jason Harville	Marc Pryor
Ollie Awolowo	David Ismailyan	Rebecca Rath
Kevin Barker	Erik Jensen	Carol Robinson
Sylvia Bender	Melissa Jones	Randy Roesser
Leon Brathwaite	Linda Kelly	Cynthia Rogers
Elise Brown	Don Kondoleon	Jana Romero
Charles Christman	Clare Laufenberg Gallardo	Ivin Rhyne
Justin Cochran	Laura Laurent	Patrick Saxton
Matt Coldwell	Samuel Lerman	Glen Sharp
Christine Collopy	Virginia Lew	Yongling Sing
Rhetta DeMesa	Grant Mack	Lori Sinsley
Anthony Dixon	Paul Marshall	Courtney Smith
Pamela Doughman	Consuelo Martinez	Angelina Sorokin
Collin Doughty	Jennifer Masterson	David Stoms
Kristen Driskell	John Mathias	Peter Strait
Catherine Elder	Heather Mehta	Gene Strecker
Andre Freeman	Marc Melaina	Kirk Switzer
Nicolas Fugate	Danielle Osborn Mills	Laurie ten Hope
Eurlyne Geiszler	Hazel Miranda	Katie Tkachuk
Elena Giyenko	Farakh Nasim	Abhilasha Wadhwa
Deborah Godfrey	Jennifer Nelson	Susan Wilhelm
Asish Gautam	Le-Quyen Nguyen	Michael Wilson
Mike Gravely	John Nuffer	Sonya Ziaja
Lynette Green	Jacob Orenberg	
Aleecia Gutierrez	Donna Parrow	

PREFACE

Senate Bill 1389 (Bowen, Chapter 568, Statutes of 2002) requires the California Energy Commission to prepare a biennial integrated energy policy report that assesses major energy trends and issues facing the state's electricity, natural gas, and transportation fuel sectors and provides policy recommendations to conserve resources; protect the environment; ensure reliable, secure, and diverse energy supplies; enhance the state's economy; and protect public health and safety (Public Resources Code § 25301[a]). The Energy Commission prepares these assessments and associated policy recommendations every two years, with updates in alternate years, as part of the Integrated Energy Policy Report. Preparation of the Integrated Energy Policy Report involves close collaboration with federal, state, and local agencies and a wide variety of stakeholders in an extensive public process to identify critical energy issues and develop strategies to address those issues.

ABSTRACT

The *2015 Integrated Energy Policy Report* provides the results of the California Energy Commission's assessments of a variety of energy issues facing California. Many of these issues will require action if the state is to meet its climate, energy, air quality, and other environmental goals while maintaining reliability and controlling costs. The *2015 Integrated Energy Policy Report* covers a broad range of topics, including energy efficiency, benchmarking under the Assembly Bill 758 Action Plan, strategies related to data for improved decisions in the *Existing Buildings Energy Efficiency Action Plan*, building energy efficiency standards, the impact of drought on California's energy system, achieving 50 percent renewables by 2030, Renewable Action Plan status, the *California Energy Demand Forecast*, the *Natural Gas Outlook*, the *Assembly Bill 1257 Report*, methane emissions, the *Transportation Energy Demand Forecast*, Alternative and Renewable Fuel and Vehicle Technology Program benefits updates, landscape-scale planning efforts, transmission projects, the California Independent System Operator energy imbalance market, the *Desert Renewable Energy Conservation Plan*, climate change vulnerability and adaptation options, update on electricity infrastructure in Southern California, an update on trends in California's sources of crude oil, and an update on California's nuclear plants.

Keywords: California Energy Commission, energy efficiency, renewables, electricity demand forecast, natural gas outlook, transportation energy demand forecast, Assembly Bill 758 Action Plan, nuclear, *Existing Buildings Energy Efficiency Action Plan*, zero-net-energy, natural gas, methane emissions, benchmarking, plug loads, crude-by-rail, climate adaptation, climate change, Under 2 MOU, landscape-scale planning, *Desert Renewable Energy Conservation Plan*, *Strategic Transmission Investment Plan*, Southern California reliability, drought, Alternative and Renewable Fuel and Vehicle Technology Program benefits, energy imbalance market, drought

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EXECUTIVE SUMMARY



California has a wealth of natural resources and human talent. It is one of the most desirable places to live with stunning scenery including mountains, coastline, giant redwoods, and majestic deserts. More than 38 million people call California home. It has a growing economy, and the technology innovations that have come from this state are used throughout the world.

California continues to be a leader in environmental stewardship and is advancing bold solutions to address climate change. On April 29, 2015, Governor Edmund G. Brown Jr. signed Executive Order B-30-15, establishing a new statewide goal to reduce greenhouse gas emissions 40 percent below 1990 levels by 2030. In his 2015 inaugural address, Governor Brown said, “Taking significant amounts of carbon out of our economy without harming its vibrancy is exactly the sort of challenge at which California excels. This is exciting, it is bold, and it is absolutely necessary if we are to have any chance of stopping potentially catastrophic changes to our climate system.” The Clean Energy and Pollution Reduction Act of 2015 (Senate Bill 350, DeLeón, Chapter 547, Statutes of 2015) (SB 350) subsequently codified two of the Governor’s goals for reducing carbon emissions: increasing renewable electricity procurement to 50 percent by 2030, and doubling energy efficiency savings by 2030.

California’s leadership extends worldwide as the Governor is spearheading the development of a growing coalition of sub-national jurisdictions that sign the Under 2 MOU climate agreement – a commitment to reduce greenhouse gas emissions and limit the increase in global average temperature. At the conclusion of the United Nations Climate Change Conference in Paris in December 2015, 127 jurisdictions had signed the Under 2 MOU, representing more than 729 million people, in both developed and developing countries, and the equivalent to more than a quarter of the global economy.

While climate change is a global issue, Californians are feeling its effects. These include more extreme fires, storms, floods, and heat waves that cost lives and property damage, as well as decreasing snow-water content in the northern Sierra Nevada. The potential human, ecological, and economic costs of climate change are large, but California’s leadership to both reduce greenhouse gas emissions and increase its resilience to climate change can make California stronger.

California is well on its way to reducing its greenhouse gas emissions to 1990 levels by 2020 as required by the California’s Global Warming Solutions Act of 2006 (Assembly Bill 32, Núñez, Chapter 488, Statutes of 2006). For example, data from the California Air Resources Board

shows that in 2013 greenhouse gas emissions from California's electricity sector was already 20 percent below the 1990 levels. The Governor's 2030 target strengthens the state's position to meet its long-term goal of reducing greenhouse gas emissions 80 percent below 1990 levels by 2050. Meeting the 2050 goal will require a deep transformation of California's energy system – it will require the innovation for which California is so well known.

Energy Efficiency is Key in All Pathways to a Low-Carbon Energy System

In his 2015 inaugural speech, Governor Brown set a goal to double the efficiency savings achieved at existing buildings and make heating fuels cleaner. SB 350 codified this goal into law and requires the Energy Commission to assess and report progress toward the goal. In September 2015, the California Energy Commission adopted a roadmap to reach this goal by 2030. The roadmap, called the *Existing Buildings Energy Efficiency Action Plan*, describes a group of goals and strategies which, if put fully into action, would accelerate the growth of energy efficiency markets, more effectively target and deliver building upgrade services, and improve quality of occupant and investor decisions, leading to vastly improved energy performance of California's existing buildings. The action plan includes strategies to enhance government leadership in energy and water efficiency, such as leading by example to improve the efficiency of public buildings, developing a new statewide benchmarking and disclosure program, encouraging local government innovations, and facilitating the application of energy codes to existing building upgrade projects. Providing building owners and their agents easy access to the building energy use data that are needed for improved decision-making is another key goal of the plan. The action plan also focuses on high-quality building upgrades and increased financing options. The action plan is designed to help achieve greenhouse gas reduction goals and help consumers save money and enjoy more comfortable homes through energy efficiency.

California continues to make progress on other energy efficiency priorities as well. Utility-ratepayer-funded programs are an important part of the state's strategy to advance energy efficiency. The California Public Utilities Commission has oversight of energy efficiency programs administered by investor-owned utilities, while the publicly owned utilities implement and monitor their own programs. These programs help reduce emissions by facilitating implementation of cost-effective efficiency resources. SB 350 will expand the types of efficiency programs available, while also tying incentive payments to measurable efficiency results. Energy efficiency upgrades in California's schools are being realized as result of funding available from the Clean Energy Jobs Act (Proposition 39). The act funds eligible measures such as high-efficiency lighting and mechanical systems and clean energy generation. The Energy Commission is primarily responsible for administering Proposition 39 for kindergarten through 12th grade schools, while the community colleges administer the funds designated for their facilities. For newly constructed low-rise homes, the state is steadily moving toward implementing zero-net energy buildings, in which energy efficiency is part of an integrated solution. Outstanding issues remain, however, including needing to identify compliance pathways when on-site renewable generation is not feasible, and the appropriate role for natural gas in zero-net-energy buildings. Throughout these programs, the primary challenge is to build a technical and regulatory foundation for orchestration of energy efficiency and all other feasible distributed and customer-sited clean energy resources.

Decarbonizing the Electricity Sector

Another important tool in meeting climate and air quality goals is decarbonizing the electricity sector as part of an integrated approach to reducing emissions from energy use. As noted above, California already has made great strides in reducing greenhouse gas emissions from the electricity sector. The state uses renewable energy to

serve about 25 percent of its electricity consumption and is on a solid trajectory to meet the state's Renewables Portfolio Standard of 33 percent by 2020. As part of his climate policy, Governor Brown set a goal of increasing California's electricity derived from renewable sources from one-third to 50 percent by 2030. SB 350 put this goal into law.

While implementing the 50 percent renewable requirement, care must be taken to maintain the reliability of the electricity system and keep costs competitive. Given the intermittent nature of renewables that are coming on-line, integrating their energy into the grid is a key challenge moving toward the 50 percent renewable goal. One key solution is a regional marketplace that balances supply and demand. Other solutions include targeted energy efficiency, demand response, time-of-use rates that encourage shifts in when consumers use energy, a more diversified portfolio of renewable resources, and energy storage. Finally, research and development will help bring new technologies and other innovations needed to meet the 2030 and 2050 greenhouse gas reduction goals.

Strategic Transmission Investment Planning to Support Decarbonization

Geographic diversity in the renewables portfolio can help achieve the 50 percent renewable goal by 2030. SB 350 paves the way for the voluntary transformation of the California Independent System Operator into a regional organization that will help integrate renewable generation for greater reductions in greenhouse gas emissions in California and neighboring states and at lower cost. However, strategic transmission investments are still needed to link our extensive renewable resources to load centers throughout the grid. Transmission planning processes will need to be streamlined and coordinated to ensure the siting, permitting, and construction of the most appropriate transmission projects takes proper consideration of renewable energy potential, land-use, and environmental factors.

Lessons from the Renewable Energy Transmission Initiative, the *Desert Renewable Energy Conservation Plan*, local planning efforts, other energy planning processes, and scientific studies have brought important insights to the environmental and operational implications of the evolving regional electricity system. To plan for meeting California's 2030 climate and renewable energy goals, the California Natural Resources Agency, the Energy Commission, the California Public Utilities Commission, and the California Independent System Operator have initiated the Renewable Energy Transmission Initiative 2.0 process to consider the relative potential of various renewable energy resources and to explore the associated transmission infrastructure through an open and transparent stakeholder process.

Moving to a Low-Carbon Transportation System

California has long been a leader in transportation policy and a low-carbon transportation system is essential for meeting the state's 2030 greenhouse gas reduction goal. The transportation sector represents the state's largest source of greenhouse gas emissions, accounting for 37 percent of California's total. Furthermore, it is the largest source of criteria air pollutants that are harmful to human health, especially in the most impacted areas of the state. To help address these issues, the state has developed a portfolio of goals, policies, and strategies designed to reduce greenhouse gas emissions, improve air quality, and reduce petroleum use while meeting the transportation demands of the future.

Governor Brown called for a 50 percent reduction in petroleum used by California's cars and trucks by 2030 in his 2015 inaugural address. The Governor has released several executive orders easing the transition to a low-carbon transportation future. These include calling for 1.5 million zero-emission vehicles to be on California roadways by 2025 and for the development of an integrated action plan that establishes targets to improve freight efficiency, increases adoption of zero-emission technologies, and

increases competitiveness of California's freight system. California was also one of the 14 members of the International Zero-Emission Vehicle Alliance to pledge at the United Nations' climate-change conference in December 2015 that all new cars sold within their jurisdictions would be emissions-free by 2050. As a result of these goals and policies, the state has implemented a number of programs and plans to put California on a path to a diversified alternative and low-carbon fueled transportation future, including the zero-emission vehicle mandate, the Low Carbon Fuel Standard, and the Cap-and-Trade Program. The Energy Commission's Alternative and Renewable Fuel and Vehicle Technology Program also plays a role in the state strategy to deploy alternative fuels and advanced vehicle technologies into California's transportation market.

The Energy Commission staff has also developed a draft transportation energy demand forecast through 2026 to help inform policy makers. The draft results show that given the information available today, gasoline and diesel will continue to be the primary sources of transportation fuel through 2026. Long-term transformation of the transportation system is achievable and will require efforts on many fronts with a diverse range of actors and partnerships.

Preliminary 10-Year Electricity Forecast Shows Low Growth

Developing a 10-year forecast of electricity consumption and peak electricity demand is a fundamental part of statewide electricity infrastructure planning. The Energy Commission, California Public Utilities Commission, and California Independent System Operator are continuing their commitment to consistently use a single forecast set in each of their planning processes, as first implemented through the *2013 Integrated Energy Policy Report (IEPR)*. SB 350, by calling on the Energy Commission to set statewide targets for energy efficiency savings, will require the Energy Commission to build its capabilities to collect and manage increasing quantities of data and provide rigorous analysis in support of energy demand

forecasts specifically and energy policy development more broadly. This leadership is more important now than ever, given that California will be pushing the envelope on various fronts and focusing resources on innovation and market support in the years ahead.

SB 350 also requires that medium and large electric utilities, both publically- and investor-owned, develop periodic integrated resource plans. These integrated resource plans will facilitate comparison and procurement of multiple, differing resources into each utility's respective system in ways that preserve and support grid reliability and resilience, in each territory and across the state.

The 2015 IEPR forecast recognizes the importance of energy efficiency and includes estimated energy efficiency impacts from energy efficiency programs administered by investor- and publicly owned utilities. The forecast also includes projected *Additional Achievable Energy Efficiency* savings for both investor- and publicly owned utilities, part of a *managed forecast* for planning purposes. Consistent with the *2013 IEPR* and *2014 IEPR Update*, the 2015 IEPR forecast incorporates anticipated changes in demand due to climate change based on analysis by the Scripps Institution of Oceanography. The 2015 forecast also includes updated projections for electric vehicles consumption.

The 2015 IEPR forecast results show slightly lower growth for electricity consumption compared to the forecast from the *2014 IEPR Update*. Annual growth rates from 2014–2025 for baseline forecast consumption average 1.27 percent, 0.97 percent, and 0.54 percent in the high, mid, and low cases, respectively, compared to 1.21 percent in the *2014 IEPR Update* mid case. Lower baseline consumption, combined with higher projections for self-generation, particularly photovoltaic systems, reduce growth in peak demand and retail sales. Annual growth rates for peak demand average 0.97 percent, 0.46 percent, and -0.28 percent in the high, mid, and low scenarios, respectively, compared to 1.08 percent in the *2014 IEPR Update* mid case. For sales, annual growth averages 1.00 percent, 0.48 percent, and -0.26 percent

in the high, mid, and low cases, respectively, versus 1.05 percent in the *2014 IEPR Update* mid case.

Natural Gas

While natural gas may provide a lower carbon fuel source when compared to other fossil fuels used for electricity generation or transportation, recent studies indicate that methane leakage can reduce the climate benefits of switching to natural gas. The gas well leak at Southern California Gas' storage facility at Aliso Canyon is an example of an unexpected methane leak that is having an impact on California's short term carbon footprint while also impacting the daily lives of residents in an entire neighborhood. Other examples of leaks in the natural gas supply chain are far less obvious yet are of increasing concern. Many research efforts are aimed at better understanding the leakage rates and the associated impacts. Converting biomass to renewable natural gas for use in the transportation sector, electricity generation, and end-use consumption reduces the climate impacts of this fuel, but resource availability may be limited and costs may be high. Protecting public safety remains an important focus in managing the natural gas system.

Assembly Bill 1257 (Bocanegra, Chapter 749, Statutes of 2013) directs the Energy Commission to explore the strategies and options for using natural gas, including biogas, to identify strategies to maximize its benefits. Highlights of the Energy Commission staff's analysis are presented on topics that include pipeline safety, renewable integration, combined heat and power, natural gas as a transportation fuel, end-use efficiency, low-emission biomethane, and greenhouse gas emissions associated with leakage from the natural gas system.

Similar to electricity, the Energy Commission develops a forecast of natural gas prices, production, and demand as detailed in the *2015 Natural Gas Outlook*. By 2024, the final forecast for end-use natural gas demand is about 9.3 percent higher than the *2013 IEPR* forecast. Staff attributes the higher growth rates to an increase in natural gas demand in the residential, commercial, and transportation sectors. Demand for natural gas used in

electricity generation, however, is expected to decline over the forecast period. This is driven by increases in the share of electricity generated from renewable resources that reduce the need for power from fossil-fueled sources.

Nuclear Issues in California

On June 27, 2013, Southern California Edison announced the permanent retirement of San Onofre Units 2 and 3. Nuclear power plant decommissioning involves transferring used fuel into safe storage, followed by disposal of radioactive components and materials within 60 years. Southern California Edison plans to complete the decommissioning of San Onofre within 20 years and, consistent with a *2013 IEPR* recommendation, to transfer its spent fuel from cooling pools into dry casks by 2019. In preparation for the decommissioning of multiple sites in the near term, the Nuclear Regulatory Commission recently launched a new rulemaking to identify potential improvements to decommissioning regulations. The Energy Commission intends to actively engage in that rulemaking with the objective of ensuring that state and local concerns about the decommissioning of nuclear plants are more effectively addressed by the Nuclear Regulatory Commission.

The Diablo Canyon Power Plant operates under its original licenses, which are set to expire in 2024 and 2025, respectively. While Pacific Gas and Electric filed a federal application to renew its operating license in 2009, it is uncertain whether Diablo Canyon will continue to operate beyond the current licenses. One factor impacting the future of Diablo Canyon is the compliance costs and time (up to \$14 billion and 14 years) associated with the State Water Resources Control Board's once-through-cooling policy, which establishes uniform standards to reduce the harmful effects associated with cooling water intake structures on marine life. Another factor influencing Diablo Canyon's license renewal application is the seismic study recommended by the *2013 IEPR*. Pacific Gas and Electric completed its study in September 2014 and concluded that the plant is designed to withstand a major earthquake on any of the faults surrounding

Diablo Canyon, reducing the level of uncertainty for some seismic hazards. However, external stakeholders and reviewers, including the Independent Peer Review Panel, have been highly critical of the study results, since some seismic hazards continue to remain poorly understood.

The *2013 IEPR* also recommended an evaluation of the potential long-term impacts and projected costs of spent fuel storage in densely packed pools versus dry cask storage, and the potential degradation of fuels and package integrity during long-term storage and offsite transportation. The Nuclear Regulatory Commission subsequently provided new guidance to nuclear plant operators on loading patterns for spent fuel in pools, advising a “dispersed” loading pattern that provides a “more favorable response” in the event of a loss of cooling water. Pacific Gas and Electric, in its recent CPUC filings, laid out a plan for spent fuel loading at Diablo Canyon that achieves the lower limit constraint in compliance with the Nuclear Regulatory Commission’s regulations, but does not achieve the more preferable dispersed loading pattern.

The federal government has yet to comply with its obligation to remove spent nuclear fuel from state facilities, leaving California to face a prolonged period of maintaining spent nuclear fuel at decommissioned plant sites. Proposed federal legislation founded on a consent-based process would authorize the U.S. Department of Energy to move forward with developing an interim storage facility and provide financial benefits to communities that agree to host such facilities.

Ongoing Vigilance to Maintain Reliability in Southern California

With the impending retirement of several fossil-powered facilities and the closure of the San Onofre Nuclear Generating Station in Southern California, ensuring the region’s electricity system reliability has been a major focus since 2011. The State Water Resources Control Board’s 2010 policy to phase out the use of once-through cooling affects 10 power plants in the Los Angeles and San Diego basins. Those power plants total just over

11,000 megawatts; taken into consideration along with the 2,200 megawatts lost with the 2013 closure of San Onofre, it is important to ensure that the region does not suffer grid reliability issues. Shortly after the announced closure of San Onofre, Governor Brown asked for a multi-agency plan to address the replacement of the power and energy that had been provided by the plant. As reported in the *2013 IEPR*, this effort resulted in the *Preliminary Reliability Plan for LA Basin and San Diego*. The plan called for a rough replacement target of 50 percent preferred resources and 50 percent conventional generation. An interagency team has continued to meet regularly to advance the plan. The *2014 IEPR Update* covered the progress made since the formation of the team, and this year’s report covers the additional work completed to date on local capacity issues, resource procurement, contingency planning, and mitigation options, as well as the work that will be needed going forward.

Trends in Crude Oil Production and Transport

Due largely to advances in drilling techniques, U.S. oil production reached 9.7 million barrels per day in April 2015 – the highest level of production since April 1971. This increased production led to increased supply, which led to lower crude oil prices. Excessive supply weighed heavily on world markets, leading to a pricing collapse that began in mid-2014 and has continued through 2015.

As outlined in the *2014 IEPR Update*, this large increase in crude oil production surpassed the ability of existing crude oil pipeline and distribution infrastructure to keep pace. Oil producers discounted their oil prices to allow the more expensive transportation of oil by rail to be competitive for refiners outside the shale oil regions. Over the last 18 months, however, additional pipeline capacity has come on-line and reduced the need for ongoing price discounts from oil producers. Whether crude-by-rail imports to California will continue rising over the next few years depends on the number of receiving facilities that are ultimately approved and built within the state.

There have been several safety-related regulation updates since the *2014 IEPR Update*. Most notably, regulations finalized in May 2015 by the Pipeline and Hazardous Materials Safety Administration place slower speed restrictions on trains transporting oil or ethanol. By 2021, these trains will also need to be equipped with electronically controlled pneumatic braking. In addition to improved braking and reduced operating speeds, rail cars transporting oil or ethanol are now also subject to more stringent construction standards.

The recent decline of crude-by-rail shipments, following rapid increases in 2014, along with a lack of detailed forecasts and the wide range of crude oil carbon intensities, further highlights the need for additional data at the state level to follow oil extraction, transportation, and distribution trends, and determine resulting implications.

California's Response to Drought

California has been suffering through four years of drought, and the tight linkages between water and energy are becoming more evident. California's climate is shifting toward warmer winters with less snowpack, affecting the availability and timing of hydropower. Further, water delivery is very energy-intensive, and so implementing water conservation programs can reduce greenhouse gas emissions in the electricity sector by reducing the need for energy to move, treat, and heat water. The drought also raises questions about the reliability of water supply for natural gas, solar thermal, and geothermal power plants that use water in electricity generation.

The drought is not a short-term problem. As the climate continues to change, California must prepare for the possibility that these drought-like conditions may become the norm rather than the exception. In response, the state is enacting many programs to help with long-term water savings on a wide variety of fronts. For example, through the Energy Commission's appliance standards regulation, the state is advancing efficiency improvements in appliances such as toilets and showers. Consumer incentives and direct installation projects for other water-efficient

appliances have been developed for implementation by the Energy Commission and the Department of Water Resources. Finally, a larger-scale effort is the Water Energy Technology program, administered by the Energy Commission, to fund for innovative water- and energy-saving technologies and reduce greenhouse gas emissions. Advancing conservation programs like these can both help make California more drought resilient, and at the same time reduce energy use and greenhouse gas emissions.

Climate Change Research

The Energy Commission continues to be a leader in supporting and conducting cutting-edge climate research related to energy sector resilience (successfully adapting to climate change) and mitigation (reducing greenhouse gas emissions).

Impacts to California's energy system from climate change include decreased capacity of transmission lines; risks to energy infrastructure from extreme events including sea level rise, coastal flooding, and wildfires; less reliable hydropower resources; increased peak electricity demand; and decreased efficiency of thermal power plants and substations. The types and severity of impacts vary across the electricity, natural gas, and petroleum sectors and vary geographically. Over the past several years, the Energy Commission has supported research to identify these potential impacts and investigate the magnitude, distribution, and adaptation options. To date, significantly more research has been done on electricity than other aspects of the energy sector like natural gas or the petroleum sector, but even for the electricity sector, more research is needed on the impacts to renewable resources such as solar and wind.

Areas for future research include the development of improved climate and sea-level-rise scenarios for the energy system, improved methods to estimate greenhouse gas emissions originating from the energy system, development of advanced methods to simultaneously consider mitigation and adaptation for the energy system, and detailed local and regional studies.

INTRODUCTION



Addressing Climate Change Is the Foundation of California's Energy Policy

On April 29, 2015, Governor Edmund G. Brown Jr. established a new statewide greenhouse gas (GHG) emissions reduction goal to reduce emissions 40 percent below 1990 levels by 2030.¹ The Clean Energy and Pollution Reduction Act of 2015 (Senate Bill 350, De León, Chapter 547, Statutes of 2015) (SB 350) requires the adoption of integrated resource plans that reflect any targets for the electric sector that may be adopted by the Air Resources Board to help achieve greenhouse gas emission reductions of 40 percent from 1990 levels by 2030. SB 350 also reflects the requirement for the procurement of 50 percent eligible renewable energy resources by December 31, 2030. The Governor's executive order and SB 350 strengthen the state's position to meet its 2050 goal of reducing GHG emissions 80 percent below 1990 levels.² The 2030 goal also builds on the mandatory target set forward in California's Global

Warming Solutions Act of 2006 (Assembly Bill 32, Núñez, Chapter 488, Statutes of 2006) to achieve 1990 emission levels by 2020. The state is well on its way to meeting its 2020 target.³ Figure 1 plots California's GHG reduction goals against historical GHG emissions. As discussed in more detail below, Governor Brown spearheaded the adoption of similar goals by subnational leaders worldwide.

Californians are feeling the effects of climate change in more extreme fires, storms, floods, and heat waves that cost lives and property damage. (For further discussion, see Chapter 9 Climate Change, the section on "Vulnerability and Adaptation Options.") The potential human, ecological, and economic costs of climate change are large, but measures to adapt to these changes can reduce overall economic costs.⁴ California must continue its leadership to both reduce GHG emissions and increase its resilience to climate change.

1 Executive Order B-30-15, <http://gov.ca.gov/news.php?id=18938>.

2 California's 2050 climate goal was reiterated in B-30-2015 and previously put forward in Executive Orders S-3-05 <http://gov.ca.gov/news.php?id=1861> and B-16-2012 <http://gov.ca.gov/news.php?id=17472>.

3 California Air Resources Board, *The First Update to the Climate Change Scoping Plan: Building on the Framework*, May 2014, http://www.arb.ca.gov/cc/scopingplan/2013_update/first_update_climate_change_scoping_plan.pdf.

4 Karhri, Fredrich, and Roland-Holst, David, 2012, *Climate Change in California. Risks and Response*, University of California Pres.

From Boom to Bust? Climate Risk in the Golden State, April 2015, A product of the Risky Business Project <http://riskybusiness.org/uploads/files/California-Report-WEB-3-30-15.pdf>.

Figure 1: California’s GHG Emission Reduction Goals



Source: Air Resources Board 2000-2013 inventory <http://www.arb.ca.gov/cc/inventory/data/data.htm>

In his inaugural address on January 5, 2015, Governor Brown said, “Taking significant amounts of carbon out of our economy without harming its vibrancy is exactly the sort of challenge at which California excels. This is exciting, it is bold, and it is absolutely necessary if we are to have any chance of stopping potentially catastrophic changes to our climate system.”⁵

In his inaugural address the Governor also said that meeting our climate goals “means that we continue to transform our electrical grid, our transportation system and even our communities.”⁶ He set the following goals to be accomplished “in the next 15 years”:

- » Increase from one-third to 50 percent our electricity derived from renewable sources;
- » Reduce today’s petroleum use in cars and trucks by up to 50 percent;
- » Double the efficiency of existing buildings and make heating fuels cleaner.

Further, he stated that “We must also reduce the relentless release of methane, black carbon and other potent pollutants across industries. And we must manage farm and rangelands, forests and wetlands so they can store carbon.”⁷

In early July 2015, the Governor’s office and relevant state agencies and boards held a series of public forums soliciting stakeholder input on each of the goals listed

5 Governor Brown’s inaugural address, January 5, 2015, <http://gov.ca.gov/news.php?id=18828>.

6 Governor Brown’s inaugural address, January 5, 2015, <http://gov.ca.gov/news.php?id=18828>.

7 Ibid.

above. Some highlights from the energy-related discussions at the public forums are included in the chapters that follow.⁸

Energy Efficiency as a Focus of This *Integrated Energy Policy Report*

As California develops strategies to meet its goals for deep GHG emissions reductions, energy efficiency will be a central component. (For further discussion, see Chapter 1.) At sufficient scale, energy efficiency can reduce the need for new generation – both fossil and renewable – while increasing system flexibility via demand response and lowering costs. Thus, energy efficiency, especially when integrated with demand response, can greatly ease the transition to a cleaner resource mix – a need accelerated by the retirement of the San Onofre Nuclear Generating Station and the impending retirement of the aging, once-through-cooled coastal generation fleet. (Nuclear energy and once-through-cooling are discussed further in Chapter 7.)

In particular, improving the energy efficiency of existing buildings, and the appliances and other devices within them, will be critical within the set of strategies that together will reach California's GHG reduction goals. Efficiency produces broad benefits independent of climate concerns, certainly – economic activity and resilience, local determination, health and air quality, and comfort – which is in part why it has been a core California policy principle for four decades. But modern, intelligent energy efficiency is more important now than ever, as an optimizing strategy that both reduces the size of the overall problem and assists diverse clean supply resources to coexist on the grid.

In his January 2015 inaugural address, Governor Brown identified a goal of doubling the efficiency of existing buildings and making heating fuels cleaner. SB 350 codifies the Governor's goal for doubling energy efficiency savings of existing buildings by 2030 and expands it to all retail end uses. Energy use at existing buildings accounts for more than one-quarter of all GHG emissions in California, including both fossil fuel consumed on-site (for example, gas or propane for heating) and emissions associated with electricity consumed in existing buildings (for example, for lighting, appliances, and cooling). Assembly Bill 758, (AB 758, Skinner, Chapter 470, Statutes of 2009) recognized the need for California to improve the energy performance of existing buildings and directed the Energy Commission to develop a plan to achieve cost-effective energy savings in California's existing homes and businesses, and to report on its implementation through the *Integrated Energy Policy Report (IEPR)*. The Energy Commission adopted the final *Existing Buildings Energy Efficiency Action Plan* in September 2015.⁹ Strategies in the action plan provide a 10-year framework to enable substantial energy savings and GHG emission reductions in California's existing buildings. The *Existing Buildings Energy Efficiency Action Plan* operationalizes the Governor's energy efficiency goal, and together they provide impetus and urgency.

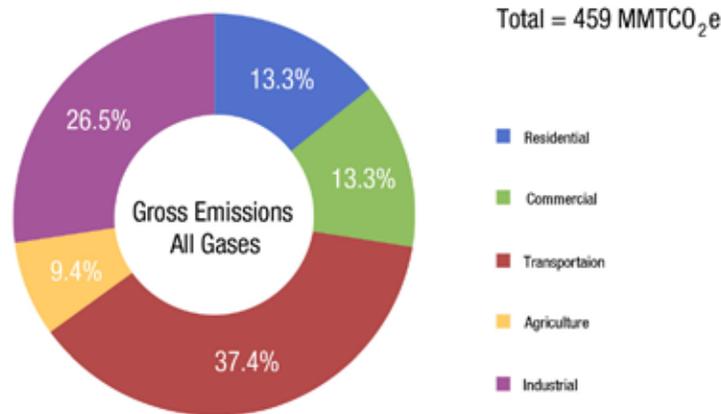
GHG Emission Sources

California's GHG emissions are primarily carbon dioxide from the combustion of fossil fuels. For the *IEPR*, the energy system is defined as including all activities related to energy extraction (for example, oil and natural gas wells), fuel and energy transport (for example, oil and natural gas pipelines), conversion of one form of energy to another (such as producing gasoline and diesel from crude oil in

8 For information about the symposiums on renewable energy, cutting petroleum use, and natural and working lands see <http://www.arb.ca.gov/cc/pillars/pillars.htm#publicmeetings>. For information on the symposium on efficiency see http://www.energy.ca.gov/2015_energy/policy/documents/#07062015.

9 California Energy Commission. 2015. *Existing Buildings Energy Efficiency Action Plan*. Publication Number: CEC-400-2015-013-F, http://docketpublic.energy.ca.gov/PublicDocuments/15-IEPR-05/TN206015_20150904T153548_Existing_Buildings_Energy_Efficiency_Action_Plan.pdf.

**Figure 2: California’s GHG Emissions by Sector
(Million Metric Tonnes of CO₂ Equivalent- MMTCO₂e)**



Source: California Air Resources Board, GHG Emission Inventory – 2015 Edition. <http://www.arb.ca.gov/cc/inventory/data/data.htm> and data from Energy Commission staff. Emissions from the electricity sector are broken down based on energy consumption data for 2013.

refineries and combusting natural gas in power plants to generate electricity), and energy services (such as electricity for lighting, natural gas use in homes and buildings for space and water heating, and gasoline and diesel use in cars and trucks).¹⁰ Under this broad definition, the energy system was responsible for about 80 percent of the gross¹¹ GHG emissions in 2013. This includes GHG emissions associated with out-of-state power plants providing electricity consumed in California.

Figure 2 shows GHG emissions by sector of the economy, including electricity sector emissions, broken down by end use. California’s transportation sector is the largest source of GHG emissions in California, account-

ing for 37.4 percent of the state’s GHG emissions. By comparison, electricity generation accounts for about 20 percent of the state’s GHG emissions (not shown as a discrete category in Figure 2). Close to half of electricity emissions are from out-of-state power consumed in California although out-of-state power represents about a third of California’s resource mix. Emissions from the industrial sector (26.5 percent) include emissions associated with oil refineries (also not shown). Emissions from the residential and commercial sectors account for 26.6 percent of emissions. Figure 2 includes energy and non-energy-related emissions from the agricultural and industrial sectors.¹²

10 California Energy Commission. 2013. *2013 Integrated Energy Policy Report*. Publication Number: CEC-100-2013-001-CM.

11 The California Air Resources Board GHG inventory also reports GHG sinks (for example, increased carbon stored in forests), but the sinks are relatively minor. For this reason, total net emissions are very close to total gross GHG emissions.

12 Examples of non-energy-related GHG emissions from these sectors include nitrous oxide from nitrogen-based fertilizers and carbon dioxide from the production of cement.

Guiding Principles for Reducing GHG Emissions

In his April 29, 2015, Executive Order (B-30-15), Governor Brown outlined that going forward state agencies' planning and investment should be guided by four principles.¹³ These guiding principles include the following:

- » **Give priority to actions that both build climate preparedness and reduce GHG emissions.** For example, adding insulation to buildings both improves occupant comfort in hot weather and reduces the need for air conditioning, which also reduces GHG emissions.
- » **Use adaptive and flexible approaches where possible to prepare for uncertain climate impacts.** A useful and easily accessible resource to identify potential climate change impacts is Cal-Adapt, a web-based climate adaptation planning tool. Using data compiled on an ongoing basis from California's scientific and research community, it allows users to see possible effects on temperature change, snowpack, precipitation, fire risk, and sea level rise downscaled to California's geography.
- » **Act to protect the state's most vulnerable populations.** Senate Bill 535 (De León, Chapter 830, Statutes of 2012) requires investments in California's most burdened communities to help improve public health, quality of life, and economic opportunity while reducing GHG emissions. The California Environmental Protection Agency identified disadvantaged communities using the California Communities Environmental Health Screening Tool (CalEnviroScreen) to identify the areas disproportionately burdened by and vulnerable to multiple sources of pollution. On a global scale, Pope Francis noted in a Papal Encyclical that climate change disproportionately affects the poor who have limited "financial activities or resources which can enable them to adapt to climate change or to face natural disasters,

13 <http://gov.ca.gov/news.php?id=18938>.

and their access to social services and protection is very limited."¹⁴

- » **Prioritize natural infrastructure solutions.** An example is to prioritize protecting natural wetlands to provide needed habitat and other benefits such as flood protection over developing walls to block storm surges.

Drought is another key consideration in the energy sector. As California continues to suffer from one of the worst droughts on record and its climate shifts toward warmer winters with less snowpack, water conservation and management have become increasingly important.¹⁵ Water and energy are inextricably linked, and efforts to better manage each resource can be mutually beneficial. The linkage is probably most readily apparent in the availability of hydropower: reduced snowpack affects the availability and timing of hydropower. Further, water delivery is energy-intensive, so water conservation programs can reduce GHG emissions in the electricity sector by reducing the need for energy to move, treat,

14 *Encyclical Letter Laudato Si' of the Holy Father Francis On Care for Our Common Home*, May 24, 2015. Excerpt: "Climate change is a global problem with grave implications: environmental, social, economic, political and for the distribution of goods. It represents one of the principal challenges facing humanity in our day. Its worst impact will probably be felt by developing countries in coming decades. Many of the poor live in areas particularly affected by phenomena related to warming, and their means of subsistence are largely dependent on natural reserves and ecosystemic services such as agriculture, fishing and forestry. They have no other financial activities or resources which can enable them to adapt to climate change or to face natural disasters, and their access to social services and protection is very limited. For example, changes in climate, to which animals and plants cannot adapt, lead them to migrate; this in turn affects the livelihood of the poor, who are then forced to leave their homes, with great uncertainty for their future and that of their children." http://w2.vatican.va/content/francesco/en/encyclicals/documents/papa-francesco_20150524_enciclica-laudato-si.html.

15 In January 2014, Governor Brown declared a Drought State of Emergency. In May 2015, he put forward mandatory statewide water cuts for the first time in the state's history, Executive Order B-29-15, <http://gov.ca.gov/news.php?id=18910>.

and heat it. The drought also raises questions about the reliability of water supply for natural gas, solar thermal, and geothermal power plants that require it for process use. The nexus between water and energy use is discussed in more detail in Chapter 8.

Air quality will be another driver of energy policy and an important consideration in efforts to reduce GHG emissions. To meet federal health-based air quality standards, the San Joaquin Valley and South Coast air basins could be required to cut oxides of nitrogen emissions up to 80 percent from current regulatory levels between 2023 and 2032. A key measure to meet these air quality standards is electrification of the transportation sector, which, coupled with increased renewables in the electricity sector, is critical to meeting GHG reduction goals. Recent research shows, however, that the largest sources of criteria pollutants, such as oxides of nitrogen, in the South Coast Air Basin, are not necessarily the most important sources of GHGs, so reductions in air pollution may not be proportional to GHG reductions, and vice versa. This conclusion highlights the need for vigilance in achieving both climate and air quality goals.¹⁶

California's Leadership in Addressing Climate Change

In issuing Executive Order B-30-15 to reduce GHG emissions 40 percent by 2030, the Governor not only set a bold policy for California, but also provided an example for other nations and sub-national bodies. The United Nations Framework Convention on Climate Change Executive Secretary Christiana Figueres said, "California's announcement is a realization and a determination that will gladly resonate with other inspiring actions within the United States and around the globe."

In May 2013, the Governor joined more than 500 world-renowned researchers and scientists in releasing a

call to action on climate change.¹⁷ The "consensus document" translates key scientific climate findings on climate change and other threats to humanity into one 20-page document that aims to help bridge scientific research and policy. This document informed development of the Governor's climate change policy.

Achieving deep GHG emission reductions will require unprecedented levels of coordination with business, the private sector, and local, state, and federal government. For example, on August 3, 2015, President Obama and the U.S. Environmental Protection Agency announced the Clean Power Plan to help reduce carbon pollution from power plants nationwide.¹⁸ The Clean Power Plan sets carbon pollution reduction goals for the power sector at 32 percent below 2005 levels by 2030, and emissions of sulfur dioxide from power plants 90 percent lower.¹⁹ In a statement made the same day, Energy Commission Chair Robert B. Weisenmiller said, "California is a strong supporter of this commonsense plan to cut carbon pollution from power plants and will continue to lead the way in reducing greenhouse gas emissions."²⁰

California is working on multiple geographic and administrative levels to create and implement a coherent strategy that reduces GHG emissions and minimizes vulnerabilities to ongoing and future climate changes. The California Air Resources Board is embarking upon a second update to the scoping plan to reduce GHG emissions. The California Natural Resources Agency will update its state climate adaptation strategy, Safeguarding

16 Joint Agency Workshop on Climate Adaptation Opportunities for the Energy Sector, July 27, 2015, http://www.energy.ca.gov/2015_energypolicy/documents/2015-07-27_cpuc_presentations.php.

17 *Scientific Consensus on Maintaining Humanity's Life Support Systems in the 21st Century: Information for Policy Makers*, May 21, 2013, <http://mahb.stanford.edu/consensus-statement-from-global-%20scientists>.

18 <https://www.whitehouse.gov/the-press-office/2015/08/03/fact-sheet-president-obama-announce-historic-carbon-pollution-standards>.

19 <http://www.epa.gov/airquality/cpp/fs-cpp-overview.pdf>.

20 http://www.energy.ca.gov/releases/2015_releases/2015-08-03_Weisenmiller_statement_re_clean_power_nr.html.

California, every three years. The Energy Commission is leading the preparation of this plan for the energy sector in cooperation with the CPUC and the Department of General Services. State agencies are implementing the Climate Action Team *Climate Change Research Plan for California*,²¹ which is designed to promote fast and efficient GHG reduction while bolstering adaptive capabilities across California.

Governor Brown has signed accords to fight climate change with leaders from Mexico, China, Canada, Japan, Israel, and Peru. On May 19, 2015, Governor Brown signed the Under 2 MOU, an agreement with international leaders from 11 other states and provinces²² to limit the increase in global average temperature to below 2 degrees Celsius (3.6 degrees Fahrenheit), the upper boundary of global temperature rise suggested by the Intergovernmental Panel on Climate Change for avoiding catastrophic climate change.²³ By signing the Under 2 MOU agreement, subnational leaders commit to either reduce GHG emissions 80 to 95 percent below 1990 levels by 2050 or achieve a per capita annual emission target of less than 2 metric tons by 2050.

The MOU will enhance cooperation by developing targets to support long-term reduction goals, sharing best practices to promote energy efficiency and renewable energy, working together to increase the use of zero-emission vehicles, ensuring consistent monitoring and

reporting of GHG emissions, reducing short-lived climate pollutants to improve air quality, and calculating the anticipated impacts of climate change on communities.²⁴

The Governor continues to develop a growing coalition of sub-national jurisdictions that commit to the Under 2 MOU. In his 2016 state-of-the-state address, the Governor said “The Paris climate agreement was a breakthrough and California was there leading the way. Over 100 states, provinces, and regions have now signed on to our Under 2 MOU. The goal is to bring per capita greenhouse gases down to two tons per person. This will take decades and vast innovation. But with SB 350, we’re on our way.”²⁵ As of the conclusion of the United Nations Climate Change Conference in Paris in December 2015, the 127 jurisdictions that signed the Under 2 MOU represented more than 729 million people in both developed and developing countries and more than \$20.4 trillion in a combined gross domestic product, equivalent to more than a quarter of the global economy.²⁶

California was also one of the 14 members of the International Zero-Emission Vehicle Alliance to pledge at the United Nations’ climate-change conference to strive to have all new cars sold within their jurisdictions be emissions-free by 2050.

The United Nations Climate Change Conference in Paris was convened to develop an agreement among nations worldwide to sufficiently reduce GHG emissions to avoid catastrophic climate change. On December 12, 2015, nearly 200 nations reached an agreement to commit to lowering greenhouse gas emissions to avoid a 2 degrees Celsius increase in global average temperature, above pre-industrial levels, and efforts toward a 1.5 degree Celsius goal.²⁷

21 California Environmental Protection Agency, Climate Action Team, *Climate Change Research Plan for California*, February 2015, http://www.climatechange.ca.gov/climate_action_team/reports/CAT_research_plan_2015.pdf.

22 The signatories include California, USA; Acre, Brazil; Baden-Württemberg, Germany; Baja California, Mexico; Catalonia, Spain; Jalisco, Mexico; Ontario, Canada; British Columbia, Canada; Oregon, USA; Vermont, USA; Washington, USA; and Wales, UK. The Mexican state of Chiapas and Cross River State in Nigeria joined in June, and the Rhône-Alpes region in France, Scotland, Spain’s Basque Country and Quebec joined in July 2015.

23 New, Mark, Diana Liverman, Heike Schoder, and Kevin Anderson, 2011, “Four Degrees and Beyond: The Potential for a Global Temperature Increase of Four Degrees and Its Implication,” *Phil. Trans. R. Soc. A* 363: 6-19.

24 <http://gov.ca.gov/news.php?id=18964>.

25 <https://www.gov.ca.gov/news.php?id=19280>.

26 <https://www.gov.ca.gov/news.php?id=19285>.

27 United Nations Framework Convention on Climate Change, Adoption of the Paris Agreement, December 12, 2015, <http://unfccc.int/resource/docs/2015/cop21/eng/109r01.pdf>.

The agreement depends on countries submitting nationally determined contributions, tailored to their specific circumstances, to progressively reduce GHG emissions. Countries will be required to reconvene every five years, starting in 2020, with updated plans to strengthen their emission reductions. Under the pact, each country will voluntarily set plans to cut emissions but is legally required to reconvene every five years starting in 2023 to publicly report on progress toward their plans to cut emissions. They are also required to use a universal accounting system to monitor and report on their emissions levels and reductions. The agreement also allows for international and subnational jurisdictions to work together to reduce emissions more directly, through internationally traded mitigation outcomes, or ITMOs. These have the potential to include carbon markets like California's.

The United Nations Secretary-General Ban Ki-moon said, "For the first time, we have a truly universal agreement on climate change, one of the most crucial problems on earth." Governor Brown issued the following statement on the global climate pact: "This is a historic turning point in the quest to combat one of the biggest threats facing humanity. Activists, businesses, and sub-national leaders now need to redouble their efforts and push for increasingly aggressive action."

Reducing GHG emissions is the challenge of today and for the next several decades. To meet the global temperature goals of the Paris Agreement and the Under2 MOU, transforming the energy sector is of paramount importance in the next few years. The policies put forward in this report aim to help California achieve its state-mandated 2030 and 2050 GHG reduction goals, with an eye toward rapid improvements over the next few decades.

CHAPTER 1

Energy Efficiency



California has long been a leader in advancing building energy efficiency. Over the last 40 years, California has implemented cost-effective building codes and appliance standards that have saved consumers billions of dollars. A variety of ratepayer-funded programs, from financial assistance to workforce education and public outreach, are helping businesses and homes reduce energy costs and carbon emissions. Efficiency is also reducing California's energy infrastructure costs by easing the energy demand that must be met by either fossil or renewable generation. Within the electricity sector, efficiency can reduce infrastructure needs and lower renewable electricity procurement requirements and similarly allow greater electric infrastructure flexibility as the state moves toward electrified transportation. Past successes in energy efficiency have helped limit electricity consumption growth to roughly 1 percent annually, and natural gas consumption growth to nearly zero. (See Chapters 5 and 6, respectively, for recent trends in electricity and natural gas consumption.)

But California needs to increase significantly energy efficiency in buildings to meet its aggressive greenhouse gas (GHG) emission reduction goals. Commercial and residential buildings account for nearly 70 percent of California's electricity consumption and 55 percent of its natural gas consumption. New efforts must activate

efficiency markets that truly compete with other energy supplies. A clear focus on the existing building stock, with a great potential to reduce current levels of energy usage, is warranted.

This chapter discusses the Energy Commission's efforts to improve the energy efficiency of the existing building stock. The chapter also discusses progress by the investor- and publicly owned utilities in meeting their energy efficiency goals, progress in implementing the Clean Energy Jobs Program (created through enactment of Proposition 39) and progress in advancing the state's zero-net-energy goals.

Existing Building Energy Efficiency

Assembly Bill 758 (Skinner, Chapter 470, Statutes of 2009) (AB 758) recognized the need for California to address climate change through reduced energy consumption in existing buildings. As part of his January 2015 inaugural address, Governor Edmund G Brown Jr. included a GHG reduction goal to double the expected energy efficiency savings from existing buildings.

Senate Bill 350 (De León, Chapter 547, Statutes of 2015) (SB 350) codified and built on the Governor's goal. The bill included provisions that will, among other things, set a similar goal of doubling energy efficiency savings by 2030, require the Energy Commission, in collaboration with the California Public Utilities Commission (CPUC), to establish annual targets toward the 2030 goal, and report progress every two years starting with the *2019 IEPR*. By November 1, 2017, the Energy Commission must establish annual targets for statewide energy efficiency savings and demand reduction that will achieve a cumulative doubling of energy efficiency savings among electricity and natural gas end uses by 2030. SB 350 requires these targets to be set in collaboration with the CPUC and local publicly owned utilities, and in a public process with opportunities for other stakeholder input. The bill also requires the CPUC to revisit its rules governing energy efficiency programs, both to authorize a broader array of program types and to tie incentive payments to measurable efficiency results. Where feasible and cost-effective, the bill requires that energy efficiency savings be measured with consideration toward the overall reduction in normalized metered electricity and natural gas consumption. The bill also requires the Energy Commission to update its *Existing Building Energy Efficiency Action Plan* every three years. All these activities will require more detailed, localized, and sector-specific analyses of energy efficiency and demand. Potential impacts from the bill on the Energy Commission's electricity demand forecasting are discussed further in Chapter 5. Finally, SB 350 also requires the Energy Commission (with input from other agencies and the public) to prepare a study by January 1, 2017, that will identify barriers to energy efficiency and weatherization investments for low-income customers

and disadvantaged communities, as well as recommendations for increasing access to such investments.

Most existing buildings have cost-effective opportunities for improving their energy performance. An illustration of the age of homes in the state can be seen in Figure 3. In the last decade California's building standards have required high levels of efficiency, such that older buildings that were once upgraded and buildings built to code five or more years ago also have significant energy savings potential.

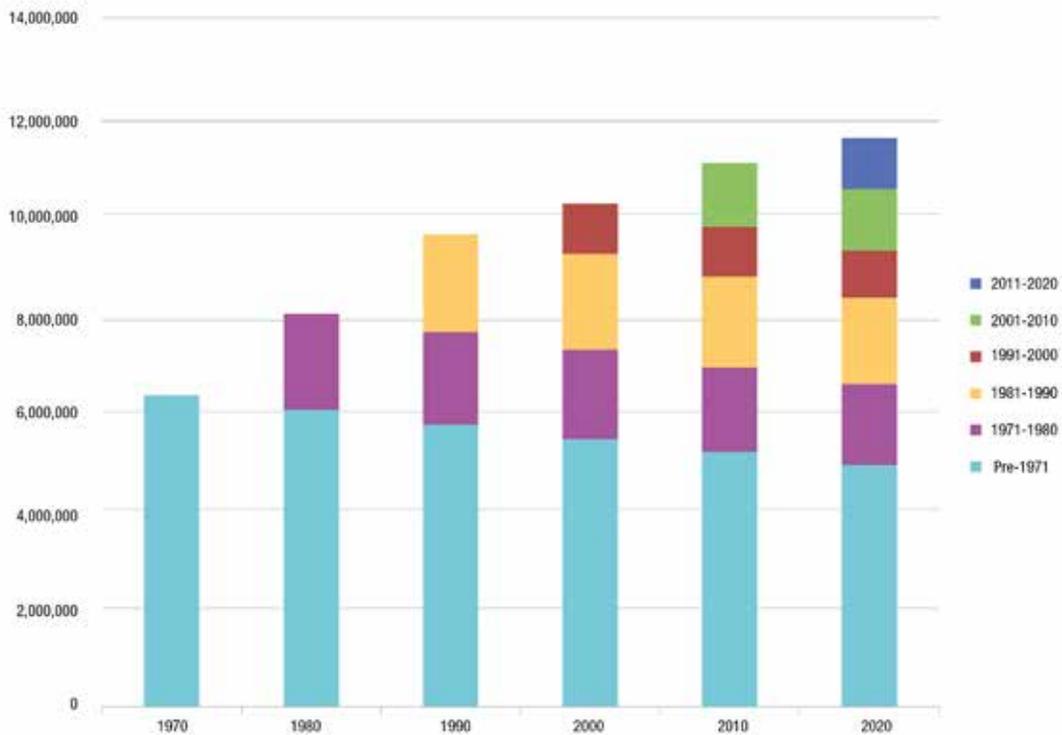
Doubling the rate of energy savings from existing building efficiency improvement projects would result in lower total building energy use in 2030 than in 2014, despite significant population and economic growth, and is equivalent to a 20 percent reduction in usage compared to projected 2030 levels. The *Existing Buildings Energy Efficiency Action Plan*, adopted by the Energy Commission in September 2015, introduces strategies to set California on a path to achieve this goal.²⁸ The plan articulates the vision of robust and sustainable efficiency markets that deliver multiple benefits to building owners and occupants through physical and operational improvements to existing homes, businesses, and public buildings.

The plan describes five discrete goals and delineates multiple strategies to achieve each goal. The plan goals are:

1. Increased government leadership in energy efficiency.
2. Data-driven decision making.
3. Increased building industry innovation and performance.
4. Recognized value of energy efficiency.
5. Affordable and accessible energy efficiency solutions.

28 California Energy Commission. 2015. *Existing Buildings Energy Efficiency Action Plan*. Publication Number: CEC-400-2015-013-F, http://docketpublic.energy.ca.gov/PublicDocuments/15-IEPR-05/TN206015_20150904T153548_Existing_Buildings_Energy_Efficiency_Action_Plan.pdf.

Figure 3: Single- and Multi-family Homes by Decade of Construction



Source: California Energy Commission. Includes estimates of future construction through 2020.

Within each of these goals are multiple strategies, each with responsible entities and time frames identified. Figure 4 outlines the overall implementation schedule for the strategies that constitute the five goals.

California’s building stock accounts for more than one-quarter of GHG emissions statewide. In 2013 (the most recent year data are available) residential and commercial end uses each accounted for 13.3 percent of statewide GHG emissions. This includes both fossil fuel consumption on-site (for example, gas or propane for heating), as well as upstream emissions from electricity that served those sectors.²⁹

²⁹ California Air Resources Board, *GHG Emission Inventory – 2015 Edition*, <http://www.arb.ca.gov/cc/inventory/data/data.htm>. Data from Energy Commission staff. Emissions from the electricity sector are broken down based on energy consumption data for 2013.

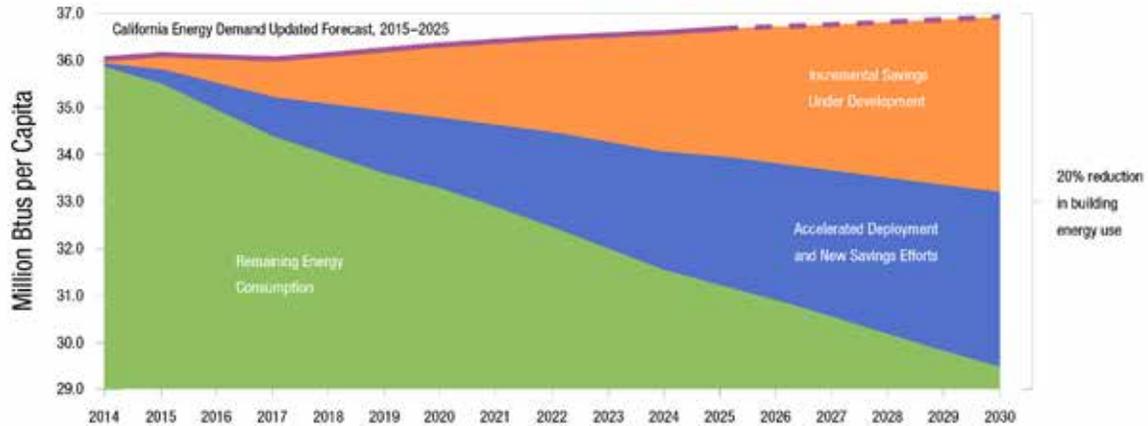
The 40 percent GHG reduction target established by Governor Brown’s Executive Order B-13-05 cannot be met within the building sector unless private capital and market forces are brought to bear; current ratepayer- and taxpayer-funded efficiency efforts will not be sufficient alone. Private capital in the range of \$10 billion annually will need to be invested in California’s existing building stock. Efficiency certainly can and should compete with other energy supply resources, but its importance goes beyond that basic energy resource contribution. Efficiency represents a highly cost-effective optimizing strategy, which can both reduce the size of the overall problem and enable diverse clean supply resources to coexist on the grid. Growing the energy efficiency enterprise and achieving its full range of benefits requires resolving the significant transaction costs and information vacuums that constrain this market.

Figure 4: Existing Buildings Energy Efficiency Action Plan Implementation Schedule



Source: California Energy Commission, *Existing Buildings Energy Efficiency Action Plan*.

Figure 5: Reduced Energy Consumption by Doubling Energy Efficiency in Existing Buildings



Source: California Energy Commission, *Existing Buildings Energy Efficiency Action Plan*.

Figure 5 shows the approximate reduction in building energy consumption per capita that will be necessary to double energy efficiency savings in existing buildings. The purple line atop the chart assumes achievement of energy efficiency from adopted and funded policies, standards, and programs (also known as “committed savings”). The orange wedge represents savings projected to occur via planned California and national appliance efficiency standards, increasing building energy efficiency standards through 2022, and continuous implementation of ratepayer-funded energy efficiency programs. The blue wedge represents a doubling thereof, achieved in part by efficiency savings from investments and behavioral changes made by consumers and businesses outside incentive programs. This doubling will require both new efforts and revised approaches to encouraging energy efficiency gains.

As part of developing the *2015 IEPR*, and in explicit relation to its parallel effort to finalize the AB 758 Action Plan, the Energy Commission held multiple workshops to present staff information and receive comments from state and federal agencies, private stakeholders, and the public. Participants discussed issues and opportunities on the overall approach toward meeting the Governor’s goal to double the expected energy efficiency savings from

existing buildings, and specifically focusing on relatively complex but high-priority topics and strategies from the *AB 758 Draft Action Plan*. Workshop topics included an introduction to the plan in general, improved data access, energy benchmarking for buildings, local government leadership, zero-net-energy buildings, plug-load efficiency, and building efficiency standards as they apply to existing buildings.³⁰ The now adopted *AB 758 Final Action Plan* is thus the most complete expression of the collection of strategies that could achieve a doubling of EE, in conformance with the goals set by Governor Brown and formalized in SB 350.

Local Government Leadership

Local governments have unique connections to their constituents and can effectively implement both voluntary and mandatory programs to increase existing building energy efficiency, not only in their own government buildings, but in homes and businesses in their

³⁰ All workshop notices, agendas, presentations, transcripts, and written comments from the *2015 IEPR*’s previous energy efficiency workshops are available online at <https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=15-IEPR-05>.

communities. However, one of the major challenges for many local governments is the lack of consistent funding sources for sustainability activities. The plan includes the recommendation that the Energy Commission modify the deployment of some remaining funds from the American Recovery and Reinvestment Act local government efforts, in order to improve effectiveness. The Energy Commission would award, via a competitive process, around \$8 million of remaining American Recovery and Reinvestment Act funds to innovative local governments and those of relatively disadvantaged communities, whose plans include initiatives that promise to enable greater flow of energy efficiency projects in their jurisdictions and beyond. The available funds are a tiny fraction of the need for local government support in this area, and the Energy Commission will seek to demonstrate success as a basis for a future broadening.

Data for Informed Decisions

Data access is critical to increase the scale of energy efficiency upgrades in California buildings. Every part of the market, from building owners and occupants to contractors, product manufacturers, and investors, needs access to data on actual efficiency upgrade equipment, costs, and savings. Experience has shown that modeled estimates will not suffice; knowledge of realized costs and measured savings reduces risks. Consumers hesitate to invest in energy efficiency improvements in part because they lack the information needed to understand these investments in concrete terms. The same can be said of the contractors who sell and install these projects, and lenders who finance them.

The California Solar Initiative (CSI) provides a highly relevant example of public data producing tremendous market value. The CSI program produced a public database of all photovoltaic (PV) systems installed in California that received program incentives. The database includes system costs, rebate amount, system size, zip code, installing contractor, project completion time, equipment brand, and other important data for each of more than

150,000 installations. As rebates have been exhausted for much of the CSI, going forward the database will be populated with investor-owned utilities' net energy metering³¹ interconnection data per direction by the California Public Utilities Commission.

This database is a valuable source of information to both the PV industry and the public. Figure 6 highlights some of the many statistics available on the California Solar Statistics website with CSI data and investor-owned utilities' net energy metering interconnection data.³²

In contrast, the measurement and evaluation reports funded by the California Public Utilities Commission (CPUC) on energy efficiency programs are focused specifically on verifying the savings claimed by the investor-owned utilities. The underlying project and cost data are not provided to the public nor to the building industry in ways that support financial decision-making or business opportunity assessments. The publicly owned utility (POU) energy efficiency reports to the Energy Commission similarly do not contain this sort of information. Data similar to that from the California Solar Initiative database should be made publicly available for all efficiency projects in the state that take advantage of ratepayer-funded financial assistance.

Building owners also need easy, routine access to their building energy use data so that ongoing benchmarking, monitoring, and efficiency opportunity identification can be integrated into their core business practices. Building owners of multi-tenant buildings almost always struggle with burdensome processes to acquire whole building energy use data from utilities.

State and local governments need access to building energy-use data, along with relevant building characteristics, to establish baselines and track progress toward effi-

31 *Net energy metering* is a billing mechanism that credits solar *energy* system owners for the electricity they add to the grid.

32 More statistics compiled from the California Solar Statistics database, as well as the original data set, are available at <https://www.californiasolarstatistics.ca.gov/>.

Figure 6: Example Screenshot from California Solar Statistics Website

Welcome to California Solar Statistics

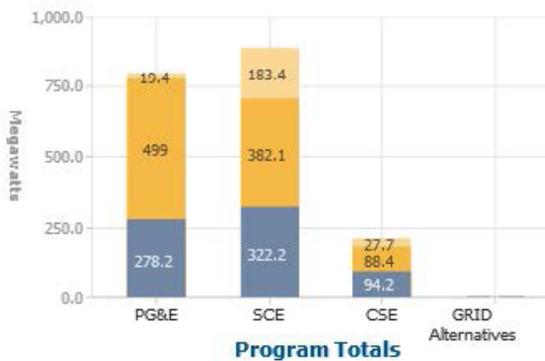
California Solar Statistics is the official public reporting site of the California Solar Initiative (CSI), presented jointly by the [CSI Program Administrators](#) and the [California Public Utilities Commission](#). This site presents actual program data, exported from the CSI online application tool each Wednesday. Users of this site can view program data summaries for the CSI General Market, Multifamily Affordable Solar Housing (MASH), and Single Family Affordable Solar Homes (SASH) programs provided in several figures and tables, and can also download the complete Working Data Set for their own analysis.

California Leads the Nation

- 247,099** solar projects
- 2,408** megawatts installed
- \$5.35** avg cost/watt <10kW
- \$4.65** avg cost/watt >10kW

NOTE: Above figures include non-CSI data
last updated: July 29, 2015

[data sources](#)



Source: Go Solar California, www.californiasolarstatistics.ca.gov/. Image taken August 4, 2015. As of January 2016, solar projects had increased to more than 450,000, and megawatts installed had increased to more than 3,600.

ciency goals. Local governments often lack the resources and the data access to identify the energy savings potential of the commercial buildings and homes in their jurisdictions. Local governments need this information, for example, to assess efficiency potential as part of their climate action plans.

The smart meter infrastructure in much of California provides a transformative opportunity to measure and monitor electricity usage at a much finer level of detail than what was historically possible.³³ This infrastructure should allow consumers to access their usage data easily and routinely, along with simple, reliable tools to

extract actionable recommendations from the data. These data allow consumers to compare their usage with peer groups, monitor and track their usage over time, and/or share their data (if they so choose) with any number of analytics firms that can help them gain a better understanding of their energy usage and savings opportunities. Data access is the first step to behavioral and operational efficiency improvements that have great potential to optimize energy use. The standardized availability of granular usage data would also enable California policy makers to rely on savings verification approaches that could be implemented more quickly, systemically and at lower cost. The Energy Commission is working with the CPUC to identify existing data that could meet some of these market needs. The Energy Commission will also update its Title 20 data collection regulations in 2016 to obtain data

³³ Assembly Bill 793 (Quirk, Chapter 589, Statutes of 2015) supports this goal by allowing utilities to provide incentives for energy management technologies that enable customers to better understand and manage their energy use.

needed both for improved long-term demand forecasting per SB 350 and to implement specific strategies of the AB 758 Action Plan.

For energy efficiency and other demand-side resources to displace traditional energy supply resources reliably, the market needs the data collection and analysis infrastructure to determine efficiency savings at the local distribution level. Depending on the specific need, measurement could be done over time on a specific project or, likely more commonly, for a group of projects collectively. Pacific Gas and Electric (PG&E) and the U.S. Department of Energy (U.S. DOE) sponsored work in this area for commercial whole-building efficiency project savings verification.³⁴ The Open EE Meter platform³⁵ may be used soon in California utility programs to verify and track whole-house upgrade project savings. The Energy Commission and the CPUC should build on these nascent efforts to encourage development of measurement and verification protocols that can be used by the market to quantify efficiency savings quickly and effectively. This could improve customer confidence, enable differentiation among contractors, and ultimately enable groups of efficiency projects to be bid into energy supply procurement auctions, for example within the CPUC's Long-Term Procurement Process.

Commercial and Multi-family Energy Benchmarking

Benchmarking is the comparison of a building's energy usage to that of other like buildings, to understand its relative energy performance. Public disclosure of a subset of benchmarking information can inform the broader marketplace for mobilization of cost-effective improvements. In 2007 California passed Assembly Bill 1103 (Saldana, Chapter 533, Statutes of 2007), the nation's first statewide commercial building energy use benchmarking

and disclosure law, and in 2013 the Energy Commission adopted implementing regulations. The program was largely ineffective, in part due to the transaction costs of compliance, primary among them the difficulty of obtaining whole-building energy use data from utilities.

California's most progressive local governments have already implemented or are planning to implement local benchmarking ordinances. The success of these programs has also been thwarted by the inaccessibility of whole-building data. Other local governments have been waiting for the data access issue to be resolved before they propose benchmarking ordinances in their jurisdictions.

Other significant factors were the complications created by having the process triggered by a private transaction, and the requirement to limit disclosure to only the parties to that transaction. Just three percent or fewer of California's commercial buildings were subject to this law each year.

The Action Plan therefore recommended a broader statewide benchmarking and disclosure program for the state's large commercial and multifamily buildings, in which owners would benchmark their buildings periodically, with eventual public disclosure of benchmarking metrics. This type of benchmarking and disclosure program builds upon what a number of large U.S. cities have implemented over the last several years.

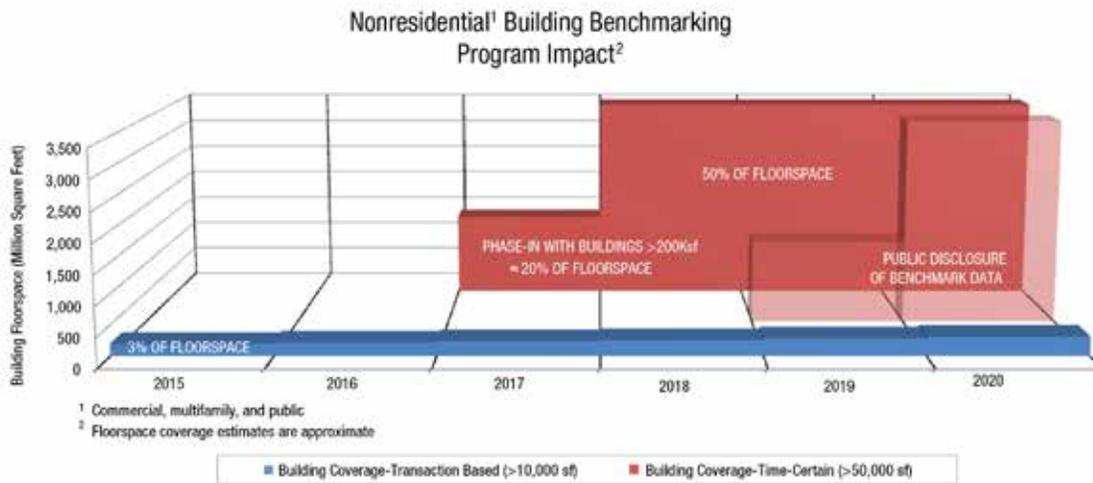
The difference between the two approaches is shown in Figure 7, where blue bars represent the nonresidential floor space benchmarked under AB 1103 (covering units greater than 10,000 square feet at time of transaction), while red bars represent a benchmarking system where units greater than 50,000 square feet are benchmarked at regular intervals.

Assembly Bill 802 (Williams, Chapter 590, Statutes of 2015) addresses the impediments identified during implementation of AB 1103, by replacing the existing statutory language with new provisions that put in place a more workable, broad statewide benchmarking and public disclosure program. Among these new provisions, AB 802 requires utilities to maintain energy usage records for all

34 Jump, Price, Granderson, and Sohn, *Functional Testing Protocols for Commercial Building Efficiency Baseline Modeling Software*, Lawrence Berkeley National Laboratory, LBNL-6593E, 2014.

35 <http://www.openeemeter.org>.

Figure 7: Comparison of Floor Space Covered by Benchmarking Strategies



Source: California Energy Commission, *Existing Buildings Energy Efficiency Action Plan*.

buildings to which they provide service, and to provide combined energy usage data to the owner, owner’s agent, or operator of a covered building upon request. The legislation also requires the Energy Commission to adopt regulations providing for the collection and public disclosure of building energy benchmarking information. Existing Energy Commission regulations that require protection of confidential end-user-specific usage data will be reviewed to ensure conformance with the provisions of AB 802.

Applying Building Energy Efficiency Standards to Existing Buildings

Building Energy Efficiency Standards (BEES) have been a part of California’s regulatory landscape since the late 1970s and have had a profound cumulative effect on statewide energy consumption. The standards make mandatory the inclusion of feasible, cost-effective advancements in building energy efficiency and apply both when new buildings are built and when additions and alterations are made to existing buildings.

Over time, those requirements have steadily improved California’s building stock, at the same time enhancing not

only energy efficiency, but also indoor air quality, thermal stability, and occupant comfort. Measures that apply to existing buildings are generally based on measures established for newly constructed buildings, either by determining that the same measures are feasible and cost-effective to implement in an addition or alteration, or by modifying a measure established for a newly constructed building. The standards are updated every three years, as a part of the general updates of the California Building Code.

Compliance with the Standards is critical to achieving the savings potential that exists at the time of alteration of existing buildings. Compliance is fundamentally the responsibility of contractors and other installers, for whom the requirements should be clear and feasible. Homeowners and contractors should understand the value of compliance. Local governments place highest priority on ensuring that buildings comply with health and safety codes. However, in the case of alterations to existing buildings, many homeowners and contractors fail to pull permits, such that many projects are completed without the building department’s knowledge, preventing even basic checks on health and safety code

requirements. Inadequate funding of building departments is a major barrier to compliance with energy codes nationwide. Solutions include increasing permit fees and/or improved collection.³⁶

The 2016 update to the Standards incorporated changes throughout the regulatory language to clarify, simplify, and streamline regulatory requirements, and in doing so make the standards more understandable and more usable both for new and for existing buildings. As the Energy Commission implements the *2016 Standards* update, the following steps can enhance the effect of these updates on existing buildings:

- » Provide early publication of compliance manuals, documents, and software. This gives builders and the building industry additional time to familiarize themselves with the 2016 requirements, and Home Energy Rating System (HERS) Providers opportunity to develop their applications for approval and to train technicians in advance of the January 1, 2017, effective date. Early availability is particularly important for addition and alteration projects, which often have much shorter timelines than new building projects.
- » Work with the CPUC and local utilities to develop and offer early compliance incentive and training programs for addition and alteration projects.
- » Work with local jurisdictions pursuing efficiency ordinances for existing buildings. The Energy Commission is aware of several jurisdictions pursuing retrofit programs and can work with local officials to ensure compliance with the Standards.

- » Develop and make available online “smart” versions of forms that can propagate information to appropriate fields and be submitted and reviewed electronically.

Looking forward to the *2019 Standards* development cycle, the Energy Commission will take the following steps to synergize Standards updates with Plan strategies:

- » Work with stakeholders, including other state agencies and local governments, to explicitly quantify the incremental costs of permitting and compliance for typical retrofit projects and their effect on overall measure cost-effectiveness.
- » Clarify and streamline the regulatory Standards language, paying particular attention where stakeholders identify added costs and other roadblocks unique to implementing the requirements in existing buildings. This includes tailoring the additions and alterations requirements to what can be practically and cost-effectively accomplished in an existing building.
- » Simplify and automate, wherever possible, the compliance pathways, options, and associated forms and materials necessary for demonstrating compliance with the energy efficiency standards. This includes implementing requested features into the Energy Commission’s compliance software, such as the ability to model and estimate the effects of solar PV, and developing more advanced electronic forms that simplify automation of compliance documentation.
- » Consider amendments to the Standards that establish tailored requirements for existing multifamily buildings. The designs of these buildings often incorporate aspects of both nonresidential buildings and single-family homes.
- » Continue its collaboration with the CPUC to develop appropriate mechanisms for offering incentives for elective projects in existing buildings (for example, additions and alterations) that result in the buildings being brought up to current code.

36 Institute for Market Transformation, *\$810 Million Funding Needed to Achieve 90% Compliance with Building Energy Codes*, 2011. Available at http://www.energy.gov/sites/prod/files/gcprod/documents/Energy_Code_Enforcement_Funding_Task_Force_-_Fact_Sheet.pdf.

» Continue its collaboration with the CPUC, investor- and publicly owned utilities, and stakeholders such as California Building Officials and the Contractors State License Board in offering technical assistance, training, education, and other support for compliance with the Standards through the California Statewide Codes & Standards Program, including the Energy Code Ace program.

AB 802, in addition to aforementioned provisions on benchmarking and disclosure, will also revisit the treatment of utility incentives for existing buildings. Historically, utility ratepayer-funded programs tended to rely on current building code to drive significant savings in existing buildings, with program incentives focusing on pushing upgrade projects “above code.” As the applicable building code has progressively tightened, for any given building vintage the distance in performance from existing conditions up to compliance with current code has widened. This dynamic has, at times, increased the portion of a project that had no program incentives available, jeopardizing the project itself. AB 802 addresses this issue by requiring the CPUC to authorize appropriate incentives for energy efficiency measures that improve the efficiency of a building from actual current conditions. This change from “code-as-baseline” to “actual-as-baseline” will allow for a broader array of incentive programs with lower costs and higher potential efficiency savings. With this change comes the opportunity for utilities to support education and incentives for customers to achieve measurable savings on their monthly utility bills, increase the value of their building in the real estate market, and improve occupant comfort.

Asset Ratings

Evaluating building energy performance and identifying opportunities for improvement are critical components of the plan. The Energy Commission is committed to clarifying the difference between, on the one hand, scoring the

relative efficiency of building properties as assets and, on the other, assessing the energy performance of a given building to identify the best opportunities for occupants to reduce energy use.

The Energy Commission intends to separate asset ratings from performance assessments. *Asset ratings* can be helpful specifically for real estate transactions for owners and buyers to value building property. Such asset ratings should be disclosed along with other property details to help inform the purchase decisions of prospective buyers.

Public Resources Code Section 25942³⁷ directs the Energy Commission to establish criteria for a statewide home energy rating program for homes: to create a consistent, accurate, and uniform asset rating system based on a statewide rating scale that can differentiate the energy efficiency levels among California homes.

The Whole-House HERS rates the energy-related characteristics of homes on a scale from 0 to 250 relative to a reference home built to meet the *2008 BEES*. However, there has been limited market uptake of Whole-House HERS to date. This voluntary asset-rating approach is perceived to be expensive, and the ability of HERS Raters to produce consistently credible ratings is in question.

Performance Assessment

An asset rating – which relates to the physical infrastructure of a building – by its nature cannot identify and prioritize measures that will best serve its specific occupants. Performance assessments generally provide recommendations that are specific to the building, related equipment and appliances, and how the occupants interact with the building. The Energy Commission intends that performance assessment tools be deployed by the private market, not by the government. Instead, government’s role could be to establish a set of minimum criteria for building performance assessment tools so

37 Warren-Alquist Act (Public Resources Code section 25000 et seq.), http://www.energy.ca.gov/reports/Warren-Alquist_Act/.

that the industry delivers reasonably reliable assessments and consumers know what to ask for and expect when hiring professionals to assess building efficiency opportunities. The Energy Commission is encouraged by the growth of affordable assessment approaches offered by the private market and integrated into performance-based efficiency programs, and by their integration of modern data tools. Robust assessment tools partnered with professional expertise will be needed to identify significantly greater levels of energy efficiency opportunities in homes and businesses.

The Energy Commission is working to resolve these issues and to clarify the role of performance assessments, if any, in the Whole House HERS program. In late 2012, the Energy Commission opened the HERS Order Instituting Informational (OII) Proceeding, Order No. 12-1114-6, to identify potential procedures and other actions to improve the Whole House HERS program and better define the role of the program in the marketplace for existing building upgrades. Information gathered through the OII process will lead to a rulemaking specific to Whole House HERS. In June 2017, the Energy Commission held a webinar to further identify the relevant issues. To inform the update to the Whole-House regulations, the Energy Commission is working to align California's energy asset rating approach with national systems and to understand the potential role, if any, for building performance assessments in the HERS Whole House program.

Efficiency Financing

New financing options for energy efficiency are emerging in California. Indeed, a new U.S. Department of Energy report highlights California's position as a leading state in clean energy finance.³⁸ Beyond the typical first-cost reductions offered by utility incentive programs, financing

allows the full costs of efficiency projects to be borrowed and paid back over time. Property Assessed Clean Energy (PACE) financing is now available in some form in most of the state, and PACE programs have, to date, provided more than \$1 billion of financing for efficiency and clean power projects. PACE programs allow the project debt to stay with the property, such that unpaid loan balances can transfer with property ownership.

The California Alternative Energy and Advanced Transportation Financing Authority (CAEATFA) manages the California Hub for Energy Efficiency Financing. CAEATFA is piloting the California Hub for Energy Efficiency Financing in collaboration with the CPUC and the state's investor-owned utilities. These pilot programs are designed to increase the availability of lower-cost financing for energy efficiency investments throughout the state. The CPUC has allocated \$65.9 million to develop, administer, and provide credit enhancements to the pilot programs.

The California Infrastructure and Economic Development Bank created the California Lending for Energy and Environmental Needs (CLEEN) Center to promote both public and private investments in clean energy projects for public facilities. Certain non-profit entities can also participate in the CLEEN Center Program. The Statewide Energy Efficiency Program focuses on energy-related projects for state and local governments in California. The CLEEN Center provides the financed capital needed to implement Statewide Energy Efficiency Program projects.

These relatively new financing options are very encouraging and support the objective in the *Existing Buildings Energy Efficiency Action Plan* to scale energy efficiency substantially by attracting private investments.

Plug-Load Efficiency

Plug loads result from devices that are plugged into power outlets, including electronic products such as computers, TVs, and cell phones; household appliances such as refrigerators and clothes washers; and miscellaneous equipment such as vacuums, power tools, and battery

38 U.S. Department of Energy, *Energy Investment Partnerships: How State and Local Governments Are Engaging Private Capital to Drive Clean Energy Investments*, 2016, <http://energy.gov/epsa/downloads/energy-investment-partnerships-how-state-and-local-governments-are-engaging-private>.

chargers. Reducing plug-load energy consumption is a key part of reducing the energy footprint of existing buildings. Plug-load efficiency will also be critical for meeting the state's goals for zero-net energy (ZNE) new buildings. Plug-load devices, unlike some built-in energy end uses, are typically selected by the occupant. They are often more dependent on the occupant's behavior and habits. Going forward, new challenges for building designers are making plug loads and equipment selection part of the basic building design and educating tenants and owners on the importance of efficient selection and operations of their plug-in appliance purchases.

Energy use by plug loads is growing rapidly in both the residential and commercial sectors. For example, the average house that contained only four or five plug-load devices 20 years ago now has as many as 65.³⁹ Combined, plug-load devices account for almost two-thirds of California home electricity use.⁴⁰ This fraction is projected to grow to 70 percent by 2024.⁴¹ At this pace, plug-load energy use will hinder achievement of the state's efficiency goals.

Appliance Efficiency Standards

The California Public Resources Code Section 25402 mandates the Energy Commission to "reduce the wasteful, uneconomic, inefficient, or unnecessary consumption of energy." The Public Resources Code authorizes the Energy Commission to set minimum levels of operating

efficiency that will reduce the growth in energy consumption. The Commission carries out this mandate by setting energy efficiency standards for appliances that are not regulated by the U.S. DOE. These standards are found in Title 20 of the California Code of Regulations. The Energy Commission, however, is often preempted by the U.S. DOE's authority. For example, the U.S. DOE set standards for refrigerators, dish-washers, and clothes dryers, among other appliances, which preempts the Energy Commission from adopting standards for these appliances.

When the Energy Commission has adopted standards for appliances that were not preempted, it has often set the stage for regional and national standards. In developing and implementing standards, the Energy Commission often works closely with other member jurisdictions in the Pacific Coast Collaborative, an association composed of the states of California, Oregon, and Washington, and the Canadian province of British Columbia.

For instance, California's television standards were adopted by Oregon, Connecticut, and the Canadian province of British Columbia. California's battery chargers standards were subsequently adopted by Oregon and British Columbia, and the U.S. DOE is proposing to increase the stringency of its proposed battery charger standards to achieve the savings of California's standards at a national level.⁴² Standards for external power supplies were adopted by all states and the international community.

In the commercial sector, plug loads consume 23 percent of the electricity in California office buildings.⁴³ Computers, monitors, printers, peripherals, audio-visual equipment, and telephony comprise 86 percent of this plug-load energy use, with computers and monitors alone

39 Natural Resources Defense Council, "Plug Load Efficiency Strategies," presentation at IEPR commissioner workshop on Plug Load Efficiency, June 18, 2015.

40 Pacific Gas and Electric, *Comments of Pacific Gas and Electric Company on Plug Load Efficiency* written comments from IEPR commissioner workshop on Plug Load Efficiency, http://doCKETPUBLIC.energy.ca.gov/PublicDocuments/15-IEPR-05/TN205273_20150707T143450_Valerie_Winn_Comments_Pacific_Gas_and_Electric_Company_Plug_Loa.pdf.

41 Natural Resources Defense Council, "Plug Load Efficiency Strategies," presentation at IEPR commissioner workshop on Plug Load Efficiency, June 18, 2015.

42 Standards adopted in 2012 for battery chargers will save enough electricity to power nearly 350,000 households, all the homes in a city roughly the size of Bakersfield. Once fully implemented, California ratepayers will save about \$306 million per year from battery charger standards alone.

43 ECOVA, *Commercial Office Plug Load Savings and Assessment: Executive Summary*, December 2011.

accounting for about two-thirds of this amount.⁴⁴ If a new energy-efficient office building contains servers, the servers could increase plug loads share of building energy consumption to 50 percent.⁴⁵ In the residential and commercial sectors, 8.3 million computers of various types are sold in California each year.⁴⁶

For these reasons, the Energy Commission is considering energy efficiency standards for computers, monitors, and displays through its Title 20 authority.⁴⁷ Such standards would reduce the average energy use for a typical computer, central processing unit, and display without affecting functionality or performance, using available, off-the-shelf technologies. The proposed standards would save more than 2,700 gigawatt hours (GWh) per year statewide after stock turnover. The standards, which would take effect in January 2018, would also save businesses and consumers an estimated \$434 million on their electricity bills.⁴⁸

Plug-Load Research

Research can help ease development of appropriate and beneficial standards. For instance, the Energy Commission's plug-load research is projected to result

in estimated savings of \$9 billion between 2005 and 2025 through adoption of three appliance efficiency standards for televisions, external power supplies, and battery chargers.⁴⁹

Many plug-load devices consume power even when not in use, known as *standby* or *idle loads*, costing consumers money while providing little or no utility. Most of these devices lack proportionality between the energy consumed and the useful work delivered by the device.⁵⁰ About 23 percent of residential plug load is caused by “always-on,” but not always in-use, equipment, such as microwaves, burglar and security systems, sprinklers, alarms, thermostats, and displays. Similarly, much of the information technology equipment in commercial buildings is left on around the clock, and power management is not being fully used.⁵¹ In September 2014, the Institute of Electrical and Electronics Engineers announced that software management company AGGIOS, Inc. and more than 30 leading electronics companies began work on a new standard for energy-proportional mobile and “wall-powered” electronic systems. The standard will enable specifying, modeling, verifying, designing, managing, testing, and measuring the energy features of a device.⁵²

44 California Public Utilities Commission, *Energy Efficiency Strategic Plan, Research and Technology Action Plan 2012-2015*, p. 4-1.

45 New Buildings Institute and ECOVA, *Plug Load Best Practices Guide: Managing Your Office Equipment Plug Load*, 2012.

46 Singh, Harinder, Ken Rider. 2015. *Staff Analysis of Computer, Computer Monitors, and Signage Displays*. California Energy Commission. CEC-400-2015-009-SD, http://dock-etpublic.energy.ca.gov/PublicDocuments/14-AAER-02/TN203854_20150312T094326_Staff_Report__FINAL.pdf.

47 California Energy Commission. *2015 Appliance Efficiency Pre-Rulemaking – Computers, Computer Monitors, and Signage Displays*. <http://www.energy.ca.gov/appliances/2014-AAER-2/prerulemaking/>.

48 Singh, Harinder, Ken Rider. 2015. *Staff Analysis of Computer, Computer Monitors, and Signage Displays*. California Energy Commission. CEC-400-2015-009-SD, http://dock-etpublic.energy.ca.gov/PublicDocuments/14-AAER-02/TN203854_20150312T094326_Staff_Report__FINAL.pdf.

49 Battery chargers – http://www.energy.ca.gov/appliances/battery_chargers/documents/2010-10-11_workshop/2010-10-11_Battery_Charger_Title_20_CASE_Report_v2-2-2.pdf.

Televisions – http://www.energy.ca.gov/appliances/2008rulemaking/documents/2008-04-01_workshop/2008-04-04_Pacific_Gas_+_Electric_Televisions_CASE_study.pdf.

External power supply – http://www.energy.ca.gov/appliances/2004rulemaking/documents/case_studies/CASE_Power_Supplies.pdf.

50 AGGIOS, “2015 IEPR Staff Workshop on Plug Load Efficiency,” presentation at IEPR commissioner workshop on Plug Load Efficiency, June 18, 2015.

51 Ibid.

52 Business Wire, *AGGIOS Heads IEEE Standardization of Unified Hardware Abstraction (UHA) for Energy Proportional Electronic Systems*, September 22, 2014.

The Energy Commission has an established track record in research and development on this issue. Past research by the Energy Commission's Public Interest Energy Research (PIER) program and the IOUs focused on set-top boxes, component power display, external power supplies, office electronics, battery chargers, flat-screen televisions, home stereo/audio systems, 24/7 kiosks (for example, ATMs), multi-media computers, and high-performance and ultra-efficient hybrid computers.

Many common electronic devices such as televisions, computers, and game consoles also lack the ability to measure and report energy use or receive control signals, but are designed to connect to the Internet. This makes many devices ideal candidates for networking. The integration of plug-load controls can reduce active and idle loads and result in better load management and response to grid conditions. Through intelligent energy devices (combined with information such as weather forecasts, occupancy forecasts, and energy prices), energy efficiency can be incorporated into daily practices and save consumers money. The key to this is the development of standardized communication and application protocols that can identify which devices are using energy, and how much they are using at any given time.

The Energy Commission is committed to developing innovative solutions to plug load challenges through its Electric Program Investment Charge (EPIC) research and development program. In the fall of 2015, the Commission issued two solicitations to address plug loads. The first, titled "Developing a Portfolio of Advanced Efficiency Solutions: Plug Load Technologies and Approaches for Buildings (GFO-15-310)," will fund the development of next-generation plug-load efficiency technologies and strategies for the building sector. Projects may target devices and components that are highly inefficient, operate uncontrolled with long operating hours, and have the potential for large energy savings (in part through power scaling) in homes and businesses. The other solicitation is titled "Reducing Costs for Communities and Businesses Through Integrated Demand-Side Management and Zero

Net Energy Demonstrations, (GFO-15-308)." The purpose is in part to develop novel controls and sensors or energy management systems for heating, ventilation, and air conditioning (HVAC); lighting; plug loads; and other energy-using systems. Proposed awards for both solicitations will be announced in early 2016.

In addition to developing innovative solutions to plug-load challenges through EPIC research and development grants, competitive programs for efficiency, like the XPRIZE program, could help move the market toward more efficient appliances. Such a program should target market breakdowns and focus on energy-consuming products that are preempted by federal regulations or that don't lend themselves well to standards, and how they might be integrated into buildings of the future. Funding from sources such as private foundations, federal grant programs, or a legislative appropriation would be needed to implement such a program.

Utility Energy Efficiency Procurement

California utilities have been offering energy efficiency programs to their customers since the 1970s. The CPUC oversees the energy efficiency programs of the IOUs, while the POUs regulate their own energy efficiency programs. These programs help reduce emissions, are the lowest-cost energy resource option, and play significant roles in meeting California's energy and climate policy objectives.

The Legislature has passed several bills to promote increased energy efficiency via utilities' involvement in California. Senate Bill 1037 (Kehoe, Chapter 366, Statutes of 2005) requires the IOUs to meet unmet resource needs through all available energy efficiency that is cost-effective, reliable, and feasible. SB 1037 also requires the

Table 1: CPUC Goals and IOU Evaluated Savings for 2010–2012

2010-2012	PG&E	SCE	SDG&E	SCG	Total
CPUC Goals					
Electricity Savings (GWh)	3,110	3,316	540	-	6,966
Peak Savings (MW)	703	727	107	-	1,537
Natural Gas (MMth)	49	-	11	90	150
IOU Reported Savings					
Electricity Savings (GWh)	3,924	4,458	786	-	9,168
Peak Savings (MW)	703	825	129	-	1,657
Natural Gas (MMth)	68	-	4	83	155
CPUC Evaluated Savings					
Electricity Savings (GWh)	3,256	3,859	630	-	7,745
Peak Savings (MW)	553	652	103	-	1,308
Natural Gas (MMth)	53	-	9	111	173
Performance against 2010-2012 Goals					
Percent of GWh Goals	105%	116%	117%	-	111%
Percent of MW Goals	79%	90%	96%	-	85%
Percent of MMth Goals	108%	-	79%	123%	115%

Source: CPUC 2010-2012 Energy Efficiency Annual Progress Evaluation Report, March 2015.

CPUC, in collaboration with the Energy Commission, to identify all potentially achievable cost-effective electric and natural gas energy efficiency measures for the IOUs, set targets for achieving this potential, review the energy procurement plans of the IOUs, and consider cost-effective supply alternatives such as energy efficiency. More recently, SB 350 requires the CPUC to review and update policies governing investor-owned utilities' efficiency programs as part of the state's 2030 goals for energy efficiency savings.

In addition to these IOU requirements, SB 1037 requires that all POUs, regardless of size, report investments in energy efficiency programs annually to their customers and to the Energy Commission. Assembly Bill 2021 (Levine, Chapter 734, Statutes of 2006) requires the Energy Commission, along with the CPUC, to develop a statewide estimate of energy efficiency potential along with statewide annual targets over a 10-year period for California's IOUs and POUs. (California also has several

community choice aggregators [CCAs] that offer energy efficiency programs to their customers. Due to data limitations, however, the CPUC can develop goals only by IOU service territories rather than by program administrator, which means there are no separate goals for CCAs.)

SB 350 strengthened these earlier requirements by directing the Energy Commission to establish a mandatory energy efficiency goal for each utility that is to be reached by 2030. Furthermore, AB 802 includes a provision that reinforces Energy Commission access to detailed energy usage and billing information for all utilities. Such data are significant building blocks for improving and localizing projections of energy efficiency savings within Energy Commission forecasts.

Investor-Owned Utilities Progress and Update

The CPUC released a report in March 2015 with the evaluation, measurement, and verification (EM&V) results

Table 2: CPUC Goals and IOU Reported Savings for 2013 and 2014

2013	PG&E	SCE	SDG&E	SCG	Total
CPUC Goals					
Electricity Savings (GWh)	853	922	221	-	1,996
Peak Savings (MW)	145	181	43	-	369
Natural Gas (MMth)	21	-	2	24	47
IOU Reported Savings					
Electricity Savings (GWh)	1,080	1,145	221	-	2,446
Peak Savings (MW)	191	193	33	-	417
Natural Gas (MMth)	31	-	1	25	57
2014	PG&E	SCE	SDG&E	SCG	Total
CPUC Goals					
Electricity Savings (GWh)	832	924	212	-	1,968
Peak Savings (MW)	132	177	41	-	350
Natural Gas (MMth)	21	-	2	23	46
IOU Reported Savings					
Electricity Savings (GWh)	1,084	1,216	237	-	2,537
Peak Savings (MW)	196	211	42	-	449
Natural Gas (MMth)	30	-	2	27	59

Sources: 2013–2014 goals are from CPUC Decision 12-11-015, November 8, 2012. Reported savings numbers are from the IOUs' Annual Reports and are unevaluated savings numbers.

for the 2010–2012 IOU portfolio cycle.⁵³ Collectively, the 2010–2012 evaluated savings from energy efficiency programs administered by the IOUs exceeded the goals for energy and gas savings but fell short in peak savings numbers. About 90 percent of the savings achieved during this program cycle occurred in the commercial and residential sectors. The majority of the electricity savings came from lighting measures and HVAC upgrades. Table 1 summarizes the goals, reported savings, and evaluated savings for each IOU during the 2010–2012 program cycle.

For 2013 and 2014, efficiency savings have been estimated by IOUs but not yet verified by third-party evaluators. However, according to the IOU estimates, the

IOUs collectively surpassed their electricity, peak, and gas savings goals set by the CPUC. For 2013, Pacific Gas and Electric (PG&E), Southern California Edison (SCE), and Southern California Gas Company (SoCal Gas) reported meeting all of their goals, while San Diego Gas & Electric Company (SDG&E) fell slightly short in achieving its peak and gas goals. For 2014, all the IOUs reported meeting their goals. Lighting measures and HVAC again made up the majority of electricity savings, while natural gas savings came from process improvements in the industrial sector. For this two-year cycle, the CPUC approved more than \$1.7 billion dollars for the IOUs to spend on energy efficiency programs and more than \$78 million to be spent on EM&V studies.

Table 2 summarizes these 2013 and 2014 results. The estimated 2013 and 2014 energy savings of 2,446 GWh and 2,537 GWh represented about 1.2 percent of overall electricity consumption for each year. (These savings are

53 CPUC, *2010-2012 Energy Efficiency Annual Progress Evaluation Report*, March 2015. Available at http://www.cpuc.ca.gov/NR/rdonlyres/052ED0ED-D314-4050-9FAA-198E45480C85/0/EE-Report_Main_Book_v008.pdf.

self-reported estimates, not yet independently verified by third-party evaluators.)

In past years, the CPUC approved three-year energy efficiency program cycles, most recently 2010–2012. Often, these three-year program cycles are followed by a one- or two-year bridge period, such as 2013–2014. In November 2013, the CPUC released an order instituting rulemaking establishing a proceeding that would address post-2014 energy efficiency issues.⁵⁴ Some of the key objectives of this proceeding include greater funding stability for energy efficiency program administrators and implementers; reduced transaction costs for program implementation; better coordination with demand forecast, procurement planning, and transmission planning; and transparent program evaluations and timely use of that information to enhance energy efficiency portfolios.

The first phase of the proceeding concluded in October 2014 with Decision D.14-10-046, which authorized 10-year funding of the energy efficiency portfolio (through 2024) at current levels. The current (second) phase of the proceeding is developing the review and approval processes for this 10-year funding authorization, which the CPUC is referring to as a “rolling portfolio cycle,” and which should avoid the stop/start nature of the previous triennial portfolio cycles and promote long-term energy efficiency projects. In addition, a longer portfolio period will project a firm future commitment to consistent funding for energy efficiency programs.

Several proposed decisions describing the new rules of engagement associated with the rolling portfolio cycle were made public in the fall of 2015, and the CPUC voted to adopt D. 15-10-028 in October 2015. One of the key changes that the proposed decision identifies is the use of a clear timeline for coordinating various activities in the regulatory process, including technical updates, program

design and portfolio planning, program operations, and program reporting and evaluation. This approach will allow for different types of EM&V studies, including studies with faster turn-around times, and will allow EM&V results to be incorporated into the portfolio on a timelier and more frequent basis.

Another evaluation approach is to have energy savings assessed by an independent party such as the California Technical Forum. The California Technical Forum is a collaboration of statewide energy efficiency experts who issue guidelines, templates, and protocols to support statewide measure development and savings estimates. By using the California Technical Forum for parts of the EM&V process, the technical evaluation for most common measures could be streamlined and transaction costs reduced.

Publicly Owned Utilities

California’s POU energy efficiency programs are also an essential component in managing growing electricity demand and reducing GHG emissions. The more than 40 POU in the state provide nearly one-quarter of California’s total electricity supply; the 15 largest POU represent roughly 95 percent of the POU electricity sales. Similar to IOUs, POU administer programs designed to increase energy efficiency within their territories. POU are organized in various forms, including municipal districts, city departments, irrigation districts, or rural cooperatives.

Following legislative mandates, for almost a decade, the California Municipal Utilities Association (CMUA) has annually filed the *Energy Efficiency in California’s Public Power Sector* status report on behalf of the POU. Energy Commission staff assesses the progress made specifically by POU and discusses efforts to help POU increase the amount of energy efficiency in their service territories.

POU Annual Program Expenditures and Savings

In 2014, POU spent a combined \$170 million on energy efficiency programs, a 26 percent increase over 2013. The POU’s electricity savings totaled 625 GWh in 2014, an

54 CPUC, *Order Instituting Rulemaking Concerning Energy Efficiency Rolling Portfolios, Policies, Programs, Evaluation, and Related Issues*, November 21, 2013, <http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M081/K631/81631689.PDF>.

Table 3: 2013 and 2014 POU Efficiency Savings and Expenditures

	2013	2014
LADWP		
Electricity Savings (Gigawatt hours)	171	252
Demand Reduction (Megawatt)	23	35
Efficiency Expenditures (\$ Millions)	\$50	\$78
SMUD		
Electricity Savings Gigawatt hours	174	142
Megawatt	27	25
Efficiency Expenditures (\$ Millions)	\$35	\$41
34 Other POU*s		
Electricity Savings (Gigawatt hours)	176	231
Demand Reduction (Megawatt)	39	50
Expenditures (\$ Millions)	\$49	\$51
POU Total		
Electricity Savings (Gigawatt hours)	521	625
Demand Reduction (Megawatt)	89	110
Efficiency Expenditures (\$ Millions)	\$134	\$170

Source: Reported electricity savings are from the California Municipal Utility Association's Annual Reports that have not been independently evaluated.

*While there are more than 40 POU's within California, electricity savings of 36 reporting POU's are assessed by the Energy Commission staff.

increase of 20 percent over 2013. POU's also reported a combined 110 MW in peak demand savings, a 24 percent increase over 2013.

After a few years of leveling off, the POU's' annual energy efficiency program expenditures are now at the highest point since 2006.⁵⁵ The two largest POU's, Sacramento Municipal Utility District (SMUD) and Los Angeles Department of Water and Power (LADWP), jointly represent more than half (55 percent) of total POU retail electricity sales. As shown in Table 3, these two largest POU's reported combined expenditures of nearly \$120 million and roughly 394 GWh in electricity savings. Of the remaining 34 POU's that report expenditures and savings to the Energy Commission, 13 reported increased

expenditures, and 21 reported decreased expenditures. The reasons for year-to-year changes in expenditures and reported electricity savings differ for each utility and depend on its unique characteristics, such as customer base, geographic location, and size.

LADWP, the largest POU in the nation, continued implementation of more than 20 energy efficiency programs, including the launch and ramp-up of three major direct install programs for low-, moderate-, and fixed-income customers, both residential and non-residential. These include the Home Energy Improvement Program, Small Business Direct Install, and the Los Angeles Unified School District Direct Install Program.

Although SMUD, the second largest POU in California, added almost 4,000 new customers in 2014, electricity sales for the year remained relatively flat.⁵⁶ SMUD also

55 Previous peak of \$146 million in POU's' program expenditures was in 2009. *Energy Efficiency in California's Public Power Sector Status Report, March 2015* at <http://cmua.org/wpcmua/wp-content/uploads/2015/03/2015-FINAL-SB-1037-Report.pdf>.

56 SMUD, *2014 Annual Report*, <https://www.smud.org/en/about-smud/company-information/documents/2014-annual-report.pdf>.

reported a \$6 million increase in efficiency expenditures compared to 2013, while electricity savings in 2014 decreased by 18 percent.

Unlike the IOUs, for which the CPUC can report evaluated savings, the POU's do not yet have uniform post-program EM&V methods, making it challenging to gather and analyze the actual results. Therefore, Energy Commission staff continues working toward improving consistency and uniformity of post-program savings estimates reported by POU's as directed in previous *IEPRs*. The CMUA recently sponsored a *Technical Reference Manual* that "provides the methods, formulas, and default assumptions used for estimating energy savings and peak demand impacts from energy efficiency measures and projects."⁵⁷ With the enactment of SB 350 and the objective of doubling energy efficiency savings, greater collaboration among the Energy Commission, utilities, and a growing list of stakeholders will be critical in assessing whether existing EM&V approaches to post-program reporting are adequate, or if a new direction is needed that will include the measurement of POU's GHG reductions.

POU Progress Toward 10-Year Goals

Following legislative mandates, the Energy Commission adopted POU energy efficiency targets in 2007 of 6,630 cumulative GWh by 2016 – roughly two-thirds of POU's economically feasible savings estimated through that year.⁵⁸ Assuming a linear trajectory toward this 2016 goal, the cumulative eight-year (2007–2014) electricity savings target for 36 POU's is 5,049 GWh. The POU's reported combined electricity savings of 3,809 GWh represents roughly 75 percent of the 2014 benchmark. SMUD and LADWP combined achieved roughly 72 percent of their

cumulative 2014 benchmark, while the other 34 POU's achieved roughly 82 percent.

In 2013, the CMUA submitted a 10-year (2014–2023) energy efficiency potential study coordinated on behalf of multiple POU's.⁵⁹ Using the Energy Efficiency Resource Assessment Model, the study developed updates for 36 POU's, excluding LADWP. Nexant Inc. subsequently conducted a separate energy efficiency potential study for LADWP in 2014, which determined that 15 percent electricity savings based on sales forecast by 2020 is attainable cost-effectively below the avoided cost of generation.⁶⁰

Studies of energy efficiency potential typically involve three types of energy savings potential: technical, economic, and market. "Technical potential" represents the complete penetration of efficiency measures where they are technically feasible to install. "Economic potential" represents the portion of technical potential that is cost-effective as defined by the results of the Total Resource Cost test. The test calculates the present value of the benefits produced by the programs to the total program administration costs and customer costs incurred to invest in the increased levels of efficiency.⁶¹ There is some discussion about the appropriateness of the TRC test, which may overweight customer costs attributed to energy efficiency, given that customers adopt measures for a variety of diverse reasons, within which energy efficiency may be only a small part. Finally, "market potential" is the portion of economic potential achievable when program designs, customer preferences, and market conditions are incorporated. With a few exceptions, the POU's used the market potential as their officially adopted targets for 2014–2023.

57 Energy & Resource Solutions, *Savings Estimation Technical Reference Manual for the California Municipal Utilities Association*, May 5, 2014. Available at: http://cmua.org/wpcmua/wp-content/uploads/2014/05/CMUA-_TRM-manual_5-5-2014_Final.pdf.

58 *Achieving All Cost-Effective Energy Efficiency for California*, December 2007, <http://www.energy.ca.gov/2007publications/CEC-200-2007-019/CEC-200-2007-019-SF.PDF>.

59 *Energy Efficiency in California's Public Power Sector Status Report*, March 2013, <http://cmua.org/wpcmua/wp-content/uploads/2013/03/FINALv3-SB-1037-AB-2021-Report-Appendices.pdf>.

60 *LADWP Territorial Potential Draft Report Volume 1*, Nexant, June 24, 2014.

61 *Total Resource Cost* benefits include avoided costs of generation, transmission and distribution investments, as well as avoided fuel costs due to energy conserved by energy efficiency programs.

Table 4: 2014–2023 Cumulative Efficiency Savings Potential for Publicly Owned Utilities

	Technical	Economic	Market	Target
LADWP				
Electricity Savings Potential (Gigawatt hours)	8,813	5,877	6,958	3,596
Demand Reduction Potential (Megawatt)	3,205	1,371	1,773	-
SMUD				
Electricity Savings Potential (Gigawatt hours)	4,145	3,017	1,862	1,824
Demand Reduction Potential (Megawatt)	2,016	1,532	771	-
34 Other POU				
Electricity Savings Potential (Gigawatt hours)	7,992	7,105	2,132	1,946
Demand Reduction Potential (Megawatt)	2,328	1,648	540	-
POU Total				
Electricity Savings Potential (Gigawatt hours)	20,950	15,999	10,952	7,366
Demand Reduction Potential (Megawatt)	7,549	4,551	3,084	-

Sources: CMUA, Energy Efficiency in California’s Public Power Sector Status Report, March 2013 <http://www.ncpa.com/~ncpa/wp-content/uploads/2015/02/FINALv3-SB-1037-AB-2021-Report-Appendices.pdf>. LADWP Territorial Potential Draft Report Volume 1, Nexant, June 24, 2014

Table 4 summarizes these respective estimates and targets for LADWP, SMUD, and other POU. For 2023, the POU in combination set a target of achieving roughly 46 percent of their estimated “economic potential” savings. This is comparatively lower than their combined 2007 goal, which represented roughly two-thirds of “economic potential” for 2016. This may be attributable to POU anticipating that they will exhaust more of their current means for achieving energy efficiency savings.

California Clean Energy Jobs Program

California voters passed the California Clean Energy Jobs Act (Proposition 39) in November 2012. The initiative changed California’s corporate tax code and allocates projected revenue to the General Fund and the Clean

Energy Job Creation Fund for five fiscal years, beginning in fiscal year 2013/2014. The goal of the act was to create jobs, and promote and provide funding for eligible energy projects, such as equipment upgrades, other efficiency improvements, and clean energy generation. The enabling legislation, Senate Bill 73 (Committee on Budget and Fiscal Review, Chapter 29, Statutes of 2013), focused the effort on schools (K–12 and community colleges) and designated most of the incoming funds to formula-based grants. The Legislature also allocated \$56 million to the Energy Conservation Assistance Act (ECAA) loan program over fiscal years 2013/14 and 2014/15 for low-interest and no-interest revolving loans and technical assistance.⁶² The Proposition 39 program will continue for eight years, with five years of disbursements from fiscal year 2013/14 through 2017/18 plus up to three additional years for completion of projects and reporting from recipients to the Energy Commission.

62 See www.energy.ca.gov/efficiency/proposition39/ for a list of approved Energy Expenditure Plans, a list of approved ECAA loans, frequently asked questions, assistance, and list server subscription.

The Energy Commission developed and administers the Proposition 39 K–12 program. Under this program, California local education agencies (LEAs), representing public school districts (K–12), charter schools, county offices of education, and state special schools, are allocated funds each fiscal year as determined by the California Department of Education based on student enrollment and participation in the free and reduced price lunch program. The LEAs submit Energy Expenditure Plans (EEPs) detailing their proposed projects to the Energy Commission based on this funding amount.

For fiscal year 2014/15, there were 2,078 eligible LEAs, ranging from a classroom of fewer than 10 students to an enormous school district of nearly 900,000 students. Given the tremendous diversity – in size, geography, climate, facility conditions, and more – the Energy Commission made it a priority to create a program with sufficient flexibility to meet the needs of each LEA. For example, LEAs have the option to:

- » Request fiscal year funding for energy planning.
- » Request retroactive funding of energy projects.
- » Submit single or multi-year EEPs.
- » Submit one EEP for the five-year period.

The Energy Commission reviews the submitted EEPs and, upon approval, notifies the California Department of Education, which then disburses the allocated funds. The funding is guaranteed for the five-year period and has a fiscal year rollover through June 30, 2018. LEAs have two additional years, until June 30, 2020, to complete their approved energy projects and another year to submit final reporting.

The Energy Commission focused on measures most prevalent in schools and likely to achieve expected savings. Eligible projects include the installation of:

- » Lighting and lighting controls.
- » Heating, ventilation, and air-conditioning systems, such as new rooftop units, chillers, boilers, and furnaces.
- » Pumps, motors, and variable-frequency drives.
- » Energy management systems, programmable/smart thermostats, and chiller controls.
- » Equipment for reducing plug load, such as power management and vending machine misers.
- » Building envelope energy-saving measures, such as more efficient windows and cool roofs.
- » On-site clean energy generation, such as solar PV.

Since April 2014, more than 641 LEAs (representing 2,319 sites) have requested a combined \$469 million. To date, 526 have been approved, totaling \$362 million in funding for 1,757 sites. Nearly 80 percent of LEAs (1,646 of 2,078 LEAs) requested energy planning funds in the first year and are in the planning stage, taking this time to identify and develop energy projects.

Education and Outreach Efforts

To promote full school participation and to gain further insight regarding program hurdles, the Energy Commission has developed and is implementing an ambitious outreach plan, including a Proposition 39 (K–12) program Web page, statewide training and educational seminars, ongoing list service announcements, social media program updates, and project representation published on the California Climate Investment Map. Energy Commission staff also targets outreach to the largest and smallest LEAs and to those in disadvantaged communities, offering relevant technical assistance and support.

Energy Conservation Assistance Act – Educational Subaccount (ECAA-Ed)

Separate from the Proposition 39 (K–12) program, the Legislature provided about \$56 million toward the ECAA-Ed subaccount. Of this amount, the Energy Commission allocated 90 percent of the funds, or \$50.4 million, to zero percent interest rate loans. As of July 2015, the Energy Commission had received 34 ECAA-Ed loan applications and had approved 24 of them, representing a total of \$39 million. (An additional six applications totaling more than \$10 million are still in review.) These funds will go toward lighting retrofit, HVAC upgrades, controls, energy generation, and other energy efficiency upgrades. The estimated cost savings for the approved projects is about \$3 million dollars per year, based on estimated annual reductions of about 17.6 GWh of electricity demand and 36,000 therms of natural gas demand. This equates to estimated GHG reductions of about 6,282 tons per year.

The remaining \$5.6 million from the ECAA-Ed subaccount, or 10 percent of the total allocation, supports the Bright Schools Program. The Bright Schools Program provides contractor-supported energy audits for up to \$20,000 of technical service per application. These audits identify eligible energy efficiency projects, informing and easing the EEP application process. Though the Bright Schools Program has been a successful program for many years, there was a marked increase in applications for energy audits and technical assistance due to Proposition 39. Since the start of Proposition 39, the Energy Commission has received 126 applications under the Bright Schools Program. Final audit reports have been completed for 63, with applications or draft reports pending for the remainder.

Developing Proposition 39 Data

Access to energy consumption data is critical for understanding baseline conditions of the state's schools, as well as for performing Proposition 39 program impact assessments. LEAs agree to share their consumption data

with the Energy Commission as a condition of receiving their Proposition 39 allocation. The Energy Commission developed working partnerships with IOUs and large POUs for timely transfer of interval energy use and billing data. The partners created a Common Utility Data Release Authorization form, in machine-readable format, in order to eliminate transcription and input errors. The data submission will ensure pre- and post-installation energy data are available at the site level. This data transfer and management infrastructure is a foundational resource that can be used for other initiatives for which the Commission requires bulk data transfer.

The secure data repository will be updated each year with the latest data with appropriate levels of information, provided to the Citizens Oversight Board, posted on a public website, and used in evaluating impacts from Proposition 39.

Related Proposition 39 Programs

In addition to the K–12 program administered by the Energy Commission, funding from Proposition 39 also created relevant programs administered by the California Conservation Corps (CCC) and the California Community Colleges Chancellor's Office. The CCC's Energy Corps Program simultaneously serves the goals of providing energy industry training and experience to young adults and returning veterans as well as reducing energy costs for LEAs. Under Proposition 39, the CCC provides no-cost and low-cost energy efficiency and renewable energy services directly to LEAs. Additionally, corpsmembers can collect energy survey data from schools and school district facilities, which are provided to the LEAs to help develop their aforementioned EEPs. As of November 2015, CCC lighting and controls retrofits of LEA facilities were expected to save more than 300 MWh per year, and more than 400 corpsmembers had completed survey training to allow the completion of more than 1,000 energy surveys.

The California Community Colleges Chancellor's Office developed guidelines for implementing Proposition 39 on behalf of California's community college system,

conducted outreach on the funding's benefits and requirements, and identified tools for campuses to prioritize qualifying energy projects (including enrollment in Energy Star's Portfolio Manager). California community colleges have received approximately \$123 million in Proposition 39 funds over the initial three years. As of October 2015, funding for the community colleges supported nearly 600 projects, with anticipated energy savings of roughly 60 GWh and 1.3 million therms totaling roughly \$9 million in energy cost savings. As of January 2016, 180 closed-out projects had received \$44 million, with 24.5 GWh of verified electricity savings and 356 thousand verified therm savings contributing to \$3.4 million in annual energy cost savings. Additional program funds support the training of students to install and maintain energy efficient structures and equipment. As of January 2016, more than 7,300 students statewide had enrolled in energy efficiency courses at their regional community college.

Citizens Oversight Board

The California Clean Jobs Act and subsequent legislation established the Citizens Oversight Board, consisting of nine members appointed by the Treasurer, Controller, and Attorney General (three each), plus ex officio members of the CPUC and Energy Commission (one each). The Board is required to meet at least four times per year, or as often as the Chair or Board deems necessary to conduct its business, in accordance with the state's Bagley-Keene Open Meeting Act.⁶³ The first three appointees were selected by the Treasurer in October 2013. The State Controller appointed three nominees in January 2014, and the Attorney General selected the final three appointees in October 2014. At the first Board meeting on September 8, 2015, the Board elected its chair and vice chair and received an update from Energy Commission staff on implementation of the Proposition 39 program to date. At its second meeting the Board heard about status and accomplishments of the main institutional partners,

63 California Government Code Section 11120 et seq.

including the California Department of Education, the community colleges, and the California Conservation Corps. The Board is responsible for reviewing expenditures from the Job Creation Fund, commissioning audits to assess the effectiveness of expenditures, publishing a complete accounting of all expenditures each year, and providing feedback on any necessary changes to the Legislature. These requirements are part of an annual report to the Governor, Legislature, and the public, to be completed within 90 days of the end of the calendar year.

Accomplishments

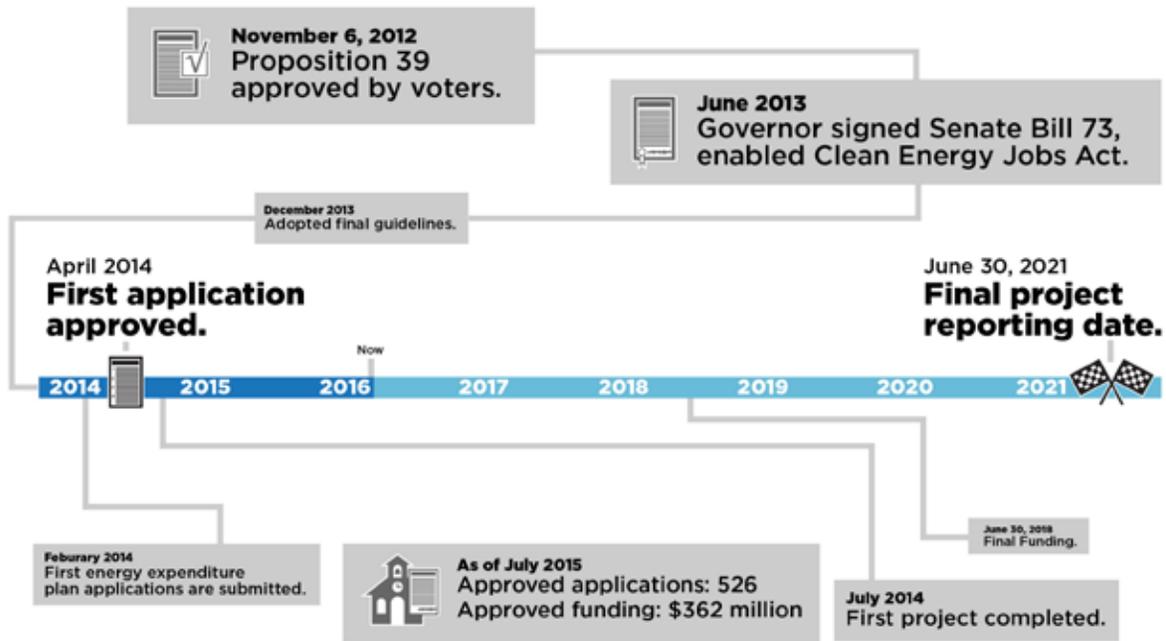
The Proposition 39 (K-12) program formally kicked off just six months after Governor Edmund G. Brown Jr. signed SB 73, with the Energy Commission's adoption of the program guidelines.⁶⁴ Figure 8 illustrates the Proposition 39 (K-12) program timeline from voter approval of Proposition 39 in November 2012, to LEA final project completion reports due by June 2021.

In July 2013, the Energy Commission initiated a comprehensive public process to gain input for the draft guidelines. This process included focus group meetings, five public meetings, and three webinars on the draft guidelines to answer questions and receive comments. These outreach efforts resulted in more than 500 participants and 175 docket submittals. On December 19, 2013, the Energy Commission adopted the *Proposition 39: California Clean Energy Jobs Act – 2013 Program Implementation Guidelines*.

Continuing on this expedited program implementation path, in January 2014, the Energy Commission launched the Proposition 39 (K-12) program and released the *Energy Expenditure Plan (EEP) Handbook*, established an

64 Haile Bucaneg, Pierre duVair, Cheng Moua, Justin Regnier, Keith Roberts, Elizabeth Shirakh, Joseph Wang. 2013. Proposition 39: California Clean Energy Jobs Act –2013 Program Implementation Guidelines. California Energy Commission, Energy Efficiency Division. Publication Number: CEC-400-2014-022-CMF. <http://www.energy.ca.gov/2014publications/CEC-400-2014-022/CEC-400-2014-022-CMF.pdf>.

Figure 8: Proposition 39 Timeline



Source: California Energy Commission.

electronic submission process, provided webinars and training seminars reaching more than 800 LEAs, and established a Proposition 39 (K-12) Hotline contact center.

The first applications started flowing into the Energy Commission in February 2014. By June 2014, the end of the first fiscal year, 2013/14, the Energy Commission had approved 33 EEPs, totaling \$16 million dollars. Some LEAs that submitted these early applications have already completed projects, achieving energy savings from their Proposition 39 energy investments within months of the program launch.

The Energy Commission continued to fast-track the program in the second fiscal year, 2014/15, while responding to school needs by launching an online EEP application system and revising the Guidelines in response to ongoing feedback from schools and their project partners. For this second fiscal year, more than 400 EEPs were approved, totaling \$257 million dollars.

As of the beginning of the third fiscal year, 2015/16, the total estimated annual energy cost savings are more

than \$25 million. This amount represents projected annual energy cost savings when all the approved energy projects are completed, and the total estimated job-years created when all energy projects are completed are estimated at 1,700 job-years.⁶⁵ These energy project implementation jobs include construction, installation contractors, vendors and purchasers, and school employees. As the project flow ramps up across the majority of eligible LEAs, these numbers will rise accordingly.

⁶⁵ A *job-year* is defined as a full-time job that lasts for one year – not one permanent job. A review of studies on labor intensity of energy efficiency projects indicates that on average 5.6 direct job-years are created per \$1 million invested for energy efficiency retrofits. A review of two studies on solar photovoltaic labor intensity indicates that on average 4.2 direct job-years are created per \$1 million invested for solar energy generation system installation. See Zabin and Scott, *Proposition 39: Jobs and Training for California's Workforce*, p. 11, http://www.irle.berkeley.edu/vial/publications/prop39_jobs_training.pdf. Reported in the Energy Commission's *Tracking Progress*, updated August 31, 2015, http://www.energy.ca.gov/renewables/tracking_progress/index.html.

Zero-Net Energy

The Energy Commission's policy recommendations for newly constructed low-rise homes to be designed and constructed to be ZNE were discussed in the *2007 IEPR*, *2011 IEPR*, and *2013 IEPR*. These policies are supported by the CPUC in the *Long-Term Energy Efficiency Strategic Plan*, by California Air Resources Board (ARB) in the *First Update to the Climate Change Scoping Plan*, and in Governor Brown's *Clean Energy Jobs Plan*.⁶⁶ Governor Brown's Executive Order B-18-12 calls for all newly constructed state buildings and major renovations that begin design after 2025 be constructed as ZNE, as well as 50 percent of the square footage of existing state-owned building area to be ZNE by 2025.⁶⁷

In the *2013 IEPR*, the Energy Commission adopted a definition for ZNE Code Buildings, developed in collaboration with the CPUC. This ZNE definition calls for a building to include on-site renewable energy generation that offsets the time-dependent value of the energy used in the building. However, the published definition inadvertently contained an error, in describing energy using two different metrics. To clarify that both the energy generated and consumed should be described in the same metric, the following revision to the definition is proposed:

*A ZNE Code Building is one where the **value of the net amount of energy produced by on-site renewable energy resources is equal to the value***

of the energy consumed annually by the building, at the level of a single "project" seeking development entitlements and building code permits, measured using the California Energy Commission's Time Dependent Valuation metric. A ZNE Code Building meets an Energy Use Intensity value designated in the Building Energy Efficiency Standards by building type and climate zone that reflect best practices for highly efficient buildings.

The amount of renewable generation necessary to designate a ZNE Code Building will vary with multiple factors, including building efficiency, plug-in load use, and climate zone. These factors are captured in Figure 9, which shows the estimated amount of PV generation capacity necessary for a building to meet the adopted definition of ZNE. The graph also shows two additional levels of increased building efficiency and the estimated contribution from loads not directly regulated by the Standards (not including electric vehicle charging).

The *2013 IEPR* made the following recommendations as interim steps toward achieving the 2020 residential ZNE goal, with recent progress identified in italics.

- » Increase efficiency by 20–30 percent with each building standard update. *The Energy Commission accomplished this through adoption of the 2016 BEES.*
- » Develop industry-specific training and financial incentives to advance reach standards; coordinate new utility construction and emerging technology programs. *The CPUC and IOUs are putting this in place, in coordination with the Energy Commission.*
- » Track market progress on ZNE construction. *IOUs developed the Residential ZNE Market Characterization Study.*⁶⁸

66 CPUC, *California Energy Efficiency Strategic Plan*, January 2011 Update, http://www.cpuc.ca.gov/NR/rdonlyres/A54B59C2-D571-440D-9477-3363726F573A/0/CAEnergyEfficiencyStrategicPlan_Jan2011.pdf.

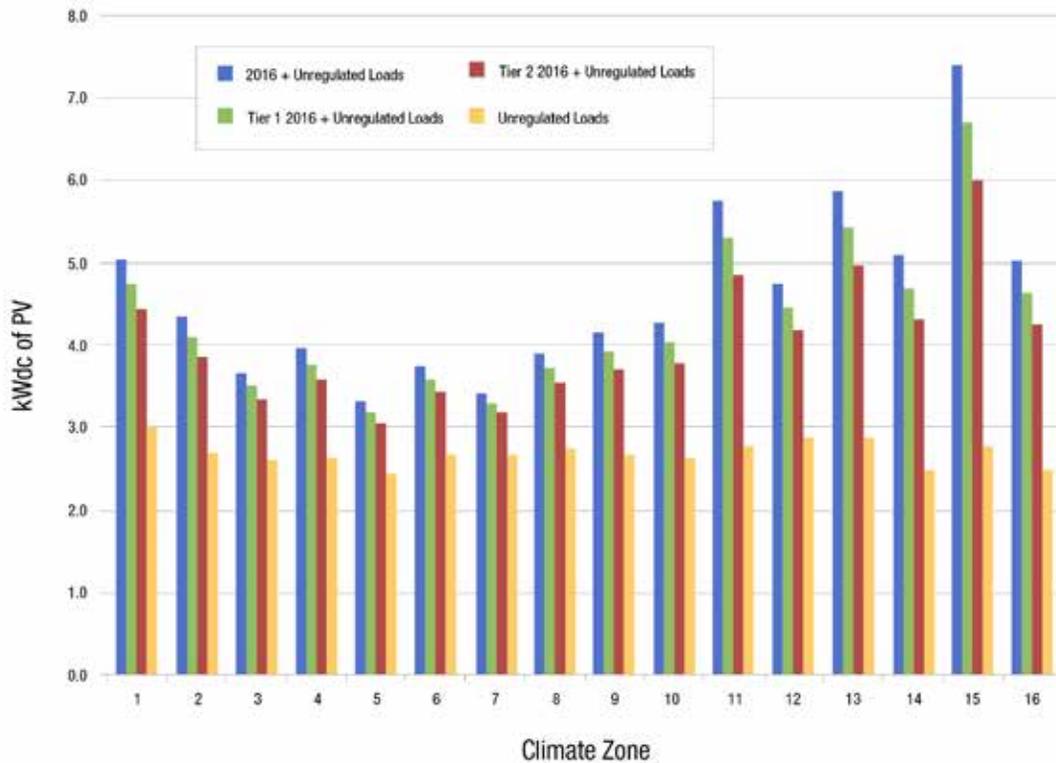
ARB, *First Update to the Climate Change Scoping Plan*, May 2014, http://www.arb.ca.gov/cc/scopingplan/2013_update/first_update_climate_change_scoping_plan.pdf.

Governor's Office of Planning and Research, *Clean Energy Jobs Plan*, http://gov.ca.gov/docs/Clean_Energy_Plan.pdf.

67 Governor Edmund G. Brown, Executive Order B-18-2012, April 25, 2012, <http://gov.ca.gov/news.php?id=17508>.

68 California Measurement Advisory Council, *Residential ZNE Market Characterization Study*, February 2015, <http://www.calmac.org/AllPubs.asp>.

Figure 9: Estimate of PV Capacity Required for ZNE Code Buildings



Source: California Energy Commission staff presentation at May 18, 2015, IEPR workshop.

- » Develop a workforce to build ZNE buildings. *The Energy Commission’s Electricity Program Investment Charge program released a solicitation for development of an energy-efficient building workforce (GFO-15-302).*
- » Add a voluntary tier for ZNE to 2016 California Green Building Standards. *Developed by the Energy Commission staff and approved by the Energy Commission. Awaiting adoption by the Building Standards Commission.*
- » The 2013 IEPR also highlighted some issues that required further discussion and that must be addressed to meet ZNE goals. Those issues included:
 - » Identifying pathways of compliance for buildings where onsite renewables aren’t feasible.
 - » Developing viable accounting and enforcement mechanisms for offsite renewable projects used to meet ZNE requirements.
 - » Educating the public about the benefits of and clarifying the correct expectations for ZNE buildings.
 - » Identifying the appropriate role of natural gas in the development of ZNE buildings (required by Assembly Bill 1257 [Bocanegra, Chapter 749, Statutes of 2013]).
 - » Updating TDV-weighted energy calculations with refined electricity and natural gas information and costs.
 - » Refining and updating the plug load assumptions used to determine the amount of renewables needed for a residential building to reach ZNE.

The Energy Commission works with stakeholders to develop solutions for these issues and will continue doing so going forward. For example, the Commission worked closely with the CPUC on developing the *New Residential ZNE Action Plan 2015–2020 (ZNE Action Plan)*⁶⁹ and is working with several California utility providers to develop training and incentive programs for builders seeking to install the high-performing walls and attics that will be critical cost-effective elements for enabling homes to achieve ZNE. Ongoing collaborations will include updating the calculation of TDV for 2019 to account for any changes that may be appropriate given changes in residential rate policies and refined estimates of plug loads in new homes.

To educate the public about the benefits of ZNE Code buildings, the Energy Commission will need to work with stakeholders to develop education and outreach materials on the Standards and ZNE buildings for consumers, contractors, building departments, builders, and others in the industry that addresses each audience's specific needs and questions. This will include setting proper expectations that a ZNE Code Building cannot guarantee a zero-energy bill. ZNE designs occur long before occupancy and so must be based on average behavior; however, very few occupants behave in a consistently *average* way. The CPUC is supporting this effort with the *ZNE Action Plan* by laying out a framework for building demand and awareness and identifying leaders to help articulate the benefits of ZNE Code buildings to the public.

For newly constructed low-rise homes that cannot accommodate onsite renewables, alternative compliance pathways that enable such buildings to meet ZNE Code building requirements must be developed. The ZNE Code Building definition anticipates considering “development entitlements” for off-site renewables, as a potential option for builders and developers. The ZNE definition clearly

allows community solar as a possibility; approaches need to be identified that would make it administratively workable and cost-effective. Any option that relies on off-site renewable resources must allow for building department verification to ensure that the identified resources exist, that they are the correct size for offsetting the energy use of the buildings they are assigned to, and that their output of these resources is not already “spoken for” by other approved developments.

For more discussion of reliability issues associated with renewable energy, see Chapter 2.

Issues Regarding Natural Gas Use in ZNE Buildings

ZNE cannot be achieved without carefully addressing the natural gas energy use that is prominent in today's buildings. This is particularly true in homes, as roughly 18.5 percent of the natural gas delivered in California is typically used for residential space and water heating, and cooking.⁷⁰ One potential way to address this situation would be to identify strategies to offset residual natural gas usage, for example, by using waste heat in lieu of natural gas (including CHP) or by using renewable gas resources, either at the building site or on a community basis. Offsite strategies such as community-level facilities might rely on a system similar to the previously discussed “development entitlements” for off-site PV.

Another way to reach ZNE is to replace natural gas appliances, such as gas stoves, water heaters, and space conditioning units, with electric appliances; such fuel-switching is called “electrification.” Under a substantially lower carbon intensity electric grid than exists today, electrification has the technical potential to realize additional GHG emission reduction benefits. However, that is not yet broadly the case because of the predominant amount of electricity in the grid is generated from natural gas combustion. End-use

69 CPUC and Energy Commission, CA Energy Efficiency Strategic Plan, *New Residential Zero Net Energy Action Plan 2015-2020*, June 2015

70 U.S. EIA, Natural Gas Consumption by End Use Database, accessed on June 1, 2015.

natural gas appliances most often represent a lower GHG emission alternative because their efficiencies are higher than power plants, avoiding energy lost in the conversion of heat (from natural gas combustion at a power plant) to electricity and back to heat. End-use natural gas appliances also avoid the major transmission and distribution losses that are inherent in the electricity system.

Today's end-use natural gas applications are typically more cost-effective from a customer perspective than their electric equivalents. The Energy Commission's statutes obligate the Commission to meet specific cost-effectiveness requirements in adopting energy efficiency standards for buildings and appliances. Therefore, under statute, complete building electrification could not be pursued within the *BEES* until the expected consumer life-cycle costs for electric appliances are lower than those of using natural gas. This is unlikely in the near term given the persistently low cost of natural gas. For example, a recent study concluded that mixed-fuel homes have cost and consumer preference advantages over electric-only ZNE homes when compared to a baseline electric-only home.⁷¹

When developing a future revision to the *BEES*, it is important for California to be consistent in including the costs of future GHG policies that affect separate energy supply markets, such that all expected consumer energy costs are considered equally. For example, there are well-established renewable energy policies implemented in California's electricity procurement market, and the expected consumer costs resulting from these policies are included in the cost-effectiveness calculations of the standards. However, there are no commensurate policies specified and implemented in the natural gas supply market. This discrepancy in policies across energy supply markets results in a method that further lowers the energy costs for gas technologies compared to

electricity technologies over the 30-year building lifetime considered in the *BEES*.

In general, further research and analysis are necessary to better understand the trade-offs associated with electrification. For example, a recent July 2015 City of Palo Alto Utility Advisory Commission Memo indicated that it may be cost-effective for its residential customers to switch from natural gas to electric heat pump technologies for water heating, and that space heating with heat pumps is close to being cost-effective.⁷² On the other hand, the same memo indicated that the overall lifetime cost and operation of electric stoves and clothes dryers was more expensive versus natural gas. The Energy Commission should complete the analysis needed to understand what the GHG emission and reduction costs must be for the consumer costs of electricity to be lower than the consumer costs of natural gas, and at what level of average electricity carbon intensity would electrification provide environmental benefits. This analysis includes evaluating the potential similarities and differences between zero-net-energy building policies and zero-net-carbon building policies, the latter of which are proposed in the ARB's *First Update to the Climate Change Scoping Plan*.⁷³

Other Sources of Uncertainty

While for the moment the Energy Commission is on course to develop cost-effective standards for newly constructed ZNE homes by 2020, there remain significant policy uncertainties at both the state and national levels that threaten to limit the success of ZNE implementation. In December 2015 the Federal solar tax credit was extended from 2017 to 2022 which aids PV cost-effectiveness going forward; however, the net costs of solar PV continue to be subject to federal policy. (For more information about the federal tax credit, see Appendix A. For more information about renewables, see Chapter 2.)

71 Navigant Consulting, *Strategy and Impact Evaluation of ZNE Regulations on Gas-Fired Appliances and Phase 1 Technology Report*, March 2015.

72 July 2014 Utility Advisory Board Memo, <https://www.cityofpaloalto.org/civicax/filebank/documents/47998>.

73 ARB, *First Update to the Climate Change Scoping Plan*, May 2014.

The CPUC has the authority to modify the net energy metering (NEM) rules that determine the value to consumers of the energy they produce. Under current NEM rules, most onsite generation receives a full retail offset, for example, the same price as the retail rate that the customer pays for power from the utility. A Proposed Decision from the CPUC would leave the existing reimbursement rate largely in place while also including a “minimum bill” provision. The proposed NEM decision also requires NEM customers to pay an interconnection fee, to pay non-bypassable charges levied on kWh the customer obtains from the utility, and for NEM customers taking service after January 1, 2018, to be on time-of-use rates. If adopted, the decision will only extend the rule to 2019. If the NEM rules were changed, either now or after the expiration of the Proposed Decision, to significantly lower the price that owners of solar homes are paid for electricity not consumed on site the cost effectiveness of solar PV systems could change significantly. Also, publicly owned utilities set their own NEM rules, which can change over time. It will be difficult for the Energy Commission to determine cost-effectiveness for on-site solar PV amid this policy uncertainty.

On the other hand, technological changes are occurring that may positively affect the viability and cost-effectiveness of approaches to achieve zero-net energy. The costs of PVs continue to come down; smart inverter technology is becoming industry standard; battery technology is improving, and costs are coming down. In particular, PVs coupled with batteries may be useful for addressing the issue of excess power simply being added to the grid during times of low onsite use and creating potential oversupply issues.⁷⁴ Also, the efficiency and costs of heat pump water heaters are improving, making them more economically viable. Finally, movement by the

CPUC and some publicly owned utilities toward residential time-of-use rates may complement the potential for load shifting, that is, shifting the timing of demand. Load shifting is likely to be a valuable strategy for achieving zero-net-energy code buildings, and the Energy Commission can develop compliance options that provide TDV credit for such technologies.

Recommendations

Local Government Leadership

» **Continue to support innovation by local government.** Local governments possess key authority and unique community connections that make them a critical partner in gaining ground on energy efficiency, particularly in existing buildings. The Energy Commission has roughly \$8 million in remaining American Recovery and Reinvestment Act funds planned for reallocation to the most deserving and innovative local governments. However, the need far exceeds this sum. Scalable, transferable local government programs should be replicated and expanded.

Data for Informed Decisions

» **Collaborate on data provision efforts.** The Energy Commission and California Public Utilities Commission (CPUC) should collaborate on new data provision efforts to increase both the level and type of building energy efficiency-related project data that are available to both the building industry and the public.

» **Develop standard protocols for meter-based savings verification.** The CPUC and the Energy Commission should establish the measurement and verification protocols needed to make meter-based savings in incentive programs and efficiency procurement programs standard practice.

74 However, the addition of behind-the-meter energy storage would also add a new customer cost to ZNE installations, especially in comparison to current NEM tariffs in which customers are credited for their generation at retail rates.

Commercial and Multi-family Energy Use Benchmarking

» **Require utilities to map utility meters to physical locations.** Building owners often have to gather all meter or account numbers prior to requesting energy usage data from utilities. A database showing which meters correspond to which buildings will greatly streamline the whole-building data request process, and contribute to the success of the benchmarking program being developed under Assembly Bill 802.

Applying *Building Energy Efficiency Standards* to Existing Buildings

» **Wherever possible, simplify standards requirements for additions and alterations.** Many of the current requirements that apply to existing buildings are either based on, or directly identical to, those applying to newly constructed buildings. However, the cost-benefit profile for measures in an existing building project may differ from similar measures in new construction. In reviewing the Standards, the Commission will seek to reflect such market realities. Revisions should reduce the compliance burden and added project cost where there are not commensurate efficiency gains. Such adjustments need not mean a decrease in realized efficiency.

» **Consider tailoring specific standards requirements for multifamily buildings.** The designs of multifamily residential buildings often incorporate both residential and nonresidential sections of the standards. Creating a set of requirements specific to multifamily buildings would provide a clearer recipe for compliance and ensure that what's required of builders makes sense for their buildings. In addition, this effort may uncover new opportunities for efficiency that are unique to multifamily buildings.

» **Develop incentives for existing building efficiency improvements with the CPUC and utilities.** These could include incentives for improving existing buildings at time

of alteration or addition, and encouraging early adoption of updates to the Standards either by local jurisdictions or within specific building projects.

Asset Ratings

» **Increase ease and lower cost of asset ratings.** Significantly reduce the costs of completing the asset ratings mandated by the Home Energy Rating System (HERS) statute.

Assessment Tools

» **Encourage a broader market for building performance assessments.** Update Whole-House HERS Regulations to encourage robust performance assessments. Establish recommended protocols for home energy assessments and a clearinghouse for relevant assessment tools.

Plug-Load Efficiency

» **Expand research into plug-load efficiency.** Focus research on advancing the development and deployment of more efficient consumer devices, including electronics and electronic infrastructure supporting the communication between devices. This research includes developing and testing efficient low-cost components and low-cost energy monitoring technologies, and integration of smart and networked controls. Research should also focus on behavior and system-level efficiency.

» **Consider power-scaling standards for plug-load efficiency.** Consider standards and other strategies to reduce the idle loads of devices that are always on. Develop and test methods to increase on-mode energy efficiency and to enable sleep modes when electronic equipment, such as game consoles and video conferencing systems, is idle.

» **Support improvement in energy monitoring, communication, and remote control infrastructure for plug-load devices.** Among other things, communication protocols will be needed to allow devices to report

data efficiently and flexibly. Enhancement of building controls can allow energy use to be adjusted in response to occupancy.

» **Increase federal collaboration and outreach.**

Participate in federal rulemakings through comments on rulemakings, participate in manufacturer interviews as a source of relevant data, engage in Appliance Standards and Rulemaking Federal Advisory Committee Working Groups on key appliance types, participate in international and national codes and standards development groups, and engage in ENERGY STAR® specification development with the U.S. Environmental Protection Agency. The goal of these efforts is to ensure that the federal standards and specifications yield the most cost-effective and technologically feasible benefits to California as available.

Utility Energy Efficiency Procurement

» **Continue the transition toward “rolling portfolios” of investor-owned utility efficiency programs and update the evaluation measurement and verification (EM&V) process accordingly.** The CPUC plan to improve and accelerate program development and EM&V processes should help align program-related analysis and lessons with the Energy Commission’s forecasting process.

» **Continue to work toward standardized savings reporting by publicly owned utilities (POUs).** The Energy Commission is assessing whether existing EM&V approaches are adequate, or if a new direction is needed to quantify energy efficiency gains and greenhouse gas reductions by POUs.

» **Align the measurement, verification, and value of energy efficiency savings across disparate regulatory proceedings and procurement channels.** To establish a robust market for energy efficiency in California, the value of energy savings from efficiency efforts must be transparent, consistent and usable for investment decisions.

The CPUC, the Energy Commission, and all appropriate market participants should support data infrastructure and analytical tools that provide consistent, reliable understanding of efficiency’s value across procurement, demand response, and efficiency programs.

California Clean Energy Jobs Program

» **Continue efficient administration of the Proposition 39 Program.** Priorities will include outreach to all local educational agencies to ensure full participation, full grant usage, and successful project completion. Update guidelines as necessary to incorporate technical advancements and to address the diversity and needs of local educational agencies. Support the Citizens Oversight Board with information and resources it needs to fulfill its duties including annual reporting and auditing.

» **Leverage data exchange infrastructure.** Oversight of the projects funded under this program will create an opportunity for collecting data on energy efficiency project costs, energy consumption trends, anticipated and actual average savings, and other valuable project information. Where feasible, the Energy Commission and its partners should take advantage of these data in developing other Commission programs and policies.

Zero-Net Energy

» **Continue the progress of building standards that will support ZNE.** Previous *Integrated Energy Policy Reports* have highlighted the ZNE policy goal, and the 2013 and 2016 Standards have furthered progress toward achieving it.

» **Evaluate key differences between ZNE and zero net carbon in new homes.** The Energy Commission’s responsibility for meeting ZNE goals cost-effectively exists in the context of other initiatives, including greenhouse gas emission reduction. Coordinating these parallel efforts could include, for instance, identifying the cost-effectiveness

threshold for ZNE based on anticipated greenhouse gas emission costs, as well as consumer costs.

- » **Characterize the role of natural gas, including biogas, in the ZNE context.** Part of identifying the appropriate role of natural gas will involve identifying the point at which gas is more expensive than electricity for determining cost-effectiveness.

- » **Incorporate CPUC and POU updates of net energy metering into future building standards.** The rules and compensation governing net energy metering have a significant effect on the anticipated lifetime costs and savings associated with photovoltaic systems. This, in turn, affects the Energy Commission's inclusion of them as part of future building standards due to statutory requirements for cost-effectiveness.

- » **Develop an allocation approach for off-site renewables.** This is basic groundwork for meeting ZNE requirements with community-level generation resources. It must by its nature be a collaborative effort with the relevant agencies and local government representatives.

CHAPTER 2

Decarbonizing the Electricity Sector



In his January 2015 inaugural speech, Governor Edmund G. Brown Jr. stated that California is “well on its way” to meeting its goal to reduce carbon pollution to 1990 levels by 2020. The Governor went on to state that “now, it is time to establish our next set of objectives for 2030 and beyond.” One of the goals he put forward is to “increase from one-third to 50 percent our electricity derived from renewable sources” within the next fifteen years.⁷⁵ The Clean Energy and Pollution Reduction Act of 2015 (Senate Bill 350, De León, Chapter 547, Statutes of 2015) codifies reducing greenhouse gas (GHG) requires the adoption of integrated resource plans that reflect any targets for the electric sector that may be adopted by the Air Resources Board to help achieve GHG emission reductions of 40 percent from 1990 levels by 2030. SB 350 also reflects the requirement for the procurement of 50 percent eligible renewable energy resources by December 31, 2030.

California has made impressive advancements in its use of renewable resources. In 2002 when California first enacted its Renewables Portfolio Standard (RPS),

75 The inaugural address is discussed further in the Introduction. The other two goals the Governor identified were “Reduce today’s petroleum use in cars and trucks by up to 50 percent; Double the efficiency of existing buildings and make heating fuels cleaner” which are discussed in Chapters 4 and 1, respectively.

the state used renewable resources to serve 11 percent of its electricity demand. The state has since more than doubled its use of renewables and is poised to serve 33 percent of its electricity use with renewables by 2020.

Moving to 50 percent renewables by 2030 will bring additional GHG benefits, but also new challenges. The president of the California Public Utilities Commission (CPUC), chair of the Energy Commission, and president and Chief Executive Officer of the California Independent System Operator (California ISO) pointed to overgeneration, which occurs when too much electricity is produced at certain times of day when demand is low, as a key challenge as the state works toward the 50 percent renewable goal. Such challenges, however, foster innovation. “More of the same policies will not do the trick.”⁷⁶

Solutions include a regional marketplace that balances supply and demand, time-of-use rates that encourage shifts in when consumers use energy, demand response programs that adjust load to generation availability, zero-emission vehicle deployment that provides incentives to charge vehicles when energy generation is high, and building enhancements

76 Sacramento Bee, “More Renewable Energy Brings New Challenges,” March 14, 2015, <http://www.sacbee.com/opinion/op-ed/soapbox/article13939937.html>.

such as batteries and control systems to better manage energy usage. Also, research and development will help bring new technologies and other innovations needed to meet the 2030 and 2050 GHG reduction goals.

This chapter explores issues and opportunities for reducing GHG emissions from the electricity sector in support of the state's climate goals. It opens with a discussion of GHG emissions from California's electricity system, showing that the sector is already below the 1990 GHG emission level. Since increasing the use of renewable resources is key to meeting the state's climate goals, the chapter then examines the state's progress toward its RPS and other renewable energy goals. Next is a summary of California's progress toward achieving the broad array of actions identified in the *2012 Integrated Energy Policy Report Update (IEPR Update)* Renewable Action Plan that was developed to support further renewable development. The chapter then focuses on the challenges and opportunities to assure reliable electricity supplies as the state moves forward to achieve the 50 percent renewable requirement by 2030. It closes with recommendations for further work. While this chapter is focused on renewable energy, any effort to advance renewables must be part of an overall portfolio that integrates all demand and supply-side resources across sectors to reduce GHG emissions, reduce criteria pollutants and meet other environmental goals, maintain reliability, and control costs.

Greenhouse Gas Emissions From the Electricity Sector

The electricity sector accounts for about 20 percent of statewide GHG emissions, with about half from electricity imported from out-of-state, whereas the transportation sector is the largest source of GHG emissions, accounting for about 37 percent. Consequently, decarbonizing the transportation sector should be a primary focus of

the state's climate goals, and policies in the electricity sector must build on policies to reduce emissions from the transportation sector. For example, new renewable procurement should go hand-in-hand with increased electric loads from electrification of the transportation sector. If they are not in lock-step, then California will not realize the full potential of the GHG reductions from decarbonizing the electricity sector.

The electricity sector has made great strides to advance the state's GHG reduction goals. According to the California Air Resource Board's (ARB's) GHG inventory, electricity sector emissions in 2013 were about 20 percent below 1990 emission levels. The Global Warming Solutions Act of 2006 (Assembly Bill 32, Núñez, Chapter 488, Statutes of 2006) sets a statewide goal to reduce GHG emissions to 1990 levels by 2020. Figure 10 shows the decline in GHG emissions from the electricity sector with the red dashed line showing 1990 level emissions.

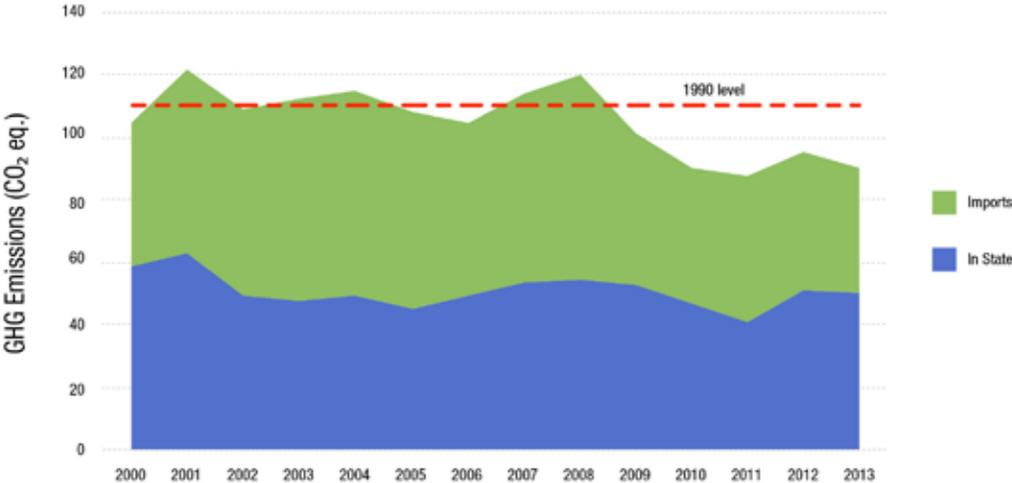
In addition to energy efficiency improvements, the state's policies driving increased renewable procurement and reduced reliance on coal-fired electricity are designed to help reduce GHG emissions from the electricity sector. In the five years from 2008 to 2013, the state has made remarkable progress in that:

- » Coal generation dropped by more than half.
- » Renewable generation almost doubled.

Decline in Coal-Fired Generation

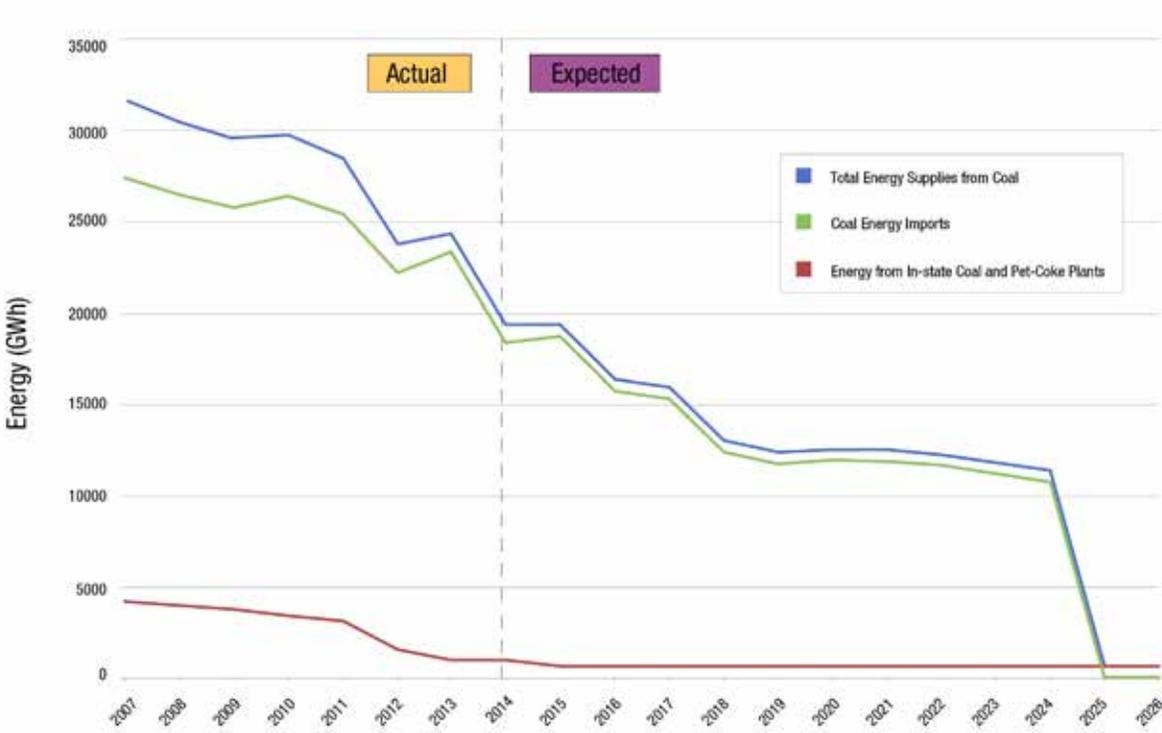
California's Emissions Performance Standard has been a driving force behind the state's significant reduction in the use of coal, a fossil fuel with high GHG emissions. Senate Bill 1368 (Perata, Chapter 598, Statutes of 2006) created the Emission Performance Standard, setting a maximum emissions rate of 1,100 pounds of carbon dioxide per megawatt-hour (MWh) for baseload generation – power plants that run most of the time. The standard applies to baseload generation that is either owned by, or under

Figure 10: Historical GHG Emissions From the Electricity Sector



Source: California Energy Commission staff using data from the ARB's 2013 GHG inventory.

Figure 11: Annual and Expected Energy From Coal Used to Serve California (1996–2026)*



Source: California Energy Commission, CPUC, and ARB presentation at the October 1, 2015, kickoff public workshop on Scoping Plan Update to Reflect 2030 Target, http://www.arb.ca.gov/cc/scopingplan/meetings/10_1_15slides/2015slides.pdf
 *(Includes imports)

long-term (five or more years) contract to, any California load-serving entity and includes restrictions on capital investments that increase generating capacity or extend the life of the project. The standard has been a driving force behind California's utilities ending, or planning to end, affiliations (contracts and/or ownership) with coal- and petcoke-fired generation resources, especially with large out-of-state plants.⁷⁷

Figure 11 shows the decline in the amount of coal-fired electricity serving California from 2007 and over the next decade. In 2014, electricity supplies from existing coal and petroleum-coke plants represented less than 5 percent of total energy requirements to serve California demand, and nearly all of it (93 percent) was from power plants located outside California. By 2026, virtually all electricity generated by known coal- and petroleum-coke-fired generation serving California loads is expected to end.

Increase in Renewable Generation

California has a decades-long history of supporting the development of renewable resources as part of the state's electricity mix. During Governor Brown's first administration in the late 1970s, the CPUC established standard offer contracts for alternative electricity suppliers, including renewable producers, to sell electricity to investor-owned utilities (IOUs) at cost-based rates equal to the buyers' full avoided cost. By the end of 1991, these contracts added more than 11,000 megawatts (MW) to the state's electricity portfolio, about half of which came from renewable resources. California established its RPS in 2002 to continue to diversify the electricity system and reduce dependence on natural gas. The original RPS target was to meet 20 percent of retail sales with renewable resources by 2017, which was subsequently accelerated and expanded to 20 percent by 2010 and

then to 33 percent by 2020. Figure 12 shows the growth in renewable generation in California by resource type from 1983–2014. Overlaid on the graph are some of the policies that helped spur the market.

There are two periods where generation increases are clearly visible: during the 1980s when renewable projects came on-line as a result of standard contracts, and then roughly after 2008, when projects procured in response to the RPS came on-line. The increase in renewable energy generation after 2008 coincides with the decrease in GHG emissions in the electricity sector.

Further growth in renewable energy to achieve the goals of SB 350 can be gained from increased renewable development in-state and regionally, through the planning efforts discussed in Chapter 3. Continued R&D in renewable resources – particularly those that also increase the state's climate resistance – will help advance renewables. A broad portfolio of resources such as biomass; geothermal; solar; wind, including offshore wind; and small-hydro technologies, including in-line distributed generation hydropower, provide opportunities for achieving the state's goals.

Potential Opportunity – Carbon Capture, Utilization, and Storage

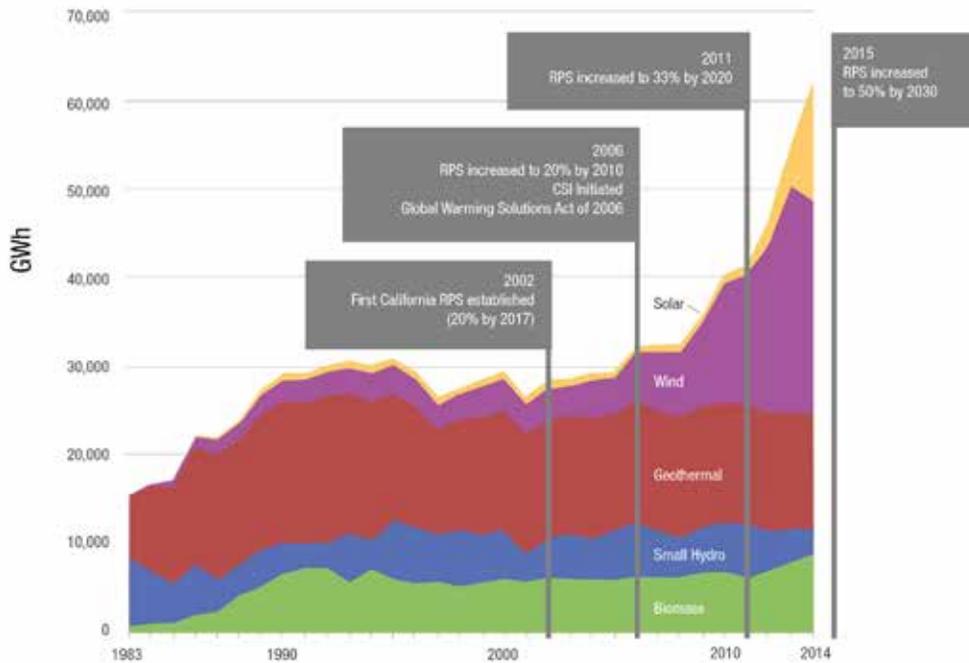
Although the state's strategy to decarbonize the electricity sector is focused on the increased use of renewable resources, another strategy that may help meet California's long-term GHG reduction goals is carbon capture and storage (CCS). CCS technologies have the potential to reduce the carbon dioxide (CO₂) emissions of large-point sources by 90 percent.

The Energy Commission, ARB, CPUC, and other agencies have been collaborating on CCS research, rulemaking, and roles definition since they jointly convened a "blue ribbon panel" on CCS in 2010.⁷⁸ The focus of their collaboration has been on jurisdictional and regulatory issues and the supporting scientific and engineering studies. The ARB is developing an accounting protocol or

77 California Energy Commission, *Tracking Progress – Coal Actual and Expected Energy From Coal for California*, http://www.energy.ca.gov/renewables/tracking_progress/index.html#coal. Updated December 15, 2015.

78 http://www.climatechange.ca.gov/carbon_capture_review_panel/.

Figure 12: California Renewable Energy Generation From 1983-2014 by Resource Type (In-State and Out-of-State)



Source: California Energy Commission. Tracking Progress webpage. *Renewable Energy*. Updated September 3, 2015.

“quantification methodology” to allow geologically stored CO₂ to satisfy AB 32 requirements. The protocol, which is scheduled for possible ARB approval in 2017, may also find use for compliance determinations under the SB 1368 Emission Performance Standard.

Several substantial barriers remain before CCS could be applied to California’s natural gas generation fleet, including technology developments, optimization studies, pilot facilities, and private and public investments. Widespread application of the technology would require additional regulatory and legal frameworks, such as clear, efficient, and consistent regulatory requirements for all phases of CCS such as standards for CO₂ capture, transport, and storage. CCS at natural gas plants is not yet feasible for several reasons, including the fact that the captured carbon must be transported to an appropriate geologic storage site through pipes, for which sites and infrastructure are not readily available.

It is also cost-prohibitive, roughly doubling the cost of building a natural gas power plant. In addition, further technology development is needed to address conditions at many California power plant locations, such as high summer ambient temperature, the limited availability of water, and dry cooling and once-through cooling policies, which result in reduced carbon capture effectiveness and increased parasitic power consumption of the carbon capture equipment.

The Energy Commission developed a research roadmap to guide its CCS research efforts.⁷⁹ The Energy Commission continues to investigate opportunities to reduce the costs and impacts of CO₂ capture for natural gas power

79 Burton, Elizabeth, Kevin O’Brien William Bourcier, and Niall Mateer. 2012. *Research Roadmap of Technologies for Carbon Sequestration Alternatives*. California Energy Commission. Publication Number: CEC-500-2013-024. <http://www.energy.ca.gov/2013publications/CEC-500-2013-024/CEC-500-2013-024.pdf>.

plants through emerging capture technologies that use less energy and water, have a compact site footprint, avoid toxic materials, and provide load-following capability. Such improvements would largely be applicable to oil refineries, cement plants, and large biofuels or agricultural processing plants. With respect to geologic CO₂ storage, the Energy Commission is funding geologists to examine changes in groundwater chemistry in the presence of CO₂, the implications of micro-seismic events, and the risk of larger earth movements at faults. Also important in the overall economics of CCS is the ability to use co-benefits such as using the captured CO₂ in enhanced oil recovery, manufacture of plastics and building materials, biofuels production, and potentially even the reduction of other climate change impacts, such as ocean acidification.

CCS technology demonstration has made progress in the past two years, such as commercial operation of the 110 MW Boundary Dam post-combustion capture project in Saskatchewan and the saline formation storage project in Decatur, Illinois, passing the million-tons-injected mark. Other large-scale CO₂ capture projects are expected to reach operational fruition in 2016. Understanding the lessons from these projects will help determine the true applicability of CCS in the California context.

Renewable Energy Goals

Given the statutory requirement to achieve 50 percent renewables by 2030 as part of the state's strategy to meet the 2030 GHG reduction goal, this section focuses on the growth of the renewable market in recent years and progress toward meeting the state's renewable goals. However, California's success in advancing renewable energy extends beyond its borders. Energy Commissioner David Hochschild emphasized at the May 11, 2015, IEPR workshop on renewable energy that policies like the RPS have provided the market certainty that has allowed

investment to flow into the clean energy sector and bring down costs. California's policies are helping bring technologies to scale for rapid deployment around the nation and the world.⁸⁰

The Energy Commission estimates that nearly 25 percent of 2014 electricity sales were served by wind, solar, geothermal, biomass, and small hydroelectric resources.⁸¹ California is well on its way to meeting the 33 percent renewables by 2020 requirement. In addition, there are about 11,800 MW of new renewable capacity being proposed that have environmental permits and are in preconstruction or construction, indicating continued interest by renewable project developers. Proposed solar photovoltaic (PV) projects account for nearly all of the new renewable energy capacity expected to come on-line in 2016.⁸² Tracking proposed projects is important for transmission planning, which is discussed in the next chapter.

The California Solar Initiative, which was established in 2007, has a goal of installing 3,000 MW of solar energy systems on homes and businesses by the end of 2016, along with 585 million therms of gas-displacing solar hot water systems by the end of 2017.⁸³ In 2015, California surpassed the 3,000 MW mark, about 1.5 years ahead of target.

There are three parts to the 3,000 MW goal:

1. 1,940 MW for IOUs for commercial buildings and existing homes (including low-income programs) as part of the California Solar Initiative.
2. 700 MW for the publicly owned utilities (POUs).

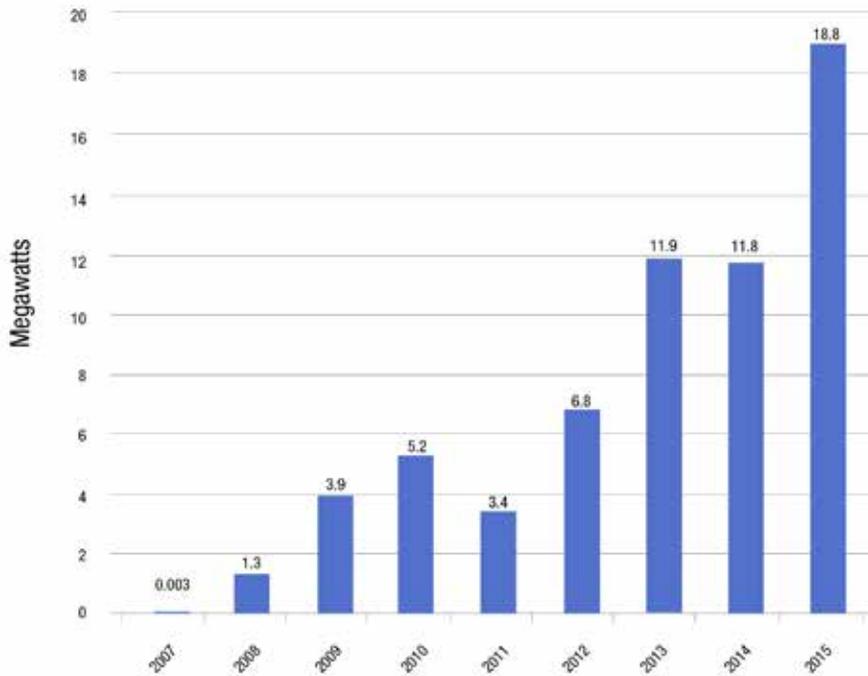
80 May 11, 2015, IEPR workshop transcript, pp. 90–91.

81 California Energy Commission, Tracking Progress, *Renewable Energy*, http://www.energy.ca.gov/renewables/tracking_progress/index.html, pp. 1–2.

82 California Energy Commission, Tracking Progress, *Renewable Energy*, http://www.energy.ca.gov/renewables/tracking_progress/index.html, p. 16.

83 GoSolar California. <http://gosolarcalifornia.org/about/index.php>.

Figure 13: Megawatts Installed Solar Capacity for NSHP, 2007–2015



Source: California Energy Commission

3. 360 MW for IOUs for the New Solar Homes Partnership (NSHP).

As of October 31, 2015, the California Solar Initiative program provided incentives for nearly 1,700 MW of installed capacity and reserved funding for more than 220 MW of pending capacity toward achieving the goal of 1,940 MW for commercial buildings and existing homes in IOU service territories.⁸⁴ The POUs have installed nearly 320 MW toward their 700 MW goal as of the end of 2014.⁸⁵

The NSHP Program has seen tremendous growth in 2015, with more than 6,300 solar systems and 18.8 MW installed this year compared to 3,900 systems and 11.8 MW in 2014. Figure 13 shows NSHP program activity in

terms of MW installed from 2007 to 2015. As of December 2015, the program has resulted in 141 MW of new residential solar either installed or in the pipeline, representing more than 44,000 systems.⁸⁶

The NSHP program assists lower-income residents by providing higher per-watt incentives for eligible residential affordable housing projects with tax-exempt system owners. Since the program began, it has provided \$19 million in rebates for solar on affordable housing, close to 14 percent of total rebate funds paid to date for all projects.⁸⁷

By helping builders become familiar with installing solar energy systems in new construction well in advance of anticipated zero-net-energy requirements, the NSHP Program also provides a critical bridge toward achieving

84 California Energy Commission, *Renewable Tracking Progress*, http://www.energy.ca.gov/renewables/tracking_progress/index.html, p. 14.

85 Ibid.

86 California Energy Commission, *Renewable Tracking Progress*, http://www.energy.ca.gov/renewables/tracking_progress/index.html.

87 California Energy Commission, *Renewable Tracking Progress*, http://www.energy.ca.gov/renewables/tracking_progress/index.html.

Table 5: RPS Progress by Large Investor-Owned Utilities

	RPS Procurement Percent in 2013	Percent of RPS Procurement Currently Under Contract for 2020
Pacific Gas and Electric Company	23.8%	31.3%
Southern California Edison Company	21.6%	23.5%
San Diego Gas & Electric Company	23.6%	38.8%

Source: CPUC website, <http://www.cpuc.ca.gov/PUC/energy/Renewables/index.htm>, accessed October 5, 2015.

California’s zero-net energy goal for new homes. (See Chapter 1 for more discussion of zero-net energy.) This experience should allow a smooth and successful transition for builders and homeowners once standards to implement zero net energy are in place.

Progress has also been made toward the Governor’s 12,000 MW distributed generation (defined here as 20 MW or smaller) target.⁸⁸ California has about 7,200 MW of renewable distributed generation (projects 20 MW or smaller, including both self-generation and wholesale), with another 900 MW in the pipeline and another 2,200 MW that could be developed through existing programs.⁸⁹ Distributed resources produce renewable electricity and are eligible for the RPS to a limited extent, but, because much of the energy generated is used on-site rather than being delivered to the grid, questions remain about the appropriate way to count that generation for RPS compliance.

Investor-Owned Utility Progress

According to the CPUC, as a group California’s three largest IOUs served 22.7 percent of their 2013 retail electricity sales with renewable power. Table 5 shows RPS procurement in 2013 and the percentage of RPS

procurement under contract for 2020.⁹⁰ All IOUs expect to comply with the 2020 RPS requirements.

Electric Service Provider, Community Choice Aggregator, and Other Retail Seller Progress

The electric service providers (ESPs), community choice aggregators (CCAs), and other non-IOU retail sellers also provided 2011-2013 compliance reports to the CPUC that include their RPS-eligible renewable energy credits (RECs)⁹¹ retired as a percentage of the retail sales.

The 11 ESps operating in the 2011–2013 compliance period reported combined RPS retirements of 20.9 percent. The one CCA active in 2011–2013, Marin Clean Energy, reported RPS retirements of 28.7 percent for this period. Although parties have raised concerns about CCAs selling customers “green” electricity composed of unbundled RECs⁹² paired with fossil fuel electricity under a green pricing program, Marin Clean Energy reported RPS retirements of 20.7 percent unbundled RECs for the 2011–2013 compliance period, well under the 25 percent maximum allowed.

88 A *distributed generation system* involves small amounts of generation located on a utility’s distribution system for meeting local (substation level) peak loads and/or displacing the need to build additional (or upgrade) local distribution lines.

89 California Energy Commission, *Renewable Tracking Progress*, http://www.energy.ca.gov/renewables/tracking_progress/index.html, pp. 13–14.

90 Generation claimed toward IOU obligations for the first RPS compliance period (2011–2013) has not yet been verified by the Energy Commission.

91 A *REC* is a renewable energy credit, which represents the green and environmental attributes of one megawatt-hour of electricity from an RPS-eligible renewable energy resource.

92 An unbundled REC is purchased separately from the underlying electricity.

In addition to ESPs and CCAs, there is one small IOU, Bear Valley Electric Services, one multi-jurisdictional utility (MJU), PacifiCorp, and one MJU successor, Liberty Utilities. Bear Valley Electric Services reported REC retirements of 33 percent of retail sales for the 2011–2013 compliance period, PacifiCorp reported 20 percent, and Liberty Utilities reported 21.9 percent.

Publicly Owned Utility Progress

The Energy Commission held an IEPR workshop on May 11, 2015, in which representatives of California’s POUs provided updates on the status of their RPS activities.

Los Angeles Department of Water and Power (LADWP) reported it has about 1,400 MW of renewables in service today, with another 1,256 MW under construction and 2,721 MW planned. LADWP noted it is on a trajectory to achieve the 33 percent by 2020 RPS targets with added generation from roughly 2,100 MW of small hydro, wind, solar, and geothermal projects. Other GHG reduction activities include the utility’s net energy metering program, which has 15,500 customers, a total of 129 MW installed to date, and \$257 million in incentives paid. LADWP has also set goals for 15 percent energy efficiency, 580,000 electric vehicles by 2030, 500 MW of demand response by 2024, and 154 MW of energy storage planned in the same time frame. In terms of a 50 percent renewable target, LADWP noted that when it reaches 33 percent renewables, it will need to curtail about 0.2 percent of that energy due to oversupply; that number rises to 4.6 percent with 50 percent renewables.⁹³

The Sacramento Municipal Utility District (SMUD) stated that from 2003 to 2013, its renewable procurement has grown steadily from a distant third to first among the largest five utilities in the state. SMUD

emphasized its commitment to a diverse portfolio of renewables, which for 2014 includes biomass, biomethane, geothermal, small hydro, solar, and wind. In the first RPS compliance period (2011–2013), SMUD reported that it procured enough renewable energy to exceed the 20 percent target by 3 percent but retired just enough renewable energy certificates to achieve compliance so as to retain flexibility for future retirement. For the second and third RPS compliance periods (2014–2016 and 2017–2020), SMUD indicated it expects to reach 27.5 percent and 30 percent, respectively, without counting any carryover it might have from the first compliance period. SMUD’s focus is on ensuring RPS compliance for 2020, but it is also positioning itself for future renewable requirements. Like LADWP, SMUD is looking at a variety of activities related to reducing GHG emissions, including launching a pilot biomass gasification project, developing better renewable forecasting models and evaluating the effect of geographic variation, examining communications capabilities in PV inverters, looking at managed charging of electric vehicles, and conducting demand response pilots.⁹⁴

The Southern California Public Power Authority (SCPPA) stated that its members “are working very hard towards meeting California’s 33 percent RPS target...and should be on track to meet interim RPS targets through 2020.”⁹⁵ SCPPA noted that some members are exceeding their RPS targets, for example, Pasadena Water and Power and Anaheim Public Utilities, which respectively procured 29 percent and 33 percent renewables in 2014.

The Northern California Power Authority (NCPA) provided several examples of progress made by its

93 May 11, 2015, IEPR workshop transcript. Comments by John Dennis, director of Power System Planning and Development, Los Angeles Department of Water and Power, http://docketpublic.energy.ca.gov/PublicDocuments/15-IEPR-06/TN205042_20150616T143227_May_11_2015_IEPR_Workshop_Transcript.pdf, pp. 223–225.

94 May 11, 2015, workshop transcript, Tim Tutt, government affairs representative with Sacramento Municipal Utility District, pp. 226–234.

95 May 11, 2015, workshop transcript, Tanya DeRivi, Director of Government Affairs, Southern California Public Power Authority, pp. 235–241. A list of publicly owned utilities represented by Southern California Public Power Authority is available at <http://www.scppa.org/>.

members.⁹⁶ The City of Palo Alto anticipates being at 50 percent renewable by 2017 and has a carbon-neutral plan that has been in place since 2013. Alameda Municipal Power and the City of Ukiah have regularly procured more than 50 percent of their energy from renewable resources. For NCPA's smallest members, a request for proposals for 40 MW of solar has been released. However, NCPA members continue to face challenges due to the drought and the effect on snowpack and hydroelectric generation. (For more information about the drought and impacts on electricity generation, see Chapter 8.) NCPA noted that without continued flexibility in RPS requirements for the POUs, it will be virtually impossible for smaller entities to comply.

The California Municipal Utilities Association (CMUA) noted that many of its members have had aggressive renewable goals since before the 33 percent RPS was put in place.⁹⁷ In total, CMUA reported that its members are meeting the 20 percent RPS target for the first compliance period (2011–2013).

50 Percent RPS by 2030

As noted above, SB 350 codified the Governor's goal for 50 percent renewable energy in California by 2030. It established the following targets beyond 33 percent by 2020:

- » 40 percent by the end of 2024.
- » 45 percent by the end of 2027.
- » 50 percent by the end of 2030.
- » No less than 50 percent in each multiyear compliance period thereafter.

Going forward, the energy agencies and ARB will continue to jointly implement the RPS to meet the requirements

96 May 11, 2015, workshop transcript, Scott Tomashefsky, regulatory affairs manager with Northern California Power Authority, pp. 241–254. For a list of Northern California Power Authority members, see <http://www.ncpa.com/>.

97 May 11, 2015, workshop transcript, Tony Andreoni, director of Regulatory Affairs with California Municipal Utilities Association, pp. 254–257. For more information about CMUA, see <http://cmua.org/>.

of SB 350 for 50 percent renewables by 2030. The CPUC has oversight responsibilities with respect to retail seller RPS compliance, and the Energy Commission and ARB have compliance oversight and penalty responsibilities, respectively, for the POUs.

By January 1, 2017, SB 350 also requires the Energy Commission, in consultation with other state agencies, to study the barriers and opportunities for access to solar PV generation in disadvantaged communities, as well as barriers to, and opportunities for, access to other renewable energy sources by low-income customers. The Energy Commission is also required to study the barriers to local small businesses in disadvantaged communities by January 1, 2017.⁹⁸

Renewable Action Plan Status

In 2013, the Energy Commission released a Renewable Action Plan as part of the *2012 IEPR Update*. The Renewable Action Plan built on suggested strategies to support renewable development that were described in a *2011 IEPR* subsidiary report titled *Renewable Power in California: Status and Issues*. That report was prepared in response to Governor Brown's direction in 2010 to the Energy Commission to prepare a plan to "expedite permitting of the highest priority [renewable] generation and transmission projects." The intent was to support investments in renewable energy that would create new jobs and businesses, increase the state's energy independence, and protect public health.

The *Renewable Power in California: Status and Issues* report identified five overarching strategies to support renewable energy:

98 Public Resources Code Section 25327 (b).

1. Identify high-priority areas in the state for renewable development.
2. Evaluate the costs and benefits of renewable projects.
3. Reduce the time and cost of renewable interconnection and integration.
4. Promote incentives for renewables that create in-state jobs and economic benefits.
5. Coordinate state and federal financing and incentive programs for critical stages in the renewable development continuum, including research, development, demonstration, precommercialization, and deployment.

These strategies formed the basis for the recommendations in the Renewable Action Plan. This section provides an overview of recommendations in the plan on which California has made the most progress, as well as recommendations needing additional work. Appendix A provides more detail on the progress made on each recommendation.

Action Items Showing Most Progress

Recommendations on which California has made significant progress since 2013 include the following:

- » **Incorporate distributed renewable energy development zones into local planning processes:** Multiple efforts are underway to support this recommendation.
 - » On July 1, 2015, IOUs submitted distribution resource plans to the CPUC. These plans identify prime locations for renewable distributed generation and other distributed resources from the utilities' perspective,

which will help developers select high-value locations for their projects.⁹⁹

- » IOUs have also posted maps on their websites as part of the Renewable Auction Mechanism feed-in tariff to assist project developers in determining what areas on the utility system where capacity for distributed generation (DG) projects may be available.¹⁰⁰ In addition, the California ISO is undertaking an annual process to identify available deliverability for distributed generation projects connected to utility distribution systems.¹⁰¹
- » An industry stakeholder initiative called the *More Than Smart* working group has been meeting regularly to discuss the role of distributed energy resources¹⁰² (DER) in California's electricity system planning and operation. The group is focused on making policy recommendations to enable the development of more DER through electricity system modernization and integrated system

99 California Public Utilities Commission, Distribution Resources Plan Applications (filed July 1, 2015), <http://www.cpuc.ca.gov/PUC/energy/drp/>. Information on the requirements for the plans is available at <http://www.cpuc.ca.gov/NR/rdonlyres/9F82A335-B13A-4F68-A5DE-3D4229F8A5E6/0/146374514finalacr.pdf>.

100 Pacific Gas and Electric: www.pge.com/en/b2b/energysupply/wholesaleelectricssolicitation/PVRFO/pvmap/index.page; Southern California Edison: www.sce.com/ram; San Diego Gas & Electric: <http://www.sdge.com/generation-interconnections/interconnection-information-and-map>.

101 California Independent System Operator, *Resource Adequacy Deliverability for Distributed Generation, 2014-2015 DG Deliverability Assessment Results*, February 11, 2015, <http://www.caiso.com/Documents/2015DeliverabilityforDistributedGenerationStudyResultsReport.pdf>.

102 DER includes distributed renewable generation resources, energy efficiency, energy storage, electric vehicles, and demand response technologies.

planning. The working group will build off the IOUs' recently filed Distribution Resource Plans and make policy recommendations beyond what is being considered in the CPUC's Distribution Resource Plans proceeding.¹⁰³ As part of the CPUC's proceeding, the working group filed a paper titled *More Than Smart: A Framework to Make the Distribution Grid More Open, Efficient and Resilient*.¹⁰⁴

» Also, the Energy Commission is partnering with Southern California Edison on a Distributed Energy Resource Pilot Study in the San Joaquin Valley to promote coordinated planning for future growth in distributed resources. Finally, the Energy Commission has published several reports that identify location-specific value for distributed generation projects.¹⁰⁵

» **Identify preferred areas for distributed generation and utility-scale renewable development:** The most noteworthy progress on this recommendation has been the *Desert Renewable Energy Conservation Plan (DRECP)*. This effort focused on more than 22.5 million

acres in the California deserts with the goal of identifying areas for renewable development with the least environmental impacts and sensitive areas that should be protected for conservation. The draft *DRECP* was released in September 2014. In March 2015, the Bureau of Land Management, the U.S. Fish and Wildlife Service, the Energy Commission, and the California Department of Fish and Wildlife announced a phased approach to finalize the development of the *DRECP*, starting with completion of the Bureau of Land Management land-use plan amendment that designates development focus areas and conservation areas on public lands.¹⁰⁶

Other actions to support renewable energy development zones include providing technical assistance to the San Joaquin Valley Identification of Least Conflict Lands study;¹⁰⁷ development of informational geo-spatial tools; the Renewable Energy and Conservation Planning Grants Program, which is providing more than \$5 million to help local jurisdictions include consideration of renewables in their local policies and ordinances; and the establishment of the Renewable Energy Transmission Initiative 2.0, which is discussed in the next chapter.

» **Electrifying the transportation system:** The focus of the Renewable Action Plan was on renewable electricity, but it also acknowledged the importance of electrifying California's transportation system to meet GHG reduction goals. The plan also discussed the potential to use vehicle-to-grid services to provide grid support and help integrate renewable electricity, and underscored the importance of transportation electrification in disadvantaged communities because they can face disproportionate negative

103 <http://www.cpuc.ca.gov/PUC/energy/drpf/>.

104 <http://morethansmart.org/wp-content/uploads/2015/06/More-Than-Smart-Report-by-GTLG-and-Caltech-08.11.14.pdf>.

105 California Energy Commission consultant reports, *Identification of Low-Impact Interconnection Sites for Wholesale Distributed Photovoltaic Generation Using Energynet® Power System Simulation*, December 2011, <http://www.energy.ca.gov/2011publications/CEC-200-2011-014/CEC-200-2011-014.pdf>.

Integrated Transmission and Distribution Model for Assessment of Distributed Wholesale Photovoltaic Generation, April 2013, <http://www.energy.ca.gov/2013publications/CEC-200-2013-003/CEC-200-2013-003.pdf>.

Distributed Generation Integration Cost Study – Analytical Framework, September 2014, <http://www.energy.ca.gov/2013publications/CEC-200-2013-007/CEC-200-2013-007-REV.pdf>.

106 "Public Input Drives Next Steps for Desert Renewable Energy Conservation Plan," news release, March 10, 2015, http://www.drecp.org/documents/docs/2015-03-10_DRECP_Path_Forward_News_Release.pdf.

107 The San Joaquin Valley Identification of Least Conflict Lands study is a stakeholder-led, landscape scale plan to identify least-conflict lands in the San Joaquin Valley that are suitable for renewable energy development.

impacts from burning fossil fuels, especially from the transportation sector. Since the adoption of the Renewable Action Plan in 2013, the Energy Commission's Alternative and Renewable Fuel and Vehicle Technology Program has awarded nearly \$40 million for plug-in electric vehicle infrastructure, including charging stations, with many projects located in environmentally high-risk communities. The program has also awarded more than \$30 million for electric trucks and buses in sensitive port areas, including manufacturing and assembly plants. (The benefits of the Alternative and Renewable Fuel and Vehicle Technology Program are discussed in Chapter 4.)

There has also been progress on improving the link between planning efforts for renewable energy, the electric distribution system, and zero-emissions vehicles. The *California Statewide Plug-In Electric Vehicle Infrastructure Assessment*, published in 2014, makes recommendations for plug-in vehicle infrastructure planning and provides guidance to local communities.¹⁰⁸ The Energy Commission has also funded 11 regional plug-in electric vehicle planning grants to develop regional plans for infrastructure, streamlining of permitting and inspection processes, building code updates, and consumer education and outreach. (See Chapter 4 for further discussion of electric vehicles and Chapter 5 for discussion on how electric vehicle use is included in the electricity demand forecast.)

» **Developing protocols for advanced inverters:**

The Renewable Action Plan emphasized the need for advanced inverters to successfully integrate and manage increasing amounts of distributed solar resources on the grid. In January 2013, the Energy Commission and the CPUC formed the Smart Inverter Working Group, which includes utilities, inverter manufacturers, renewable developers, government, and other stakeholders. The

first phase of the project was to develop recommendations for seven critical autonomous inverter functions; the resulting recommendations were approved by the CPUC in 2014 and will be implemented by the IOUs by mid-2016. In the second phase, the working group focused on inverter communication capabilities, and the CPUC is coordinating with the IOUs to implement the resulting recommendations. The third phase of the project will consider advanced functions such as the ability to respond to power pricing signals and to connect or disconnect from the grid upon command.

» **Fostering regional solutions to renewable**

integration: Because regional coordination of electricity markets allows more efficient and economic sharing of renewable and other generating resources across a broad geographic area, the Renewable Action Plan recommended continuing to explore opportunities for an energy imbalance market (EIM) in the West. There has been substantial progress on this recommendation. Progress on the EIM and developing a more regional grid are discussed in detail below in the section "Renewables and Reliability" and in detail in Chapter 3.

» **Providing clear tariffs, rules, and performance**

requirements for integration services: The Renewable Action Plan recommended designing clear tariffs, rules, and performance requirements for integration services to fully leverage automated demand response, energy storage, and other distributed resources to provide renewable integration. Major progress on this recommendation was made in July 2015 with the California ISO's announcement of approval of rules and processes to enable distributed energy resources to participate in the wholesale energy market. Smaller resources can now be bundled by utilities or third parties so they collectively can meet the half-megawatt minimum requirement for participating in

108 California Energy Commission, *California Statewide Plug-In Electric Vehicle Infrastructure Assessment*, May 2014, <http://www.energy.ca.gov/2014publications/CEC-600-2014-003/CEC-600-2014-003.pdf>.

the energy market.¹⁰⁹ Also, the California ISO is working toward introducing a formal flexible ramping product into its market system.¹¹⁰ While the CPUC has taken initial steps described below to facilitate the participation of preferred resources into the California ISO's wholesale energy market, further CPUC action is needed.

The CPUC worked with the IOUs and other stakeholders in 2015 to facilitate greater participation in the California ISO demand response market options. Under the demand response “bifurcation” scheme instituted by agreement between the California ISO and the CPUC, two demand response product types were defined. First, the CPUC specified load-modifying demand response as those demand response resources that result in permanent load shifts of a nature that would, logically, influence the Energy Commission demand forecast. Second, supply-side demand response is event-based and meant to directly compete with, or even supplant, traditional generation capacity resources.¹¹¹ The CPUC's Resolution E-4728 launched the Demand Response Auction Mechanism which, among other things, requires all bidders to integrate their demand response into the California ISO's wholesale market and relies on third parties to provide that demand response.¹¹² In November 2015, the CPUC issued a decision aligning valuation of demand response with its long-standing goal

of integrating the IOU demand response portfolios into the California ISO markets.¹¹³ To lay the groundwork for expanding opportunities for demand response, the CPUC is working with Lawrence Berkeley National Laboratory to develop a comprehensive study of demand response potential across all customer sectors.¹¹⁴

» **Establishing research initiatives to support renewable development:** California continues to be a leader in advancing research and development (R&D) to support renewable energy development and use. Since 2010, the Energy Commission has awarded more than \$200 million to projects that support the recommendations in the Renewable Action Plan in the following areas:

- » \$70 million to support existing and colocated renewable technologies, including projects to reduce installation and maintenance costs; improve reliability and performance; develop community-scale bioenergy; conduct environmental impact assessment and mitigation; examine opportunities for synergies from combining renewable technologies; reduce the cost of distributed PV; integrate advanced inverter technologies and smart grid components; and identify strategies to make bioenergy projects more economic.
- » \$20 million to bring innovative technologies closer to commercialization, examine

109 California Independent System Operator, “ISO Board approves gateway to the distributed energy future” press release, July 16, 2015, <http://www.caiso.com/Documents/ISOBoardApproves-GatewayToTheDistributedEnergyFuture.pdf>.

110 California Independent System Operator, *Draft Technical Appendix*, June 10, 2015, http://www.caiso.com/Documents/Draft-TechnicalAppendix_FlexibleRampingProduct.pdf.

111 CPUC, Decision Addressing Foundational Issue of the Bifurcation of Demand Response Programs, D.14-03-026, Rulemaking 13-09-011, <http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M089/K480/89480849.PDF>.

112 CPUC, Approval with Modifications to the Joint Utility Proposal for a Demand Response Auction Mechanism Pilot Pursuant to Ordering Paragraph 5 of Decision 14-12-024, Resolution E-4728, July 23, 2015, <http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M153/K436/153436367.pdf>.

113 CPUC, Decision Addressing the Valuation of Load Modifying Demand Response and Demand Response Cost-Effectiveness Protocols, *Decision 15-11-042*, November 30, 2015, <http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M156/K099/156099197.pdf>.

114 Mary Ann Piette, Andrew Satchwell, Michael D. Sohn, Michael A. Berger, Laurel N. Dunn, Peter Alstone, Emre Kara, Jennifer Potter, Sarah Smith, Janie Page, Becky Li, and Kristina LaCommare, Lawrence Berkeley National Laboratory, “Draft Research Plan 2015 California Demand Response Potential Study: Charting California's Demand Response Future,” May 13, 2015.

the potential of technologies on the horizon, develop data and tools to support market facilitation, verify the performance of innovative technologies, and develop technologies in the areas of biomass conversion, offshore wind, concentrating solar power, small hydro, and geothermal. Other projects have evaluated strategies to reduce peak demand, minimize the environmental impacts of energy generation, and bring technologies to market that provide increased environmental benefits, greater system reliability, and reduced system costs.

- » \$109 million for projects to integrate intermittent generation, improve solar and wind forecasting, develop smart grid technologies and microgrids, improve energy storage technologies, and develop grid planning tools, distribution system upgrades, and demonstration and deployment projects for renewable-based microgrids.
- » \$9 million to reduce and resolve environmental barriers to renewable deployment; develop new technology designs, scientific studies, and decision-support tools to avoid impacts to environmentally sensitive areas and permitting delays; and provide environmental analysis to identify preferred areas for renewable development, such as the San Joaquin Valley.

Action Items Needing Further Work

Suggested actions in the Renewable Action Plan for which there has been less progress include:

- » **Developing renewables on state properties.** In 2011, the Energy Commission's *Developing Renewable Generation on State Property* report recommended a goal

of 2,500 MW of renewables on state properties by 2020, with interim targets of 833 MW by 2015 and 1,666 MW by 2018.¹¹⁵ According to the Department of General Services' Renewable Energy Directory, there are 43 MW of renewable projects installed on state properties, with another 8 MW planned, far short of the 833 MW interim goal for 2015. In addition, the majority of installed and planned projects are less than 1 MW, indicating more focus may be needed on promoting larger installations going forward to achieve the interim and long-term targets. In support of this effort, on October 1, 2015, the California State Lands Commission and the Bureau of Land Management announced a historic agreement to pursue an exchange of state lands with federal lands. This State Land Exchange will protect conservation lands and promote renewable energy development.

- » **Improving the transparency of renewable cost information and distribution planning.** Improving the ability to track publicly available information on renewable project costs will expand the state's understanding of cost trends and drivers in the growing distributed renewable energy portfolio and help support distribution planning. California's energy agencies need to increase efforts to work with the National Renewable Energy Laboratory, Lawrence Berkeley National Laboratory, U.S. Department of Energy, utilities, customers, and developers to develop a framework to prepare transparent estimates of the system costs of renewable distributed generation. In addition, the Energy Commission needs to coordinate with local, state, and federal agencies to identify available cost data and what additional information is needed to support distribution planning.

The energy agencies and utilities need to continue to improve coordination and integration of distributed generation procurement programs, long-term procurement

¹¹⁵ California Energy Commission, *Developing Renewable Energy on State Property*, April 2011, <http://www.energy.ca.gov/2011publications/CEC-150-2011-001/CEC-150-2011-001.pdf>.

plans, smart grid deployment plans, and transmission planning so that the distribution planning process is better informed. The energy agencies should explore options to improve the transparency of the IOUs' distribution planning process, leveraging the tools and methods being considered in the CPUC's Distribution Resources Plan proceeding. The work being done through the "More Than Smart" working group made up of industry stakeholders is an important contributor to this effort.¹¹⁶

» **Instituting workforce development to support the renewable industry:** The Renewable Action Plan emphasized the importance of developing a well-trained workforce to support California's renewable policy goals. Strategic partnerships among energy, labor, and education agencies are needed to ensure that training matches the needs of the industry. For example, in June 2015 the State of California's Employment Training Panel approved more than \$300,000 in renewable fuel and vehicle technology job training funds to train more than 400 workers in the clean technology sector.¹¹⁷ These kinds of efforts are needed in the electricity sector as well.

Renewables and Reliability

Success in advancing renewable resources necessarily means facing the challenge of integrating increasing

amounts of variable resources into the grid. To maintain reliability, the grid operator must balance supply and demand. This balance becomes more challenging as increasing amounts of intermittent resources without storage are deployed, producing large daily upward and downward ramps in energy generation. Many options are available to help manage the unique characteristics and increasing scale of renewables' en route to achieving the state's climate goals. The discussion below draws largely from a July 9, 2015, symposium¹¹⁸ held by the Governor's office and joint energy agencies to solicit input on achieving Governor Brown's 50 percent renewables goal¹¹⁹ as well as a May 11, 2015, IEPR workshop on renewable resources.

At the May 11, 2015, IEPR workshop, the California ISO noted that the magnitude of overgeneration due to renewable generation in excess of electricity demand could be as great as 12,000 MW under a 33 percent RPS. Keith Casey, vice president of Market and Infrastructure Development at the California ISO, noted that the California ISO's analysis showed that under a 40 percent RPS there are times when net load¹²⁰ becomes negative. This means that the California ISO system would not be able to accommodate all of the renewable generation during that period.¹²¹

An analysis in the CPUC's Long Term Procurement Planning (LTPP) shows significant curtailment will be needed in 2024 to maintain grid reliability, assuming today's RPS rules favoring generation produced or scheduled into a California balancing authority apply to a 40 percent renewables target. With a 50 percent RPS, overgeneration will become increasingly challenging regardless of whether current RPS rules apply.¹²²

116 The "More Than Smart" working group is an offshoot of the *More Than Smart – A Framework to Make the Distribution Grid More Open, Efficient, and Resilient* white paper by Greentech Leadership Group and Resnick Sustainability Institute. <http://authors.library.caltech.edu/48575/1/More-Than-Smart-Report-by-GTLG-and-Caltech.pdf>.

117 State of California Employment Training Panel, "Employment Training Panel Awards \$368,280 to Train Clean/Green Sector Workers in Partnership with the California Energy Commission," June 26, 2015, <http://www.labor.ca.gov/pdf/ETPPressRelease-June2015.pdf>.

118 <http://www.arb.ca.gov/cc/pillars/pillars.htm#publicmeetings>.

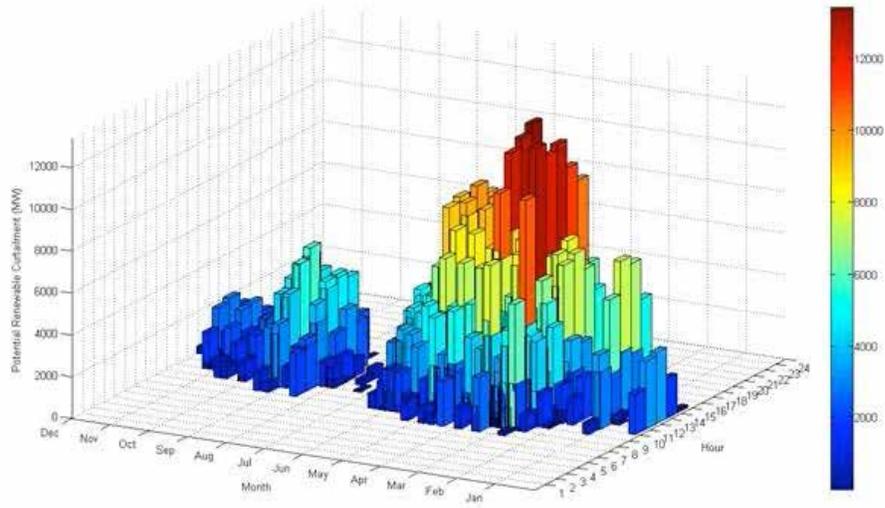
119 Executive Order B-30-15, <http://gov.ca.gov/news.php?id=18938>.

120 A *net load curve* is total load less the production of wind and solar generating facilities.

121 May 11, 2015, IEPR workshop transcript, p. 161.

122 July 9, 2015, Greenhouse Gas Symposium, presentation by Phil Pettingill, director of State Regulatory Affairs at the California ISO.

Figure 14: Potential Curtailment in 2024 at 40 Percent Renewables



Source: California ISO

Figure 14 shows the amount of overgeneration expected in calendar year 2024, assuming a 40 percent renewable requirement in a business-as-usual scenario. In this graph, overgeneration refers to renewable capacity that would have nowhere to go and could be curtailed in 2024 if business-as-usual continued. Under those conditions, roughly 10 percent of the year is expected to have some amount of overgeneration. However, tools such as demand response, storage (many types), bi-directional electric vehicle dispatch, electrification of thermal end uses, and hydrogen production for fuel cell vehicles will likely be deployed to avoid deep and frequent curtailment.

The Union of Concerned Scientists (UCS) presented a different perspective on overgeneration, suggesting that it can be considered as failure to curtail natural gas generation, rather than a direct effect of renewables. Figure 15 shows UCS' version of a net load curve highlighting those hours in the day with excess generation. Laura Wisland, a senior energy analyst at UCS suggested, "It's our challenge to figure out how to take advantage of as much solar as we can, in the middle of the day, when it's generating. And then, also bring on additional types of resources to smooth that generation over time and turn

down the gas plants as much as possible, so we're getting the commensurate greenhouse gas benefit."¹²³

At the May 11, 2015, IEPR workshop, Steven Kelly, director of policy at Independent Energy Producers Association, suggested that real-time prices could push businesses and homeowners in the California balancing authorities to take advantage of the free power rather than giving it away outside California.¹²⁴ Mr. Kelly also noted that if power plant owners modified their plants to allow them to run at lower generation levels, they could, but the market signals are not there to create an incentive for them to do so.¹²⁵

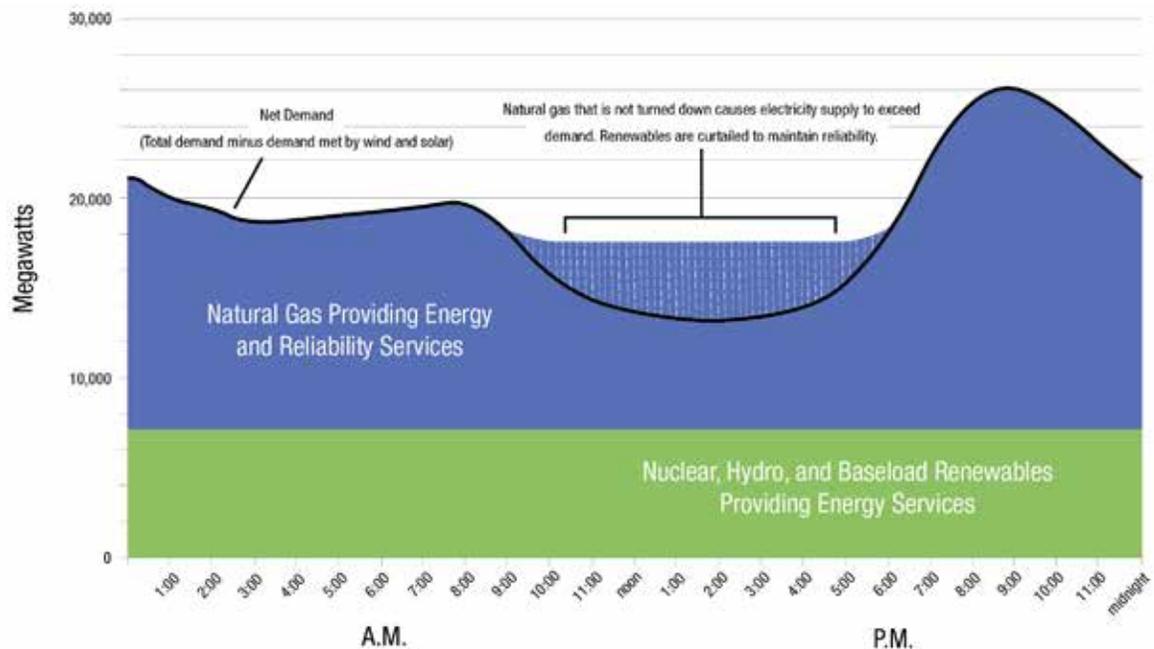
Westlands Solar Park stressed the importance for geographic diversity throughout the state to avoid overreliance on any geographic region (and the particular renewable technologies there) at the expense of other regions and technology types, such as solar development in Central

¹²³ May 11, 2015, IEPR workshop transcript, p. 169.

¹²⁴ Ibid., p. 192.

¹²⁵ Ibid., p.196.

Figure 15: Potential Curtailment Scenario



Source: Laura Wisland’s presentation (UCS) during the May 11, 2015, IEPR workshop, see <https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=15-IEPR-06>.

California.¹²⁶ Westlands also stressed the importance of focusing on water use as part of siting and transmission planning for renewable development.¹²⁷ (Water-energy issues are discussed in Chapter 8.)

Pathways Study on GHG Reductions Needed by 2030 to Achieve 2050 Goals

Energy+Environmental Economics (E3) developed a study on GHG reduction levels needed in 2030 for a pathway to the 2050 GHG reduction goal.^{128, 129} The study analyzed a series of scenarios with different technology combinations and differing paces of emission reductions. The Pathways

study uses a bottoms-up approach to analyze hand-constructed scenarios, and the scenarios are not optimized to find the least-cost way to reach GHG goals. It is policy-neutral and provides results showing levels of efficiency, renewables, electric vehicles, demand response, storage, and so forth, and how to combine such resources to reach a given level of emissions reductions by a given time.

The chief finding is that decarbonizing the California economy depends on four transitions, with progress needed on each by 2030:¹³⁰

- » Achieve greater efficiency and conservation in buildings, industry, infrastructure, water, and the vehicle fleet.
- » Switch fuels to increase the share of electricity and hydrogen in the energy mix.

¹²⁶ Ibid., pp. 108–111.

¹²⁷ Ibid., pp. 100–101.

¹²⁸ https://ethree.com/public_projects/energy_principals_study.php.

¹²⁹ The heads of the California Air Resources Board, Energy Commission, CPUC, and the California ISO engaged E3 to conduct the study.

¹³⁰ The study also looked at a carbon sequestration scenario; this summary focuses on the renewables goal.

- » Decarbonize electricity.
- » Decarbonize fuels (liquid and gas).

At the July 9, 2015, symposium, Dr. Nancy Ryan, senior director for policy and strategy at E3, noted that one central conclusion is that to realize cost-effective decarbonization, California must use all sources of potential flexibility, including tight integration of the transportation sector. Increased regional diversification and resource diversity are critical, and flexible loads will also be important. She suggested that the study shows that California will still need fast-ramping gas plants with low minimum generation well into the future. Finally, Dr. Ryan suggested the need to integrate the energy system across sectors.

Integrated Planning

Taking an integrated approach to energy planning is a key tool for addressing the potential challenges associated with increased amounts of renewable resources. At the July 9, 2015, symposium, there was broad agreement that the traditional, more siloed approach to energy planning in which renewable energy goals are considered separately from energy efficiency or demand response or storage goals,¹³¹ for example, does not generate the best results. Each area progresses towards the respective goals but is not integrated and not necessarily part of an effective strategy to meet climate goals. A more integrated approach aimed at GHG reductions is needed.

Such an integrated approach should consider a broad array of tools to de-carbonize the grid, including a balanced portfolio of renewable technologies, targeted energy efficiency, time-of-use rates, demand response, storage, and reconfiguration of the existing natural gas fleet to allow for greater operational flexibility such that they are capable of ramping both up and down. At the symposium, parties also suggested that resource diversity

needs go beyond a diversified portfolio for the timing of energy generation to include all reliability services such as voltage support and other ancillary services.

A more integrated approach to planning also allows for more flexibility as the state works to transform the energy sector to achieve overall GHG reduction goals. At the May 11, 2015, IEPR workshop, Commissioner David Hochschild emphasized that policy makers must anticipate what the electricity sector will look like in the near future and set policy accordingly. One major anticipated change is the increasing electrification of the building sector, including smart appliances that can respond to the needs of the grid. Yet anticipating all the impacts of a rapid evolution of generation towards renewables is difficult, because some of those impacts are unknowable.¹³² Commissioner Andrew McAllister identified the opportunity to build in flexibility throughout the system, including on the demand side. Malleable demand can respond to grid conditions, facilitating system reliability and full utilization of available renewables. Cutting-edge technologies, particularly low-cost communication technologies, will be important for enabling grid responsiveness down to the appliance level.¹³³ Meeting the state's climate goals requires planning approaches that better integrate demand and supply-side resources.

As discussed above in “Renewable Action Plan Status,” the California ISO and CPUC have made considerable progress to develop a viable market for demand response in California that provides cost-effective flexibility and reliability capabilities. Still, demand response participation in the California ISO's market is in its infancy with just 58 resources participating, representing about 1,200 MWs. Further work is underway to increase participation. (See the side bar on “Advancing Demand Response” for information on the Energy Commission's role).

¹³¹ See Appendix F for an update on energy storage goals as required by AB 2514 (Skinner, Chapter 469, Statutes of 2010).

¹³² May 11, 2015, IEPR workshop transcript. pp. 141–143.

¹³³ *Ibid.*, pp. 145–147.

Efforts by Advanced Microgrid Solutions provide an example of how various tools can be integrated together to improve system efficiency. (A project with the Inland Empire Utilities Agency is discussed in Appendix F). The company deploys storage in combination with renewable distributed generation and demand response. Software with site-specific time-of-use rates integrates energy use and production at a building to provide real time support to the electric grid. Such integrated systems have the promise to replace conventional flexible capacity overtime if deployed to scale and strategically located.

Also, as noted above, efforts to decarbonize the electricity and transportation sectors must be integrated: for example, balancing the optimization of electric vehicle charging to support grid reliability and meeting a driver's needs will be key. The California ISO led the development of the *California Vehicle-Grid Integration (VGI) Roadmap* through a comprehensive stakeholder review process and in coordination with the Governor's Office, Energy Commission, CPUC, and California Air Resources Board. Through this planning effort, "The intention is to keep consumers in the driver's seat during the transformation to a cleaner grid by enabling managed EV charging consistent with grid conditions. Eventually, two-way interfaces between EVs and the bulk power network could benefit both EV owners and the grid-at-large."¹³⁴

The CPUC has already started to look at clean energy procurement in a comprehensive way. An example is the CPUC's decision 15-09-022, which provides a foundation for the integration of distributed energy resources.¹³⁵ The decision establishes a framework for distributed energy resources that "is based on the impact and interaction of such resources on the grid as a whole, on a customer's

134 California ISO, *California Vehicle-Grid Integration (VGI) Roadmap: Enabling vehicle-based grid services*, February 2014, <https://www.caiso.com/Documents/Vehicle-GridIntegrationRoadmap.pdf>.

135 CPUC, *Decision Adopting an Expanded Scope, a Definition, and a Goal for the Integration of Distributed Energy Resources*, R. 14-10-003. D. 15-09-022, September 17, 2015, <http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M154/K464/154464227.PDF>.

Advancing Demand Response

In 2007, the IEPR recommended initiating a formal rulemaking process involving the CPUC and California ISO to pursue the adoption of new load management standards under the Energy Commission's existing authority, and in January 2008 the Energy Commission opened an informational proceeding and rulemaking. The Energy Commission published a Committee draft analysis and held workshops throughout 2008 and 2009, but developments in advanced metering infrastructure (an integration of smart meters, communication capability, and data management systems that allow two-way communication between consumers and utilities) as well as American Recovery and Reinvestment Act funding for demand response led the Committee to re-evaluate the need for amending the regulations, and the proceeding was not completed.

Since 2009, the electric industry has seen tremendous change, the management of which – in support of the transition to low-carbon energy systems – is a theme of the *2015 IEPR*. Advanced meters are present at a large majority of customer sites; analytical support tools are increasingly powerful; and business models exist to mobilize and aggregate cost-effective demand-side resources that can produce various grid services at all scales. The Energy Commission will therefore consider updating its load management regulations to reflect the current context and leverage these powerful recent developments.

energy usage, and on the environment” with the goal “to deploy distributed energy resources that provide optimal customer and grid benefits, while enabling California to reach its climate objectives.” SB 350 puts into statute a shift to a more integrated approach to electricity resource planning by requiring the retail sellers of electricity and larger publicly owned utilities to develop integrated resource plans (IRPs). The IRPs will incorporate both supply- and demand-side resources to meet GHG emission reduction goals, maintain reliability, and control costs.

Beginning in 2017, the CPUC is required to adopt a process for each retail seller to file an IRP. Similarly, by January 1, 2019, each POU with annual demand exceeding 700 GWhs (average) per year is required to adopt an IRP and a process for updating the plan at least once every five years. The Energy Commission will adopt guidelines for the applicable POUs to submit IRPs by 2019. The Energy Commission will work together with the CPUC, ARB, and California ISO to have a coordinated approach to the IRPs and meet all obligations identified in statute.

In their IRPs, the retail sellers and POUs are required to describe how they will:

- » Meet the GHG emissions reduction targets established by the ARB in achieving the economy-wide greenhouse gas emissions reductions of 40 percent from 1990 levels by 2030.
- » Procure at least 50 percent eligible renewable energy resources by December 31, 2030.
- » Serve their customers at just and reasonable rates.
- » Minimize effects on ratepayers’ bills.
- » Ensure system and local reliability.
- » Strengthen the diversity, sustainability, and resilience of the bulk transmission and distribution systems and local communities.

- » Enhance distribution systems and demand-side energy management.
- » Minimize localized air pollutants and other greenhouse gas emissions, with early priority on disadvantaged communities

The CPUC is required to “identify a diverse and balanced portfolio of resources needed to ensure a reliable electricity supply that provides optimal integration of renewable energy in a cost-effective manner.”¹³⁶

The statute requires that the POUs’ IRPs include procurement for energy efficiency, demand response, storage, transportation electrification, and a diverse portfolio with short- and long-term agreements, and that the plans meet resource adequacy requirements.¹³⁷ The Energy Commission will review POUs’ IRPs for consistency with the statutory requirements and provide recommendations to correct any deficiencies.

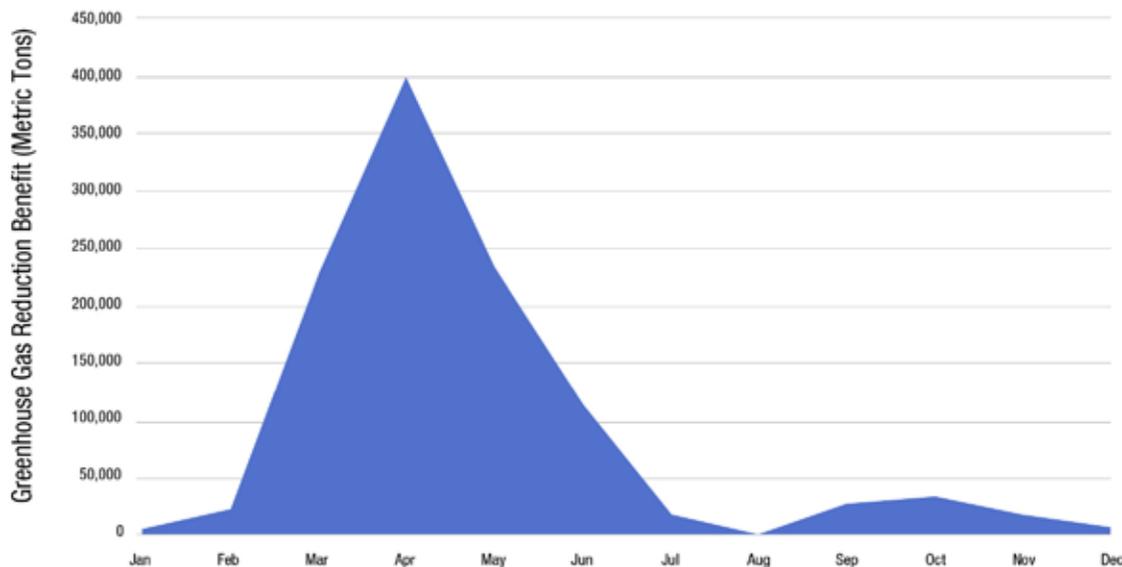
Regional Grid

Expanding to a more regional electrical grid is also critical to advancing California’s climate goals while maintaining reliability and controlling costs. (For more information on developing a regional grid, see Chapter 3.) An important tool to help integrate renewables into the grid is the California ISO’s real-time EIM. The EIM is a voluntary market to automatically balance differences in supply and demand in real-time and is expanding in the West. Moving beyond a regional EIM, a fully integrated regional market would provide greater benefits. With a regional market, overgeneration in California could be used in other parts of the west rather than being curtailed. For example, California’s late afternoon resources can serve peak period load after sunset in Utah. Moreover, a more regional grid with a bigger footprint includes a broader diversity of renewable resources with varying generation

¹³⁶ Public Utilities Code 454.51.

¹³⁷ Public Utilities Code Section 9621.

Figure 16: Potential Regional GHG Reductions With 40 Percent Renewables



Source: California ISO presentation at the July 9, 2015, Joint Agency Symposium on the Governor's Greenhouse Gas Reduction Goals http://docket-public.energy.ca.gov/PublicDocuments/15-IEPR-06/TN205457-3_20150722T101921_California_Climate_STrategy.pdf.

profiles such that combining them can reduce the overall variability of supply.

The CPUC's LTPP analysis showed that a regional grid would eliminate curtailment *and* reduce GHG emissions by 1.1 million tons per year under a 40 percent PRS by 2024. Westwide coordination at a 50 percent RPS would lower carbon emissions by an additional 1.5 million tons per year.¹³⁸ Figure 16 translates the overgeneration hours to potential GHG savings if the excess generation could be used regionally rather than being curtailed. Most of the GHG savings potential occurs between March and June.

PacifiCorp has shown interest in joining the California ISO as a participating transmission owner rather than continuing to operate as separate balancing authorities. Recognizing the importance of a regional market, SB 350 paves the way for the voluntary transformation of the

California ISO into a regional organization.¹³⁹ The EIM and development of a regional electricity market in the West are discussed in detail in Chapter 3.

Other Proposed Solutions

Poseidon Water proposed that using excess renewable energy to power the production of drinking water through desalination is an opportunity to help meet both energy and water needs in California. Graham Beatty from Poseidon Water noted that desalination is energy-intensive, with electricity use accounting for about 50 percent of the operating expense. As an example, Mr. Beatty stated that the Carlsbad plant produces 50 million gallons of drinking water per day using 30 MW to 35 MW and has some ability to store additional water onsite. He stated that desalination projects can be designed to ramp up or down quickly as needed to have the capability to use renewable

¹³⁸ Symposium on the Governor's Greenhouse Gas Reduction Goals, July 9, 2015, comments by Phil Pettingill with the California ISO.

¹³⁹ See Senate Bill 350, Article 5.5. Transformation of the Independent System Operator, Section 359 (a), http://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201520160SB350.

energy that would otherwise be curtailed.¹⁴⁰ Given the size of the project, this would likely produce on the order of a few MW of flexible capacity.

Another potential solution is to convert surplus renewable power to hydrogen gas.¹⁴¹ This is a potential long-term strategy that could result in a new supply of renewable hydrogen for transportation use, as well as an input to the natural gas pipeline system to reduce the carbon content of natural gas. (See Chapter 6 for discussion on natural gas issues.)

Emerging Technologies

R&D is needed to help advance the new tools, technologies, and systems that are required to integrate the clean energy infrastructure needed to contribute to the state's GHG reduction goals. California's research investments have developed improved capabilities to forecast the generation of intermittent renewable resources that have helped lower the cost of using these resources, but further work is needed. Better forecasting in both longer duration (day ahead) and short duration (5 minute) would allow grid operators to more effectively balance renewables with other generation and demand-side resources. Ongoing research projects are working to implement improved forecasting techniques into the planning and operations of the California ISO grid and individual microgrids that have a high penetration of variable renewables. California's research investments are also developing renewable energy integration solutions, including increasing regional coordination, diversifying the clean energy portfolio, enabling flexible loads, adding flexibility and controllability to renewable generators, and demonstrating advanced energy storage technologies and microgrids. The Energy Commission supports this research through funding from the Electric Program Investment Charge (EPIC).

140 Ibid., pp. 185–187.

141 Ibid., p. 149.

The Energy Commission has funded several technologies that are being used to support a more regional grid, better integrate variable generation and increasingly variable load, and deploy localized community-scale renewable energy projects and microgrids. For example, synchrophasors were in the laboratories in the 1980s and the Energy Commission's demonstration and deployment efforts were pioneering in getting the technology into the California and Western grid in the 2000s. Synchrophasors are high-speed, utility data collection systems that can collect up to 30 samples (of phase angles) per second. This high-resolution data can show abnormalities in the grid and identify their origin. Synchrophasors are now deployed throughout the national grid.

Microgrids are a tool to integrate distributed energy resources and add resiliency to locations with critical loads such as military bases, prisons, hospitals, or laboratories, and can serve as a platform to enable very high penetrations of solar and wind energy. Microgrids are especially effective for critical facilities that require high reliability. Microgrids typically use grid power when the utility grid is stable but have the capability to *island*, or provide power in isolation, if the utility grid becomes unstable. Microgrids are capable of firming and controlling the energy export, including intermittent wind and solar, to the utility grid while integrating supply- and demand- side controls within the microgrid. These microgrid capabilities are needed when customers want to reap the benefits of coordinating multiple energy systems such as distributed renewables, demand response technologies, and energy storage. The Energy Commission's early R&D efforts focused on microgrid controller design and system configurations, and through EPIC the Energy Commission is focused on taking these advanced designs and configurations and demonstrating the full value to support commercialization of microgrid systems. Future research efforts should focus on system standardization and lowering costs so these commercialization efforts can be successful. The Energy Commission, CPUC, and California ISO worked in partnership to develop state level roadmaps

for energy storage, vehicle-grid integration, and demand response. These agencies should continue that work on a microgrid roadmap in 2016 that can address how the institutional and cost barriers can be addressed.

Also, the Energy Commission has funded projects to help communities develop and deploy localized renewable energy-optimized energy management strategies. These strategies are designed to enable higher levels of renewable energy with minimal grid impacts by enabling functions such as peak-load reduction, load shifting, and a range of other functions for the local community and the grid.

Storage is another key technology to help improve grid reliability with increasing amounts of renewable resources. Further research and economies-of-scale are needed to help bring down costs. The CPUC established a programmatic market for energy storage in California and set a 1.3 GW energy storage target for the IOUs to support a 33 percent RPS by 2020. The Energy Commission's R&D efforts focus on helping California achieve the energy storage target with technologies that are safe, reliable, and cost-effective for IOU ratepayers. Research is also focused on improving technology performance and identifying optimal locations, sizes, and technology types for specific energy storage functions. Recognizing the potential benefits of storage and the need for further work, in 2014 the CPUC, Energy Commission, and California ISO jointly developed a roadmap to identify actions that can help advance a marketplace for energy storage resources.¹⁴²

Technologies that enable demand response also help integrate renewable resources, especially demand response that can be reliably dispatched and is resource-adequate. Innovative coupling of demand response with other technologies like storage can assure the grid operator of its capability to shed or call on load when needed

142 California ISO, CPUC, Energy Commission, *Advancing and Maximizing the Value of Energy Storage Technology, a California Roadmap*, December 2014, https://www.aiso.com/Documents/Advancing-MaximizingValueofEnergyStorageTechnology_CaliforniaRoadmap.pdf.

and assure customers that their electricity needs will not be compromised. A roadmap developed by the California ISO in close coordination with the CPUC and Energy Commission provides a guide for expanding demand response in California.¹⁴³

R&D is also helping advance flexible generation resources that can help fill the gaps and balance the ramps created by intermittent renewables. Some renewable resources that have typically been operated as baseload resources, such as geothermal, and biomass, may be able to provide the flexibility needed to maintain grid operations in the face of higher levels of wind and solar.

California also needs to develop permitting processes for renewable facilities that do not currently have a clear regulatory process for development, such as offshore wind that faces review from multiple local, state, and federal entities.

Given the critical nexus between the transportation and electricity sectors in meeting the state's climate goals, several research efforts are underway to advance vehicle-grid integration for a growing population of electric vehicles. At a high level, the research efforts support the development of open communication protocols that enable two-way communication between the utility and the vehicle to manage the vehicle battery by charging with excess generation, and drawing from it when ancillary services, such as frequency regulation, are needed for grid stability. As noted above, the *California Vehicle-Grid Integration (VGI) Roadmap* lays out "a way to develop solutions that enable electric vehicles to provide grid services while still meeting consumer driving needs."¹⁴⁴

The state's long-term climate laws and goals are driving investments in innovations that will significantly

143 California ISO, *Demand Response and Energy Efficiency Roadmap: Maximizing Preferred Resources*, December 2013, <https://www.aiso.com/Documents/DR-EERoadmap.pdf>.

144 California ISO, *California Vehicle-Grid Integration (VGI) Roadmap: Enabling vehicle-based grid services*, February 2014, <https://www.aiso.com/Documents/Vehicle-GridIntegrationRoadmap.pdf>.

change how the electric grid is planned and operated. California is demonstrating that it is possible to power a large economy with diverse clean energy technologies, while at the same time making clear that higher penetrations of these resources will require updated approaches to planning and operating the electric grid. As the state continues to develop markets to increase investment in clean energy technologies, it is important to make sure customers and grid operators have the tools and resources they need to integrate technologies that make the most economic and environmental sense. Continued R&D is critical to building a smart California grid that is capable of integrating the clean energy resources that will help power a low-carbon economy.

Recommendations

- » **Pursue a diverse renewables portfolio.** Different renewable technologies provide different benefits and services to the grid. The procurement process should avoid overreliance on cost alone, rather considering the range of benefits renewables can provide individually and collectively. Strategies to reach 50 percent renewables by 2030 should explicitly address resource diversity.
- » **Zero-carbon solutions should maintain system reliability while integrating renewables.** Further efforts are needed to develop renewable resources in combination with demand response and a variety of energy storage options to enable low- or no-carbon electricity while maintaining system reliability at reasonable cost. Energy procurement should consider combinations of desired attributes rather than focusing only on traditional products such as bulk energy or baseload power.
- » **Further consideration is needed on the role of distributed resources in the Renewables Portfolio Standard (RPS) and on more fully integrating distributed resources into the system.** California's RPS Program was designed at a time when distributed renewable resources represented a tiny percentage of total renewables. With increasing penetration of customer-side renewables and the inclusion of distributed resources in the California Independent System Operator wholesale market, the future role of distributed renewables in the RPS should be carefully evaluated through public processes such as the California ISO's Energy Storage and Distributed Energy Resources initiative. Also, further work is needed to support deployment of distributed renewable resources with storage and demand response to maximize greenhouse gas reduction benefits, maintain system reliability, and control costs.
- » **Further work is needed to advance renewables on state property.** California has been a leader in promoting the development and use of renewable resources for decades, yet the state's public buildings and lands do not yet reflect that commitment. The recommendations in the *Developing Renewables on State Property Report* should be revisited and more effort devoted to developing renewables on state properties, particularly larger-scale projects of 1 megawatt or more.
- » **Continue to support research and development for renewable resources through the Electric Program Investment Charge (EPIC).** Emerging renewable technologies can transform the market by establishing new industries and providing new products and services to improve the efficiency, cost-effectiveness, and reliability of the low-carbon electricity system. However, the market seldom provides adequate incentives to develop the innovative technologies that will be needed in the future. The state should therefore continue to fund and support the EPIC to advance new technologies, strategies, and demonstrations of systems such as microgrids that support renewable development and deployment.

» **Continue research to improve the integration of increasing amounts of renewable resources.** Solar and wind forecasting techniques have improved by leaps and bounds in recent years, but there is still significant room for improvement. Further research is needed on new technologies that support stabilizing variable loads on the grid, deliver more responsive and affordable energy storage, aggregate distributed generation resources into a single manageable resource, and provide new system control technologies that can assess the status of the grid and respond appropriately in real time.

» **See Chapter 3 for recommendations on encouraging greater participation in the Energy Imbalance Market and development of a regional electricity market in the West.**

CHAPTER 3

Strategic Transmission Investment Planning



Developing the transmission needed to support increasing amounts of renewable resources will be critical to meeting the state's greenhouse gas (GHG) reduction goal to cut emissions 40 percent below 1990 levels by 2030. Chapter 2 provides a discussion of Governor Edmund G. Brown Jr.'s goal to increase from one-third to 50 percent the percentage of electricity from renewable resources as a key component of the state's strategy to address climate change. Senate Bill 350 (De León, Chapter 547, Statutes of 2015) (SB 350) codifies the goal to serve half of the state's electricity needs with renewable resources by 2030. This chapter focuses on transmission needed to support the state's climate goals.

Collaboration among the California Energy Commission, the California Public Utilities Commission (CPUC), and the California Independent System Operator (California ISO), with appropriate stakeholder and public input, is crucial for ensuring that the most robust, cost-effective, sustainable, and environmentally responsible energy infrastructure system is planned consistent with federal, state, tribal, and local mandates and goals. An important element to attaining this higher level of renewable generation is the continued improvement in landscape-scale planning tools and the application of these tools to generation and transmission planning solutions. Such

collaboration maximizes the probability that transmission planning decisions will elicit appropriate transmission projects that can be permitted promptly. In addition, California needs to continue coordinating with the rest of the Western Interconnection¹⁴⁵ in generation and transmission planning, system operations, renewables integration, and energy imbalance market activities to ensure that California's policy objectives are achievable.

In 2004, Senate Bill 1565 (Bowen, Chapter 692, Statutes of 2004) directed the Energy Commission, in consultation with other stakeholders, to adopt a strategic plan for the state's electric transmission grid. Subsequently, Senate Bill 1059 (Escutia and Morrow, Chapter 638, Statutes of 2006) linked transmission planning and permitting by authorizing the Energy Commission to designate transmission corridor zones on nonfederal lands to allow for the timely permitting of future high-voltage transmission projects. The statute also required that any corridor proposed for designation must be consistent with

145 The Western Interconnection extends from Canada south to Mexico and includes the Canadian provinces of Alberta and British Columbia, the northern part of Baja, Mexico, and all or portions of 14 Western states (California, Oregon, Washington, Idaho, Montana, Wyoming, Nevada, Utah, Colorado, Arizona, New Mexico, South Dakota, Nebraska, and Texas).

the state's needs and objectives as identified in the latest adopted strategic transmission investment plan.

This chapter puts forward the Energy Commission's *Strategic Transmission Investment Plan* for the *2015 Integrated Energy Policy Report (2015 IEPR)*. It describes efforts to integrate environmental information into renewable energy generation and transmission planning. The state continues to refine these processes and tools as it works closely with other federal and state agencies, local governments, and stakeholders to plan for California's renewable generation and GHG reduction goals. The chapter also describes in-state and interstate transmission planning and projects that can help California meet its current and future renewable generation goals, and opportunities for easing future potential transmission build-out.

Landscape-Scale Planning Efforts and Analytical Tools

In the *2014 IEPR Update* process, the Energy Commission held a workshop on integrating environmental information in renewable energy planning. This workshop built upon themes highlighted in several previous *IEPRs* and *IEPR Updates* regarding the need to proactively address environmental and land-use issues to promote renewable project development, integrate that information into planning and procurement, and coordinate land-use and transmission planning in the *Desert Renewable Energy Conservation Plan (DRECP)* area¹⁴⁶ with the goal of expanding planning to other areas of the state. Recommendations from the *2014 IEPR Update* included the following:

- » Finalize and implement the *Desert Renewable Energy Conservation Plan*.
- » Collaborate and improve agency energy infrastructure planning.
- » Advance the current capabilities of the state in performing landscape-scale analysis.
- » Evaluate how to best apply landscape considerations in statewide transmission plans.

A public workshop for the *2015 IEPR* process was held on August 3, 2015, to continue the discussion in the *2014 IEPR Update* of using landscape-scale environmental evaluations for energy infrastructure planning. The workshop provided a forum to receive information and updates on various renewable energy and landscape-scale planning activities underway in California. This workshop included an overview of activities and lessons learned by local governments that received Renewable Energy Conservation Planning Grants from the Energy Commission, as well as information on ongoing renewable energy and transmission planning activities at the CPUC, the California ISO, and the Energy Commission. The workshop discussion also included an update on the Western Electricity Coordinating Council (WECC) efforts to identify the environmental risks for regional transmission need studies.

Energy Commission staff presented information on analytical tools and approaches developed for the *DRECP* that can be scaled up to support planning efforts beyond the *DRECP* area. The experience gained through the *DRECP* and related renewable energy planning efforts underscores the importance of using advanced analytical tools to support landscape planning, through fostering information sharing, collaboration, and stakeholder and public engagement. Indeed, such tools can be applied to many problems with geographical elements, including aspects of the built environment. Commissioner McAllister

146 The *DRECP* area totals roughly 22.5 million acres of federal and nonfederal desert land in California's Mojave and Colorado deserts in seven counties: Kern, San Bernardino, Riverside, Inyo, Imperial, Los Angeles, and San Diego.

stated his interest in adapting the *DRECP* development model for application to the built environment, for example to incorporate data from county assessors, local building departments, and utilities to create local-level energy usage baselines.¹⁴⁷ Such tools could facilitate implementation of SB 350 by standardizing metrics (for example, energy intensity) and tracking them over time, across buildings sectors and jurisdictions.

Prior to the above noted workshop, on July 30, 2015, Energy Commission Chair Robert B. Weisenmiller and CPUC President Michael Picker sent a joint letter to California ISO President and CEO Stephen Berberich requesting California ISO's participation in a new transmission planning initiative, the Renewable Energy Transmission Initiative (RETI) 2.0.¹⁴⁸ This effort would help achieve California's climate and energy policy goals. Governor Brown's Executive Order, B-30-15 calls for a 40 percent reduction in GHG emissions below 1990 levels by 2030. SB 350, which requires electric utilities to prepare long-term plans to meet GHG goals, establishes targets to increase retail sales of qualified renewable electricity to at least 50 percent by 2030, and allows for the regional expansion of the California ISO. In addition, in August 2015, the federal Clean Power Plan was finalized, requiring every state to significantly reduce electricity-sector GHG emissions. Developing the transmission needed to support increasing amounts of renewable resources will be critical to meeting these goals and will require careful planning and coordination across the West.

147 August 3, 2015, IEPR workshop transcript, pp. 86–89, http://docketpublic.energy.ca.gov/PublicDocuments/15-IEPR-08/TN205788_20150820T155922_Transcript_of_the_August_3_2015_Lead_Commissioner_Workshop.pdf.

148 http://www.energy.ca.gov/reti/reti2/documents/2015-07-30_Letter_to_CAISO_RE_RETI_2_Initiative_from_CEC_and_CPUC.pdf.

Update on Ongoing Renewable Energy and Transmission Planning Efforts

DRECP and Related Planning Efforts

In late 2008, the Energy Commission, California Department of Fish and Wildlife, the U.S. Bureau of Land Management (BLM), and the U. S. Fish and Wildlife Services signed a memorandum of understanding (MOU)¹⁴⁹ formalizing the Renewable Energy Action Team (REAT) for expediting the development of renewable energy resources in California's desert region to help meet the state's renewable energy goals.

These agencies developed the *DRECP*, a landscape-scale, multi-agency, science-based renewable energy and conservation plan covering 22.5 million acres in California's desert. The *DRECP* sought to identify the most appropriate areas for renewable energy development and related transmission projects while conserving important biological and natural resources. Through more than 70 public meetings, the *DRECP* team worked closely with local agencies, conservation and environmental groups, the public, tribes, and other interested stakeholders. The *Draft DRECP* was released in September 2014, and the public comment period ended in February 2015. The agencies received nearly 12,000 comments during the comment period.

In March 2015, the REAT agencies announced that the *DRECP* planning process would move forward in a phased manner.¹⁵⁰ Phase I is focused on completing a BLM land use plan amendment for the *DRECP* area.

149 http://www.energy.ca.gov/siting/2008-11-17_MOU_CEC_DFG.PDF.

150 http://drepcp.org/documents/docs/2015-03-10_DRECP_Path_Forward_News_Release.pdf.

The land use plan amendment will amend existing land designations to create areas for both energy development and conservation areas on public federal lands. The BLM land use plan amendment and final environmental impact statement (EIS) were released on November 10, 2015.¹⁵¹ Phase I will conclude when the Department of the Interior issues a Record of Decision in 2016.

Phasing the *DRECP* had the benefit of providing additional time for the counties that received Renewable Energy and Conservation Planning Grants to complete their planning. Counties have land-use and permitting authority for most projects on private land, and counties are key partners in meeting the state's renewable energy and conservation goals. Phase II of *DRECP* will explore better alignment of renewable energy development and conservation goals and policies at the local, state, and federal levels, including opportunities for a tailored county-by-county approach that supports the overall set of renewable energy and conservation goals in the *DRECP* area.

Coordination with Federal Section 368 Corridors

Section 368 of the Energy Policy Act of 2005 required the U.S. Department of Energy (U.S. DOE), the BLM, and the U.S. Forest Service (USFS), in cooperation with the departments of Agriculture, Commerce, Defense, and Interior, to designate new right-of-way corridors on western federal lands for electricity transmission, distribution facilities, and oil, gas, and hydrogen pipelines. The U.S. DOE, BLM, and USFS prepared a *West-Wide Energy Corridor Programmatic Environmental Impact Statement* that evaluated issues associated with the designation of energy corridors on federal lands in 11 western states.¹⁵² In late 2005, BLM designated the Energy Commission as a co-

151 http://drecp.org/documents/docs/2015-11-10_BLM_LUPA_final_EIS_news_release.pdf.

152 For more information, see <http://energy.gov/oe/services/electricity-policy-coordination-and-implementation/transmission-planning/energy>.

operating agency, and thereafter in coordination with U.S. DOE, BLM, and USFS, the Energy Commission established an interagency team¹⁵³ of federal and state agencies to review proposals to designate new and/or expand existing energy corridors and examine alternatives on California's federal lands. In 2009, the corridors were designated by BLM and USFS. Thereafter, multiple organizations filed a lawsuit against the U.S. Department of the Interior.¹⁵⁴ In 2012, a settlement agreement required the agencies to complete a corridor study and periodically review designated corridors.¹⁵⁵ A 2013 Presidential Memorandum also required the Secretaries to undertake a continuing effort to identify and designate energy corridors.

BLM is in the early stages of reviewing corridors for possible additions, deletions, or modifications in Western Arizona, Southern Nevada, and Southern California. The Energy Commission will work closely with BLM in its evaluation of corridors and coordinate that activity with RETI 2.0 and other planning processes.

Electricity Infrastructure Planning Processes

Since the formation of the original RETI¹⁵⁶ and *DRECP*, the Energy Commission, CPUC, and California ISO have recognized the value of collaborating to align their electricity infrastructure planning with the primary goal of ensuring

153 State agencies on this interagency team include the California Department of Fish and Wildlife, the Native American Heritage Commission, the CPUC, and the Governor's Office of Planning and Research. In addition, the State Lands Commission and the Department of Parks and Recreation have provided input and been monitoring the interagency team's activities. Federal agencies actively involved include the USFS, the National Park Service, the U.S. Air Force, the U.S. Marine Corps, and other Department of Defense services.

154 See: *Wilderness Society, et al. v. United States Department of the Interior, et al., No. 3:09-cv-03048-JW (N.D. Cal.)*.

155 The settlement agreement is located at http://corridoreis.anl.gov/documents/docs/Settlement_Agreement_Package.pdf.

156 RETI was initiated in 2007 as a joint effort among the Energy Commission, CPUC, California ISO, utilities, and other stakeholders. See chapter discussion below for more information.

that California’s energy and environmental policies are met in a coordinated, transparent, and effective manner. The alignment process has helped ensure that a consistent set of technical assumptions are used and applied by the three agencies to establish the analytical link among the different infrastructure studies. The coordinated agency planning activities have become more critical as higher levels of renewable generation capacity are expected to be developed for California.

The Energy Commission collaborated with the CPUC to develop the environmental scoring metric that has been an input to the RPS Calculator for developing scenarios of renewable generation projects. The RPS Calculator is a screening tool, developed by Energy+Environmental Consulting¹⁵⁷ for the CPUC to sort the potential renewable generation projects identified by the CPUC and the Energy Commission into supply curves using different evaluation criteria (project costs or environmental scores, for example). The calculator ultimately identifies a set of renewable project portfolios for procurement evaluations that are transmitted to the California ISO for their transmission need studies. The CPUC and Energy Commission are in close cooperation as the RPS Calculator is being redesigned and updated within the current RPS proceeding at the CPUC (Rulemaking 15-02-020).

The Western Electricity Coordinating Council (WECC) is a nonprofit organization dedicated to assuring a reliable bulk electric system in the geographic area known as the Western Interconnection. WECC developed a four-tier environmental risk classification system for assessing the likelihood that a transmission project developer might encounter environmental risks in the development

process.¹⁵⁸ These environmental risk metrics will simplify evaluation of transmission options, together with information on capital cost, reliability, and engineering. The Energy Commission will work with the WECC and stakeholders on how to best incorporate these regional environmental metrics with statewide energy infrastructure planning.

Further work is needed to better characterize the environmental implications of proposed renewable generation and transmission projects throughout California and in other Western regions. The Energy Commission continues to investigate environmental information sources developed for different landscape-level studies and consider geographic information system (GIS) mapping tools for energy stakeholder planning evaluations. The Energy Commission supports the inclusion of environmental information in interagency planning.

Local Government Planning Activities

California county governments are the permitting authority for most nonthermal power plants, such as wind and solar photovoltaic (PV), located on private lands in California. Projects approved by counties are subject to applicable federal and state law, as well as local governments’ land-use rules and policies. Counties, especially those rich with renewable energy resources, play an integral role in siting projects and helping California meet its energy and environmental goals.

157 E3 first developed the RPS Calculator to support the CPUC’s 33 percent RPS Implementation Analysis.
https://ethree.com/public_projects/rps.php.

158 Risk class 1 encompasses the lowest risk of environmental sensitivities and represents preferred areas for transmission development, such as existing transmission rights-of-way. Risk classes 2 and 3 have low-to-medium and high risks of environmental sensitivities, respectively, and a likelihood of mitigation requirements. Risk class 4 includes exclusion areas where transmission development is precluded by legislation or regulatory restrictions.

Kern County, for example, adopted a Renewable Energy Goal of 10,000 MW of permitted capacity by 2015. The County has permitted 9,723 MW and has an additional 270 MW under review. The benefits to the County and the state from this renewable development include 8,000 construction jobs, 1,500 operational jobs, \$25 billion of direct investment, \$50 million in new property tax revenue, more than \$25 million in sales tax, and power production for more than 7 million people.¹⁵⁹ Butte County implemented PowerButte in May 2015. This initiative is intended to encourage renewable energy, support the County's General Plan and Climate Action Plan, and help meet county and state GHG reduction targets and renewable energy goals. As part of the initiative, Butte County is working closely with the public and stakeholders to identify appropriate areas within the county for the development of solar energy facilities, as well as identifying farmland and natural resources that should be protected.

Most local governments face staffing and other resource challenges that affect their ability to plan adequately for renewable energy development in their jurisdictions. To help address these challenges, Governor Brown signed Assembly Bill X1 13 (V. Manuel Pérez, Chapter 10, Statutes of 2011) (AB X1 13), which authorized the Energy Commission to award up to \$7 million in grants to "qualified counties" to develop or revise rules and policies that promote the development of eligible renewable energy resources, the associated transmission facilities, and the processing of permits for eligible renewable energy resources. "Qualified counties" identified in AB X1 13 are Fresno, Imperial, Inyo, Kern, Kings, Los Angeles, Madera, Merced, Riverside, San Bernardino, San Diego, San Joaquin, Stanislaus, and Tulare. In 2012, Assembly Bill 2161 (Achadjian, Chapter 250, Statutes of 2012) added San Luis Obispo county as a qualified county.

159 See the Energy Commission Docket Log, 15-IEPR-08 (Transmission and Landscape Scale Planning), Transaction Number 205564, available at <https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=15-IEPR-08>.

To implement AB X1 13, the Energy Commission established the Renewable Energy and Conservation Planning Grants (RECPG) in 2012 and awarded more than \$5 million out of the available \$7 million. RECPG helps qualified counties update their general plans and zoning codes, complete environmental studies and mitigation plans, and engage the public. Grants also help ensure that county land-use plans are consistent with federal and state goals for renewable resource development and natural resource conservation.

The Energy Commission held competitive solicitations to award RECPG funding in February 2013, January 2014, and February 2014 and approved grant awards to Imperial, Inyo, Los Angeles, Riverside, San Bernardino, and San Luis Obispo Counties. Activities funded by the grants include development of renewable energy elements as part of counties' general plan updates, preparation and certification of environmental impact reports, identification of areas within a county where renewable resources will be given priority and be eligible for streamlined permitting, collection and development of data, and engagement of public, private, and tribal partners to plan for renewable energy development. The work funded by RECPG grants represents important steps toward achieving California's long-term GHG reduction, energy, and natural resource conservation goals.

As California moves to implement the 50 percent RPS by 2030 requirement, the state expects to see additional renewable energy development in California. Local governments have permitted many of the renewable energy projects that are contributing to meeting the 33 percent RPS, and will continue to be important partners in permitting and planning going forward. To help achieve the state's energy goals, the Energy Commission should continue to work closely with local governments on renewable energy planning, including providing technical assistance on permitting and sharing information about renewable energy projects, mitigation, and best management practices.

Planning with Stakeholders for Solar Development on Least-Conflict Lands in the San Joaquin Valley

Over the last several years, the San Joaquin Valley has experienced a significant increase in the number of solar projects under development to meet the state's 33 percent RPS requirement. The area is appropriate for solar development because of its abundant sunshine and hot, dry climate. However, the region is also one of California's most important agricultural production areas, as well as home to several important species and habitat areas. A variety of stakeholders have expressed concern over continued solar development and the associated potential impact to both agricultural areas and sensitive habitats. In addition, there is a continued shortage of available water for irrigation needs and long-standing issues associated with the natural buildup of selenium and other chemicals on drainage-impaired agricultural lands and the retirement of impacted lands from agricultural production.

In June 2015, the Governor's Office of Planning and Research launched a stakeholder-led process to identify *least-conflict* lands in the San Joaquin Valley for solar development and provide input to policy makers for eliminating barriers to siting projects on those least-conflict areas. Using the best available data and information, stakeholder work groups, for example, agriculture (rangeland and farmland), conservation, transmission, solar industry, and others, identified and mapped a set of least-conflict lands for solar development. State and federal agencies provided data and technical assistance to the workgroups.

Once the work groups agreed to least conflict areas, a preliminary evaluation of existing transmission facilities and already-approved transmission projects began. Transmission planners from SCE, PG&E, and the California ISO have begun discussions and believe that available capacity on the current transmission system, including projects already in progress, ranges between 2,000 MW to 3,000 MW. This effort, relying on previous studies, identified existing transmission facilities in the area and current system constraints. A final report on this project is expected in February 2016. The data and stakeholder work product produced in the San Joaquin Valley Identification of Least-Conflict Lands study will provide an input into RETI 2.0.

Renewable Energy Transmission Initiatives

RETI

The Renewable Energy Transmission Initiative (RETI) was initiated in June 2007 to (1) help identify the transmission projects needed to accommodate California's renewable energy goals, (2) ease the designation of corridors for future transmission line development, and (3) expedite transmission line and renewable generation siting and permitting. Using a collaborative analysis, RETI stakeholders identified 31 competitive renewable energy zones throughout the state. These competitive renewable energy zones were the geographical areas that were the most favorable for cost-effective and environmentally responsible renewable generation development with corresponding transmission interconnections and lines. The competitive renewable energy zones included about 80,000 MW of potential statewide renewable resource development, with nearly 66,000 MW of the potential located in California's Mojave and Colorado Deserts.

RETI established a precedent for taking a landscape-scale planning approach to renewable energy and transmission planning by bringing together state, federal, and local agencies and a diverse group of stakeholders. The stakeholders worked together toward a common goal of helping the state achieve important renewable energy goals.¹⁶⁰

RETI 2.0

As noted earlier, on July 30, 2015, Energy Commission Chair Robert B. Weisenmiller and CPUC President Michael Picker sent a joint letter to California ISO President and CEO Stephen Berberich noting their intent to establish the RETI 2.0 and requesting that California ISO join the effort. RETI 2.0 is intended to help achieve the state's current climate and policy goals, including a reduction in GHG emissions to 40 percent below 1990 levels by 2030 and further reductions to 80 percent below 1990 levels by 2050.

RETI 2.0 is a proactive, statewide, non-regulatory planning forum intended to identify the constraints and opportunities for new transmission to access and integrate new renewable resources in California and across the West that can help meet the state's long-term GHG and renewable energy goals. Convened by the California Natural Resources Agency, Energy Commission, CPUC, California ISO, and the BLM California Office, RETI 2.0 is intended to facilitate the long-range planning, inter-agency coordination, and stakeholder engagement necessary to reach these goals with the lowest costs and greatest benefit. In addition to energy, environmental, and agricultural stakeholders, RETI 2.0 will seek voluntary participation from tribal and local governments, public power entities, other western states, and regional energy planning bodies to help look for solutions that serve multiple interests.

Specifically, RETI 2.0 will:

- » Convene a broad range of stakeholders in one Plenary Group and two technical work groups
- » Explore conceptual combinations of renewable generation resources in California and throughout the West that can best meet economic, environmental, and reliability goals
- » Identify land use and environmental opportunities and constraints to accessing these resources
- » Build understanding of the transmission implications of these renewable scenarios, and support for “least regrets” transmission investments
- » Inform future planning and regulatory proceedings.

As noted by Chair Weisenmiller and President Picker, it is important to ensure that the RETI 2.0 process is inclusive and transparent to promote robust stakeholder engagement in this process. The result of this process will be to inform the Energy Commission, CPUC, California ISO, and other participating public agencies and balancing authorities in their post-2020 transmission planning.

Landscape-Scale Planning Conclusions

Landscape-scale planning for renewable energy and transmission has proven to be an important part of meeting California's renewable energy and climate goals. From the first RETI process to the joint REAT agency work on the DRECP and the stakeholder-led San Joaquin Valley Identification of Least-Conflict Lands study, California agencies, local governments, tribes, and stakeholders have become increasingly familiar with planning approaches that seek to

160 For more information on RETI, see <http://www.energy.ca.gov/reti/>.

identify the best areas for renewable energy development. These approaches take into consideration a wide range of potential constraints and conflicts including environmental sensitivity, agricultural and other land uses, tribal cultural resources, and more. As noted in the letter by Chair Weisenmiller and President Picker, there is proven value in using this approach to assess the relative potential of different locations for renewable energy, especially in the context of identifying policy-driven transmission lines.

In the time that has ensued since the first RETI process, California has made tremendous strides in achieving its renewable energy goals. A record number of new renewable energy projects have been built in California, and California is on track to exceed the 33 percent RPS requirement by 2020. This experience in planning for and permitting renewable energy generation and transmission projects, along with the strong relationship among agencies that have worked together to help achieve these goals, will be an important asset to the state in the RETI 2.0 process and, more broadly, in achieving the 50 percent renewable requirement by 2030.

Incorporating Landscape-Scale Planning into Transmission Planning Processes

As noted in previous IEPR cycles, transmission planning processes need to be streamlined and coordinated to ensure siting, permitting, and construction of the most appropriate transmission projects to connect renewable resources while ensuring proper consideration of land-use and environmental issues. In many cases, the project development process that identifies routing issues and

constraints does not begin until after the “wires” planning process is complete. This lengthens transmission development and increases the risk of approved transmission projects not being developed due to environmental issues.

As discussed above, the RETI was a statewide land-use planning process to help identify transmission projects needed to meet the state’s 33 percent RPS by 2020 requirement. This established the precedent for using landscape-level approaches in renewable energy and transmission planning and led directly to the collaborative land-use planning occurring in the DRECP process. In addition, the California Transmission Planning Group,¹⁶¹ formed in 2009, addressed California’s transmission needs in a coordinated manner by developing a conceptual statewide transmission plan that identified the necessary transmission infrastructure to meet the state’s 33-percent-RPS-by-2020 requirement. In December 2010, FERC approved the California ISO’s revised transmission planning process that requires the development of an annual conceptual statewide transmission plan, thereby replacing the California Transmission Planning Group’s planning function.

The lessons of these past collaborations have been incorporated into a planning alignment process among the Energy Commission, CPUC, and California ISO for evaluating and approving new transmission system projects. To date, the transmission projects that are needed to support achievement of California’s 33 percent RPS are already approved and operating or progressing through the CPUC approval process, as discussed below.

Looking forward, the RETI 2.0 process will provide a non-regulatory, stakeholder process to consider possible

161 The formation of the California Transmission Planning Group was an outcome of RETI’s recognition that detailed transmission planning was needed. The California Transmission Planning Group conducted joint transmission planning and coordination to meet California’s transmission needs and was composed of all entities within California responsible for transmission planning. RETI and other stakeholders provided feedback and input into the California Transmission Planning Group’s conceptual statewide transmission plan.

scenarios and strategies for meeting California's 2030 goals which will help inform the possible identification of new policy-driven¹⁶² transmission based on 2030 renewable energy portfolios in the fall of 2016. This effort needs to complement existing efforts currently underway and seek to optimize use of the existing transmission system.

California ISO Transmission Planning

A core responsibility of the California ISO is to identify upgrades needed to maintain grid reliability, successfully meet California's policy goals, and bring economic benefits to consumers through an annual stakeholder transmission planning process. Below is an update on the highest priority approved transmission projects and potential backup transmission solutions identified in the two most recent annual *California ISO Transmission Plans*.¹⁶³

2013–2014 Transmission Planning Process

The focus of the 2013–2014 transmission planning process was to identify transmission solutions to address grid reliability in the Los Angeles (L.A.) Basin and San Diego areas in light of SCE's June 7, 2013, decision to retire the San Onofre Nuclear Generating Station (San Onofre), along with the enforcement timeline of once-through

cooling (OTC) regulations for retiring power plants using ocean or estuarine water for cooling. (This is discussed in detail in Chapter 7, "Electricity Infrastructure in Southern California.") The California ISO conducted an analysis of the bulk transmission system in light of these changes. As a result, it subsequently received several transmission proposals in the 2013 request window. The California ISO grouped the proposals into three categories:

- » Group I – transmission upgrades that optimize the use of existing transmission lines and do not require new transmission rights-of-way. Projects include:
 - » San Luis Rey Substation to provide dynamic reactive support. Expected in-service date: 2017.
 - » Imperial Valley Substation Flow Controller to help address voltage instability concerns. Expected in-service date: 2017.
 - » Mesa Substation 500 kilovolt (kV) Loop-In that allows Southern California Edison (SCE) to bring a new 500 kV electric service into its metropolitan load center, delivering power from the Tehachapi wind resources area or resources located in Pacific Gas and Electric's (PG&E's) service territory or the Northwest via the 500 kV bulk transmission system. Expected in-service date: 2020.
- » Group II – transmission lines that strengthen the L.A./San Diego connection and upgrade existing corridors. Conceptual projects include:
 - » Talega-Escondido/Valley-Serrano to new Case Springs 500 kV transmission line.

162 In 2010, the California ISO revised its transmission planning process to include a transmission category for evaluating and approving policy-driven transmission additions and upgrades to support the state's policy objectives. Beginning with the *2010–2011 Transmission Plan*, the California ISO focused on the state's 33 percent RPS requirement for identifying and approving policy-driven transmission additions and upgrades.

163 For more information, please refer to <http://www.caiso.com/planning/Pages/TransmissionPlanning/Default.aspx>.

- » High Voltage DC submarine cable from Alamitos to four termination options: Encina, San Onofre, Peñasquitos, or Bay Boulevard (Chula Vista).
- » Valley-Inland 500 kV transmission line.
- » Group III – new transmission into the greater L.A. Basin/San Diego area. Conceptual project includes:
 - » Imperial Valley-Inland 500 kV transmission line.

For the *2013–2014 Transmission Plan*, the California ISO took a least-regrets approach¹⁶⁴ and approved Group I projects that reduced the local capacity requirements (LCR),¹⁶⁵ provided the best use of existing transmission lines and rights-of-way, and minimized permitting risk. The California ISO also recommended further analysis of Groups II and III in future planning cycles with input from state and federal agencies and stakeholders. In addition, the California ISO approved two interregional economic projects with reliability and policy benefits: Delaney-Colorado River and Harry Allen-Eldorado. See the Update to Transmission Projects to Meet the 2020 RPS section below for more information.

164 This least regrets approach is based on balancing the two objectives of minimizing the risk of constructing underused transmission capacity while ensuring that transmission needed to meet policy goals is built promptly.

165 *Local capacity requirements* refer to the amount of generating capacity required within a local capacity area. Local capacity areas are transmission-constrained areas, which are identified when the maximum combined import capacity across the set of transmission line segments between pairs of substations defining a region is less than the peak load within the region. To serve load reliably, each local capacity area must have enough generation located within the local area to meet peak load, less the maximum import capacity of the transmission lines connecting that area to the high-voltage transmission system. For more information, see Chapter 7.

High-level Environmental Assessment for the Transmission Planning Process

As discussed above, in its *2013-2014 Transmission Plan*, the California ISO identified several transmission projects that could alleviate the transfer limitations and reliability problems caused by the shutdown of San Onofre. At the request of the California ISO, the Energy Commission funded a consultant report that provides a high-level assessment of the environmental feasibility of several electric transmission alternatives under consideration by the California ISO to address reliability and other system challenges resulting from the San Onofre closure.¹⁶⁶ Since the May 2014 publication of the consultant report, the California ISO found that the closure of San Onofre significantly reduced the capability of the transmission system to deliver future renewable generation from Imperial County due to changes in electricity flow patterns over the electric transmission system. To develop a comprehensive list of potential transmission solutions, the California ISO conducted an Imperial County Transmission Consultation¹⁶⁷ meeting in July 2014 to provide opportunities for stakeholder input on issues surrounding the deliverability from the Imperial County area to the California ISO's balancing area. In September 2014, following that meeting, an addendum to the consultant report¹⁶⁸ was prepared that evaluated two additional trans-

166 Aspen Environmental Group. 2014. *Transmission Options and Potential Corridor Designations in Southern California in Response to Closure of San Onofre Nuclear Generating Stations (SONGS): Environmental Feasibility Analysis*. CEC-700-2014-002 Consultant Report, May 2014. <http://www.energy.ca.gov/2014publications/CEC-700-2014-002/CEC-700-2014-002.pdf>.

167 The Imperial County Transmission Consultation process can be found at <http://www.caiso.com/planning/Pages/TransmissionPlanning/2014-2015TransmissionPlanningProcess.aspx>.

168 Aspen Environmental Group. 2014. *Addendum to Transmission Options and Potential Corridor Designations in Southern California in Response to Closure of San Onofre Nuclear Generating Stations (SONGS): Environmental Feasibility Analysis*. CEC-700-2014-002-AD Consultant Report, September 2014. <http://www.energy.ca.gov/2014publications/CEC-700-2014-002/CEC-700-2014-002-AD.pdf>.

mission alternatives proposed by Imperial Irrigation District (IID) and SCE. A second addendum¹⁶⁹ was prepared in January 2015 that includes additional transmission alternatives suggested in the consultation workshop. As noted in the *2014 IEPR Update*, “One or more of the alternatives may be considered by Energy Commission staff in the state’s electric transmission corridor designation process.”¹⁷⁰

2014–2015 Transmission Planning Process

The California ISO focused on analyzing potential backup transmission solutions that could address both a resource development shortfall in the L.A. Basin/San Diego area and provide additional transmission deliverability for higher levels of renewable generation from the Imperial County area as recommended in the 2013–2014 planning cycle. The California ISO developed a list of potential transmission options based on input from the consultation meetings and projects previously submitted in its request window. The California ISO developed the final list of projects to analyze based on scope of work, estimated potential LCR benefits, deliverability of higher levels of renewable generation from the Imperial County area, preliminary environmental assessments provided by the Energy Commission consultant reports, and high-level cost estimates.¹⁷¹ The list of transmission solutions include:

- » IID Strategic Transmission Expansion Plan (Hoover–San Onofre): 180-mile 500 kV DC line.
- » IID Midway-Inland: 125-mile 500 kV DC or AC line.
- » Comisión Federal de Electricidad-California ISO Tie and Miguel-Encina (Option A): combined 102-mile 500 kV AC line and 94-mile underground/submarine 500 kV DC line.
- » Comisión Federal de Electricidad-California ISO Tie and Miguel-Huntington Beach DC Line (Option B): combination of a 102-mile 500 kV AC line and a 148-mile 500 kV bipole DC line.
- » Comisión Federal de Electricidad-California ISO Tie and Laguna Bell Corridor Special Protection Scheme (Phase 1) and Miguel-Huntington Beach (Phase 2) – Option C: combination of 102-mile 500 kV AC line and 148-mile 500 kV DC line.
- » Talega-Escondido/Valley-Serrano Interconnect: 32 mile 500 kV AC line.

The California ISO’s assessment found the two best backup options addressing a potential resource development shortfall in the L.A. Basin/San Diego area and providing additional transmission deliverability for potentially higher levels of renewable generation from the Imperial County area were the following:

- » Comisión Federal de Electricidad-California ISO Tie Line Option C, Phase 1
 - » If siting is viable in northern Mexico
 - » Provides lowest cost and high LCR reduction benefits

169 Aspen Environmental Group. 2015. *Second Addendum to Transmission Options and Potential Corridor Designations in Southern California in Response to Closure of San Onofre Nuclear Generating Stations (SONGS): Environmental Feasibility Analysis*. CEC-700-2014-002-AD2 Consultant Report, January 2015. <http://www.energy.ca.gov/2014publications/CEC-700-2014-002/CEC-700-2014-002-AD2.pdf>.

170 California Energy Commission. 2015. *2014 Integrated Energy Policy Report Update*. Publication Number: CEC-100-2014-001-CMF. <http://www.energy.ca.gov/2014publications/CEC-100-2014-001/CEC-100-2014-001-CMF-small.pdf>, p. 153.

171 See *California ISO 2014-2015 Board of Governors Approved Transmission Plan*, Tables 2.6-8 and 2.6-9, pp. 103 and 106-109 for more detail. <http://www.aiso.com/Documents/Board-Approved2014-2015TransmissionPlan.pdf>.

» IID Midway-Inland

- » Provides best balance of the options considered – LCR reduction, Imperial County renewable deliverability benefits, siting viability, and cost
- » Provides most flexibility to stage components to meet the two needs

The California ISO noted the alternatives involve challenging rights-of-way and lengthy permitting and construction timelines. Continued analysis will be required as needs evolve in future planning cycles.

California ISO Participation in RETI 2.0

The recent changes to energy policy goals as outlined in Governor Brown's Executive Order B-30-15, along with improved generation and demand-side technologies, evolving challenges to integrating new intermittent generation, and the need to maintain electricity system reliability, require periodic updates for renewed, broad, and coordinated attention to transmission planning in California and the Western Interconnection. As a result, the California ISO is participating in the newly formed RETI 2.0 that could help inform its future transmission planning cycles.

Update to Transmission Projects to Meet the 2020 RPS

As noted in the *2013 IEPR*, the California ISO, the IID, and the Los Angeles Department of Water and Power (LADWP) identified and approved 17 transmission projects for the integration of renewable resources to enable California to meet the 33 percent RPS by 2020 requirement. Fifteen of the projects are within the California ISO's control area, one project (Path 42) is within both the California ISO's and IID's control area, and one project is within LADWP's control area. As noted above, in the *2013–2014 Transmission Plan*, the California ISO identified two interregional projects, Delaney-Colorado River and Harry Allen-Eldorado, as economic projects with reliability and policy benefits. In May 2015, the CPUC determined that the Coolwater-Lugo transmission project was no longer needed and dismissed the application without prejudice. Below is an update of the projects presented according to their associated actual or expected on-line date.

2011 Projects

Midway-Bannister: On March 15, 2011, the IID completed and energized the 8.7-mile 230 kV transmission project.

2012 Projects

Sunrise Powerlink: On June 17, 2012, San Diego Gas & Electric (SDG&E) completed and energized the 117-mile 230/500 kV transmission project.

2013 Projects

Colorado River-Valley: On September 29, 2013, SCE completed and energized the 153-mile 500 kV transmission project.

Eldorado-Ivanpah: On July 1, 2013, SCE completed and energized the 35-mile double-circuit, 230 kV transmission project.

Carrizo-Midway: On March 20, 2013, PG&E completed and energized the 35-mile double-circuit, 230 kV transmission project.

2014 Projects

None.

2015 Projects

SCE/IID Joint Path 42: The SCE/IID Joint Path 42 project will increase the transfer capacity from 600 MW to 1,500 MW of renewable energy from IID to SCE's portion of the California ISO controlled grid. SCE's portion of the project includes upgrading a 15-mile double-circuit, 230 kV transmission line between SCE's Devers and Mirage Substations. The IID upgrade consists of replacing 20 miles of a double-circuit, 230 kV transmission line between SCE's Mirage and IID's Coachella Valley and Ramon Substations. SCE and IID completed construction and the project will be fully energized by December 31, 2015.

Imperial Valley-Liebert: The Imperial Valley-Liebert project is a one-mile 230 kV transmission line from the new Liebert Substation to the existing Imperial Valley Substation. The project will deliver at least 1,400 MW of renewable energy to the California ISO grid. The project qualified for the California ISO's competitive solicitation process. On July 11, 2013, the California ISO selected IID as the approved project sponsor. The project is on hold, and a new on-line date is yet to be determined.

El Centro-Imperial Valley: IID's El Centro-Imperial Valley project, S line, replaces an existing 230 kV line with a double-circuit 230 kV transmission line between the jointly owned IID/SDG&E Imperial Valley Substation and the IID El Centro Switching Station. This upgrade is required for completion of the Imperial Valley-Liebert project approved by the California ISO. The project is on hold, and a new on-line date is yet to be determined.

2016 Projects

Tehachapi Renewable Transmission Project: SCE's Tehachapi Renewable Transmission Project is being built in 11 segments and includes more than 300 miles of new and upgraded 220 kV and 500 kV transmission lines and substations. The project will deliver 4,500 MW of renewable generation from eastern Kern and Los Angeles counties to the Los Angeles Basin. Most of the generation will be wind resources from Kern County, but the line will also accommodate future solar and geothermal projects. All segments except the underground portion of Segment 8 are operational. The underground portion of Segment 8 is under construction and expected to be in service in 2016.

Borden-Gregg: PG&E will replace the existing Borden-Gregg 230 kV transmission line with a larger capacity conductor. The project will deliver 800 MW of solar generation proposed near Fresno, specifically the Westlands area. The project was identified as needed in the California ISO's Generator Interconnection Procedures. The project is on hold until generators make further progress, at which time PG&E will submit an application to the CPUC requesting approval.

Barren Ridge Renewable Transmission Project: LADWP's Barren Ridge Renewable Transmission Project includes 87 miles of 230 kV transmission lines. The project will provide additional transmission capacity to access 1,400 MW of wind, solar, and other renewable resources. The project is under construction.

2017 Projects

Sycamore-Peñasquitos: The Sycamore-Peñasquitos project is a 17-mile 230 kV transmission line between SDG&E Sycamore and Peñasquitos Substations. The project will deliver renewable generation and reliability benefits to the San Diego area. The project qualified for the California ISO's competitive solicitation. On March 4, 2014, the California ISO selected SDG&E and Citizens Energy Corporation as the approved project sponsors. The project is in permitting at the CPUC.

South of Contra Costa: PG&E's South of Contra Costa project includes replacing 47 miles of existing 230 kV transmission lines south of the Contra Costa Substation with a larger capacity conductor. The project will deliver 300 MW of wind generation in Solano County. The project was identified as needed in the California ISO's Generator Interconnection Procedures. The project is on hold until generators make further progress, at which time PG&E will apply to the CPUC requesting approval.

Warnerville-Bellota: PG&E will replace the existing Warnerville-Bellota 230 kV transmission line with larger capacity conductor. The project, along with the Wilson-Le Grand and Gates-Gregg projects discussed below, will deliver 700 MW of renewable generation in the Greater Fresno, Central Valley North, Merced, and Westlands areas. The project has an approved Notice of Exempt Construction and is in the engineering design phase.

2018 Project

El Centro-to-Highline: IID's El Centro-to-Highline project replaces existing 161 kV and 92 kV lines with a double-circuit 230 kV transmission line. IID identified the need for this project to interconnect generation resources in its Transitional Cluster. The project is in the engineering design phase.

2020 Projects

West of Devers: The West of Devers project consists of removing and replacing roughly 48 miles of existing 220 kV transmission lines with new double-circuit, 220 kV transmission lines between the existing SCE Devers Substation, Vista Substation, and San Bernardino Substation. The project, combined with the Colorado River-Valley project discussed earlier, will deliver about 4,000 MW from Riverside County. The project is in the permitting stage.

Wilson-Le Grand: PG&E will replace the existing Wilson-Le Grand 115 kV transmission line with larger capacity conductor. The project, along with the Warnerville-Bellota project discussed earlier and the Gates-Gregg project discussed below, will deliver 700 MW of

renewable generation in the Greater Fresno, Central Valley North, Merced and Westlands zones. The project has an approved Notice of Exempt Construction and is in the planning phase.

Delaney-Colorado River: The California ISO identified the need for an interregional 500 kV transmission line between the existing SCE Colorado River Substation and the new APS Delaney Substation as an economic project with reliability and policy benefits in its Board of Governors-approved *2013-2014 Transmission Plan*. The approximate length of the single-circuit, 500 kV transmission line is 115-140 miles, depending on the approved route. The project is eligible for competitive solicitation. On July 10, 2015, the California ISO selected DCR Transmission, LLC, a joint venture company owned by Abengoa Transmission & Infrastructure, LLC and an affiliate of Starwood Energy Group Global, Inc., as the approved project sponsor to finance, construct, own, operate, and maintain the Delaney-Colorado River project.

Harry Allen-Eldorado: The California ISO identified the need for an interregional 500 kV transmission line between SCE majority-owned Eldorado Substation and NV Energy Harry Allen Substation as an economic project with reliability and policy benefits in its Board of Governors-approved *2013-2014 Transmission Plan*. The approximate length of the single-circuit, 500 kV transmission line is 60 miles. The project is eligible for competitive solicitation.

2022 Projects

Gates-Gregg (Central Valley Power Connect): The Gates-Gregg project is a new double-circuit 230 kV transmission line between PG&E Gates and Gregg Substations. The project, along with the Warnerville-Bellota and Wilson-Le Grand projects discussed earlier, will allow for delivery of 700 MW of renewable generation in the Greater Fresno, Central Valley North, Merced, and Westlands zones. The project qualified for the California ISO's competitive solicitation process. On November 7, 2013, the California ISO selected the consortium of PG&E, MidAmerican Transmission, and Citizens Energy

Corporation as the approved project sponsors. The consortium recently renamed the project the Central Valley Power Connect.¹⁷² The project is in the engineering design phase and will file with the CPUC in 2016.

Status of Removed Projects

Pisgah-Lugo: The California ISO identified the need for the Pisgah-Lugo transmission project to interconnect the proposed Calico Solar Project. On June 20, 2013, K Road Calico Solar, LLC filed a request with the Energy Commission to terminate the Calico Solar Project. The Energy Commission approved this request on June 20, 2013. With the termination of the Calico Solar Project, the California ISO determined that the Pisgah-Lugo transmission project was no longer needed.

Coolwater-Lugo: The California ISO identified the need for the Coolwater-Lugo transmission project to interconnect the Mojave Solar project with full capacity deliverability status. In 2015, as a result of the California ISO's annual reassessment of network upgrades identified in previous generator interconnection studies, it determined the Coolwater-Lugo transmission project was no longer needed to interconnect the Mojave Solar project with full capacity deliverability status. The change in deliverability status for the Mojave Solar project was primarily due to the election by several generating facilities in the area to permanently retire and forego repowering. On April 20, 2015, the CPUC-assigned administrative law judge (ALJ) issued a proposed decision¹⁷³ to dismiss without prejudice, or without any loss of rights or privileges, SCE's application for a certificate of public convenience and necessity to construct the Coolwater-Lugo Transmission Project

(A.13-08-023). On May 21, 2015, the CPUC Commissioners approved the ALJ proposed decision.¹⁷⁴ SCE's application was closed.

Regional Transmission Planning Issues

Interest in multistate transmission projects continues to increase in light of the 50 percent RPS by 2030 requirement, the California ISO's EIM covering eight states in the West (discussed below), the potential addition of PacifiCorp to the California ISO's balancing authority area, compliance with FERC's interregional Order No. 1000, and the Clean Power Plan's implementation of Section 111(d) of the 1990 Clean Air Act. Planned generation associated with several multistate transmission projects could provide seasonal and geographical diversity that could complement California's renewable generation.

The Western states have continued to work closely together in the past two years through a productive analytic period relying on the U.S. DOE funding for state planning. These states have continued to monitor the evolution of reliability regulation in the western interconnection through engagement with federal regulators (NERC and FERC) and the bifurcated regional entities (WECC and Peak Reliability). The states' interests have focused on implementing the EIM and transmission expansion planning. Most recently, states have initiated important collaborative work related to carbon reduction from electric generation, which will build on transmission expansion planning. This new effort will require extensive coordination and complex analytics.

172 <http://cvpowerconnect.com/>.

173 CPUC ALJ Moosen's Proposed Decision can be found at <http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M151/K169/151169662.PDF>.

174 CPUC Commission Decision 15-05-040 can be found at <http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M152/K058/152058507.PDF>.

Ongoing Challenges: Engaging in Reliability Regulation

States have consistently emphasized the central importance of system reliability and have been closely engaged in the evolution of regional reliability regulation. As described in the *2013 IEPR*, one outcome of the September 8, 2011, Southwest outage was the restructuring of WECC with the goal to separate the responsibility for real-time reliability operation from the regulatory oversight functions of standards development and compliance enforcement. On June 27, 2013, the WECC Board of Directors approved the bifurcation of the company into a Regional Entity (WECC) and a Regional Coordination Company (Peak Reliability). Thus, WECC retained its regulatory oversight functions, while Peak Reliability is responsible for real-time reliability operation. The bylaws of each entity required an annual governance review after one year of operation. These reviews identified a number of successes as well as areas for continued refinement.

WECC succeeded in multiple areas, including unanimous approval of its budget and business plans for 2015 and 2016, as well as renegotiation of its regional delegation agreement, signed with NERC. In May 2015 WECC reached a settlement with FERC regarding its responsibility (predating bifurcation) as the reliability coordinator at the time of the Southwest outage.¹⁷⁵ As a result, FERC imposed significant monetary penalties on WECC. On the other hand, members of some classes of WECC expressed complaints about the cost of WECC, lack of access to decision-making, and opposition to use of Federal Power Act Section 215 funding for non-traditional reliability matters.

Peak Reliability also succeeded in establishing itself as a new reliability coordinator. However, there is debate over whether the appropriate funding mechanism is

through member contracts or Section 215. The Western Interconnection Regional Advisory Board supported the Peak Reliability Board's approach (contracting) after significant compromise occurred. Controversy has also unfolded over how and who pays for what data transferred from Peak Reliability to WECC.

Continuing Attention: Support for Western Transmission Expansion Planning

As described earlier in this chapter and noted in the August 3, 2015, IEPR workshop, a 50 percent RPS by 2030 requirement will entail development of renewable projects and associated transmission additions. Key questions include what combination of technologies present the best portfolio and how to value potential out-of-state resource and transmission opportunities. These questions will be considered in two arenas: at the interconnection-wide level with the WECC Transmission Expansion Planning Policy Committee (TEPPC) and at the interregional level with the FERC Order 1000 planning regions. The RETI 2.0 effort could also help inform future transmission planning efforts in the Western Interconnection.

With respect to interconnection-wide transmission planning, WECC and the states support a robust transmission planning function, even though the U.S. DOE-funded American Recovery and Reinvestment Act grants ended in 2014. TEPPC continues to lead a strong stakeholder process that allows WECC to develop a production cost data-base that reflects consensus of all major participants. The database includes assumptions necessary to perform production cost assessments for varied generation and transmission futures. The assumptions are reflected in the *common case*, which is used by multiple major utility, state and consultant studies to address issues such as renewables integration. Among many other initiatives, TEPPC's Scenario Planning Steering Group has initiated a new major effort to develop a climate change

175 Federal Energy Regulatory Commission, Order Approving Stipulation and Consent Agreement, May 26, 2015, Docket No. IN14-11-000, <http://www.ferc.gov/CalendarFiles/20150526093037-IN14-11-000.pdf>.

scenario and evaluate potential impacts of a 3 degree Fahrenheit increase in temperature on the electric system in 2034.¹⁷⁶ (See Chapter 9 for more information on climate change research.)

The Western planning regions have made significant progress on interregional transmission planning under FERC Order 1000. On May 10, 2013, the California ISO, Columbia Grid, Northern Tier Transmission Group, and WestConnect filed tariff revisions to comply with the interregional transmission coordination and cost allocation requirements of FERC Order No. 1000. On December 18, 2014, FERC issued an order conditionally accepting their interregional compliance filings subject to further filings.¹⁷⁷ On June 1, 2015, FERC issued a final order accepting the California ISO, Northern Tier Transmission Group, and WestConnect compliance filings with an effective date of October 1, 2015, and Columbia Grid with an effective date of January 1, 2015. Beginning in 2016, as part of the California ISO's transmission planning process, proponents' interregional transmission projects will be evaluated over a two-year cycle. As the four Western planning region transmission plans emerge over 2015-2016, WECC has committed to evolve its interconnection-wide approach to best support and complement the regional tariff provisions and planning processes.

Pursuing New Initiatives: State and Regional Collaboration on Carbon Reduction

The Clean Power Plan, as described in the Introduction, implements Section 111(d) of the 1990 Clean Air Act and is intended to reduce carbon dioxide emissions from the

176 WECC Scenario Planning Steering Group, *Energy-Water-Climate Change Scenario Report*, May 5, 2015, https://www.wecc.biz/_layouts/15/WopiFrame.aspx?sourcedoc=/Reliability/WECC-Energy-Water-Climate-Change-Scenario-Final.pdf&action=default&DefaultItemOpen=1.

177 Interregional FERC Order No. 1000, http://www.caiso.com/Documents/Dec18_2014_OrderConditionallyAcceptingOrder1000InterregionalCompliance_ER13-1470.pdf.

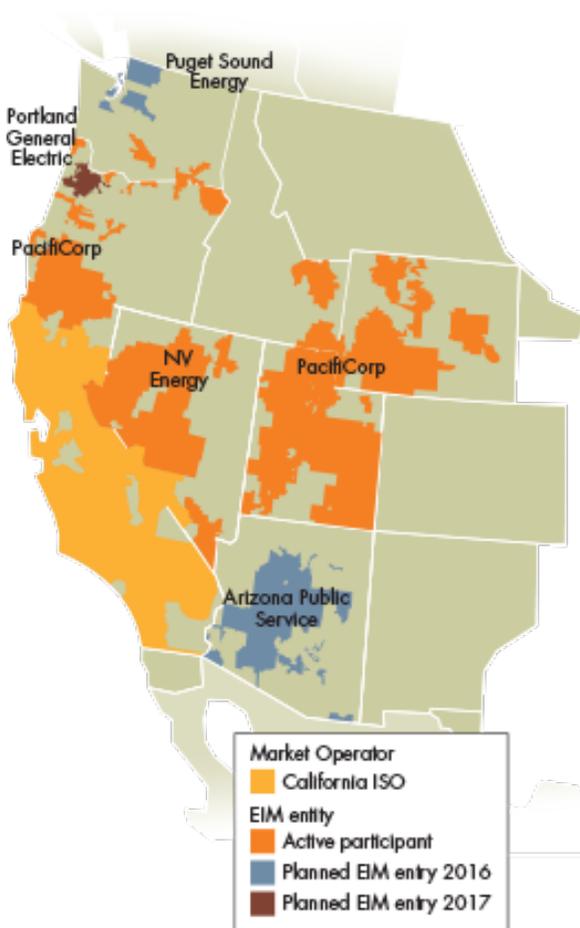
electric sector by 32 percent from 2005 levels by 2030. Western states had commented on the draft rule and had organized themselves to collaborate in evaluating potential compliance paths that could be considered. This was done in close coordination with WECC and the TEPPC analysis/staff capabilities. Under the direction of the Western states 111(d) modeling task force, formed by the Western Interstate Energy Board, WECC will conduct a test that will model two hypothetical compliance scenarios provided by the states. This will include not only evaluation of carbon reductions through production cost modeling, but evaluation of potential reliability impacts of compliance. The latter assessment will rely on the WECC's emerging ability to perform an analysis that applies both production cost and power flow modeling methods in sequence, relying on the common case as the starting point.

Regional Transmission Planning Actions

California ISO Energy Imbalance Market

An important tool to help integrate renewables into the grid is the California ISO's real-time energy imbalance market (EIM). The EIM is a voluntary market for trading procuring imbalance energy to balance supply and demand deviations in real time from 15-minute energy schedules and dispatching least-cost resources every five minutes in the combined network of the California ISO and EIM Entities. The many benefits of the EIM include reduced costs for utility customers and California ISO market participants, reduced carbon emissions and more efficient use and integration of renewable energy, and enhanced reliability through broader system visibility.

Figure 17: Existing and Future EIM Entities



Source: California ISO, <http://www.caiso.com/informed/Pages/Clean-Grid/EIMOverview.aspx>.

PacifiCorp was the first entity to join the EIM,¹⁷⁸ while NV Energy was the second. Figure 17 depicts the existing and future EIM entities, as discussed in more detail below.

Scheduling renewables in smaller time intervals, such as the real time market, can reduce the amount of reserves needed since the opportunity for differences between forecast and actual generation is reduced from an hour to a shorter time interval. Germany has been

¹⁷⁸ PacifiCorp operates within two balancing authorities: Pacific Power in Oregon, Washington and California; and Rocky Mountain Power in Utah, Wyoming, and Idaho.

a leader in advancing renewable energy with renewable resources increasingly serving up to 50 percent of demand on sunny and windy days. A study on behalf of Agora Energiewende found that "... energy and balancing services markets can be structured to reduce the need for additional flexibility [by making] them 'faster.' Fast energy markets are those in which the dispatching of system resources takes place as close to real time as possible, and where dispatch schedules are updated at multiple points throughout the day based on updated weather forecasts."¹⁷⁹ Energy Commission Chair Robert B. Weisenmiller stated that a clear message from a June 2015 meeting between U.S. and German energy experts was that shorter dispatch periods was key to reducing the amount of reserves needed and for allowing in variability in the accuracy of forecasts.¹⁸⁰

Existing and Future EIM Entities

The California ISO and PacifiCorp launched the EIM on November 1, 2014. NV Energy began its participation as an EIM entity on December 1, 2015. Puget Sound Energy and Arizona Public Service balancing authorities are in the process of joining the real-time market as EIM entities with planned implementation dates of October 2016. On November 23, 2015, Portland General Electric and the California ISO filed an implementation agreement with FERC, which paves the way for Portland General Electric to join the EIM in October 2017. On September 24, 2015, Idaho Power Company announced its plan to pursue participation in the California ISO's EIM.

¹⁷⁹ RAP, *Power Market Operations and System Reliability: A contribution to the market design debate in the Pentilateral Energy Forum*, study on behalf of Agora Energiewende, December 2014, http://www.agora-energiewende.de/fileadmin/Projekte/2014/Power-Market-Operations/Agora_Power_Market_Operations_and_System_Reliability_web.pdf, p. 24.

¹⁸⁰ Symposium on the Governor's Greenhouse Gas Reduction Goals, July 9, 2015.

EIM Transitional Committee and Governance Structure

The California ISO EIM expansion requires that all participating entities, whether inside or outside California, are given a voice in the decision-making process. Eight members were appointed by the Board of Governors to the EIM Transitional Committee and were charged with setting up the governance structure. Members included market participants; state regulators, including Energy Commission Chair Robert B. Weisenmiller;¹⁸¹ and public interest groups. In addition to PacifiCorp, the California ISO Board of Governors appointed entities from NV Energy, Puget Sound Energy, and APS. On August 25, 2015, the committee adopted the final proposal that was then approved by the Board of Governors on September 17, 2015.

The governance structure establishes the EIM Governing Body as the primary decision-maker on policy initiatives that change EIM-specific market rules and has the key advisory role on market rules that affect EIM. Each member is financially independent of stakeholders and works to ensure that the interests of all market participants are represented. Members will be selected by stakeholder nominating committee and approved by the California ISO Board of Governors. At its December 18, 2015, meeting, the California ISO Board of Governors adopted the three documents (proposed amendments to the California ISO bylaws, charter for the EIM Governing Body, and selection policy for the EIM Governing Body) approved by the EIM Transitional Committee at its November 19, 2015 meeting.

PacifiCorp Exploring Joining California ISO as Participating Transmission Owner

On April 13, 2015, the California ISO and PacifiCorp signed a memorandum of understanding to explore the feasibility, costs and benefits of PacifiCorp's full participation in the

California ISO as a participating transmission owner. As discussed above, PacifiCorp participates in the California ISO's 15-minute and 5-minute markets through the EIM. Joining the California ISO would extend PacifiCorp's participation to the day-ahead energy market and allow for full coordination of the region's two largest high-voltage transmission grids in the West thereby giving customers served by both entities access to a broader array of power generation at lower costs. The study on behalf of Agora Energiewende put it this way "Increasing the size of balancing control areas reduces the need for more resource flexibility. Larger control areas are beneficial in any case, but where the share of variable production is significant, the benefit can be especially large. . . The benefit derives from three main sources: (1) increasing the size of the control area reduces the impact of any single system event and affords the control area authority a more diverse portfolio of resource options with which to maintain system balance; (2) demand across large geographic areas is generally not well correlated and thus the natural variability of demand cancels out to some extent; (3) the variability of variable renewable resources is generally not well correlated over large geographic areas, reducing the variability of supply."¹⁸²

On October 13, 2015, PacifiCorp and the California ISO released the results of a benefits study performed by Energy+Environmental Economics.¹⁸³ The study found that integrating the two grids to create a regional ISO could produce between \$3.4 billion and \$9.1 billion in shared cost reductions in the first 20 years through better grid management and efficiencies gained by planning for the resource needs of a single, rather than multiple systems. The parties have extended the MOU to further

181 A complete list of EIM Transitional Committee members is available at <https://www.caiso.com/informed/Pages/BoardCommittees/EnergyImbalanceMarketTransitionalCommittee/Default.aspx>.

182 RAP, *Power Market Operations and System Reliability: A contribution to the market design debate in the Pentalateral Energy Forum*, study on behalf of Agora Energiewende, December 2014, p. 23.

183 Energy+Environmental Economics, Inc., *Regional Coordination in the West: Benefits of PacifiCorp and California ISO Integration*, October 2015, <http://www.caiso.com/Documents/StudyBenefits-PacifiCorp-ISOIntegration.pdf>.

explore costs and other requirements needed to achieve the benefits of integration outlined in the study, as well as to develop a transition agreement to outline the terms and conditions for the potential integration of PacifiCorp into a regional market.¹⁸⁴ PacifiCorp and the California ISO aim to reach a transition agreement by early 2016 to fully outline the steps and timeline required for the transition. Necessary steps would include a full stakeholder process to consider the tariff, policy, and process changes that need to be completed before implementation.

The California ISO has begun (or plans to begin in 2016) several stakeholder initiatives that support this expansion effort, including the Transmission Access Charge Options, Regional Resource Adequacy, Regional Integration California Greenhouse Gas Compliance, Metering Rules Update, and Full Network Model Enhancements.¹⁸⁵ PacifiCorp plans to participate in these initiatives as well as continue to work with its stakeholders to explore issues which affect it and its customers. In addition, approval would be sought from the California ISO Board of Governors, the public utility commissions in the six states where PacifiCorp serves customers, and the FERC.¹⁸⁶ As noted in SB 350 (De León, 2015), Section 359 (a): It is the intent of the Legislature to provide for the evolution of the Independent System Operator into a regional organization to promote the development of regional

electricity transmission markets in the western states and to improve the access of consumers served by the Independent System Operator to those markets.¹⁸⁷

Multi-state Transmission Project Proposals

Centennial West Clean Line Transmission Project

The Centennial West Clean Line Transmission Project is an estimated 900-mile, 600 kV high-voltage direct current (HVDC) line with a capacity of 3,500 MW that will connect wind and solar resources in New Mexico and Arizona directly to the Southern California grid.¹⁸⁸ In January 2011, Clean Line applied for a right-of-way across federal lands and submitted a preliminary Plan of Development to the U.S. Bureau of Land Management (BLM). On June 18, 2012, the Centennial West Clean Line LLC and Western Area Power Administration (Western) entered into an advance funding agreement that outlines a working relationship to advance development of the proposed Centennial West Clean Line Transmission Project. The projected in-service date is 2020.

Southwest Intertie Project

The Southwest Intertie Project (SWIP) is being developed by Great Basin Transmission, LLC (an affiliate of LS Power) in three segments: Southwest Intertie Project – North, One Nevada Transmission Line, and the Southern Nevada Intertie Project. The SWIP will provide access to transmission for

184 PacifiCorp and California ISO news release, *Western Grid Integration could Produce Significant Cost Savings, Environmental Benefits*, October 13, 2015, <http://www.caiso.com/Documents/WesternGridIntegrationCouldProduceSignificantCostSavings-EnvironmentalBenefits.pdf>.

185 A complete list of current stakeholder initiatives can be found at <http://www.caiso.com/informed/Pages/StakeholderProcesses/Default.aspx>. The final 2016 Stakeholder Initiatives Catalog and Roadmap, which includes initiatives planned to start in late 2015 and in 2016, was published on December 15, 2015 and is available at: <http://www.caiso.com/informed/Pages/StakeholderProcesses/StakeholderInitiativesCatalogProcess.aspx>.

186 California ISO-PacifiCorp *FAQ: Expanding Regional Energy Partnerships*, April 14, 2015, <http://www.caiso.com/Documents/FAQ-ExpandingRegionalEnergyPartnerships.pdf>.

187 See Senate Bill 350, Article 5.5. Transformation of the Independent System Operator, Section 359 (a), http://leginfo.ca.gov/faces/billNavClient.xhtml?bill_id=201520160SB350.

188 <http://www.centennialwestcleanline.com/site/home>.

renewable generation and improve capacity and reliability for the western grid. Once all three phases are completed, the project will provide 2,000 MW of capacity and connect the existing high-voltage transmission infrastructure near Twin Falls, Idaho, with existing systems in northern Nevada and the Las Vegas area.

The Southwest Intertie Project – North (SWIP North) is at the northern end of the SWIP corridor and is a 275-mile, 500 kV transmission line from the Idaho Power Midpoint Substation to the NV Energy Robinson Summit Substation. LS Power submitted an economic study request for the SWIP North in the California ISO's 2015-2016 transmission planning process that is underway.

One Nevada Transmission Line is a 235-mile, 500 kV line from NV Energy Harry Allen Substation to NV Energy Robinson Summit Substation and is the middle segment of the SWIP. On January 23, 2014, the line was completed and energized, providing an initial capacity of about 800 MW.

The Southern Nevada Intertie Project is an estimated 60-mile, 500 kV transmission line from NV Energy Harry Allen Substation to SCE majority-owned Eldorado Substation. In the California ISO's 2013-2014 transmission planning process, the Harry Allen Substation to Eldorado Substation was approved as an economic project with reliability and policy benefits. The projected in-service date is 2020.

SunZia

The SunZia Southwest Transmission Project (SunZia) is sponsored by the Salt River Project, Shell Wind Energy, Southwestern Power Group, Tri-State Generation and Transmission Association, and Tucson Electric Power. SunZia is about 500 miles long and consists of two single-circuit 500 kV transmission lines with 3,000 MW of capacity. The transmission lines will originate from the proposed SunZia East Substation in Lincoln County, New Mexico, and terminate at the TEP Pinal Central Substation in Pinal County, Arizona. SunZia provides a point of interconnection for generating resources, including renewables, located in Arizona and New Mexico for

delivery to customers in the western markets.¹⁸⁹ On June 13, 2013, BLM published the Final Environmental Impact Statement (EIS) and Proposed Resource Management Plan.¹⁹⁰ On January 24, 2015, the BLM issued a Record of Decision approving SunZia's application for a right-of-way across federally owned property.¹⁹¹ Construction is slated to begin in 2018, with a projected in-service date of 2021.

TransWest Express Transmission Project

TransWest Express, LLC is developing the TransWest Express Transmission Project (TWE) that is a 730-mile, 600 kV HVDC multistate transmission line with 3,000 MW of capacity. TWE will deliver renewable energy produced in Wyoming to Arizona, Nevada, and Southern California and provide a transmission backbone between the Intermountain and Desert Southwest regions. TWE will run from south-central Wyoming, crossing Colorado and Utah, to the LADWP Marketplace Substation about 25 miles south of Las Vegas, Nevada. The Marketplace Substation provides interconnections to the California, Nevada, and Arizona grids. About 67 percent of the preferred alternative route lies on federal land principally managed by the BLM. The TWE follows designated utility corridors and is co-located with existing transmission when possible to minimize impacts. On June 28, 2013, the U.S. Environmental Protection Agency published in the *Federal Register* a Notice of Availability for the BLM/Western TransWest Express Draft EIS with a comment period

189 <http://www.sunzia.net/index.php>.

190 The Final EIS/RMPA can be found at http://www.blm.gov/nm/st/en/prog/more/lands_realty/sunzia_southwest_transmission/feis/feis_docs.html.

191 BLM Record of Decision can be found at http://www.blm.gov/style/medialib/blm/nm/programs/more/lands_and_realty/sunzia/sunzia_docs.Par.94853.File.dat/SunZia_ROD_Record%20of%20Decision%20%281%29.pdf.

ending on September 25, 2013.¹⁹² On April 30, 2015, BLM and Western published the Final EIS document.¹⁹³ On May 1, 2015, the U.S. Department of Interior and U.S. Department of Energy published in the *Federal Register* a Notice of Availability of the Final EIS.¹⁹⁴ The project proponent plans to begin construction in 2017, with a projected in-service date of 2019.

Zephyr Power Transmission Project

In 2011, Duke-American Transmission Company (DATC) acquired the Zephyr Power Transmission Project from TransCanada Corporation of Calgary. On September 23, 2014, four companies – DATC, Pathfinder Renewable Wind Energy, Magnum Energy, and Dresser-Rand – jointly proposed an \$8 billion green energy initiative that will bring clean electricity to the Los Angeles area by 2023. The project will require construction of the proposed 2.1 gigawatt (GW) Pathfinder wind project in Wyoming, a 1.2 GW compressed-air storage facility in Utah, and the corresponding 500 kV HVDC transmission line, about 525 miles long, with a capacity of 3,000 MW. A separate, existing 490-mile transmission line traversing Utah, Nevada, and California would transport electricity from the Utah energy storage facility to the Los Angeles area. The transmission line will maximize the use of existing utility and federal energy corridors.¹⁹⁵

192 The Notice of Availability can be found in *Federal Register*/Volume 78, No.125/Friday, June 28, 2013/Notices, p. 38975, at <http://www.gpo.gov/fdsys/pkg/FR-2013-06-28/pdf/2013-15612.pdf>. The Draft EIS can be found at <http://www.blm.gov/wy/st/en/info/NEPA/documents/hdd/transwest/DEIS.html#vol1>.

193 The TWE Final EIS can be found at <http://www.blm.gov/wy/st/en/info/NEPA/documents/hdd/transwest/FEIS.html>.

194 The Notice of Availability can be found in *Federal Register*/Volume 80, No.84/Friday, May 1, 2015/Notices, p. 24962, at <http://www.blm.gov/style/medialib/blm/wy/information/NEPA/hddo/twe/FEIS/8.Par.99152.File.dat/fedregnotice-050115.pdf>.

195 <http://www.datcllc.com/projects/zephyr/>.

Opportunities for Facilitating Future Potential Transmission Build-outs

Update on Right-Sizing Policy

Transmission right-sizing was first discussed in the *2011 IEPR* and raised by stakeholders in the *2014 IEPR Update*.¹⁹⁶ *Right-sizing* entails looking beyond the current planning horizon – typically 10 years – to see if needed projects should initially be built larger or built in such a way that they can easily be made larger in the future. Where appropriate, right-sized projects can reduce future costs and environmental impacts of transmission facilities. The right-sizing concept was used throughout the Tehachapi Regional Transmission Project¹⁹⁷ where SCE built transmission facilities to 500 kV specifications but energized the lines at only 220 kV.

In 2014, DATC submitted the San Luis Transmission Project in the California ISO's 2014 request window. The San Luis Transmission Project is an example of a right-sizing opportunity for the California ISO to evaluate, consistent with its tariff. In this case, Western needs 230 kV facilities to provide power to the U.S. Bureau of Reclamation for the water pumps at the San Luis Reservoir. The right-sizing opportunity would have DATC and Western build the facilities to 500 kV specifications, with the

196 California Energy Commission. 2015. *2014 Integrated Energy Policy Report Update*. Publication Number: CEC-100-2014-001-CMF. <http://www.energy.ca.gov/2014publications/CEC-100-2014-001/CEC-100-2014-001-CMF-small.pdf>, pp. 153-154.

197 More information on the Tehachapi Renewable Transmission Project is available at <http://www.sce.com/tehachapi>.

California ISO funding 75 percent of the total cost,¹⁹⁸ in exchange for 1,200 MW of additional transmission capacity. In its *2014–2015 Transmission Plan*¹⁹⁹ the California ISO did not find an immediate need to pursue this right-sizing project but acknowledged that it will continue to evaluate the proposal in the 2015–2016 transmission planning process. While not every transmission project is appropriate for right-sizing, California utilities and the California ISO should continue looking beyond 10-year planning horizons and their own footprints for cost-effective, environmentally sound right-sizing opportunities.

Right-sizing could include:

- » Planning/building a transmission project with a higher rating than is identified as needed in the most current transmission plan because it is likely that more transmission capacity will be needed beyond the current planning horizon.
- » Building facilities to a higher capacity standard than is identified as needed but energize them at the voltage needed today (that is, a 230 kV need built within a 500 kV right-of-way with 500 kV towers). This leaves the option of increasing the capacity at a future date with minimal environmental impact.
- » Building joint projects to accommodate the needs of two or more transmission owners.
- » Any combination of the above.

Many parties that commented on right-sizing at the August 3, 2015, IEPR workshop and/or in written comments (Agricultural Energy Consumers Association,

Defenders of Wildlife and Sierra Club, Duke American Transmission Company, Natural Resources Defense Council, TransCanyon LLC, and Westlands Solar Park LLC) agree that right-sizing is an appropriate planning tool. For example, DATC provided detailed responses to staff's right-sizing questions that highlight California's need for a comprehensive policy on transmission right-sizing.

Given the limited availability corridors for new transmission lines, and the expectation that corridors will be even more limited in the future, the state should assume right-sizing new transmission facilities is the best option. California's GHG policies will likely require significant development of central station renewable generation that is not located near load centers and will require new transmission lines. The corridors required for new transmission facilities in California are limited by urban growth, terrain, and the need to protect the environment. "As a practical matter, this means that any proposal to *not* right-size a transmission project should only be adopted after a careful examination of the long-term environmental and economic consequences of such a decision."²⁰⁰ The state should seek to maximize the value of the remaining corridors through right-sizing where appropriate.

A comprehensive discussion of right-sizing and how it should be applied in California is still required. The Energy Commission recommends that the state develop a set of right-sizing policies through the *2016 IEPR Update* process, informed by the RETI 2.0 process. These policies, at a minimum, should include a comprehensive definition of right-sizing, as well as describe the process through which the costs and benefits would be analyzed.

198 California ISO ratepayers would therefore be responsible for 75 percent of the total cost.

199 The *California ISO 2014–2015 Transmission Plan* is available at <http://www.caiso.com/Pages/documentsbygroup.aspx?GroupID=55EBA03B-525E-438B-8D9A-C3C5B7B3DD3C>.

200 Christopher Ellison, Ellison, Schneider & Harris LLP, *Duke American Transmission Company's Comments on the 2015 Integrated Energy Policy Report: Transmission and Landscape-Scale Planning*, Docket 15-IEPR-08, August 17, 2015, http://docketpublic.energy.ca.gov/PublicDocuments/15-IEPR-08/TN205763_20150817T155259_Christopher_T_Ellison_Comments_Duke_America_Transmission_Compan.pdf, p. 5.

Transmission Corridors for Possible Designation

In 2004, Senate Bill 1565 (Bowen, Chapter 692, Statutes of 2004) directed the Energy Commission, in consultation with other stakeholders, to adopt a strategic plan for the state's electric transmission grid. Subsequently, Senate Bill 1059 (Escutia and Morrow, Chapter 638, Statutes of 2006) linked transmission planning and permitting by authorizing the Energy Commission to designate transmission corridor zones on nonfederal lands to allow for the timely permitting of future high-voltage transmission projects, with the further requirement that any corridor proposed for designation must be consistent with the state's needs and objectives as identified in the latest adopted strategic transmission investment plan.

The *2013 IEPR*, which includes the *2013 Strategic Transmission Investment Plan*, makes the following recommendation with respect to corridors that would be appropriate for designation: "From a timing perspective, it makes sense to identify and designate, where appropriate, transmission corridors in advance of future generation development so that needed transmission projects can be permitted and built in an effective, environmentally responsible manner, contemporaneous with the generation development. The Energy Commission will work with the utilities; federal, state, and local agencies; and stakeholders to identify transmission line corridors that are a high priority for designation such as those corridors that would ease the development of renewable energy resources. Appropriate corridors could be identified as a result of the *Desert Renewable Energy Conservation Plan*, future examination of opportunities and needs in the San Joaquin Valley (southern area of the Central Valley), and the ongoing San Onofre transmission alternatives under consideration."

The *2014 IEPR Update* discussed the Energy Commission-funded consultant report (and subsequent addenda) that provides a high-level assessment of the environmental feasibility of several electric transmission alternatives under consideration by the California ISO to address

reliability and other system challenges resulting from the San Onofre closure. The *2014 IEPR Update* noted that one or more of the alternatives may be considered by Energy Commission staff in the state's electric transmission corridor designation process.

The Energy Commission staff summarized this recent history of corridor identification at the August 3, 2015, IEPR workshop and solicited feedback from stakeholders on the appropriate corridor opportunities to be identified for the 2015 IEPR.²⁰¹ Westlands Solar Park submitted written comments, in which it agrees with the *2013 IEPR* recommendation that the San Joaquin Valley is an important area for corridor consideration. It recommends that the Energy Commission explore ways to use its transmission corridor planning and designation authority under Senate Bill 1059 to coordinate and partner with local and federal agencies, especially in regions such as the San Joaquin Valley where multiple transmission projects (the Gates-Gregg Central Valley Power Connect and the San Luis Transmission Project) are proposed. Westlands Solar Park recommends that the Energy Commission work with the CPUC, California ISO, Western Area Power Administration Sierra Nevada region office, and local governments to develop a transmission planning strategy that best adheres to the Garamendi Principles and that right-sizes the proposed transmission improvements, thereby minimizing the need to create new corridors. No parties proposed any additions or deletions to the *2013 IEPR* recommendation on high-priority corridors. However, parties believe RETI 2.0 provides an opportunity for the identification of high-priority corridors to expedite long-term transmission planning goals. As mentioned above, this effort should also include continuity with federal Section 368 corridors.

201 Judy Grau (Energy Commission), *Strategic Transmission Planning and Corridors* presentation, presented at the IEPR Workshop on Landscape-Scale Environmental Evaluations for Energy Infrastructure Planning and the Strategic Transmission Investment Plan, August 3, 2015, slides 5 and 8, http://docketpublic.energy.ca.gov/PublicDocuments/15-IEPR-08/TN205566_20150730T112902_Strategic_Transmission_Planning_and_Corridors.ppt.

Update on Deliverability Issue Identified in the 2013 IEPR

The 2013 IEPR also discusses recent efforts to improve the coordination between generation and transmission planning and permitting. Improvement in better synchronizing generation development and the transmission upgrades is needed to reliably interconnect and deliver that generation to load. The 2013 IEPR noted that the power purchase agreements signed by renewable generators typically require full deliverability during peak conditions, which can require costly transmission upgrades that may not be operational until several years after the generator is on-line. To that end, the Energy Commission made the following recommendation: “The cost-effectiveness, prudence, and alternatives for requiring full deliverability for future renewable generation that is procured to meet RPS requirements should be evaluated by California’s energy agencies in the overall context of long-term planning for meeting RPS and GHG emission reduction goals.”

In response to this recommendation, the California energy agencies began evaluating full deliverability requirements for renewable generators required to meet future RPS and GHG reduction goals. The CPUC *Order Instituting Rulemaking to Continue Implementation and Administration, and Consider Further Development of, California Renewables Portfolio Standard Program*²⁰² discusses deliverability requirements as part of the instructions for the development of 2015 Renewables Portfolio Standard Procurement Plans and in the ongoing process to revise the RPS Calculator. The California ISO in its 2015–2016 transmission planning process will perform a sensitivity study that analyzes the impacts of energy-only renewables (resources that are not fully deliverable) in 2030. These steps effectively fold the analysis of deliverability requirements for renewables into existing planning and procurement processes.

202 *Order Instituting Rulemaking to Continue Implementation and Administration, and Consider Further Development, of California Renewables Portfolio Standard Program*, March 6, 2015, <http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M148/K296/148296751.PDF>.

The CPUC requires utilities to discuss needs for renewable resources with various characteristics in their plans to meet RPS program requirements. The *Assigned Commissioner’s Revised Ruling Identifying Issues and Schedule of Review for 2015 Renewables Portfolio Standard Procurement Plans* requires the utilities to include within their RPS plans a description of the specific characteristics of the renewable resources they are seeking. As noted in the ruling, “This written description must include the retail seller’s need for RPS resources with specific deliverability characteristics, such as peaking, dispatchable, baseload, firm, and as-available capacity as well as any additional factors, such as ability and/or willingness to be curtailed, operational flexibility, etc.”²⁰³ Utility procurement plans are also required to evaluate resources using a least-cost, best-fit method that includes transmission congestion and capacity valuations.

The CPUC is also considering deliverability requirements for renewable generators in its update of the RPS Calculator. The CPUC staff’s *Draft 2015–2016 RPS Calculator Work Plan*²⁰⁴ includes modifications that would allow and account for energy-only renewable projects. Coordinating with the CPUC staff, the California ISO is studying ways to analyze energy-only resources and incorporate them into the RPS Calculator. The California ISO’s special study will be incorporated into the 2015–2016 transmission planning process.

As renewable generation requirements grow, California energy agencies are exploring the value of energy-only renewable resources. Full deliverability is no longer a presumed requirement for renewable resources in utility portfolios. The California energy agencies are making progress

203 *Assigned Commissioner’s Revised Ruling Identifying Issues and Schedule of Review for 2015 Renewables Portfolio Standard Procurement Plans*, p. 9, May 28, 2015, <http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M152/K045/152045579.PDF>.

204 *Administrative Law Judge’s Ruling Seeking Post-Workshop Comments*, Attachment A: Energy Division Staff’s Draft 2015-2016 RPS Calculator Work Plan, April 13, 2015, <http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M151/K169/151169497.PDF>.

on the issue of deliverability for renewable resources, and efforts should be continued in both the CPUC procurement process and California ISO transmission planning.

Recommendations

» **Finalize and Implement the Desert Renewable Energy Conservation Plan (DRECP).** The Energy Commission should continue to work closely with Federal and state agencies, local governments, and stakeholders to finalize and implement the DRECP.

» **Continue to coordinate with local governments on renewable energy planning and permitting to help achieve the state's energy goals.** The Energy Commission should continue to work closely with local governments on renewable energy planning, provide technical assistance on permitting, and share information about renewable energy projects, mitigation and best management practices. These efforts would leverage the work done by the counties who received Renewable Energy and Conservation Planning Grants.

» **Leverage analytical tools to conduct further landscape-scale analysis for renewable planning.** The Energy Commission should continue to leverage the tools and approaches developed for the *Desert Renewable Energy Conservation Plan* and related planning efforts, including the Data Basin Gateway, to ease successful landscape-scale planning of renewable resources, transmission investments, and conservation, and to support statewide energy planning.

» **Encourage county planning efforts and use best practices in Renewable Energy Transmission Initiative (RETI) 2.0.** The Energy Commission should assist and encourage county planning efforts that support state climate, renewable energy, conservation and climate adaptation policy goals. The California Natural Resources Agency, California Energy Commission, California Public Utilities Commission,

California Independent System Operator (California ISO) and the U.S. Bureau of Land Management California Office are leading RETI 2.0 to facilitate the long-range planning, inter-agency and local government coordination, and stakeholder engagement necessary to reach these goals with the lowest costs and greatest benefit. The Energy Commission should work closely with stakeholders to ensure the RETI 2.0 planning process is open, transparent, and science-based and provides for robust stakeholder dialogue and engagement.

» **Encourage even greater participation in the energy imbalance market.** To take advantage of the benefits of real-time balancing of load and resources and the regional diversity in renewable resources, where resources are traded every 15 minutes and least-cost resources are dispatched every five minutes, the state should continue to encourage other entities, both in state and out of state, including publicly owned utilities, to join the California ISO's energy imbalance market.

» **To support the 50 percent Renewables Portfolio Standard by 2030 goal and the development of a regional electricity market in the West, encourage the transformation of the California ISO into a regional organization through the provisions of Senate Bill 350.** To promote the development of regional electricity transmission markets in the Western states and to improve the access of consumers served by the California ISO to those markets, the state should encourage PacifiCorp and other entities to join the California ISO as a participating transmission owner, allowing for further coordination of high-voltage transmission grids in the West.

» **Develop right-sizing policies.** The Energy Commission recommends that the state develop a set of right-sizing policies through the *2016 Integrated Energy Policy Report Update* process and informed by RETI 2.0. These policies, at a minimum, should include a comprehensive definition of right-sizing, as well as describe the process through which the costs and benefits would be analyzed.

CHAPTER 4

Transportation



California has long been a leader in achieving needed reductions from the transportation sector to meet climate and clean air goals, and today's transportation sector is cleaner and more efficient than it was even several years ago. However, there is still more to be done. The production, refining, and use of petroleum represent some of the state's largest sources of pollution – accounting for about 50 percent of California's greenhouse gas (GHG) emissions, and the transportation sector is responsible for about 80 percent of smog-forming emissions, and more than 95 percent of diesel particulate matter emissions.²⁰⁵ To help address these environmental quality issues, the state has developed a portfolio of rules, regulations, goals, policies, and strategies designed to address emission reductions, air quality, and petroleum reductions while meeting transportation demands of the future.

This chapter starts with a discussion of many of these regulations and goals. The chapter then highlights the Governor's 2030 climate goals and summarizes the state's framework for decarbonizing the transportation sector. It also provides the staff's draft transportation

energy demand forecast through 2026, based on staff analysis presented at a November 24, 2015, Integrated Policy Report (IEPR) workshop,²⁰⁶ an analysis of transportation fuel trends, and concludes with a discussion of the benefits of the Energy Commission's Alternative and Renewable Fuel and Vehicle Technology Program (ARFVTP – a critical part of the state strategy to deploy alternative fuels and advanced vehicle technologies into California's transportation market.

Achieving Greenhouse Gas Reduction and Clean Air Goals

The federal Clean Air Act requires the U.S. Environmental Protection Agency (U.S. EPA) to set outdoor air quality standards for the nation. It also allows states to adopt

²⁰⁵ Air Resources Board, 2015, *Mobile Source Strategy*, Information Update, Slide 4, October 22, 2015, <http://www.arb.ca.gov/board/books/2015/102215/15-8-6pres.pdf>.

²⁰⁶ http://www.energy.ca.gov/2015_energy_policy/documents/2015-11-24_presentations.html.

more protective air quality standards, if needed. Through the State Implementation Process, California identifies the strategies needed across sectors to achieve state and federal air quality standards. In addition to the state's requirement to achieve federal air quality standards, California also has progressive goals for combating climate change. California's goals for GHG emission reductions originated with the goal of reducing GHG emissions to 1990 levels by 2020 established by Assembly Bill 32 (Núñez, Chapter 488, Statutes of 2006). Governor Edmund G. Brown, Jr. built upon this by mandating that California reduce GHG emissions to 40 percent below 1990 levels by 2030 in his April 2015 Executive Order B-30-15.²⁰⁷

California already has an effective suite of policies, plans, and programs aimed at reducing air pollution and GHG emissions from the transportation system. These policies range from increasingly stringent tailpipe emission standards for cars and trucks, regulations requiring the development and sale of zero-emission technology vehicles, incentive programs for zero-emission vehicles (ZEV) and near-ZEV technology development, and strategies for integrated land-use development to reduce vehicle travel demand. As a result of these goals and policies, the state has implemented several programs and plans to put California on a path of transitioning to a diversified alternative and low-carbon-fueled transportation future.

While the state is on track to meet its 2020 climate change target set by Assembly Bill 32, more is needed to achieve its air quality and long-term climate goals. Recognizing this, Governor Brown has issued executive orders and provided strong leadership and direction, including:

- » Issuing in March 2012 an Executive Order calling for 1.5 million ZEVs to be on California roadways by 2025 and adequate infrastructure to support 1 million

ZEVs by 2020.²⁰⁸ To chart a path toward meeting the Governor's ZEV Executive Order, the *2013 ZEV Action Plan*²⁰⁹ delineates specific actions for California agencies to simplify deployment and adoption of ZEV-related fueling and charging infrastructure. The *2013 ZEV Action Plan* is being updated.

- » Calling for a 50 percent reduction in petroleum used by California's cars and trucks by 2030 in his 2015 inaugural address.²¹⁰
- » Setting a goal for California to reduce its GHG emissions 40 percent below 1990 levels by 2030.
- » Directing state agencies to work together to develop an integrated action plan that establishes targets to improve freight efficiency, increases adoption of zero-emission technologies, and increases competitiveness of California's freight system in his July 2015 Executive Order B-32-15.²¹¹

Clean Vehicle and Fuel Programs

Below lists some of the programs in place to help advance low-carbon, clean fuels in California.

- » **Advanced Clean Cars:** The landmark ZEV regulations set by the California Air Resources Board (ARB) in January 2012 establishes ZEV credit requirements for automakers selling light duty vehicles in California, while providing several options for manufacturers to meet these

208 Governor Edmund G. Brown Jr., Executive Order B-16-12, March 23, 2012, <http://gov.ca.gov/news.php?id=17463>.

209 Office of Governor Edmund G. Brown Jr., *2013 ZEV Action Plan*, February 2013, [http://opr.ca.gov/docs/Governor's_Office_ZEV_Action_Plan_\(02-13\).pdf](http://opr.ca.gov/docs/Governor's_Office_ZEV_Action_Plan_(02-13).pdf).

210 Governor Edmund G. Brown Jr., Inaugural Address, January 5, 2015, <http://gov.ca.gov/news.php?id=18828>.

211 Governor Edmund G. Brown Jr., Executive Order B-32-15, July 17, 2015, <http://gov.ca.gov/news.php?id=19046>.

207 Governor Edmund G. Brown Jr., Executive Order B-30-15, April 29, 2015, <http://gov.ca.gov/news.php?id=18938>

requirements. It is expected that by 2025 the largest automakers will derive over 1.5 million of their cumulative new vehicle sales in California from electric vehicles and other ZEVs or near-ZEVs.

» **State Implementation Plan:** To meet federal health-based air quality standards, air basins in extreme nonattainment with ozone standards, such as the San Joaquin Valley and South Coast air basins, could require up to an 80 percent reduction in transportation oxides of nitrogen (NO_x) emissions from current regulatory levels between 2023 and 2032. Air Districts are pursuing local strategies to reduce these emissions.

» **U.S. EPA “Phase 2 Program”:** The U.S. EPA and Department of Transportation’s National Highway Traffic Safety Administration (NHTSA) are jointly proposing a national program that would establish standards to support the development and deployment of cost-effective technologies that will help reduce GHG emissions and promote energy security through vehicle efficiency gains.

» **Low Carbon Fuel Standard (LCFS):** The LCFS requires a 10 percent reduction in the carbon intensity of all fuels sold in California by 2020. Importers and refiners of petroleum fuels are required to reduce the carbon intensity of their fuels products by developing their own low-carbon fuels or by buying LCFS credits from third-party developers of low-carbon fuels.

» **Cap-and-Trade Program:** Implemented as part of AB 32, the Cap-and-Trade Program sets a cap on GHG emissions and requires covered industries to reduce emissions or purchase permits accordingly. Starting January 1, 2015, fuels such as gasoline, diesel, and natural gas are included under the Cap-and-Trade Program. This inclusion will require fuel suppliers to reduce the GHG emissions produced when the fuel they sell is burned, either by lowering the carbon content of the fuel or by purchasing pollution permits.

Transportation Demand Management Policies and Strategies

As part of its multipronged effort to advance its transportation sector goals, the state is also implementing programs to help reduce transportation demand, as listed below.

» **Senate Bill 375:** The Sustainable Communities and Climate Protection Act of 2008 (Sustainable Communities Act, Chapter 728, Statutes of 2008) requires Metropolitan Planning Organizations to demonstrate how their regions will meet regional GHG reduction targets by reducing passenger vehicle travel demand through more integrated land use, housing, and transportation planning.

» **California Department of Transportation (Caltrans) Freight Mobility Plan:** Several elements of the Freight Mobility Plan will also help reduce transportation vehicle miles traveled (VMT), including Caltrans’ efforts to reduce congestion and introduce advanced efficiency technologies into traffic management systems.

» **High-Speed Rail (HSR):** California’s High-Speed Rail Authority will develop a modern high-speed electric rail system between San Francisco and Los Angeles. HSR is projected to reduce petroleum fuel consumption by 2 billion to 3 billion barrels per year by 2030 and reduce VMT by 10 million miles per day by 2040.

Providing Incentives for the Transformation

The transition toward cleaner technologies, lower-carbon fuels, and more sustainable choices will also require marked public investment to spur technology and market development and needed infrastructure. The state’s current transportation incentive funding includes:

» **Assembly Bill 118 and Assembly Bill 8:** The Energy Commission and ARB incentive funding programs

authorized by AB 118, Núñez, Chapter 750, Statutes of 2007) and extended by AB 8 (Perea, Chapter 401, Statutes of 2013), will provide about \$2 billion in incentive funding between 2007 and 2024 for development and deployment of alternative technology vehicles, fueling infrastructure, and fuels. The ARFVTP has invested nearly \$600 million in about 500 projects to develop and deploy ZEV and near-ZEV fueling and charging infrastructure, sustainable low-carbon biofuels, and ZEV and near-ZEV technologies. AB 8 also extended funding for the Carl Moyer Program, the Enhanced Fleet Modernization Program, the California Tire Recycling Program, and other air district programs.

» **Proposition 1B:** Out of the nearly \$740 million in Proposition 1B funding for emission reductions through June 2015, more than \$735 million has been used to offer incentives for cleaner trucks, including early compliance with the 2010 clean diesel truck regulatory standards.²¹² By 2017, all California trucks will need to comply with this standard. ARB is modifying the Proposition 1B fund program regulations to allow for eligibility of alternative-fueled trucks, such as natural gas-fueled trucks with low emissions of NO_x.

» **Cap-and-Trade Auction Proceeds:** Each year, the Legislature and Governor appropriate proceeds from the sale of state-owned allowances out of the Greenhouse Gas Reduction Fund (GGRF) for projects that support the goals of AB 32. The GGRF is an important part of the state's overall climate investment efforts. With this money, the state is funding the accelerated adoption of ZEVs – including innovative clean bus/truck technology demonstrations, public transit investment, affordable transit-oriented housing, and sustainable community strategies for the most disadvantaged communities.

The ongoing AB 8 investments for the ARB's Air Quality Improvement Program (AQIP) and Energy Commission's ARFVTP, bolstered with funding from Cap-and-Trade auction proceeds, are helping increase consumer acceptance and use next-generation ZEVs.

Pending Actions

Building upon the success of California's current array of programs and policies, several efforts and activities are underway to accelerate transformation of the transportation sector to attain the needed reductions in carbon, criteria, and particulate emissions.

» **Utility Proposals for ZEV Infrastructure:** California's three large investor-owned utilities have submitted applications to the California Public Utilities Commission (CPUC) to allow for installation of up to 60,000 electric vehicle chargers throughout California. In December 2015, the CPUC issued preliminary decisions for two of the investor-owned utilities' proposals: Southern California Edison's (SCE's) Charge Ready and Market Education Programs and San Diego Gas & Electric's Electric Vehicle-Grid Integration (VGI) Program. On January 14, 2016, the CPUC authorized SCE to develop a pilot program to incentivize the deployment of approximately 1,500 electric vehicle charging stations and conduct education and outreach in support of electric transportation. Final decisions on San Diego Gas & Electric's and PG&E's proposals are pending. These initiatives have the potential to help accelerate the deployment of electric vehicle chargers in California beyond the current level of about 2,500 installed public chargers, in accordance with the Governor's ZEV Mandate to accommodate 1 million ZEVs by 2020. Senate Bill 350 (De León, Chapter 547, Statutes of 2015) (SB 350), requires the CPUC, in consultation with the ARB and Energy Commission, to direct electrical corporations to file applications for programs and investments to accelerate transportation electrification, reducing California's dependence on petroleum.

212 ARB, *Proposition 1B: Goods Movement Emission Reduction Program – 2015 Funding Awards*, Staff Report, September 2015, http://www.arb.ca.gov/bonds/gmbond/docs/prop_1b_goods_movement_program_september_2015_staff_report.pdf.

» **Report on Access to Zero-Emission and Near-Zero-Emission Transportation Options for Low-Income Customers:** SB 350 requires the ARB, in consultation with the Energy Commission, other state agencies, and the public, to report on barriers and recommendations for increasing access to zero-emission and near-zero-emission transportation options to low-income customers, including those in disadvantaged communities. The report is due by January 1, 2017.²¹³

» **California Sustainable Freight Strategy:** Governor Brown's Executive Order B-32-15²¹⁴ requires the California State Transportation Agency, Environmental Protection Agency, Natural Resources Agency, Caltrans, ARB, the Energy Commission, and the Governor's Office of Business and Economic Development to establish clear targets for emissions reductions while maintaining the economic competitiveness of California's ports and freight sector by July 2016.

» **2030 Petroleum Reduction Effort:** The ARB convened a symposium on July 8, 2015, which hosted representatives from several state agencies and research organizations.

2030 Climate Commitments

As part of his 2015 inaugural address, Governor Brown outlined five pillars for meeting the goal of 40 percent GHG emission reductions from 1990 levels by 2030. (See the Introduction for more information.) Within the transportation sector, this included a goal of reducing today's petroleum use in cars and trucks by up to 50 percent.

213 Public Resources Code Section 25327 (d).

214 Governor Edmund G. Brown Jr., Executive Order B-32-15, July 17, 2015, <http://gov.ca.gov/news.php?id=19046>.

At its July 8, 2015, symposium, panelists discussed pathways for reducing petroleum consumption within the framework of sustainable freight leadership, advanced vehicle technologies, cleaner fuels, and smarter growth and transportation choices. Below are highlights that came out of the symposium about what might be needed to achieve the 2030 goal.

» Reducing petroleum use in California will require building on and accelerating existing air quality and climate efforts, including:

» Improving existing vehicle fuel efficiencies for both passenger vehicles and light trucks (through the use of lightweight materials, variable-speed transmissions, efficient drive trains, and so forth). These efficiencies are largely driven by federal fuel economy standards.

» Continuing to accelerate the technology advancement and adoption of ZEVs in both the light- and heavy-duty sectors.

» Replacing diesel and gasoline with alternative and renewable fuels, where zero-emission technologies and fuels are not available, such as in many heavy-duty applications, can greatly reduce the carbon intensity of these operations.

» Reducing vehicle travel demand through better transportation and land-use planning being pursued through regional Sustainable Communities Strategy development.

» New strategies will be explored through several new planning efforts, which include:

- » *Short-Lived Climate Pollutants Plan*, being developed by the ARB. A draft is available and the plan identifies strategies to reduce methane, black carbon, and fluorinated gases.²¹⁵
- » Sustainable Freight Strategy, a multi-agency effort to build supply chain efficiencies throughout California's freight sector.
- » The *Scoping Plan Update* to reflect the 2030 goal being developing by ARB in consultation with other state agencies. This plan will identify new strategies across economic sectors, including natural and working lands, energy, and more, to address the Governor's 2030 climate reduction targets.

Achieving this ambitious climate goal will require a sustained and accelerated transformation of California's transportation system. The state strategy for decarbonizing its vast transportation sector includes increasing the use of cleaner vehicles with zero-emission and near-zero-emission technologies in all vehicle categories; reducing the carbon content of motor vehicle, rail, and aviation fuels; reducing vehicle travel demand; and improving system efficiencies.

Transportation Energy Demand Forecast

The state and federal policies discussed above encourage the development and use of renewable and alternative

215 California Environmental Protection Agency, Air Resources Board, *Draft Short-Lived Climate Pollutant Reduction Strategy*, September 2015, <http://www.arb.ca.gov/cc/shortlived/2015draft.pdf>.

fuels and technologies to reduce California's dependence on petroleum-based fuels, cut GHG emissions, and promote sustainability. While there has been significant growth in these fuels in recent years, the Energy Commission's draft transportation energy demand forecast shows that gasoline and diesel will continue to be the primary sources of transportation fuel through 2026. The following draft transportation energy demand forecast analyses were presented and discussed at an *IEPR* workshop on November 24, 2015.²¹⁶

The increasing interrelationship and impact the transportation sector will have on electricity and other energy sectors require a strong ability to forecast transportation energy demand to inform near- and mid-term electricity procurement, provide historically based projections to conservatively gauge progress, and subsequently inform policy and program adjustments/redirection.

Forecasting Models

The draft forecast presented here results from several inputs and assumptions run in behavioral models that represent key transportation sectors in California. These behavioral models represent light-duty vehicle demand for both residential and commercial sectors, urban and intercity travel demand, and travel demand for freight transport and service provisions. With the exception of aviation/jet fuel demand, there have been no major changes to the preliminary transportation energy demand forecast process since 2013.

The aviation fuel demand forecast in the *2015 IEPR* is not derived from behavioral models at the Energy Commission due to resource and data constraints and therefore, does not respond to variations in key inputs used for other transportation sector models presented here.

The transportation energy demand forecast shows the results for three demand cases, which apply the same economic and demographic inputs and energy prices as

216 <https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=15-IEPR-10>.

the demand cases used in the electricity and natural gas demand forecasts prepared by the Energy Commission. The electricity and natural gas forecasts are discussed in Chapters 5 and 6, respectively.

Demand Cases: Overview and Assumptions

The transportation energy demand case definitions are consistent with the “common demand cases” referenced throughout the *2015 IEPR*. The economic, demographic, and price inputs for these cases are common to the various forecasting efforts at the Energy Commission, including electricity and natural gas. The three common demand cases are defined as follows:

- » High demand case: High population and income, and low energy prices.
- » Mid demand case: Mid population, income, and energy prices.
- » Low demand case: Low population and income, and high energy prices.

More details on these demand cases can be found in Chapter 5 on California’s electricity demand forecast.

Various local, state, and federal regulations; standards; and incentive programs apply to the transportation sector, all of which aim to address climate change and improve air quality and energy security. The primary regulations and incentives considered in this forecast include the National Highway Traffic and Safety Administration (NHTSA) Corporate Average Fuel Economy (CAFE) standards for passenger car and light truck model years 2017–2021, California’s LCFS, and California’s ZEV regulation, as these regulations can be quantified. Proposed laws and regulations are not considered in this forecast because there can be significant changes to those regulations prior to adoption.

Since both the ZEV regulations and CAFE standards apply to manufacturers, they are met by the attributes of vehicles (such as vehicle price and miles per gallon) in the market. The ZEV mandate and CAFE standards are captured in all the transportation demand cases used in this forecast through projected vehicle attributes, such as prices and fuel economy, that are used as inputs in the vehicle demand forecast.

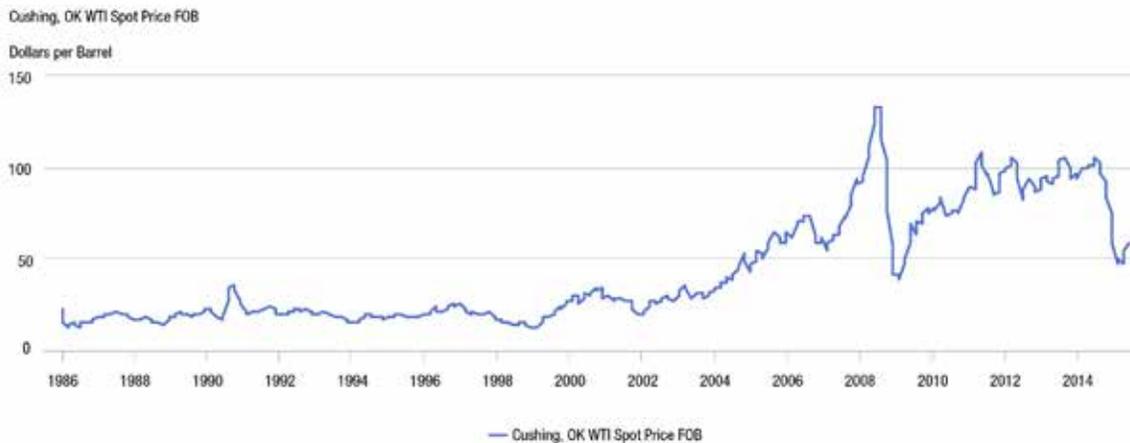
The California High-Speed Rail Authority provided its high-speed rail electricity demand forecast to the Energy Commission and is included in the mid electricity demand case. Further explanation as to how high-speed rail electricity demand is incorporated into this forecast is discussed later in this chapter.

Finally, the Energy Commission’s behavioral demand models do not necessarily account for all transportation regulations and goals. For example, the Sustainable Communities Act (SB 375), which requires the reduction of GHG emissions through coordinated transportation and land-use planning, is not considered at this time. In addition, the Governor’s Executive Order calling for a 50 percent reduction in petroleum consumption is not incorporated into forecasting assumptions as the mechanisms to achieve this goal are still being determined.

Sectors

Transportation energy is used for moving people and freight for personal and commercial purposes in light-duty, medium-duty, and heavy-duty vehicles using multiple travel modes on the ground and in the air. Light-duty vehicles (LDVs) serve the personal transportation needs of the residential and commercial sectors, as well as the overall needs of the rental fleet and government sectors. LDVs compete with bus and rail in urban (local) travel and with bus, rail, and airplanes in intercity (long-distance) travel. Medium-duty vehicles (MDVs) and heavy-duty vehicles (HDVs) are used in mass transit of people and services, and in freight transport, where they compete with rail and air freight. HDVs also provide services for local activities such as construction and refuse movements,

Figure 18: West Texas Intermediate Crude Oil Monthly Spot Prices



Source: EIA

in the absence of competition from other modes of travel. Transportation energy demand covers all these movements in all sectors, accounting for vehicle populations and fuel economies, as well as VMT.

Key Inputs

The models and surveys conducted by the Energy Commission's Demand Analysis Office show that the key drivers of transportation fuel and vehicle demand are consumer preferences, population, economy, and fuel and vehicle prices. Transportation fuel prices are crucial to the transportation energy demand forecast, as consumers are sensitive to current fuel prices when deciding on which type of vehicle to purchase.

Transportation Energy Price Forecast

According to the U.S. Energy Information Administration (EIA), prices for petroleum fuel have seen a significant shakeup since 2013, driven by a precipitous drop in crude prices, as shown in Figure 18. For further discussion on crude oil prices and national and global trends in production, see "Changing Trends in California's Sources of Crude Oil" in Chapter 7.

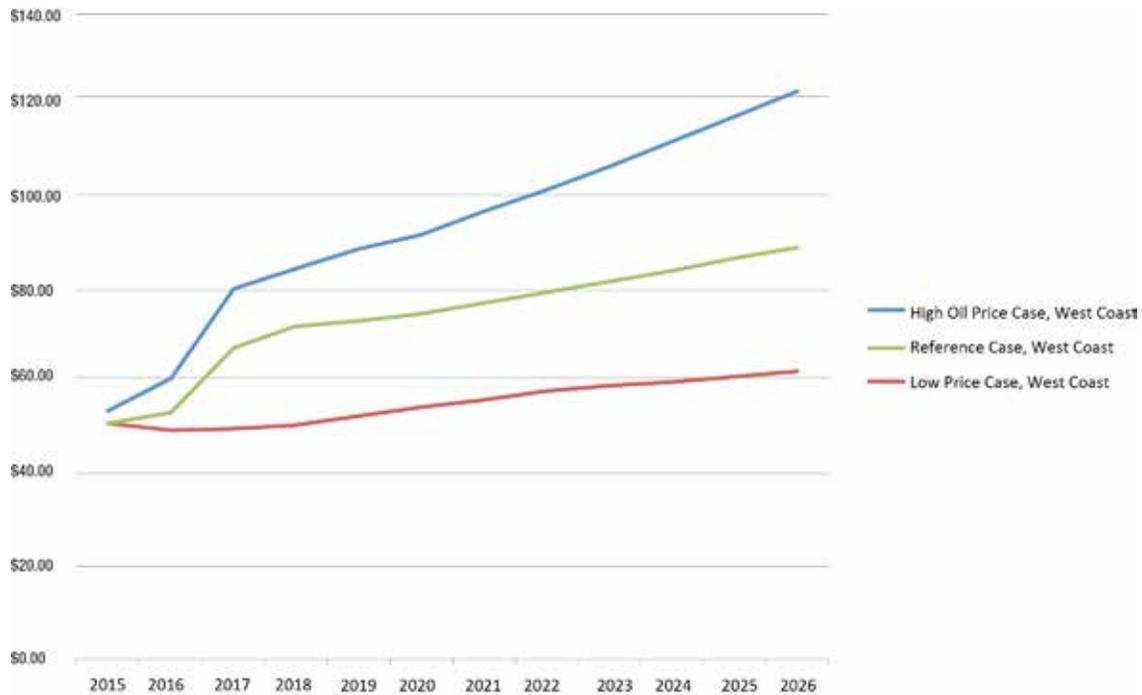
The Energy Commission traditionally looks to the *Annual Energy Outlook (AEO)*, published by the EIA, for crude oil price forecasts to serve as inputs to the transportation liquid fuel price forecasts.

The Crude Oil Refiner Acquisition Cost (RAC) is the cost of crude oil, including transportation and other fees paid by the refiner. Staff used EIA's forecast of RAC prices for the Petroleum Administration for Defense District (PADD) for the west coast (Alaska, Arizona, California, Hawaii, Nevada, Oregon, and Washington), known as PADD 5. Composite PADD RAC prices include both domestic and imported crude oil. The Energy Commission RAC forecast was constructed by assembling a forecast from the *2015 Short Term Energy Outlook*, also published by EIA, and the model update to the 2014 AEO scenarios that was published in the 2015 AEO.

The crude oil prices in Figure 19 were used to forecast liquid fuel prices.

The natural gas and electricity prices were developed based on the Energy Commission's price analysis for the *2015 Natural Gas Outlook* and *California Energy Demand 2016–2026, Revised Electricity Forecast*, presented in Chapter 6.

Figure 19: Crude Oil Cost (Refiner Acquisition Cost) Forecast, (2012\$)



Source: California Energy Commission, Supply Analysis Office, and EIA

To derive fuel cost per mile for the fuel types listed in Figure 20, staff used fuel economies for compact cars from Sierra Research.²¹⁷ Once vehicle fuel economies are accounted for, electric vehicles have the lowest cost per mile. An example for a compact vehicle is shown below in Figure 20.

In December 2015, the Energy Commission and the Air Resources Board released the Joint Agency Staff Report on *Assembly Bill 8: Assessment of Time and Cost Needed to Attain 100 Hydrogen Refueling Stations in California* (AB 8

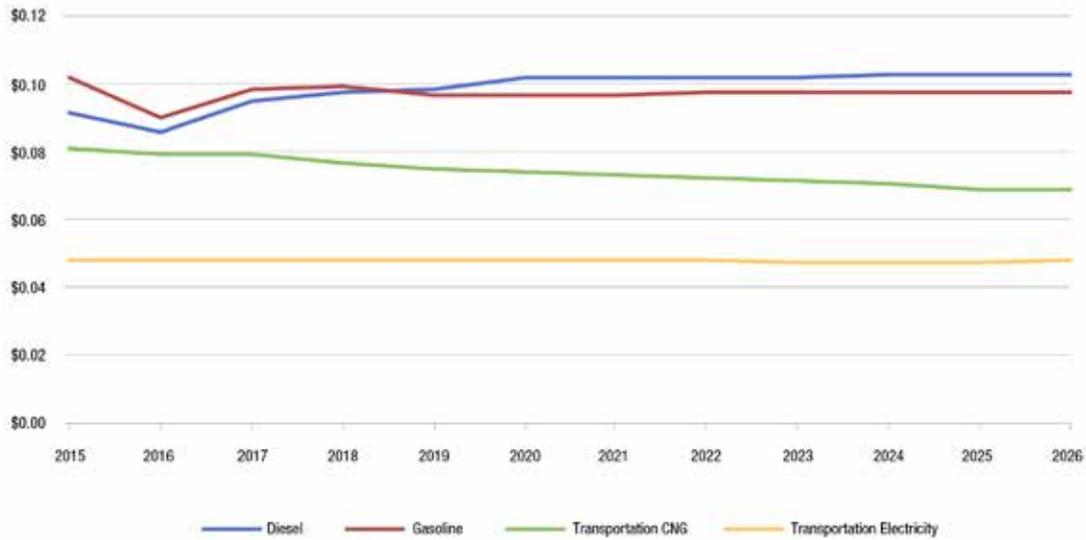
report).²¹⁸ This report summarizes an analysis conducted by the National Renewable Energy Lab (NREL) as part of the AB 8 report to provide insight into projected fuel costs per mile for hydrogen transportation fuel.

According to the AB 8 report, current hydrogen fuel prices range from \$12.85 to more than \$16 per kilogram (kg), but the most common price is \$13.99 per kg, which translates to an operating cost of \$0.21 per mile. While future price is uncertain, NREL estimates that hydrogen fuel prices may fall to the \$10 to \$8 per kg range in the 2020 to 2025 period. A fuel price of \$8 per kg hydrogen fuel translates to about \$0.12 per mile to drive a hydrogen vehicle.

217 September 30, 2015, IEPR workshop, presentation by Jim Lyons with Sierra Research, http://docketpublic.energy.ca.gov/PublicDocuments/15-IEPR-10/TN206225-3_20150929T111158_Light_Duty_Vehicle_Attributes_by_Jim_Lyons_of_Sierra_Research_1.pdf.

218 McKinney, Jim, et al. 2015. Joint Agency Staff Report on Assembly Bill 8: Assessment of Time and Cost Needed to Attain 100 Hydrogen Refueling Stations in California. California Energy Commission. Publication Number: CEC-600-2015-016.

Figure 20: Forecast of Cost per Mile (Compact Vehicles)



Source: California Energy Commission, Supply Analysis Office and EIA

Transportation Energy Demand Forecast

Different fuel types dominate different transportation sectors in California. While natural gas dominates public transit, diesel is the dominant fuel in freight movement, and gasoline dominates the LDV sector. However, data from recent years, along with the forecast, show that alternative fuels, such as electricity and E-85, are growing across different transportation sectors in California. Alternative fuels as defined for this forecast include electricity, hydrogen, ethanol, and natural gas.

The following transportation energy demand forecasts for gasoline, diesel, natural gas, electricity, and jet fuel were presented and discussed at an *IEPR* workshop on November 24, 2015.²¹⁹

Gasoline

Data from the Department of Motor Vehicles show that gasoline demand is largely driven by LDVs, which

represent more than 90 percent of all gasoline consumption in California. As shown in Figure 21, gasoline vehicles made up 92 percent of California LDVs in 2014. Gasoline also fuels hybrid vehicles and accounts for more than 95 percent of the fuel used by flexible-fuel vehicles in California. In other words, 95 percent of the time, flexible-fuel vehicle owners use gasoline instead of E-85 when refueling.

CAFE standards provide for significantly improved fuel economy, and NHTSA estimates that this trend will continue through 2025. Figure 22 shows NHTSA's estimates of cumulative fuel savings as these standards are applied over time.²²⁰

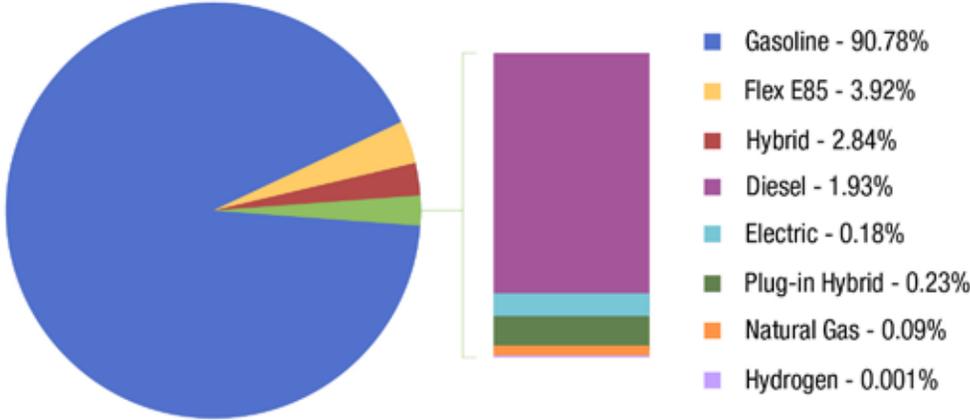
Figure 23 shows the gasoline demand forecast for all transportation sectors, travel modes, and both LDV and HDV classes on-road in California.²²¹ Most of the demand for gasoline in California can be attributed to LDVs in the

219 <https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=15-IEPR-10>.

220 <http://www.transportation.gov/mission/sustainability/corporate-average-fuel-economy-cafe-standards>.

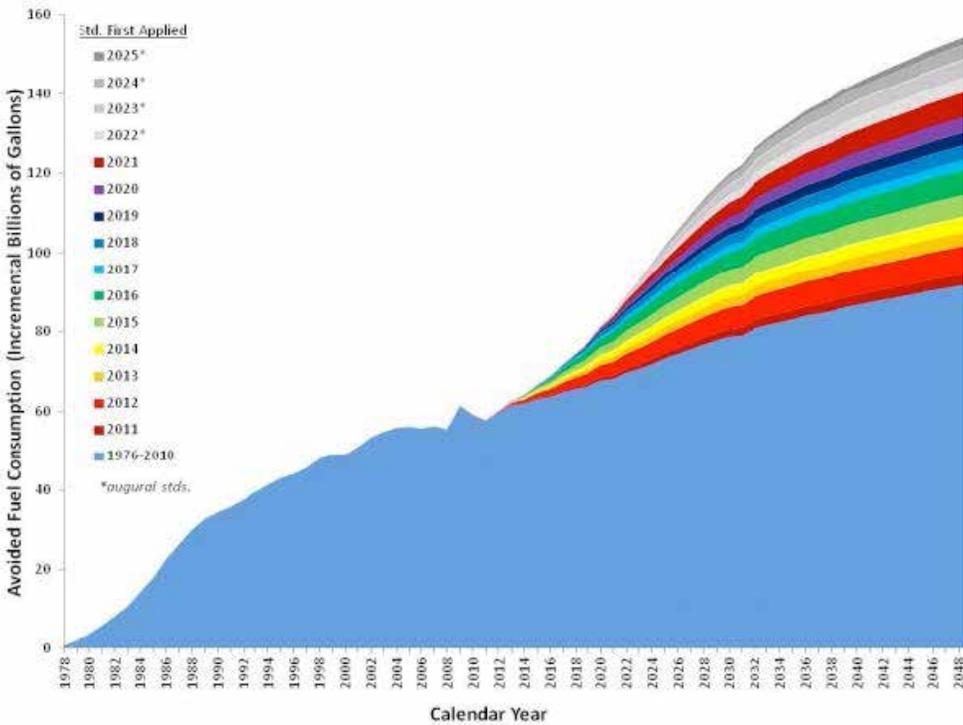
221 http://www.energy.ca.gov/2015_energy_policy/documents/2015-11-24_presentations.html.

Figure 21: California Light-Duty Vehicle Distribution by Fuel Type



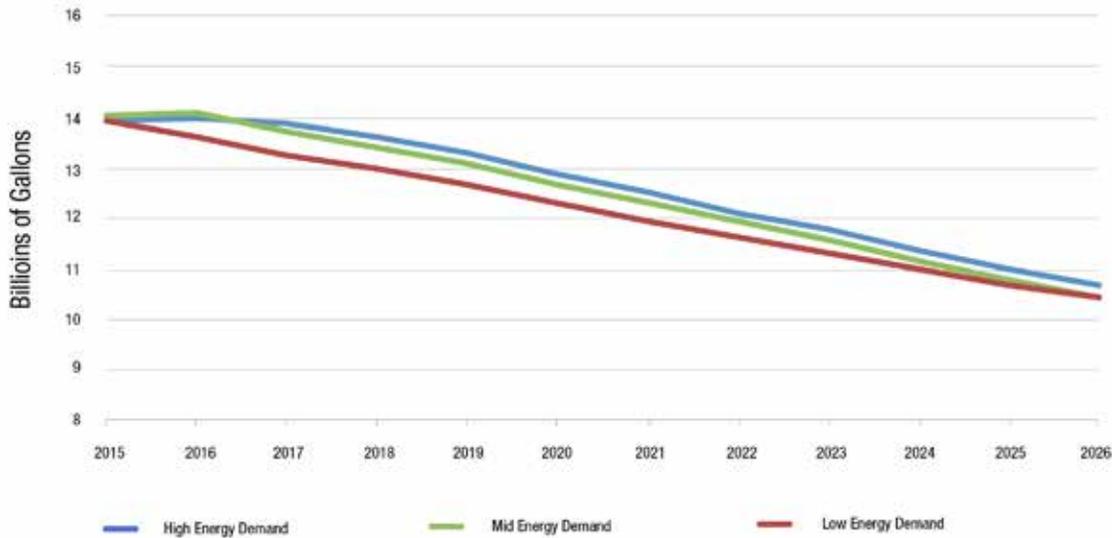
Source: California Energy Commission and Department of Motor Vehicles

Figure 22: NHTSA's Estimates of CAFE's Cumulative Fuel Savings for the U.S. Fleet



Source: U.S. Department of Transportation

Figure 23: California On-Road Gasoline Demand Forecast



Source: California Energy Commission

residential sector. The slow growth in population, coupled with improvements in fuel economy, explains the overall decline in demand for gasoline.

All three demand forecast cases show reductions of up to 3.7 percent per year due to improved fuel economy, driven by CAFE standards and displacement by alternative fuels, primarily driven by the ZEV regulations.

Diesel

In contrast to gasoline, most on-road diesel is consumed by medium- and heavy-duty vehicles, most notably freight trucks. Diesel vehicles comprised about 65 percent of the medium- and heavy-duty vehicles in California in 2014, as seen in Figure 24.

Figure 25 shows diesel demand for on-road vehicles and rail. While diesel consumption is projected to continue climbing through 2020, all three diesel demand cases project this trend to reverse as alternative fuels increase in market share. The projected growth in alternative fuel HDVs is led primarily by natural gas trucks in freight, as almost 60 percent of transit vehicles in California are already powered by natural gas. This forecast does not

include Executive Order 13423 (Strengthening Federal Environmental, Energy, and Transportation Management), but as this executive order is implemented, a further decline in diesel demand is anticipated.

Natural Gas

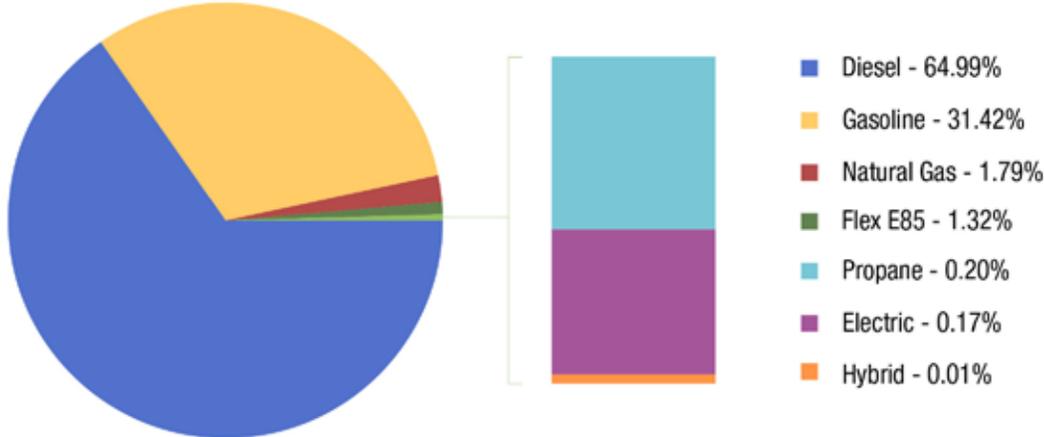
The natural gas vehicle fleet in California is almost exclusively MDVs and HDVs, such as urban transit buses and utility trucks. While there are light-duty natural gas vehicles, the only model available on the U.S. market was discontinued in 2015, and the existing natural gas stock makes up a very small percentage of the LDV fleet.

Natural gas used for transportation is forecast to experience steady growth, as shown in Figure 26. Heavy-duty natural gas vehicle market shares were derived using fuel economy and the incremental vehicle price projections for MD/HD vehicles by Sierra Research.

Electricity

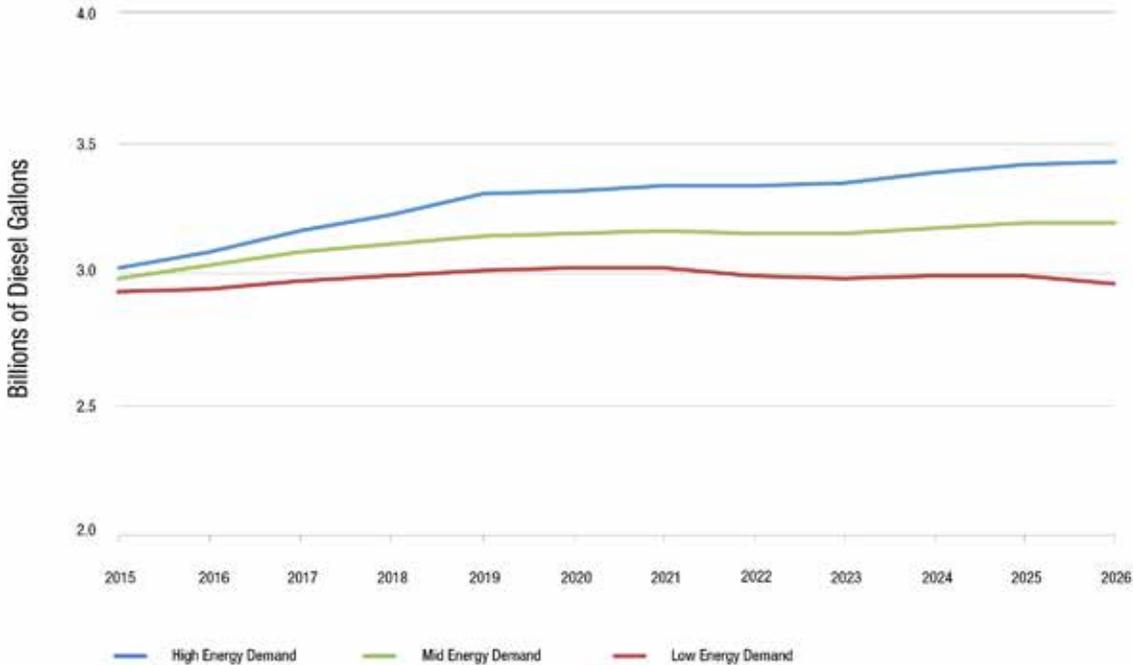
Most of the electricity used for transportation in California can be attributed to LDVs, light rail, and cable cars. The forecast shows an increase in the number of plug-in

Figure 24: California Medium-/Heavy-Duty Vehicles Distribution by Fuel Type in 2014



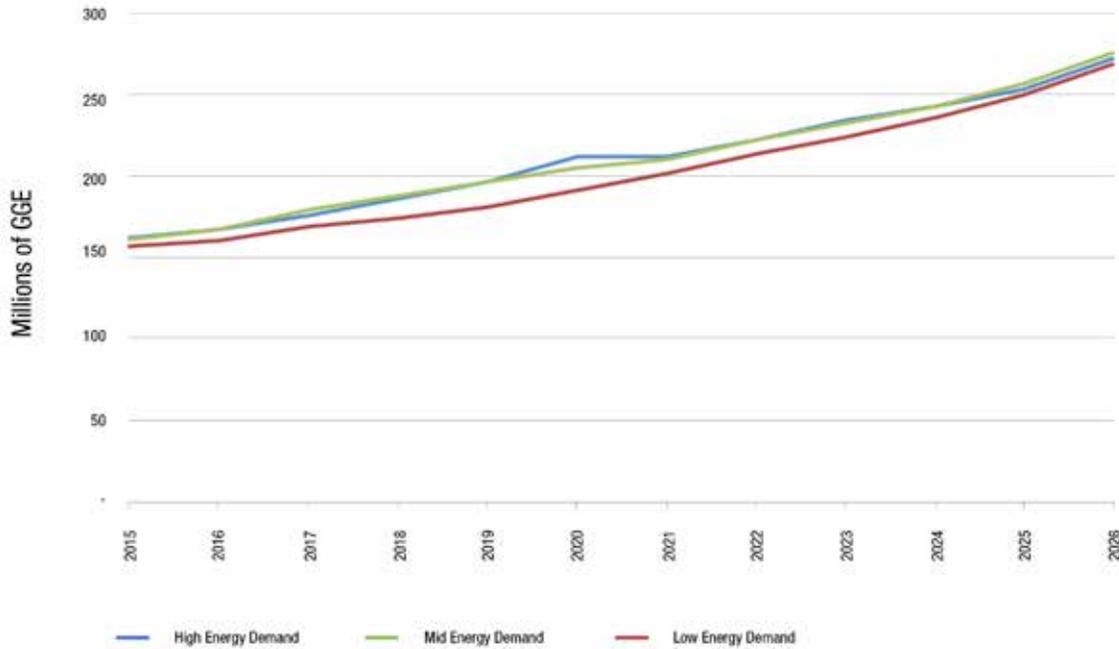
Source: California Energy Commission and Department of Motor Vehicles

Figure 25: California On-Road and Rail Diesel Demand Forecast



Source: California Energy Commission

Figure 26: Transportation Natural Gas Demand Forecast



Source: California Energy Commission

electric vehicles, meeting and exceeding the ZEV most likely scenario, but not enough to make electricity the primary fuel source for LDVs over the forecast which ends in 2026. In addition to the projected shift to electric vehicles, high-speed rail is scheduled to begin operation in 2022, which will further drive the increase in transportation electricity in the final years of the forecast period.

High-Speed Rail (HSR)

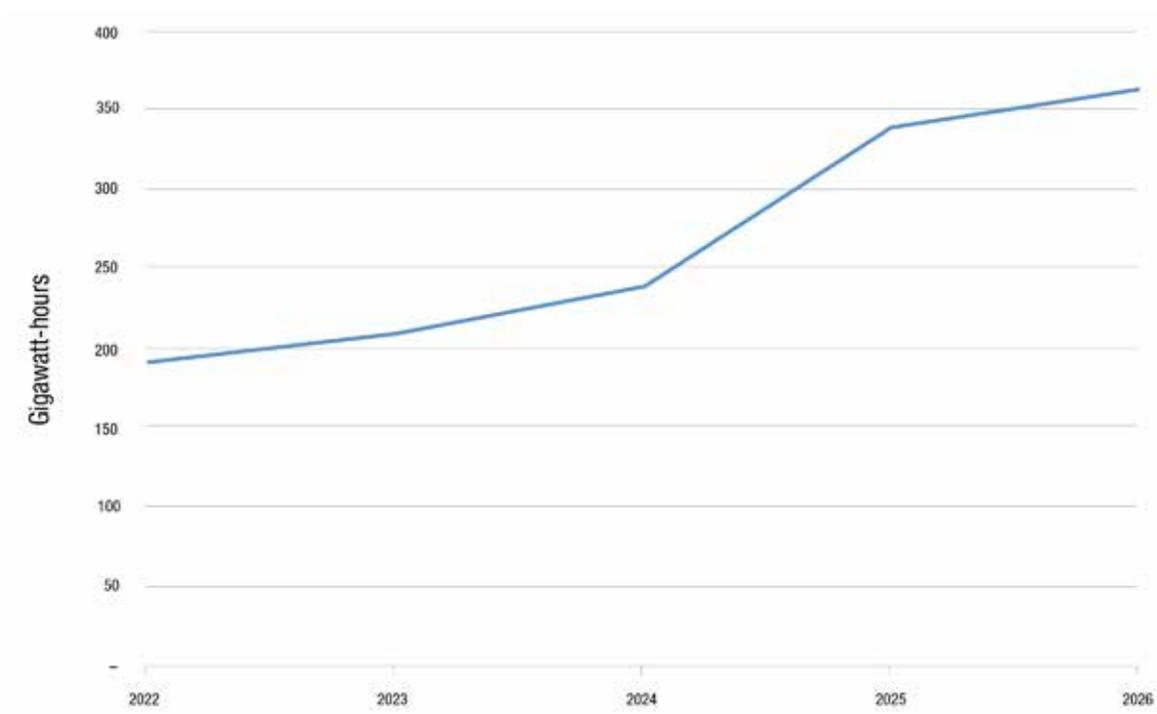
The California High-Speed Rail Authority (CalHSR) provided the HSR energy consumption forecast presented in Figure 27, which was developed in support of *Connecting California 2014 Business Plan, April 2014*.²²² Initially, HSR is slated to run 300 miles from Merced to the San Fernando Valley, with a projected completion date of 2022. Next, the Bay-to-Basin section, which extends northward to San Jose, is expected to be completed in 2026. Since this

forecast estimates out only to 2026, staff considered only the initial operating section (Merced to the San Fernando Valley) of the HSR network for this forecast.

The HSR forecast has been considered only as an “add-on” to the reference case because the economic and demographic assumptions used for the CalHSR base scenario more closely align with the Energy Commission’s own assumptions. Input assumptions – including fuel price and income – to CalHSR’s high demand scenario were not comparable with the input assumptions for the Energy Commission’s input assumptions for the high energy demand case. The same is true for the low demand cases for both forecasts. CalHSR’s mid demand scenario is more compatible with the Energy Commission’s mid demand case; therefore, it is the only case considered in the initial work on the transportation energy demand forecast and is included to give some indication of what additional electricity may be needed. In the reference case, HSR forms 5 to 6 percent of total electricity consumption in the years in which it is active.

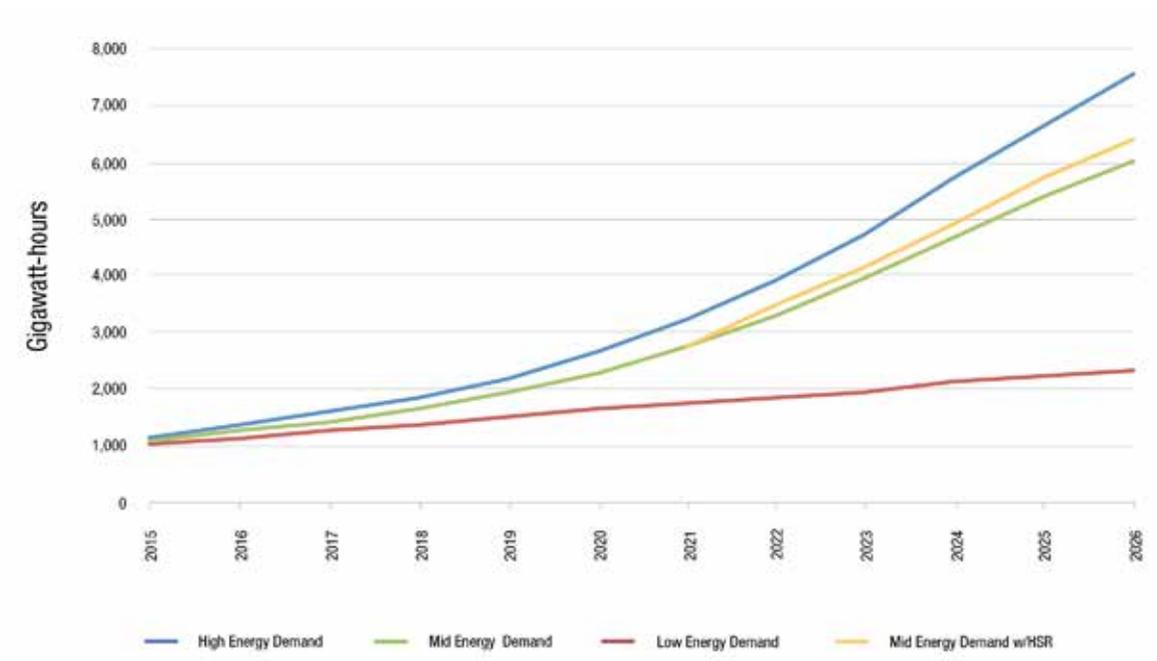
²²² http://www.hsr.ca.gov/docs/about/business_plans/BPlan_2014_Business_Plan_Final.pdf.

Figure 27: Forecasted High-Speed Rail Electricity Consumption



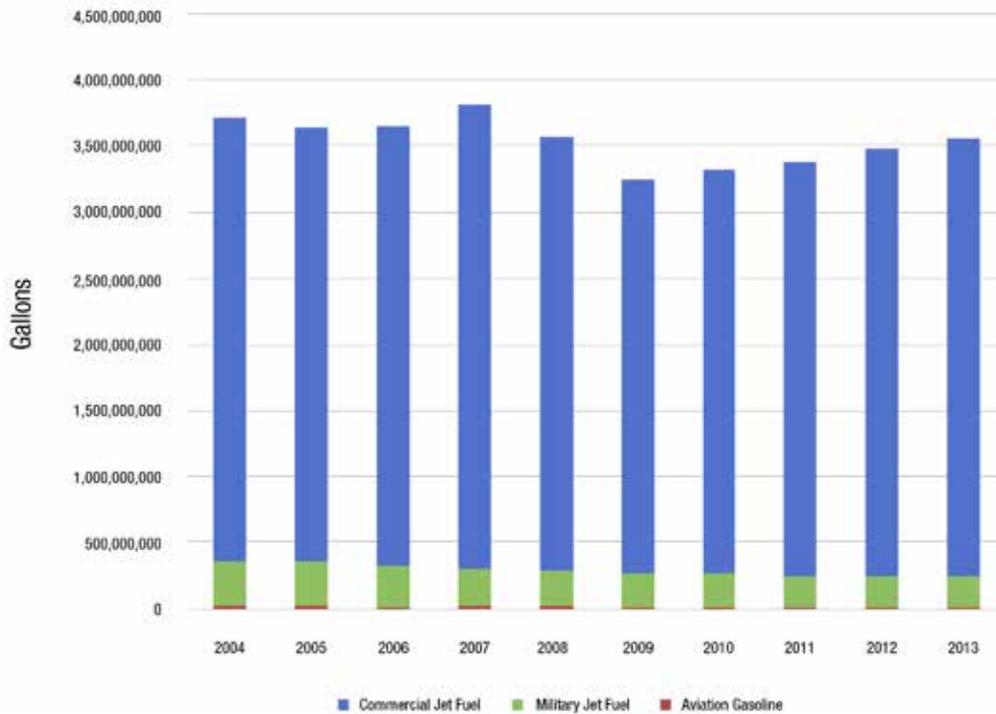
Source: California High-Speed Rail Authority

Figure 28: Forecasted Transportation Electricity Demand



Source: California Energy Commission

Figure 29: Aviation Fuel Consumption by Use and Type



Sources: California State Board of Equalization, Defense Logistics Agency, and Petroleum Industry Information Reporting Act data

Figure 28 shows the projected growth in total transportation electricity demand in the high, mid, and low demand cases. To maintain consistency with the low demand and high demand scenarios, the mid case shows electricity demand if HSR is not operational by 2026, and the mid with HSR case assumes that operation remains on schedule starting in 2022. The difference between these two mid demand cases show the projected contributions of HSR in the mid demand case.

Jet Fuel

California aviation fuels consist primarily of commercial jet fuel, followed by military jet fuel and aviation gasoline (used in small private planes). Commercial jet fuel dominates California aviation fuel use, accounting for 91.4 percent of the total over the last decade, while military jet fuel accounted for 8 percent, and aviation gasoline only

0.6 percent.²²³ Figure 29 shows the relative contribution from the various types between 2004 and 2013.

Energy Commission analysis shows future consumption of aviation fuels in California will be driven by changes in demand for airline travel to domestic and foreign destinations originating from California airports and changes in fuel economy trends for air carriers over the forecast period. The Energy Commission does not forecast airline passenger activity within California. Number of passengers getting on the planes, or *enplaned passengers*, departing from California determines the jet fuel sold in California. The Federal Aviation Administration (FAA) tracks historical passenger activity by airport (measured by *enplaned passengers*), as well as forecasting growth

²²³ California aviation fuel consumption in California in 2013 amounted to 3,307 million gallons commercial jet fuel, 242 million gallons of military jet fuel, and 16 million gallons of aviation gasoline.

Figure 30: Commercial Jet Fuel Consumption



Source: California Energy Commission analysis of FAA historical and forecast data

by each airport.²²⁴ The FAA also develops estimates of jet fuel consumption for both historical and forecasted periods but only for the United States as a whole.²²⁵ Staff assumed that the relative contribution of foreign destinations for California airport activity will change in a fashion similar to that of the United States: a slightly higher ratio of foreign destinations throughout the forecast period.

California enplaned passenger activity is forecast to grow at a rate of 2.5 percent per year, slightly lower than the near-term historical growth rate of 2.7 percent per year. An additional 28.9 million passengers will be boarding flights originating in California by 2025 compared to 2014.

Estimates of fuel consumption per passenger vary by class of destination, with domestic destinations averaging

less than those for foreign destinations due to the longer flight distances for most foreign routes. For example, average consumption of jet fuel per enplaned passenger originating in the United States and headed for a domestic destination amounted to 18.5 gallons during 2014, while the average for foreign destinations averaged 72.3 gallons per enplaned passenger. The average jet fuel use for all domestic and foreign destinations was 24.7 gallons per enplaned passenger.

California's average jet fuel use per enplaned passenger was estimated to be 36.8 gallons during 2014, nearly 49 percent greater than the U.S. average. This higher rate is due to a greater ratio of foreign destinations for California enplaned passengers than that of destinations in the United States. Energy Commission staff used enplaned passenger projections for California airports in conjunction with per-passenger fuel consumption trends for the United States to derive estimates of commercial jet fuel demand for California between 2015 and 2025. Figure 30 shows how commercial jet fuel consumption in California is forecast to grow from 3,357 million gallons during 2014 to 4,212 million gallons by 2025.

224 Federal Aviation Administration, *FAA Aerospace Forecast Fiscal Years 2015-2035*, 2015, https://www.faa.gov/about/office_org/headquarters_offices/apl/aviation_forecasts/aerospace_forecasts/2014-2035/media/2015_National_Forecast_Report.pdf.

225 *Ibid*, Table 23, p. 120.

Alternative and Renewable Fuel and Vehicle Technology Program Benefits Update

Introduction

As part of its strategy to reduce GHG and criteria emissions from the transportation sector, the California Legislature created an incentive funding program for the development of alternative fuel and vehicle technologies with the passage of Assembly Bill 118. This legislation created the Alternative and Renewable Fuel and Vehicle Technology Program (ARFVTP), administered by the Energy Commission. With funds collected from vehicle and vessel registration fees, and vehicle identification plates and smog fees, the ARFVTP provides up to \$100 million per year for projects that will “transform California’s fuel and vehicle types to help attain the state’s climate change policies.” The statute also calls for the Energy Commission to “develop and deploy technology and alternative and renewable fuels in the marketplace, without adopting any one preferred fuel or technology.” Assembly Bill 8 subsequently extended the collection of fees that support the ARFVTP through January 1, 2024.

Assembly Bill 109 (Núñez, Chapter 313, Statutes of 2008) requires the Energy Commission to prepare “an evaluation of research, development, and deployment efforts funded by this chapter” every two years, in conjunction with the Energy Commission’s *IEPR*. The evaluations must include a list of all funded projects, expected benefits from the projects, overall contributions of the projects toward a portfolio of clean fuels, and obstacles and recommendations. This section of the

2015 IEPR fulfills the AB 109 reporting requirement and includes ARFVTP activities and expenditures through December 31, 2015.

Role of the ARFVTP Investment Plan

The Energy Commission allocates ARFVTP funds through preparation and adoption of an annual investment plan update that identifies the funding priorities for the coming fiscal year. The funding allocations reflect the potential for each alternative fuel and vehicle technology to contribute to the goals of the program; the anticipated barriers and opportunities associated with each fuel or technology; the effect of other entities’ investments, policies, programs, and statutes; and a portfolio-based approach that avoids adopting any preferred fuel or technology. With the adoption of the *2015–2016 Investment Plan Update for the Alternative and Renewable Fuel and Vehicle Technology Program (2015–2016 Investment Plan)*²²⁶ at its April 2015 Business Meeting, the Energy Commission has developed and adopted seven Investment Plans.

Description of Funded Projects

As of December 31, 2015, the Energy Commission has issued or proposed \$606 million in ARFVTP funding across 545 agreements that span California.²²⁷ These agreements support a broad portfolio of fuel types, supply chain phases, and commercialization phases. In most cases, projects are still in progress: production facilities are still being sited and constructed, infrastructure is still being installed, and vehicles are still being demonstrated or deployed. On a dollar basis, 29 percent of the projects have been completed to date.

226 Smith, Charles, Jacob Orenberg. 2015. *2015-2016 Investment Plan Update for the Alternative and Renewable Fuel and Vehicle Technology Program* Commission Report. California Energy Commission, Fuels and Transportation Division. Publication Number: CEC-600-2014 -009- CMF.

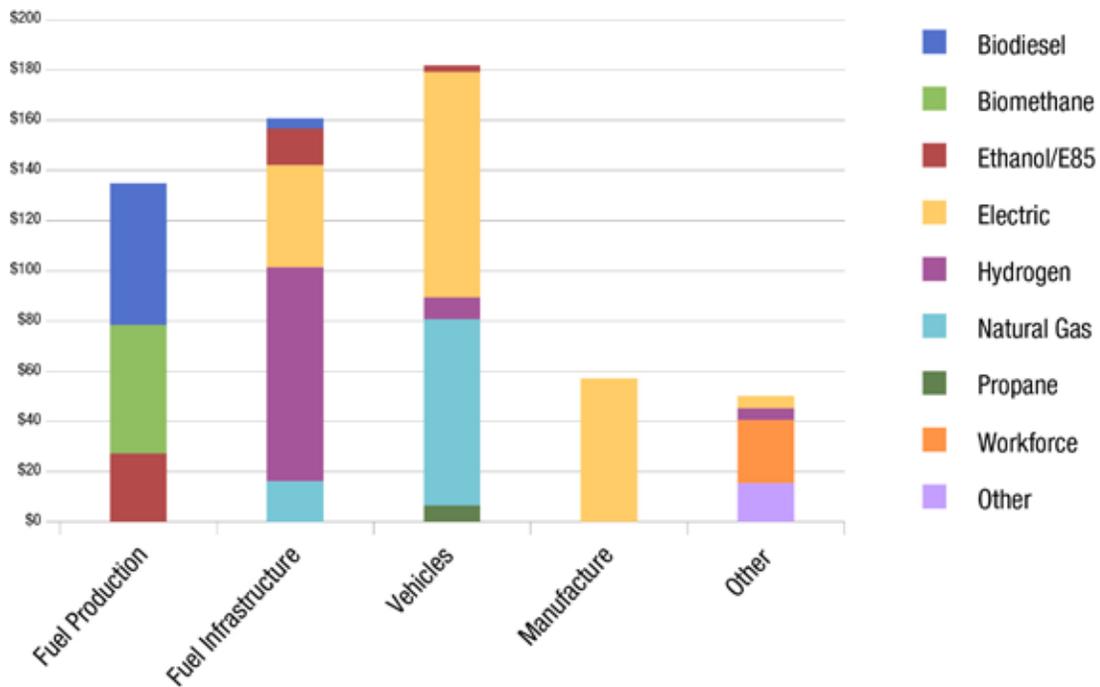
227 The Energy Commission DRIVE website contains a map of ARFVTP-funded projects in California <http://www.energy.ca.gov/drive/projects/map/index.html>.

Table 6: ARFVTP Investments by Primary Fuel Category Through December 31, 2015

Investment Areas	Funding Amount (in millions)	Percent of Total	Number of Awards
Biofuels	\$158	26	61
Electric Drive	\$199	33	153
Natural Gas	\$95	16	185
Hydrogen	\$113	19	72
Workforce Development	\$28	4	58
Market & Program Develop.	\$13	2	16
Total	\$606	100	545

Source: California Energy Commission staff

Figure 31: ARFVTP Investments by Fuel Category and Supply Chain Phase Through December 31, 2015



Source: California Energy Commission staff

Table 6 shows ARFVTP investments by primary fuel and program category. Figure 31 shows ARFVTP investments by fuel category and supply chain phase.

The more than \$600 million in ARFVTP investments are beginning to create meaningful levels of market penetration for advanced technology fuels, fueling infrastructure and vehicles. However, given the vast scale of California's transportation sector, with more than 28 million light-duty passenger vehicles and medium- and heavy-duty trucks and 18 billion gallons in fuel consumption, the transition to low-carbon and ZEVs and fuels remains modest. Listed below are highlights of the ARFVTP funding portfolio to date.

Building the Foundational Charging and Fueling Infrastructure for Zero-Emission Vehicles

- » 7,490²²⁸ installed and planned chargers for plug-in electric vehicles, including 4,176 residential charging points, 2,818 commercial chargers, 376 workplace charging stations, and 120 direct current (DC) fast chargers.
- » 34 regional readiness planning grants to help regions throughout the state plan for electric vehicle deployment, new charging infrastructure, and permit streamlining.
- » 49 new or upgraded hydrogen refueling stations that will support the early commercial deployment of fuel cell electric vehicles by major automakers such as Toyota, Hyundai, and Honda. California's hydrogen fueling network is one of the largest in the world.

Advancing Commercial Development of Low-Carbon Biofuels in California

- » 50 projects to promote the production of sustainable, low-carbon biofuels within California. Most will use

228 Energy Commission staff has revised the units for charging infrastructure from *charge points* or *charging stations* to *chargers*. Chargers denote a charging pedestal that may have multiple charge points or connectors. For example, The *2015–2016 Investment Plan Update* cited 9,369 charging stations.

waste-based feedstocks, which contribute to some of the lowest carbon-intensity pathways recognized under the LCFS. Cumulatively, these projects expand California's ethanol production capacity by 8.8 million gallons per year, biodiesel production capacity by 56.7 million gallons per year, and renewable diesel production capacity by 17.9 million gallons per year.

Investing in Advanced-Technology Zero-Emission Trucks

- » 44 projects to demonstrate zero- and near-zero-emission advanced technologies and alternative fuels in a variety of medium- and heavy-duty vehicle applications. These projects include 30 medium-duty electric drive trucks, 17 medium-duty hydrogen fuel cell trucks, 5 heavy-duty all electric drayage trucks, 1 heavy-duty fuel cell drayage trucks, 23 electric school and transit buses, and 8 hydrogen fuel cell buses.
- » 22 manufacturing projects for electric drive-related vehicles and components that will support in-state economic growth while reducing the supply-side barriers for alternative fuels and advanced technology vehicles.

Capitalizing on Low-Cost, Low-Emission Natural Gas Truck Technologies

- » 2,809 natural gas vehicles now or soon-to-be in operation in a variety of applications, including roughly 2,400 medium- or heavy-duty trucks.²²⁹ Natural gas trucks offer immediate but modest reductions in carbon and criteria emissions in a cost-effective manner. As new low-NO_x natural gas engines are introduced and fleets incorporate

229 The natural gas vehicle voucher rebate program is in transition. Due to falling petroleum and diesel prices, demand for natural gas trucks has diminished; \$4.5 million in natural gas vehicle funding went unused and reverted. In addition, Honda Motor Corporation announced the cancelation of the Honda CRG, the last light-duty natural gas vehicle offered by a major auto manufacturer in the United States. The Energy Commission has entered into a new administration and research contract with the University of California at Irvine to administer this portion of ARFVTP.

Table 7: Geographic Distribution ARFVTP Funding by Air District

Air District	Total Funding Amount (\$ millions)	Percent of Total ARFVTP Funding	Percent of State Population
Bay Area	102.7	16.9%	18.4%
Monterey	9.4	1.6%	2.0%
Sacramento	24.9	4.1%	3.6%
Santa Barbara	3.3	0.5%	1.1%
San Diego	32.5	5.4%	8.4%
San Joaquin	85.8	14.2%	10.5%
South Coast	167.7	27.7%	44.0%
Ventura	1.3	0.2%	2.2%
Yolo-Solano	12.3	2.0%	0.9%
Other Northern California	16.7	2.8%	8.9%
Other So Cal Districts	5.6	0.9%	-
Statewide	143.8	23.7%	-
Total	606.0	100.0%	100.0%

Source: California Energy Commission staff

low-carbon biomethane into their fueling, natural gas trucks can also become a long-term option for much larger reductions of carbon and criteria emissions. (See “Natural Gas as a Transportation Fuel” subsection in Chapter 6 for more information on low-NO_x engines and biomethane.)

- » 65 natural gas fueling stations to support a growing population of natural gas vehicles. These include at least five stations that will incorporate low-carbon biomethane into the dispensed fuel.

Advancing Workforce Training and Development

- » Workforce training for 14,762 trainees and more than 240 businesses that will translate California’s clean technology investments into sustained employment opportunities.

As shown in Table 7, ARFVTP grants are distributed throughout the state primarily in proportion to regional population levels. However, the San Joaquin Valley air basin receives about 14 percent of the funding awards and

has 10 percent of the state’s population, while the South Coast air basin receives 28 percent of program funding and has 44 percent of the state’s population.

Table 8 illustrates some of the positive impacts ARFVTP projects will have when completed on levels of alternative fueling infrastructure and vehicles in California since the Program was initiated in 2009. The table shows the percentage increase in fueling infrastructure and some vehicle types from a 2009–2010 baseline.

Summary of ARFVTP Benefits

For the 2015 IEPR, the Energy Commission has contracted with the NREL²³⁰ to calculate the expected benefits of the ARFVTP consistent with the statutory requirements of AB 109. Dr. Marc Melaina, principal investigator, and his team expanded on the methods, data, and timeline

230 California Energy Commission Agreement Number 600-11-002.

Table 8: ARFVTP Funding Impacts on Infrastructure and Vehicle Deployment in California

	Fuel Area	Existing 2009-2010 Baseline Levels	Additions Funded from ARFVT or AQIP Program Funding	Percent Increase
Alternative Fueling Infrastructure	Electric	2,540 charge points	7,490 charging stations <i>(residential, public, workplace, DC fast charger)</i>	300
	E85	39 fueling stations	158 fueling stations	405
	Natural Gas	443 fueling stations	65 stations	15
	Hydrogen	6 public fueling stations	49 fueling stations	800
Alternative Fuel Vehicles	Electric Cars (ARB Vouchers)	13,268 <i>(mostly neighborhood electric vehicles)</i>	(21,000 via ARFVTP) 110,000: Total AQIP*	829
	Electric Trucks	1,409	160	11
	Natural Gas Trucks	13,995	2,400	17

Source: California Energy Commission staff

* Total number of CVRP vouchers issued through AQIP through June 30, 2015. ARFVTP funding accounts for 19 percent of total CVRP voucher funding.

developed for the 2014 Benefits Report.²³¹ NREL analyzed updated ARFVTP project data for 262 projects totaling \$552 million, representing the ARFVTP project portfolio as of June 30, 2015.

NREL used the same method in 2015 as in 2014. Because the *2014 IEPR Update* analyzed ARFVTP benefits through the fourth quarter of 2014, the number of new projects to be assessed for 2015 is modest, as are the 2015 increases in carbon emission reduction and petroleum reduction.

NREL has developed a framework of four quantifiable benefit categories for petroleum reduction, GHG emissions reductions, and criteria emissions reductions:

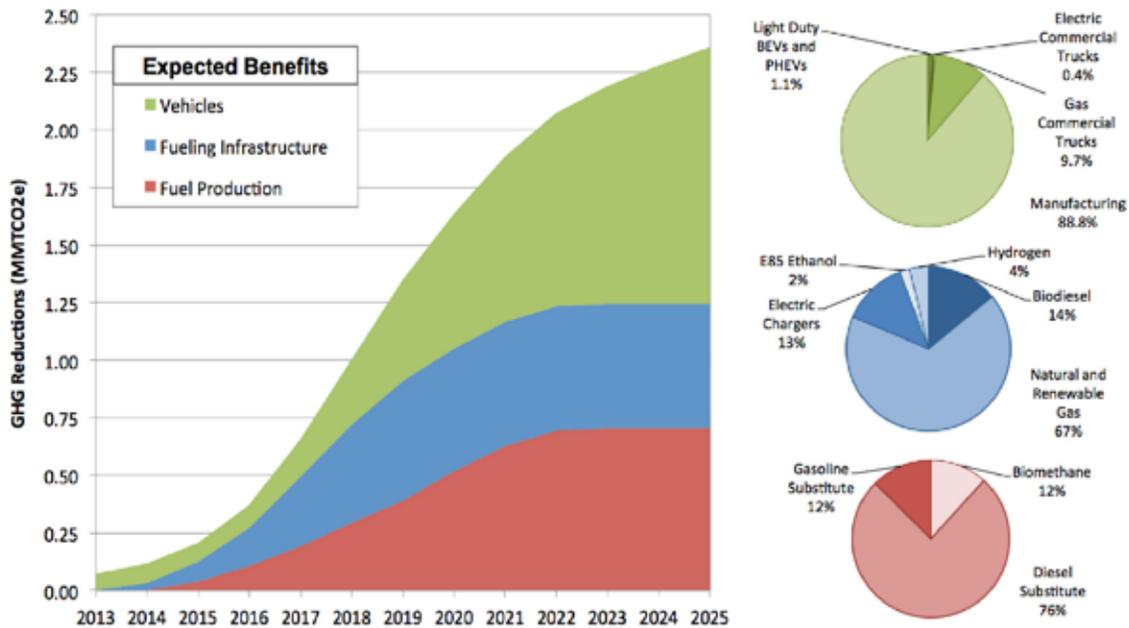
» **Baseline Benefits** expected to accrue without support from ARFVTP.

» **Expected Benefits** directly associated with vehicles and fuels deployed through projects receiving ARFVTP funds. Expected benefits are quantified as the most likely benefits to occur from ARFVTP projects being executed successfully, assuming one-to-one substitution of the service or technical performance of the new technology replacing the existing technology. Project categories include vehicles, refueling infrastructure, and fuel production. NREL evaluated 225 of the 320 total projects funded as of June 30, 2015, to determine expected benefits.

» **Market Transformation Benefits** accrue due to the influence of ARFVTP projects on future market conditions to accelerate the adoption of new technologies. Influences include increased availability of public electric vehicle supply equipment and hydrogen refueling stations, consumer incentives for ZEVs, investments in ZEV demonstrations and manufacturing facilities, deployment of next-generation fuel production facilities, and advanced truck demonstrations. NREL evaluated these seven categories of ARFVTP-funded projects to determine market transformation benefits.

231 Melaina, Dr. Marc et al., November 2013, *Draft Analysis of Benefits Associated with Projects and Technologies Supported by the Alternative and Renewable Fuel and Vehicle Technology Program*, National Renewable Energy Laboratory.

Figure 32: Summary of Annual GHG Emissions Reductions Through 2025 From Expected Benefits of 219 Funded Projects



Source: NREL

» **Required Carbon Market Growth Benefits:** associated with projections of future market growth trends comparable to those needed to achieve deep reductions in GHGs by 2050.

For a full list of ARFVTP projects analyzed by NREL for the 2015 IEPR see Appendix D.

Expected Benefits Results

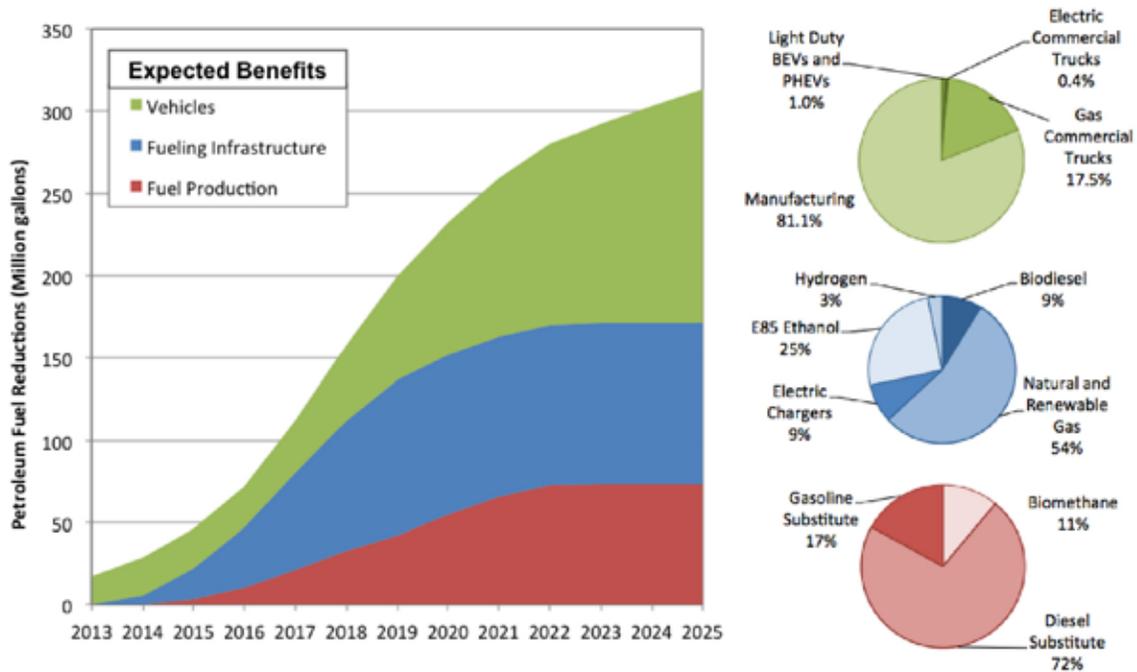
Of the projects NREL analyzed for expected benefits, ARFVTP has invested \$155 million (22 projects) in vehicles, \$158 million (157 projects) in refueling infrastructure, and \$123 million (40 projects) on fuel production infrastructure. The major new awards since 2014 included 4 electric drive manufacturing projects, 11 medium-duty and heavy-duty zero-emission truck and bus technology demonstration projects, 4 early stage biofuels demonstrations, and 13 compressed natural gas fueling stations. Figure 32 shows estimated total GHG

emissions reductions across broad project categories.

The GHG emission reductions are comparable among the three categories by 2025, ranging from 0.5 million to 1.1 million metric tons of carbon dioxide equivalent (MMT-CO₂e). The steady growth in GHG reductions in the vehicle category is due largely to electric drive vehicle production and manufacturing projects for medium- and heavy-duty trucks. The pie charts to the right of the figure indicate the percentage of cumulative reductions over the period for various project subcategories, with manufacturing, natural and renewable natural gas, and diesel substitute dominating the vehicles, fueling infrastructure, and fuel production categories, respectively.

Figure 33 shows total petroleum use reductions across these major project categories. Annual petroleum use reductions by 2025 includes 142 million gallons per year from vehicle projects, 98 million gallons per year from refueling infrastructure, and about 73 million gallons from fuel production projects. In sum, petroleum fuel

Figure 33: Summary of Annual Petroleum Fuel Reductions From Expected Benefits Through 2025



Source: NREL

reductions for all three expected benefit categories approach 313 million gallons per year by 2025.

In comparing petroleum fuel and GHG reductions, the refueling infrastructure makes a larger relative contribution to petroleum fuel reductions than GHG reductions. This is due largely to ethanol and natural gas refueling stations displacing large volumes of petroleum fuel, despite the relatively high fuel carbon intensity compared to fuels used in other projects.

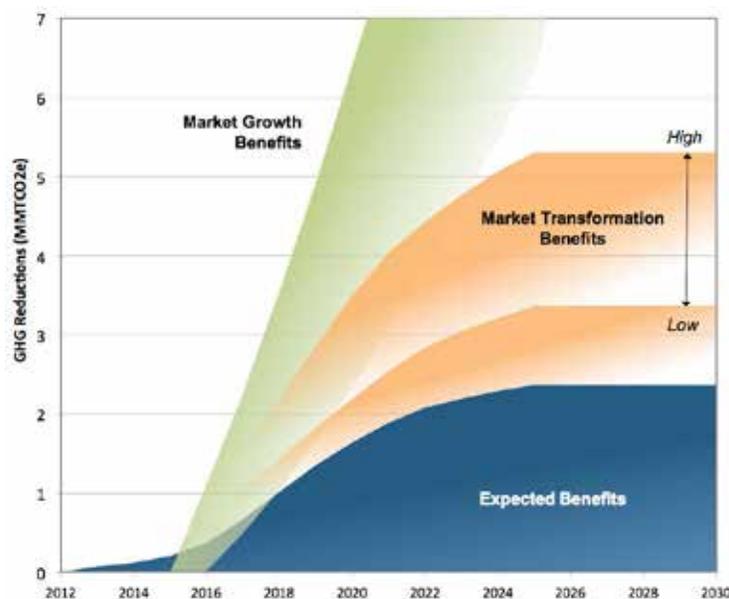
Market Transformation

The Energy Commission’s core mission with ARFVTP is to transform California’s petroleum-based transportation system into a low-carbon, low-emission transportation system. Market transformation benefits are as real and tangible as the direct or expected benefits described earlier. They are, however, based upon more uncertain data and more hypothetical estimation methods than the

expected benefits in terms of GHG reductions and petroleum use reductions.

Market transformation may be *second order* benefits that follow from successful deployment of technologies. For example, the goal in demonstrating a small-scale biofuel production process would be to validate the technology, production process, and production costs, all of which are critical to future market success. Yet this important technology validation would yield only a small volume of low-carbon fuel that is directly attributable to the initial ARFVTP project grant (expected benefit). A successful demonstration project would increase the likelihood of larger-scale deployment by the initial company and perhaps by other companies. A successful demonstration would also provide performance and potential market data to attract new private or public funding. The magnitude of these future benefits is measured by NREL as market transformation benefits. For more information

Figure 34: GHG Reductions From Expected and Market Transformation Benefits in Comparison to Needed Market Growth Benefits



Source: NREL

on the methods used to measure market transformation benefits, see the *2014 IEPR Update*.²³²

Market Transformation Benefits Results

Market transformation benefits are additive to the expected benefits. Figure 34 shows the total range of expected and market transformation GHG reduction benefits from ARFVTP projects, which are projected to range from 3.2 to 5.6 MMTCo₂e by 2025. This represents a modest 300,000 ton increase from the 2014 high case of 5.3 MMTCo₂e. Overall, California expects the suite of adopted transportation sector measures, including the LCFS and the Advanced Clean Cars program, will result in GHG emission reductions of 23 MMTCo₂e in 2020.²³³ The largest proportion of these

emission reductions are expected to come from the LCFS program, reducing 15 MMTCo₂e in 2020.²³⁴ Significant on-going public and private sector investments will be needed to continue developing advanced technologies, low-carbon fuels, fueling infrastructure, and vehicles to build consumer and commercial market acceptance for these products to achieve the needed market growth and associated benefits represented in the green portion of Figure 34.

Public Health and Social Benefits

Reducing petroleum fuel use through investments in alternative technology fuels and vehicles reduces carbon and criteria emissions. These emission reductions also create a series of public health and other social benefits, including job creation benefits.

²³² California Energy Commission. 2015. *2014 Draft Integrated Energy Policy Report Update*. Publication Number: CEC-100-2014-001-CMF. Appendices C and D.

²³³ California Air Resources Board, *First Climate Change Scoping Plan Update*, Table 5. "Meeting the 2020 Emissions Target," May 2014.

²³⁴ California Air Resources Board, Low Carbon Fuel Standard Advisory Board Meeting, staff presentation, May 19, 2014, as reported by Jim McKinney, staff presentation at the June 12, 2014, Integrated Energy Policy Report workshop.

Public health impacts in the San Joaquin Valley and South Coast Air Basin from transportation sector emissions are significant.²³⁵ Reducing NO_x and PM2.5 emissions creates the most important public health benefits.²³⁶ NO_x emissions combine with volatile organic compounds and sunlight to form ozone. The public health impacts from ozone pollution include increased mortality due to respiratory diseases; increased incidences of heart attacks, strokes, and heart disease; low birth weight and developmental delays in children; and substantial increases in rates of asthma and other respiratory diseases. Children and the elderly are especially susceptible to ozone-related health impacts.²³⁷ At this time, there is insufficient data from the ARFVTP data set to assess public health benefits of reduced NO_x emissions from California's transportation sector.

The health benefits of reduced PM2.5 emissions include reduced premature deaths and morbidity, including avoided instances of upper and lower respiratory symptoms, bronchitis, asthma exacerbation, hospital and emergency room visits, and work-loss days. NREL calculates the benefits of reduced PM2.5 emissions by quantifying the emissions reductions and then monetizing the public health benefits on a geographic basis.

235 See, for example, U.S. Environmental Protection Agency, 2002, *Health Assessment Document for Diesel Engine Exhaust*, Prepared by the National Center for Environmental Assessment, Washington, DC, for the Office of Transportation and Air Quality; EPA/600/8-90/057F, <http://www.epa.gov/ncea>; and American Lung Association, *State of the Air City Rankings, 2013* <http://www.stateoftheair.org/2013/city-rankings/>. Note that 6 of the 10 worst cities in the United States for ozone pollution are in California's Central Valley and South Coast regions, while 7 of the 10 worst cities for particulate matter pollution are in these same regions.

236 *PM2.5 emissions* refer to fine particles in the air measuring less than 2.5 micrometers in diameter. Because of their size these particles can lodge deeply into the lungs.

237 U.S. Environmental Protection Agency, *Integrated Science Assessment for Ozone and Related Photochemical Oxidants*, 2013. EPA/600/R-10/076F.

Reductions in PM2.5 emissions are estimated for electric-drive vehicles, primarily light-duty PHEVs, BEVs, and FCEVs, as well as some medium-duty PHEVs and BEVs. The health benefits from reduced PM2.5 tailpipe emissions are due primarily to reduced premature deaths and morbidity.

These reductions range from 2 to 5 tons per year in 2025.²³⁸ The monetized values of these PM2.5 reduction benefits range from \$4 million to \$8 million per year, with the benefit-per-unit reduction (million dollars per ton PM2.5 reduced, or \$M/ton) varying significantly by county and averaging to \$1.7 million per ton across all counties.

Job Creation and Workforce Training Benefits

While the primary policy goals of ARFVTP are to reduce petroleum fuel use and reduce carbon and criteria emissions, important social benefits such as economic development and job creation are also created.

To estimate job creation benefits, staff administered an electronic survey to recipients of all new technical project grants awarded since early 2013 when the last IEPR jobs survey was administered. Table 15 survey results incorporate the previous survey results with the 2015 IEPR survey results. Staff did not include job training, natural gas truck buydown, research, technical support, and program support grants and contracts in the survey. The response rate was high, with just a handful of grantees not responding.

The survey requested both short-term and long-term job creation estimates. Short-term jobs were defined as lasting 18 months or less and assumed to relate to project development, engineering and design, and construction phases. Long-term jobs are assumed to be greater than 18 months and relate to project operations, manufacturing,

238 These projected decreases in PM2.5 emissions from the transportation sector reflect only the emissions reductions attributable to Expected Benefits from direct ARFVTP investments as reported in the NREL Benefits Report.

Table 9: Projected Job Creation by Category

	Administrative	Manufacturing	Construction	Engineering	Operation and Maintenance	Other	Total
Short-term	478	701	1,486	1,125	224	130	4,144
Long-term	437	512	164	1,696	482	421	3,712
Totals	914	1,213	1,650	2,822	706	550	7,856

Source: California Energy Commission staff (Note: There is a slight tally error due to rounding).

maintenance, sales and administration. The survey includes jobs created by the primary grantee and all major partner and subcontractor firms listed in the grant agreements. It does not include jobs created upstream for equipment supply chains or by secondary multipliers. Although 29 percent of ARFVTP projects are now complete, the majority of the program projects are still in the development or construction phases. This means that most job creation benefits continue to be projected estimates, rather than final confirmed figures from completed projects.

Table 9 shows the estimated total number of jobs created through ARFVTP grant awards. Short-term jobs total 4,144, and long-term jobs total 3,712. Cumulative job creation to date is estimated to be 7,856. Construction-related jobs are the biggest category for short-term jobs, accounting for 35 percent of the total. For long-term jobs, manufacturing and operations and maintenance-related jobs predominate, representing 45 percent and 13 percent of the total.

Workforce Training Benefits

The program also aligns clean technology investments with economic development. The program has invested about \$25 million to help provide training for more than 13,600 individuals, 600 businesses, and 14 municipalities to support all aspects of alternative fuel technologies. The program has also provided funding to community colleges throughout California for curriculum development, train-the-trainer programs, essential equipment needs, and other approved activities to support alternative fuel and advanced vehicle technology training and education.

California community colleges continue to lead in the training of alternative fuels and advanced vehicle technologies in California by focusing on employer needs within each community and having those employers support new and existing training programs. Funding to the Employment Training Panel delivers training across multiple fuel and technology types and requires employers to commit matching funds.

Recommendations

Alternative and Renewable Fuel and Vehicle Technology Program

» **Continue to monitor utility electric vehicle**

proposals. The Energy Commission should monitor the California Public Utilities Commission (CPUC) decisions on California’s three largest investor-owned utilities applications for installation of up to 60,000 electric vehicle chargers throughout California. In December 2015, the CPUC issued preliminary decisions for two of the investor-owned utilities’ proposals: Southern California Edison’s (SCE’s) Charge Ready and Market Education Programs and San Diego Gas and Electric’s Electric Vehicle-Grid Integration (VGI) Integration Program. On January 14, 2016, the CPUC authorized SCE to develop a pilot program to incentivize the deployment of approximately 1,500 electric vehicle charging stations and conduct education and outreach in support of electric transportation. Final decisions on San Diego Gas & Electric’s and Pacific Gas and

Electric's proposals are pending. If approved, this large-scale installation will need to be coordinated with ongoing Alternative and Renewable Fuel and Vehicle Technology Program (ARFVTP) electric vehicle installation investments to ensure the most efficient and effective build-out of statewide electric vehicle charging infrastructure.

» **Continue ARFVTP investment in a portfolio of projects.** To achieve the Governor's ambitious 50 percent petroleum reduction goal by 2030, as well as the existing array of carbon, criteria, and particulate emission reduction goals, the Energy Commission must continue to evaluate and assess its current technology investments and adjust annual ARFVTP funding allocations in response to changing markets. The Energy Commission's policy of funding a portfolio of alternative fuels and advanced vehicle technologies recognizes that pursuing a single fuel type or vehicle technology will not achieve California's 50 percent petroleum reduction goal.

» **Assist in carrying out California's sustainable freight strategy and California's ports initiative, both of which offer critical opportunities to reduce greenhouse gas emissions.** The Energy Commission should continue to collaborate with the California Air Resources Board, California Department of Transportation, the Governor's Office of Business and Economic Development, and others to identify opportunities to leverage ARFVTP funds to maximize emission reductions and improve economic competitiveness at California's ports and freight sectors.

» **Support the updated 2015 ZEV Action Plan and implement Energy Commission-led actions.** Continue close involvement and support of the 2015 and future *ZEV Action Plans*. The *2015 ZEV Action Plan* offers opportunities for ARFVTP to continue supporting the expanding use of zero-emission vehicle technologies in the medium- and heavy-duty truck and bus sectors.

» **Continue diversity and disadvantaged community outreach efforts under the ARFVTP.** The ARFVTP should continue outreach to small businesses, women-, and disabled veteran-, minority-, and LGBT-owned businesses to increase their participation in ARFVTP funding opportunities. The ARFVTP should also continue actions to increase program participation rates of California's economically and environmentally disadvantaged communities.

Alternative and Renewable Fuel and Vehicle Market Expansion

» **Expand zero-emission-vehicle purchase incentives to disadvantaged communities.** California should continue to provide greater allocation of vehicle purchase incentives to disadvantaged communities and low- and middle-income people to expand the zero-emission-vehicle market in California.

» **Collaborate with other states and nations to expand market.** California should continue to coordinate and collaborate with other states and nations to promote and expand renewable fuels and alternative vehicle markets.

CHAPTER 5

Electricity Demand Forecast



Since the restructuring of California’s electric industry in the late 1990s under Assembly Bill 1890 (Brulte, Chapter 854, Statutes of 1996), electricity infrastructure planning in California has been split among the California Energy Commission, the California Public Utilities Commission (CPUC), and the California Independent System Operator (California ISO) (collectively the “energy agencies”). Three major cyclical processes now form the core of electric infrastructure planning:

- » The long-term forecast of energy demand produced by the Energy Commission as part of its biennial *Integrated Energy Policy Report (IEPR)*
- » The biennial Long Term Procurement Plan proceeding (LTPP) conducted by the CPUC
- » The annual Transmission Planning Process (TPP) performed by the California ISO.

More recently, with the adoption of new energy and environmental policy goals and the emergence of diverse supply and demand-side technologies, it has become apparent that closer collaboration among the energy agencies and alignment of these processes are needed. One outgrowth of

collaboration was the establishment of the management-level Joint Agency Steering Committee to ensure regular communication on planning coordination and to support agency leadership in its agreement on a *single forecast set*, composed of a baseline forecast and projections for additional achievable energy efficiency (AAEE) savings, for planning. In addition, an interagency process alignment technical team was created as a forum for planning staff from the Energy Commission, the CPUC, and the California ISO to discuss technical issues and improve infrastructure planning coordination.

The agencies also agreed on an annual process to be performed in the fall of each year to translate the single forecast set into assumptions and scenarios to be used in infrastructure planning activities in the coming year. Work is now expanding from energy efficiency and demand response to properly account for other load-modifying assumptions included in the Energy Commission’s demand forecast; for example, new demand response strategies, time-of-use rates, customer-side distributed generation, combined heat and power, distributed energy storage, and electric vehicles.²³⁹

²³⁹ *Alignment of Key Infrastructure Planning Processes by CPUC, CEC and CAISO Staff*, December 23, 2014, http://www.energy.ca.gov/assessments/documents/CEC-CPUC-ISO_Process_Alignment_Text.pdf.

The Energy Commission prepares 10-year forecasts of electricity consumption and peak electricity demand for California and for individual utility planning areas and forecast zones within the state. The *California Energy Demand 2016–2026, Revised Electricity Forecast (CED 2015 Adopted)* includes both baseline forecasts and AAEE savings scenarios. The electricity results put forward in the *CED 2015 Adopted* were presented at an IEPR workshop on December 17, 2015 and adopted on January 27, 2016. The full forecast report is posted on the Energy Commission’s website.²⁴⁰ The preliminary end-user natural gas forecast developed by staff in conjunction with electricity is summarized in Chapter 6.

The *CED 2015 Adopted* includes three cases designed to capture a reasonable range of demand outcomes over the next 10 years. The *high energy demand* case incorporates relatively high economic/demographic growth and climate change impacts, and relatively low electricity rates and self-generation impacts. The *low energy demand* case includes lower economic/demographic growth, higher assumed rates, and higher self-generation impacts. The *mid energy demand* case uses input assumptions at levels between the high and low cases.

This chapter provides the highlights of the *CED 2015*. It opens with changes relative to the previously adopted forecast presented in the *2014 IEPR Update*. It then discusses the forecast results in terms of projected statewide electricity consumption, peak demand, and retail electricity sales through 2026. The chapter reviews key factors in the forecast including expected increases in self-generation and the potential incremental impacts of climate change. Next is the results of adjusting the baseline forecast with AAEE savings that are not yet considered committed but likely to occur to develop the adjusted, or *managed*, demand forecast for resource planning. The chapter closes with recommendations for future work.

240 Kavalec, Chris, Nick Fugate, Cary Garcia, and Asish Gautam. 2016. *California Energy Demand 2016-2026, Revised Electricity Forecast*. California Energy Commission. Publication Numbers: CEC-200-2016-001-V1 and CEC-200-2016-001-V2.

Summary of Changes to the Forecast

The following discusses key changes relative to the previously adopted forecast, *California Energy Demand Updated Forecast, 2015–2025 (CEDU 2014)*.²⁴¹ In an effort to make the demand forecast more useful to resource planners, the *CED 2015 Adopted* uses a revised geographic scheme for planning areas and climate zones, more closely based on California’s balancing authority areas. The *CED 2015 Adopted* includes 20 climate zones, compared to 16 in previous forecasts. This new scheme is described in detail in Chapter 1 of Volume 1 of the *CED 2015 Adopted* forecast report.

CED 2015 Adopted includes estimated efficiency impacts not included in *CEDU 2014*, from 2015 investor-owned utility (IOU) programs and 2014 programs administered by publicly owned utilities (POUs) as well as from new state and federal appliance standards. Projected AAEE impacts for the IOUs have been updated, based on the CPUC’s *2015 California Energy Efficiency Potential and Goals Study for 2015 and Beyond (2015 Potential Study)*.²⁴² The forecast also includes estimates of AAEE savings for the two largest POUs.

CED 2015 Adopted incorporates new projections for electric vehicle fuel consumption, based on scenarios developed by the transportation unit of the Energy Commission’s Demand Analysis Office. In addition, the forecast includes estimated impacts from additional transportation-related electrification.

241 Kavalec, Chris. 2015. *California Energy Demand Updated Forecast, 2015-2025*. California Energy Commission, Electricity Supply Analysis Division. Publication Number: CEC-200-2014-009-CMF. <http://www.energy.ca.gov/2014publications/CEC-200-2014-009/CEC-200-2014-009-CMF.pdf>.

242 Navigant, *Energy Efficiency Potential and Goals Study for 2015 and Beyond*, Stage 1 Final Report, Prepared for the CPUC, September 26, 2015. <http://www.cpuc.ca.gov/General.aspx?id=2013>.

The most significant change compared to previous forecasts, in terms of peak demand and retail sales, comes through the projections for self-generation. The *CED 2015 Adopted* incorporates refinements to staff's predictive models for self-generation, including the introduction of tiered residential rates for the photovoltaic (PV) system adoption model. As a result, residential PV impacts are significantly higher than in the *CEDU 2014*.²⁴³

With the passage of Senate Bill 350 (De León, Chapter 547, Statutes of 2015) and Assembly Bill 802 (Williams, Chapter 590, Statutes of 2015) (AB 802), future iterations of the electricity demand forecast will include greater emphasis on detailed, localized, and sector-specific analysis of energy demand trends. This more granular analysis will be needed to support the state's policy goals including setting, assessing, and advancing energy efficiency goals discussed in Chapter 1 and to help optimize the integration of increasing amounts of renewable energy discussed in Chapter 2. Among other provisions, AB 802 clarifies the Energy Commission's authority to collect energy usage data needed to support implementation of the various provisions in the bill. As a result, the Energy Commission will build its capabilities to manage and provide rigorous analysis of the data in support of energy demand forecasts.

As part of the *2016 IEPR Update*, the Energy Commission will work to forecast hourly loads as opposed to annual loads. For example, incorporating hourly load data into the forecast is needed to better understand the potential impacts of increases in behind-the-meter PV systems and electric vehicle charging on the magnitude and timing of peak demand (peak is shifting to later in the day).

243 Using a tiered structure within the PV predictive model means a higher marginal benefit for PV adoption, especially for high users.

California Energy Demand Forecast Results

A comparison of the *CED 2015 Adopted* baseline statewide electricity forecast with the *California Energy Demand Updated Forecast, 2015-2025 (CEDU 2014)* mid demand case for selected years is shown in Table 10. As the table shows, the consumption forecast for 2014 from *CEDU 2014* was higher than actual historical consumption. (*CEDU 2014* incorporated historical consumption data through 2013.) Consumption in the *CED 2015 Adopted* mid demand case grows at a slower rate through 2025 as compared to the *CEDU 2014* mid case as a result of additional appliance standards and a reassessment of Title 24 standards for existing buildings.

CED 2015 Adopted statewide noncoincident peak demand (the sum of planning area peaks, which may occur at different hours), adjusted to account for atypical weather, grows at a slower rate from 2015-2025 in the mid case compared to *CEDU 2014*, reflecting the drop in consumption as well as a higher self-generation forecast, particularly for PV. All three *CED 2015 Adopted* cases are significantly lower than the *CEDU 2014* mid case throughout the forecast period.

Projected electricity consumption for the three *CED 2015 Adopted* baseline cases and the *CEDU 2014* mid demand forecast is shown in Figure 35. By 2025, consumption in the new mid case is projected to be 2.8 percent lower than the *CEDU 2014* mid case, around 9,000 gigawatt-hours (GWh). Annual growth from 2014-2025 for the *CED 2015 Adopted* forecast average 1.27 percent, 0.97 percent, and 0.54 percent in the high, mid, and low cases, respectively, compared to 1.21 percent in the *CEDU 2014* mid case.

Projected *CED 2015 Adopted* peak demand for the three baseline scenarios and the *CEDU 2014* mid demand peak forecast is shown in Figure 36. By 2025, statewide peak demand in the *CED 2015 Adopted* mid case is projected to be almost 10 percent lower than in the *CEDU*

Table 10: Comparison of CED 2015 Adopted and CEDU 2014 Mid Case Demand Baseline Forecasts of Statewide Electricity Demand

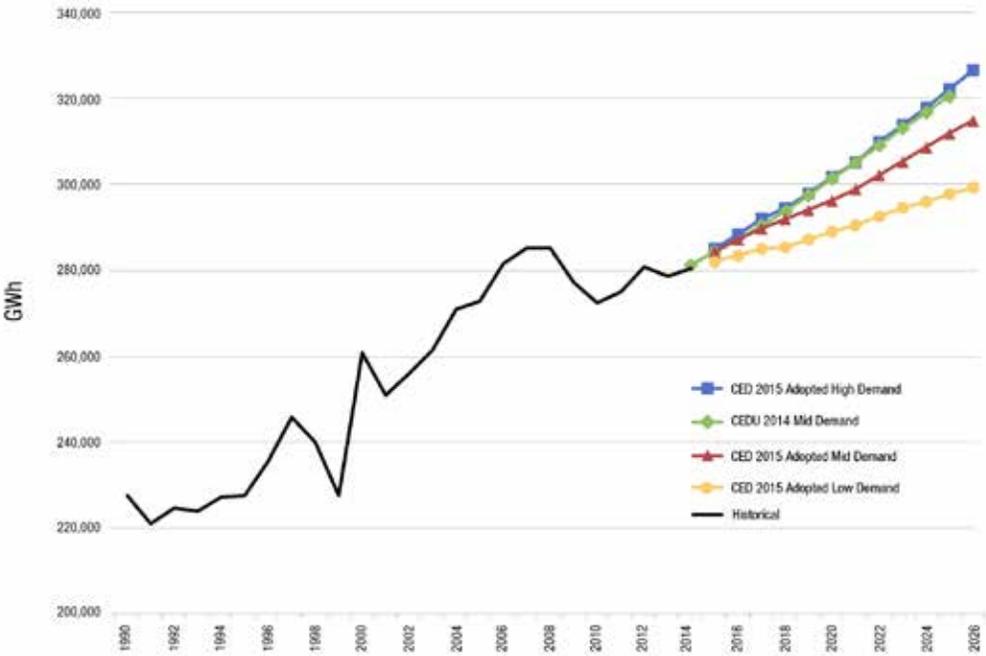
Consumption (GWh)					
	CEDU 2014 Mid Energy Demand	CED 2015 Adopted High Energy Demand	CED 2015 Adopted Mid Energy Demand	CED 2015 Adopted Low Energy Demand	
1990	227,576	227,606	227,606	227,606	
2000	260,399	261,037	261,037	261,037	
2014	281,195	280,536	280,536	280,536	
2020	301,290	301,884	296,244	289,085	
2025	320,862	322,266	311,848	297,618	
2026	--	326,491	314,970	299,372	
Average Annual Growth Rates					
1990-2000	1.36%	1.38%	1.38%	1.38%	
2000-2014	0.55%	0.52%	0.52%	0.52%	
2014-2020	1.16%	1.23%	0.91%	0.50%	
2014-2025	1.21%	1.27%	0.97%	0.54%	
2014-2026	--	1.27%	0.97%	0.54%	
Noncoincident Peak (MW)					
	CEDU 2014 Mid Energy Demand	CED 2015 Adopted High Energy Demand	CED 2015 Adopted Mid Energy Demand	CED 2015 Adopted Low Energy Demand	
1990	47,543	47,123	47,123	47,123	
2000	53,702	53,529	53,529	53,529	
2015*	63,577	60,968	60,968	60,968	
2020	67,373	63,658	62,414	60,560	
2025	70,763	67,167	63,848	59,293	
2026	--	67,830	64,007	58,835	
Average Annual Growth Rates					
1990-2000	1.23%	1.28%	1.28%	1.28%	
2000-2015	1.13%	0.87%	0.87%	0.87%	
2015-2020	1.17%	0.87%	0.47%	-0.13%	
2015-2025	1.08%	0.97%	0.46%	-0.28%	
2015-2026	--	0.97%	0.44%	-0.32%	

Source: California Energy Commission, Demand Analysis Office, 2015. (GWh= gigawatt hours, MW= megawatts)

Actual historical values are shaded.

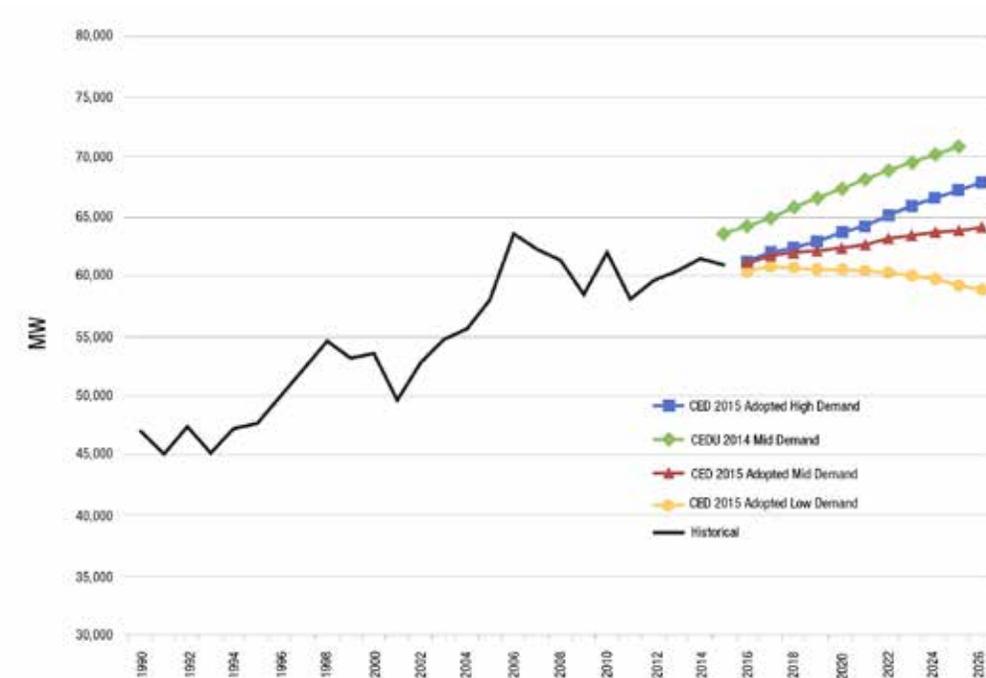
*Weather normalized: *CED 2015* uses a weather-normalized peak value derived from the actual 2015 peak for calculating growth rates during the forecast period.

Figure 35: Statewide Baseline Annual Electricity Consumption



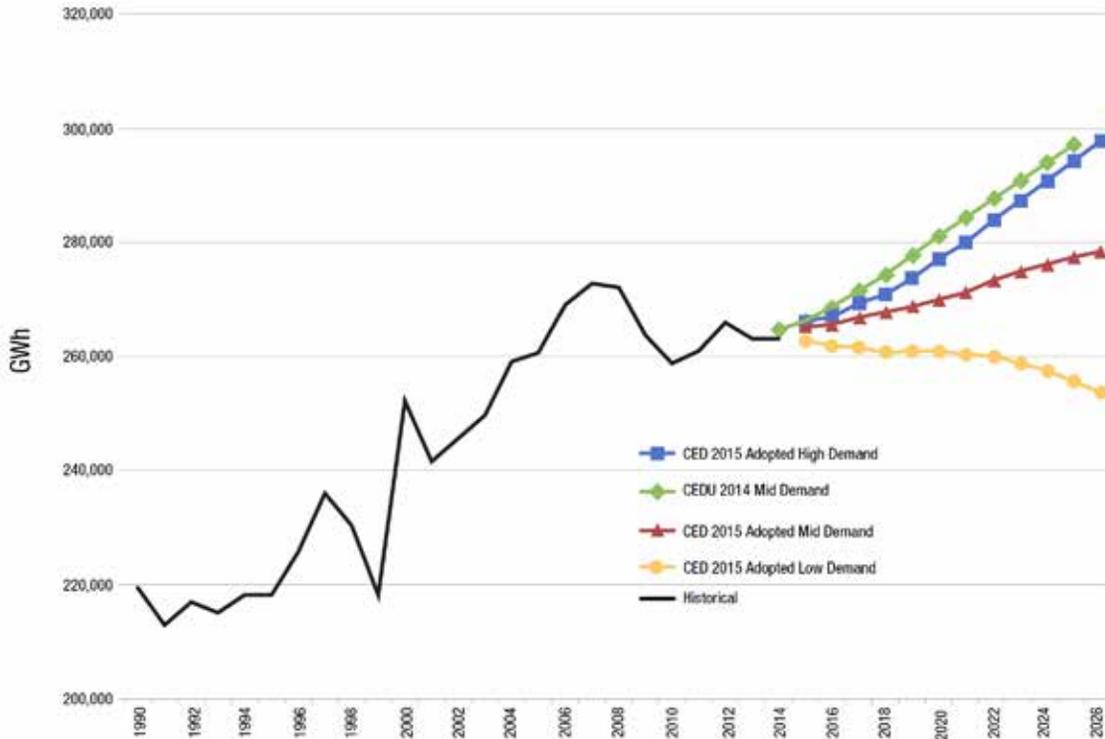
Source: California Energy Commission, Demand Analysis Office, 2015.

Figure 36: Statewide Baseline Annual Noncoincident Peak Demand



Source: California Energy Commission, Demand Analysis Office, 2015.

Figure 37: Statewide Baseline Retail Electricity Sales



Source: California Energy Commission, Demand Analysis Office, 2015.

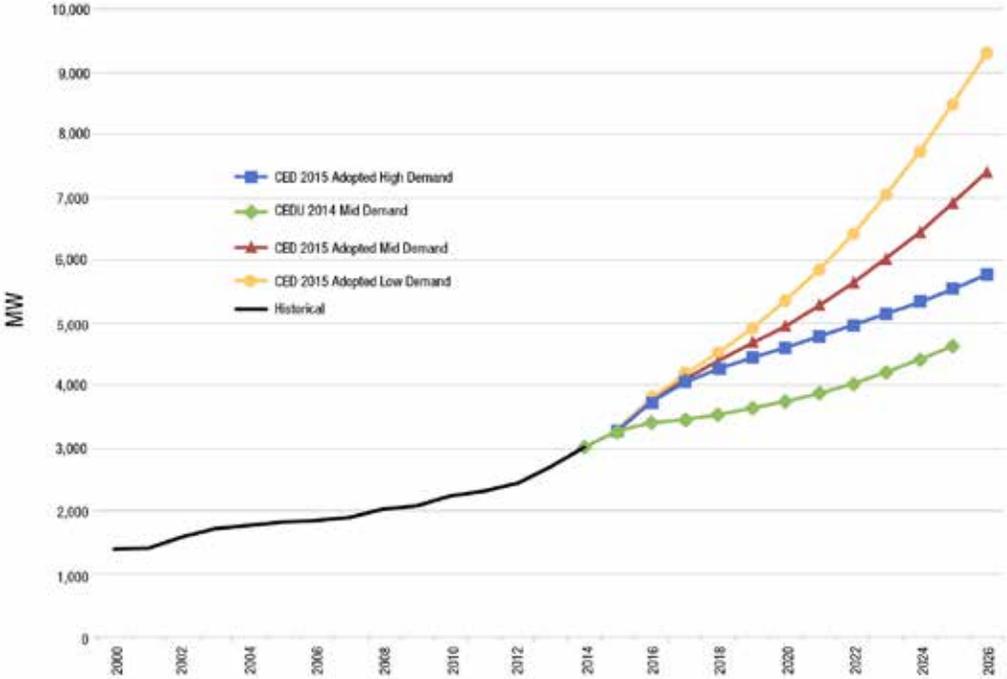
2014 mid case. Annual growth rates from 2015-2025 for *CED 2015 Adopted* average 0.97 percent, 0.46 percent, and -0.28 percent in the high, mid, and low cases, respectively, compared to 1.08 percent in the *CEDU 2014* mid case. Higher projected self-generation from PV adoption reduces the growth rate in the new mid case compared to *CEDU 2014*.

The higher forecast for self-generation also has a significant impact on projected statewide retail electricity sales, as shown in Figure 37. All three new forecast cases are lower than the *CEDU 2014* mid case throughout the forecast period. By 2025, sales in the *CED 2015 Adopted* mid case are projected to be almost 20,000 GWh lower than in the *CEDU 2014* mid case, around 6.6 percent. Annual growth from 2014-2025 for *CED 2015 Adopted* averages 1.00 percent, 0.48 percent, and -0.26 percent in the high, mid and low cases, respectively, compared to 1.05 percent in the *CEDU 2014* mid case.

Historical and projected peak reduction impacts of self-generation for the three *CED 2015 Adopted* demand cases and the *CEDU 2014* mid case are shown in Figure 38. Self-generation is projected to reduce peak load by more than 6,900 megawatts (MW) in the new mid case by 2025, an increase of more than 2,000 MW compared to *CEDU 2014*. Residential PV is a key factor in this increase: by 2026, residential PV peak impacts reach almost 3,000 MW in the *CED 2015 Adopted* mid case, corresponding to more than 7,700 MW of installed capacity.

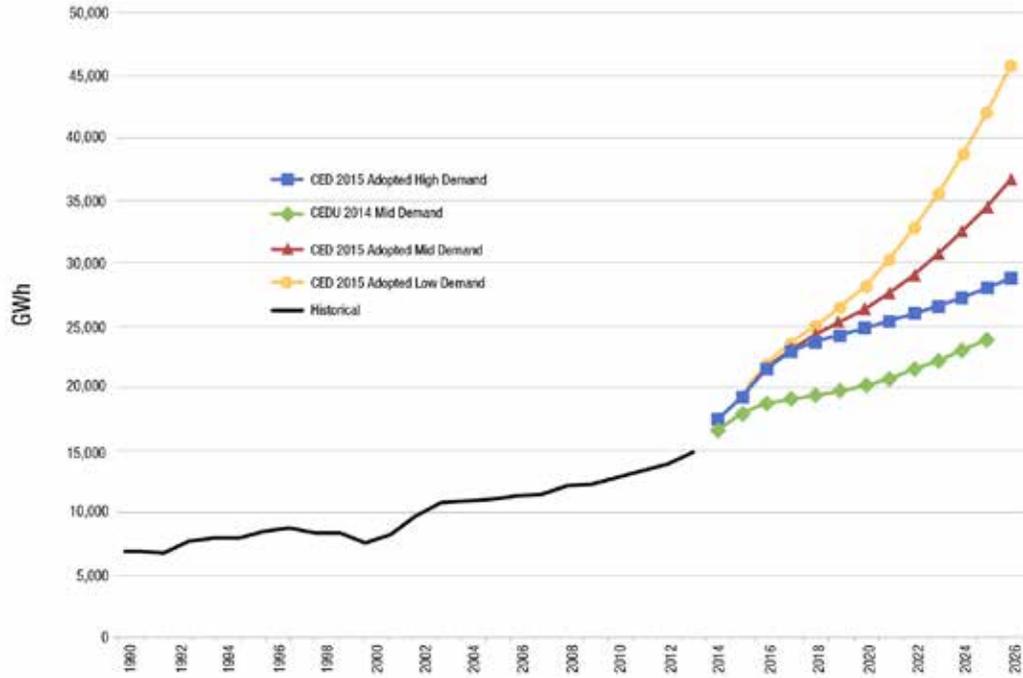
Electricity consumption impacts of self-generation for the three *CED 2015 Adopted* demand cases and the *CEDU 2014* mid case are shown in Figure 39. Consumption met through self-generation is projected to reduce retail sales by almost 35,000 GWh in the new mid case by 2025, an increase of around 10,500 GWh compared to the *CEDU 2014* mid case in 2025.

Figure 38: Statewide Self-Generation Peak Reduction Impact



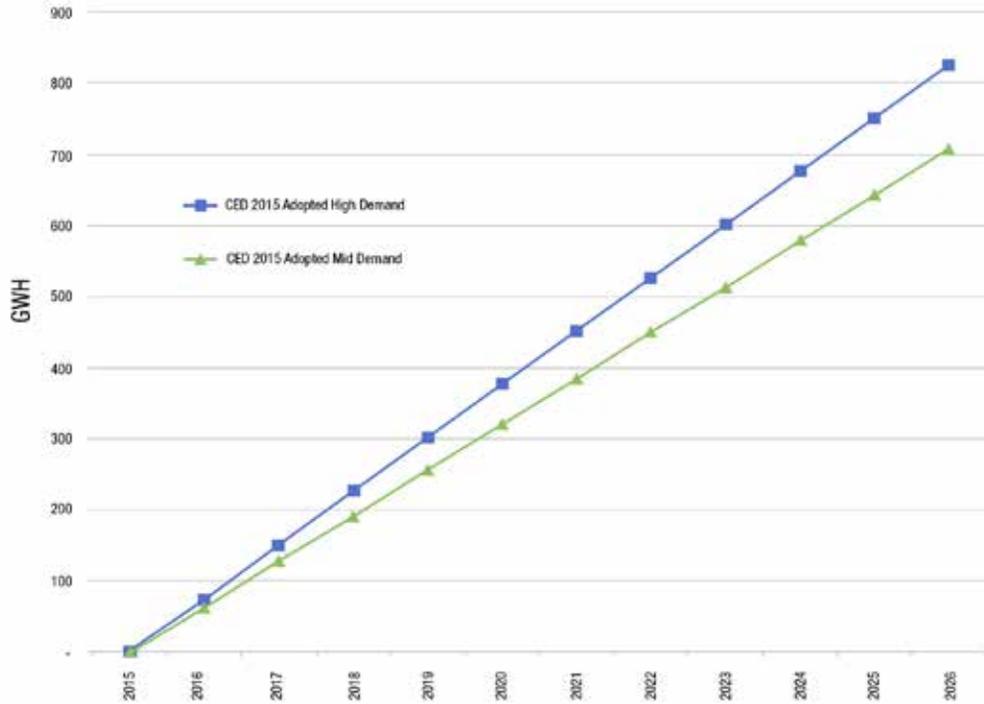
Source: California Energy Commission, Demand Analysis Office, 2015.

Figure 39: Statewide Self-Generation Consumption Impact



Source: California Energy Commission, Demand Analysis Office, 2015.

Figure 40: Climate Change Energy Consumption Impacts



Source: California Energy Commission, Demand Analysis Office, 2015

The Impacts of Climate Change

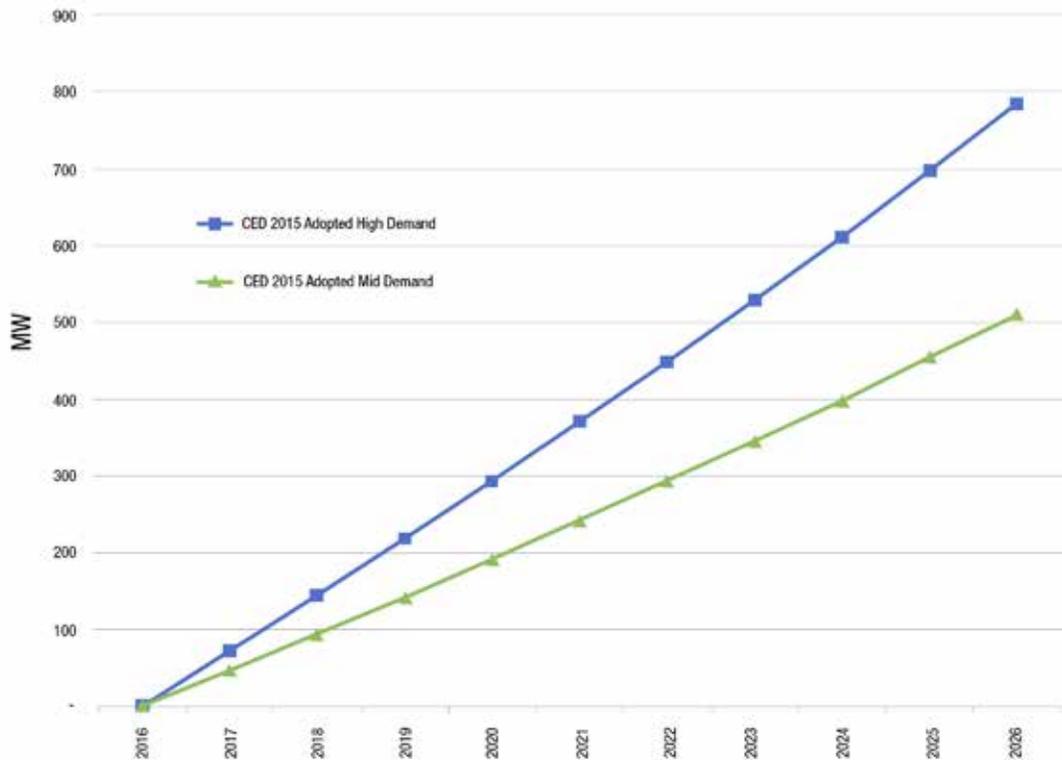
CED 2015 Adopted incorporates the potential incremental²⁴⁴ impacts of climate change on both electricity consumption and peak demand using temperature simulations developed by the Scripps Institution of Oceanography (Scripps). (For more information on the model Scripps used, see Chapter 9, Research on Climate Impacts to the Electricity System). Consumption effects are estimated through projected changes in the number of annual heating and cooling degree days,²⁴⁵

while peak demand impacts are estimated through increases in annual maximum daily average temperatures. Electricity consumption is affected by both heating and cooling degree days, so the effect of increases in the average annual number of cooling degree days as a result of climate change is tempered by a decreasing average number of heating degree days (since both minimum and maximum temperatures increase). The Scripps simulations involve two scenarios, each simulated by various worldwide climate change models, with the results downscaled for California. The two scenarios can be characterized as average and more aggressive in terms of climate change temperature impacts. Staff developed median temperature impacts for each set of simulations, and the results for the average scenario were used in the mid demand case and those in the more aggressive scenario for the high demand case. The low demand case assumed no climate change impacts. These results were applied to weather-sensitive econometric models for electricity consumption and

244 These impacts should be considered incremental to the extent that climate change has already affected temperatures, and therefore consumption and peak demand, in California

245 *Heating and cooling degree days* are determined by the difference between the daily average temperature and a reference temperature (for example, 65 degrees). The number of days is summed for a given year. An average temperature below the reference temperature adds to heating degree days and an average above the reference temperature adds to cooling degree days.

Figure 41: Climate Change Peak Demand Impacts



Source: California Energy Commission, Demand Analysis Office, 2015

for peak demand to estimate consumption and peak impacts for each planning area and forecasting zone.

Figure 40 shows projected statewide incremental impacts of climate change in the mid and high demand cases on electricity consumption. Consumption is projected to increase by around 700 GWh in the mid demand case by 2026. Underlying these impacts is a shift in consumption from cooler months, as heating degree days decline, to now warmer months.²⁴⁶

Figure 41 shows the projected statewide impacts of climate change on peak demand in the mid and high demand cases. In the mid-case, peak demand increases by around 500 MW by the end of the forecast period. Over the 10-year period, annual maximum temperatures increase

in each planning area by an average of around ½ degree Fahrenheit in the mid demand case and ¾ degree in the high demand case. The impacts are lower than in *CEDU 2014* because the maximum temperature increases are not as high over the 10 years in both the mid and high cases.

Additional Achievable Energy Efficiency and Managed Forecasts

An adjusted, or *managed*, demand forecast for resource planning requires a baseline forecast combined with AAEE savings; savings not yet considered committed

²⁴⁶ In the mid case in 2026, consumption in the warmer months is projected to increase by around 1,100 GWh while consumption in the cooler months drops by around 400 GWh.

but deemed likely to occur, including impacts from future updates of building codes and appliance standards and utility efficiency programs expected to be implemented after 2015.²⁴⁷ *CED 2015 Adopted* provides AAEE impacts for the IOU service territories, based on the *2015 Potential Study*.

The *2015 Potential Study* estimated energy efficiency savings that could be realized through utility programs as well as codes and standards within the IOU service territories for 2006-2026,²⁴⁸ given current or soon-to-be-available technologies. Because many of these savings are already incorporated in the Energy Commission's *CED 2015 Adopted* baseline forecast, staff needed to estimate the portion of savings from the *2015 Potential Study* not accounted for in these forecasts. These non-overlapping savings become AAEE savings.

Energy Commission and Navigant Consulting developed nine AAEE scenarios, with input from the Demand Analysis Working Group²⁴⁹ (DAWG). These scenarios were designed to capture a range of possible outcomes determined by a host of input assumptions, with three AAEE scenarios (high, mid, and low savings) assigned to each of the three *CED 2015 Adopted* demand cases. This means that the scenarios assigned to a given demand case share the same assumptions for building stock and retail rates. Energy Commission staff, in consultation with the JASC,

subsequently pared the number of scenarios down to five, with one scenario each assigned to the high and low demand cases and three scenarios assigned to the mid demand case. These five scenarios are thus defined by the demand case and AAEE savings scenario (high, mid, or low), as follows:

- » Scenario 1: High Demand-Low AAEE Savings (high-low)
- » Scenario 2: Mid Demand-Low AAEE Savings (mid-low)
- » Scenario 3: Mid Demand-Mid AAEE Savings (mid-mid)
- » Scenario 4: Mid Demand-High AAEE Savings (mid-high)
- » Scenario 5: Low Demand-High AAEE Savings (low-high)

Scenarios 1 and 5 serve as bookends designed to keep a healthy spread among the adjusted forecasts when applied to the high and low demand baseline cases. The three scenarios corresponding to the mid demand case are likely options to be applied to the *CED 2015 Adopted* mid baseline forecast to yield a managed forecast or forecasts for planning purposes. These five scenarios are similar to those developed for *CED 2013*, except that the extreme cases are designed to be less so.²⁵⁰ Details on input assumptions for each scenario are provided in Chapter 2 of Volume 1 of the *CED 2015 Adopted* forecast report.

The five scenarios were presented at another DAWG meeting, and stakeholders expressed concern about the relatively high peak-to-energy ratios of standards savings (much higher than in 2013). After further investigation, Navigant Consulting determined that the change was due to uncertainty factors that had been applied to standards savings in 2013 but removed for the *2015 Potential Study*. These factors were based on standards savings realization rates calculated from the 2006–2008 CPUC Evaluation,

247 CPUC Decision (D.) 14-10-046 (OP 21, COL 7) authorized EE program funding for 10 years (through 2025), unless otherwise directed by the CPUC. Thus, unlike past funding cycles, IOU program funding has been committed through nearly the end of the forecast period.

248 The analysis begins in 2006 because results are calibrated using the CPUC's Standard Program Tracking Database, which tracks program activities from 2006-2011.

249 The Demand Analysis Working Group provides a forum for interaction among key organizations on topics related to demand forecasting and demand-side programs and policies. Membership in the Demand Analysis Working Group includes staff from the Energy Commission, the CPUC Energy Division, the Department of Ratepayer Advocates, the California IOUs, several POUs, and other interested parties, including the ARB, The Utility Reform Network, and the Natural Resources Defense Council

250 Many DAWG members felt that the high and low AAEE savings cases developed in 2013 were too improbable to be useful, so these cases included more "best estimates" than in 2013.

Measurement, and Verification (EM&V) study²⁵¹ and were meant to account for lower than expected savings as yielded in the study. The subsequent 2010–2012 EM&V study²⁵² provided very different results in that realized standards savings appeared in general to match expected savings. Based on this result, Navigant Consulting removed the uncertainty factors in the *2015 Potential Study*. However, the 2006–2008 EM&V study pointed to significantly lower realization rates for peak demand compared to energy, and therefore removing the uncertainty factors increased peak savings much more than energy savings. After consultation with JASC, Navigant Consulting reintroduced the uncertainty factors at 50 percent of values calculated in 2013, thereby giving equal weight to the two EM&V studies.²⁵³

Figure 42 and Figure 43 show the final estimated AAEE savings by scenario for the IOUs combined for energy and peak demand, respectively. AAEE savings begin in 2015 because 2014 was the last recorded historical year for consumption in *CED 2015 Adopted*. By 2026, AAEE savings reach roughly 18,000 GWh energy savings and about 4,500 MW of peak savings in Scenario 3 (mid-mid). The high savings scenarios reach around 21,500 GWh and over 5,000 MW in 2026, while projected totals in the low savings scenarios are about 13,500 GWh and 3,300 MW. Totals for the low-high and mid-high scenarios are very similar as are the high-low and mid-low because the impacts of building stock and electricity rates work in opposite directions and approximately offset each other. Figure 42 and Figure 43 also show AAEE saving in 2025 for the Mid Demand Mid AAEE Savings case from *CEDU 2014*, well above the new mid-mid scenarios for GWh and MW. With the same set of input assumptions, AAEE savings are lower compared to *CEDU 2014* because some

standards previously included as AAEE are now committed savings. In addition, program savings in the *2015 Potential Study* are generally lower compared to 2013, reflecting downward adjustments to realization rates based on the 2010-2012 EM&V study. Detailed results are available in Chapter 2 of Volume 1 of the *CED 2015 Adopted* forecast report and the demand forms accompanying the forecast report.²⁵⁴

Figure 44 and Figure 45 show the effects of the estimated mid-low, mid-mid, and mid-high AAEE savings scenarios on *CED 2015 Adopted* mid baseline demand for the combined IOU service territories for electricity sales and noncoincident peak demand. AAEE peak impacts are adjusted upward to account for transmission and distribution line losses. Adjusted electricity sales and peak demand decrease in all three AAEE scenarios, reflecting the lower baseline sales and peak forecasts in *CED 2015 Adopted*.

Figure 46 and Figure 47 show the *CED 2015 Adopted* high demand, mid demand, and low demand baseline forecasts when adjusted by high-low AAEE savings, mid-mid savings, and low-high savings, respectively, for the combined IOU service territories. Only the adjusted high demand case shows increases in sales and peak over the forecast period. Relative to the baseline forecasts, electricity sales in 2026 are reduced by 6.1 percent, 8.9 percent, and 11.6 percent for the high, low, and mid demand cases, respectively. Peak demand is reduced by 7.1 percent, 10.2 percent, and 13.3 percent, respectively, in 2026.

Choice of Managed Forecast

The adjusted service territory forecasts provided in this chapter constitute options to form the basis for a managed forecast to be used for planning purposes in Energy Commission, CPUC, and California ISO proceedings.

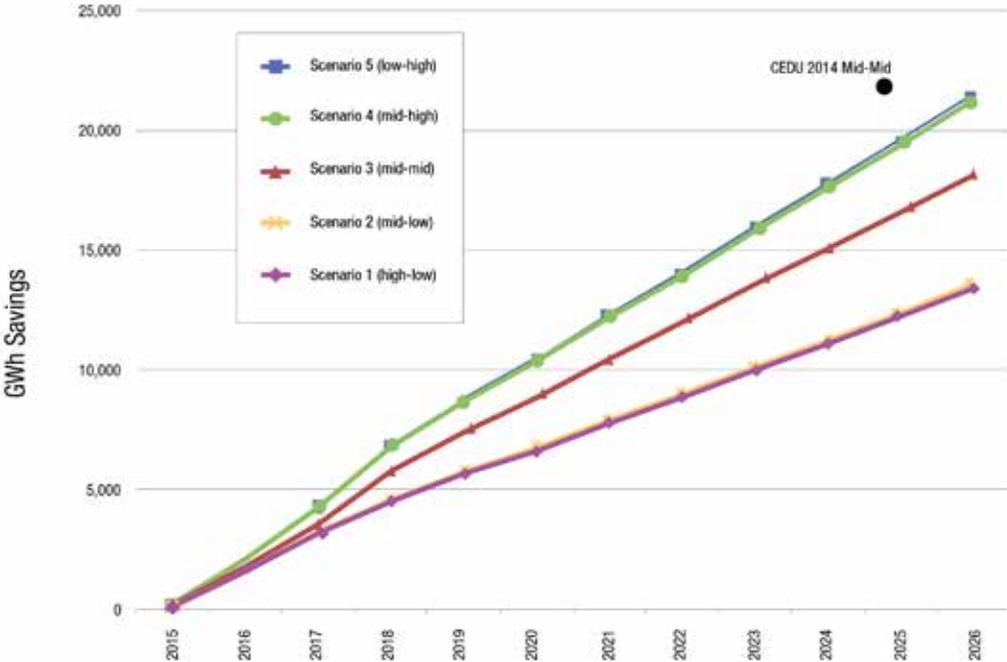
251 <http://www.cpuc.ca.gov/General.aspx?id=4288>.

252 <http://www.cpuc.ca.gov/General.aspx?id=6391>.

253 Using the revised uncertainty factors reduced savings overall for standards by around 5 percent for energy and 15 percent for peak demand.

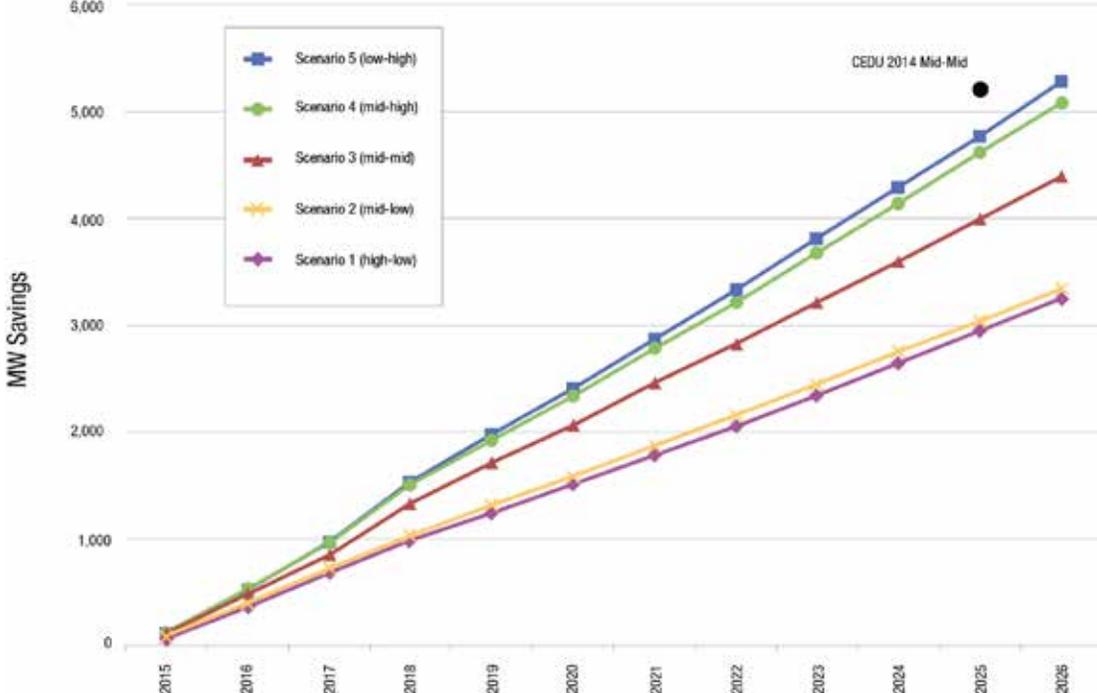
254 Kavalec, Chris, Nick Fugate, Cary Garcia, and Asish Gautam. 2016. California Energy Demand 2016-2026, Revised Electricity Forecast. California Energy Commission. Publication Number: CEC-200-2016-001-V1.

Figure 42: AAE Energy Savings (GWh by Scenario, Combined IOUs)



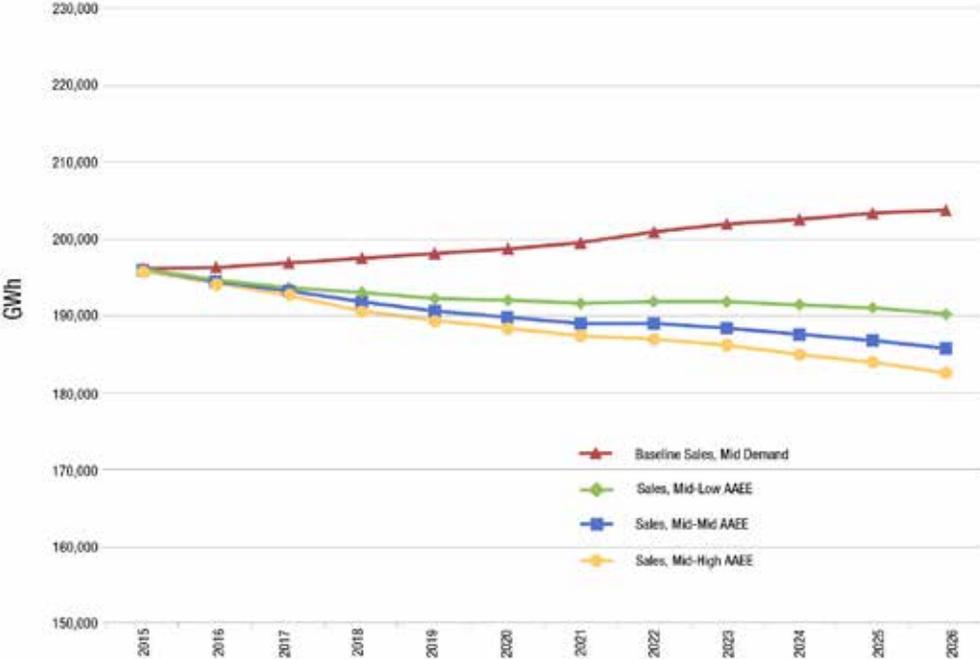
Source: California Energy Commission, Demand Analysis Office, 2015

Figure 43: AAE Savings for Peak Demand (MW) by Scenario, Combined IOUs



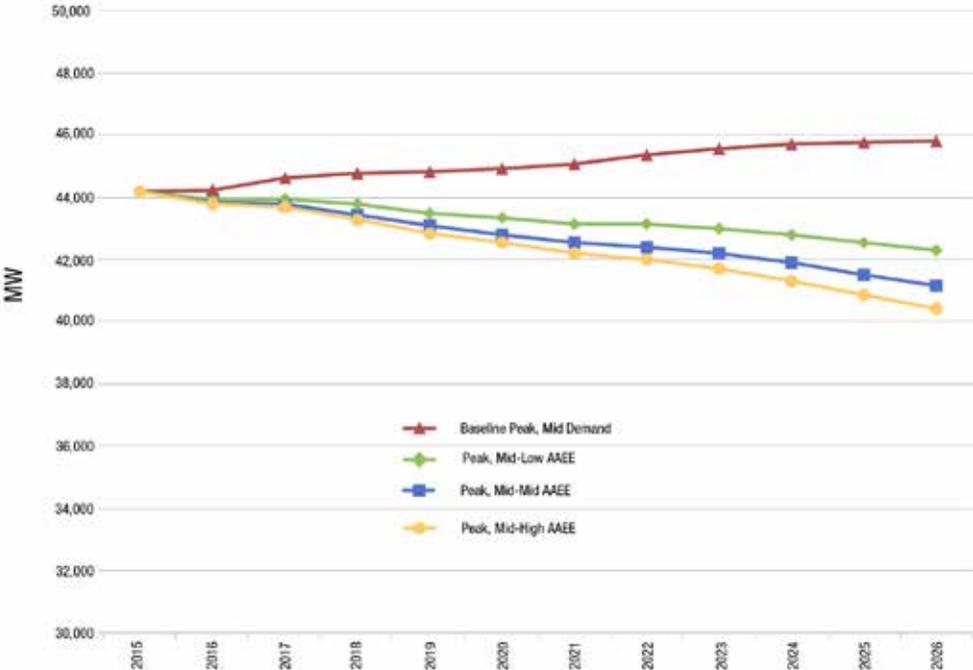
Source: California Energy Commission, Demand Analysis Office, 2015

Figure 44: Mid Baseline Demand and Adjusted Sales, Combined IOU Service Territories



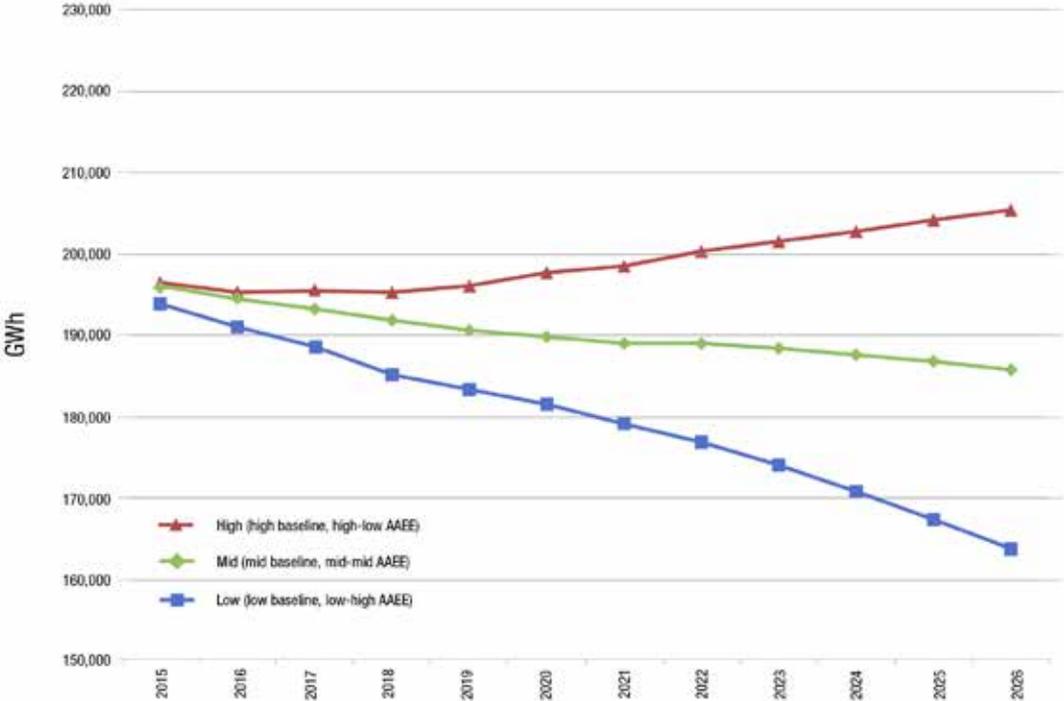
Source: California Energy Commission, Demand Analysis Office, 2015

Figure 45: Mid Baseline Demand and Adjusted Peaks, Combined IOU Service Territories



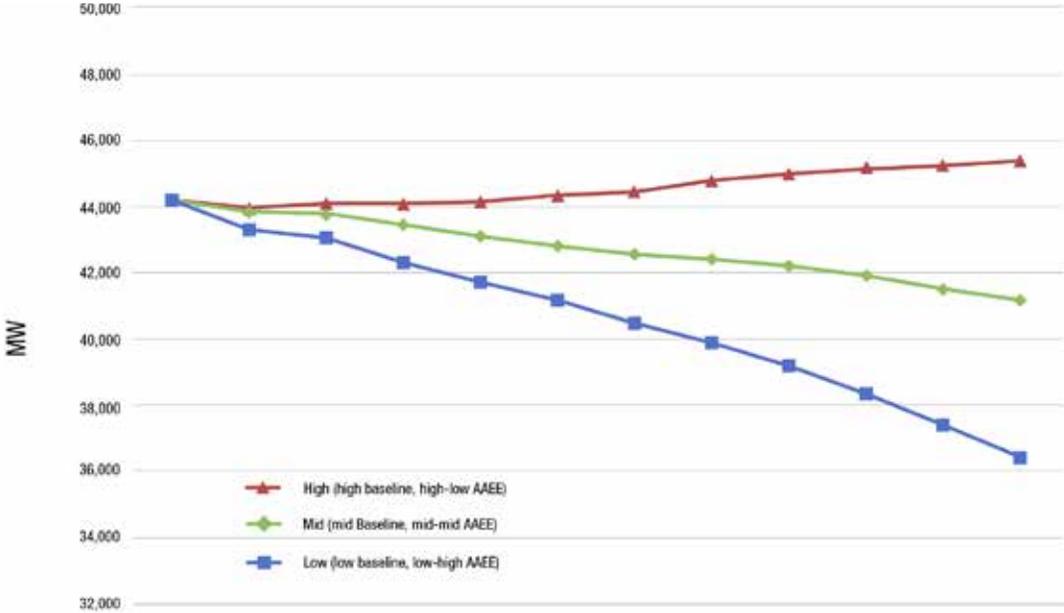
Source: California Energy Commission, Demand Analysis Office, 2015

Figure 46: Adjusted Demand Cases for Electricity Sales, Combined IOU Service Territories



Source: California Energy Commission, Demand Analysis Office, 2015

Figure 47: Adjusted Demand Cases for Peak, Combined IOU Service Territories



Source: California Energy Commission, Demand Analysis Office, 2015

Energy Commission, CPUC, and California ISO leadership have once again agreed on a *single forecast set* to be used for planning and procurement in the California ISO's TPP, the CPUC's LTPP, resource adequacy, and other planning processes.

The term "single forecast set" is intended to clarify that what has commonly been called a "single forecast" is not a single number, but actually a set of forecast numbers drawn from the Energy Commission's demand forecast report *CED 2015 Adopted*, adopted as part of the *2015 IEPR*. CED 2015 contains 3 baseline cases (high, mid, and low) and 5 scenarios of AAEE (high-low, mid-low, mid-mid, mid-high, and low-high). The first part of the hyphenated term refers to assumptions for econ-demo and rates (consistent with the appropriate baseline demand case) and the second part to AAEE variations using these assumptions. This interagency agreement includes specification on the use for each component of the set.

The single forecast set is comprised of two primary components that are drawn from the IEPR demand forecast: (1) a baseline case with its weather variants, and (2) two scenarios of AAEE.

The combination of a *CED 2015 Adopted* baseline forecast plus an AAEE forecast depends on the purpose of their use.

» **The selected CED 2015 Adopted baseline case will be the "mid demand" case**, for the combined IOU service areas that comprise the California ISO balancing area. The mid demand case includes variants for different weather conditions all of which have been applied consistently by the CPUC and California ISO as follows:

- » 1 year in 2 weather conditions – used for system flexibility studies performed by the California ISO for input to the LTPP, and for economic studies in the California ISO TPP.
- » 1 year in 5 weather conditions – used for public-policy transmission assessments and bulk system studies in the California ISO TPP.
- » 1 year in 10 weather conditions – used for local capacity requirements and California ISO TPP local reliability studies.

» The Energy Commission, CPUC, and California ISO leadership agree, in principle, that the same AAEE forecast scenario should be applied to the uses described in (1) above, however our ability to characterize and assign the locational attributes of the demand forecast, procurement authorizations, and transmission additions continues to evolve. Because of the local nature of reliability needs and the difficulty of assigning AAEE or demand to specific locations, the agencies' leadership agrees to use **the mid-low AAEE forecast scenario for local studies.**²⁵⁵ **The agencies' leadership also agrees to use the CED 2015 Adopted mid-mid AAEE forecast scenario for system-wide and flexibility studies for the upcoming (2016-2017) cycles of TPP and LTPP.**

The agencies' leadership intends to have future AAEE forecasts converge on the use of a single scenario for all studies. To achieve this, the three agencies are collaborating to create more-geographically specific, local-area disaggregation and load-shape impact methods, thereby eliminating the need for a lower AAEE forecast for local studies in future planning and procurement cycles.

Another area for continued agency discussion will be modeling capability for behind-the-meter PV. At some point, continued growth in PV adoption will likely reduce demand for utility-generated power at traditional peak hours to the point where the hour of

255 See the presentation of Expert Panel member Alan Sanstad before the Energy Commission on May 30, 2013. http://www.energy.ca.gov/2013_energypolicy/documents/2013-05-30_workshop/presentations/03_Sanstad-CEC-May_30_2013.pdf

peak utility demand is pushed back to later in the day. This means that future PV peak impacts could decline significantly as system performance drops in the later hours. This possibility has not been incorporated into the demand forecast through *CED 2015 Adopted*, since Energy Commission staff has not yet developed models to forecast hourly loads in the long term. Staff expects to develop this capability for the *2017 IEPR*, and such an adjustment to PV peak impacts could significantly affect future peak forecasts.²⁵⁶

Recommendations

» **Continue efforts to align agency planning cycles.**

Energy Commission staff continues to work with the California Public Utilities Commission (CPUC) and the California Independent System Operator to ensure the alignment of planning cycles coincides. The Energy Commission should broaden efforts to include greater visibility for all load-modifying assumptions in the forecast, not only energy efficiency and demand response. Also, the Energy Commission should continue to study impacts to the forecast from recent CPUC decisions on time-of-use rates.

» **Define data needs for greater granularity in the demand forecast.** The Energy Commission should work with utility resource planners and stakeholders to determine what data will be needed for further forecast granularity to support resource planning needs as well as Senate Bill 350 (De León, Chapter 547, Statutes of 2015) goals. In conjunction with the Order Instituting Rulemaking process for Assembly Bill 802 (Williams, Chapter 590, Statutes of 2015) and Senate Bill 350, methods should be developed for procuring the data periodically

and efficiently and determining what analytical, physical, and staff resources are required to develop and execute a more granular forecast.

» **Focus efforts in the next year on data needs and methodology improvement.** In addition to developing an assessment of data needs and accompanying procurement process, the Energy Commission, CPUC, and the California Independent System Operator, along with the utilities, should cooperate as part of the *2016 Integrated Energy Policy Report Update* to facilitate methodological improvements associated with the demand forecast. This should include solar photovoltaic and efficiency modeling and potential influences of other load-modifying resources identified in Senate Bill 350, through Demand Analysis Working Group and Joint Agency Steering Committee discussions.

²⁵⁶ SCE has developed this capability and, as a result, their latest peak forecasts grow at a markedly higher rate than the *CED 2015 Adopted* SCE peak forecasts.

CHAPTER 6

Natural Gas



Natural gas provides a flexible energy source for a wide range of applications such as electricity generation, including generation that can quickly ramp up and down to help integrate renewable generation; cooking; space heating; and transportation. While natural gas provides a relatively low-carbon fuel source when compared to other fossil fuels used for electricity generation or transportation, recent studies indicate that in certain circumstances methane leakage can reduce the climate benefits of switching to natural gas. This is because natural gas is composed primarily of methane, a potent greenhouse gas (GHG). Many research efforts are aimed at better understanding the leakage rates and these tradeoffs. There may be opportunities to reduce GHG emissions by converting biomass to renewable biogas or biomethane for use as a replacement for petroleum-based natural gas in transportation, electricity generation, and end-use consumption. Protecting public safety continues to be another important focus in managing the natural gas system. The gas well leak at Southern California Gas' (SoCalGas) storage facility at Aliso Canyon is an example of a large but unexpected methane leak that is not only having a large impact on California's total carbon footprint, but is disrupting the daily lives of those living nearby.

Assembly Bill 1257 (Bocanegra, Chapter 749, Statutes of 2013) (AB 1257) directs the Energy Commission to explore the strategies and options for using natural gas, including biogas, to maximize the benefits of natural gas. The highlights of the Energy Commission staff's analysis are presented in this chapter. Topics include pipeline safety, natural gas for electric generation, combined heat and power (CHP), natural gas as a transportation fuel, end-use efficiency, low-emission biomethane, and GHG emissions associated with the natural gas system. This chapter also summarizes Energy Commission staff's analysis of projected natural gas prices, production, and demand, as detailed in the forthcoming *2015 Natural Gas Outlook*.

Assembly Bill 1257 Report

In response to AB 1257 direction, the Energy Commission identified strategies to maximize the environmental and societal benefits of natural gas and reports on its findings in this *2015 Integrated Energy Policy Report (IEPR)*. Energy Commission staff developed a report that addressed the following areas relating to natural gas:

- » Natural gas pipeline infrastructure, storage, and reliability
- » Natural gas for electric generation
- » Combined heat and power using natural gas
- » Natural gas as a transportation fuel
- » End-use efficiency applications using natural gas for heating and cooling, water heating, and appliances
- » Natural gas and zero-net-energy (ZNE) buildings
- » Other natural gas low-emission resources and biogas
- » GHG emissions associated with the natural gas system.

Energy Commission staff released a draft *Strategies to Maximize the Benefits Obtained from Natural Gas as an Energy Source* report in mid-September 2015 and held a workshop September 21, 2015, to provide stakeholders an opportunity to comment on it. Energy Commission staff released a final staff report in November 2015 and delivered it to the Legislature.²⁵⁷ A discussion of the major topic areas, as well as a summary of the feedback received at the workshop, is provided below.

257 MacDonald, Rachel, Silas Bauer, Andre Freeman, Rey Gonzalez, Jason Harville, Melissa

Jones, Chris Marxen, Brad Meister, Garry O'Neill, Bill Pennington, Charles Smith, David Vidaver. 2015. *Strategies to Maximize the Benefits Obtained From Natural Gas as an Energy Source*. California Energy Commission. CEC-200-2015-006. http://docketpublic.energy.ca.gov/PublicDocuments/15-IEPR-04/TN206470_20151030T160233_STAFF.pdf.

Natural Gas Pipeline Safety and Infrastructure

California consistently ranks as the second highest gas-consuming state in the United States, with daily natural gas demand ranging from a little more than 6 billion cubic feet per day to as high as 11 billion cubic feet per day, depending on the time of year.²⁵⁸ Increased demand and the opening of new production areas in recent years have provided California with access to diverse natural gas sources. The immediate gas infrastructure challenges California faces relate to pipeline safety, Southern California infrastructure enhancements, and potential exports to Mexico along the pipelines east of California.

As a result of the pipeline explosion in San Bruno on September 9, 2010,²⁵⁹ the California Public Utilities Commission (CPUC) formed an independent review panel of experts to gather and review facts and make recommendations to Pacific Gas and Electric (PG&E) and the CPUC.²⁶⁰ The report determined that lapses in pipeline safety led to the San Bruno explosion. Key among the recommendations was that PG&E review its integrity management threat assessment method, ensure capture of all relevant pipeline design data, improve and apply risk management, improve its automated control and monitoring systems, and modify its corporate culture so that safety is emphasized over financial performance. The panel's recommendations for the CPUC form the cornerstone of a comprehensive effort launched by the CPUC to create a culture where safety permeates all of

258 California Gas and Electric Utilities, *2014 California Gas Report*, 2014, http://www.pge.com/pipeline_resources/pdf/library/regulatory/downloads/cgr14.pdf, p.31.

259 A segment of a 30-inch gas transmission line exploded and took the lives of eight people, injured 58 others, destroyed 38 homes, and damaged 70 other homes. <http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M150/K539/150539121.PDF>.

260 California Public Utilities Commission, *Report of the Independent Review Panel: San Bruno Explosion*, Decision 13-10-024, October 2013, <http://www.cpuc.ca.gov/NR/rdonlyres/85E17CDA-7CE2-4D2D-93BA-B95D25CF98B2/0/cpucfinalreportrevised62411.pdf>.

its regulatory activity. A natural gas system that does not satisfy the requirements of the Public Utilities Code cannot meet California's future need for natural gas.

Early in 2011, acting on a recommendation from the National Transportation Safety Board, the CPUC's Executive Director ordered all four of California's investor-owned natural gas utilities to produce "traceable, verifiable and complete records" to validate minimum acceptable operating pressure on transportation pipelines located in heavily populated areas. Initial response revealed that only Southwest Gas (a Lake Tahoe area utility) believed it possessed records for all its pipeline segments pertinent to the National Transportation Safety Board recommendation.²⁶¹ The passage of Senate Bill 705 (Leno, Chapter 522, Statutes of 2011) reinforced this by establishing that "[i]t is the policy of the state that the [California Public Utilities] Commission and each gas corporation place safety of the public and gas corporation employees as the top priority" and by requiring utilities to submit safety plans. These plans became known as Pipeline Safety Enhancement Plans (PSEPs).

Implementation of the PSEPs continues in 2015. As of August 2014, PG&E completed pressure validation of its 6,750-mile transmission pipeline system and hydrostatically tested more than 565 miles of pipeline. It also replaced 90 miles of pipeline and expects its PSEP to be complete in 2017.²⁶² Not all has gone smoothly for PG&E since the San Bruno incident. Several dig-in rupture events have occurred because of inadequate information in the hands of construction work crews. PG&E also committed a serious error in the information provided to the CPUC in asking to restore operating pressure on Line

147, incurring a \$14.35 million fine in December 2013 related to having misled the CPUC about welds on six segments of the line.

SoCalGas has reported that it was able to find records for about 245 miles of the 385 miles of pipeline initially thought to have to be strength-tested or replaced.²⁶³ The PSEP work for the Sempra utilities is scheduled to be completed by the end of 2018, although PSEP work to address the mainline into San Diego (Line 1600) will be delayed until the CPUC acts on an application to loop that line so that the existing line can be taken out of service without creating reliability problems.²⁶⁴

In approving the PSEPs, the CPUC has ruled that SoCalGas/SDG&E shareholders should "absorb the portion of the Safety Enhancement costs that were caused by any prior imprudent management," the costs of pressure testing where the company cannot produce records, and for pipelines it chooses to replace rather than test.²⁶⁵ PG&E's rate recovery also was significantly less than requested, with the CPUC disallowing portions such as a contingency reserve and increasing the portion borne by shareholders.

California is improving its pipeline safety with research and analysis as well. The Energy Commission funded research to help address natural gas safety soon after the San Bruno explosion and continues to award research funds for natural gas system projects on an ongoing basis. Current research is focused on developing new technologies – such as sensors and ultrasonic transducers – to monitor the integrity of gas pipelines. These projects are intended to reduce the cost and size of leak detection sensors and diagnostic tools and improve

261 The National Transportation Safety Board letter can be found at <http://www.nts.gov/safety/safety-recs/reclatters/P-10-002-004.pdf>, and the Executive Director's order was ratified by the Commission by resolution on January 13, 2011.

262 August 14, 2014, letter from Paul Clanon, Executive Director CPUC, to National Transportation Safety Board Acting Chairman Christopher A. Hart.

263 December 5, 2014, Letter of Sempra's Tamara Rasberry in Docket No. 15-IEPR-04 – "AB1257 Natural Gas Act Report."

264 A. 14-12-015, "Chapter III Description of PSRMA Costs Prepared Direct Testimony of Richard D. Phillips," p. 3 and p. 11.

265 D. 14-06-007, Findings of Fact 13 and 14. There apparently remains some dispute about whether the cutoff date for ratepayers versus shareholders bearing pressure test costs is 1961 or 1956. See D. 15-03-049.

accuracy of leak and defect detection. The Energy Commission should continue to support research that improves natural gas infrastructure and safety.

Infrastructure issues of another type are apparent in Southern California, especially in the southern zone that includes the SDG&E gas service area and territory east to the California/Arizona border receiving gas through Ehrenburg. This area is relatively isolated with limited interconnection to other gas receipt points in California and no storage facilities. This causes economic disincentives for both gas shippers (higher-priced markets elsewhere) and end users (prices lower at other pipeline receipt points), even when there is excess capacity. The CPUC has granted SoCalGas permission to enter the market and purchase gas, assuming these are infrequent, small amounts of gas to meet total demand in the southern system that is delivered to Ehrenburg, Arizona. Unfortunately, a combination of conditions led to a noncore customer curtailment watch on the June 30 and July 1, 2015, – high gas demand when gas infrastructure was down for planned maintenance, coupled with high temperatures causing high electricity demand when electricity supplies were limited by lack of hydroelectricity and constraints on imports. This watch transformed into an actual curtailment of natural gas service to certain power plants in the Los Angeles Basin, causing the California Independent System Operator (California ISO) to issue a “Flex Alert.”

Localized curtailments or near-curtailments also occurred in the winter of 2013-2014 when SoCalGas did not receive sufficient gas supply at Ehrenburg. Curtailments in the SDG&E gas service area are of particular concern for two reasons. First, there is virtually no industrial load in San Diego County, so there is little to curtail other than electric generation. Second, much of the local area electricity generation was operating at higher levels to make up for power generation lost with the closure of San Onofre Nuclear Generating Station. (See Chapter 7 for more information.)

In response to the event, SoCalGas filed an application²⁶⁶ with the CPUC to modify the gas curtailment rules and asked the CPUC to approve the new rules by August 2016. The changes reflect formal recognition that the gas and electric utilities and California ISO need greater clarity and flexibility to work together to preserve electricity reliability when gas reliability is threatened

With the problem occurring more frequently than anticipated, SoCalGas developed a more comprehensive, physical solution to this “southern system minimum” problem by filing an application with the CPUC to build a north-south pipeline.²⁶⁷ The project would allow gas received at northern receipt points to flow into the southern zone by adding a new 60-mile, 36-inch diameter pipeline.

The \$621.3 million project is still pending at the CPUC. Interveners have proposed several alternatives that they claim could be constructed faster and at lower cost. Evidentiary hearings on the proposals were held in August, allowing for CPUC action which is expected in early 2016.

The final infrastructure issue centers on increasing demand in Mexico for natural gas. Mexican consumption increased by 4 percent per year in recent years, while production has grown by only 1.2 percent. Electricity generation is at the heart of this increased gas use, as up to 24 gigawatts of new natural gas combined-cycle power plants are expected to be added by 2018.²⁶⁸

Mexico produces its own natural gas, but it is uncertain whether the country can increase the production at a pace that can match its growth in demand. Constitutional reforms recently signed into law will allow foreign

266 A-15-05-020

267 A13-12-013, Application for Authority to Recover North-South Project Revenue Requirement in Customer Rates and for Approval of Related Cost Allocation and Rate Design Proposals.

268 2014 Energy & Commodities Conference, Cadawalder, Wickersham & Taft, LLP, October 8, 2014, <http://www.energylawresourcecenter.com/blog/wp-content/uploads/2020/10/Panel-Five-Electric-Market-Update-FERC-and-CFE1.pdf>, p.20.

companies to share profits with Petróleos Mexicanos and explore and drill for oil and gas in Mexico.²⁶⁹ This could lead to higher production in Mexico rather than relying on imports from the United States.

Mexico's three liquefied natural gas (LNG) import terminals remain underused as LNG commands higher prices in Asia than North America. This makes it more economic for Mexico to pay for gas pipeline transportation from the United States pipelines east of California than to import LNG from overseas. Delivering more gas to Mexico has meant adding new pipeline capacity. Projects completed, proposed, or pending add up to more than 7 billion cubic feet per day of new pipeline export capacity from the United States to Mexico.²⁷⁰

Most of these projects are located in South Texas and will export natural gas that could not otherwise come to California. Several, however, notably the Sierrita Pipeline, Samalayuca Lateral/Norte Crossing Pipelines, Willcox Lateral Expansion, Waha – San Elizario Pipeline and Waha – Presidio/Ojinaga Pipeline, could siphon off gas that could otherwise compete to serve load in California. These projects create additional competition for supplies that could come to California. That impact could become more pronounced given that these new export lines will receive supply from the same line that interconnects with SoCalGas at Ehrenberg to supply SoCalGas' southern zone. Higher prices in markets east of California could exacerbate the southern zone problems by further reducing the relative attractiveness of the Ehrenberg receipt point.

269 See, for example, <http://rt.com/business/179824-mexico-signs-energy-reform-law/> or Diana Villiers Negroponete, *Mexico's Energy Reforms Become Law*, Brookings Institution, August 2014. Found at <http://www.brookings.edu/research/articles/2014/08/14-mexico-energy-law-negroponete>.

270 Canonica, Rocco, Ellen Nelson, Darrell Proctor, and Tricia Bulson, *Growing Mexican Gas Market Creates Southwest Price Premiums*, Energy Market Fundamentals Report, Bentek Energy, Platts, May 2013; Sempra Energy Third Quarter 2014 Earnings Results, Nov. 4, 2014, p. 22, http://files.shareholder.com/downloads/SRE/3699542155x0x791009/39C03F43-0449-4AE8-A8EA-17BAD6F1AD7F/Q3-14_Presentation.pdf.

Shale gas production in North America has resulted in a substantial increase in natural gas supply, as well as a corresponding decrease in the price of natural gas. Because the 11 LNG import terminals in the United States now sit mostly idle, producers are seeking to sell U.S. supply into export markets that pay higher prices than available here in the United States.

This has led to several existing U.S. LNG import terminals filing applications with the U.S. Department of Energy Office of Fossil Energy for authorization to export LNG under the 1938 Natural Gas Act. To date, five U.S. LNG export terminals have received export authorizations, representing 9.2 billion cubic feet per day of export capacity. Only four have commenced construction, and all are located on the Gulf or east coasts.

Natural Gas for Electric Generation

Several proposed or adopted federal air and water quality regulations are expected to reduce the United States' reliance on coal for generating electricity. These rules include the air toxics rule,²⁷¹ the Clean Power Plan (111d),²⁷² the GHG new source performance standard,²⁷³ changes to water effluent rules,²⁷⁴ and others. Together, they may increase demand for natural gas-fired generation at the national level, depending on what choices utilities make about how to replace the electricity formerly generated by coal. California utilities are decreasing their reliance on out-of-state coal generation and increasing their reliance on renewable resources.

As California works to transform its energy system to dramatically reduce GHG emissions, natural gas is expected to play an important, but smaller, role in the

271 <http://www.epa.gov/airquality/powerplanttoxics/>.

272 <http://www2.epa.gov/cleanpowerplan/clean-power-plan-existing-power-plants>.

273 <http://www2.epa.gov/cleanpowerplan/carbon-pollution-standards-new-modified-and-reconstructed-power-plants>.

274 <http://water.epa.gov/scitech/wastetech/guide/index.cfm>.

state's energy mix in the coming decades.²⁷⁵ Roughly 40 percent of natural gas consumption in California is used to generate electricity; for the United States, the amount of natural gas used for electric generation is 31 percent. As California electric utilities convert electricity generation portfolios away from carbon-intensive resources, the way natural gas is used will change. These changes will affect not only the quantity of natural gas used to generate electricity, but how and when natural gas-fired resources need to operate. These new operational profiles will require a higher degree of coordination between the gas and electric industries.

Keeping the gas system in balance could potentially become more challenging as the state further increases the portion of the electricity generated from renewables. The electricity produced from renewables such as wind and solar varies depending on conditions each hour or even minute to minute. The California ISO and CPUC have been working to identify the flexibility needs of California's electricity system and the capability of the system to ramp both electricity production and demand up and down to keep the system in balance. Ongoing efforts to increase the flexibility of the natural gas-generating fleet – as well as other strategies to integrate renewables, including through broader regional coordination – can be expected as the state pursues a larger share of its electricity production from renewable energy.²⁷⁶ (See Chapter 2 and Chapter 9, "Climate Impacts on Renewable Energy Generation and Hydropower," for further discussion of efforts to integrate increasing amounts of renewable energy.)

Combined Heat and Power Systems and Natural Gas

A CHP system produces a combination of useful thermal, electrical, and sometimes mechanical energy through the use of waste heat from an electrical generator or preexisting, thermally intensive process (such as manufacturing or industrial). In using heat that would otherwise be wasted, a properly sized and operated CHP facility can produce energy using less fuel than would normally be used to acquire the same energy via a more traditional system of boilers and central-station grid electricity. While the cost-savings associated with this increased fuel efficiency have historically been the primary incentive for installing CHP systems, CHP can also provide secondary benefits for owners and operators, including increased price certainty, energy security, control over business processes, and protection from grid electricity outages. Furthermore, the state recognizes the potential for CHP to provide benefits beyond the needs of owners and operators, including decreased emissions of GHGs and criteria pollutants, contribution to regional grid resource adequacy requirements, reduced risk of major grid outages, reduction in net demand, reduction in power transmission and distribution costs, and greater energy security for critical facilities.

In support of these benefits, the state has established several policies, programs, and incentives to deploy CHP systems. The California Air Resources Board's (ARB) *Climate Change Scoping Plan* sets a target of an additional 4,000 megawatts (MW) of CHP capacity by 2020, which corresponds to a target reduction of 6.7 million metric tons carbon dioxide equivalent (MMTCO₂e) of GHG emissions.²⁷⁷ Governor Edmund G. Brown Jr.'s 2010 *Clean Energy Jobs Plan* calls for an additional 6,500 MW of new CHP capacity by 2030.²⁷⁸

275 The California Air Resources Board *Climate Change Scoping Plan* can be found at http://www.arb.ca.gov/cc/scopingplan/resolution_14-16.pdf.

276 California Energy Commission, *Tracking Progress, Resource Flexibility*, http://www.energy.ca.gov/renewables/tracking_progress/index.html, updated August 19, 2015.

277 ARB, *Climate Change Scoping Plan*, December 2008, http://www.arb.ca.gov/cc/scopingplan/document/adopted_scoping_plan.pdf, pp. 33–34.

278 Office of the Governor, *Clean Energy Jobs Plan*, 2011, http://gov.ca.gov/docs/Clean_Energy_Plan.pdf, p. 6.

The value of CHP is also articulated in statute. Public Utilities Code Section (Pub. Util. Code §) 372(a) states, “it is the policy of the state to encourage and support the development of CHP as an efficient, environmentally beneficial, competitive energy resources that will enhance the reliability of local generation supply, and promote local business growth.” This objective was recognized in CPUC D. 10-12-035 that approved the Qualifying Facility (QF) and CHP Program Settlement Agreement²⁷⁹ (QF Settlement), which established a process enabling existing CHP facilities to transition from a federal standard-offer contract model to a state CHP program. CHP is also considered a preferred resource for meeting utility resource needs.²⁸⁰

The QF Settlement ended numerous legal disputes among investor-owned utilities (IOUs), QF representatives, ratepayer advocacy groups, and the CPUC and required that California’s three largest IOUs procure 3,000 MW of CHP and achieve 4.8 MMTCO₂e of the 2008 *Climate Change Scoping Plan* GHG reduction target – proportional to the amount of electricity sales by the IOUs.

On June 11, 2015, the CPUC issued Decision 15-06-028²⁸¹ establishing new procurement targets for the QF Settlement’s Second Program Period. The decision also revised the GHG Emissions Reduction Targets to collectively achieve 2.72 MMTCO₂e of emissions reductions from CHP facilities by 2020 and established a schedule for

the IOUs to release four competitive solicitations to achieve these targets from CHP plants between 2015 and 2020.

Procurement Mechanisms and Incentives that Support CHP

The following programs and tariffs provide support to increase the economic viability of, and encourage investment in, the development of CHP plants in California:

» Assembly Bill 1613 (Blakeslee, Chapter 713, Statutes of 2007), the Waste Heat and Carbon Emissions Reduction Act, established a feed-in tariff for CHP installations of no more than 20 MW that meet specified fuel efficiency and emission standards. This program has received little participation to date.

» The Self-Generation Incentive Program offers monetary incentives to encourage customer adoption of eligible behind-the-meter, distributed generation technologies. Though it began in 2001 as a peak-load reduction program, the program has since shifted the primary focus to reducing GHG emissions. Eligible technologies include (nonsolar) renewables, fuel cells, advanced energy storage, and CHP. By supporting the deployment of highly efficient CHP, the Self-Generation Incentive Program helps ensure that natural gas is consumed in California as efficiently as possible. To that end, program support for natural gas-fueled technologies is limited to those that achieve a net GHG emissions reduction. The CPUC has issued a proposed decision that, if adopted, would reduce the allowable emissions rate of participating technologies by 5 percent – from 379 kgCO₂/MWh to 360 kgCO₂/MWh.

» The CPUC recently issued a proposed decision that would adopt, with modification, SoCalGas’ application (A.14-08-007) to establish a Distributed Energy Resources Services Tariff. The Distributed Energy Resources Services Tariff would allow SoCalGas to design, install, own, operate, and maintain advanced energy systems, including many forms of CHP, on or near the customer’s

279 CPUC, CHP Program Settlement Agreement (D.10-12-035), 2010, http://docs.cpuc.ca.gov/word.pdf/FINAL_DECISION/128624.pdf, p. 2.

280 In 2003, the CPUC, Energy Commission, and California Power Authority adopted the *Energy Action Plan*, articulating a unified approach to meeting California’s electricity and natural gas needs. A key element was the *loading order*, which specified California’s policy to invest first in energy efficiency and demand response and then renewables and distributed generation before convention generation. CHP, as a form of distributed generation, is given preferred resource status in the loading order.

281 CPUC Decision on Combined Heat and Power Procurement Matters, June 2015, <http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M152/K559/152559026.PDF>.

premises. It is designed to help overcome barriers for potential customers that might lack the internal capital and experience necessary to develop and operate such facilities. If adopted, the Distributed Energy Resources Services Tariff could help develop the largely untapped market potential of CHP plants with 20 MW or less in nameplate capacity.

Role of CHP in Reducing GHG Emissions in the Future

Despite these many ambitious goals and policies, CHP growth and development in California have been relatively flat in recent years and are likely to decline in the future. When explaining this lack of progress, CHP developers and owners commonly cite economic and regulatory barriers that result in a combination of cost and risk that is too high to justify a project.

How CHP facility owners and developers respond to the new solicitations required by the CPUC D. 15-06-028 remains to be seen. In the future, it is likely that some existing CHP plants relying on power purchase contracts for export power will be unable to secure new contracts and will shut down; however, it is unclear how much of the more than 4,000 MW of existing CHP facilities counted under the QF Settlement will close and install boilers in the next 5 to 10 years. This is important to study and assess so that self-generation forecasts, especially in the large industrial sector, can be adjusted to account for the closure of these plants.

Finally, evaluating the potential of small distributed CHP (less than 20 MW), as well as emerging technologies and applications (for example, heating greenhouses and use of carbon dioxide for ripening produce) is important to understanding the potential environmental and grid system benefits of CHP. According to the *Combined Heat and Power: Policy Analysis and Market Assessment*, a study done by ICF International for the Energy Commission in 2012, most technical potential for new CHP is in

the 50 kW to 5 MW range.²⁸² Exploring renewable-fueled CHP and how it fits into the state's renewable energy goals, looking at applications for critical facilities, and soliciting new microgrid applications are all opportunities that should be pursued and studied so clean, efficient, and reliable CHP can continue to contribute to California's energy and environmental goals.

Natural Gas as a Transportation Fuel

As discussed in detail in Chapter 4, the state has developed a portfolio of goals, policies, and strategies designed to reduce GHG emissions, improve air quality, and reduce petroleum use, while meeting transportation demands of the future. Transportation accounts for nearly 37 percent of California's total energy consumption and roughly 37 percent of the state's GHG emissions.²⁸³ While petroleum accounts for more than 90 percent of California's transportation energy sources,²⁸⁴ there could be significant changes in the fuel mix by 2020 as a result of technology advances, market trends, consumer behavior, and government policies. The range of alternatives to petroleum-based fuels is diverse – including biofuels, electricity, hydrogen, and natural gas.

The *2014 IEPR Update* discusses the role of natural gas as a transportation fuel in depth. It points out that the Energy Commission has long considered natural gas as a near-term bridging fuel to reduce carbon emissions – offering a modest carbon reduction from petroleum fuels. In 2012, medium- and heavy-duty vehicles (such as long-haul trailers, package delivery vans, shuttles,

282 Hedman, Bruce; Darrow, Ken; Wong, Eric; Hampson, Anne, ICF International, Inc. 2012. *Combined Heat and Power: 2011-2030 Market Assessment*. California Energy Commission. CEC-200-2012-002. Table ES-1, p.4.

283 <http://www.arb.ca.gov/cc/inventory/inventory.htm>.

284 California Energy Commission, *2013 Integrated Energy Policy Report*, 2013, p. 5. <http://www.energy.ca.gov/2013publications/CEC-100-2013-001/CEC-100-2013-001-CMF.pdf>.

and buses) comprised about 3.7 percent of the California vehicle population yet consumed more than 20 percent of the fuel. Medium- and heavy-duty vehicles are responsible for as much as 23 percent of transportation-related GHG emissions and they account for 30 percent of oxides of nitrogen emissions. Using lower carbon-intensity fuels and advanced engine and pollution control technologies can help reduce tailpipe pollution from medium- and heavy-duty vehicles.

On September 10, 2015, the ARB certified a Cummins Westport 8.9 liter natural gas engine at the 0.01 gram oxides of nitrogen standard – or 95 percent lower than the prevailing standard of 0.86.²⁸⁵ No other heavy-duty engine has been certified to such a low level. This engine is expected to be available in 2016, with a similar 12 liter version market-ready in 2017. Using these recently introduced low NO_x natural gas engines, in combination with low-carbon biomethane fuel, provides an opportunity to deploy vehicles that have significantly reduced NO_x and GHG emissions. These advanced natural gas vehicles are one potential option to help reduce criteria pollutants in the San Joaquin Valley and South Coast Air Basins. In its *Mobile Source Strategy Discussion Draft*, ARB identifies low-NO_x trucks as the “most viable approach” to meeting 2031 air quality goals in the South Coast region, with low-NO_x natural gas engines already leading the way.²⁸⁶ (For more discussion, see Chapter 9: Climate Change, “Climate Change and Air Quality Considerations.”) On the GHG front, a natural gas truck using pure biomethane could reduce GHG emissions anywhere from 67 percent to 125 percent compared to a conventional diesel truck,

depending on the origin of the biomethane.²⁸⁷ Similarly, a mix of natural gas and biomethane (if incorporated at sufficient levels) could provide GHG emission reductions comparable to an all-electric truck.²⁸⁸ For these reasons, natural gas pathways are being explored in truck and bus applications, as well as the marine and rail sectors.

Natural gas is also playing an important role in the development of the emerging hydrogen vehicle industry. Natural gas use in vehicles accounts for about 1 percent of total transportation fuel consumption.²⁸⁹ There are several options available for producing hydrogen fuel for transportation. A majority of existing hydrogen fueling stations use hydrogen made by a steam reformation process that converts methane or natural gas to hydrogen. This process could be used to allow hydrogen fueling stations and centralized fuel producers to use the existing natural gas infrastructure as a secure source of fuel for hydrogen production.

The Energy Commission’s Fuels and Transportation Division implements the Alternative and Renewable Fuel and Vehicle Technology Program, which provides up to \$100 million per year for projects that will transform California’s fuel and vehicle types to help attain the state’s climate change and clean air policies. (For further discussion, see Chapter 4: Transportation, Alternative and Renewable Fuel and Vehicle Technology Program Benefits Update.) To support natural gas-related activities in California’s transportation sector, funding is targeted at the major areas where public investment can help remove barriers to the adoption of

285 ARB Executive Order A-021-0630, http://www.arb.ca.gov/msprog/onroad/cert/mdehdehdv/2016/cummins_mhdd_a0210630_8d9_0d20-0d01_ng.pdf.

286 ARB, *Mobile Source Strategy – Discussion Draft*, October 2015. Available at: http://www.arb.ca.gov/planning/sip/2016sip/2016mobsrc_dd.pdf.

287 MacDonald, Rachel, Silas Bauer, Andre Freeman, Rey Gonzalez, Jason Harville, Melissa Jones, Chris Marxen, Brad Meister, Garry O’Neill, Bill Pennington, Charles Smith, David Vidaver. 2015. *AB 1257 Natural Gas Act Report: Strategies to Maximize the Benefits Obtained From Natural Gas as an Energy Source*. California Energy Commission. CEC-200-2015-006. See Table 2: Low-Carbon Fuel Standard Carbon Intensity Values.

288 Ibid. Based on the assumption of average grid electricity (at 105.16 grams of carbon dioxide – equivalent per megajoule) and the higher energy efficiency factor of 2.7 for an electric truck.

289 Energy Commission, 2014 *Integrated Energy Policy Report Update*, p. 103. <http://www.energy.ca.gov/2014publications/CEC-100-2014-001/CEC-100-2014-001-CMF.pdf>.

this alternative fuel. In addition, the *2014 Integrated Energy Policy Report Update*²⁹⁰ indicates that one key area showing improvement is transportation research. The Energy Commission's Energy Research and Development Division's transportation research program is focused on developing and advancing state-of-the-art electricity and natural gas-fueled transportation solutions that reduce fossil fuel consumption, GHG emissions, and air pollutants in the state.

Many of California's transit, municipal service, waste disposal, and freight transport fleets have already converted their petroleum-consumption vehicle fleets to operate on natural gas.

Current natural gas vehicle options have a greater incremental cost compared to similar gasoline or diesel vehicles. During times of high petroleum prices, this incremental cost can be recouped through fuel savings over a short period. With the significant drop in petroleum prices since late 2014, the payback period needed to recoup this incremental cost has increased significantly.

As discussed below in the section on "GHG Emissions Associated With the Natural Gas System," scientific understanding of the scale of methane emissions due to leakage throughout the natural gas system – from extraction, gathering, processing, distribution and transmission, and at the end use – is evolving. The final *AB 1257 Natural Gas Act Report* explores recent scientific and academic studies in greater detail.²⁹¹ Because methane is the primary component of natural gas and a potent GHG, continued engagement and research will be critical as the state continues to initiate solutions to

transform the transportation sector to reduce GHG and criteria pollutant emissions.²⁹²

End-Use Efficiency Applications and Natural Gas, Including Zero-Net Energy Buildings

California households and businesses consume about one-third of the total state natural gas demand, or about 7 billion therms of natural gas annually.²⁹³ Residential natural gas consumption is driven mostly by space and water heating, followed distantly by cooking and miscellaneous home uses, such as clothes dryers and pools. Similarly, commercial natural gas consumption comes primarily from space and water heating, with cooking being a significant end use as well. Other end uses in commercial buildings include process loads, such as commercial laundry, heated pools, and other loads, such as paint dryers in auto shops.

Residential and commercial natural gas consumption has remained relatively flat for the past two decades despite increases in population, jobs, and gross state product.²⁹⁴ During this period the *California Building Energy Efficiency Standards* have become increasingly stringent, as have investments in statewide utility energy efficiency programs, contributing to the relative flattening of natural gas consumption. The industrial sector is a major energy consumer and one of the largest users of natural gas in the state, accounting for about 25 percent of total use

290 <http://www.energy.ca.gov/2014publications/CEC-100-2014-001/CEC-100-2014-001-CMF.pdf>.

291 MacDonald, Rachel, Silas Bauer, Andre Freeman, Rey Gonzalez, Jason Harville, Melissa

Jones, Chris Marxen, Brad Meister, Garry O'Neill, Bill Pennington, Charles Smith,

David Vidaver. 2015. *AB 1257 Natural Gas Act Report: Strategies to Maximize the Benefits Obtained From Natural Gas as an Energy Source*. California Energy Commission. CEC-200-2015-006

292 Energy Commission. *2014 Integrated Energy Policy Report Update*. <http://www.energy.ca.gov/2014publications/CEC-100-2014-001/CEC-100-2014-001-CMF.pdf>, p. 4.

293 California Energy Commission. *The Natural Gas Research, Development and Demonstration Program: Proposed Program Plan and Funding Request for Fiscal Year 2012-13*, CEC-500-2012-084, March 2012, <http://www.energy.ca.gov/2012publications/CEC-500-2012-084/CEC-500-2012-084.pdf>, p. 17.

294 *Gross state product* is a measurement of the economic output of a state or province. It is the sum of value added by all industries within the state and is the state counterpart to national gross domestic product.

in 2012.²⁹⁵ The largest users include petroleum and coal products manufacturing, oil and natural gas extraction, food processing, printing, and manufacture of electronics, transportation equipment, fabricated metals, furniture, chemicals, plastics, and machinery. These sectors represent prime areas of opportunity for reducing industrial natural gas use. Consequently, industry represents an important target for improving the efficiency of natural gas use through the adoption of new technologies and improved energy management practices.

The passage of Senate Bill 350 (De León, Chapter 547, Statutes of 2015) will further support energy efficiency programs for natural gas end uses. SB 350 requires the doubling of energy efficiency savings by 2030 for electricity and natural gas combined. As with electricity, the CPUC will be responsible for updating its policies on energy efficiency programs funded by ratepayers to authorize a broader array of programs and tie incentive payments to measurable efficiency results.

As the *California Building Energy Efficiency Standards* advance toward a goal of ZNE buildings by 2020, there does not appear to be a clear-cut path for natural gas policy in end-use applications when considering ZNE buildings. However, the cost-effectiveness requirement of the *California Building Energy Efficiency Standards* regulations also do not support universal electrification of natural gas end-uses. Furthermore, many natural gas end-uses represent a lower GHG emission alternative compared to grid electricity. These issues are further discussed in Chapter 1 under “Issues Regarding Natural Gas Use in ZNE Buildings.”

Low-Emission Resources and Biomethane

As part of his 2015 inaugural address, Governor Edmund G. Brown Jr. called for transitioning to cleaner heating fuels to help achieve the state’s climate goals. Using

eligible biomass to produce renewable natural gas can be an important step in reducing GHG emissions from the natural gas system.²⁹⁶ The *2014 Integrated Energy Policy Report Update* discussed pathways to achieving a decarbonized natural gas supply chain that can serve transportation, electricity, and direct end-use sectors. California’s gas utilities should begin developing strategies that will enable these goals.

Biomass sources such as residue from forest management practices, agricultural and food processing wastes, organic human waste, and waste and emissions from water treatment facilities, landfill gas, and other organic waste sources can be used to develop renewable natural gas. *Biogas* is the raw, untreated gas generally produced from biomass and is principally composed of methane and carbon dioxide. *Biomethane* is the treated product of biogas where carbon dioxide and other contaminants are removed. *Biomass* is the biological material used to create biogas. Biogas (or biomethane) can supplement or directly replace the use of natural gas.

In most cases, the potential for methane production is limited by immutable factors, such as “waste-in-place” at a landfill or the volumetric flow of water into a wastewater treatment plant. Production can be increased if there are opportunities to process additional biomass feedstocks within normal agricultural or industrial operations, such as dairy digesters accepting food waste or wastewater treatment plants codigesting fats, oils, and grease. Manure management, landfills, and wastewater treatment are three of California’s largest anthropogenic methane-producing sources. Thus, the capture and subsequent reduction of these methane emissions are arguably one of the greatest benefits for using biomethane. This option may be limited, however, because of limited availability of sustainable sources of biomass with very low net GHG emissions, as well as cost and feasibility issues.

295 California Energy Almanac available at <http://energyalmanac.ca.gov/naturalgas/overview.html>.

296 Energy Commission RPS eligibility guidebook available at <http://www.energy.ca.gov/2013publications/CEC-300-2013-005/CEC-300-2013-005-ED7-CMF.pdf>

The *2014 IEPR Update* provided a more detailed discussion of the potential role of biomethane as a low-carbon transportation fuel. The Energy Commission provides information to the U.S. Environmental Protection Agency so that low-carbon biofuels are appropriately recognized and categorized in the annual Renewable Fuel Standard volumetric targets.

The goal of Assembly Bill 1900 (Gatto, Chapter 602, Statutes of 2012) is to “promote the in-state production and distribution of biomethane” and to “facilitate the development of a variety of sources of in-state biomethane.” A provision of the bill requires the CPUC to adopt pipeline access rules that ensure that each gas corporation provides nondiscriminatory open access to its gas pipeline system to any party for physically interconnecting with the gas pipeline system and bringing about the delivery of gas. On February 13, 2013, the CPUC opened Rulemaking 13-02-008,²⁹⁷ which resulted in Decision 14-01-034²⁹⁸ on January 16, 2014, and Decision 15-06-029²⁹⁹ on June 11, 2015.

Decision 14-01-034 adopted standards that specify the concentrations of constituents of concern that are found in biomethane, and monitoring, testing, reporting, and recordkeeping protocols. Decision 15-06-029 concluded that the costs of complying with the standards and protocols should be borne by the biomethane producers. To provide initial support to the developing biomethane market, the decision adopted a policy and plan of a five-year monetary incentive program to encourage biomethane producers to design, construct, and successfully operate biomethane projects that interconnect with the gas utilities’ pipeline systems to inject biomethane that can be used at an end user’s home or business. The support allows that each biomethane project that is built

297 <http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M050/K674/50674934.PDF>.

298 <http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M086/K466/86466318.PDF>.

299 <http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M152/K572/152572023.PDF>.

over the next five years – or sooner if the program funds are exhausted before that period – can receive 50 percent of the project interconnection costs (up to \$1.5 million) to help offset interconnection costs.

Testimony received during the rulemaking estimated that the costs of interconnection can vary and that the producer – even with the proposed support – may be required to expend substantial interconnection costs. The Coalition for Renewable Natural Gas stated that interconnection costs (for example, necessary studies, permitting, and/or equipment and materials) could range from \$1.5 million to \$3 million, depending on the landfill location (rural or urban) and the proximity of the project to the utility’s pipeline. For a point-of-receipt facility, Sempra estimates that the cost will depend on facility size and output and that the costs could range from \$1.2 million to \$1.9 million.³⁰⁰

GHG Emissions Associated With the Natural Gas System

Natural gas is composed of multiple chemical compounds, but methane is the main component, comprising about 90 percent of the natural gas. According to the ARB, methane comprised about 9 percent of California’s GHG emissions in 2013. Of this 9 percent, natural gas pipelines emit about 9.3 percent of the methane released to the atmosphere, and process losses from oil and gas extraction account for an additional 4.4 percent. Therefore, methane emissions associated with the natural gas system contribute up to 13.7 percent of California’s methane emissions but only just over 1 percent of the total GHG emissions in California. As explained below, methane emissions estimates are highly uncertain and in-state emissions do not account for imported natural gas related emissions, even though imported natural gas represents about 90 percent of the natural gas consumed in California.

300 <http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M152/K572/152572023.PDF>, pp. 8–9.

Natural gas has the potential to reduce GHG emissions by shifting away from higher carbon dioxide emitting fuels like coal, gasoline, or diesel. Methane, however, is a highly potent, short-lived GHG that can reduce or potentially eliminate the climate change benefits of switching to natural gas. The ARB's September 2015 *Draft Short-Lived Climate Pollutant Reduction Strategy* report indicates that the state is making strides in reducing these pollutants.³⁰¹

Since the release of the ARB's report on short-lived climate pollutant reduction, however, a large gas leak was discovered at SoCalGas' storage facility at Aliso Canyon. (See side bar.) A preliminary estimate by the ARB shows that leakage from Aliso Canyon from October 23, 2015, to January 12, 2016, added about 2 MMTCOe, which is equivalent to about 21.6 percent of the methane emissions from all sources in California for the same period (82 days).³⁰²

On January 6, 2016, Governor Brown issued a proclamation for a State of Emergency in Los Angeles County due to the ongoing natural gas leak.³⁰³ The proclamation "builds on months of regulatory and oversight actions from seven state agencies mobilized to protect public health, oversee SoCalGas actions to stop the leak, track methane emissions, ensure worker safety, safeguard energy reliability and address any other problems stemming from the leak." The California Governor's Office of Emergency Services is coordinating the multi-pronged state agency response to the leak and provides frequent updates to affected residents, as well as local officials and interested parties. The Division of Oil, Gas and Geothermal Resources is overseeing the SoCalGas efforts to stop the leak, including issuing emergency orders directing SoCalGas to halt gas



Natural Gas Leak at Aliso Canyon

On October 23, 2015, a natural gas leak was detected in SoCalGas' Aliso Canyon natural gas storage facility. Initial efforts to plug the leak were unsuccessful and nearby residents complained of noxious odors and physical ailments as a result of the exposure. On November 18, 2015, the California Department of Conservation, Division of Oil, Gas and Geothermal Resources issued an order to SoCalGas that required the operator to provide testing results, data, and written plans to address the leak. SoCalGas indicated that they would construct a relief well to stop the leak and then close or abandon the leaking well permanently. The construction of the relief well is expected to be complete by the end of February 2016. On January 15, 2016, the Office of Environmental Health Hazard Assessment announced the appointment of eight physicians and scientists to the independent panel to review public health concerns stemming from the gas leak and evaluate whether additional measures are needed to protect public health beyond those already put in place. Estimates of the amount of methane that escaped into the atmosphere also raised concerns about the potential adverse greenhouse gas impacts of the leak.

<http://www.caloes.ca.gov/ICESite/Pages/Aliso-Canyon.aspx>

301 California Environmental Protection Agency, Air Resources Board, *Draft Short-Lived Climate Pollutant Reduction Strategy*, September 2015, <http://www.arb.ca.gov/cc/shortlived/2015draft.pdf>.

302 http://www.arb.ca.gov/research/aliso_canyon/aliso_canyon_natural_gas_leak_updates-sa_flights_thru_jan_12_2016.pdf.

303 Governor Brown Issues Order on Aliso Canyon Gas Leak, <https://www.gov.ca.gov/news.php?id=19263>.

injections into the storage facility, immediately work on alternatives to stop the leak, and provide testing results, daily briefings, and a written plan and schedule for sealing the well. The Division also established a panel of experts from national laboratories to provide independent monitoring and technical expertise. The Office of Environmental Health Hazard Assessment is reviewing air quality measurements, evaluating public health concerns from the leak, and helping to determine whether additional actions are needed. The CPUC is investigating the cause of the gas leak and the cost of the responding to and fixing the leak. The ARB is measuring the leak and estimating its total methane emissions. The Division of Occupational Safety and Health is ensuring on-site worker safety and the Energy Commission is coordinating with the CPUC to maintain energy reliability. As part of the *2016 IEPR Update*, the Energy Commission will add a review of Aliso Canyon natural gas issues as part of its continuing efforts to ensure reliability of the electricity system in southern California. (See Chapter 7, “Electricity Infrastructure in Southern California.”)

While Aliso Canyon is an example of a major leak from a single site, relatively small methane emissions originate from the intentional operations of the natural gas system (for example, venting of natural gas or pneumatic devices using natural gas), as well as from leakage throughout the natural gas supply chain from the production, gathering, processing, transportation, storage, distribution, and use of natural gas. A recent report from the CPUC, *SB 1371 Natural Gas Leakage Abatement Best Practices*,³⁰⁴ defines a leak as any release of methane from the gas system into the atmosphere, whether intentional or unintentional, whether hazardous or nonhazardous. Methane emissions from Aliso Canyon and other catastrophic events are very rare and are somewhat distinct from the more common emissions discussed below.

304 <http://www.cpuc.ca.gov/NR/rdonlyres/78171FC7-C5D9-44E5-A922-F49BF9C9D7F9/0/SEDSB1371LenoNaturalGasLeakageAbatementBestPracticesFinal.pdf>.

Estimating methane emissions from the normal operations of the natural gas system has proven challenging, with divergence in estimates of methane emissions from recent research studies. Additional research is underway at both the national and state level to reduce the uncertainty surrounding current estimates. These efforts will help provide California policy makers with accurate and comprehensive assessments of emissions from natural gas to develop effective GHG reduction approaches.

The fundamental question regarding the climate benefits of using natural gas is how much methane is escaping from the natural gas system. Researchers estimate emissions using bottom-up, top-down, and hybrid methods. The *bottom-up* method is a straightforward summing of emissions using emissions factors for the various components of the natural gas system. *Top-down* estimates use ambient measurements of methane and other compounds in the atmosphere to estimate emissions. Hybrid methods try to take advantage of both methods by reconciling the estimates from the top-down and bottom-up methods.

Methane emission estimates for California are uncertain. Recent work estimating methane emissions from California’s natural gas system suggested emissions of less than 1 percent of total throughput. Some studies indicate these may be underestimated. A comparison of various study results is complicated by the use of different methods, data, and differences in the different components of the natural gas system that are either excluded or included. This is an area of ongoing research, and the *Final AB 1257 Natural Gas Act Report* discusses various studies in greater detail.³⁰⁵

The uncertainties and gaps in estimating methane emissions include:

- » Most studies to date are not comprehensive life-cycle studies in that they typically do not capture all

305 http://docketpublic.energy.ca.gov/PublicDocuments/15-IEPR-04/TN206470_20151030T160233_STAFF.pdf.

of the components of the natural gas system, such as emissions downstream of the distribution system (for example, end use in homes) or from out-of-state natural gas production areas.

- » Problems with measurement and sample bias may occur in the various studies because sample sizes are not large enough – due to cost and practicality – to be statistically representative of the population of various components of the natural gas system being measured and extrapolated.
- » The presence of *superemitters* that emit at significantly greater rates and volumes than other similar types of emitters may be missed in sampling and, as a result, emissions may be underestimated. Several studies suggest that methane emissions are dominated by a small fraction of the emitters.
- » Bottom-up and top-down estimates from oil and gas production in other states vary widely and are complicated by the lack of accepted methods to allocate the emissions between the natural gas and petroleum sectors, since many wells produce both oil and natural gas.

Despite the uncertainty in the emission estimates, there is adequate evidence that California needs to move forward aggressively to reduce methane emissions both inside and outside the state. Ongoing research is underway to better understand emissions from the natural gas system and identify actions to immediately reduce methane emissions. In addition, natural gas utilities are already taking steps to reduce emissions. The following examples highlight some of these activities:

- » The Energy Commission is funding ongoing research to assess methane emissions and support natural gas pipeline infrastructure and safety. This includes research to survey the main sources of emissions such as production, gathering, and processing; transmission and distribution;

underground storage units; abandoned wells; liquefied natural gas fueling stations; and end-uses in homes.

- » The Energy Commission is also supporting studies on safety issues to be able to detect leaks that may endanger public health and safety. For example, several ongoing projects focus on developing and testing cost-effective leak detection and pipeline integrity monitoring sensors and tools, as well as demonstrating them in the lab, under simulated field conditions, and at a few actual field sites.
- » California natural gas utilities are already taking actions to reduce methane emissions on their distribution system; many of these actions are being driven primarily by safety concerns following the San Bruno explosion. IOUs have replaced old cast iron pipelines, which are notorious sources of emissions, and have plans to accelerate replacement of other pipes in their systems.
- » Natural gas utilities are also engaged in research and development involving the leak detection technologies and real-time notification of leaks. For example, PG&E is using a mobile platform to detect leaks in the distribution system and to immediately implement measures to eliminate these emissions. In another example, SoCalGas and SDG&E are installing smart gas meters to help with detecting leaks.
- » The ARB is developing a strategy to further reduce short-lived climate pollutants, including methane, in accordance with Senate Bill 605 (Lara, Chapter 523, Statutes of 2014). In addition, the ARB has already developed regulations for methane from municipal solid waste landfills and is developing regulations to reduce methane from oil and gas production, gathering, processing, and storage operations.
- » The ARB is also sponsoring several research efforts on methane, including a study to develop California-specific emission factors for distribution pipelines. Moreover, the

ARB continues to fund research taking measurements of greenhouse gases at towers located throughout the state.

- » The CPUC, working in partnership with the ARB, opened a rulemaking to reduce emissions from natural gas transportation and distribution pipeline leaks under Senate Bill 1371 (Leno, Chapter 525, Statutes of 2014). It requires the CPUC to establish and requires the use of best practices for leak surveys, patrols, leaks survey technology, leak prevention, and leak detection.
- » Assembly Bill 1496 (Thurmond, Chapter 604, Statutes of 2015) requires the ARB to monitor and measure methane emissions and collect information to conduct life-cycle GHG analysis of gas produced or imported into the state.
- » The Environmental Defense Fund is coordinating a comprehensive study of methane leakage with more than 100 academics, natural gas utilities, research institutions, and others. The 16 projects include studies to measure and estimate methane emissions at natural gas production sites, utility distribution systems, and other components of the natural gas system. More than ten studies have been completed and several others will be finalized in the near future. One recent synthesis paper combining multiple lines of evidence for the Barnett Shale oil and gas-producing region of Texas confirms the top-down estimates. The new synthesis study indicates that the U.S. Environmental Protection Agency's GHG inventory most likely underestimates methane emissions by 90 percent for this basin.³⁰⁶ Additional Environmental Defense Fund synthesis papers are expected in the future.
- » At the federal level, the Federal Energy Regulatory Commission has adopted a policy to allow pipeline owners

306 Zavala-Araiza, D., D.R. Lyon, R.A. Alvarez, et al, 2015, *Reconciling Divergent Estimates of Oil and Gas Methane Emissions*, Proceedings of the National Academy of Sciences.

to recover major capital investment costs that address pipeline safety or reduce GHG emissions. The U.S. Environmental Protection Agency has proposed regulations to reduce methane emissions from compressors, well completions and fracturing, and pneumatic devices.

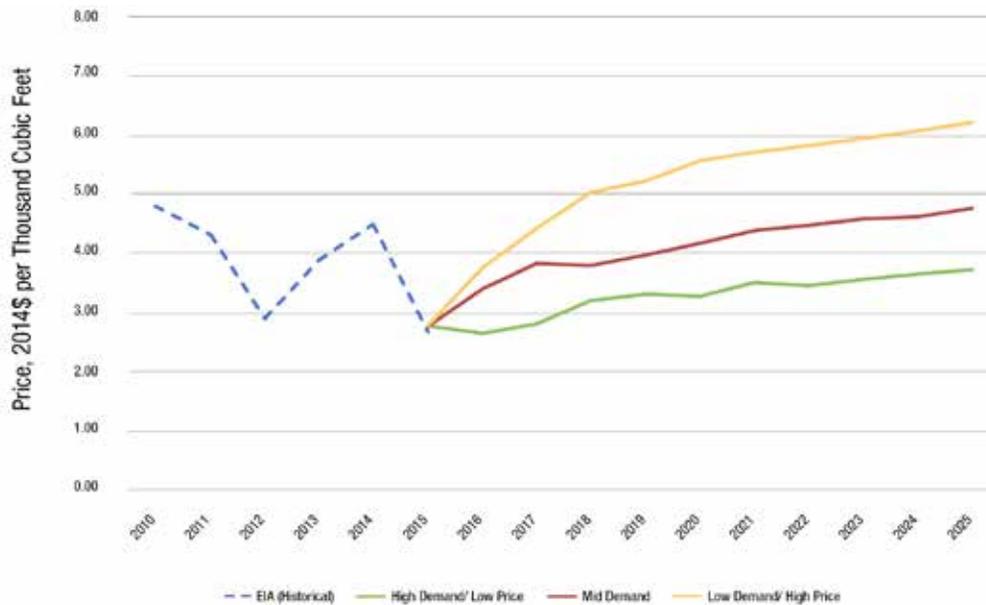
- » Several federal agencies, including the National Oceanic and Atmospheric Administration, the U.S. Department of Energy, the National Aeronautics and Space Administration, and others, are engaged in research and development primarily focused on the advancement of methane sensors and establishing better ways to identify methane emissions.

The results of the research underway, including the Environmental Defense Fund research, will be important in determining the role that natural gas should play in California climate change strategies. In addition, new research and development is ongoing or very likely to be initiated in the coming months to address the gaps and uncertainties identified above. The 2016 IEPR will provide an assessment of the available studies, including studies sponsored by the Energy Commission covering production, transmission, distribution, storage, and end-uses of natural gas.

Natural Gas Outlook

Assessments of future natural gas demand, supply, prices, and infrastructure needs are a critical part of the state's efforts to ensure reliable supplies. These assessments also have broader, cross-cutting uses. For example, the price of natural gas is a key input into the state's *Building Energy Efficiency Standards* as it is used in the evaluation of the cost-effectiveness of proposed efficiency measures. (For more information about energy efficiency, see Chapter 1.) These assessments are also a key input into the state's

Figure 48: Common Case Natural Gas Price Results (Henry Hub Prices)



Source: California Energy Commission

electricity forecast, as discussed in Chapter 5. Furthermore, the CPUC, other agencies, and some utilities use these assessments for planning and decision-making. The Energy Commission’s natural gas end-use assessments will need to evolve over time toward a similar level of granularity as in the electricity forecast to support the provisions of Senate Bill 350 (De León, Chapter 547, Statutes of 2015) that calls for doubling energy efficiency savings by 2030.

These assessments require an understanding of emerging issues and trends that could affect natural gas markets and disruptions in supply. Factors that affect natural gas supply and demand include production, population growth, pipeline capacity, the economic outlook, weather, national and global markets, environmental concerns, and the effects of energy policies. Supply and demand, in turn, affect natural gas prices.

For the *2015 Natural Gas Outlook Report*, staff developed natural gas market cases, or *common cases*,³⁰⁷

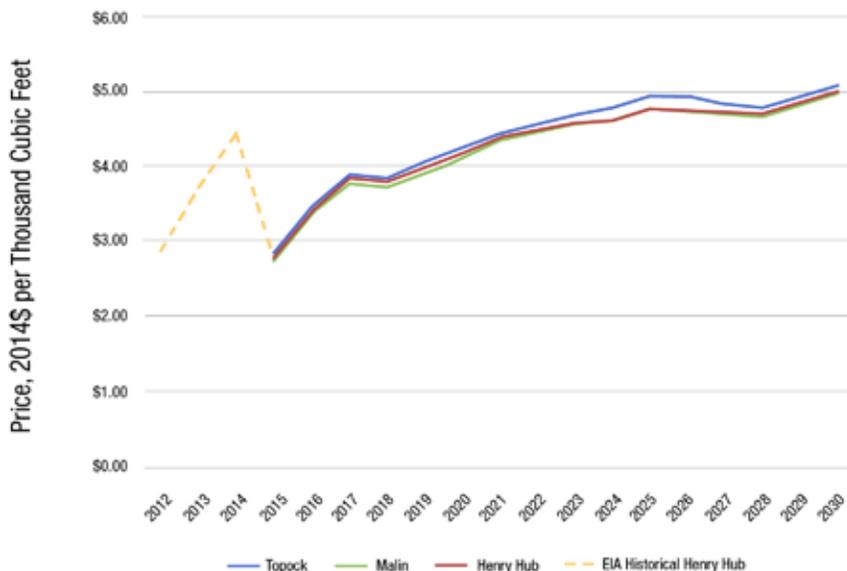
around trends that represent three possible future energy demand scenarios: a business-as-usual or mid demand case, a high demand case, and a low demand case. The mid demand case represents a future in which the economy and commercial activity remain consistent with trends experienced over the last several years. The high demand and low demand cases were created by altering assumptions in ways that would move natural gas prices higher or lower, respectively, than in the mid demand case. Varied assumptions include economic growth, technology improvements, renewable portfolio standards, coal-fired generation retirements, natural gas supply cost curves, demand, and the production cost environment.

Natural Gas Prices

Figure 48 shows projected natural gas prices from 2015 to 2030. All prices are for natural gas traded at Henry Hub, which is the North American benchmark pricing point near Erath, Louisiana, and is the trading location used to price the New York Mercantile Exchange natural gas futures contracts. These prices reflect the estimated cost of producing natural gas, processing it for injection

³⁰⁷ Staff refers to these cases as “common” because they are common to several analyses performed for the *2015 Integrated Energy Policy Report* across several Energy Commission offices.

Figure 49: Prices at Malin, Topock, and Henry Hub



Source: California Energy Commission

into the pipeline system, and transporting it to that hub. The NAMGas model used in this analysis produces annual average estimates of supply, demand, and price; therefore, they are annual averages and do not account for temperature-driven or other fluctuations that can occur in the natural gas market on a daily or seasonal basis.

To transition from short-term market forces seen in daily trading to longer-term outcomes modeled in the North American Market Gas Trade Model, October Bidweek values blended with model estimates were used. This process smoothed the transition from short-term drivers to longer-term outcomes and provided a basis in actual prices seen in the market. The Bidweek forward prices were combined with both the low demand and mid demand cases.

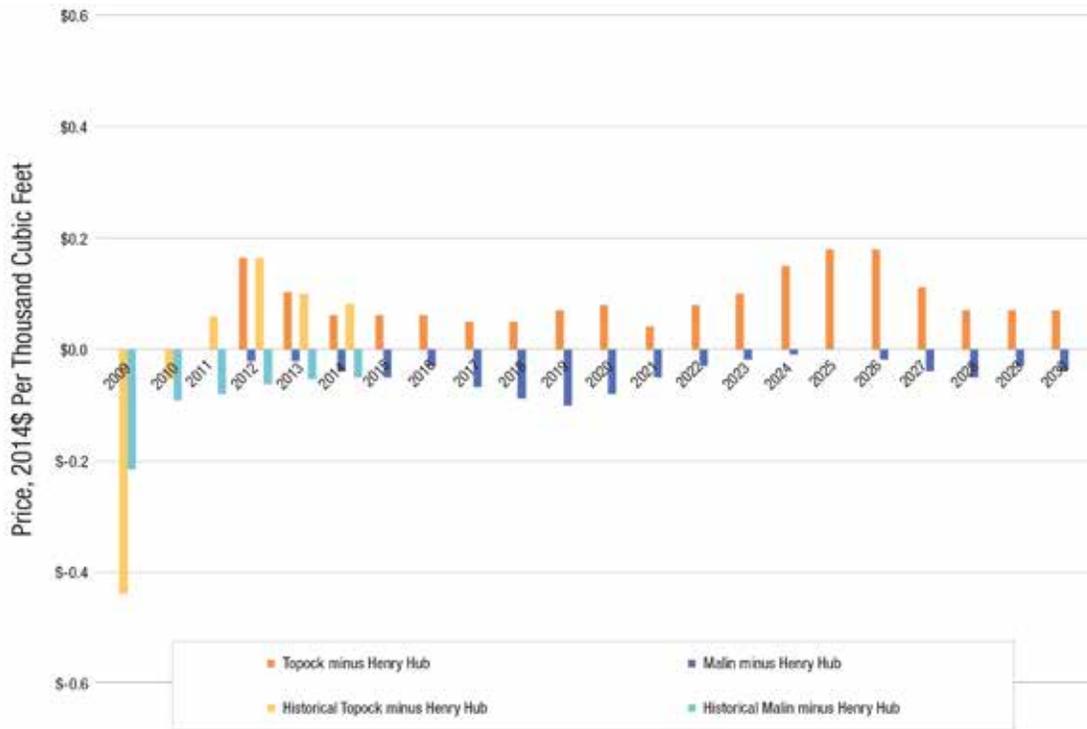
In the high demand/low price case, the model high price values were blended with the blended mid demand case values from 2015–2019 to produce a reasonable slope to approach the fundamentally higher price level for the high demand/low price case. The low demand/high price case uses NAMGas model results exclusively. Staff produced all values from 2020 forward within the NAMGas model.

Henry Hub prices exhibit annual growth rates between 2.6 percent and 6.2 percent per year from 2015 to 2030 for the three cases. By 2030, prices in the high demand/low price case reach \$4.08 (2014\$) per thousand cubic feet, and prices in the low demand/high price case reach \$6.87 (2014\$) per thousand cubic feet. Between 2015 and 2020, the gas market reflects traders’ expectations of slowly rising gas prices combined with fundamental market forces driving prices upward at an average rate of 4 percent per year. In the United States, natural gas is rising slowly, while excess production is diminishing, leading staff to expect prices to rebound from the 2015 low.

The majority of natural gas imported into California flows through two hubs, the Topock pricing hub, located at the California-Arizona border, and the Malin pricing hub, located at the California-Oregon border. The relative variations at the Topock and the Malin pricing hubs allow market participants to gauge the relative supply-demand balance in California. Figure 49 shows the three price tracks (Malin, Topock, and Henry Hub).

While the patterns of price movements at the California pricing points parallel that of Henry Hub, California’s

Figure 50: Prices Differentials (Point of Interest – Henry Hub)



Source: California Energy Commission

gas sources and Henry Hub gas are physically separate and linked only by the market influence Henry Hub has in the larger U.S. market. Figure 50 shows the price deviation of Malin and Topock relative to Henry Hub.

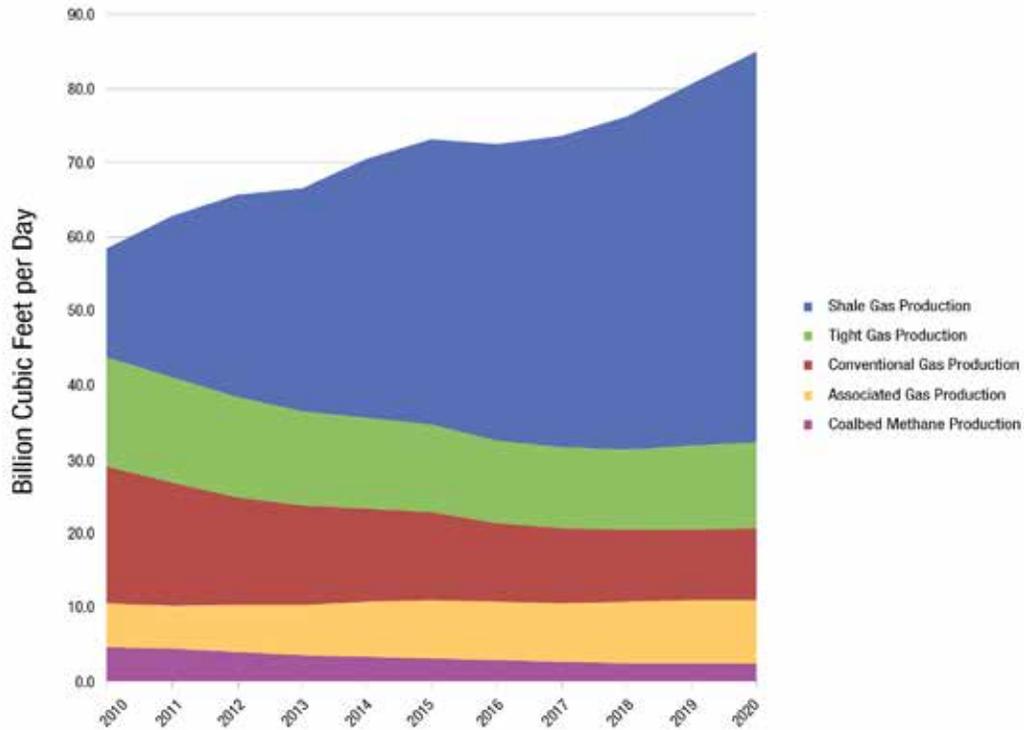
The negative price differential between Henry Hub and Malin, California’s main northern receiving hub, will persist. This difference reflects the fundamentally lower cost of gas production both in the Rocky Mountain and Canadian regions and competition between natural gas flowing south on the GTN pipeline and natural gas flowing west on the Ruby pipeline. The positive price differential between Henry Hub and Topock, California’s main southern receiving hub, persists throughout the forecast horizon. This positive price differential reflects relatively higher costs of resources produced in the San Juan basin and the added cost of transporting gas to the California border. There are no new projects likely to disrupt the current market dynamics, and, therefore, staff does not

expect this relative cost to change over the next decade. As a result, the differential remains positive throughout the outlook horizon.

Natural Gas Production

The net effect of any price variation involves a combination of the two responses: consumers can change the amount they purchase, and suppliers can alter the amount they produce. The NAMGas model uses more than 400 supply cost curves, each of which portrays a relationship between the marginal cost of the next unit of natural gas and the amount of natural gas available. As a result, each curve competes with the other curves to satisfy the determined demand. Figure 51 shows U.S. production by resource type, along with the relative share each type occupies in the supply portfolio. The prominence of shale gas production has dramatically altered, and will continue to reconfigure, the supply portfolio between 2010 and 2020.

Figure 51: Historical and Projected Natural Gas Production by Resource Type in the United States



Source: Derived from PointLogic Energy Database

Natural Gas Demand

As part of each IEPR cycle, staff forecasts end-user natural gas demand for California with a suite of end-use and econometric models structured along utility planning area boundaries. The demand forecast results include projections for fuel use in the residential, industrial, commercial, agricultural, and transportation, communications, and utilities demand sectors. The estimates produced by the end-use demand forecast models are then used as inputs to the NAMGas model for California and combined with estimates of price responsiveness for areas outside California to produce demand estimates covering all of North America in the mid demand case. The high demand/low price and low demand/high price cases used a similar process that pushes demand either above or below the mid demand case, respectively, while maintaining consistency with the other Energy Commission models.

Natural gas end-use demand in California is shown in Table 11.

The new forecasts begin at a higher point in 2015, as actual natural gas consumption in California was higher in 2015 than forecasted in the CED 2013 mid case. Staff attributes this to an expected steep increase in forecasted prices that did not materialize. The new forecasts grow at a higher rate in all three cases from 2012 – 2024. Staff attributes the higher growth rates to an increase in natural gas demand for transportation (light-duty vehicles, buses, medium- and heavy-duty trucks, with heavy-duty trucks having a large increase over the forecast period), followed by an increase in residential demand. The mid cases also include potential climate changes in the forecasts, while the high and low cases do not; this results in mid cases demand being lower than the low case in some instances. Staff projects by 2024, demand in the 2015

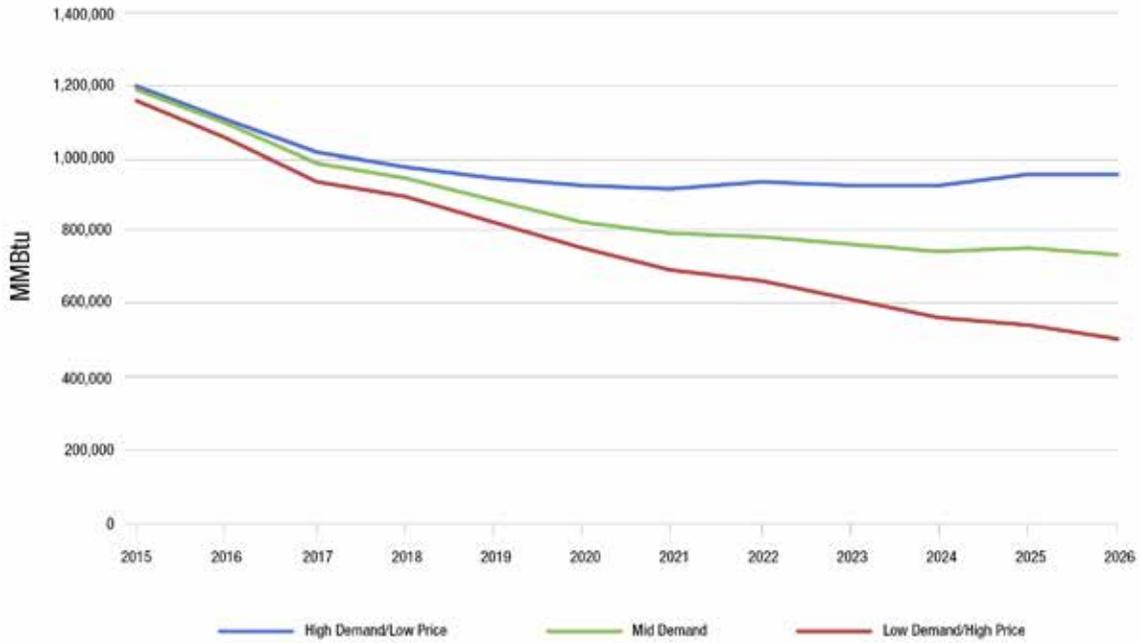
Table 11: Statewide End-Use Natural Gas Demand Forecast Comparison With AAE

	2013 CED End-Use Natural Gas Mid Demand Case	2015 CED End-Use Natural Gas High Demand Case	2015 CED End-Use Natural Gas Mid Demand Case	2015 CED End-Use Natural Gas Low Demand Case
1900	12,892	12,892	12,892	12,892
2000	13,917	13,913	13,913	13,913
2013	13,042	13,240	13,240	13,240
2015	13,208	13,164	13,103	13,086
2020	13,260	13,545	13,136	12,782
2024	13,271	13,731	13,123	12,673
Average Annual Growth Rates				
1990–2000	0.77%	0.77%	0.77%	0.77%
2000–2012	-0.50%	-0.38%	-0.38%	-0.38%
2012–2025	0.64%	-0.29%	-0.52%	-0.58%
2012–2022	0.24%	0.33%	-0.11%	-0.50%
2012–2024	0.16%	0.33%	-0.08%	-0.40%

Source: California Energy Commission staff

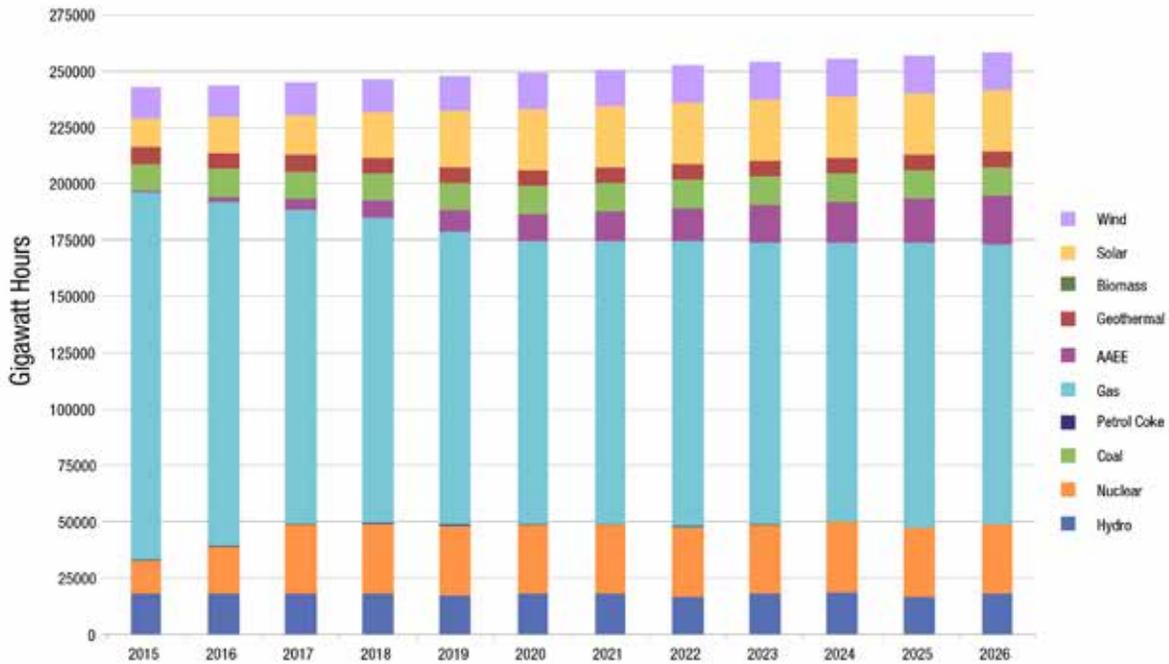
Historical date appear in the shaded cells

Figure 52: Natural Gas Burn for Power Generation in California (00s MMBtu)



Source: California Energy Commission

Figure 53: Mid Demand Case Generation Fuel Sources 2015-2026



Source: California Energy Commission

revised end-use natural gas demand mid case to be about 9.3 percent higher than the CED 2013 mid case.

Natural gas demand for power generation was estimated using electricity production cost modeling for electric generation in the Western Electricity Coordinating Council (WECC) area, which includes California. These natural gas demand projections were used as fixed values in the NAMGas model in a similar fashion to the way natural gas end-use demand was used. Natural gas demand for power generation for areas outside the WECC were estimated using the NAMGas model. Figure 52 shows the estimated gas demand for power generation inside California produced in the production cost model.

In all three cases, natural gas demand for power generation falls over the forecast period. This is driven by increases in alternative generation sources such as renewable energy that reduce the need for power from

fossil-fueled sources. Figure 53 shows the breakdown of generation sources by type for the mid cases.

Recommendations

» **Continue to monitor changes in the natural gas and electricity generation interface.** As the use of natural gas for power generation increases nationwide and the need for quick-ramping gas-fired generation to integrate intermittent renewable resources has grown, natural gas and electricity industries have become increasingly interdependent. To ensure continuity of both wholesale and retail supply as wholesale reliance on natural gas increases, there is need for better coordination of pipeline delivery of natural gas with electric system reliability needs, particularly in the San Diego region. Monitor Southern

California Gas Company proposals at the California Public Utilities Commission (CPUC) to either increase gas deliveries to Ehrenberg or build new infrastructure to connect its northern and southern pipeline systems.

» **Work with the California Air Resources Board (ARB) and the CPUC to overcome barriers to the use of biogas.** The *2014 Integrated Energy Policy Report Update* points to biogas being injected into natural gas pipelines as a way to help ensure that biogas can be safely and economically used in the state. The Energy Commission should work with the ARB and CPUC to overcome potential barriers impeding commercial biogas projects and explore the availability of potential funding or incentive programs to help bring additional low-carbon biogas projects on-line. The Energy Commission should also provide information to the ARB so that low-carbon biofuels are appropriately recognized and categorized in the annual Renewable Fuel Standard volumetric targets.

» **Use ongoing research to better understand the societal benefits of natural gas as a transportation fuel and apply to policy decisions.** Research and investigations into the impact of methane leakage on the environment are ongoing. Initial reports have shown that methane leakage may have a larger impact on the environment than originally estimated. Due to the intricacies of regional natural gas systems and the scale of possible leakage points that need to be monitored, continuing research on this topic will be necessary to clarify and refine environmental impact estimates. Information gathered from these efforts should be integrated into decisions on the best mix of technologies California should use to achieve the state's transportation sector emissions reduction goals.

» **Monitor economic impacts on the adoption rate of advanced natural gas vehicles.** California has been a leader in not only supporting the advancement of cleaner transportation options, but also in supporting the accelerated deployment of those technologies. One of the major

driving factors that determine the rate of turnover for older more polluting vehicles is the costs of transitioning to those cleaner technologies. The Energy Commission should continue to closely monitor the economic conditions surrounding the replacement of the aging gasoline and diesel fleet with advanced natural gas engines. This information will be essential to determining the cost-benefit ratio for possible investments in this sector.

» **Support the valuation of combined heat and power (CHP).** Continue to support the development of frameworks, markets, and analyses that more accurately value the costs and benefits of CHP to better align the incentives of CHP users, utilities, and state goals. Furthermore, little progress has been made toward achieving the Governor's goal of 6,500 megawatts of additional CHP capacity by 2030. It is unlikely that significant progress will be made toward this goal in the near future. The state should continue to support efforts to understand and remove barriers to the development of clean, cost-effective CHP.

» **Increase funding for natural gas research.** Consider increasing funding for natural gas research issues, specifically to support newly implemented legislation, safety concerns, mitigating leakage from an aging infrastructure, and greenhouse gas reductions.

» **Develop strategies and plans for implementing the state's energy policy goals.** California's natural gas utilities must begin developing near-term strategies and plans for meeting California's energy policy goals in relation to energy efficiency, greenhouse gas emissions reduction, and generation. The Energy Commission should continue to work with natural gas utilities to explore solutions and partner in areas of promising research such as power-to-gas, power-to-hydrogen, and biomass.

» **Utilities should develop strategies and plans for decarbonizing the natural gas system.** California's natural gas utilities must develop near-term strategies

and actionable plans for decarbonizing natural gas and achieving the Governor's goal to develop cleaner heating fuels by 2030. The Energy Commission will partner with utilities to help implement solutions for developing clean heating fuels.

CHAPTER 7

Updates From the *2013 Integrated Energy Policy Report (IEPR)* and the *2014 IEPR Update*



This chapter provides updates on three topics discussed in the *2013 Integrated Energy Policy Report (IEPR)* and the *2014 IEPR Update*: progress in implementing *2013 IEPR* recommendations for San Onofre Nuclear Generating Station (San Onofre) and Diablo Canyon Nuclear Power Plant, electricity infrastructure in Southern California, and changing trends in California's sources of crude oil.

California's Nuclear Power Plants

In the *2013 IEPR*, the Energy Commission made various recommendations related to the safety and security of the decommissioning of San Onofre and to the continued operation of the Diablo Canyon Nuclear Power Plant (Diablo Canyon). The decommissioning for San Onofre is underway. At the same time, the Nuclear Regulatory Commission (NRC) recently launched a new rulemaking proceeding to identify potential improvements to its decommissioning regulations. The Energy Commission will be actively engaged in that rulemaking as it moves forward. Diablo Canyon continues to generate power under the current licenses, which are set to expire in

2024 and 2025. Pacific Gas and Electric (PG&E) is working to address several regulatory and policy issues at both the state and federal levels in preparation for a possible relicensing of the plant in the near future. At the state level, the State Water Resources Control Board (SWRCB) and the California State Lands Commission will be making critical decisions regarding Diablo Canyon's use of once-through cooling and its land leases, respectively. Spent fuel storage remains a high priority for California in light of federal inaction to approve a permanent nuclear waste depository. New efforts by the U.S. Department of Energy (U.S. DOE) to craft an interim consolidated nuclear storage policy will be monitored closely by the Energy Commission. This section provides an update on decommissioning activities at San Onofre, the current status of relicensing and related activities at Diablo Canyon, and the future of spent fuel storage in California.

Decommissioning San Onofre Nuclear Generating Station

On June 7, 2013, Southern California Edison (SCE) announced it would retire San Onofre Units 2 and 3. On June 13, 2013, SCE formally notified the NRC that it had permanently ceased operation of San Onofre Units 2 and 3 in a certification of permanent cessation of

power operations, which was the first step in preparing for decommissioning. The Energy Commission received public comments on the draft *2015 IEPR* urging the repair and restart of the San Onofre plant; in light of the status of decommissioning activities underway at the plant, the Energy Commission concludes that restarting San Onofre is not a viable option.

Decommissioning is a defined NRC process that involves transferring the used fuel into safe storage, followed by the removal and disposal of radioactive components and materials. The NRC permits nuclear plant operators up to 60 years to decommission a nuclear plant; however, SCE has stated that it plans to complete the full NRC-mandated decommissioning process within 20 years. As described in more detail in the accompanying text box, the NRC recently launched a new rulemaking proceeding with the objective of identifying ways in which the NRC can improve upon the current decommissioning process and regulations. California further requires the decommissioned plant site be restored to its original condition; this requirement involves additional activities beyond what the NRC may require. These additional activities will extend beyond SCE's current 20-year plan.

Actions to Date

Activities are underway to decommission and decontaminate the San Onofre plant and continue to maintain the facility in a safe condition. SCE certified to the NRC in June and July 2013 that all fuel had been removed from the Unit 2 and 3 reactors, respectively. In September 2014 SCE submitted a Post-Shutdown Decommissioning Activities Report, Irradiated Fuel Management Plan, and Site-Specific Decommissioning Cost Estimate to the NRC, as required under federal regulations. The NRC notified SCE in August 2015 that the agency had approved the Post-Shutdown Decommissioning Activities Report and Irradiated Fuel Management Plan as submitted by SCE. SCE will continue to submit additional information related to its decommissioning plan to the NRC during 2015 and 2016.

NRC Decommissioning

On November 19, 2015, the NRC issued an Advance Notice of Proposed Rulemaking to obtain input from stakeholders on developing improved regulations for the decommissioning of nuclear power plants. (Docket ID: NRC-2015-0070*). The NRC's objective in amending its current regulations is to provide an efficient decommissioning process, reduce the need for exemptions from existing regulations, and support the principles of good regulation, including openness, clarity, and reliability. (NRC AJ59-ANPR-80FR72358). The Energy Commission plans to engage with the NRC throughout the rulemaking process. Moreover, the Energy Commission will reach out to its sister agencies such as the California Public Utilities Commission, the California Office of Emergency Services, and the California Coastal Commission; local government agencies; advisory panels such as the Diablo Canyon Independent Safety Committee, the Independent Peer Review Panel, and San Onofre Community Engagement Panel; and community groups to engage them in this rulemaking. Nuclear plant decommissioning is of critical importance to California as local communities and state agencies will be active in the decommissioning for the foreseeable future. A generic NRC Decommissioning process that fails to consider circumstances unique to California's coastal nuclear plants puts citizens' health and safety at risk; especially, when considering the ever present risk of an earthquake and how global climate change may exacerbate tsunami risks along the state's extensive coastline.

*<http://www.regulations.gov/#!docketDetail;D=NRC-2015-0070>

The decommissioning underway at San Onofre is focused upon fulfilling NRC requirements and meeting specific NRC milestones of the decommissioning. These activities include obtaining licensing changes and submittal of decommissioning documents to the NRC. After 2016, the focus will shift to transferring spent fuel from the spent fuel pools to a dry cask storage facility. At the end of the NRC-mandated decommissioning, SCE will need to submit a license termination plan to the NRC. SCE may elect to reduce the site to an “independent spent fuel storage installation only” site if spent nuclear fuel remains stored at the site.

In the long term, decommissioning activities will also include environmental restoration of the San Onofre site. The San Onofre plant lies within the boundaries of the Marine Corp’s Camp Pendleton. Under the site lease agreement between the U.S. Navy and SCE, the San Onofre site must be restored and remediated to the original condition of the land before the San Onofre plant was built. SCE and the Navy have not reached a final agreement on the terms for decommissioning the plant site.

The potential costs to decommission the San Onofre plant are the focus of a regulatory proceeding underway at the California Public Utilities Commission (CPUC), which is the agency with regulatory jurisdiction over the costs for decommissioning San Onofre.³⁰⁸ In December 2014 SCE filed an application with the CPUC seeking regulatory approval of the decommissioning cost estimate for Units 2 and 3. SCE estimated that the costs of decommissioning San Onofre will total \$4.411 billion (2014 dollars). License termination activities account for 48 percent of the total cost, while spent fuel management (for example, transferring fuel to dry storage and maintaining dry storage)

308 Application 14-12-007, Joint Application of SCE and SDG&E Company to Find the 2014 SONGS Units 2 and 3 Decommissioning Cost Estimate Reasonable and Address Other Related Decommissioning Issues.

accounts for 29 percent of the total estimated costs.³⁰⁹ Site restoration accounts for the remainder.

Parties to the proceeding have raised concerns over the accuracy and reasonableness of this cost estimate. One concern is that spent fuel will remain onsite for many years after 2030, which is the date SCE has assumed that the federal government will begin taking spent fuel from San Onofre for final nuclear waste disposal.³¹⁰ Depending on the federal government’s plans for spent nuclear fuel, SCE could face higher costs than it is anticipating. Another concern is whether the decommissioning cost estimate should include estimates for contingencies such as major maintenance or replacement of dry storage components in the event spent fuel remains onsite for a lengthy period. The Navy’s decommissioning requirements, which are not yet final, may also be more expensive than estimated by SCE. The CPUC has not yet issued a decision in this proceeding on the reasonableness of the decommissioning cost estimates and whether contingencies for long-term spent fuel storage should be included.

SCE is expected to file a revised or updated decommissioning plan and cost estimate in March 2016 when the CPUC begins the next Nuclear Decommissioning Cost Triennial Proceeding.³¹¹ In these proceedings the CPUC reviews and approves the utilities’ cost estimates for decommissioning their nuclear plants and, based on the approved cost estimates, establishes the contribution rates to the decommissioning trust fund of each plant.

Spent Fuel Storage

In the *2013 IEPR*, the Energy Commission recommended that SCE expand San Onofre’s existing independent spent

309 SCE presentation. SONGS 2 & 3 Cost Accounting Workshop, February 24, 2015, p. 9.

310 SCE also assumed that all spent fuel from San Onofre would be removed completely by 2049.

311 PG&E will also make a similar filing for Diablo Canyon and the Humboldt Bay nuclear plant. SDG&E, as a part owner of San Onofre, will make the filing jointly with SCE.

fuel storage installation and transfer spent fuel from pools into dry casks, while maintaining compliance with the NRC requirements. SCE already has a dry storage facility at San Onofre to store spent fuel from the retired Unit 1 reactor. Instead of adding the spent fuel from Units 2 and 3 to the existing, above-ground independent spent fuel storage installation, SCE plans to build a separate underground dry storage facility. SCE may in the future elect to move the Unit 1 spent fuel currently stored in the above-ground dry storage facility to the new underground facility.

In December 2014 SCE awarded a contract to Holtec International for the construction of a HI-STORM (Holtec International Storage Module) storage facility at San Onofre.³¹² The HI-STORM facility will be an underground facility for the storage of spent fuel assemblies from the decommissioned plant's Units 2 and 3. Holtec will also be responsible for the transfer of the spent fuel assemblies from the pools to the HI-STORM facility. In July 2014 Holtec International submitted an application to the NRC seeking approval of an amendment to its existing license for the HI-STORM dry storage system. The amendment provides for a seismically enhanced version of the HI-STORM system. The NRC granted the license amendment on September 8, 2015.

SCE was also asked to report to the Energy Commission on its progress until all spent fuel is transferred to dry cask storage. The Energy Commission has previously advocated that spent fuel be stored in dry casks once the spent fuel has sufficiently cooled in a pool (a period of about five years), a policy supported by the CPUC and the Union of Concerned Scientists.³¹³ Leaving spent fuel rods in pools longer than is needed to cool the rods for safe dry storage is an unnecessary safety risk, particularly in a seismic hazard area. An earthquake or other natural disaster, a malfunction, or even a terrorist attack that leads to a loss of cooling water in a spent fuel pool poses

a serious risk of the fuel rods overheating and the release of radiation into the atmosphere. As noted above, SCE has removed all fuel from the reactors of Units 2 and 3 to the spent fuel pools. SCE expects to complete the transfer of spent fuel from the pools to dry cask storage by 2019. SCE's decommissioning cost estimate of \$4.411 billion is based in part on the spent fuel remaining in the pools for only this seven-year period. It is possible that decommissioning costs would be higher if SCE is unable to meet its target of completing the transfer of spent fuel to dry storage by 2019.

In March 2014, SCE sought approval from the NRC for certain exemptions from the NRC's emergency planning requirements. More specifically, SCE sought an exemption from the requirements for maintaining formal offsite radiological emergency plans and a reduced scope for onsite emergency plans. SCE's primary justification for seeking the exemptions was that San Onofre had ceased operating and shut down, and thus the types of possible accidents had diminished. The Energy Commission expressed its concerns to the NRC that approving SCE's request would diminish the safeguards in place to protect the public's health and safety. With the approval of the exemption, SCE would be able to replace the emergency plan that was in place for an operational San Onofre plant with an emergency plan based on a "permanently defueled" plant. The Energy Commission noted in its comments to the NRC that it will be several years before all spent fuel is removed from the spent fuel pools and that the unique seismic hazards at San Onofre necessitate maintaining a high level of emergency preparedness until such time as the spent fuel has been transferred into dry storage.³¹⁴

On March 2, 2015, the NRC voted to approve SCE's request for exemptions from certain emergency planning requirements. The NRC staff recommendation explains

312 The system in use prior to the shutdown of San Onofre is a system manufactured by Areva.

313 <http://allthingsnuclear.org/dry-cask-storage-vs-spent-fuel-pools/>.

314 May 14, 2015, letter from Chair Weisenmiller to Ms. Vietti-Cook of the Nuclear Regulatory Commission concerning SCE's license amendment request, <http://pbadupws.nrc.gov/docs/ML1513/ML15135A304.pdf>.

that “the risk of an offsite radiological release is significantly lower and the types of possible accidents are significantly fewer, at a nuclear power reactor that has permanently ceased operations and removed fuel from the reactor vessel than at an operating power reactor.”³¹⁵ On this basis, the NRC has previously granted similar exemptions from [emergency planning] requirements for permanently shut down and defueled power reactor licensees.”³¹⁶ In the past, the NRC has granted similar emergency planning exemptions when the licensee was able to demonstrate that, in the unlikely event of a beyond design-basis event in which a spent fuel pool lost cooling ability, there should be a minimum of 10 hours before the spent fuel temperature would reach 900 degrees Celsius. SCE provided an analysis to the NRC that more than 17 hours would be available between the time the spent fuel “is initially uncovered (at which time adiabatic heatup is conservatively assumed to begin)” until the temperature reaches 900 degrees.³¹⁷

Chairman Stephen Burns, Commissioner Kristine Svinicki, and Commissioner William Ostendorff approved the request without reservation, while Commissioner Jeff Baran approved the staff recommendation in part and

disapproved it in part.³¹⁸ In particular, he noted that San Onofre is located in a more seismically active region and is thus more likely to experience large earthquakes. He also described a rulemaking plan from 2000, which recommended a four-tiered approach to emergency planning for decommissioning plants that is based on the cooling of spent fuel and associated diminished risks over time.

The exemption granted to SCE by the NRC is illustrative of the low priority placed by the NRC on state and local concerns with the decommissioning process. The new NRC decommissioning rulemaking (discussed above) will provide the Energy Commission and its partner agencies the opportunity to voice its concerns and shape new regulations that better encompass the concerns of local communities.

Long-Term Safety and Security Issues at San Onofre Site

One key issue that has emerged in the period since SCE announced the permanent closure of San Onofre is the safety and security of the spent nuclear fuel that will remain on the San Onofre site for an undetermined length of time. In 2014 the NRC published its final “Continued Storage” rule.³¹⁹ The rule confirms that spent fuel may be stored in dry storage facilities safely for an indefinite period. In the absence of a federal waste disposal facility, the nuclear waste stored in dry casks will remain at San Onofre. This presents potential security and safety issues not only through the mere presence of nuclear waste in a heavily populated region, but as a result of the aging of the dry casks used for storage.

Two recent developments related to long-term spent nuclear fuel offer a reason for optimism but also a reason for concern. The U.S. DOE recently invited public comments on the “design of a consent-based siting process

315 NRC responses to the Energy Commission’s May 14, 2015, letter, June 5, 2015,

http://docketpublic.energy.ca.gov/PublicDocuments/15-IEPR-12/TN206525_20151106T084138_US_Nuclear_Regulatory_Commission_Letter_to_Thomas_J_Palmisano_0.pdf

http://docketpublic.energy.ca.gov/PublicDocuments/15-IEPR-12/TN206526_20151106T084137_US_Nuclear_Regulatory_Commission_Letter_to_Thomas_J_Palmisano652.pdf

316 Satorius, Mark, Policy Issue (Notation Vote), Request by Southern California Edison for Exemptions from Certain Emergency Planning Requirements, SECY-14-0144, December 17, 2014. <http://www.nrc.gov/reading-rm/doc-collections/commission/secys/2014/2014-0066scyc.pdf>.

317 NRC Approved Exemptions, ML15082A204, June 4, 2015, see p. 12 of Enclosure 1.

318 U.S. NRC, Commission Voting Record, Decision Item SECY-14-0144, Request by Southern California Edison for Exemptions from Certain Emergency Planning Requirements, March 2, 2015. <http://pbadupws.nrc.gov/docs/ML1506/ML15062A141.pdf>.

319 CLI-14-08.

for nuclear waste storage and disposal facilities.”³²⁰ This proposal is discussed below in the section on nuclear waste storage issues. However, a recent decision by the NRC gives reason for some concern. In 2014 the NRC published its final “Continued Storage” rule.³²¹ The rule confirms that spent fuel may be stored in dry storage facilities safely for an indefinite period. The San Diego County Board of Supervisors urged the U.S. DOE to take action and develop a federal disposal facility so that spent nuclear fuel can be removed from the San Onofre site.³²²

The adoption by the NRC of the Continued Storage rule presents new challenges for California with regard to the long-term, on-site storage of spent nuclear fuel. Prior to the NRC’s approval of the Continued Storage rule, the NRC had authorized on-site spent fuel storage for a period of up to 30 years under the NRC’s Waste Confidence Rule. The NRC extended this period to 60 years in 2008 when it revised the Waste Confidence Rule. This decision prompted legal challenges in 2010 that ultimately led to a court decision in which the court ordered the Waste Confidence Decision to be vacated, making the decision legally void.

Following the court’s decision, the NRC undertook a Generic Environmental Impact Statement (GEIS) to study the environmental impacts, consequences, and safety of storing spent fuel in dry cask storage facilities at reactor sites. The NRC studied three time frames: short term (60 years), long term (160 years), and indefinite term. The NRC concluded that spent nuclear fuel could be stored safely and securely at reactor sites for any of the three terms. The states of New York, Vermont, and Connecticut – along with several environmental organizations – are now challenging the NRC’s final Continued Storage rule in the U.S. Court of Appeals, arguing that the Continued Storage rule violates the National Environmental Policy Act.

320 Federal Register, DOE Document # 2015-32346.

321 CLI-14-08.

322 Letter to Secretary Moniz, Department of Energy, from Bill Horn, Chairman of the San Diego County Board of Supervisors, dated September 22, 2015.

The Energy Commission filed an amicus curiae brief in support of the other states’ legal challenge of the Continued Storage rule.³²³ The Energy Commission presented its concerns that the GEIS by its very nature as a generic document fails to evaluate any local, regional, or site-specific characteristics and vulnerabilities in determining the long-term safety and security of storing spent nuclear fuel at reactor sites. The failure of the GEIS’ to differentiate between foreseeable seismic risks posed to sites within affected states like California, along with the remote and unlikely risks of seismic activity elsewhere, renders the GEIS flawed, incomplete, and inconsistent with NEPA. The litigation brought by the states and environmental groups is pending and until a court ruling is issued, the Continued Storage rule provides the new framework for long-term spent fuel storage at nuclear power plant sites.

With the Continued Storage rule in place, the choice of dry cask storage technology and the strategies for ensuring the safety and security of spent fuel in dry storage become even more critical. The Community Engagement Panel for San Onofre, a volunteer panel of elected officials, technical experts, and business and environmental representatives organized by SCE, convened a task force to review the technical literature on the specific technology SCE intends to use for dry cask storage and long-term strategies for dry cask storage of spent fuel. David Victor, Chairman of the Community Engagement Panel and a member of the task force, presented his own conclusions in a paper:³²⁴

1. A 20-year time horizon, which is the initial license period for NRC-approved dry cask technologies, is artificial

323 Motion for Leave to File Amicus Curiae Brief and Amicus Curiae Brief of the California State Energy Resources Conservation and Development Commission, filed in State of New York, et al. v. Nuclear Regulatory Commission in the United States Court of Appeals.

324 Mr. Victor had a fourth conclusion that SCE should select one of two vendors with a major market presence in the United States. This conclusion is now moot with SCE’s selection of Holtec International to provide its HI-STORM cask technology.

and too short. He noted that the NRC and other industry stakeholders are considering periods longer than 20 years for dry cask storage, but their efforts may be overly focused on highly technical issues, while overlooking the need for an overall strategy.

2. Aging casks will be an issue regardless of which vendor's cask technology is used. Given this reality, contingency plans to address maintenance, repairs, and even replacement should be developed.

3. SCE should strive to transfer all spent fuel from the pools to casks as soon as feasible as dry cask storage, in Mr. Victor's opinion, is the safer option.

SCE, the Community Engagement Panel, and interested stakeholders continue to debate the safety and security issues of long-term dry cask storage at San Onofre. Of particular concern for some stakeholders are the differing time horizons for 1) the likely very long period of time in which spent fuel will remain at the San Onofre site, 2) the initial NRC license period for the HI-STORM system vis-à-vis the NRC's own Continued Storage rule, and 3) Holtec's warranty to SCE of only 10 years for the HI-STORM system. How and to what extent the stored spent fuel will be monitored for radiation leaks or cracks in the casks is another safety concern. Security hazards revolve around the potential for sabotage of the dry cask storage area and the use of weapons or other means to breach the casks. These types of concerns have led to discussions of a concept known as "defense in depth": a multilayered strategy of monitoring and safeguarding the spent fuel such that if one monitoring or safety element fails, other layers are in place and function to ensure the safety and security of the stored spent fuel.³²⁵

There are some stakeholders who believe that SCE should use a "thick wall" dry storage technology instead

of the selected "thin wall" technology.³²⁶ With the former option, spent fuel rods are sealed inside thick-walled metal casks bolted closed with metallic seals, whereas in the latter option, spent fuel is placed inside thin-walled canisters and covered with a metal or concrete outer shell for radiation shielding. In Europe, thick-walled dry cask storage is the leading choice for storing spent fuel outside pools. Nuclear power plant owners in the United States have opted for the thin-cask technology.

Critics of the thin-walled canister technologies say that these canisters are problematic for several reasons. First, the thin-walled canisters such as the Holtec canisters SCE plans to use at San Onofre are prone to corrosion and cracking. The canisters may be particularly prone to corrosion due to the marine environment in which they will be located at San Onofre. Second, the technology to inspect the Holtec canisters for corrosion or cracking does not exist. Thus, there is no way of spotting cracks at an early stage before a radiation leak could potentially occur. Third, if the canisters do develop cracks or otherwise need to be replaced or repaired, the funds to do so have not been set aside. Aside from the costs, it is possible that the spent fuel pool at San Onofre would have already been demolished as part of the decommissioning. Without a pool, transferring spent fuel from a failing cask to a new one would be very challenging if not impossible.

There are no thick-walled canister systems licensed by the NRC for use in the United States. The process to obtain a license would likely take 18 to 30 months. But the lack of customers in the United States for this type of technology makes it unlikely that any vendor will step forward to apply for a license from the NRC.

Diablo Canyon Status Update

Diablo Canyon Units 1 and 2 are operating under their original licenses, which are set to expire in 2024 and 2025, respectively. Several factors related to the plant

³²⁵ Victor, David, *Safety of Long-Term Storage in Casks: Issues for San Onofre*, December 9, 2014, p. 3.

³²⁶ See for example, Comments of Donna Gilmore in Docket 15-IEPR-12, May 7, 2015.

in particular and the electricity market in general have come together to create a degree of uncertainty as to whether Diablo Canyon will continue to generate power in the future. This section presents an update on the status of relicensing Diablo Canyon and discusses those factors that may ultimately impact the long-term operations at Diablo Canyon.

Relicensing Update

PG&E filed an application with the NRC to renew the operating license for Diablo Canyon in 2009. The NRC-led license renewal process involves both a safety review and an environmental review. PG&E suspended relicensing activities in April 2011 to complete certain seismic studies. PG&E subsequently provided new information to the NRC in December 2014 and February 2015 in support of its license renewal application.³²⁷ In August 2015, the NRC held a public meeting to brief the public on the milestones and timelines for the restarted license review and to solicit the public's comments on environmental issues related to Diablo Canyon. In particular, the NRC reopened the environmental impact review to accept additional public comments through the end of August.³²⁸ The NRC will now develop the scope of the environmental review and then prepare a plant-specific supplement to the Generic Environmental Impact Statement.

During the April 2015 workshop at the Energy Commission on nuclear issues, PG&E indicated that it had not decided whether it will operate Diablo Canyon beyond its

California State Lands Commission Review

In 1969 and 1970 the California State Lands Commission (SLC) granted PG&E two 49-year land leases, giving PG&E the authority to build certain structures for the Diablo Canyon power plant on state-owned land near Avila Beach. These structures include the cooling water discharge channel and the plant's water intake structure. These land leases will expire in 2018 and 2019, six years before PG&E's operating licenses for Diablo Canyon expire. PG&E submitted an application requesting the termination of the two current leases and issuance of a new General Lease – Industrial Use for the continued use and maintenance of the following: water intake structures, breakwaters, cooling water discharge channel, and a number of other structures. The new lease term would coincide with the expiration of PG&E's current NRC licenses.

At a December 2015 meeting of the SLC, the Commissioners, which include Lt. Governor Newsom, considered a staff recommendation to delay a decision on PG&E's request. Lt. Governor Newsom asked that a full environmental review be completed before any approval for new land leases is given. A plan to conduct such an environmental review is expected to be presented early in 2016.

(The California State Lands Commission report can be downloaded at http://archives.slc.ca.gov/Meeting_Summaries/2015_Documents/12-18-15/Items_and_Exhibits/123.pdf)

327 Nuclear Regulatory Commission, letter to Mr. Edward Halpin re: Schedule Revision for the Review of the Diablo Canyon Power Plant, Units 1 and 2, License Renewal Application, April 28, 2015.

328 Nuclear Regulatory Commission, presentation "Diablo Canyon Power Plant, Units 1 and 2 License Renewal Environmental Scoping Meeting," <http://adamswebsearch2.nrc.gov/webSearch2/view?AccessionNumber=ML15202A098>.

current licensed period, (2024 and 2025).³²⁹ PG&E noted several factors that will influence its decision, including whether or how it must comply with the once-through cooling (OTC) policy and any feedback or developments arising from the recently completed seismic studies. (See below for more details on these subjects.)³³⁰ PG&E now also faces the possibility that the California State Lands Commission may require PG&E to complete an environmental impact review as part of its review of a renewal of certain land leases (see the sidebar on the previous page for further details). An additional consideration raised in public comments to the Energy Commission is that the operation of Diablo Canyon supports the local economy by providing high paid technical, scientific, and engineering positions.³³¹

In light of the re-start of the NRC relicensing review, PG&E may seek approval from the CPUC to recover through rates the costs of the NRC relicensing process. If PG&E seeks the CPUC's approval for cost recovery of relicensing-related costs, PG&E will need to respond to certain requests previously made by the CPUC, which are outlined below. PG&E may elect instead to use shareholder funds to pay for relicensing-related costs, in which case PG&E would not need to be responsive to the CPUC.

In May 2015 CPUC President Michael Picker sent a letter to Christopher Johns, president of PG&E, reminding

PG&E that “review and approval of PG&E’s request for ratepayer funding related to license extension of Diablo Canyon at the California Public Utilities Commission...will involve a thorough assessment of the cost-effectiveness of the license extension for Diablo Canyon considering the plant’s reliability and safety especially in light of the plant’s geographic location regarding seismic hazards and vulnerability assessments.”³³² President Picker requested a cost-effectiveness study from PG&E, as well as a report on PG&E’s progress in implementing any recommendations in the 2013 and pending *2015 IEPR* as related to nuclear issues affecting Diablo Canyon. The cost-effectiveness study is to include PG&E’s analysis or assessment of a number of the most important safety and security issues facing Diablo Canyon, including:

- » The major findings of the most recent seismic studies (discussed below).
- » A full response to the Independent Peer Review Panel’s (IPRP) comments and recommendations on the Central Coastal California Seismic Imaging Project (CCCSIP).
- » A summary of the lessons learned from Japan’s Fukushima disaster.
- » An assessment of the adequacy of access roads at Diablo Canyon and evacuation plans for the current population and plant workers.
- » A review of the adequacy of liability coverage in the event of a major accident or disaster.
- » A study of the waste disposal costs covering a license extension period.

329 April 27, 2015, Integrated Energy Policy Report workshop on Nuclear Power Plants, http://docketpublic.energy.ca.gov/PublicDocuments/15-IEPR-12/TN204516_20150506T152343_Transcript_for_the_April_27_2015_Nuclear_Joint_Lead_Commissione.pdf, p. 94.

330 April 27, 2015, Integrated Energy Policy Report Workshop Transcript, p. 95.

331 Docket number 15-IEPR-12, TN Number: 210179, Docket number 15-IEPR-12, TN Number: 210179, Francis Kowalik, Diablo Canyon, February 5, 2016, http://docketpublic.energy.ca.gov/PublicDocuments/15-IEPR-12/TN210179_20160205T110320_Francis_Kowalik_Comments_Diablo_Canyon.pdf, and TN Number 210175, Michael Shellenberger, January 29, 2016, http://docketpublic.energy.ca.gov/PublicDocuments/15-IEPR-12/TN210175_20160205T104629_2416_Email_Response_from_Chair_Weisenmiller_to_Kirk_Gothier_RE.pdf.

332 CPUC letter from President Picker to Christopher Johns, President of Pacific Gas and Electric, Diablo Canyon License Extension, May 27, 2015.

- » An assessment of the public's comments and response to SCE's decommissioning plans for San Onofre and what the implications might be for Diablo Canyon.
- » Proposals for alternative spent fuel management schemes that include the expeditious transfer of spent fuel from the pools to dry storage and a showing that sufficient space exists at Diablo Canyon for the storage of all spent fuel accumulated through a license renewal period.
- » An evaluation of the structural integrity of the spent fuel pools.
- » An analysis of replacement power options, including costs and environmental impacts.
- » A detailed study of the costs, benefits, and safety issues of cycling the Diablo Canyon units to address overgeneration problems on the grid.
- » An assessment of the costs for once-through cooling alternatives plus the assessment of the Diablo Canyon Independent Safety Committee of the safety implications of such alternatives.
- » Tsunami risk and pressure vessel embrittlement studies.
- » The status of INPO downgrades, if any, and the reason for any downgrades.
- » PG&E's responses to the Diablo Canyon Independent Safety Committee's (DCISC's) 21st and 23rd annual reports.
- » A status update on the litigation between PG&E and the NRC Resident Inspector regarding the seismic design requirements of the Diablo Canyon operating license.
- » PG&E's summary of responses to or actions taken under the Energy Commission's recommendations in past and current *IEPRs*.

The CPUC recently denied a petition filed by Friends of the Earth to broadly examine the regulatory treatment of Diablo Canyon.³³³ The CPUC's decision noted that future conditions in the state's electric market, as well as the outcome of the OTC policy review for Diablo Canyon and the seismic hazard reviews, may ultimately warrant a CPUC proceeding that both considers the ratemaking treatment for Diablo Canyon and the need for any contingency planning, such as for power procurement policies. Similarly, the Energy Commission received public comments on the draft of this report urging the state energy agencies to undertake contingency planning for an unplanned future shut-down of Diablo Canyon. The California Independent System Operator has said that the closure of Diablo Canyon does not present a reliability challenge for the grid. Thus, the Energy Commission finds that such contingency planning is not warranted at this time.

Seismic and Tsunami Studies

Of particular focus to the Energy Commission on nuclear matters is implementation of Assembly Bill 1632 (Blakeslee, Chapter 722, Statutes of 2006) and the *AB 1632 Report* recommendations, as well as the results of research from the seismic hazard reevaluations associated with implementation of the Japan Lessons-Learned Near-Term Task Force Recommendations. The NRC mandated this latter area of analysis. PG&E completed two analyses of the seismic hazards at Diablo Canyon following the NRC directive and the AB 1632 recommendations.

333 CPUC, *Decision Denying a Petition to Open a Rulemaking to Examine the Rate Regulation of Diablo Canyon, a Nuclear-Powered Generation Station*, April 9, 2005, Decision 15-04-019, <http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M150/K866/150866513.PDF>.

In response to the *AB 1632 Report* recommendations, PG&E undertook the CCCSIP³³⁴ and published a final report in September 2014. The CCCSIP used advanced three-dimensional seismic-reflection mapping to gain greater understanding of the seismic risks posed by the fault zones surrounding Diablo Canyon. PG&E conducted both onshore and some offshore surveys to collect new geologic and geophysical data. The final technical studies comprising the CCCSIP present PG&E's updated results of the ground-motion values that could result from an earthquake on the faults studied under the CCCSIP. While PG&E believes that the new research confirms that Diablo Canyon is designed to withstand a major earthquake on any of the faults surrounding Diablo Canyon, outside peer reviewers and other concerned stakeholders have been highly critical of the results.³³⁵

An independent panel of peer reviewers – the IPRP – provided input and recommendations to PG&E for the scope of and study plans for the CCCSIP. The IPRP was established by the CPUC in 2010 to conduct an independent review of PG&E's seismic studies. The IPRP is composed of representatives of key state agencies and San Luis Obispo County. PG&E and the IPRP members met several times in 2012-2013 to discuss the study plans for

the CCCSIP studies and again in 2015 to review findings from the CCCSIP studies.³³⁶

The IPRP provided a critique of the CCCSIP study in three separate reports (IPRP Reports 7, 8, and 9)³³⁷. The IPRP concluded in Report No. 7, which addressed off-shore seismic surveys, that the CCCSIP had added to the knowledge base of the Hosgri fault slip rate and, as a result, had decreased the uncertainty over the Hosgri fault slip rate and decreased the seismic hazard uncertainty associated with the Hosgri fault. The IPRP's Report No. 8 reviewed onshore seismic surveys and, in particular, the CCCSIP's efforts to develop and analyze a tectonic model of the Irish Hills in the area surrounding Diablo Canyon. The IPRP concluded that the new data contained in the tectonic model ultimately may be very valuable for understanding the seismic hazards near Diablo Canyon. But the IPRP did not support the CCCSIP's interpretations of the modeled faults in the Irish Hills, finding the interpretations to be inconsistent. The IPRP's final report, No. 9, reviewed the CCCSIP's analytical efforts and methods pertaining to onshore seismic studies in the immediate vicinity of Diablo Canyon.

The IPRP was critical of this latter area of study. First, the IPRP noted its concerns with the shear wave velocity modeling. Chris Wills from the California Geological Survey and the chair of the IPRP noted in comments at the April

334 The *CCCSIP Report* is composed of 12 technical reports and a summary that provide analyses of key regional seismic features around the Diablo Canyon plant. <http://www.pge.com/en/safety/systemworks/dcpp/seismicsafety/report.page>.

335 See, for example, the public comments of the Alliance for Nuclear Responsibility and Friends of the Earth in the docket for the 2015 *IEPR*, <https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=15-IEPR-01>.

336 The IPRP did not review a preliminary draft of the studies. Alliance for Nuclear Responsibility and PG&E are engaged in litigation before the CPUC regarding the role of the IPRP in reviewing draft study results (see Application 15-02-023). Alliance for Nuclear Responsibility contends the IPRP should have been given the opportunity to review draft findings and supports its position in part by pointing to an email by PG&E's Chief of State Agency Relations Valerie Winn that indicates PG&E at one point intended to share draft technical reports with the IPRP. PG&E contends that the IPRP's scope of responsibilities did not include reviewing draft results for the CCCSIP studies and points to the language of CPUC Decision 10-08-003 in support of its position. PG&E also believed that sharing the final, comprehensive study with the IPRP would allow for a more thorough review than if PG&E shared preliminary results of individual portions of the study. The CPUC has not yet ruled on this matter.

337 <http://www.cpuc.ca.gov/puc/energy/nuclear.htm>.

2015 workshop that he remains concerned with the velocity modeling performed for the plant site.³³⁸ The velocity modeling performed for the CCCSIP did not correspond well with previously measured velocities done in the 1970s. Not having a better understanding of why the CCCSIP velocity modeling does not correspond well with earlier data creates a degree of uncertainty with the recent modeling effort.

Second, the IPRP noted that PG&E did not address site-specific conditions and amplifications “through analysis of broadband ground-motion data and ground motions from small earthquakes” or by using analytical approaches the IPRP had recommended previously.³³⁹ PG&E used essentially the same method to account for site amplification in both the CCCSIP and Shoreline Fault reports. For the CCCSIP, PG&E updated site amplification factors to incorporate new velocity values (which, as noted above, the IPRP was critical of) and new ground motion prediction equations.³⁴⁰ The result of these actions by PG&E was the conclusion in the CCCSIP report that the site amplification at the plant site was lower than previously reported. However, the IPRP had criticized the Shoreline Fault study for using only two earthquakes (the San Simeon and Parkfield earthquakes) to characterize site amplification and had recommended that PG&E demonstrate that specific site effects were the reason for low site amplification (rather than other potential reasons). This critique of the earlier Shoreline Fault report by the IPRP was not addressed fully in the more recent *CCCSIP Report*.

Finally, the IPRP noted its concerns with the CCCSIP’s analysis of the ground motion hazards impacting the Diablo Canyon site. As a result of the CCCSIP’s various

technical studies, it is now understood that the faults surrounding the plant site are larger than previously believed and are more connected. This means that the potential magnitude of an earthquake on any one of the faults could be of a higher magnitude than previously estimated. The IPRP in its Report No. 9 presented two graphs (not reproduced here) to illustrate how different analytical approaches to measuring the ground motion spectra at the Diablo Canyon site can lead to differing results of the potential hazard represented by earthquakes on the faults near Diablo Canyon.³⁴¹ In IPRP Report No. 9, an alternative analysis comparing deterministic spectra for the CCCSIP sensitivity scenario assuming linked co-seismic ruptures indicates that the most influential factor affecting deterministic ground motion estimates is the single station sigma assumption and the site term.³⁴²

PG&E responded to the IPRP’s three reports in a letter to the IPRP in April 2015 and held meetings with the IPRP to discuss the issues raised by the IPRP.³⁴³ PG&E indicated in its response that some of the IPRP’s concerns would be addressed either through future studies conducted through the Long-Term Seismic Program or in NRC study processes such as the Senior Seismic Hazard Analysis Committee (SSHAC) process and updated probabilistic seismic hazard analysis (PSHA) report. For example, whether the Hosgri preferred slip rates (IPRP Report No. 7 topic) were justified or not was, according to PG&E, better addressed through the SSHAC process. Modeling to evaluate site amplification, a topic addressed in the IPRP’s Report No. 9, is to be included in a separate NRC-driven study for Soil-Structure Interaction. PG&E also defended its tectonic model of the Irish Hills and said it follows standard practices for data interpretation methods. The Energy Commission recognizes PG&E’s

338 Integrated Energy Policy Report workshop on Nuclear Power Plants, California Energy Commission, April 27, 2015, http://docketpublic.energy.ca.gov/PublicDocuments/15-IEPR-12/TN204516_20150506T152343_Transcript_for_the_April_27_2015_Nuclear_Joint_Lead_Commission.pdf, p. 58.

339 IPRP Report No. 9, p. 3.

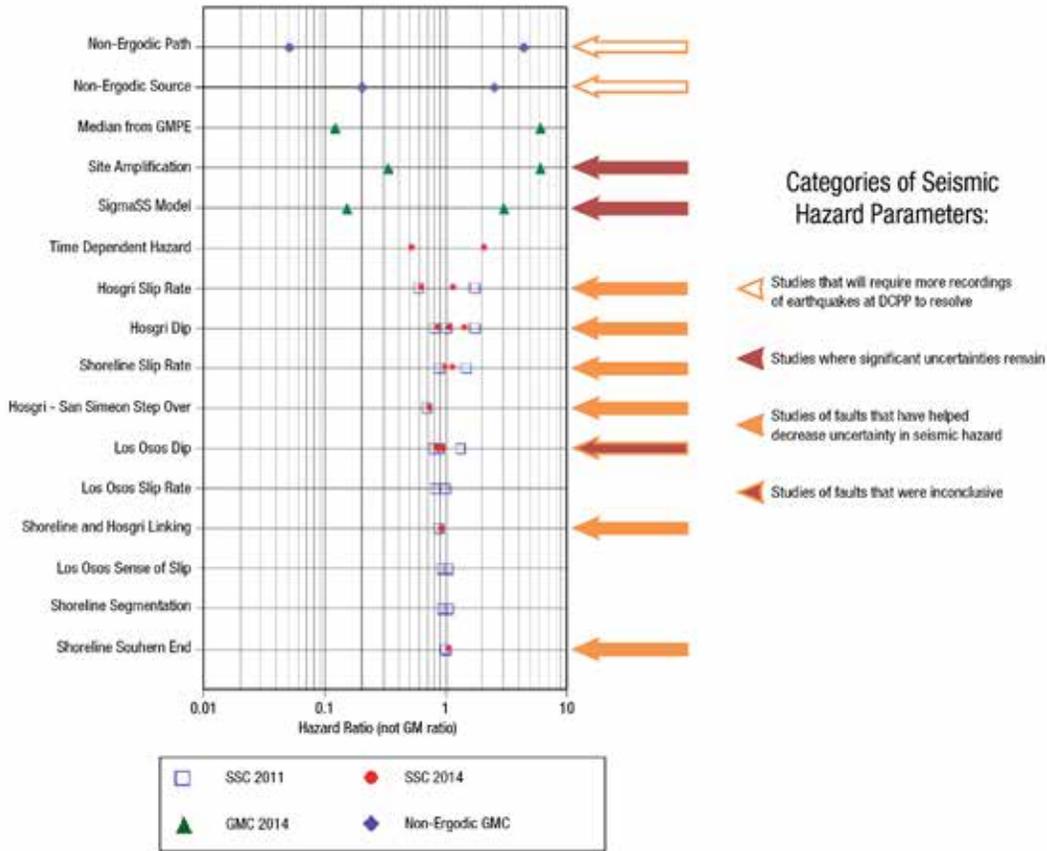
340 A multidisciplinary research team coordinated by the Pacific Earthquake Engineering Research Center developed the ground motion prediction equations.

341 To view the graphs, see IPRP Report No. 9, p. 13.

342 IPRP Report No. 9, p. 12, Figure 6.

343 Letter from Valerie Winn, PG&E to Eric Greene, IPRP, dated April 22, 2015. PG&E and the IPRP met in January and September 2015.

Figure 54: Seismic Hazard Categories at Diablo Canyon



Source: Chris Wills' presentation at April 27, 2015, IEPR workshop

efforts to continue to study the seismic hazards at Diablo Canyon but notes that the SSHAC process and PSHA study fall under the jurisdiction of the NRC and, therefore, may be beyond the oversight role granted the IPRP by the CPUC. Nevertheless, the CPUC can insist that PG&E respond to the IPRP's concerns as a condition of any future regulatory approval for cost recovery associated with the relicensing process.

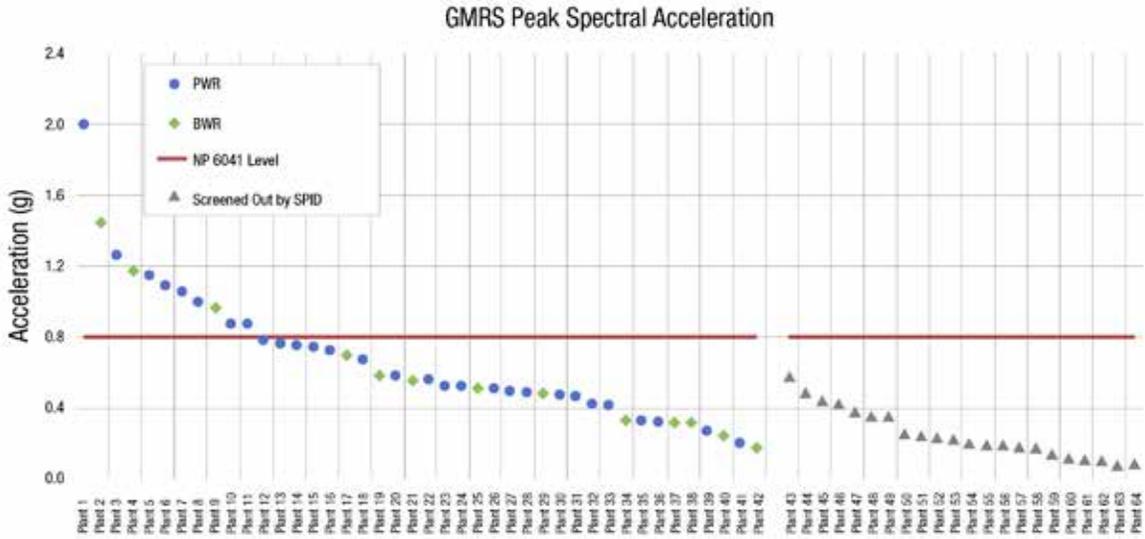
The IPRP and PG&E held a public meeting in September 2015 to further discuss the 3-D velocity model for the Diablo Canyon foundation area and how additional studies will help improve the quantification of site amplification.

The IPRP is reviewing the SSHAC reports to see if recommendations made to PG&E were considered in its determinations of seismic hazards.³⁴⁴

As the foregoing discussion makes clear, understanding the various seismic hazard sources for Diablo Canyon is critical. Indeed, a primary objective of the CCCSIP study was to reduce the uncertainty of key seismic hazard sources. Figure 54, known as a *tornado* plot, shows the different types of seismic hazard categories to understand

344 Integrated Energy Policy Report workshop on Nuclear Power Plants, California Energy Commission, April 27, 2015, http://docketpublic.energy.ca.gov/PublicDocuments/15-IEPR-12/TN204516_20150506T152343_Transcript_for_the_April_27_2015_Nuclear_Joint_Lead_Commission.pdf, pp. 61–62.

Figure 55: Ground Motion Response Spectrum Acceleration for the Nation’s Nuclear Power Plants



Source: EPRI, 2015 (via *California Current*, July 24, 2015, Volume 13, Number 29, p. 12)

for Diablo Canyon.³⁴⁵ As the figure illustrates, recent analytical efforts have reduced the degree of uncertainty for some seismic hazard sources. However, Figure 54 also demonstrates that other seismic hazard categories remain poorly defined in terms of the seismic hazard each category represents for Diablo Canyon. Further studies will be needed to improve the collective knowledge of these seismic hazards.

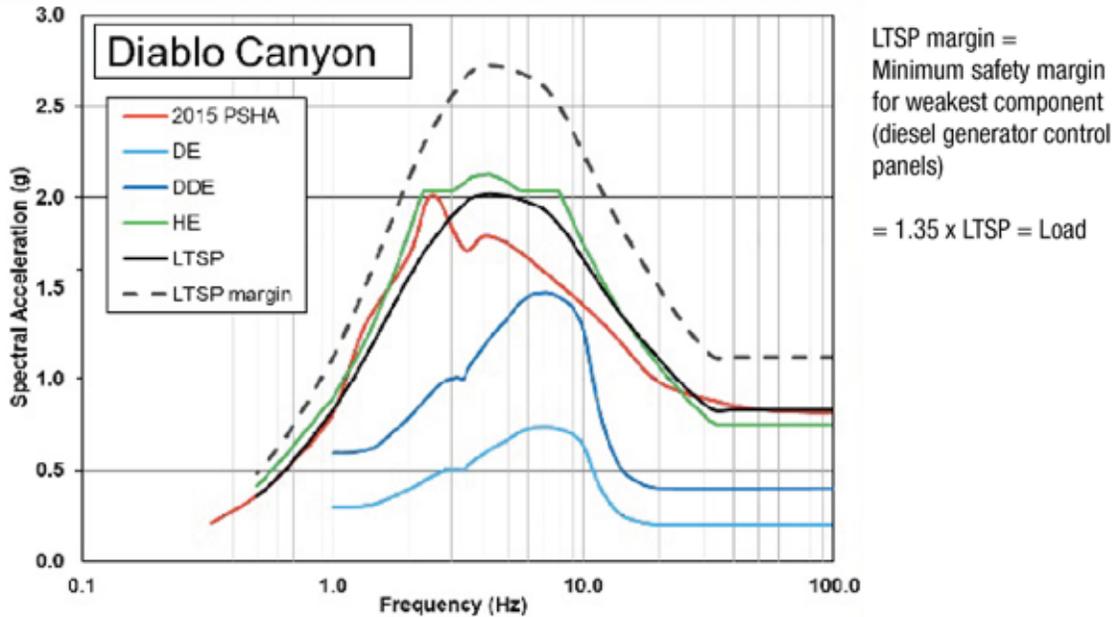
The second major seismic hazard analysis PG&E has undertaken since the *2013 IEPR* was prepared under an NRC directive. As part of its response to the 2011 Fukushima temblor in Japan, the NRC directed all U.S. commercial nuclear power plants to reassess the potential seismic and flooding hazards to their facilities. Figure

55 is a plot of the Ground Motion Response Spectrum (GMRS) acceleration of the United States’ nuclear power plants. This plot compares the spectral acceleration, a measure of structural perturbation during a temblor, for the unnamed nuclear plants. Based upon the NRC’s evaluation method, the grey triangles represent facilities that are deemed seismically sound while the plants above the 0.8 g spectral acceleration level are still undergoing a more extensive analysis. The most significant outlier, identified as Plant 1, represents PG&E’s Diablo Canyon Nuclear Power Plant, hence, the unique nature of the seismic analysis imposed upon the facility. This reassessment of the seismic hazards at Diablo Canyon included an updated PSHA using models for seismic source characterization, ground motion characterization, and site response developed under the SSHAC method. PG&E submitted the updated PSHA study to the NRC on March 12, 2015.³⁴⁶

³⁴⁵ Figure 58 is known as a *tornado diagram*. For each of the various seismic hazard categories shown on the vertical axis, the range of uncertainty regarding the seismic hazard is plotted in the graph. Seismic hazard categories with the largest range of uncertainty and/or with a large effect on seismic hazard are shown at the top of the tornado plot while categories with smaller ranges of uncertainty and/or less effect on seismic hazard are at the bottom of the tornado plot.

³⁴⁶ The study is available at www.pge.com/dcpp_itsp.

Figure 56: Comparison of Diablo Canyon Response Spectra



2015 PSHA = PG&E March 2015; DE = Design Earthquake;
 DDE = Double DE; HE = Hosgri Evaluation; LTSP = 1988 Long Term Seismic Program

Source: NRC Presentation, Adams Number ML15266A275, September 23, 2015, Slide 9

Figure 56 presents PG&E’s findings from the most recent PSHA study as compared to seismic hazard evaluations completed previously for licensing the plant and as part of the Long-Term Seismic Program. This graph shows that the earthquake potential at Diablo Canyon, (as measured by PG&E’s most recent study), is less than a calculated “safety margin” using a 1991 study and less than the Hosgri Earthquake. However, the graph also shows that results of the 2015 PSHA analysis are above the double design earthquake standard. Presumably for this reason, and after a preliminary review of PG&E’s PSHA study, the NRC directed PG&E to undertake additional earthquake risk analysis and to submit the additional analysis by June 2017.

The seismic design basis of the plant is a topic of continued discussion among PG&E, seismic experts, the NRC, and former resident inspector Dr. Michael Peck. Moreover, it was the subject of a legal challenge by Friends of the

Earth to the Atomic Safety and Licensing Board and is likely a topic that the NRC will review in light of the recently submitted PSHA study. Friends of the Earth filed a lawsuit in the U.S. Court of Appeals in 2014 challenging the seismic licensing basis of Diablo Canyon. That case was put on hold by the Court to allow the NRC time to act on a similar petition by Friends of the Earth. The NRC’s Atomic Safety and Licensing Board ruled in September 2015 on the narrow issue of whether the NRC granted PG&E greater operational authority than provided under its current licenses, finding that the NRC had not granted PG&E greater authority than provided under the current license. Friends of the Earth is pursuing its case in the U.S. Court of Appeals.

Since 2006, PG&E has been working to improve its understanding of the possible tsunami hazards that could threaten the Diablo Canyon site. The initial focus of study encompassed tsunami potential generated both by distant sources and near-shore sources (such as a landslide). The

result of this early effort was a tsunami inundation map for a section of the California coast with grid resolution of about 150 meters. PG&E is now focusing its study efforts on local source potential to create a tsunami with a higher level of grid resolution. According to a review of PG&E's analytical efforts to date by the DCISC, the "most likely phenomenon...that could produce a tsunami as high as 10 meters (about 30 feet) at the Diablo Canyon site is thought to be a local landslide offshore."³⁴⁷ PG&E reported to the DCISC that technical results of its current studies will be made available in the 2014-2015 time frame.

Safety Issues

The Energy Commission has made numerous recommendations over the years related to the safe operations of California's nuclear power plants, including Diablo Canyon. In its *2013 IEPR*, the Energy Commission recommended that PG&E provide updated evacuation time estimates, including a real-time evacuation scenario following an earthquake, and submit it to the Energy Commission as part of the IEPR reporting process. PG&E stated that the utility is working to update the Evacuation Time Estimate report and that the updated report will incorporate an evacuation time estimate following a seismic event.³⁴⁸

In 1980, the NRC adopted fire protection regulations intended to reduce the chance of disabling fires at nuclear power plants. The NRC adopted an alternative set of fire protection regulations in 2004 and gave plant owners the option of complying with the 1980 recommendations or the 2004 regulations, and PG&E expressed its intent to comply with the most recent set, which involves extensive modifications to the plant and its procedures to obtain necessary

protection against fire hazards. An NRC Event Notification Report in 2012 identified three fire protection deficiencies and implemented a corrective action program. PG&E submitted a license amendment request to the NRC in June 2013, which would transition the DCPD fire protection program to a new risk-informed, performance-based alternative. The NRC has not yet approved this license amendment request.³⁴⁹

The Energy Commission also has made recommendations related to the management of spent nuclear fuel at Diablo Canyon, as it has for San Onofre. Among these is a *2013 IEPR* recommendation to evaluate the potential long-term impacts and projected costs of spent fuel storage in pools versus dry cask storage of higher burn-up fuels in densely packed pools, and the potential degradation of fuels and package integrity during long-term wet and dry storage and transportation offsite. The Energy Commission and the CPUC requested that PG&E should submit all findings to them. The Energy Commission further recommended that the CPUC require expedited transfer of spent fuel assemblies from wet pools to dry cask storage in the decommissioning, and that the costs of this expedited removal should be included in the decommissioning funds before license renewal funding is granted. Finally, the Energy Commission recommended that spent fuel be transferred to dry casks as expeditiously as possible to reduce the density of spent fuel assemblies stored in pools. In a final decision in PG&E's 2014 General Rate Case proceeding, the CPUC directed PG&E to file a "satisfactory plan" that complies with the Energy Commission's recommendations for expedited transfer of spent fuel from wet pools to dry cask storage.³⁵⁰

347 Diablo Canyon Independent Safety Committee, *Twenty-Fourth Annual Report on the Safety of Diablo Canyon Nuclear Power Plant Operations*, Volume 2, Section 3.4.

348 August 5, 2015, PG&E Supplemental Response to the CEC on Nuclear Issues, p. 2, http://docketpublic.energy.ca.gov/PublicDocuments/15-IEPR-12/TN205641_20150805T174531_Valerie_Winn_Comments_Pacific_Gas_and_Electric_Company_Suppleme.pdf.

349 August 5, 2015, PG&E Supplemental Response to the CEC on Nuclear Issues, p. 2, http://docketpublic.energy.ca.gov/PublicDocuments/15-IEPR-12/TN205641_20150805T174531_Valerie_Winn_Comments_Pacific_Gas_and_Electric_Company_Suppleme.pdf.

350 CPUC, *Decision Authorizing Pacific Gas and Electric Company's General Rate Case Revenue Requirement for 2014-2016*, Investigation 13-03-007, Decision 14-08-032, August 14, 2014, <http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M102/K361/102361873.PDF>, p. 412.

In the wake of the Fukushima-Daiichi disaster, the NRC undertook a study to consider whether the agency should require the expedited transfer of spent fuel from pools to dry cask storage at U.S. nuclear power plants. The NRC staff concluded that expedited transfer of spent nuclear fuel from pools to dry cask was not justified given limited benefits to public safety such a requirement would yield. Importantly, however, the NRC's conclusion was based on a seismic assessment of nuclear plant sites in the eastern and central United States; the NRC did not specifically study nuclear power plants in the western United States, a more seismically active area. Moreover, the study produced insights into operating practices and mitigation capabilities that would reduce the likelihood of spent fuel assemblies overheating in the event of damage to a pool. Finally, NRC Chairman Macfarlane criticized the staff for not adequately exploring this issue and for truncating its study of the issue before exploring a broader range of options.³⁵¹

The NRC shared with operators of nuclear power plants the insights gleaned from its study in an Information Notice in November 2014.³⁵² In that notice, the NRC provided guidance on how a dispersed loading pattern for spent fuel assemblies will provide a "more favorable response" in the event of a loss of cooling water. A standard loading pattern at many plants is 1 x 4 (although there is no direct NRC requirement to do so).³⁵³ A dispersed pattern for spent fuel assemblies would be 1 x 8. The NRC found that a 1 x 8 pattern provides superior heat removal capabilities compared with a 1 x 4 pattern.

351 Chairman Macfarlane's Comments on COMSECY-13-0030, April 8, 2014.

352 NRC Information Notice 2014-14, ADAMS Accession No. ML 14218A493, November 14, 2014.

353 In a 1 x 4 loading pattern, one hot fuel assembly is surrounded by four older fuel assemblies at each face. In a 1 x 8 loading pattern, the hottest fuel assembly is surrounded by eight cooler assemblies at each face and each corner.

PG&E reported in its 2017 General Rate Case application that it must keep 772 cold fuel assemblies in the spent fuel pool to accommodate a 193 element core (for example, a 1 x 4 configuration).³⁵⁴ This 1 x 4 configuration is the lower limit constraint that is in compliance with NRC's regulations for spent fuel stored in pools. In the aforementioned study by the NRC of spent fuel pools, this type of configuration was characterized by the NRC as a high-density loading configuration. The NRC defined a low-density loading configuration for a pool such as Diablo Canyon's pools as one that stores 312 assemblies (as compared to 772) and where roughly 78-84 fuel assemblies are discharged in each cycle.³⁵⁵ According to PG&E, it plans to complete the construction of eight dry casks in 2015 and 12 casks in 2016, allowing PG&E to approach the high density 1 x 4 loading pattern. Beginning in 2018, PG&E plans to move spent fuel from the pools to dry casks at a rate that will maintain this loading pattern. The CPUC should not allow PG&E to recover from ratepayers the additional costs associated with its failure to expedite the movement of spent fuel from the pool to dry casks. In addition, PG&E should file annual reports with the CPUC and the Energy Commission on its efforts to comply with California regulators' directives in this area, and its estimate of the costs implications. These reports should contain the amount of spent fuel and the associated radiation in the spent fuel pool and an estimate of the incremental amount above the level desired by the Energy Commission and the CPUC.

Status of Compliance with California's Once-Through Cooling Policy

Another factor affecting the future of Diablo Canyon will be the method and costs associated with compliance with the SWRCB's once-through cooling (OTC) policy. The OTC policy establishes uniform, technology-based standards

354 PG&E General Rate Case 2017, Exhibit PG&E-5, September 1, 2015, pp. 3-45 and 3-46.

355 NRC COMSECT-13-0030, ADAMS Accession No. ML13329A-913 November 12, 2013, p. 72.

to implement federal Clean Water Act section 316(b) at coastal power plants with the goal of reducing harmful effects associated with cooling water intake structures on marine and estuarine life.³⁵⁶ The policy provisions require the owner or operator of a nuclear plant to undertake special studies to investigate alternatives to meet policy requirements. Bechtel Power Corporation completed the special study of alternatives to OTC for Diablo Canyon.³⁵⁷

Bechtel's estimates of total project costs for the solutions evaluated ranged from \$456 million for offshore modular wedge wire screening to more than \$14 billion for dry-air cooling technology.³⁵⁸ Closed-cycle cooling systems could range from more than \$8 billion to \$14 billion, with modifications taking as long as 14 years to complete. Each of five closed-cycle cooling options studied by Bechtel involves extensive modifications to the plant, each of which has the potential to affect the operability of safety-related systems both during and following construction. Friends of the Earth rejected as too high; the organization pointed to lengthy construction timelines and the proposed site location for cooling towers as contributors to inflated cost estimates.³⁵⁹

At the request of the SWRCB's Review Committee for Nuclear Fueled Power Plants, the DCISC performed a technical evaluation of safety-related issues for each of the different possible solutions. The DCISC reviewed Bechtel's safety evaluations, which were based only on the information available at that time and Bechtel's own evaluation of NRC regulations. Based upon this review, the DCISC concluded that a license amendment request would likely

be required for installation of any of the five closed-cycle cooling options in large part because each of those options would involve extensive modifications to the plant.³⁶⁰ The DCISC also found, however, that NRC approval of an alternative cooling option would likely be obtained. In addition to this broad finding, the DCISC took its safety evaluation one step further and considered the safety impacts of alternative cooling technologies on the plant's Auxiliary Saltwater System, a system also referred to as the Ultimate Heat Sink. The DCISC expressed its concern that any alternative cooling option, if selected, not adversely impact plant reliability and not impact the plant's ultimate heat sink.

The Energy Commission offered comments and recommendations as part of a subcommittee of the Review Committee for Nuclear Fueled Power Plants. This subcommittee concluded that there is no basis for an exemption from the OTC policy and that "closed-cycle cooling is a viable technology that can ensure Diablo Canyon's compliance with OTC policy." The subcommittee suggested that the only definitive way to determine the costs of retrofitting Diablo Canyon is to competitively bid the project with the appropriate risk management and performance terms.³⁶¹ In addition, the subcommittee recommended that the SWRCB require PG&E to bring Diablo Canyon into compliance with Track 1 of the OTC policy as a condition of relicensing the plant, rather than requiring compliance by a specific date.

Construction costs account for a sizeable share of total project costs in the options evaluated by Bechtel Power. The other significant cost – around \$1.2 billion–\$1.3 billion – would be for replacement power costs due to unit outages during construction of the alternative cooling

356 http://www.swrcb.ca.gov/water_issues/programs/ocean/cwa316/rcnfpp/index.shtml.

357 Bechtel Power Corporation, *Alternative Cooling Technologies or Modifications to the Existing Once-Through Cooling System for the Diablo Canyon Power Plant*, August 22, 2014. The complete study is available for download at http://www.swrcb.ca.gov/water_issues/programs/ocean/cwa316/rcnfpp/.

358 Bechtel Report, Revised Report on September 17, 2014, pp. 8–9.

359 Friends of the Earth, Comments on Bechtel Phase 2 Report, November 2013.

360 Diablo Canyon Independent Safety Committee, Letter to Mr. Jonathan Bishop of State Water Resources Control Board, September 5, 2013. Exhibit A, p. 5. http://www.swrcb.ca.gov/water_issues/programs/ocean/cwa316/rcnfpp/docs/dcisc_comments.pdf.

361 Subcommittee Comments on Bechtel's Assessment of Alternatives to Once-Through-Cooling for Diablo Canyon Power Plant, November 18, 2014. http://www.swrcb.ca.gov/water_issues/programs/ocean/cwa316/rcnfpp/docs/subbechcom_111314.pdf.

option. The closed-cycle cooling options involve outages of about 18–19 months. PG&E further estimated that the utility would incur ongoing additional costs of between \$50 million to \$86 million annually for replacement power due to derating of the units at Diablo Canyon, as well as other increased operations and maintenance costs.³⁶²

The time frame for elimination of OTC for Diablo Canyon lines up with the license expiration: 2024 and 2025 for Units 1 and 2, respectively. The SWRCB has the option to amend the state’s OTC policy if the Board finds that compliance costs are out of proportion to costs previously identified or if compliance is unreasonable based on specified factors. A decision by the SWRCB is pending.

Role of the Plant in the California Independent System Operator’s System

In light of the uncertainty of relicensing, seismic determinations, and OTC policy, and given the 2024 and 2025 expiration dates for Diablo Canyon Units 1 and 2, some interested stakeholders have urged California’s energy agencies to explore contingency planning in the event that Diablo Canyon is not able to continue generating baseload power. The *AB 1632 Report* addresses potential impacts of a major disruption at Diablo Canyon.³⁶³ The study found that some generation replacement scenarios would result in violations of reliability criteria in the event of a Diablo Canyon shutdown, but that such violations could be addressed without the construction of additional transmission lines, voltage support equipment, or generation. The study further explored mitigation for scenarios where generation was replaced entirely with generation either north of Path 15 or south of Path 26.

In its 2012-2013 Transmission Planning Process, the California Independent System Operator (California ISO) also studied the grid reliability impacts of a shutdown of

Diablo Canyon. The California ISO concluded that there would be no material “mid or long term transmission system impacts” in the absence of an operational Diablo Canyon if renewable generation projects are developed according to the CPUC’s RPS Portfolio.³⁶⁴ The California ISO has stated that the electric grid would operate reliably in the event of a shutdown of Diablo Canyon.

Since the *AB 1632 Report* was published, a significant amount of new renewable resources have been added to the system. More renewable resources will be added in the future to meet the Governor’s 50 percent renewable goal that is a requirement under Senate Bill 350 (De León, Chapter 547, Statutes of 2015). But with more renewable energy coming on-line, there is a greater need for a flexible and responsive grid. The California ISO has expressed its concern that overgeneration conditions will occur with increasing frequency as a result of the greater number of renewable resources connected to the grid. (For further discussion, see Chapter 2.) At the April 2015 workshop, the issue came up as to whether Diablo Canyon has the capability to respond flexibly (for example, ramping or load following) to certain circumstances such as overgeneration (due to the greater number of renewable resources). PG&E’s Jearl Strickland noted that the utility is “evaluating what type of options [it] may have to be able to provide additional flexibility for the plant.”³⁶⁵ Mr. Strickland further clarified that the ability of the plant to ramp is “...a small percentage. It’s...in the range of no more than 10 to 18 percent to be able to come down

362 http://www.swrcb.ca.gov/water_issues/programs/ocean/cwa316/rcnfpp/docs/pgebechcom_091214.pdf.

363 <http://www.energy.ca.gov/2008publications/CEC-100-2008-005/CEC-100-2008-005-F.PDF>, p. 190.

364 Integrated Energy Policy Report workshop on Nuclear Power Plants, California Energy Commission, presentation by Jeff Billinton, April 27, 2015.

365 Integrated Energy Policy Report workshop on Nuclear Power Plants, California Energy Commission, April 27, 2015, http://docketpublic.energy.ca.gov/PublicDocuments/15-IEPR-12/TN204516_20150506T152343_Transcript_for_the_April_27_2015_Nuclear_Joint_Lead_Commission.pdf, p. 80.

at any point in time for... a day-to-day type basis.”³⁶⁶ In supplemental comments filed after the workshop, PG&E stated that Diablo Canyon is unable to provide load-following services due to safety and operations provisions that are based on 100 percent power operations.³⁶⁷ Nevertheless, as California continues to add renewable resources to the electric system, flexible generating resources will be increasingly needed. To this end, CPUC President Picker directed PG&E in his April 2015 letter to prepare a detailed study of the costs, benefits, and safety issues of cycling the Diablo Canyon units to address overgeneration problems on the grid.

Role of the Plant in Achieving the State’s Greenhouse Gas Emissions Goals

Assembly Bill 32 (Núñez, Chapter 488, Statutes of 2006) requires that California achieve a statewide goal of reducing greenhouse gas (GHG) emissions to 1990 levels by 2020. Although the requirement is not sector-specific, California’s electricity system has already achieved this level of GHG reductions, as noted in Chapter 2.

A study completed by Energy+Environmental Economics, the *Pathways Study*,³⁶⁸ shows that Diablo Canyon is not needed to meet California’s GHG goals. The study examined various pathways to reduce GHG levels in 2030 to achieve the 2050 GHG reduction goal. The study assumed in the reference case and several other scenarios that Diablo Canyon would not be relicensed and would

cease operations after 2025. The study showed that natural gas-fired generation would increase in the years after Diablo Canyon ceases to operate, and this generation would not be GHG emissions-free. However, the state will still be able to meet its climate goals by relying on other measures to reduce GHG emissions.

Still, the Energy Commission recognizes that Diablo Canyon is a low GHG source of electricity that can help meet the state’s energy requirements at a time when the focus is increasingly on reducing GHG emissions. In response to public comments in support of Diablo Canyon for its GHG benefits, and because of the multifaceted issues surrounding nuclear energy in California, the Energy Commission plans to hold a public workshop on nuclear power as part of the *2016 IEPR Update*.³⁶⁹

Nuclear Waste Storage Issues for California

The initial regulatory pact between nuclear power plant operators and the federal government called for the federal government to take the spent nuclear fuel away from the plants either for reprocessing or final disposal at a federally owned or managed site. For years the federal government researched and studied building a final waste depository at Yucca Mountain in Nevada. That effort has been mired in controversy, leaving nuclear plant operators with no clear federal plan for removing spent nuclear fuel from plant sites for final disposal in a safe and secure location. On November 20, 2015, the State of California submitted comments on NUREG-2184, the NRC staff’s draft *Supplement to the U.S. DOE’s Environmental Impact Statement for a Geologic Repository for the Disposal of Spent Nuclear Fuel and High-Level Radioactive Waste at Yucca Mountain, Nye County, Nevada*. The Energy Commission maintains that the U.S. DOE’s original environmental impact statements, which the NRC staff has augmented with the Supplement, are deficient.

366 Integrated Energy Policy Report workshop on Nuclear Power Plants, California Energy Commission, April 27, 2015, http://docketpublic.energy.ca.gov/PublicDocuments/15-IEPR-12/TN204516_20150506T152343_Transcript_for_the_April_27_2015_Nuclear_Joint_Lead_Commission.pdf, p. 84.

367 PG&E Comments: Supplemental Nuclear Response, August 5, 2015, http://docketpublic.energy.ca.gov/PublicDocuments/15-IEPR-12/TN205641_20150805T174531_Valerie_Winn_Comments_Pacific_Gas_and_Electric_Company_Suppleme.pdf, p. 1.

368 Energy+Environmental Economics (E3), 2015, *Summary of the California State Agencies’ PATHWAYS Project: Long-term Greenhouse Gas Reduction Scenarios*, https://ethree.com/public_projects/energy_principals_study.php.

369 For a listing of public comments received on the October 2015 final draft 2015 IEPR, see http://www.energy.ca.gov/2015_energypolicy/documents/#02102016.

U.S. DOE EFFORTS ON NUCLEAR WASTE STORAGE

In December 2015 the U.S. DOE invited public comments on the “design of a consent-based siting process for nuclear waste storage and disposal facilities.” (Federal Register, DOE Document # 2015-32346.) The U.S. DOE plans to implement a new type of siting process that is based on garnering local consent for a site at which a storage facility for commercial spent nuclear fuel and high level defense radioactive waste would be built. The proposed approach is modeled in part after the recommendations outlined by the Blue Ribbon Commission on America’s Nuclear Future that propose a phased, adaptive, consent-based siting process as the best approach to gain public trust and confidence. Based upon the recommendations of the Blue Ribbon Commission, the U.S. DOE established a database of nuclear waste facility siting experience gained both in the United States and abroad. (<https://curie.ornl.gov/>.) This effort was followed by a 2014 report by Sandia National Laboratories, *Progress in Siting Nuclear Waste Facilities – Fuel Cycle Research & Development*, which outlines the siting process used by various countries and focuses on three countries in particular that are furthest in the process. One of the key conclusions of the Sandia report is that a successful siting process requires a defined method for public participation.

With respect to nuclear waste storage, the Energy Commission presented two recommendations in the *2013 IEPR*: represent California’s interests in federal nuclear waste management proceedings and forums and support federal efforts to develop an integrated system for management and disposal of nuclear waste. As expressed in the *2013 IEPR*, the Energy Commission supports federal efforts to develop an integrated system for management and disposal of nuclear waste, including the establishment of a new, consent-based approach to siting future nuclear waste management facilities. The U.S. DOE’s recent invitation for public comment on a consent-based siting process brings into question the long-term status of the Yucca Mountain repository and issues related to interim storage as well as concerns over the monitoring and maintenance of aging Independent Fuel Storage Installations. The Energy Commission will continue to represent the State of California by actively engaging with federal agencies towards the establishment of an integrated waste management system.

In the absence of a repository at Yucca Mountain or some other geologic site, California now faces a prolonged period of maintaining spent nuclear fuel at San Onofre, Humboldt Bay, and other decommissioned plant sites. Chair Weisenmiller noted during the April 2015 workshop that “none of the reactors were sited with an expectation that they would be high-level waste sites, which they are now.”³⁷⁰ The San Diego Board of Supervisors similarly raised its concerns over the San Onofre site being used as a long-term nuclear waste site and took the historic step of approving an effort to advocate for the removal and relocation of all spent nuclear fuel from the San Onofre site.³⁷¹ In general, as long as high-level nuclear waste remains at the reactor sites, these sites cannot be released for other uses. This reality has led to a degree of support within the industry for some sort of consolidated interim storage. Within California, some people have suggested that California should develop its own interim high-level nuclear waste storage strategy for consolidated interim storage.³⁷²

Developing an interim strategy to deal with the state’s nuclear waste would face several significant challenges. In particular, federal jurisdiction over high-level radioactive waste, as well as existing statutory provisions in the Nuclear Waste Policy Act, would need to be addressed. The federal government would need to empower local and state legislative and regulatory bodies to address environmental impacts. In addition, an interim consolidated storage site would most certainly lead to concerns that the facility would become a de facto final repository. For this reason and others, state and local support for any site would also be critical.

370 Integrated Energy Policy Report workshop on Nuclear Power Plants, California Energy Commission, April 27, 2015, http://docketpublic.energy.ca.gov/PublicDocuments/15-IEPR-12/TN204516_20150506T152343_Transcript_for_the_April_27_2015_Nuclear_Joint_Lead_Commission.pdf, p. 9.

371 San Diego Board of Supervisors, September 15, 2015.

372 Victor, David and T. Brown, D. Stetson, Memorandum to SONGS Community Engagement Panel, April 13, 2015.

New transportation routes and plans for the safe transport of nuclear waste to a new interim consolidated storage site would need to be developed and vetted in regulatory and public forums. Moreover, the delays in dealing with the current accumulation of nuclear waste at California’s nuclear sites mean that when an interim storage facility is finally opened, the number of shipments will be markedly higher. Plans for a private interim consolidated storage facility in Utah have stalled as a result of difficulties in siting a transport route to the planned site.³⁷³ The challenges in addressing the state’s nuclear waste are not insurmountable, but they are significant.

Several efforts are underway to make a consolidated interim storage facility a reality in the not too distant future. At the federal level, the U.S. DOE has laid out a multistep plan to move toward a consolidated interim storage facility. The first step would be the development of a pilot interim storage facility, followed by the siting and licensing of a larger interim storage facility (see the sidebar on the previous page for more details). The final step would be to site and license a permanent geologic repository. U.S. DOE’s proposals were codified in proposed bipartisan legislation for the Nuclear Waste Administration Act Amendments of 2015,³⁷⁴ a bill co-sponsored by Senator Dianne Feinstein and supported by the Energy Commission.³⁷⁵ The bill’s key provisions include: an independent Nuclear Waste Administration, a consent based process for siting waste storage facilities, a defined link between interim storage and a repository,

373 Victor, David and T. Brown, D. Stetson, “Moving SONGS Spent Nuclear Fuel Away or: The Need for a California Waste Strategy,” April 14, 2015, p. 3.

374 Bipartisan Senate Coalition Introduces Comprehensive Nuclear Waste Legislation, http://www.energy.senate.gov/public/index.cfm/files/serve?File_id=6edbd163-d34a-41d4-997b-bc0d95387b53.

375 Chair Robert B. Weisenmiller, Letter to Senator Dianne Feinstein, October 23, 2015, http://docketpublic.energy.ca.gov/PublicDocuments/15-IEPR-12/TN206538_20151109T095923_Letter_to_Senator_Diane_Feinstein.pdf.

modification of the Nuclear Waste Fund, and authorization for the U.S. Secretary of Energy to review defense waste options. The bill would authorize U.S. agencies to move forward with the development of an interim storage facility, and to provide support and financial benefits to communities that agree to host such a facility.

A private entity, Waste Control Specialists, announced plans to build a consolidated depository in Andrews County, Texas, that attempts to work within the existing legal and regulatory framework for high-level nuclear waste. Waste Control Specialists' proposal calls for the federal government to take title to spent nuclear fuel at reactor sites and then assume responsibility for transport of the spent nuclear fuel to the Andrews County site. The federal government would retain title of the spent nuclear fuel while the fuel is stored at the site.

Although these efforts are a positive step toward addressing the nation's nuclear waste, substantial hurdles remain. First, it is very likely that any consolidated interim storage facility would first accept nuclear waste from already-decommissioned (or non-operational) nuclear plant sites. Second, the nuclear waste will need to be transported to the consolidated storage facility, and these transport routes and the associated emergency planning and impact assessments will also need to be performed.

Electricity Infrastructure in Southern California

Background

With the closure of San Onofre and the retirement of several fossil-powered facilities, ensuring reliability of the electricity system in southern California has been a major focus for the last several years. This issue has been included each year in the *IEPR* since 2011. End-users can suffer from reliability problems caused at the generation, transmission, or distribution elements of the electricity system, and any of these can stem from physical infrastructure or operational problems. Southern California, principally customers of San Diego Gas & Electric (SDG&E), has suffered outages that create inconvenience, discomfort, and economic harm.³⁷⁶

The retirement of fossil-powered facilities stems from a policy to better protect coastal waters. In May, 2010, the SWRCB approved a policy to phase out the use of OTC in California power plants.³⁷⁷ The policy included many grid reliability recommendations and an implementation proposal developed jointly by the Energy Commission, the CPUC, and the California ISO. The policy became

³⁷⁶ The SDG&E area suffered a major outage (1.4 million customers) on September 8, 2011, lasting about 12 hours originating from operational errors in an Arizona substation. SDG&E suffered a smaller scale outage (100,000 customers) on September 20, 2015, lasting two hours. In the 2015 outage, the California Independent System Operator ordered SDG&E to shed 150 MW of firm load to assure system integrity and to avoid a large, uncontrolled collapse of the scale of the 2011 outage. Participants in Southern California Edison's demand response programs were also called upon several times in 2015 to prevent overall system problems.

³⁷⁷ *Once-through cooling* is a form of power plant turbine condenser cooling technology that pumps water from a natural source (such as the ocean), through a steam turbine condenser, and then returns it back to the source. On May 4, 2010, the State Water Resources Control Board approved an OTC policy that required the phase out of these technologies.

regulation in October 2010, affecting 19 California power plants. Of those, 10 power plants totaling about 11,026 megawatts (MW) are in the Los Angeles and San Diego Basin. Of these, seven facilities are in the California ISO balancing authority area, and three are in the Los Angeles Department of Water & Power (LADWP) balancing area.³⁷⁸

San Onofre has turned out to be especially critical to reliability in Southern California because it predated much of the growth in the region, and the transmission system was planned under the assumption that it would always be operational. Although now retired, San Onofre was a 2,200 MW facility that had provided about 9 percent of California's electricity generation and other important reliability services to the grid. Following the initial January 2012 shutdown of San Onofre, the California ISO's summer 2012 operational reliability assessments revealed voltage collapse consequences that had not previously been studied. Mitigation actions were taken to address these concerns. Shortly following SCE's June 2013 announcement that it would retire San Onofre rather than repair the damaged steam generators, Governor Edmund G. Brown, Jr. asked the energy agencies, utilities, and air districts to draft a plan for replacing the power and energy that had been provided by San Onofre. This effort resulted in the *Preliminary Reliability Plan for LA Basin and San Diego*, prepared jointly by technical staff of energy agencies, air districts, the California Air Resources Board (ARB), and utilities. This report was presented in the *2013 IEPR*.³⁷⁹

The preliminary plan sought to identify actions state and local agencies can take to maintain reliability in the Los Angeles and San Diego region, based on the California ISO's estimates of local capacity requirements. The plan put forward a rough replacement target of 50 percent preferred

resources (energy efficiency, demand response, fuel cells, renewable distributed generation, combined heat and power, and so forth) and 50 percent conventional generation. The plan also raised the need to authorize transmission upgrades to reduce local capacity requirements. Lastly, the plan called for establishing contingency plans in the event resources fail to materialize. While the document was not finalized by the executive management of participating energy agencies at that time, an interagency team (known as the Southern California Reliability Project, or SCRP³⁸⁰) has continued to meet regularly since the fall of 2013. SCRP members reported on their progress at an August 2014 *IEPR Update* workshop in Los Angeles and most recently at an IEPR workshop on August 17, 2015, in Irvine.

Local Capacity Area Requirements

Ensuring sufficient resources in *local capacity areas* is a key component of ensuring reliability in the Southern California region. Local capacity areas are transmission-constrained areas, which are identified when the maximum combined import capacity across the set of transmission line segments between pairs of substations defining a region is less than the peak load within the region. To serve load reliably, each local capacity area must have enough generation located within the local area to meet peak load, less the maximum import capacity of the transmission lines connecting that area to the high-voltage transmission system. *Local capacity requirements* (LCR) refer to the amount of generating capacity required within the local area. Upon the 2007 implementation of a resource adequacy program by the CPUC and California ISO – with support from the Energy Commission – local capacity areas and LCRs became a more visibly important part of electricity reliability planning.³⁸¹

378 California Energy Commission, *Tracking Progress, Once-Through Cooling*, updated February 17, 2015, http://www.energy.ca.gov/renewables/tracking_progress/index.html#otc.

379 *Preliminary Reliability Plan for LA Basin and San Diego*, August 30, 2013, http://www.energy.ca.gov/2013_energypolicy/documents/2013-09-09_workshop/2013-08-30_prelim_plan.pdf.

380 SCRP member agencies are the Energy Commission, the CPUC, the California ISO, and the ARB.

381 CPUC, Opinion on Local Resource Adequacy Requirements, Rulemaking 05-12-013, D.06-06-064, June 29, 2006, http://docs.cpuc.ca.gov/PublishedDocs/WORD_PDF/FINAL_DECISION/57644.PDF.

Beginning in 2006, the California ISO began preparing annual assessments for each of 10 load pockets for one- and five-year forward time horizons. One-year-ahead studies provide the basis of local resource adequacy requirements that each load-serving entity must satisfy by obtaining net qualifying capacity to meet its peak load ratio share of total LCR requirement in the load pocket. The five-year-ahead study results also provide useful information to inform generation planning and procurement. Beginning in 2010, the California ISO began conducting 10-year-ahead LCR studies as part of its support for the Assembly Bill 1318 project.³⁸² Ten-year-ahead studies were also performed for the CPUC in its 2012 Long Term Procurement Plan (LTPP)–Track 4 proceeding and have become an important part of the California ISO’s annual transmission planning.

Given how involved and labor-intensive the power flow modeling techniques used in LCR studies can be, California ISO staff analysis is limited to a small number of specific cases with alternative sets of assumptions.

Aging Natural Gas Fleet in Southern California

Southern California relies upon a large number of old, natural gas-fired steam boiler plants that have long outlived the original design life and purpose. Much of this capacity is located along the coast line to use OTC technologies. Motivated to reduce criteria air pollutant emissions, South Coast Air Quality Management District (SCAQMD) adopted an incentive for owners to replace such steam boiler

382 Assembly Bill 1318 (Wright, Chapter 206, Statutes of 2009) requires the California Air Resources Board, in consultation with the Energy Commission, CPUC, California ISO, and the State Water Resources Control Board, to prepare a report for the Governor and Legislature that evaluates the electrical system reliability needs of the South Coast Air Basin. See <http://www.arb.ca.gov/energy/esr-sc/esr-sc.htm>.

Key Power Engineering Terms

Reactive power is a by-product of alternating current (AC) systems when voltage and current are not in phase. It is produced when the current leads voltage and consumed when the current lags voltage. Reactive power (vars) is required to maintain the voltage to deliver active power (watts) through transmission lines. Several devices (rated in MVars) can be used to control reactive power in addition to traditional generating plants.

» **Shunt capacitors** – mechanically switched or fixed capacitor banks installed at substations or near loads that control voltage by charging and discharging capacitors

» **Static VAR compensators** – combined capacitors and inductors with fast-switching time frame capability

» **Synchronous condensers** – synchronous machines are designed exclusively to provide continuously variable reactive power support

Source: Oak Ridge National Laboratory, <http://web.ornl.gov/sci/decc/RP%20Definitions/Reactive%20Power%20Overview.jpeg.pdf>

generating units with advanced gas turbine technology.³⁸³ The Energy Commission adopted a recommendation urging the CPUC to authorize replacement capacity for aging power plants in the *2003 IEPR*. After studying the issue for several years, in May 2010, the SWRCB adopted its OTC policy to phase out the use of this technology and established December 31, 2020, as the compliance date for most plants still using once-through cooling.³⁸⁴

In its 2012 and 2014 Long-Term Procurement Plan rulemakings, the CPUC examined the need for resources to replace OTC facilities and San Onofre. The CPUC authorized SCE and SDG&E to procure a combination of preferred resources and conventional gas fired generation. As a result, SDG&E proposed and the CPUC has approved development of a gas-fired peaking facility at Carlsbad to replace Encina, a 946 MW OTC facility. SCE submitted a package of preferred resource contracts and proposed power purchase agreements (PPA) for new generation in November 2014. The CPUC issued D.15-11-041 approving the majority of the proposed PPAs.

The retirement of San Onofre revealed the extent to which the entire Los Angeles Basin/San Diego region was vulnerable to low-voltage and posttransient voltage instability concerns (voltage stability problems in the period beyond the initial contingencies).³⁸⁵ Importantly, the results of technical studies shifted from localized thermal overload concerns into regionwide, low-voltage, and posttransient voltage instability issues. The California ISO strategy has been to replace reactive power that was supplied from San Onofre with nongeneration electrical components (shunt capacitors, static VAR compensators,

synchronous condensers, and so forth) that can control voltage.³⁸⁶ (See sidebar for definitions.) The California ISO approved such projects in its annual transmission planning process. Installation of these kinds of transmission elements has reduced the amount of new generating capacity that needs to be located close to load and thus increased the flexibility in locating replacement resources. Substantial local capacity is still required, however, due to the limitations of the existing transmission system.

Current Interagency Collaboration to Ensure Reliability in Southern California

Normal mechanisms are underway at the energy agencies to review and approve a mixture of preferred resources,³⁸⁷ conventional generating capacity additions, and transmission system upgrades. The CPUC is overseeing the investor-owned utilities' (IOU) implementation of D.14-03-004,³⁸⁸ directing SCE and SDG&E to target preferred resource development and new generation in desired locations. The Energy Commission is processing permits for a variety of proposed generation projects, some of which may be built if the CPUC approves a PPA.³⁸⁹ The California ISO is studying, and in some cases authorizing, transmission system upgrades that address the voltage

383 SCAQMD Rule 1304(a)(2) allows an exemption from the provision of offsets for an advanced gas turbine project by retiring existing steam boiler capacity on a megawatt-for-megawatt basis.

384 http://www.waterboards.ca.gov/water_issues/programs/ocean/cwa316/policy.shtml.

385 Addendum-2013LCTA Report, http://www.caiso.com/Documents/Addendum-Final2013LocalCapacityTechnicalStudyReportAug20_2012.pdf.

386 Control of the electrical grid using reactive power maintains the necessary balance among the phases of alternating current systems. However, reactive power devices do not generate real power or energy; thus, actual resources (either preferred or conventional) needed to supply load must be developed to replace the generating capacity and energy provided by San Onofre and the fossil OTC facilities.

387 *Preferred resources* include energy efficiency, demand response, fuel cells, renewable distributed generation, combined heat and power, and so forth.

388 CPUC, *Decision Authorizing Long-Term Procurement for Local Capacity Requirements Due To Permanent Retirement Of The San Onofre Nuclear Generations Stations*, Decision14-03-004, issued March 14, 2014, <http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M089/K008/89008104.PDF>.

389 <http://www.energy.ca.gov/sitingcases/alphabetical.html>.

instability concerns created by the retirement of San Onofre. The IOUs, and in some cases independent transmission developers, are designing, building, and operating the transmission projects authorized by the California ISO. The SCRPs agencies frequently communicate about the development of these numerous resources and are closely following the schedules put forward by project developers.

In its *2014–2015 Transmission Plan*,³⁹⁰ the California ISO restudied local capacity requirements in Southern California. In its assessment of local capacity issues for 2024, the California ISO found that the combined L.A. Basin/San Diego region would be slightly deficient if SCE and SDG&E pursued only the projects submitted to the CPUC for approval as of late 2014 and identified repurposing³⁹¹ demand response as a potential mitigation measure.³⁹²

Local Capacity Needs in Southern California

Concerned about the California ISO findings of insufficient resources in 2024, Energy Commission staff developed a local capacity annual assessment tool to supplement the California ISO’s analysis of local capacity requirements.³⁹³ In the tool, the Energy Commission staff uses the assumptions from the CPUC’s 2014 LTPP rulemaking and the California ISO’s *2014–2015 Transmission Plan* for its baseline inputs. The analysis provides year-by-year

projections of resource surpluses or deficits relative to local capacity requirements for five areas within Southern California. This tool is capable of quickly assessing the consequences of many combinations of input assumptions. In comparison, the California ISO’s analysis uses power flow studies that are highly resource-intensive, thus limiting the number of variations that can be assessed with the staffing levels and time constraints of the annual transmission planning process.

The Energy Commission staff analyses using baseline assumptions show deficits in the combined Los Angeles Basin/San Diego area, the Los Angeles Basin local capacity area, and the West Los Angeles subarea beginning in 2021 and extending through 2024. Although transmission system upgrades and demand-side savings reduce local capacity requirements from what they otherwise would have been, the expected decline of resources due to OTC retirements at the end of 2020 results in deficits by 2021. The pattern of near-term surplus and longer-term deficit is common to all three regions, but it is more pronounced for the Los Angeles Basin than for the combined Los Angeles Basin/San Diego area because the OTC plants retired in 2021 are all located in the Los Angeles Basin. The deficit is greatest as a proportion of load in the West Los Angeles subarea, because all of the OTC facilities retired are in the West Los Angeles subarea. Figure 57 shows this general pattern for the Los Angeles Basin.

There is uncertainty surrounding the assumptions used in the baseline assessment; therefore, staff conducted both a sensitivity study for the effect of each variable and a scenario study changing assumptions for multiple variables in logical groupings. Staff developed four alternative scenarios, including an *optimistic* and *pessimistic* scenario designed as “bookend” cases unlikely to be encountered. The other two scenarios involve fewer departures from baseline and are more likely to reflect the expected range of outcomes. Figure 58 plots the supply-versus-requirements surplus/deficit for the baseline and four alternative scenarios for the Los Angeles Basin area. Each of the four alternative scenarios

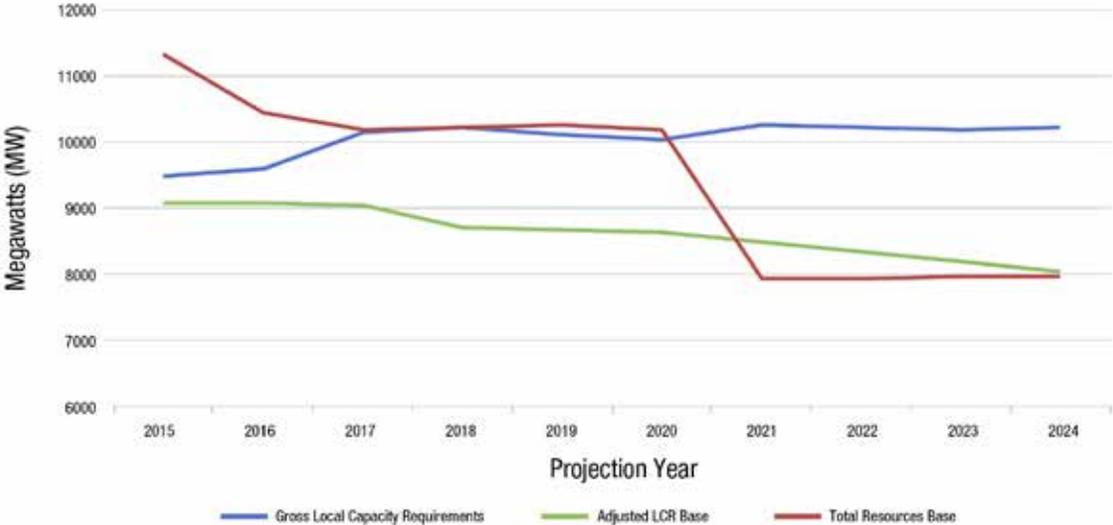
390 <http://www.caiso.com/planning/Pages/TransmissionPlanning/2014-2015TransmissionPlanningProcess.aspx>.

391 The California ISO uses the term *repurposed* to describe demand response that has sufficient operational characteristics to be used by the California ISO to meet contingency conditions (for example, demand response that is available within 20 minutes of notification that it is needed).

392 California ISO, *2014–15 Transmission Plan*, pp. 147–150.

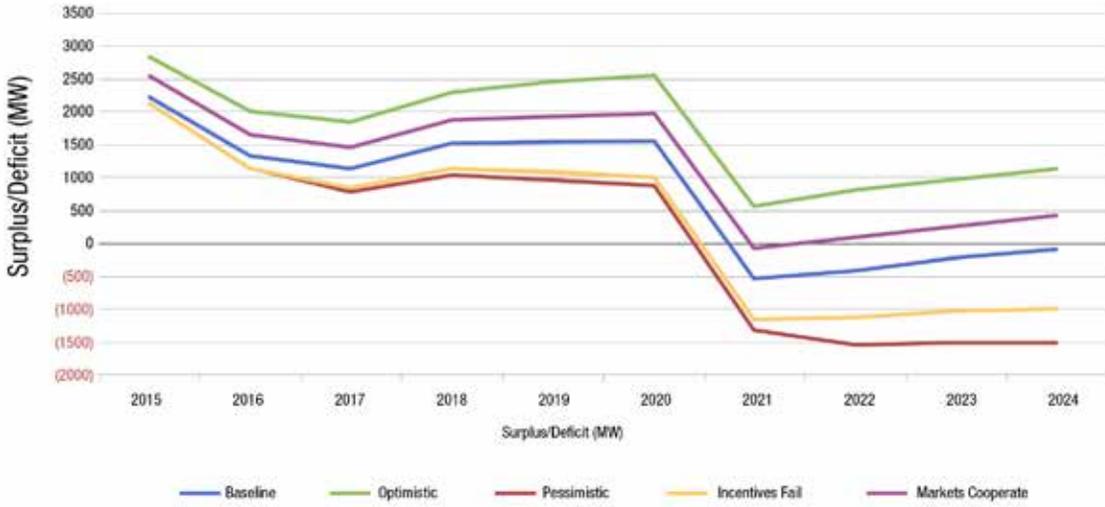
393 California Energy Commission, *Assessing Local Reliability In Southern California Using A Local Capacity Annual Assessment Tool*, CEC-200-2015-004, August 2015, <http://www.energy.ca.gov/publications/displayOneReport.php?pubNum=CEC-200-2015-004>.

Figure 57: Baseline Projections Showing Local Capacity Surpluses/Deficits for the Los Angeles Basin Local Capacity Area



Source: California Energy Commission staff, 2015

Figure 58: Baseline and Alternative Scenario Results Showing Local Capacity Surpluses/Deficits for the Los Angeles Basin Local Capacity Area



Source: California Energy Commission staff, 2015

Table 12: Conventional Generation Projects Tracked by the Joint Interagency Team

	Conventional Generation Projects	PTO/Sponsor	Target in-service dates
1	Cabrillo II Peaking Generation Renewed (113 MW)	SDG&E	12/30/13
2	Pio Pico (305 MW)	SDG&E	6/1/2017
3	Carlsbad Energy Center (500 MW)	SDG&E	11/1/2017
4	AES Alamitos (640 MW)	SCE	6/1/2020
5	AES Huntington Beach (644 MW)	SCE	5/1/2020
6	Stanton Energy Reliability Center (98 MW)	SCE	7/1/2020

Source: California Energy Commission staff, January 19, 2015

shows the same basic pattern as the baseline results, for example, substantial local capacity surplus through 2020 and a major decline in local capacity for 2021 due to OTC retirements. The two more pessimistic scenarios have deeper deficits that are not overcome through the end of the analysis period. Even the moderately optimistic scenario has a very small single-year deficit in 2021. The optimistic scenario shows surpluses for all years. Similar patterns were found for the other areas that the local capacity annual assessment Tool (LCAAT) assesses, except for the San Diego subarea, which shows surpluses throughout future years until 2024.

The Energy Commission intends to continue use of the LCAAT tool and will update its inputs to remain consistent with the generally agreed-upon planning assumptions used in multiagency planning studies. The California ISO has agreed to conduct a power flow study of year 2021 using its power flow and stability modeling tools. The schedule anticipates results in the first quarter of 2016. The Energy Commission will consider the results of this study to refine the LCAAT.

Contingency Planning if Development of Preferred Resources, Conventional Generation, and Transmission do not Advance as Planned

A new undertaking of the SCRPP is tracking preferred resource development and sharing the data among the

energy agencies. The SCRPP is attempting to track both conventional programs and additional preferred resource development that was ordered in D.14-03-004 and assumed in California ISO power flow modeling studies to establish local capacity requirements.³⁹⁴ The CPUC is providing quarterly updates to document both preferred and conventional resource development. Similarly, the California ISO is providing frequent updates about the transmission upgrade projects that are relied upon to reduce local capacity requirements. For its part, the Energy Commission is sharing information on the progress that specific generating projects are making in the permitting process. These monitoring mechanisms enable the agencies to be continuously aware of expectations for all pertinent resource development.

Conventional Generation Projects

The SCRPP team is tracking conventional generation projects noted in Table 12. In the SDG&E service territory, the team is tracking three specific projects totaling 918 MW including: Pio Pico, Carlsbad Energy Center (comprised

³⁹⁴ Unlike generation or transmission projects, the energy efficiency portion of preferred resources are studied indirectly. Evaluation, measurement and verification (EM&V) studies can lag behind the installation date of efficiency measures in an end-user's premise. Improved EM&V tools can mitigate these issues and should be aggressively pursued, given the opportunity to rely on efficiency as resource as it scales up per the requirements codified in SB 350, (as described in Chapters 2 and 6).

Table 13: Preferred Resource Projects Tracked by the Joint Interagency Team

	Authorized Preferred Resource Projects	PTO/Sponsor	Target in-service dates
1	SCE Energy Storage (263.64 MW)	SCE	2016 –2023
2	SCE Energy Efficiency (124.04 MW)	SCE	2016 –2020
3	SCE Demand Response (5 MW)	SCE	2016 –2023
4	SCE Renewable Distributed Generation (37.92 MW)	SCE	2016 –2023
5	SCE Preferred Resources Pilot (209.37 MW)	SCE	2014-2020
6	SDG&E Preferred RFO (300 MW authority Remaining)	SDG&E	TBD

Source: California Energy Commission staff, January 19, 2015

of five 100 MW peakers), and the collection of small peaking plants known as Cabrillo II. Full construction of the Pio Pico project began on February 11, 2015, and as of December 2015 the project was 34 percent complete and on schedule for its target in-service date. The CPUC’s approval of the SDG&E/NRG PPA for the Carlsbad project now has two challenges filed on December 7, 2015, with the California Court of Appeals. NRG has begun demolition of the old oil storage tanks within the Encina site to allow construction of Carlsbad, but a firm schedule of milestones to meet a 2017 in-service date cannot be provided until the appeals process is complete. The joint team is also tracking the progress of three specific SCE projects totaling 1,382 MW that the CPUC approved on November 19, 2015, in D. 15-11-041. This includes projects for Alamitos, Huntington Beach, and Stanton.

Preferred Resources Projects

The SCRPP team is tracking both LTPP “authorized” preferred resources as well as “assumed” preferred resources as shown in Table 13. The CPUC authorized SCE to procure 600 MW–1,000 MW of preferred resource through D.13-02-015 and D.14-03-004 (as well as an additional 300 MW– 500 MW that could be from any resource).The CPUC approved SCE’s application for 500.6 MW of preferred resources located in LA Basin on November 19, 2015, with the exception of 70 MW of demand response. Six demand response contracts were denied

on the basis of not meeting the definition for “preferred resources” and excessive costs. The authorized preferred resources will begin coming online as early May 1, 2016.

SCE has also submitted an application for contracts resulting from its Preferred Resources Pilot in Orange County. This effort is investigating if, and how, preferred resources will allow SCE to meet local needs at the distribution level and manage or offset projected electricity demand growth from 2013-2022 in the Johanna and Santiago substation area of Orange County. If successful, the Preferred Resources Pilot will allow SCE to meet demand growth with less conventional generation. As of October 2015, SCE had procured 85.91 MW of energy efficiency, demand response, distributed generation, and energy storage. It is unclear whether this effort will result in a net increase over and above traditional programs or merely concentrate participation in the targeted area.

Transmission Projects

The SCRPP is also tracking nine active transmission projects, including two critical transmission lines and up to 1,800 MVars of reactive support. Details of the projects are shown in Table 14. The Talega synchronous condensers were completed and placed in-service in August. The California ISO authorized the extension of the reliability must-run contract for the Huntington Beach synchronous condensers through 2016 in September 2015. The two transmission line projects (Sycamore Canyon–Penasquitos

Table 14: Transmission Projects Tracked by the Joint Interagency Team

	Transmission Projects	PTO/Sponsor	Target in-service dates
1	Talega Synchronous Condensers (2x225 MVAR)	SDG&E	In Service 8/7/2015
2	Extension of Huntington Beach Synchronous Condenser (280 MVar)	SCE	Extended for 1/1/16-12/31/16
3	Imperial Valley Phase Shifting Transformers (2x400 MVA)	SDG&E	6/1/2017
4	Sycamore Canyon–Penasquitos 230kV Line	SDG&E	6/1/2017
5	Miguel Synchronous Condensers (450/-242 MVAR)	SDG&E	6/1/2017
6	San Luis Rey Synchronous Condensers (2x225 MVAR)	SDG&E	6/30/2017
7	San Onofre Synchronous Condensers (1x225 MVAR)	SDG&E	12/31/2017
8	Santiago Synchronous Condensers (1x225 MVAR)	SCE	6/1/2018
9	Mesa Loop-in Project and South of Mesa 230kV Line Upgrades	SCE	12/31/2020

Source: California Energy Commission staff, January 19, 2015

230kV Line and Mesa Loop-in Project and South of Mesa 230kV Line Upgrades) are in the CPUC permitting process, with final permitting activities expected to be completed mid-2016 or shortly thereafter.

Contingency Planning if Development of Preferred Resources, Conventional Generation, and Transmission do not Advance as Planned

If all preferred resources, conventional generation, and transmission resource development continues as planned, reliability in Southern California would likely be assured within a small tolerance that can be met with minor changes in programs or fully using procurement authority that the IOUs have not yet exercised.³⁹⁵ Because resource margins are tight in Southern California, however, maintaining reliability requires closely coordinating the fossil OTC retirement and resource development in the right locations to satisfy local capacity requirements.

Over the past year, the SCRP team has worked to develop contingency mitigation measures that can be

triggered if resource expectations do not match requirements. Two concepts were introduced at the *2014 IEPR Update* workshop:

- » A request to the SWRCB to defer compliance dates for specific OTC facilities whose retirement is linked to a specific new power plant that would replace it.
- » Developing conventional power plant proposals as far through the permitting and procurement processes as practicable, but then holding the projects in reserve to receive final approval and begin construction only if triggered by expected reliability problems.

The details of each of these two types of mitigation measures have been refined over the past year.

OTC Compliance Date Deferral

Efforts to develop the OTC compliance date deferral measure are now essentially complete. The sequence of steps has been discussed among the SCRP team and with the SWRCB staff. Five broad steps would be followed in sequence:

³⁹⁵ SCE has not yet satisfied the minimum preferred resource requirement of D.14-03-004 and has additional capacity authorization it may pursue at its discretion.

- » Conducting analyses and preparing a draft request to Statewide Advisory Committee on Cooling Water Intake Structures (SACCWIS)³⁹⁶ ready for public comment
- » Issuing the draft request for comments, responding to comments, revising requests, and conducting a publicly noticed SACCWIS meeting
- » SWRCB review of SACCWIS report and preparation of the staff recommendation
- » Public notice, comment, comment response, and board consideration
- » Preparation of Office of Administrative Law package and review by the Office of Administrative Law

Allowing normal periods for each of the above steps to enable a full public process would take roughly one year, although this could be accelerated if unforeseen circumstances warranted it, or it might take longer if the energy agencies believed new analyses were necessary to substantiate the need for deferral.

New Gas-Fired Generation Development

Energy Commission staff, with input from technical staff of the other SCRP agencies, developed a paper outlining three options for a new generation mitigation measure.³⁹⁷ These were:

396 SACCWIS includes seven organizations: California ISO, Energy Commission, CPUC, California Coastal Commission, State Lands Commission, California Air Resources Board (ARB), and SWRCB and was established by SWRCB when the OTC policy was adopted in May 2010.

397 Jaske, Michael and Lana Wang. 2015. *Gas-Fired Generating Plant as Mitigation for Contingencies Threatening Southern California Electric Reliability*. California Energy Commission, Energy Assessments Division, CEC-200-2015-005. http://docketpublic.energy.ca.gov/PublicDocuments/15-IEPR-07/TN205700_20150812T141329_GasFired_Generating_Plant_as_Mitigation_for_Contingencies_Threa.pdf.

1. Option 1: Utility issues a request for offers to elicit project proposals from developers.
2. Option 2: Utility develops a project and takes it through the permitting process and then turns it over to developers once triggered.
3. Option 3: Rely exclusively on a pool of projects that are already permitted but do not have PPAs.

Each of the options can be thought of as having two stages. Stage 1 is to develop a specific power plant project proposal and to move it through the permitting process at the Energy Commission and the procurement approval process at the CPUC to the point that most issues are resolved, and then for the project to essentially “sit on the shelf.” If circumstances warrant triggering the project, then the permitting and procurement efforts would be completed, and the project would be constructed and become operational. The first two options essentially start from scratch to begin the development of new facilities and would take a lengthy period to complete stage 1. Option 3 takes advantage of an expected pool of projects likely to receive Energy Commission permits and could “sit on the shelf” for a few years waiting to be triggered if contingencies warrant construction.

Each option has advantages and disadvantages. Projects designed under Options 1 and 2 could be located to address specific problems that transmission reliability assessments would reveal, for example, thermal overloads on specific transmission line segments, voltage stability issues in specific regions, and so forth. Only Option 3 would provide a mitigation measure that could actually be constructed and become operational by summer of 2021. Options 1 and 2 would incur expenses from project design, site acquisition, and the permitting and procurement processes that would need to be recovered in some manner. Similar expenses under Option 3 have been made by developers going through the process to design and permit projects that have not been selected by a utility for a PPA

or approved by the CPUC.³⁹⁸ Since air quality agencies have made clear that permits will become stale and need to be updated, creating further expenses for speculative projects that one hopes will never be constructed, it is unclear how long a pool of projects will persist to make this approach viable beyond the next few years. Despite this potential limitation, the SCRCP team recommended to the leadership of the Energy Commission, CPUC, California ISO, ARB, and the California Environmental Protection Agency (this group is collectively referred to as the Energy Principals) that Options 1 and 2 be deferred. Investigatory discussions about permit longevity issues are underway with air agencies to fully understand the implications of Option 3.

Triggering the Mitigation Measures

The contingency process discussed among the SCRCP agencies seeks to assure reliability by anticipating any projected shortfall of resources needed to meet local capacity requirements. To accomplish this requires creation of an analytic process for the early detection of such shortfalls. As described above, Energy Commission staff has developed a local capacity projection tool that builds off California ISO power flow study results for snapshot years to provide a year-by-year accounting for resource surpluses or deficits compared to local capacity requirements. A protocol would be developed to determine whether any projected shortfalls revealed by this tool justify a recommendation to trigger mitigation measures. The California ISO would be asked to conduct confirmatory power flow studies to verify the conclusions of the projection tool in some instances. If the leadership from the energy agencies recommends triggering mitigation measures, then the applicable agencies overseeing a specific mitigation measure approval would implement proposed actions according to established approval processes.

³⁹⁸ If such a project is eventually constructed, the development costs would be recovered through the financial arrangements of the PPA. If never developed, then these expenses would be written off by the developer and/or investors.

Other Mitigation Options

The contingency mitigation options are designed for a failure of a gas-fired resource addition, a substantial shortfall in the collective impacts of preferred resources, or the inability to bring the transmission system upgrades on-line. Such options need to be capable of providing effective capacity with a short lead time. It is not clear whether preferred resources that build up slowly through voluntary participation by end users can readily satisfy this requirement. Very aggressive levels of energy efficiency are already being assumed through additional achievable energy efficiency projections (discussed further in Chapter 5 on the Electricity Demand Forecast); it may not be feasible or sensible to design further programs with savings that are extremely predictable and then implemented only when a contingency warrants. It seems preferable that when preferred resource savings can be identified that are cost-effective, feasible, and achievable with existing programs designs, then they should be implemented now rather than being held back as a contingency option. The sensitivity analyses carried out by Energy Commission staff with the local capacity annual assessment tool showed that two other options would be useful – demand response and storage. The California ISO's *2014-2015 Transmission Plan* analyses assumed only existing demand response program capability that was effective in relieving contingencies, such as programs located in Orange County and responsive within 30 minutes. When California ISO results showed a deficit in the combined L.A. Basin/San Diego region, they assumed the deficit could be satisfied by *repurposing* additional demand response capacity to meet effectiveness criteria. Accomplishing this task much earlier, by 2021 rather than 2024, would be harder and is ultimately dependent upon end users volunteering for these programs and sustaining their performance when the programs are actually called upon. Developing additional storage up to the levels required of SCE and SDG&E in D.13-10-040 would also be useful and would not necessarily involve any end-user participation issues. Storage does require net additional energy, could

create new total load shape issues if recharge is not carefully controlled, and is still expensive.

Assessing Progress

The SCRIP project is moving forward satisfactorily. The agency staffs continue to share information. The CPUC has not yet been able to accelerate completion of energy efficiency evaluation, measurement, and verification studies to validate planning assumptions. Fortunately, load forecasts adopted in successive *IEPR* cycles appear to be lower than originally anticipated, suggesting some reduction in local capacity requirements. The CPUC and Energy Commission have approved the Carlsbad PPA and permit, respectively, but court challenges are expected. Utilities appear to be on track in implementing the transmission system upgrades. Mitigation measures have been refined and are nearly ready. Energy Commission staff have developed the analytic tool – essential to triggering the mitigation measures – needed to assess annual requirements, but this effort needs to be refined and continually updated.

In previous *IEPR* cycles, parties have raised concerns about GHG consequences if additional gas-fired peaking capacity were triggered as a contingency option; however, California's Cap-and-Trade Program ensures that GHG emissions will not increase in California. As noted above and in Chapter 2 on Decarbonizing the Electricity Sector, California's electric generating sector has already achieved considerable GHG emission reductions.³⁹⁹ In addition, installing sufficient peakers to assure reliability can allow preferred resources with high energy benefits (and GHG reduction qualities) to be pursued even more vigorously. It is not possible to assure that demand-side resources can perform a reliability function in the same manner as dispatchable resources. Thus, assuring that reliability standards can be maintained may require installing some additional gas-fired capacity in the

399 Using ARB's 2013 GHG emission inventory, GHG emissions from the electricity sector in 2013 were about 20 percent below 1990 levels.

locations critical to satisfying local capacity area needs. To the extent preferred resources are successful at demonstrating load-reduction capabilities covering a wide range of generation and transmission outage conditions, then peakers will run even less.

Finally, close attention to local reliability issues with respect to local capacity area requirements must be expanded to address reliability of the broader South of Path 26 region.⁴⁰⁰ Much more OTC capacity is being shut down in southern California as a whole than is being replaced by either new supply-side resources or demand-side load reductions. As a result, Southern California is becoming more dependent upon renewable generation located far from load centers.

The Energy Commission has been hosting a series of workshops with commissioners and executives of key agencies since 2013 to discuss southern California reliability issues. As evident from both previous workshops and the most recent workshop held August 17, 2015, the Energy Commission and the collaborating agencies in the SCRIP are committed to assuring electrical reliability for the region. The coordinated planning discussed at the workshop promotes this assurance. Implementing actions that are part of this multiagency effort requires actions from each agency. All of the procedural opportunities to participate in the decision-making processes of the agencies continue to exist and will allow stakeholders to provide input if specific projects are proposed. The Energy Commission anticipates a similar update from the staffs of the key agencies next summer in the *2016 IEPR Update* proceeding at a workshop in Southern California.

400 Path 26 is a Western Electricity Coordinating Council designation for power flows from Northern California to Southern California. The cut plane defining this path is essentially through the lower San Joaquin Valley. All the loads of SCE and SDG&E transmission access charge areas are included, as well as a small portion of PG&E loads at the extreme southern portion of its distribution service area.

August 17, 2015, Workshop Comments

On August 17, 2015, the Energy Commission hosted a public workshop on the UC Irvine campus to review the progress since the August 2014 *IEPR* workshop to implement the preliminary reliability plan and help assure electricity reliability in Southern California. The management of the Energy Commission, the California ISO, the SCAQMD, the SWRCB, and the CPUC participated. Staff of the agencies, utilities, and air permitting districts provided updates on progress implementing the CPUC's D.14-03-004 and on transmission projects approved by the California ISO Board in the 2012–2013, 2013–2014, and 2014–2015 *Transmission Plans*. Energy Commission staff, ARB staff, and senior representatives of the South Coast Air Quality Management District and San Diego Air Pollution Control District provided an overview of contingency plan efforts, OTC retirement extensions, and some key air permitting issues.

Stakeholders provided a range of feedback, including the following:

» Cogentrix commented on behalf of several peaking plant owners that reactive power could be provided by existing peaking plants that could either modify software or install clutches that would enable them to operate as synchronous condensers without burning any fuel.⁴⁰¹ Cogentrix further commented that such beneficial changes should qualify modified peakers to be considered comparable to other higher loading order resources, such as energy efficiency.⁴⁰²

» The AES Corporation (AES) said that, given the shortfalls in local capacity demonstrated by Energy Commission staff's modeling and the California ISO

presentation, it was important to plan for the development of resources given the reliability consequences of such shortfalls.⁴⁰³

» AES also disputed the timeline in the staff report describing mitigation options for judicial review of Energy Commission permits stating that three six-month periods were more likely even if the California Supreme Court denied such a writ.⁴⁰⁴ AES supported Option 3 for multiple reasons, such as it's the lowest cost and lowest risk to ratepayers, but also it would not be susceptible to such court appeals.

» The Bay Area Municipal Transmission Group (BAMx) supported the Energy Commission staff modeling tool to assess year-by-year local capacity concerns but requested that the model be made public and that the Energy Commission address ratepayer cost concerns in an enlarged study.⁴⁰⁵

» The California Energy Storage Alliance (CESA) commended Energy Commission staff for developing its modeling tool but proposed a more expansive role for storage in resolving any identified local capacity shortfalls. CESA agreed that the CPUC should study local capacity requirements in the 2016 LTPP rulemaking.⁴⁰⁶

401 Cogentrix written comments on the August 17, 2015, IEPR commissioner workshop on Southern California Electricity Reliability, http://docketpublic.energy.ca.gov/PublicDocuments/15-IEPR-07/TN205952_20150831T154151_CalPeak_Operating_Services_LLC_Comments_Docket_No_15IEPR07_Sout.pdf, p. 2.

402 Ibid, p. 3.

403 AES, written comments on the August 17, 2015, IEPR commissioner workshop on Southern California Electricity Reliability, http://docketpublic.energy.ca.gov/PublicDocuments/15-IEPR-07/TN205949_20150831T150730_Julie_Gill_Comments_15IEPR07_Southern_California_Electricity_In.pdf, pp.2–3.

404 Ibid., p. 6.

405 BAMx written comments on the August 17, 2015, IEPR commissioner workshop on Southern California Electricity Reliability, http://docketpublic.energy.ca.gov/PublicDocuments/15-IEPR-07/TN205936_20150831T122755_Pushkar_Wagle_Comments_Bay_Area_Municipal_Transmission_Group_BA.pdf, p. 1.

406 CESA, written comments on the August 17, 2015, IEPR commissioner workshop on Southern California Electricity Reliability, http://docketpublic.energy.ca.gov/PublicDocuments/15-IEPR-07/TN205942_20150831T140956_Donald_Liddell_Comments_083115_CESA_IEPR_Comments.pdf, pp. 1–2.

- » Nevada Hydro Company requested recognition that its large pumped hydro project at Lake Elsinore and the associated transmission line would resolve Southern California local capacity problems. Three volumes of supporting reports were submitted.⁴⁰⁷
- » FuelCell Energy asserted that fuel cells should be included as a preferred resource to satisfy local capacity problems. They have minimal emissions, could be carbon-neutral if fueled by biogas, and could serve as a hydrogen source for transportation vehicles.⁴⁰⁸
- » Sierra Club California expressed alarm that the Energy Commission's development of the local capacity tool and development of contingency mitigation options were undercutting the CPUC's Long-term Procurement Plan rulemaking, which it asserted was the proper forum for these issues. If the Energy Commission persisted, then the Sierra Club noted a large number of assumptions that it proposed would better characterize the low-carbon future of California and wanted these to be used in a revised study.⁴⁰⁹

407 Nevada Hydro Company, written comments on the August 17, 2015, IEPR commissioner workshop on Southern California Electricity Reliability, http://docketpublic.energy.ca.gov/PublicDocuments/15-IEPR-07/TN205944_20150831T142615_David_Kates_Comments_Information_on_Southern_California_Reliabi.pdf, p. 1.

408 FuelCell Energy written comments on the August 17, 2015, IEPR commissioner workshop on Southern California Electricity Reliability, http://docketpublic.energy.ca.gov/PublicDocuments/15-IEPR-07/TN205953_20150831T154105_Frank_Wolak_and_Mike_Levin_Comments_FuelCell_Energy_2015_IEPR_C.pdf, pp. 1–4.

409 Sierra Club written comments on the August 17, 2015, IEPR commissioner workshop on Southern California Electricity Reliability, http://docketpublic.energy.ca.gov/PublicDocuments/15-IEPR-07/TN205959_20150831T203448_Kathryn_Phillips_Comments_Sierra_Club_Comments_on_15IEPR07.pdf, p. 103.

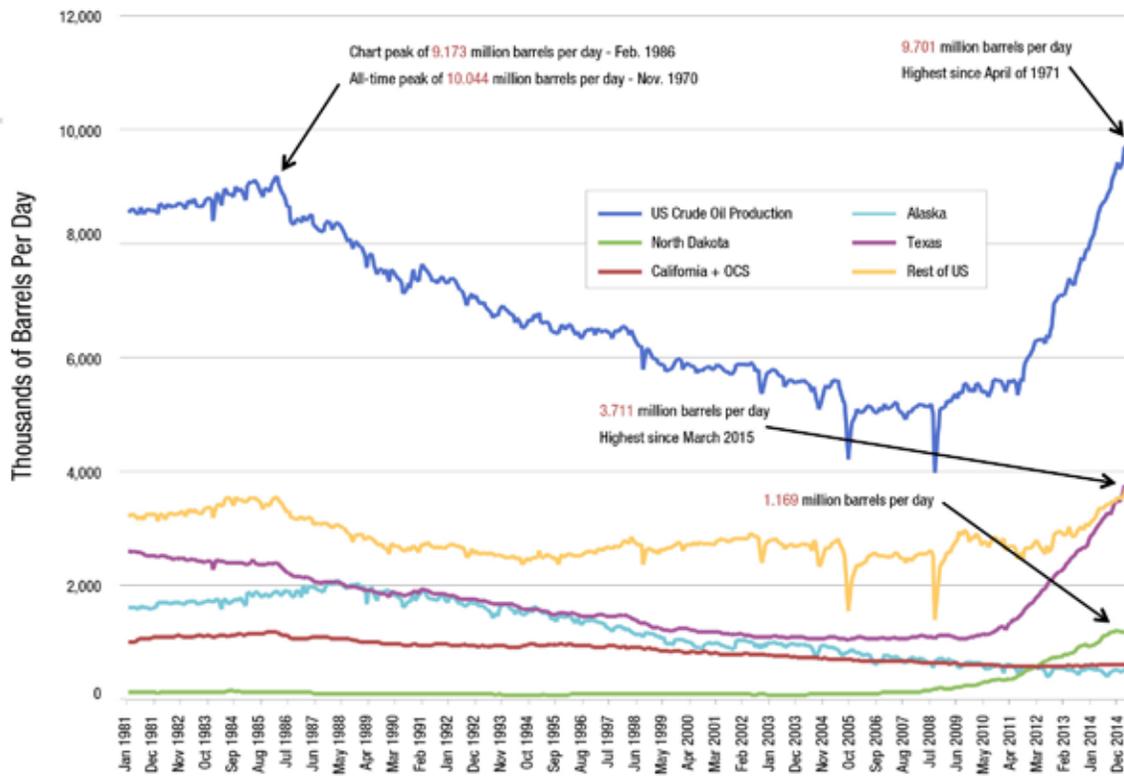
- » Three parties (BAMX, California ISO, and Sempra Utilities) submitted comments on the *Draft 2015 IEPR* that are relevant to this section of Chapter 7.

Appropriate changes to the text have been incorporated to address comments filed after the August 17th workshop and submitted regarding the *Draft 2015 IEPR* itself. The Energy Commission, CPUC, California ISO, and ARB are committed to assuring reliability in Southern California. Special attention will continue for this region of the state until the reliability issues it faces can be undertaken by general electricity planning and procurement processes.

Changing Trends in California's Sources of Crude Oil

The Energy Commission explored changing trends in crude oil production, pricing, and transportation safety concerns as part of the *2014 IEPR Update*. In June 2014, the Energy Commission convened a workshop to better understand the changing landscape with respect to California's sources of crude oil. That workshop brought together a broad set of stakeholders for the first time and helped provide insight into the differing roles of federal, state, and local levels of government. To build on the information gathered during last year's effort, and to evaluate the progress made in addressing safety concerns with the transportation of crude-by-rail (CBR), the Energy Commission hosted an IEPR workshop July 20, 2015, in Sacramento. This section provides updates on domestic crude oil production trends, trends in California hydraulic fracturing activity, changes in crude oil pricing, CBR trends, and updates on safety measures covered in the *2014 IEPR Update*.

Figure 59: U.S. Crude Oil Production (1981–April 2015)



Source: Energy Information Administration

U.S. Crude Oil Extraction Developments and Resulting Increased Output

Domestic crude oil production has continued its dramatic rebound in the United States, largely due to the extensive use of horizontal drilling techniques and well treatment referred to as hydraulic fracturing, or “fracking.”

Fracking is a technique used by the petroleum industry to obtain crude oil and natural gas from geological formations that require additional effort to increase the volume of petroleum that can be removed from an existing field. These “tight oil and gas” formations require the rock to be fractured to enable the crude oil and natural gas to flow through the fissures to well bores and on to the surface. As detailed in the *2014 IEPR Update*, hydraulic

fracturing is not a new procedure and is estimated to have been used in more than 1 million wells worldwide.

Much progress has been made to improve the understanding of the impacts associated with hydraulic fracturing in California and providing public access to information.⁴¹⁰ For example, Senate Bill 1281 (Pavley, Chapter 561, Statutes of 2014) requires oil and gas operators to submit quarterly water reports detailing the source, quality, and treatment of all waters used for injection, disposal, and other oil and gas field activities.⁴¹¹ The 2015

410 The Division of Oil Gas and Geothermal Resources provides extensive information related to hydraulic fracturing activities in California at <http://www.conservation.ca.gov/dog/Pages/Index.aspx>.

An overview of the hydraulic fracturing reporting requirements may be viewed at http://www.conservation.ca.gov/dog/general_information/Documents/121712NarrativeforHFRegs.pdf.

411 http://www.conservation.ca.gov/dog/SB_1281/Pages/Index.aspx.

first quarter water summary report and data tables are now publicly available and represent filings from roughly 60 percent of oil and gas operators.⁴¹²

Production of oil in the United States was 9.7 million barrels per day during April 2015, the highest level of output since April 1971. Figure 59 depicts the rebound of crude oil production in the United States over the last several years, along with changes in output from key producing states. The U.S. Energy Information Administration forecasted that production could continue increasing and eventually exceed the all-time record output of 10.044 million barrels per day achieved during November 1970.⁴¹³

Global Crude Oil Production Trends

The tremendous rebound in domestic crude oil production has had a direct impact on imports into the United States. Figure 60 portrays how crude oil imports for the United States have declined from the peak of 10.13 million barrels per day during 2005 to an average of 7.26 million barrels per day for the first five months of 2015, a decline of 28.3 percent.

The increase in supply has led to lower crude oil prices, which in turn has discouraged domestic drilling. It is possible that this steady drop in crude oil imports will not be sustained as a growing glut in global crude oil supplies has placed downward pressure on crude oil prices. (See below.) Figure 61 shows that by July 2015, the number of rigs deployed to drill for oil in the United States had plummeted 56.9 percent from a peak in October 2014, increasing the likelihood that the continued growth of domestic production could be halted over the near term and begin to decline.

412 http://www.conservation.ca.gov/dog/SB_1281/Pages/SB_1281DataAndReports.aspx.

413 According to the Energy Information Administration's May 2015 update of its *Annual Energy Outlook*, crude oil production in the United States could reach 10.60 million barrels per day by 2020 under the "Reference Case" scenario. *U.S. Crude Oil Production to 2025: Updated Projection of Crude Types*, Energy Information Administration, May 2015, Figure 1, p. 1, <http://www.eia.gov/analysis/petroleum/crudetypes/pdf/crudetypes.pdf>. The annual values and different scenarios can be found at <http://www.eia.gov/analysis/petroleum/crudetypes/xls/figure-data.xlsx>.

The surge in crude oil production from the United States, coupled with the unwillingness of Saudi Arabia and other members of the Organization of Petroleum Exporting Countries (OPEC) cartel to reduce their own output, led to a growing imbalance between supply and demand for crude oil that was the primary factor for placing downward pressure on prices. Figure 62 shows the quarterly supply and demand values for crude oil since the beginning of 2013. Global supply of crude oil began to overtake demand during the first quarter of 2014.

The continued build of excess supply weighed heavily on world markets, leading to a collapse of crude oil prices that began during the summer of 2014 and continued through the third quarter of 2015. Figure 63 illustrates the change in price for Brent North Sea crude oil, an international benchmark type of crude oil that is a good surrogate price for foreign sources of crude oil processed in California refineries.

Brent oil dropped 59.5 percent between June 19, 2014, and January 13, 2015. Although prices rebounded somewhat during the first half of 2015, the downward pressure on global oil prices is expected to continue into 2016 and possibly 2017. Absent a change in policy by OPEC to cut back its production and yield market share, there could be even greater downward pressure on pricing when the Iranian nuclear accord is finalized by both countries. When also considering the downward changes in China's economy, it becomes less likely that crude oil prices can rebound in a meaningful way any time before late 2016.

Changing Infrastructure Trends for Crude Oil Distribution

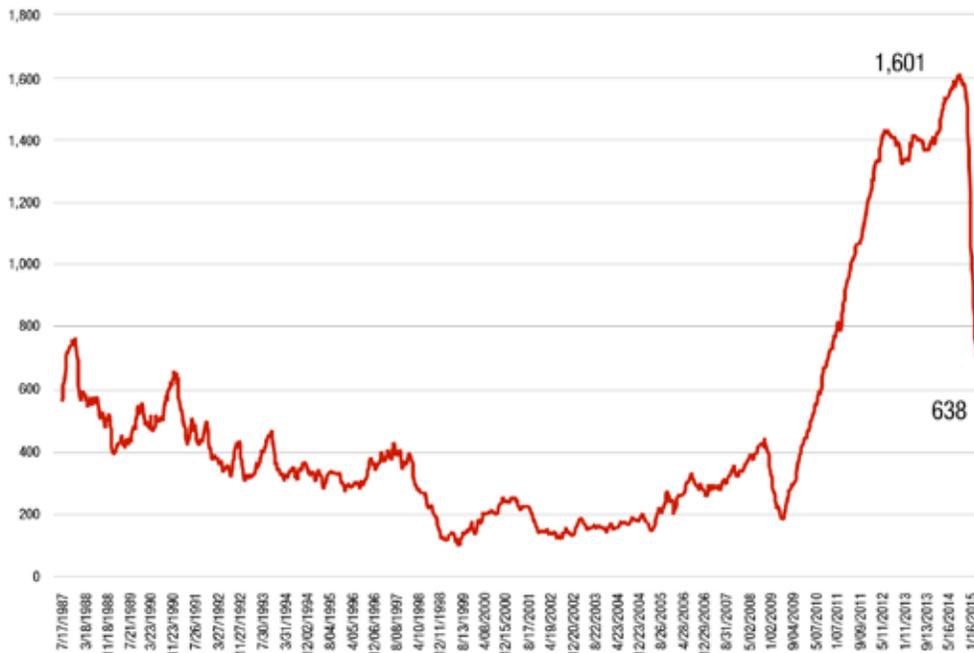
As outlined in the *2014 IEPR Update*, the dramatic increase of crude oil production has surpassed the ability of the crude oil pipeline gathering and distribution infrastructure to keep pace. Consequently, producers have sufficiently discounted their oil prices to make the more expensive means of rail transportation an economically viable option for refiners outside the shale oil regions.

Figure 60: U.S. Crude Oil Imports (1990–2015)



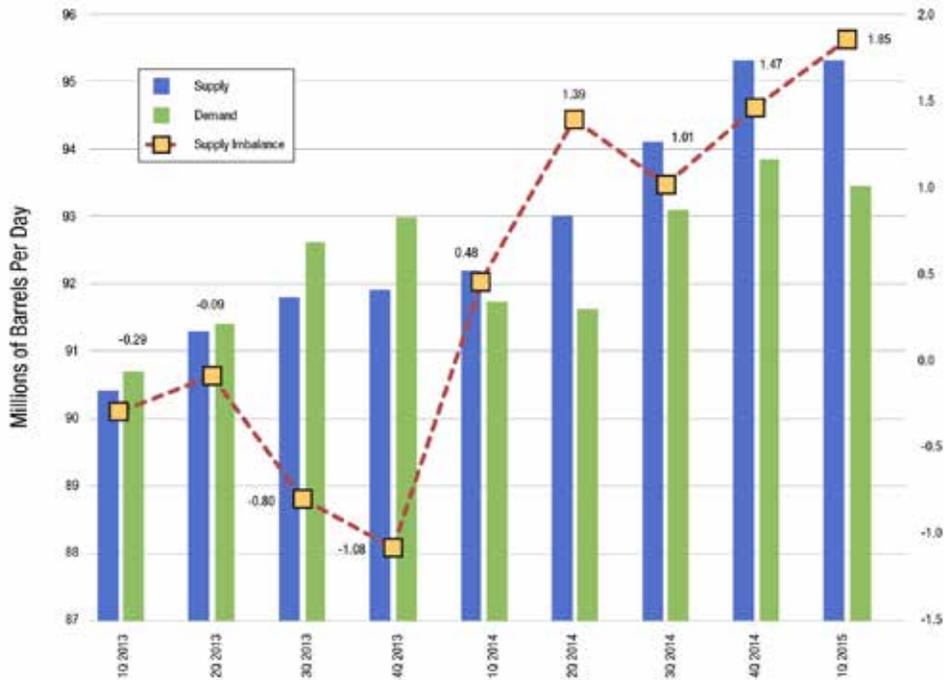
Source: Energy Information Administration

Figure 61: U.S. Oil Rig Deployment Declines with Price



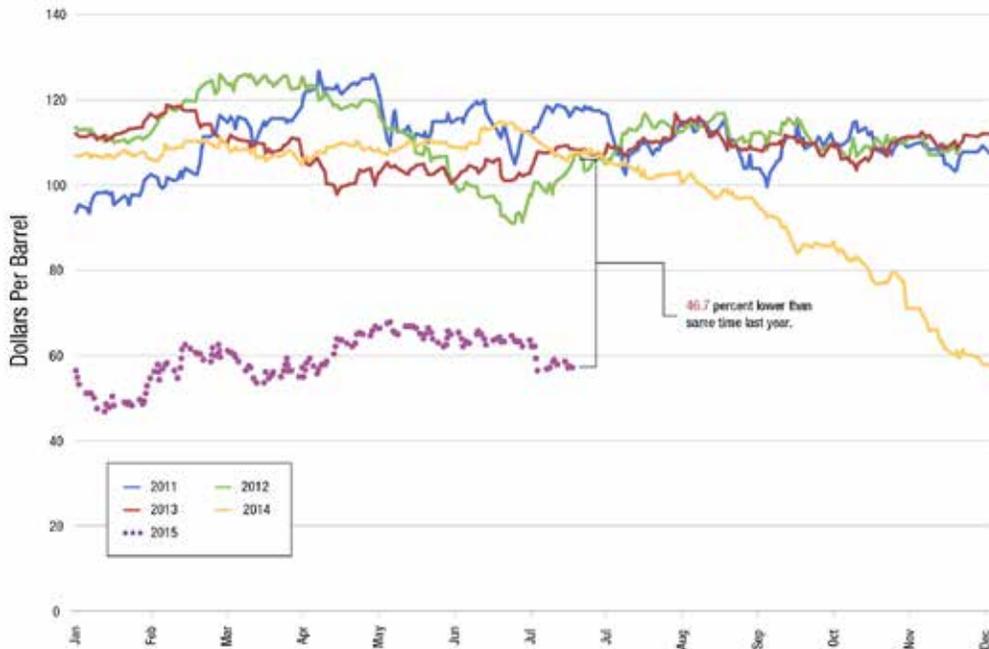
Source: Baker Hughes data – through July 17, 2015

Figure 62: Global Crude Supply Imbalance (Q1 2013–Q1 2015)



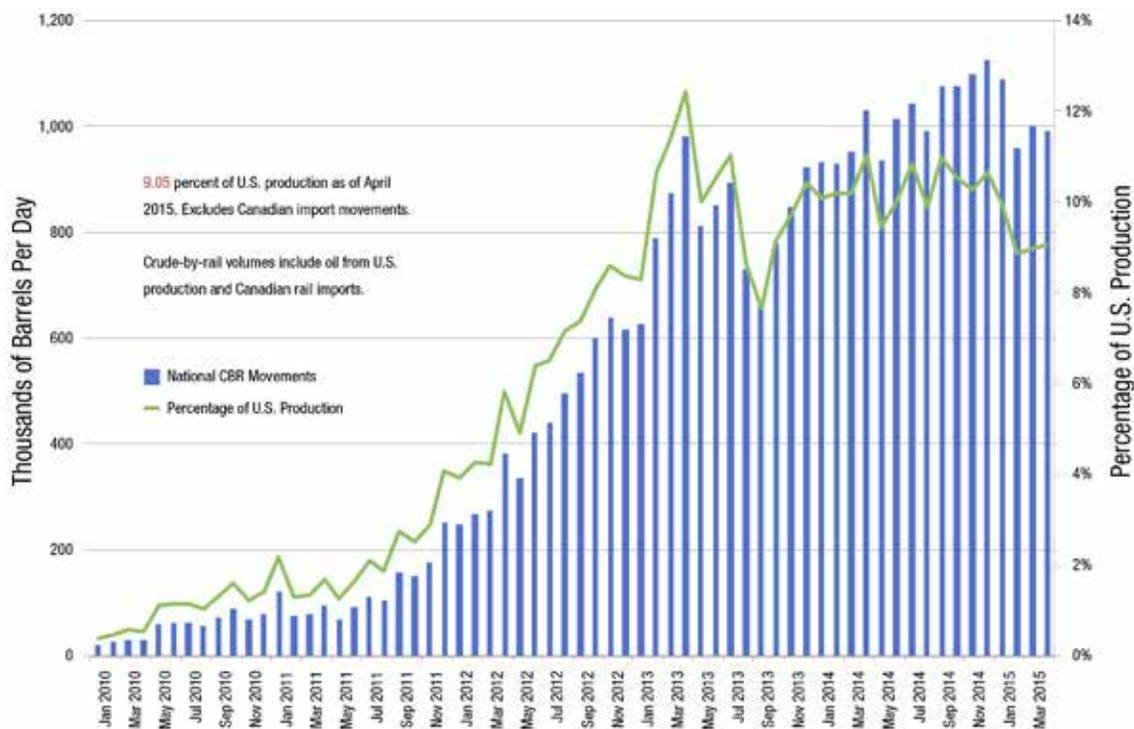
Source: International Energy Agency and Energy Commission analysis

Figure 63: Daily Brent Crude Oil Prices (2011–July 17, 2015)



Source: Energy Information Administration

Figure 64: Crude Oil Transportation by Rail Tank Car



Source: California Energy Commission analysis of data from the Energy Information Administration

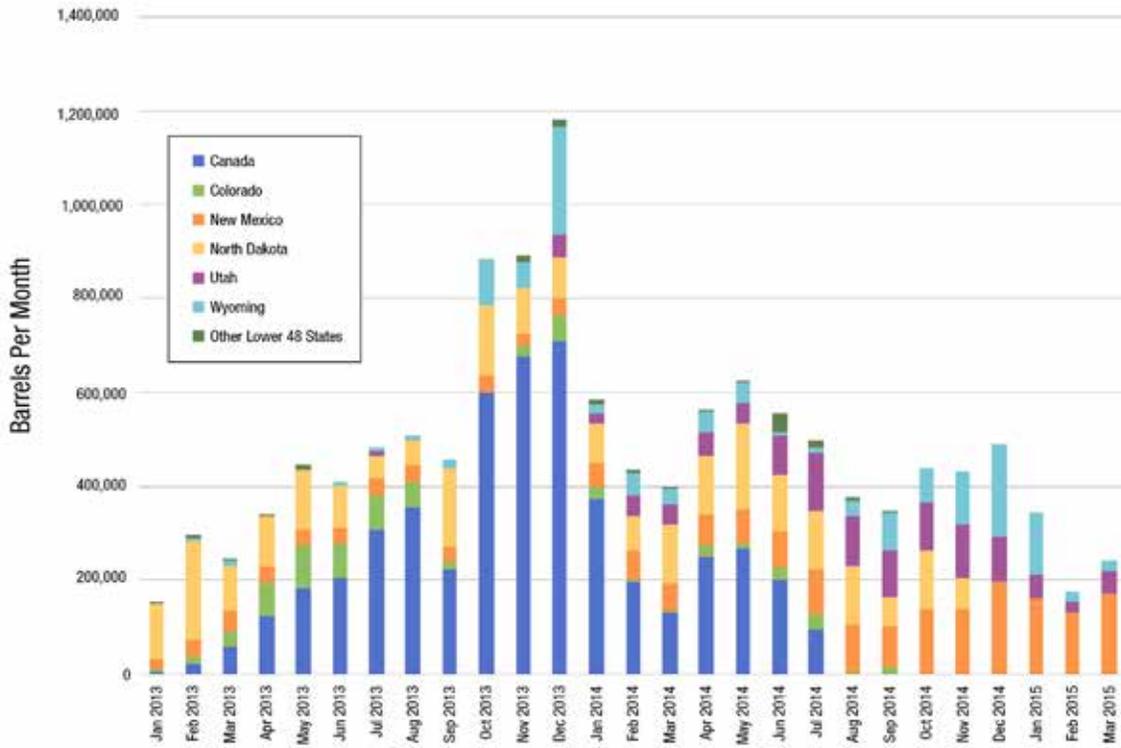
CBR is a somewhat recent phenomenon. Figure 64 shows the rapid increase over the last five years as logistical providers have ramped up the capability to load crude oil into rail cars at production locations in Canada, North Dakota, Texas, Colorado, and New Mexico. These projects have been recently completed to take advantage of crude oil price discounts for Canadian and domestic crude oil, whose rapid increase in output has overwhelmed the capacity of crude oil pipelines to transport to refineries. Shipments peaked at 1.124 million barrels per day during December 2014. More recently, CBR deliveries have declined as additional pipeline capacity for oil transportation has come on-line, providing local producers access to cheaper pipeline transportation and the ability to charge higher prices. This has been decreasing the incentive to use railways to transport crude oil that is more expensive than transport by pipeline.

California refiners received 1.1 million barrels of crude oil via rail during 2012. During 2013, California refiners

received 6.3 million barrels, a nearly sixfold increase within one year. However, that upward trend did not continue during 2014 as rail oil imports declined slightly to 5.7 million barrels. Figure 65 shows monthly CBR deliveries since January 2013. The volumes peaked during December 2013 at nearly 1.2 million barrels but have since declined to fewer than 0.3 million barrels by March 2015.

California crude-by-rail deliveries have dropped off from the December 2013 peak as a consequence of narrowing differences between international crude oil prices (like Brent North Sea) and North American crude oil types (such as Canadian, North Dakota, and Texas). As rapid increases in output from U.S. shale oil formations outpaced the capacity of pipelines to transport the crude oil to market, producers were forced to discount their oil prices such that the higher cost of rail tank car transport would be economical for refiners purchasing their oil. Over the last 18 months, however, additional pipeline capacity has come on-line, enabling additional shipments of crude oil by

Figure 65: California Crude Oil Imports via Rail Tank Cars



Source: PIIRA data, California Energy Commission analysis

pipeline and reducing the need for oil producers to continue providing steep discounts for their oil. This is why the Energy Commission’s previous outlook for continued increase in CBR deliveries to California during 2015 did not transpire.

The Energy Commission receives monthly reports from Class 1 railroad companies (Union Pacific and BNSF Railway) for all imports and exports via rail tank car of crude oil, refined petroleum products, and renewable transportation fuels (like ethanol and biodiesel). While the originating state or country (such as Canada) for each shipment is provided, the type of crude oil being transported is not. The density of crude oil being transported via rail can vary significantly and be characterized as either *heavy* or *light*. This type of information is important for state agencies needing to formulate different emergency response plans based on the volume and density of crude oil moving by rail. The Energy Commission is unable to quantify the volumes

of *heavy* and *light* crude oil rail shipments based on the point of origin alone and would need to collect additional information sufficient to calculate density,⁴¹⁴ (such as API gravity or weight and volume for each rail tank car transporting crude oil).

Rail deliveries of crude oil to California refineries represent the smallest source, about 1 percent of the more than 605 million barrels of crude oil received during 2014. Foreign crude via marine tankers accounted for just over 47 percent, followed by roughly 40 percent from California crude oil received via pipeline and just over 11 percent from Alaska via marine tankers.

⁴¹⁴ One approach is for the Class 1 railroads to provide the weight of each rail tank car along with the volume of oil. Another method would be for the railroads to provide a measure of the crude oil density such as the American Petroleum Institute gravity value or API gravity for short.

During 2013 and 2014, some CBR imports were transferred to tanker trucks at two locations in California: the Kinder Morgan rail yard in Richmond and the SAV Patriot Rail Company facility in Sacramento. The Sacramento CBR operation ceased activity during early November 2014 after the permit from the Sacramento Air Quality Management District was revoked by the issuing agency. There have been no CBR deliveries to Northern California locations since November 2014.

Over the next couple of years, there is an increased likelihood that CBR facilities in Oregon and Washington will be used to load marine vessels for delivery of crude oil to California refineries. The ability of the Energy Commission to accurately quantify these deliveries and monitor changing trends for sources and means of transportation is contingent upon the submittal of appropriate information from all obligated parties. Cargo vessel operators are required to submit a Notice of Arrival/Departure to the U.S. Coast Guard's National Vessel Movement Center within 24 to 96 hours of arrival/departure.⁴¹⁵ Access to this type of information would allow the Energy Commission to more accurately monitor movements of imports and exports of refinery feedstocks (such as crude oil) and transportation fuels that may not be captured during normal data collection due to underreporting by obligated parties.

California CBR Potential for Increased Imports

The likelihood that CBR imports to California will continue rising over the next couple of years will depend on the number of CBR receiving facilities that are ultimately approved and constructed within the state. At the July 20, 2015, IEPR workshop, Gordon Schremp of the Energy Commission explained that the Commission is tracking three CBR projects that have either received permits but

not yet initiated construction or are still undergoing permit review.⁴¹⁶ If the three projects are constructed and begin operating at full capacity, the contribution of CBR for California refiners could significantly increase from 1 percent in 2014 to 19 percent by 2017.⁴¹⁷ (Please see Appendix B for more information on California CBR projects.)

It is possible that not all proposed projects will receive financing and be constructed. Those that eventually do become operational will receive CBR deliveries that will most likely displace imports of oil via marine tanker that are of similar quality to the properties of the CBR oil. There are also several CBR facilities in Washington state that are operational, with more planned. (Please see Appendix B for more information on projects.)

CBR Safety Concerns

Transportation of crude oil and other flammable material is not without risk. There have been several derailments involving rail tank cars from which oil and ethanol have been released. In many of these instances, there were fires and explosions that caused fatalities, injuries, and contamination of the nearby environment. The most serious example of a CBR derailment was in Lac-Mégantic, Quebec, where 47 people were killed by an unmanned, runaway train that derailed and exploded in this community on July 6, 2013.⁴¹⁸ In his presentation at the July 20, 2015, workshop, Paul King from the CPUC outlined how earlier derailments had already spurred action by government agencies in the United States and Canada to improve safety standards for

415 Electronic Notice of Arrival/Departure (eNOAD) User Guide, U.S. Department of Homeland Security, May 15, 2015, [http://www.nvmc.uscg.gov/NVMC/\(S\(ol1v1n4x11y4xrescinjg4l\)\)/Forms/eNOADUserGuide.pdf](http://www.nvmc.uscg.gov/NVMC/(S(ol1v1n4x11y4xrescinjg4l))/Forms/eNOADUserGuide.pdf), p. 1.

416 The Alon project in Bakersfield, Valero project in Benicia, and the Phillips 66 project in Santa Maria.

417 Integrated Energy Policy Report workshop on Trends in Crude Oil Market and Transportation, California Energy Commission, July 20, 2015, http://docketpublic.energy.ca.gov/PublicDocuments/15-IEPR-13/TN205401_20150720T084540_Crued_Oil_Overview__Changing_Trends.pptx, slide 35.

418 A detailed description of the accident, resulting investigation, and report issued by the Transportation Safety Board of Canada may be viewed at <http://www.tsb.gc.ca/eng/enquetes-investigations/rail/2013/r13d0054/r13d0054.asp>.

rail operations and tank car standards, as well as additional efforts following the tragedy in Lac-Mégantic.⁴¹⁹ Highlights of significant steps undertaken by California, federal, and Canadian agencies are detailed in Appendix C.

The most notable updates in safety-related regulations associated with transportation of oil and ethanol via rail tank cars cover three areas: operation of trains, construction standards for rail tank cars, and oversight of oil transportation via rail within California.

Operation of Trains Transporting Crude Oil or Ethanol

The traveling speed and braking capability of trains transporting oil or ethanol are two important factors that can affect the severity of derailments involving these cargos. The faster a train is traveling, the greater its momentum and force during a derailment. This is why regulators have, among other efforts, focused on limiting the speed of trains transporting oil or ethanol. This is especially the case through densely populated areas. Recent regulations finalized by the Pipeline and Hazardous Materials Safety Administration in May 2015 place slower speed restrictions on trains transporting oil or ethanol under specific circumstances.⁴²⁰

How quickly and effectively the braking systems in a train can be deployed are important factors for reducing speed and impact prior to a collision or derailment. Mr. King explained, “When they took the conductor . . . and the caboose off the train, you no longer had somebody back there. . . in case you had a failure of the train line system somewhere. . . You didn’t have somebody back there to put the train into

emergency brake application. So (an) end-of-train device is a telemetry device to replace the caboose and the conductor, basically.”⁴²¹ Enhanced braking will now be required for all high-hazard flammable trains (HHFTs).⁴²² The systems are designed to increase the reaction time to apply brakes or use additional locomotives within the string of rail tank cars.

By 2021, HHFTs will need to be equipped with electronically controlled pneumatic braking. Mr. King provided a summary of these new requirements at the July 20, 2015, workshop.⁴²³ At the workshop, Commissioner Janea Scott questioned why the requirements are scheduled to take effect so far into the future. Mr. King explained “They’ll have to retrofit old tank cars. And they’ll have to build new ones with the electronic braking control systems on them. And they also have to retrofit locomotives and any new ones will have to have those systems. My sense is that the Federal Railroad Administration looked at how long it would take, what it would do to the fleet if you required it too soon, and how that would impact the cost benefit.”⁴²⁴

419 Integrated Energy Policy Report workshop on Trends in Crude Oil Market and Transportation, California Energy Commission, California Public Utilities Commission, July 20, 2015, http://docketpublic.energy.ca.gov/PublicDocuments/15-IEPR-13/TN205403_20150720T084533_Crude_Oil_Ethanol_Railroad_Shipments.pptx, slides 28–32.

420 DOT Announces Final Rule to Strengthen Safe Transportation of Flammable Liquids by Rail, U.S. Department of Transportation. <http://www.transportation.gov/briefing-room/final-rule-on-safe-rail-transport-of-flammable-liquids#sthash.mUlzytpZ.dpuf>.

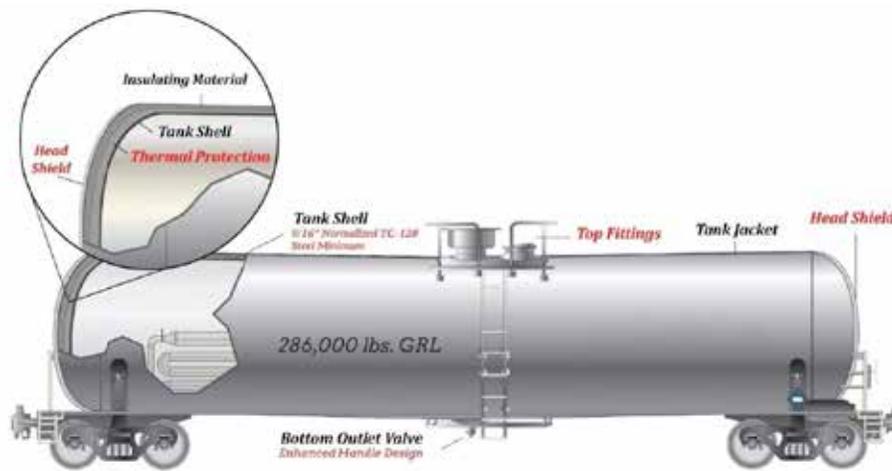
421 Integrated Energy Policy Report workshop on Trends in Crude Oil Market and Transportation, California Energy Commission, California Public Utilities Commission, July 20, 2015, http://docketpublic.energy.ca.gov/PublicDocuments/15-IEPR-13/TN205690_20150812T085120_Transcript_of_the_July_20_2015_IEPR_Commissioner_Workshop_on_Tr.pdf, p. 68.

422 A *high-hazard flammable train* is defined as a continuous block of 20 or more tank cars loaded with a flammable liquid or 35 or more tank cars loaded with a flammable liquid dispersed through a train.

423 Integrated Energy Policy Report workshop on Trends in Crude Oil Market and Transportation, California Energy Commission, California Public Utilities Commission, July 20, 2015, slides 11-17 and 20, http://docketpublic.energy.ca.gov/PublicDocuments/15-IEPR-13/TN205403_20150720T084533_Crude_Oil_Ethanol_Railroad_Shipments.pptx.

424 Integrated Energy Policy Report workshop on Trends in Crude Oil Market and Transportation, California Energy Commission, California Public Utilities Commission, July 20, 2015, http://docketpublic.energy.ca.gov/PublicDocuments/15-IEPR-13/TN205690_20150812T085120_Transcript_of_the_July_20_2015_IEPR_Commissioner_Workshop_on_Tr.pdf, p. 69.

Figure 66: DOT Specification 117 Rail Tank Car



Safety enhancements of DOT Specification 117 Tank Car:

- Full-height 1/2 inch thick head shield
- Tank shell thickness increased to 9/16 inch minimum TC-128 Grade B, normalized steel
- Thermal protection
- Minimum 11-gauge jacket
- Top fittings protection
- Enhanced bottom outlet handle design to prevent unintended actuation during a train accident

Source: U.S. Department of Transportation

Construction Standards for Rail Tank Cars

Besides reducing operating speeds and improving braking capabilities, the construction standards for rail tank cars used to transport oil or ethanol must meet much stricter specifications. These more stringent specifications apply to both newly constructed rail tank cars and retrofitted existing rail tank cars for continued use in oil and ethanol service. These new requirements are referred to as DOT Specification 117 cars and apply to all new rail tank cars constructed after October 1, 2015, if they are used in HHFTs. Depending on the type of legacy tank car being used in HHFTs, the deadline for retrofitting can be as early as May 1, 2017, or as late as May 1, 2025. Figure 66 provides an overview of the primary safety enhancements for the DOT 117 design.⁴²⁵

⁴²⁵ Ibid, slide 18.

Oversight of Oil Transportation via Rail Within California

There are several California agencies involved in oversight of various safety-related elements associated with the transportation of crude oil within the state. The most recent significant changes highlighted here involve the activities of the California Office of Spill Prevention and Response (OSPR). This agency has traditionally focused oil spill prevention and response activities along coastal waterways. With passage of SB 861, the oversight of this agency has been expanded to encompass the entire state. Ryan Todd of OSPR provided an overview of his agency and details of its expanded roles and responsibilities during his presentation at the IEPR workshop on July 20, 2015.⁴²⁶

⁴²⁶ Integrated Energy Policy Report workshop on Trends in Crude Oil Market and Transportation, California Energy Commission, Office of Spill Prevention and Response, July 20, 2015, http://docketpublic.energy.ca.gov/PublicDocuments/15-IEPR-13/TN205408_20150720T102553_Overview_of_the_Office_of_Spill_Prevention__Response_CA_Departm.pptx, pp. 37–57.

OSPR estimates that its expanded role will encompass 250 to 300 additional operators that must submit contingency plans for responding to a worst case spill from their operations. Transporters of crude oil via rail tank car will also have to demonstrate sufficient financial capabilities to fund any response and clean-up costs associated with a spill, much like the financial responsibility requirements for importers of crude oil via marine vessel but with fewer financial requirements due to the smaller worst case spill volumes that could result from the derailment of a train transporting crude oil. During his presentation, Mr. Todd explained, “[W]e had to figure out what’s appropriate financial responsibility for the inland part of the state. You know, a spill into a dry wash is probably generally going to be a cleaner cleanup versus... cleaning up a tide pool. It’s much more expensive, much more difficult to clean up generally, a coastal environment or an estuary than it is to clean up a spill inland.”⁴²⁷ These provisions are designed to help ensure that the costs of any spill are borne by the responsible party rather than taxpayers. Emergency regulations are being developed for these increased OSPR responsibilities and were released for comment on August 3, 2015.⁴²⁸

Next Steps

Although crude-by-rail deliveries into California are less than 1 percent of total supply for refineries, this means of transportation could significantly increase by up to 19 percent if all planned facilities are developed. There has been significant progress in development and oversight of safety-related regulations for oil transportation by rail, including a growing enhancement to California agency in-

spection and oversight. However, as discussed at the *2014 IEPR Update* workshop on this topic, the state is likely to need more data that can enhance the state’s efforts to follow these trends and understand their implications. Continued vigilance and coordination among local, state, federal, and Canadian governments are needed since the most recently approved safety standards will be phased in over a period of years (2017 through 2025) and harmonization of standards between the United States and Canada has yet to be achieved.

Recommendations

California’s Nuclear Power Plants

Decommissioning

» **Provide updates on the development of underground dry cask storage.** Southern California Edison (SCE) should provide periodic updates to the Energy Commission on the status of developing new underground dry cask storage system to be built by Holtec International. In addition, SCE should notify the Energy Commission when the transfer of spent fuel from wet pools to the new facility begins and SCE’s progress toward its intended target completion date of 2019. Finally, SCE should file an annual report with the Energy Commission that details how much spent fuel remains in the spent fuel pool and the level of radiation associated with that fuel until all spent fuel canisters have been transferred into dry cask storage.

» **Provide updates on decommissioning.** SCE should continue to update the Energy Commission on the decommissioning of San Onofre Nuclear Generating Station until the decommissioning is completed.

» **Engage in the Nuclear Regulatory Commission (NRC) rulemaking on improved regulations for decommissioning nuclear power plants.** The engagement of

427 Integrated Energy Policy Report workshop on Trends in Crude Oil Market and Transportation, California Energy Commission, Office of Spill Prevention and Response, July 20, 2015, http://docketpublic.energy.ca.gov/PublicDocuments/15-IEPR-13/TN205690_20150812T085120_Transcript_of_the_July_20_2015_IEPR_Commissioner_Workshop_on_Tr.pdf, p. 51.

428 The proposed OSPR regulations can be found at <https://www.wildlife.ca.gov/OSPR/Legal/Proposed-Regulations>.

California representatives is needed to assure that the NRC rulemaking to develop improved regulations for decommissioning nuclear power plants considers circumstances unique to the state's coastal nuclear power plants, including consideration of the ever present risk of an earthquake and how global climate change may exacerbate tsunami risks along the state's extensive coastline. The Energy Commission should work in partnership with other state agencies including the California Public Utilities Commission (CPUC), California Office of Emergency Services, and California Coastal Commission; local government agencies; advisory panels such as the Diablo Canyon Independent Safety Committee, the Independent Peer Review Panel, and San Onofre Community Engagement Panel; and community groups to engage in this rulemaking.

Diablo Canyon

- » **Provide updates on NRC's license renewal.** In light of the reopening of the NRC's review for a license renewal for Diablo Canyon, Pacific Gas and Electric (PG&E) should provide semi-annual progress updates to the Energy Commission on any developments in the NRC's process.
- » **Provide updates on compliance with CPUC President Picker's itemized list.** CPUC President Picker provided a lengthy list of compliance items to be completed by PG&E as part of any funding request for the relicensing application process. PG&E should make a compliance filing that responds to President Picker's itemized list by providing status updates on each of the items in President Picker's letter. This compliance filing should be submitted to the Energy Commission and the CPUC annually or quarterly, as appropriate.
- » **Prepare a cost-benefit study on cycling at Diablo Canyon.** Under President Picker's directives, PG&E should prepare a detailed study of the costs, benefits, and safety issues of cycling the Diablo Canyon units to address overgeneration problems on the grid.
- » **Complete planned studies on ground motion at Diablo Canyon site.** PG&E should complete the additional studies to improve the quantification of site amplification at the Diablo Canyon site. PG&E should report on its findings to the Energy Commission and the Independent Peer Review Panel.
- » **Complete Evacuation Time Estimate and report to Energy Commission.** PG&E should complete the update of the Evacuation Time Estimate report and provide the completed report to the Energy Commission. The updated report should incorporate an evacuation time estimate following an earthquake.
- » **Provide updates on Nuclear Regulatory Commission's review of seismic analyses.** As part of the IEP reporting process, PG&E should provide periodic status reports to the Energy Commission on the progress of the NRC's review and evaluation of the Probabilistic Seismic Hazard Analysis study and related seismic information submitted by PG&E to the NRC.
- » **Report annually to the Energy Commission on spent nuclear fuel storage in pools.** PG&E should update the Energy Commission annually on the current status of spent nuclear fuel stored in pools versus dry cask storage. This annual report should detail how much spent fuel is stored in the pool and the amount of radiation associated with the spent fuel stored in the pool. PG&E also should report its plans for moving spent nuclear fuel from the pools to dry cask storage as additional capacity becomes available.
- » **Fully address all comments of the Independent Peer Review Panel (IPRP) on seismic hazards at Diablo Canyon.** PG&E should continue to interact with the IPRP on PG&E's studies of seismic hazards and respond to the comments of the IPRP as presented in previous or future IPRP reports.

Nuclear Waste Storage Issues for California

» **Monitor federal waste management activities.**

The Energy Commission will continue to monitor federal nuclear waste management program activities and represent California in the Yucca Mountain licensing proceeding to ensure that California's interests are protected regarding potential groundwater and spent fuel transportation impacts in California.

» **Support federal development of long-term nuclear waste management facilities.** The Energy Commission continues to support federal efforts to develop an integrated system for management and disposal of nuclear waste, including the establishment of a new, consent-based approach to siting future nuclear waste management facilities. The Energy Commission supports the proposed Nuclear Waste Administration Act of 2015 as cosponsored by Senator Dianne Feinstein.

» **Report on aging cask management.** Spent fuel will be stored in thin cask storage technology at both San Onofre and Diablo Canyon. It is highly likely that the spent fuel stored in dry casks will remain at the nuclear plant sites for a much longer period than the initial licensing period of the dry cask technology. PG&E and SCE should report to the Energy Commission during the next *Integrated Energy Policy Report* cycle on developments within the nuclear engineering community on the issue of aging cask management and related technological considerations.

Electricity Infrastructure in Southern California

» **Complete mitigation measure development.** The Southern California Reliability Project should finalize development of mitigation measures, especially the details of expeditiously updating air permits for facilities that have received the initial permit and are likely to be developed only if contingencies are encountered.

» **Maintain/enhance forward assessment capability.**

The Southern California Reliability Project agencies should continue efforts to support Energy Commission staff in maintaining and enhancing the local capacity annual assessment tool (LCAAT) tool. LCAAT should be operated periodically and results reported to the Energy Principals.

» **Initial concerns about 2021 deficits in L.A. Basin local capacity areas should be studied by the California Independent System Operator (California ISO).** The California ISO has stated it will conduct a 2021 study to confirm or refute the concerns raised by Energy Commission Staff using the LCAAT tool. These results should be communicated promptly, and if there are discrepancies in findings, the California ISO should help the Energy Commission staff upgrade the tool.

» **The California Public Utilities Commission (CPUC) should include local capacity as a topic in the 2016 Long Term Procurement Plan (LTPP).** The scope of the CPUC's 2016 LTPP rulemaking should take into consideration all of the components of the Integrated Resource Plans, including local capacity requirements, and examining intermediate time horizons such as 2020-2022 should be an explicit focus of the assessment.

» **The Joint Reliability Plan rulemaking should be resurrected as a forum for common assessments of resource needs.** Joint Reliability Plan, Track 2 is properly scoped to provide a forum in which the CPUC, California ISO, and Energy Commission can develop a common set of projections about system, local, and flexible capacity requirements annually out 10 years or more. Analysis needs to be resurrected, and this process should be completed in a manner that creates a functional assessment capability that can form the basis for a common understanding of resource needs.

Changing Trends in California's Sources of Crude Oil

» **Collect data needed to improve emergency preparedness.** The Energy Commission will work with the appropriate state agencies to help ensure an accurate-as-feasible accounting of the volumes and delivery locations for all crude oil transported by rail into the state. To improve state and local emergency response capabilities, the Energy Commission should:

- » Collect data on the weight and volume or the API gravity (or density) of crude deliveries by tank car or marine vessel into California. The Energy Commission should collect data on the API gravity (or density) per rail tank car. Also, shippers of crude oil via marine vessel to California from Oregon, Washington state, and Canada should provide the Energy Commission with the API gravity per marine vessel (tanker and barge). This information would allow the Energy Commission to better quantify the types of crude oil being delivered as either "heavy" or "light."
- » Collect data on marine vessel arrivals and departures for transporting liquid bulk refinery feedstocks, refined petroleum products, and renewable fuels into or out of California. The Energy Commission should work with the United States Coast Guard and stakeholders to identify data needs and the best process for data collection.
- » Work with the Class 1 railroad companies to determine the feasibility of obtaining confidential routing information for all unit and manifest shipments of crude oil into California by rail tank car on a monthly basis. If feasible, that information would be provided through the

Petroleum Industry Information Reporting Act with appropriate confidentiality requirements.

- » Work with the Class 1 railroad companies to determine the feasibility of obtaining confidential routing information for all unit train shipments of crude oil into California a week in advance of these shipments. If feasible, that information would be provided through the Petroleum Industry Information Reporting Act with appropriate confidentiality requirements.

» **Collect additional data needed to follow oil extraction, transportation and distribution trends, and understand potential climate impacts.** Given the lack of detailed trend forecasts available to the state and wide range of crude oil carbon intensities, state agencies will coordinate and explore data gaps; determine specific data needed to quantify emissions, carbon intensities, and so forth; and request necessary information.

» **Collect data needed to follow oil production trends to understand potential climate impacts.** For example, understanding trends for specific types of crude oil production (such as oil sands, thermally enhanced oil recovery, and others) would help inform estimates of potential climate impacts.

» **Monitor development of crude-by-rail projects.** The Energy Commission will continue to monitor development and status of crude-by-rail projects within California and the Pacific Northwest.

CHAPTER 8

California Drought



The drought in California has become steadily more severe over the past few years, to the point where Governor Edmund G. Brown Jr. declared a continued state of emergency on April 25, 2014.⁴²⁹ California's climate is shifting toward warmer winters with thinner snowpack that affects both energy production and demand. The impacts of climate change on the energy system include reduced hydroelectric production, reduced thermal power plant production, and a greater need for recycled water use and efficient water use by power plants. Pumping and treating water requires energy and these demands increase during drought. Also, climate change and droughts lead to dry conditions that increase the risk of fires that pose serious threats to public health and safety, including damage to energy infrastructure – transmission and distribution lines, power plants, and substations.

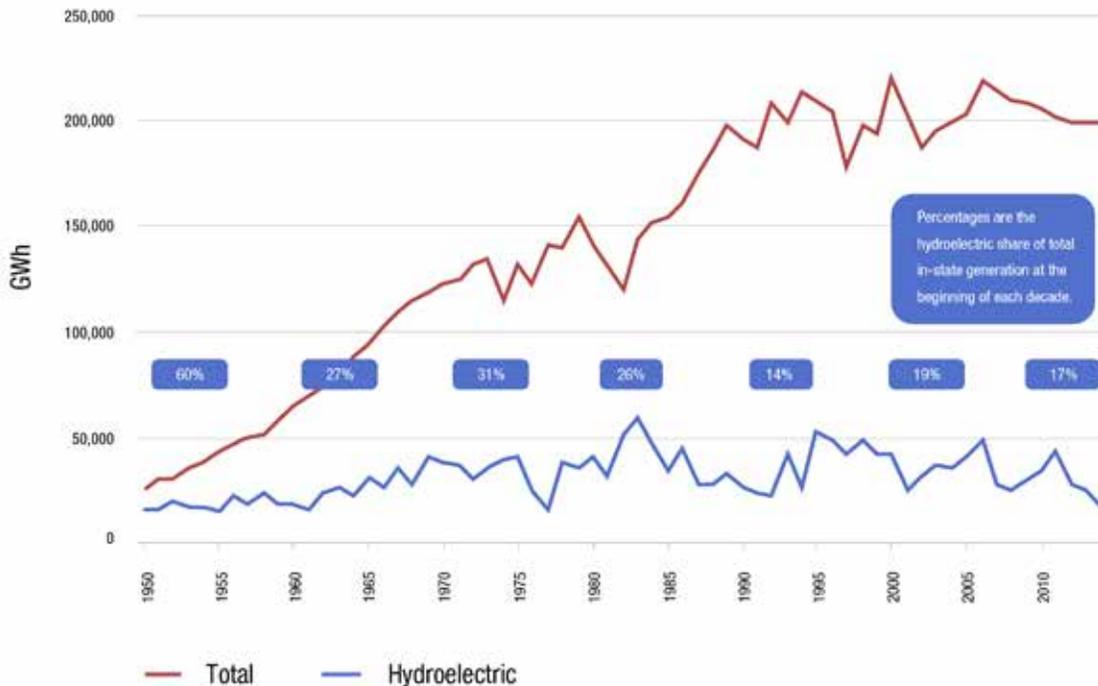
Moreover, the drought is not a short-term problem. As the climate continues to change, California must prepare for the possibility that these drought conditions may become the norm rather than the exception. In response, many programs are being enacted to help with long-term water-saving plans on a wide variety of fronts. For example, new efficiency standards will reduce water use in

toilets and showers. The Water Energy Technology (WET) program is designed to advance innovative water- and energy-saving technologies and reduce greenhouse gas (GHG) emissions. It funds technologies that can be used across a wide variety of sectors, including agriculture, industry, and residential. Programs like these not only help make California more drought-resilient, but reduce energy use from water pumping, treating, and heating. Other state agencies' water conservation and efficiency efforts, such as the mandatory reduction targets established by the State Water Resources Control Board (SWRCB), have similar embedded energy savings impacts.

For more information about climate change, drought, and subsidence impacts on the energy system and adaptation measures, see Chapter 9 on Climate Change Research. This chapter summarizes actions the Energy Commission has taken to date in response to Executive Order B-29-15, including evaluating drought impacts on the power supply and improving water efficiency, as well as the responses of other state agencies.

⁴²⁹ <https://www.gov.ca.gov/news.php?id=18496>.

Figure 67: Historical Hydroelectric Generation Compared to In-State Electricity Production



Source: California Energy Commission

Drought and Energy Impacts

Water and energy are inextricably linked. The most obvious impacts of the drought are to hydroelectric production. Thermal power plants, however, are also affected as they, too, use water to operate. The drought has raised questions about reliability of water supplies for power plants and the impacts water use by power plants may have on other consumptive uses. This section will focus on the condition of hydroelectricity supply, the amount of water consumed annually by power plants, the reliability of those water supplies, and steps to save water through efficiency and conservation across the power sector. The effects of climate change on hydropower are further discussed in Chapter 9, Climate Change Research, under Renewable Energy Generation and Hydropower. Chapter 9 also discusses research on the effects of climate change

and drought on the natural gas and petroleum transportation fuel infrastructure, whereas this chapter focuses on the electricity sector.

Hydro Conditions

California's hydroelectric system consists of 14,000 megawatts (MW), spread across 287 conventional hydroelectric facilities largely dependent on snowmelt (6,000 MW), 4 pumped storage plants (2,800 MW), and 79 multipurpose reservoirs (5,200 MW). Even without the drought, hydropower production is a declining portion of California's in-state generation mix as shown in Figure 67, accounting now for about 14 percent of the state's annual generation on average. Hydroelectric production varies considerably from year to year. For instance, a six-year drought ended in 1992, and the low hydroelectric production that year (11 percent of the state's total power) marked the end of a 10-year decline in hydroelectric generation. By contrast, in 1995,

a wetter year, hydroelectric power approached 28 percent. California's hydroelectric production in 2015 is about half of recent averages.

Shortfalls in hydroelectric production are made up in a variety of ways. California facilities using natural gas and renewable fuels are expected to generate significantly more energy in 2015 than in past years to fill reductions of in-state hydroelectricity generation. Over the past three years, electric generation using natural gas has remained virtually constant, but solar generation has more than tripled.

In addition, California normally imports hydropower from the Pacific Northwest and from Hoover Dam in the Pacific Southwest. Indeed, additional energy imports from the Pacific Northwest are often available. This is expected to continue, despite drier conditions in the Pacific Northwest, in part because the Pacific Northwest tends to be winter peaking as opposed to summer peaking. Conditions for hydroelectric generation in the Pacific Southwest appear stable through 2015, though the average elevation at Lake Mead (formed by Hoover Dam) has continued to drop to levels much lower than normal.

The effects of the drought and additional power replacement expenditures will not be known immediately. For the major investor-owned utilities (IOUs), rates and power purchase agreements are based primarily on forecasts; thus, the potential rate impacts of low hydro generation will not be passed on to ratepayers immediately. Nonetheless, retail rates for the major IOUs may increase this year due to other factors (for example, already scheduled rate increases).

Drought-related outages as a result of reduced hydropower are not expected. Climate change is leading to higher temperatures – an increase of 2 degrees over the last 120 years⁴³⁰ – and it could get much hotter. As discussed in Chapter 9, climate change and droughts lead to dry conditions that increase the risk of fires. Of the top 20 recorded major fires in California's history, 13 have occurred since

2002.⁴³¹ California's fire season is becoming longer and wildfires more unpredictable as they threaten lives and the environment. Wildfires can make the state's electric grid more susceptible to outages because fires can take out substations, power plants, and transmission and distribution lines. This interruption to transmission is more of a concern than outages resulting from a reduced supply of hydropower.

The Valley Fire in Lake and Sonoma Counties in September 2015 was devastating to local people and economic activities. The fire also damaged transmission lines and geothermal electric generation facilities in The Geysers, the largest geothermal complex in the world. At least five geothermal generating plants were damaged, with extensive repairs and replacement required before they return to service. They are expected to be offline for several months. Geothermal energy is a baseload resource and provided more than 4 percent of California's electricity in 2014. The Geysers area provides a large portion of this energy.

Similarly, the Butte Fire, which affected Amador and Calaveras Counties, threatened to shut down and potentially destroy equipment and transmission for a 250 MW hydroelectric plant. Such fires disrupt the supply of renewable energy to California consumers, which would likely be replaced with fossil-fueled generation. According to the Northern California Power Authority, wildfires are also having a longer-term effect on hydropower generation. They report that erosion from run-off in areas scorched by wildfires, such as the Rim Fire in 2013 and the King Fire in 2014, is reducing reservoir capacity and hydroelectric services.⁴³² Aside from the personal human toll associated with

430 California Climate Tracker (http://www.wrcc.dri.edu/monitor/calmon/frames_version.html) accessed on August 15, 2015.

431 California Department of Forestry and Fire Protection, "Top 20 Largest California Wildfires," http://www.fire.ca.gov/communications/downloads/fact_sheets/20LACRES.pdf.

432 Northern California Power Authority (NCPA), NCPA Statement to California Air Resources Board regarding wildfire management, California Air Resources Board meeting, December 17, 2015, Regarding 15-10-3: Public Hearing on the Cap-and-Trade Auction Proceeds Draft Second Investment Plan (Fiscal Years 2016-17 through 2018-19), <http://www.ncpa.com/wp-content/uploads/2016/01/NCPA-Statement-on-Wildfires-to-CARB-Board-121515.pdf>.

the wildfires, there will be an environmental toll in terms of GHG emissions that has yet to be fully documented.

Thermal Power Plant Water Uses

Water supplies for thermal plants could be vulnerable for several reasons: curtailed federal and state water project deliveries, water rights seniority issues, reduced recycled water amounts, insufficient carryover or banked water, or depleted groundwater access. Plant owners are being urged to conserve and contact their water suppliers to fully understand current circumstances, and to determine whether actions to find alternative sources are needed or regulatory agencies need to be notified about potential production changes. In some cases, license or certification amendments could become necessary. For this reason, the Governor's Executive Order on the drought grants the Energy Commission authority to expedite the processing of amendments for power plant certifications for procuring alternative water supplies, if needed.⁴³³

Every thermal power plant generates heat that must be removed to keep the plant running efficiently, whether for condensing steam or cooling lubricating oil. Generally, the largest water use is condensing steam in a condenser to allow boiler water to be reused in the boiler cycle. Other power plant uses include, but are not limited to, cooling inlet air by evaporating water; cooling intermediate stages of compressors; quenching high combustion temperature to reduce oxides of nitrogen formation; steam and water injection to increase power output; cooling lubricating oils and fluids; cleaning equipment, including solar mirrors; and sending supplemental water to cooling towers. Most uses are integral components of enhanced energy production, but many uses can be replaced by *dry* processes (for example, air-cooled condensers and brushes to clean mirrors). *Dry* processes for rejecting heat will generally result in some degradation of power plant efficiency and output.

433 Governor Edmund G. Brown, Executive Order B-29-15. Issued April 1, 2015.

California has a relatively modern fleet of thermal power plants that consume little water. Since the *2003 Integrated Energy Policy Report*, the Energy Commission has worked with applicants to build new power plants in California to reduce water consumption through the use of recycled water and water-efficient technologies such as dry cooling. These sources and technologies provide a more environmentally responsible option and make the associated power plants more resilient to drought conditions. Since 2004, nearly 9,000 MW of combined-cycle projects have been built. Of that new capacity, about 34 percent use dry cooling and 51 percent use recycled water. The use of these types of cooling has significantly reduced freshwater demand.

Typical water consumption at power plants can vary due to technology, age, efficiency, fuel type, location, water quality, and wastewater disposal requirements/limitations. Overall, the California fossil-fueled power plant fleet is fairly water-efficient. Table 15 shows the typical water consumption by technology type. Coastal power plants using ocean water for cooling do not *consume* water and, therefore, have small impact on fresh water supplies and are not included in Table 15. The facilities using once-through cooling (OTC) do, however, have environmental impacts, such as impingement and entrainment of organisms on intake screens and thermal loading of the water body where discharge from the power plant occurs. As they are subject to the SWRCB's policy on OTC, most are likely to be replaced or shut down over the next decade. (OTC policies with respect to electricity reliability in Southern California are discussed further in Chapter 7.)

Thermal Power Plant Water Supplies

In response to California's drought and potential impacts on water sources for thermal power plant operations, Energy Commission staff identified relatively large power plants (75 MW or larger) and the water supplies they rely on for operation. Staff reviewed all 78 operating thermal power plants that met the size criterion and

Table 15: Water Consumption Rates for Thermal Power Plants

Technology	Typical Water Consumption Ranges Gallons per MWh		
	Minimum	Maximum	Average Use
Wet-cooled combined-cycle	200	300	250
Dry-cooled combined-cycle	5	20	13
Simple-cycle peaker – aero-derivative (1-100 MW)	12	345	180
Simple-cycle peaker – frame machine (>200 MW)	39	51	45
Geothermal – wet cooled	2,000	5,700	3,850
Solar thermal – dry cooled	24	52	38
Solar Thermal – wet cooled	500	1,500	1,000

Source: California Energy Commission staff

were under the Energy Commission’s jurisdiction, as well as an additional 22 nonjurisdictional power plants. Staff determined the location of these 100 thermal power plants and the water supply source for each power plant as one of three categories: recycled or reclaimed water, surface water, or groundwater.⁴³⁴

Energy Commission staff analyzed the water consumption at these 100 power plants, representing 29,000 MW of installed natural gas, solar thermal, and geothermal power, to estimate a representative water consumption rate. For reference, California has more than 78,000 MW⁴³⁵ of installed generation. The 100 projects do not include the roughly 14,000 MW⁴³⁶ of OTC power plants as they do not use fresh water nor *consume* the water they withdraw from the river or ocean, but use it only to reject heat. As they are subject to the State Water Resources Control Board’s (SWRCB) policy on OTC, most are likely to be replaced or shut down during the policy compliance period.

434 http://www.energy.ca.gov/siting/documents/2015-06-25_water_supplies_map.pdf.

435 http://energyalmanac.ca.gov/electricity/electric_generation_capacity.html.

436 Ibid. As of December 31, 2014, there are 14,705 MW of OTC capacity on-line, including the Diablo Canyon Nuclear Plant. Natural gas-fired OTC capacity as of December 31, 2014, is 12,382 MWs – the capacity factor of these OTC units averaged about 11 percent.

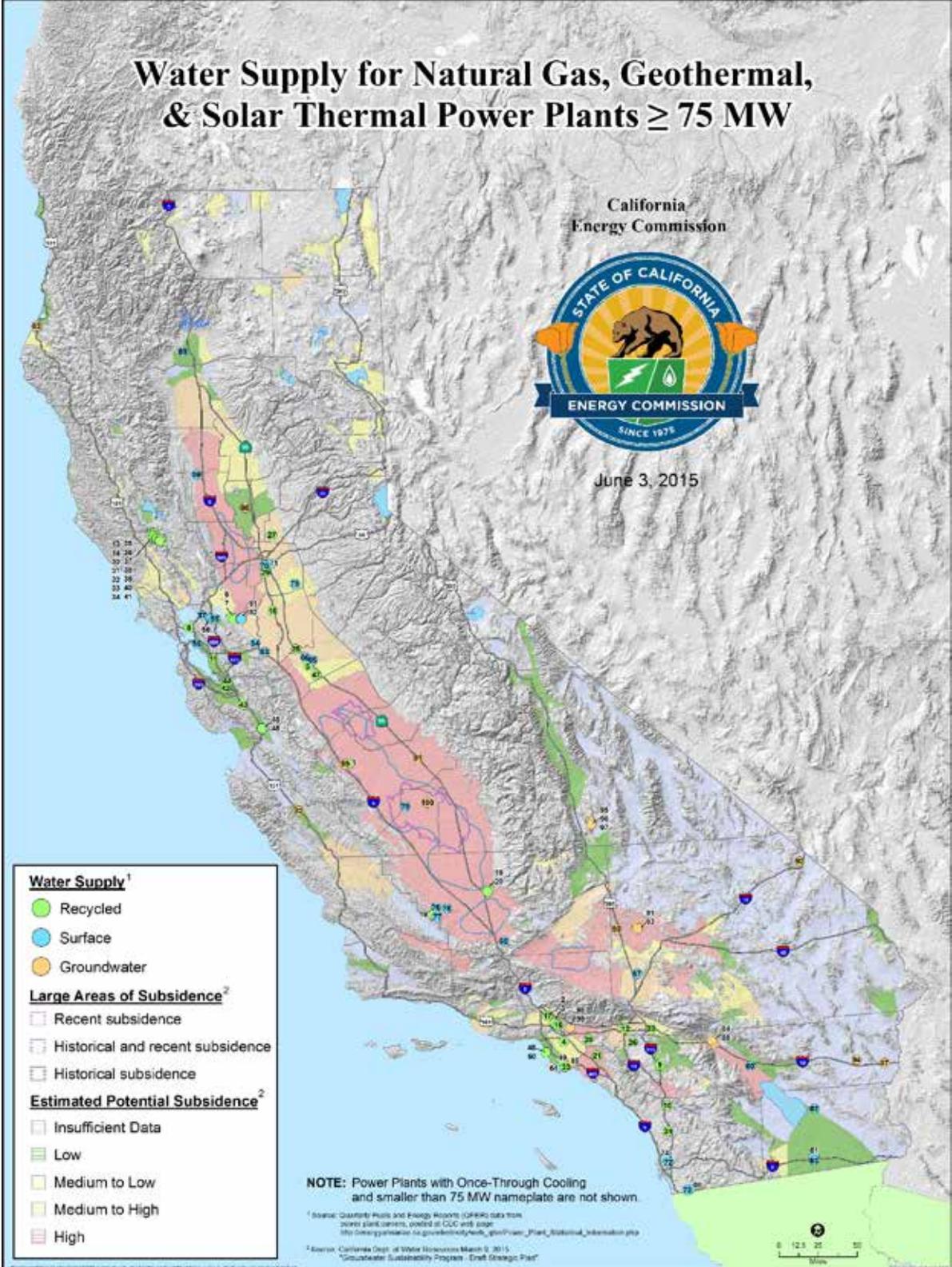
The 100 thermal power plants examined use nearly 123,000⁴³⁷ acre-feet of water per year.⁴³⁸ Among these are 30 power plants that use surface water, 20 that use groundwater, and 50 that rely on recycled and degraded groundwater as the primary water source. The plants using surface water are spread across 17 water districts, with no water district having more than 8 percent of the total operating capacity (in megawatts). (See Figure 68.) The 20 plants using groundwater as a primary supply are spread across 13 groundwater basins, limiting the effect to any groundwater basin. Only two plants are in basins with significant overdraft and subsidence related to groundwater pumping. These latter plants represent about 2 percent of the 29,000 MW of operating capacity examined.

Surface water supplies are the most uncertain supply sources. Power plants that receive freshwater supply from a public supplier have generally been informed that they will receive their contracted amount similar to other municipal and industrial users. In some cases, however, the public supplier is delivering surface water as the primary supply, which is subject to water rights

437 This is only part of the fleet, as many water-intensive geothermal units are not larger than 75 MW and are not included in this list or the estimate of average acre-feet of water per year.

438 One acre-foot is 325,851 gallons.

Figure 68: Water Supply for Natural Gas, Geothermal, and Solar Thermal Power Plants



Source: California Energy Commission staff

regulated by the SWRCB. Federal and state regulators have significantly curtailed some surface water deliveries, which has the potential to reduce deliveries to power plants. So far, affected plants have been able to identify and access alternative water supplies, sometimes requiring license amendment approvals by the Energy Commission. Over the past 18 months, four projects have required and obtained licensing amendments for water supply. To date, however, none have had to rely on the authority for expedited licensing granted by the Governor's Executive Order.

Power plants operators that rely on groundwater from on-site wells generally are concerned about the depth of groundwater and the adequacy of their wells to produce the necessary supply. In some areas of California, groundwater levels have dropped, and modification of well equipment has been required to maintain the necessary supply. Although adequate supply from groundwater for the near term appears to be available, (sometimes requiring well modification where needed), this use does not address long-term effects, such as overdraft and subsidence of the groundwater basin.

Power plants that use secondary- or tertiary-treated recycled water as the primary supply are considered to have the most drought-resistant supply. Many power plants in California are priority customers for the recycled water suppliers. These power plants generally are a customer that uses recycled water year-round, which is desirable for recycled water suppliers. In several cases, the supplier has specifically agreed to supply multiple power plants first and provide other users only a portion of the supply, if there is excess available.

There is some concern about the effects of water conservation being required in cities and how that conservation may affect recycled water supply. If significant water conservation is achieved, as directed by the recently adopted SWRCB regulations, the flows to wastewater treatment plants that produce recycled water could be reduced. Recycled water could also become more valuable to sell on the market. Experience thus far is that there has been little effect on recycled water supplies, and there does not appear to be significant concern on the part of the suppliers.⁴³⁹

Energy Commission staff believes the effects of urban water conservation on recycled water will be case-specific and depend on the source(s) of flow the treatment plant receives. In some cases, there are significant volumes of wastewater treated at a plant to both secondary and tertiary levels. In these cases, secondary-treated effluent is discharged where there is little to no further human use. Any reduction in flow could be made up by treating more of the secondary treated effluent to tertiary standards. In other areas of California, wastewater is treated to tertiary standards, yet there are limited customers to use it, and excess is discharged with no further human use. In these cases, even if there were reductions in wastewater flow, there would be adequate flow to make up for the need at a power plant or other customers. In general, municipalities that supply recycled water specifically for reuse will plan and build only the infrastructure necessary to serve known and proposed customers that have indicated they are willing or required to use recycled water for operation. In those cases, supply of wastewater may not be a limitation, but the ability to expand infrastructure to meet demand may be.

439 Most water conservation plans expect significant reductions in landscape irrigation, which do not affect flows to wastewater treatment plants.

Energy Efficiency and Water Appliances Regulations

In addition to tracking the impacts of the drought on the energy sector, the Energy Commission is also focused on improving drought resiliency and energy efficiency through new and existing programs. Among these, the Energy Commission is responsible for adopting water efficiency standards to reduce the water consumption of appliances that use a significant amount of water on a statewide basis. Under this authority, the Energy Commission began investigating standards for toilets, urinals, and faucets as part of the first phase of its 2012 Order Instituting Rulemaking Proceeding.⁴⁴⁰

Executive Order B-29-15 authorized the Energy Commission to adopt emergency regulations establishing standards that improve the efficiency of water appliances for sale and installation in new and existing buildings.⁴⁴¹ Within seven days of the Governor's Executive Order, the Energy Commission adopted standards for toilets, kitchen and lavatory faucets, and urinals. These standards are projected to save 10.3 billion gallons of water, 30.6 million therms of natural gas, and 218 gigawatt-hours (GWh) of electricity each year after the regulations are in effect.⁴⁴² Over 10 years, the regulations will save an estimated 730 billion gallons of water.

440 http://energy.ca.gov/appliances/2012rulemaking/notices/prerule-making/2012-03-14_Appliance_Efficiency_OIR.pdf.

441 http://gov.ca.gov/docs/4.1.15_Executive_Order.pdf.

442 Natural gas savings, electricity savings, and avoided GHG emissions are based on both the reduced amount of electricity required to distribute water across the state and, for products that use hot water, the reduced amount of energy (natural gas or electricity) required to heat water. Additional unquantified energy savings and avoided GHG emissions may accrue from reduced wastewater treatment.

On August 12, 2015, the Energy Commission adopted tiered showerhead standards. Tier I reduces the maximum flow rate from 2.5 gallons per minute to 2.0 gallons per minute, and Tier II will require showerheads to use no more than 1.8 gallons per minute. Tier I is in alignment with the WaterSense specification, the California Plumbing Code, and the California Green Building Code Tier II, which is effective in 2018.⁴⁴³ The combined tiered standards will save 38 billion gallons of water annually once all existing stock is replaced. The Energy Commission also amended its residential bathroom faucet standards to immediately implement a 1.5 gallon-per-minute requirement, saving an additional 730 million gallons of water, delaying the 1.2 gallon-per-minute standard for six months to give manufacturers sufficient time to comply and allowing retailers to sell existing stock.

Tables 16 and 17 below show the regulatory changes and estimated savings for each appliance, both in first-year savings and after full stock turnover.

The Energy Commission is investigating additional opportunities to achieve water savings through standards for landscape and agricultural irrigation equipment and commercial dishwashers. In this effort to identify additional savings opportunities, it will be important to have the cooperation and support of the investor-owned and publicly owned utilities during development of codes and standards, as well as during implementation of incentive programs for water-efficient appliances.

443 U.S. EPA, "WaterSense Specification for Showerheads," http://www.epa.gov/watersense/docs/showerheads_finalspec508.pdf.

California Plumbing Code, Title 24, Chapter 4, section 408.2.

Department of Housing and Community Development, *A Guide to the California Green Building Standards Code (Low-Rise Residential)*, June 2010, http://www.hcd.ca.gov/codes/state-housing-law/calgreenguide_complete_6-10.pdf.

Table 16: First-Year Savings from Water Appliance Regulatory Standards

	Regulatory Changes		First-Year Savings			
	Original standard	New standard	Water (Mgal)	Natural Gas (million therms)	Electricity (GWh)	Savings (\$M)
Toilets	1.6 gpf*	1.28 gpf	904.6	-	9.08	8.21
Urinals	1.0 gpf	0.125 gpf	308	-	3.10	2.31
Kitchen Faucets	2.2 gpm**	1.8 with optional 2.2 gpm	3,290	10.78	82.9	48.56
Residential Lavatory Faucets	2.2 gpm	Tier I: 1.5 gpm Tier II: 1.2 gpm***	4,453	16	118	68
Public Lavatory Faucets	2.2 gpm	0.5 gpm	1,420	5.81	14.2	16.95
Showerheads	2.5 gpm	Tier I: 2.0 gpm	2,433	13	83	44
		Tier II: 1.8 gpm	1,448	8	49	26
Total			14,256.6	53.59	359.28	214.03

Source: California Energy Commission

*gpf= gallons per flush, **gpm=gallons-per-minute, *** For simplicity, first-year savings for faucets presented after Tier II takes effect because Tier I is effective for less than the full year

Table 17: Annual Savings from Water Appliance Regulatory Standards After Stock Turnover

	Annual Savings After Stock Turnover				GHG Emissions Avoided (tons eCO ₂)
	Water (Mgal)	Natural Gas (million therms)	Electricity (GWh)	Savings (\$M)	
Toilets	16,990	-	171.2	154.7	58,880
Urinals	3,550	-	35.6	26.6	12,290
Kitchen Faucets	29,700	97.4	749	439	1,807,370
Residential Lavatory Faucets	44,834	160	1,187	683	
Public Lavatory Faucets	16,280	53.4	164	184	
Showerheads	38,802	202	1,322	702	
Total	150,156	512.8	3,628.8	2,189.3	3,511,151

Source: California Energy Commission

Water Appliance Rebate Program

In Executive Order B-29-15, the Governor directed the Energy Commission, jointly with the Department of Water Resources (DWR) and the SWRCB, to implement a time-limited statewide appliance rebate program to provide monetary incentives for the replacement of inefficient household devices. The Energy Commission proposes to establish two programs using this funding: a statewide rebate program and a direct-install program focused on disadvantaged communities. The Energy Commission initially developed the programs around an estimated budget of \$30 million; however, funding for the programs has not yet been authorized.

Statewide Rebate Program

The Energy Commission proposes to offer a statewide water appliance rebate program through participating retailers. Rebates may be claimed through a simple online application, mail-in rebate, or instant rebates at participating big box retailers (for example, Sears, Home Depot, and Best Buy). At the outset of the program, the Energy Commission plans to focus on appliance rebates for clothes washers, given the reliance of these appliances on heated water (which increases GHG emissions) and the associated large share of indoor water consumption. Additional appliances such as dishwashers, kitchen and lavatory faucets, and showerheads may be considered for inclusion in the rebate program, depending on initial program uptake.

The Energy Commission is contracting with an experienced rebate administrator to manage the statewide rebate program. The rebate administrator will perform services that include developing and managing a website to administer the rebate program; creating a database to record and track all program elements; educating consumers and retailers about the rebate program; providing estimates of available incentive funding for the program duration; tracking estimated water savings, energy savings, and GHG

emission reductions; developing an online rebate application; receiving rebate applications and validating claims to ensure program guidelines are met; issuing rebate checks to consumers who submit compliant applications; and developing a point-of-sale instant rebate program at participating big box retailers. The rebate administrator will also provide a toll-free customer service call center and, overseen by the Energy Commission, guard against fraud, waste, and abuse of the rebate program.

Initial rebates for clothes washers are proposed at \$100 each. The Energy Commission has selected qualifying clothes washers based on the greatest available water savings, energy savings, and GHG reductions compared to the cost of administering a rebate program. Eligible clothes washers must be listed in the Energy Commission's Appliance Efficiency Database and be ENERGY STAR®-compliant. A list of qualifying clothes washers will be made available on the rebate program website, and only those appliance models that have been shown to meet the specified rebate program criteria will qualify for a rebate.

The Energy Commission selected the ENERGY STAR certification as the efficiency standard for the rebate program based on:

- » The prominence ENERGY STAR brand has in the marketplace of providing consumers with information on products that can save energy, save money, and help reduce GHG emissions.
- » ENERGY STAR-certified clothes washers use about 25 percent less energy and 40 percent less water than other washers, resulting in significant savings.
- » The ENERGY STAR criteria for clothes washers changed on March 7, 2015, resulting in greater savings.

To calculate water savings and energy savings for clothes washers, the Energy Commission estimates savings of 13 gallons of water per load compared to 27 gallons of

water per load as the base for older, inefficient models.⁴⁴⁴ This is roughly consistent with ENERGY STAR-certified clothes washers that average 13 gallons of water per load. Once implemented, the appliance rebate program anticipates issuing \$100 rebates for 130,000 clothes washers, with annual savings of 5,110 gallons of water and 212 pounds of carbon dioxide emissions per unit.

Direct-Install Appliance Program

The direct-install appliance program is the second phase of the Energy Commission's drought-response incentives under Executive Order B-29-15. This program proposes to target disadvantaged and drought-impacted communities in California by dedicating funding to projects physically located within disadvantaged community census tracts using the CalEnviroScreen tool.

The Energy Commission proposes to partner with the Department of Community Services & Development (CSD) and DWR through CSD's existing residential Low-Income Weatherization Program by adding water-reducing measures to the existing weatherization program, including the installation of new clothes washers, dishwashers, kitchen and bathroom faucets, and showerheads to eligible single-family and multifamily residents. The aim of the partnership is to leverage CSD's ability to identify disadvantaged community residents in need of energy-efficient, water-reducing appliances and fixtures. The intent is not only to save water during the current drought, but to lower GHG emissions due to reduced water heating demand. CSD proposes to amend its existing contracts with providers across California to include water-saving appliances in the program and include water-saving measures in its tracking database to report water savings, energy savings, and GHG emissions reductions.

Coordination with Other State Agencies

In addition to working directly with CSD, the Energy Commission and DWR have formed a partnership to implement both phases of the Executive Order appliance rebate programs. Using the same rebate administrator as the Energy Commission, DWR will offer online rebates for water-efficient toilets and for turf replacements to residents statewide with funds from Proposition 1 (2014).⁴⁴⁵ Alongside the Energy Commission's direct-install program, DWR will provide water-efficient toilets through CSD's Low-Income Weatherization Program, under a separate Interagency Agreement. The DWR effort will focus on disadvantaged communities, particularly in California's Central Valley. Funding for this DWR work will also use Proposition 1 funds.

Together, the Energy Commission and DWR staff held public information and guideline workshop meetings to inform communities and receive input on the rebate program in three locations around the state. Future public meetings will also be held related to the direct-installation program with CSD. The interagency coordination for both the rebate and direct-install effort will provide the public a coordinated point of access for the toilet, clothes washer, and turf replacement rebates and a similarly coordinated process for engaging the direct-install program through the long-standing Low-Income Weatherization Program.

444 Vickers, Amy, *Handbook of Water Use and Conservation*, Water-Plow Press, 2001.

445 California Water Code, Section 79750 et seq.

Table 18: Proposed Water Energy Technology Program Budget

Topic	Funding Amount (\$)
Phase 1. Agriculture. Rebates and Grants	Up to \$10 million
Phase 2. Commercial, Industrial, and Residential Sectors. Competitive Grants	Up to \$16 million
Phase 3. Desalination (existing facilities). Competitive Grants	Up to \$3 million
Administration	\$1 million
Total	\$30 million

Source: California Energy Commission staff

Water Energy Technology Program

In response to California’s ongoing drought, Governor Brown’s Executive Order B-29-15 also directed the Energy Commission to implement a statewide water energy technology program as part of its work to address the drought.⁴⁴⁶

To accelerate the deployment of innovative water- and energy-saving technologies and reduce GHG emissions, the Energy Commission, jointly with DWR and the SWRCB, will implement the Water Energy Technology (WET) Program to fund innovative technologies for businesses, residents, industries, and agriculture that meet the following criteria:

- » Document readiness for rapid, large-scale deployment (but not yet widely deployed) in California.
- » Demonstrate actual operation beyond the research and development stage.

- » Display significant GHG emission reductions as a result of implementing technologies that reduce on-site energy and water use.

In addition to the DWR and the SWRCB, the program was developed with input from other state agencies and stakeholders participating in four public meetings held between June and August 2015 in Fresno, Chico, Lynwood, and Pomona.⁴⁴⁷ More than 60 comments were received on program development and design, and these were considered in the developing the program.⁴⁴⁸ The Energy Commission approved the *WET Rebate Program Guidebook* on July 8, 2015, contingent upon legislative approval of funding. The rebate and grant solicitations for the WET Program will be released subsequent to funding approval.⁴⁴⁹

Like the water appliance rebate program, the Energy Commission developed the WET Program around an estimated budget of \$30 million; however, funding for this program has not yet been authorized. Table 18 summarizes the proposed funding areas for the WET Program.

446 Governor Edmund G. Brown Jr., *Executive Order B-29-15*, April 1, 2015, http://gov.ca.gov/docs/4.1.15_Executive_Order.pdf.

447 <http://www.energy.ca.gov/wet/documents/index.html>.

448 <https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=15-WATER-01>.

449 http://docketpublic.energy.ca.gov/PublicDocuments/15-WATER-01/TN205314_20150709T172849_WET_Rebate_Guidebook.pdf.

This program will reduce GHG emissions by funding the use of advanced energy- and water-saving technologies. Funded projects must reduce potable on-site energy use through more energy-efficient equipment and reduce water use through the low- or no-water appliances, water recycling, or other measures. This program will also fund innovations to reduce energy use and GHG emissions from existing desalination facilities, while increasing water production efficiency.

Once funding has been approved, the Energy Commission plans to implement the WET Program in three phases:

» Phase 1 will focus on the agricultural sector, including rebates for high-efficiency irrigation systems that meet specified design and equipment performance criteria, and competitive grants for customized projects. Greater use of innovative energy- and water-saving technologies will have the added benefit of reducing water pollution in the agriculture sector, as fertilizer use and water use are directed to what the plant needs and eliminates excess fertilizer runoff into surface or groundwater. Farmers will also benefit from lower energy and water costs, without affecting crop yield.

» Phase 2 will focus on the residential, commercial, and industrial sectors, including water and wastewater treatment providers. Grants will be available for customized projects that reduce on-site energy and water use. Examples include installation of innovative water-saving technologies that also reduce energy use for food service, use of waste heat recovery and water reuse projects, and use of no- or low-water using systems that have energy-saving benefits for industry.

» Phase 3 will fund grants for existing desalination projects, including existing plants and plants under construction. Projects must result in GHG emission reductions, while increasing on-site water production efficiency. Projects must use commercially available, innovative technologies; research projects are not eligible.

The Energy Commission has set a target of at least 10 percent of WET Program funds for projects located in disadvantaged communities that directly benefit disadvantaged communities. To achieve this target, the WET Program will conduct outreach in disadvantaged communities and provide higher rebate and grant amounts for projects that benefit disadvantaged communities. For instance, projects located in and benefitting disadvantaged communities can receive a rebate or competitive grant that provides up to 75 percent of eligible costs, provided the projects meet applicable requirements. WET program funding for other projects will be limited to 50 percent of eligible project costs. The projects funded will also provide sustained economic benefits to disadvantaged communities by decreasing energy and water costs.

State Agency Updates on the Drought

On August 28, 2015, the Energy Commission hosted a multiagency workshop focused on the drought, with representatives from federal, state, and local agencies, as well as research, industry, agriculture, and business groups. Within the workshop, Energy Commission staff summarized the analyses and programs described in this chapter, while other state agencies and other organizations provided updates on their own activities.

Several representatives summarized their research on the drought and its impacts on California's hydrological systems. Peter Gleick, cofounder of the Pacific Institute, presented data highlighting the severity of recent temperature and precipitation anomalies, with the 36-month period ending in 2014 being both the

hottest and driest of such periods since 1895.⁴⁵⁰ While California's combined agricultural revenues are at all-time highs, this is based in part on an unsustainable combination of unsustainable production practices, improving water-use efficiency, and strong markets.⁴⁵¹ A representative from DWR summarized a U.S. National Air and Space Administration study on subsidence resulting from groundwater depletion, indicating the Central Valley is sinking nearly 2 inches per month, which is without precedent. Subsidence threatens many types of infrastructure, including water aqueducts, pumping wells, gas pipelines, and rail lines.⁴⁵² (See Chapter 9 on Climate Change Research, Climate Impacts on the Natural Gas System, for more discussion on subsidence.) Finally, Dan Cayan with the Scripps Institution of Oceanography highlighted recent oceanic conditions that are historically associated with strong El Niño years. A multivariate index of El Niño conditions through the spring and summer of 2015 suggests the potential for an unusually large El Niño season, which is historically correlated with higher amounts of precipitation. While encouraging from a water supply perspective, the potential confluence of large storms, high tides, and rising sea levels could also be of concern.⁴⁵³ El Niño seasons also tend to provide more rainfall in Southern California than Northern California, which could have implications for regional groundwater recharging.⁴⁵⁴

Meanwhile, research from the Energy Commission's Public Interest Energy Research (PIER) and the Electric

450 Integrated Energy Policy Report workshop on California's Drought Response, August 28, 2015, transcript, pp. 134–135.

451 Integrated Energy Policy Report workshop on California's Drought Response, August 28, 2015, transcript, p. 136.

452 Integrated Energy Policy Report workshop on California's Drought Response, August 28, 2015, transcript, p. 88.

453 Integrated Energy Policy Report workshop on California's Drought Response, August 28, 2015, transcript, pp. 43–49.

454 Integrated Energy Policy Report workshop on California's Drought Response, August 28, 2015, transcript, pp. 43–49.

Program Investment Charge (EPIC) programs has also informed understanding of climate and the drought.⁴⁵⁵ Key among these findings:

- » Within the Sierra Nevada region, average precipitation from 2012 to 2015 has been low, but not exceptionally so within the historical record. Average temperature, however, has been exceptionally high.
- » Using paleorecord and historical data to characterize natural variability for the U.S. Southwest, the likelihood of severely prolonged droughts (less than 35 years) within this century is between 20 and 50 percent.
- » Water managers can improve reservoir management practices by incorporating probabilistic hydrologic forecasts, rather than relying on observed precipitation.
- » Researchers can identify areas of the state where there is highest suitability for groundwater banking in agriculture soil.
- » Ongoing subsidence may compromise the integrity of plugged well casings, which risks increasing methane leakage from abandoned wells.

The representative from the California Independent System (California ISO) Operator reported that the organization is looking at programs for better dispatch flexibility and pumps, as well as water management to help maintain reliability and address overgeneration issues discussed in Chapter 2. Along with this, specialized processes are being developed to help the more isolated regions of the state that rely heavily on hydropower.⁴⁵⁶

455 Integrated Energy Policy Report workshop on California's Drought Response, August 28, 2015, transcript, pp. 159–165.

456 Integrated Energy Policy Report workshop on California's Drought Response, August 28, 2015, transcript, pp. 36–43.

Several agencies are also involved in water conservation. The SWRCB oversees mandated reductions in urban water use, including the state's overall goal of a 25 percent reduction relative to 2013. The SWRCB representative reported that mandatory requirements began in June 2015, and, when combined with July 2015, reductions were averaging roughly 29 percent.⁴⁵⁷ DWR is implementing programs that are focused on consumer incentives for low-flow toilets and turf replacements.⁴⁵⁸ The California Department of General Services' representative reported that its Water Conservation Grant Program, focused on improving water efficiency at state facilities, has supported 153 water conservation projects, with savings totaling around 278 million gallons per year.⁴⁵⁹ Finally, the California Public Utilities Commission (CPUC) presented information on its water-energy nexus proceeding, intended to determine the cost-effectiveness of joint water energy projects for utility ratepayers. As part of this proceeding, the CPUC has developed a water-energy calculator that quantifies the amount of energy required to move and treat water and calculates the associated savings benefits.⁴⁶⁰

Nonstate agency workshop participants also highlighted the efforts they were undertaking to conserve water and provided lessons for how others might adopt them. For instance, the University of California representative reported that the UC system is taking steps to reduce irrigation of ornamental turf while preserving irrigation for significant plant assets, enhancing leak detection, and expanding use of recycled water. Having completed most of the improvements it could self-finance,

the UC system is also looking into establishing a financing program for water efficiency akin to its energy efficiency program.⁴⁶¹ The Los Angeles Department of Water and Power representative reported that it is developing an Energy Efficiency Technical Assistance Program that offers incentives for customized water conservation projects at large facilities.⁴⁶²

The need for better data collection and data availability was also a frequent subject of participants' comments. The representative from the U.S. Navy Region Southwest reported that it considers water data acquisition to be a key area of focus in its Water Strategy goal of 25 percent water reduction. A key priority is the installation of advanced metering infrastructure, which allows for real-time analysis of water use (rather than having to wait weeks for results). Dr. Frank Loge of the UC Davis Center for Water-Energy Efficiency presented a tool under development that allows customers to view and compare their water use within their neighborhood. The same tool allows for localized estimates of the energy intensity of water pumping and delivery, which can advance the understanding of energy savings and GHG emission reductions from specific water efficiency measures.⁴⁶³ The CPUC's water-energy nexus proceeding is also proposing a pilot for energy utilities to provide water utilities with access to smart meter data collection information as an energy efficiency measure.⁴⁶⁴

Workshop participants also made presentations on the value and opportunities for expanding and sustaining the water supply, including storm water capture, recycled water, and groundwater recharging. The representative

457 Integrated Energy Policy Report workshop on California's Drought Response, August 28, 2015, transcript, pp. 108–111.

458 Integrated Energy Policy Report workshop on California's Drought Response, August 28, 2015, transcript, pp. 85–87.

459 Integrated Energy Policy Report workshop on California's Drought Response, August 28, 2015, transcript, pp. 125–126.

460 Integrated Energy Policy Report workshop on California's Drought Response, August 28, 2015, transcript, pp. 72–82.

461 Integrated Energy Policy Report workshop on California's Drought Response, August 28, 2015, transcript, pp. 120–123.

462 Integrated Energy Policy Report workshop on California's Drought Response, August 28, 2015, transcript, pp. 230–231.

463 Integrated Energy Policy Report workshop on California's Drought Response, August 28, 2015, transcript, pp. 141–151.

464 Integrated Energy Policy Report workshop on California's Drought Response, August 28, 2015, transcript, p. 78.

from the SWRCB reported that it is developing the Storm Water Strategic Initiative, which aims to shift management of storm water in ways that improve water quality and supply, including immediate support for increasing storm water capture and use.⁴⁶⁵ The use of recycled water also offers an opportunity to increase the state's supply of nonpotable water. California uses 600,000-700,000 acre-feet of recycled water per year for a mix of agricultural uses, landscape irrigation, groundwater recharge, and industrial uses (including power generation, as previously mentioned). SWRCB has established goals for increasing this by 200,000 acre-feet by 2020 and an additional 300,000 acre-feet by 2030. Toward these goals, SWRCB provided funding in March 2014 of roughly \$800 million for recycled water projects.⁴⁶⁶ Peter Gleick of the Pacific Institute highlighted protection of agricultural lands that can also serve as locations for recharging depleted groundwater, particularly in the southern San Joaquin valley.⁴⁶⁷

Recommendations

» **Increase accessibility of real-time water and energy data.** By providing more detailed and accessible reports of water and energy consumption, both companies and consumers can make effective changes to usage and efficiency by changing habits and technology in both the short and long term. Investment in widespread installation of metering technology could enable the analytics required for customers to understand and optimize their water usage.

» **Support diversification of water resources.** Integrated management of water supplies must combine variable supplies, such as storm water, and reliable supplies, such as recycled water. Increasing the use of storm water can help reduce draw on local reservoirs. Agricultural land can play a role through on-farm storm water capture and groundwater recharge. Similarly, the state needs to develop broader, sustained strategies for increasing the use of recycled water. The State Water Resources Control Board has already adopted goals of increasing recycled water usage over 2002 levels by at least 1 million acre-feet per year by 2020 and 2 million acre-feet per year by 2030, as well as increasing storm water usage over 2007 levels by at least 500,000 acre-feet per year by 2020 and 1 million acre-feet per year by 2030. Developing adequate data for measuring progress toward these goals remains a key priority.

» **Encourage research and investment into water system improvements that promote leak detection and minimization of water losses.** Poorly designed and managed water infrastructure can lead to tremendous amounts of water leakage and loss. In September 2014, Governor Brown signed Senate Bill 1420 (Wolk, Chapter 490, Statutes of 2014) that required, among other things, that all urban water suppliers quantify water losses in their respective urban water management plans, beginning with plan updates that were filed July 1, 2016. Information on leaks from these updates can be used to guide future research and investment into minimizing future water losses.

» **Investigate additional opportunities to achieve water savings through appliance efficiency standards.** The near-term focus should be on landscape and agricultural irrigation equipment, as well as commercial dishwashers. When identifying additional savings opportunities, it will be important to have the cooperation and support of the investor-owned and publicly owned utilities through codes and standards proposals and implementation of incentive programs for water-efficient appliances.

465 Integrated Energy Policy Report workshop on California's Drought Response, August 28, 2015, transcript, p.16.

466 Integrated Energy Policy Report workshop on California's Drought Response, August 28, 2015, transcript, pp.113-115.

467 Integrated Energy Policy Report workshop on California's Drought Response, August 28, 2015, transcript, pp. 139-140.

» **Encourage efficient designs of home hot water delivery systems.** The length of piping between the water heater and each fixture, the pipe diameter, and the material from which the pipe is made can all have a significant effect on the hot water delivery system efficiency because those factors determine the volume of water stored within the delivery system. The volume of stored water affects how long it takes for hot water to reach each fixture and the temperature retention of the water as it is delivered; systems with the least stored volume waste the least amount of water and energy.

» **Continue the California Public Utilities Commission's (CPUC's) evaluation of the water-energy nexus.** The CPUC recently authorized pilot programs to examine whether utility-sponsored water-saving projects can provide sufficient ratepayer benefit to qualify as energy efficiency projects. The CPUC has developed a Water-Energy Calculator to help evaluate such programs. If water savings programs can be reliably expected to enhance energy efficiency, there may be added opportunities for electric utilities to sponsor such programs in the future.

» **Implement and sustain consumer incentives for water conservation.** In 2015, California state agencies have begun developing and implementing several incentive programs designed to encourage water conservation, including water appliance rebates; direct installations of toilets, faucets, and other water appliances; turf replacement rebates; and early market deployment of innovative water technologies. Local water agencies have also begun offering incentives of their own. As initial results from these projects become available, the programs can be reviewed, revised (if needed), and expanded to further maximize these benefits.

CHAPTER 9

Climate Change Research



Addressing climate change is the driving force in California's energy policy. The energy sector is the leading source of climate pollutants – accounting for about 80 percent of the state's greenhouse gas (GHG) emissions. As discussed throughout this report, the state is working to dramatically reduce its GHG emissions through multipronged efforts to advance the Governor Edmund J. Brown Jr.'s 2030 goals to:

- » Double energy efficiency in existing buildings (Chapter 1) and advance low-carbon heating fuels (Chapter 6).
- » Increase renewable energy to 50 percent (Chapter 2 for renewable generation and Chapter 3 for transmission planning to support increased use of renewable energy).
- » Reduce petroleum use in the transportation sector by 50 percent (Chapters 4 and 6).

In turn, climate change affects how energy is used (see Chapter 5 on the electricity forecast) and is likely to lead to future droughts like the one California is experiencing, which also affects energy use and production (Chapter 8). To meet the state's long-term GHG reduction goals, advancement of these efforts will require additional

research and development to help new technologies come to market. This chapter is focused on research on climate science as it applies to California's energy system.

In April 2015, Governor Brown issued an Executive Order (B-30-15)⁴⁶⁸ that set a goal to reduce emissions to 40 percent below 1990 levels by 2030. This builds on the historic Global Warming Solutions Act of 2006 (Núñez, Chapter 488, Statutes of 2006) that requires California to reduce GHG emissions to 1990 levels by 2020. The 2030 goal will guide midterm regulatory policy and investments in California and maintain momentum to reduce GHG emissions to 80 percent below 1990 levels by 2050.

Executive Order B-30-15 also directed state agencies to strengthen California's preparedness for climate change. As discussed in more detail in the Introduction, Executive Order B-30-15 directed the California Natural Resources Agency to update the state's climate adaptation plan every three years and ensure that the provisions of the plan are fully implemented. The updates must include information on vulnerabilities of each sector, including energy, and take into account differential impacts across California's geographic regions. In support of these efforts, the Governor ordered the state to continue its rigorous climate change research program,

468 <http://gov.ca.gov/news.php?id=18938>.

which is focused on understanding the impacts of climate change and how best to prepare for, mitigate, and adapt to such impacts. This comprehensive research program is laid out in the *Climate Change Research Plan for California*.⁴⁶⁹

The Energy Commission through its research program and outreach efforts, such as the *Integrated Energy Policy Report (IEPR)*, has been a leader in conducting and supporting cutting edge climate research related to energy sector resilience. The *2013 IEPR* included a discussion of the vulnerability of the energy sector to climate change and strategies to safeguard it, with a focus on the electricity sector. This chapter summarizes new research findings on the vulnerability of California's energy system since the *2013 IEPR*, including analysis of the vulnerability and potential adaptation options for the natural gas sector and petroleum transportation fuels. The chapter closes with recommendations on next steps for further research on adaptation to climate change in the energy sector.

Vulnerability and Adaptation Options

California's energy system is vulnerable to a variety of climatic changes, including impacts from changes in temperature and precipitation patterns, extreme events (including wildfire, inland flooding, and severe storms), and sea-level rise.^{470, 471} Some impacts to the energy

sector, including more frequent and severe extreme heat episodes and decreasing snow-water content in the northern Sierra Nevada, are already becoming evident.⁴⁷² Historical climatic data will not suffice to support future management of energy systems, nor public health or environmental management as they relate to energy, as the climate is diverging from the historical "envelope." In other words, key climate parameters are starting to move beyond historically observed variability at a rate that makes historical data a poor predictor of future climate. This phenomenon, commonly called *nonstationarity*, may be at work in historical annual temperature data for California and the world. (See Figure 69.) However, there are not yet enough data to conclude definitively whether California is already outside the envelope. There are two important features to note in Figure 69 below. First, the natural fluctuations, or variability, of temperature at the planetary scale are less pronounced than in California. Second, 2014 was the hottest year on record in California; annual temperature moved far outside the envelope of natural variability.⁴⁷³ It is also important to note that most of the warming in California occurred during the winter, contributing to snowpack reduction in the Sierra Nevada.

Planning for the energy sector in California must work under the assumption that future climatic conditions will be beyond the envelope of prior experience; however, this does not mean that the energy sector has to operate in an information vacuum. Many impacts of the changing climate regime are known. The California Coastal Commission, for example, has determined that sufficient information exists that sea-level rise must be taken into account in permitting major new, long-lived facilities in

469 California Environmental Protection Agency, Climate Action Team, *Climate Change Research Plan for California*, February 2015, http://www.climatechange.ca.gov/climate_action_team/reports/CAT_research_plan_2015.pdf.

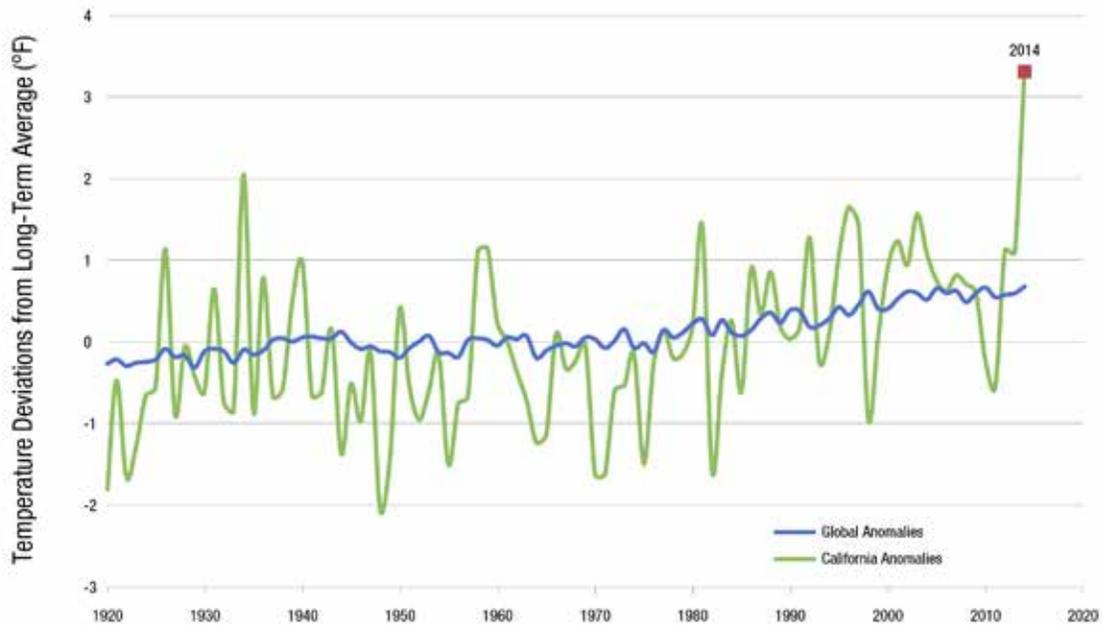
470 Franco, Guido, Mark Wilson. 2005. *Climate Change Impacts and Adaption in California*. California Energy Commission. Publication Number: CEC-500-2005-103-SD.

471 Stoms, David, Guido Franco, Heather Raitt, Susan Wilhelm, Sekita Grant. 2013. *Climate Change and the California Energy Sector*. California Energy Commission. Publication Number CEC-100-2013-002.

472 Office of Environmental Health Hazard Assessment, *Indicators of Climate Change in California Report Summary*, 2013.

473 The deviations are from the 1949 to 2005 average. Absolute temperature in 2014 in California was 59.4 °F, which is a deviation of 3.3 °F from the 1949 to 2005 average temperature. This is both the greatest deviation from the average and the highest annual temperature experienced in California.

Figure 69: Global and California Temperature Anomalies



Source: California Climate Tracker and NASA

the coastal zone.⁴⁷⁴ Still, there are clear areas for future research that would better inform the process of making the energy sector more resilient to climate impacts.

The Vulnerability of California's Energy Sector

The impacts of climatic changes on California's energy system include decreased efficiency of thermal power plants and substations; decreased capacity of transmission lines; risks to energy infrastructure from extreme events, including sea-level rise, coastal flooding, and wildfires; less reliable hydropower resources; and increased peak electricity demand.⁴⁷⁵

⁴⁷⁴ California Coastal Commission, *Sea Level Rise Policy Guidance: Interpretive Guidelines for Addressing Sea Level Rise in Local Coastal Programs and Coastal Development Permits*, August 2015, <http://www.coastal.ca.gov/climate/slrguidance.html>.

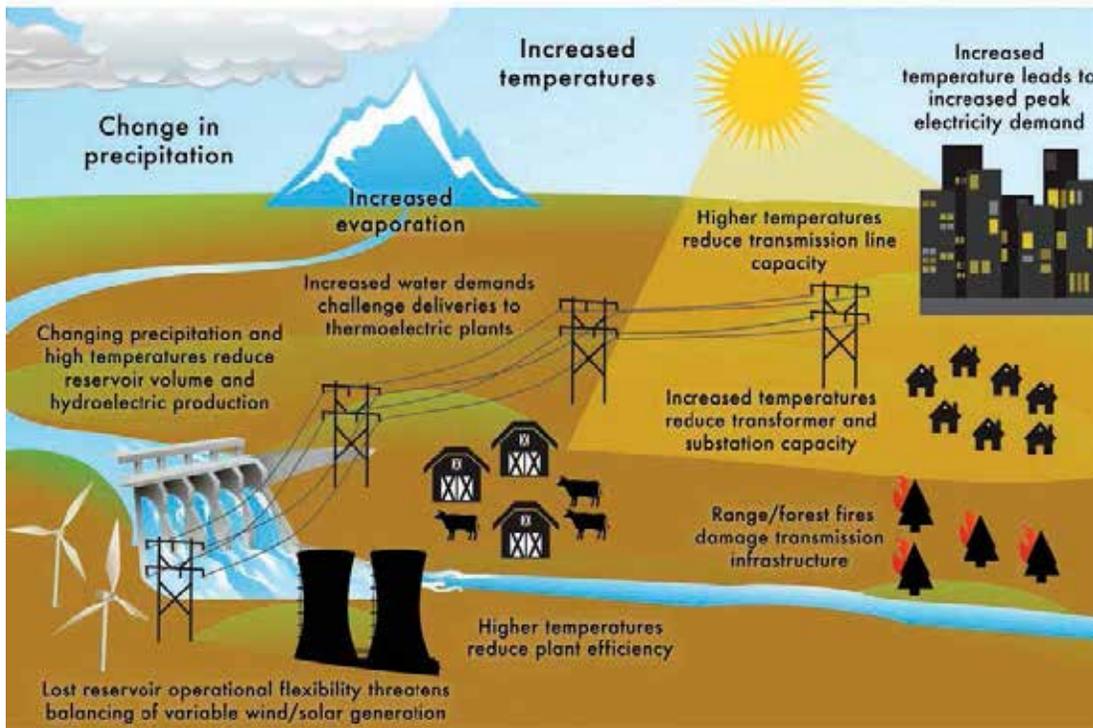
⁴⁷⁵ Stoms, David, Guido Franco, Heather Raitt, Susan Wilhelm, Sekita Grant. 2013. *Climate Change and the California Energy Sector*. California Energy Commission. Publication Number CEC-100-2013-002.

The types and severity of impacts vary across the electricity, natural gas, petroleum, and transportation sectors and vary geographically. Over the past several years, the Energy Commission has supported research to identify these potential impacts and investigate magnitude, distribution, and adaptation options. A few key examples from recently completed research on climate impacts on energy supply (including infrastructure and capacity) and energy demand are described below. To date, significantly more research has been done on electricity than on other aspects of the energy sector like natural gas or transportation fuels.

Climate Impacts to the Electricity System

As outlined in the *2013 IEPR*, California has invested considerable resources to understand the potential impacts of

Figure 70: Vulnerabilities to Climate Change in the Electricity Sector



Source: *Assessment of Climate Change in the Southwest United States*, 2013, Chapter 12

climate change on the electricity system.^{476, 477} Figure 70 illustrates the potential impacts of climate change for the six states in the southwest United States, including California.

The rest of this section focuses on scientific information generated in the two years since the release of the *2013 IEPR*. Recent studies indicate that the severity of the financial costs to the electricity system from climate impacts depend on whether the system is designed to reduce GHG emissions.⁴⁷⁸ The U.S. Environmental Protection Agency

(U.S. EPA) engaged research groups using different models of the electricity system for an analysis of costs associated with a business-as-usual scenario and two policy scenarios.⁴⁷⁹ The policy scenarios assume global climate mitigation efforts in concert with deep GHG reductions in the United States. As a result, these scenarios experience much lower ambient temperatures than the business-as-usual scenario. Prior work on energy scenarios has assumed an electricity

476 California Energy Commission. 2013. *2013 Integrated Energy Policy Report*. Publication Number: CEC-100-2013-001-CMF.

477 Stoms, David; Franco, Guido; Raitt, Heather; Wilhelm, Susan; Grant, Sekita. 2013. *Climate Change and the California Energy Sector*. California Energy Commission. Publication Number CEC-100-2013-002.

478 Many mitigation measures in the electricity sector are also adaptive. See, for example, discussions of renewable energy in this chapter.

479 These are 1) POL4.5 CS3, an emissions reduction policy and temperature pathway that are consistent with a radiative forcing target of 4.5 watts per meter square, along with cumulative power sector emissions reductions of 8.9 percent from 2015-2050; and 2) POL3.7 CS3, an emissions reductions policy and temperature pathway consistent with a radiative forcing target of 3.7 watts per meter square, with no emissions reduction policy. McFarland, J., Y. Zhou, L. Clarke, P. Sullivan, J. Colman. 2015. "Impacts of Rising Air Temperatures and Emissions Mitigation on Electricity Demand and Supply in the United States: A Multi-Model Comparison." *Climatic Change*. Volume 131, Issue 1, p. 113.

infrastructure that is static and compared the changes in demand under different climate regimes, or has estimated changes in the electricity system without considering climate impacts. The U.S. EPA's study considered both changes to the electricity system and climate impacts, for example, increased temperatures leading to greater demand for the electricity required for cooling. The policy scenarios in the U.S. EPA's work simulated the changes needed in the electricity system to reduce emissions to levels that are compatible with climate stabilization,⁴⁸⁰ such as 4.5 watts per meter square by 2050.⁴⁸¹

The climate effects simulated included the overall increased demand of electricity in the United States and the degraded efficiency of thermal power plants due to higher temperatures. The researchers found similar costs for both the business-as-usual and the policy scenarios.⁴⁸² This controverts the commonly held belief that substantial reductions of GHG emissions are expensive and increase overall costs. However, because the business-as-usual scenario experienced higher temperatures than in the policy scenarios, the business-as-usual scenario saw increases in electricity demand and, therefore, required more generating capacity. These extra costs are more or less equivalent to the additional investments required to decrease electricity sector GHG emissions by nearly 50 percent by 2050.⁴⁸³ In other words, the cost of mitigation (reducing GHG emissions) in the electricity systems was roughly equivalent to the cost of serving the

increased electricity demand of a hotter climate in the business-as-usual scenario.

This finding is in agreement with an Energy Commission study, which found that higher temperatures at the end of this century would require about a 40 percent increase of generation capacity under a scenario not involving GHG emission reductions (business-as-usual).⁴⁸⁴ The U.S. EPA also supported similar studies for other sectors of the U.S. economy, such as public health, agriculture, forestry, and water resources. Its summary report *Climate Change in the United States: Benefits of Global Action*,⁴⁸⁵ released in June 2015, concludes that global GHG mitigation avoids costly damages in the United States, the benefits of mitigation increase with time, and adaptation reduces overall damages to certain sectors.

The *2013 IEPR* included a 10-year peak electricity demand forecast to 2024 using climate scenarios the Scripps Institution of Oceanography (Scripps) developed for the Energy Commission. The forecast estimated a potential peak electricity demand of up to 1.6 gigawatts (GW), equivalent to the generating capacity of two large power plants. The 2013 forecasts were based on the climate scenarios driven by the results of global climate models that were used for the 2007 Intergovernmental Panel on Climate Change (IPCC) Assessment.⁴⁸⁶ For the *2015 IEPR*, Scripps developed an improved method to translate the outputs from a new suite of climate

480 *Climate stabilization* refers here to the maximum amount of extra energy per unit of time absorbed by the Earth above preindustrial levels. The extra energy is measured in watts per square meters.

481 McFarland, J., Y. Zhou, L. Clarke, P. Sullivan, J. Colman, 2015, "Impacts of Rising Air Temperatures and Emissions Mitigation on Electricity Demand and Supply in the United States: A Multi-Model Comparison," *Climatic Change*, Volume 131, Issue 1, pp. 11–125.

482 The study considered only the *direct* costs of serving increased generation demand in *all* scenarios; however, the study did not estimate or compare costs of other climate impacts, for example, damage to infrastructure from sea-level rise, across scenarios.

483 *Ibid.*

484 Sathaye, Jayant, Larry Dale, Peter Larsen, Gary Fitts, Kevin Koy, Sarah Lewis, and Andre Lucena. 2012. *Estimating Risk to California Energy Infrastructure From Projected Climate Change*. California Energy Commission. Publication Number: CEC-500-2012-057.

485 U.S. Environmental Protection Agency, 2015, *Fuel and Carbon Dioxide Emissions Savings Calculation Methodology for Combined Heat and Power Systems*.

486 IPCC, 2007, *Climate Change 2007: Synthesis Report*, Contribution of Working Groups I, II and III to the Fourth Assessment Report of the Intergovernmental Panel on Climate Change (Core Writing Team, Pachauri, R.K and A. Reisinger. [eds.]), IPCC, Geneva, Switzerland, p.104.

models used for the 2014 IPCC Assessment⁴⁸⁷ into climate projections for California. As explained in Chapter 5, higher projected maximum temperatures derived from the scenarios increased the statewide peak demand forecast by more than 500 MW in the mid demand case by 2026 and by about 780 MW for a global emission scenario that is more compatible with historical carbon dioxide emissions. Both are mid demand projected changes, while the 2013 forecast was closer to the maximum expected demand. Staff also derived projected changes in heating and cooling degree days from the scenarios, which affect electricity consumption. The impact on consumption was slight (around 70 GWh statewide in 2026) in the mid demand forecast, as heating degree days decreased at a much higher rate than cooling degree days increased.⁴⁸⁸

Climate Impacts on Renewable Energy Generation and Hydropower

By 2020, California's Renewables Portfolio Standard requires 33 percent of electricity used in California to be generated by eligible renewable resources. Governor Edmund G. Brown Jr. set a goal of increasing this to 50 percent by 2030.⁴⁸⁹ Large hydropower is not eligible to meet the state's renewable energy targets under statute, but it provides an important source of electricity for California. (See Chapter 2 for more information about meeting the state's renewable goals). Figure 71 shows the close relationship between

annual precipitation from October 1 to September 30 (water year) and hydropower generation in July through September. For more information about the current drought, including how it is affecting the state's energy system and California's response to it, see Chapter 8.

With climate change, patterns of precipitation in California are expected to continue shifting toward rain rather than snow, which California has traditionally relied on as a natural reservoir, storing water for the drier summer months. The shift from snow to rain appears to be due to increased temperatures. As shown in Figure 72, there has traditionally been a close link between hydropower generation and annual precipitation⁴⁹⁰ that falls prior to the summer; however, higher temperatures may disrupt that relationship. The changing precipitation patterns may mean a reduction in California hydropower in the hotter months of the year.⁴⁹¹ Having a better understanding of climate change impacts on hydropower is critical to modeling the Northern California electricity system.

In addition to the problems of reduced snowpack, hydropower faces a less certain future from the possibility of temperature-exacerbated droughts. Some scientists argue that climate change will substantially increase the risk of drought because high temperatures increase the transport of water from land to atmosphere via evaporation and transpiration.^{492, 493} Chapter 8 discusses the need to prepare for a future in which drought is the norm rather than the exception in California.

487 IPCC, 2014, *Climate Change 2014: Synthesis Report*. Contribution of Working Groups I, II and III to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change (Core Writing Team, R.K. Pachauri and L.A. Meyer [eds.]), IPCC, Geneva, Switzerland, p. 151.

488 Kavalec, Chris and Asish Gautam. 2015. *California Energy Demand Updated Forecast, 2016-2026, Preliminary Electricity Forecast*. California Energy Commission, Energy Assessment Division. Publication Number: CEC-200-2015-003. http://docketpublic.energy.ca.gov/PublicDocuments/15-IEPR-03/TN207439_20160115T152221_California_Energy_Demand_20162026_Revised_Electricity_Forecast.pdf.

489 Inaugural Address. Remarks as prepared January 5, 2015. Edmund G. Brown Jr.

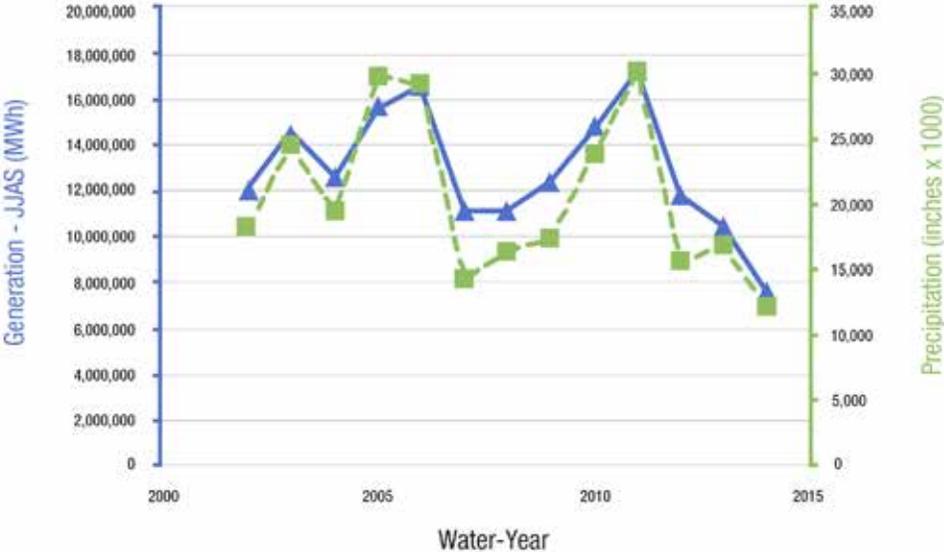
490 Annual precipitation here is measured by water years.

491 Rheinheimer, D.E., Scott T. Ligare, Joshua H. Viers. 2012. *Water and Energy Sector Vulnerability to Climate Warming in the Sierra Nevada: Simulated the Regulated Rivers of California's West Slope Sierra Nevada*. California Energy Commission. Publication Number: CEC-500-2012-016.

492 Diffenbaugh, N. S., Daniel L. Swain, Danielle Touma. 2015, "Anthropogenic Warming Has Increased Drought Risk in California," *Proceedings of the National Academy of Sciences* 112:3931-3936.

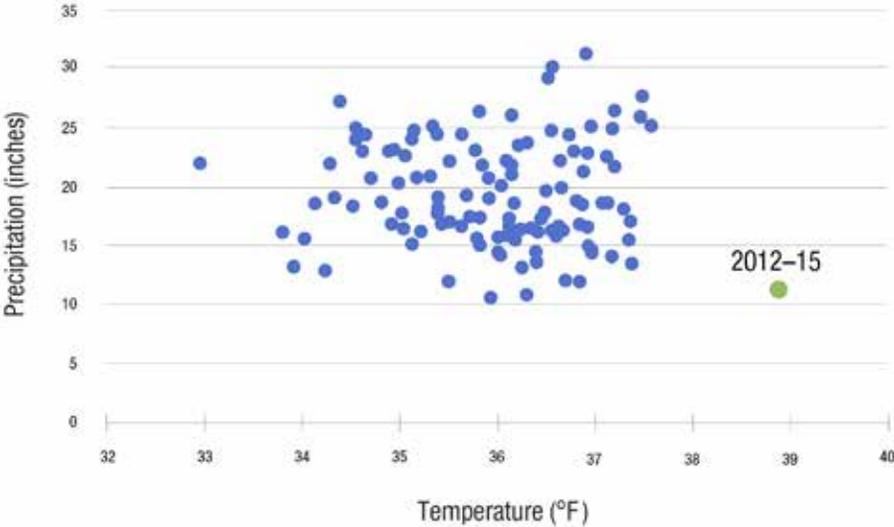
493 Mann, M.E., Peter H. Gleick. 2015, "Climate Change and California Drought in the 21st Century," *Proceedings of the National Academy of Sciences*, Vol. 112, no. 13, 3858-3859.

Figure 71: Hydropower Generation in July-September and Annual Water-Year Precipitation



Source: Generation from the Energy Information Administration, precipitation from the California Climate Tracker

Figure 72: Sierra Nevada Region Temperature (°F) and Precipitation (inches) for Winter (December, January, and February) in the Last 115 Years Plotted as Four-Year Averages



Source: California Climate Tracker

The severity of the current drought is evident in Figure 66, which shows temperature and precipitation in the last 115 years in the Sierra Nevada. As illustrated in Figure 72, the average winter (defined as the months of December, January, and February) over the past four years was not only dry, but unusually hot. Precipitation – especially snow – in the Sierra Nevada is of primary importance for hydropower generation. The combination of dry and warm temperatures in that region tends to exacerbate water scarcity for summer power generation because under those conditions precipitation tends to fall as rain instead of snow. Furthermore, under dry and hot conditions more water than usual is “lost” to evaporation and transpiration. This one-two punch of decreased snowpack and increased evapotranspiration has led some studies to conclude that the current drought is the most severe in the last 1,000 years.⁴⁹⁴

Research supported by the Energy Commission has included analyses of high-elevation reservoirs used mainly to produce hydropower^{495, 496, 497, 498, 499} and

low-elevation units such as Folsom Lake near Sacramento that are designed primarily to store water for consumption in cities and agricultural fields^{500, 501, 502} and for flood protection. These were separate studies that did not consider the hydraulic connection between high- and low-elevation units. Understanding that connection is critical, however, because climate impacts may result in high-elevation units releasing substantially higher water flows in the wintertime (see Figure 73), somewhat hampering the flood protection function of low-elevation units.

Sources of geothermal energy are tied to underground systems fed by rainwater and snowmelt. Geothermal power plants reinject groundwater from the geothermal resource to replenish the system.⁵⁰³ Geothermal power plants tend to decline in productivity over time because the resource is used faster than is naturally replenished by rainwater and snowmelt. At the Geysers geothermal power plant near Santa Rosa, California, treated wastewater is used to replenish the geothermal resource and help stabilize declining productivity.⁵⁰⁴ If patterns and location of rainwater or snowmelt change, or the availability of rainwater or snowmelt declines, this could affect natural long-term recharge

494 Griffin, D., K. J. Anchukaitis, 2014, “How Unusual Is the 2012–2014 California Drought?” *Geophys. Res. Lett.*, 41:2014GL062433+.

495 Vicuña, Sebastian, Rebecca Leonardson, John A. Dracup, Michael Hanemann, Larry Dale. 2006. *Climate Change Impacts on High-Elevation Hydropower Generation in California’s Sierra Nevada: A Case Study in the Upper American River*. California Energy Commission. Publication Number: CEC-500-2005-199-SF.

496 Vicuña, Sebastian, John A. Dracup, Larry Dale. 2009. *Climate Change Effects on the Operation of Two High-Elevation Hydropower Systems in California*. California Energy Commission. Publication Number: CEC-500-2009-019-D.

497 Madani, K., J.R. Lund. 2010, “Estimated Impacts of Climate Warming on California’s High-Elevation Hydropower,” *Climatic Change*, Vol. 102, No. 3-4, pp. 521–538.

498 Guegan, Marion, Kaveh Madani, Cintia B., Uvo. 2012. *Climate Change Effects on High-Elevation Hydropower System with Consideration of Warming Impacts on Electricity Demand and Pricing*. California Energy Commission. Publication Number: CEC-500-2012-020.

499 Rheinheimer, D.E., Scott T. Ligare, Joshua H. Viers. 2012. *Water and Energy Sector Vulnerability to Climate Warming in the Sierra Nevada: Simulated the Regulated Rivers of California’s West Slope Sierra Nevada*. California Energy Commission. Publication Number: CEC-500-2012-016.

500 Lund, Jay R., Tingju Zhu, Marion W. Jenkins, Stacy Tanaka, Manuel Pulido, Melanie Taubert, Randy Ritzema, Inês Ferreira, 2003, *Climate Warming & California’s Water Future*, pp. 1-10.

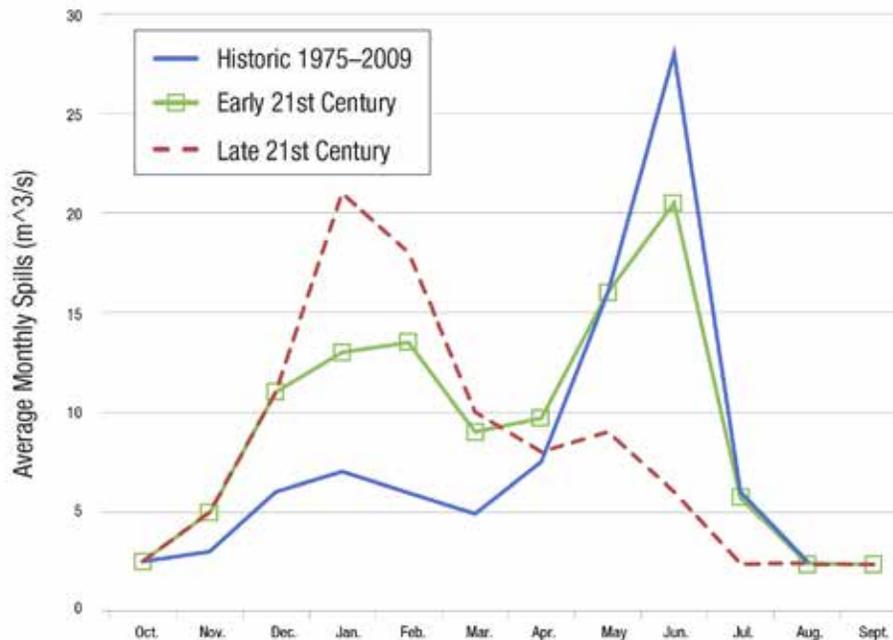
501 Georgakakos, K. P., N. E. Graham, T. M. Carpenter, T. M., and H. Yao, 2005, “Integrating Climate-Hydrology Forecasts and Multi-Objective Reservoir Management for Northern California,” *Eos, Transactions American Geophysical Union*, AGU 86:122-127.

502 Georgakakos, K. P., Nicholas E. Graham, Aris P. Georgakakos. 2007. *Integrated Forecast and Reservoir Management (INFORM) for Northern California: System Development and Initial Demonstration*. California Energy Commission. Publication Number: CEC-500-2006-109.

503 Clark, C.E., C.B. Harto, J.L. Sullivan, M.Q. Wang, 2011, *Water Use in the Development and Operation of Geothermal Power Plants*.

504 “The Santa Rosa Geysers Recharge Project Celebrates 10 Year Anniversary”. 2013. <http://ci.santa-rosa.ca.us/news/Pages/UtilitiesNewsRel.aspx>.

Figure 73: Simulated Operations for Upper American River Project System During Three Periods



Source: Adapted from Vicuña et al., 2011

rates, potentially increasing the need for outside water to replenish the productivity of geothermal resources.

Solar photovoltaic (PV) systems tend to be less efficient at higher temperatures.⁵⁰⁵ Projections for the Southwest suggest efficiency reductions on the order of 0.7 to 1.7 percent with higher temperatures in 2050.⁵⁰⁶ Information on whether and where patterns of excessive heat may change in California due to climate change can help inform research on solar PV systems to improve performance on hot days. Similarly, additional studies on whether and where wind patterns in California may change due to climate

change⁵⁰⁷ can help inform wind energy planning, forecasting, and integration as California increases the proportion of electricity it consumes from wind energy. The scientific understanding of how climate change may affect solar and wind resources has not substantially changed since the release of the *2013 IEPR*. In other words, projections of changes in solar and wind regimes for the California region have not matured enough to provide a clear picture of potential changes. A recent paper noted that wind performance depends not only on wind speed, but on the density of the air; unfortunately, there are substantial uncertainties in the projections of both parameters.⁵⁰⁸

505 U.S. Department of Energy. 2013. "Photovoltaic Cell Conversion Efficiency Basics."

506 Bartos, Matthew D., Mikhail V. Chester, "Impacts of Climate Change on Electric Power Supply in the Western United States," *Nature Climate Change*, 5, pp. 748–752, 2015, Macmillan Publishers Limited.

507 Rasmussen, D. J., T. Holloway, and G. F. Nemet, 2011, "Opportunities and Challenges in Assessing Climate Change Impacts on Wind Energy – A Critical Comparison of Wind Speed Projections in California," *Environmental Research Letters* 6:024008+.

508 Bartos, Matthew D., Mikhail V. Chester, "Impacts of Climate Change on Electric Power Supply in the Western United States," *Nature Climate Change*, 5, pp. 748–752. 2015, Macmillan Publishers Limited.

Climate Impacts on the Natural Gas System

Aspects of the energy system are vulnerable to sea-level rise and intense storms. Recent work on natural gas infrastructure in the San Francisco Bay and Sacramento/San Joaquin Delta sheds light on the nature of that vulnerability and on the importance of dynamic modeling to assess risk. The islands of the Sacramento-San Joaquin Delta contain crucial natural gas infrastructure: transmission lines, underground natural gas storage facilities, distribution infrastructure, and abandoned natural gas wells. The islands – and the infrastructure they house – rely on levees to protect them from flooding. Prior research using satellite data suggested that the levees and Delta islands may be subsiding,⁵⁰⁹ leaving the islands and the natural gas infrastructure more vulnerable to flooding. That enhanced risk is compounded by projected sea-level rise.

A recent study led by University of California, Berkeley, uses high-resolution hydrodynamical modeling to investigate the impacts of an extreme storm coupled with sea-level rise on natural gas pipelines in the Bay Area and the Delta, as well as the California coast.⁵¹⁰ This work was a substantial improvement over previous models that are either too coarse in scale to simulate flooding events in the Delta or do not capture the dynamic processes associated with storms. These dynamic processes include wave action, diurnal tides, and short-term peak water levels – all of which are critical in determining actual risks to infrastructure.

According to the study, the Delta levees are not at risk from overtopping from an extreme storm (100-year event) in the absence of sea-level rise and in the absence of

substantial further subsidence, provided that “prepared” is defined as no overtopping from a storm. If such a storm were paired with a 1.4 meter sea-level rise – which is a possible, high-end 2100 estimate for California – then the storm would pose extensive risk to critical natural gas infrastructure, as well as other energy-related and transportation infrastructure. Such risks include inundation of roughly 400 miles of transmission lines, including backbone transmission at Antioch, key transmission on Sherman Island, and transmission loops in San Jose, San Francisco, and Sacramento. Moreover, under such conditions, inundation of natural gas storage at MacDonald Island is indicated.⁵¹¹

Even with this new information, risks may still be underestimated because the research did not account for subsidence of Delta levees, which exacerbates impacts of sea level due to lowering levee crests. Given the importance of subsidence in the Delta, the Energy Commission’s Public Interest Energy Research (PIER) Natural Gas Research and Development program has an ongoing interagency agreement with the U.S. Geological Survey to deploy a new portable Light Detection and Ranging system and determine the actual level of subsidence in key levees protecting islands with important natural gas infrastructure. While other monitoring systems like aircraft sampling would take months or years to return data, the Light Detection and Ranging surveys will be available within a few days of field collection. This new Light Detection and Ranging system has the potential to substantially lower the costs of periodic surveying of the Delta levees.

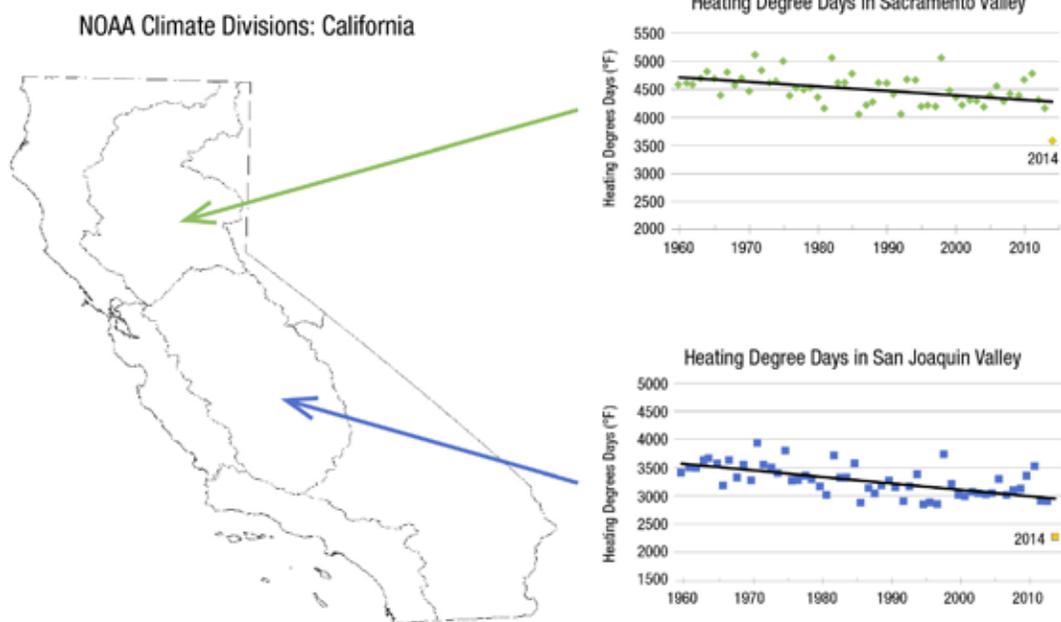
Another story related to climate change and subsidence appears to be unfolding in the interior of California, where subsidence that is linked to heavy reliance on

509 Brooks, Benjamin A., and Deepak Manjunath. 2012. *Twenty-First Century Levee Overtopping Projections from InSAR-Derived Subsidence Rates in the Sacramento-San Joaquin Delta, California: 2006–2010*. California Energy Commission. Publication Number: CEC-500-2012-018.

510 Radke, J., et al, 2015, *Assessment of Bay Area Gas Pipeline Vulnerability to Sea Water*, University of California, Berkeley, Public Interest Energy Research report in preparation.

511 Ibid.

Figure 74: Changes in Heating Degree Days in the National Oceanic and Atmospheric Administration (NOAA) Sacramento and San Joaquin Climatic Zones



Source: NOAA

groundwater in the absence of surface water supplies⁵¹² may be exposing abandoned natural gas wells and natural gas pipelines. Subsidence can be geographically uneven and result in deformation or even ruptures of underground pipelines.⁵¹³ The risk to the natural gas supply system from climate-linked subsidence is an emerging issue that has not yet been thoroughly studied; yet the potential for improving climate adaptation for the energy sector while lowering GHG emissions makes this a priority area for future research on climate-related impacts to the natural gas system. For information on the effects of subsidence

as a result of increased groundwater withdrawal due to drought, see Chapter 8.

Space and water heating in California is dominated by energy devices, such as furnaces, consuming natural gas. Observations of heating degree days⁵¹⁴ in California in the last few decades show a declining trend. For example, as depicted in Figure 74, the decline of heating degree days is about 15 percent from 1960 to 2014 in the San Joaquin Valley, which should have decreased the amount of natural gas consumed for space heating in a more or less proportional way. Since the consumption of natural gas in weather-dependent energy services for space and

512 Scanlon, Bridget R., Claudia C. Faunt, Laurent Longuevergne, Robert C. Reedy, William M. Alley, Virginia L. McGuire, and Peter B. McMahon, 2012, "Groundwater Depletion and Sustainability of Irrigation in the US High Plains and Central Valley," *Proceedings of the National Academy of Sciences*. USGS Staff – Published Research, Paper 497.

513 Baum, R. L., D. L. Galloway, and E. L. Harp, 2008, *Landslide and Land Subsidence Hazards to Pipelines: U.S. Geological Survey Open-File Report 2008-1164*, p. 192.

514 *Heating degree days* is a parameter that is designed to reflect the demand for energy needed to heat a home or building. Heating degree days are calculated using ambient air temperatures and a base temperature (for example, 65 degrees) below which it is assumed that space heating is needed. Similarly, *cooling degree days* are designed to reflect the demand for energy needed to cool a home or building.

water represents about 88 percent⁵¹⁵ of the natural gas consumed in the residential sector, the number of heating degree days and cooling degree days is closely linked to energy demand and, consequently, energy savings. For example, a decrease in heating degree days can result in substantial energy savings. The overall downward trend in heating degree days, at least in the Central Valley, seems to be linked to reported reductions of Tule fog in the same region.⁵¹⁶

Climate Impacts on Petroleum Transportation Fuels

The vulnerability of oil refineries to climate change is an understudied area of research.⁵¹⁷ Yet given the proximity of most of California's refineries to the ocean, they may be at risk of saltwater intrusion and damage from sea-level rise and storm surges.⁵¹⁸ Refineries are also major consumers of electricity. This means that the climate vulnerabilities of some electricity generation stations would be shared by those refineries. Water availability is also a concern for oil refineries. Refineries in California use a great deal of water to create steam used in industrial processes. Weather-related extreme events linked to climate change, such as prolonged droughts, could alter the average quantity and seasonal deposition of snowfall in the Sierra Nevada watershed, significantly reducing the volume of seasonal runoff and water availability in

California. Decreased water supplies tend to give rise to competition among all uses, with the possibility of decreased availability for energy. To the extent that potable water sources are no longer available for use by industry (including refineries), other potential sources would have to be pursued, along with strategies and technologies aimed at reducing water intensity at refineries. For more information on how the drought is impacting California's energy system, see Chapter 8.

Oil pipelines may also be sensitive to sea-level rise at ports. California's petroleum and transportation fuels infrastructure normally involves the movement of raw and finished transportation fuel products via marine vessels and a network of pipelines that connect wharves to refineries, storage tank farms, distribution terminals, and associated structures. The wharf structures used to unload and load marine vessels are designed to accommodate a wide range of tidal variation daily and annually. An increase in the mean average sea level, however, would significantly raise the maximum high-tide levels, such that the existing wharf system used for moving petroleum products and other waterborne commerce might need to be adjusted.

There are no studies available on the climate impacts on the transportation fuel supply network in California (for example, oil refineries and oil pipelines), although the California Department of Transportation has funded and continues to support studies on the vulnerability of the surface transportation system in California. The Energy Commission plans to help fill this gap with a study that will also be part of California's fourth climate change assessment with a focus on the transportation fuels infrastructure. Risks may potentially include those from sea-level rise, inland flooding, landslides, and wildfires; but the severity of those risks and associated geographic distribution have yet to be determined. For example, it is possible that some refineries may be well protected by levees or are situated outside areas that are most at risk of inundation during extreme storms.

515 *California Historical Residential Natural Gas Use*, 2015, http://www.energyalmanac.ca.gov/naturalgas/residential_use.html.

516 Baldocchi, Dennis, Eric Waller, 2014, "Winter Fog Is Decreasing in the Fruit Growing Region of the Central Valley of California," *Geophys. Res. Lett.* 41:2014GL060018+.

517 More information about GHG emissions from the petroleum sector is also needed to better understand climate impacts from this sector. Chapter 7, *Changing Trends in California's Sources of Crude Oil* puts forward a recommendation to address this need.

518 Perez, Pat. 2009. *Potential Impacts of Climate Change on California's Energy Infrastructure and Identification of Adaptation Measures*. California Energy Commission. Publication Number: CEC-150-2009-001.

Initial Integration of Mitigation and Adaptation

The elements of California's energy system do not stand independent of one another. They are interconnected with broader policy and socioeconomic changes and biogeochemical changes from altered climate. California's energy system is not independent from those of other western states. Yet thus far, energy scenarios developed for California have separated elements; they have tended to assume either a static energy infrastructure and compared that against future climate change, or have examined evolving energy infrastructure in light of policy goals, but not taken into account climate change. In practice, both California's climate and energy systems are changing very rapidly. Future studies for California must consider both simultaneously. In addition, a rapid decarbonization of the energy system (mitigation) represents an opportunity for the scientific community to develop information that could be used to guide this development to create an energy system that is less vulnerable (adaptation) to climate impacts.

The California Natural Resources Agency is leading the preparation of the next California climate assessment. It published a draft scope of work⁵¹⁹ late in 2014 identifying the research projects that it plans to support, covering non-energy research such as the identification of adaptation options for the agricultural sector and how increased frequency and intensity of wildfires may affect insurance rates. The Energy Commission, via its Electric Program Investment Charge (EPIC) and Natural Gas Research and Development Programs, is supporting energy-related research for the climate assessment. The California Natural Resources Agency scope of work

describes how the energy and non-energy research projects are being coordinated and integrated. For example, all the research teams will use a common set of climate, sea-level rise, and socioeconomic scenarios to ease the integration of results.

Multiple studies and new areas of research have been identified for the energy sector, such as the evaluation of risks to electricity distribution networks from wildfires. Prior work on wildfire risk done for the 2012 California climate assessment addressed only the risk to transmission lines. Since most of the grid disruptions from wildfires are due to their effects on the distribution system, new research is needed. Another study will identify potential barriers to the timely adoption of attractive adaptation measures such as regulatory, legal, and institutional constraints. In-depth regional studies for the electricity and natural gas systems are also planned. Prior assessments identified only exposure of energy facilities to 100-year storms on top of sea-level rise to identify power plant, transformers, and other energy facilities potentially at risk; however, the inundation maps used for these studies did not consider the evolution of the California shoreline with sea-level rise and the protecting effect afforded by levees and armoring that may be protecting these energy plants. The new studies will address these issues. The California Natural Resources Agency will fund the application of an advanced coastal evolution model that takes into account the movement of sand with currents, wave action during storms, and erosion of cliffs, among other important physical factors. The Energy Commission will use this information to produce more realistic estimates of the impacts to energy facilities.

For the first time the Energy Commission will be able to support studies looking at the vulnerability of oil refineries, oil pipelines, and other units that are part of the network supplying transportation fuels such as gasoline and diesel. The Energy Commission is promoting a joint effort by three major research groups (LBNL along with UC Berkeley, UC Irvine, and E3) to develop more realistic energy scenarios for California that simultaneously

519 California Natural Resources Agency, 2015, *California's Fourth Climate Change Assessment*.

consider rapid changes to energy infrastructure, changing climate, and climate impacts to energy infrastructure. Final results of these coordinated scenarios will be released in 2018. The combined work represents the next generation of scenarios for California, being produced with an eye toward making the research products that are feasible and useable for decision makers and energy stakeholders. The scenarios will build off prior work and include several common elements; for example, they will use common climate and sea-level rise scenarios that are under development for the fourth California climate assessment. The energy scenarios will also be intercomparable. To estimate the robustness of the results, the scenarios will also use different models of the electricity system.

The Energy Commission is also supporting other related studies that are expected to be win-win opportunities⁵²⁰ under current and future climatic conditions. It is funding the development of methods to improve seasonal (a few months in advance) and decadal (next 20 years) forecasts in a probabilistic framework. This work will be conducted in close coordination with Energy Commission demand forecast staff, the California ISO, and energy utilities to make sure the results are tailored to their needs and provided in a format that they can use. Prior studies supported by the Energy Commission and others show that this type of work will also be useful to adapt planning and decision-making to a changing climate. A prior research project using probabilistic hydrologic climate projections and a modern decision support system was demonstrated to outperform current management practices at five of the major water reservoirs in Northern California by providing more water for consumption while increasing electricity generation.⁵²¹ The same system was

520 “Win-win” opportunities are also described as *no regrets strategies*. These are strategies that result in benefits even without the consideration to climate benefits.

521 Georgakakos, K. P., N. E. .Graham, , T. M. Carpenter, and H. Yao, 2005, “Integrating Climate-Hydrology Forecasts and Multi-Objective Reservoir Management for Northern California,” *Eos, Transactions American Geophysical Union*. AGU 86:122-127.

shown to be extremely helpful in ameliorating climate impacts, especially under dry climate conditions.⁵²²

Finally, the Energy Commission developed Cal-Adapt,⁵²³ a web-based interactive platform that enables users to visualize local and regional climate change impacts associated with high- and low-GHG emission trajectories based on current peer-reviewed scientific research. Users can also download datasets and, pending upcoming release of version 2.0 that will include an Applications Programming Interface, develop custom tools to manipulate data that lends itself to support specific decision-making and planning processes. Cal-Adapt provides access to regionally downscaled climate scenarios developed through Energy Commission funding, as well as “secondary” scenarios (such as hydrological modeling or wildfire risks) that are derived from downscaled climate scenarios. These scenarios will be used for original research and as a basis for California’s fourth climate change assessment. The scenarios will ensure cross-sectoral coherence, providing grounds for integration of studies across sectors, as well as between mitigation and adaptation.

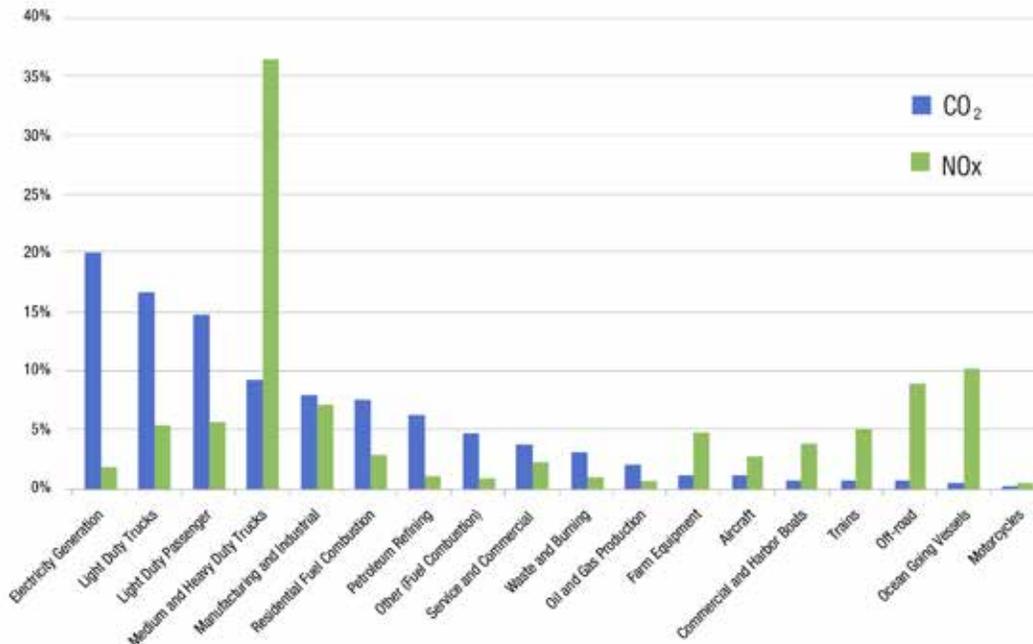
Climate Change and Air Quality Considerations

Reducing fossil fuel consumption to reduce CO₂ emissions also decreases emissions of traditional air pollutants such as oxides of nitrogen (NO_x), which are the precursors to ozone. However, as shown in the figure below,

522 Georgakakos, A.P., H. Y., M. Kistenmacher, K .P. Georgakakos, N. E. Graham, F.-Y. Cheng, C. Spencer, and E. Shamir, 2011b, “Value of Adaptive Water Resources Management in Northern California Under Climatic Variability and Change,” *Advanced Reservoir Management and Engineering*, Elsevier, 13.

523 <http://cal-adapt.org/>.

Figure 75: Percentage Contribution of NO_x and CO₂ Emissions by Different Sources



Source: California Energy Commission using data from the ARB.

the major sources of NO_x are not necessarily the main sources of carbon dioxide. Figure 75 shows the percentage statewide contribution of different sources to total NO_x and CO₂, as reported by the California Air Resources Board (ARB). Further, ambient air quality standards are assessed for individual air basins – where emissions can become sufficiently concentrated to create health hazards – while GHG emissions have global, not local, air quality consequences. Therefore, as suggested by some,⁵²⁴ in the next decade or two, reductions of CO₂ and other GHG emissions are not necessarily accompanied by proportional improvements in ambient air quality in the most impacted air basins. Compliance with ozone ambient air quality standards in the South Coast and San Joaquin Air Basins would require NO_x emission reductions of about 90 percent below current levels. An analysis by the South Coast Air Quality Management District shows

that although NO_x emissions will be significantly reduced as result of policies to meet the 2030 GHG reduction goal, the reductions are not expected to be enough to meet 2023 and 2031 ozone attainment standards. The analysis shows that special energy strategies will be needed in the South Coast to meet air quality standards.⁵²⁵

The Energy Commission and others are funding research to substantially lower NO_x emissions from heavy-duty trucks. California's transportation sector – particularly heavy-duty vehicles, such as transit buses, refuse trucks, and parcel delivery vehicles operating in densely populated neighborhoods – is one of the primary sources of harmful emissions that contribute to air quality issues, preventing several California regions from meeting federal ambient ozone standards. Ongoing efforts to reduce emissions in heavy-duty vehicles has been a priority

524 Tarroja. B., *Transition to a Low-Carbon Economy: Air Quality Consideration*, June 24, 2015, IEPR workshop.

525 SCAQMD, *Draft Final Energy Outlook Whitepaper*, October 2015, <http://www.aqmd.gov/home/about/groups-committees/aqmp-advisory-group/2016-aqmp-white-papers>.

for the Energy Commission's Research and Development Natural Gas Program, beginning with the development of advanced heavy-duty natural gas engines that easily meet the ARB 2010 Heavy-Duty Emission Standards. Following the successful development of these engines, efforts have been made to advance engine designs to increase performance, improve efficiency, and reduce emissions, including NO_x and other harmful emissions. More recent research projects include development of natural gas engines and systems with electric hybridization strategies, cylinder deactivation methods, and cutting-edge advanced ignition systems, with the goals of driving to near-zero NO_x emissions or 90 percent below ARB 2010 Emission Standards. Continued advancement of near-zero natural gas vehicle technologies will support efforts to improve air quality in California and especially in disadvantaged communities where people are more reliant on public transportation or located near high-traffic areas.

U.S. Department of Energy, Partnership for Energy Sector Climate Resilience

In addition to the resources provided at the state level, the U.S. Department of Energy recently launched a program to partner with local energy utilities to promote energy infrastructure that is resilient to climate impacts and extreme weather events. The foundation of these partnerships is an agreement on the part of utilities to identify their climate vulnerabilities; develop, prioritize, and pursue strategies for resilience; and measure and report the results of those strategies. In return, the U.S. Department of Energy provides utilities with technical assistance, access to relevant climate data, assistance with the development of climate decision-making tools, and national recognition for partner

utilities. In California Pacific Gas and Electric, San Diego Gas & Electric, Southern California Edison, and Sacramento Municipal Utility District have signed up as partners.

Future Research Directions

The prior section described ongoing and planned work that will start late in 2015 and early in 2016, which may take two to three years to complete. This section describes, at a conceptual level, future energy-related climate change research that the Energy Commission will support under its EPIC and PIER Natural Gas Research and Development programs. No ongoing research funding is available to support similar studies for the petroleum sector, including the network that provides petroleum-based transportation fuels. For this reason, the following section does not address climate-related research needs for the petroleum sector.

Climate and Sea-Level Rise Scenarios

California is a national leader in developing climate and sea level rise scenarios that are useful not only for research, but relevant for long-term planning.⁵²⁶ A new downscaling technique developed by Scripps, with funding from the Energy Commission, is being adopted at the national level.⁵²⁷ However, more work is still needed, as described in the *Climate Change Research Plan for*

526 Cayan, Daniel R, Amy L. Luers, Guido Franco, Michael Hanemann, Bart Croes, and Edward Vine, 2008, "Overview of the California Climate Change Scenarios Project," *Climatic Change*, 87:1-6.

527 Franco, Guido, 2015, "Climate Scenarios for the California Energy System: Expected Outcomes," Presentation.

California.⁵²⁸ For example, current studies are not at a stage of development to indicate how climate change may impact renewable sources of energy.

Improve Methods to Estimate GHG Emissions from the Energy System

The Energy Commission supported the first national pilot program measuring ambient GHG concentrations using tall communication towers.⁵²⁹ These measurements demonstrated that actual emissions of methane and nitrous oxide are most likely severely underestimated in California.^{530, 531, 532} This conclusion has influenced policy as well as initiated a host of new measurement programs in California.⁵³³ The Energy Commission plans to continue supporting research that attempts to better quantify energy-related emissions in California. The substantial research program measuring methane emissions from the natural gas system will continue focusing on identifying gross emitters and options to reduce emissions. This work is and will continue to be conducted in coordination with the ARB and other entities and will help fulfill the mandates of AB 1496, which acknowl-

528 California Environmental Protection Agency, Climate Action Team, 2015, Climate Change Research Plan for California, February 2015, http://www.climatechange.ca.gov/climate_action_team/reports/CAT_research_plan_2015.pdf

529 "Greenhouse-Gas Sensors Tower Over California," 2007, *Nature* 449, 960 (270).

530 Zhao, C., A. E. Andrews, L. Bianco, J. Eluszkiewicz, A. Hirsch, C. MacDonald, T. Nehrkorn, and M. L. Fischer, 2009, "Atmospheric Inverse Estimates of Methane Emissions From Central California," *J. Geophys. Res.*, 114, D16302, doi:10.1029/2008JD011671.

531 Jeong, S., C. Zhao, A.E. Andrews, L. Bianco, J.M. Wilczak, M.L. Fischer, 2012, "Seasonal Variation of CH₄ Emissions From Central California," *J. Geophys. Res.*, Vol. 117, No. D11, D11306.

532 Ibid.

533 California Public Utilities Commission, *What Gets Measured: A Summary of Recent Policies, Studies, and Pilot Projects Related to Methane Emissions from California's Natural Gas Transmission and Distribution System*, Staff White Paper, November 9, 2015, <http://www.cpuc.ca.gov/NR/rdonlyres/B4CE3B9A-7291-4A7F-9672-9C09C99A7456/0/PPDIntrotoMethaneemissionmeasurements.pdf>.

edges the need for better information related to methane emissions and requires the state to continue using the best available science and methods to illuminate methane hot spots and life-cycle impacts of natural gas.

Simultaneous Consideration of Mitigation and Adaptation for the Energy System

There are multiple ways to improve this area of work. For example, the Energy Commission has plans to support more granular technical research studies that address issues such as the consideration of individual and institutional behavior in the adoption of mitigation/adaptation measures for the energy system. An exploratory study conducted by LBNL for the Energy Commission found good opportunities for nontechnical measures to address mitigation needs in California.⁵³⁴ Physical assessments of renewable energy potential that have been conducted to date⁵³⁵ have not considered factors such as water availability, effects of climate change, permitting issues, and other factors that may render prior resource assessments unrealistic. More realistic resource assessments are greatly needed. Work completed for the *Desert Renewable Energy Conservation Plan* (discussed further in Chapter 3) applied some constraints to better estimate the potential for solar and wind in the southeast desert region of California.⁵³⁶ For example, planners accounted for the anticipated constraints to siting and developing renewable energy in specific regions, such as land-use constraints, feasibility of added transmission capacity, and the extent to which land is parcelized (for example, with multiple small privately

534 Mills, Andrew and Ryan Wisser, 2014, *Strategies for Mitigating the Reduction in Economic Value of Variable Generation With Increasing Penetration Levels*.

535 Hernandez, Rebecca R., Madison K. Hoffacker, and Christopher B. Field, 2015, "Efficient Use of Land to Meet Sustainable Energy Needs," *Nature Clim. Change* 5, no. 4: 353–58.

536 http://www.drecp.org/draftdrecp/files/Appendix_F_Megawatt_Distribution/Appendix_F1_Methods_for_MW_Distribution.pdf.

owned parcels) and therefore viewed as more difficult to develop. The value of lands for biological conservation also factored into limiting the technological potential for renewable energy. The primary constraint in the plan alternatives was areas needed for conservation of special-status species now and areas for their potential movement as an adaptation response to future climate change.

Future research developing new long-term energy scenarios for California will be used to integrate the technology information generated by the EPIC and PIER Natural Gas Research and Development programs in an overall picture of the energy system. This could show what technology development paths are the most promising options to achieve 80 percent GHG reductions by 2050.

Finally, the research on long-term energy scenarios must consider other policy goals such as the ones outlined in Executive Order B-32-15,⁵³⁷ requiring the development of an integrated action plan by July 2016 that establishes clear targets to improve freight efficiency, transitions to zero-emission technologies, and increases the competitiveness of California's freight system.

Local and Regional Studies

Local and regional mitigation-adaptation studies can provide high-level detail that can make these studies more realistic and informative for decision-making than large-scale studies. Close cooperation with energy utilities is essential, however, and may include sharing sensitive information. A framework must be developed to allow data sharing with the research community while protecting the economic and legal rights of the utilities and their customers.

Regional studies will also include the development of models that link higher-elevation hydropower units with rim or low-elevation reservoirs. This is needed to better understand the challenges posed to the system by changes in precipitation patterns while exploring the potential opportunities identified as result of this integrated view to hydropower generation.

537 <http://www.gov.ca.gov/news.php?id=19046>.

Recommendations

California has been an early leader on innovative climate research programs that connect the changing climate to the state's energy system. To create actionable science and increase the resiliency of the energy system, this work must continue and be enhanced to more effectively address the needs of the rest of this century.

» **Expand transparency of utility energy data, within legal constraints, to better inform analyses of the impacts of climate change on California's energy system.** The California Public Utilities Commission should monitor the implementation of its prior orders to expand transparency and data-sharing on the part of utilities, and develop a framework for closer research coordination between energy utilities and local and regional actors. Coordination of this kind has the potential to ensure research is actionable and informs the actual needs of both utilities and stakeholders. This is needed for a stronger, more unified effort to make the state's energy system and communities more resilient to climate change impacts.

» **Oil industry should study climate impacts.** The oil industry should study the impacts of climate change, including sea level rise, wildfire, and drought, on extraction, refinery, storage, transport, and distribution infrastructure. This is an understudied area that requires more research to inform adaptation planning.

» **Harmonize climate studies for the energy sector using the Energy Commission's climate and sea level rise scenarios.** To easily compare studies on climate impacts and adaptation studies for the energy sector, private and public energy utilities and other entities should use the climate and sea-level rise scenarios being developed for the energy part of the upcoming *California's Fourth Climate Change Assessment*.

ACRONYMS

AAEE	—	additional achievable energy efficiency
AB	—	Assembly Bill
AEO	—	<i>Annual Energy Outlook</i>
ALJ	—	Administrative Law Judge
AQIP	—	Air Quality Improvement Program
ARB	—	California Air Resources Board
ARFVTP	—	Alternative and Renewable Fuel and Vehicle Technology Program
BEES	—	<i>Building Energy Efficiency Standards</i>
BLM	—	Bureau of Land Management
BPD	—	barrels per day
CAEATFA	—	California Alternative Energy and Advanced Transportation Financing Authority
CAFE	—	Corporate Average Fuel Economy
CalHSR	—	California High-Speed Rail Authority
California ISO	—	California Independent System Operator
CBR	—	crude-by-rail
CCA	—	community choice aggregator
CCCSIP	—	Central Coastal California Seismic Imaging Project
CCS	—	Carbon capture and storage
CHP	—	combined heat and power
CLEEN	—	California Lending for Energy and Environmental Needs
CMUA	—	California Municipal Utilities Association
CO ₂	—	carbon dioxide
CPCN	—	certificate of public convenience and necessity
CPUC	—	California Public Utilities Commission
CSD	—	Department of Community Services and Development
CSI	—	California Solar Initiative
DATC	—	Duke-American Transmission Company
DC	—	direct current
DCISC	—	Diablo Canyon Independent Safety Committee
DDE	—	double design earthquake
DE	—	design earthquake
DG	—	renewable distributed generation
DRECP	—	<i>Desert Renewable Energy Conservation Plan</i>
E85	—	blend of 85 percent ethanol and 15 percent gasoline
ECAA	—	Energy Conservation Assistance Act- Educational Subaccount
ECAA-Ed	—	Energy Conservation Assistance Act- Educational Subaccount
EEP	—	energy expenditure plan

EIA	—	United States Energy Information Administration
EIM	—	energy imbalance market
EIS	—	environmental impact statement
EM&V	—	evaluation, measurement, and verification
EPIC	—	Electric Program Investment Charge
ESP	—	electric service provider
FAA	—	Federal Aviation Administration
FERC	—	Federal Energy Regulatory Commission
GGRF	—	Greenhouse Gas Reduction Fund
GHG	—	greenhouse gas
GIS	—	geographic information system
Gpf	—	gallons-per-flush
Gpm	—	gallons-per-minute
GW	—	gigawatt
GWh	—	gigawatt hours
HE	—	Hosgri Evaluation
HERS	—	Home Energy Rating System
HI-STORM	—	Holtec International Storage Module
HSR	—	high-speed rail
HHFT	—	high hazard flammable train
HVAC	—	heating, ventilation, and air conditioning
HVDC	—	high-voltage direct current
IEPR	—	<i>Integrated Energy Policy Report</i>
IID	—	Imperial Irrigation District
ITC	—	investment tax credit
IOU	—	investor-owned utility
IPCC	—	Intergovernmental Panel on Climate Change
IRP	—	integrated resource plan
IPRP	—	Diablo Canyon Independent Peer Review Panel
kV	—	kilovolt
kW	—	kilowatt
LADWP	—	Los Angeles Department of Water and Power
LBNL	—	Lawrence Berkeley National Laboratory
LCFS	—	Low Carbon Fuel Standard
LCR	—	local capacity requirement
LDV	—	light-duty vehicle
LEA	—	local education agencies
LGIA	—	Large Generator Interconnection Agreement
LLC	—	limited liability corporation
LNG	—	liquefied natural gas

LTPP	—	Long Term Procurement Plan
LTSP	—	Long Term Seismic Program
MDV/HDV	—	medium- and heavy-duty vehicles
MMTCO ₂ E	—	million metric tons of carbon dioxide equivalent
MOU	—	Memorandum of Understanding
MW	—	megawatt(s)
NAMGas	—	North American Market Gas Trade
NCPA	—	Northern California Power Authority
NEM	—	net energy metering
NHTSA	—	National Highway Traffic and Safety Administration
NOAA	—	National Oceanic and Atmospheric Administration
NO _x	—	oxides of nitrogen
NRC	—	Nuclear Regulatory Commission
NREL	—	National Renewable Energy Laboratory
NSHP	—	New Solar Homes Partnership
OII	—	Order Instituting Informational
OPEC	—	Organization of Petroleum Exporting Countries
OSPR	—	Office of Spill Prevention and Response
OTC	—	once-through cooling
P2G	—	power-to-gas
PACE	—	Property Assessed Clean Energy
PADD	—	Petroleum Administration for Defense District
PEA	—	Proponent's Environmental Assessment
PG&E	—	Pacific Gas and Electric Company
PHEV	—	plug-in hybrid electric vehicle
PIER	—	Public Interest Energy Research
PM	—	particulate matter
POU	—	publicly owned utility
PPA	—	power purchase agreement
PSEP	—	pipeline safety enhancement plan
PSHA	—	probabilistic seismic hazard analysis
PTC	—	production tax credit
PV	—	photovoltaic
QF	—	qualifying facility
R&D	—	research and development
RAC	—	refiner acquisition cost
REAT	—	Renewable Energy Action Team
REC	—	renewable energy credit
RECPG	—	Renewable Energy and Conservation Planning Grants
RETI	—	Renewable Energy Transmission Initiative

RPS	—	Renewables Portfolio Standard
SACCWIS	—	Statewide Advisory Committee on Cooling Water Intake Structures
San Onofre	—	San Onofre Nuclear Generating Station
SB	—	Senate Bill
SCE	—	Southern California Edison Company
SCPPA	—	Southern California Public Power Authority
Scripps	—	Scripps Institution of Oceanography
SCRP	—	Southern California Reliability Project
SDG&E	—	San Diego Gas & Electric
SEIR	—	supplemental environmental impact report
SEIS	—	supplemental environmental impact statement
SMUD	—	Sacramento Municipal Utility District
SoCalGas	—	Southern California Gas Company
SR	—	State Route
SunZia	—	SunZia Southwest Transmission Project
SWIP	—	Southwest Intertie Project
SWRCB	—	State Water Resources Control Board
TDV	—	time dependent valuation
TEPPC	—	Transmission Expansion Planning Policy Committee
TPP	—	Transmission Planning Process
TRTP	—	Tehachapi Renewable Transmission Project
TWE	—	TransWest Express Transmission Project
UCS	—	Union of Concerned Scientists
U.S. DOE	—	United States Department of Energy
U.S. EPA	—	United States Environmental Protection Agency
USFS	—	United States Forest Service
VAR	—	Volt-ampere reactive
VMT	—	vehicle miles traveled
WECC	—	Western Electricity Coordinating Council
Western	—	Western Area Power Administration
WET	—	Water Energy Technology
ZEV	—	zero-emission vehicle
ZNE	—	zero net energy

APPENDIX A

Renewable Energy Action Plan Progress

The Energy Commission's *2012 Integrated Energy Policy Report Update* included a Renewable Action Plan for increasing renewable development in California. This appendix summarizes progress made on the action items identified in the plan since adoption of the plan in early 2013.⁵³⁸

Strategy 1: Identify Priority Areas for Renewable Development

An important lesson learned over the last decade when it comes to renewable development is that project location is crucial. The site of a utility-scale or distributed renewable project affects how quickly a project can be permitted and interconnected, which in turn affects the overall cost of the

project. The Renewable Action Plan recommended that priority areas for renewable development should have high levels of renewable resources, be located where development will have the least environmental impact, and be close to planned or existing transmission or distribution infrastructure.

Recommendation 1: Incorporate Distributed Renewable Energy Development Zones Into Local Planning Processes

With increasing amounts of renewable distributed generation (DG) being installed in California, the first recommendation under Strategy 1 was to incorporate renewable DG into local planning processes. Local governments typically have permitting authority for many types of renewable projects, but many local governments do not have the data and resources to include renewable development in their land-use plans.

Since adoption of the Renewable Action Plan, several initiatives have been launched to identify preferred areas for renewable DG development.

» Assembly Bill 327 (Perea, Chapter 611, Statutes of 2013) requires investor-owned utilities (IOUs) to submit distribution resource plans to the California Public Utilities

⁵³⁸ More detail on recommendations and action items is available in the *2012 Integrated Energy Policy Report Update*, Chapter 5, Renewable Action Plan, http://www.energy.ca.gov/2012_energy-policy/.

Commission (CPUC) that identify the best locations for renewable DG and other distributed energy resources from a utility perspective. This will help developers identify the higher value locations for these projects. The plans were filed on July 1, 2015, and are available for public review.⁵³⁹

» The California Independent System Operator (California ISO) has begun an annual process to identify available deliverability for DG projects connected to utility distribution systems. Available deliverability indicates where existing transmission capacity is available to support deliverability status assignments.⁵⁴⁰

» As part of the CPUC's Renewable Auction Mechanism, IOUs are posting maps to help project developers determine potential project sites. The maps show areas on the utility system where capacity for DG projects may be available, which helps developers determine how expensive a project might be and how long it might take to get interconnected.⁵⁴¹

» To help bridge the gap between utility planning and local land-use planning, the Energy Commission is partnering with Southern California Edison on a distributed energy resource pilot study in the San Joaquin Valley to explore the potential of relying on distributed resources to

meet forecasted electricity system needs. Most distributed resource growth to date has occurred largely as the result of random customer investment decisions, but going forward investments need to be planned and coordinated to provide the most value. This can be accomplished in part through closer coordination between utility and local planning processes to direct investments to locations that benefit electric system operations, provide value to customers, and minimize adverse environmental impacts.

» The Energy Commission has published three reports that have identified location-specific value for renewable projects, particularly distributed generation projects: *Identification of Low-Impact Interconnection Sites for Wholesale Distributed Photovoltaic Generation Using Energynet® Power System Simulation*;⁵⁴² *Integrated Transmission and Distribution Model for Assessment of Distributed Wholesale Photovoltaic Generation*;⁵⁴³ and *Distributed Generation Integration Cost Study – Analytical Framework*.⁵⁴⁴

Recommendation 2: Identify Renewable Energy Development Zones

The second recommendation for identifying high-priority areas for renewable development was to identify renewable energy development zones for all sizes and technology types of renewable resources, with the goal of using the existing built environment first, followed by areas with minimal environmental or habitat value, such as marginal or impaired agricultural lands.

539 California Public Utilities Commission, Distribution Resources Plan Applications (filed July 1, 2015), <http://www.cpuc.ca.gov/PUC/energy/drp/>. Information on the requirements for the plans is available at: <http://www.cpuc.ca.gov/NR/rdonlyres/9F82A335-B13A-4F68-A5DE-3D4229F8A5E6/0/146374514finalacr.pdf>.

540 California Independent System Operator, *Resource Adequacy Deliverability for Distributed Generation, 2014–2015 DG Deliverability Assessment Results*, February 11, 2015, <http://www.caiso.com/Documents/2015DeliverabilityforDistributedGenerationStudyResultsReport.pdf>.

541 Pacific Gas and Electric: www.pge.com/en/b2b/energysupply/wholesaleelectricssuppliersolicitation/PVRFO/pvmap/index.page; Southern California Edison: www.sce.com/ram; San Diego Gas & Electric: <http://www.sdge.com/generation-interconnections/interconnection-information-and-map>.

542 California Energy Commission consultant report, New Power Technologies, December 2011, <http://www.energy.ca.gov/2011publications/CEC-200-2011-014/CEC-200-2011-014.pdf>.

543 California Energy Commission consultant report, New Power Technologies, April 2013, <http://www.energy.ca.gov/2013publications/CEC-200-2013-003/CEC-200-2013-003.pdf>.

544 California Energy Commission consultant report, Navigant Consulting, Inc., September 2014, <http://www.energy.ca.gov/2013publications/CEC-200-2013-007/CEC-200-2013-007-REV.pdf>.

» This recommendation is intended to build on experience and science gained through the *Desert Renewable Energy Conservation Plan (DRECP)* to identify high-priority areas for renewable energy development throughout the state.

» The most significant progress on this recommendation has been the success of the DRECP effort and the unprecedented coordination among local governments, federal and state agencies, utilities, and various stakeholders to identify areas where renewable development can occur with fewer environmental impacts, as well as sensitive areas that should be protected. The effort focused on more than 22.5 million acres in the California Deserts, with a draft plan and programmatic environmental analysis released in September 2014. Based on comments received on the draft plan, in March 2015 the Bureau of Land Management, the U.S. Fish and Wildlife Service, the Energy Commission, and the California Department of Fish and Wildlife announced a phased approach to finalize development of the *DRECP*, starting with completion of the *BLM Land Use Plan Amendment*, which designates development focus areas and conservation areas on public lands. This phased approach also allows time for the counties to complete their Renewable Energy and Conservation Planning Grant projects, for agencies to continue to collaborate with the counties to address local needs in the planning process, and to ensure better alignment of local, state, and federal goals.

Other actions to support identifying renewable energy development zones include the following:

» In 2013 and 2014, the Energy Commission provided more than \$5 million in grants to local governments through the Renewable Energy and Conservation Planning Grants Program to develop or amend rules and policies that “facilitate the development of eligible renewable energy resources and the associated electric transmission facilities, and the processing of permits for eligible renewable energy resources.”⁵⁴⁵

545 California Energy Commission, http://www.energy.ca.gov/renewables/planning_grants/.

Counties that received awards include Imperial, Inyo, Los Angeles, Riverside, San Bernardino, and San Luis Obispo. Grant projects from the 2013 solicitation were completed in 2015, and grants from the 2014 solicitation will be completed in early 2016.

» The Energy Commission is providing technical expertise for the San Joaquin Valley Solar convening. The San Joaquin Solar convening is a stakeholder-led effort to identify least-conflict lands in the San Joaquin Valley that are suitable for renewable energy development.

» The Energy Commission, in collaboration with Conservation Biology Institute, has developed several geospatial tools, including the DRECP Data Basin Gateway, DRECP Climate Console, and the Renewable Energy Generation Scenario Builder, to integrate multiple layers of scientific data and develop transparent renewable and conservation planning scenarios.

» On July 31, Energy Commission Chair Weisenmiller and CPUC President Picker sent a letter to California ISO President and CEO Berberich announcing the establishment of the Renewable Energy Transmission Initiative 2.0. This initiative will identify the relative renewable energy potential associated with various locations of the state and the associated transmission infrastructure. The stakeholder-driven process will commence this year with the goal to send policy recommendations for the 2030 renewables portfolios to the California ISO in 2016.

Recommendation 3: Conduct 2030 Analysis

This recommendation targeted the need for planning efforts beyond 2020 given interest in higher renewable targets and uncertainty about continued operation of the state’s nuclear plants. Analysis of the electricity sector in 2030 and beyond is taking place in several forums.

» The “Pathways Study,” commissioned by the energy agencies and the Air Resources Board was completed in January 2015, with updated materials made available in April 2015. It included multiple scenarios to evaluate a range of possible 2030 targets on the way to meeting California’s 2050 greenhouse gas (GHG) emission reduction target.⁵⁴⁶ The study found that it is possible to reduce GHG emissions by 26 percent to 38 percent from 1990 levels by 2030 through increased energy efficiency, development of renewable energy, electrification of buildings and vehicles, and reductions in the carbon content of liquid fuels.

» The California Independent System Operator’s (California ISO) 2015-2016 Transmission Planning Process is examining several renewable portfolios for 2030, including two that evaluate a 50 percent RPS. (See Recommendation 11 for more information.)

» The DRECP is continuing to look at future renewable development scenarios, including an assessment of potential central-station renewable project development in 2040 in the DRECP area.⁵⁴⁷

Recommendation 4: Continue Development of Renewable Energy on Government Property

In 2011, the Energy Commission’s *Developing Renewable Generation on State Property* report recommended a goal of 2,500 MW of renewables on state properties by 2020, with interim targets of 833 MW by 2015 and 1,666 MW by 2018.⁵⁴⁸ The target was based on an inventory of technical

potential at state buildings, properties, and lands with potential for wholesale generation.

Progress on this recommendation has been slow. According to the Department of General Services’ Renewable Energy Directory, there are 43 MW of renewable projects installed on state properties, with another 8 MW planned, far short of the 833 MW interim goal for 2015. In addition, the majority of installed and planned projects are less than 1 MW, indicating more focus may be needed on promoting larger installations going forward to achieve the interim and long-term targets. In support of this effort, on October 1, 2015, the California State Lands Commission and the Bureau of Land Management announced a historic agreement to exchange state lands with federal lands. This State Land Exchange will advance state and federal conservation and energy strategies of the DRECP by consolidating federal lands within the National Conservation Lands area and providing the state with lands that have operational, or potential for, renewable energy facilities.

Strategy 2: Evaluate Costs and Benefits of Renewable Projects

Strategy 2 focused on the importance of broadening the assessment of renewable costs beyond simple technology costs to include things like renewable integration, permitting, and interconnection, while considering the system and nonenergy benefits of renewable resources, particularly those that improve grid stability and reduce environmental and public health costs.

546 Energy+Environmental Economics (E3), 2015, *Summary of the California State Agencies’ PATHWAYS Project: Long-term Greenhouse Gas Reduction Scenarios*, https://ethree.com/public_projects/energy_principals_study.php.

547 California Energy Commission, <http://www.drecp.org/>.

548 California Energy Commission, *Developing Renewable Energy on State Property*, April 2011, <http://www.energy.ca.gov/2011publications/CEC-150-2011-001/CEC-150-2011-001.pdf>.

Recommendation 5: Modify Procurement Practices to Develop a Higher Value Portfolio

There has been some progress on this recommendation relative to procurement by publicly owned utilities (POUs) as a result of requirements for POUs to adopt and implement renewable resource procurement plans for the RPS and procure enough eligible resources to meet their RPS targets. Energy Commission staff also found that POUs have generally improved their planning for, and acquisition of, renewable generation.

There is less progress on other actions identified under Recommendation 5, particularly that RPS procurement decisions by the IOUs and POUs should be based on a wider variety of information, such as integration costs and benefits, interconnection costs, ability to provide reliability services, and geographic and technology diversity.

The CPUC did evaluate RPS procurement reform starting in October 2012, with a November 2014 decision released on the 2014 RPS procurement plans that adopted findings related to certain elements of RPS procurement.⁵⁴⁹ While the decision adopted an interim renewable integration cost adder, it did not fully address the expanded suite of renewable energy benefits identified in the Renewable Action Plan. The CPUC intends to complete work on a final method for calculating a renewable integration cost adder as part of the RPS continuation rulemaking opened in February 2015.⁵⁵⁰

549 California Public Utilities Commission, D. 14-11-042, *Decision Conditionally Accepting 2014 Renewables Portfolio Standard Procurement Plans and an Off-Year Supplement to 2013 Integrated Resource Plan*, November 20, 2014, <http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M143/K313/143313500.PDF>.

550 California Public Utilities Commission, R.15-02-020, *Scoping Memo and Ruling of Assigned Commissioner*, May 22, 2015, <http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M151/K862/151862437.PDF>.

Recommendation 6: Revise Residential Electricity Rate Structures

The Renewable Action Plan supported a revised electricity rate design that fairly spreads new costs, including infrastructure costs, among all customers while maintaining an incentive for the efficient use of electricity. It identified residential rate design as the first priority but noted that commercial and industrial rate design may also need to be considered in the future, and expressed support for the CPUC's proceeding on residential rate structures.

In April 2015, the CPUC issued a proposed decision in the residential rate reform proceeding that lays out a path to transition customers to fairer, more economically efficient rates.⁵⁵¹ Implementation is expected to begin in 2019, informed by pilot studies on time-of-use rate design. The goal is to provide transparent, cost-based rates that will encourage residential customers to shift their energy use to certain times of day to support a cleaner, more reliable grid and reduce total electricity costs for all customers.

To achieve this goal, the IOUs will begin by:

- » Continuing to consolidate and narrow the existing energy usage tiers so that electricity prices are more understandable and less distorted.
- » Implementing improved tools to compare bills and a special outreach program to educate lower-tier customers on low- or no-cost ways to save energy.
- » Implementing a minimum bill to ensure that all customers connected to the system contribute some amount toward system costs.

551 California Public Utilities Commission, R.12-06-013, *Decision on Residential Rate Reform for Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company and Transition to Time-of-Use Rates*, Proposed Decision of SLJs McKinney and Halligan, April 21, 2015, <http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M151/K305/151305677.PDF>.

- » Designing time-of-use pilots (both opt-in and default).

These efforts will be followed over the next few years by:

- » Evaluating opt-in and pilot time-of-use rates in preparation for widespread enrollment.
- » Propose a default time-of-use rate structure to begin in 2019, assuming statutory conditions have been met.
- » Phase in a superuser surcharge that will signal to customers when their usage is far in excess of the typical household and that conservation steps should be taken.

The IOUs may request a fixed monthly charge, but only after the CPUC has evaluated which, if any, costs are appropriate to collect through a fixed charge and how to do so fairly. Implementation would not begin until after time-of-use rates have been in place for one year.

With expanded use of time-of-use rates, it is increasingly important that the definitions of periods reflect the changes in hourly system costs from increasing penetration of renewable resources. Ongoing rate design proceedings will refine the process used to define and update time-of-use periods.

Recommendation 7: Improve Transparency of Renewable Generation Costs

As California's renewable portfolio continues to grow, it becomes increasingly important to track publicly available information on costs of recently built renewable projects, particularly smaller projects. This information helps decision makers understand key cost trends and drivers in California and supports statewide renewable planning efforts.

The Energy Commission conducted a study on how costs of renewable DG vary based on location,⁵⁵² and the *Distributed Energy Resource Pilot Study* is examining the value of DG and other distributed resources in helping to meet state policy goals. However, additional work is needed on improving the Energy Commission's data collection process to track publicly available information on the costs of recently built renewable projects.

Recommendation 8: Strengthen Links Between Transportation and Clean Electrification

Although the Renewable Action Plan was focused on renewable electricity, it also recognized the importance of electrifying the transportation system to meet California's GHG reduction goals. There are also potential benefits from encouraging electric vehicle charging during times of low load and high wind generation to improve the value of wind energy, and from using "vehicle-to-grid" services to provide grid support. This recommendation also emphasized the need for transportation electrification in disadvantaged communities because they often face disproportionate impacts from burning fossil fuels.

California has made significant progress on efforts to support electrification of the transportation system. Since the Renewable Action Plan was adopted, the Energy Commission's Alternative and Renewable Fuel and Vehicle Technology Program has awarded nearly \$40 million for plug-in electric vehicle infrastructure, including charging stations for multiunit dwellings, workplaces, and highways. Examples of projects in environmentally high-risk communities or areas with environmental justice indicators include:

552 California Energy Commission consultant report, *Distributed Generation Integration Cost Study*, Navigant Consulting, Inc., September 2014, <http://www.energy.ca.gov/2013publications/CEC-200-2013-007/CEC-200-2013-007-REV.pdf>.

- » EV Connect – Public charging at five transit parking areas for the Los Angeles County Metropolitan Transit Authority (Completed 12/31/2013).
- » Clipper Creek – Upgrade legacy public chargers throughout California (Completed 6/30/2014).
- » Alameda-Contra Costa Transit District – Hydrogen fueling station to support 12 hydrogen fuel cell buses in the transit fleet (Completed 11/30/2014).
- » AeroVironment – Charging for Car2Go vehicles at apartment venues (Completed 3/28/2015) and YMCAs (Planned completion 2/28/2016).
- » Green Charge Networks, LLC – Installation of 16 DC fast charging stations with battery-storage and building management systems at sites throughout California (Planned completion 3/31/2016).
- » Southern California Regional Collaborative – Public charging at 315 sites that potentially could include hospitals and medical centers (Planned completion 6/30/2016).
- » Southern California Public Power Authority – Four level 2 electric vehicle chargers and nine electric vehicle DC fast chargers in various Southern California locations (planned completion 7/1/2016).
- » Electric Vehicle International – Manufacture and assembly of components for electric drive medium-duty delivery vehicles (Completed 5/8/2015).
- » Kenworth Truck Company – Electric hybrid Class 8 goods movement truck (Completed 5/15/2015).
- » Electric Power Research Institute – Plug-in electric hybrid delivery trucks (Planned completion 3/31/2016).
- » Electricore – Plug-in electric delivery trucks (Planned completion 3/31/2016).
- » CALSTART – Plug-in electric shuttle buses and drayage trucks, and hybrid electric drayage trucks (Planned completion 3/31/2018).
- » Motiv Power Systems – Demonstration of Class C electric school buses in the school districts of Los Angeles Unified, Kings Canyon Unified, and Colton Joint Unified (Planned completion 5/31/2018).

The program has also awarded more than \$30 million for electric trucks and buses in sensitive port areas, including:

- » Transpower – Heavy-duty electric truck manufacturing (Completed 9/30/2013).
- » Wrightspeed – Range-extended electric drive systems for medium- and heavy-duty delivery and goods movement vehicles (Completed 10/31/2013).

There has also been progress on improving the link between planning for renewable energy, the distribution system, and zero-emission vehicles. In May 2014, the Energy Commission published the *California Statewide Plug-In Electric Vehicle Infrastructure Assessment* with the assistance of the National Renewable Energy Laboratory. The report provides recommendations for plug-in vehicle infrastructure planning and provides guidance to local communities and regions.⁵⁵³

In addition, the Energy Commission funded 11 Regional Plug-In Electric Vehicle Planning Grants to develop regional plans for infrastructure, streamlining of permitting

⁵⁵³ California Energy Commission, *California Statewide Plug-In Electric Vehicle Infrastructure Assessment*, May 2014, <http://www.energy.ca.gov/2014publications/CEC-600-2014-003/CEC-600-2014-003.pdf>.

and inspection processes, building code updates, and consumer education and outreach. (See Chapter 4 for further discussion of electric vehicles and Chapter 5 for discussion on how electric vehicle use is included in the electricity demand forecast.) Regions that received grants included the Bay Area, the Central Coast, the Coachella Valley, Monterey, North Coast, the Sacramento Valley, San Diego, the San Joaquin Valley, Southern California, the Tahoe-Truckee region, and Upstate. Energy Commission staff continues to meet regularly with each planning region to provide coordination and share lessons learned.

The Energy Commission's Alternative and Renewable Fuel and Vehicle Technology Program held solicitations for alternative fuel readiness plans and zero-emission vehicle readiness in 2013 and 2014, with awards to 24 projects totaling \$5.6 million. In 2015, the Energy Commission also funded \$3.3 million for zero-emission vehicle implementation efforts to assist regions with implementing their plans. The Commission is also supporting various vehicle-to-grid projects, including cofunding a demonstration project with the United States Department of Defense that is scheduled for completion in March 2016.

Strategy 3: Reduce Time and Costs of Renewable Interconnection and Integration

Strategy 3 focused on the need to minimize costs and requirements for renewable integration, and on improving and reducing the costs of integration tools and technologies like storage, demand response, and the most effective use of the existing natural gas-fired power plant fleet.

Recommendation 9: Consider Environmental and Land-Use Factors in Renewable Scenarios

Recommendation 9 was intended to promote the use of environmental and land-use factors in renewable scenarios that are used in long-term procurement and transmission planning. Since the Renewable Action Plan was adopted in 2013, California's energy agencies have been working together to identify areas in the state with high renewable potential and relatively low environmental conflicts, as well as areas with sensitive environmental issues where permitting costs and challenges are likely to be high. The Energy Commission has identified environmental issues with new projects and is involved in analyzing the most appropriate areas for renewable generation and transmission to coordinate and streamline renewable project permitting.

As part of that effort, the Energy Commission recommended that environmental and land-use information from the *DRECP* be incorporated into the renewable scenarios used in the CPUC's Long-Term Procurement Plan proceeding and the California ISO's Transmission Planning Process.

In the *2014 IEPR Update*, the Energy Commission recommended that California should improve its ability to perform landscape-scale analysis, and is leading an effort with local, state, and federal partners and other stakeholders to assess the available data and tools, identify knowledge and other gaps, and develop the ability to perform this type of analysis. This effort, which is continuing under the *2015 IEPR*, is focused outside the *DRECP* area and includes the western United States and potential international partners in the western grid.

Recommendation 10: Monitor Status of California ISO-Approved Transmission Projects to Ensure Timely Completion

California needs to continue to develop the transmission infrastructure necessary to deliver remote renewable gen-

eration to load centers and meet reliability and economic needs. The *2013 IEPR* listed 17 transmission projects approved by the California ISO, the Imperial Irrigation District, and the Los Angeles Department of Water and Power that will enable California to meet the 33 percent RPS by 2020. Since publication of that report, the California ISO approved two more major transmission projects in its *2013-2014 Transmission Plan* – the Delaney-Colorado River and Harry Allen-Eldorado projects. Of the 17 original projects listed in the *2013 IEPR*, four are now operating and 1 was removed from the list. With the 2 new projects approved by the California ISO, the Energy Commission is now tracking 14 transmission projects to support renewable delivery.

In its *2014–2015 Transmission Plan*, the California ISO did not identify a need for new transmission projects to support the RPS, given the transmission projects already approved or progressing through the permitting process.

Recommendation 11: Streamline Transmission Permitting in California

Recommendation 11 was intended to reduce the amount of time needed to plan, license, and build major transmission facilities in California to support the state's renewable electricity goals. Identifying transmission routes and performing environmental analyses for these major transmission projects typically does not begin until the California ISO determines the projects are needed, which can occur about the same time as the renewable generators that need the transmission are ready to begin construction. This means that transmission projects can lag behind generation projects by three or more years.

In May 2013, the Energy Commission conducted a workshop to discuss the need for synchronization between generation and transmission planning and permitting. Workshop participants concluded that the California ISO's Generator Interconnection and Deliverability Allocation Procedures and the annual Transmission

Planning Process represent a large improvement in how new policy-driven transmission projects are identified. However, the *2013 IEPR* noted this does not ensure that transmission will be built by the time the generation is available. This creates significant risks for generators because their power purchase agreements often require their generation to be fully deliverable during peak conditions, and full deliverability may require transmission upgrades. The *2013 IEPR* recommended that California's energy agencies should evaluate the cost-effectiveness, prudence, and alternatives for requiring full deliverability for future renewable generation that is procured to meet RPS requirements.

In support of this recommendation, CPUC staff prepared five study scenarios for the California ISO to begin investigating the impacts of higher RPS targets on transmission planning. The California ISO selected two "energy-only" scenarios that address a 50 percent RPS portfolio by 2030 and will assume that additional generation to meet the renewable net short will not require full deliverability. The 2015 special study provides an opportunity to inform future transmission planning cycles without a direct effect on the current transmission plan.

Successful identification of transmission corridors requires consideration of environmental information early in transmission planning. Toward that end, the Energy Commission funded a consultant report that provides a high-level assessment of the environmental feasibility of several transmission alternatives under consideration by the California ISO to address reliability and other system challenges arising from the closure of the San Onofre Nuclear Generating Station.⁵⁵⁴ While the alternatives may provide electrical solutions for addressing challenges, the report examined the likely siting constraints that may

554 California Energy Commission, *Transmission Options and Potential Corridor Designations in Southern California in Response to Closure of San Onofre Nuclear Generation Station (SONGS) – Environmental Feasibility Analysis*, May 2014, and two addenda (September 2014 and January 2015), <http://www.energy.ca.gov/2014publications/CEC-700-2014-002/index.html>.

have to be considered during the environmental permitting process for each potential alternative. The report findings demonstrate that most of the transmission projects will likely encounter serious challenges for attaining land-use permits, and an early screening of environmental considerations in the California ISO's transmission planning process may effectively identify a short list of the most feasible projects for further consideration in planning studies.

Another streamlining consideration for the energy regulatory agencies is to encourage utilities to propose transmission projects that are "right-sized" to meet current and future needs and to avoid the risk of stranded assets by approving transmission projects are located near or in existing corridors. This issue of "right-sizing" was first identified in the *2011 IEPR* proceeding in which the Energy Commission considered ways to make better use of the existing grid by allowing projects to be upsized beyond what is needed to provide unused capacity for future use. Upsizing could maximize the value of land associated with transmission investments that are already needed, while avoiding costlier upgrades to accommodate additional development that may be needed in the future.

Recommendation 12: Develop a Dialogue on Distribution Planning and Opportunities for a More Integrated Distribution Planning Process

California's transmission planning processes are well-developed and transparent, allowing all stakeholders to provide input into and understand the planning decisions as they are made. However, the state lacks a similarly comprehensive planning process for the distribution system, which can lead to interconnection delays, lost opportunities for strategic deployment of distributed resources, and increased costs.

There has been some progress on this recommendation. Utilities submitted detailed distribution resource plans on July 1, 2015, as required by the CPUC's AB 327 Distribution Resource Plan rulemaking (R.14-08-013). The plans identify prime locations for distributed energy resources, evaluate locational benefits, propose mechanisms to deploy cost-effective distributed resources, identify utility spending needed to integrate distributed resources into distribution planning, and identify barriers to deployment.⁵⁵⁵

Another effort is the "More Than Smart" working group that is led by California ISO staff and includes the Energy Commission, the CPUC, utilities, and other stakeholders. The working group is an offshoot of the "More Than Smart" paper published by the Greentech Leadership Group that describes a framework to improve the distribution grid.⁵⁵⁶ The working group is focused on developing a transparent distribution plan integrated with all other state energy planning and is discussing how to integrate the utilities' new distribution resource plans into other statewide planning efforts, such as the CPUC's Long-Term Procurement Plan proceeding, the California ISO's Transmission Planning Process, utility rate cases, and the Integrated Energy Policy Report proceeding. The working group provides regular updates at CPUC workshops held under the Distribution Resource Plan proceeding.

Recommendation 13: Disaggregate the Energy Commission's Demand Forecast

In the Renewable Action Plan, the Energy Commission committed to evaluating ways to disaggregate, or provide

⁵⁵⁵ California Public Utilities Commission, Distribution Resources Plan Applications (filed July 1, 2015), <http://www.cpuc.ca.gov/PUC/energy/drp/>.

⁵⁵⁶ Greentech Leadership Group and Resnick Sustainability Institute, *More Than Smart – A Framework to Make the Distribution Grid More Open, Efficient, and Resilient*, <http://greentechleadership.org/wp-content/uploads/2014/08/More-Than-Smart-Report-by-GTLG-and-Caltech.pdf>.

greater detail for, its electricity demand forecast beyond the utility planning area level to give stakeholders location-specific data on electricity demand. The first step for this recommendation was providing forecast results by climate zone. In the *2013 IEPR*, the Energy Commission's electricity demand forecast included 16 climate zones in addition to the usual eight utility planning areas.⁵⁵⁷ The *2015 IEPR* forecast will include 20 climate zones and redefine the planning areas to be more consistent with the balancing authority areas in the state. The Energy Commission will continue to examine further geographic detail in future forecasts contingent staff resources and data availability.

Recommendation 14: Create a Statewide Data Clearinghouse for Renewable Energy Generation Planning

Recommendation 14 was to create a statewide renewable data clearinghouse to help coordinate land-use planning with utility system planning at both the distribution and transmission levels. The success of this recommendation depended on the public availability of data, which continues to be a challenge. Data collection for the energy sector and accessibility to data can be complex and contentious, and until enough useful data are publicly available, the ability to establish a statewide data clearinghouse is limited.

There are, however, some data sources that are useful for planning:

- » In May 2014, the CPUC published a decision under rulemaking 08-12-009, which adopted rules that provide access to energy usage data to local governments, researchers, and state and federal agencies

⁵⁵⁷ California Energy Commission, *California Energy Demand 2014-2024 Final Forecast*, January 2014, http://www.energy.ca.gov/2013_energypolicy/documents/#adoptedforecast.

when that access is consistent with state law and procedures protecting the privacy of consumer data.⁵⁵⁸

- » As part of the CPUC's Rule 21 proceeding, California's investor-owned utilities must file quarterly Net Energy Metering interconnection reports.⁵⁵⁹
- » The Energy Commission continues to collect and post renewable energy statistics for California on its website.⁵⁶⁰
- » Several California counties have begun posting useful information on where renewable projects are filing for permits.

Recommendation 15: Enable Deployment of Advanced Inverter Functions for Volt-Var and Frequency Management

Successful integration and management of increasing amounts of distributed solar photovoltaic resources will require inverters that can provide fast and flexible control of output current.

In January 2013, the Energy Commission and the CPUC formed the Smart Inverter Working Group to develop technical recommendations for inverter-based distributed resources to support operation of the distribution system. The working group includes utilities, inverter manufacturers, renewable developers, government, and other organizations and has held weekly conference calls since it began in 2013.

⁵⁵⁸ California Public Utilities Commission, Decision 14-05-016, *Decision Adopting Rules to Provide Access to Energy Usage and Usage-Related Data While Protecting Privacy of Personal Data*, May 1, 2014, <http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M090/K845/90845985.PDF>.

⁵⁵⁹ California Public Utilities Commission, <http://www.cpuc.ca.gov/PUC/energy/rule21.htm>.

⁵⁶⁰ California Energy Commission, <http://energyalmanac.ca.gov/electricity/> and http://www.energy.ca.gov/renewables/tracking_progress/index.html.

The group is developing technical recommendations in three phases. Phase 1 recommendations included seven critical autonomous functions, which were adopted by the CPUC in December 2014 and will be implemented by mid-2016.

In Phase 2, the working group focused on inverter communication capabilities for monitoring, updating settings, and control. The group submitted the Phase 2 document to CPUC staff in February 2015, and the CPUC is coordinating with the IOUs on implementation.

In March 2015, the group began working on Phase 3 recommendations, which will include advanced inverter functionality, and is discussing priorities for which functions to consider.⁵⁶¹

Recommendation 16: Develop a Forward Procurement Mechanism

The Energy Commission recommended a forward procurement mechanism for 3–5 years ahead to provide revenue streams for the flexible capacity resources needed to integrate renewable resources and allowing all integration resources – such as demand response, energy storage, and flexible natural gas-fired power plants – to compete on a level playing field.

There has been little progress on this recommendation. The CPUC established the 2014 Long-Term Procurement Plan proceeding in late 2013, which was focused principally on flexibility issues at the 10-year forward horizon.⁵⁶² Efforts of parties to develop satisfactory forward projections of flexibility requirements were unsuccessful, and the CPUC terminated this portion of the proceeding in March 2015. Instead, the CPUC has initiated a model development effort for the balance of 2015 to improve the

models for use in the upcoming 2016 Long-Term Procurement Plan proceeding.

In early 2014, the CPUC established the Joint Reliability Plan rulemaking, which investigated whether to extend resource adequacy requirements from the one-year forward horizon to a three-year forward horizon.⁵⁶³ In October 2014, CPUC staff issued a report summarizing several workshops, but parties were opposed to mandating the current interim method of setting forward flexibility requirements, and the CPUC suspended this portion of the Joint Reliability Plan rulemaking in January 2015. As of July 2015, the portion of the proceeding addressing forward planning requirements (system, local, and flexible) is awaiting CPUC Energy Division staff analyses intended to shed light on the risk of retirement for existing generators.

Recommendation 17: Define Clear Tariffs, Rules, and Performance Requirements for Integration Services

Recommendation 17 focused on the need to develop a comprehensive package of clear tariffs, rules, and performance requirements for renewable integration services. The California ISO has led several efforts contributing to this effort. These include working closely with stakeholders to develop wholesale demand response products that can participate directly in the market, as well as educational forums to clarify existing requirements, rules, and market products for energy storage and aggregated distributed resources to participate in California ISO markets.

The California ISO, in coordination with energy agencies and stakeholders, has also developed detailed roadmaps for energy storage, demand response, and energy efficiency that include pathways for bringing more

561 For more information about the Smart Inverter Working Group, see <http://www.cpuc.ca.gov/PUC/energy/rule21.htm>.

562 California Public Utilities Commission, R.13-12-010, *Order Instituting Rulemaking to Integrate and Refine Procurement Policies and Consider Long-Term Procurement Plans*, December 19, 2013, <http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M084/K241/84241040.PDF>.

563 California Public Utilities Commission, R.14-02-001, *Order Instituting Rulemaking to Consider Electric Procurement Policy Refinements pursuant to the Joint Reliability Plan*, February 5, 2014, <http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M087/K779/87779434.PDF>.

of these resources into the system over the next several years and identify activities and milestones needed to make that happen.

Most importantly, in July 2015, the California ISO Board of Governors approved rules and processes to allow aggregated distributed resources to participate in the wholesale energy market. This effort is meant to open a pathway for smaller distributed resources such as rooftop solar, energy storage, and plug-in electric vehicles to participate effectively in the California ISO market.⁵⁶⁴

Recommendation 18: Provide Regional Solutions to Renewable Integration

The Renewable Action Plan recognized the value of near-term, low-cost integration solutions available in the Western Interconnection, such as expanding subhourly dispatch and intrahour scheduling, promoting dynamic transfers between balancing authorities, and accessing greater flexibility in the dispatch of existing generating plants.

There has been major progress on this recommendation. The California ISO and PacifiCorp announced a partnership in February 2013 to develop an Energy Imbalance Market (EIM) that would operate across participating balancing areas.

The EIM is an important renewable integration tool because it allows participants to leverage resources across the entire region, as well as providing the added benefit of more frequent dispatching in real time to make the best use of available energy supplies. For more information about regional solutions, see Chapter 2 “Renewables and Reliability” and Chapter 3.

The California ISO and PacifiCorp have also entered into a memorandum of understanding to explore PacifiCorp’s becoming a participating transmission owner in the

California ISO.⁵⁶⁵ A comprehensive benefits study is underway and is expected to be completed in fall of 2015. The California ISO expects this regional partnership to provide important benefits such as reduced costs for customers and market participants, reduced carbon emissions and more efficient use and integration of renewable energy, and enhanced reliability by increasing visibility across grids.⁵⁶⁶

Recommendation 19: Ensure Adequate Natural Gas Pipeline Infrastructure

Natural gas-fired power plants remain an important tool to integrate increasing amounts of variable renewable resources while maintaining grid reliability. Making the best use of the state’s natural gas fleet and ensuring that these plants can be called on when needed requires adequate natural gas pipeline infrastructure and better alignment of electricity and natural gas markets. Efforts in support of this recommendation include the following:

» In April 2013, ColumbiaGrid released a study on electric transmission system reliability issues with a hypothetical limitation of gas supply to electric generators along the Interstate 5 (I-5) corridor, which found that the electric transmission system performed acceptably under the stressed conditions. Further, in a *2013 IEPR* workshop on natural gas issues, the California ISO stated that short-term operational coordination between natural gas supply and electricity production in California has been occurring with few incidents. The *2013 IEPR* also included a report on natural gas infrastructure, natural gas and electric system interactions, and impacts to the natural gas market as a result of renewable integration.

564 California Independent System Operator, http://www.caiso.com/Documents/Decision_ExpandingMetering_TelemetryOptions-Memo-Jul2015.pdf.

565 “PacifiCorp to Study Joining the California ISO,” April 14, 2015, <http://www.pacificorp.com/about/newsroom/2015nrl/study-joining-california-iso.html>.

566 California Independent System Operator, <http://www.caiso.com/Documents/FAQ-ExpandingRegionalEnergyPartnerships.pdf>.

- » The Federal Energy Regulatory Commission (FERC) issued an order in March 2014 requiring all interstate pipelines to set up a system to post offers to buy excess capacity, which was intended to help improve the flow of natural gas to facilities such as gas-fired electric generators.⁵⁶⁷
- » In July 2014, Energy+Environmental Economics (E3) released a report on natural gas infrastructure adequacy in the western interconnection that concluded that it is technically feasible to meet the variable gas demands needed to integrate high penetrations of renewables in the west.⁵⁶⁸ The report noted, however, that as penetrations of variable renewable resources increase, forecasting the amount of gas needed to serve gas generators will become increasingly challenging.
- » Also in 2014, Pacific Gas and Electric Company and Southern California Gas Company submitted biennial advice filing letters to the CPUC demonstrating they have adequate backbone natural gas transmission capacity to meet both current and forecasted demand.
- » Energy Commission staff continues to monitor FERC proceedings on natural gas-electricity harmonization issues. FERC recently issued an order under Docket No. RM14-2-000, which revises FERC regulations to better coordinate the scheduling of wholesale natural gas and electricity markets to reflect increasing reliance on natural gas for electricity generation and to

provide additional scheduling flexibility to shippers on interstate gas pipelines.⁵⁶⁹

Strategy 4: Promote Incentives for Renewables that Create In-State Jobs and Benefits

Strategy 4 focused on economic development opportunities from supporting renewable projects and technologies by creating in-state jobs and supporting in-state industries, including manufacturing and construction.

Recommendations 20-22: Better Align Workforce Training to Needs; Enhance Linkage Between Clean Energy Policies, Workforce, and Employers; and Support the Innovation Hub Initiative at the Governor’s Office of Business and Economic Development

From 2009 to 2012, the Energy Commission had a strong role in workforce development and education in California through its distribution of American Recovery and Reinvestment Act funding. That commitment to workforce development is continuing through the efforts of the agency’s Energy Research and Development Division. In February 2013, the California Smart Grid Center at California State University, Sacramento, completed a strategic plan for Smart Grid workforce

567 Federal Energy Regulatory Commission, “FERC Announces Reforms to Improve Gas-Electric Coordination,” news release, March 20, 2014, http://www.ferc.gov/media/news-releases/2014/2014-1/03-20-14-M-1.asp#.VYMFg6Hn_cs.

568 Energy+Environmental Economics, *Natural Gas Infrastructure Adequacy in the Western Interconnection: An Electric System Perspective, Phase 2 Report*, July 2014, https://www.ethree.com/documents/E3_WIEB_Ph2_Report_full_7-28-2014.pdf.

569 Federal Energy Regulatory Commission, Docket No. RM14-2-000, Order No. 809, *Coordination of the Scheduling Processes of Interstate Natural Gas Pipelines and Public Utilities*, April 16, 2015, <http://ferc.gov/whats-new/comm-meet/2015/041615/M-1.pdf>.

development using funding from the Energy Commission. In addition, the market facilitation element of the Electric Program Investment Charge Program funds the strengthening of the clean energy workforce by creating tools and resources that connect the clean energy industry to the labor market.

The California Workforce Investment Board continues to be active in workforce training and has a five-year strategic plan that recognizes the importance of clean energy jobs in California. The plan identifies a wide variety of green trades ranging from carpenters and electricians to solar installers. The Board has also received \$3 million in Proposition 39 funds to develop and implement a competitive grant program for eligible workforce training organizations to prepare disadvantaged youth, veterans, and others for employment in clean energy fields.

California also has Clean Technology and Renewable Energy Partnership Academies that were established by legislation in 2011, with annual funding established in 2013 of \$8 million per year through 2017, for about 100 academies focused on green energy and technologies. The academies are available to students in grades 9-12 and provide career technical education in the fields of energy or water conservation and renewable energy.

Strategy 5: Coordinate Financing and Incentives for Critical Stages of Development

Strategy 5 centered on the importance of providing funding during key stages of the renewable research and development continuum, and of coordinating financing and incentive programs to provide the most value.

Recommendations 23-26: Advance R&D for Existing and Colocated Renewable Technologies, Innovative Renewable Technologies, Renewable Integration, and Proactive Siting of Renewable Projects

The primary action items for Recommendations 23–26 were to ensure that all research proposals are evaluated through a publicly vetted process, leverage cofunding opportunities, avoid duplication, and publish all research results on the Energy Commission’s website and make the information available to renewable developers and generators, integration service providers, grid system operators, regulatory agencies, policy makers, and research groups, as appropriate.

Since 2010, the Energy Commission’s Energy Research and Development Division has awarded more than \$200 million to projects that support the recommendations in the Renewable Energy Action Plan. Consistent with the recommendations of the action plan, each award was evaluated through a public process with results published on the Energy Commission’s website and provided to all interested stakeholders, and every effort is made

to leverage other funding opportunities when available and avoid duplicative research. More information about projects funded that support each recommendation is provided below.

The Energy Commission has funded 41 projects totaling more than \$70 million to support existing and co-located renewable technologies, including planning projects to reduce installation and maintenance costs, improving reliability and performance; developing community-scale bioenergy, conducting environmental impact assessment and mitigation, examining opportunities for synergies from combining renewable technologies, reducing the cost of distributed PV, integrating advanced inverter technologies and smart grid components, and identifying strategies to make bioenergy projects more economical.

To advance research and development for innovative renewable technologies, the Energy Commission has funded projects totaling more than \$20 million to bring technologies closer to commercialization, examine the potential of technologies on the horizon, develop data and tools to support market facilitation, verify the performance of innovative technologies, and develop technologies in the areas of biomass conversion, offshore wind, concentrating solar power, small hydro, and geothermal. Other projects have evaluated strategies to reduce peak demand, minimize the environmental impacts of energy generation, and bring technologies to market that provide increased environmental benefits, greater system reliability, and reduced system costs.

The Energy Commission has funded 75 projects to support renewable integration for a total of \$109 million. These include projects to integrate intermittent generation, improve solar and wind forecasting, develop smart grid technologies and microgrids, and improve energy storage technologies. Applied research projects that were funded include energy storage, grid planning tools, distribution system upgrades, and technology demonstration and deployment projects for renewable-based microgrids to demonstrate the benefits of local renewable generation enhanced with load management.

To support siting and permitting of renewable projects, the Energy Commission has funded 21 projects totaling around \$9 million to reduce and resolve environmental barriers to renewable deployment; develop new technology designs, scientific studies, and decision-support tools to avoid impacts to environmentally sensitive areas and permitting delays; and provide environmental analysis to support identifying preferred areas for renewable development such as the San Joaquin Valley.

Recommendations 27-29: Create an Interagency Clean Energy Financing Working Group, Support Extension of Federal Tax Credits, and Study the Effectiveness and Impacts of the Property Tax Exclusion

Recommendations 27, 28, and 29 focused on the need for providing clean energy financing programs, leveraging those programs, increasing public awareness of financing options, and supporting the extension of federal tax credits for renewables.

The 30 percent federal investment tax credit (ITC) has helped advance the renewable market, particularly for rooftop solar. Effective in 2017, the tax credit was scheduled to fall to between 0 and 10 percent for homeowners and utility-scale development, respectively, but was extended five years on December 18, 2015. Below is the schedule for the federal ITC:

2015	—	30 percent
2016	—	30 percent
2017	—	30 percent
2018	—	30 percent
2019	—	30 percent
2020	—	26 percent
2021	—	22 percent
2021–2023	—	commence construction for commercial projects only as long as the project is placed in service by December 31, 2023.

Table 19: Projects Funded Since 2010 to Advance Research and Development for Existing and Colocated Renewable Technologies (\$70,257,605)

Project Title	Researcher	Amount	Status
Air Quality Implications of Electrification and Renewable Energy Options	Advanced Power and Energy Program – UC Irvine	\$835,711	Active
Considering Climate Change in Hydropower Relicensing	Regents of the University of California (University of California, Davis)	\$299,970	Active
Hyperlight Low-Cost Solar Thermal Technology	Combined Power Cooperative (formerly Advanced Lab Group Cooperative)	\$1,000,000	Active
Economically and Environmentally Viable Strategies for Conversion of Bioresources to Power	Advanced Power and Energy Program – UC Irvine	\$397,236	Active
Air Quality Issues Related to Using Biogas from Anaerobic Digestion of Food Waste	CSU Fullerton	\$164,201	Active
Air Quality Implications of using Biogas (AQIB) to Replace Natural Gas in California	Regents of the University of California (University of California, Davis)	\$775,064	Active
Bay Area Biosolids to Energy	Delta Diablo Sanitation District	\$999,924	Active
Gasification of Almond Shell Biomass for Natural Gas Replacement	The Regents of the University of California (CIEE)	\$463,852	Active
Breakthrough Power Density for Rooftop PV Applications	Sun Synchrony	\$475,095	Active
Pollution Control and Power Generation for Low-Quality Renewable Fuel Streams	The Regents of the University of California; University of California, Irvine	\$1,499,386	Active
The Lakeview Farms Dairy	ABEC #3 LLC, dba Lakeview Farms Dairy Biogas	\$4,000,000	Active
The West Star North Dairy	ABEC #2 LLC, dba West Star North Dairy Biogas	\$4,000,000	Active
Organic Energy Solutions Community Scale Digester with Advanced Interconnection to the Electric Grid	Organic Energy Solutions	\$5,000,000	Active
Lowering Food-Waste Co-digestion Costs through an Innovative Combination of a Pre-sorting Technique and a Strategy for Cake Solids Reduction	Kennedy/Jenks Consultants	\$1,496,902	Active
Installation of a Lean-Burn Biogas Engine with Emissions Control to Comply with Rule 1110.2 at a Wastewater Treatment Plant in South Coast air Quality	Biogas & Electric, LLC	\$2,249,322	Active
Enabling Anaerobic Digestion Deployment for Municipal Solid Waste-to-Energy	Lawrence Berkeley National Laboratory	\$4,300,000	Active
North Fork Community Power Forest Bioenergy Facility	The Watershed Research and Training Center	\$4,965,420	Active
Modular Biomass Power Systems to Facilitate Forest Fuel Reduction Treatments	West Biofuels, LLC	\$2,000,000	Active

Table 19 Continued

Project Title	Researcher	Amount	Status
Interra Reciprocating Reactor for Low-Cost & Carbon-Negative Bioenergy	Interra Energy	\$2,000,000	Active
Cleaner Air, Cleaner Energy: Converting Forest Fire Management Waste to On-Demand Renewable Energy	All Power Labs Inc.	\$1,990,071	Active
Advanced Recycling of MSW	Taylor Energy	\$1,499,481	Active
The SoCalGas Waste-to-Bioenergy Applied R&D Project	The Southern California Gas Company	\$1,494,736	Active
Paths to Sustainable Distributed Generation through 2050: Matching Local Waste Biomass Resources with Grid, Industrial, and Community Needs	Lawrence Berkeley National Laboratory	\$1,500,000	Active
Low-Cost Biogas Power Generation with Increased Efficiency and Lower Emissions	InnoSeptra, LLC	\$1,318,940	Active
Meteorological Observations of Precipitation Processes to Improve Hydropower Forecasting	National Oceanic and Atmospheric Administration	\$1,105,000	Completed
California Landfill-Based Solar Projects	Project Navigator, LTD	\$120,000	Completed
Waste Vegetable Oil Driven CHP for Fast Food Restaurants	Altex Technologies Corporation	\$1,435,575	Completed
Production of Substituted Natural Gas from the Wet Organic Waste by Utilizing PDU-Scale Steam Hydrogasification Process	University of California, Riverside	\$649,214	Completed
Demonstration of Community-Scale, Low-Cost, Highly efficient PV and Energy management system at the Chemehuevi Community Center	The Regents of the University of California	\$2,588,906	Pending
Low-Emission Renewable Power Generation System	Recology Bioenergy	\$1,500,000	Pending
Community-Scale Renewable Combined Heat and Power Project	Recology Bioenergy	\$1,915,500	Pending
Dairy Renewable Combined Heat and Power	ABEC #4	\$3,000,000	Pending
Advancing Biomass Combined Heat and Power Technology to Support Rural California, the Environment, and the Electrical Grid	Sierra Institute for Community and Environment	\$2,603,228	Pending
College of San Mateo Internet of Energy	Prospect Silicon Valley dba Bay Area Climate Collaborative (BACC)	\$2,999,601	Pending

Table 19 Continued

Project Title	Researcher	Amount	Status
Demonstration of Community-Scale, Low-Cost, Highly Efficient PV and Energy Management System	UC Davis	\$1,238,491	Pending
Advancing Novel Biogas Cleanup Systems for the Production of Renewable Natural Gas	Institute of Gas Technology dba Gas Technology Institute (GTI)	\$1,000,000	Pending
Renewable Natural Gas Production from Woody Biomass via Gasification and Fluidized-Bed	The Regents of the University of California, San Diego	\$1,000,000	Pending
Cost Reduction for Biogas Upgrading via a Low-Pressure, Solid-State Amine Scrubber	Mosaic Materials, Inc.	\$1,000,000	Pending
Las Gallinas Valley Biogas Energy Recovery System (BERS) Project	Las Gallinas Valley Sanitary District	\$999,070	Pending
Investigation and Implementation of Improvements to Biogas Production Using Micronutrients, Operational Methodologies, and Biogas Processing Equipment to Enable Pipeline Injection of Biomethane	Biogas Energy Inc.	\$415,000	Pending

Source: California Energy Commission staff

Table 20: Projects Funded Since 2010 to Advance Research and Development for Innovative Renewable Technologies (\$20,230,777)

Project Title	Researcher	Amount	Status
Smart Inverter Interoperability Standards	SunSpec Alliance	\$2,000,000	Active
Mass-Manufactured, Air Driven Trackers for Low-Cost, High-Performance Photovoltaic Systems	Sunfolding, Inc.	\$1,000,000	Active
Demonstration of integrated photovoltaic systems and smart inverter functionality utilizing advanced distribution systems	Lawrence Berkeley National Laboratory	\$1,000,000	Active
Exploration Drilling and Assessment of Wilbur Hot Springs, Colusa County, California	Renovitas, LLC	\$264,229	Completed
High Solar PV Penetration Modeling	UC San Diego	\$500,000	Completed
SMUD's Smart Grid Pilot at Anatolia	Sacramento Municipal Utility District	\$500,000	Completed
Technologies for extracting valuable metals and compounds from geothermal fluids	Simbol, Inc.	\$380,000	Completed
Caldwell Ranch Exploration and Confirmation Project	Calpine Corporation	\$410,000	Completed
UC Davis West Village Energy Initiative: American Recovery and Reinvestment Act Cost-Share Funding	Regents of the University of California (University of California, Davis)	\$500,000	Completed
SMUD Community Renewable Energy Deployment	Sacramento Municipal Utility District	\$500,000	Completed
Plumas Energy Efficiency and Renewable Management Action Plan	Sierra Institute for Community and Environment	\$300,000	Completed
Energizing Our Future: Community Integrated Renewable Energy Assessment	Department of the Environment- City and County of San Francisco	\$300,000	Completed
Davis Future Renewable Energy and Efficiency	City of Davis	\$300,000	Completed
MaxSun- A Novel Community-Scale Renewable Solar Power System for California	Cogenra Solar, Inc.	\$525,000	Completed
Predictable Solar Power and Smart Building Management for California Communities	Cool Earth Solar, Inc.	\$1,726,438	Completed
Renewable Energy Regional Exploration Project	South Tahoe Public Utility District	\$139,830	Completed
Repowering Humboldt with Community-Scale Renewable Energy	Redwood Coast Energy Authority	\$1,750,000	Completed
Camp Pendelton Area 52 FractalGrid Demonstration Project	Harper Construction Company, Inc.	\$1,722,890	Completed
Assessing Smart Inverters and Consumer Devices to Enable more Residential Solar Energy	EPRI	\$1,705,487	Pending
Self-Tracking Concentrator Photovoltaics for Distributed Generation	Glint Photonics, Inc.	\$999,994	Pending

Source: California Energy Commission staff

Table 21: Projects Funded Since 2010 to Promote Research and Development for Renewable Integration (\$109,245,960)

Project Title	Researcher	Amount	Status
Renewable Energy Resource, Technology, and Economic Assessments	Regents of the University of California (University of California, Davis)	\$2,000,000	Active
Improving Solar & Load Forecasts: Reducing the Operational Uncertainty Behind the Duck Chart	Itron, Inc., dba IBS	\$998,926	Active
Investigating Flexible Generation Capabilities at the Geysers	Geysers Power Company, LLC	\$3,000,000	Active
Low-Cost Thermal Energy Storage for Dispatchable CSP	University of California, Los Angeles	\$1,497,024	Active
Systems Integration of Containerized Molten Salt Thermal Energy Storage in Novel Cascade Layout	Halotechnics	\$1,500,000	Active
Solar Forecast Based Optimization of Distributed Energy Resources in the L.A. Basin and UC San Diego Microgrid	The Regents of the University of California, San Diego	\$999,984	Active
Improving Short-Term Wind Power Forecasting Through Measurements and Modeling of the Tehachapi Wind Resource Area	University of California - Davis	\$1,000,000	Active
Flow Battery Solution to Smart Grid Renewable Energy Applications	EnerVault Corporation	\$476,428	Active
Smart Grid Demonstration Project	Los Angeles Department of Water & Power	\$1,000,000	Active
Grid-Saver Fast Energy Storage Demonstration	Transportation Power, Inc.	\$2,000,000	Completed
Demonstration and Validation of PV Output Variability Modeling	Clean Power Research	\$450,000	Completed
Utility-Scale Solar Forecasting, Analysis and Modeling	EnerNex, LLC	\$450,000	Completed
Evaluation and Optimization of Concentrated Solar Power Coupled With Thermal Energy Storage	KEMA, Inc.	\$447,642	Completed
Application of a Solar Forecasting System to Utility-Sized PV Plants on a Spectrum of Timescales	AWS Truepower, LLC	\$442,136	Completed
Energy Resource Forecasting and Integration Analysis	The Regents of the University of California (CIEE)	\$322,508	Completed
Surface Deformation Baseline in Imperial Valley From Satellite Radar Interferometry (InSAR)	Imageair, Inc.	\$672,234	Completed
Borrego Springs Microgrid Demonstration Project	San Diego Gas & Electric Company	\$2,808,488	Completed
Pacific Gas and Electric Energy Storage Demonstration	Pacific Gas and Electric Company	\$3,300,000	Completed

Table 21 Continued

Project Title	Researcher	Amount	Status
Renewable Resource Management at UCSD	The Regents of the University of California, San Diego	\$2,994,298	Completed
Using High Speed Computing to Estimate the Amount of Energy Storage and Automated Demand Response Needed to Support California's RPS.	Lawrence Livermore National Laboratory	\$1,750,000	Completed
Determining Best Location for Energy Storage to Maximize Effectiveness With Residential Renewable Generator Clusters	San Diego Gas & Electric Company	\$539,350	Completed
Electric Vehicle Charging Simulator for Distribution Grid Feeder Modeling	San Diego Gas & Electric Company	\$680,000	Completed
Wind Ramp – Short-Term Event Prediction Tool – Development and Implementation of an Analytical Wind Ramp Prediction Tool for the CAISO	Regents of the University of California (University of California, Davis)	\$398,662	Completed
WindSENSE – Determining the Most Effective Equipment for the CAISO to Gather Wind Data for Forecasting	Regents of the University of California (University of California, Davis)	\$646,661	Completed
Advanced Control Technologies for Distribution Grid Voltage and Stability With Electric Vehicles and Distributed Renewable Generation	Pacific Gas and Electric Company	\$1,535,725	Completed
Distribution System Field Study With California Utilities to Assess Capacity for Renewables and Electric Vehicles	The Regents of the University of California (CIEE)	\$1,167,380	Completed
A Low-Cost Inverter With Battery Interface for Photovoltaic-Utility System	Texas A&M University	\$95,000	Completed
Adaptive Power Flow Controls for Distribution Circuits With Renewables	California State University, Long Beach Research Foundation	\$49,999	Completed
Low-Cost Ultra-Thick Electrode Batteries for Grid-Level Storage	Ballast Energy, Inc	\$95,000	Completed
New Portable Electricity Storage Units Using Nanstructured Supercapacitors	University of California, Davis	\$86,420	Completed
Intelligent Energy Management for Solar-Powered EV Charging Stations	University of California, Davis	\$94,917	Completed
Cloud Speed Sensor	UC San Diego	\$95,000	Completed
Dampening System Oscillations Utilizing Phasor Measurement Units and Photovoltaic Inverters	UC San Diego	\$95,000	Completed
PEV-Based Active and Reactive Power Compensation in Distribution Networks	University of California, Riverside	\$95,000	Completed
Liquid Metal Thermal Energy Storage	thermaphase Energy, Inc	\$95,000	Completed
Vehicle-Grid Integration Roadmap	KEMA, Inc.	\$109,965	Completed
AB 2514 Energy Storage	KEMA, Inc.	\$350,000	Completed
Energy Storage Roadmap	KEMA, Inc.	\$50,000	Completed

Table 21 Continued

Project Title	Researcher	Amount	Status
Microgrid Assessment and Recommendation(s) to Guide Future Investments.	KEMA, Inc.	\$100,000	Completed
Strategic Analysis of Energy Storage Technology	The Regents of the University of California (CIEE)	\$324,998	Completed
Enabling Renewable Energy, Energy Storage, Demand Response and Energy Efficiency with a Community Based Master Controller-Optimizer	The Regents of the University of California, San Diego	\$999,949	Completed
Wind Firming Energy Farm	Primus Power Corporation	\$1,000,000	Completed
Sacramento Municipal Utility District Supervisory Control and Data Acquisition Retrofit	Sacramento Municipal Utility District	\$1,000,000	Completed
California ISO SynchroPhasor Technology Investment & Implementation	Electric Power Group	\$999,743	Completed
Glendale Water & Power – Marketing. Public Benefits	City of Glendale	\$1,000,000	Completed
Solid State Batteries for Grid-Scale Energy Storage	Seeo Inc.	\$600,000	Completed
SGIG Distribution Infrastructure Substation Upgrades	Modesto Irrigation District	\$149,315	Completed
Burbank Water and Power American Recovery and Reinvestment Act Smart Grid Program	Burbank Water and Power	\$1,000,000	Completed
Advanced Underground CAES Demonstration Project Using a Saline Porous Rock Formation as the Storage Reservoir	Pacific Gas and Electric Company	\$1,000,000	Completed
Validated and Transparent Energy Storage Valuation and Optimization Tool	Electric Power Research Institute	\$1,000,000	Completed
Pilot Testing and Demonstration of a Solar Hybrid System With Advanced Storage and LowTemperature Turbine to Produce On-Demand Solar Electricity	Cogenra Solar, Inc.	\$2,530,952	Completed
Utility Demonstration of Zynth Battery Technology at \$100/kWh or Less to Characterize Performance and Model Grid Benefits	Eos Energy Storage, LLC	\$2,156,704	Completed
High-Temperature Hybrid Compressed Air Energy Storage	Regents of the University of California, Los Angeles	\$1,621,628	Completed
City of Fremont Fire Stations Microgrid Project	Gridscape Solutions	\$1,817,925	Completed
Bosch Direct Current Building-Scale Microgrid	Robert Bosch LLC	\$2,817,566	Completed
Demonstrating a Secure, Reliable, Low-Carbon Community Microgrid at Blue Lake Rancheria	Humboldt State University Sponsored Programs Foundation	\$5,000,000	Completed

Table 21 Continued

Project Title	Researcher	Amount	Status
Las Positas Community College Microgrid	Chabot-Las Positas Community College District	\$1,522,591	Completed
Demonstration of PEV Smart Charging and Storage Supporting Grid Operational Needs	Regents of the University of California, Los Angeles	\$1,989,432	Completed
Smart Charging of Plug-In Vehicles and Driver Engagement for Demand Management and Participation in Electricity Markets	Lawrence Berkeley National Laboratory	\$1,993,355	Completed
Laguna Subregional Wastewater Treatment Plant Advanced Microgrid	Trane U.S., Inc.	\$4,999,804	Completed
Borrego Springs – A Future Photovoltaic Based Microgrid	San Diego Gas & Electric Company	\$4,724,802	Completed
High-Fidelity Solar Power Forecasting Systems for the 392 MW Ivanpah Solar Plant (CSP) and the 250 MW California Valley Solar Ranch (PV)	The Regents of the University of California, San Diego	\$999,898	Pending
Addressing Renewable Integration Issues Impacting DOD Bases in CA	KEMA, Inc.	\$120,288	Pending
High Solar PV Penetration Modeling	UC San Diego	\$500,000	Pending
College of San Mateo Internet of Energy	Prospect Silicon Valley dba Bay Area Climate Collaborative	\$2,999,601	Pending
Demonstration of Community–Scale, Low–Cost, Highly Efficient PV and Energy Management System	The Regents of the University of California, Davis	\$1,238,488	Pending
Demonstration of Community–Scale, Low–Cost, Highly Efficient PV and Energy Management System at the Chemehuevi Community Center	The Regents of the University of California, Riverside	\$2,588,906	Pending
Bosch Direct Current, Building-Scale Microgrid	Robert Bosch LLC	\$2,817,566	Pending
Demonstrating a Secure, Reliable, Low-Carbon Community Microgrid at the Blue Lake Rancheria	Humboldt State University Sponsored Programs Foundation	\$5,000,000	Pending
Borrego Springs – A Future Photovoltaic-Based Microgrid	San Diego Gas & Electric Company	\$4,724,802	Pending
Renewable Microgrid for the John Muir Medical Center	Charge Bliss, Inc.	\$4,776,171	Pending
City of Fremont Fire Stations Microgrid Project	Gridscape Solutions	\$1,817,925	Pending
Las Positas Community College Microgrid	Chabot-Las Positas Community College District	\$1,525,000	Pending
Laguna Subregional Wastewater Treatment Plant Advanced Microgrid	Trane U.S., Inc.	\$4,999,804	Pending
Control of Networked Electric Vehicles to Enable a Smart Grid With Renewable Resources	The Regents of the University of California (CIEE)	\$400,000	Pending

Source: California Energy Commission staff

Table 22: Projects Funded Since 2010 for Proactive Siting of Renewable Projects (\$9,196,414)

Project Title	Researcher	Amount	Status
Analysis of Forest Biomass Removal on Biodiversity	USDA Forest Service, Sierra Nevada Research Center, Pacific Southwest	\$1,149,361	Active
Assessing the Long-term Survival and Reproductive Output of Desert Tortoises at a Wind Energy Facility Near Palm Springs, California.	U.S. Geological Survey, Southwest Biological Science Center	\$319,936	Completed
Mapping Habitat Distributions of Desert Rare Plants from Optimized Data	Regents of the University of California (University of California, Davis)	\$580,907	Completed
Use of Habitat Suitability Models and Head-Start Techniques to Minimize Conflicts between Desert Tortoises and Energy Development Projects in the Mojave Desert	Regents of the University of California (University of California, Davis)	\$238,310	Completed
Cumulative Biological Impacts Framework for Solar Energy Projects in the California Desert	The Regents of the University of California, Santa Barbara	\$383,787	Completed
Potential Habitat Modeling, Landscape Genetics, and Habitat Connectivity for the Mohave Ground Squirrel	U.S. Geological Survey	\$223,755	Completed
Methodology for Characterizing Desert Streams to Facilitate Permitting Solar Energy Projects	California State University, Fresno Foundation	\$297,948	Completed
Measure of Carbon Balance in California Deserts: Impacts of Widespread Solar Power Generation	University of California Riverside	\$164,879	Completed
Assessment of Offshore Wind Development Impacts on Marine Ecosystems	University of California Los Angeles	\$153,017	Completed
Evaluation of a Passive Acoustic Monitoring Network for Harbor Porpoises in California	San Jose State University	\$149,815	Completed
Development of an Environmental Impact Assessment Tool for Wave Energy	San Diego State University	\$165,000	Completed
Development of a Modeling Tool to Assess and Mitigate the Effects of Small Hydropower on Stream Fishes in a Changing California Climate	University of California Davis	\$133,000	Completed
Assessment of the Potential Environmental Impacts of Alternative Energy Scenarios for California	University of California Berkeley	\$133,000	Completed
Aerial Line Transect Surveys for Golden Eagles within the Desert Renewable Energy Conservation Plan Area	Humboldt State University Sponsored Programs Foundation	\$200,000	Completed
Research to Improve Golden Eagle Management in the Desert Renewable Energy Conservation Planning Area	US Geological Survey	\$314,000	Completed
Population Viability and Restoration Potential for Rare Plants Near Solar Installations	BMP Ecosciences	\$753,100	Completed
Desert Tortoise Spatial Decision Support System	Redlands Institute, University of Redlands	\$350,000	Completed
Effect of Utility-Scale Solar Development and Operation on Desert Kit Foxes	Randel Wildlife Consulting, Inc.	\$606,257	Completed

Table 22 Continued

Project Title	Researcher	Amount	Status
Improving Environmental Decision Support for Proposed Solar Energy Projects Relative to Mojave Desert Tortoise	Redlands Institute, University of Redlands	\$563,776	Completed
Test of Avian Collision Risk of a Closed Bladed Wind Turbine	Shawn Smallwood, sole proprietor	\$716,596	Completed
Considering Climate Change in Hydropower Relicensing	UC Davis	\$299,970	Completed

Source: California Energy Commission staff

The permanent 10 percent for commercial projects remains in place after 2021. The federal budget bill also extended the production tax credit (PTC) for wind⁵⁷⁰ and allows wind developers to opt for the ITC instead of the PTC. The schedule shown above for solar also applies to the federal ITC available for wind. In addition to solar and wind, eligibility for the PTC was extended to additional types of renewable energy projects; biomass, landfill gas, geothermal, incremental hydroelectric, and ocean energy projects will qualify for a 30 percent PTC if construction begins by December 2016. Since the 30 percent ITC for fuel cells was not extended, fuel cell projects would need to be in service by December 2016 to qualify under existing law.⁵⁷¹ There has been little progress on creating a clean energy financing working group or evaluating the property tax exclusion, but there has been movement on helping to finance customer-side renewable projects through property-assessed clean energy (PACE) programs. In 2013, Senate Bill 96 (Skinner, Chapter 356, Statutes of 2013) directed the California Alternative Energy and Advanced Transportation Financing Authority (CAEATFA) to develop the PACE Loss Reserve Program to reduce the risk to mortgage lenders from residential PACE financing for energy efficiency or distributed renewable installations. The Energy Commission provided \$10 million for CAEATFA's Loss Reserve, which makes first mortgage lenders whole for any losses in a foreclosure or a forced sale attributed to a PACE lien. According to the CAEATFA website, as of March 2015, there were more than 24,000 residential PACE financings valued at about \$500 million covered by the program and no claims on the loss reserve

570 The PTC extension for wind projects that have commenced construction through December 2016 qualify for the full PTC value for 10 years. Projects with construction beginning in 2017 qualify for 10-yr of credits at 80 percent of the full PTC value, 60 percent for projects started in 2018, and 40 percent for projects started in 2019.

571 California Energy Commission, Tracking Progress, *Renewable Energy*, Updated December 22, 2015, http://www.energy.ca.gov/renewables/tracking_progress/index.html, p. 17.

to date.⁵⁷² CAEATFA initially estimated the loss reserve would last 8 to 12 years but is reevaluating that now that the program has been active for almost a year.

Recommendation 30: Modify the Clean Energy Business Financing Program

The Energy Commission's Clean Energy Business Financing Program was originally funded under the American Recovery and Reinvestment Act of 2009. Unfortunately, the program experienced difficulties with funded projects not achieving goals, and eventually the program became too cumbersome for the Energy Commission to administer given the demands of private sector loans. The Energy Commission is working to transfer remaining program funds to the Department of General Services for administration of the funds.

Recommendation 31: Develop Marketing Outreach Plan for Energy Conservation Assistance Account Programs

Recommendation 31 was to develop a marketing outreach plan for the Energy Commission's Energy Conservation Assistance Account (ECAA) program. At the time the Renewable Action Plan was published, few local entities were taking advantage of the ECAA program to finance renewable energy projects because the requirements for energy payback periods did not accommodate the longer payback periods typical of renewable installations.

In 2013, the ECAA loan payback period was changed in statute from 15 to 20 years, which has allowed more loan applicants with solar projects to qualify for funding. Since 2013, the Energy Commission has funded 26 ECAA loans that include PV installations, which indicates that local agencies are more interested in taking advantage of the program.

572 California Alternative Energy and Advanced Transportation Financing Authority, Property Assessed Clean Energy (PACE) Loss Reserve Program, <http://www.treasurer.ca.gov/CAEATFA/pace/activity.asp>, accessed June 18, 2015.

The ECAA program also received additional funds as a result of Proposition 39 that have been allocated to zero interest rate loans and energy audits for K-12 schools and community colleges. The ECAA program also has been allocated funding from the Greenhouse Gas Reduction Fund for eligible state-owned and operated facilities and the University of California and California State University for energy efficiency and renewable energy projects, with emphasis placed on projects within, or benefiting, a disadvantaged community. The lower interest rates offered by the program elements funded through Proposition 39 and the Greenhouse Gas Reduction Fund may make these programs more attractive for applicants seeking to install renewable systems.

APPENDIX B

California and Washington Crude-by-Rail Projects

Excluding the Plains All American crude-by-rail (CBR) facility near Taft (Kern County), there is 58,000 barrels per day of permitted CBR receiving capacity in California. (See below.) The Plains CBR facility is the only one in California that can receive one unit train per day.

ALREADY OPERATIONAL FACILITIES		
Receipt Capability in Thousands of Barrels Per Day		
SAV Patriot–Sacramento (PR)	10	Permit rescinded
KinderMorgan–Richmond	16	
Kern Oil–Bakersfield	26	
Plains–Bakersfield	65	Operational November 2014
Tesoro–Carson	3	
Alon–Long Beach	10	
ExxonMobil–Vernon	3	

There is one CBR project (Alon–Bakersfield) that has completed the permit review, yet not started construction. In addition, there four other projects either still undergoing permit review or still in the development phase.

PROPOSED FACILITIES (all large)

Receipt Capability in Thousands of Barrels Per Day

Valero–Benicia (SP)	70	EIR Process
Phillips66–Santa Maria (SP)	37	EIR Process
Alon–Bakersfield (APNC)	150	Permit issued September 9, 2014
Targa–Stockton (SP)	65	Not yet completed marine terminal approval & upgrades
Questar–Coachella Valley (PP)	120	Company performing engineering analysis

California CBR Projects

Northern California

WesPac Energy Project – Pittsburg – Revised Permit Review⁵⁷³

- » Will no longer include rail access
- » Still plan marine terminal for receipt and loading – average of 192,000 BPD
- » Connection to KLM pipeline– access to Valero, Shell, Tesoro and Phillips 66 refineries
- » Connection to idle San Pablo Bay Pipeline– access to Shell, Tesoro and Phillips 66 refineries
- » Notice of Preparation (NOP) of a Second Recirculated Draft EIR released
- » Construction could be completed within 18 months of receiving all permits
- » Lead agency – City of Pittsburg
- » Could be operational by 2017

Valero – Benicia Crude Oil by Rail Project - Undergoing Permit Approval⁵⁷⁴

- » Benicia refinery
- » Up to 100 rail cars per day or 70,000 BPD
- » Recirculated Draft Environmental Impact Report released August 31, 2015
- » Construction would take six months
- » Project will require approval of the City of Benicia
- » Could be operational by 2016

573 <http://www.ci.pittsburg.ca.us/index.aspx?page=700>.

574 http://www.ci.benicia.ca.us/index.asp?Type=B_BASIC&SEC={FDE9A332-542E-44C1-BBD0-A94C288675FD}.

Central California

Phillips 66 – Santa Maria Refinery – Undergoing Permit Approval⁵⁷⁵

- » Average of 37,142 BPD
- » Planning and Building Department is working toward releasing a Final Environmental Impact Report
- » Construction expected to require 9–10 months to complete
- » Project will require approval of the San Luis Obispo County Planning Commission
- » Could be operational by 2016

Bakersfield Region

Alon Crude Flexibility Project – Permits Approved

- » Alon–Bakersfield Refinery
- » 2 unit trains per day – 104 rail cars per unit train
- » 150,000 BPD offloading capacity
- » Will be able to receive heavy crude oil
- » Oil tankage connected to main crude oil trunk lines – transfer to other refineries in Northern and Southern California
- » Kern County Board of Supervisors approved permits for the project on September 9, 2014
- » Contract awarded for initial engineering work – May 2015
- » Construction has not commenced but would take nine months to complete
- » Could be operational by 2016

575 http://www.slocounty.ca.gov/planning/environmental/EnvironmentalNotices/Phillips_66_Company_Rail_Spur_Extension_Project.htm.

Plains All American – Bakersfield Crude Terminal – Operational

- » Up to 65,000 BPD
- » Connection to additional crude oil line via new six-mile pipeline
- » Initial delivery during November 2014
- » Poor rail economics have limited deliveries
- » Litigation underway regarding permit

The Energy Commission is also monitoring the progress of two other potential CBR projects, one in Stockton (Northern California) and another in Riverside County (Southern California). The Targa project in the Port of Stockton is designed to receive CBR cargoes and transfer the oil to marine vessels for delivery to California refineries. The planned capacity of the facility is nearly 65,000 BPD. Another project being tracked by the Energy Commission is the Questar/Spectra CBR project that is designed to import up to 120,000 BPD of crude oil into a yet-to-be-determined facility in Riverside County that would then be off-loaded into storage tanks before being shipped via a combination of existing and new pipelines to refineries in Southern California. These two CBR proposals have the potential to contribute an additional 185,000 BPD to California's CBR receiving capacity by end of 2017.

Washington CBR Projects

Northwest Washington

BP – Cherry Point Refinery (1) – Operational

- » Up to 60,000 BPD
- » Permits received from Whatcom County, Washington, on April 13, 2013
- » Operational December 26, 2013

Tesoro – Anacortes Refinery (2) – Operational

- » Up to 50,000 BPD
- » 40 percent of refinery crude oil supply
- » Operational September 2012

Shell – Anacortes Refinery (3) – Permit Review

- » Up to 62,000 BPD
- » Will require permits from Army Corps of Engineers, Washington Department of Ecology, and Skagit County
- » Draft EIS to be developed after Shell appeal to obtain a Mitigated Determination of Non-Significance was denied in May 2015
- » Could be operational by late 2016

Phillips 66 – Ferndale Refinery (4) – Operational

- » Up to 20,000 BPD, mixed freight cars
- » Permits for expansion to 40,000 BPD received from Whatcom County, Washington, during 2014

Southwest Washington and Northwest Oregon

Global Partners LP – Clatskanie, Oregon (5) – Operational

- » Original crude oil transloading capability up to 28,600 BPD
- » Revised permit issued August 19, 2014; increases capacity to 120,000 BPD
- » Deepwater marine terminal
- » Operational November 2012

Figure 76: Northwest Washington CBR Facilities



Source: WSDOT State Rail & Marine Office map and California Energy Commission

Imperium Renewables, Port of Grays Harbor Project (6) – Permit Review

- » Rail receipts of unit trains and loading of marine vessels
- » Capacity up to 75,000 BPD
- » Shoreline Substantial Development Permit was issued June 17, 2013
- » SSDP remanded and SEPA determination invalidated by State Shorelines Hearing Board on November 12, 2013
- » Environmental impact statements (EIS) being developed – Washington Department of Ecology and City of Hoquiam are lead agencies for the project permit review
- » Start-up date uncertain

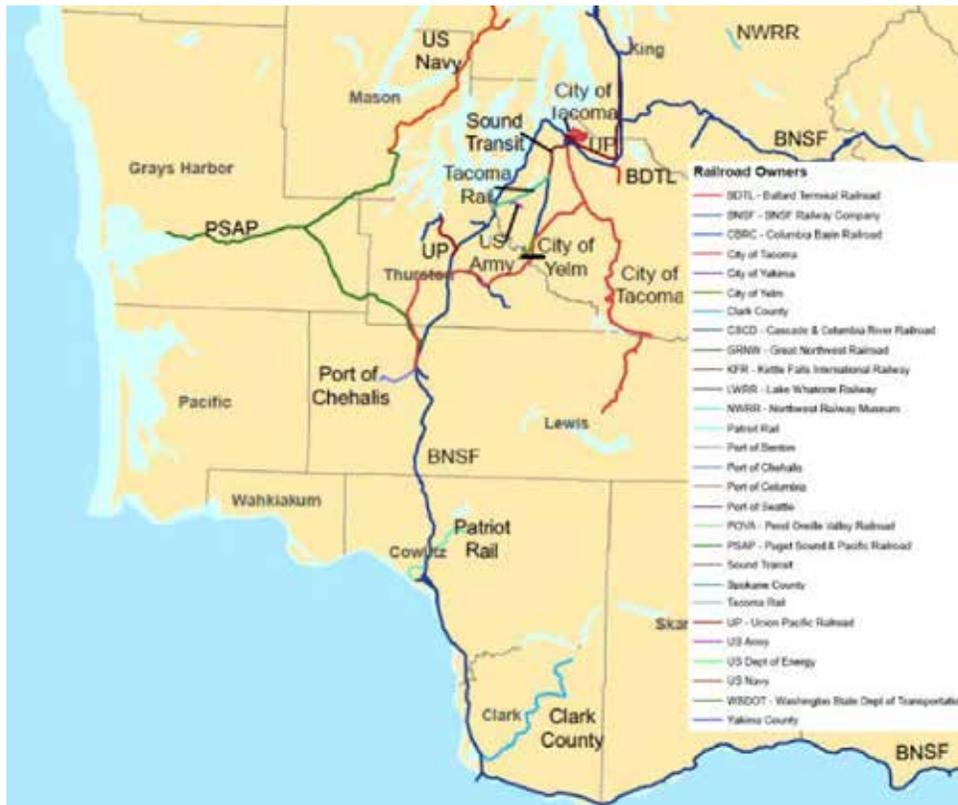
NusStar, Port of Vancouver (7) – Permit Review

- » Rail receipts of unit trains and loading of marine vessels
- » Capacity up to 41,000 BPD
- » Permit review underway
- » Initial start-up date uncertain

Targa Sound, Tacoma Terminal (8) – Permit Review

- » Rail receipts of unit trains and loading of marine vessels
- » Capacity up to 41,000 BPD
- » Permit review underway
- » Start-up date uncertain

Figure 77: Southwest Washington and Northwest Oregon CBR Facilities



Source: WSDOT State Rail & Marine Office map and California Energy Commission

Tesoro – Savages, Port of Vancouver Project (9) – Permit Review

- » Rail receipts of unit trains and loading of marine vessels
- » Initial capacity up to 120,000 BPD
- » Tesoro will have offtake rights to 60,000 BPD
- » Expansion capability of up to 360,000 BPD
- » Revised draft EIS to be released late November 2015
- » Lead agency – Energy Facility Site Evaluation Council
- » Start-up could occur by 2017

U.S. Oil & Refining – Tacoma Refinery (10) – Operational and Planned Expansion

- » Up to 6,900 BPD, mixed freight cars
- » Operational April 2013
- » Seeking permits to expand capacity to 48,000 BPD

Westway Terminals, Port of Grays Harbor Project (11) – Permit Review

- » Rail receipts of unit trains and loading of marine vessels
- » Capacity up to 26,000 BPD for first phase of project, up to 48,900 BPD second phase
- » Shoreline Substantial Development Permit issued on April 26, 2013
- » SSDP remanded and SEPA determination invalidated by State Shorelines Hearing Board on November 12, 2013
- » EIS being developed – Washington Department of Ecology and City of Hoquiam are lead agencies for the project permit review
- » Start-Up date uncertain; construction would take 12–16 months to complete once all permits have been received

APPENDIX C

Crude-By-Rail Chronology of Safety-Related Actions

August 31, 2011

Association of America Railroads issues Casualty Prevention Circular 1232 (CPC 1232). Requires all manufacturers to construct rail tank cars to upgraded standards beginning October 10, 2011.⁵⁷⁶

August 7, 2013

Federal Railroad Administration issues Emergency Order No. 28. Primarily requires trains transporting crude oil and other flammable liquids to be manned at all times whether the train is temporarily idled on side tracks.⁵⁷⁷ Intended to prevent an unattended train from rolling away from its idle position and derailling, as was the case with the Lac Mégantic, Quebec, Canada, accident.

⁵⁷⁶ *Crude Oil Tank Cars – Economics, Specification, Supply, Regulation, and Risk*: GATX, February 13, 2013, slide 17, <http://www.crude-by-rail-destinations-summit.com/media/downloads/127-paul-titterton-vice-president-and-group-executive-fleet-management-marketing-and-government-affairs.pdf>.

⁵⁷⁷ “Emergency Order Establishing Additional Requirements for Attendance and Securement of Certain Freight Trains and Vehicles on Mainline Track or Mainline Siding Outside of a Yard or Terminal,” *Federal Register*, Vol. 78, No. 152, August 7, 2013, pages 48218–48224, <https://www.fra.dot.gov/eLib/details/L04719>.

September 6, 2013

Pipeline and Hazardous Materials Safety Administration issues an Advance Notice of Proposed Rulemaking covering standards for rail tank cars and operations of trains transporting flammable liquids.⁵⁷⁸

February 21, 2014

Department of Transportation sends a letter to the Association of American Railroads requesting specific voluntary steps to be undertaken to reduce the risk of derailment and release of crude oil.⁵⁷⁹ Actions include:

- » Maximum speeds of 50 miles per hour.
- » Maximum speed reduced to 40 miles per hour for any trains shipping crude oil using pre-CPC 1232 rail tank cars.

⁵⁷⁸ “Hazardous Materials: Rail Petitions and Recommendations To Improve the Safety of Railroad Tank Car Transportation (RRR),” *Federal Register*, Vol. 78, No. 173, September 6, 2013, pages 54849–54861, <http://www.gpo.gov/fdsys/pkg/FR-2013-09-06/pdf/2013-21621.pdf>.

⁵⁷⁹ A copy of the letter can be found at <http://www.dot.gov/briefing-room/letter-association-american-railroads>.

- » Operational changes to improve emergency braking capability.
- » Increased inspections.
- » Installation of devices to detect defective bearings.

April 23, 2014

Transport Canada issues a Protective Direction that prohibits older style rail tank cars from transporting Class 3 flammable liquids such as crude oil and ethanol. Further, pre-CPC 1232 rail tank cars are to be phased out of service within three years or retrofitted to meet stricter standards. In addition, Transport Minister issues an order limiting the speeds of trains transporting crude oil and ethanol to 50 miles per hour (MO 14-01).⁵⁸⁰

May 7, 2014

U.S. Department of Transportation issues Emergency Order OST-2014-0067 requiring railroad companies to alert State Emergency Response Commission representatives of the specific counties that trains carrying Bakken crude oil in excess of 1 million gallons will traverse.⁵⁸¹ In the case of California, that would be the Governor's Office of Emergency Services.

June 10, 2014

California Interagency Rail Safety Working Group issues report on crude-by-rail activities that contain extensive recommendation to federal and state agencies directed at improving rail safety of flammable liquid transportation.⁵⁸²

580 Minister of Transport Order Pursuant to Section 19 of the Railway Safety Act, April 23, 2014, <http://www.tc.gc.ca/eng/mediaroom/ministerial-order-railway-7491.html>.

581 A copy of the Emergency Order can be found at https://www.fra.dot.gov/eLib/details/L05225#p1_z5_gD_ISO_y2013_y2014.

582 *Oil by Rail Safety in California*, State of California Interagency Rail Safety Working Group, June 10, 2014, <http://www.caloes.ca.gov/FireRescueSite/Documents/IRSWG-Oil%20By%20Rail%20Safety%20in%20California.pdf>.

June 20, 2014

Governor Brown signs into law Senate Bill 861 (Corbett, Chapter 35, Statutes of 2014) that, among other actions, expands the role of the California Office of Spill Prevention and Response from coastal responsibility to a state-wide responsibility.⁵⁸³ The Office of Spill Prevention and Response has initiated activities to develop new rules that will be used to enforce the legislation. A fee assessed for crude oil delivered to California refineries will be used to fund 38 permanent staff members.⁵⁸⁴

June 25, 2014

Energy Commission convenes a public workshop of various federal, state, private, and public stakeholders to discuss emerging trends in crude oil transportation, recent developments of rail-related safety regulations, and expanded oversight of crude-by-rail activities by various state agencies.⁵⁸⁵

California Interagency Rail Safety Working Group unveils its interactive rail risk and response map tool. This software "helps identify areas along rail routes in California with potential higher vulnerability and shows nearby emergency response capacity".⁵⁸⁶

August 1, 2014

Pipeline and Hazardous Materials Safety Administration issues a Notice of Proposed Rulemaking covering standards for rail tank cars and operations of trains

583 http://www.leginfo.ca.gov/pub/13-14/bill/sen/sb_0851-0900/sb_861_bill_20140620_chaptered.pdf.

584 A description of OSPR responsibilities and new activities in response to SB 861 may be viewed at <https://www.wildlife.ca.gov/OSPR/About>.

585 *Lead Commissioner Workshop on Trends in Sources of Crude Oil*, California Energy Commission, June 25, 2014. The workshop proceeding can be found at http://www.energy.ca.gov/2014_energypolicy/documents/#06252014.

586 The Rail Risk & Response Map is at <http://california.maps.arcgis.com/apps/OnePane/basicviewer/index.html?appid=928033ed043148598f7e511a95072b89>.

transporting flammable liquids.⁵⁸⁷ Primary proposed regulatory changes:

- » Designates trains transporting Class 3 flammable liquids (such as crude oil and ethanol) as *high-hazard flammable trains* (HHFTs.)
- » Limits all HHFT to maximum speed of 50 miles per hour along all routes.
- » Seeks comments on proposed lower maximum speeds under various circumstances.
- » Requires railroads to analyze of HHFT routes to identify the ones with the least risk.
- » Requires adoption of new operating procedures and/or equipment to improve braking responses to emergency stops.
- » Requires new construction standards for all rail tank cars constructed after October 2015 that would be used to transport Class 3 flammable liquids – new Department of Transportation Specification 117.⁵⁸⁸

587 “Hazardous Materials: Enhanced Tank Car Standards and Operational Controls for High-Hazard Flammable Trains,” *Federal Register*, Vol. 79, No. 148, August 1, 2014, pages 45016–45079. The presentation can be found at <http://www.gpo.gov/fdsys/pkg/FR-2014-08-01/pdf/2014-17764.pdf>.

588 According to William Finn of the Railway Supply Institute, there were 43,750 rail tank cars in crude oil service at the end of 2013, of which 14,350 rail tank cars were compliant with the more stringent CPC 1232 standards. In addition, there were 29,850 rail tank cars in ethanol service at that time, of which 500 were compliant with the more stringent CPC 1232 standards. By the end of 2015, the number of rail tank cars meeting the CBC 1232 standards is expected to number 57,200 at the current rate of construction. Mr. Finn’s presentation can be found at http://www.energy.ca.gov/2014_energypolicy/documents/2014-06-25_workshop/presentations/Finn_PPT_Updated.pdf.

- » Requires all noncomplying rail tank cars (legacy fleet) to be repurposed, retired, or refurbished to meet the stricter standards by October 1, 2017, for the most flammable commodities (Packing Group I).

September 9, 2014

Federal Railroad Administration issues a Notice of Proposed Rulemaking to codify many of the directives specified in Emergency Order 28 related to the securement of unattended locomotives.⁵⁸⁹ These measures are designed to prevent trains carrying certain hazardous materials (such as crude oil) from being unmanned while on sidings or mainline track. Exceptions are allowed if train crews follow various additional safety and securement protocols.

December 9, 2014

The North Dakota Industrial Commission issues new standards related to the treatment of Bakken crude oil to ensure that the more volatile components are removed through application of heat or pressure before being loaded into rail tank cars. New standards go into effect on April 1, 2015, and limit the volatility of the treated crude oil to a maximum of 13.7 pounds per square inch, lower than the ASTM standard of 14.7 pounds per square inch.⁵⁹⁰

March 15, 2015

California Governor’s Office of Emergency Services issues an updated gap analysis report that “outlines existing hazardous material capabilities and emergency response resources operated by our local, state, federal, industrial, and tribal partners, and may be available to respond either directly or as part of a mutual aid request to an

589 “Securement of Unattended Equipment,” *Federal Register*, Vol. 79, No. 174, September 9, 2014, pages 53356–53383. The document can be found at <http://www.gpo.gov/fdsys/pkg/FR-2014-09-09/pdf/2014-21253.pdf>

590 North Dakota Industrial Commission Order Number 25417, December 9, 2014. The document can be found at <https://www.dmr.nd.gov/oilgas/Approved-or25417.pdf>

accident resulting in a major hazardous materials release. It also identifies gaps in adequate planning, training, and response capabilities.”⁵⁹¹

May 1, 2015

Pipeline and Hazardous Materials Safety Administration and the Federal Railroad Administration issue a “final rule” related to improving the standards for rail tank cars used to transport crude oil and ethanol, as well as operation of trains transporting such materials.⁵⁹²

August 3, 2015

The California Office of Spill Prevention and Response (OSPR) posts emergency regulations to implement SB 861. The regulations cover contingency plans, certificates of financial responsibility, and drills and exercises requirements for the new inland entities now under OSPR’s jurisdiction.⁵⁹³

591 *Updated Gap Analysis for Rail in California*, Governor’s Office of Emergency Services, March 15, 2015. The document can be found at http://www.caloes.ca.gov/FireRescueSite/Documents/Updated_Gap_Analysis_for_Rail_in_California-20150313.pdf.

592 *Rule Summary: Enhanced Tank Car Standards and Operational Controls for High-Hazard Flammable Trains*, U.S. Department of Transportation, May 1, 2015. See more at: <http://www.transportation.gov/mission/safety/rail-rule-summary#sthash.Cs7rjA9i.dpuf>

593 The proposed OSPR regulations can be found at <https://www.wildlife.ca.gov/OSPR/Legal/Proposed-Regulations>.

APPENDIX D

Full List of ARFVTP Projects
Analyzed by NREL for 2015 IEPR

Table 23: Full List of ARFVTP Projects Analyzed by NREL

Project Categories	Fuel Class or Sub Class	Awards to 6/15		Projects Evaluated in Benefits Analysis		
		(\$M)	No. Awards	(\$M)	No. Awards	Number Units
Fuel Delivery Infrastructure						
Electric Drive Charging Infrastructure	Electric Drive	\$40.9	69	\$40.9	69	40 Level 1 9540 Level 2 132 DCFC
Hydrogen Fueling Infrastructure	Hydrogen	\$83.5	37	\$82.5	36	47 Stations
Natural Gas Fueling Infrastructure	Natural Gas	\$16.0	44	\$16.0	44	51 Stations
E85 Fueling Stations	Gasoline Substitute	\$14.6	4	\$14.6	4	205 Stations
Upstream Infrastructure	Diesel Substitute	\$4.0	4	\$4.0	4	5 Facilities or Expansions
Hydrogen Fuel Standards Development	Hydrogen	\$4.1	2	-	-	-
Fuel Delivery Infrastructure Subtotal		\$163.1	160	\$158.0	157	
Vehicles						
Light-Duty Incentives, CVRP	Electric Drive	\$24.5	3	\$24.5	3	109,661 Rebates
Medium- Heavy-Duty Incentives, HVIP	Electric Drive	\$4.0	1	\$4.0	1	155 vehicles
Natural Gas Vehicle Deployment Incentives	Natural Gas	\$71.2	5	\$71.2	5	2826 vehicles
LPG Vehicle Deployment Incentives	Propane	\$21.0	2	\$21.0	2	509 vehicles
Light-Duty Demonstration	Electric Drive	\$0.6	1	\$0.6	1	50 LDVs
Medium- and Heavy-Duty Vehicle Demonstration	Electric Drive	\$70.6	26	\$70.6	26	Various ¹
Fuel Cell Bus Demonstration	Hydrogen	\$4.6	2	\$2.4	1	1 bus
Medium- and Heavy-Duty Vehicle Demonstration	Natural Gas	\$6.3	2	\$6.3	2	2 natural gas engine demos

Project Categories	Fuel Class or Sub Class	Awards to 6/15		Projects Evaluated in Benefits Analysis		
		(\$M)	No. Awards	(\$M)	No. Awards	Number Units
Medium- and Heavy-Duty Vehicle Demonstration	Gasoline Substitute	\$2.7	1	\$2.7	1	1 hybrid E85 powertrain
Component Demonstration	Hydrogen	\$4.4	2	\$4.4	2	4 vans, 2 bus
Component Demonstration	Electric Drive	\$20.6	9	\$20.6	9	Various ²
Vehicle Manufacturing	Electric Drive	\$34.5	10	\$34.5	10	Various ³
Vehicles Subtotal		\$265	64	\$262.8	63	
Fuel Production						
Bench Scale & Feasibility	Biodiesel	\$5.0	1	-	-	-
Commercial Production	Biomethane	\$43.5	10	\$43.5	10	-
Bench Scale & Feasibility	Biomethane	\$12.5	6	\$12.5	6	-
Commercial Production	Diesel Substitutes	\$33.9	9	\$33.9	9	-
Bench Scale & Feasibility	Diesel Substitutes	\$17.8	8	\$17.8	8	-
Commercial Production	Gasoline Substitute	\$17.5	6	\$17.5	6	-
Bench Scale & Feasibility	Gasoline Substitute	\$5.9	3	\$5.9	3	-
Fuel Production Subtotal		\$136.1	43	\$131.1	42	
Other						
PEV Regional Readiness	Electric Drive	\$6.9	30	-	-	-
Regional Readiness	Hydrogen	\$0.8	4	-	-	-
Sustainability Research	Biofuels	\$2.1	2	-	-	-
Workforce Training and Development	Workforce Training/Dev.	\$25.2	3	-	-	-
Technical Assistance and Analysis	Program Support	\$13.9	14	-	-	-
Other Subtotal		\$48.9	53	-	-	
TOTAL		\$613.1	320	\$551.9	262	

Notes: (1) 12 HD hybrid hydraulic delivery trucks, 10 range-extender MD truck demo, 5 HD truck retrofits to PHEV, 1 class 8 hybrid natural gas truck, 1 all electric fleet at Air Force Base, 1 diverse fleet of 378 vehicles, 1 prototype class 4 all-electric, feasibility and testing for 1 truck manufacturing facility, 1 CLEAN Truck Demo Program, 1 HD truck retrofits to pantograph system; (2) 3 lithium battery production/assembly processes, 1 electric motorcycle powertrain, 2 battery management/communication systems, 2 electric drive manufacturing and assembly processes, and 4 electric drive demonstration projects including 14 MD trucks, 17 class 6 trucks, 6 schools buses, and 7 walk-in vans; (3) 1 new production line for electric motorcycle, 1 BEV manufacturing and assembly expansion, 1 new manufacturing facility for M/HD BEVs, 1 manufacturing expansion for range-extended MD trucks, 1 pilot production line for flexible all-electric platform, and 1 pilot production line for powertrain control systems. (4) 6 of 26 projects

Table 24 shows ARFVTP investments by each 2015-2016 Investment Plan category, along with the number of projects or vehicles and fueling infrastructure funded to date. It also shows cumulative completion of ARFVTP projects. On a dollar basis, 29 percent of projects are complete (\$172 million out of \$589 million in cumulative contract awards).

Table 24: Cumulative ARFVTP Investments Through June 30, 2015, by Investment Plan Category

Category	Funded Activity	Cumulative Awards to Date (in millions)*	No. of Projects or Units	Percent Complete (% dollar basis)
Alternative Fuel Production	Biomethane Production	\$50.9	15 Projects	28.3
	Gasoline Substitutes Production	\$29.3	14 Projects	11.6
	Diesel Substitutes Production	\$57.4	20 Projects	8.4
Alternative Fuel Infrastructure	Electric Vehicle Charging Infrastructure	\$40.7	7,515 Charging Stations	34.4
	Hydrogen Refueling Infrastructure	\$88.0	49 Fueling Stations	0.0**
	E85 Fueling Infrastructure	\$13.7	158 Fueling Stations	16.8
	Upstream Biodiesel Infrastructure	\$4.0	4 Infrastructure Sites	97.5
	Natural Gas Fueling Infrastructure	\$15.5	50 Fueling Stations	49.0
Alternative Fuel and Advanced Technology Vehicles	Natural Gas Vehicle Deployment**	\$57.0	2,956 Trucks and Cars	74.7
	Propane Vehicle Deployment**	\$6.4	514 Trucks	100.0
	Light-Duty Electric Vehicle Deployment	\$25.1	10,700 Cars	80.1
	Medium- and Heavy-Duty Electric Vehicle Deployment	\$4.0	150 Trucks	100.0
	Medium- and Heavy-Duty Vehicle Technology Demonstration and Scale-Up	\$89.7	42 Demonstrations	11.7
Related Needs and Opportunities	Manufacturing	\$57.0	22 Manufacturing Projects	24.9
	Emerging Opportunities	†	†	
	Workforce Training and Development	\$25.2	55 Recipients	75.0
	Fuel Standards and Equipment Certification	\$3.9	1 Project	100.0
	Sustainability Studies	\$2.1	2 Projects	0.0
	Regional Alternative Fuel Readiness and Planning	\$7.6	34 Regional Plans	21.1
	Centers for Alternative Fuels	\$5.8	5 Centers	0.0
Technical Assistance and Program Evaluation	\$5.6	5 Agreements	5.4	
Total		\$588.9		29.3

Source: California Energy Commission

* Includes all agreements that have been approved at an Energy Commission business meeting or are expected for Business Meeting approval following publication of a Notice of Proposed Award.

** Although three Energy Commission-funded hydrogen stations are operational, final invoices have not been paid out due to the multiple stations per grant award.

APPENDIX E

Status of Past IEPR Nuclear Policy Recommendations

Table 25: Status of Past IEPR Nuclear Policy Recommendations

2013 IEPR – Diablo Canyon Power Plant			Status
2013-6-01	PG&E	PG&E should continue to provide updates on its progress in completing the <i>AB 1632 Report</i> -recommended studies to the Energy Commission and make its findings and conclusions available to the Energy Commission, the CPUC, and the NRC during their reviews of the Diablo Canyon license renewal application.	Central Coastal California Seismic Imaging Project (CCCSIP) completed in September 2014 and made available to state and federal regulators.
2013-6-02	PG&E	PG&E should provide updated evacuation time estimates, including a real-time evacuation scenario following a seismic event, and submit to the Energy Commission as part of the <i>IEPR</i> reporting process.	Update of Evacuation Time Estimate report is underway; updated report will incorporate an evacuation time estimate following a seismic event.
2013-6-03	PG&E	Based on mounting clean-up costs for the 2011 Fukushima accident, PG&E should provide to the Energy Commission and CPUC a comprehensive study on whether the Price-Anderson liability coverage for a severe event at Diablo Canyon would be adequate to cover liabilities resulting from a large offsite release of radioactive materials in San Luis Obispo County and adjacent counties included in the Ingestion Pathway Zone, and if not, identify and quantify other funding sources that would be necessary to cover any shortfall. The CPUC should consider requiring PG&E to complete such a study as a condition of future License Renewal funding approval.	A study of all sources of funding available (primary and secondary insurance) to meet any potential liabilities of a severe event at Diablo Canyon has not been completed. An act of Congress is required to provide additional funds if primary and secondary insurance funds are insufficient.
2013-6-04	PG&E	To help ensure plant reliability and minimize costs to ratepayers, the Nuclear Regulatory Commission should, in an open, timely and transparent process, ensure that all seismic hazard analyses for Diablo Canyon are evaluated against the licensed design basis elements for the Design Earthquake and the Double Design Earthquake, in addition to the Hosgri earthquake element prior to consideration or approval of the Diablo Canyon license renewal application. As part of the <i>IEPR</i> reporting process, PG&E should update the Energy Commission on the progress of this evaluation and provide the final product to the Energy Commission when it is completed.	PG&E completed a Probabilistic Seismic Hazard Analysis (PSHA) study and submitted it to the NRC in March 2015.

2013-6-05	PG&E	PG&E should, as expeditiously as possible, bring Diablo Canyon into compliance with the applicable 2004 National Fire Protection Agency fire protection regulations and report to the Energy Commission on its progress until full compliance is achieved.	A license amendment request submitted to the NRC in June 2013 would transition the fire protection program to a risk-informed, performance-based alternative. NRC approval is pending.
2013-6-06	PG&E CPUC	PG&E should evaluate the potential long-term impacts and projected costs of spent fuel storage in pools versus dry cask storage of higher burn-up fuels in densely packed pools, and the potential degradation of fuels and package integrity during long-term wet and dry storage and transportation offsite and submit the findings to the Energy Commission and CPUC. The Energy Commission recommends that the CPUC require expedited transfer of spent fuel assemblies from wet pools to dry cask storage be included in the decommissioning process and the costs of this expedited removal be included in decommissioning funds before license renewal funding is granted.	No stand-alone cost-benefit analysis of wet vs. dry storage has been performed. Spent fuel is stored in pools for a minimum of five years before being placed in dry cask storage.
2013-6-07	PG&E	To help ensure plant reliability and minimize costs to ratepayers, prior to reactivating the Diablo Canyon license renewal application with the Nuclear Regulatory Commission, PG&E should provide to the Energy Commission and CPUC an evaluation of the structural integrity of the concrete and reinforcing steel in the spent fuel pools, including any increased vulnerability to damage resulting from a seismic event.	No stand-alone study was performed.
2013-6-08	PG&E	PG&E should perform, and report to the Energy Commission and CPUC as part of the <i>IEPR</i> reporting process, an evaluation of the inventory of the spent fuel pools to determine the maximum number of spent fuel bundles it can move on a per year basis from the spent fuel pools into dry cask storage, taking into consideration the following constraints: <ul style="list-style-type: none"> » Thermal limits of the dry casks imposing a minimum threshold on the age of the spent fuels » Federal requirements on older spent fuels surrounding newer spent fuels » Availability of dry casks » Building schedule(s) of dry cask storage pads » Coordination of refueling outages and dry casks loading schedules » Availability of plant staff and contractors for dry cask loadings. 	Spent fuel is stored in spent fuel pools for minimum of five years. Spent fuel will be transferred to dry casks during 2015-2016 to achieve a minimum complement of used fuel assemblies that meet NRC spacing requirements. Future loading of spent fuel into dry casks will be done about every other year to maintain the NRC minimum.
2013-6-09	PG&E	To reduce the volume of spent fuel packed into Diablo Canyon's storage pools (and consequently the radioactive material available for dispersal in the event of an accident or sabotage), PG&E should, as soon as practicable and while maintaining compliance with Nuclear Regulatory Commission spent fuel cask and pool storage requirements, transfer spent fuel from the pools into dry casks and report to the Energy Commission on its progress until the pools have been returned to open racking arrangements.	See above.

2015-11-17	DCISC PG&E	<p>The Diablo Canyon Independent Safety Committee (DCISC) and the Nuclear Regulatory Commission (NRC) concluded that PG&E's progress in completing the root cause evaluation of laminar flaws on the Unit 2 pressurizer nozzles and identification of required corrective actions over the next cycle of operation were adequate. The NRC has approved the enhanced procedures and methods implemented by PG&E (ML14255A232) with respect to this issue. RR REP-1, U2, Revision 1, contains the acceptance criteria for examinations using a Manual Phased Array Ultrasonic Examination technique (UT). <i>The NRC staff notes that the licensee is required to perform periodic UT of the subject welds in accordance with ASME Code Case N-770-1, "Alternative Examination Requirements and Acceptance Standards for Class 1 PWR Piping and Vessel Nozzle Butt Welds Fabricated with UNS N06082 or UNS W86182 Weld Filler Material With or Without Application of Listed Mitigation Activities, Section XI, Division 1," as conditioned in 10 CFR 50.55a(6)(g)(II)(F). In addition, the licensee is required to perform three successive UT examinations of the overlaid pressurizer nozzle welds that contain the unacceptable indications in accordance with the ASME Code, Section XI, IWB-2420. The licensee also is required to perform visual VT-2 examinations when performing system leakage testing in accordance with the ASME Code, Section XI, IWA-5000 in every refueling outage. Based on the proposed inspection procedures and anticipated growth of the indications, the NRC staff concludes that augmentation of the mandatory inspections is not required... Accordingly, the NRC staff concludes that the licensee has adequately addressed all of the regulatory requirements set forth in 10 CFR 50.55a(a)(3)(ii). Therefore, the NRC authorizes use of RR SWOL-REP-1 U2 at the DCP, Unit 2, for the expected life of the overlays, which is August 26, 2045. Additionally, during the December 2014 NRC inspection, inspectors observed this process in action and PG&E provided documented evidence of previous inspections (ML15030A083). The DCISC also accepted the findings of their staff and PG&E with respect to this issue as reported in the DCISC 24th Report pages 354-358 (http://www.dcisc.org/24th-pdf.pdf). An excerpt from the report has been docketed (DCISC 24th Report Excerpt).</i></p>	<p>DCISC followed this issue. A root case evaluation was completed and reported to NRC. A more comprehensive flaw analysis procedure was also completed and accepted by the NRC (ML14255A232).</p>
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2013 IEPR – San Onofre Nuclear Generating Station			Category
2013-6-11	SCE	<p>SCE should complete the seismic studies identified in Advice Letter 2930-E, approved by the CPUC Energy Division on September 18, 2013, and provide results of the studies to the Energy Commission and CPUC.</p>	<p>Field studies have been completed. A final report is expected by the end of 2015.</p>
2013-6-12	SCE	<p>SCE should, as soon as practicable, expand the Independent Spent Fuel Storage Installation and transfer spent fuel from pools into dry casks, while maintaining compliance with Nuclear Regulatory Commission spent fuel cask and pool storage requirements and report to the Energy Commission on its progress until all spent fuel is transferred to dry cask storage.</p>	<p>Awarded a contract to Holtec International for the construction of a HI-STORM below ground storage facility. Transfer of spent fuel from pools to dry casks expected to be completed by 2019.</p>
2013-6-13	SCE	<p>SCE should submit a decommissioning plan to the Nuclear Regulatory Commission as soon as possible and proceed with decommissioning of San Onofre swiftly, providing progress updates to the Energy Commission until decommissioning of the site is completed.</p>	<p>A Post-Shutdown Decommissioning Activities Report, Irradiated Fuel Management Plan, and Site-Specific Decommissioning Cost Estimate were submitted to the NRC in September 2014.</p>

2013 IEPR – Nuclear Waste			Category
2013-6-14	CEC	The Energy Commission will continue to monitor federal nuclear waste management program activities and represent California in the reactivated Yucca Mountain licensing proceeding to ensure that California's interests are protected regarding potential groundwater and spent fuel transportation impacts in California.	Ongoing.
2013-6-15	CEC	The Energy Commission supports federal efforts to develop an integrated system for management and disposal of nuclear waste, including the establishment of a new, consent-based approach to siting future nuclear waste management facilities.	Federal legislation proposed in March 2015 to implement an interim consolidated storage strategy.

Source: California Energy Commission staff

APPENDIX F

Energy Storage Goals

Energy storage is an important part of a portfolio of tools used to help integrate intermittent renewables into the grid at the transmission, distribution, and customer levels. Energy storage technologies can be used to store renewable generation when supply is high and demand is low and put it back into the grid when needed. Additionally, energy storage can respond to renewable energy variable generation in a rapid manner and help stabilize the grid in times of need. Recognizing the value of energy storage, in 2010 the legislature passed and Governor Brown signed Assembly Bill 2514 (Skinner, Chapter 469, Statutes of 2010). The bill put into motion the development of energy storage procurement targets for the state's load serving entities and requires the Energy Commission to include a summary of reports that the Publicly Owned Utilities (POUs) submit on their energy storage goals in the Integrated Energy Policy Report.

AB 2514 required the California Public Utilities Commission (CPUC) to determine appropriate targets, if any, for load-serving entities under its jurisdiction to procure viable and cost-effective energy storage systems. The CPUC adopted targets totaling 1,325 megawatts (MW) of energy storage to be procured by Pacific Gas and Electric Company (PG&E) (580 MW), Southern California Edison Company (SCE) (580 MW), and San Diego Gas & Electric

Company (SDG&E) (165 MW) by 2020, with installations required no later than the end of 2024.⁵⁹⁴

Toward these targets, the three IOUs each issued a request for offers (RFO) in 2014 for energy storage contracts. The initial incremental targets for 2014 were 90 MW each for SCE and PG&E and 20 MW for SDG&E. On December 1, 2015, the IOUs filed their applications for contract approval with the CPUC that were result of the 2014 RFO.

SCE selected three energy storage contracts totaling 16.3 MW through its 2014 energy storage RFO.⁵⁹⁵ SCE selected one offer from Stanton Energy Reliability Center for 1.3 MW of General Electric sourced lithium-ion battery storage and one offer from Western Grid Development for 15 MW of EOS sourced battery storage, which resulted in two contracts – one for 10 MW and one for 5 MW. The CPUC had previously allowed SCE to include 23.68 MW of existing energy storage and 50 MW of energy storage from its Local Capacity Requirements RFO towards the 90 MW goal.

594 CPUC, Decision Adopting Energy Storage Procurement Framework and Design Program, Decision 13-10-040, Rulemaking 10-12-007, October 17, 2013, <http://docs.cpuc.ca.gov/Published-Docs/Published/G000/M079/K533/79533378.PDF>.

595 <https://www.sce.com/wps/portal/home/procurement/solicitation/energy-storage-rfo/> as of November 3, 2015.

PG&E selected seven projects that total 75 MW of transmission- and distribution-connected energy storage resources through its 2014 energy storage RFO. Of the seven projects selected, four are lithium ion battery projects and totaled 42 MW, two are zinc-air battery projects and totaled 13 MW, and one is a 20 MW flywheel project. PG&E is applying existing energy storage and energy storage expected from other programs towards meeting its 90 MW goal.

Through existing and in-progress energy storage projects, SDG&E has already met its 20 MW energy storage goal. SDG&E did not select any additional projects in its energy storage RFO, however, SDG&E does expect to procure at least 25 MW of energy storage contracts through its All Source RFO, the results of which are expected in March 2016. The All Source RFO is open to transmission-, distribution-, and customer-level resources.⁵⁹⁶ SDG&E has 51 MW of existing and under-construction energy that the CPUC has approved as counting towards its 165 MW target for 2020, including 40 MW of pumped hydro at Lake Hodges, approximately 7 MW smart grid storage demonstration projects, and roughly 4 MW of customer-connected storage or permanent load shifting technology.

The CPUC decision also established a target for community choice aggregators and electric service providers. They are required to procure energy storage equal to 1 percent of their annual 2020 peak load with installations no later than 2024, consistent with the investor-owned utilities. On January 1, 2016, community choice aggregators and electric service providers started submitting their first round of filings to the CPUC to demonstrate compliance. They must continue to file progress reports every two years.

POUs are also required to determine appropriate targets, if any, to procure viable and cost-effective energy storage systems. AB 2514 calls on the POU's to achieve an initial target by December 31, 2016, and a second by December 31, 2020.

⁵⁹⁶ <http://www.sdge.com/all-source-2014-rfo> as of November 3, 2015.

If POU's chose to adopt energy storage system targets, they were required to do so by October 1, 2014, and report to the Energy Commission on their adopted targets and policies. Energy Commission staff received reports from the majority of California POU's and developed a web page to make the reports available to the public.⁵⁹⁷ Most POU's opted not to adopt targets. A total of 37 POU's submitted AB 2514 reports or resolutions to the Energy Commission. Four POU's have not submitted reports or resolutions. Thirty POU's declined to adopt energy storage procurement targets or adopted targets of zero while seven POU's adopted energy storage targets greater than zero. For the POU's that did not adopt targets, the primary reasons cited were the lack of viable or cost-effective energy storage options currently available or a lack of need for storage. However, AB 2514 directs the POU's to reconsider their targets every three years, and many of the POU's indicated that they have an interest in energy storage and will continue to monitor the energy storage landscape for possible revisions to their targets. Table 26 outlines the targets for the POU's that adopted non-zero energy storage targets.

Those POU's that did establish targets tended to be fairly conservative. The resolutions adopted by the City of Cerritos, City of Corona, and City of Victorville set a target of 1 percent of 2015 peak load. They note that energy storage is not currently cost-effective, but the targets were adopted to capture potential market opportunities. The resolutions state that the targets should be re-evaluated if cost-effective storage options are not identified. The City of Glendale's target of 1.5 MW for 2015 and 2020 represents the city's existing energy storage portfolio. Redding Electric Utility's energy storage targets of 3.6 MW for 2016 and 4.4 MW for 2020 represent approximately a 3 MW expansion of currently installed energy storage. Silicon Valley Power's (SVP) 30 kW energy storage target is solely customer-based and

⁵⁹⁷ http://www.energy.ca.gov/assessments/ab2514_energy_storage.html.

Table 26: POU Storage Targets

POU	2016 Target	2020 Target
Cerritos, City of	1 percent of 2015 peak load (200 kW based on 2014 peak load of 20 MW).	1 percent of 2020 peak load (200 kW based on 2014 peak load of 20 MW)
Corona Department of Water and Power	1 percent of 2015 peak load (270 kW based on 2014 peak load of 27 MW).	1 percent of 2020 peak load (270 kW based on 2014 peak load of 27 MW).
Glendale Water and Power	1.5 MW	1.5 MW
Los Angeles Department of Water and Power (LADWP)	24.08 MW	154 MW
Redding Electric Utility	3.6 MW	4.4 MW
Silicon Valley Power (City of Santa Clara)	30 kW	30 kW
City of Victorville	1 percent of 2015 peak load (140 kW based on 2014 peak load of 14 MW).	1 percent of 2020 peak load (140 kW based on 2014 peak load of 14 MW).

Source: California Energy Commission staff

*Except for LADWP, all POUs adopted energy storage targets that represent cumulative installed energy storage. LADWP’s targets represent incremental additions to their 1,284.08 MW existing energy storage. If existing energy storage is included, LADWP’s 2016 target would be 1,308.16 MW, and its 2020 target would be 1,462.16 MW.

does not include transmission or distribution connected storage. SVP’s target will be met by a pilot project to reduce customer-side demand charges due to high energy use for electric vehicle fast charging.

LADWP adopted the highest energy storage targets of any POU. LADWP has an existing energy storage portfolio of 1284 MW, primarily from the Castaic Pumped Hydroelectric Plant. LADWP’s incremental target for 2016 is 24.08 MW and for 2020 is an additional 154 MW. LADWP’s 2016 target includes a 21 MW expansion of the Castaic Pumped Hydroelectric Plant, 3 MW of customer-side thermal energy storage, and 75 kW of customer-side battery energy storage. The 2020 target includes 50 MW of transmission-connected battery storage, 4 MW of distribution-connected battery storage, 40 MW of customer-side thermal energy storage, and 60 MW of thermal energy storage associated with the Valley Generating Station.

Although the Sacramento Metropolitan Utility District (SMUD) did not adopt an energy storage target, the utility reported on its research pilots and lessons learned at a December 2014 Energy Commission “advancements in energy storage” workshop. SMUD reported that distributed energy storage systems are not currently cost-effective given the utility’s avoided costs and rates, but that it expects the technology will become cost effective within the next 10 years.⁵⁹⁸

On August 19, 2015, the Inland Empire Utilities Agency⁵⁹⁹ approved a *Demand Response Energy Storage* agreement with Advanced Microgrid Solutions that

598 Mark Rawson, SMUD, Storage R&D Program Lessons Learned, http://www.energy.ca.gov/research/notices/2014-12-01_workshop/presentations/Mark_Rawson_SMUD.pdf. Presentation at the Energy Commission’s December 1, 2014, workshop.

599 The utility is a municipal water treatment and distribution agency in Southern California. For more information on the close linkage between energy and water use, see Chapter 8.

combines energy storage with renewable generation and demand response. A total of 3.75 MW of storage will be installed at six sites with software to help optimize savings for site-specific time-of-use rates.⁶⁰⁰

600 Inland Empire Utilities Agency, Agenda, Meeting of the Board of Directors, August 19, 2015, <http://www.ieua.org/wp-content/uploads/2015/07/8-19-15-Board-of-Directors-Meeting-Part-2.pdf>.