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CALIFORNIA
ENERGY COMMISSION

Edmund G. Brown Jr., Governor

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DISCLAIMER

This final report was prepared under the *2013 Integrated Energy Policy Report* proceeding, Docket #13-IEP-1A. The final report will be considered for adoption by the full Energy Commission at its Business Meeting on January 15, 2014. The views and recommendations contained in this document are not official policy of the Energy Commission until the report is adopted.

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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 *2013 Integrated Energy Policy Report Update* provides the results of the California Energy Commission's assessments of a wide variety of energy issues currently facing California. These issues include future demand for electricity, natural gas, and transportation fuels; energy efficiency in California's existing buildings; publicly owned utilities' progress toward achieving 10-year energy efficiency targets; the definition of zero-net-energy and its inclusion in state building standards; challenges to increased use of geothermal heat pump/ground loop technologies and procurement of biomethane; using demand response to meet California's energy needs and integrate renewable technologies; bioenergy development; California's electricity infrastructure needs given potential retirement of power plants and the closure of the San Onofre Nuclear Generating Station; ~~potential electricity system needs in 2030;~~ new generation costs for utility-scale renewable and fossil-fueled generation; the need for investments in new or upgraded transmission infrastructure; utility progress in implementing past recommendations related to nuclear power plants; natural gas market trends; the Alternative and Renewable Fuel and Vehicle Technology Program; potential vulnerability of California's energy supply and demand infrastructure to the effects of climate change, and potential electricity system needs in 2030. Definitions for technical terms can be found in the glossary.

Keywords: California Energy Commission, energy efficiency, demand response, electricity, electricity demand, electricity infrastructure, hydraulic fracturing, natural gas demand, natural gas pipelines, renewable, climate change, biomethane, bioenergy, geothermal, transportation, transmission

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TABLE OF CONTENTS

LIST OF FIGURES AND TABLES

EXECUTIVE SUMMARY

California is the most populous state in the nation and the eighth largest economy in the world. While California is a leader in addressing climate change, further work is needed both to reduce greenhouse gas emissions and to ~~increase the resiliency of~~prepare California's energy system ~~to~~ for the impacts of climate change. California's energy system contributes about 85 percent of the state's greenhouse gas emissions. The state's economy, environment, and public health depend on reducing greenhouse gas emissions by using less energy, electrifying the transportation system, and producing power both sustainably and with lower overall greenhouse gas emissions. California continues to lead the nation in designing and implementing innovative policies and strategies to use energy more efficiently, replace fossil fuels with renewable resources, and develop the power infrastructure needed to deliver safe, reliable, and affordable energy to consumers and businesses throughout the state.

The *2013 Integrated Energy Policy Report (IEPR)* looks at a variety of energy issues facing the state today. The state's "Loading Order" is a guiding policy which places energy efficiency (using less energy to do the same job) and demand response (~~manipulating~~ using less energy ~~use~~ when needed for optimal grid operation) ~~remain~~ as ~~California's~~ top priorities for meeting ~~the state's~~California's energy needs. Next, the loading order calls for renewable resources and distributed generation. To produce the energy needed by a growing population and recovering economy, ~~as population continues to grow and the economy recovers.~~ maximizing the use of these "preferred resources" becomes even more important as California works toward reducing greenhouse gas emissions to 80 percent below 1990 levels by 2050. The state's energy efficiency standards for new buildings and appliances have saved consumers an estimated $75~~4~~ billion since 1975 in reduced electricity bills, not including billions of dollars more in natural gas savings. Still, there is huge potential for additional savings by increasing the energy efficiency and optimizing the use of existing buildings. California also has a goal of making all new buildings zero-net-energy – essentially combining energy efficiency measures and renewable power generation so that a building can produce as much power as it uses annually – by 2020 for homes and 2030 for businesses. Utilities also need to work toward meeting targets set by the California Energy Commission and the California Public Utilities Commission (CPUC) to achieve all cost-effective energy efficiency.

In addition to reducing energy demand when needed, demand response can reduce the need for new power plants and transmission lines and help integrate the high levels of renewable resources that will be needed to meet California's long-term greenhouse gas emission reduction goals. However, demand response continues to face technical, regulatory, and market barriers that need to be resolved to reach its full potential.

Renewable energy is another of California's top priorities, and the state continues to make progress toward achieving its goal of generating a third of its electricity using renewable resources like solar and wind. Some renewable resources, such as biomethane, still face significant barriers to development. Also, renewable energy presents challenges to the electricity system as a whole because intermittent renewable resources require integration services to minimize negative effects on the electricity grid. Further, California needs to better synchronize the planning and permitting processes for renewable generation and the power lines needed to bring that generation to market.

The electricity system in Southern California faces a multifaceted set of challenges. Emission offsets in Southern California are scarce due to stringent air quality regulations, but such offsets are needed to repower or to provide replacement power for power plants that must comply with the phase-out of once-through cooling. Southern California also faces new challenges from the permanent closure of one of the state's two nuclear power plants and the potential effects of that closure on electricity supplies and reliability. There are also seismic safety and spent fuel storage concerns with the remaining nuclear plant in the wake of the 2011 nuclear disaster in Fukushima, Japan.

To help ensure progress toward its 2050 greenhouse gas reduction goals, California needs to determine what the electricity system should look like in 2030 as an interim target. Similarly, California must assess and plan for the potential effects of climate change on the energy sector itself, such as increased electricity demand, decreased power plant efficiency, and changes in the availability of hydropower because of less precipitation and earlier runoff. Climate change could also affect reliability because of increased risk of wildfires that can damage power lines and flooding in coastal power plants.

A large portion of California's energy needs has traditionally been met with natural gas. Natural gas supplies are currently plentiful and relatively inexpensive as a result of technological advances that allow recovery of natural gas from formations such as shale reservoirs that were previously inaccessible. However, potential environmental concerns are causing decision makers to reexamine the development of shale resources and consider tighter regulations, which could affect future natural gas supplies and prices.

The transportation sector contributes about 39~~40~~ percent of California's greenhouse gas emissions, a fact that highlights the importance of the state's efforts to promote low-carbon alternative and renewable transportation fuels. Although gasoline consumption continues to decrease, the state's population continues to grow, and the penetration of alternative vehicles and fuels remains relatively low. Increased public and private investment in the development of alternative and renewable fuel vehicles and fueling infrastructure is needed to achieve the goal of reducing the carbon intensity of California's transportation fuels by at least 10 percent by 2020.

Each of these issues has been the subject of ongoing analysis and evaluation as part of the *2013 IEPR* proceeding. Results of those analyses and recommendations to address challenges facing California's energy sector are summarized below.

Energy Efficiency

Efficiency in Existing Buildings

As directed by Assembly Bill 758 (Skinner, Chapter 470, Statutes of 2009), the Energy Commission is developing a comprehensive program to improve the energy efficiency of existing buildings. After working closely with the CPUC and holding a series of statewide public workshops to get input from stakeholders, in June 2013 the Energy Commission released the *Draft Action Plan for the Comprehensive Energy Efficiency Program for Existing Buildings.* The draft plan outlines actions needed to support a strong and viable energy efficiency upgrade market for existing residential, commercial, and public buildings. The Energy Commission will consider the final action plan for adoption in ~~late 2013~~2014, with implementation beginning immediately.

Recommendations in the draft plan include foundational actions such as improved data reporting and management to support program development and to enable the marketplace~~,~~ ~~tools~~ and code enforcement to improve compliance with standards, education to motivate building owners and managers, and workforce training and development to ensure a skilled workforce. Other actions include encouraging a portfolio of options for upgrades ranging from a single measure to a whole-building approach, developing standard building assessment tools, focusing attention on multifamily and smaller commercial building upgrades, working with local governments to improve public buildings, and offering innovative financing options for building owners. Adopting appliance standards that focus on reducing plug loads and that can assist in grid resilience and responsiveness will also help advance California's energy efficiency goals.

Other opportunities for advancements in energy efficiency include achieving the goals for improved energy efficiency at state buildings in Governor Brown's Executive Order B-18-12 and increasing energy efficiency in schools through the use of Proposition 39 funds. In 2012 California voters passed Proposition 39, which resulted in increased tax revenue after changes to corporate income taxes. The proposition dedicated $550 million annually for five years to fund energy efficiency projects that create clean energy jobs in California. As California continues to develop and implement its energy efficiency programs, it will gain knowledge and experience that can help advance the market and further California's ongoing leadership in energy efficiency.

Zero-Net-Energy New Buildings

California has a policy goal of achieving zero-net-energy building standards by 2020 for low-rise residential buildings and by 2030 for commercial buildings. Governor Brown's Executive Order B-18-12 calls for all new state buildings and major renovations that begin design after 2025 to be constructed as zero-net-energy facilities and also calls for achieving zero-net-energy for 50 percent of the square footage of existing state-owned building area by 2025. ~~To achieve these goals and make zero-net-energy an enforceable reality~~As a step toward achieving these goals, the Energy Commission ~~needs to incorporate the zero-net-energy definition as a requirement in the California Building Energy Efficiency Standards (Title 24, Part 6). The Energy Commission~~ has worked closely with the CPUC and stakeholders to develop the following definition:

> *A Zero-Net-Energy Code Building is one where the net~~societal value~~ amount ~~of the amount~~ of energy ~~provided~~ 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 zero-net-energy 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.

Making the zero-net-energy definition operational will require ongoing efforts through the 2016 and 2019 code development cycles. To ensure that all buildings have a pathway to compliance, the Energy Commission anticipates establishing reasonable exceptions to account for building and building site limitations, including the need for "development entitlements" for off-site renewable energy resources, such as community based renewable energy generation. Several other issues also require further discussion and should be addressed through broad working group participation.

Recommendations to ensure success in meeting the zero-net-energy goals as they are currently outlined include adopting triennial building standards updates that increase the efficiency of new buildings by 20 to 30 percent in each update, developing industry-specific training and financial incentives to help achieve reach standards, tracking market progress on zero-net-energy construction and performance; coordinating with the CPUC on future investor-owned utility new construction-related programs, collaborating with the CPUC and stakeholders to create workforce development programs that provide the skills needed to meet zero-net-energy goals, and including a voluntary energy tier for zero-net-energy in the California Green Building Standards Code.

Utility Energy Efficiency Targets

Assembly Bill 2021 (Levine, Chapter 734, Statutes of 2006) directs the Energy Commission and the CPUC to develop statewide energy efficiency potential estimates and targets for California's publicly owned and investor-owned utilities. In 2012, investor-owned utilities reported surpassing their energy savings and peak savings (energy efficiency efforts that reduce the highest level of demand) goals; publicly owned utilities, however, reported declines in energy savings for the third consecutive year, with a few individual exceptions. Since passage of Assembly Bill 2021, publicly owned utilities have spent more than $737 million on energy efficiency programs, resulting in energy savings of about 2,700 gigawatt hours and 515 megawatts in peak demand reduction. To ensure continued progress toward achieving greater energy savings, Energy Commission staff plans to work with publicly owned utilities to encourage ~~deeper~~ further energy savings; improve transparency about funding levels and sources; and improve the evaluation, measurement, and verification process.

The CPUC approves three-year efficiency program cycles for the investor-owned utilities, and for the 2010-2012 program cycle, investor-owned utilities administered their portfolios of efficiency programs with a total budget of $3.1 billion. The CPUC anticipates considering its~~'s~~ *2013 California Energy Efficiency Potential and Goals Study* ~~is under consideration and will be released shortly~~as part of Rulemaking 13-11-005.

Efforts needed to help achieve all cost-effective energy efficiency include advancing mechanisms to finance energy efficiency measures, advancing locational and peak period energy efficiency, and increasing natural gas end-use efficiency. Also, the Energy Commission and CPUC will collaborate to analyze the near and longer-term savings from energy efficiency codes and standards and their interaction with other efficiency programs. Further, increased interagency collaboration is needed to modernize energy-related information management practices to enable robust, cross-agency data management and sharing; provide clear access procedures and timely data services to researchers; facilitate appropriately detailed reporting to the Legislature; and enable greater information availability to the public.

Geothermal Heat Pump and Ground Loop Technologies

As a further means to achieve greater energy efficiency in California's buildings, Energy Commission staff evaluates technologies that may provide efficiency savings over traditional heating and cooling systems. Assembly Bill 2339 (Williams, Chapter 608, Statutes of 2012) directs the Energy Commission to evaluate policies to assist greater penetration of geothermal heat pump and ground loop technologies, and to include recommendations in the *2013 IEPR*. Geothermal heat pumps use the constant below-ground temperature of water or soil to heat and cool interior spaces. While purchase and installation costs can be higher than those of conventional heating or cooling systems, geothermal heat pump systems can use 25 percent to 50 percent less electricity. Challenges faced by the geothermal heat pump industry include inability of approved compliance models to accurately represent efficiency gains from these systems; inconsistent local permitting requirements and fee schedules; and rules and regulations for borehole drilling and ground loop installation. To begin addressing these barriers, the Energy Commission encourages the industry to develop an Alternative Calculation Method application to model the technology, produce a model local ordinance that could be adopted by local jurisdictions, and promote the use of California-specific geothermal heat pump standards for training and certification of industry professionals, among other recommendations.

Demand Response

Demand response can play an important role in maintaining a reliable electric system by influencing demand according to system needs and constraints, potentially offsetting the need for new power plants and transmission lines. Despite its many potential benefits and its position together with efficiency atop the Loading Order, there has been insufficient progress toward meeting demand response goals set in the early 2000s. Demand response programs created in the past were based on the technology available at the time; today proven, cost-effective technologies exist to communicate the needs of the system and respond with customer loads, both individually and collectively. Markets themselves have also evolved: outside California, successful efforts have developed wholesale and retail products that appropriately value the system benefits provided by demand response. For California to catch up in this area, energy agencies must develop a workable model that stimulates scale-up of effectively useable, environmentally sound demand response resources that are palatable to end users.

Technical, economic, market, and policy barriers currently limit the increased use of demand response. There is a need for wholesale market design to recognize the advantages and limitations of demand response as compared to traditional generation. Customer loads cannot always be as easily and consistently manipulated as traditional generation. These issues are manageable by a functioning marketplace: demand response products can be composed of a large number of loads that together provide a portfolio, ~~comprised~~ consisting of both load reductions and strategic load additions, that balances performance risk and customer needs. Finally, rules for participation by demand response providers in existing California Independent System Operator (California ISO) wholesale markets need to be resolved and finalized. On the technology side, current telemetry requirements are a challenge because of expensive equipment requirements to participate in the demand response market.

The various recent developments in Southern California—the San Onofre Nuclear Generating Station (San Onofre) retirement, once-through-cooling requirements, and the increasing need for flexibility to integrate intermittent renewable resources—as well as the long-term challenge of ~~responding to~~preparing for the impacts of climate change, dictate that demand response play a much larger and substantially different role in electricity supply and reliability enhancement than today. Further, time certainty is required for mobilizing fast-response demand response at relevant scale: slippage in demand response market development will necessitate more generation and/or transmission than would otherwise be required. Given the long lead time required to develop generation and transmission, the need to prove demand response is urgent. Intentionally enabling multiple market options in the near term decreases the risk of ongoing anemia of demand response resources.

The Energy Commission has identified five strategies to help demand response fulfill its role in California's loading order of preferred resources. These strategies are 1) establishing rules for direct participation of demand response in California ISO markets; 2) developing and pilot testing additional market products to identify the most promising program and tariff approaches and to develop a multiyear, forward auction mechanism to target demand response in capacity constrained areas; 3) resolving regulatory barriers for the development and implementation of a multiyear reliability framework that accounts for customer attributes and the type of load reductions they can provide; 4) continuing the collaborative process among the Energy Commission, CPUC, California ISO, and Governor's Office to advance fast-response demand response, develop a joint workplan, and advance forecasting accuracy; and 5) advancing customer acceptance of demand response, informed by an independent assessment of potential customer participation in a range of targeted demand response programs, communication strategies and evaluation reports, and communication lessons learned by early 2014.

Bioenergy

California is the leading producer of renewable energy nationwide and is on track to meet 33 percent of its electricity needs with renewable resources by 2020. Bioenergy is a small but important part of California's portfolio of renewable resources that still faces challenges, despite state policies to support bioenergy that have been in place for many years. Bioenergy production can help achieve California's environmental protection, waste reduction, and greenhouse gas reduction goals, primarily through alternative disposal and treatment options for low-value biomass. Bioenergy production provides additional value by displacing fossil fuels and may be a future source of flexible electricity generation.

~~The use of biomass offers many benefits including providing a pathway to low carbon fuels that can replace fossil fuels and the continue to use of California's existing infrastructure, helping meet waste reduction goals, reducing wildfire risks, reducing fossil greenhouse gas emissions, and providing local jobs.~~

As of 2012, there was 681 megawatts of solid-fuel biomass capacity in California, and new project development is expected to be relatively small. Biopower facilities—those that generate electricity using biomass fuel—face high costs associated with fuel collection and transport, environmental review, permitting, complying with air quality regulations, and securing financing. For biofuels for the transportation sector, in-state production capacity in 2013 was roughly 220 million gallons per year, including ethanol and biodiesel. In-state ethanol producers continue to have difficulty competing with ethanol from Midwest corn and Brazilian sugarcane, but many companies are looking at alternative fuel sources with lower carbon intensities and less competition for feedstock such as grain sorghum.

Biomass is also used to produce biomethane, which can be used to generate electricity, produce transportation fuels, or replace natural gas in utility pipelines. Because of unique obstacles faced by biomethane producers, Assembly Bill 1900 (Gatto, Chapter 602, Statutes of 2012) directs the Energy Commission, as part of the biennial *IEPR*, to evaluate barriers to procurement of biomethane in California and provide potential solutions. Challenges identified during the *2013 IEPR* proceeding include regulatory uncertainty and its effect on long-term contracts; the expense of upgrading biogas to pipeline quality; limited access to natural gas distribution pipelines; lengthy and costly pipeline interconnection; pipeline safety concerns; low natural gas prices that make it difficult to compete; and the need for technology commercialization. Research and development can help address several of these issues.

Recommended strategies to address biomass challenges include: exploring all mechanisms to fund biomass collection and distribution; developing standards for beneficial forest biomass harvest, developing aggressive biomass-use goals, developing standards for sustainable forest biomass use, developing a statewide programmatic environmental impact report to focus on streamlining environmental reviews, expanding consideration of the benefits provided by biomass facilities as part of the CPUC's procurement process, and ~~development of sustainability standards for biomass fuel harvesting, and support~~ increasing research and development for advanced biofuels and for pipeline quality biomethane ~~injection~~technologies.

Electricity

Interagency Coordination

In January 2013, the California State Senate Committee on Energy, Utilities, and Communications held a hearing to examine how energy efficiency investments can most effectively reduce the need for future power plants and to address concern that the three energy agencies lacked a comprehensive framework for fully coordinating state programs. Following the hearing, the leaders of the Energy Commission, CPUC, and California ISO sent a joint letter to Senators Alex Padilla and Jean Fuller affirming their commitment to coordinated energy planning. The Energy Commission, CPUC, and California ISO laid out a framework for improving coordination and aligning forecasting and planning processes.

Electricity ~~and Natural Gas~~ Demand Forecast

Every two years the Energy Commission prepares a 10-year electricity demand forecast. This forecast is used in many applications, including the CPUC's Long Term Procurement Planning proceeding and the California ISO's transmission planning studies. The *California Energy Demand Final Forecast 2014-2024 ~~Preliminary Forecast~~* presents three demand scenarios: high, mid, and low, reflecting different assumptions about economic and population growth, energy efficiency savings, electric vehicle penetration, climate change impacts, and electricity prices, among other factors. The forecast also includes five additional achievable energy efficiency scenarios. Average annual electricity demand growth from 2012–2024 is expected to range from 0.78~~64~~ ~~percent~~ to 1.56~~37~~ percent~~, an historically modest range that is a result of various drivers including lower projected population growth and new building and appliance standards introduced during the forecast period~~. Peak demand growth is expected to range from 0.88~~69~~ ~~percent~~ to 1.82~~65~~ percent.

As part of the *California Energy Demand 2013* adoption process, the Energy Commission requested stakeholder input into the choice of a base case and one or more scenarios of additional achievable energy efficiency for use in long-term planning. This combination or forecast set also is referred to as a "managed" demand forecast. The recommendation is to use the mid base case forecast in combination with the mid additional achievable energy efficiency scenario for system wide planning for the 2014-2015 procurement and transmission planning cycles. While the agencies agree, in principle, that the same combination should be applied to all planning uses, the State's ability to assign geographic specificity to the demand forecast, procurement authorizations, and transmission additions is still evolving. Challenges include the local nature of reliability needs, the difficulty and uncertainty of forecasting load and additional achievable energy efficiency at specific locations, and the difficulty estimating daily load-shape impacts. Thus, it is prudent at this time to use a combination of the mid base case forecast and the mid-low additional achievable energy efficiency scenario for local studies in these planning processes. In future planning cycles, the agencies will collaborate to make improvements in the baseline demand forecast and additional achievable energy efficiency forecasts for use in local studies.

To help advance energy planning, the energy agencies must also continue discussions about the timing and alignment of the demand forecast, energy efficiency funding cycles, measurement and evaluation, transportation electrification forecasts, and agency planning cycles. Additionally, the Energy Commission must explore the use of new modeling techniques and work with the CPUC and the California ISO to determine the appropriate level of granularity for demand forecasts.

Electricity Infrastructure Needs

In addition to forecasting future demand for electricity in California, it is important to make sure that the infrastructure needed to generate and deliver that electricity is in place. Southern California is uniquely vulnerable in this regard not only because of the potential retirement of power plants that use once-through cooling, but because of the recent permanent closure of San Onofre, which provided more than 2,000 megawatts of generating capacity and voltage support for the region.

California's energy agencies have been working together closely to evaluate reliability needs in Southern California and the potential to serve those needs with preferred resources such as demand response and renewable energy. A balanced portfolio of options is needed. Studies completed to date indicate the need to repower much of the once-through cooling capacity located along the Southern California coastline, with only limited ability for renewable resources or distributed generation to substitute for conventional dispatchable power plants. There will likely be a need for additional generating capacity above what is strictly required for local reliability to help integrate increasing levels of renewables; but demand response programs could have a strong influence on the amount needed if successfully deployed at scale. The agencies are committed to seeking 50 percent of the incremental resource need from energy efficiency, demand response, distributed generation, and storage.

However, there are significant uncertainties in all the studies to date that need to be resolved. Next steps to ensure the necessary amount of available resources include the following:

- The Energy Commission will continue to make decisions on Applications for Certification to license power plants in a timely manner that is consistent with statutory requirements and seeks to optimally reduce environmental impacts.
- The Energy Commission will continue to explore energy efficiency, demand response, and combined heat and power on state properties in Southern California.
- The CPUC will implement its decision, as part of its Long Term Procurement Plan proceeding, to replace San Onofre capacity and new load growth with 50 percent preferred resources and 50 percent conventional resources. Also, the CPUC will make timely decisions regarding approval of power purchase agreements for capacity.
- The California ISO will evaluate transmission alternatives, including synchronous condensers and other forms of reactive power support, to maintain reliability in its 2013-2014 Transmission Planning Process, which is underway.
- The Energy Commission, CPUC, and California ISO will continue to evaluate the roles of energy efficiency and demand response in the modern grid, specifically identifying what value they can bring in capacity and ancillary services markets, and how these markets can be made operational in California.
- The Energy Commission, CPUC, and California ISO will consider any changes needed in response to public comments on the *Preliminary Reliability Plan for LA Basin and San Diego* and submit a finalized plan to the Governor. The purpose of the plan is to ensure reliability in Southern California in light of San Onofre shutting down and the expected closure of power plants using once-through cooling. Recommendations from the preliminary plan were presented by staff to the leaders of the state energy agencies, the California ISO, and the South Coast Air Quality Management District on September 9. These recommendations will culminate in an action plan, to be implemented by the agencies and closely monitored by the Governor's Office.

- The South Coast Air Quality Management District will determine whether the amount of repowering identified in the California ISO's local capacity studies can be permitted using its Rule 1304(a)(2).
- The Energy Commission will also evaluate whether local capacity requirements or other criteria would justify the need for exercising the provision in the State Water Resources Control Board policy to request delays in once-through cooling compliance dates.
- The Energy Commission, CPUC, and California ISO will put into place contingency plans, including extensions to the schedule for once-through cooling plant retirements, fast-tracking additional conventional generation, or contingent site permits for new generation resources ~~must also be put into place~~ in the event preferred resources do not materialize on schedule or in the amounts required for reliability, or in the event identified transmission projects are found infeasible or unavailable in the defined time horizon.

Furthermore, to support the planning processes necessary to ensure California's energy infrastructure needs are met, in 20154 the Energy Commission will begin ~~the process of~~ updating data reporting requirements to ensure that up-to-date, appropriately granular energy data and other information are available for policy analysis and development. Finally, there is a need to complete nuclear replacement studies identified in the *2011 IEPR* to assess energy replacement options in the event of a shutdown of Diablo Canyon.

Estimates of the Costs of New Generation

Generation cost trends are important when evaluating the kinds of resources that will meet California's future energy demand and provide the infrastructure needed to maintain system reliability and reduce greenhouse gas emissions from the electricity sector. In the *2011 IEPR* proceeding, the Energy Commission evaluated its method of analyzing and estimating future generation costs, and for the *2013 IEPR* has used the refined methods to prepare updated estimates of generation costs from a developer's perspective for new generation. Solar photovoltaic technologies are expected to continue a rapid decline in costs, while solar thermal technologies are expected to see cost reductions as improvements are made by developers and manufacturers. Cost reductions for wind are expected to continue, although they are expected to be offset by increases in the cost of land and transmission.~~, costs are expected to offset the gains in technology cost in California.~~ Other renewable technologies, such as biomass and geothermal, are not expected to see substantial cost reductions. For fossil-fueled technologies, the underlying technology costs for combined-cycle and combustion turbines are expected to remain flat, but there will be cost increases of roughly 15 percent over the coming decade because of costs associated with mitigating or offsetting criteria air pollutants and greenhouse gas emissions.

Strategic Transmission Investment Plan

To support the 33 percent by 2020 Renewables Portfolio Standard, California needs to ensure that transmission projects that deliver renewable energy to customers are permitted and built quickly and effectively. ~~Eighteen~~ Seventeen transmission projects have been identified and approved for the integration of renewable resources, and the California ISO has noted that there is no need to approve any new major projects for this purpose at this time. As Governor Brown noted in his Clean Energy Jobs Plan, the energy agencies should continue to work together with a sense of urgency to permit these new transmission lines without delay. ~~Sixteen~~ Fifteen of the projects are within the California ISO's control area, and the Energy Commission is assisting interested parties in tracking these projects by updating and posting their status annually on its website. The *2013 IEPR* provides a list of the projects but also discusses other transmission issues, such as the need to better synchronize generation and transmission planning and permitting, which typically have very different timelines; coordinating land use and transmission planning efforts through the Desert Renewable Energy Conservation Plan and the potential of using that plan as a model for other regions~~s, like the Central Valley~~; opportunities to designate appropriate transmission corridors in advance of need, particularly in Southern California; and emerging trends in the Western Interconnection that could affect California.

Recommendations related to transmission include encouraging participation in the California ISO's energy imbalance market; energy agencies continuing to work together to analyze and recommend long-term potential transmission solutions to address reliability concerns associated with the recent shutdown of San Onofre, and ways to reduce transmission permitting timelines; and identifying appropriate transmission corridors. In addition, the energy agencies should evaluate the cost-effectiveness, prudency, and alternatives for requiring full deliverability for future renewable generation that is procured to meet Renewables Portfolio Standard requirements.

Nuclear Power Plants

In 2011, nuclear energy provided 18 percent of California's in-state electricity generation. However, California's two nuclear plants – the Diablo Canyon Power Plant and San Onofre – are located near major earthquake faults, causing increased concern about potential safety issues, particularly given the Fukushima Daiichi nuclear disaster on March 11, 2011. The *2011 IEPR* recommended actions by Pacific Gas and Electric and Southern California Edison on issues such as spent fuel pool storage, seismic issues, station blackouts, plant liability coverage, replacement power and reliability, emergency response planning, lessons learned, relicensing, and plant safety. The *2013 IEPR* provides updates on utility progress implementing these recommendations.

Though the June 7, 2013, announcement of the permanent closure of San Onofre negated many of the recommendations for Southern California Edison, the continued storage of spent nuclear fuel on site will require ongoing attention. The *2013 IEPR* discusses the events that led to the closure of San Onofre; recent federal efforts on nuclear waste transport, storage, and disposal; and pending legislative proposals on nuclear issues. It also includes new policy recommendations for comprehensive design-basis seismic analyses, timely compliance with fire protection regulations, accelerated transfer of spent fuel storage, and support of federal efforts to develop an integrated system for management and disposal of nuclear waste.

Natural Gas

Natural gas continues to play an important and varied role in California. In 2012, nearly 45~~6~~ percent of the natural gas burned in California was used for electricity generation, and much of the remainder consumed in the residential (21~~0.8~~ percent), industrial (2~~14.~~5 percent), and commercial (~~8.6~~9 percent) sectors. California continues to depend upon out-of-state imports for nearly 90 percent of its natural gas supply, underscoring the importance of monitoring and evaluating ongoing market trends and outlook.

~~The most influential issues affecting natural gas supply and demand in California include development of shale deposits in North America, factors that affect natural gas-powered electricity generation and natural gas infrastructure.~~

~~No issue has done more to transform the natural gas field than the~~The widespread development of shale gas by means of horizontal drilling coupled with hydraulic fracturing, or “fracking,” has transformed the natural gas market in recent years. Fracking involves pumping high-pressure fluid, mostly sand and water mixed with chemicals, into the ground to fracture the rock, allowing oil and gas to be pumped out. In 2007, California appeared to be facing dwindling supplies and increased development costs. Just five years later, the country is now experiencing a period of sustained production of shale gas, leading to the lowest prices for natural gas in a decade. On September 20, 2013, the Governor signed Senate Bill 4 (Pavley, Chapter 313, Statutes of 2013) to increase regulatory oversight for hydraulic fracturing in California which could affect shale gas supply.

Energy Commission staff produce ~~a forecast~~estimates of natural gas supply, demand, and price as part of each biennial *IEPR* process. S~~The preliminary s~~taff’s ~~forecast~~ outlook indicates a ~~fairly flat gas prices after 2015, which~~ gradual rise in price over the ~~forecast period~~next several years. By 2025, prices are ~~forecast~~ likely to range from $4.39~~25~~ to $6.83~~00~~ per ~~million British thermal units~~thousand cubic feet, as compared to a 2013 real average price to date of approximately $3.7~~5~~0 per ~~million British thermal units~~thousand cubic feet (Henry Hub). The Energy Commission expects to ~~adopt~~ release the final natural gas ~~forecast~~ outlook report in December 2013.

Pipeline safety in the wake of the San Bruno pipeline explosion in 2010 remains a critical concern of the Energy Commission, the CPUC, and the Legislature. In response to California’s continued focus on pipeline safety, the Energy Commission continues to provide research, development and deployment funding to projects that explore new technologies to monitor and address pipeline safety.

The *2013 IEPR* also discusses natural gas ~~infrastructure~~ issues such as the need to harmonize the natural gas and electricity generation industries to support increasing use of natural gas facilities to help integrate renewable energy; ~~the need for new pipeline development to support increasing~~storage; exports to Mexico; ~~and replacement of~~ coal-fired plant replacements~~s with natural gas~~; increased interest in exporting liquefied natural gas; and c~~. Other issues include the use of biomethane as a renewable substitute for natural gas and the potential impact on demand from increasing use of c~~ombined heat and power ~~facilities~~. Recommendations include: continuing to monitor and better integrate pipeline delivery of natural gas with electric system reliability needs; monitoring the national interest in liquefied natural gas and its implications for California; and staying abreast of the changing revenue dynamics for natural gas in light of shale abundance, generation shifts away from coal, and the implications of expiring pipeline contracts for maintaining necessary supply into California.

Transportation

Transportation accounts for nearly 40 percent of California's total energy consumption and roughly 39~~8~~ percent of the state's greenhouse gas emissions. While petroleum accounts for more than 90 percent of California's transportation energy sources, there could be significant changes in the fuel mix by 2020 as a result of technology advances, market trends, consumer behavior, and government policies. Compared to 2008, gasoline consumption has declined by 6 percent, due in part to the national economic recession and higher vehicle fuel economy standards. Expectations are that gasoline consumption will continue to decline over the next 10 years. At the same time, California has experienced modest but noticeable increases in alternative fuels—primarily natural gas, biofuels, and electricity—to approximately 7 percent of total transportation fuel use. While these California trends have shown strong initial progress, new circumstances are poised to push significant advances.

In September 2013, the California Legislature reauthorized the Alternative and Renewable Fuel and Vehicle Technology Program with Assembly Bill 8 (Perea, Chapter 401, Statutes of 2013) extending program funding through January 1, 2024. The Alternative and Renewable Fuel and Vehicle Technology Program was originally established by Assembly Bill 118 (Núñez, Chapter 750, Statutes of 2007). As of June 2013, the Energy Commission has funded 233 projects through the program, totaling more than $400 million in the categories of electric drive, hydrogen, natural gas, propane, biofuels, multiple fuel types, manufacturing, emerging opportunities, and workforce training and development. This investment supports the State's energy, clean air, and climate goals.

The *IEPR* is required to report on the status of projects funded under Alternative and Renewable Fuel and Vehicle Technology Program. Program investments are adding 7,200 electric vehicle charging stations, 205 E85 (a blend of 85 percent ethanol and 15 percent gasoline) fueling stations, 50 natural gas stations, and 24~~6~~ hydrogen fueling stations, along with more than 26,000 electric vehicles, 160 electric trucks, and 1,375 natural gas trucks. As a result of the Alternative and Renewable Fuel and Vehicle Technology Program, California now has the largest network of electric vehicle charging systems and the largest number of hydrogen fueling stations in the country. Although still in its early years, the program is playing an important role in building the alternative fuel vehicles and support infrastructure needed for California to meet its low-carbon transportation fuel goals.

The Energy Commission is also required to include an evaluation of projects funded by the Alternative and Renewable Fuel and Vehicle Technology Program in the biennial *IEPR*, including their expected benefits and contribution toward improving air quality, reducing petroleum use and greenhouse gas emissions, and transitioning to a diverse portfolio of clean, alternative transportation fuels. The Energy Commission has contracted with the National Renewable Energy Laboratory to develop a methodology to calculate expected benefits to 2025. Benefit estimates are ~~expected to be available for the final *2013 IEPR*~~summarized and will be in a stand-alone Energy Commission Contractor Report. In addition to reporting on the status and benefits of the Alternative and Renewable Fuel and Vehicle Technology Program, the Energy Commission is required to report on transportation fuel supply, demand, and trends in each biennial *IEPR*.

In July 2013, the Energy Commission held a workshop on alternative transportation fuel scenarios at which participants provided growth projections to at least 2020 by all alternative fuels and diesel vehicles, identified challenges to continued growth, and recommended actions to achieve California's low-carbon transportation energy goals. Based on workshop findings, the Energy Commission estimated plausible growth to 2020 for several low carbon alternative fuel options, including gasoline substitutes, diesel substitutes, natural gas, electric transportation, and propane. Existing government incentives and regulations combined with alternative fuel price advantages, expected economy of scale vehicle manufacturing, and technology advances could lead to at least a three-fold increase in alternative fuel growth by 2020. This progress should allow California to fulfill 2020 goals to reduce transportation related greenhouse gas emissions, displace petroleum, and develop in-state biofuel projects.

Challenges to achieving growth potential for alternative fuels include the need to balance multiple policy objectives in electrifying the transportation system; ethanol blend limits in the federal Renewable Fuels Standard; demand for alternative fuel incentives in excess of funding availability; the limited number of natural gas vehicle models; the market need for certainty about hydrogen vehicle availability and fueling infrastructure; changing trends in gasoline, diesel, and aviation fuel consumption that may pose challenges to making needed investments in refineries; and challenges tracking and evaluating alternative fuel growth.

Recommendations to address these challenges include: implement actions identified in the Governor's Executive Order B-16-2012 advancing zero emission vehicles and the associated Zero Emission Vehicle Action Plan; work with utilities, the CPUC, the California ISO, and other ~~public and private~~ stakeholders to balance multiple objectives with the electrification of transportation; ~~government facilitation of investment and development;~~ encourage stricter adherence by obligated parties to advanced, low-carbon, Renewable Fuels Standard goals; develop a multi-year strategy to fund electric, hydrogen, and natural gas vehicle rebates and incentives for related infrastructure; evaluate options to use state, federal, or other mechanisms to structure incentives to increase private sector project financing; evaluate factors affecting California's crude oil production and refining; and expand the Energy Commission's and Air Resources Board's joint data collection authority.

Climate Change

The Governor joined more than 500 world-renowned researchers and scientists in releasing a groundbreaking call to action on climate change and other global threats to humanity. The 20-page consensus statement, produced at the Governor's urging and signed by more than 500 concerned scientists from ~~more than~~nearly 44 countries, translates key scientific findings from disparate fields into one unified message (*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-scientists]). The document aims to improve the nexus between scientific research and political action on climate change.

California's efforts to reduce greenhouse gas emissions from the energy sector include pursuing all cost-effective energy efficiency, adding renewable generation to the state's power mix, reducing the carbon content of transportation fuels through the Low Carbon Fuel Standard, and funding investments in alternative fuels, vehicles, and infrastructure. To achieve its greenhouse gas reduction goals, California must be even more aggressive in developing and implementing these policies. Also, the state needs to be prepared to deal with the effects of climate change on the energy sector itself. From direct effects such as increased electricity demand, decreased efficiency of thermal power plants, and the availability of hydropower, to indirect effects such as increased exposure of coastal power plants to flooding due to sea-level rise, policy will need to continue evolving over time to ensure the safety and reliability of California's energy infrastructure.

Since 2006, the state has sponsored a series of climate change assessments that have established that lowering greenhouse gas emissions can reduce climate change effects, emphasized adaptation as a complement to reducing emissions, and explored vulnerabilities while highlighting concrete actions to reduce climate change impacts. As part of the *2012 IEPR Update* and *2013 IEPR* proceedings, Energy Commission staff held public workshops to discuss the latest findings on climate projections relevant to the energy sector, potential impacts on California's energy supply, and responses the energy sector is taking to prepare for climate change. A staff paper with the results of those workshops ~~is expected to be~~was released ~~in the fall of~~~~by the end of~~in December 2013 with recommendations for areas where future research is needed to support California's existing and future policy goals. In particular, research is needed on the effect of extreme weather-related events on the energy sector and on renewable energy goals, how California's energy system will need to change over the next few decades, and improvements to climate change indicators to allow better tracking, evaluation, and reporting on efforts to reduce climate change.

California's 2030 Electric System

Achieving California's 2050 greenhouse gas emission reduction goals will require substantial transformation of California's energy system. These challenges are being explored as part of the *2013 Scoping Plan* update, ~~in particular~~in addition to potential ~~targets~~ interim goals for 2030. The analysis will focus on three strategies to reduce greenhouse gas emissions: energy efficiency, particularly in existing buildings; expanded zero-emission vehicles deployment; and decarbonizing the Western grid. The Energy Commission and California Air Resources Board will also jointly develop metrics to track progress against the *2013 Scoping Plan* update.

CHAPTER 1:
Energy Efficiency

Energy efficiency remains California's highest priority resource to offset increased ~~electricity~~ energy demand. The state's loading order established by the energy agencies in 2003 calls for meeting new electricity needs first with efficiency and demand response, followed by renewable energy and distributed generation, and then with clean fossil generation.[1] Developing and enforcing energy efficiency codes and standards are critical tools for implementing the loading order. It is important to note that as energy efficiency codes and standards continue to improve, energy efficiency savings from incentives programs may diminish unless those programs continue to expand beyond traditional efficiency measures. To accomplish this, the state may need to modify its incentive mechanisms to provide value for both compliance with the standards and the total energy savings from upgrading inefficient equipment and building measures.

This chapter covers four topics related to California's continuing commitment to energy efficiency. First is a status report on the Energy Commission's development of a comprehensive program to increase energy efficiency in existing buildings. Second is a discussion of the accepted definition of "zero-net-energy" (ZNE) and ongoing development of a pathway to include ZNE buildings in California's building standards. Next is a report on the progress of California's utilities toward achieving efficiency targets.[2] Fourth is an evaluation of barriers to the use of geothermal heat pump and ground loop technologies – which can provide energy savings by reducing electricity and natural gas use. Finally, recommendations for the four efficiency topics are provided at the end of the chapter.

The Benefits of Energy Efficiency Standards

Since they were established in 1975, California's building and appliance efficiency standards have saved consumers over $75~~4~~ billion on their energy bills for electricity alone.[3] ~~Going forward, the *2013 Building Energy Efficiency Standards* are projected to save $1.6 billion in energy costs over the next 30 years.~~ R~~while r~~ecently adopted appliance standards for battery chargers are expected to save 2,200 GWh per year, which would be sufficient to power 350,000 California

1 California Energy Commission, California Public Utilities Commission, and Consumer Power and Conservation Financing Authority, *2003 Energy Action Plan*, http://www.energy.ca.gov/energy_action_plan/2003-05-08_ACTION_PLAN.PDF.

2 California Energy Commission, *Achieving Cost-Effective Energy Efficiency for California 2011-2020*, Final Staff Report, December 2011, http://www.energy.ca.gov/2011publications/CEC-200-2011-007/CEC-200-2011-007-SF.pdf.

3 Updated in November 2013, the Energy Commission staff estimated savings based on annual average rates by sector and the results are reported in $2012. This estimate does not incorporate any costs associated with developing or complying with building and appliance standards.

households each year.[4] The benefits of both the building energy efficiency standards and the appliance efficiency standards are realized beyond the state boundaries, are models for other states, the nation and other countries, and contribute strongly to energy efficiency gains throughout these broader areas of influence.

Energy efficiency standards help overcome well-understood barriers in markets for appliances and buildings. ~~When a consumer has limited knowledge of, or influence on the energy performance characteristics of a product, the marketplace will not tend to prioritize efficiency, even if it is simple and inexpensive to do so.~~ Standards eliminate the least efficient products and practices from the marketplace, reaping large benefits for California's consumers. Building standards, for example, ensure that cost-effective efficiency features are incorporated into each building during construction, the point at which these features are least expensive and most cost-effective. Once a building is constructed, ~~—the ideal moment to do so, since~~ the subsequent owner of the building cannot change the basic characteristics of the building without substantially higher expense. Similarly, purchase of an appliance represents a forward commitment by the consumer ~~for~~ to ~~an~~ unknown ~~, often large,~~ energy cost over the lifetime of ~~that~~ the device that in many cases surpass the purchase cost itself. When a consumer has limited knowledge of, or influence on the energy performance characteristics of a product, the marketplace will not tend to prioritize efficiency, even if it is simple and inexpensive to do so. Appliance standards ~~protect~~ benefit consumers by ensuring that the most cost effective efficiency is incorporated into their purchases.~~forward commitment meets a minimum bar for reasonableness.~~

~~The direct benefits—energy bill savings, improved indoor environment, increased building functionality, improved health and safety—of energy efficiency in newly constructed buildings and newly manufactured appliances or equipment appropriately accrue to the owner or user of the building or appliance.~~ Standards are a foundational part of California's long-term goals for meeting energy demand, resource conservation and environmental stewardship: they avoid ~~long-term~~the lost opportunity of failing to make buildings and appliances efficient at their crucial point of construction/manufacture, by ensuring that builders and manufacturers make appropriate, cost-effective investments in energy efficiency, to the benefit of all Californians.

Comprehensive Energy Efficiency Program for Existing Buildings

Existing buildings represent great untapped potential for additional energy savings and account for nearly a fourth of California's greenhouse gas emissions. More than 55 percent of existing residential buildings and more than 40 percent of existing nonresidential buildings were built before California building energy efficiency standards were in place. Many more buildings constructed since then, particularly in the inland areas of the state, present very

4 California Energy Commission, http://www.energy.ca.gov/appliances/battery_chargers/documents/Chargers_FAQ.pdf.

significant opportunities for energy savings. These factors underscore the need for a comprehensive program to promote efficiency improvements in all existing buildings.[5]

Assembly Bill 758 (Skinner, Chapter 470, Statutes of 2009) directs the ~~California~~ Energy Commission to develop and implement ~~such~~ a permanent and ongoing, comprehensive program to achieve cost-effective energy savings in California's existing residential and nonresidential buildings, and to report on the status of the program in its biennial *Integrated Energy Policy Report (IEPR)*. The Energy Commission recognizes that state resources are not adequate to provide financial assistance to achieve all the efficiency gains possible. A recent consultant report to the CPUC[6] shows that 30 percent of all households are low-income. Also, low-income multifamily households (defined as 5 or more housing units) represent about 9 percent of total residential households, 42 percent of multifamily households, and 32 percent of low-income households. Energy Savings Assistance is an important tool in reaching low income households, but given the large need and broad upgrades envisioned under AB 758, additional resources are needed. The state will need to work closely with utilities and other stakeholders to leverage existing programs and unlock other resources in the private sector to achieve the full potential of upgrades envisioned statewide.

In June 2013, the Energy Commission issued its *Draft Action Plan for the Comprehensive Energy Efficiency Program for Existing Buildings*.[7] Public workshops were held throughout the state to solicit feedback on the draft action plan from stakeholders and the public, and the final action plan will be considered for adoption by the Energy Commission in June 2014. The Energy Commission in collaboration with the California Public Utilities Commission, regional and local governments, the state's major utilities, and industry stakeholders began active efforts to implement the aims of AB 758 in 2009, even before its enactment.

Purpose and Principles

In addition to implementing specific requirements contained in AB 758, the action plan seeks to establish conditions that will support a flourishing energy efficiency upgrade market using a diverse portfolio of approaches, a broad range of strategies and initiatives, and engagement with all market actors. The plan represents a roadmap that encompasses all relevant energy efficiency programs in the state, and encourages extensive coordination and leveraging for optimum outreach to local implementers, utilities, and existing building owners and tenants. The coordinated strategies of the plan will maximize energy efficiency for all building types,

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5 California Air Resources Board, *Climate Change Scoping Plan: A Framework for Change*, 2008, http://arb.ca.gov/cc/scopingplan/document/scopingplandocument.htm, p.12.

6 CADMUS, ESA Program Multifamily Segment Study Report DRAFT, November 6, 2013, http://www.energydataweb.com/cpucFiles/pdaDocs/991/ESA%20MF%20Segment%20Study_Draft_2013.11.04.pdf.

7 California Energy Commission, *Draft Action Plan for the Comprehensive Energy Efficiency Program for Existing Buildings*, June 2013, http://www.energy.ca.gov/2013publications/CEC-400-2013-006/CEC-400-2013-006-D.pdf.

including single-family and multifamily; small, medium, and large nonresidential buildings; and public buildings.

Guiding principles in the plan include maintaining cost-effectiveness of efficiency efforts, improved data collection management and analysis, support for contractors and other building professionals, public outreach and education, increased availability of building and assessment tools, availability of rebate and financing programs where appropriate, energy performance disclosure, improved compliance and enforcement of codes and standards, and development of a robust clean energy workforce.

Implementation

Further expansion of the active implementation efforts that the Energy Commission has already been conducting will be launched consistent with the adopted action plan, focusing ~~Implementation will begin after the Energy Commission adopts the action plan and will focus~~ on new ~~implementing~~ strategies identified in the action plan, building partnerships, and developing the market. Going forward, it will be critical to assess which areas of the energy efficiency market have reached a level of maturity that will allow public consideration of a potential transition from voluntary pathways to potential mandatory upgrades, as appropriate, to accomplish the energy savings goals of the program.

One barrier to full investment in energy efficiency upgrades in existing buildings is the practice of viewing building energy efficiency standards requirements as a "bright line" threshold, below which no public incentives are made available. This can be dysfunctional in two ways: 1) failure to motivate the act of compliance even though many projects are completed without building permits and without code enforcement because the marketplace does not provide clear benefits for compliance; and 2) failure to achieve the savings that would occur from upgrading inefficient equipment and building materials because only the incremental improvement above the standards is eligible for incentives. These conditions lead to purposeful avoidance of building permits and standards compliance, and to decisions to postpone upgrade projects. This prolongs the wasteful energy impact of inefficient equipment and materials, and discourages participation in energy efficiency programs because program requirements are too high and incentives are too low.

Strategies

Recommended strategies in the plan fall into three general categories.[8] **No regrets strategies** are intended to provide a strong foundation for growth in the demand for energy efficiency upgrades while supporting and streamlining current energy efficiency programs and markets. Sufficiently robust efforts to establish these foundational strategies can then be leveraged and adapted over time to multiple building sectors. These strategies include:

8 California Energy Commission, *Draft Action Plan for the Comprehensive Energy Efficiency Program for Existing Buildings*, June 2013, http://www.energy.ca.gov/2013publications/CEC-400-2013-006/CEC-400-2013-006-D.pdf.

- Data reporting and management to support private sector development and investment, ~~and~~ effective program design, monitoring, and evaluation of the energy efficiency upgrade market.
- Permitting support tools and active code enforcement ~~activities~~ to improve building practices ~~generally,~~ and ensure compliance with standards for alterations to existing buildings~~ code~~.
- Improvements to codes and standards that increase their functionality and practicality for existing buildings.
- Education to motivate building owners and building managers to make energy efficiency upgrades.
- Workforce training and development to ensure measured scale-up of an appropriately skilled clean energy workforce.

Voluntary pathways will build on past efforts, channel existing resources, and support upgrade projects for all categories of the building stock. These strategies include:

- Promoting a broad array of pathways for each building sector to achieve energy efficiency upgrades during ~~various~~ all stages in the life of the building. These pathways would recognize the value of achieving all opportunities for building upgrade, whether ~~could incorporate~~ a single measure, multiple measures, a whole-building approach, or onsite renewable ~~self-~~generation projects.
- Expanding engagement with the contracting industry and related building professionals.
- Developing standardized tools for benchmarking, energy assessments and audits, and building retrocommissioning in commercial and public buildings.
- Focusing attention on small and medium commercial building upgrades.
- Enabling efficiency solutions for ~~multifamily rental~~rented and leased properties, both residential and commercial, with special focus on disadvantaged communities.
- Working with local and regional governments to increase energy performance of public buildings while encouraging upgrades of privately owned buildings.
- Developing effective approaches to ~~include~~ ensure energy efficiency ~~upgrades in~~becomes a mainstream part of property valuation.
- Offering multiple innovative financing options for all building owners.

Mandatory approaches will be considered alongside other efforts. Energy usage d~~D~~isclosure policies are proliferating across the country and internationally, and good models exist which California ~~might~~ can emulate. Mandatory implementation of ~~certain~~ basic, cost-effective upgrades may be considered, through a public process, to determine their potential and acceptance. Mandatory approaches could include:

- A statewide, public ~~disclosure program for~~ energy usage disclosure program for the largest commercial and municipal buildings. This effort would coordinate with and build upon implementation of California Executive Order B-18-12[9] and the associated Green Building Action Plan,[10] which focus on state buildings.

- Disclosure of energy performance ratings on existing residential and nonresidential buildings, and considering the ~~case for~~feasibility of required completion of basic energy efficiency upgrades on existing residential and nonresidential buildings~~.~~

Zero-Net-Energy Buildings

The *2011 IEPR* (and previously the *2007 IEPR*) discussed the Energy Commission's policy recommendations regarding the pursuit of ZNE Buildings for newly constructed buildings within the Building Energy Efficiency Standards. These policies have been suppo*rted by t*he California Public *Utilities* Commission (CPUC) in the Long-Term Energy Efficiency Strategic Plan, the California Air Resources Board (ARB) in the *Climate Change Scoping Plan*,[11] and Governor Brown's *Clean Energy Jobs Plan*.[12] Separately, Governor Brown's Executive Order B-18-12[13] calls for all newly constructed State buildings and major renovations that begin design after 2025 be constructed as *zero-net-energy facilities.* The Executive Order also *calls for achieving z*ero-net-energy for 50 percent of the square footage of existing state-owned building area by 2025.

The *2011 IEPR* made the following recommendations related to ZNE delivery:

- The Energy Commission should adopt triennial building standards updates that increase the energy efficiency of newly constructed buildings by 20-30 percent in every triennial update to achieve ZNE standards for newly constructed homes by 2020.
- The Energy Commission should adopt reach standards for newly constructed buildings that provide best practices energy efficiency levels for the marketplace to strive for and to serve as a means to pull the industry rapidly to the level needed to achieve ZNE goals.
- The Energy Commission, CPUC, local governments, and builders should collaborate to encourage the building industry to reach these advanced energy efficiency levels in a substantial segment of the market through industry-specific training and financial incentives.

9 Executive Order B-18-12, April 25, 2012, http://gov.ca.gov/news.php?id=17508.

10 Green Building Action Plan – For Implementation of Executive Order B-18-12, April 25, 2012, http://gov.ca.gov/docs/Green_Building_Action_Plan_B.18.12.pdf.

11 California Air Resources Board, *Climate Change Scoping Plan: A Framework for Change*, 2008, http://arb.ca.gov/cc/scopingplan/document/scopingplandocument.htm, p. 12.

12 http://gov.ca.gov/docs/Clean_Energy_Plan.pdf.

13 Executive Order B-18-12, April 25, 2012, http://gov.ca.gov/news.php?id=17508.

- The Energy Commission and CPUC should coordinate future investor-owned utility (IOU) "new construction-related" programs with the Energy Commission's efforts to meet the ZNE goals through triennial updates of mandatory and reach standards. By offering incentives for achieving reach standards, providing technology demonstration and development, and conducting pilot programs for demonstrating ZNE solutions, new technologies and building practices will be integrated into upcoming triennial updates of the Building Standards quicker and with more success.
- The Energy Commission, CPUC, builders, and other stakeholders should collaborate to accomplish workforce development programs to impart the skills necessary to change building practice to accomplish ZNE in newly constructed buildings.
- The Energy Commission should adopt appliance standards that focus on reducing plug loads to enable California's ZNE goals to be achieved.

> **"Demand is the real opportunity."**
> Ed Mazria, California Energy Commission, ZNE Definition Workshop, July 18, 2013
>
> According to the McKinsey Global Institute, "Urban World: Cities and the Rise of the Consuming Class,"[1] by 2030 an additional 1.6 billion people will live in cities and 900 billion cubic feet of new and rebuilt buildings will be constructed in cities worldwide. Over half of this construction will occur in China, the United States, and the rest of the Pacific Rim.
>
> **"What California does influences China and, in turn, the rest of the world."**
> Ed Mazria, California Energy Commission, ZNE Definition Workshop, July 18, 2013
>
> "…So where is all that building going to take place? About nine percent of that is going to take place in the Middle East. About another nine percent in Latin America; India itself will be responsible for about nine percent. Other emerging nations, mostly Southeast Asia, will be responsible for about twelve percent. The U.S. and Canada… will be responsible for about 15 percent of that total gross over the next two decades; and obviously, China is critical, it is about 38 percent.
>
> But between China and the U.S. you have over 50 percent and if you include the rest of Southeast Asia you are well over 65 percent of the total construction in the world. That is critical, because the U.S. influences what happens in China. So you have a majority of the growth happening between those two areas."

The Energy Commission, CPUC, and partners in the building industries have together made major progress on all of these ZNE delivery recommendations, ~~centrally~~ including the adoption of the *2013 ~~T24~~ California Building Energy Efficiency Standards*. This latest update to the ~~code~~ Standards, effective July 1, 2014, ~~update~~ achieves 25 percent savings over the existing ~~code~~Standards for residential buildings.~~, and comes into effect~~ *~~January~~* ~~1, 2014.~~

The *2011 IEPR* also made this additional recommendation related to the definition for ZNE Code Buildings:

- The Energy Commission and the CPUC should work jointly on developing a definition of ZNE that incorporates the ~~societal~~ geographical and temporal value of energy (consistent with the time dependent energy valuation approach used for the California Building Energy Efficiency Standards).[14]

14 The *2011 IEPR* used the terminology "societal value."

The Energy Commission, working with the CPUC, has accomplished this recommendation, and proposes adoption of the following definition.

> "A ZNE Code Building is one where the net~~societal value~~ of the amount of energy produced~~provided~~ 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 (TDV) 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."[15]

The adoption of this definition will enable the Energy Commission to update the California Building Energy Efficiency Standards for 2016 and 2019 with clear orientation toward the upcoming ZNE targets for low-rise residential buildings (three stories or fewer) in 2020 and nonresidential buildings in 2030.[16] Once the definition is incorporated into CPUC guidance to ~~investor-owned utilities~~ IOUs, it will help to further define and target activities of the utilities' emerging technologies, codes and standards, ~~and~~ new construction, and other building-related programs that will be needed to accelerate the shift to ZNE.

The goal for ZNE Code Buildings, established in the *2011 IEPR* and other California policy documents, applies to the design of the building and to its construction, before the building is occupied. The ZNE Code Building concept is that the building is designed with energy efficiency and on-site renewable energy production such that the net ~~societal cost~~amount of ~~the~~ energy used over the course of a year, measured using the TDV metric, is equal to zero. A ZNE Code Building does not imply a building with zero utility costs. Actual ~~energy bills~~utility costs will ~~be~~ depend ~~ent~~ on how the building is operated by the building owners and occupants ~~after the design/construction stage is long past,~~ and ~~will depend~~ on the application of specific utility rates ~~on their~~to the net energy consumption of the building during each period of the day and month. Public education is important so that people understand ~~that~~ the estimated energy use for the ZNE Code Building is determined for the building design, and that the actual energy use of the building will depend on how the building is ~~actually~~ operated. Public education should clarify the correct expectations for ZNE Code Buildings, and should also illuminate the benefits of ZNE Code Buildings in achieving optimum energy performance, ~~improved statewide energy~~

15 The ZNE Code Building definition was presented at a publicly noticed workshop at the Energy Commission on July 18, 2013, attended by Energy Commission staff and Commissioners, CPUC staff, noted national ZNE experts, and representatives from each of the IOUs and Sacramento Municipal Utility District. Modifications to the definition proposed at the workshop are shown in underline and strikethrough.

16 The California Building Energy Efficiency Standards are required to meet life cycle cost effectiveness requirements. Any ZNE requirement included in those standards would also be required to meet the life cycle cost effectiveness requirements.

~~system reliability,~~ reduced criteria pollutants, and reduced greenhouse gas emissions, as well as non-energy benefits such as improved comfort and building functionality.

For a building to achieve the ZNE Code Building ~~requirements~~level, substantial energy efficiency advances will be required. Together, the California Building Energy Efficiency Standards, California Appliance Efficiency Standards and the federal Appliance Standards and appropriately-sized onsite renewable energy ~~power~~ production will enable newly constructed buildings in California to reach the ZNE Code Building ~~requirements~~level. ~~Building owners and occupants will count on buildings that have zero or very low energy use levels, depending on how they are operated.~~

The California Building Energy Efficiency Standards necessarily focus on the capital improvements of the building itself (its physical assets), since those are under the control of the building designer and builder; the building standards cannot influence the portable equipment that is brought into the building later ("plug loads"). Energy consumption from plug loads ~~can~~, however, can be influenced by California and federal appliance standards that apply to portable equipment used by building occupants. The increasing number of plug loads in buildings highlights the crucial role of appliance standards in achieving ZNE Code Buildings. The ZNE ~~Building~~ Code Building determination will be based on "typical" levels of portable "plug load" equipment. The current "plug load" assumptions are in Chapter 4 of the Home Energy Rating System (HERS) Technical Manual.[17]

There will be particular buildings or situations where it will be infeasible for the building to meet the onsite renewable energy resources component of the ZNE Code Building ~~requirements~~definition. ~~In adopting~~ If the ZNE ~~Building~~ Code Building is adopted as a requirement in the future, the Energy Commission will use normal building code practice to establish specific exceptions for these cases. Also, the ZNE Code Building definition anticipates the possibility of buildings satisfying renewable energy generation obligations off-site through "development entitlements," as long as these obligations are commitments that are formally recognized and enforceable by the applicable enforcement agency. An example would be community based renewable energy resources, offsetting the energy consumption of a large number of homes in subdivisions, which were committed to and approved when the developer obtained planning permits for the subdivisions.~~of a possible exception would be allowing the use of off-site renewable energy sources where the site cannot accommodate collocated generation of any sort.~~

The Energy Commission's California HERS Program established the California HERS Scale (Figure 1).

17 California Energy Commission, HERS Technical Manual, December 2008, www.energy.ca.gov/2008publications/CEC-400-2008-012/CEC-400-2008-012-CMF.PDF.

Figure 1: Standards on the Home Energy Rating System (HERS) Scale

Source: California Energy Commission

The California HERS Scale establishes a rating score of 0 for the ZNE Code Building. The scale benchmarks a home built to comply with the 2008 California Building Energy Efficiency Standards at a score of 100. A home built to comply with the 2013 Standards will have a HERS score of around 90 (varying by climate zone). The graphic also shows a "ZNE Ready" level to represent a home with the energy efficiency improvements that sufficiently reduce demand so that the addition of onsite renewable power production could achieve ZNE (the "ZNE Ready" level assumes that the onsite renewable ~~power~~ energy production is not actually installed). A home built to be "ZNE Ready" would have a HERS score in the range of 30 to 40.

Establishing a definition for ZNE is one step toward the upcoming ZNE targets; however, making ZNE operational will continue through the 2016 and 2019 code development cycles. Recognizing that all buildings require a pathway to compliance, it would be necessary to establish ZNE Code Building requirements with reasonable exceptions to account for building and building site limitations. As mentioned above, the ZNE Code Building definition anticipates the need for "development entitlements" for off-site renewable energy resources, such as community based renewable energy generation, to be a viable option for builders and developers. Such options must be enforceable by the applicable enforcement agency and must enable tracking and matching to the specific buildings for which the energy consumption is being offset. As a practical matter, there is a need to allow for meaningful flexibility as a significant number of buildings may be unable to meet the on-site renewable energy sources component of the ZNE Code Building definition.

Other issues requiring further discussion include, but are not limited to, the role of transportation energy, housing density, and land use in the ZNE context; the availability and refinement of electricity and natural gas system information and costs used to update TDV; revisions to "plug load" assumptions; and the effect of ZNE Code Buildings on the operation of the electricity grid. Energy Commission consideration of what constitutes enforceable "development entitlements" for off-site renewable energy resources, and other technical issues requiring resolution prior to possible establishment of a ZNE requirement could be assisted by discussions in the ZNE working group that has already been established by the CPUC or in a new working group established by the Energy Commission. At a minimum, the Energy

Commission should obtain the input of the CPUC, the ARB, the Governor's Office of Planning and Research, investor-owned and publicly-owned utilities, the building industry, environmental groups, and environmental justice representatives on these issues.

Additionally, the *2015 IEPR* will include a determination of the appropriate role of natural gas in the development of zero-net-energy buildings, as required by Assembly Bill 1257 (Bocanegra, Chapter 749, Statutes of 2013).

Key Terms in the ZNE Code Building Definition

~~*Societal Cost*~~

~~The societal value of energy includes forecasted energy system costs that Californians pay for energy. This cost of delivering energy to meet building energy demand depends upon when and where it is needed. The societal value of energy is established by the concept of Time Dependent Valuation, first used in the 2005 California Building Energy Efficiency Standards.~~

Time-Dependent Valuation

The TDV concept, first used in the *2005 California Building Energy Efficiency Standards*,~~ime Dependent Valuation~~ is based on the forecasted seasonal and hourly costs for generating, transmitting~~,~~ and distributing electricity, and producing and distributing natural gas and propane. TDV values are established for every hour of the year for each type of energy in each of California's 16 climate zones. The ~~TDV~~ set of values considered under TDV are specific to the intent of the metric to recognize the premium utility costs that must be paid for energy consumed during peak conditions compared to the substantially lower costs during off-peak conditions—as a result, energy efficiency improvements that drive lower on-peak energy use are highly valued by TDV. Additionally, TDV allows for use of a single energy metric to account for buildings that consume multiple fuels. Generally, natural gas has a notably lower TDV energy value than electricity.

The TDV values that the Energy Commission adopts are based on a forecast of the mix of energy system resources that are expected to be in operation over the 30-year time horizon analyzed for the Building Energy Efficiency Standards. For each three-year cycle of the standards, TDV is updated to incorporate the most recent publicly available information on ~~energy~~ electricity and natural gas systems costs and the forecast is reevaluated resulting in ~~true up~~ adjustments to the TDV values to capture the impacts of changing energy supply and demand conditions and policies. The Energy Commission will work with all stakeholders in the 2016 Building Energy Efficiency Standards proceeding to update the current TDV values to reflect changes in, and evolving information from, California's electricity ~~generation~~ and natural gas systems. ~~resource mix.~~

TDV provides a systematic way to recognize the societal value of energy savings accomplished through different times of the year. In theory, buildings with low TDV energy consume less energy during peak conditions, resulting in a reduction in electricity system peak demands, saving Californians the high costs of new power plants and distribution systems, ~~on-peak~~ and helping to make the California's energy systems more reliable. For TDV to work in practice as intended, the following are needed: 1) retail rates must reflect the cost of service, and 2) geographic and temporal variation must be taken into account in both TDV calculations and applicable rates. Achieving this requires ongoing interagency work on both TDV development and rate reform.

On-Site, Single-Project, Renewable Energy Resources, Development Entitlements, and Building Permits

ZNE Code Buildings ~~will~~ would be required to incorporate on-site renewable resources to serve the remaining energy demands of the building after energy efficiency capital improvements. Each single project seeking development entitlements and building permits ~~must~~ would be required to install ~~enough~~ sufficient renewable energy resources on-site to reduce the TDV energy value of the project to zero. The single project would typically be a single building but could include a ~~bigger~~ larger project that is seeking (or has approved) development entitlements for more than one building. As discussed, all buildings require a pathway to compliance which necessitates establishing appropriate flexibility and exceptions for buildings where it is infeasible to meet the onsite renewable energy resources component of the ZNE Code Building definition.

Energy-Use Intensities

The *Building Energy Efficiency Standards* will set requirements for each ZNE Code Building that include energy-use intensities for each major end use (for example, space heating, space cooling, lighting, water heating) in TDV energy. These energy-use intensities will be based on evaluation of best practices for highly efficient buildings during Standards update proceedings.

Utility Progress Toward Achieving Energy Efficiency Targets

Utility energy efficiency programs also help reduce California's electricity demand. A wide array of energy efficiency programs for utility customers has contributed to keeping energy use per person in California relatively constant, while use in the rest of the United States has increased by roughly 40 percent. California's investor- and publicly owned utilities remain key players in the state's efforts to achieve all cost-effective energy efficiency. The CPUC oversees energy efficiency programs for the state's IOUs, primarily Pacific Gas and Electric Company, Southern California Edison, Southern California Gas Company, and San Diego Gas & Electric, while California's more than 40 publicly owned utilities (POU) are responsible for their own efficiency programs.

To promote increased energy efficiency in all of California's utility territories, Senate Bill 1037 (Kehoe, Chapter 366, Statutes of 2005) provided the first step by codifying the pursuit of energy efficiency as the first priority among energy resources. The bill requires the CPUC, in consultation with the Energy Commission, to identify all potentially achievable cost-effective electric and natural gas energy efficiency for the IOUs, set targets for achieving this potential, and review the energy procurement plans of IOUs for consideration of supply alternatives such as energy efficiency. SB 1037 also requires all POUs to report historical 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 with the CPUC to develop a statewide estimate of energy efficiency potential along with statewide annual targets over a 10-year period ~~targets~~ for California's investor and publicly owned utilities. With the passage of AB 2021, POUs joined the IOUs in being required to provide a forecast of energy efficiency savings. Under AB 2021, POUs are directed to provide an annual report to the Energy Commission on energy efficiency investments, programs, expenditures, cost-effectiveness, and results; and provide an independent evaluation of reported energy savings. The Energy Commission is to report on utility progress in the biennial *Integrated Energy Policy Report*.~~and to report utility progress in implementing AB 2021 in the biennial *Integrated Energy Policy Report*.~~

~~AB 2021 follows up on prior legislation, Senate Bill 1037 (Kehoe, Chapter 366, Statutes of 2005), which requires electric utilities to meet their resource needs first with energy efficiency. For IOUs, SB 1037 requires the CPUC and the Energy Commission to identify all potentially achievable cost-effective electric and natural gas energy efficiency savings and to set goals for achieving this potential. The agencies are required to review the procurement plans to ensure consideration of energy efficiency and other cost-effective supply options. SB 1037 also requires publicly owned utilities, regardless of size, to report annually to their customers and to the Energy Commission investments in energy efficiency programs.~~

~~Under AB 2021, POUs are directed to identify all potentially achievable cost-effective electricity savings; establish annual targets for energy efficiency savings and demand reduction for the next 10-year period; provide an annual report to the Energy Commission on energy efficiency investments, programs, expenditures, cost-effectiveness, and results; and provide an independent evaluation of reported energy savings.~~ In 2012, Assembly Bill 2227 (Bradford, Chapter 606, Statutes of 2012) amended the reporting timeline and consolidated the POU reporting requirements of AB 2021 to make compliance easier and ~~reduce~~ improve reporting ~~costs~~ efficiency by aligning the requirements more closely with the *IEPR* timeline. This consolidation will streamline the process and allow the POUs to focus their resources on implementing efficiency programs rather than on reporting. Under the ~~consolidated~~ amended ~~requirements~~timeline, POUs will provide updated targets every four years rather than every three, as was originally required by AB 2021. The Energy Commission plans to address the statewide goal for energy efficiency in the next *IEPR*.

Table 1 shows the IOU and POU energy savings for electricity, peak, and natural gas in 2011 and 2012. The IOUs reported savings exceeded their energy and peak savings goals, while the POUs in general reported declines in energy savings, as discussed in more detail in the "Publicly Owned Utilities" section below.

Table 1: IOU and Publicly Owned Utility 2011 and 2012 Energy Savings and Program Expenditures

	IOUs		POUs	
	2011	**2012**	**2011**	**2012**
Gigawatt hours	3,512~~57~~	3,898	456	440
Megawatts	629~~44~~	678	81	82
Therms (Millions)	6~~9~~7	54	-	-
Expenditures ($ Millions)	$846~~959~~	$~~1,~~897~~004~~	$129	$127

Source: Investor-owned utilities' annual reports for 2010- 2012, http://eega.cpuc.ca.gov/Documents.aspx; California Public Utilities Commission; California Municipal Utilities Association.

Investor-Owned Utilities

The CPUC approves three-year efficiency program cycles for the IOUs. For the 2010-2012 cycle, IOUs administered their portfolios of efficiency programs under CPUC Decision 09-09-047 with a total budget of $3.1 billion. Often, three-year program cycles are followed by a "bridge" year, which extends the energy efficiency programs of the previous cycle ~~energy efficiency programs~~ while plans for the next three-year cycle are developed. However, the CPUC issued Decision 12-05-015 in 2012 with guidance for the 2013-2014 program years, thereby establishing a two-year "transition" period that is neither a bridge year nor a full portfolio cycle.

In 2011, the CPUC began a multiphased study on IOUs energy savings potential with the primary objectives of assessing ~~IOU~~ technical, economic, and market energy savings potential and establishing efficiency goals for the 2013-2014 transition period.[18] Phase 2 of the study began in 2012 and will lead to broader changes for the post-2014 portfolio guidance. Looking forward to the post-2014 program cycle, the CPUC will work with the Energy Commission and the California Independent System Operator (California ISO) to help the IOUs focus their energy efficiency programs on local reliability areas and programs that target specific times of day.[19] Some of the IOU strategies intended to meet these goals include increased marketing and outreach, higher incentives, and more direct install programs.

The CPUC is finishing the evaluation, measurement, and verification (EM&V) studies for the 2010-2012 portfolio cycle. While some of the results of the studies will be published in the CPUC's annual EM&V report to be released in ~~fall 2013~~mid 2014, the majority will not be completed until spring 2014. The results of these studies are important because they may result in the IOUs eliminating unsuccessful programs and revising other programs that have merit but may not be realizing full-ratepayer benefit. The CPUC also directed utilities to design their

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18 California Public Utilities Commission, *Analysis to Update Energy Efficiency Potential, Goals, and Targets for 2013 and Beyond: Track 1 Statewide Investor Owned Utility Energy Efficiency Potential Study*, March 19, 2012, http://www.cpuc.ca.gov/NR/rdonlyres/5A1B455F-CC46-4B8D-A1AF-34FAAF93095A/0/2011IOUServiceTerritoryEEPotentialStudyFinalReport.pdf.

19 California Public Utilities Commission, California Independent System Operator, California Energy Commission, letter to Senators Padilla and Fuller, February 25, 2013.

portfolios to shift from short-lived individual energy savings measures to programs that encourage utility customers to adopt more comprehensive "suites" of measures characterized by more and longer-lasting savings.

The 2013-2014 program cycle evaluations are also underway. The CPUC has announced the contractors for this cycle and will have a final evaluation plan ready this fall. Once the plan is ready, the evaluations will begin.

Publicly Owned Utilities

California's POUs deliver about 25 percent of the state's electricity and 2 percent of natural gas supply.[20] The size of POUs ranges from the largest public utility in the nation, Los Angeles Department of Water and Power, to entities such as the Lassen Municipal Utility District that serve fewer than 500 customers. The California Municipal Utilities Association (CMUA) reports to the Energy Commission annually on behalf of its members on energy efficiency progress, while the Sacramento Municipal Utility District and the Los Angeles Department of Water and Power report directly to the Energy Commission and not always during the same time frame as the CMUA, which can interfere with staff's ability to conduct its analysis of statewide progress toward meeting energy efficiency targets.

Since AB 2021 was passed in 2006, POUs have spent more than $737 million on energy efficiency programs and delivered roughly 2,700 gigawatt hours (GWhs) of energy savings and 515 megawatts (MW) of peak demand reduction. Most energy savings were attributed to lighting and heating, ventilation, and air-conditioning programs. Energy savings can differ markedly among utilities because of different customer bases, geographic locations, and size. In 2012, the POUs spent a combined total of $127 million on energy efficiency programs, which represented a 2 percent decrease from 2011, and reported combined savings of 440 GWh, a decline of 3 percent compared to 2011. This is the third consecutive year that POUs, with a few exceptions, reported declines in energy savings. Cost-effectiveness is difficult to compare between POUs and IOUs because of the differences in their regulatory, financing, and revenue structures and the lack of data about cost-effectiveness inputs for individual POUs.

Advancing energy efficiency gains for POUs will require stimulating new program designs, tracking program accomplishments, verifying energy savings, improving program forecasts, and using this information to strive for deeper energy savings. The staff assessment of POUs' reported energy savings results revealed that several smaller and mid-sized POUs are likely to reach the 10 percent energy reduction goal contained in AB 2021; however, several are just as likely to fall short. To meet energy efficiency targets, certain POUs will need to capture significantly higher levels of energy savings and peak demand reduction going forward. As energy codes and standards raise the baseline, utilities must increasingly look for new opportunities, such as energy usage disclosure programs and financing mechanisms to lower demand.

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20 The number of POUs reporting energy savings is different not only from the number of POUs in the state, but from year to year. Staff performed assessments of only 36 POUs for which targets were established in 2007.

Evaluation, Measurement, and Verification of Publicly Owned Utility Efficiency Savings

Unlike the IOUs, for which the CPUC can report evaluated savings, most POUs do not have consistent independent EM&V methods. Since 2006, only half of the POUs have filed at least one EM&V impact study for program years 2007-2012. Savings reported this year were not adjusted as a result of EM&V analysis.

In 2010, the Energy Commission developed an EM&V guide to clarify the reporting requirements needed to improve EM&V studies and reports. These guidelines included how and when to apply the framework of evaluation criteria. Some POUs indicated that size, diversity in customer base, and program types made the "one-size-fits-all" approach outlined in the guidelines impractical. As a result of utility feedback, the Energy Commission is revising the EM&V guidelines. In 2014, staff will publish revised EM&V guidance, designed to ~~The intent of the revised guidelines is to~~ better meet the needs of the POUs, improve the transparency of the methods used to develop program savings estimates, and improve overall credibility of the reported energy savings. ~~help overall credibility of the reported energy savings. The revised guidelines are expected to be completed by the end of 2013.~~The Energy Commission is committed to encouraging and assisting the POUs in their EM&V efforts as a means to increasing energy efficiency effectiveness.

Geothermal Heat Pump and Ground Loop Technologies

As a further means to achieve greater energy efficiency in California's buildings, Energy Commission staff evaluates technologies that may provide efficiency savings over traditional heating and cooling systems. In 2012, Governor Brown signed Assembly Bill 2339 (Williams, Chapter 608, Statutes of 2012), which requires the Energy Commission to evaluate policies to help overcome barriers to geothermal heat pump and ground loop technologies, and to provide recommended solutions in the *2013 IEPR*. The Energy Commission staff held a public workshop in March 2013 and convened a working group to discuss barriers to the use of geothermal heat pump and geothermal ground loop technologies and recommend policies that may overcome those barriers. A staff paper discussing industry input that helped inform the findings and recommendations put forward here will be available the first quarter of 2014.

Geothermal heat pumps have existed in the United States for more than 50 years. Using the relatively constant temperature of the ground, they perform a heat exchange to both heat and cool buildings. In winter, heat from the warmer ground is transferred to a water-source heat pump, which provides warm air for the home or business. During hot weather, the process is reversed. Geothermal heat pumps also provide domestic hot water (or chilled water in some cases) at the same time through the same process.

Challenges

A primary challenge for the geothermal heat pump industry is how buildings are modeled in *California's Building Energy Efficiency Standards*. Currently, residential and nonresidential compliance software does not adequately model geothermal heat pump systems. Because utility rebate programs generally require modeling of a building with the Energy Commission's approved compliance models and since these models do not adequately represent the efficiency gains of geothermal heat pump systems, geothermal heat pump systems may not have sufficient access to utility rebate programs.

This unintentional barrier affects the industry in several ways. Building owners proposing to install a geothermal heat pump may not qualify for a utility rebate simply because the model does not represent geothermal heat pumps well (or at all). Further, <u>in the planning phase </u>the existing compliance models make it difficult ~~for installation in the planning phase~~ to demonstrate compliance with the *Building Energy Efficiency Standards* as well as to <u>determine the</u> ~~what~~ extent <u>to which </u>the geothermal heat pump (and the rest of the building) might exceed the standards. The verification of a HERS rater may be required to show that an energy efficiency measure exceeds the standards, but without an Alternative Calculation Method for geothermal heat pumps,[21] a verification system for HERS raters cannot be developed. Local jurisdictions with permitting authority have allowed geothermal heat pump advocates to use parallel building energy models (which are not approved compliance models for the state's standards) that do a better job of predicting geothermal heat pump efficiencies and to couple those results with the Energy Commission's approved compliance models. <u>To date, when a technology is added to the state's building code, industry representatives develop an Alternate Calculation Method based on the technical details of the technology as agreed upon among a consensus of stakeholders. </u>Other challenges include the following:

- The lack of local enforcement agency knowledge of geothermal heat pump industry standards leads to inconsistent local permitting requirements and variable fee schedules. For open-loop geothermal heat pump systems, there are also multiple and inconsistent permitting requirements due to the number of permitting agencies at the federal, state, and local levels.
- Geothermal heat pump systems are often considered "renewable," by the geothermal heat pump industry, but they do not generate electricity and therefore do not meet California's statutory definition of a renewable resource eligible for California's Renewables Portfolio Standard.
- The tiered utility electric residential rate structure may not reduce the customer's utility costs even when energy consumption has been reduced.[22]
- Boreholes for closed-loop geothermal heat pumps are fundamentally different from water wells but are subject to the same rules and regulations. There is a need for state-adopted standards for geothermal heat pump boreholes and ground loop installations. In addition, it can be difficult and expensive to collect data for the proper design and installation of systems with many borehole drillers forced to rely on a limited number of publicly available well/bore logs, their own well logs, or potentially expensive onsite test drilling.

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21 *2013 California Building Energy Efficiency Standards*, (Title 24, Part 1), Section 10-109(c)(2). http://energy.ca.gov/title24/2013standards/index.html.

22 A geothermal heat pump installation typically saves energy—both gas and electricity—in the summer months. However, in the winter months it saves only gas while marginally increasing electricity consumption due to the pump.

Recommendations

Comprehensive Energy Efficiency Program for Existing Buildings

- **Implement the *Action Plan for the Comprehensive Energy Efficiency Program for Existing Buildings.*** The Energy Commission plans to adopt its final *Action Plan for the Comprehensive Energy Efficiency Program for Existing Buildings* in ~~late 2013~~June 2014. The Action Plan and future year updates should become a core component of the *California Long Term Energy Efficiency Strategic Plan* and ~~the *Scoping Plan for*~~implementation of AB 32, the Global Warming Solutions Act of 2006. Initiatives consistent with the AB 758 Action Plan ~~It~~ should also become a critical component of California's efforts to replace San Onofre with 50 percent preferred resources (for further discussion, see Chapter 4).

- ***Work with national and state efforts to incorporate energy efficiency into the mainstream property valuation and appraisal process.*** California should actively work with the appraisal industry and with real estate professionals to change the current practice of leaving energy efficiency out of property valuation. California should collaborate with market actors and California stakeholders who have been involved in national efforts by the Appraisal Institute and others to modify current standard practices to enable energy efficiency to impact property values.

- **Implement energy ~~performance~~ usage disclosure requirements for large commercial and public buildings.** California should develop disclosure approaches and programs that build on existing efforts in California and other states, expanding them to the broadest range of building types, including State Buildings in alignment with Governor Brown's Executive Order B-18-12.

- **Improve ~~Title 24~~ Building Energy Efficiency Standards code compliance rates for existing building upgrade projects.** This will require much greater, ongoing emphasis on code-related outreach, education and training, and expansion of ~~as well as on-going~~ enforcement action. California should work with building departments and stakeholders to develop online ~~consider developing or adopting low-cost~~ permitting platforms that local building departments could adopt and strategies to ensure that HVAC equipment that is sold in the state is installed with building permits in compliance with state licensure law and the Title 24 Building Energy Efficiency Standards.

- **~~Enhance usability of~~Improve the ~~Title 24~~ Building Energy Efficiency Standards for additions and alterations to existing buildings to encourage compliance.** The Energy Commission should strive ~~for~~ in future updates to California Building Energy Efficiency Standards ~~Title 24 building efficiency standards~~ to establish requirements for additions and alteration to existing buildings that are highly functional and practical to encourage compliance.~~for additions and alterations to existing buildings.~~

- **Target energy efficiency improvements in difficult to reach building categories including engagement with ~~Collaborate with~~ real estate and property management industries.** Both the Energy Commission and the California Public Utilities Commission (CPUC) should involve real estate industry stakeholders in crafting aggressive but practical solutions for achieving high penetration of efficiency upgrades to all existing buildings, placing special emphasis on improving the energy performance of class B and C commercial buildings, multifamily buildings, and rental housing.

- **Leverage Proposition 39 efforts.** As lead agency for implementation of the California Clean Energy Jobs Act, Proposition 39/Senate Bill 73 (Committee on Budget and Fiscal Review, Chapter 29, Statutes of 2013)~~/ Proposition 39)~~, the Energy Commission should, where possible, ensure that tools developed for program management, tracking, and impact assessment have broader applicability for public sector buildings and across the clean energy marketplace.

- **Consider ways that standards can address demand response and grid resource opportunities.** Future California Building Energy Efficiency and Appliance Energy Efficiency Standards updates, potentially in collaboration with the U.S. Department of Energy for equipment subject to federal appliance standards, should consider cost-effective incorporation of features that can assist in promoting demand response and grid resilience and responsiveness. This should include the possibility of standard control communication protocols and control infrastructure that would enable building owners to voluntarily participate in programs to receive and respond to signals that could allow certain building loads to be dispatchable.

- ~~**View plug loads as a grid resource.** Future California Title 20 updates and corollary collaborative work with the U.S. Department of Energy on appliance standards should focus both on realizing cost-effective energy savings and on incorporation of features that can assist in grid resilience and responsiveness. Key features to include in the standards are communication protocols and control infrastructure to receive and respond to signals which will enable visibility for grid operators.~~

- **Conduct a new Commercial End-Use Survey**. The Energy Commission should perform a new *Commercial End-Use Survey* as soon as support funds can be identified. The last *Commercial End-Use Survey* occurred in 2002-2003, and is now out of date. Sophisticated tools are available that, together with updated survey instruments, will allow efficient, rich, and relevant characterization of California's commercial building stock.

Zero-Net-Energy Buildings

- **Increase efficiency by 20-30 percent with each building standard update.** To achieve zero-net-energy standards for newly constructed homes by 2020, each triennial update to the building standards should increase the energy efficiency of newly constructed buildings by 20 to 30 percent.[23]

- **Develop industry-specific training and financial incentives to advance reach standards.** "Reach standards" for newly constructed buildings should provide best practices energy

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23 California Energy Commission, *2011 Integrated Energy Policy Report*, Publication Number CEC-100-2011-001-CMF, http://www.energy.ca.gov/2011publications/CEC-100-2011-001/CEC-100-2011-001-CMF.pdf, posted February 15, 2012.

efficiency levels in terms of Energy Use Intensity for each building type and climate zone in California. The Energy Commission, the CPUC, local governments, builders, investor-owned utilities, and publicly owned utilities should collaborate to encourage the building industry to reach these advanced energy efficiency levels through industry-specific training and financial incentives.

- **Track market progress on zero-net-energy construction.** To inform its development of ZNE code requirements within the Building Energy Efficiency Standards~~Title 24~~, the Energy Commission will work in concert with the CPUC and ~~California Air Resources Board~~ARB to track zero-net-energy adoption rates, monitor related construction trends, assess performance of zero-net-energy buildings, and develop best practices for implementation.
- ~~lessons applicable for standards.~~
- **Coordinate utility new construction and ~~retrofit~~ emerging technology programs.** The Energy Commission and the CPUC should coordinate future investor-owned utilities new construction and ~~retrofit~~ emerging technology-related programs with the triennial updates of mandatory and reach standards. Judicious incentives for achieving reach standards, technology development, and zero-net-energy demonstration programs will facilitate integration of new technologies and practices **in**to future updates of the building standards. The Electric Program Investment Charge research program will ~~provide funding for~~fund technology innovations and demonstrations to achieve zero-net-energy buildings.~~in both new construction and retrofit applications.~~
- **Develop workforce to build zero-net-energy buildings.** The Energy Commission and the CPUC should actively work with the building industry to develop information and training for production builders to address changes in building practice that will be needed to meet the energy efficiency improvements required for "ZNE Ready" and "ZNE Code Buildings." Going beyond this near-term need, the Energy Commission and CPUC should work with the ~~CPUC,~~ Labor and Workforce Development Agency, the California Workforce Investment Board and its Green Collar Jobs Council, the Division of Apprenticeship Standards, the Community Colleges Chancellor's Office, and other stakeholders ~~should~~ to collaborate on ~~judiciously developed~~ programs that provide workers with the skills needed to build ~~new~~ zero-net-energy buildings. Programs and resources should be aligned and leveraged to best use pooled resources.
- **Add voluntary tier for zero-net energy to 2016 California Green Building Standards Code.** To help advance early adoption of zero-net energy, the Energy Commission should include a voluntary energy tier for zero-net-energy in the 2016 California Green Building Standards Code (Title 24, Part 11, CALGreen Code).

Investor-Owned Utility Progress Toward Achieving All Cost-Effective Efficiency Targets

- **Advance financing mechanisms.** The CPUC and Energy Commission will collaborate to evaluate what new types of savings could be expected as a result of extensive customer access to financing for energy efficiency measures, and to develop the financing mechanisms needed.

- **Advance locational and peak period energy efficiency.** The CPUC, California Independent System Operator, and Energy Commission will collaborate to develop the data and tools needed to advance energy efficiency in specific, targeted areas to defer or avoid development of or upgrades to transmission and distribution systems as well as generation.
- **Increase natural gas end-use efficiency.** The CPUC and Energy Commission will collaborate to develop the data and tools needed to further advance end-use natural gas efficiency.
- **Address data issues.** The Energy Commission intends to work on ongoing data issues including 1) working with the CPUC to address data concerns regarding CPUC programs and interagency sharing and 2) open an administrative proceeding to update the Energy Commission's data request authority.
- **Modernize energy-related information management practices.** Interagency collaboration should enable robust, cross-agency data management and sharing; provide clear access procedures and timely data services to researchers; facilitate appropriately detailed reporting to the legislature; and enable greater information availability to the public. Collaboration should extend beyond the Energy Commission and CPUC to include the California Air Resources Board, Contractors State Licensing Board, Department of Water Resources, local governments, and others.
- **Analyze savings.** The CPUC and Energy Commission will collaborate to analyze the near- and longer-term savings impacts of energy efficiency codes and standards and their interaction with other efficiency programs.

Publicly Owned Utility Progress Toward Achieving Energy Efficiency Targets

The Energy Commission is committed to encouraging and assisting the POUs to increase the scale of cost-effective investment in energy efficiency through creativity and good program models. Cost-effectiveness will depend on the particular procurement structure of each utility. To support continued progress toward achieving higher levels of energy savings, Energy Commission staff recommends the following:

- **Improve transparency.** In their 2014 report to the Energy Commission, the publicly owned utilities shall disclose data on their energy efficiency funding levels so that all investment sources can be tracked, as well as the E3 calculator inputs used to determine energy efficiency savings.
- **Improve evaluation, measurement, and verification (EM&V).** The Energy Commission aims to complete the EM&V guidelines ~~by the end of 2013~~early in 2014 for the publicly owned utilities to use in their next EM&V cycle to increase confidence and ensure independent verification; the publicly owned utilities should subsequently complete development of an EM&V program tracking system within 12 months.

Geothermal Heat Pump and Ground Loop Technologies

The Energy Commission supports the proper design and installation of geothermal heat pump technologies as a strategy for meeting California's energy efficiency goals. To advance the design, installation, and permitting of geothermal heat pump and ground loop technologies, the Energy Commission encourages geothermal heat pump industry to:

- Submit an Alternative Calculation Methodology application to the Energy Commission consistent with the *2013 Building Energy Efficiency Standards*, Section 10-109(c)(2). The Energy Commission will counsel industry on the process and path for developing an Alternative Calculation Methodology.
- Propose protocols for the proper design, installation, site verification, and commissioning of geothermal heat pump ground loop systems.
- Standardize training and certification of industry professionals in the proper design, installation, site verification, and commissioning of ground loop systems installed in California to provide system owners and operators with the assurance that these systems will perform as expected.
- Develop a model local ordinance. Industry should take the lead and consult with the Energy Commission, local International Code Council Chapters, Regional Water Quality Boards, the California Building Standards Commission, the California Department of Housing and Community Development, the Department of Water Resources, the CPUC, and develop a model local ordinance based on vetted industry standards that can be adopted by local jurisdictions.
- Collaborate with federal, state, and local agencies to resolve permitting issues.

CHAPTER 2: Demand Response

Demand response (DR) shares the top slot with energy efficiency in California's loading order of preferred resources to satisfy current and future electricity demand. DR – essentially reducing electricity use or shifting it to another period – provides many benefits including a more efficient electric system with lower overall system costs, reduced need for new power plants and transmission infrastructure, and more control by customers over their electric bills. DR is a flexible resource that can play a variety of roles in the electric system. Most commonly, it can reduce demand when needed – important, for example, with the loss of more than 2,000 megawatts of generating capacity from the recent shutdown of the San Onofre Nuclear Generating Station (San Onofre) in Southern California. DR can also help integrate the renewable resources needed to meet California's 33 percent by 2020 Renewables Portfolio Standard (RPS). Importantly, DR can lower net load swings in either direction by strategically increasing load (for example, to accommodate plentiful wind supply in early morning) or reducing it (for example during a summer afternoon upward ramp). DR represents an important low-carbon option for load-balancing services to integrate the even higher levels of renewable resources that will be necessary to meet California's long-term (2050) greenhouse gas emission reduction goals.

This chapter discusses some of the technical, economic, market, and policy barriers to using DR and recommends actions intended to make DR a vibrant part of California's electricity market. The actions build on efforts over the past decade by the California Independent System Operator (California ISO), the California Public Utilities Commission (CPUC), and the Energy Commission to promote and facilitate DR in California.

Despite its primary position in the loading order, there has been little progress toward increasing the amount of DR used in the state. A 2012 Federal Energy Regulatory Commission (FERC) report indicated that the DR available to the California ISO remains flat, while in other areas of the country, particularly in the PJM Interconnection and the Midwest Independent System Operator, DR availability and use have significantly increased.[24]

California's utility DR programs have traditionally focused on maintaining reliability either by having dependable emergency resources that can respond to rare and unpredictable generation or transmission outages, or by reducing peak demand to reduce stress on the transmission and distribution system. In addition, programs were designed before "smart grid" technologies were available so that operators telephoned large industrial customers to trigger the contracted load interruptions and utilities used broadcast radio signals to switch off large groups of air conditioners.

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24 Federal Energy Regulatory Commission, *Assessment of Demand Response & Advanced Metering*, December 2012, http://www.ferc.gov/legal/staff-reports/12-20-12-demand-response.pdf, p. 25.

Over the past decade, however, the same technological advancements seen in telecommunications have dramatically altered the way electricity generation and use are measured, analyzed, and managed. At the same time, sustained growth in both distributed and central-station renewable generation has made managing the electricity system more complex. Because the dominant renewable sources, wind and solar, are fundamentally variable, the electricity system operator must procure flexible resources to "firm" that variability to maintain constant voltage and frequency across the system. Whether that flexibility is provided by new fossil generation or new and expanded DR or storage will depend on the ability of state policy makers to work quickly and effectively with critical institutions and stakeholders to resolve institutional and regulatory barriers and mediate stakeholder interests.

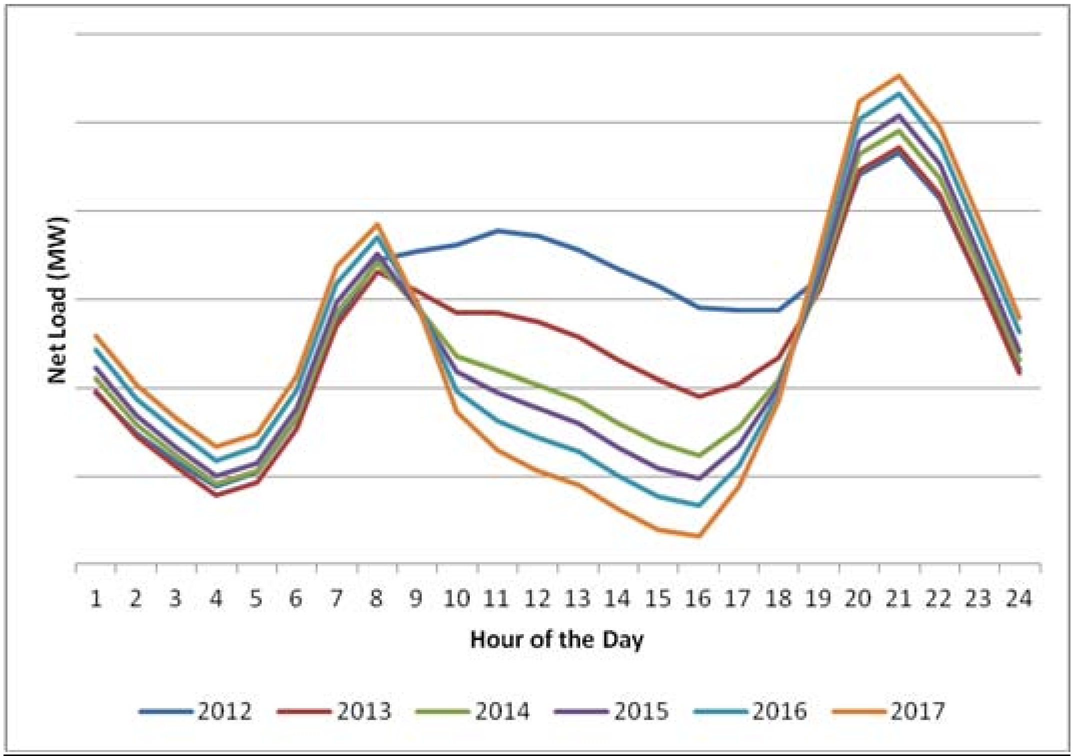
The California ISO developed a "net load curve" (the "duck chart") to illustrate the grid management challenge facing system operators from increasing amounts of renewable generation. Figure 2 (prepared by Energy Commission staff based on California ISO projections) illustrates the extent to which resources must be available to ramp up or down to satisfy the "net load" curve.[25] The "net load curve" shows one set of scenarios, based on typical March load shapes, for future levels of demand that would need to be met by other resources after subtracting projected must-take renewable resources. Ramps in the morning and late afternoon represent substantial challenges to the system operator to maintain service voltage and frequency within required limits under variable net load.

Figure 2 uses actual California ISO system data from March 22, 2013. The net load curve labeled 2013 is the actual data from the California ISO Renewables Watch website.[26] The net load curves for years 2014-2017 use the same load, wind, and solar shapes as were experienced that day, but scaled up using load forecasts prepared by the Energy Commission and intermittent capacity expected to come on-line in future years. Figure 2 suggests that the late afternoon up ramp will be nearly twice as large by 2017 as it was in 2012. The problem is likely most severe in the months of November through March. ~~Figure 2 was developed by the California ISO to illustrate the grid management challenge facing system operators from increasing amounts of renewable generation. The "net load curve" shows one set of scenarios, based on typical March load shapes, for future levels of demand that would need to be met by other resources after subtracting projected must-take renewable resources. Ramps in the morning and late afternoon represent substantial challenges to the system operator to maintain service voltage and frequency within required limits under variable net load.~~Due to the uncertainty of forecasting hourly loads profiles and intermittent resource profiles many years in the future, Figure 2 is stylized to show the relative changes in capacity needs over a day, without showing the amount of net load at a particular time.

25 By definition, a net load curve is the hourly total load less the hourly production of wind and solar generating facilities.

26 http://www.caiso.com/green/renewableswatch.html.

Figure 2: Projected Net Load Curves for 2012-2017 Based on an Illustrative March 2013 Day



Source: California ~~ISO presentation, June 17, 2013 *IEPR* Workshop~~Energy Commission, Electricity Supply Analysis Division

The need for ancillary services (load following, ramping, and regulation) increases substantially when load changes rapidly at the magnitudes projected by the California ISO and Energy Commission for 2020. Traditionally, system operators have used fossil-fueled generators to provide nonspinning reserves (generators that can be started and brought to stable operation quickly) and spinning reserves ("unloaded" but running generators whose power output could be added to or subtracted from the grid in real time) to balance demand. DR has shown great potential as a substitute ~~for reducing the need~~ for fossil generation in providing ancillary services. FERC is also encouraging its use, and other system operators—notably the PJM Interconnection, the Midcontinent Independent System Operator, and the Electric Reliability Council of Texas—are already incorporating DR into their markets. However, California has not yet been successful at creating the right conditions under which DR can scale significantly, much less achieve its full potential.

There is an urgency to expand DR as a frontline resource for maintaining system reliability and taking full advantage of the contributions of low-carbon renewable generation. The necessary technology advancements—communication, monitoring, data collection, and real-time analysis—are well underway~~The necessary technology advancements – communication, monitoring, data collection, and real-time analysis – are well underway~~. What is lacking is a clear and consistent regulatory structure under which the necessary market designs and business models can take root and thrive.

Demand Response Efforts in California

Energy Commission and California Public Utilities Commission Efforts

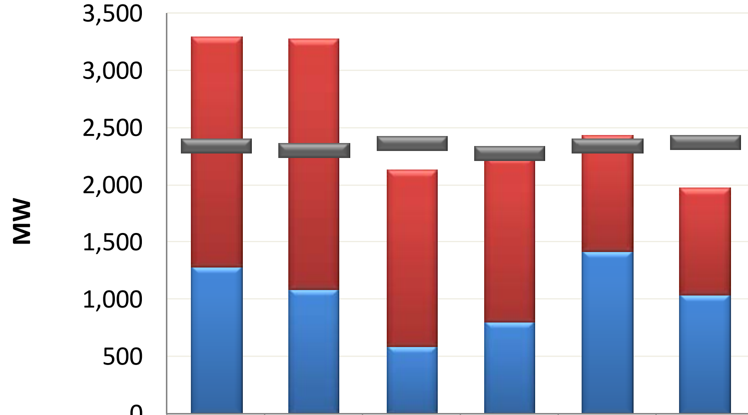
DR efforts in California were originally intended to support a dynamic pattern of systemwide price response that reflected actual system costs. Program goals were to enhance reliability, mitigate the market power of generators, incentivize investments in cost-effective energy efficiency and load management technologies, and minimize ratepayer costs over the long term.

The energy agencies' *Energy Action Plan* and *Energy Action Plan II* incorporated a statewide DR goal of 5 percent of system peak demand. This goal was first articulated in CPUC Decision 03-06-032 in Rulemaking 02-06-001. When that decision was adopted, most DR was available only under emergency conditions and was intended as a backstop reliability measure. DR triggers varied but were aligned with either critical supply shortages or transmission failures. Customers participating in the reliability programs were typically large manufacturing, water transport, process heat, and other facilities with substantial loads that provided significant relief to the system when curtailed. However, curtailment costs to participants could be large in terms of lost production, ruined product, restart costs, and other effects, so compensation agreements—usually a discount on the electric rate for the load subject to curtailment—contemplated infrequent curtailment calls.

From summer of 2000 to spring of 2001, California's electric system reached "critical" reliability conditions frequently due to supply shortages accompanied by extremely high prices. Reliability program participants rapidly tired of repeated unexpected curtailments, which ultimately did not prevent rolling blackouts.

A new vision for price-responsive DR was built on the idea that system reliability depended on protection from economic risk as well as the risk from physical system failures. While funding has grown to just under $450 million, participation in price-responsive DR options continues to be far below the 2007 goal (Figure 3). Large commercial and industrial investor-owned utility (IOU) customers (whose loads peak at more than 200 kilowatts [kW]) are on a default critical peak price, but most have opted out. Small commercial customers are now seeing time-of-use prices. For residential customers, these rates are optional and largely undersubscribed.

Figure 3: IOU Demand Response 2008-2013



	2008	2009	2010	2011	2012	2013
Emergency	2,007	2,172	1,544	1,428	1,010	924
Price-Responsive	1,287	1,095	589	814	1,420	1046
5% Target	2,345	2,302	2,368	2,277	2,342	2,371

Source: California ISO presentation, June 17, 2013, *IEPR* Workshop

The *2007 Integrated Energy Policy Report* (*IEPR*) stated that, as of summer 2007, California had achieved less than half of the *Energy Action Plan II* goal of reducing peak demand by 5 percent. One impediment to reaching that goal was the lack of advanced meters needed to support dynamic pricing programs for small and medium-sized customers. Over the next few years, Energy Commission and CPUC efforts led to the approval and deployment of the advanced metering infrastructure in all three IOU service territories. However, the simple presence of advanced meters has not resulted in significant levels of participation by residential customers.

DR for residential customers faces some unique barriers not faced by commercial customers, in particular a lack of time-variant pricing. Assembly Bill 1X (Keeley, Chapter 4, Statutes of 2001), passed during an extraordinary legislative session in February 2001, authorized the California Department of Water Resources to issue bonds and procure power on the behalf of the struggling IOUs. The bill contained a provision to partially protect residential customers from the cost of servicing those bonds. This provision has been interpreted by the CPUC to apply not only to the Department of Water Resources bond charges, but to the other underlying rate components as well—effectively freezing the price of electricity at 2001 levels for 60 percent to 75 percent of total residential consumption.

Two unintended consequences resulted: the increasing allocation of normal increases in utility costs to a smaller portion of total consumption, and the effective prohibition of time-based pricing. Senate Bill 695 (Kehoe, Chapter 337, Statutes of 2009) attempted to address some of these consequences by specifying how baseline utility rates could (gradually) be increased and by allowing time-variant pricing after 2013 under specific conditions. Assembly Bill 327 (Perea, Chapter 611, Statutes of 2013) prohibits the CPUC from requiring utilities to implement mandatory or default "time-variant pricing" for residential customers until 2018, when the restriction would be lifted for default time-of-use rates; dynamic rates would still be prohibited except on an opt-in basis.[27] Under existing IOU programs, customers receive bill credits for manually reducing their electricity use during certain peak times, and a premium incentive for using automated enabling technologies. These event-based programs do not provide anything close to the response time and precision needed for DR to provide grid management support. As prior *IEPR*s have recommended, rate reform should be pursued by the CPUC and utilities with the goal of providing clear, fair, cost-based incentives to ratepayers for energy efficiency and DR. The post-AB 1X world offers the opportunity to develop an intentional, modern, rational, and equitable rate regime. Such a regime has the potential to provide a lasting foundation to support not only DR, but customer engagement more generally, as well as related technical and service-related innovations that can drive cost-effective system optimization. The utilities should redouble their efforts to educate their customers and design reasonable, consumer-friendly rate options that attract participation while achieving these goals.

Consistent with the *2012 IEPR Update*, there is a need to reevaluate residential electricity rate structures to reflect the evolving nature of the electric system while ensuring that infrastructure investments are recovered through equitable pricing. The Energy Commission supports the CPUC's proceeding R.12-06-013, *Order Instituting Rulemaking on Commission's Own Motion to Conduct a Comprehensive Examination of Investor Owned Electric Utilities' Residential Rate Structures, the Transition to Time Varying and Dynamic Rates, and Other Statutory Obligations*.

On the technology side, in 2004 the Energy Commission established the Demand Response Research Center (DRRC) at the Lawrence Berkeley National Laboratory~~ in 2004~~. The DRRC conducts research to promote the near-term adoption of DR technologies, policies, programs, strategies, and practices. The DRRC has demonstrated the value of automated DR and the Energy Commission's Public Interest Energy Research Program has also helped develop the OpenADR[28] communications standards to support DR automation and integration with utility and independent system operator programs. OpenADR has been adopted as both a national and international standard for DR and distributed energy resource operations, allowing large numbers of loads to participate reliably in DR ~~activities~~ in other states and countries. In 2008, the Energy Commission began to develop load management standards for California, but in light of parallel efforts at the CPUC to advance DR, ~~ultimately~~ the proposed standards were not ~~adopted~~brought to the Commission for adoption. T~~However, t~~he Energy Commission continues to have broad statutory authority to adopt such standards, which could be used to require many of the activities described in this action plan.

27 At issue in A.10-08-005 is whether the CPUC can authorize Pacific Gas and Electric to adopt default time-variant price rates for all customer usage or only for usage above 130 percent of baseline. Resolution will affect pending residential rate design at Southern California Edison and San Diego Gas & Electric.

28 OpenADR is an open source communications protocol that can carry the type of information necessary (such as price data, emergency signals, specific program signals, and more) for customers to automate their DR strategies. http://www.openadr.org/.

CPUC Efforts

The CPUC developed and adopted DR load impact protocols in 2008 and cost-effectiveness protocols in 2010, which were necessary to document load reductions and determine program effectiveness reliably. Other accomplishments include approval of multiyear contracts between IOUs and aggregators, rollout of default critical peak pricing and mandatory time-of-use rates for nonresidential customers, and conversion of DR programs from emergency-based to price-based programs.

In June 2010, the CPUC issued Decision 10-06-002, stating jurisdictional authority over DR providers to establish customer protection rules and financial responsibility standards. The CPUC held two workshops in the summer of 2013 and is working with stakeholders to develop these rules under its Electric Rule 24.[29]

The CPUC's Integrated Demand Side Management (IDSM) program is a new effort to deliver all demand-side management options—efficiency, DR, energy management, and self generation—through coordinated marketing and regulatory integration. However, a recent evaluation[30] of the IDSM program found that integrating efficiency and DR into a project often reduces the anticipated impact of DR~~for the project relative to DR without efficiency improvements~~. Also, the definition of IDSM is not concrete or comprehensive, making it difficult for the IOUs to achieve IDSM without a clear description of what it entails.[31]

In Decision 12-04-045, the CPUC specifically considered the potential for DR to provide the additional grid flexibility required to implement the 33 percent RPS and to participate in the California ISO's wholesale market through a broader set of resource acquisition and load aggregation programs. Several automated DR pilots were included. The decision also acknowledged a number of fundamental issues raised during the proceeding, including concern that the "utilitycentric" model of DR procurement and program development was not achieving sufficient DR potential and that other models, including third-party provider participation in wholesale markets, should be considered.

In May 2013, CPUC staff released a report[32] on lessons learned from existing DR programs at Southern California Edison and San Diego Gas & Electric. Staff found a number of fundamental problems with the programs, including a demonstrated preference for dispatching fossil generators instead of available DR, despite state policy on the loading order of preferred resources. On September 19, 2013 the CPUC issued a new Order Instituting Rulemaking (OIR) (R.13-09-011) to "Enhance the Role of Demand Response in Meeting the State's Resource

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29 http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M037/K494/37494080.PDF and http://docs.cpuc.ca.gov/PublishedDocs/WORD_PDF/FINAL_DECISION/128488.PDF.

30 http://www.calmac.org/publications/CPUC_IDSM_FinalReport.pdf.

31 Itron, *2010-2012 CPUC Omnibus IDSM Process Evaluation*, October 2012, http://www.calmac.org/publications/CPUC_IDSM_FinalReport.pdf.

32 http://www.cpuc.ca.gov/NR/rdonlyres/523B9D94-ABC4-4AF6-AA09-DD9ED8C81AAD/0/StaffReport_2012DRLessonsLearned.pdf.

Planning Needs and Operational Requirements."[33] This rulemaking is considering changes to the current DR program paradigm under CPUC jurisdiction to address lack of participation in and performance of existing utility programs. The purpose of the proceeding is to "(1) review and analyze current demand response programs to determine whether and how we should bifurcate them into demand-side (customer-focused programs and rates) and supply-side resources (reliable and flexible demand response that meets system resource planning and operational requirements); (2) create an appropriate competitive procurement mechanism for supply-side demand response resources; (3) determine the program approval and funding cycle; (4) provide guidance for transition years; and (5) develop and adopt a roadmap with the intent to collaborate and coordinate with other CPUC proceedings and state agencies in order to strategize the future of demand response in California."[34] ~~The OIR anticipates coordination with the California ISO and the Energy Commission to address procurement rules and market designs, categorization of DR by "supply-" and "demand-side" resources, and development of a roadmap and strategies for the future of DR in California.~~

In November of 2013, the CPUC and SCE held a workshop to discuss proposals for SCE's "Living Pilot." The goal of this process is to develop a comprehensive, accelerated approach to assembling efficiency and demand response resources in the areas of SCE's territory most affected by the SONGS shutdown. The assembled approaches are intended to be followed closely and modified as necessary to increase the effect of the pilot.

California Independent System Operator Efforts

In 2008, the FERC issued Order 719, which instructed independent system operators to modify their tariffs to allow DR participation in their markets. As of June 2013, the California ISO had developed two products for DR participation, the Participating Load product and the Proxy Demand Resource product, and has been seeking approval from FERC of a third, the Reliability Demand Response Resource program, since May 2011.

Both Participating Load and Proxy Demand Resource programs give customers and DR providers an opportunity to bid load reductions into energy and nonspinning reserve markets, the major difference being that the participating load must be represented in the market by its load-serving entity, while proxy demand resources may be represented by DR providers. Moreover, proxy demand resources are subject to the DR net benefits test developed for FERC Order 745 compliance. The Proxy Demand Resource program is open to both individual and aggregated loads that meet specific requirements for availability, performance, communications, and settlement capability. The Reliability Demand Response Resource program is attempting to create a pathway for retail emergency DR products to be represented in the wholesale market. The California ISO expects that further integration of DR into wholesale markets will increase competition, promote efficiency, and reduce costs, and has

33 California Public Utilities Commission, http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M077/K151/77151993.PDF.

34 California Public Utilities Commission, p.2, http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M077/K151/77151993.PDF.

instituted a stakeholder process to develop a *Demand Response and Energy Efficiency Roadmap.* (See Appendix C and sidebar below for summaries of the roadmap.)

The California ISO has also been working with the CPUC to address a number of specific issues related to the inclusion of preferred resources in a DR program without violating the California ISO's neutrality obligation toward participation in its wholesale markets. To this end, it has engaged in a number of ongoing stakeholder efforts to develop participation rules and market designs for flexible resources, capacity markets, and resource adequacy procurement.[35] These efforts are closely tied to the CPUC's Resource Adequacy[36] processes and the Joint Reliability Multi-year Framework[37] activities.

> **California ISO Demand Response and Energy Efficiency Roadmap**
>
> The California ISO Demand Response and Energy Efficiency Roadmap identified four paths to advance DR and energy efficiency that would defer or offset investment in transmission and generation infrastructure. The following provides a brief description of the purpose and goals of the roadmap:
>
> - The **Load Reshaping Path** focuses on applying DR and energy efficiency resources to the demand side of the supply-demand balance equation. These resources can create a flatter load shape for the ISO system generally and, in specific geographic areas, reduce ISO operating needs and complexity.
> - The **Resource Sufficiency Path** focuses on the supply-side of the balance equation to ensure sufficient resources, with needed operational characteristics, are available in the right places and at the right times. This path includes activities that specify needed resource characteristics—as well as policy developments—to guide and facilitate DR and energy efficiency procurement and program development.
> - The **Operations Path** focuses on making the best use of all resources that are made available through the resource sufficiency path. It involves changing some existing policies, modifying or developing new market products to expand DR market participation, and addressing relevant technical and process requirements to achieve operational excellence.
> - The **Monitoring Path** is the essential feedback loop for the other three paths. Systematic monitoring of each stage of activity will foster a deeper understanding of the operational capabilities of DR resources, the effectiveness of DR and energy efficiency procurement programs in aligning with system-wide and locational needs, and the impacts of energy efficiency and other load-modifying programs in reshaping load profiles both locally and at the system level.

Utility Efforts

California's three largest electric IOUs (Pacific Gas and Electric Company, Southern California Edison, and San Diego Gas & Electric Company) offer commercial AutoDR programs that use OpenADR in businesses and homes. At the end of 2012, the IOUs had just 250 megawatts (MW) of dispatchable load using OpenADR. There are pilot projects for using OpenADR for small commercial and residential facilities to support both retail and wholesale DR markets in California.

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35 http://www.caiso.com/informed/Pages/StakeholderProcesses/FlexibleCapacityProcurement.aspx and http://www.caiso.com/informed/Pages/StakeholderProcesses/DemandResponseInitiative.aspx.

36 http://delaps1.cpuc.ca.gov/CPUCProceedingLookup/f?p=401:56:1334887330275601::NO:RP,57,RIR:P5_PROCEEDING_SELECT:R1110023.

37 http://www.caiso.com/informed/Pages/StakeholderProcesses/Multi-YearReliabilityFramework.aspx.

Standardization of communication and interfaces with customer-side protocols (including meters, controls systems, and so on) such as that provided by OpenADR is key to providing AutoDR capabilities securely and cost-effectively, providing customer choice for different utility or independent system operator DR programs, ~~and preventing vendor lock-in and~~avoiding stranded assets and preventing future equipment choices from being limited to the original vendor. OpenADR also standardizes distributed energy resource signals to customer facilities, which can support the CPUC's Rule 21 utility and distributed energy resource interconnection guidelines.

The Sacramento Municipal Utility District (SMUD) is in a unique position to adopt DR compared to other utilities due to its independent governance structure and its additional role as balancing authority over its own (along with some smaller publicly owned utilities) service area. With supplementary funding from an American Recovery and Reinvestment Act grant, SMUD has experimented with different DR technologies and program designs while testing to establish DR capabilities. SMUD is also building the ability to use different types of DR, including AutoDR, pricing, direct load control, and energy storage to meet its system needs, including resource adequacy, reserves, regulation and renewable firming in addition to more traditional peak-load management. SMUD is actively pursuing expansion of DR programs and technologies that are proven effective and is engaged in ongoing pilot testing of additional technologies and program designs. The utility anticipates being able to achieve a DR portfolio of about 9 percent of system load by 2021 with a sustained commitment to DR.[38]

Other Models

In attempting to build a successful DR program in California, several approaches have been shown to be successful in other markets. PJM, a regional transmission organization that coordinates the movement of wholesale electricity in 13 states and the District of Columbia, operates a Reliability Pricing Model,[39] which allows DR to be offered as a forward capacity resource. Under its model, even infrequent resources must receive enough revenue to cover their costs. Capacity payments, or payments received in exchange for making electrical capacity available, provide a revenue stream to maintain and keep current resources operating and to develop new resources. PJM recognizes that investors need sufficient long-term price signals to encourage the development and maintenance of generation, transmission, and demand-side resources. Its Reliability Pricing Model, which is based on making capacity commitments in advance of the energy need, creates a long-term price signal to attract needed investments for reliability in its region.

Successful DR programs not only provide reliable payments and predictability for investors, but require accountability from load aggregators. This accountability ensures that the promised capacity will materialize, yet allows aggregators to provide flexibility to their customers by independently deciding which customers to source that capacity from.

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38 Harlan Coomes, SMUD presentation at the IEPR workshop, June 17, 2013.

39 PJM, "Reliability Pricing Model: Demand Response and Energy Efficiency," http://www.pjm.com/~/media/markets-ops/rpm/20090406-dr-ee-in-rpm-collateral.ashx, p. 1.

Demand Response Challenges

The June 17, 2013, *IEPR* Workshop on "Increasing Demand Response Capabilities in California" sought public input on opportunities for and challenges to expanding DR to lower critical load in constrained areas, providing low-cost peak-reduction services and providing fast automated DR as a flexible generationlike product to support renewable integration and potential future emergencies. Participants and subsequent comments identified a number of DR challenges and opportunities:

- Opportunities for customers to participate in DR are limited, and participation rules do not reflect the capabilities and limitations of customers and loads. Market rules, participation costs, and incentive structures are not as attractive in California as in other regions, such as in PJM where larger resources can bid directly into the wholesale market and tariff structures and contract agreements are consistent across multiple utilities. For example, in other states a chain such as Walmart can sign an agreement on behalf of multiple stores; in California, however, each store must sign a separate agreement, making the transaction costs unattractive compared to other states.

- Outstanding issues affecting direct participation of DR in California ISO markets include limitations on participation by bundled customers, the need for rules for direct participation by retail customers on their own or through aggregators, DR compensation, and the appropriate role, if any, for IOUs under CPUC jurisdiction between electricity customers and third-party DR providers. In part, ~~Allowing~~ direct participation in wholesale markets depends on rules being developed through the CPUC's Rule 24 proceeding. Rules ~~(Rule 24)~~ governing the participation of bundled-service IOU customers in third-party DR provider aggregation programs add complexity and cost for both participants and DR providers. The CPUC is engaged with DR providers, the California ISO, IOUs, and other stakeholders in addressing some of these issues with the intent of promoting expanded participation.

- Aggregators face uncertainty regarding the time horizon of rates and program commitments. Knowing how long tariffs will last is essential for a provider to gauge its ability to honor agreements with customers. Lack of market certainty can sometimes be misinterpreted as customer reticence. However, aggregators have indicated that in other jurisdictions, they are able to participate directly in ISO markets in multiple ways, allowing them to give customers longer-term participation agreements that provide the tariff certainty needed to justify investments in DR infrastructure.

- Strict participation requirements attempt to treat DR like a generation resource which limits the appeal and availability of California ISO DR market products. This situation has implications for availability, visibility, dispatch, performance, verification, and payment. Manipulation of loads has different characteristics and constraints than traditional generation resources. For example, ~~Unlike~~ generation ~~generation that can run any time, DR loads can be reduced only when they are actually on. In addition, generation~~ resources are usually expected to perform consistently for long periods, while short commitments are preferable for DR. Because ~~particularly aggregated DR, because~~ it involves avoided consumption and reduced services that can disrupt production processes ~~and air-~~

~~conditioning use~~if not managed proactively, DR lends itself to aggregation approaches. Further, ~~, for generators,~~ it is simple to verify performance and measure generation output, while for DR, load reductions are frequently calculated against a baseline of "normal" operation that can add complexity and cost to the process.

- Telemetry requirements are a challenge in California because of expensive equipment required to allow DR participants to participate as "load." Large industrial facilities that are compensated for dropping ~~large numbers of MW~~sizeable loads can do this, but for smaller units the high cost restricts participation. Relaxed telemetry requirements and reduced technology costs could allow enrollment of large numbers of smaller loads that can provide DR benefits without significant negative effects on customers because those effects would be spread across a wider population. This could also increase portfolio diversification and improve DR performance.
- DR factors into a variety of energy agency processes that are critical to the functioning of the electricity system in California, requiring increased coordination between agencies on DR definitions and accounting methods. For example, DR triggered by discrete events throughout the year is included in the CPUC's resource adequacy and long-term procurement proceedings, while the Energy Commission includes non-event-based programs, such as time-of-use and real-time pricing and permanent load shifting, in its demand forecast. DR is categorized based on the distinction between event-based and non-event-based DR and can be further characterized as either a load modifier or a resource. However, the way some DR programs are structured can lead to ambiguity as to whether they should be included as a resource or a load modifier in energy planning.
- Constructing participation rules that take advantage of load diversity and allow third-party aggregation, utility aggregation, or even system-operator-level portfolio development can substantially increase DR participation. For example, performance of aggregated load ~~should~~ can be measured statistically, by measuring the aggregate impact, rather than directly by measuring the impact of each end-use load reduction. Rules that hold participating loads to high levels of performance—in terms of magnitude over the performance period and the probability of performance for each and every call—make sense for large participating loads. However, one of the major advantages of aggregated loads is the ability to assemble a portfolio of customers and end uses that together can produce more reliable, more consistent, and more flexible performance than can be achieved with individual participating loads. Such aggregation can garner participation and manage customer "fatigue." For instance, a seven-hour peak load commitment could be met with successive, shorter tranches of customer loads, or with multiple consecutive-day performance commitments from different subgroups of customers. By managing the portfolio to account for nonperformance risk, an aggregator can meet contracted performance commitments while allowing additional flexibility for customers.

Recommendations

California policy must focus on scaling up development of demand response (DR) products that have the characteristics required to avoid new generation capacity and transmission. Existing

DR programs in Southern California have ~~seriously~~ underperformed.[40] However, the various recent developments in Southern California—San Onofre retirement, approaching once-through-cooling requirements, and the increasing need for flexibility to integrate intermittent renewable resources—as well as the long-term challenge of responding to the impacts of climate change, dictate that DR play a much larger and substantially different role in electricity supply and reliability enhancement than today. Further, time-certainty is required for mobilizing fast-response DR at relevant scale: slippage in DR market development will necessitate more generation and/or transmission than would otherwise be required. Given the long lead time required to develop generation and transmission, the need to prove the value of DR is urgent. Intentionally enabling multiple market options in the near term decreases the risk of blocking out potentially viable DR strategies and business models~~ongoing anemia of DR resources~~. At the same time, the existence of disparate independent DR programs and products runs the risk of undermining participation due to either dilution of the benefit stream(s) for the customer and aggregators, or confusion resulting from complexity. Thus, the imperative is to tightly link CPUC and California ISO efforts so that DR enrollment and participation are simple and seamless for the customer and straightforward for the aggregator. The Energy Commission has identified five strategies to help DR take its rightful place in California's loading order of preferred resources.

Resolve Rule 24 Issues to Enable DR Participation in the California ISO Market

- **Complete the Rule 24 process.** Rule 24 terms will establish rules for direct participation of DR in the California Independent System Operator (California ISO) market, as well as enhancing customer protection and safety. Clarity on Rule 24 is a necessary—though not sufficient—condition for expanding DR opportunities for new customers with useable DR resources and opening opportunities for third-party aggregator to participate in wholesale markets, in Decision 13-12-029. The CPUC has moved positively to resolve a number of issues of concern to stakeholders. At the same time, the CPUC plans to resolve a number of remaining issues via resolution. The CPUC should endeavor to ~~complete this process~~resolve the outstanding issues as early as possible. This Decision, while effectively reducing many existing administrative barriers to participation, leaves in place a structure where the utilities retain a gatekeeper role in access to data required for effective DR program operation. Despite utility assertions about the "noteworthy accomplishments"[41] of existing efforts, the 2007 five percent goal still has not been met, and program participation has not been growing. It is important to maintain existing programs; but the critical challenge we face is to rapidly increase DR resources. The path forward should include alternatives to the utility-centric model of program delivery that can create new participation opportunities for customers who have not been interested in the utility offerings. As the CPUC states in

40 California Public Utilities Commission, *Lessons Learned From Summer 2012 Southern California Investor Owned Utilities' Demand Response Programs*, May 1, 2013.

41 PG&E comments from October, 29, 2013, workshop, p. 29, http://www.energy.ca.gov/2013_energypolicy/documents/2013-10-15_workshop/comments/Pacific_Gas_and_Electric_Company_Comments_2013-10-29_TN-72292.pdf.

Decision 13-12-029, Finding of Fact 12, "The [CPUC] strives to improve access to demand response direct participation and limit barriers to enrollment.";[42] fulfilling this aspiration will require resolving the problem of maintaining appropriate customer privacy and confidentiality protections while allowing workable alternatives to the utility role as middleman in the customer's relationship with their third-party DR provider. Additionally, within or alongside its Order Instituting Rulemaking (OIR),[43] the CPUC should investigate and resolve the technical and process barriers to customer participation with third-party providers in both investor-owned-utility-managed and direct wholesale markets such as dispatch, payment, and settlement.~~Additionally, within or alongside its Order Instituting Rulemaking (OIR),the CPUC should investigate and resolve the technical and process barriers to customer participation with third-party providers in both investor-owned-utility-managed and direct wholesale markets.~~

Develop and Pilot Test Market Products

- **Identify and explore program and tariff approaches.** The CPUC has approved funding for limited pilot activity as part of the current investor-owned utility DR program budgets (D.12-04-045). The CPUC and investor-owned utilities should collaborate with the California ISO, the Energy Commission, and stakeholders to identify promising DR program and tariff approaches being used effectively in other jurisdictions that could be adapted to California's needs. SCE's nascent "Living Pilot" is an example of such a collaborative approach and should be actively monitored and improved.

  From a program design perspective, it is best to establish rules that preserve flexibility and limit the downside for participating customers. A number of customer groups and third-party providers expressed concern that current nonperformance penalties for participants were greater for DR than for other generation resources. As long as the intended system resources are provided and the contributors appropriately compensated, participation agreements that avoid onerous penalties will encourage rather than discourage increased participation.

  Innovative options should be explored to expand market and program designs along two of the paths outlined in the *Roadmap*[44]: the "resource sufficiency" and "load reshaping" paths. Agencies must efficiently address concerns related to these pathways, particularly the issue of resource adequacy value for each path. This will ensure that programs that modify the

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42 http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M082/K904/82904047.PDF.

43 California Public Utilities Commission, *Order Instituting Rulemaking, To Enhance the Role of Demand Response in Meeting the State's Resource Planning Needs and Operational Requirements*, http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M076/K440/76440646.docx.

44 The California *ISO Demand Response and Energy Efficiency Roadmap* identified four paths to advance DR and energy efficiency that would defer or offset investment in transmission and generation infrastructure: the Load Reshaping path, the Resource Sufficiency path, the Operations path, and the Monitoring path. A detailed description of each path and their interactions can be found in the *Roadmap* itself at http://www.caiso.com/Documents/Draft-ISODemandResponseandEnergyEfficiencyRoadmap.pdf.

load shape are reflected in the demand forecast, thereby reducing the resource adequacy requirement and enabling these dispatchable resources to receive appropriate resource adequacy value as supply-side resources. These options should be tested and adjusted to ensure that the intent of the pilot actually meets grid needs and eases customer participation. Specific actions should include reviewing pilot proposals in process; directing the investor-owned utilities to develop proposals in concert with the California ISO; and engaging stakeholders in developing the demand response proposals with the goal of offsetting the need for transmission and generation resources. Ideally a suite of DR products would be in place to procure preferred resources for the 2015 resource adequacy compliance year to help address potential challenges in compensating for the loss of San Onofre.

- **California ISO should implement a multi-year forward DR auction in the region impacted by San Onofre.** The post-San Onofre reliability plan prepared jointly by the state's energy agencies highlights preferred resources as critical both near term and long term~~and includes a goal of 50 percent preferred resources going forward~~.[45] Plan execution ~~This~~ will require an aggressive set of demand response programs, including a ~~. California ISO should, in the near-term, develop a~~ DR auction mechanism for the capacity areas impacted by San Onofre, which the California ISO is prepared to develop and implement. Achieving meaningful participation and positive customer experiences will depend on program design and implementation detail, and requires lockstep coordination with the CPUC's DR efforts.

  If appropriately targeted to relevant load pockets, this effort could sharpen the agencies' understanding regarding locational benefits, dispatch, value, duration and availability of DR resources, as well as the extent to which these qualities interface with customer preferences and match aggregation models. Again, the California ISO DR auction would be developed in parallel, and in coordination, with CPUC efforts to update investor-owned utility-driven DR procurement.

Resolve Regulatory Barriers

- **Continue development and implementation of a multi-year reliability framework.** The current draft of the CPUC/California ISO framework[46] expands the forward resource adequacy obligations of the load-serving entities from one to three years, increases transparency through a joint reliability planning process 10 years ahead, and replaces the California ISO's current administrative capacity procurement mechanism with a market-based capacity auction. Market products will need to reflect the attributes of these customers and the types of load reductions they can provide; this will entail looking beyond current customers toward a broader customer base, large numbers of smaller loads, and

45 Energy Commission, California Public Utilities Commission, and California ISO joint staff presentation, "Preliminary Reliability Plan for LA Basin and San Diego," September 9, 2013, http://www.energy.ca.gov/2013_energypolicy/documents/2013-09-09_workshop/2013-09-09_reliability_presentation.pdf.

46 http://www.caiso.com/informed/Pages/StakeholderProcesses/Multi-YearReliabilityFramework.aspx.

developing incentives and ~~. Incentives and~~ participation rules that appropriately accommodate and reward participation by a wide range of customers.

While emphasis should continue on providing market designs that encourage fast-response DR, the pool of potential participants is likely inversely proportional to the strictness of participation rules—especially when there are few participation options. To enhance participation, resources that can provide consistent response over long periods but require more than 30 minutes to respond could be combined with quicker-responding resources that have limits on how long they can be sustained to meet local capacity resource needs. The emphasis here on fast-response DR is not at the exclusion of other forms of DR as expressed in prior *IEPRs*. The purpose of the current focus on fast-response DR is to achieve, in collaboration with the California ISO and CPUC, a rapid, coordinated resolution of the significant existing barriers to providing an underlying market structure for energy resources that can serve as the basis for rate designs and market products that appropriately value demand reductions of all types.

- **Timely development and conclusion of the CPUC's DR rulemaking.** The OIR anticipates turning first to the issue of continued "bridge year" funding for utility DR programs, with an anticipated decision in the second quarter of ~~2015~~2014. The CPUC should engage immediately in the policy and technical issues of DR procurement and program design, in parallel if necessary, to avoid delaying resolution of the pressing procurement and program design issues this proceeding is intended to address.

Continue the Collaborative Process Among the Energy Commission, the CPUC, the California ISO, and the Governor's Office

- **Advance fast-response DR.** The agencies should focus their efforts on advancing fast-response DR, both for callable (contingency) and price-responsive DR, through the Energy Commission's *IEPR* process, the California ISO's *Roadmap* process, and the CPUC's Rule 24 and DR OIR processes.
- **Develop a joint workplan.** The energy agencies should begin addressing and resolving timelines (both timing and issue priority) developed in the California ISO's *Roadmap*, *IEPR*, and CPUC processes. By the second quarter of 2014, the agencies should develop a joint policy document that articulates the resolution of current differences and presents a unified, clearly executable path forward.
- **Improve DR forecasting techniques and methods.** The energy agencies should engage in research and development to improve DR forecasting. Accurate forecasting verified by actual results of DR capability in several time frames, for both planning and operations, is required to ensure that DR resources are integrated as a grid resource. In addition to forecasting capabilities of DR programs, the agencies should support studies to determine areas and end uses with the best DR potential across the state. These findings should then be overlaid with grid needs to prioritize DR resource development.

Gain Customer Acceptance of DR

- **Conduct independent assessment to help advance DR market outreach.** From a system perspective, expanding the customer base is critical to optimize resource availability in specific regions where it is needed for local capacity. At the same time, DR is not well-understood by customers, yet its expansion requires customer comfort and acceptance. An independent entity should assess customers and market sectors most likely and least likely to participate in a range of targeted DR programs, examine existing communication strategies and evaluation reports, develop a set of communication lessons learned and business value cases, and conduct a cost assessment to enable DR across different customer classes, especially for fast-response DR. This effort should begin in the first quarter of 2014.~~by early 2014. This effort should include a cost assessment to enable DR across different customer classes, especially for fast response DR.~~

CHAPTER 3: Bioenergy Status and Issues

Bioenergy in California includes using biomass, biogas, and biomethane to generate electricity (biopower) and produce transportation fuels (biofuels). Bioenergy is renewable energy produced from biomass feedstocks, such as residue from forest management practices and the wood industry, agriculture and food processing wastes, organic urban waste, waste and emissions from water treatment facilities, landfill gas, and other organic waste sources.

California has adopted many policies to promote energy from biomass resources, but there are still challenges, particularly for resources such as biomethane. In 2012, Governor Brown signed Assembly Bill 1900 (Gatto, Chapter 602, Statutes of 2012), which requires the Energy Commission to identify and recommend solutions to challenges that limit procurement of biomethane in California and report on its findings in the biennial *Integrated Energy Policy* Report (*IEPR*). Also, California's Bioenergy Interagency Working Group periodically publishes a "bioenergy action plan" that reviews biomass development and outlines opportunities and challenges, and past *IEPRs* have relied heavily on those documents to report on biomass progress.[47]

This chapter reports on the status of the industry and challenges to operating and developing bioenergy production facilities in California. The Energy Commission held public workshops in May and June 2013 to seek stakeholder input on the status of and opportunities for bioenergy development in California. This chapter summarizes the results of those workshops and subsequent staff analysis.

Biomass Value, Technical Potential, and Development Goals

Bioenergy production can provide value toward achieving California's environmental protection, waste reduction, and greenhouse gas reduction goals, primarily through alternative disposal and treatment options for low-value biomass. Bioenergy production provides additional value by~~can~~ displacing fossil ~~transportation~~ fuels and may be a future source of flexible electricity generation, if ~~cost hurdles~~challenges can be overcome to help manage growth in wind and solar electricity generation.

Despite this value, biomass, as a resource, has a limited availability. This requires prudent policy decisions that make best use of biomass while protecting the environment from

47 Bioenergy Interagency Working Group, *2012 Bioenergy Action Plan*, August 2012, http://www.resources.ca.gov/docs/2012_Bioenergy_Action_Plan.pdf. The Bioenergy Interagency Working Group includes representatives from the California Natural Resources Agency, the Department of Food and Agriculture, the California Environmental Protection Agency, the California Air Resources Board, the California Public Utilities Commission, the California Energy Commission, the Department of Forestry and Fire Protection, the Department of Resources Recycling and Recovery, the Central Valley Regional Water Quality Control Board, and the California Biomass Collaborative.

overharvest. Considering this, the technical potential for biopower~~, however,~~ is relatively small compared to the total California renewable energy ~~electricity generation~~ potential. Table 2 compares the amount of electricity generating capacity theoretically possible given resource availability, geographical restrictions, environmental considerations, and technical limitations for each renewable resource. In these terms, available biomass resources[48] (including solid-fuel biomass residues as well as landfill gas, dairy digester gas, and other sources of biogas) comprise about 0.02 percent of potentially available renewable energy resources for electricity generation in California.

Table 2: California's Renewable Energy Potential

Technology	Technical Potential (MW)
Biomass	3,820
Geothermal	4,825
Small Hydro	2,158
Solar	
Concentrating Solar Power	1,061,362
Photovoltaic	17,000,000
Wave and Tidal	32,763
Wind	
On-shore	34,000
Off-shore	75,400
TOTAL TECHNICAL POTENTIAL	**18,214,328**

Source: California Energy Commission, *Renewable Power in California: Status and Issues* Report

A report by the California Council of Science and Technology[49] found that substantial amounts of low-carbon biofuels are needed to reduce greenhouse gas emission 80 percent below 1990 levels by 2050, even with optimistic assumptions about efficiency, electrification, and use of other renewable energy sources. The study found that in-state supplies of biomass would meet about 7 to 22 percent of 2050 demand in a business-as-usual case and 21 to 61 percent in a more optimistic high-efficiency and electrification scenario. The analysis found that, even with ambitious assumptions about the ability to gather biomass residues for energy production, in-state resources cannot meet demand by 2050.

The California Council of Science and Technology also states that there is a large potential for biomass production on abandoned agricultural and unreserved forested land, which is not included in Table 2. Using this land for energy producing crops can greatly increase the biomass energy potential for 2020 and beyond. However, more analysis is needed to evaluate

48 This analysis included a small amount of energy crops. This does not include potential scenarios that unused marginal farmland in California would be used for energy crops.

49 Heather Youngs and Christopher R. Somerville, California Council on Science and Technology, *California's Energy Future – the Potential for Biofuels*, May 2013, http://www.ccst.us/publications/2013/2013biofuels.pdf.

the environmental and water use impacts as well as quantifying the energy potential of these resources considering economic and technological factors.

The limited resource potential for biomass indicates that bioenergy policy going forward must recognize the limits to energy production from this resource. Prudent bioenergy policy must take a holistic approach to understand future energy sector needs as California transforms its energy infrastructure away from dependence on fossil fuels. In many cases, bioenergy can provide an alternative option that allows existing infrastructure to be used during this transition.

California has had a long-standing commitment to expand in-state bioenergy production through state agency action and production targets, such as the *Bioenergy Action Plan* and Executive Order S-06-06, and California remains committed to developing sustainable bioenergy production facilities. The Energy Commission recommends that biomass use or bioenergy production~~is a limited resource for energy production. There is a desire to move toward biomass~~ goals continue to be aggressive but also consider ~~based on~~ sustainable biomass yield that promotes greenhouse gas reduction, waste reduction, recycling, composting, and environmental protection.

Biomass Collection and Distribution

Much of California's biomass is derived from activities such as harvesting timber, milling lumber, processing food, and collecting residential green waste as well as wildfire prevention, agriculture and dairy operations, and urban forestry. While California has an abundance of biomass and a need for alternative disposal options, the development of new facilities and the operation of existing bioenergy facilities has been curtailed because it is costly to collect and distribute dispersed biomass or the material is not readily available throughout the year.

As an example, wood residues from lumber harvesting or forest thinning are often expensive to procure as a result of costs associated with the collection, processing, and transportation of the feedstock. Collecting wood residues is labor-intensive because the feedstock is widely dispersed. After the wood residues have been piled, processing such as chipping is needed before transporting residues to the facility, typically by large diesel trucks. All together, the logistics of collecting, processing, and transporting wood residues can cost a facility from $45.00 to $60.00 per bone dry ton. If a biopower facility is paid $90 per megawatt hour (MWh) (the initial RE-MAT[50] price is set at $89.23 per megawatt-hour) then one-half to two-thirds of revenue would be needed for solid-fuel biomass collection, processing, and transport alone.

Biomass collected from different activities can provide a range of benefits such as turning a process waste (cost) into a commodity or reduce the environmental impact of current waste disposal options. Some activities, such as fire prevention and forest thinning projects provide unique environmental benefits. Increasing the beneficial collection of biomass from these activities could be enhanced.

50 RE-MAT is the Renewable Market Adjusting Tariff.

There have been a number of market-based attempts to increase funding for the beneficial collection of biomass through electricity rates or other energy projects. Ratepayer advocates and utilities question relying solely on this approach because it puts a burden on investor- owned utility ratepayers to fund activities that benefit society as a whole. Pacific Gas and Electric Company recommends that the state "consider broader policy actions to more fairly allocate the costs of societal benefits associated with bioenergy projects."[51] Alternative approaches are needed, including actions from other state agencies and departments, to help advance projects with multisector environmental benefits.

With historically low natural gas prices and the declining cost of other renewables, it is clear that biomass collection benefits cannot rely on energy sales to fund biomass collection activities. California agencies should take a broad state policy approach to increase beneficial biomass collection, particularly agencies whose mission benefits from the use and disposal of biomass. Through these agencies, programs should be expanded or developed that offset the cost of biomass collection and distribution projects that help achieve their mandate (such as biomass collection projects in high fire threat zones).

Biomass from Forest Management

Disagreement over the environmental benefits of biomass derived from forest management activities also poses a barrier to development of forest-based bioenergy projects. According to the Center for Biological Diversity (CBD), energy from forest biomass "entails potentially significant adverse environmental impacts and costs, particularly with respect to air pollution, greenhouse gas emissions, water supply and quality issues, and effects on forest habitat associated with the harvest and combustion of woody biomass."[52] CBD also raises numerous concerns about greenhouse gas benefits of forest biomass in terms of rate of carbon sequestration and actual emissions.[53]

Proponents of increasing forest management projects state that removing biomass trimmings and brush material following sustainable forestry plans provides many benefits to the ecosystem, as well as greenhouse gas benefits, primarily as a result of improved forest health. Because greenhouse gas emissions from the projects are "biogenic," they are part of the natural carbon cycle.[54] Forestry experts identify significant co-societal benefits associated with the removal of forest biomass in terms of forest health, alteration of fire behavior, water quality,

51 Comments of Pacific Gas and Electric Company on the Draft 2013 Integrated Energy Policy Report, October 29, 2013, http://www.energy.ca.gov/2013_energypolicy/documents/2013-10-15_workshop/comments/.

52 Written comments submitted by Center for Biological Diversity to Docket 13-IEP-1, June 19, 2013. http://www.energy.ca.gov/2013_energypolicy/documents/2013-06-03_workshop/comments/.

53 Written comments submitted by Center for Biological Diversity to Docket 13-IEP-1, June 19, 2013. http://www.energy.ca.gov/2013_energypolicy/documents/2013-06-03_workshop/comments/.

54 Transcript of Energy Commission Staff Workshop on the Status of Bioenergy Development in California, June 3, 2013, Session 3 discussion.

and wildlife. They also point out that biomass from forest management will likely be more expensive feedstock for energy production compared to other biomass sources and other renewables.[55]

There is disagreement on the basis for accounting for sequestration of greenhouse gas emissions from bioenergy. Proponents argue that bioenergy carbon emissions are negligible if the amount of biomass removed from the forest does not exceed growth. Opponents argue that removal of a tree, alive or dead, results in higher carbon emissions in the short term, which can take decades to sequester.

These issues are also being discussed on the federal level. The U.S. EPA is considering the scientific and technical issues associated with accounting for biogenic carbon emissions from stationary sources and has developed a framework to account for those emissions. The report was submitted for peer review to the Science Advisory Board (SAB)[56] and the SAB responded on September 28, 2012, noting several deficiencies in the proposed accounting framework. The SAB provided several recommendations to improve the framework for accounting for greenhouse gas emissions from biopower, including forest-derived woody biomass sources.[57] On November 26, 2013, 41 scientists sent a letter to U.S. EPA urging the agency to revise the final framework as recommended by the SAB to ensure that the regulatory system is science-based.[58]

While the Energy Commission believes that forest biomass harvest can occur beneficially, information using the best science available should be developed considering California's regulatory structure. Research and expert analysis can help address questions, such as what is the maximum amount of biomass that can or should be removed from the forest before it will impact the ability of the forest to act as a carbon sink? Are federal harvest rules adequate for protecting forests from overharvest in the context of California's renewable energy policies? Are protections in place to minimize the risk of overharvest of California's forests?

Biopower Status

Biopower is electricity generated from biomass materials. This section discusses the status, opportunities, and challenges of solid-fuel biomass to biopower conversion technologies and resource applications that are eligible for California's Renewables Portfolio Standard (RPS).[59]

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55 USDA Forest Service, Pacific Southwest Research Station. 2009. *Biomass to Energy: Forest Management for Wildfire Reduction, Energy Production, and Other Benefits.* California Energy Commission, Public Interest Energy Research (PIER) Program. CEC-500-2009-080.

56 U.S. Environmental Protection Agency, *Accounting Framework for Biogenic CO2 Emissions from Stationary Sources*, July 2013, http://www.epa.gov/climatechange/ghgemissions/biogenic-emissions/study.html.

57 http://yosemite.epa.gov/sab/sabproduct.nsf/0/57B7A4F1987D7F7385257A87007977F6/$File/EPA-SAB-12-011-unsigned.pdf.

58 http://switchboard.nrdc.org/blogs/slyutse/41_leading_scientists_call_on.html.

59 This section discusses biomass resources in general assuming that the feedstock is not comingled with ~~are not currently eligible for the state's RPS, such as~~ municipal solid waste ~~using~~ when thermal energy

Feedstocks used to produce biogas or biomethane (such as landfill gas and dairy waste) are discussed separately in this chapter.

Existing Generation

California's fleet of existing solid-fuel biomass facilities, facilities that were online or idle in 2009, is composed primarily of biomass combustion facilities selling power under qualifying facility contracts. Most have operated continually since the 1980s. In recent years, two of California's existing in-state coal facilities converted to 100 percent solid-fuel biomass, with a third due to be 100 percent by the end of 2013. Reportedly, some of the other coal facilities are investigating the feasibility of cofiring with solid-fuel biomass. Since 2009, operating capacity at existing solid-fuel biomass facilities has declined, although two previously idle biomass facilities have successfully restarted operations—SPI Anderson and SPI Sonora.[60] Table 3 summarizes the active and idle capacity of solid-fuel biomass facilities in California.[61]

Table 3: Summary of Existing Solid-Fuel Biomass Facilities

	2009 Capacity (MW)	2012 Capacity (MW)*
Solid-Fuel Biomass	~~757~~ ~~(139 idle)~~618	637
Coal-Biomass Cofiring	0	44
Total	**618~~757~~**	**681**

* The 2012 Capacity estimates do not include biomass capacity from facilities that are not required to, fail to, or inaccurately report solid-fuel biomass generation. These facilities include several small thermochemical conversion projects under 1 MW, existing solid-fuel biomass facilities, and biomass cofired at existing in-state coal facilities. Energy Commission staff estimates that unreported capacity is more than 20~~15~~0 MW.

Source: California Energy Commission Quarterly Fuels Energy Report database

Capacity losses during this period were limited by successful contract price amendment renegotiations between Pacific Gas and Electric Company and many existing facilities. New contract amendments allowed facilities to operate under better price terms through the end of the 30-year contract term and avoid rates set by historically low natural gas prices. However, some facilities retired due to unfavorable economic conditions and unsuccessful attempts to amend power purchase agreements.

New facilities have been proposed and developed. Most proposed facilities are under 3 megawatts and use thermochemical conversion processes to convert solid-fuel biomass to

conversion technologies are ~~not discussed in this report~~used. However, biological conversion or anaerobic ~~technologies~~ digestion of biomass with MSW impurities is included in the discussion in ~~are eligible for the RPS and will be discussed in~~ the Biogas and Biomethane section of this chapter.

60 News10 (ABC), "Sawmill reopens in Sonora," October 12, 2011, http://www.news10.net/news/local/article/158686/2/Sawmill-reopens-in-Sonora, accessed June 20, 2013; also David Branchcomb, Sonora Facility Operator, e-mail correspondence, April 1, 2013.

61 Not including municipal solid waste facilities that may also be converting biomass to electricity.

producer gas.[62] The producer gas can be used to generate electricity or offset on-site propane or natural gas use. Energy Commission staff estimates that at least 3 facilities are operating in California with 10 to 20 additional projects proposed by various groups.[63]

Biopower Opportunities and Challenges

This section ~~describes~~ updates opportunities and challenges related to bioenergy development during predevelopment and operation. A comprehensive list of challenges and opportunities can be found in the 2011 and 2012 *Bioenergy Action Plans.*[64]

Predevelopment: Project Feasibility, Permitting, Regulation, and Financing

~~Much of California's biomass is derived from activities such as harvesting timber, milling lumber, processing food, and collecting residential green waste as well as wildfire prevention, agriculture and dairy operations, and urban forestry. While California has an abundance of biomass and a need for alternative disposal options, the use of biomass for energy production may not be economical because it is costly to collect and distribute the material or the material is not readily available throughout the year. Studies commissioned during the predevelopment stage identify such challenges and are used to identify appropriate development locations.~~

~~As an example, wood residues from lumber harvesting or forest thinning are often expensive to procure as a result of costs associated with the collection, processing, and transportation of the feedstock. Collecting wood residues is labor-intensive because the feedstock is widely dispersed. After the wood residues have been piled, processing such as chipping is needed before transporting residues to the facility, typically by large diesel trucks. All together, the logistics of collecting, processing, and transporting wood residues can cost a facility from $45.00 to $60.00 per bone dry ton.If a biopower facility is paid $90/megawatt hour (MWh) of electricity, one-half to two-thirds of revenue would be needed for solid-fuel biomass collection, processing, and transport.~~

Predevelopment costs for biopower projects can range from $168,000–$765,000, which includes feasibility analysis and California Environmental Quality Act-related (CEQA) activities. CEQA-related costs can cause the greatest uncertainty. Obtaining funding for this range of~~these~~ costs is difficult for small developers and communities. ~~CEQA-related costs can cause the greatest uncertainty.~~ Stakeholders contend that the cost of completing a CEQA analysis dissuades project developers from using precommercial technologies that have not been demonstrated in California. Also, many investors are not willing to finance the planning work under CEQA on an unproven technology or development approach.[65] To address these concerns, stakeholders support developing programmatic environmental impact reports (EIR) for precommercial solid-fuel biomass development. A programmatic EIR developed for dairy digesters in California's

62 Producer gas is composed of carbon monoxide, hydrogen, carbon dioxide, methane, and nitrogen.

63 Phoenix Energy Merced (500 kW); Phoenix Energy Modesto (1 MW); Dixon Ridge Farms 50 kW,

64 http://www.energy.ca.gov/bioenergy_action_plan/

65 Fred Tornatore (TSS Consultants), op. cit., pp. 133-134.

Central Valley has been shown to make the CEQA process more straightforward for small developers.[66]

The cost of financing can also pose a barrier to development. Increasingly, bioenergy developers are transitioning from traditional conversion technologies, such as direct combustion steam turbines, to more efficient and environmentally friendly technologies. Private financers seek a high rate of return on unproven technologies and development strategies, including thermochemical conversion and anaerobic digesters. Therefore, the cost of financing these projects can be much higher than other bioenergy projects. In addition, federal incentives are declining. For instance, the American Recovery and Reinvestment Act 1603 Program[67] that provided large grants in lieu of tax credits for renewable energy property is closed to new applicants.

The CPUC has established funding and ~~is considering~~approved investment plans for a new program to support precommercial clean energy technologies and development strategies. This program, known as the Electric Program Investment Charge (EPIC), is designed to fund research and development, technology demonstration and deployment, and market facilitation. The California Public Utilities Commission (CPUC) has identified the Energy Commission and the state's three largest investor-owned utilities (IOUs) to administer EPIC. The Energy Commission ~~proposed providing~~investment plan provides a minimum of $27 million during the 2012-2014 investment cycle for bioenergy technology demonstration and deployment projects. T~~If the plan is approved and funding is authorized, t~~his funding could help advance the competitiveness of precommercial bioenergy technologies and development strategies. The CPUC approved the Energy Commission's EPIC Investment Plan in November 2013. ~~However, funding will likely be needed from other agencies, too, to help advance projects with multi-sector benefits.~~

Operation: operating costs, market prices, and regulatory changes

Operating costs, market prices, and regulatory changes also make biopower development and operation challenging~~important challenges for biopower~~. The relatively high cost to generate electricity from biomass compared to other renewable electricity sources reduces its ability to compete successfully for power purchase agreements. For example, stakeholders continue to argue that although small biopower projects cost more than other renewable resource facilities, the value that these projects can provide outweighs the cost.[68, 69]

Biomass has had little success competing in the Renewable Auction Mechanism (RAM), a simplified, market-based procurement mechanism for renewable projects sized from 3 MW to

66 Transcript of Energy Commission Staff Workshop on the Status of Bioenergy Development in California, June 3, 2013, comments by Michael Boccadoro (Dolphin Group), p. 137.

67 http://www.treasury.gov/initiatives/recovery/Pages/1603.aspx.

68 Kim Carr, (Sierra Nevada Conservancy), op. cit., p. 165.

69 Michael Boccadoro, (Dolphin Group), op. cit., p. 166.

20 MW.[70] Through the RAM program, the CPUC has directed the investor-owned utilities to procure a total of 1,299 MW of renewable capacity through the RAM process. To date, there have been three RAM auctions yielding one approved bioenergy contract for 4.5 MW out of a total of 695 MW of approved contracts. The lack of bioenergy projects participating in the RAM represents the difficulty of competing against other renewable energy technologies that have lower costs and/or higher subsidies.[71]

The CPUC is also implementing a feed-in tariff (FIT)[72] for investor-owned utilities to procure power from small renewables sized up to 3 MW, including biopower. The FIT program has undergone several legislative revisions since its inception that increased the program goal from 250 MW to 500 MW, increased the maximum eligible project size from 1.5 MW to 3 MW, and expanded the scope to include all investor-owned utility service territories and other renewable energy resources.[73] Under this tariff, IOUs have signed contracts to procure 19.9 MW of renewable capacity from 15 bioenergy projects.

In May 2012, the CPUC adopted a new pricing mechanism for the FIT program that project proponents say sets the price too low to spur development of small biopower technologies.[74] The pricing mechanism is called the Renewable Market Adjusting Tariff (ReMAT) structure and the price will start out at $89 per MWh with the ability to move the price up or down based on market demand or the market price.

In 2012, the Legislature expanded this FIT program to spur development of precommercial small bioenergy projects. Under SB 1122[75] the CPUC is to direct the investor-owned utilities to collectively procure at least 250MW of renewable capacity from bioenergy projects of 3 MW or less. The proceeding to design and implement this portion of the FIT program is underway at the CPUC.[76] Project proponents state if the SB 1122 FIT uses the ReMAT price mechanism, which starts at $89 per MWh, there will be delays of one to three years until the ReMAT price signal is high enough to incentivize development.[77] [78] In November 2013, CPUC staff proposed

70 California Public Utilities Commission, Decision Adopting the Renewable Auction Mechanism, Decision 10-12-048 issued December 17, 2010, http://docs.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/128432.htm and expanded to 1,299 MW by Decision 12-02-035 and Decision 12-02-002.

71 Transcript of Energy Commission Staff Workshop Status of Bioenergy Development in California, June 3, 2013, comments by Michael Boccadoro (Dolphin Group), p. 166.

72 For more information, see http://www.cpuc.ca.gov/PUC/energy/Renewables/hot/SB_1122_Bioenergy_Feed-in_Tariff.htm.

73 Legislation expanding the FIT included SB 380, SB 32, and SB X1-2.

74 Michael Boccadoro (Dolphin Group), op. cit., pp. 145-146.

75 Senate Bill 1122 (Rubio, Chapter 612, Statutes of 2012).

76 For more information, see http://www.cpuc.ca.gov/PUC/energy/Renewables/hot/SB_1122_Bioenergy_Feed-in_Tariff.htm.

77 Michael Boccadoro (Dolphin Group), op. cit., p. 146.

a higher starting price of $124.66 per MWh. CPUC staff argues that to achieve the SB 1122 legislative objective, "the FIT payment rate offered to projects seeking contracts pursuant to SB 1122 must be sufficient to stimulate their development."[79]

A study by Black and Veatch conducted for the CPUC assessed the resource potential, costs, and implementation challenges for the SB1122 FIT program.[80] To analyze potential project development delays, Black and Veatch assumed that the SB 1122 FIT will follow the general criteria in the ReMAT. ReMAT includes viability criteria designed to screen out only the most viable projects. The draft report from Black and Veatch suggests that the screening criteria that pose the greatest challenges for biopower include the requirement that projects be "strategically located."[81] The CPUC has defined "strategically located" to mean "a generator must be interconnected to the distribution system and sited near load, meaning in an area where interconnection of the proposed generation to the distribution system requires $300,000 or less of upgrades to the transmission system." Most of the biomass in California is located in rural regions that may not be located near large load centers. Black and Veatch found very few biopower projects in the current interconnection queue that would pass the requirement that FIT projects be "strategically located."

Also, utilities have stated that biopower interconnection takes longer than other renewable resources, such as solar PV. Biopower that needs synchronous generators, unlike induction generators, must be precisely synchronized with the utility system during operation. This synchronization requires matching the frequency, phase angle, and voltage magnitude in certain parameters at the instant of interconnection of the customer's tie breaker to avoid problems with the generator or utility system equipment.[82] Biopower generators are often much larger than other customer-side-of-meter generation equipment, requiring more analysis and preparation before interconnection to the utility's electricity network.[83] The benefit to the utility is that unlike induction generators, synchronous generators can provide reactive voltage support. In the spring of 2013, Energy Commission staff formed a working group with the CPUC, utilities, project developers, and other interested parties to focus on interconnection challenges that are unique to synchronous generators. The working group has succeeded in opening a productive dialogue between utilities and developers, including providing clarity to

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78 Fred Tornatore, (TSS Consultants), op. cit., p. 129.

79 http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M081/K583/81583311.PDF, p. 45.

80 Black & Veatch, *Draft Consultant Report, Small-Scale Bioenergy: Resource Potential, Costs, And Feed-In Tariff Implementation Assessment*, April 2013, http://www.cpuc.ca.gov/NR/rdonlyres/9ABE17A5-3633-4562-A6DA-A090EB3F6D07/0/SmallScaleBioenergy_DRAFT_04092013.pdf.

81 Public Utilities Code 399.20 (b)(3)

82 Synchronous Generation, conEdison, http://www.coned.com/dg/configurations/synchronous.asp.

83 Written comments submitted by PG&E to Docket 13-IEP-1, June 19, 2013, p. 4.

expensive interconnection upgrade requirements, allowing developers to make better financial decisions about project size and location.

Another challenge is that biopower projects have traditionally operated as baseload generators because boiler technologies that dominate existing biopower generation could not change output quickly to meet fluctuating demand. However, investor-owned utility interest in new baseload energy is limited due to the growing risk of overgeneration. Instead, generation sources that have the flexibility to ramp up and down quickly are increasingly critical to maintain system reliability. As solar distributed generation deployment increases, large daily swings in net load (load minus intermittent generation) are expected to cause overgeneration during the day, even during peak load hours, followed by a sharp drop at night when PV no longer produces energy. To compensate, the system will require more flexible capability by 2015 and beyond.[84] A notable exception is the need to replace baseload capacity in Orange and San Diego Counties in response to the retirement of the San Onofre Nuclear Generating Station. However, developing new biopower facilities in the South Coast Air Quality Management District will be challenging given the scarcity of emission reduction credits for particulate matter and nitrous oxide emissions.[85]

Given the changing needs of the system, new biopower installations that can provide flexible ramping capacity will provide value that could help close the price gap between biopower and other renewable resources.[86] New biopower gasification and digester technologies can ramp up and down quickly.[87] [88] The approach varies by technology; for instance, gas storage is not needed for biopower gasification or other biopower thermochemical conversion technologies.[89] Covered lagoon digesters have a natural storage capability for biogas, and some developers are studying the feasibility of developing peak power digesters.[90] The feasibility will depend on actual prices paid during peak power periods compared to cost recovery,[91] which may be especially challenging given that facilities used to meet flexibility needs may operate only 40 percent of the time.

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84 California ISO, *Comprehensive Forward Capacity Procurement Framework*, February 2013, http://www.caiso.com/Documents/CaliforniaISO-BriefingPaper-LongTermResourceAdequacySummit.pdf.

85 See "Chapter 4: Electricity" subsection "The Need for New Electricity Infrastructure," for more information on this topic.

86 Statement by PG&E at the June 3, 2013, Energy Commission staff IEPR workshop on the status of bioenergy development in California.

87 Michael Boccadoro (Dolphin Group), op. cit., pp. 159-160.

88 Fred Tornatore (TSS Consultants), op cit., p. 159.

89 Fred Tornatore (TSS Consultants), op cit., p. 159.

90 Michael Boccadoro (Dolphin Group), op. cit., pp. 159-160.

91 Fred Tornatore (TSS Consultants), op. cit., p. 159.

~~Forest Biomass Resources~~

~~Disagreement over the environmental benefits of bioenergy also poses a barrier to development. According to the Center for Biological Diversity (CBD), energy from forest biomass "entails potentially significant adverse environmental impacts and costs, particularly with respect to air pollution, greenhouse gas emissions, water supply and quality issues, and effects on forest habitat associated with the harvest and combustion of woody biomass." CBD also raises numerous concerns about greenhouse gas benefits of forest biomass in terms of rate of carbon sequestration and actual emissions.~~

~~Proponents of bioenergy projects state that removing biomass trimmings and brush material following sustainable forestry plans provides many benefits to the ecosystem, as well as greenhouse gas benefits, primarily as a result of improved forest health. Because greenhouse gas emissions from the projects are "biogenic," they are part of the natural carbon cycle.~~

~~There is disagreement on the basis for accounting for sequestration of greenhouse gas emissions from bioenergy. Proponents argue that bioenergy carbon emissions are negligible if the amount of biomass removed from the forest does not exceed growth. Opponents argue that removal of a tree, alive or dead, results in higher carbon emissions in the short term, which can take decades to sequester.~~

~~These issues are also being discussed on the federal level. The U.S. EPA is considering the scientific and technical issues associated with accounting for biogenic carbon emissions from stationary sources and has developed a framework to account for those emissions. The report is under peer review by the Science Advisory Board.~~

~~Further information using the best science available is needed. Research can help address questions, such as what is the maximum amount of biomass that can or should be removed from the forest before it will impact the ability of the forest to act as a carbon sink? Are federal harvest rules adequate for protecting forests from overharvest in the context of California's renewable energy policies? Are protections in place to minimize the risk of overharvest of California's forests?~~

Biofuels Production

Biofuels, which includes renewable gasoline substitutes, diesel substitutes, and biomethane, ~~currently~~ represent the largest category of alternative fuel use in California.[92] In-state production is predominantly ethanol derived from corn grain imported from Midwest farms and biodiesel derived from waste grease and tallow and some imported virgin oils, including palm and soybean oil. However, other fuels such as biomethane, "drop-in" biomass-derived

92As used in the *2013-2014 Investment Plan Update for the Alternative and Renewable Fuel and Vehicle Technology Program*, "gasoline substitutes" refers to any liquid fuel that can directly displace gasoline in internal combustion engines including ethanol and renewable drop-in gasoline substitutes. Similarly, "diesel substitutes" refers to any liquid fuel that can significantly displace diesel including biodiesel, renewable diesel, and renewably derived dimethyl ether (assuming fuel system modifications).

hydrocarbons (renewable diesel and gasoline components) and renewable hydrogen are also being developed.

Ethanol use dominates the biofuels market in California with nearly 1.5 billion gallons consumed in 2012, an increase of nearly one-half billion gallons since 2008, introduced originally for use as a gasoline oxygenate. A small portion is used in E85 sales (a blend of 85 percent ethanol for use in flexible fuel vehicles.) In 2012, 6.5 million gallons of E85 were sold in California.

As reported in the *2011 Bioenergy Action Plan*,[93] the five existing ethanol facilities in California were idle for much of 2009, and only one refinery reported production of ethanol in 2010. Since then, three of the five facilities have begun regular operations. Of the two remaining, one has been shut down and dismantled, and the other is operating intermittently. The increased operation of existing facilities has resulted in a significant increase in biofuel production within California. In 2013, in-state capacity was roughly 220 million gallons (147million gge[94]) per year.

Similar to ethanol, most of the biodiesel consumed in California is blended with conventional diesel (at levels ranging from 5 to 20 percent.) Diesel blend levels for light-duty and passenger vehicles have been limited to 5 percent because equipment manufacturers and companies offering extended warranties on their products are reluctant to guarantee their products using higher biodiesel blends. Recently, major manufacturers including VW and Audi notified vehicle owners that they will accept the use of diesel blends up to a B20 level (about 80 percent conventional diesel and 20 percent biodiesel) without voiding vehicle warranties. The Chevrolet Cruze Diesel will also accept up to B20 blends.

Progress has been difficult to track for biodiesel production. Improvements in estimates of biodiesel data suggest that earlier estimates overstated ~~its use~~production, including estimates reported in the *2011 Bioenergy Action Plan.* While estimates continue to improve, verifiable data sources on California biodiesel production remain unavailable. ~~Table 4 shows various estimates for the number of facilities, capacity, and production for 2009 and 2012.~~

While biodiesel facilities are required to report production totals to the Energy Commission under the Petroleum Industry Information Act,[95] full compliance has been difficult to achieve. Energy Commission staff is working with the California Biodiesel Alliance and the California Air Resources Board (through the Low Carbon Fuel Standard Reporting Tool) to improve the accuracy of future data on biodiesel in California. Initial estimates show that in 2012 there was

93 Garry O'Neill and John Nuffer, *2011 Bioenergy Action Plan.* California Energy Commission, Efficiency and Renewables Division, 2011. Publication number: CEC-300-2011-001-CTF.

94 gge = gasoline gallon equivalents.

95 California Air Resources Board, *LCFS Reporting Tool*, July 2013, http://www.arb.ca.gov/fuels/lcfs/reportingtool/reportingtool.htm.

an installed capacity of ~~over 80~~46 million gallons per year of bio- and renewable diesel production in California.[96] There was about 19.5 million gallons of actual production.

Challenges and Opportunities

In-state ethanol producers (especially start-up companies) continue to face challenges when competing with ethanol derived from Midwest corn and Brazilian sugarcane. Moreover, California has a limited availability of arable lands and feedstock. However, with both federal and state directives driving advances in biofuels, many companies are looking to alternative fuel sources with lower carbon intensities and less feedstock competition.

One example of an alternative feedstock is the use of grain sorghum coupled with biogas. Sorghum was recently qualified as an eligible advanced biofuel under the federal Renewable Fuel Standard (RFS2). The RFS2 allows producers and distributors of alternative fuels to generate and trade renewable identification number (RIN) credits[97] for excess renewable fuels, which may be purchased or sold for compliance purposes.[98] As a result, RIN credits can provide a revenue stream for fuel producers, and sorghum will provide higher RIN credits than conventional corn ethanol now that it is an eligible biofuel under RFS2. Demand for sorghum is very low as it is not found in many food products, making it more economical than corn or sugar feedstocks. The process for using grain sorghum is very similar to that of corn, so producers do not need to make major changes to their equipment to switch to grain sorghum. Furthermore, grain sorghum is very appealing to California farmers because it can be planted in saline soils and requires very little water. Some California ethanol producers have started incorporating grain sorghum into their feedstock.

The number of E85 fueling stations has increased in recent years from 20 in 2009 to 83 stations in 2013.[99] However, high construction costs coupled with uncertainty in demand have hindered additional development in California, despite continuing investments through the Alternative and Renewable Fuel and Vehicle Transportation Program (ARFVTP). E85 sales have consistently grown since 2005 as more stations are installed. In addition, developers and operators are concerned about the profitability of building new fueling stations. To raise

96 Joe Gershen, "California Biodiesel Alliance – Funding Request for AB 118 ARFVTP." Presented at the ARFVT Program Advisory Committee meeting on September 19, 2012. Available at http://www.energy.ca.gov/2012-ALT-2/documents/2012-09-19_meeting/presentations/CBA_Gershen_9-19-2012.pdf.

97 The RIN system allows EPA to monitor compliance with the Renewable Fuel Standard (RFS), a federal program that requires transportation fuels sold in the United States to contain minimum volumes of renewable fuels. http://www.afdc.energy.gov/laws/RIN.

98 California Energy Commission, *2013-2014 Investment Plan Update for the Alternative and Renewable Fuel and Vehicle Technology Program*, May 2013, http://www.energy.ca.gov/2012publications/CEC-600-2012-008/CEC-600-2012-008-CMF.pdf.

99California Energy Commission, *2013-2014 Investment Plan Update for the Alternative and Renewable Fuel and Vehicle Technology Program*, May 2013, http://www.energy.ca.gov/2012publications/CEC-600-2012-008/CEC-600-2012-008-CMF.pdf.

consumer demand for E85, more E85 stations are needed, and the price of ethanol must remain competitive with gasoline.

The biodiesel industry has made progress and overcome most of the fuel quality issues identified in the first generation of biodiesel fuel. The American Society for Testing and Materials has developed a new standard for biodiesel, which producers are meeting already.

While biodiesel can contribute toward reducing the carbon intensity of California's transportation sector, development, infrastructure and production costs continue to be a major challenge. The Energy Commission has funded research, development, and demonstration projects to reduce advanced biodiesel production costs. ~~for algal-based biodiesel production. Biodiesel from algae has long been considered a promising alternative fuel and is a "drop-in" fuel, meaning it can easily replace conventional diesel in vehicles and can use the existing infrastructure.~~ While cost continues to be a major challenge, ~~for this technology as well,~~ there have been some recent projects that were able to successfully reduce costs.[100] ~~More research is needed to fully examine the environmental impacts.~~

Biomethane Production

Biogas is the raw, untreated gas produced during the anaerobic decomposition of 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. Types of biogas and biomethane include landfill gas, anaerobic digester gas, and reformed producer gas from thermochemical conversion processes. Biomass feedstock sources include wastewater treatment plants, dairy and animal waste, agricultural waste, and food processing waste.

Status of Existing Biogas and Biomethane Production

As of 2012 the United States Environmental Protection Agency Landfill Methane Outreach Program reported that landfills in California operate 75 landfill gas-to-electric facilities (299 MW of renewable capacity). There are also 33 landfill gas facilities that have been shut down (81.5MW), 8 landfill gas facilities under construction (53.1MW), and 37 candidate[101] locations.[102] Table 4 summarizes the changes in capacity of operating, nonoperating, and proposed or under-construction facilities, as well as the number of candidate landfills.

100 http://idealab.talkingpointsmemo.com/2012/04/nasa-ready-to-show-off-algae-biofuel-research-project.php and http://abclocal.go.com/kgo/story?section=news/business&id=8884425.

101 The Landfill Methane Outreach Program defines a *candidate landfill* as one that is accepting waste or has been closed for five years or less, has at least one million tons of waste, and does not have an operational or under-construction project; candidate landfills are also designated based on actual interest or planning.

102 U.S. Environmental Protection Agency, *Landfill Methane Outreach Program*, July 2013, http://www.epa.gov/lmop/documents/xls/states/lmopdataca.xls.

Table 4: Changes in Landfill gas facilities operating in California

	Operating MW	Nonoperating MW	Proposed/Under Construction MW	Candidate Landfills #
2009	282	No Data	57	38
2012	299	82	53	37

Source: U.S. EPA Landfill Methane Outreach Program

According to the U.S. EPA's AgSTAR Program, California is the home of 11 operating dairy digester projects that combine for a total of 3.4 MW of renewable capacity, with 9 nonoperational facilities that total 5.9 MW of renewable capacity.[103] California's renewable capacity from dairy digesters has decreased as shown in Table 5.

Table 5: Dairy Anaerobic Digester Gas Projects in California

	Operating MW	Nonoperating MW	Proposed/Under Construction MW
2009	3.9	4.6	4.3
2012	3.4	5.9	0.6

Source: California Energy Commission, U.S EPA AgSTAR

Renewable natural gas or high BTU biomethane can be used as a direct replacement for natural gas in most cases and holds promise for use in California's truck fleet which is an emerging market for natural gas. Trucks represent a smaller amount of fuel use in California than passenger vehicles, but they produce more emissions.[104] Trucks are being incentivized to use natural gas as a fuel through California's Low Carbon Fuel Standards (LCFS) and the higher cost of petroleum compared to natural gas. Although high BTU biomethane has been more expensive to produce than natural gas, it has a lower carbon intensity value (at about 11 to 13 grams of carbon dioxide per megajoule). To improve the commercial viability of high BTU biomethane, the Energy Commission has funded nine production projects through ARFVTP. As of 2013, the Energy Commission has awarded $50 million for these projects.[105]

The use of biomethane in hydrogen fuel production is also being tested. Currently, California has 9 publicly available hydrogen fueling stations, 15 private hydrogen fueling stations, and 16

103 AgStar is a collaborative effort among the U.S. Environmental Protection Agency, the U.S. Department of Agriculture, and the U.S. Department of Energy. http://www.epa.gov/agstar/downloads/digesters_all.xlsx.

104 Transcript of Energy Commission "Staff Workshop Status of Bioenergy Development in California," June 3, 2013, comments by Jim McKinney (California Energy Commission), p. 24.

105 California Energy Commission Alternative and Renewable Fuel and Vehicle Technology Program Project Funding Summary. Some of the funds have been used for developing of current projects or expanding current facilities.

hydrogen fueling stations in development.[106] The ARFVTP has awarded $36.8 million dollars for fueling station infrastructure construction and $2.4 million dollars for demonstration projects since 2013.[107] However the funds have been used only for hydrogen storage tank expansion and refueling equipment; 16 of the fueling stations funded by the Energy Commission have their hydrogen fuel transported by truck, and 1 fueling station has onsite generation through electrolysis.

New Developments

The statutory and regulatory landscape for biomethane projects is undergoing a number of changes. For example, the RPS no longer allows biomethane delivered through the natural gas pipeline to be eligible as a renewable resource unless the project provides environmental benefits to California.[108] Also, the utilities and the CPUC must develop nondiscriminatory open-access pipeline quality standards for biomethane.

In the *2011 Bioenergy Action Plan*, the Energy Commission found that the varying pipeline quality standards and approaches to applying standards were limiting development of pipeline biomethane projects.[109] In addition, statutory restrictions created by statute referred to as "the Hayden Bill"[110] resulted in the exclusion of landfill gas from injection into natural gas pipelines in California. In 2012, the Legislature passed Assembly Bill 1900 (Gatto, Chapter 602, Statutes of 2012), which requires the CPUC to adopt pipeline access rules to ensure gas corporations provide nondiscriminatory open access to the pipeline system for biomethane, regardless of the type or source of the biogas.

In addition to providing biomethane producers open-access to the utility pipeline system, AB 1900 requires the CPUC to develop standards for constituents of concern[111] in biogas to protect human health and pipeline integrity and safety. The CPUC opened Rulemaking 13-02-008 for this proceeding. The bill further requires the Office of Environmental Health and Hazards Assessment and California Air Resources Board to recommend health-based exposure limits and constituents of concern in raw biogas. The agencies released their recommendations to the CPUC on May 15, 2013.[112]

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106 California Fuel Cell Partnership, *Station Map*, July 2013, http://cafcp.org/stationmap#st-map.

107 California Energy Commission, *Alternative and Renewable Fuel and Vehicle Technology Program Project Funding Summary.*

108 Assembly Bill 2196 (Skinner, Chapter 605, Statutes of 2012).

109 California Energy Commission, *2011 Bioenergy Action Plan*, March 2011, http://www.energy.ca.gov/2011publications/CEC-300-2011-001/CEC-300-2011-001-CTF.PDF.

110 Assembly Bill 4037 (Hayden, Chapter 932, Statutes of 1988).

111 *Constituents of concern* are components of biogas that could pose a health risk and that are at levels that significantly exceed the concentrations of those constituents found in natural gas.

112 California Air Resources Board, *Recommendations to the California Public Utilities Commission Regarding Health Protective Standards for the Injection of Biomethane into the Common Carrier Pipeline*, May 2013,

Prior to the passage of AB 1900, the San Diego Point Loma Waste Water Treatment Plant was the only operating project injecting biomethane into a common carrier pipeline in California. The Point Loma Plant was adapted for pipeline injection from a combined heat and power facility that used the biogas produced to offset on-site electricity use and export excess electricity to the grid.[113] About 50 percent of the biogas produced at Point Loma was unused at the site and flared, as it was not economical for the site to produce more electricity due to its size limitations and air pollution regulations.[114] Although the gas flared met the San Diego Air Pollution Control District permit, an added benefit of using the excess methane is that the need to flare is reduced, which reduces local air pollution emissions.

BioFuels Energy, LLC, secured the rights for the biogas produced at the Point Loma plant in 2007 through competitive bidding. The total project cost to build the site was quoted at $45 million and took five years before becoming operational in 2012.[115] The BioFuels Energy process at the Point Loma Wastewater Treatment Plant is composed of two projects. The digester gas is first purified with the use of activated carbon polishing vessels, such that the end product meets SDG&E's Rule 30 pipeline injection standards.[116] [117] During the second part of the process, BioFuels nominates[118] the directed biomethane to the University of California, San Diego, and the City of San Diego South Bay Water Reclamation Plant. BioFuels owns and operates a 2.8 MW fuel cell at the University of California, San Diego; at the South Bay Reclamation Plant,

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http://www.arb.ca.gov/energy/biogas/documents/FINAL_AB_1900_Staff_Report_&_Appendices_%20051513.pdf.

113 City of San Diego, *Point Loma Waste Water Treatment Plan overview*, July 2013, http://www.sandiego.gov/mwwd/facilities/ptloma/index.shtml.

114 BioFuels Energy, LLC., *Point Loma Wastewater Treatment Plant's Beneficial Use of Digester Gas (BUDG) Project with BioFuels Energy, LLC Fact Sheet*, February 2011, http://scap1.org/POTW%20Reference%20Library/BUDG%20Projects%20Fact%20Sheet-SDGE%202-7-11%20(2).pdf.

115 Transcript of Energy Commission Staff Workshop on Challenges to Procuring Biomethane in California, May 31, 2013, comments by Frank Mazanec (Biofuels Energy, LLC.), p 98.

116 Southern California Gas Company, *Rule No. 30, Transportation of Customer-Owned Gas*, July 2013, www.socalgas.com/regulatory/tariffs/tm2/pdf/30.pdf.

117 *Activated carbons* are the adsorbents with the most favorable characteristics for ANG storage because they have a large microporous volume, are efficiently compacted into a packed bed, and can be cheaply manufactured in large quantities. Delavar, M. and A.A. Ghoreyshi, M. Jahanshahi, M. Irannejad, *Experimental Evaluation of Methane Adsorption on Granular Activated Carbon (GAC) and Determination of Model Isotherm.*2010, http://www.waset.org/journals/waset/v38/v38-9.pdf.

118 In this context, *nominate* refers to the producers of the biomethane injecting the gas into the natural gas pipeline. While the gas is physically mixed with other gas in the pipeline, the producer has a contractual agreement to sell the gas to another entity connected to the pipeline system. This arrangement ensures that the "renewable" attributes of the gas are passed to the gas purchasers.

there is a 1.4 MW fuel cell that BioFuels uses. The cleaned biomethane produced from the plant has 98.1 percent average methane content.[119]

In general, one of the challenges facing biomethane production facilities is uncertainty whether biogas upgrading equipment can produce biomethane gas of consistent quality.[120] To address this concern, the Biofuels Energy LLC plant is tested quarterly to ensure its biomethane continues to meet pipeline injection standards.[121]

Using Anaerobic Digesters in Organic Materials Management

The California Integrated Waste Management Act of 1989 requires that landfills divert 50 percent of all solid waste from landfill disposal or transformation, through source reduction, recycling, and composting. Assembly Bill 341 (Chesbro, Chapter 476, Statutes of 2011) updated this goal to require at least 75 percent of all solid waste generated to be source reduced, recycled, or composted by 2020.[122]

According to CalRecycle, about 15 million tons of nonfossil organic material is sent to landfills each year.[123] To achieve the 75 percent waste reduction goal, CalRecycle seeks to increase development of anaerobic digester systems to convert organic waste to energy, compost, and biomethane. CalRecycle seeks to encourage the development of anaerobic digesters by providing funds to develop facilities and to expand existing recycling facilities. CalRecycle has additionally established the Local Enforcement Agency Grant Program to help local agencies with enforcement and inspection of solid waste plants. CalRecycle's Recycling Market Development Program provides loans, technical assistance, and free product marketing to businesses located within a development zone to manufacture products from waste materials.[124]

Challenges and Opportunities for Biomethane Production

Regulatory issues, cost, safety, and technology development issues pose challenges and opportunities for biomethane production in California.

119 Transcript of Energy Commission Staff Workshop on Challenges to Procuring Biomethane in California, May 31, 2013, comments by Mazanec, Frank (Biofuels Energy, LLC.), p. 101.

120 Ibid, Jim Lucas, (Southern California Gas Company) p. 60.

121 Ibid, Mazanec, Frank, (BioFuels Energy LLC), p. 94.

122 Assembly Bill 341 (Hasbro, Chapter 476, Statutes 2011)

123 Cal Recycle, Organic Materials Management: Conversion Technologies, Accessed June 25, 2013, http://www.calrecycle.ca.gov/organics/Conversion/.

124 For more information on the Recycling Market Development Zones Programs, see http://www.calrecycle.ca.gov/RMDZ/.

Regulatory Issues

A common concern that many project developers, utilities, and gas providers have cited is the effect of regulatory uncertainty and the effect of regulation changes on long-term contracts.[125] Uncertainty creates development risk, which increases debt financing costs and may also increase other costs. This uncertainty can jeopardize the viability of a project. For example, while there is little debate that AB 1900 will benefit development of biomethane in California, some have raised concerns regarding the increased costs to meet new biomethane pipeline quality standards.[126]

Contracting terms can aggravate or reduce regulatory uncertainty. Developers have stated concerns that gas utilities are including regulatory "out clauses"[127] in new biomethane contracts to shift regulatory risk from the utility to the developer.

Costs

One of the key challenges of developing biogas has been the cost. Upgrading biogas ~~production facilities produce relatively small quantities of methane, and upgrading biogas~~ to pipeline quality can be expensive and access to pipelines for distribution of ~~biogas~~ biomethane can ~~also~~ pose a challenge. For locations that do not have feasible natural gas pipeline access, the biogas must be used for onsite generation or for transportation biofuels.

Pipeline interconnection costs have been identified by utility and project developers as major challenges contributing to the cost of producing biomethane in California. The pipeline interconnection costs can exceed $3 million,[128] but the cost depends on specifications unique to each project. Lengthy interconnection processes for biomethane facilities further increase costs for project developers. In addition, the feasibility of locating a biomethane facility near a natural gas pipeline depends on the availability of feedstock within a reasonable distance.[129]

Generally, facilities such as dairies, landfills, and wastewater treatment facilities produce biogas as a by-product of normal operation. In most cases, the potential for methane production is

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125 Transcript of Staff Workshop Challenges to Procuring Biomethane in California, May 31, 2013, Comments from Colony Energy Partners, p. 1, http://www.energy.ca.gov/2013_energypolicy/documents/2013-05-31_workshop/comments/Kent_Hawkins_Comment_on_Challenges_to_Bio_Methane_into_Pipeline_2013-06-24_TN-71375.pdf.

126 Comments from Division of Ratepayer Advocates to the California Public Utilities Commission on opening comments to CPUC Rulemaking R. 13-02-008 February 13, 2013, p. 2, http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M062/K909/62909593.PDF.

127 An out clause is a part of an agreement or contract that allows one party to cancel the agreement if the conditions of the clause are met.

128 Transcript of Staff Workshop Challenges to Procuring Biomethane in California, May 31, 2013, comments by Jim Lucas (Southern California Gas Company), p. 49 ; Frank Mazanec (Biofuels Energy LLC), p. 106.

129 Ibid comments by Jim Lucas (Southern California Gas Company), p. 59.

limited by unchangeable factors, such as the volume of a landfill or wastewater treatment plant. Increased production can be possible if the facility can process alternative feedstock within normal operation. Examples can include dairy digesters accepting food waste and wastewater treatment plants codigesting fats, oils, and grease. However, compared to natural gas, these projects will likely continue to be relatively small and will have difficulty absorbing infrastructure capital costs.

Biomethane can be used as a direct replacement for natural gas. However, natural gas prices have been much lower than the production cost of biomethane. For example, the Point Loma Wastewater Plant produces biomethane at roughly $8.50 per mmBTU[130] compared to an average of $4.00 per mmBTU for natural gas. This price disparity, paired with the high cost of interconnection, deters development of new biomethane projects in California.

One way of addressing high production costs of renewables has been through federal and state incentives. However, federal incentives for the production of biomethane and biogas do not benefit pipeline biomethane projects because the incentives are tied only to electricity production. Southern California Gas Corporation stated it has not seen incentives for constructing biomethane production facilities.[131]

Long-term contracts requiring consistent biogas production are preferred over short-term contracts, five years or fewer, which are harder to finance because revenues and costs are harder to forecast. Long-term predictability of RIN and LCFS credits would help bring value to these credits and help provide more incentives for long-term contracts. Although RIN credits are available to renewable natural gas producers, the pricing is uncertain and prices may not be high enough to attract long-term contracts.[132]

Safety

Pipeline safety is another issue for biomethane. Utilities have said that it is imperative to monitor and test biomethane going into their pipelines. While utilities have experience injecting biomethane into their pipelines, they still lack data, especially for interconnections into low-demand pipelines.[133] ~~Some of the utilities also feel that lowering the 990 BTU per cubic foot minimum gross heating value requirement could potentially threaten the pipeline as it goes against standards set by the CPUC.~~Utilities are also concerned that potentially blending

130 Ibid comments by Frank Mazanec (BioFuels Energy, LLC), p. 108.

131 Jim Lucas, Southern California Gas Corporation, Presentation at the California Energy Commission, May 31, 2013, http://www.energy.ca.gov/2013_energypolicy/documents/2013-05-31_workshop/presentations/Jim-Lucas_Southern_California_Gas_Company.pdf.

132 Transcript of Staff Workshop "Challenges to Procuring Biomethane in California," May 31, 2013, presentation by Coalition for Renewable Natural Gas, http://www.energy.ca.gov/2013_energypolicy/documents/2013-05-31_workshop/presentations/Evan_Williams_Impediments_and_Solutions_to_RNG_in_California.pdf.

133 Ibid., comments by Bill Raymundo (Pacific Gas and Electric), p. 63.

noncompliant biomethane with compliant natural gas is unreliable and could damage pipeline integrity and compromise customer safety.[134]

Technology Commercialization Challenges

Not all biogas technologies have not been fully commercialized in California. Some biogas and biomethane technologies are in the research and development phases and need further technological advances to bring down costs; others are ready to enter the market. To enter the market successfully, emerging biogas technologies need additional performance data to help attract financing and build economies of scale that can further reduce installed costs.

Recommendations

Biomass Management

- **Explore all mechanisms to fund biomass collection and distribution.** Solving the cost-allocation challenge for biomass collection and distribution will require development of non-ratepayer-funded mechanisms to mobilize sustainably available sources of biomass feedstock. Various agencies in the Bioenergy Interagency Working Group would play a role, including, California Department of Forestry and Fire Protection, California Air Resources Board, CalRecycle, and the Natural Resources Agency.
- **Develop Aggressive Biomass-Use Goals.** The Energy Commission recommends that biomass use goals continue to be aggressive but also consider sustainable biomass yield, greenhouse gas impacts, reduction of climate risk and increased forest health and resilience, waste reduction, air and water quality benefits, recycling, composting, and environmental protection. Various agencies in the Bioenergy Interagency Working Group would play a role, including California Department of Forestry and Fire Protection, California Air Resources Board, CalRecycle, and the Natural Resources Agency.
- **Develop standards for sustainable forest biomass use.** Further work is needed to analyze existing state and federal forest and wildland protections to ensure that biomass use will not increase net long-term greenhouse gas emissions. Building on the recommendation in the *2012 Bioenergy Action Plan* to establish sustainability standards for forest biomass feedstock, the state should develop a uniform state sustainable forest-biomass usage policy.

Biopower

- **Develop programmatic Environmental Impact Report**. The Bioenergy Interagency Working Group should identify an appropriate funding source for developing a statewide programmatic Environmental Impact Report for thermochemical conversion technologies

134 Comments from Southern California Gas/San Diego Gas &Electric) to the California Energy Commission "Staff Workshop on Challenges to Procuring Biomethane in California," May 31, 2013, p. 1, http://www.energy.ca.gov/2013_energypolicy/documents/2013-05-31_workshop/comments/Southern_California_Gas_and_San_Diego_Gas_and_Electric_Joint_Comments_2013-06-14_TN-71271.pdf.

using biomass. The Environmental Impact Report should focus on streamlining the environmental review process for SB 1122-type projects.

- **Modify procurement practices to develop higher-value portfolio.** Consistent with the recommendation in the *2012 IEPR Update*, the California Public Utilities Commission should modify procurement practices to develop a higher-value portfolio. Procurement decisions should consider an expanded suite of renewable energy benefits, including RPS-eligible facilities that can provide dispatchable and reliable power, integration benefits, reduction in forest fires that threaten public health and safety and damage transmission lines, reduction in transmission and distribution costs, increased investment in disadvantaged communities, and creation of green jobs.

- ~~**Develop sustainability standards for biomass harvest.** The California Air Resources Board and the Department of Forestry and Fire Protection should analyze existing forest and wildland protections to ensure biomass harvest, including biomass harvest for California's renewable energy policies, will not increase net greenhouse gas emissions from California's forests. Also, standards ensuring sustainable biomass harvest should be developed to apply to all biomass harvest, regardless of end use.~~

Biofuels

- **Support research and development for advanced biofuels.** The Energy Commission should continue research and development needed to reduce the cost of algal-based and other advanced biodiesel fuels.

Biomethane

- **Support research and development for pipeline biomethane injection.** The Energy Commission should continue research, development, and demonstration of biogas-to-biomethane technologies and projects that inject biomethane into California's natural gas pipelines. The priority should be research that provides needed data identifying constituents of concern for additional feedstock sources not identified in the California Air Resources Board and Office of Environmental Health Hazard Assessment staff report *Recommendations to the California Public Utilities Commission Regarding Health Protective Standards for the Injection of Biogas into the Common Carrier Pipeline*.[135] Second, the Energy Commission should fund research and development of small-scale biogas conditioning technologies.

135 http://www.arb.ca.gov/energy/biogas/biogas.htm.

CHAPTER 4: Electricity

This chapter highlights energy topics related to California's electricity system. Meeting the State's electricity needs requires extensive planning and coordination between the key agencies charged with managing the electricity system. The chapter opens with a discussion of these efforts, and then reviews the Energy Commission's biennial update to its 10-year forecast of annual electricity consumption and peak demand. This forecast serves as the foundation for many of the analyses contained in the *Integrated Energy Policy Report* (*IEPR*) and plays a prominent role in procurement and transmission planning at the California Public Utilities Commission (CPUC) and by the California Independent System Operator (California ISO). The *2012 IEPR Update* recommended three changes to future forecasts, which are reflected in the 2013 forecast: including climate change effects, disaggregating the forecast down to the climate zone level, and addressing the uncertainty regarding the interaction and implementation of California's policies for zero-emission vehicles, combined heat and power, and distributed generation. The forecast includes multiple scenarios for future demand and additional achievable energy efficiency. Consistent with the Energy Commission, California ISO, and CPUC's commitment to improved coordination, the leaders of these organizations have jointly agreed upon a single managed forecast set to use for statewide planning purposes.~~This chapter also includes an evaluation of the resource adequacy of the publicly owned utilities (POU).~~

When crafting California's energy policy, decision makers must balance system reliability with environmental compliance and reasonable costs. Part of planning for California's energy future is not only anticipating what the future will require, but assessing the current situation and what needs to be done to meet future demand. This includes an evaluation of the resource adequacy of the publicly owned utilities (POU). Also, past *IEPRs* have focused on electricity infrastructure needs in Southern California, and given the recent closure of the San Onofre Nuclear Generating Station (San Onofre), this topic has become even more relevant.

Next, this chapter includes an update of estimates of generation costs for renewable and fossil-fuel generating technologies. The chapter concludes with recommendations addressing the various issues discussed.

Renewed Focus on Interagency Coordination

On January 28, 2013, the Energy Commission, the CPUC, and the California ISO appeared at a legislative hearing called by the Chair and Vice Chair of the California State Senate Committee on Energy, Utilities, and Communications, Senator Alex Padilla and Senator Jean Fuller.[136] The hearing was called to examine how energy efficiency investments can most effectively reduce the need for future power plants and to address the Legislative Analyst's Office's December 19,

136 Background and Agenda for January 28, 2013, Legislative Hearing of the California State Senate Committee on Energy, Utilities, and Communications, http://seuc.senate.ca.gov/sites/seuc.senate.ca.gov/files/01-28-13%20agenda.PDF.

2012, report, which maintained that the three energy agencies lacked a comprehensive framework for fully coordinating state programs and expressed concern over the steady decline of cost-effectiveness in California's IOU energy efficiency programs over the past eight years. Robert Weisenmiller, Chair of the Energy Commission, Keith Casey, Vice President of Markets and Infrastructure Development at the California ISO, and Edward Randolph, Energy Division Director at the CPUC provided testimony.

As a result of the testimony presented, Senators Padilla and Fuller sent a letter[137] asking each of the three agencies to provide specific joint recommendations for policy or legislative changes that would address concerns discussed at the hearing. In their response,[138] the Energy Commission, CPUC, and California ISO addressed each of the issues noted in Senators Padilla and Fuller's original letter as described below.

- How can the joint agencies improve the demand forecast and procurement planning processes to more efficiently reach agreement on how to account for reduced energy demand from energy efficiency?

  Energy Commission/CPUC/California ISO response—The agencies are pursuing several reforms to the demand forecasting process: implementing a joint work plan in each *IEPR* proceeding, modifying existing Energy Commission models to support forecasting at more granular geographic levels in response to the needs of the CPUC and California ISO, developing new modeling methods at the Energy Commission to more robustly capture efficiency impacts, using the Energy Commission's expected mid-case demand forecast, adjusted by the 2012 "low" scenario for incremental uncommitted energy efficiency as the basis for the California ISO's 2013-2014 transmission planning process, agreeing on a single recommended forecast case to be used consistently in the next transmission planning and procurement cycles following the Energy Commission's adoption of the demand and additional achievable efficiency forecasts, and committing to using the current efficiency portfolio cycle to investigate additional planning improvements.

- How can the design, implementation, and coordination of energy efficiency programs be improved so that they best match grid operational requirements, including reliability and local capacity, with consideration of grid impacts from renewable energy and other state energy policies?

  Energy Commission/CPUC/California ISO response—The CPUC, in collaboration with the Energy Commission and California ISO, is exploring a range of approaches to

137 Letter to the Energy Commission, CPUC, and California ISO from Senators Alex Padilla and Jean Fuller, http://seuc.senate.ca.gov/sites/seuc.senate.ca.gov/files/01-28-13%20group%20letter.pdf.

138 Letter from the Energy Commission, CPUC, and California ISO to Senators Alex Padilla and Jean Fuller, http://seuc.senate.ca.gov/sites/seuc.senate.ca.gov/files/CEC%20CPUC%20ISO%20response%20to%20Padilla%20and%20Fuller_02%2025%2013.pdf.

deploy energy efficiency in a manner that best matches grid operational requirements while complying with adopted state energy policies. They are also coordinating to ensure future energy efficiency programs help to reduce the need for generation resources at critical times of the day and year. The Energy Commission and California ISO are planning to develop recommendations that can be used by the CPUC to focus utility efficiency programs on local reliability areas and specific times of day. The CPUC has taken steps toward requiring utilities to procure energy efficiency resources as part of all-source procurement, meaning the utilities would procure efficiency in competition with all other resources and will more accurately balance the grid impacts of all their procurement.

- How can it be ensured that energy efficiency investments will be cost-effective as California increases its focus on "market transformation" efficiency strategies that the CPUC has stated may not be cost-effective, especially in the near term?

  Energy Commission/CPUC/California ISO response—The current CPUC process for determining cost-effectiveness for energy efficiency programs is evaluated through a portfolio approach. Under this approach, while some individual programs might not be cost-effective, the overall investment assures that for every rate payer dollar invested in energy efficiency, ratepayers will save at least $1.25. This allows the CPUC to direct utilities to pursue a variety of market transformation programs whose benefits will take longer to achieve, while balancing these efforts with more immediately cost-effective programs to ensure that the overall portfolio is cost-effective.

  As noted by the Legislative Analyst's Office, the cost-effectiveness ratio has decreased over the past few years. That downward trend is a result of several factors, including an increased size of utility energy efficiency portfolios which have added measures with lower cost-effectiveness, more stringent oversight and monitoring of program evaluations by CPUC staff, and aggressive code and standard efforts which move cost-effective technologies into code more quickly than in the past, reducing cost-effective opportunities for utility voluntary programs.

  The CPUC plans to explore improvements to the cost-effectiveness process, such as potentially adding more locational or shoulder load reduction (hours on either side of peak demand) avoided cost benefits and estimating future benefits of market transformation activities. The goal will be to achieve a high degree of confidence that real benefits to ratepayers are represented.

~~In addition, the CPUC, Energy Commission, and California ISO agreed to increase the transparency of and coordination between their respective procurement and transmission planning processes by using a single demand and additional achievable energy efficiency forecast that will be developed during the *Integrated Energy Policy Report* proceeding. The joint agencies are committed to ongoing coordination and collaboration.~~

Looking beyond 2013, the agencies see three key issues to be addressed in the next collaborative work planning effort:

- Identifying data needs and methods to advance forecast disaggregation to smaller geographic areas than climate zones.
- Increasing the level of confidence in future energy efficiency savings so that efficiency can reduce the need to generate electricity and, under certain circumstances, substitute "for investments in traditional transmission and power generation infrastructure."[139]
- Improving timing and alignment of the demand forecast, energy efficiency funding cycles, measurement and evaluation, and agency planning cycles.

~~Preliminary~~ Forecast of California Energy Demand

The Energy Commission's forecasting process involves continuously developing and refining a suite of end-use and econometric models, as well as collecting and analyzing the data required to populate and run those models. Through decades of forecasting, the Energy Commission has compiled a wealth of historical information about annual retail sales and hourly electric loads, economic and demographic trends, building characteristics, the number and efficiency of appliances in the market, and daily temperature statistics, as well as demand-side management program effects and evaluation data.

Staff uses these data not only to draw a realistic picture of California's energy needs over the next decade, but to create a versatile planning tool that can be used in as many applications as needed. Toward that end, staff regularly meets with the Demand Analysis Working Group (DAWG), a group of stakeholders and organizations with an interest in the demand forecast. A primary goal of the technical advisory group is to help staff understand how the forecast is used outside the Energy Commission. The DAWG also assists in procuring additional data, comparing alternative forecasts, vetting new modeling approaches, identifying emerging problems, and brainstorming possible solutions.

Much of the work on the *2013 IEPR* forecast relates to three issues. Since the *IEPR* forecast is intended to be used to develop energy policy that ensures reliable and affordable energy amid a changing climate, staff must continue to refine its analysis of ways in which demand may be impacted by climate change. Also, because it plays a central role in California's energy system planning, it is critically important that the forecast reflect realistic assumptions concerning California's top priority preferred resources — particularly energy efficiency — and that these assumptions are consistent with those used by the CPUC and the California ISO. Finally, to identify preferred renewable development zones throughout California and improve distribution system planning, Energy Commission staff is following up on a recommendation from the *2012 IEPR Update* to further disaggregate the demand forecast at a finer geographic resolution.

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139 California ISO, *Demand Response and Energy Efficiency Roadmap: Making the Most of Green Grid Resources* Draft, June 12, 2013.

Below is a summary of the work done to address these issues as well as the work still left to do. More details are available in the *California Energy Demand* Final ~~Preliminary~~ *Forecast 2014-2024* (*CED 2013*).[140]

Updates to the Forecast

Routine changes to the forecast include updating historical energy data. The previous long-run forecast, *CED 2011*, was based on 2011 peak demand and 2010 energy consumption. For the current forecast, staff added 2012 peak data and 2011 and 2012 energy consumption data to the historical series such that 2013 is the first forecast year for both peak demand and consumption.

As with previous demand forecasts, *CED 2013* presents three demand scenarios: high, mid, and low. These scenarios are derived by varying key input assumptions. Relative to the mid demand scenario, for example, the high demand scenario incorporates higher levels of economic and demographic growth, lower estimates of future efficiency and distributed generation impacts, and lower electricity prices. Structurally, these scenarios are similar to those developed for *CED 2011*; however, these key inputs have been updated to reflect the latest available data. Staff presented the details of these scenarios at a public workshop on February 19, 2013.

For the *2013 IEPR* cycle, staff expanded its suite of econometric models to include a model for each customer sector. This means that forecasts were developed in two ways: through the Energy Commission's existing models and through econometric models. Existing models were adjusted based on the econometric estimations, with the results compared to econometric results. In addition, staff is developing a new industrial end-use energy model that, although not yet complete, is far enough along to use in *CED 2013*.

Staff also developed a predictive model for the commercial sector that projects adoption of photovoltaic and combined heat and power systems to replace the simple trend analysis used in previous forecasts. This effort was based on methods used by the United States Energy Information Administration, as part of its National Energy Modeling System, and by the National Renewable Energy Laboratory. ~~Staff is developing a predictive model for commercial photovoltaic adoption as well.~~

Recognizing the importance of climate change considerations in planning California's energy future, staff continues to explore the potential impacts of climate change on energy demand. This forecast incorporates effects on both electricity consumption and peak demand using temperature scenarios from the Scripps Institution of Oceanography.

As part of the continuing effort to capture comprehensively the effects of energy efficiency initiatives, *CED 2013* incorporates recent revisions to Energy Commission building codes and appliance standards. These revisions include projected effects from the 2013 updates to the Title 24 building standards and the battery charger standards that will be implemented in 2014. The forecast also updated utility program effects to include projected savings from the 2013-2014

140 http://www.energy.ca.gov/2013_energypolicy/documents/#12112013.

CPUC efficiency program cycle for investor-owned utilities (IOUs) and from 2013 programs for the POUs.

Because stakeholders have expressed a strong interest in a more disaggregated demand forecast to better inform resource and infrastructure-related analyses and decisions, staff developed results at the climate zone level in addition to the usual planning area forecasts. This is a first step toward potential further disaggregation in the future. The appropriate level of disaggregation for future forecasts given data and other resource constraints will be determined after further discussion with stakeholders and Commissioners.

Statewide Forecast Results

Each new *IEPR* forecast differs from the last, reflecting recently recorded historical information, new economic and demographic projections, updated model parameters, and new analysis regarding demand modifiers such as energy efficiency, distributed generation, demand response, climate change, and electrification. A detailed description of each forecast component is available in the ~~preliminary draft~~final forecast report.[141]

Table 6 compares the *CED 2013 Final* baseline forecast for selected years with the *CED 2011* mid demand case. For statewide electricity consumption, the new forecast begins about 0.3~~1~~ percent below *CED 2011* in 2012, reflecting actual economic growth in California that was lower than predicted. Consumption in the new mid scenario grows at a slower rate through 2022 compared to the *CED 2011* mid case as a result of lower projected population growth, higher projected price effects, and the introduction of updated Title 24 and new Title 20 standards during the forecast period. By 2022~~0~~, consumption is around 1.4 percent lower. The high demand case, with higher projected growth in consumption, matches the *CED 2011* mid case by 2016~~22~~. Statewide noncoincident,[142] weather-normalized[143] 2012 peak demand is almost 3 percent lower than predicted in the *CED 2011* mid case but grows at a slightly higher rate from 2012 – 2022~~and grows at a slower rate from 2012-2022 for the same reasons as consumption, although the difference in growth rates is not as large~~.

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141 http://www.energy.ca.gov/2013_energypolicy/documents/#12112013.

142 The state's coincident peak is the actual peak, while the noncoincident peak is the sum of actual peaks for the planning areas, which may occur at different times.

143 Peak demand is weather-normalized in 2012 to provide the proper benchmark for comparison to future peak demand, which assumes either average (normalized) weather or hotter conditions measured relative to 2012 due to climate change.

Table 6: Comparison of Statewide Energy Demand Scenarios

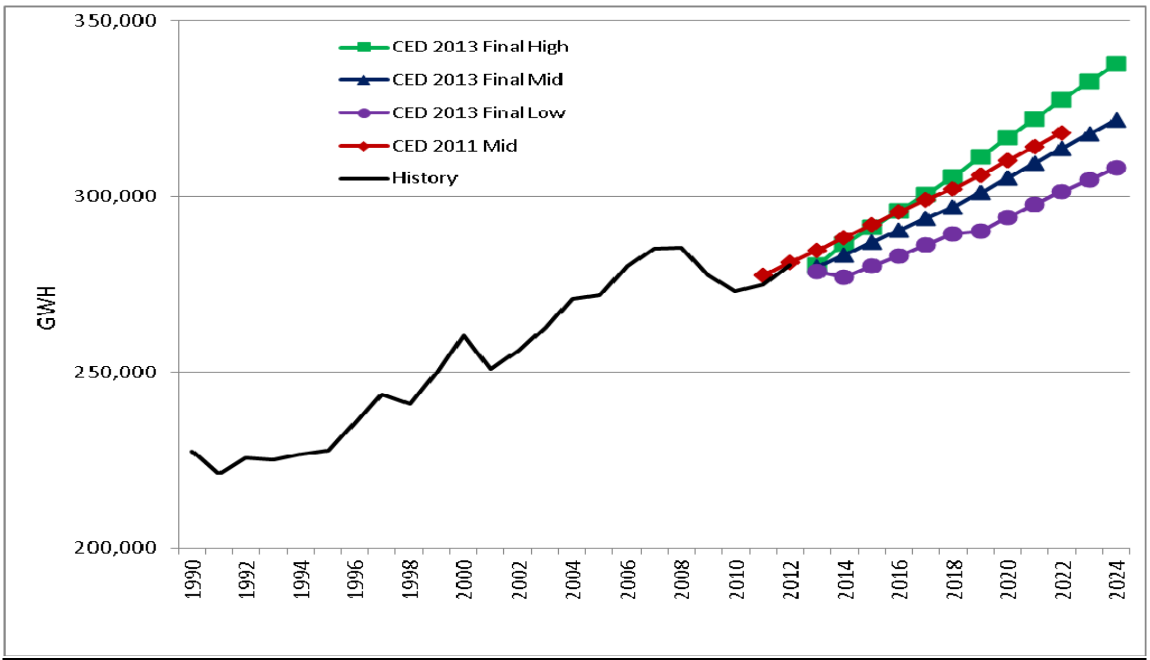
Consumption (GWh)				
	CED 2011 Mid Energy Demand	**CED 2013 ~~Preliminary~~ Final High Energy Demand**	**CED 2013 ~~Preliminary~~ Final Mid Energy Demand**	**CED 2013 ~~Preliminary~~Final Low Energy Demand**
1990	227,586	227,576	227,576	227,576
2000	261,381	260,399	260,399	260,399
2012	281,347	280,561	280,561	280,561
2015	291,965	291,307	287,104	280,314
2020	310,210	316,874	305,218	294,056
2024	--	337,713	321,734	308,277
	Average Annual Growth Rates			
1990-2000	1.39%	1.36%	1.36%	1.36%
2000-2012	0.62%	0.62%	0.62%	0.62%
2012-2015	1.24%	1.26%	0.77%	-0.03%
2012-2022	1.20%	1.56%	1.12%	0.72%
2012-2024	--	1.56%	1.15%	0.79%
Noncoincident Peak (MW)				
	CED 2011 Mid Energy Demand	**CED 2013 ~~Preliminary~~Final High Energy Demand**	**CED 2013 ~~Preliminary~~Final Mid Energy Demand**	**CED 2013 ~~Preliminary~~Final Low Energy Demand**
1990	47,546	47,543	47,543	47,543
2000	53,700	53,702	53,702	53,702
2012	--	59,931	59,931	59,931
2012*	61,796	59,811	59,811	59,811
2015	65,036	64,221	63,413	61,221
2020	69,418	70,121	67,550	64,306
2024	--	74,278	70,495	66,445
	Average Annual Growth Rates			
1990-2000	1.22%	1.23%	1.23%	1.23%
2000-2012	1.18%	0.90%	0.90%	0.90%
2012-2015	1.72%	2.40%	1.97%	0.78%
2012-2022	1.38%	1.91%	1.46%	0.92%
2012-2024	--	1.82%	1.38%	0.88%
Historical values are shaded. Weather normalized: *CED 2013 ~~Preliminary~~ Final* uses a weather-normalized peak value derived from the actual 2012 peak for calculating growth rates during the forecast period				

Source: California Energy Commission

The historical data used for the 2013 forecast differ slightly from *CED 2011* to reflect staff's effort to improve classification of data submitted by utilities. In addition, continuing review of self-generation data has found cases where onsite consumption was improperly estimated.

Figure 4 shows statewide historical electricity consumption, projected *CED 2013* consumption for the three scenarios, and the *CED 2011* mid demand consumption forecast. Growth is flat or declining in 2013 in the new forecast because (1) the number of warm days—those that lead to greater air conditioning usage—was historically high in 2012, and the forecast assumes average weather in 2013; (2) new efficiency programs not included in *CED 2011* are introduced by utilities; and (3) price effects from 2012 to 2013. *CED 2013* consumption grows at a faster average annual rate from 2012 to 2022 in the high case (1.7~~3~~4 percent) at about the same rate in the mid case (1.27 percent), and at a slower rate in the low scenario (0.88 percent) compared to *CED 2011* mid case (1.24 percent).~~and a slower rate in the mid scenario (0.93 percent) relative to *CED 2011* mid case (1.20 percent).~~

Figure 4: Statewide Annual Electricity Consumption

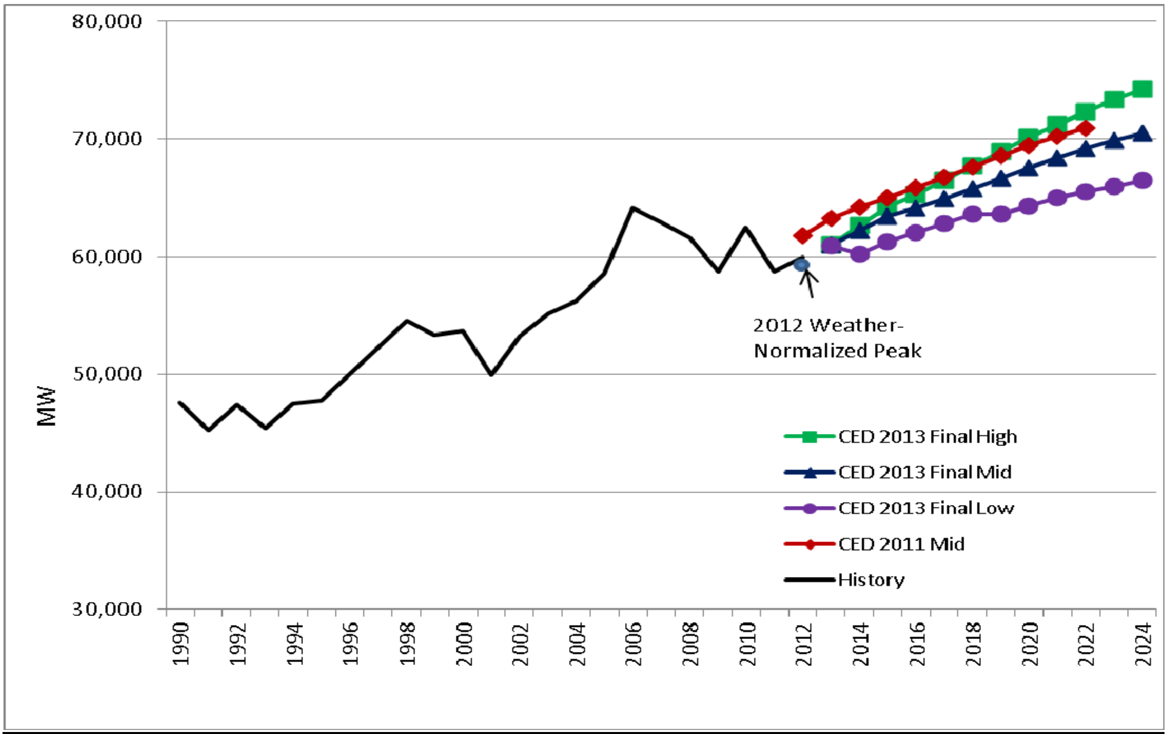


Source: California Energy Commission

Figure 5 compares *CED 2013* statewide noncoincident peak demand with the *CED 2011* mid demand case. Actual peak demand in 2012 was lower than projected in the *CED 2011* mid case, reflecting slower economic growth than was predicted in 2011. There is little growth in all three scenarios from 2012-2013, a result of efficiency improvements in 2013, price effects, and low economic growth. By 2022, the new mid case is almost 4 percent below the previous. With smaller price effects over the forecast period and higher population growth, the *CED 2013* high case reaches the *CED 2011* mid case level by 2022.

Figure 5 also shows the statewide weather-normalized peak in 2012. This is typically a very important point, since growth rates in the forecast period are calculated relative to this weather-normalized total. In *CED 2011*, for example, peak temperatures in the base year were actually relatively mild, so the peak forecast started from a weather-normalized value that was about 1,600 MW higher than the actual recorded peak. This *IEPR* forecast, however, uses 2012 as its base year. While 2012 was fairly warm overall, the highest temperatures were relatively normal, so the adjusted total is very close to the actual peak.

Figure 5: Statewide Annual Noncoincident Peak Demand



Source: California Energy Commission

The Impacts of Climate Change

CED 2013 estimates the effects of potential climate change for both energy (electricity and natural gas) and electricity peak demand. Energy effects are estimated through changes in the number of annual heating and cooling degree days,[144] while peak demand impacts are simulated through increases in annual maximum daily average temperatures.

Electricity consumption is affected by both heating and cooling degree days. The effect of increases in the average annual number of cooling degree days as a result of climate change is tempered, though, by a decreasing average number of heating degree days since both minimum and maximum temperatures increase.

To gauge the potential effect of climate change on annual degree days and average temperatures through 2024, staff used a 2012 update of a climate change impact assessment by

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144 Heating and cooling degree days measure the difference between daily average temperature and a reference temperature (for example, 65 degrees) summed over all days in 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.

the California Climate Change Center, sponsored by the Energy Commission.[145] The update uses 24 climate change simulations for California consisting of two scenarios for each of 12 models, providing simulation results for daily maximum and minimum temperatures, average daily humidity, and sea-level rises through 2099.

Staff chose climate change scenarios that resulted in an average temperature impact over all scenarios for the mid demand case and a relatively high temperature impact for the high demand case.[146] The low demand scenario does not include climate change impacts. Staff converted simulated daily averages for each weather station to degree days and temperature indices for each planning area by weighting each climate zone either by estimated number of air conditioners (temperature and cooling degree days) or population (heating degree days). Changes in annual degree days and maximum temperatures starting in 2013 were derived using long-term trends (2010-2040) from the two climate scenarios.[147]

Table 7 shows the projected impacts of climate change in the mid and high demand scenarios on electricity consumption for the five major planning areas[148] and for the state as a whole. By 2024, statewide consumption impacts reach almost 1,2~~3~~00 GWh in the mid demand case and almost 1,700 ~~more than 1,800~~ GWh in the high demand case. Also shown are the simulated annual heating and cooling degree days (weighted by climate zone) for the two climate change scenarios used. Degree days in 2012 represent a historical 30-year average for the planning area.

These consumption increases described above and shown in Table 8 are *net* impacts, representing increasing electricity consumption from cooling minus reduced usage from less heating need. Heating impacts are typically 10-40 percent of cooling increases, depending on the planning area and year. For example, in the mid case, the roughly 1,2~~3~~00 gigawatt hours (GWh) of net consumption impacts represent an expected ~~1,500 GWh~~ increase in consumption of more than 1,400 GWh due to greater cooling loads, which is offset somewhat by an expected decrease in consumption of around 250 GWh due to less heating. For the state as a whole, the largest portions of the consumption increase come from the commercial sector since the effect from warmer temperatures is not mitigated by decreasing heating degree days, as in the residential sector.

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145 California Energy Commission, *Climate Change Scenarios and Sea Level Rise Estimates for the California 2008 Climate Change Scenarios Assessment*, March 2009, CEC-500-2009-014-D, http://www.energy.ca.gov/2009publications/CEC-500-2009-014/CEC-500-2009-014-D.PDF.

146 Staff wishes to thank Mary Tyree at the Scripps Institute of Oceanography for providing the simulation data.

147 A long-term trend was used rather than the actual temperatures in each scenario because year-to-year fluctuations simulated in the climate change models sometimes resulted in degree days or maximum temperatures in 2024 as low as or lower than in 2012.

148 Los Angeles Department of Water and Power (LADWP), Pacific Gas and Electric (PG&E), Southern California Edison (SCE), San Diego Gas & Electric (SDG&E), and Sacramento Municipal Utility District (SMUD)

Table 7: Projected Electricity Consumption Impacts From Climate Change by Scenario and Planning Area

		Mid Demand Scenario		High Demand Scenario			
		Annual Cooling Degree Days (65° reference)	Annual Heating Degree Days (65° reference)	Annual Cooling Degree Days (65° reference)	Annual Heating Degree Days (65° reference)	Consump. Impact, Mid Scenario (GWh)	Consump. Impact, High Scenario (GWh)
LADWP	2012	1,275	1,410	1,275	1,410	--	--
	2015	1,310	1,382	1,343	1,339	25	43
	2020	1,369	1,334	1,458	1,219	68	116
	2024	1,417	1,296	1,550	1,123	104	171
PG&E	2012	1,387	2,464	1,387	2,464	--	--
	2015	1,424	2,432	1,442	2,389	108	138
	2020	1,484	2,379	1,533	2,264	298	379
	2024	1,533	2,336	1,606	2,164	457	574
SCE	2012	1,536	1,381	1,536	1,381	--	--
	2015	1,577	1,350	1,608	1,307	87	129
	2020	1,645	1,299	1,729	1,182	240	339
	2024	1,700	1,257	1,826	1,082	365	497
SDG&E	2012	800	1,177	800	1,177	--	--
	2015	840	1,137	876	1,101	48	83
	2020	906	1,070	1,002	974	128	211
	2024	960	1,016	1,103	872	190	300
SMUD	2012	1,267	2,586	1,267	2,586	--	--
	2015	1,307	2,565	1,332	2,523	16	23
	2020	1,374	2,529	1,441	2,417	43	63
	2024	1,428	2,501	1,528	2,332	66	95
State	2015	--	--	--	--	288	426
	2020	--	--	--	--	790	1,133
	2024	--	--	--	--	1,198	1,676

Source: California Energy Commission

Table 8 shows the projected impacts of climate change in the mid and high demand scenarios on peak demand for the five major planning areas and for the state as a whole. By 2024, statewide peak impacts reach ~~more than 1,000~~950 MW in the mid demand case and around 1,5~~7~~50 MW in the high demand case. Also shown are the simulated annual maximum temperatures in degrees Fahrenheit for the two climate change scenarios used. Temperatures in 2012 represent a historical 30-year average for the planning area.

Table 8: Projected Peak Impacts From Climate Change by Scenario and Planning Area

		Annual Maximum Temperature (°F), Mid Demand Scenario	Annual Maximum Temperature (°F), High Demand Scenario	Peak Impact, Mid Scenario (MW)	Peak Impact, High Scenario (MW)
LADWP	2012	83.5	83.5	--	--
	2015	83.8	84.0	21	37
	2020	84.3	84.8	61	107
	2024	84.6	85.4	95	169
PG&E	2012	85.7	85.7	--	--
	2015	86.0	86.1	83	123
	2020	86.4	86.7	239	360
	2024	86.8	87.3	377	569
SCE	2012	85.8	85.8	--	--
	2015	86.0	86.2	78	121
	2020	86.5	86.8	225	358
	2024	86.8	87.4	355	570
SDGE	2012	78.0	78.0	--	--
	2015	78.2	78.4	16	28
	2020	78.6	79.0	45	82
	2024	78.9	79.6	72	131
SMUD	2012	85.2	85.2	--	--
	2015	85.4	85.6	7	17
	2020	85.7	86.3	21	50
	2024	85.9	86.8	33	80
State	2015	--	--	209	334
	2020	--	--	604	982
	2024	--	--	950	1,559

Source: California Energy Commission

As part of a continuous effort to refine and improve the Energy Commission's forecasting methods, staff plans to further analyze how climate change might affect the distribution of temperatures and therefore the relationship between "1 in 10" (extreme weather) and "1 in 2" (normal weather) peak demand. This is a particularly important consideration since resource adequacy requirements for load-serving entities are determined using a 1-in-10 peak forecast.

Energy Efficiency Considerations

Energy Commission demand forecasts seek to account for efficiency and conservation reasonably expected to occur. Traditionally, staff has included in the baseline demand forecast only those efficiency initiatives deemed "committed." Committed initiatives include utility and public agency programs, codes and standards, legislation and ordinances that have final authorization, firm funding, and a design that can be readily translated into characteristics that can be evaluated and used to estimate future impacts. Committed impacts also include price and other effects not directly related to a specific initiative.

While this *IEPR* continues that distinction, staff has developed "additional achievable" energy efficiency savings estimates to be used with the forecast. Additional achievable energy efficiency savings are those that are not included in the baseline demand forecast but are still likely to occur given current state, federal, and local government policies. These estimates are based largely on the CPUC's forthcoming *2013 California Energy Efficiency Potential and Goals Study*, which is expected to be considered as part of Rulemaking 13-11-005.

~~This effort will involve Energy Commission, CPUC, and California ISO staff and is critical in developing a "managed" forecast for procurement, transmission need, and resource adequacy purposes. As documented in the joint agency letter to Senators Padilla and Fuller, the agencies are working together in this and future *IEPR* cycles to arrive at a recommended forecast that encompasses both the Energy Commission-adopted electricity demand forecast and the Energy Commission-adopted additional achievable energy efficiency forecast. This coordinated effort will ensure that energy efficiency is properly and consistently accounted for by each of the planning agencies.~~

Transportation Electrification Considerations

CED 2013 incorporates scenarios for electric vehicle (EV) fuel consumption based on those developed by the Energy Commission in early 2012 for use in *CED 2011*.[149] Staff updated these projections by incorporating the latest California sales numbers for EVs and considering the latest information on credit allowances available within the California Air Resources Board's Zero-Emission Vehicle (ZEV) mandates. ~~Revised CED 2013 current electricity and natural gas demand forecasts include additional demand from plug-in electric and natural gas vehicles. The transportation energy demand forecast currently included is identical to that produced for the CED 2011.~~ The low electricity demand case incorporates projections ~~which~~ that are based on the most likely compliance scenario of the California Air Resources Board (ARB) Zero Emission Vehicle[150] regulation~~'s most likely compliance scenario~~. Although this estimate is based upon a number of assumptions, it reflects the ARB's attempt at producing a reasonable compliance future. The mid and high electricity demand cases contain additional electricity consumption significantly exceeding the ARB's regulations. ~~Transportation natural gas demand grows slightly over the forecast period and primarily reflects existing market technology penetrations.~~

California ports are becoming more regulated as the state moves toward lower emission activities throughout the transportation sector including all areas of goods movement. The December 2007 adoption of the At-Berth Regulations[151] by the ARB implements provisions of the 2006 Goods Movement Emission Reduction Plan aimed at reducing emissions from

149 California Energy Commission, June 2012, *California Energy Demand 2012 – 2022 Final Forecast*, CEC-200-2012-001-CMF, Volume I, pp. 38-41, http://www.energy.ca.gov/2012publications/CEC-200-2012-001/CEC-200-2012-001-CMF-V1.pdf.

150 Currently under the Air Resources Board's Advanced Clean Car program, http://www.arb.ca.gov/msprog/zevprog/zevprog.htm.

151 At-Berth Regulations refer to adopted regulations titled "Airborne Toxic Control Measure For Auxiliary Diesel Engines Operated On Ocean-Going Vessels At-Berth in a California Port" adopted in 2007.

container, passenger, and refrigerated cargo vessels docked at California ports.[152] The regulations specifically require obligated vessels to use electric shore power to perform services that would normally be provided by onboard auxiliary diesel engines or to implement other equivalent emission-reduction strategies.[153] ~~The revised~~ *CED 2013* includes demand anticipated by the implementation of these regulations.

A More Disaggregated Forecast

Staff intends to provide, to the extent possible, more granular results in future demand forecasts. An important reason is to support subregional electricity system analysis for CPUC/California ISO resource adequacy and other related proceedings. Staff currently separates the planning area and climate zone forecasts to correspond to transmission control areas and congestion zones[154] in a "top-down" analysis. Disaggregation of the demand forecast beyond the climate zone level would allow more refined, "bottom-up" analyses for local congestion zones.

Table 9 shows the forecast results for electricity consumption and peak demand by climate zone for the mid demand scenario. For each planning area, the fastest growth in both consumption and peak demand is projected to be inland. These results reflect expected resumption of migration from coastal to inland areas, migration that decreased during the recent recession. Potential climate change impacts contribute to faster peak demand growth in the inland climate zones as well.

Separating the forecast by climate zone is only a first step. The further it can be disaggregated, the more useful the forecast will be for resource and transmission planning, particularly as those activities shift away from traditional considerations—power plants and transmission lines—to preferred resources such as targeted efficiency, demand response, and distributed generation.

As mentioned, future *IEPR* forecasts will be disaggregated at some level to better support planning efforts. That exact level of granularity will be determined by the joint energy agencies and the availability of data to support granular models. Likely, this will be an extended effort that advances incrementally over multiple *IEPR* cycles.

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152 http://www.arb.ca.gov/ports/shorepower/finalregulation.pdf.

153 Existing fleets opting for the alternative compliance methodology are currently using shore power solutions but may alter their compliance strategy in the future. Personal communication with Jonathon Foster, California Air Resources Board, August 30, 2013.

154 A *congestion zone* is an area with concentrated load, where transmission within the area is not sufficient to allow access to competitively priced energy.

Table 9: Consumption and Peak Demand by Climate Zone

	PG&E					SCE				LADWP	
	1	2	3	4	5	7	8	9	10	11	12
	Consumption (GWh)										
2013	4,924	10,273	31,572	38,477	24,387	6,373	38,616	28,187	26,579	8,503	16,553
2024	5,546	12,299	37,751	43,531	27,572	7,692	42,549	32,437	31,824	9,356	18,806
Avg. Growth 2013-2024	1.09%	1.65%	1.64%	1.13%	1.12%	1.72%	0.89%	1.29%	1.65%	0.87%	1.17%
	Peak Demand (MW)										
2013	970	2,395	7,135	7,098	5,318	723	8,356	5,431	7,379	1,715	4,066
2024	1,088	2,884	8,666	8,095	5,886	935	9,355	6,268	8,857	1,915	4,630
Avg. Growth 2013-2024	1.05%	1.70%	1.78%	1.20%	0.93%	2.36%	1.03%	1.31%	1.67%	1.01%	1.19%

Source: California Energy Commission

Choosing the Single "Managed" Demand Forecast

The Energy Commission, the CPUC, and the California ISO have been actively engaged in collaborative discussion on how to consistently account for reduced energy demand from energy efficiency in their planning and procurement processes to offset the need for additional generation and transmission infrastructure. The Energy Commission's demand forecast is the first step in these planning processes.

The Energy Commission adopted the *CED 2013* at its December 11, 2013, Business Meeting. The adopted forecast contains three baseline cases (high, mid, and low) and five scenarios of additional achievable energy efficiency (high, high-mid, mid, low-mid, and low). The three middle additional achievable energy efficiency (AAEE) scenarios all share common economic-demographic, building stock and price assumptions with the mid base case to provide consistent alternatives for planning purposes. For good reasons, the single forecast for planning and procurement is not, in fact, a single number, but a set of forecast numbers drawn from the adopted *IEPR* forecast report. The single forecast set for generation and transmission infrastructure planning is a combination of two components: (1) a base case from the *CED* with its weather variants (likelihood of normal to more extreme temperatures) and (2) one or more scenarios of AAEE. This combination is also referred to as a "managed" demand forecast.

As part of the *CED 2013* adoption process, the Energy Commission requested stakeholder input into the choice of a baseline case and one or more scenarios of AAEE for use in long-term planning. Sempra Utilities, SCE, and Natural Resources Defense Council/Sierra Club provided docketed comments; PG&E, SCE, and Natural Resources Defense Council~~NRDC~~ made oral comments at the Business Meeting. Most parties suggested the mid case baseline forecast be used for planning purposes. From among the AAEE scenarios, the mid scenario was recommended most often, especially for general or system planning purposes. Only SCE suggested a combination of a high baseline case and a low AAEE scenario to match what was originally considered to be an understated peak forecast. Parties also recognized that different combinations could be important for more localized planning areas.

Leadership from the Energy Commission, in consultation with the CPUC and the California ISO, carefully considered public input in selecting a managed demand forecast. The selected base case will be the mid demand case for the combined IOU service areas that comprise the California ISO balancing area. The mid case includes variants for different weather conditions, all of which have consistently been used in transmission and procurement planning as follows:

- 1 year in 2 weather conditions – used for system flexibility studies
- I year in 5 weather conditions – used for public-policy transmission assessments and bulk systems studies
- 1 year in 10 weather conditions – used for local capacity requirements and local reliability studies

The Energy Commission, CPUC, and California ISO leadership agree that the same AAEE scenario should, in principle, be applied to all of the analyses listed above. However, the ability to characterize and assign the locational attributes of the demand forecast, procurement authorizations, and transmission additions is still evolving. Therefore, agency leadership recommends using the mid AAEE forecast scenario for system-wide and flexibility studies for the upcoming 2014-2015 LTPP and TPP cycles. Because of the local nature of reliability needs and the difficulty of forecasting load and additional achievable energy efficiency at specific locations and estimating their daily load-shape impacts, using the mid-low AAEE scenario for local studies is more prudent at this time.

To be able to converge on the same AAEE scenario for all studies in the future, the agencies are collaborating to create more geographically-specific, local-area disaggregation and load-shape impact methods.[155] Increased locational accuracy will help alleviate uncertainty about the underlying demand and AAEE expected to occur within the defined local area, versus the balance of the electric system. Better understanding of the types of load being modified by the AAEE will improve the results of planning studies and may inform the development of geographically targeted AAEE programs and strategies.

The leadership's selection of a managed forecast fulfills one of the commitments made in the joint agency letter to Senators Padilla and Fuller (for more information, see the section on *Renewed Focus on Interagency Coordination*). The Energy Commission, CPUC, and California ISO

155 See the presentation by Demand Forecast 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.

will use the managed forecast for procurement, transmission need, resource adequacy, and other planning processes. This coordinated effort will ensure that energy efficiency is properly and consistently accounted for by each of the planning agencies.

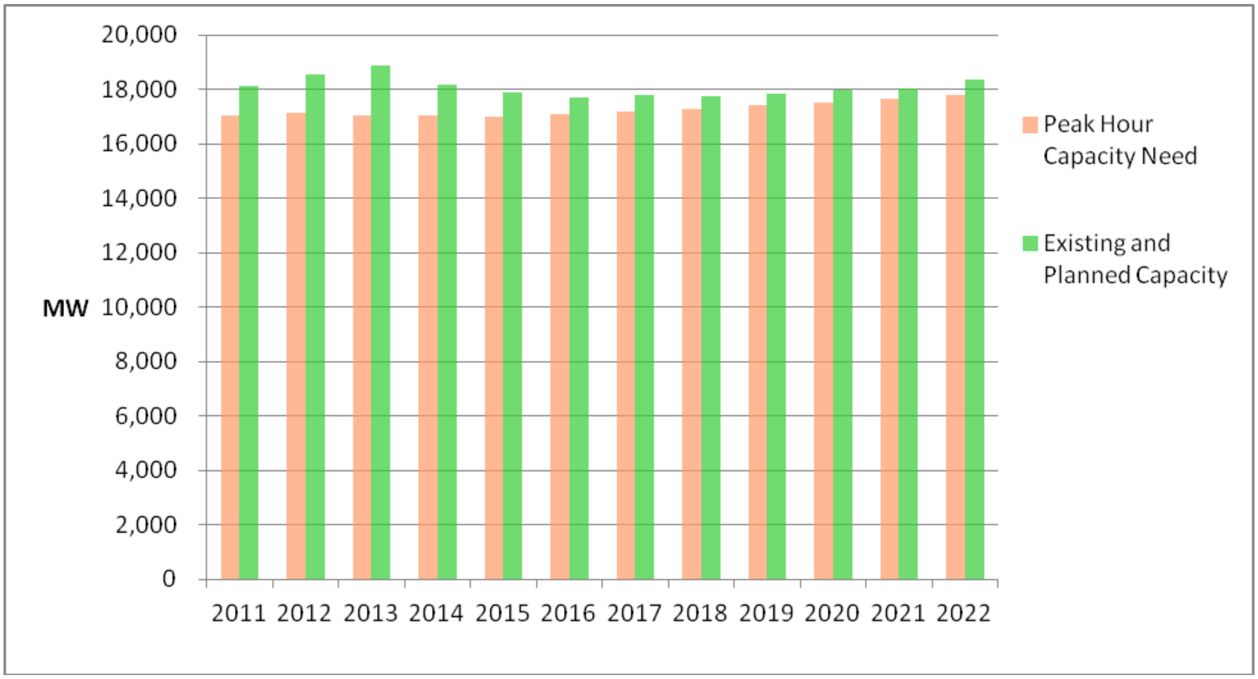
Resource Adequacy of Publicly Owned Utilities

In September 2005 the Legislature passed and the Governor signed AB 380 (Núñez, Chapter 367, Statutes of 2005), which requires POUs to report their respective supply circumstances to the Energy Commission so that an evaluation of their resource adequacy can be included in each *IEPR*.

In 2012, POUs represented 22.9 percent of California peak loads and 22.7 percent of energy needs. The largest 15 POUs account for 95 percent of POU peak loads and 94 percent of energy requirements.

Energy Commission staff has reviewed load and resource information from all 50 POUs in California. Based on those filings, the Energy Commission has found them to be resource adequate for both the year ahead and the long term. All POUs are complying with their resource adequacy requirements in the form of reserve margins. Under AB 380, POUs set their own requirements. The larger POUs, except LADWP, use the Western Electricity Coordinating Council's requirement of a 15 percent planning reserve margin applied to each POU's 1-in-2 forecast peak load. LADWP uses the alternative Western Electricity Coordinating Council method to use LADWP's 1-in-2 forecast peak load plus the single largest contingency. These are different from the requirements applied to the IOUs because the IOUs use the Energy Commission forecasts, and the POUs do not have month-ahead and year-ahead requirements as do the IOUs. (LADWP maintains its requirement on a daily basis.) Some POUs have projected planning reserve margins that are larger than the 15 percent requirement, such as LADWP's 16 percent for 2013. Smaller POUs have determined they need lower reserve margins, such as City of Industry's 7 percent. AB 380 allows them the discretion to do so. For the largest 15 POUs, Figure 6 shows the existing and planned capacity resources to meet their forecast peak loads through 2022.

Figure 6: Capacity of Large Publicly Owned Utilities and Forecast Peak-Hour Requirements



Source: California Energy Commission staff and utility capacity supply plans from 2013 posted at http://energyalmanac.ca.gov/electricity/index.html

The Need for New Electricity Infrastructure

Southern California has faced electricity infrastructure planning and procurement challenges for several years. These challenges were discussed in the *2011 IEPR* and *2012 IEPR Update* and have become more complex since the initial outage and subsequent announced retirement of the 2,200 MW San Onofre Nuclear Generating Station (San Onofre) in June 2013.

In response to the State Water Resources Control Board's (SWRCB) policy to phase out the use of once-through cooling[156] (OTC) in power plants, most generator owners now expect to retire their facilities and to repower at the same sites using air-cooled generating technologies if they can secure CPUC-approved power purchase agreements.[157] However, a key factor in whether these sites can be repowered is the criteria pollutant offset rules of the South Coast Air Quality Management District (SCAQMD) and the federal government. Commercially available offsets—

156 *Once-through cooling* in California entails the intake of water to cool the steam that has been used to spin the turbines that generate electricity. This allows the steam to be reused; the now-heated ocean water is then discharged back into the ocean. Both the intake and discharge processes have negative impacts on marine and estuarine environments.

157 Integrated utilities like Los Angeles Department of Water & Power make decisions on the basis of cost, rate impacts, access to financing and other criteria that differ somewhat from those used by merchant plants trying to secure contracts with CPUC-regulated investor-owned utilities. The department also plans to repower all of its steam boiler capacity into air-cooled modern gas turbine technology.

known as *emission reduction credits* (ERCs) —are scarce and extremely expensive in the South Coast Air Basin.[158] In 2009, Assembly Bill 1318 (V. Manuel Pérez, Chapter 285, Statutes of 2009) directed the ARB, in conjunction with various state agencies and the California ISO, to study the need for generation development in the South Coast Air Basin to assure reliability and identify whether new criteria pollutant emission rules for power plants are needed.

The SWRCB's OTC policy included two components to help address concerns about electricity reliability.~~, when the SWRCB adopted its OTC policy, it included two considerations.~~ First, ~~the compliance schedule put~~ Southern California power plants with no known replacement facility ~~further ahead in time~~are shown relatively late in the compliance schedule to allow the energy agencies more time to devise infrastructure replacement projects. Second, the OTC policy included a mechanism to adjust compliance schedules for OTC facilities if the energy agencies requested such delays. This would allow for an orderly process to repower some portion of the existing OTC fleet or allow for new facilities in comparable locations, if needed. The principal force likely to justify changes in OTC compliance dates was difficulties in securing emission offsets, either directly by the generator owner in the form of ERCS or by the SCAQMD in the form of credits from its Rule 1315 internal bank.[159]

Then came the San Onofre outages in January 2012. The California ISO conducted local reliability studies for the summer of 2012, which led to broader understanding about the ramifications of the San Onofre outage on reliability in the Los Angeles Basin and in San Diego. In summer 2012, ARB decided to delay the AB 1318 report process to allow for additional analyses from the energy agencies and California ISO when it became clear that the San Onofre outage was turning into a San Onofre retirement. By spring of 2013, these studies were complete, and the AB 1318 report was being drafted for public release and review.

SCE's announcement on June 7, 2013, that it would permanently close both units accelerates the need for decisions about the replacement of capacity and energy produced by San Onofre. To address this need, Governor Brown asked the leaders of the state's energy agencies to assemble a team to develop and assess options, with an initial report due in 90 days from the June 7 retirement announcement.

Existing and scheduled studies will provide some of the information needed to make a decision.[160] The emphasis of these studies is on local capacity area requirements as a key component of assuring reliability. However, completed or ongoing studies are not designed to answer the question "What resources should be added that can collectively replace the energy

158 Particulate Matter 10 (PM10) has been the most scarce and expensive of the criteria pollutants.

159 SCAQMD's Rule 1315 established a bank of emissions offsets based on retired offsets, for example due to business closure, that SCAQMD can use to "provide offsets" to entities that are exempt from the requirement to purchase them, such as essential public services and those modernizing facilities, including the replacement of steam boilers.

160 An informal Energy Commission staff paper, "Summary of Studies of Southern California Infrastructure," provides a basic comparison of input assumptions and results for these studies. http://www.energy.ca.gov/2013_energypolicy/documents/2013-07-15_workshop/background/.

generated by San Onofre?" because they focus on reliability, which is based on generating capacity rather than actual energy generated.

From 2001 through 2011, San Onofre operated with an average 82 percent capacity factor. In 2011, San Onofre generated about 14,500 GWh, nearly three times the energy generated by the entire fossil OTC fleet in Southern California. With San Onofre offline nearly all of 2012, the generation needed to make up for lost San Onofre energy came almost entirely from the non-OTC fossil plants in Southern California.

Electricity Infrastructure Studies

Four types of studies are relevant to the topic of replacing San Onofre. Three are oriented toward determining the amount of capacity needed to satisfy reliability standards, and the fourth looks at satisfying energy needs at lowest cost.

Local Capacity Area Requirements

Local capacity area studies identify the amount of capacity needed within a transmission-constrained area to meet 1-in-10 peak demand when the import capacity on the constraining transmission lines is at the highest level under critical contingency conditions. The California ISO has identified 10 such local capacity areas across its entire balancing authority area, three of which are in Southern California (the Los Angeles Basin, Ventura/Big Creek, and San Diego). Some of these areas also have subareas with even more localized issues of nearby generation being required to serve load.

Operating Flexibility Studies

Flexible capacity is a new concept that has emerged with increasing penetration of intermittent renewable resources. Operating flexibility studies determine the amount of flexible capacity required by a system operator to cover variable production of intermittent renewable resources like wind and solar. The idea of a net load curve (load curve less the production profile of wind and solar resources) has been developed to represent the pattern of load that dispatchable generators must serve. The dispatchable fleet must be capable of ramping output up and down rapidly and perhaps multiple times per day.

System Supply and Demand Balances

System supply/demand balances determine whether there are enough resources to satisfy summer peak demand plus a planning reserve margin that account for plant outages, extreme weather impacts on load, and other sources of uncertainty for an entire balancing authority area (or major subdivisions like the California ISO's SP 26 and NP26 regions[161]).

Energy Cost Minimization

These studies look at whether a given set of resources will satisfy annual energy requirements and at what cost to ratepayers. This examination is usually done by comparing alternative resource plans. All such resource mixes presumably satisfy reliability requirements at roughly

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161 These are the portions of the California ISO balancing authority area below and above Path 26, respectively. Path 26 is the transmission corridor between the PG&E and SCE service territories.

equal levels because if they do not, then additional costs of customer outages would have to be accounted for. Evaluating a range of resource mixes helps identify which mix tends to have lower expected aggregate costs through time.

Status of Infrastructure Studies and Results

The California ISO, utilities, and staff of the Energy Commission and CPUC each conduct studies or participate in developing some of the inputs needed by other agencies for their studies. This has involved close collaboration over the years, especially with the shared responsibility among the California ISO, the CPUC and the Energy Commission to implement the short lead time resource adequacy program. The California ISO's studies in its annual transmission planning process are designed to (1) determine whether transmission system upgrades are needed and (2) provide locational generating capacity information to the CPUC and other entities responsible for generation planning and procurement. The CPUC is responsible for providing appropriate procurement authority to the IOUs and to base its record for such decisions on sound analytic studies submitted by the California ISO, agencies such as the Energy Commission, utilities, and interested parties.

Five studies have been completed since March 2012 that assess local capacity area requirements in Southern California. Some of these have been thoroughly documented and vetted, while others are so new that their results have not yet completed public review. The four local capacity area studies prepared by the California ISO all assume the San Onofre outage would be permanent and can be used to guide infrastructure planning in light of SCE's decision to retire San Onofre. A fifth study by LADWP examines only the local capacity needs of that utility, which do not interact with San Onofre in any way. The studies by the California ISO used a variety of assumptions about the development of preferred resources, OTC retirements, and non-OTC retirements. In some cases the California ISO itself selected the assumptions, while in other cases the study used inputs specified by another agency. Each study reached a different conclusion about the need for repowering OTC facilities and/or building new generation. Table 10 summarizes the input assumptions and repowering/new generation results of these four studies.

Table 10: Summary of Input Assumptions and Results of California ISO Local Capacity Area Studies Assuming Generation is Minimized in San Diego

	Study 1 2012-2013 TPP Base LCR	Study 2 2012-2013 TPP Sensitivity	Study 3 AB1318 Low Sensitivity	Study 4 2012 LTPP Track 4 w/o SONGs
Inputs				
Incremental EE (MW)	0	0	973 MW SCE; 187 MW SDG&E	973 MW SCE (751 MW LA Basin); 187 MW SDG&E
Incremental CHP (MW)	0	0	15.1 MW SCE; 0 MW SDG&E	0 MW SCE; 0 MW SDG&E
Fast, Effective DR (MW)	0	0	382 MW SCE; 25 MW SDG&E	181 MW LA Basin; 4 MW SDG&E
Other DR (MW)	0	0	0 MW	794 MW balance of SCE; 203 MW SDG&E
DG (nameplate MW)	431 MW LA Basin 409 MW San Diego	1,538 MW LA Basin 490 MW San Diego	431 MW LA Basin 409 MW San Diego	549 MW LA Basin 467 MW San Diego
OTC Retirements (MW) (LA Basin & San Diego)	Five fossil plants- 5,875 MW San Onofre- 2,246 MW	Five fossil plants- 5,875 MW San Onofre- 2,246 MW	Five fossil plants- 5,875 MW San Onofre- 2,246 MW	Five fossil plants- 5,875 MW San Onofre- 2,246 MW
Non-OTC Retirements (MW)	0 MW LA Basin 136 MW SD	0 MW LA Basin 136 MW SD	0 LA Basin 135 MW SD	1645 MW SCE (965 MW LA Basin) 238 MW SD
Resource Additions	1920 MW LA Basin 0 MW SD	1920 MW LA Basin 0 MW SD	1920 MW LA Basin 0 MW SD	2035 MW LA Basin 45 MW SD
Results				
OTC Repower	2,900 MW LA Basin 620-820 MW San Diego	not reported	2,900 MW LA Basin 520 MW San Diego	2,912 MW LA Basin 520 MW San Diego
New Generation	1,400-1,700 MW LA Basin 300 MW San Diego	not reported	400-560 MW LA Basin 300 MW San Diego	810 MW LA Basin 400 MW San Diego
Total Repower & New Gen	4,300-4,600 MW LA Basin 920-1,120 MW San Diego	4,112 MW LA Basin San Diego not reported	3,300-3,460 MW LA Basin 820 MW San Diego	3722 MS LA Basin 920 MW SD

Source: California Energy Commission

Studies of local capacity conducted by the California ISO and LADWP all identify the need to repower much of the OTC capacity located along the Southern California coastline from El Segundo south to Encina. The California ISO's 2011-12 Transmission Planning Process (TPP) study of OTC retirement found that ~~a substantial percentage~~3,320 MW of the total 6,116 MW of OTC capacity in the LA Basin and San Diego areas needed to be repowered,[162] even with San Onofre operating. Subsequently, the California ISO's 2012-13 TPP study of ~~the question of~~ nuclear replacement found that 5,235 MW of 5,674 MW of OTC capacity in the LA Basin and San Diego areas had ~~an even larger percentage had~~ to be repowered with San Onofre offline.[163] The ARB's AB 1318 project found that the amount of repowering needed could be decreased somewhat through increased energy efficiency and combined heat and power. The California ISO's 2012-13 Transmission Planning Process sensitivity studies of increased distributed generation found only limited ability to substitute for conventional dispatchable power plants. The California ISO's testimony submitted into the CPUC 2012 LTPP, Track 4 rulemaking assuming a greater level of preferred resource additions found that about 4600 MW of gas-fired capacity should be added to replace 5,874 MW of OTC capacity and about 1,100 MW of other old gas-fired resources in the LA Basin and San Diego areas.[164] All of these studies assumed that the state's Renewables Portfolio Standard (RPS) was achieved by 2020 or earlier. Because most renewable projects expected to satisfy the RPS are already in the pipeline and are not "generic" plants that can be steered to the most useful location, RPS renewables make little difference in displacing capacity that must be located in transmission-constrained areas along the coast.

In addition to these formal, publicly visible studies, SCE and SDG&E have periodically provided results from their own studies that remain unpublished at this time. SCE has apparently assessed five options for resolving the San Onofre outage. Because one option was returning one or both San Onofre units to service, only the four San Onofre replacement scenarios continue to be relevant. SCE has briefed various energy agencies and the California ISO from time to time, but the detailed inputs, methods, and results have not yet been published. Similarly, SDG&E has studied the impacts of various resource and transmission options that might partly or fully alleviate the impacts of San Onofre and fossil OTC power plant retirement. SDG&E is understood to be assisting SCE by reviewing analytic results and to be gaining knowledge of benefits of transmission lines interconnecting the SDG&E and SCE systems, but details (scope, methods, assumptions, and results) are not known. Both SCE and

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162 California ISO 2011-12 Transmission Plan, March 2012, Tables 3.3-25 and 3.3-44.

163 California ISO 2012-13 Transmission Plan, Table 3.5-10, Alternate #1.

164 California ISO, Track 4 Testimony of Rober Sparks, August 5, 2013.

SDG&E filed testimony in the CPUC's 2012 LTPP rulemaking (Track 4)[165] concerning their views on the need for local capacity area resource additions.[166]

The Energy Commission and CPUC jointly hosted a workshop (with the active participation of management of the ARB, the California ISO, the SWRCB, and SCAQMD) in Los Angeles on July 15, 2013, to hear from the ISO, utilities, and agency staff about the results of these studies, and to receive comments from stakeholders and the public.[167] A panel provided independent comments about the nature and assumptions of the studies and whether to rely upon them in making San Onofre replacement decisions. Most panelists (Natural Resources Defense Council, Center for Energy Efficiency and Renewable Technologies, Division of Ratepayer Advocates) supported aggressive use of preferred resources, but acknowledged the need for monitoring and evaluation mechanisms to assure that any such targets would actually be achieved. Communities for a Better Environment and California Environmental Justice Alliance expressed skepticism about the analytic results of the local capacity studies prepared by the ISO. The Division of Ratepayer Advocates and The Utility Reform Network both emphasized that resources must be cost-effective to moderate electricity affordability issues. The Independent Energy Producers stressed the need for near-term decisions to delay any OTC compliance dates since owners of the facilities are acting as though the current compliance dates will be enforced.[168] Alliance for Nuclear Responsibility stressed the need for redundant capacity additions to assure that reliability criteria could be met, for example authorizing natural gas-fired peakers along with preferred resources.[169] Most public commenters, especially members of the EHC, stressed (1) a general opposition to generation additions with fossil technology and instead favored complete reliance upon preferred resources, and (2) use of public processes like the CPUC's 2012 LTPP rulemaking as a the venue for making San Onofre replacement decisions. Written comments largely echoed those delivered at the workshop. The Sierra Club's San Diego Chapter submitted an extensive assessment urging that preferred resources be used to fill the entire need with no fossil additions. The Energy Commission does not believe that Sierra Club demonstrated that this resource mix can actually satisfy local capacity requirements and maintain reliability.

Uncertainty in Fundamental Assumptions

Several fundamental assumptions being made in most studies of Southern California electricity infrastructure have yet to be proven. These assumptions affect the amount of capacity that the studies find is needed, or alter the timing of when such capacity is needed and perhaps whether

165 http://www.dra.ca.gov/ltpp.aspx.

166 California ISO filed its Track 4 analyses on August 5, 2013, while the two IOUs submitted their testimony of August 26, 2013.

167 For notice, background paper, presentations, and comments, see http://www.energy.ca.gov/2013_energypolicy/documents/#07152013.

168 July 15, 2013 Transcript, page 203 line 21 to page 204, line 5.

169 July 15, 2013 Transcript, page 213, lines 2-9.

generators will be able to submit viable bids into utility requests for offers based upon procurement authority relying upon such studies.

Use of South Coast Air Quality Management District Rule 1304(a)(2) to Avoid Providing Offsets

The idea of repowering OTC sites with flexible capacity, and perhaps yet additional capacity at other greenfield sites within South Coast Air Basin, presumes use of SCAQMD's Rule 1304(a)(2) for 3,000 MW to 5,000 MW of fossil capacity construction over the next decade.[170] SCAQMD's rule relieves owners of old steam boiler capacity from the obligation to provide offsets when they repower using an advanced gas turbine technology; rather, SCAQMD itself provides the offsets from credits in its Rule 1315 bank. The original purpose of the Rule 1304(a)(2) exemption was for essential public services, and at the July 15, 2013, *IEPR* workshop, SCAQMD expressed concern about the power plant proportion of credits used during the 2000s.[171] SCAQMD has not yet provided any public comments, but will address this issue through the AB 1318 process. SCAQMD's Rule 1315 may prove incapable of providing sufficient credits from a federally sanctioned internal bank to enable this degree of repowering with flexible capacity. More will be known about this issue as the AB 1318 report is finalized.

Fixed Compliance Dates for State Water Resources Control Board's Once-Through Cooling Policy

~~Unwillingness of the State Water Resources Control Board to Modify Once-Through Cooling Compliance Dates~~

The amount of capacity that the California ISO's 2012-2013 TPP studies indicate must be repowered by 2022 presumes that adopted OTC compliance dates for southern California plans are maintained. In its 2012-12 TPP studies, the California ISO made a similar assumption when it studied 2021. Generator owners have proposed changes in OTC compliance dates based on what they say are the practical considerations of repowering one or two units at a time at geographically constrained sites, presuming that total capacity at the site must be maintained to satisfy California ISO reliability standards. Generally these proposals stretch out compliance as pairs of units are built, others demolished, and eventually the entire plant is converted to modern gas turbine technology. The SWRCB's adopted OTC policy includes provisions that would allow modification of compliance dates if the energy agencies through the Statewide Advisory Committee on Cooling Water Intake Structures (SACCWIS) recommend delays due to reliability concerns.[172] At the July 15, 2013, workshop, the SWRCB representative acknowledged

170 SCAQMD Rule 1304(a) (2) allows owners of steam generating power plants to replace them, on an equal or lesser capacity basis, with advance gas turbines power plants without providing offsets. Instead, SCAQMD satisfies federal new Source Review rule requirements by debiting credits in its internal bank pursuant to Rule 1315.

171 SCAQMD, Presentation of Mohsen Nazemi, July 15, 2013, slide 16.

172 SACCWIS was established by the SWRCB in the adopted OTC policy as a formal advisory body. Its members are representatives of the Energy Commission, CPUC, California ISO, California State Lands Commission, California Coastal Commission, ARB, and staff of the SWRCB. The adopted OTC policy establishes that SACCWIS should report annually whether it believes compliance date changes are warranted.

the importance of reliability and indicated that compliance date changes would be considered as the need arises.[173]

California Public Utilities Commission Approval of Long-Term Power Purchase Agreements

Repowering all of the OTC capacity in southern California assumes that the owners of these facilities and load-serving entities (most likely SCE and SDG&E) can secure mutually agreeable power purchase agreements that will be approved by the CPUC. The generating industry will not build capacity on a "merchant" basis, speculating that capacity and energy products can be sold in short-term markets. The proposed Carlsbad facility at the existing Encina site illustrates a situation in which a project developer and a likely purchaser have not yet been able to come to an agreement and put a power purchase agreement before the CPUC for approval.[174] The CPUC rejected the Pio Pico and Quail Brush power purchase agreements, even though it had authorized 343 MW of procurement authority, because the SDG&E application assumed that San Onofre was operating~~there is clear evidence that the CPUC will not approve agreements that it finds are unnecessary~~.[175] SDG&E has since submitted a new PPA for Pio Pico.[176]

Role of Preferred Policy Resources

It is expected that the preferred policy resources enumerated by the Energy Commission and CPUC (energy efficiency, demand response, combined heat and power, and so forth) will play a considerable role in either reducing need for or in satisfying resource requirements. In D.13-02-015, the CPUC directed SCE to undertake a mix of preferred resources as well as authorize replacement capacity to address OTC retirements. In that decision the CPUC authorized about two thirds gas-fired generation and about one-third preferred resources despite the absence of analytic studies on the impacts of preferred resources to satisfy local capacity requirements. There has been a progression of local capacity area studies from those conducted in the California ISO's 2012-13 TPP with no inclusion of impacts from demand-side policies to the set of scenarios submitted by the California ISO into the CPUC's 2012 LTPP Track 4 that include considerable amounts of these resource types.[177] However, such studies reveal that preferred resource additions cannot reduce the need for repowering to satisfy local capacity requirements on a one-for-one basis. The Energy Commission, CPUC, and California ISO are working

173 July 15, 2013 Transcript, page 42, lines 20-22.

174 Despite the Energy Commission issuing a permit for Carlsbad (May 31, 2012) after a licensing proceeding that took 4½ years, SDG&E and NRG have still not come to a mutually acceptable power purchase agreement.

175 In D13-03-029 the CPUC rejected PPAs for the Pio Pico and Quail Brush projects, reasoning that SDG&E had not justified a need for the facilities on the date the projects would commence generation, given the record of the proceeding.

176 On June 25, 2013, SDG&E filed an application with the CPUC to accept a power purchase agreement with Pio Pico with different terms and conditions than in the original agreement rejected by the CPUC.

177 See Jaske and Wong, "Summary of Studies of Southern California Infrastructure," op. cit. Table 1, for a comparison of how preferred policies have been incorporated into local capacity studies.

together to better understand the extent to which energy efficiency and demand response programs can be geographically targeted to serve local reliability needs.

Joint Agency Southern California Reliability Team

Following SCE's announcement of its intentions to retire San Onofre, Governor Brown directed the leaders of California's energy agencies to examine Southern California reliability issues exacerbated by the short-term closure and permanent retirement of San Onofre.[178] The 90-day period allowed for this review necessitated use of existing studies rather than commissioning new ones. A preliminary plan was prepared by the staff of the member organizations and discussed at a public workshop conducted by the Energy Commission on September 9, 2013 (Commissioners from the CPUC, Board Members from the ARB and SWRCB, and executives from the California ISO and SCAQMD participated.)[179] As presented, the plan relies upon a mix of resource additions and transmission system upgrades. These include:

- A mix of near to mid-term actions that mitigate against reliability threats as a result of growing loads. These include maintaining the Flex Alert program,[180] pursuing additional capacity with 50 percent preferred resources and 50 percent conventional generation with triggers and off-ramps if the preferred resources do not come to fruition, or if transmission infrastructure or development of needed conventional generation is delayed.~~and pursuing additional transmission system upgrades.~~
- Initiation of contingent permitting, timely decisions on power plants in San Diego that have construction permits, and possibly delaying the compliance date for OTC compliance for the Encina or LA Basin OTC facilities.
- Long-term actions including expanding demand-side preferred resources through new programs and/or market mechanisms, building new generation through repowering some existing facilities and at new greenfield sites as appropriate, and major transmission system upgrades.

The preliminary plan relies upon local capacity studies to establish the aggregate need for new resources but recommends that preferred resources provide 50 percent of the needed capacity. The 50 percent level for preferred resources is an increase over what the CPUC adopted in D. 13-02-015 for SCE. Flexible resources that could both satisfy local capacity requirements and operate to integrate renewables were proposed for the balance of needed capacity additions.

Recommended reliance upon 50 percent preferred resources is acknowledged to require changes from business as usual. Additional energy efficiency and demand response will require

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178 Participating organizations include the Energy Commission, CPUC, California ISO, SCAQMD, SCE, and SDG&E.

179 CPUC, Energy Commission, and California ISO staff, *Preliminary Reliability Plan for the LA Basin and San Diego*, http://www.energy.ca.gov/2013_energypolicy/documents/#09092013.

180 An urgent appeal to consumers to reduce electricity demand. See http://www.caiso.com/Documents/FlexAlertFAQs.pdf.

active participation of customers in targeted areas of Southern California that can actually contribute to a reduction in local capacity requirements. Close monitoring of such programmatic activities is needed to determine whether energy efficiency impacts or demand response capabilities are actually being developed in the amounts and in the locations required to displace generation alternatives. If the preferred resources are not coming to fruition in the amounts and locations needed, alternatives such as conventional generation and transmission will need to be triggered. Transmission development, if found feasible and cost-effective, can be controversial and have lengthy development timelines. Generation development, whether repowering onsite or new development, will require SCAQMD to implement its Rule 1304(a)(2) exemption from offsets and such exemptions would need to be covered from credits in its internal bank. The idea of developing contingent resources is to shorten these leads times by doing permitting and authorization in advance so that the resources can be developed as quickly as possible if needed.

Lastly, the preliminary plan recommends no new mechanism for planning and procuring resources. Instead, the preliminary plan relies upon the existing mechanisms of the CPUC, California ISO, and Energy Commission to develop the detailed plans, permit and authorize facilities, and to plan and implement programs and/or market mechanisms needed to develop preferred resources. The tight coordination among the staff of the organizations participating in this effort is expected to continue even though each organization would retain its existing decision-making authority. The Governor's Office would track progress of various implementation actions against the plan and validate initiating contingency actions if elements were not progressing according to plan.

Below is a summary of oral and written comments from the September 9 workshop:

- Reliability is critical to the economic health of the Southern California economy, and even the appearance of reliability concerns will have harmful effects on those considering business expansion.
- The joint agency team should not make recommendations that substitute for transparent, public deliberation using the existing processes of the agencies.
- The California ISO's Track 4 local capacity study results use the Western Electricity Coordinating Council Category C reliability standard, but this is excessive, has not been subject to CPUC review, and would lead to overestimates of resource need.
- No delay in OTC compliance dates should be considered, even as a contingency.
- Relating the California ISO's Track 4 local capacity study results to the suggested policy of 50 percent preferred resources is problematic. First, the quantity of need in the draft report is confusing and direct linkage to Track 4 results has not been provided. Second, it is unclear what 50 percent of need actually means and how to account for resources authorized prior to creating the policy.
- A higher level of preferred resources ought to be targeted, as much as 100 percent.

- Adding further gas-fired capacity will both reduce prices in energy markets and worsen progress toward greenhouse gas emission reductions goals.

T~~he Joint Agency leadership will review t~~he preliminary plan developed by the staff of the participating agencies was presented at the September 9, 2013, workshop, ~~consider~~ comments were received orally at the workshop and submitted in writing to the Energy Commission as part of the 2013 IEPR docket. This plan does not prejudge the several proceedings underway at various agencies responsible for implementing portions of the proposed plan. Once the outcomes of these agency-specific proceedings are clear, the joint agency leadership will hold another workshop in summer 2014 to consider adjustments to the plan.~~, and submit a final plan to the Governor's Office.~~

Next Steps

Numerous activities are required from state agencies to enable the necessary amount of desired resource additions to move forward.

Air Quality Permits

SCAQMD needs to determine whether the amount of repowering identified in the California ISO's local capacity studies can be permitted using its Rule 1304(a)(2) exemption in conjunction with federally accepted internal credits under Rule 1315. For two large power plants, SCAQMD's Rule 1325 governing $PM^{2.5}$ emissions[181] may limit the capacity of repowered facilities to a level less than what currently exists. To the extent that SCAQMD's rules limit capacity additions below those found necessary by the California ISO or others, then additional studies will be required to develop a mutually satisfactory resource mix.

Fossil Power Plant Permitting

Of the OTC capacity that California ISO studies indicate would be effective in replacing OTC capacity that is scheduled to be retired, only the Carlsbad and Pio Pico projects have a permit from the Energy Commission. None of the AES plants (Huntington Beach, Redondo Beach, and Alamitos) have permits, although Applications for Certification have been submitted by AES for Huntington Beach and Redondo Beach, and NRG Energy has submitted a proposed permit amendment to repower El Segundo 4. The Energy Commission's licensing process, although it incorporates SCAQMD's air permit, addresses many other factors crucial to overall licensing.

The Energy Commission does not have a contingency permitting process. The regular Energy Commission licensing process issues a permit that expires in five years, and can be extended if approved by the Commission at a Business Meeting. Changes in law or regulations may be needed to issue contingent permits for generating facilities. Such permits would be finalized in an expedited manner if specific triggering conditions were satisfied, such as the failure of

181 Particles less than 10 micrometers in diameter (PM_{10}) pose a health concern because they can be inhaled into and accumulate in the respiratory system. Particles less than 2.5 micrometers in diameter ($PM_{2.5}$) are referred to as "fine" particles and are believed to pose the greatest health risks. Because of their small size (approximately 1/30th the average width of a human hair), fine particles can lodge deeply into the lungs.

preferred demand-side policies to develop savings in the amounts or at the locations required, or a transmission system upgrade project fell too far behind schedule to alleviate local reliability needs. ~~If changes in law or regulations are required, then~~ The Energy Commission ~~needs to~~will take appropriate action in 2014 to implement the contingent permitting concept ~~can be implemented~~through regulation.

Procurement Authority

Beginning before, and extending beyond, the time frame of the joint agency Southern California reliability team, the CPUC has various proceedings that are establishing procurement authority for the IOUs. In May 2013, the CPUC issued a revised scoping order and assigned commissioner ruling in the 2012 LTPP proceeding to establish Track 4, which focuses on the need for resource procurement authority for capacity to satisfy local capacity requirements presuming San Onofre was offline. The California ISO studies were submitted on August 5, 2013, further studies and testimony were submitted by other parties, and ~~the CPUC hopes to issue a decision in late 2013 or early 2014~~evidentiary hearings were conducted in late October. In hearings, parties actively contested numerous aspects of the ISO's LCR studies and the proposed 50:50 allocation of identified need between gas-fired generation and preferred resources (plus storage[182]).

~~Specifically, the decision sets a procurement target of 1,325 MW of storage capacity by 2020, with installation complete by 2024.~~ The CPUC will have to determine to what extent it will choose to displace fossil capacity with assumed future demand-side policies to reduce local capacity requirements, the extent to which supply-side additions like demand response, distributed generation,[183] and storage can be used in lieu of fossil capacity to satisfy local capacity requirements.[184] The CPUC hopes to issue a decision in early 2014.

Development and Authorization of Demand-Side Policies

The CPUC, the Energy Commission, and the California ISO need time to address the design and funding for incremental energy efficiency, combined heat and power, and demand response programs that will produce effects comparable to those assumed in various studies. In the past

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182 Through Rulemaking 10-12-007, the CPUC has been assessing how to implement the statutory directives of Assembly Bill 2514 (Skinner, Chapter 469, Statutes of 2010). The CPUC issued D.13-10-040 on October 17, 2013, directing utilities and other load-serving entities to acquire specific amounts of transmission, distribution, and end-use storage capacity by 2024. Specifically, the decision sets a procurement target of 1,325 MW of storage capacity by 2020, with installation complete by 2024. Some portion of this capacity is likely to satisfy local capacity area requirements in Southern California. Although storage is not included explicitly within the loading order adopted by the Energy Commission and CPUC, it can be configured to enable renewable integration and can be considered part of the package of resources types that are "preferred" to gas-fired generation.

183 Although distributed generation is sometimes used synonymously as solar photovoltaics, DG is broader and encompasses technologies like stationary fuel cells.

184 As with D.13-02-015, the CPUC may choose to provide procurement authority only for a portion of the amount identified in California ISO studies, reasoning that further studies could be useful in finalizing the mix of procurement authority and direction to pursue demand-side policy programs.

year, as long-term local capacity studies have been completed, the California ISO has raised legitimate questions about the ability of such programs to provide the amount of savings at specific points in the electricity system that directly influence power flow modeling. While energy efficiency and demand response can clearly reduce generation requirements, specific qualities such as location, level of anticipated reduction for base loads, and permanency are crucial for determining actual reductions in capacity needed in specific local areas. Demand response resources may be suitable substitutes for some amount of flexible capacity needed to integrate renewable energy into the system. "Flexible capacity" refers to generation facilities that can start up quickly and move up or down quickly to match changing load.[185] Further, the design of these demand-side programs may be novel and, to achieve the geographic targets implied in satisfying local capacity requirements, will require intensive monitoring in both development and implementation phases. More intensive data collection efforts are needed to enable effective monitoring, and such data will need to be shared among the relevant agencies. Such efforts can improve understanding of the ability to achieve targeted energy efficiency and demand response program participation, which will reduce uncertainty about relying upon such resources.~~program impacts are equivalent to generation as a source of generic energy or capacity, a concerted multiagency effort is needed to determine whether they are also equivalent to capacity needed in specific local areas and able to operate flexibly—come on-line and move up or down quickly to match changing load.Further, the design of these demand-side programs may be novel and, to achieve the geographic targets implied in satisfying local capacity requirements, may require intensive monitoring in both development and implementation phases.~~

OTC Compliance Date Revisions

The SWRCB OTC policy considers the possibility that delays in adopted compliance dates might be justified by delays in developing infrastructure needed to allow a specific OTC power plant to retire. However, the energy agencies have not yet suggested to SWRCB that such a delay is needed and have not completed any studies showing that the timeline for a preferred infrastructure project needed for local capacity requirements or other criteria would justify a delay for a specific OTC facility or unit. It is unclear what constitutes enough evidence (for example, demand side policy monitoring data that reveals a shortfall in savings impacts) for the energy agencies to make such a recommendation or for SWRCB to accept it in the face of likely opposition from environmental advocates seeking to maintain the original OTC compliance schedule. The Energy Commission will lead a joint agency effort to determine whether delays in specific facility compliance dates can be identified, and how short-lead time requests for compliance date deferrals can be used as a contingency measure.

Further Analytic Studies

The Energy Commission, CPUC, and California ISO routinely update various planning studies on an annual or biennial cycle. In fact, the California ISO will provide the leading transmission

185 SCE has proposed a Living Pilot effort that would develop new locationally targeted programs, rapid assessment through new evaluation, measurement and verification mechanisms, and quick changes in program design if necessary savings were not being realized.

options assessment results through its 2013-14 Transmission Planning Process (TPP) about the time this *2013 IEPR* is finalized. In its forthcoming 2014-15 TPP, the California ISO will use the adopted demand forecast from this *2013 IEPR* cycle. Continuously updating these analyses provides an opportunity to incorporate new assumptions and modeling techniques for preferred resources that may not have been feasible to date. These periodic analyses also provide an opportunity to focus on specific policy issues that may benefit from in-depth analytic focus.

Interagency Coordination and Tracking Progress

Currently, the joint agency leadership team ~~will~~ expects to finalize a Southern California Reliability report in 2014 and present it to the Governor's Office. Although a strong consensus exists among current Commissioners, Board Members, and agency executives to cooperate in pursuing resolution of the Southern California reliability concern, each organization is subject to its own decision-making processes within ~~the~~ its own policy framework ~~of each organization~~. Many of the measures in the preliminary staff plan are being pursued in these forums already, but what is adopted may not exactly match the preliminary plan. Assuring reliability while trying to preserve affordability and environmental stewardship for electricity services will require ongoing attention to coordinated planning, procurement, and permitting actions needed to accomplish the plan. The Governor's Office will create a mechanism to track progress against the plan.

Updated Estimates of New Generation Costs

Generation cost trends are an important consideration when evaluating the types of resources that will be used to meet California's future energy demand and provide the infrastructure needed to maintain system reliability and reduce GHG emissions from the electricity sector. In the *2011 IEPR* proceeding, the Energy Commission evaluated its method of analyzing and estimating future generation costs. For the *2013 IEPR*, staff has prepared the following updated estimates of generation costs for new generation. These estimates are only from the point of view of the developer, not the utility. This means that costs such as integration are not included in the analysis.

Renewable Cost Trends

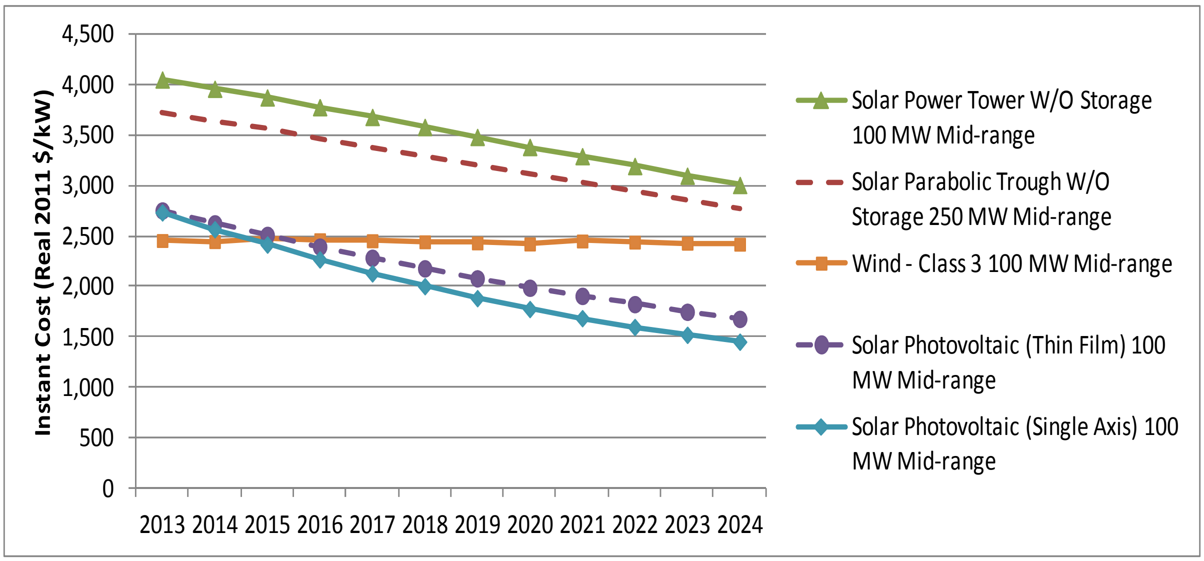
The market for renewable energy has grown in the United States over the last several years as renewable resources have become more attractive due to national efforts such as investment tax credits to make renewables more cost-competitive and funding available under the American Recovery and Reinvestment Act of 2009. Increased numbers of installations are driving costs lower as manufacturers and developers refine and improve technologies.

Solar photovoltaic (PV) technologies have experienced the most rapid decline in costs and are expected to continue this trend. In addition, investment in solar thermal technologies is expected to help reduce costs as rapid improvements and refinements are made by both developers and manufacturers.

Wind technology has experienced a far less dramatic reduction in cost. Cost reductions are projected to continue, although increases in the cost of land and transmission costs are expected to offset the gains in technology cost, keeping the cost before accounting for financing (known as the *instant cost*) relatively flat in California[186]. Figure 7 shows a selection of renewable technology instant costs representative of technologies being installed in California. The decline in costs for solar PV, as well as for solar thermal, is readily apparent, while the cost of wind is expected to remain stable over the next decade.

Other renewable technologies, such as biomass and geothermal, are not expected to experience the same decline in instant costs as solar technologies. Unlike wind and solar where substantial investment is fueling a learning curve, biomass and geothermal are not expected to experience substantial cost reductions over the next decade.

Figure 7: Renewable Technology Instant Cost Trends



Source: California Energy Commission

Fossil-Fueled Generation Cost Trends

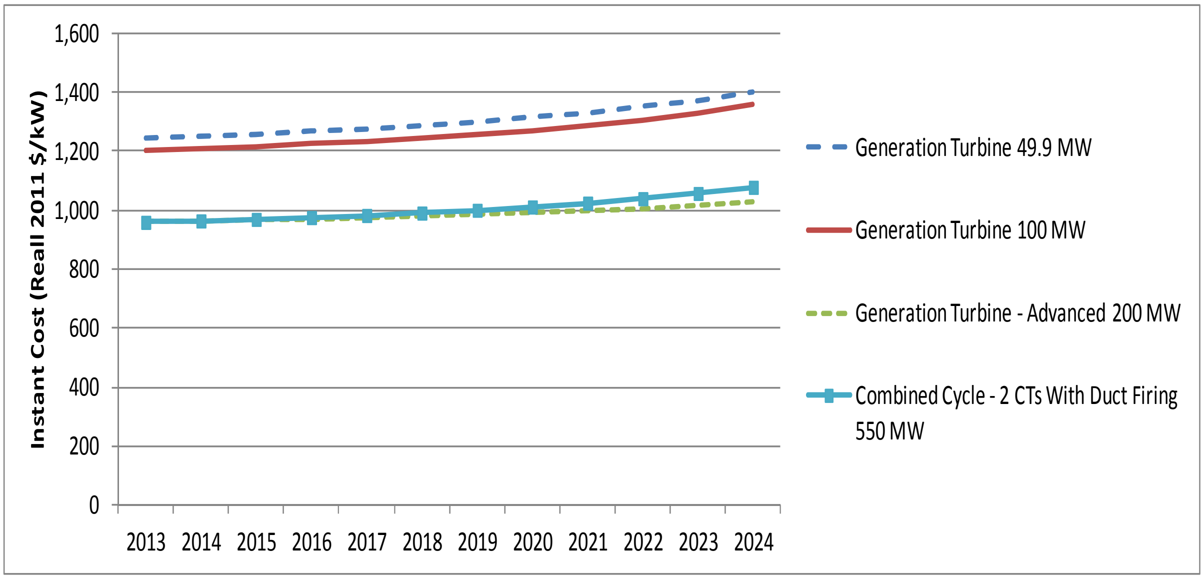
The Energy Commission conducted a survey in 2012 on both the construction and operational costs of combined-cycle and simple-cycle gas turbine generators. The results of the survey were combined with a careful study of industry literature and expectations to estimate the future path of costs for new power plants.

Combined-cycle and combustion turbines are mature technologies that have not seen significant cost declines in several years. These resources represent a major portion of California's supply portfolio and will likely continue to play a role in the future. The underlying technology costs are expected to remain flat over the coming years. However, there are significant particulate

186 States with lower land and transmission interconnection and service costs are expected to see continued investment in wind resources as they are able to take advantage of the underlying technology cost reductions.

and carbon emissions associated with these technologies. The Energy Commission estimates that increasing costs for emissions will cause a roughly 15 percent increase in instant costs per kilowatt in real dollar terms over the coming decade for simple-cycle turbines and about a 10 percent increase in combined cycles. Figure 8 shows the expected increase over the next 10 years.

Figure 8: Instant Costs of Fossil-Fueled Generation (Real 2011 $/kW)



Source: California Energy Commission

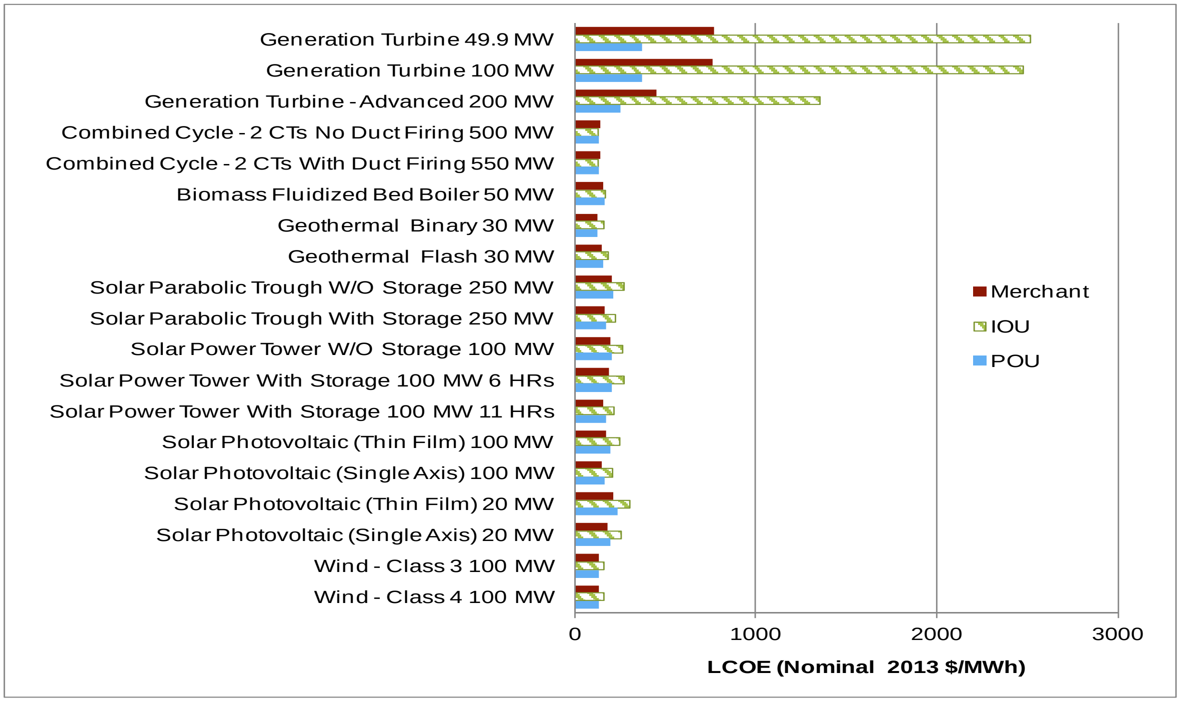
Summary of Estimated Levelized Costs

When developers negotiate the prices of contracts for energy with utilities, they must estimate how much will be ~~expended~~ spent over the contract period and translate that value into a cost per unit of energy. The most straightforward way to do this is to convert assumptions about varying costs over the life of the contract into a stream of level payments. This process is referred to as the *levelized cost* (also known as *levelized cost of energy* or LCOE) approach.

Figure 9 shows the estimated LCOE for a variety of technologies that may be built in California over the next decade, expressed in real dollars per MWh. The cost of building and operating these resources varies depending on who finances and operates them for two reasons. First, the cost of borrowing differs among IOUs, which typically have the highest cost of borrowing due to higher perceived risk in the lending market, independent merchant power plant owners, and POUs, which are able to offer low lending cost/lower risk municipal bonds to finance their projects.~~, which have the lowest cost of lending due to having lower risks.~~

Second, the operational profile differs depending on who owns the plant. For most renewable technologies, there is no difference in operation since they are typically operated as “must take” resources, meaning they are seldom, if ever, curtailed. Fossil-fueled plants, however, participate in a market for energy. When fossil-fueled plants are operated fewer hours—either through competition with newer, more efficient resources, or as renewable resources cause them to reduce operational hours—the total cost is spread over less total energy, increasing the levelized costs. A review of historical operation profiles shows that IOUs, POUs, and merchant operators have different operational profiles and therefore different lifetime costs for fuel and maintenance.

Figure 9: Summary of Mid-Case Levelized Costs (LCOEs)—Start-Year=2013



Source: California Energy Commission

Levelized Cost Trends

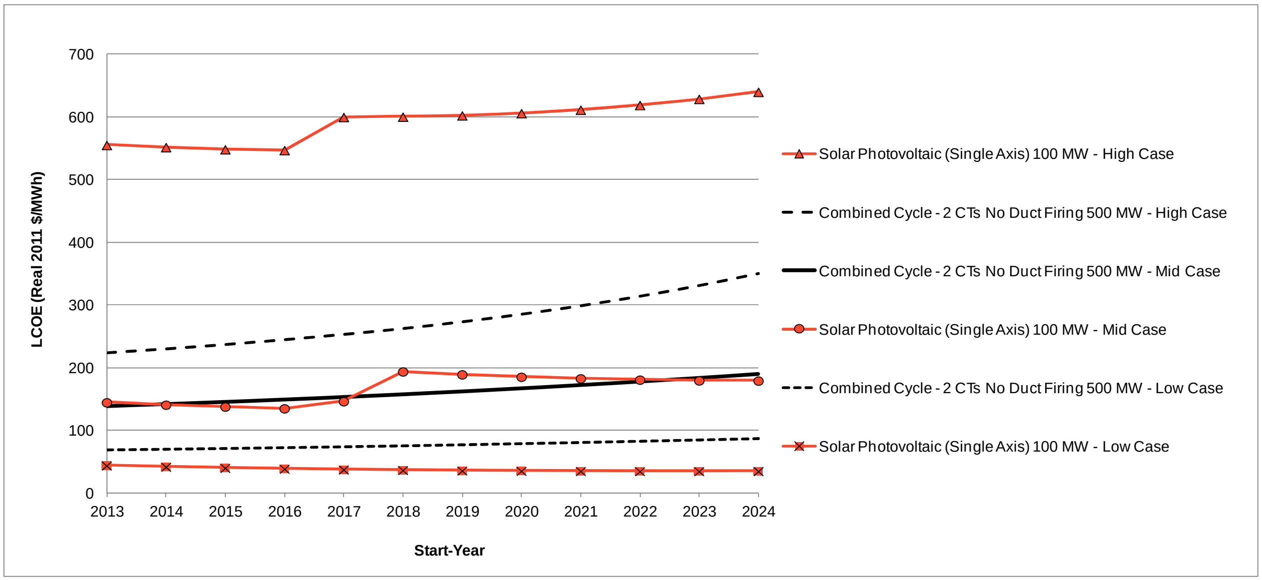
One of the most significant cost trends is the steady movement of renewable technologies toward being cost-competitive with traditional fossil resources on a cost-per-unit energy basis. Specifically, solar PV LCOE has improved dramatically since the Energy Commission's last assessment in the *2009 IEPR.* The cost of new solar technologies will not be identical throughout the state, so a reasonable range was constructed to show the high, mid, and low costs of this new generation in California.

Figure 10 compares the range of the current single-axis-tracking solar PV 100 MW to that of the 500 MW combined-cycle. While solar installations are expected to see a wider range of costs over the next 10 years, the mid-cost estimate is very nearly aligned with the mid-cost estimate of a 500 MW combined-cycle facility on a cost-per-unit energy basis. Not only is solar more competitive in the early years when it has the benefit of tax credits, it continues to be competitive after the tax credits are assumed to have expired between 2016 and 2018.

<u>The comparison in Figure 10 is limited to the viewpoint of the developer, rather than the cost to the utility or to the ratepayer. This is because renewable technologies have costs associated with</u>

integration that must be accounted for. While this graph does not show grid parity, it does show that costs have reached an important milestone on the road toward grid parity.[187]

Figure 10: Comparing LCOE Ranges for Combined-Cycle 500 MW and Solar Photovoltaic Single-Axis 100 MW



Source: Energy Commission

Recommendations

- **Improve alignment of agency planning cycles.** Continue discussions among the Energy Commission, California Independent System Operator (California ISO), and California Public Utilities Commission (CPUC) about the timing and alignment of the demand forecast, energy efficiency funding cycles, measurement and evaluation, and agency planning cycles.
- **Explore the use of new modeling techniques.** Continue to explore and implement new modeling techniques that combine behavioral aspects related to energy use and efficiency through econometric/statistical methods and engineering aspects through end use modeling and other "bottom-up" techniques.
- **Determine the appropriate level of granularity for demand forecasts.** Continue discussions with stakeholders on the appropriate granularity for location-specific demand forecasts to support subregional electricity system analysis for the CPUC and California ISO resource adequacy and other related proceedings. Determining the level of granularity will depend upon the needs of the joint energy agencies and consideration of the costs—in

187 Grid parity occurs when an alternative energy source can generate electricity at an LCOE that is less than or equal to the price of purchasing power from the electricity grid. Reaching grid parity is considered to be the point at which an energy source becomes a contender for widespread development.

money, time, and data reliability—of procuring the data and developing the models necessary to meet those needs.

- **Collaborate to ensure grid reliability in Southern California.** The Energy Commission, CPUC, and California ISO will ~~collaborate~~ plan together ~~in forthcoming planning~~ to implement near-and long-term activities identified in the joint agency examination of Southern California reliability, including transmission system upgrades, specialized energy efficiency, and other preferred resources program designs targeted to affected areas; power purchase agreements for permitted generating facilities; and new backstop contingency permitting and procurement mechanisms if preferred resources fail to develop in the amount and on the schedule needed for local reliability. The Energy Commission will work with the CPUC and California ISO to identify long-run choices among viable sets of preferred resources, transmission system upgrades, and generating resources needed to assure local reliability. The agencies should also jointly make decisions to trigger contingency mechanisms if higher priority resource development falters. Where appropriate, the agencies should work with the California Air Resources Board, State Water Resources Control Board, and South Coast Air Quality Management District to coordinate their environmental protection objectives with resource development strategies, in general, and regulatory requirements for necessary generating facilities, in particular.
- **Complete nuclear replacement studies recommended in the *2011 IEPR*.** To fulfill the nuclear replacement study recommendations of the *2011 Integrated Energy Policy Report*, the CPUC, California ISO, and Energy Commission, with input from SCE and PG&E, should assess the energy replacement options in the event of the shutdown of Diablo Canyon.
- **Update the Energy Commission's data reporting requirements.** The Commission should open an administrative proceeding in 2015~~4~~ to update its data reporting requirements, processes and protocols to ensure that up-to-date, appropriately granular energy data and other information from relevant stakeholders are available in timely fashion, for current and anticipated future policy analysis and development.

CHAPTER 5: Strategic Transmission Investment Plan

California needs to plan, permit, and build appropriate transmission infrastructure to support the 33 percent by 2020 Renewables Portfolio Standard (RPS) while delivering reliable electricity service that considers environmental, land-use, and economic effects and increasing stress on the system as a result of climate change. To date, it appears that planning has been successful in identifying the transmission needed to meet the RPS. The state now needs to ensure that these projects are permitted and constructed quickly and effectively. In addition, California needs to continue coordinating with the rest of the Western Interconnection in transmission planning activities to ensure that state policy objectives are considered appropriately in those activities, including the potential for higher levels of renewables in the future.

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 that will be available in the future to allow for the timely permitting of 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.

To follow up on transmission-related recommendations from the *2012 IEPR Update* and emerging issues and opportunities since that report was published, the Energy Commission held two workshops as part of the *2013 IEPR* proceeding to solicit input from stakeholders and develop recommendations. The first workshop was on the consideration of environmental and land-use factors in renewable scenarios for transmission planning and renewable energy project database issues, and the second focused on transmission planning and permitting issues. Summaries of these workshops are available in Appendix B.[188]

This chapter represents the Energy Commission's 2013 Strategic Transmission Investment Plan and discusses transmission challenges and opportunities in meeting California's 2020 RPS mandates, in-state coordinated land-use and transmission planning, emerging trends in Western Interconnection, and recommendations for next steps.

Approved Transmission Projects to Meet 2020 Renewable Goals

To date, the California ISO, the Imperial Irrigation District (IID) and the Los Angeles Department of Water and Power (LADWP) have identified and approved 17~~8~~ transmission projects for the integration of renewable resources that will enable California to meet its 33

188 The complete workshop record is available at http://www.energy.ca.gov/2013_energypolicy/documents/.

percent RPS by 2020. The California ISO has noted that there is no need to approve new major transmission projects at this time to support achievement of California's 33 percent RPS, given the transmission projects already approved or progressing through the CPUC's approval process.[189]

Sixteen of the projects are within the California ISO's control area. To help interested parties track the status of these projects, the Energy Commission staff will annually update and post the status of transmission projects being developed for the integration of renewable resources on the Energy Commission website.[190]

The Energy Commission staff will work with the California ISO, LADWP, IID, investor-owned utility staff, and publicly owned utility staff to update this information. Project status is posted in a spreadsheet along with a map showing the approximate location of each project. The following information about each project is excerpted from detailed descriptions and citations provided in Appendix A and is in order of actual or expected in-service date.

2012 Projects

Sunrise Powerlink: On June 17, 2012, San Diego Gas & Electric Company (SDG&E) completed and energized the 117-mile 500 kV Sunrise Powerlink. Combined with the Imperial Valley (IV) Collector Station and Sycamore-Peñasquitos projects discussed below, this high-voltage transmission line increases the import capability into San Diego by 1,000 MW for a total of 1,700 MW from the renewable energy-rich Imperial Valley.

2013 Projects

Colorado River-Valley (and Red Bluff Substation): SCE's Colorado River-Valley is a 153-mile, 500 kV transmission project that includes the Colorado River-Devers project. Combined with the West of Devers project discussed below, this will allow for delivery of about 4,000 MW from Riverside County. On September 29, 2013, SCE completed and energized the Colorado River-Valley project.

Eldorado-Ivanpah: SCE's Eldorado-Ivanpah project replaces 35 miles of existing 115 kV transmission line with a double-circuit 220 kV transmission line. The project will allow for delivery of 1,400 MW of new solar energy generation in the Ivanpah Dry Lake area. On July 1, 2013, SCE completed and energized the Eldorado-Ivanpah project.

Carrizo-Midway: PG&E's Carrizo-Midway is a 35-mile reconductoring, or upgrade, of the existing Morro Bay-Midway double-circuit 230 kV transmission line. The project will deliver up to 900 MW of new solar generation in the Carrizo Plain in southeastern San Luis Obispo

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189 California ISO Board approved 2012-2013 Transmission Plan, p. 8, http://www.caiso.com/Documents/BoardApproved2012-2013TransmissionPlan.pdf.

190 The status of the transmission projects will be posted on the Renewables/Tracking Progress/Transmission Expansion page of the Energy Commission website at http://www.energy.ca.gov/renewables/tracking_progress/.

County~~area~~. On March 20, 2013, PG&E completed reconductoring and energized the Morro Bay-Midway transmission line.

2014 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's controlled grid. Upgrading Path 42 requires improvements to SCE's and IID's facilities. 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's and IID's expected in-service date is April 30, 2014.

IID Additional Upgrades: Additional IID upgrades are needed to interconnect renewable generation in the Imperial Valley. These upgrades include (1) El Centro-Highline replacing existing 161 kV and 92 kV lines with a double-circuit 230 kV line; (2) El Centro-Imperial Valley (S line) replacing an existing 230 kV line with a double-circuit 230 kV line; and (3) Midway-Bannister installing eight miles of a new 230 kV line between IID's Midway and the proposed Bannister Substation.

2015 Projects

Imperial Valley (IV) Collector Station and IV Collector Line: The IV Collector project includes a one-mile 230 kV transmission line from a new Collector Substation to the existing IV Substation. The project will allow delivery of at least 1,400 MW of renewable energy to the California ISO grid. The project qualifies for the California ISO's competitive solicitation process.[191] On July 11, 2013, the California ISO selected IID as the approved project sponsor and accepted its offer of a cost cap of $14.3 million to build the project.[192] The California ISO's expected in-service date is no later than 2015.

Tehachapi Renewable Transmission Project: SCE's Tehachapi Renewable Transmission Project (TRTP) 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. On July 11, 2013, the CPUC voted in favor of President Michael Peevey's Alternate Proposed Decision and released the construction stay on the project. The decision requires SCE to build a 3.5-mile 500 kV underground cable in Chino Hills (Segment 8A) and remove the previously installed towers.[193] TRTP will allow delivery of 4,500 MW of renewable generation from eastern Kern and Los Angeles counties to

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191 Phase 3 of the California ISO's transmission planning process includes a competitive solicitation process where project sponsors can submit proposals to finance, construct, and own the transmission line for policy-driven and economically driven transmission projects, as well as for reliability-driven projects that provide additional policy and economic benefits.

192 The California ISO's Imperial Valley Policy Element Project Sponsor Selection Report can be found on the California ISO website at http://www.caiso.com/Documents/ImperialValleyPolicyElement-ProjectSponsorSelectionReport_Jul11_2013.pdf.

193 CPUC Decision on undergrounding TRTP Segment 8A can be found on CPUC website at http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M071/K423/71423831.pdf.

the Los Angeles Basin. Most of the generation will be wind resources from Kern County, but the line will also accommodate planned or future solar, geothermal, and peaker projects. SCE's expected in-service date for all segments is late 2015 or early 2016.

2016 Projects

Borden-Gregg: PG&E's Borden-Gregg project is a reconductoring of the existing Borden-Gregg 230 kV transmission line. The project will allow delivery of 800 MW of solar generation proposed near Fresno, specifically the Westlands area. According to PG&E, the project is on hold. Once the project moves forward, PG&E will submit a notice of exempt construction[194] to the CPUC. PG&E's expected in-service date is 2016.

LADWP 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 1,4~~0~~00 MW of wind, solar, and other renewable resources. LADWP's ~~will begin construction in 2013 with an~~ expected in-service date is 2016.

2017 Projects

Sycamore-Peñasquitos: The Sycamore-Peñasquitos project is a 230 kV transmission line between SDG&E's Sycamore and Peñasquitos Substations. The project will ensure delivery of renewable generation and reliability benefits to the San Diego area. As part of its 2012-2013 Transmission Planning Process, the California ISO examined reliability in the absence of Diablo Canyon Power Plant and San Onofre Nuclear Generating Station (San Onofre). The Nuclear Generation Back-Up Plan study identified several transmission system upgrades that, in addition to generation replacement and mitigation measures already underway, would help manage future unplanned extended outages to the San Onofre plant. The upgrades included the installation of dynamic reactive support near the San Onofre and the Sycamore- Peñasquitos project. Construction of this project becomes more important in light of SCE's June 7, 2013, decision to permanently retire San Onofre Units 2 and 3.[195] The project qualifies for the California ISO's competitive solicitation process.

South of Contra Costa: PG&E's South of Contra Costa project includes reconductoring of about 47 miles of existing 230 kV transmission lines south of the Contra Costa Substation. The project will allow delivery of 300 MW of wind generation in Solano County.

Warnerville-Bellota: PG&E's Warnerville-Bellota project is a reconductoring of the existing Warnerville-Bellota 230 kV transmission line. The project, along with the Wilson-Le Grand and Gates-Gregg projects discussed below, will allow delivery of 700 MW of renewable generation in the Greater Fresno, Central Valley North, Merced, and Westland zones.

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194 Replacement of existing transmission lines are issued a notice of exempt construction and are exempt from CPUC CEQA review pursuant to CPUC General Order 131-D, Section III, Subsections A or B.1.

195 SCE's news release can be found on SCE website at http://edison.com/pressroom/pr.asp?id=8143.

2018 Projects

Coolwater-~~Jasper~~-Lugo (Jasper Substation): SCE's Coolwater-~~Jasper~~-Lugo project includes ~~the~~ 34 miles of a new ~~Jasper substation, 35 miles of a new~~ 220 kV double-circuit transmission line, and replacement of ~~28~~ 29 miles of 220 kV transmission line with 14~~2~~ miles of double-circuit 220 kV and 17~~6~~ miles of 500 kV transmission lines. The project initially included a proposed Jasper Substation; however, SCE is developing the substation separately from the Coolwater-Lugo project. The expected in-service date of the Jasper Substation is 2015, prior to the Coolwater-Lugo project's expected in-service date of 2018. SCE intends to loop the Coolwater-Lugo transmission lines into the proposed Jasper Substation. The project will provide an additional 1,000 MW transmission capacity in the Kramer Junction and Lucerne Valley areas (San Bernardino County) to support renewable generation development and ensure system reliability. On August 28, 2013, SCE filed a proponent's environmental assessment with the CPUC and the United States Bureau of Land Management.

2019 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. The project, combined with the Colorado River-Valley project discussed earlier, will allow for delivery of about 4,000 MW from Riverside County.

2020 Projects

Wilson-Le Grand: PG&E's Wilson-Le Grand project is a reconductoring of the existing Wilson-Le Grand 115 kV transmission line. The project, along with the Warnerville-Bellota project discussed earlier and the Gates-Gregg project discussed below, will allow for delivery of 700 MW of renewable generation in the Greater Fresno, Central Valley North, Merced and Westland zones.

2022 Projects

Gates-Gregg: PG&E's Gates-Gregg project is a new double-circuit 230 kV transmission line between PG&E's 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 Westland zones. The project qualifies 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 sponsor to finance, own, construct, operate, and maintain the Gates-Gregg project.

Status of Pisgah-Lugo

Pisgah-Lugo: SCE's Pisgah-Lugo project was identified by the California ISO as being needed for the interconnection of the 850 MW K Road Calico Solar Project. On June 20, 2013, K Road, LLC filed a request with the Energy Commission to terminate the Calico Solar Project. The California ISO noted that the project is not reflected in any other interconnection agreements. As a result, the Pisgah-Lugo project was removed from the CPUC portfolios and the California ISO 2012-2013 TPP. However, there remains a likelihood that the Desert Renewable Energy Conservation Plan may identify a Development Focus Area in the same location as the Pisgah-

Lugo project to access solar resources in the Mojave Desert. At this time the Pisgah-Lugo project is not moving forward, but a similar project could be identified in the future by the California ISO as generator projects in its interconnection queue move forward.

~~*Project Requiring Reevaluation*~~

~~**Pisgah-Lugo:** SCE's Pisgah-Lugo project is 125 miles of 230 kV lines that would be rebuilt to 500 kV transmission lines and provide access to 1,400 MW of renewable capacity in the Mojave Desert. Because of multiple generator withdrawals in the Mojave Desert, including the 850 MW K Road Calico Solar Project, the California ISO and SCE are reassessing the scope and need for the Pisgah-Lugo Renewable Transmission Project. If the project is determined to be unnecessary, there are still enough transmission projects already identified to support California's 33 percent RPS.~~

~~California ISO's Potential~~Various Long-Term Transmission Alternatives Under Evaluation by the California ISO in Light of San Onofre Shutdown

On June 7, 2013, Southern California Edison (SCE) announced it was permanently closing San Onofre. Prior to SCE's announcement, the California ISO examined reliability in the absence of Diablo Canyon Power Plant and San Onofre Nuclear Generating Station (San Onofre) in its 2012-2013 Transmission Planning Process. At the September 9, 2013 Energy Commission *IEPR* Workshop on the Preliminary Reliability Plan for LA Basin and San Diego,[196] the California ISO presented the following transmission alternatives for consideration.

Alberhill-Suncrest 500 kV Line: A proposed 65-mile 500 kV transmission line between the existing SCE Alberhill Substation and SDG&E Suncrest Substation.[197]

Enhanced Talega-Escondido/Valley-Serrano Transmission: This proposal includes the following two 500 kV line(s) options for connecting the SCE and SDG&E systems:

- Option 1:
  - 11.4 mile, 500 kV line from existing SCE Alberhill Substation to proposed Lake Elsinore Advanced Pumped Storage (LEAPS) 500 kV Substation
  - 19.8 mile, 500 kV line from proposed LEAPS 500 kV Substation to proposed Case Springs Substation located south of LEAPS
  - 14 mile, 500 kV line from proposed Case Springs Substation to existing SDG&E Talega Substation.
- Option 2:

196 Edward Randolph (CPUC), Sylvia Bender (Energy Commission), and Phil Pettingill (California ISO), *Southern California Reliability Preliminary Plan* presentation, presented at the Energy Commission IEPR Workshop, September 9, 2013, slide 16, http://www.energy.ca.gov/2013_energypolicy/documents/2013-09-09_workshop/2013-09-09_reliability_presentation.pdf.

197 California ISO Board approved 2012-2013 Transmission Plan, p. 187, http://www.caiso.com/Documents/BoardApproved2012-2013TransmissionPlan.pdf.

- Convert existing Serrano-San Onofre 230 kV line and Talega-Serrano 230 kV line to 500 kV, terminating at the existing SDG&E Talega Substation.

Imperial Valley-San Onofre 500 kV HVDC or AC line: A proposed 500 kV HVDC or AC transmission line with about 1,450 MW of capacity. Based on a preliminary assessment by SDG&E, construction of this line would potentially reduce generation needed in the San Onofre study area (for example, LA Basin and San Diego local capacity areas) by about 1,000-1,200 MW. There are two routes being proposed by SDG&E.

- Option A: 145 miles of 500 kV HVDC or AC transmission line between existing SDG&E Imperial Valley Substation and San Onofre.
- Option B: 50 miles of 500 kV HVDC or AC transmission line between existing SCE Valley Substation and proposed Inland Substation.
  - Requires upgrading the existing Escondido-Talega 230 kV transmission line

Alamitos or Huntington Beach-South Bay area 300 kV HVDC Submarine Cable: This proposal was submitted as a reliability project in the California ISO's 2012 Request Window that would also provide reactive power support. The California ISO expanded the scope of the original proposed project of a voltage-sourced HVDC unidirectional submarine cable (600-1,000 MW range) connecting SCE Alamitos or Huntington Beach Substations to one of the following existing substations:

- SCE San Onofre 230 kV switchyard or vicinity location near San Onofre
- SDG&E Encina 230 kV switchyard
- SDG&E Penasquitos 230 kV Substation
- SDG&E South Bay 230 kV Substation
- SDG&E Old Town 230 kV Substation
- SDG&E Silvergate 230 kV Substation.

The above list represents some of the major bulk transmission options that were submitted to the California ISO for evaluation as of September 15, 2013. Since then, additional transmission options were submitted by third-party transmission developers to the California ISO's 2013-2014 Request Window for further evaluation, ranging from power flow controllers to AC or DC transmission lines into SDG&E's load-serving area.

The California ISO and state energy agencies are working together to evaluate these projects, as well as additional recent submittals into the California ISO Request Window, for further consideration in conjunction with other options such as resource and nonconventional alternatives[198] ~~and recommend the appropriate solutions~~ to address reliability concerns associated with the recent shutdown of San Onofre. The California ISO will document the results of its evaluations in its 2013-2014 Transmission Plan. The study results can be used to guide further actions for addressing reliability concerns related to the San Onofre shutdown.

198 See Chapter 4 (Electricity) for more information on resource and non-conventional alternatives to address the San Onofre shutdown.

For example, the Energy Commission could use the study results to identify potential new and/or expanded transmission corridors for designation to facilitate the timely siting, permitting, licensing and construction of any appropriate new transmission line.~~The California ISO will present the results in its 2013-2014 Transmission Planning Process. The results can be used to identify potential transmission corridors for designation.~~

Another issue that needs to be resolved in the next 10 years is the land lease agreement with the U.S. Navy (Department of Defense). The lease agreement ~~(Mesa side)~~ requires SCE to remove all of the buildings unless the U.S. Navy (Marine Corps) requests otherwise. The easement agreements (plant side and transmission towers) require SCE to return the land to its original condition at the conclusion of the decommissioning of San Onofre. Alternative uses of the site under easements will require agreement from the U.S. Navy and approval by Congress.[199]

The San Onofre transmission infrastructure consists of a 230 kV switchyard with nine 230 kV transmission lines and is the primary connection point between SCE's and SDG&E's transmission systems. The San Onofre switchyard needs to remain in operation to manage real-time reliable power flows in bidirectional mode ~~order to flow power~~ from the north and south into Northern San Diego County. The energy agencies need to work closely with SCE, U.S. Navy, and Congress to resolve the easement agreements so that the critical infrastructure remains in place.

In-State Coordinated Land-Use and Transmission Planning Efforts

Improved Coordination between Generation and Transmission Planning and Permitting

As outlined in Governor Brown's Clean Energy Jobs Plan, the Energy Commission prepared a renewable energy plan intended to "expedite permitting of the highest priority generation and transmission projects." In December 2011, the Energy Commission released the *Renewable Power in California: Status and Issues* report, which identifies high-level strategies to support renewables development. The *2011 IEPR* included a summary of the report, including transmission issues. One of the transmission issues identified by the Energy Commission in the *2011 IEPR* was the length of time required to plan and license major transmission facilities for the interconnection of renewable resources.[200] The California ISO Generator Interconnection and Deliverability Allocation Procedures (GIDAP) and Transmission Planning Process (TPP) are vast improvements on past reliance on generator interconnection procedures as the main identifier of new policy-driven transmission projects. Through the GIDAP, the California ISO can "…plan and approve major ratepayer-funded upgrades through the single holistic transmission planning process, rather than having major network upgrades that would

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199 Steve Pickett, Southern California Edison, *SONGS Shutdown and Decommissioning* presentation, presented at the Senate Energy, Utilities, and Communications Committee hearing, August 13, 2013, slides 4, 6, and 19-20, http://seuc.senate.ca.gov/sites/seuc.senate.ca.gov/files/08-13-13Edison.pdf.

200 California Energy Commission, *2011 Integrated Energy Policy Report*, p. 38, Sacramento, California, Publication Number CEC-100-2011-001-CMF, http://www.energy.ca.gov/2011publications/CEC-100-2011-001/CEC-100-2011-001-CMF.pdf, posted February 15, 2012.

ultimately be funded by ratepayers proceeding on one track through the transmission planning process and other projects also being identified through generator interconnection process."[201] Under the GIDAP, ratepayer-funded transmission upgrades are identified only through the transmission planning process, which relies on renewable generation forecasts or scenarios provided by the Energy Commission and the CPUC. The scenarios have been used in the TPP for two years and rely largely on commercial interest[202] or developer commitment and progress to forecast future locations of generators. This is a reasonable approach but one that means generators are not included in the transmission planning process until they have spent considerable time and resources negotiating power purchase agreements (PPAs) and started the environmental permitting process.

While the California ISO's GIDAP should improve identification of transmission projects needed for policy-driven generation, such as renewables for RPS targets or greenhouse gas (GHG) reduction goals, it does not ensure that transmission will be built by the time generation is commercially available. The current process still takes six to eight years from the time a transmission project is identified and approved in the California ISO Transmission Plan to when construction is completed by the transmission developer. Generators have already made significant progress with licensing and contracting through an approved PPA before this six-to-eight-year transmission planning process begins and can likely be commercially available in three to five years. The delay or lack of synchronization creates significant risks for generators because their PPAs often require their generation to be fully deliverable during peak conditions. Full deliverability typically requires transmission upgrades. For example, Abengoa's Mojave Solar Project requires the Coolwater~~r-Jasper-~~Lugo Transmission project to be able to achieve full deliverability and "if they don't get transmission in place by the on-line date of 2018, they will soon thereafter incur incredible penalties that could put the generator out of business."[203]

Going forward, if developers are unable to finance projects due to uncertainty in transmission, it could be very difficult to meet the state's renewables goals at reasonable prices based on comments made at the May 2013 *IEPR* workshop on transmission issues:

201 Neil Millar, California Independent System Operator, *transcripts from Lead Commissioner Workshop on California and Western States Transmission Planning and Permitting Issues*, May 7, 2013, p. 41, http://www.energy.ca.gov/2013_energypolicy/documents/2013-05-07_siting_workshop/2013-05-07_transcript_afternoon.pdf.

202 The commercial interest scenario heavily weights projects with an executed or approved power purchase agreement and data adequacy for a major siting application.

203 Peter Weiner, Paul Hasting LLP for Abengoa Solar, *transcripts from Lead Commissioner Workshop on California and Western States Transmission Planning and Permitting Issues*, May 7, 2013, p. 75, http://www.energy.ca.gov/2013_energypolicy/documents/2013-05-07_siting_workshop/2013-05-07_transcript_afternoon.pdf.

"Generators may be at commercial penalties or termination, at the worst, if transmission timing and requirements cannot be made to align with generation time and requirements."[204]

"…Without a transmission schedule that aligns with contracts and COD (commercial operation date), we're unlikely to have projects that are financeable, and this is a huge issue for us."[205]

"…viable projects can be scrapped because a fully permitted project is out of sync with shared transmission upgrades required for the project to come on-line."[206]

Two areas where the synchronization of generation development and the necessary transmission to reliably interconnect and deliver that generation to load can be improved include:

1. Reducing the number of significant and costly interconnection upgrades by ~~eliminating or~~ modifying the deliverability requirements in PPAs for renewable generators.

2. Designating transmission corridors, planning, licensing, and developing transmission to specific areas where the state wants to encourage the development of renewable resources before the generators are committed through PPAs or environmental permitting.

As noted by the California ISO during the May 2013 *IEPR* workshop, "…looking over the track record of the major projects moving forward, the most significant and costly interconnection upgrades are actually to ensure resource adequacy deliverability."[207] The Bay Area Municipal Transmission Group (BAMx) also provided some compelling information in written comments on the May 2013 workshop estimating the costs for resource adequacy capacity as it related to the policy-driven transmission projects in the California ISO footprint. The group indicates, "The annualized transmission cost is significantly higher than the RA [resource adequacy] value

204 Joe Desmond, BrightSource, *transcripts from Lead Commissioner Workshop on California and Western States Transmission Planning and Permitting Issues*, May 7, 2013, p. 70, http://www.energy.ca.gov/2013_energypolicy/documents/2013-05-07_siting_workshop/2013-05-07_transcript_afternoon.pdf.

205 Renee Robin, SunPower Corporation, *transcripts from Lead Commissioner Workshop on California and Western States Transmission Planning and Permitting Issues*, May 7, 2013, p. 84, http://www.energy.ca.gov/2013_energypolicy/documents/2013-05-07_siting_workshop/2013-05-07_transcript_afternoon.pdf.

206 Diane Ross-Leach, Pacific Gas and Electric Company, *transcripts from Lead Commissioner Workshop on California and Western States Transmission Planning and Permitting Issues*, May 7, 2013, p. 93, http://www.energy.ca.gov/2013_energypolicy/documents/2013-05-07_siting_workshop/2013-05-07_transcript_afternoon.pdf.

207 Neil Millar, California Independent System Operator, *transcripts from Lead Commissioner Workshop on California and Western States Transmission Planning and Permitting Issues*, May 7, 2013, p. 43, http://www.energy.ca.gov/2013_energypolicy/documents/2013-05-07_siting_workshop/2013-05-07_transcript_afternoon.pdf.

associated with the renewable resources."[208] BAMx also notes, "Currently, California ISO's TPP analysis determines policy-driven transmission based on the assumptions that it is a state policy to provide RA credits to all renewable resources needed to meet 33 percent RPS by 2020."[209] As Tony Braun, representing the California Municipal Utilities Association (CMUA), stated in the workshop, "The procurement decisions drive the transmission development and they also drive a host of other environmental and other factors that are important to achieving the overall goals of the state energy policy."[210]

Requiring full deliverability for future PPAs for renewable generators in the state may not be a cost-effective strategy and modification of deliverability requirements should be considered in light of the billions of dollars in transmission investments the requirement triggers. If major transmission upgrades were not required for remote renewable resources to meet the terms of their PPAs, then the synchronization issue would disappear.

In the longer term, identifying preferred development areas for renewable resources and then planning the transmission to serve those areas could alleviate issues with the current unsynchronized approach and encourage renewable development that minimizes impacts on California's environment. The key to overcoming the synchronization challenge is to develop a long-term transmission plan for preferred renewable generation zones. Two efforts underway that help with synchronization are the Desert Renewable Energy Conservation Plan and the Energy Commission's corridor designation process, discussed below.

Desert Renewable Energy Conservation Plan

~~The purpose of the Desert Renewable Energy Conservation Plan (DRECP) is to conserve and manage plant and wildlife communities in the Mojave and Colorado Desert regions of California while helping with the timely permitting of compatible renewable energy projects.~~ The Desert Renewable Energy Conservation Plan, or DRECP, is a collaboration among local, state and federal agencies to streamline renewable energy project permitting and transmission line permitting while conserving biological, cultural, and natural resources in the California

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208 Barry Flynn and Dr. Pushkar Waglé, Bay Area Municipal Transmission Group, comments on the *CEC 2013 IEPR – Transmission Planning and Permitting Issues (13-IEP-1E),* Docket 13-IEP-1E, May 21, 2013, p. 3, Table 2, http://www.energy.ca.gov/2013_energypolicy/documents/2013-05-07_transmission_workshop/comments/Bay_Area_Municipal_Transmission_Group_Comments_2013-05-21_TN-70932.pdf.

209 Barry Flynn and Dr. Pushkar Waglé, Bay Area Municipal Transmission Group, comments on the *CEC 2013 IEPR – Transmission Planning and Permitting Issues (13-IEP-1E),* Docket 13-IEP-1E, May 21, 2013, p. 4, http://www.energy.ca.gov/2013_energypolicy/documents/2013-05-07_transmission_workshop/comments/Bay_Area_Municipal_Transmission_Group_Comments_2013-05-21_TN-70932.pdf.

210 Tony Braun, Braun Legal on behalf of California Municipal Utilities Association, *transcripts from Lead Commissioner Workshop on California and Western States Transmission Planning and Permitting Issues*, May 7, 2013, p. 101, http://www.energy.ca.gov/2013_energypolicy/documents/2013-05-07_siting_workshop/2013-05-07_transcript_afternoon.pdf.

desert. Federal and California state agencies will take a number of discrete, coordinated actions designed to provide for both renewable energy development and habitat conservation in the desert. The DRECP will result in an efficient and effective biological mitigation and conservation program while providing renewable project developers with certainty about permit timing and cost under the federal and California Endangered Species Acts in a way that avoids or minimizes environmental impacts~~The DRECP is a collaboration being developed under the California Natural Community Conservation Planning Act and the Federal Endangered Species Act, and the Federal Land Policy and Management Act.The DRECP will result in an efficient and effective biological mitigation and conservation program while providing renewable project developers with certainty about permit timing and cost under the federal and California Endangered Species Acts in a way that avoids or minimizes environmental impacts.~~[211]

The DRECP is being undertaken by the Renewable Energy Action Team (REAT), a collaborative effort among the California Department of Fish and Wildlife, the U.S. Bureau of Land Management, the U.S. Fish and Wildlife Service, the Energy Commission, and the California State Lands Commission. The REAT agencies are developing the DRECP with input from a wide array of stakeholders, including local governments in the desert regions, renewable energy developers, environmental organizations, recreation and nongovernmental organizations, Native American organizations, electric utilities, and individual residents of desert communities.

The DRECP is focused on the desert regions and adjacent lands of seven California counties – Imperial, Inyo, Kern, Los Angeles, Riverside, San Bernardino, and San Diego – totaling roughly 22.5 million acres of federal and nonfederal California desert land. The DRECP will delineate renewable energy development areas that are located where large-scale renewable energy development is commercially viable and that are sufficient to help meet California's long-term climate and renewable energy goals out to 2040 and beyond. Development Focus Areas (DFAs) identified in the DRECP may include areas of immediate commercial interest, as well as areas that could be viable for future development. The DRECP's conservation framework is designed to provide comprehensive conservation for desert ecosystems and covered species. The renewable energy development areas must also be compatible with this framework.

~~The DRECP is focused on the desert regions and adjacent lands of seven California counties – Imperial, Inyo, Kern, Los Angeles, Riverside, San Bernardino, and San Diego – totaling roughly 2.5 million acres of federal and nonfederal California desert land. It represents an unprecedented collaboration among the Energy Commission, the California Department of Fish and Wildlife, the U.S. Bureau of Land Management, and the U.S. Fish and Wildlife Service, collectively known as the Renewable Energy Action Team (REAT), with input from local governments, environmental organizations, industry, tribes, and other interested parties.~~ Implementation of the DRECP is intended to "provide regulatory certainty for projects that are

211 For more information, see http://www.drecp.org/ and http://www.energy.ca.gov/siting/2008-11-17_MOU_BLM_FWS_DFG_CEC.PDF, p. 1.

proposed within ~~Development Focus Areas~~DFAs. Certainty will come from implementation of an integrated and coordinated multi-agency permitting process, with clear terms and conditions for permits and clear requirements for permit application from DRECP participating agencies."[212] Implementation will also provide species conservation certainty through the creation of Biological Goals and Objectives (BGOs). BGOs are the management and conservation actions that once implemented, will result in conservation of desert specifies. The BGOs serve as the primary basis for the creation of a reserve design, which identifies the areas in the plan that will be targeted for conservation.

The REAT agencies developed ~~several~~ seven draft alternatives, which contain different distributions of potential conservation ~~and mitigation~~ areas and ~~areas in which~~ renewable energy DFAs.~~could be developed (DFAs).~~ An informal document, *Description and Comparative Evaluation of Draft DRECP Alternatives* was made public in December 2012, and public comments were received.[213] ~~The REAT agencies now are preparing the draft environmental impact report/environmental impact statement (EIR/EIS) which is scheduled for formal public review in late fall of 2013.~~

In anticipation of the analysis that would occur in the draft plan and EIR/EIS, the REAT agencies created the Transmission Technical Group (TTG) in January 2012. The TTG includes representatives from the Energy Commission, the California ISO, the CPUC, and the U.S. Military along with experienced transmission planners from IID, LADWP, PG&E, SDG&E, and SCE. The TTG was assigned the responsibility to develop an estimate of the land (acreage) that could be affected by transmission upgrades needed to connect and deliver specific amounts of renewable power from within DFAs of the DRECP to the ultimate buyers of the renewable energy under various alternatives developed by the REAT.[214]

Applying the Desert Renewable Energy Conservation Plan Model to the ~~Central Valley~~San Joaquin Valley and Other Areas

After the DRECP is complete, the next ~~logical~~ region for a ~~similar~~ renewable energy planning effort may be the San Joaquin Valley (~~also known as~~southern ~~the~~ Central Valley). In the ~~Central~~ San Joaquin Valley, some agricultural land parcels are now considered "marginal" because they may no longer be economically viable for agricultural production. This may be the result of accumulated soil contamination from leaching of naturally occurring selenium, water shortages,

212 http://www.drecp.org/documents/docs/DFA_and_streamlining_concepts_papers_March_28_2013.pdf, accessed June 10, 2013.

213 http://www.drecp.org/documents/docs/2013-03-25_Message_and_proposed_covered_spps_list.pdf, dated March25, 2013.

214 Transmission Impacts in the DRECP, June 11, 2012, p.2, http://www.drecp.org/meetings/2012-04-25-26_meeting/background/Transmission_Planning/Transmission_Technical_Group_report_final_4_6_12.pdf .

or overfarming.[215] According to a report by the University of California, many of these lands in the southern Central Valley "retain little or no agricultural or biological value."[216] Renewable energy projects sited on these lands may, therefore, be more easily permitted and require less mitigation, potentially leading to shorter development times. In addition, the heart of the Northern California section of California's high-voltage electrical transmission system (known as Path 15) runs through this area. This intersection of large amounts of degraded land, good solar resources, and the potential to interconnect to the bulk transmission system argue for this region to be considered for a coordinated planning effort similar to DRECP. Establishing such an effort would also support Governor Brown's direction in his Clean Energy Jobs Plan to "expedite permitting of the highest priority generation and transmission projects." The Energy Commission will continue to partner and coordinate activities with the Governor's Office of Planning and Research.

The University of California report also noted that California's renewable goals could be greatly enhanced by considering large-scale solar plants located on degraded farmland. Moreover, the report argues that given the difficulties with increasing numbers of large renewable energy projects on public lands, "developers in California are increasingly looking to agricultural land to site their projects."[217] For example, the Westlands Solar Park Master Plan provides an opportunity to move forward with development on degraded lands that are close to the high-voltage transmission grid and relatively close to population centers in the southern Central Valley. According to the report, "up to a quarter million acres of impaired lands in the Westlands Water District in the Central Valley may soon have to be retired from agricultural production, leaving significant tracts available for renewable energy production."[218]

The Energy Commission will focus on planning for renewable energy development in the San Joaquin Valley and other areas of the state, when the DRECP is complete. In addition, the Energy Commission will continue to evaluate the barriers to renewable energy development at the Salton Sea. This evaluation includes, but is not limited to, the concerns of geothermal developers and the need for transmission in the Salton Sea area. As agency and stakeholder resources become available, it may be possible to initiate foundational work on renewable energy generation and associated transmission facility development. The Energy Commission's Renewable Energy and Conservation Planning Grants[219] will give qualified counties an opportunity to take the initiative through local government planning.

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215 Bank of America, Berkeley Law, and UCLA Law, *Harvesting Clean Energy: How California Can Deploy Large-Scale Renewable Energy Projects on Appropriate Farmland*, October 2011, http://www.law.berkeley.edu/files/HarvestingCleanEnergy.pdf.

216 Ibid.

217 Ibid.

218 Ibid, p. 1.

219 For more information on the Energy Commission's Renewable Energy and Conservation Planning Grants, see website link at http://www.energy.ca.gov/renewables/planning_grants.

Potential Corridor Opportunities

The U.S. Congress enacted the Energy Policy Act of 2005 (EPAct-05), which directed the U.S. Department of Energy to conduct assessments every three years of transmission congestion in major regions of the country.[220] The first study, completed in 2009, provided a basis for the Secretary of Energy to designate National Interest Energy Transmission Corridors, including one covering most of Southern California. EPAct-05 also directed the Secretaries of Agriculture, Commerce, Defense, Energy, and the Interior to designate energy corridors on federal land in 11 Western States. More recently, President Barack Obama issued a Presidential Memorandum "Transforming our Nation's Electric Grid through Improved Siting, Permitting, and Review" in June 2013, discussed later in this chapter in the section titled "Emerging Trends in the Western Interconnection." Among other items, the Presidential Memorandum specifically references the need to "collaborate with State, local, and tribal governments to ensure, to the extent practicable, that energy corridors can connect effectively between Federal lands."[221]

As noted earlier in this chapter, SB 1059 authorizes the Energy Commission to designate transmission corridors within the state and, after designation, identify those transmission corridor zones in its subsequent strategic plans.

These factors support an effort by the Energy Commission to investigate the designation of a corridor in Southern California. Most of the area adjacent to Interstate 10 from the California-Arizona border heading west to approximately the southern border of Joshua Tree National Park has been designated as a U.S. Bureau of Land Management (BLM) Section 368 Energy Corridor.[222] California's designation of an SB 1059 corridor composed of the patchwork of nonfederal lands that lie near the Section 368 lands in this area would support the federal designation and build off the work of the TTG report to the DRECP. The combination of the federal and state designations would provide a reasonable, well-considered transmission corridor that is seamless, contiguous, and of adequate width to allow for flexibility in siting in a highly impacted part of the state, paving the way for any necessary future expansion of the high-voltage electrical transmission system in that area.

The BLM has already approved the Devers-Palo Verde No. 2 Transmission Line Project, now known as the Colorado River to Devers Transmission Line. According to the BLM:

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220 http://www1.eere.energy.gov/femp/pdfs/epact_2005.pdf.

221 http://www.whitehouse.gov/the-press-office/2013/06/07/presidential-memorandum-transforming-our-nations-electric-grid-through-i.

222 Section 368 of the Energy Policy Act of 2005 directed the Secretaries of Agriculture, Commerce, Defense, Energy, and the Interior to designate multi-purpose energy corridors on federal land in 11 Western States , including Arizona, California, Colorado, Idaho, Montana, Nevada, New Mexico, Oregon, Utah, Washington, and Wyoming. See proposed Section 368 Energy Corridors Map, http://corridoreis.anl.gov./documents/fpeis/maps/Section368Corridors_Nov2008.pdf, and specific 368 Energy Corridor on the southern border of Joshua Tree National Park at http://corridoreis.anl.gov/documents/fpeis/maps/Part_1/WWEC_LargeScale_BMS_D09.pdf

> This 500 kV line will provide interconnection and electrical transmission for numerous solar energy facilities proposed for construction, including nine large-scale solar projects in California and Nevada with a potential output of more than 3,600 megawatts that were approved by Secretary Salazar [in 2010] … The line will extend 115 miles from the Colorado River Substation near Blythe to the Devers Substation in Palm Springs and from the Devers Substation to the Valley Substation in Romoland, Riverside County, about 41.6 miles. The line will cross 57 miles of BLM land and two miles of San Bernardino National Forest land, running primarily along the I-10 Interstate, a primary corridor for energy transmission in Southern California.[223]

In the December 2012 TTG report prepared for the DRECP, the TTG identified a conceptual transmission plan—not a siting evaluation—and its associated land impacts which included five alternatives. In the analysis, four of the five alternatives indicated the potential need for an additional high-voltage electrical transmission line parallel to the Interstate 10 corridor~~ in four of the five alternatives that were analyzed~~.[224] While the TTG will update its analysis based on the alternatives that are analyzed in the draft plan and the EIR/EIS, the results will likely be reasonably similar. The BLM-controlled portion of this potential corridor has already been approved. This conceptual route could be a good candidate for linking nonfederal lands in California with the federal Section 368 corridor.

Additionally, in 2002, the IID issued a Notice of Preparation that it and the BLM were preparing a draft EIR/EIS to address the environmental impacts of constructing and maintaining a new transmission line from west of Blythe to near Palm Springs.[225] The BLM approved this line in 2006.[226] However, the California ISO's 2010-2011 Transmission Plan subsequently listed this project among those that were "not needed."[227] This area could provide another opportunity for investigation of a transmission corridor by the Energy Commission.

Because significant amounts of environmentally responsible renewable generation potential have been identified in these areas of the state and are likely to be developed, it would be prudent for California to plan the transmission upgrades necessary to interconnect large amounts of renewable resources in these areas. From a timing perspective, it makes sense to

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223 http://www.blm.gov/wo/st/en/info/newsroom/2011/july/NR_07_14_2011A.html, http://www.blm.gov/pgdata/etc/medialib/blm/wo/MINERALS__REALTY__AND_RESOURCE_PROTECTION_/energy/priority_projects.Par.1290.File.tmp/Devers_PV2_Transmission_fact_sheet.pdf, and http://www.blm.gov/pgdata/etc/medialib/blm/wo/MINERALS__REALTY__AND_RESOURCE_PROTECTION_/energy/priority_projects.Par.38666.File.tmp/Devers_PV2-map2.pdf.

224 http://www.drecp.org/documents/docs/alternatives_eval/Appendices/Appendix_A_TTG_Report.pdf, pp. 19 – 21.

225 http://www.blm.gov/pgdata/etc/medialib/blm/ca/pdf/pdfs/palmsprings_pdfs/desert_southwest/desert_southwest_appendices.Par.20839.File.dat/Appendix_A%20-DSWTP-NOP&NOI.pdf.

226 See http://www.blm.gov/ca/st/en/info/newsroom/2006/09/CDDNews06-89_DSW_ROW.html.

227 http://www.caiso.com/Documents/Board-approvedISO2010-2011TransmissionPlan.pdf, pp. 7-399.

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.

Transmission Opportunities to Enable Higher Levels of Renewables

California Independent System Operator Leveraging Opportunities

As California moves closer to attaining its renewable electricity goals, there is discussion about moving beyond the 33 percent by 2020 RPS. To achieve higher RPS goals, California could look to renewable resources outside California. This could be achieved in a number of ways.

Footprint Expansion

On December 14, 2011, the Federal Energy Regulatory Commission (FERC) approved the transition agreement with Valley Electric Association (VEA) allowing VEA to transition from the Nevada Power Company balancing authority area to the California ISO. The VEA is located in Pahrump, Nevada, on the border of California near the Eldorado Valley in the Mojave Desert. As part of the agreement, VEA turned over operational control of its facilities to the California ISO, merged its generator interconnection queue, and became a participating transmission owner. On January 3, 2013, VEA joined the California ISO grid. VEA becoming part of the California ISO provides additional import capability and allows the California ISO to achieve efficiencies in providing renewable resources from VEA to California. VEA's interconnection rights at Western Area Power Administration's ~~LADWP's~~ Mead Substation and a new interconnection planned at SCE's Eldorado Substation increase the California ISO's ability to access renewable resources outside California to meet California's renewable objectives. In addition, there is a 230 kV transmission line under construction from NV Energy Northwest Substation-VEA Desert View Substation-VEA Pahrump Substation. The line will provide a second 230 kV source into VEA's major system substation at Pahrump and form a looped 230 kV supply source. ~~The project is expected to be completed in 2013.~~

Joint Transmission Projects with Neighboring States

In August 2012, NV Energy announced it was launching a joint project with the California ISO to study the possibility of developing transmission facilities between their two systems to share both conventional and renewable energy resources for the benefit of both parties. NV Energy's service territory stretches from Elko to Laughlin in Nevada. As part of the California ISO's 2012-2013 Transmission Planning Process, a 500 kV transmission line from NV Energy's Harry Allen Substation to SCE's Eldorado Substation was studied as an economic project. The project is located in the area being jointly studied by NV Energy and the California ISO. The California ISO recommended further evaluation as part of an ongoing joint study with NV Energy and as a possible transmission alternative in its transmission planning process.[228]

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228 California ISO, *2012-2013 Transmission Plan*, March 20, 2013, p. 357, http://www.caiso.com/Documents/BoardApproved2012-2013TransmissionPlan.pdf.

Energy Imbalance Market Expansion

On February 12, 2013, the California ISO and PacifiCorp[229] entered into a memorandum of understanding to create a real-time energy imbalance market[230] (EIM) by October 2014. The California ISO operates a real-time, five-minute dispatch for its existing customers and will make it available to PacifiCorp and future EIM participants. The EIM being developed through a California ISO stakeholder process will be a voluntary market for procuring imbalance energy to balance supply and demand deviations in real time from 15-minute energy schedules[231] and five-minute dispatch in the combined network of the California ISO and EIM Entities. Implementation of an EIM will provide economic, reliability, and renewable integration benefits for both balancing authorities.[232] California needs to encourage adequate participation by entities within California.

On April 30, 2013, the California ISO filed an implementation agreement with FERC.[233] The agreement sets forth the terms under which the California ISO will modify its real-time energy market to provide EIM service to PacifiCorp. On June 28, 2013, FERC approved the agreement with an effective date of July 1, 2013.[234] On November 7, 2013, the California ISO Board of Governors approved California ISO's Energy Imbalance Market proposal.

One of the benefits noted by the California ISO is that the EIM takes advantage of the geographical diversity of load and resources. Wind resources produce at different times in the northwest and southwest, and electric loads peak at different times across the region as the sun moves westward. For example, wind power from Wyoming may be available at ~~critical~~ times

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

230 An *energy imbalance market* is a regional real-time energy market that automatically balances electricity supply and demand every five minutes by choosing the least-cost resources to meet the needs of the grid while ensuring reliability.

231 FERC Order 764 requires the California ISO and other entities to offer a 15-minute scheduling option in the real-time market, which will reduce barriers to integration of variable energy resources. Implementation of these real-time market changes is expected in spring 2014, prior to the implementation of the EIM. For more information on FERC Order 764, see California ISO website at http://www.caiso.com/informed/Pages/StakeholderProcesses/FERCOrderNo764MarketChanges.aspx.

232 Edson, Karen, California ISO, *Decision on PacifiCorp Energy Imbalance Market Implementation Agreement Board Memo*, March 19, 2013, p. 1, http://www.caiso.com/Documents/UpdatedDecisionPacifiCorpEnergyImbalanceMarketImplementationAgreement-Memo-Mar2013.pdf.

233 The implementation agreement filing with FERC can be found on the California ISO website at http://caiso.com/Documents/Apr30_2013EnergyImbalanceMarketImplementationAgreementPacifiCorpER13-1372-000.pdf.

234 FERC's Order on the implementation agreement can be found on the California ISO website at http://www.caiso.com/Documents/Jun28_2013OrderAcceptingPacifiCorpEnergyImbalanceImplementationAgreement_ER13-1372-000.pdf.

when California's wind is not blowing. ~~and when the load on the California's electrical grid most requires it.~~ The EIM will improve efficiencies of the existing transmission infrastructure by moving ~~resources~~ electricity to take advantage of regional resource diversity.[235] California needs to encourage entities both within and outside California to join the California ISO's EIM to take advantage of the benefits of real-time balancing of loads and resources. To support the benefits of regional resource diversity, the University of Wyoming's Wind Research Center released a report, *Wind Diversity Enhancement of Wyoming/California Wind Energy Projects*,[236] focusing on the importance of geographic diversity in wind, specifically Wyoming and California wind resources. ~~resources and the benefits of combining Wyoming and California wind resources.~~Integrating regionally diverse wind generation such as wind from Wyoming may result in less reliance on fossil fuels and reduced GHG emissions.[237]

~~In addition, integration of wind generation from Wyoming has the capability to shape California's wind portfolio and result in less reliance on fossil fuels and reduced GHG emissions. For example, Pathfinder Renewable Wind Energy, LLC, is building high-quality wind generation in Wyoming. Pathfinder has two projects underway, Pathfinder Zephyr Wind and Whirlwind I. Pathfinder Zephyr Wind is partnering with landowner associations, ranchers, and farmers in Platte and Laramie counties to develop 2,000 MW to 3,000 MW of wind energy. In 2010, Pathfinder bid to use 70 percent of the capacity of the Zephyr Transmission Project. In 2011, Pathfinder partnered with Whirlwind, LLC, to develop the Whirlwind I project, located near the proposed terminus of the TransWest Express Transmission Project near Rawlins, Wyoming. When TransWest Express holds its open season for transmission capacity, Whirlwind I plans to bid on its available capacity.~~

Multistate and Publicly Owned Projects in the Transmission Planning Process

Duke-American Transmission Company (DATC) will develop, construct, own, and operate the Zephyr Power Transmission Project.[238] The transmission project is an 850-mile 500 kV high-voltage, direct-current (HVDC) line with a capacity of 3,000 MW that will originate near Chugwater, Wyoming and terminate south of Las Vegas, Nevada, in the Eldorado Valley with

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235 California ISO, *Energy Imbalance Market—Revised Straw Proposal*, May 30, 2013, p. 2, http://www.caiso.com/Documents/RevisedStrawProposal-EnergyImbalanceMarket-053013.pdf.

236 Jonathan Naughton, Thomas Parish, and Jerad Baker, *Wind Diversity Enhancement of Wyoming/California Wind Energy Projects*, issued January 2013, http://wyia.org/wp-content/uploads/2013/01/final-report-wy-ca-geo-diversity-study1.pdf.

237 Christopher T. Ellison, Attorney for Pathfinder Renewable Wind Energy and Zephyr Power Transmission, LLC, comments on the *2013 Integrated Energy Policy Report*, Docket 13-IEP-1E, May 21, 2013, p. 8, http://www.energy.ca.gov/2013_energypolicy/documents/2013-05-07_transmission_workshop/comments/Pathfinder_and_Zephyr_Joint_Comments_on_May_7_Workshops_in_2013_IEPR_2013-05-21_TN-70925.pdf.

238 Zephyr Power Transmission Project overview, p. 2, http://www.datcllc.com/wp-content/uploads/2013/05/Zephyr-Overview-04.2.13-Print.pdf.

interconnection to the California ISO grid.[239] By the end of 2013, DATC will initiate the federal and state right-of-way permitting process. DATC's target completion date for the Zephyr project is 2020.[240]

TransWest Express, LLC, is permitting and developing the TransWest Express Transmission Project (TWE). The TWE is a 725-mile, 600 kV HVDC line with a capacity of 3,000 MW. The project will deliver renewable energy to the Desert Southwest markets in Arizona, Nevada, and Southern California and provide a transmission backbone between the Intermountain and Desert Southwest regions. About 67 percent of the proposed route is on federal land administered primarily by BLM and the U.S. Forest Service. In October 2011, TWE was one of seven transmission projects designated as a Rapid Response Project by the U.S. Department of Energy's Rapid Response Team for Transmission. On June 28, 2013 the U.S. Environmental Protection Agency published in the *Federal Register* a "Notice of Availability" for the BLM/Western Area Power Administration's TransWest Express Draft EIS with a comment period that ends on September 25, 2013.[241] Construction is slated to begin in 2015 and take roughly three years to complete.[242]

Clean Line Energy Partners LLC is developing the Centennial West Clean Line Transmission Project as an estimated 900-mile, 600 kV HVDC line with a capacity of 3,500 MW that would connect wind and solar resources in New Mexico and Arizona directly to the southern California grid. The line route has not yet been determined. In January 2011, Clean Line submitted an application for right-of-way across Federal lands and a preliminary Plan of Development to the BLM. Construction is estimated to begin in 2017 and the project could begin operations by 2020.[243]

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239 Christopher T. Ellison, Attorney for Pathfinder Renewable Wind Energy and Zephyr Power Transmission, LLC, comments on the *2013 Integrated Energy Policy Report*, Docket 13-IEP-1E, May 21, 2013, pp. 2-3, http://www.energy.ca.gov/2013_energypolicy/documents/2013-05-07_transmission_workshop/comments/Pathfinder_and_Zephyr_Joint_Comments_on_May_7_Workshops_in_2013_IEPR_2013-05-21_TN-70925.pdf.

240 Zephyr Power Transmission Project overview, p. 2, see DATC website at http://www.datcllc.com/wp-content/uploads/2013/05/Zephyr-Overview-04.2.13-Print.pdf.

241 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 on the EPA website at http://yosemite.epa.gov/oeca/webeis.nsf/EIS01/6DDACAE22181AD1A85257B9C001BD82E?opendocument.

242 David F. Smith, TransWest Express, LLC, comments on the 2013 IEPR Transmission Planning and Permitting Issues (13-IEP-1E), Docket 13-IEP-1E, May 22, 2013, p.1, http://www.energy.ca.gov/2013_energypolicy/documents/2013-05-07_transmission_workshop/comments/TransWest_Express_LLC_Comments_re_Transmission_Planning_and_Permitting_Issues_2013-05-21_TN-70927.pdf.

243 Clean Line Energy Partners Centennial West Clean Line Website, http://www.centennialwestcleanline.com/site/home.

Startrans IO is a participating transmission owner in the California ISO balancing area authority that is requesting the California ISO to consider an alternative project as part of the 2013-2014 TPP. The Mead Upgrade Phase I involves converting the existing Mead-Adelanto[244] 500 kV transmission line from alternating current to HVDC operation that would bring in 2,200 MW of additional capacity into Southern California, and the intermittency issue would no longer need to be addressed.[245] Mead-Adelanto is owned by municipal utilities in Southern California (Southern California Public Power Authority), Western Area Power Administration, Modesto Irrigation District, City of Santa Clara, City of Redding, and Startrans.[246] The transmission line was originally designed, built, and permitted with HVDC standards.[247] The upgrade will use the existing towers and conductors, construct converter stations on a low environmental 40-acre footprint on each end, and install 13 miles of new transmission line for maintaining reliability and integrating into the existing system. Estimated completion of the project is in 2017.[248] This project provides an opportunity to take advantage of the existing unused capacity on existing conductors and bring new generation from a generation-rich region to SCE's load centers.[249]

During the California ISO's 2012-2013 TPP, the Zephyr and TransWest Express transmission projects requested to be studied as economic projects. At the May 2013 *IEPR* workshop, DATC stated there is not a mechanism in the California ISO transmission planning process that looks at out-of-state generation to get an economic study and the benefits quantified to make an informed decision. One of DATC's recommendations at the workshop was to "start planning for transmission now, plan for more than you might need because it's much easier to scale back and not build it than it is to try and catch up."[250] TWE made similar comments requesting an

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244 The Mead-Adelanto project, built in 1995, is a 202-mile 500 kV AC transmission line from the existing Adelanto Substation in Southern California to the existing Marketplace Substation near Boulder City, Nevada, with a rating of 1,291 MW. See Southern California Public Power Authority's website at http://www.scppa.org/pages/projects/mead_adelanto.html.

245 Ali Amirali, Starwood Energy Group, *Transcripts From Lead Commissioner Workshop on California and Western States Transmission Planning and Permitting Issues*, May 7, 2013, p. 119, http://www.energy.ca.gov/2013_energypolicy/documents/2013-05-07_siting_workshop/2013-05-07_transcript_afternoon.pdf.

246 Southern California Public Power Authority participants include Anaheim, Azusa, Banning, Burbank, Colton, Glendale, LADWP, Pasadena and Riverside with 67.92 percent ownership rights. The remainder of the ownership on the line includes Western (8.33 percent), Startrans (6.25 percent) and Modesto Irrigation District, City of Santa Clara and City of Redding (M-S-R 17.5 percent).

247 Amirali, Ali, Starwood Energy Group, transcripts from Lead Commissioner Workshop on California and Western States Transmission Planning and Permitting Issues, May 7, 2013, p. 118, http://www.energy.ca.gov/2013_energypolicy/documents/2013-05-07_siting_workshop/2013-05-07_transcript_afternoon.pdf.

248 Ibid, p. 119.

249 Ibid, p. 118.

250 Jeff Gates, Duke American Transmission Company, transcripts from Lead Commissioner Workshop on California and Western States Transmission Planning and Permitting Issues, May 7, 2013, p. 132,

analysis about how out-of-state transmission projects would be incorporated into a system, and does it make sense to incorporate them. TWE's request to the Energy Commission was for consideration about how out-of-state projects could fit into a broader transmission plan.[251] Startrans requested that in meeting the state's energy policy goals the Energy Commission develop a means to submit these projects into the California ISO and help the California ISO in defining the policy projects and getting ahead of the curve.[252] Clean Line Energy Partners sent letters to the Energy Commission[253] and CPUC[254] requesting support at the California ISO for their recommendation of including out-of-state transmission in the GIDAP that would benefit the Centennial West Clean Line Transmission Project and other out-of-state transmission projects. Both agencies found no compelling reason to support Clean Line's recommendation since investor-owned utilities have reached 20 percent renewables and have contracted to meet 33 percent renewables even with some degree of contract failure by 2020. In addition, Energy Commission Chair Robert Weisenmiller identified more pressing policy issues dealing with the reliability of the transmission and distribution system. Some of these issues include:

- Reliability of transmission in Orange County and the San Diego regions with the recent shutdown of San Onofre.
- Increasing the use and efficiency of the existing transmission with an EIM in the West.
- California ISO interconnection queue management.
- The need for a more coordinated effort for environmental and land-use planning of transmission lines identified in the California ISO's Transmission Planning Process.

Both agencies encouraged Clean Line Energy Partners to participate in the California ISO's generator interconnection procedures stakeholder process, which is the proper venue for vetting their recommendation.

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http://www.energy.ca.gov/2013_energypolicy/documents/2013-05-07_siting_workshop/2013-05-07_transcript_afternoon.pdf.

251 David Smith, representing TransWest Express, *transcripts from Lead Commissioner Workshop on California and Western States Transmission Planning and Permitting Issues*, p.138, http://www.energy.ca.gov/2013_energypolicy/documents/2013-05-07_siting_workshop/2013-05-07_transcript_afternoon.pdf.

252 Ali Amirali, Starwood Energy Group, *transcripts from Lead Commissioner Workshop on California and Western States Transmission Planning and Permitting Issues*, May 7, 2013, p. 120, http://www.energy.ca.gov/2013_energypolicy/documents/2013-05-07_siting_workshop/2013-05-07_transcript_afternoon.pdf.

253 Robert B. Weisenmiller, California Energy Commission, Letter to Ms. Jayshree Desai dated January 9, 2013, Clean Line Energy Partners, LLC, Docket No. 13-IEP-1E, TN 71925, August 29, 2013.

254 Michel P. Florio, California Public Utilities Commission, Letter to Ms. Jayshree Desai dated January 18, 2013, Clean Line Energy Partners, LLC, Docket No. 13-IEP-1E, TN 71926, August 29, 2013.

NV Energy Acquisition by MidAmerican Energy

On May 29, 2013, MidAmerican Energy Holdings, a Berkshire Hathaway subsidiary, acquired NV Energy in Nevada. MidAmerican Energy Holdings' other acquisitions include PacifiCorp, Nevada Power, and Rocky Mountain Power. NV Energy is working with the California ISO in developing joint transmission projects between Nevada and California. Also, PacifiCorp, Nevada Power, and Rocky Mountain Power will be participating in the EIM being developed by the California ISO. In addition, MidAmerican Energy Holdings is developing transmission and renewable projects in the West. The company's Energy Gateway Transmission Project is under construction and proposes to connect PacifiCorp's wind and gas assets in Wyoming with its Rocky Mountain Power subsidiary in Utah and its Pacific Power unit in Oregon.

Westlands Solar Park

Westlands Water District (WWD) is proposing to establish the Westlands Solar Park Master Plan and Related Facilities (WSP). Located in west-central Kings County, the area affected is almost entirely cultivated agricultural land. The WWD issued a Notice of Preparation for a draft EIR in April 2013 for potential conversion of 24,000 acres from farmland into a solar park. Over a 12-year period, WWD expects to build a utility-scale solar energy generation facility capable of producing about 2,400 MW.[255]

The proposed WSP area would lead to major changes on existing transmission lines in the area: construction of a new 230 kV transmission line running parallel and adjacent to the existing 230 kV Henrietta-Gates transmission line; potential upgrade to Path 15, the major north-south high-voltage transmission line between northern and southern California between the Gates and Los Banos Substations; and construction of a new Helm-Gregg transmission line that interconnects the Helm Substation (not to be confused with the Helms Pumped Storage Facility in the Sierras) with the Gregg Substation.[256] An alternative that could be explored is to study the use of lower voltage (69 kV and 115 kV) collection lines and interconnect into existing substations.

Supporters of using previously disturbed agricultural land that is no longer productive for development of renewable energy resources include the Defenders of Wildlife,[257] the Natural Resources Defense Council,[258] <u>and the Nature Conservancy.</u>[259]

255 https://cs.westlandswater.org/resources/resources_files/misc/environmental_docs/WWD-WSP-NOP-Final_3-13-2013.pdf.

256 https://cs.westlandswater.org/resources/resources_files/misc/environmental_docs/WWD-WSP-NOP-Final_3-13-2013.pdf, pp. 2-3.

257 https://www.defenders.org/sites/default/files/publications/smartfromthestartreport12_print.pdf.

258 http://switchboard.nrdc.org/blogs/czichella/growing_a_solar_park_in_califo.html.

259 Erica Brand, The Nature Conservancy, comments on *California Energy Commission Docket No. 13-IEP-1A: Draft 2013 IEPR*, October 29, 2013, p. 6, http://www.energy.ca.gov/2013_energypolicy/documents/2013-10-15_workshop/comments/The_Nature_Conservancy_Comments_2013-10-29_TN-72298.pdf.

Emerging Trends in the Western Interconnection

Restructuring the Western Electricity Coordinating Council

Regional oversight of the operation of the high-voltage transmission system in the Western Interconnection is the responsibility of the Western Electricity Coordinating Council (WECC). Its primary mission is to “maintain a reliable electric power system in the Western Interconnection that supports efficient, competitive power markets.” WECC functions under a delegation agreement with the North American Electric Reliability Corporation (NERC), the electricity reliability organization for the United States. Under this agreement, WECC is responsible for implementing and enforcing compliance with the mandatory reliability standards put in place by FERC. WECC is funded through provisions of Section 215 of the Federal Power Act, as approved by FERC. WECC also has contractual arrangements with the governments of British Columbia, Alberta, and Baja Norte Mexico to assist those governments in assuring that entities in their territories with electric system planning and operating responsibilities in the Western Interconnection meet comparable reliability requirements.

Since its formation in 2002, WECC has been governed by a large “hybrid” board of directors, composed of a combination of 26 stakeholder directors and 7 independent directors. The seven member classes include large transmission owners, small transmission owners, other electric lines of business entities (generators/marketers), states/provinces, consumers, Canadian members, and “other.” Key functions WECC undertakes include enforcing continentwide reliability standards; developing and enforcing additional reliability requirements for the Western Interconnection; performing interconnection reliability coordination and interchange authority responsibilities; establishing flow ratings for transmission paths, including capacity ratings for proposed transmission projects and seasonally updated operating path ratings, taking into account actual changes in Western Interconnection topology; conducting interconnectionwide transmission expansion planning; housing the Western Renewable Energy Generation Information System (WREGIS); and providing annual assessments of resource adequacy to NERC for inclusion in national adequacy assessments.

<u>WECC is important to California and the western states and provinces because it performs functions that are essential to the electricity industry. Key among these are establishing and maintaining path ratings for major transmission paths, studying safe operations, and undertaking systematic examinations of disturbances to learn from them and continuously improve reliable operations. Under the delegation agreement, WECC enforces compliance with reliability standards, of which implementation costs are significant and paid for by all consumers and the state economy. Violations of standards anywhere in the 1.8 million-mile Western Interconnection territory can cause hugely disruptive cascading outages that result in substantial economic damage. With the largest load centers in the Western Interconnection, California can bear the brunt of cascading outages, such as those that occurred in the mid 1990s and again in September 2011. It is thus important that California closely monitor the initiative in the West to restructure WECC, led by the WECC Board of Directors at the behest of NERC and FERC commissioners and as approved by the membership.</u>

The goal of restructuring WECC is to separate the responsibility for real-time reliability operation from the regulatory oversight functions of standards development and compliance enforcement. The process was not without opposition, and some members of the large and small transmission owner classes raised substantial objections to the governance and bylaw changes. Key entities in California raised concerns, including the California ISO, SDG&E, the Western Area Power Authority, and others. 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 (RCCo).[260] There will no longer be a hybrid or stakeholder board that governs decisions; instead there will be complete independence required of all board members, with no affiliation with WECC members.

On August 19, 2013, WECC announced that the RCCo will be named Peak Reliability. On January 1, 2014, Peak Reliability will begin Reliability Coordination and Interchange Authority operations as an independent entity. Each entity will be incorporated independently and have separate boards of directors. The soon-to-be-named WECC Board will consist of nine members. The Peak Reliability is a seven-member Board named on October 4, 2013, with authority beginning January 1, 2014. To address membership concerns, each board will be advised by a strong member advisory committee, consisting of three members from each of five classes: large transmission owners, small transmission owners, end users, other electric lines of business entities, and states.

With respect to funding, on March 12, 2013, the WECC filed a petition for declaratory order regarding WECC's plan to establish a separate, independent company, RC Company, to perform the reliability coordinator function in the Western Interconnection, a function currently performed by WECC. WECC sought confirmation that the RC Company could continue to fund the reliability coordinator and WECC interchange tool functions under section 215 of the Federal Power Act. On June 20, 2013, FERC conditionally approved WECC's petition for declaratory order.

~~An important new initiative in the West, led by the WECC Board of Directors at the behest of NERC and FERC commissioners, is the restructuring of WECC. This proposal could, if approved by the membership of WECC, lead to bifurcation and changes in governance of WECC, among other changes. The following subsections briefly describe the proposal, the schedule and status of the proposal, and potential implications for states.~~

~~Proposed Restructuring~~

~~The most significant elements of the proposal are related to structure, governance, and funding. With respect to structure, the WECC Board has approved splitting WECC into two entities: a new reliability coordination company (RCCo) and the existing reliability entity that would be WECC. The goal is to separate the responsibility for real-time reliability operation from the regulatory oversight functions of standards development and compliance enforcement. Each~~

260 Link provides additional information about WECC and Peak Reliability, http://westgov.org/newsite/reliability/reliability-coordination-company-rcco/.

~~entity would be incorporated independently and would have separate boards of directors (described below).~~

~~For governance, significant changes would be made. Specifically, there would no longer be a hybrid or stakeholder board that governs decisions. Instead, there would be complete independence required of all board members, with no affiliation with WECC members. The RCCo would be governed by a seven-member independent board and the RE by a nine-member independent board. To address membership concerns, each board would be advised by a strong member advisory committee, consisting of three members from each of five classes: large transmission owners, small transmission owners, end users, other electric lines of business entities, and states.~~

~~With respect to funding, FERC has been petitioned to approve Section 215 funding for all functions of both entities.~~

~~*Status and Potential Implications*~~

~~All major decisions have been made by the board and the membership has approved bylaw revisions needed to implement bifurcation. On June 27, 2013, the WECC Board of Directors approved bifurcation of the company into a Regional Entity (WECC) and a reliability coordination company (RCCo). Two new member advisory committees have been formed with elected representatives. Candidates for independent board of director positions will likely be nominated in late summer 2013 with elections held in the fall. It is possible that the new RCCo will go live in January 2014.~~

~~The process has not been without opposition, and some members of the large and small transmission owner classes have raised substantial objections to the governance and bylaw changes. Key entities in California have raised concerns, including the California ISO, SDG&E, the Western Area Power Authority, and others. Successful implementation will depend on cooperation of affected parties and could be deterred by potential litigation. Final approval will rest with the NERC in approving a revised delegation agreement and by FERC in approving funding and all reliability-related matters for jurisdictional entities.~~

Potential implications of restructuring moving forward include the following:

- WECC members, including states, lose direct representation with an independent board.
- Eastern United States directors may become more prominent than on the current board because of the requirement for all directors to be nonaffiliated with western entities.
- An independent board may be more inclined toward regional transmission operatorlike functions that have not traditionally been pursued in the Western Interconnection.
- Contingency reserve requirements and other standards essential to reliable operations may change.
- Continuing location and funding of WREGIS and interconnectionwide transmission planning could face increased scrutiny.

- Consensus support for one interconnectionwide reliability coordinator or regional entity function may be eroded.
- Increased membership dues to participate in both WECC and Peak Reliability.

~~*Observations*~~

~~WECC is important to California and the western states and provinces because it performs functions that are essential to the electricity industry. Key among these are establishing and maintaining path ratings for major transmission paths, studying safe operations, and undertaking systematic examinations of disturbances to learn from them and continuously improve reliable operations. Under the delegation agreement, WECC enforces compliance with reliability standards whose implementation costs are significant and paid for by all consumers and the state economy. Violations of standards anywhere in the 1.8 million-mile Western Interconnection territory can cause hugely disruptive cascading outages that result in substantial economic damage. With the largest load centers in the Western Interconnection, California can bear the brunt of cascading outages, such as those that occurred in the mid 1990s and again in September 2011. It is thus important that California closely monitor implementation of changes at WECC as approved by the membership.~~

Presidential Memorandum on Improved Transmission Siting, Permitting, and Review

On June 7, 2013, the White House issued a presidential memorandum titled *Transforming Our Nation's Electric Grid Through Improved Siting, Permitting, and Review*.[261] The memorandum builds on the work of the administration's Rapid Response Team for Transmission (RRTT) aimed at improving the performance of federal siting, permitting, and review for infrastructure development.[262] In particular, the memorandum builds upon the work of the RRTT related to transmission projects, noting that a transmission project may cross multiple jurisdictions over hundreds of miles, thereby requiring robust coordination among federal, state, local, and tribal governments. The memorandum notes that an important avenue for improving these processes is the designation of corridors on federal land because the designation of such corridors can help expedite siting, permitting, and review for projects within such corridors and improve the predictability and transparency of these processes.

The memorandum also builds upon previous corridors designated under to Section 368 of EPAct-05. In January 2009, the Secretaries of the Interior and Agriculture designated energy

261 Available at http://www.whitehouse.gov/the-press-office/2013/06/07/presidential-memorandum-transforming-our-nations-electric-grid-through-i.

262 The Rapid Response for Transmission Team (RRTT) aims to improve the overall quality and timeliness of electric transmission infrastructure permitting, review, and consultation by the Federal government on both Federal and nonfederal lands. The RRTT is focusing initially on seven pilot project transmission lines, one of which is the TransWest Express Transmission Project, discussed earlier in the chapter. For more information on the Rapid Response Team for Transmission, see http://www.whitehouse.gov/administration/eop/ceq/initiatives/interagency-rapid-response-team-for-transmission.

corridors in the 11 contiguous western states.[263] In July 2009 environmental groups sued various agencies of the federal government, challenging their compliance with EPAct-05 and the National Environmental Policy Act, and challenged several Records of Decisions and some requirements of the Endangered Species Act. On July 3, 2012, the parties filed a settlement agreement that required the completion of a new memorandum of understanding among the parties within 12 months and, that once signed, "the agencies will commence a periodic review of section 368 corridors, with recommendations due twelve months thereafter."[264] According to the Wilderness Society, "Through the settlement, the designations will be reevaluated and revised to better: avoid environmentally sensitive areas, diminish proliferation of dispersed right-of-ways (ROWs), and facilitate development of renewable energy projects."[265]

The Energy Commission believes the tasks outlined in the presidential memorandum are timely, appropriate, and consistent with the state's transmission corridor designation process established by SB 1059. In particular, the Energy Commission agrees with the "Principles for Establishing Energy Corridors" in section 1 of the memorandum. These include facilitation of renewable resources; collaboration with state, local, and tribal governments to ensure that energy corridors can connect effectively between federal lands; and designing energy corridors to minimize environmental and cultural resource impacts to the extent practicable, including impacts that may occur outside the boundaries of federal lands. The Energy Commission also supports the encouragement of the memorandum on the use of designated federal corridors and the steps to be taken to consider additions, deletions, and revisions to those corridors as outlined in Section 2 of the memorandum "Energy Corridors for the Western States." Finally, the Commission appreciates the focus of Section 4, "Improved Transmission Siting, Permitting, and Review Processes," and supports the creation of an integrated, interagency preapplication process for significant transmission projects requiring federal approval.

Recommendations

- **Encourage 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, the state should encourage entities both within and outside California to join the California ISO's energy imbalance market.
- **Identify long-term transmission solutions and ways to reduce transmission permitting timelines.** The energy agencies should continue to work together to analyze and recommend the long-term potential transmission solutions to address reliability concerns associated with the recent shutdown of San Onofre. The energy agencies should continue to

263 For more information, see the Westwide Energy Corridor Programmatic EIS Information Center website at http://corridoreis.anl.gov/.

264 For more information, see the settlement agreement at http://corridoreis.anl.gov/documents/docs/Settlement_Agreement_Package.pdf.

265 http://www.npca.org/assets/pdf/Settlement_Facts_West_Wide_Energy_Corridors.pdf, p. 1.

explore ways to achieve the Governor's goals on reducing the permitting time for transmission projects in California.

- **Evaluate deliverability requirements.** The cost-effectiveness, prudency, 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 greenhouse gas emission reduction goals.
- **Identify transmission corridors.** 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 effort, 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.

CHAPTER 6:
Nuclear Power Plants

In 2011, nuclear power played a significant role in California's energy mix, providing roughly 18 percent of California's ~~in-state~~ electricity generation. This generation came from three plants: the Diablo Canyon Power Plant (Diablo Canyon) and the San Onofre Nuclear Generating Station (San Onofre) in California, and the Palo Verde nuclear power plant in Arizona. Given the importance of California's nuclear facilities to the state's electricity supply, in 2006 Assembly Bill 1632 (Blakeslee, Chapter 722, Statutes of 2006) directed the Energy Commission to evaluate major issues related to the future role of these plants in the state's energy portfolio. The Energy Commission issued the *Assessment of California's Nuclear Power Plants: AB 1632 Report* as part of the *2008 Integrated Energy Policy Report Update*, which included a detailed list of recommendations on issues such as seismic events, plant aging, and potential effects of plant disruption on reliability, public safety, and the economy.

In 2011, the disaster at the Fukushima Daiichi nuclear plant in Japan heightened concerns about safety issues for California's coastal nuclear plants. The Nuclear Regulatory Commission (NRC) established a task force to evaluate what lessons might apply to the safety of United States reactors and instructed NRC plant inspectors to conduct immediate, independent assessments of each plant's level of emergency preparedness. In 2011, the NRC's Near-Term Task Force (NTTF)[266] issued post-Fukushima recommendations for enhancing reactor safety and a priority list of actions, and, following up on the AB 1632 report, the *2011 IEPR* called for utilities to report on their progress in implementing report recommendations related to seismic and tsunami hazard studies and emergency response planning.

On June 7, 2013, Southern California Edison (SCE) announced it was permanently closing San Onofre because of economic considerations and continued regulatory uncertainty related to plans to restart Unit 2 at reduced power. Both Units 2 and 3 had been shutdown since January 2012 due to damaged steam generator tubes. While the San Onofre closure has made some of the *2011 IEPR* recommendations obsolete, concerns remain about the storage of spent nuclear fuel onsite and plans for decommissioning.

This chapter discusses progress toward implementing recommendations made in the *AB 1632 Report* and the *2011 IEPR*, and by the NRC's Near-Term Task Force. It also summarizes recent federal efforts on nuclear waste transport, storage, and disposal; pending legislative proposals on nuclear issues; and events related to the shutdown of the San Onofre Units 2 and 3 that ultimately led to SCE's announcement to permanently close the plant.

266 The Near-Term Task Force was established in response to NRC direction to conduct a systematic and methodical review of U.S. NRC processes and regulations to determine whether the agency should make additional improvements to its regulatory system and to make recommendations to the NRC for its policy direction, in light of the accident at the Fukushima Daiichi Nuclear Power Plant.

Background

In 2006, AB 1632 directed the Energy Commission to assess the potential vulnerability of "large baseload generation facilities of 1,700 megawatts or greater" to a major disruption due to a seismic event or plant age-related issues. In response to AB 1632 and as part of the *2008 IEPR Update,* the Energy Commission developed *An Assessment of California's Nuclear Power Plants: AB 1632 Report*.[267] The *AB 1632 Report* addressed seismic and tsunami hazards, reliability concerns, and specific vulnerabilities of Diablo Canyon[268] and San Onofre [269] and made policy recommendations that were incorporated into the *2008 IEPR Update*. Beginning with the *2009 IEPR*, Pacific Gas and Electric Company (PG&E) and Southern California Edison (SCE) have reported every two years on their progress in implementing the *AB 1632 Report* recommendations. Several policy recommendations from the *2011 IEPR* also call for updates and progress reports from PG&E and SCE.

Since the March 2011 Fukushima Daiichi nuclear disaster,[270] the NRC has been working to understand the events in Japan and relay important information to U.S. nuclear power plants. In July 2011, the NRC's NTTF provided recommendations to enhance U.S. reactor safety,[271] and these became the foundation for the NRC's post-Fukushima activities. The NRC has since created the Japan Lessons Learned Project Directorate in the Office of Nuclear Reactor Regulation to implement those recommendations.

The U.S. Department of Energy (DOE) has for decades worked toward resolving issues associated with the safe transport, storage, and permanent disposal of nuclear waste. In January 2013, the DOE issued the *Strategy for the Management and Disposal of Used Nuclear Fuel and High-Level Radioactive Waste*[272] as a framework for moving toward a sustainable program to deploy an integrated system capable of transporting, storing, and disposing of used nuclear fuel and high-

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267 California Energy Commission, *An Assessment of California's Nuclear Power Plants: AB 1632 Report*, October 2008, CEC-100-2008-009-CMF, available at http://www.energy.ca.gov/2008publications/CEC-100-2008-009/CEC-100-2008-009-CMF.PDF.

268 Diablo Canyon is located north of Avila Beach in San Luis Obispo County and is owned by Pacific Gas and Electric Company.

269 San Onofre is located south of San Clemente in San Diego County and is co-owned by Southern California Edison, San Diego Gas & Electric, and Riverside Public Utilities.

270 On March 11, 2011, a 9.0-magnitude earthquake struck Japan and was soon followed by a tsunami, estimated to have exceeded 45 feet (14 meters) in height, resulting in extensive damage to the six nuclear power reactors at the Fukushima Daiichi site.

271 Recommendations for Enhancing Reactor Safety in the 21st Century, July 12, 2011, http://pbadupws.nrc.gov/docs/ML1118/ML111861807.pdf.

272 http://energy.gov/sites/prod/files/Strategy%20for%20the%20Management%20and%20Disposal%20of%20Used%20Nuclear%20Fuel%20and%20High%20Level%20Radioactive%20Waste.pdf.

level radioactive waste from civilian nuclear power generation, defense, national security, and other activities.

The NRC's Waste Confidence Decision and Rule represent the generic determination by the NRC that spent nuclear fuel can be stored safely and without significant environmental effects for a period after the end of the licensed life of a nuclear power plant. However, on June 8, 2012, the U.S. Court of Appeals for the District of Columbia Circuit found that some aspects of the NRC's 2010 Decision did not satisfy the NRC's National Environmental Policy Act (NEPA)[273] obligations and vacated the decision and rule. The court indicated that the NRC needed to add discussions concerning the consequences of failing to secure permanent disposal for spent nuclear fuel and the effects of certain aspects of potential spent fuel pool leaks and spent fuel pool fires. On August 7, 2012, the NRC suspended all final licensing activities that rely on the decision[274] and created a Waste Confidence Directorate within the Office of Nuclear Material Safety and Safeguards to oversee drafting of a new Waste Confidence Generic Environmental Impact Statement (GEIS) and Rule.

In 2012, the percentage of nuclear generation in California's power mix dropped by half to about 9 percent[275] because of the total loss of generation from the outage at San Onofre.[276] O~~Beginning i~~n January 9, 2012, San Onofre Unit 2 was taken offline for a scheduled refueling outage that included steam generator inspections. On January 31, 2012, San Onofre Unit 3 was removed from service due to a steam generator tube leak. The investigation of the steam generators on both units identified ~~due to~~ unexpected degradation of the newly installed steam generator tubes in both Units 2 and 3. ~~Damage to Unit 3 was extensive, and the fuel was removed in late 2012~~SCE first focused its efforts on the restart of Unit 2 and decided to remove the fuel from the Unit 3 reactor vessel which was completed on October 5, 2012. After many months of uncertainty regarding the possibility of restarting Unit 2, on June 7, 2013, SCE announced plans to permanently retire San Onofre Units 2 and 3.[277]

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273 Signed into law on January 1, 1970, NEPA was the first major environmental law in the United States. NEPA requires federal agencies to assess the environmental effects of their proposed actions before making decisions.

274 http://pbadupws.nrc.gov/docs/ML1222/ML12220A100.pdf.

275 Percentage excludes imported electricity. Source: Installed Capacity Tracking Progress, Table 2: In-State Electric Generation by Fuel Type from Power Plants Larger than 1 MW, pg. 4.

http://www.energy.ca.gov/renewables/tracking_progress/documents/installed_capacity.pdf.

276 San Onofre Units 2 and 3 have been offline since January 2012 due to unexpected degradation of tubes in the newly installed steam generators; see http://www.nrc.gov/info-finder/reactor/songs/tube-degradation.html.

277 http://www.songscommunity.com/news2013/news060713.asp.

Implementing AB 1632 Report and *2011 IEPR* Recommendations

The *AB 1632 Report* made recommendations that required the utilities to report biennially on topics such as seismic vulnerability, plant aging-related degradation, impacts of a major disruption, economic and environmental policy issues, nuclear waste accumulation, and licensing renewal issues. The *2011 IEPR* included recommendations on seismic issues, the spent fuel pool and Independent Spent Fuel Storage Installation (ISFSI), station blackout, liability coverage, Fukushima lessons learned, and plant safety.

Much of the reporting from utilities on these topics covers activities that are taking place concurrently or are ongoing. Some of the activities involve processes that will take many years to complete. This section discusses progress made on activities that are new or continuing. (See Appendix I for a Summary and Status of all *2011 IEPR* Nuclear Policy Recommendations.)

Diablo Canyon

Seismic and Tsunami Hazards

The *AB 1632 Report* recommended that PG&E report on the overall status of ongoing efforts to understand seismic hazards affecting the Diablo Canyon site through its Long Term Seismic Program (LTSP) and the results of the research. NRC NTTF recommendation 2.1 requires nuclear power plants to conduct seismic hazard and risk evaluations in conformance with the Senior Seismic Hazard Analysis Committee (SSHAC) Level 3 process as outlined in the NRC's NUREG-2117, *Practical Implementation Guidelines for SSHAC Level 3 and 4 Hazard Studies.*[278] Risk evaluations are required for plants where the hazard exceeds the design basis of the plant. Based on the information from the seismic hazard and risk evaluations, the NRC will determine appropriate regulatory actions (such as issuing orders for upgrades to the plant).

A seismic hazard update is underway for the Diablo Canyon site that will use an updated Seismic Source Characterization (SSC) and updated Ground Motion Characterization (GMC) as basic inputs to a site-specific probabilistic seismic hazard analysis (PSHA). The SSC describes the future earthquake potential (that is, magnitudes, locations, and rates) for the region surrounding the Diablo Canyon site, and the GMC describes the distribution of the ground motion as a function of magnitude, style-of-faulting, source-to-site geometry, and site condition.

The Diablo Canyon SSHAC Level 3 study started in April 2011. The project was designed as a combined SSC and GMC study. In June 2012, the study was divided into two SSHAC Level 3 studies—a site-specific SSC project for the Diablo Canyon site region and a regional GMC study that would be applicable to the southwestern United States (SWUS). The new project structure and organization of the SWUS GMC included SCE and Arizona Public Services. Workshop 2 for the SSHAC SSC study was held in November 2012 with the primary goal of interactively using the "proponent experts"[279] to explore the center, body, and range of technical defensible

278 http://pbadupws.nrc.gov/docs/ML1211/ML12118A445.pdf.

279 A *proponent expert* advocates a particular hypothesis or technical position. Examples of proponent experts include representatives from federal agencies (for example, U.S. Geological Survey), educational

interpretations for the SSC for the Diablo Canyon region, with a focus on those parameters most significant to the seismic hazard.

The SWUS GMC Workshop 2 ~~is planned for~~was held in October 2013 in Berkeley, California. Workshop 3, "Preliminary Model and Hazard Feedback," is scheduled for the first quarter of 2014 for both the SSC and SWUS GMC SSHAC studies. The completion of the study is on track for March 2015, with an updated site-specific PSHA and new ground motion response spectra (GMRS).

One outstanding issue related to the seismic hazards affecting Diablo Canyon is the evaluation of seismic hazards against the plant's licensed design basis. Two elements of the design basis, the Design Earthquake[280] (DE) and the Double Design Earthquake[281] (DDE), include more conservative assumptions about seismic hazards than the third element, the Hosgri Evaluation, which was the basis for the Diablo Canyon's LTSP ground motion response spectra. In August 2011, the NRC noted[282] that "Region IV was unable to confirm the licensee's statements that new seismic information was only required to be evaluated under the LTSP. Although the LTSP margin analysis demonstrated that the new Shoreline Fault Zone information was bounded by the [Hosgri Evaluation[283]], the licensee didn't evaluate the new seismic information against the other two design basis earthquakes, the DE and DDE."

The NRC concluded that the Hosgri Evaluation was not by itself bounding for Diablo Canyon seismic qualification. New seismic information developed by PG&E must be evaluated against all three of the seismic design basis earthquakes and the assumptions used in the supporting safety analysis; comparison to the LTSP by itself is not sufficient.

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institutions, organizations representing the scientific community (such as the Southern California Earthquake Center), and specialized consultants.

280 Design Earthquake (0.2g) —The amount of vibratory ground motion for which those plant features necessary for continued operation remain functional without undue risk to the health and safety of the public.

281 Double Design Earthquake (0.4g) —The evaluation of the maximum earthquake potential (producing the maximum vibratory ground motion) for which structures, systems, and components needed to prevent or mitigate an accident will remain functional, allowing for some plastic deformation of structural material.

282 Task Interface Agreement, Concurrence on Diablo Canyon Seismic Qualification Current Licensing and Design Basis (TIA 2011-010) http://pbadupws.nrc.gov/docs/ML1121/ML112130655.pdf

283 Hosgri Event (0.75g) —A postulated 7.5 M earthquake (unique to Diablo Canyon) assumed to occur on the Hosgri Fault line. Only equipment credited in the alternate Hosgri Event shutdown path is required to remain functional following a Hosgri design basis earthquake.

In November 2011, PG&E reported on the implications of this issue in its quarterly report to the Securities Exchange Commission:[284] "the NRC found that a report submitted by the Utility to the NRC on January 7, 2011 to provide updated seismological information did not conform to the requirements of the current Diablo Canyon operating license. On October 21, 2011, the Utility filed a request that the NRC amend the operating license to address this issue. If the NRC does not approve the request the Utility could be required to perform additional analyses of Diablo Canyon's seismic design which could indicate that modifications to Diablo Canyon would be required to address seismic design issues. The NRC could order the Utility to cease operations until the modifications were made or the Utility could voluntarily cease operations if it determined that the modifications were not economical or feasible."

PG&E withdrew the proposed license amendment after NRC staff allowed it to delay the DDE test until completion of its post-Fukushima seismic evaluation (that is, the current SSHAC process) in 2015. This action by the NRC resulted in assertions by the Alliance for Nuclear Responsibility[285] that Diablo Canyon is operating in violation of its licensing conditions and that NRC staff, by electing to waive enforcement of the DDE criteria for operability determinations against the new seismic information associated with the Shoreline Fault, the San Luis Bay Fault, and the Los Osos Fault, has in effect approved a "*de facto*" license amendment.[286]

PG&E has stated[287] that this position is not supported by NRC documentation including an October 12, 2012 news release[288] that states, "The Nuclear Regulatory Commission's latest analysis of faults near the Diablo Canyon nuclear power plant in California continues to conclude the plant's design would withstand earthquakes near the site" and Revised Task Interface Agreement (TIA) 2012-012[289] (superseding TIA 2011-010),[290] that states, "[T]he

284 Form 10-Q Quarterly Report Pursuant to Section 13 OR 15(d) of the Securities Exchange Act of 1934, Period ended September 30, 2011, http://www.sec.gov/Archives/edgar/data/75488/000119312511295273/d234790d10q.htm.

285 The Alliance for Nuclear Responsibility identifies itself as a nonprofit organization that works to educate and protect the citizens of the State of California and future generations from the dangers of radioactive contamination. http://a4nr.org.

286 Prepared Rebuttal Testimony of John Geesman on Behalf of the Alliance for Nuclear Responsibility Before the California Public Utilities Commission, June 28, 2013, http://a4nr.org/wp-content/uploads/2013/06/A-12-11-009-Rebuttal-Testimony-_-Apend.pdf.

287 Comments of Pacific Gas and Electric Company on Draft 2013 IEPR, October 29, 2013, http://www.energy.ca.gov/2013_energypolicy/documents/2013-10-15_workshop/comments/Pacific_Gas_and_Electric_Company_Comments_2013-10-29_TN-72292.pdf.

288 Press Release-12-112: Additional NRC Analysis Confirms Earthquake Safety At Diablo Canyon Nuclear Power Plant, October 12, 2012, http://pbadupws.nrc.gov/docs/ML1228/ML12286A313.pdf.

289 Diablo Canyon Power Plant, Units 1 and - Revised Response to Task Interface Agreement, Diablo Canyon Seismic Qualification Current Licensing and Design Basis, TIA 2011-010 (TIA 2012-012) (TAC NOS. ME9840 AND ME9841) November 19, 2012, http://pbadupws.nrc.gov/docs/ML1229/ML12297A199.pdf.

Shoreline scenario should be considered as a lesser included case under the Hosgri evaluation and the licensee should update the Final Safety Analysis Report Update, as necessary, to include the Shoreline scenario." Furthermore, in TIA 2012-012, the NRC concluded that the 50.54(f) seismic reevaluation process is the appropriate venue for addressing new seismic information and that NRC staff expects PGE to use the DDE for comparison with the reevaluated seismic hazard GMRS. The NRC has indicated that for Diablo Canyon, the probabilistic hazard analysis will likely exceed the DDE, and plant risk evaluations will be needed.[291] Plant risk evaluations include an expedited and complete plant risk evaluation. PG&E has already performed a seismic probabilistic risk assessment (PRA) but will need to update it to account for new, reevaluated ground motion levels that will be coming out of the SSHAC process.

The *AB 1632 Report* also recommended that PG&E use three-dimensional geophysical seismic reflection mapping and other advanced techniques to explore fault zones near Diablo Canyon. In November 2012, PG&E's plans to conduct the recommended 3-D, high-energy seismic surveys offshore of Diablo Canyon were denied by the California Coastal Commission,[292] partly because of potentially significant environmental impacts.[293] As a result, no high-energy marine seismic surveys have been conducted. However, PG&E still plans to conduct other surveys and studies, such as low-energy two-dimensional and 3D (which the Diablo Canyon Independent Peer Review Panel[294] will continue to review), in addition to seismic hazard reevaluations being performed as required by NRC NTTF recommendations.

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290 Ibid

291 Cliff Munson, U.S. NRC, Lead Commissioner Workshop on California Nuclear Power Plant Issues, June 19, 2013.

292 The California Coastal Commission also objected to PG&E's certification of the proposed project's consistency with California's approved coastal zone management program because the proposed project did not meet the first test of Coastal Act Section 30260 (the coastal-dependent industrial development "override" policy of the Coastal Act). http://www.coastal.ca.gov/fedcd/cach3.pdf.

293 California Coastal Commission Staff Report and Addendum, November 13, 2012. http://documents.coastal.ca.gov/reports/2012/11/W13b-11-2012.pdf.

294 The Diablo Canyon Independent Peer Review Panel is a multiagency panel of seismic hazard specialists who work under the auspices of the CPUC to provide independent review of PG&E's plans and analyses of enhanced seismic studies. Established by CPUC Decision 10-08-003 (http://docs.cpuc.ca.gov/word_pdf/FINAL_DECISION/122059.pdf), its members include representatives from the California Geological Survey, California Coastal Commission, California Emergency Management Agency, California Energy Commission, California Seismic Safety Commission, California Public Utilities Commission, and the County of San Luis Obispo. IPRP reports are available on the CPUC's website on nuclear power at http://www.cpuc.ca.gov/PUC/energy/nuclear.htm.

Vulnerabilities

PG&E completed a tsunami hazard study titled ~~*Pacific Gas & Electric Company,*~~ *Methodology for Probabilistic Tsunami Hazard Analysis: Trial Application for the Diablo Canyon Power Plant Site* on April 9, 2010.[295] PG&E found no new hazards that warrant inclusion into the Diablo Canyon design and license basis. The NRC's 50.54(f) request for information[296] regarding NTTF Recommendation 2.1 directed all licensees to perform a flood hazard reevaluation of all appropriate external flooding sources, including the effects from local intense precipitation on the site, probable maximum flood on stream and rivers, storm surges, seiches,[297] tsunamis, and dam failures. The flood hazard reevaluation collects information for the NRC to determine if there is a need to update the design basis and systems, structures, and components important to safety to protect against updated hazards at operating reactor sites. In response to this request, PG&E agreed to perform a flood hazard reevaluation and provide a final report documenting results, as well as pertinent site information and detailed analysis by March 12, 2015.[298] Along with this flood hazard reevaluation, PG&E will consider new and significant information and research conducted since the *2010 Probabilistic Tsunami Hazard Analysis* draft was completed (such as sea-level rise and extreme wave characteristics).

The inventory of the Diablo Canyon spent fuel pools as of June 2013 was 2,112 spent nuclear fuel assemblies, including 1,060 assemblies from Unit 1 and 1,052 assemblies from Unit 2.[299] PG&E's *2011 IEPR* response indicated that the spent fuel pool inventory was 2,164 assemblies and that the ISFSI contained 16 storage casks, each containing 32 spent fuel assemblies. In 2012, PG&E loaded an additional 7 casks, bringing the number of storage casks to 23. PG&E plans to load an additional 6 casks during the summer of 2013.

Although PG&E has made progress in moving used fuel assemblies from wet to dry storage, the density in the spent fuel pools is still roughly four times the design capacity of the original spent fuel racks. Furthermore, if relicensed,[300] PG&E intends to store the spent fuel generated during the 20-year relicensing period in the spent fuel pools at close to the existing density.

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295 https://www.pge.com/regulation/DiabloLicenseRenewal/Other-Docs/PGE/2011/DiabloLicenseRenewal_Other-Doc_PGE_20110201Atch01_205921.pdf.

296 http://pbadupws.nrc.gov/docs/ML1205/ML12054A735.pdf.

297 A *seiche* is a wave that oscillates in lakes, bays, or gulfs from a few minutes to a few hours as a result of seismic or atmospheric disturbances.

298 http://pbadupws.nrc.gov/docs/ML1233/ML12333A145.pdf.

299 *2013 Integrated Energy Policy Report*: Pacific Gas and Electric Company Supplemental Response to Nuclear Data Request, June 18, 2013. http://www.energy.ca.gov/2013_energypolicy/documents/nuclear_responses/PGandE_Response_TN-70883_Files/PGandE_Supplemental_Nuclear_Data_Response.pdf.

300 On April 10, 2011, PG&E requested that the NRC defer issuance of renewed operating licenses until updated seismic studies were completed (see http://pbadupws.nrc.gov/docs/ML1110/ML111020618.pdf). The NRC responded on May 31, 2011 (see http://pbadupws.nrc.gov/docs/ML1113/ML11138A315.pdf) by revising the remaining review schedule for the license renewal application to "To Be Determined" and

In July 2010, the NRC issued Requests for Additional Information (RAIs) for PG&E structures aging management programs (AMPs) reviewed during the AMP audit.[301] RAI B2.1.32-4 requested further information in response to reports from Diablo Canyon personnel that the spent fuel pool has had a persistent minor leak for many years. It was unclear to staff if leakage of the borated water has degraded either the concrete or embedded steel reinforcement that is inaccessible for inspection. PG&E's response indicated that the Unit 2 spent fuel pool has had persistent minor leakage varying from 50 to 975 milliliters (ml) per week, with a typical range of 300 to 500 ml per week, and that the evaluations to date have not been able to identify conclusively the root cause of the leakage.[302] The path of the leakage is through the liner to the spent fuel pool leak chase monitoring location.[303] Structures that could be potentially affected by the presence of the borated water are the spent fuel pool concrete and structural steel. PG&E concluded that, based on evaluation of industry experience on spent fuel pool leakage,[304] the amount of leakage being experienced was acceptable as there is a negligible adverse effect on the concrete and reinforcing steel. However, the extent of damage to the Unit 2 spent fuel pool concrete and embedded steel reinforcement remains unknown in inaccessible areas.

PG&E's current and planned wet storage practices at Diablo Canyon comply with NRC license requirements,[305] the safety of which is supported by a July 2013 consequence study conducted by the NRC.[306] The study sought to examine if faster removal of older, colder spent reactor fuel from pools to dry cask storage significantly reduces risks to public health and safety. This study compared potential accident consequences from a pool nearly filled with spent fuel and a pool in which fuel that had cooled sufficiently had been removed. The regulatory analysis for the NRC study indicates that expediting movement of spent fuel from the pool does not provide a substantial safety enhancement for the reference plant.

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instructing PG&E to update the NRC on the schedule of completion of the 3-D seismic studies and estimated receipt of a coastal consistency certification.

301 http://pbadupws.nrc.gov/docs/ML1025/ML102530542.pdf.

302 http://pbadupws.nrc.gov/docs/ML1025/ML102530195.pdf.

303 A *leak chase* is a channel that collects water leaking through the liner of spent fuel pool. The leak chase monitoring location is where the amount of water leakage can be measured.

304 *Repair and Replacement Applications Center: Boric Acid Attack of Concrete and Reinforcing Steel in PWR Fuel Handling Buildings*, EPRI, Palo Alto, CA: 2009. 1019168, Final Report, June 2009.

305 The NRC approved Diablo Canyon's 1985 license amendment request (LAR-85-13) allowing expansion of the spent fuel pool storage capacity for each spent fuel pool from the original 270 to 1,324 spent fuel assembly spaces.

306 Consequence Study of a Beyond-Design-Basis Earthquake Affecting the Spent Fuel Pool for a U.S. Mark I Boiling Water Reactor, https://www.federalregister.gov/articles/2013/07/02/2013-15840/consequence-study-of-a-beyond-design-basis-earthquake-affecting-the-spent-fuel-pool-for-a-us-mark-i.

However, the NRC study does not appear to be supported by National Academy of Sciences conclusions from the report *Safety and Security of Commercial Spent Nuclear Fuel Storage: Public Report (2006)*[307] that dry cask storage offers several advantages over pool storage. Dry cask storage is a passive system that relies on natural air circulation for cooling, rather than requiring water to be continually pumped into cooling pools to replace water lost to evaporation caused by the hot spent fuel. Also, dry cask storage divides the inventory of spent fuel among a large number of discrete, robust containers, rather than concentrating it in a relatively small number of pools. The NAS report also concluded that while successful attacks on spent fuel pools are difficult, they are a possibility and could lead to the release of large amounts of radioactive material.

In 1980, the NRC adopted fire protection regulations intended to reduce the chance of disabling fires at nuclear power plants. In the late 1990s, NRC inspectors discovered that many nuclear plants did not conform to these regulations. In 2004, the NRC adopted an alternative set of fire protection regulations,[308] and plant owners had the option of complying with either the 1980 or 2004 regulations. Diablo Canyon notified the NRC of the intention to comply with the 2004 regulations. Compliance with the 2004 regulations involves extensive modifications to the plant and its procedures to obtain necessary protection against fire hazards. On October 10, 2012, an NRC Event Notification Report[309] identified three unanalyzed fire protection deficiencies. The report noted that Diablo Canyon staff identified fire areas that neither conformed to 10 CFR 50.48(b)[310] requirements nor had established, proceduralized, and practiced compensatory measures in place. The issues were identified in the Diablo Canyon corrective action program, and compensatory measures were established in accordance with Diablo Canyon fire protection program requirements. Roving fire watches are serving as interim fire protection (compensatory) measures for the three deficiencies until permanent corrective measures are determined and implemented.

PG&E submitted a fire protection license amendment request to the NRC on June 26, 2013,[311] which according to PGE[312], upon approval, would transition the DCPP fire protection program to a new risk-informed, performance-based alternative in accordance with 10 CFR 50.48(c) (incorporating by reference NFPA 805). In the license amendment request, PG&E also requested

307 http://www.nap.edu/openbook.php?isbn=0309096472.

308Alternate Fire Protection Rule [10 CFR 50.48(c), National Fire Protection Association (NFPA) 805], http://www.nrc.gov/reactors/operating/ops-experience/fire-protection/protection-rule.html.

309 Event Notification Report for October 10, 2012, Event Number: 48395, http://www.nrc.gov/reading-rm/doc-collections/event-status/event/2012/20121010en.html.

310 Code of Federal Regulations (CFR) § 50.48 Fire Protection, http://www.nrc.gov/reading-rm/doc-collections/cfr/part050/part050-0048.html.

311 http://pbadupws.nrc.gov/docs/ML1319/ML13196A139.pdf.

312 Comments of Pacific Gas and Electric Company on Draft *2013 IEPR*, October 29, 2013, http://www.energy.ca.gov/2013_energypolicy/documents/2013-10-15_workshop/comments/Pacific_Gas_and_Electric_Company_Comments_2013-10-29_TN-72292.pdf.

certain changes to the DCPP facility operating licenses that describe how PG&E may make changes to its approved fire protection program without prior approval by the NRC.[313] NRC staff will complete a detailed technical review and make an independent assessment regarding the acceptability of the proposed amendment in terms of regulatory requirements and the protection of public health and safety and the environment.

In 2011, in its Twenty-first Annual Report on the Safety of Diablo Canyon Nuclear Power Plant Operations,[314] the Diablo Canyon Independent Safety Committee (DCISC),[315] in response to the Energy Commission's *2009 IEPR* recommendation, reported on its evaluation of reactor pressure vessel integrity for Diablo Canyon over a 20-year license extension period in the context of any change to seismic hazard at the site. In its evaluation of pressurized thermal shock[316] and seismic interactions at Diablo Canyon, the DCISC concluded that there is no direct relationship between having earthquakes, even very large earthquakes, and pressurized thermal shock issues associated with neutron embrittlement[317] of the reactor vessel.

In a separate issue related to the Unit 2 pressurizer nozzles, in March 2013, PG&E submitted a request to the NRC for relief from certain American Society of Mechanical Engineers (ASME) Code requirements for pressure vessels. The request for relief was on the basis that complying with the ASME Code requirement to remove laminar indications (flaws) on preemptive structural weld overlays would result in hardship or unusual difficulty without a compensating increase in the level of quality or safety. The weld overlays were originally inspected in March 2008 using ultrasonic testing and again in 2009. In February 2013, using more advanced ultrasonic testing techniques, several flaws were discovered that were outside the ASME Code allowable screening size. PG&E plans to initiate an evaluation to determine the root cause(s) of the flaws, to understand why they were not detected originally, and to identify any required corrective actions. On August 28, 2013, the NRC determined that PG&E's proposed alternative (to permit the unacceptable laminar flaws to remain in service) provides reasonable assurance

313 http://pbadupws.nrc.gov/docs/ML1328/ML13281A495.pdf.

314 Diablo Canyon Independent Safety Committee Twenty-first Annual Report on the Safety of Diablo Canyon Nuclear Power Plant Operations, July 1, 2010–June 30, 2011, http://www.dcisc.org/21st-pdf.pdf.

315 The DCISC was created by the CPUC in 1988 (D.88_12_083) to assess safety of DCPP operations and makes recommendations for the plant's safe operation. The Energy Commission Chair appoints one of three members; in 2012, Dr. Peter Lam was reappointed for a three-year term beginning July 1, 2012, through June 30, 2015.

316 *PTS* is a phenomenon that may occur due to an accident condition of some kind wherein cold water is injected into a reactor vessel, thereby causing an area of the vessel to go through a transition from ductile to brittle and whereby preexisting small flaws in the metal vessel could propagate and cause failure of the reactor vessel.

317 *Neutron embrittlement* can be caused by the presence of significant amounts of copper in metal used in existing reactors. (Some steel that was used in existing reactors came from recycled materials that may have contained copper.) Thus, new reactor vessels do not use steel or weld materials containing significant amounts of copper.

of structural integrity and leak tightness and authorized use of the proposed alternative for one cycle of operation (about 18 months).[318]

Emergency Response Planning

Following the Fukushima Daiichi nuclear disaster, the NRC initiated lessons-learned evaluations for U.S. nuclear plants. The NRC established the NTTF to develop a comprehensive set of recommendations using defense-in-depth concepts of prevention, mitigation, and emergency preparedness. These recommendations were prioritized into three tiers. The first tier consists of those recommendations that the NRC determined should be started without unnecessary delay.

Seismic and flooding walkdowns (detailed inspections) of accessible components of Diablo Canyon Units 1 and 2 were completed in November 2012, and the results were provided to the NRC on November 27, 2012.[319] None of the walkdown findings were determined to have any adverse effect on the performance of any required safety function; there are no planned or newly installed changes to Unit 1. Unit 2 seismic walkdowns of inaccessible components[320] were completed in April 2013. Unit 1 walkdowns of inaccessible components have not yet been completed.

An overall integrated plan providing Diablo Canyon's approach for providing mitigation strategies for beyond-design-basis external events[321] in accordance with NTTF Recommendations was developed and submitted to the NRC on February 27, 2013.[322] These strategies rely on installed plant equipment as well as onsite and offsite portable equipment. These strategies will be implemented by October 30, 2015, for Unit 1 and May 31, 2016, for Unit 2.

The Diablo Canyon phase 1 staffing study was completed in March 2013. The results of this study found 1) the minimum on-shift staffing is sufficient to support implementation of current Diablo Canyon procedures simultaneously for Units 1 and 2 with no collateral duties; 2) Diablo Canyon has the staffing needed to support an expanded response capability for a beyond-design-basis external event; and 3) procedures will need to be enhanced to integrate the expanded response and transportation capabilities.

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318 http://pbadupws.nrc.gov/docs/ML1323/ML13232A308.pdf.

319 http://pbadupws.nrc.gov/docs/ML1233/ML12333A270.pdf.

320 Inaccessible areas are areas that cannot reasonably be inspected due to significant personnel safety hazard. Very High Radiation Areas, major equipment disassembly, or no reasonable means of access (for example, buried). Items classified as "inaccessible" require the utility to justify that there is reasonable assurance that the feature is available and will perform the protection or mitigation function for the full duration of the seismic and/or flood condition.

321 External events (for example, earthquakes and tsunamis) that exceed what a nuclear facility was designed and built to withstand without loss to the systems, structures, and components necessary to ensure public health and safety.

322 http://pbadupws.nrc.gov/docs/ML1305/ML13059A501.pdf.

An assessment of Diablo Canyon's capability for emergency preparedness communications systems to perform the intended function during a large-scale loss of alternating current power event was submitted to the NRC in October 2012. Based on this assessment, enhancements will be implemented, which include additional phones, radios, radio console, and communications trailers. These enhancements will be implemented in two phases. The satellite phone "footballs" and communication trailers will be implemented by December 31, 2013. The remaining enhancements will be implemented by October 27, 2015.

Updated evacuation time estimates (ETE)[323] for Diablo Canyon were completed in November 2012. According to Table 7-2, Time to Clear the Indicated Area of 100 Percent of the Affected Population, the longest evacuation time scenario would be more than 19 hours during a summer special event (such as fireworks shows at Avila Beach, Pismo Beach, and Morro Bay Harbor). However, evacuation time estimates do not include a time estimate for a seismic event. PG&E reports that additional evacuation time estimate analyses for seismic events are being developed as part of a supplemental report that PG&E expects to issue by December 2013.[324]

Economic Considerations

In June 2013, PG&E released a study titled *Economic Benefits of Diablo Canyon Power Plant: An Economic Impact Study.*[325] For 2011, the study estimates a beneficial economic impact of $919.8 million to San Luis Obispo and Northern Santa Barbara counties. The indirect and induced impacts[326] totaled $244.3 million and included positive influences on many local businesses such as restaurants, real estate, wholesale trade, retail shops, financial institutions, and health care. With 11 and 12 years remaining on the current licenses for the Diablo Canyon units, it is expected that PG&E would continue to operate Diablo Canyon for the duration of those licenses and that the plant would continue to generate economic benefits similar to those that exist today. When the study area is expanded to include all of California, the economic impacts increase significantly primarily because of two factors: larger expenditures for goods and services, and larger multipliers. The study further estimates the total output impact for Diablo Canyon nationally is $1.969 billion.

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323 Diablo Canyon Power Plant Development of Evacuation Time Estimates, November 2012, http://pbadupws.nrc.gov/docs/ML1236/ML12363A209.pdf.

324 http://www.energy.ca.gov/2013_energypolicy/documents/nuclear_responses/PGandE_Response_TN-70883_Files/PGandE_Supplemental_Nuclear_Data_Response.pdf.

325 http://www.pge.com/includes/docs/pdfs/shared/edusafety/systemworks/dcpp/PGE_Economic_Impact_Report_Final.pdf.

326 For example, a dollar spent at a grocery store is divided among the suppliers of the grocery store, the workers at the grocery store, the landlord of the grocery store, and the owner of the grocery store business. Any dollar spent at the grocery store is parceled out and "respent" by the store's suppliers and landlord (the "indirect effect"), and the employee's households (the "induced effect"). The "multiplier" effect of the original dollar spent combines the indirect and induced effects, often referred to as the indirect effect.

PG&E purchases the maximum limit of nuclear liability coverage ($375 million) from American Nuclear Insurers through the Facility Form Policy, which is purchased by all commercial nuclear power plant operators in the United States and satisfies the Price-Anderson Act[327] requirement for primary financial protection. In addition, the Secondary Financial Protection (SFP) Policy provides coverage for losses that exceed the primary limit. Diablo Canyon Units 1 and 2 each has a certificate to the SFP program. The total protection amount for nuclear claims at Diablo Canyon is equal to the primary and SFP program for a total of roughly $12.6 billion. If sufficient funds may not be available from primary and secondary insurance to pay for claims for an actual event, the Price-Anderson Act further provides that the President must submit a report and proposals for compensation to Congress. Congress is authorized to allocate additional federal funds and charge licensees and others additional amounts to provide for full and prompt compensation for claims.[328]

However, recent reports estimate the Japanese government's portion of clean-up costs for the 2011 Fukushima accident to be over $80 billion[329] with comprehensive ~~some preliminary~~ cost estimates ~~for the 2011 Fukushima accident~~ ranging from $250 billion[330] to $500 billion.[331] Also, a recent study conducted by the the French Institute for Radiological Protection and Nuclear Safety[332] estimated the cost of a major nuclear accident in France to be $580 billion.[333] The *2011 IEPR* recommended that PG&E provide a comprehensive study on the adequacy of Price-Anderson liability coverage for a severe event at Diablo Canyon resulting in a large offsite release of radioactive materials. PG&E has not completed such a study and reports that it has no plans to perform one at this time.[334]

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327 The Price-Anderson Act, enacted in 1957, was designed to ensure adequate funds would be available for public liability claims for personal injury and property damage in the event of a nuclear accident at a commercial nuclear power plant. The limit of liability for a nuclear accident is now more than $12 billion.

328 Comments of Pacific Gas and Electric Company on Draft *2013 IEPR*, October 29, 2013, http://www.energy.ca.gov/2013_energypolicy/documents/2013-10-15_workshop/comments/Pacific_Gas_and_Electric_Company_Comments_2013-10-29_TN-72292.pdf.

329 http://www.reuters.com/article/2013/11/12/us-japan-fukushima-borrowing-idUSBRE9AB0H520131112?feedType=RSS&irpc=932.

330 http://newsonjapan.com/html/newsdesk/article/89987.php.

331 Massive Radiological Releases Profoundly Differ From Controlled Releases, February 2013, http://www.irsn.fr/FR/Actualites_presse/Actualites/Documents/EN_Eurosafe-2012_Massive-releases-vs-controlled-releases_Cost_IRSN-Momal.pdf.

332 The French Institute for Radiological Protection and Nuclear Safety (IRSN) is the national public expert in nuclear and radiological risks, http://www.irsn.fr/EN/Presentation/about_us/Pages/who_are_we.aspx.

333 http://www.reuters.com/article/2013/02/07/us-france-nuclear-disaster-cost-idUSBRE91603X20130207.

334 PG&E Supplemental Nuclear Data Response, June 18, 2013, http://www.energy.ca.gov/2013_energypolicy/documents/nuclear_responses/PGandE_Response_TN-70883_Files/PGandE_Supplemental_Nuclear_Data_Response.pdf.

~~Such a study could provide valuable new information on the potential economic costs associated with a severe nuclear event. PG&E has not completed such a study and reports that it has no plan at this time to perform the study.~~Another economic consideration for Diablo Canyon will be the costs associated with complying with the State Water Board's OTC policy. Currently the OTC policy calls for the elimination of OTC for Diablo Canyon by 2024 and 2025 for Units 1 and 2, respectively, which is when their current licenses expire. According to a report prepared by Bechtel[335] for PG&E and the State Water Resources Control Board Nuclear Review Committee[336], construction costs for closed-cycle systems could range as high as $6 billion to $12 billion and with the modifications taking as long as 8 to 14 years to complete. The report also concludes that, based on Bechtel's assessment of the nuclear-reactor safety of each of seven alternative cooling options, a license amendment request for the modifications would not be required from the NRC. However, a September 2013 evaluation of the Bechtel report by the DCISC[337] concluded that the various closed-cycle cooling options involve very extensive modifications to the plant that have the potential to affect the operability of safety-related systems both during and following construction. One of the findings from the DCISC evaluation states "We … find that it is unlikely, given how extensive the plant modifications are, that the installation of any of the five closed cooling options could be performed without a license amendment request."

San Onofre Nuclear Generating Station

Seismic and Tsunami Hazards

With the closure of San Onofre and a new focus on the decommissioning process, many of the *AB 1632 Report* and *2011 IEPR* recommendations may no longer be applicable. SCE submitted a letter to the NRC dated September 30, 2013 informing the NRC that the NTTF Recommendations regarding seismic, flooding, and emergency planning are no longer applicable to San Onofre Units 2 and 3 because the units have permanently ceased operation.

In Advice Letter 2930-E dated August 13, 2013, SCE informed the CPUC's Energy Division of the scope of the seismic studies that will be completed. The activities include the geophysical data reanalysis, the GPS array, onshore studies, and shallow marine surveys. The high energy marine surveys, seismic monitoring, and the seafloor sediment sampling and age dating will not be completed. The CPUC's Energy Division approved Advice Letter 2930-E by a September

335 *Alternative Cooling Technologies or Modifications to the Existing Once-Through Cooling System for the Diablo Canyon Power Plant (Draft)*, Issued September 20, 2013, http://www.swrcb.ca.gov/water_issues/programs/ocean/cwa316/rcnfpp/docs/juotc_rpt.pdf.

336 http://www.swrcb.ca.gov/water_issues/programs/ocean/cwa316/rcnfpp/index.shtml.

337 Diablo Canyon Independent Safety Committee's Evaluation of Safety Issues for "Independent Third Party Final Technologies Assessment for the Alternative Cooling Technologies or Modifications to the Existing Once-Through Cooling System for the Diablo Canyon Power Plant," September 2013, http://www.dcisc.org/draft-once-through-cooling-2013.php.

18, 2013 letter. The San Onofre Independent Peer Review Group[338] will continue to review and report on ongoing seismic studies.

~~SCE officials are consulting with NRC staff to understand how the regulatory requirements for the SSHAC process apply to San Onofre as they transition into decommissioning the plant. Seismic hazard analyses for SSC study Workshop 2 were held in August 2013. However, seismic activities are under review and likely will be terminated.~~

~~In a letter to the CPUC dated August 5, 2013, SCE stated that it is evaluating the scope of San Onofre seismic activities, and is planning to reduce the scope to only those activities that are required to fulfill NRC 50.54(f) requirements or are research projects that have already been initiated and are nearing completion. SCE indicated that AB 1632 recommendations to conduct high-energy two-dimensional/three-dimensional marine acoustic surveys are no longer required since San Onofre is not an operational plant and thus, SCE does not plan to complete them. The San Onofre Independent Peer Review Group will continue to review and report on ongoing seismic studies.~~

~~SCE is performing an evaluation of external flooding sources, including the effects of tsunamis, using guidance and methods consistent with the NRC's 10 CFR 50.54(f) request for information. This information is due to the NRC by March 2015. Previously completed tsunami analysis demonstrated no additional protection was warranted for San Onofre, however, updated tsunami hazard evaluations are not complete. Upon review of the evaluation results, SCE and the NRC staff will determine whether additional actions are necessary (for example, updating the design basis) to provide additional protection against tsunami hazards.~~

Vulnerabilities

San Onofre has 2,77~~34~~6 spent fuel assemblies in wet storage and 1,187~~792~~ assemblies in dry cask storage.[339] SCE reports that the size of ISFSI at San Onofre will have to be tripled to move all spent fuel assemblies out of wet storage.[340] The ISFSI is located in the area formerly occupied by Unit 1 (now decommissioned), and sufficient space exists there to store all the spent fuel

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338 The San Onofre Independent Peer Review Group (IPRG) is a multiagency panel of seismic hazard specialists who work under the auspices of the CPUC to provide independent review of SCE's plans and analyses of enhanced seismic studies. Established by CPUC Decision 12-05-004 (http://docs.cpuc.ca.gov/PublishedDocs/WORD_PDF/FINAL_DECISION/166519.PDF), its members include representatives from the California Geological Survey, California Coastal Commission, California Emergency Management Agency, California Energy Commission, California Seismic Safety Commission, and the California Public Utilities Commission. IPRG reports are available on the CPUC's website on nuclear power at http://www.cpuc.ca.gov/PUC/energy/nuclear.htm.

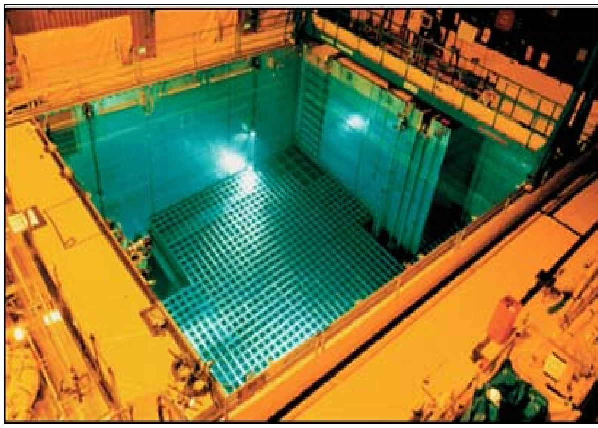
339 Southern California Edison Company's (SCE's) Comments on the California Energy Commission Docket No. 13-IEP-1A: Draft 2013 IEPR http://www.energy.ca.gov/2013_energypolicy/documents/2013-10-15_workshop/comments/Southern_California_Edisons_Comments_2013-10-29_TN-72296.pdf.

340 Mark Nelson, SCE, Lead Commissioner Workshop on California Nuclear Power Plant Issues, June 19, 2013.

assemblies.[341] Movement of used fuel from pools to dry cask storage is estimated to occur over the next 7 to 12 years after the assemblies have cooled enough to be moved to dry casks. Dry casks are concrete and metal containers that are filled with inert gas and then placed on concrete pads or in large concrete silos at the reactor site. Unlike cooling pools that require mechanically driven water circulation (a typical pump flow of 17,000 gallons per minute through the salt water cooling system~~which is estimated to use between 200,000 to 500,000 gallons of water per minute at San Onofre~~), dry casks employ "passive" cooling: air enters an opening at the bottom of the cask, absorbs heat from the spent fuel, then rises and exits through an opening at the top, creating a "chimney effect" that pulls more air into the bottom of the cask.

Passive cooling makes dry casks less likely to lose cooling capacity than "active" systems like cooling pools, which are vulnerable to mechanical failure, technical or human error, terrorist attack, and natural disasters.

Figure 11: Spent Fuel Pools Versus Dry Cask Storage



Spent Fuel Pool

Dry Cask Storage

Source: Nuclear Regulatory Commission, http://www.nrc.gov/waste/spent-fuel-storage/wcd/pub-involve.html and http://www.nrc.gov/waste/spent-fuel-storage/pools.html

Emergency Response Planning

SCE submitted updated Emergency Planning Zone evacuation time estimates (ETE)[342] to the NRC on December 19, 2012. This study was developed using the area, infrastructure, and population described by the San Onofre Emergency Plan and off-site response organization emergency response plans. As indicated in a letter dated April 16, 2013,[343] from the NRC to the

341 Caroline McAndrews, SCE, Lead Commissioner Workshop on California Nuclear Power Plant Issues, June 19, 2013.

342 San Onofre Nuclear Generating Station Development of Evacuation Time Estimates, November 2012, http://pbadupws.nrc.gov/docs/ML1236/ML123630620.pdf.

343 Quarterly Report of Activity Related to Updated Evacuation Time Estimates, April 16, 2013, http://pbadupws.nrc.gov/docs/ML1310/ML13105A417.pdf.

Federal Emergency Management Agency (FEMA), SCE's ETE report was reviewed by the NRC, found generally consistent with the guidance in NUREG/CR-7002, and found to be complete in accordance with 10 CFR Part 50, Appendix E.IV.3. Table 7-2, Time to Clear the Indicated Area of 100 Percent of the Affected Population, indicates the longest evacuation time to be more than 20 hours during a summer earthquake.

Economic Considerations

The NRC requires operators of nuclear power plants to put aside funds for decommissioning while the plant is operating. The money is collected from customers and invested in dedicated trusts. The cost to decommission San Onofre Units 2 and 3 is estimated to be $4.1 billion. SCE's share is $3 billion, of which $2.7 billion had been collected through June~~March~~ 30~~1~~, 2013. Other owners of San Onofre [344] have collected more than $927 million through December 2012. On July 22, 2013, SCE submitted updated plans and decommissioning cost estimates to the CPUC as part of the 2012 Nuclear Decommissioning Cost Triennial Proceeding (A.12-12-013) to reflect the permanent shutdown of San Onofre.[345] SCE submitted a cessation of operation of San Onofre Units 2 and 3 to the NRC on June 12, 2013. The transfer of fuel from the Units 3 and 2 reactors was completed on October 5, 2012, and July 18, 2013, respectively. Letters dated June 28, 2013, and July 22, 2013, were sent to the NRC indicating the fuel had been permanently removed from Units 3 and 2, respectively. With the cessation of power operation and the defueling of the reactors letters, SCE is licensed only to possess the fuel from San Onofre Units 2 and 3. ~~completed the transfer of fuel from the Unit 2 reactor to the spent fuel pool on July 18, 2013, and sent a letter to the NRC on July 23, 2013, certifying that the fuel was removed from the Unit 2 reactor. Once the NRC certifies the Unit 2 defueling, the nuclear plant will have a possession-onlylicense rather than an operating license, and will no longer be authorized to place fuel in the reactor vessel.~~ Within two years of permanently ceasing operations, SCE must submit to the NRC and state officials a detailed plan (known as a Post-Shutdown Decommissioning Activities Report) that spells out specific decommissioning activities and schedules, cost estimates, and potential environmental impacts.[346] SCE anticipates Units 2 and 3 decommissioning activities to commence in mid-2015.

Japan Lessons Learned—NRC Near-Term Task Force Recommendations

After the Fukushima Daiichi nuclear accident, a task force of senior NRC staff reviewed the circumstances of the event to determine what lessons could be learned. In July 2011, the task

344 San Onofre is co-owned by Southern California Edison, San Diego Gas & Electric, and Riverside Public Utilities.

345 Testimony of Edward Randolph, CPUC Energy Division Director, California State Senate Committee on Energy, Utilities, and Communications Informational Hearing (Padilla), Life after San Onofre: The Decommissioning Process, August 13, 2013, http://seuc.senate.ca.gov/20132014informationalhearings/#August132013.

346 http://pbadupws.nrc.gov/docs/ML0037/ML003701163.pdf.

force provided recommendations to enhance U.S. reactor safety, and these became the foundation of the NRC's post-Fukushima activities. At Fukushima, flooding from the tsunami disabled internal electrical power systems after the earthquake had cut off external power sources, leaving the plants with only a few hours' worth of battery power. Nuclear power plants need electrical power 24 hours a day, even when the nuclear reactors are shut down, to run equipment that cools the reactor core and spent nuclear fuel. The NRC approved a three-tiered prioritization of recommendations;[347] Tier 1 recommendations are activities to be implemented without unnecessary delay, Tier 2 recommendations are those that cannot be initiated in the near term due to resource or critical skill set limitations, and Tier 3 recommendations require further staff study to determine if regulatory action is necessary.

Tier 1 Activities

Tier 1 activities include orders, requests for additional information (RAIs), and rulemakings. The NRC issued three orders in March 2012 to implement Tier 1 recommendations from the Japan Lessons Learned. Two orders apply to every U.S. commercial reactor, while the third order applies only to reactors with designs similar to the Fukushima plant (which Diablo Canyon and San Onofre do not have).

The first order includes mitigation strategies requiring plants to obtain and protect additional post-9/11 equipment to support all reactors at a given site simultaneously. The mitigation strategies are expected to use a combination of currently installed equipment (such as steam-powered pumps), additional portable equipment that is stored on-site, and equipment that can be flown or trucked in from support centers. Seismic and flooding reevaluations for Diablo Canyon and San Onofre are due March 2015.

The second order requires all U.S. nuclear power plants to install enhanced equipment for monitoring water levels in each plant’s spent fuel pool. During the accident at Fukushima, the plants lost their ability to cool the spent fuel pools. Plant operators couldn't determine how much water was in the pools during the accident, which was a problem because if enough water boiled away or was otherwise lost, the spent fuel rods could emerge from the receding water and potentially release significant amounts of radiation. The NRC issued the order requiring plants to install water-level instrumentation in their spent fuel pools to remotely report at least three distinct water levels: 1) normal level; 2) low level but still enough to shield workers above the pools from radiation; and 3) a level near the top of the spent fuel rods where more water should be added without delay. SCE reports that this order is no longer applicable to San Onofre Units 2 and 3, as indicated in its September 30, 2013, letter to the NRC.

The third order applies to boiling-water reactors with hardened containment vents. These reactors must improve or install emergency venting systems that can relieve pressure in the event of a serious accident. The order for ensuring reliable hardened containment vents does not apply to Diablo Canyon or San Onofre because they are pressurized water reactors. Every U.S. plant must comply with the relevant orders by December 31, 2016.

347 http://www.nrc.gov/reactors/operating/ops-experience/japan-dashboard/priorities.html#tier-02.

RAIs address reevaluation of seismic and flooding hazards and staffing needs and communications capabilities to respond effectively to an emergency event affecting multiple reactors at a site. Longer-term rulemaking activities will address station blackout/mitigation strategies (2016), onsite emergency response (2016), and filtering and confinement strategies[348] (2017).

Tier 2 and 3 Activities

Tier 2 activities address spent fuel pool makeup capability (to provide a reliable means of adding extra water to spent fuel pools) and emergency preparedness for multireactor and loss of power events (including training and exercises, equipment and facilities, and multiunit dose assessment capability).[349] Tier 3 activities evaluate the need for additional enhancements in areas related to reactor oversight. The NRC plans to address these activities through long-term evaluation and planned rulemaking. See Appendix H for a complete list of NRC Post-Fukushima Activities.

Federal Efforts on Nuclear Waste Transport, Storage, and Disposal

United States Department of Energy

The DOE has broad authority under the Atomic Energy Act of 1954,[350] as amended, to regulate all aspects of activities involving radioactive materials that are undertaken by DOE or on its behalf, including the transportation of spent nuclear fuel (SNF). The DOE uses this authority to manage certain SNF shipments that usually involve special circumstances, such as SNF from foreign research reactors, DOE-owned research and defense reactors, and nuclear-powered U.S. Navy ships to DOE storage facilities. In addition, the DOE manages the shipment of SNF from NRC-licensed nonpower reactors to DOE facilities for interim storage because of the lack of a permanent disposal facility for SNF.

In January 2012, the Blue Ribbon Commission on America's Nuclear Future identified removal of stranded used nuclear fuel at shutdown sites as a priority so that these sites may be completely decommissioned and put to other beneficial uses.[351] In ~~April~~ September 2013, the DOE Office of Nuclear Energy, as part of the Used Fuel Disposition Campaign, released a

348 Applicable only to boiling-water reactors; does not apply to Diablo Canyon or San Onofre because they are pressurized water reactors.

349 The capability of assessing radiation doses from multiple sources (for example, more than one reactor, a spent fuel pool, and so forth).

350 The Atomic Energy Act of 1954, 42 U.S.C. § 2011 et seq., is the fundamental U.S. law on both the civilian and the military uses of nuclear materials. It covers laws for the development, regulation, and disposal of nuclear materials and facilities in the United States. http://www.nrc.gov/reading-rm/doc-collections/nuregs/staff/sr0980/v1/sr0980v1.pdf.

351 *Transportation and Storage Subcommittee Report to the Full Commission*, January 2012, http://cybercemetery.unt.edu/archive/brc/20120620215746/http://brc.gov/sites/default/files/documents/final_updated_ts_report_012612.pdf.

preliminary evaluation of removing used nuclear fuel from nine shutdown sites,[352] including Humboldt Bay Nuclear Power Plant[353] and Rancho Seco Nuclear Generating Station.[354] Objectives of the study will be to characterize the actions necessary to remove used nuclear fuel from the shutdown sites and develop a plan and schedule for key program activities.

United States Nuclear Regulatory Commission

The NRC regulates commercial nuclear power plants that generate electricity under the Atomic Energy Act of 1954. The Waste Confidence Decision and Rule represent the generic determination by the NRC that spent nuclear fuel can be stored safely and without significant environmental impacts for a period after the end of the licensed life of a nuclear power plant. Historically, this generic analysis has been incorporated into the Commission's NEPA reviews for new reactor licenses, license renewals, and ISFSI licenses through the Waste Confidence Rule. The Waste Confidence Decision and Rule satisfy the NRC's obligations under NEPA, with respect to post-licensed-life storage of spent nuclear fuel.

In June 2012, the District of Columbia Circuit Court found that some aspects of the NRC's 2010 Waste Confidence Decision and Rule (2010 Decision and Rule) did not satisfy the NRC's National NEPA obligations and vacated the 2010 Decision and Rule.[355] The Court identified three specific deficiencies in the analysis: 1) it did not evaluate the environmental effects of failing to secure permanent disposal; 2) it failed to properly examine the risk of spent fuel pool leaks in a forward-looking fashion; and, 3) it failed to properly examine the consequences of spent fuel pool fires.

In response to the Court's decision, the NRC ordered that no final decisions on issuing licenses that rely on the 2010 Decision and Rule will be made until the court's remand was appropriately addressed.[356] The NRC created a Waste Confidence Directorate to oversee the drafting of a new Waste Confidence Environmental Impact Statement (EIS) and Rule and instructed the Directorate to issue the final EIS and Rule by no later than September 2014. The NRC published the draft GEIS[357] for public comment on September 13, 2013. During the 75-day comment

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352 *Preliminary Evaluation of Removing Used Nuclear Fuel From Nine Shutdown Sites* (FCRD-NFST-2013-000238), September 30, 2013, http://energy.gov/sites/prod/files/2013/10/f4/FCRD-NFST-2013-000238_M2_Final.pdf.~~Preliminary Evaluation of Removing Used Nuclear Fuel From Nine Shutdown Sites (FCRD-NFST-2012-000613), April 30, 2013, http://curie.ornl.gov/.~~

353 Humboldt Bay Nuclear Power Plant operated from 1963 to 1976 and is being decommissioned. It is located just south of Eureka in Humboldt County and is owned by PG&E.

354 Rancho Seco Nuclear Generating Station was commissioned in 1975 and decommissioning was completed in 2009. It is located in Herald in Sacramento County and is managed by Sacramento Municipal Utility District.

355 New York v. NRC, 681 F.3d 471 (D.C. Cir. 2012).

356 NRC Memorandum and Order, CLI-12-16, August 7, 2012, http://pbadupws.nrc.gov/docs/ML1222/ML12220A100.pdf.

357 *Waste Confidence Generic Environmental Impact Statement,* Expected Publish Date August 2013, http://pbadupws.nrc.gov/docs/ML1315/ML13150A347.pdf.

period, the NRC ~~will hold~~held several public meetings around the country to present the proposed rule and draft GEIS and receive comments. Two of these meetings ~~will be~~were held in Southern and Central California.

On August 13, 2013, the U.S. Court of Appeals for the District of Columbia issued an order[358] ~~granting a writ of mandamus~~ directing the NRC to "promptly continue the legally mandated licensing process" for Yucca Mountain. The Court's order became effective on September 3, 2013. On August 30, 2013, the NRC requested input from participants in the adjudicatory proceeding to offer views on how to restart the Yucca Mountain licensing process.[359] This input, which the NRC accepted during a 30-day comment period ending September 30, 2013, will help the NRC ensure the most efficient and productive use of nearly $11 million the agency has left to resume the licensing process (which had previously been suspended in September 2011). On November 18, 2013, the NRC directed its staff[360] to ~~gather pertinent budgeting information during the 30-day comment period. The Commission will review the comments submitted by the parties as well as the information it receives from the NRC staff and decide the path forward in the licensing process.~~complete and issue the Safety Evaluation Report associated with the Yucca Mountain construction authorization application.

Nuclear Waste Administration Act of 2013

In June 2013, Senators Dianne Feinstein (D-California) and Lamar Alexander (R-Tennessee) — the leaders of the Senate Appropriations Subcommittee on Energy and Water Development— and Energy and Natural Resources Committee Chairman Ron Wyden (D-Oregon) and Ranking Member Lisa Murkowski (R-Alaska) introduced the Nuclear Waste Administration Act of 2013 (S. 1240).[361] This bill is intended to implement the recommendations of the Blue Ribbon Commission on America's Nuclear Future[362] to establish a nuclear waste administration and create a consent-based process for siting nuclear waste facilities. The bill would enable the federal government to fulfill its commitment to managing nuclear waste, ending the costly liability the government bears for its failure to dispose of commercial spent fuel. The integrated storage and repository system established by this legislation would expand opportunities for nuclear power to supply carbon-free energy, provide long-term protection of public health and

358 http://www.atg.wa.gov/uploadedFiles/Home/About_the_Office/Cases/Yucca/Opinion.pdf.

359 http://www.nrc.gov/reading-rm/doc-collections/news/2013/13-070.pdf.

360 NRC Memorandum and Order dated November 18, 2013 http://www.nrc.gov/reading-rm/doc-collections/commission/orders/2013/2013-08cli.pdf.

361 http://www.feinstein.senate.gov/public/index.cfm/files/serve/?File_id=a7095770-9cab-41bb-a5a3-152fdb51adfa.

362 *Blue Ribbon Commission on America's Nuclear Future Report to the Secretary of Energy*, January 2012, http://cybercemetery.unt.edu/archive/brc/20120620220235/http://brc.gov/sites/default/files/documents/brc_finalreport_jan2012.pdf.

safety for both commercial and defense high-level waste, and ensure adequate funding for managing nuclear waste.[363] The proposed bill includes the following key components:

- Establishes a new federal agency, headed by a single administrator, appointed by the President by and with the advice and consent of the Senate, to manage the nuclear waste program in place of DOE.
- Directs the new agency to build a pilot spent fuel storage facility to store spent fuel from decommissioned nuclear power plants and emergency shipments from operating plants.
- Directs the new agency to build one or more consolidated storage facilities to store nonpriority spent fuel for utilities or defense wastes for DOE temporarily.
- Establishes a new siting process, applicable to both repositories and storage facilities, that requires the new nuclear waste agency to 1) establish technical siting guidelines to evaluate sites, 2) solicit states and communities to volunteer sites, 3) obtain state and local consent to study sites, 4) hold ~~multiple~~ public hearings before studying or selecting sites, 5) obtain state and local consent to site a repository or storage facility, 6) obtain congressional ratification of any consent agreement for a site, and 7) obtain a license from the NRC to construct and operate a repository or storage facility.
- Authorizes the administrator to begin siting consolidated storage facilities immediately, and does not set waste volume restrictions on storage.
- Proposes a requirement that, while constructing and operating the storage facility, the administrator ~~is required to~~ continue making progress on siting and constructing a repository as measured against its own mission plan.
- Establishes a new Working Capital Fund in the Treasury, into which the fees collected from the utilities (currently about $765 million per year), would be deposited. These funds would be available to the Administration without further appropriation. Fees already collected (about $28.2 billion as of January 2013) remain in the Nuclear Waste Fund, where they will continue to be subject to appropriation.

The proposed bill updates an April draft after consideration of more than 2,500 public comments on the measure. The Energy and Natural Resources Committee held a hearing on the bill in July 2013.

Permanent Closure of San Onofre Nuclear Generating Station

Steam Generator Tube Degradation

On January 31, 2012, SCE, operator of San Onofre, began a precautionary shutdown of Unit 3 after readings from highly sensitive instruments detected a reactor coolant leak in one of the unit's steam generator tubes. Although the leak rate was small, it increased enough in a short

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363 Summary of the Nuclear Waste Administration Act of 2013 Discussion Draft, http://www.energy.senate.gov/public/index.cfm/files/serve?File_id=e10c815a-4baf-4eb3-a55a-be05fe0f88e4.

period for SCE to perform a rapid shutdown when the estimated leak rate exceeded 75 gallons per day. Unit 2 was already offline for a planned maintenance, refueling, and technology upgrade. SCE began extensive testing to understand fully the cause of the leak and discovered unexpected wear in both steam generators, including significant tube-to-tube wear in the free span areas of more than 100 tubes. Testing results from Unit 2 also revealed unexpected tube wear at the retainer bars, and additional analysis and testing identified two tubes with tube-to-tube wear similar to what was observed in Unit 3. For both Units 2 and 3, this was the first cycle of operation with new replacement steam generators. SCE had replaced the Unit 2 steam generators in January 2010 and Unit 3 steam generators in January 2011.

NRC Confirmatory Action Letter Process

On March 27, 2012, the NRC issued a Confirmatory Action Letter (CAL) to SCE to confirm the actions that SCE committed to take before returning Units 2 and 3 to power operation. The CAL specified that before restarting either unit, SCE would identify the cause(s) of the excessive tube wear and take corrective actions to ensure that steam generator tube integrity could be maintained. The CAL also specified that SCE would provide in writing to the NRC its protocol of inspections and/or operational limits for the planned operating interval and the basis for SCE's conclusion that there was reasonable assurance that the units will operate safely. Neither unit would be allowed to resume operations until SCE responded to the items in the CAL, and the NRC had completed a thorough review of those actions and wrote that it was satisfied the plant could operate without undue risk to public health and safety.

Unit 2 Restart Plan

On October 3, 2012, SCE submitted its CAL response and return-to-service report for Unit 2. SCE stated it had determined the causes of tube-to-tube interactions that resulted in steam generator tube wear in Unit 3, implemented actions to prevent loss of tube integrity due to these causes in the Unit 2 steam generators, and established a protocol of inspections and operational limits, including plans for a mid-cycle shutdown. SCE's return-to-service plan included operating Unit 2 at reduced power for an initial five-month period, followed by more inspection.

The NRC indicated that months of NRC inspection and analysis would precede any decision on whether to restart the reactor. Over the next eight months, NRC staff reviewed SCE's CAL responses and issued more than 72 requests for additional information (RAIs). RAI 32 addressed Unit 2 technical specifications that require steam generator structural integrity to be maintained over the full range of normal operating conditions (that is, 100 percent power). To address this issue, on April 5, 2013, SCE submitted a license amendment request proposing to lower permissible operating levels from 100 to 70 percent. SCE asserted that the license amendment request was a technical change only that posed no significant hazards. However, this request increased mounting concerns about the safety of restarting Unit 2; several challenges to the NRC CAL process were already underway. On May 13, 2013, the NRC's

Atomic Safety and Licensing Board issued an order[364] in response to one of these challenges, concluding that the CAL process for San Onofre Units 2 and 3 constituted a de facto license amendment proceeding subject to a hearing opportunity under the Atomic Energy Act. By some estimates, a full adjudicatory hearing process would take a year or more to complete.

CPUC Order Instituting Investigation

On October 25, 2012, the CPUC voted unanimously to open a proceeding on a new Order Instituting Investigation (OII)[365] to obtain information on the outages and investigate the causes, the future of the San Onofre units, and the resulting effect on the provision of safe and reliable electric service at just and reasonable rates. The order states that all revenues collected in recovery of costs on and after January 1, 2012 related to San Onofre Generating Station Units 2 and 3 are subject to refund, and all Steam Generator Replacement Program costs, and rates collected in recovery of those costs, are subject to reasonableness review and refund.

In January 2013, the CPUC held the prehearing conference to consider the schedule for issues raised by the extended outages. The proceeding was divided into four phases with a preliminary schedule indicating that phase 1 rulings could be expected mid-2013, and Phase 2 and Phase 3 rulings could be expected in mid-2014.[366] The CPUC held Phase 1 evidentiary hearings in August 2013 to address the method for calculating the cost of replacement power during 2012 due to the San Onofre outage. On November 19, 2013, the CPUC released a proposed decision[367] on Phase 1 adopting interim rate reductions for SCE and SDG&E ratepayers and ordering refunds of approximately $94.0 million. The scope of Phase 2 evidentiary hearings,[368] scheduled for October 2013, will include determining the value(s) of San Onofre assets in rate base, and which of these assets should be removed from rate base pursuant to Public Utilities Code Section 455.5.[369] A Phase 2 decision is anticipated in February 2014.

The CPUC OII will ultimately determine who is responsible for paying the costs associated with the outage at San Onofre, including among other costs, the cost of the steam generator replacement project, substitute market power costs, capital expenditures, operation and maintenance costs, and seismic study costs. According to SCE, these costs are estimated to be more than $2 billion.[370]

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364 http://libcloud.s3.amazonaws.com/93/8f/0/2930/13-05-13_MEMO_AND_ORDER_Resolving_Issues_Referred_in_CLI_12_20_LBP_13_07.pdf.

365 I.12-10-013, http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M032/K192/32192692.pdf.

366 http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M042/K157/42157052.PDF.

367 http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M081/K627/81627425.PDF.

368 http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M073/K768/73768014.PDF.

369 http://www.leginfo.ca.gov/cgi-bin/displaycode?section=puc&group=00001-01000&file=451-467.

370 SCE 2013 SEC Filing, Second Quarter 10Q; Note 9, Permanent Retirement of San Onofre, pp. 29-33. http://www.edison.com/images/cms_images/c8156_EIX_2013_Q2_AS_FILED_3043.pdf.

Permanent Closure and Decommissioning

On June 7, 2013, SCE announced it had decided to permanently retire San Onofre Units 2 and 3. Economic reasons were cited as the basis of the decision, as well as the need to eliminate continued uncertainty about San Onofre to assist with orderly planning for California's energy future. On June 13, 2013, SCE formally notified the NRC[371] that it had permanently ceased operation of San Onofre nuclear plant Units 2 and 3. The notification, called a Certification of Permanent Cessation of Power Operations, was the formal administrative step following SCE's announcement to retire San Onofre that sets the stage for SCE to begin preparations for decommissioning. Decommissioning is a well-defined NRC process[372] that involves transferring the used fuel into safe storage, followed by the removal and disposal of radioactive components and materials. Within two years of shutdown, SCE must submit to the NRC and state officials a detailed plan that spells out specific decommissioning activities and schedules, cost estimates, and potential environmental impacts. SCE has indicated it intends to file a decommissioning plan by mid-~~the end of~~ 2014.[373] SCE estimates that movement of used fuel from pools to dry cask storage will occur over a period of 7 to 12 years, which would put completion of those activities between 2020 to 2025.

Recommendations

Diablo Canyon Power Plant

- **Complete and make available *AB 1632 Report*-recommended studies.** PG&E should continue to provide updates on its progress in completing the *AB 1632 Report*-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.
- **Update evacuation time estimates**. 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 *IEPR* reporting process.
- **Assess liability coverage adequacy**. Based on mounting clean-up costs for the 2011 Fukushima accident, ~~prior to reactivating the Diablo Canyon license renewal application with the Nuclear Regulatory Commission,~~ 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

371 http://pbadupws.nrc.gov/docs/ML1316/ML131640201.pdf.

372 http://www.nrc.gov/reading-rm/doc-collections/fact-sheets/decommissioning.html.

373 Testimony of Stephen Pickett, SCE Executive Vice-President of External Relations, California State Senate Committee on Energy, Utilities and Communications Informational Hearing (Padilla), Life After SONGS: The Decommissioning Process, August 13, 2013, http://seuc.senate.ca.gov/20132014informationalhearings/#August132013.

included in the Ingestion Pathway Zone,[374] 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.

- ~~The CPUC should consider requiring PG&E to complete such a study as a condition of License Renewal funding approval.~~
- **Evaluate seismic hazard analysis against the licensed design.** 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 IEPR 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.~~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 evaluate all seismic hazard analyses for Diablo Canyon against the licensed design basis elements for the Design Earthquake and the Double Design Earthquake, in addition to the Hosgri earthquake element.~~
- **Comply with applicable fire protection regulations.** 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.
- **Evaluate long-term impacts and costs of spent fuel storage options.** 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[375] 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.
- **Evaluate the structural integrity of the spent fuel pools.** ~~To help ensure plant reliability and minimize costs to ratepayers, prior to reactivating the Diablo Canyon license renewal application with the Nuclear Regulatory Commission,~~ To help ensure plant reliability and

374 The *Ingestion Pathway Zone* covers an approximate 50-mile radius around the plant. In this zone, plans are in place to reduce the effects on a radioactive contamination to agriculture, and food processing and distribution. http://www.calema.ca.gov/planningandpreparedness/pages/nuclear-power-in-california.aspx.

375 For example, average assembly burnups exceeding 45 gigawatt days per metric ton of uranium (GWd/MTU).

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.

- **Evaluate the annual capability of moving spent fuel bundles to dry cask storage.** PG&E should perform, and report to the Energy Commission and CPUC as part of the *IEPR* reporting process~~2014 *IEPR Update*~~, 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:
  - 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.
- **Transfer spent fuel to dry casks as expeditiously as possible.** 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 ~~while maintaining compliance with Nuclear Regulatory Commission spent fuel cask and pool storage requirements~~ and report to the Energy Commission on its progress until the pools have been returned to open racking arrangements.[376]
- **Complete the evaluation of laminar flaws on Unit 2 pressurizer nozzles.** The Diablo Canyon Independent Safety Committee should monitor 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, and follow the issue until it is resolved.

San Onofre Nuclear Generating Station

- **Complete and make available *AB 1632 Report*-recommended studies ~~on security of spent fuel~~that SCE has committed to complete.** 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.~~SCE~~

376 *Open racking arrangements* would reduce the density of spent fuel assemblies stored in the pools to levels consistent with their original design capacity (prior to re-racking).

~~should continue to complete *AB 1632 Report*-recommended studies as they apply to the security of spent fuel storage facilities at San Onofre and provide updates to the Energy Commission and CPUC on its progress.~~

- **Expand timely and safe transfer of spent fuel to dry casks.** 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.

- **Develop and implement a decommissioning plan as quickly as possible.** 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.

Nuclear Waste

- **Represent California's interests in federal nuclear waste management program activities**. 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.

- **Support federal efforts to develop an integrated system for management and disposal of nuclear waste**. 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.

~~Nuclear Waste~~

- ~~Represent California's interests in federal nuclear waste management program activities. 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.~~

CHAPTER 7: Natural Gas

Natural gas is used in California for everything from generating electricity to cooking and space heating to an alternative transportation fuel. Because natural gas continues to represent a large percentage of California's energy mix, it is important to ensure reliable supplies through assessments of future natural gas demand, supply, prices, and infrastructure needs. In turn, these assessments require an understanding of future issues and trends that could affect natural gas markets and disruptions in supply.

Issues and trends that affect natural gas supply and demand include production, population growth, pipeline capacity, economic outlook, weather, national and global markets, environmental concerns, and the effects of energy policies. Supply and demand, in turn, affect natural gas prices. California and the rest of the United States are experiencing the lowest natural gas prices in the last decade largely because of technological advances in producing shale gas. California has also been able to take advantage of price competition facilitated by expanded natural gas pipeline capacity that brings natural gas to the state's consumers.

This chapter presents the results of the Energy Commission's 2013 assessment of future natural gas supply, demand, infrastructure issues, and prices. Energy Commission staff produced a range of scenarios based upon reasonable and transparent assumptions to give planners and decision makers the information needed to determine near- and long-term procurement needs and to conduct contingency planning. Results are based on inputs on natural gas demand for residential, industrial, commercial, and transportation needs from the Demand Analysis Office, electric generation needs from the Electricity Analysis Office, and industry experts.

This chapter also briefly discusses the most influential issues affecting natural gas supply and demand in California, including development of shale deposits in North America, pipeline safety, factors affecting changes in natural gas demand for electric generation and combined heat and power (CHP), and natural gas infrastructure. Pipeline-quality biomethane, a renewable, low-carbon substitute for natural gas, is discussed in Chapter 3.

Natural Gas Outlook

Staff developed natural gas price and supply cases, or *common cases*, around trends that represent three possible future scenarios: a business-as-usual or reference case; a high-energy-demand/low-price case; and a low-energy demand/high-price case. The reference case, or the starting point case, represents a future in which the economy and commercial activity remain consistent with trends experienced over the last several years. The high-energy-demand/low-price and low-energy-demand/high-price cases were created by altering assumptions in ways that would move the natural gas prices lower or higher than in the reference case. Assumptions that were varied include economic growth, technology improvements, renewable portfolio and combined heat and power targets, coal capacity changes, once-through cooling and nuclear power plant capacity replacement, natural gas supply cost curves, demand, and costs (Table 11).

Table 11: Assumptions for Common Cases

Assumptions	Reference Case	Low Demand/High Price Case	High Demand/Low Price Case
GDP Growth Rate	2.50%	3.00%	2.00%
Natural Gas Technology Improvement Rate	1%	1%	2.50%
CHP Demand (Bcf)/Capacity (MW) for CA in 2024[a]	83/1424	130/3084	14/210
Total US Natural Gas Demand (Tcf/yr)			
2014	24.5	24.1	24.4
2019	28.4	27.9	27.2
2024	30.5	29.9	28.1
Maximum RPS Target			
CA Meets Target	On time	10 year delay	On time
WECC Meets Target	On time	10 year delay	On time
Other States Meet	5 year delay	10 year delay	On time
Additional US Coal Generation Converts to Natural Gas Starting in 2014 (GW)	61	80	31
LNG Capacity Additions	No	Yes	No
Grow or Shrink Natural Gas Resource Available (US)	N/A	Shrink by 5.5%	Grow by 5.5%
Additional Environmental Mitigation Cost (2010$/Mcf)	N/A	$0.50/Mcf Shale $0.30/Mcf Conventional	N/A
Cost Environment[b]	Mid (P50)	High (P10)	Low (P90)

Source: Energy Commission.

a) Percentage of total from Fossil/Nuclear/Hydro/Renewable Generation.

b) Each scenario is a function of the sustained cost environment and reserve estimates. A P50 assessment means there is a 50 percent probability, meaning there is an equal chance that the cost or reserve estimate will fall above or below the mean value. These cost and reserve estimates are established by the Potential Gas Committee. The reference case is the function of a P50 sustained cost environment and a P50 reserve estimate. The low-demand, high-price case assumes a P10 sustained cost environment, while assuming the adjusted lower bound of the P50 reserve estimate. The high-demand, low-price case is the combination of a P90 sustained cost environment and the adjusted upper bound of the P50 reserve estimate.

Natural Gas Prices

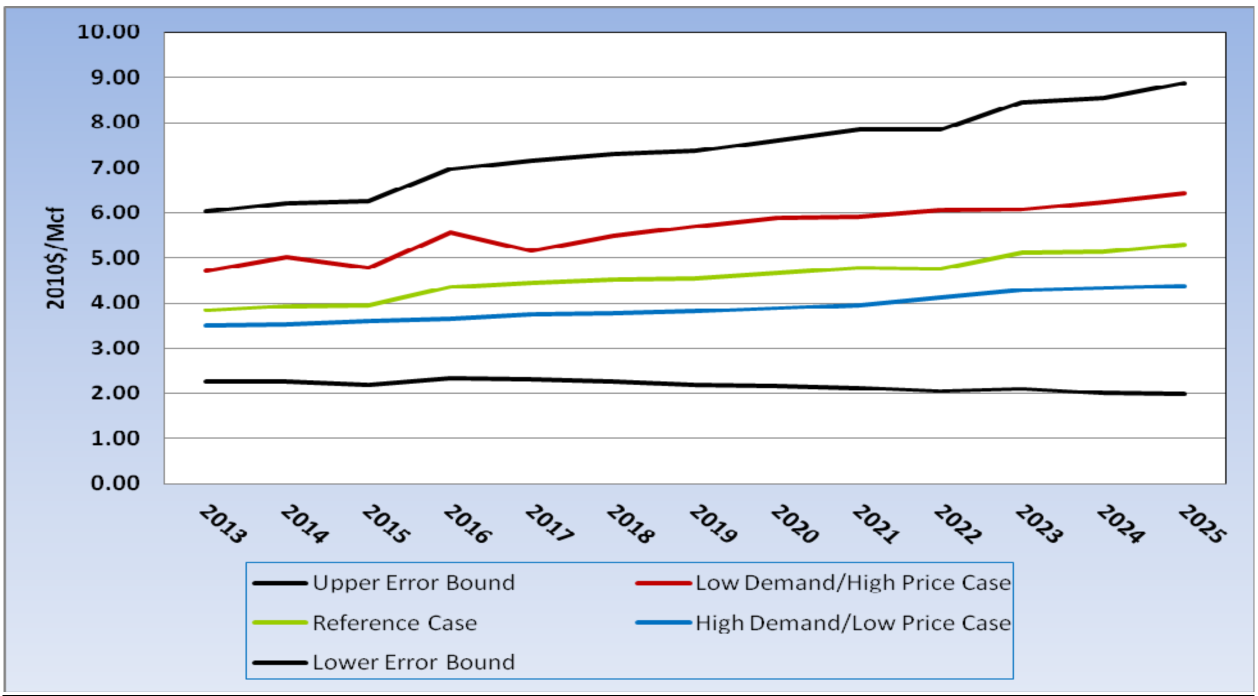
Figure 12 shows the projected price for natural gas from 2013 to 2025 for the three common cases. The prices of natural gas provided by the North American Market Gas Trade (NAMGas) model are estimates at interstate pipeline border crossings, utility city-gates, and other hubs. These prices reflect the estimated cost of producing natural gas, processing it for injection into the pipeline system, and transporting it to a given hub. The NAMGas model used in this analysis produces annual average values and does not account for fluctuations that occur in the natural gas market on a daily or seasonal basis.

To account for inherent uncertainty in natural gas supply and demand, staff used past natural gas price forecast results generated by the Energy Commission to produce error bands around price results of the three common cases. Staff determined percentage differences between the

Energy Commission's forecasts and actual natural gas market prices to develop trend-line equations and apply them to the current reference case price results. The resulting error bands produce a wider range of price uncertainty than seen in the price differential between the common cases.

Natural gas prices show small, steady increases in inflation-adjusted dollars for all three cases, rising by only about $1.00 over the 12-year period. In the low-demand/high-price case, staff added liquefied natural gas (LNG) export capacity in 2014 – 15, which increased demand and raised prices. By 2017-2018, LNG export capacity was reduced and production increased resulting in lowered prices. By 2025, prices range from $4.39 to $6.42 per thousand cubic feet (Mcf), indicating that supplies from shale gas will remain productive.

Figure 12: Common Case Price Projections with Adjusted Error Bands



Source: Energy Commission.

End-User Natural Gas Prices

In addition to hub prices, California end-use customers also pay the added costs of transporting the natural gas from the hub through interstate or backbone pipelines and local utility distribution networks. Some large-volume end users such as power generators and some industrial facilities are connected directly to the interstate pipelines so costs are lower. Residential and commercial customers are connected to the gas infrastructure by a series of several distribution and lateral pipelines operated by local distribution companies, and therefore, pay more. Table 12 shows the estimated price paid by customer classes modeled in the NAMGas model. Price changes are more pronounced in the industrial and power generation sectors as these historically have greater exposure to changes in the commodity price of gas (typically measured at Henry Hub).

Table 12: California Natural Gas End-User Prices in 2015, 2020 and 2025

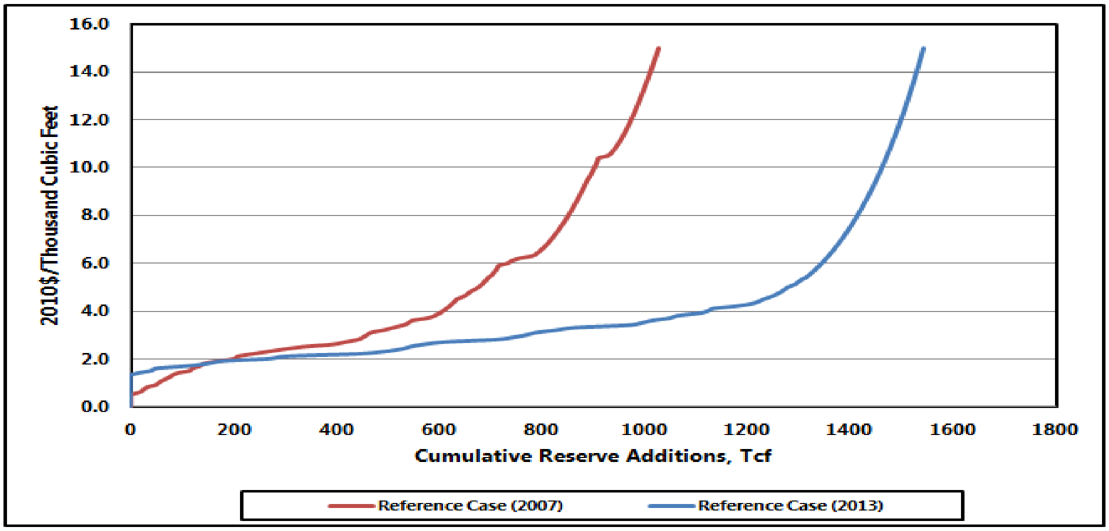
	Low-Demand/High-Price Case	Reference Case	High-Demand/Low-Price Case
2015			
Residential	$10.23	$9.43	$9.42
Commercial	$8.06	$7.25	$7.24
Industrial	$5.92	$5.11	$5.10
Power Generation	$5.34	$4.53	$4.54
Transportation	$5.80	$5.80	$5.79
EOR	5.45	$4.65	$4.61
California	$6.81	$5.95	$5.87
2020			
Residential	$11.10	$10.04	$9.63
Commercial	$8.92	$7.87	$7.45
Industrial	$6.79	$5.73	$5.32
Power Generation	$6.23	$5.13	$4.75
Transportation	$5.79	$5.79	$5.78
EOR	$6.31	$5.26	$4.81
California	$7.89	$6.70	$6.13
2025			
Residential	$11.72	$10.67	$10.16
Commercial	$9.54	$8.49	$7.98
Industrial	$7.40	$6.35	$5.85
Power Generation	$6.81	$5.73	$5.28
Transportation	$5.78	$5.78	$5.78
EOR	$6.93	$5.87	$5.35
California	$8.59	$7.35	$6.67

Source: California Energy Commission: Electricity Analysis Office

Natural Gas Production

As a result of technological innovations, some natural gas-bearing formations such as shale reservoirs, once inaccessible, are now producing (or will be producing) in 31 of the Lower 48 states, causing a dramatic reassessment of North American gas resources. As a result, the outlook for gas supply costs is markedly different than what was predicted in 2007. Figure 13 shows the outlook in 2007 was about 700 trillion cubic feet (Tcf) of gas economically recoverable at price of $6.00, but that has now increased to nearly 1400 Tcf, a 100 percent increase.

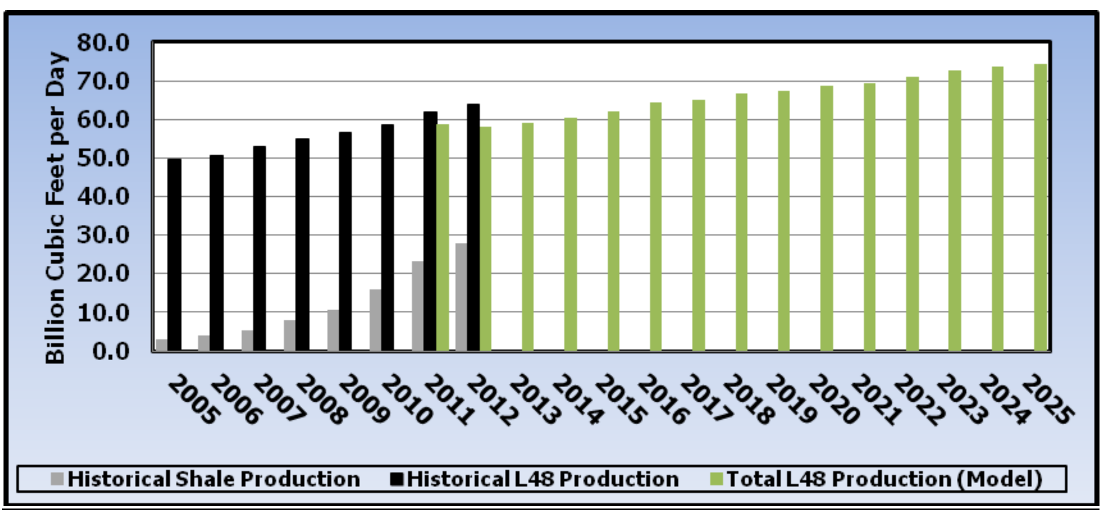
Figure 13: Cumulative Supply Cost Curves



Source: Rice World Gas Trade Model.

Figure 14 shows the projected trend of increasing natural gas production in the Lower 48. While energy efficiency measures and increased generation from renewable sources are reducing gas demand, population growth, increased demand from Mexico, potential LNG exports, reductions in coal-fired generation, and modest increases in use for natural gas vehicles will push demand higher. In addition to improving the productive capacity of natural gas-bearing formations, producers are focusing extraction operations on "wet plays."In addition to methane, these plays have a higher content of natural gas liquids such as butane and ethane, which can be sold separately, generating additional revenue to help offset the low price of natural gas.

Figure 14: Lower 48 Natural Gas Production (Historical and Modeled)



Source: Energy Commission, Lippman Consulting.

Hydraulic Fracturing

Hydraulic fracturing, the fracturing of rock by injecting high-pressure fluid into formations to stimulate oil and natural gas production, has been used by the industry on a limited basis to unlock oil and natural gas from geologic formations since the 1950s. In recent years, the coupling of hydraulic fracturing with horizontal drilling techniques has dramatically increased the economic production of shale gas resources in the United States. As production has increased the supply of natural gas available to consumers, prices have declined.

However, because of health and environmental concerns, the practice of hydraulic fracturing has become very controversial and decision makers are re-examining policies and regulations related to shale gas production. The large water requirements, especially in arid climates, and potential for groundwater contamination, increased seismic activity and additional methane emissions have led to public opposition to hydraulic fracturing. In addition, there are concerns about the impacts on wildlife, native plants, and habitat, including habitat fragmentation. Some jurisdictions such as New York have delayed the development of their shale gas resources, while others have instituted environmental mitigation fees. The U.S. Environmental Protection Agency is investigating hydraulic fracturing and is considering new regulations. In May 2012, the U.S. Bureau of Land Management released regulations on hydraulic fracturing of wells on federal lands.

In September 2013, California enacted Senate Bill (SB) 4 (Pavley, Chapter 313, Statutes of 2013) that will require increased well testing, community notification, and the disclosure of chemicals used in the subsurface technique for hydraulic fracturing. The California Department of Conservation released draft regulations for hydraulic fracturing in December 2012 and expects to issue a rulemaking by the end of 2013 to formally consider new rules. They anticipate that the process will be completed by January 2015.

Natural Gas Demand

As part of each *IEPR* cycle, staff forecasts California end-user natural gas demand in a process that parallels the electricity demand forecast described in Chapter 4—with a suite of end-use and econometric models organized along utility planning area boundaries. The demand forecast results include projections for residential, industrial, commercial, and light-duty natural gas vehicle fuel use. Detailed results and a description of inputs and methodologies are available as part of the *California Energy Demand 2014-2024 Final Forecast* (CED 2013).[377] Staff performed electricity production cost modeling to estimate demand for natural gas for electric generation in the state. These natural gas demand projections were used as inputs to the NAMGas model to project natural gas prices.

Natural gas demand by sector is shown in Table 13. Values for 2011 are actual and values for subsequent years are projected. In all cases, demand for the residential sector remains relatively the same as energy efficiency measures are expected to continue to reduce demand in this sector. For all cases, demand in the power generation sector increases in 2015, followed by a

377 http://www.energy.ca.gov/2013_energypolicy/documents/#12112013.

decrease in demand. Demand for power generation from natural gas fired units was low in 2011 as high precipitation that year resulted in higher supplies from hydroelectric power. The closure of San Onofre Nuclear Generating Station (San Onofre) in 2012 will likely require some replacement generation from natural gas as discussed in Chapter 4. By 2020, 33 percent of generation will be met with renewable sources, but daily or intra-day analysis would be necessary to further examine this issue. The current NAMGas model focuses on analysis of annual requirements and it is not currently set up to perform daily or intra-day assessments.

Table 13: Actual (2011) and Modeled Natural Gas Demand for All Sectors in California

	Million Cubic Feet per Day				
Reference Case	**2011**	**2015**	**2020**	**2025**	**% Change 2011-2025**
Residential	1,352	1,297	1,312	1,333	-1%
Commercial	554	544	574	593	7%
Industrial	1,486	1,478	1,437	1,398	-6%
Transportation	42	40	40	42	0%
Power Gen	2,180	2,670	2,204	2,157	-1%
EOR/Cogen	124	123	117	115	-7%
Total	**5,738**	**6,152**	**5,684**	**5,639**	**-2%**
Low Demand/High Price Case					
Residential	1,352	1,273	1,311	1,346	0%
Commercial	554	530	556	582	5%
Industrial	1,486	1,382	1,363	1,340	-11%
Transportation	42	38	37	39	-8%
Power Gen	2,180	2,446	1,825	1,616	-35%
EOR/Cogen	124	116	111	107	-15%
Total	**5,738**	**5,786**	**5,203**	**5,030**	**-14%**
High Demand/Low Price Case					
Residential	1,352	1,297	1,312	1,328	-2%
Commercial	554	549	579	593	7%
Industrial	1,486	1,491	1,447	1,408	-5%
Transportation	42	40	42	45	6%
Power Gen	2,180	3,026	2,895	2,864	31%
EOR/Cogen	124	157	158	166	34%
Total	**5165**	**6,561**	**6,433**	**6,404**	**12%**

Source: Energy Commission.

Natural Gas Demand for Power Generation

As the use of natural gas for power generation increases nationwide, natural gas and electricity industries have become increasingly interdependent and there is a need to better coordinate natural gas pipeline delivery and electric system reliability. Many regions of the United States that have until recently relied heavily on coal-fired generation for electricity production are now switching to natural gas-fired generation because the price of natural gas is now competitive with coal. In addition, coal plant retirements may be accelerated by the introduction of new federal greenhouse gas (GHG) standards that could require very large investments in existing coal plants.

California already relies on natural gas generation for as much as 50 percent of its electricity supplies and has a minimal amount of power generation from in-state and out-of-state coal facilities.[378] The rest of the Western Electricity Coordinating Council (WECC) area has about 37 GW of coal-fired generation capacity, but it is uncertain how much of this capacity is subject to retirement. Converting from coal to natural gas generation will have a larger impact on the region as a whole, than it will on California.

California's Renewables Portfolio Standard (RPS) mandate of 33 percent renewables by 2020 is leading to a build-out of renewable generating capacity that is producing energy that likely would have otherwise been met by natural-gas fired generating units. However, because of the intermittent nature of renewable generation, natural gas-fired units may be needed to fill in short-term mismatches between supply and demand. Going forward, it is important that the natural gas system has the flexibility to accommodate the short-term ramps up and down of natural gas units that will be required to integrate renewables. Spare pipeline and storage capacity in California provides a degree of flexibility to the gas system that will allow it to better respond to the changing power generation needs of the state. As referred to in Chapters 4 and 5, the California Independent System Operator has announced the creation of a real-time energy imbalance market aimed at facilitating the greater use of renewables, which will involve more efficient use of the West's natural gas fleet.

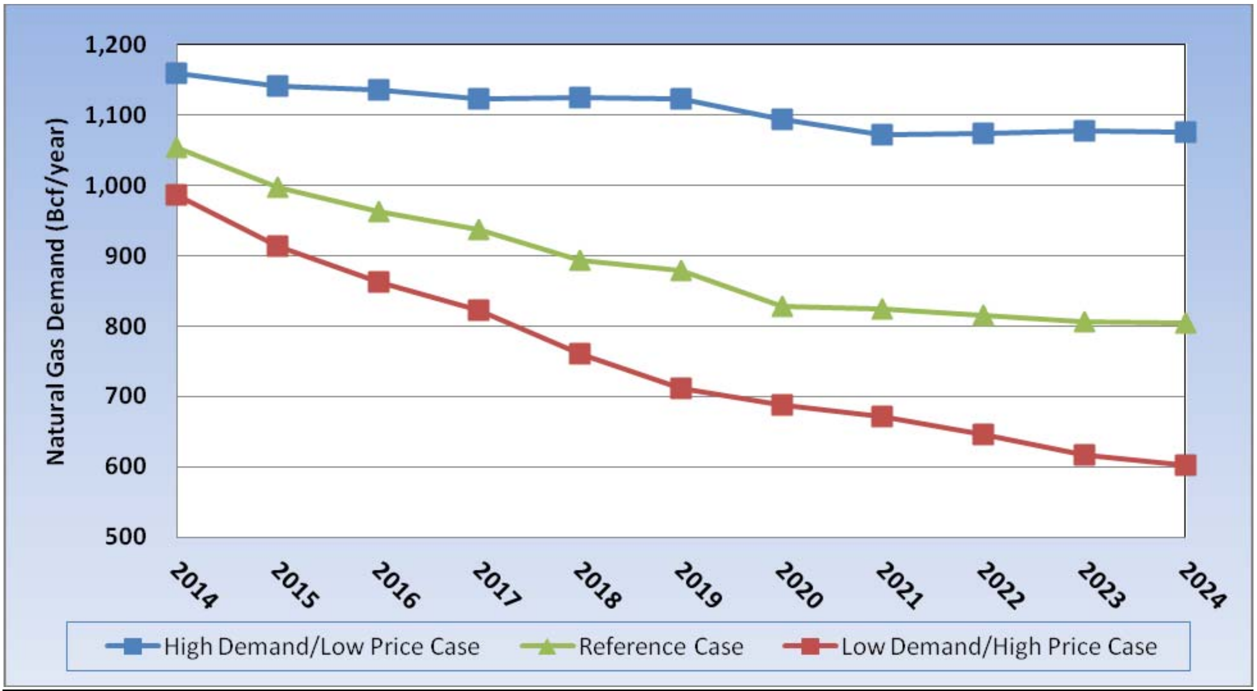
Energy Commission staff's electricity demand forecast results were used in electricity production cost modeling to estimate natural gas demand for power generation in California and the WECC for each of the outlook scenarios. Staff then used the resulting natural gas demand outputs as inputs to the NAMGas model to estimate natural gas prices.

Results in Figure 15 show a decline in demand for natural gas in the power generation sector in California over the next decade, particularly for the reference and high-demand/low-price cases in Figure 15 as more renewable generation and efficiency measures reduce need for natural gas-fired generation. Demand for power generation is much higher in the high-demand/low-price case in 2024 due to assumptions of higher electric load, a better economy, larger population, and less additional achievable energy efficiency. In the WECC, demand for power generation, shown in Figure 16, remains fairly constant from 2014 to 2020 but begins to increase after 2020

378 Roughly 400 MW in 2012 and 200 MW in 2013 (California Energy Commission's Electricity Analysis Office data). http://energyalmanac.ca.gov/electricity/total_system_power.html.

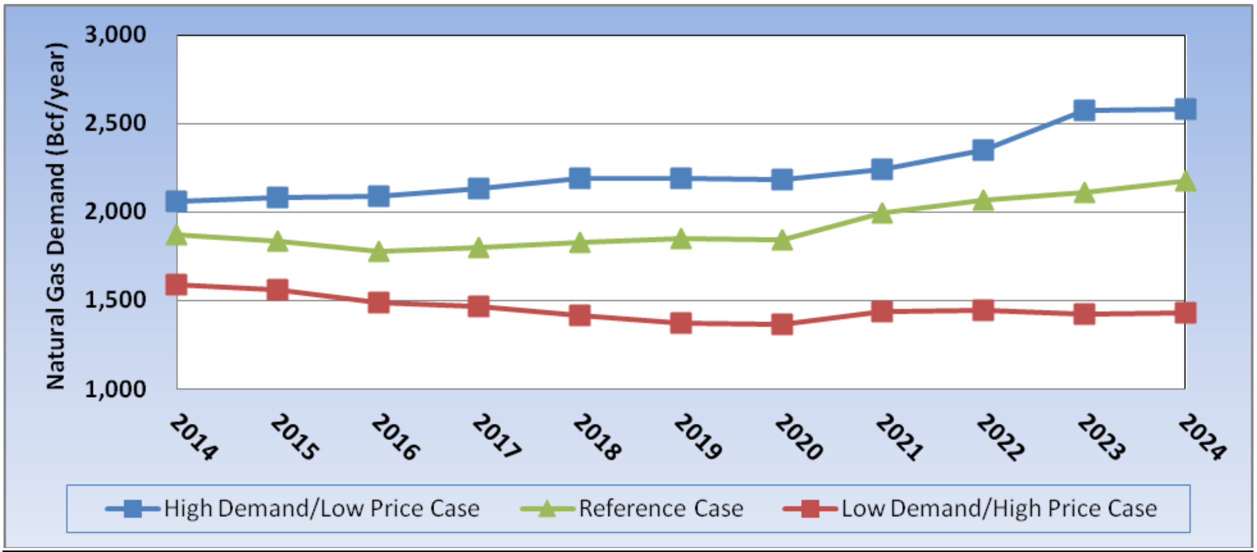
as more natural gas-fired generation is needed to replace coal-fired generation units. The closure of San Onofre in 2012 requires some replacement generation from a combination of natural gas and preferred resources. By 2020, 33 percent of generation will be met with renewable sources, which will result in less natural gas needed to meet load. Some natural gas generation may be needed to integrate intermittent renewable resources, but daily and intra-day analysis would be necessary to further examine this issue. The current NAMGas model focuses on annual requirement and is not set up to perform daily or intra-day assessments.

Figure 15: California Natural Gas Demand for Power Generation in California



Source: Energy Commission.

Figure 16: Natural Gas Demand for Power Generation in WECC



Source: Energy Commission.

Natural Gas Demand for CHP

Despite the overall decline in natural gas for power generation in California, a significant amount of this natural gas could be redirected to onsite generation in California's industrial and commercial sectors. CHP, also known as cogeneration, is an integrated system that generates both electricity and thermal energy using a single fuel source such as natural gas, biogas, biomass, coal, waste heat, or oil. Less fuel is consumed in a typical CHP system than would be required to obtain electricity and thermal energy separately. Since less fuel is consumed, CHP systems offer GHG reduction benefits over the conventional method of obtaining heat from a boiler and power from the electric grid. With very few exceptions, CHP generation uses natural gas or biofuel.

California policy supports the use of CHP as a GHG emissions reduction measure and to support California's industrial economy. The California Air Resources Board's AB 32 *Climate Change Scoping Plan* includes a target of 6.7 million metric tons of carbon dioxide equivalent (CO^2e) reductions from new and existing CHP resources,[379] and Governor Brown's Clean Energy Jobs Plan sets a goal of 6,500 MW of new CHP capacity by 2030.[380] California has several programs to support these policies and promote clean and efficient CHP systems. These include the Self-Generation Incentive Program,[381] the Waste Heat and Carbon Emissions Reduction

379 California Air Resources Board. *Climate Change Scoping Plan: A Framework for Change*. 2008. http://arb.ca.gov/cc/scopingplan/document/scopingplandocument.htm, pp. 42 – 43.

380 "Brown Announces Clean Energy Jobs Plan," at http://www.jerrybrown.org/Clean_Energy

381 CPUC Decision 01-03-073 implementing Assembly Bill 970 (Ducheny, Chapter 329, Statutes of 2000), later amended by Assembly Bill 1685 (Leno, Chapter 894, Statutes of 2003), Assembly Bill 2778 (Lieber, Chapter 617, Statutes of 2006), Senate Bill 412 (Kehoe, Chapter 182, Statutes of 2009), and Assembly Bill 1150 (Pérez, Chapter 310, Statutes of 2011).

Act[382] (also known by its founding legislation Assembly Bill 1613), and a program for competitively bid CHP resources established by the Qualifying Facility and Combined Heat and Power Settlement Agreement.[383]

In 2011 the Energy Commission contracted with ICF Consulting to identify existing CHP capacity and quantify the long-term market potential for CHP in California and the degree to which CHP can reduce potential GHG emissions over the next 20 years.[384] The resulting *Combined Heat and Power: 2011-2030 Market Assessment* identified 8,518 MW of installed CHP at the end of 2011 and indicated that cumulative market penetration for new CHP in 2030 varies between 1,888 MW and 6,108 MW.[385] Existing capacity has decreased by roughly 330 MW with the closure of some CHP facilities that used coal or petroleum coke, as well as the economic closure of the Campbells's Soup plant in Sacramento.

Some applications of CHP are a natural fit for the use of onsite digester biogas. These include wastewater treatment facilities and dairy processing facilities. The creation and use of biogas at these facilities offset the need for natural gas or electricity from the grid. A 2009 Energy Commission study, *Combined Heat and Power Potential at California's Wastewater Treatment Plants*,[386] estimates the market potential for additional capacity at wastewater treatment plants as 100 MW. However, the capacity could be increased to 450 MW by adding biodegradable waste from California dairies and food processing plants, and restaurant oil and grease to the sludge in the anaerobic digesters.

While future CHP development is expected in both the commercial (for example, big box retail and restaurants) and industrial (such as food processing and water treatment) sectors, Energy Commission staff analysis allocated the shift in natural gas demand from the power generation sector to generation for CHP in the industrial sector. CHP is assumed to be topping-cycle[387] CHP.

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382 Assembly Bill 1613 (Blakeslee, Chapter 713, Statutes of 2007), later amended by Assembly Bill 2791 (Blakeslee, Chapter 253, Statutes of 2008).

383 California Public Utilities Commission. 2010. *Decision Adopting Proposed Settlement*. Decision 10-12-035, at http://docs.cpuc.ca.gov/WORD_PDF/FINAL_DECISION/128624.PDF.

384 ICF 2012. *Combined Heat and Power Policy Analysis and 2011-2030 Market Assessment*. CEC-200-2012-002.

385 Hedman, Bruce, Ken Darrow, Eric Wong, Anne Hampson. ICF International, Inc. 2012. *Combined Heat and Power: 2011-2030 Market Assessment*. California Energy Commission. CEC-200-2012-002.

386 Kulkarni, Pramod, 2009, *Combined Heat and Power Potential at the California Wastewater Treatment Plants*. California Energy Commission. Publication# CEC-200-2009-014-SD.

387 In a typical *topping-cycle* system, fuel is combusted in a prime mover such as a gas turbine or reciprocating engine to generate electricity. Energy normally lost in the prime mover's hot exhaust and cooling systems is instead recovered to provide heat for industrial processes (such as petroleum refining or food processing), hot water (for example, for laundry or dishwashing), or for space heating, cooling, and dehumidification.

Figure 17 shows the net additional natural gas demand shifted to CHP for industrial sector customers in each of the Energy Commission staff's forecast scenarios. Growth in average annual natural gas demand is expected in both the reference and low-demand/high-price cases. The high-demand/low-price case assumes minimal CHP addition in the industrial sector.

A shortcoming of the NAMGas model in analyzing natural gas demand for CHP is that it is unable to distinguish end-use detail. When analyzing CHP, the model assumes that the increase in natural gas is solely associated with electricity generation. It does not consider the fact that fuel used in CHP facilities generates both electricity and thermal energy, nor the reduction of natural gas previously used in boilers to meet the thermal need of the host site prior to the installation of a CHP unit. The model also assumes that all new CHP would be topping-cycle CHP.[388]

Figure 17: Natural Gas Demand for New CHP to Generate Electricity for California's Industrial Sector Customers

Source: Energy Commission.

388 In a typical topping cycle system, fuel is combusted in a prime mover such as a gas turbine or reciprocating engine to generate electricity. Energy normally lost in the prime mover's hot exhaust and cooling systems is instead recovered to provide heat for industrial processes (such as petroleum refining or food processing), hot water (e.g., for laundry or dishwashing), or for space heating, cooling, and dehumidification. In a bottoming cycle system, also referred to as "waste heat recovery," fuel is combusted to provide thermal input to a furnace or other industrial process and heat rejected from the process is then used for electricity production. http://www.epa.gov/chp/documents/faq.pdf.

Natural Gas Pipeline Safety

Pipeline safety, in the wake of 2010 explosion of a Pacific Gas & Electric (PG&E) pipeline in San Bruno, is a critical concern of the Energy Commission, the California Public Utilities Commission (CPUC) and the legislature. Since the explosion, the CPUC has required the gas utilities to: verify pipeline maximum allowable operating pressures (MAOP); subject segments without acceptable records to hydrostatic or other strength testing, or to replace those segments; and submit pipeline safety enhancement plans. In the meantime, either under CPUC order or by PG&E decision, many high pressure pipelines operated at pressures as much as 20 percent below their pervious maximum operating pressures. The Energy Commission continues to provide research, development, and deployment funding to projects that explore new technologies to monitor and address pipeline safety. The Energy Commission is also closely monitoring the effective capacity reductions imposed as PG&E reduces operating pressures.

In December 2012, the CPUC approved PG&E's 2012–2014 Pipeline Safety Implementation Plan, which spelled out criteria and a timetable as to how PG&E would upgrade its gas system, including the addition of remote or automatic valves and making more of its system able to use in-line inspection techniques.[389] The CPUC authorized PG&E to spend up to $2 billion between 2011 and 2014 to address safety issues through pipeline testing and modernization, authorizing $299 million of the associated expenditures to be paid for through rate recovery. PG&E estimates that its rate for residential core services will increase by 1.5 percent.[390] Southern California Gas, likewise, has filed its Pipeline Safety Enhancement Plan[391] with the CPUC, which is a multiyear pipeline testing and replacement effort that will target upgrading, replacing or adding roughly 487 valves on its system with remote control capability. Phase 1 of the Plan is estimated to cost $2.5 billion over 10 years.

In April 2013, the CPUC released its updated Natural Gas Safety Action Plan,[392] which focuses on setting, monitoring, and enforcing rules for regulated utilities based on risk assessment and risk management. The CPUC is also tracking improvements being made that are responsive to recommendations of the Independent Review Panel and the National Transportation Safety Board related to the PG&E San Bruno pipeline explosion. Specifically, the plan aims to ensure the safety of the existing gas system by: upgrading and replacing the gas system to make it

389 CPUC, "Decision Mandating Pipeline Safety Implementation Plan, Disallowing Costs, Imposing Earnings Limitations, Allocating Risk Of Inefficient Construction Management To Shareholders, And Requiring Ongoing Improvement in Safety Engineering" http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M040/K622/40622382.PDF.

390 CPUC, "CPUC Approves Pipeline Safety Plan for PG&E; Increases Whistleblower Protections," press release, December 20, 2012, http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M040/K531/40531580.PDF.

391 *Southern California Gas Company (U 904 G) Natural Gas System Operator Safety Plan*, http://www.socalgas.com/regulatory/documents/r-11-02-019/SCG-Cover%20Filing-6.29.12.pdf.

392 http://www.cpuc.ca.gov/PUC/safety/Pipeline/Natural_Gas_Safety_Action_PlanApril2013.htm.

safer; reforming the CPUC to make safety its first priority; and instilling a safety culture in gas operators.

PG&E informed the CPUC in July 2013, however, that its 2011 application presenting "traceable, verifiable and complete" records and therefore requesting approval to increase the operating pressure on Line 147 in San Carlos to 365 pounds per square inch gauge (psig) had in fact been based on inaccurate information about the pipeline. PG&E reduced the pressure on Line 147 to 300 psig, and the CPUC asked in a Show Cause Order why it should not rescind all of the orders it had approved to restore operating pressures. At the Show Cause Order hearing, PG&E indicated that the impact of reducing operating pressures on all of the lines whose pressures had since been restored would be to curtail natural gas service to power plants, noncore customers on the San Francisco Peninsula, and core customers in San Francisco's Financial District this winter should we experience cold temperatures that are expected to occur once in every ten years.

PG&E's errata explained that the information it filed in October 2011 in support of its request to lift operating pressure restrictions on these pipelines was erroneous. Information contained PG&E records—developed as part of the pipeline records validation process ordered by the CPUC after the San Bruno explosions—showed that these pipelines contained double submerged arc welds or were seamless and had joint efficiency factors of 1.0. PG&E argued that this justified an MAOP of 365 psig. Based on this representation by PG&E, the CPUC granted permission to raise the MAOPs of the lines to no more than 365 psig in December 2011.

The errata revealed that PG&E had learned upon repair resulting from a routine leak inspection that as many as six segments of Line 147 actually have single submerged arc welds, implying a joint efficiency factor of 0.8, which effectively reduces the pipeline's MAOPs to 330 psig from the approved 365 psig. The implications from a pipeline safety perspective are clear. Due to PG&E's admitted error, the pipelines received approval to operate at pressures that are higher than the recommended MAOP. PG&E noted in the errata that it has reduced the operating pressures to safe levels, but both the length of time it took PG&E to file the errata—18 months—and the fact that the information contained in the errata was substantive, led the CPUC to order PG&E to appear at a hearing and show cause why it shouldn't be sanctioned for violating Rule 1.1 of the Commission's Rules of Practice and Procedure. Rule 1.1 states that any person who transacts business with the CPUC agrees to "never mislead the Commission or its staff by an artifice or false statement of law or fact."[393] The Show Cause Order also asks PG&E to show why all of the CPUC orders approving PG&E requests to restore operating pressures arising out of the post-San Bruno effort to verify pipeline features and maximum allowable operating pressures should not be rescinded until "competent demonstration that PG&E's natural gas system records are reliable."

Separately, PG&E in late September reduced operating pressures on Line 300. This line is the backbone transmission line that comes from the interstate pipeline connections at the

393 CPUC Rules of Practice & Procedure, http://docs.cpuc.ca.gov/WORD_PDF/AGENDA_DECISION/143256.PDF, p. 1.

California-Arizona border and delivers natural gas to the southern Bay Area and Peninsula, as well as the San Joaquin Valley. The pressure decrease reflects a "class location change," made in response to finding increased population density around certain areas along the pipeline. Federal rules scale a pipeline's maximum allowable operating pressure to population density, protecting the public safety by requiring that operating pressures on a given pipeline decline as population density around the pipeline increases. The reduced operating pressures decrease the maximum throughput capability of this important high-pressure transmission line. As indicated in the *2011 IEPR*, this additional pressure reduction, needed for safety purposes, could pose reliability issues for Californians under certain cold winter conditions.

Natural Gas Infrastructure

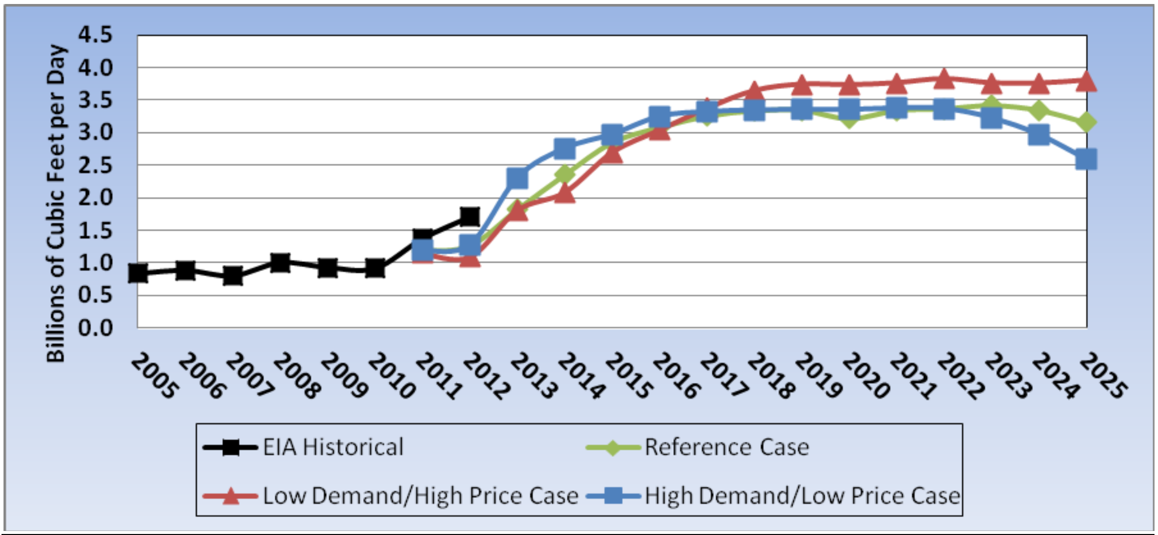
Energy Commission staff has identified four areas of potential natural gas infrastructure changes: exports to Mexico, exports of LNG, pipeline development in the Lower 48 states, and natural gas storage in California.

Exports to Mexico

In 2012, Mexico imported an average of 1.7 billion cubic feet per day (Bcf/d) of natural gas from the United States. By 2018, U.S. exports to Mexico are expected to increase more than 100 percent based on a report by Bentek Energy (3.6 Bcf/d)[394] and on the Energy Commission staff's reference case forecast (3.3 Bcf/d, Figure 18). Most of the increase comes from increased natural gas demand for power generation in Mexico. Mexico possesses large natural gas reserves, but they are controlled by its state-owned oil company, Petróleos Mexicanos (PEMEX). PEMEX is known for focusing more on oil production than on gas and is said to be relatively inefficient. Foreign direct investment in oil and gas production is prohibited under Mexico's Constitution, and PEMEX (the Mexican state-owned petroleum corporation) has no real experience developing shale reserves. Staff's NAMGas assumptions reflect these factors by assuming higher finding and development costs for gas in Mexico, which in turn make it cost-effective for Mexico to import gas from the United States.

394 Rocco Canonica, Ellen Nelson, Darrell Proctor, and Tricia Bulson. *Growing Mexican Gas Market Creates Southwest Price Premiums. Energy Market Fundamentals Report.* Bentek Energy, Platts, May 2013, p395 ICF International. *Natural Gas Pipeline and Storage Infrastructure Projections Through 2030*. Washington D.C.: The INGAA Foundation, October 2009. http://www.ingaa.org/File.aspx?id=10509.

Figure 18: Historical and Forecasted Lower 48 Exports to Mexico



Source: Energy Commission staff forecast, U.S. EIA.

El Paso Natural Gas system's southern mainline pipeline, which supplies the San Diego area, is currently undersubscribed. Some, but not all, of the increased exports to Mexico would be delivered via this line and could thus improve revenues for the pipeline owner. The combination of current low level of deliveries on the pipeline and the presence of plentiful natural gas resources in the Southwest supply basins mean that the projected United States-to-Mexico exports are feasible with little price impact over the long-term.

Liquefied Natural Gas Exports

The boom in U.S. shale gas production and the difference in the price of natural gas in the United States versus prices abroad have led to increased interest in exporting LNG. There are 28 planned LNG export terminals that have filed with the U.S. Department of Energy (DOE) for licenses to export to non-Free Trade Agreement countries. Four of these export terminals received approved non-Free Trade Agreement licenses over the last three years. DOE has been cautious about approving these licenses because of concerns that high levels of LNG exports might cause gas shortages and price increases in the United States. Prospective export terminals can take two to four years to build and cost billions of dollars. In that time frame, the foreign market for U.S. LNG could be met by other sources closer to demand, such as Australia or Qatar. Among the four approved export terminals, only the Sabine Pass LNG terminal in the Cameron Parish of Louisiana has begun construction. The prospects for California to be an exporter are extremely low as the state is neither a big producer nor net exporter of natural gas.

Natural Gas Pipeline Development

The United States natural gas pipeline system is facing a period of uncertainty because of changing supply and demand dynamics from the abundance of shale gas, expected increases in natural gas-fired electricity generation as coal generation is retired, and expiration of contracts by 2015 that is causing pipeline companies to look for ways to replace lost revenue. In the Northeast, Pennsylvania's Marcellus Shale has brought gas supply much closer to demand.

Long-haul Tennessee and Rocky Mountain Express pipelines, which carry gas from the Gulf of Mexico to the Northeast and the Rocky Mountain Basin to the Northeast, respectively, are considering reversing or enabling bidirectional pipeline flow to deliver gas out of the Marcellus shale and meet the pipeline's capacity.

In the southwest, the El Paso Natural Gas pipeline from Texas to Southern California has unsubscribed capacity. Although the pipeline owner explored two plans to increase revenue—first, by abandoning some compressor stations to lower the capacity and operating costs, and second, by converting a segment of the pipeline from gas transmission to oil—both plans were eventually dropped. To accommodate expected replacement of coal plants with natural gas, an Interstate Natural Gas Association of America study projects a need for 25 Bcf/d of new pipeline capacity.[395] An Aspen Environmental Group study of a worst-case scenario in which all existing coal generation is replaced with gas indicates that annual gas demand would rise by 14.1 Tcf and require 70 Bcf of new pipeline capacity.[396]

For most of California, the analysis indicates that the capacity is sufficient to meet estimated demand. In Southern California, however, there could be supply constraints because of increased natural gas demand from the closure of San Onofre. In some cases, there has been less natural gas to serve the needs of customers who could only be served by natural gas delivered to the Ehrenberg receipt point on the California-Arizona border. This delivery requirement, known as the Southern System Minimum (SoSysMin), refers to the minimum amount of gas that must be delivered through the pipeline at Ehrenberg to serve all load in the SDG&E gas service area. The SDG&E service area is in SoCal Gas' Southern Zone, which receives the majority of its gas through Ehrenberg from the El Paso Natural Gas south mainline. There are smaller pipeline interconnects between SoCal Gas's Northern System and Southern System, but the capacity is too small to deliver to all loads and they create bottlenecks. Consequently, on days when the gas deliveries at Ehrenberg are insufficient to serve all load in the Southern System, SoCal Gas has permission from the CPUC to go into the market and purchase more gas for delivery on the El Paso Natural Gas south mainline to make up the deficiency. Without this permission, SoCal Gas is allowed to purchase gas only for its core customers, which, given the current gas delivery reductions at the Ehrenberg receipt point, would result in curtailments for noncore customers, including electric generators, along the southern system.

SoCalGas and SDG&E are additionally exploring the idea of paralleling the existing 16" Line 1600 from Rainbow to Santee with a new 36" line. This would serve both to bolster the two-way transfer capability system and allow SDG&E to maintain gas service, including to critical gas-fired power plants while the existing Line 1600 is tested and inspected as required by the CPUC's order to test or replace gas pipelines for which complete records do not exist. The Sempra utilities estimate this line to cost $500 million. Additional system reinforcements may be

395 ICF International. *Natural Gas Pipeline and Storage Infrastructure Projections Through 2030*. Washington D.C.: The INGAA Foundation, October 2009. http://www.ingaa.org/File.aspx?id=10509.

396 Elder, Catherine. *Implications of Greater Reliance on Natural Gas for Electricity Generation*. Prepared for the American Public Power Association. Aspen Environmental Group, July 2010.

needed should development of projects such as the Pendleton Energy Center, for example, come to fruition.

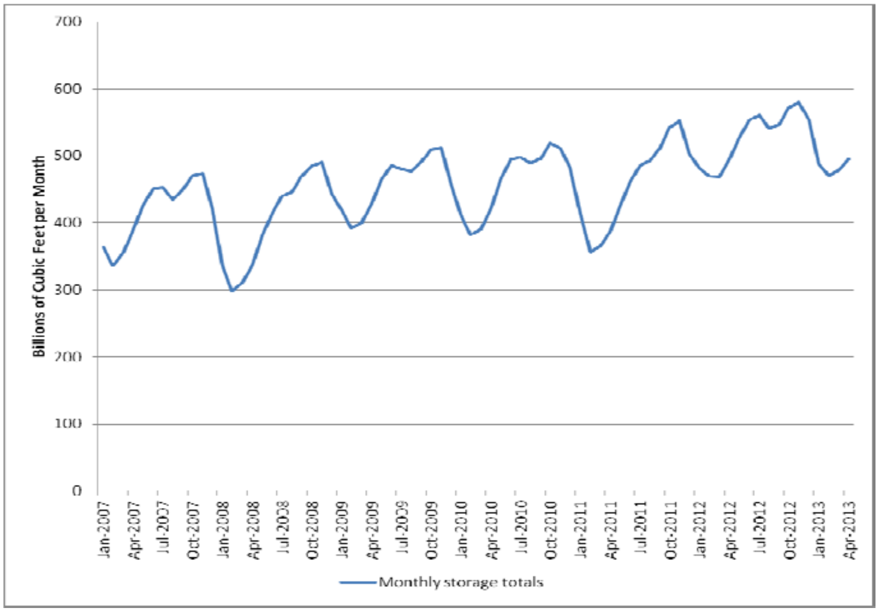
Since the shutdown of San Onofre, the SoSysMin has risen from an annual average of 420 MMcf/d in 2011 to 520 MMcf/d in 2012. SoCal Gas had to purchase additional gas to meet this rising SoSysMin on more than 100 days during the past 12 months. These purchases usually take place later in the day when there is a higher likelihood that there will not be enough gas available for purchase, which could lead to curtailments. SoCal Gas is exploring options to solve this issue, which include a minimum percentage of gas that shippers would have to deliver to the Ehrenberg receipt point or a new pipeline that would connect SoCal Gas's northern system to its southern system.

The Energy Commission does not expect any significant pipeline disruptions due to unsafe or aging infrastructure, given the active attention that PG&E and other California gas utilities have given to pipeline safety following the San Bruno pipeline explosion in 2010.

Natural Gas Storage in California

Storage plays a unique role in the natural gas market that involves both meeting natural gas demand and storing natural gas for later use. In the spring/summer, storage operators inject gas into their underground facilities and, in the fall/winter, withdraw to meet peak demand. Storage, therefore, serves as a market balancer. In addition, storage may be used to provide a buffer against natural disasters such as hurricanes and tornadoes, or to aid in reducing price volatility by ensuring consistent supply. California has 13 underground natural gas storage facilities with a total working gas inventory of 335 Bcf as of 2011. As shown in Figure 19, storage capacities in 2012 rose in the winter and spring by up to 24 percent compared to 2011 on the heels of a warmer-than-usual winter and lower-than-usual demand. This trend has continued in 2013 with storage totals through April 2013 staying relatively even. Overall, the trend has been increased storage totals each year over the past six years as working storage capacity has increased, and because demand is expected to grow as economic conditions improve.

Figure 19: California Monthly Natural Gas Storage Totals (Total Inventory Including Working Gas)



Source: U.S. EIA.

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 SoCal Gas proposals at the CPUC to either increase gas deliveries to Ehrenberg or build new infrastructure to connect its northern and southern pipeline systems.

- **Monitor and evaluate interest in exporting liquefied natural gas.** Monitor the current national interest in exporting LNG and the analyze implications of this for California's natural gas supply needs.

- **Monitor changing revenue dynamics for natural gas.** Monitor changing natural gas corporation revenue requirements and their potential effects on ratepayers in an era marked by shale abundance, generation shifts away from coal, and expiring pipeline contracts and the implications for maintaining necessary supply flows into California.

CHAPTER 8: Transportation Energy

The transportation sector is a major user of energy and is essential to California's economy. Movement of people and goods by vehicles, rail, airplanes, and other transportation modes accounts for about 40 percent of all energy consumed within the state[397] and produces roughly 39~~8~~ percent of the state's greenhouse gas (GHG) emissions.[398] There are more than 27 million registered vehicles in California~~,~~ and those vehicles consume nearly 18~~9~~ billion gallons of fuel each year. Petroleum comprises 92 percent of California's transportation energy sources, but technology advances, market trends, consumer behavior, and government policies could lead to significant changes in the fuel mix by 2020. In fact, over the last decade, California has initiated several actions and put in place policies, rules, and regulations to improve vehicle efficiency, increase the development and use of alternative fuels, reduce air pollutants and GHG emissions from the transportation sector, and reduce vehicle miles traveled. These California trends have initially shown modest progress~~,~~ but new circumstances are poised to push significant advances. California needs a fuller understanding of the impact of these potential changes and assurances that transportation and infrastructure options will continue to provide reliable mobility for people and businesses. This chapter describes a series of investments that California is making to transform the transportation sector and then identifies emerging transportation energy trends.

Alternative and Renewable Fuel and Vehicle Technology Program

California's investment in transforming the transportation sector. Assembly Bill 118 (Núñez, Chapter 750, Statutes of 2007) created the Alternative and Renewable Fuel and Vehicle Technology Program (ARFVTP) in 2007 and authorized the Energy Commission to develop and deploy alternative and renewable fuels and advanced transportation technologies in the marketplace to help attain California's climate change and petroleum dependence policies. The ARFVTP is authorized at up to $100 million per year in funding to accomplish these objectives ~~develop and deploy technology and alternative and renewable fuels in the marketplace,~~ without adopting any preferred fuel or technology. ~~Since the inception of the program, the Energy Commission has invested more than $400 million into some 233 fuel, vehicle, and infrastructure projects across the state. This investment supports the State's energy, clean air, and climate goals.~~ In September 2013, the California Legislature reauthorized this program with Assembly Bill 8 (Perea, Chapter 401, Statutes of 2013), extending ARFVTP funding through January 1, 2024. Reauthorization of ARFVTP will enable the Energy Commission to invest a total $1.5 billion between 2009 and 2024 to support development and deployment of zero- and low-emission vehicles and low-carbon fuels, by far the largest state-level incentive program in the country.

397 U.S. Energy Information Administration, http://www.eia.gov/state/?sid=CA#tabs-2.

398 California Air Resources Board, Greenhouse Gas Inventory, http://www.arb.ca.gov/cc/inventory/data/data.htm.

Developing a plan that invests in a broad transportation portfolio. The Energy Commission uses a portfolio approach that balances near- and long-term technologies to reduce criteria, particulate and carbon emissions from the multiple vehicle types, users, and market applications that typify California's large and diverse vehicle fleets of 26 million passenger vehicles and 1 million trucks. This portfolio approach is specified by the Legislature and has been supported and recommended in multiple publications including the *2007 State Alternative Fuels Plan*;[399] the Low Carbon Fuel Standard (LCFS) planning documents prepared by UC Berkeley and UC Davis; [400] and more recently in the draft *2050 Vision for Clean Air* released by the California Air Resources Board (ARB) and South Coast Air Quality Management District.[401]

The Energy Commission has developed and adopted five investment plans since 2008, with $548.7 million in technology development and deployment investments for the first six fiscal years of the ARFVT Program. Program funding for each annual cycle is determined by the Energy Commission through updates to the annual *Investment Plan* based on a public process that features a multistakeholder, 20-plus-member Advisory Committee and multiple public workshops. The Advisory Committee includes representatives from industry trade associations; academic institutes; nongovernmental environmental, public health, and alternative energy organizations; labor; and energy and environmental agencies. The Energy Commission uses the data, experiences, and expertise gathered during this important public process, in addition to its knowledge, analyses, and expertise, to inform and help shape the *Investment Plan*.

As of June 30, 2013, the Energy Commission has funded 233 projects totaling $409.6 million since the initial round of solicitations were released in 2009 and 2010. Table 14 and Figure 20 summarize the $409.6 million in funding awards by fuel category and specific technology application and show the distribution of ARFVTP awards across the portfolio by primary fuel and program categories. To date, the ARFVTP has:

- Invested roughly one-third of total ARFVTP investments into **electric drive** technologies (including the manufacturing category). These include light-duty passenger vehicle chargers, components, voucher support, and planning grants, as well as medium- and heavy-duty advanced technology truck grants.
- Dedicated another third ($127.6 million) of the total program funding to **biofuel production and development**. More than $100 million is being used to fund 36 fuel production projects. This portfolio of biogas, conventional ~~ethanol~~ and cellulosic ethanol, and biodiesel and renewable diesel projects feature very low-carbon intensity values, generally 75 percent lower than gasoline and diesel. This portfolio also includes

399 *State Alternative Fuels Plan,* California Energy Commission, 2007, 600-2007-011-CMF.

400 Alexander Farrell and Daniel Sperling, *A Low Carbon Fuel Standard for California, Part 1: Technical Analysis*, UC Berkeley and UC Davis, August 2007.

401 *Vision for Clean Air: A Framework for Air Quality and Climate Planning*, California Air Resources Board, San Joaquin Valley Air Quality Management District, South Coast Air Quality Management District, June 2012.

waste-based biomass feedstocks from municipal waste streams, dairies, and feedlots, and other agricultural residues, as well as alternative feedstocks such as sweet sorghum and sugar beets.

Table 14: Detailed Accounting of ARFVTP Award Categories through June 30, 2013

Fuel Type	Funding Activity	Amount ($ millions)	No. of Awards	Total ($ millions)
Electric Drive	Charging Infrastructure	$24.8	27	$87.1
	Vehicle Deployment Incentives *	$24.1	4	
	Medium- and Heavy-Duty Advanced Vehicle Demonstration	$36.2	21	
	PEV Regional Readiness	$2.0	10	
Hydrogen	Hydrogen Fueling Infrastructure	$36.8	8	$43.2
	Fuel Standards Development	$4.0	1	
	Fuel Cell Bus Demonstration	$2.4	1	
Natural Gas	Vehicle Deployment Incentives	$33.5	3	$55.5
	Medium- and Heavy-Duty Advanced Vehicle Demonstration	$6.3	4	
	Fueling Infrastructure	$15.7	42	
Propane	Vehicle Deployment Incentives	$7.3	2	$7.3
Biofuels	Biomethane Production	$49.9	13	$127.6
	Diesel Substitutes Production	$26.0	12	
	Gasoline Substitutes Production	$26.4	11	
	Sustainability Research	$2.1	2	
	E85 Fueling Stations	$16.5	4	
	Upstream Diesel Substitutes Infrastructure	$4.0	4	
	Medium- and Heavy-Duty Advanced Vehicle Demonstration	$2.7	1	
Manufacturing	Manufacturing Facilities and Equipment	$48.3	18	$48.3
Workforce Training/Dev.	Workforce Training and Development	$23.3	30	$23.3
Program Support	Technical Assistance and Analysis	$17.3	15	$17.3
Total		**$409.6**	**233**	**$409.6**

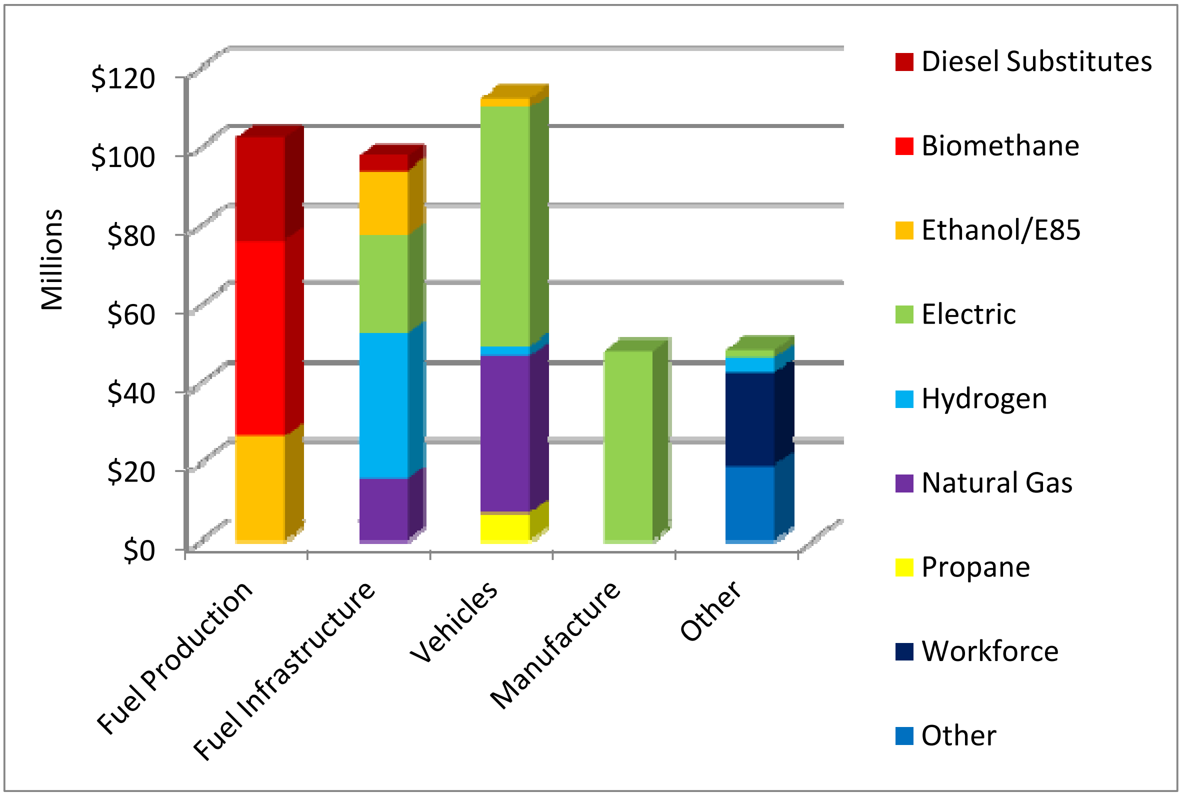
*Table 15 shows ARFVTP funding awards to the end of June 2013, which is the end of the state fiscal year. Assembly Bill 101 ~~will transfer~~ transferred another $24.55 million from ARFVTP to the ARB's Clean Vehicle Rebate Project.

Source: California Energy Commission, Emerging Fuels and Technology Office

- Incentivized and accelerated a transition from older, higher polluting vehicles, to new less polluting vehicles. The Energy Commission's investments in **natural gas trucks and fueling infrastructure** total more than $55 million and include funding for nearly 1,400 natural gas vehicles, a series of natural gas engine development projects, and 50 new natural gas fueling stations throughout California.

- Distributed awards widely throughout the state. As shown in Table 15, about 25 percent of program funding has gone to the South Coast, while the Bay Area received about 18 percent of funds, and the San Joaquin Valley received about 13 percent.

Figure 20: Cumulative 2009-13 Program Investments by Fuel Type and Supply Phase



Source: California Energy Commission

- Allocated about 64 percent of program investments to commercial deployment and production projects; 26 percent to precommercial demonstration, research, and development; and 10 percent to clean transportation workforce development.
- Leveraged $1.80 of private sector or other public sector funding for each $1 invested. Private sector and additional public sector matching contributions to the 233 projects total nearly $740 million. To date, the largest public funds leveraged by the ARFVT Program have been federal monies made available through the American Reinvestment and Recovery Act of 2009.

Making Progress on Zero-Emission Vehicles. California leads the nation in market adoption and policy support for alternative fuels and vehicles. Reducing carbon from the transportation sector; reducing petroleum fuel use; reducing criteria, particulate, and toxic emissions; and promoting zero-emission vehicle (ZEV) technologies are core policy goals for Governor Brown and the Legislature. These policy goals are articulated in legislation, executive orders, and program regulations.

~~These policy goals are supported with incentive funding from ARFVTP and the Air Quality Improvement Program, totaling $548 million and $227 million to date for each program, respectively. The eight-year reauthorization will enable up to $1.12 billion in additional incentive funding through 2023.~~

Table 15: Geographic Distribution of ARFVTP Awards

Air District	Funding Amount ($ millions)	Percent of Total (%)	Number of Awards
Bay Area	73.6	18.0	42
Monterey	2.7	0.7	2
Sacramento	17.4	4.3	16
Santa Barbara	1.9	0.5	6
San Diego	15.7	3.8	15
San Joaquin	54.0	13.2	28
South Coast	103.2	25.2	68
Ventura	11.3	2.7	3
Yolo-Solano	10.5	2.5	6
Other Nor Cal Districts	5.1	1.2	9
Other So Cal Districts	2.1	0.5	6
Statewide	112.1	27.4	32
Total	**409.6**	**100**	**233**

Source: California Energy Commission

Assembly Bill 101, (Committee on Budget, Chapter 354, Statutes of 2013), Section 27, transfers an additional $24.55 million from the Alternative and Renewable Fuel and Vehicle Technology Fund to the Air Quality Improvement Fund. These funds were previously loaned to the state General Fund and likely will not affect funding levels for the *2014-15 Investment Plan*. This transfer is an additional contribution to the ARB's Clean Vehicle Rebate Project. This additional funding will support roughly 12,400 additional rebates for battery-electric and plug-in electric vehicles through the Clean Vehicle Rebate Project.

The Energy Commission's Role. The Energy Commission's investments in light-duty electric vehicle deployment in California total $90.8 million, or 20 percent of grant agreements to date. These investments include nearly $25 million for more than 7,200 electric chargers, $23.5 million for 9,063 vehicle purchase vouchers via the ARB's Air Quality Improvement Program (AQIP),[402] $2 million for regional readiness planning, and $40.3 million for 11 component, battery, and vehicle development grants through manufacturing solicitations.

For ZEV truck funding, the Energy Commission has invested a total of $60 million in demonstration and deployment projects. This amount includes $36.2 million for 21 demonstration projects for all-electric, plug-in electric, and hybrid electric drive trucks that

402 ARFVTP transfers to AQIP: 8,903 light-duty electric vehicle vouchers totaling $19.5 million and 160 electric truck vouchers totaling $4 million.

range from Class 8 electric drayage trucks to Class 3 and 4 electric shuttle vans, to initial funding for a demonstration of an overhead wire catenary-electric trolley truck configuration for the Interstate 710 corridor near the ports of Los Angeles and Long Beach. The $60 million investment also includes seven grants from the manufacturing category to support new electric truck assembly plants in California from companies such as Electric Vehicles International, Transpower, and Boulder Electric.

The Energy Commission has also invested more than $43 million in hydrogen fuel station development for 24 new and refurbished vehicle fueling stations, a fuel cell bus fueling station and bus demonstration, and development of retail fueling dispensing standards and regulations through the California Division of Weights and Measures. Through AB 8, the Legislature has directed the Energy Commission to invest $20 million per year in new hydrogen station development until a network of at least 100 stations is developed in California. AB 8 also requires the ARB and Energy Commission to collaborate on assessing hydrogen station development and fuel cell vehicle deployment. To help guide these investments, the Energy Commission uses research and expertise from a wide variety of stakeholders, including the ARB, automakers and station developers, and entities like the California Fuel Cell Partnership, whose recent roadmap identifies 68 station sites in Northern and Southern California that can serve as the initial network of stations needed to support commercial launch of fuel cell vehicles in California between 2015 and 2017. ARFVTP funding will be critical to meeting these hydrogen fueling station network goals.

The Zero-Emission Vehicle Regulation. The ARB adopted the ZEV requirement in 1990 as part of the Low Emission Vehicle regulation. The ZEV Program is designed to achieve the state's long-term emission reduction goals by requiring manufacturers to offer for sale specific numbers of the cleanest cars available. Since 1990, not only have partial ZEVs and advanced technology become commercially viable, but ZEVs and ZEV-enabling technologies are coming to market.

The ZEV Program remains an important regulation for meeting California's air quality and GHG reduction goals and has spurred many new technologies that are being driven on California's roads today. The goal of the regulation is to have zero-emission technologies available on a commercial scale as quickly as possible so that future fleet average standards can count on ZEVs and the entire fleet can approach zero-emission levels. These ZEV program technologies, which include battery electric, fuel cell electric, and plug-in hybrid electric vehicles, are just beginning to enter the marketplace.

The 2012 amendments increase requirements of ZEVs and plug-in hybrid electric vehicles to more than 15 percent of the new vehicle sales by 2025. This will ensure ZEV volumes are at a level sufficient to reduce the incremental ZEV costs and reach commercialization. Cumulative ZEV sales under the new requirements should reach 1.4 million by 2025.

Executive Order B-16-12 and the Governor's ZEV Action Plan. On March 23, 2012, Governor Brown signed Executive Order B-16-12[403] directing state government to help accelerate the

403 http://gov.ca.gov/news.php?id=17472.

market for ZEVs in California and support the ZEV regulation. The Executive Order established several milestones on a path toward widespread infrastructure to support 1.0 million ZEVs by 2020 and cumulative ZEV sales of 1.5 million by 2025. The Executive Order also sets a longer-term target of reducing transportation-related GHG emissions by 80 percent below 1990 levels by 2050, augmenting the original Executive Order S-3-5 that established an economywide 80 percent target.[404] In addition, the Governor published a *Zero Emission Vehicle Action Plan,* which specifies clear action items to promote the building of fueling infrastructure, increase vehicle adoption, and develop of ZEV-related California jobs.[405] Most recently, the Governor's Office created an ombudsman position to help facilitate rapid permitting and construction of the hydrogen fueling stations and electric charging infrastructure that will be needed to support the ZEV targets for 2020 and 2025. This position will be funded through ARFVTP.

Program Impacts and Changes to California's Alternative Fueling Infrastructure, Vehicle Fleets, and Biofuels Industry: 2008-2013

As articulated in the ARFVT Program investment plans, the Energy Commission's strategic program goals for allocating the ARFVT Program's funding have been to:

- Establish the foundation for a ZEV and near-ZEV transportation future by focusing on battery electric, hydrogen fuel cell electric, natural gas, E85 (a blend of 85 percent ethanol and 15 percent gasoline) retail fueling stations, and biodiesel wholesale fueling terminals. Early establishment of alternative fueling networks signals California's commitment to the long-term transition to alternative fueled and powered vehicles, which should, in turn, boost early market sales of alternative vehicles in California.
- Accelerate shifts in medium and heavy-duty truck fleets from diesel to natural gas to capture early carbon reduction benefits and begin investments in ZEV truck technologies to meet long-term carbon and criteria emissions reduction goals. While diesel-fueled trucks are a small percentage of the state's total vehicle fleet (3.3 percent), they are responsible for a disproportionately large amount of fuel consumption and vehicle emissions due to their large engine sizes, low fuel mileage, and high levels of vehicle miles traveled. In fact, these trucks account for about 23 percent[406] of the total on-road emissions in California. Program investments in this relatively small sector have the potential to achieve large reductions in petroleum fuel consumption and associated carbon and criteria emission pollutants and are being used to shift California trucking fleets away from their dependence on diesel and gasoline.
- Provide funding for feasibility studies, demonstrations, and commercial production of advanced technology biofuels in California that avoid the use of food crops and prime

404 http://gov.ca.gov/news.php?id=17463.

405 http://opr.ca.gov/docs/Governor's_Office_ZEV_Action_Plan_(02-13).pdf.

406 California Air Resources Board, California Greenhouse Gas Inventory for 2000-2011 — by Category as Defined in the *2008 Scoping Plan*, calculated as emissions from heavy-duty trucks as a percentage of on-road transportation greenhouse gases, http://www.arb.ca.gov/cc/inventory/data/tables/ghg_inventory_scopingplan_00-11_2013-08-01.pdf.

agricultural soils for feedstock production by focusing on waste-based resources and alternative feedstocks that can be developed on degraded agricultural lands or in industrial facilities.

While the percentage increases in alternative technology vehicle and fueling systems shown below are important, they still represent small fractions of the total fleet of more than 27~~6~~ million vehicles and 9,7~~10,0~~00 retail gasoline fueling stations in California. The growth of key alternative fuel, vehicle, and infrastructure sectors is an early indicator that California's fuel and vehicle markets are beginning the shift toward alternative and renewable fuels and advanced vehicle technologies. California now has the largest network of electric vehicle charging systems and hydrogen fueling stations in the country. As shown in Table 16, the ARFVT Program is playing an important role in accelerating this transition by meeting some of the initial strategic program goals discussed above.

Table 16: Alternative and Renewable Fuel and Vehicle Technology Program and Air Quality Improvement Program Funding Impact on Infrastructure and Vehicle Deployment in California (Through June 30, 2013)

	Fuel Area	Existing 2009-2010 Baseline Levels	Additions from ARFVT or AQIP Program Funding	Percent Increase
Alternative Fueling Infrastructure	Electric	~~1,270~~2,540 charge points~~ing stations~~	7,200 charge points~~ing stations~~ (public, fleet and workplace)	~~566~~283
	E85	39 fueling stations	205 fueling stations	525
	Natural Gas	443 fueling stations	50 stations	11
	Hydrogen	6 public fueling stations *(plus 5 more under construction)*	24 fueling stations	218
Alternative Fuel Vehicles	Electric Cars (ARB Vouchers)	13,268 (mostly neighborhood electric vehicles)	(8,903 – ARFVTP) 26,331 – Total AQIP~~26,331~~*	198
	Electric Trucks	1,409	160	11
	Natural Gas Trucks	13,995	1,375	10

* The Energy Commission has provided funding for 8,903 of these vouchers, about 33 percent of the total Clean Vehicle Rebate Project vouchers.

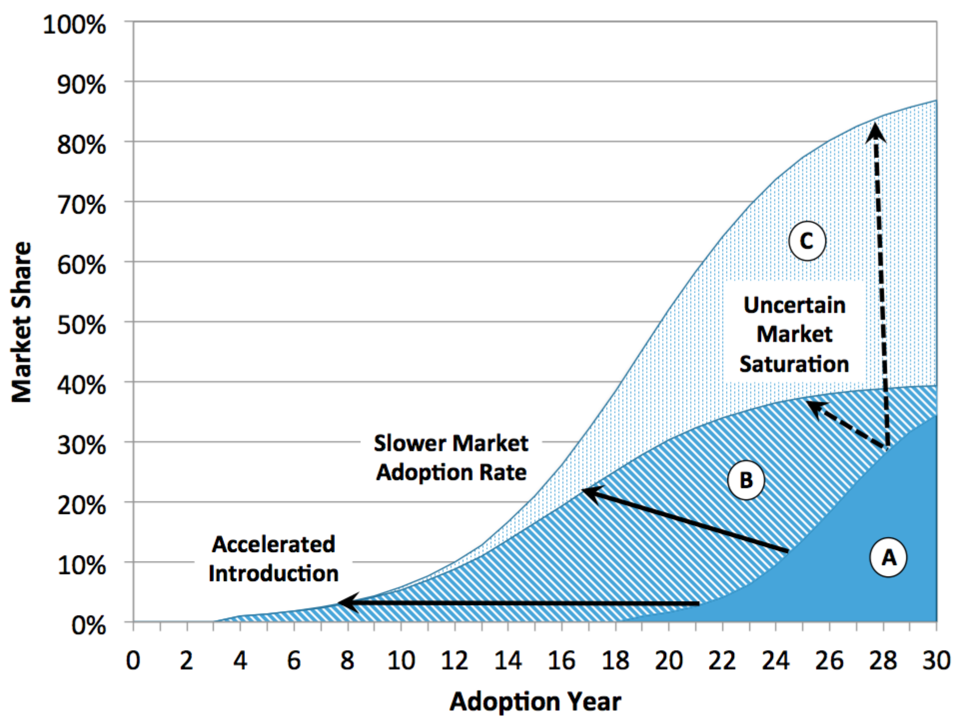
Source: Extrapolated from 2009 Department of Motor Vehicle data, plus actual deployment data. Electric truck and natural gas trucks extrapolated from 2009 data.

Market Transformation Challenges for Sustainable Vehicles and Fuels

To achieve significant market growth, alternative renewable fuels and vehicles need to overcome barriers such as cost, lack of manufacturing scale, and lack of infrastructure development. Support from government agencies and industry initiatives is justified based upon the social and environmental benefits accrued as a result of GHG emission reductions, increased energy security from reduced reliance on petroleum-based fuels, reductions in criteria air emissions, savings to consumers on fuel costs, and resulting direct or indirect contributions to California's regional economy.

Figure 21 depicts a "transitional" view of market transformation dynamics with a new technology achieving significant market share only after market conditions become favorable over time, shown as area "A." Examples for this delayed adoption could be battery electric vehicles or fuel cell electric vehicles becoming favorable when both petroleum prices remain consistently high and technology costs decline through slow and steady improvements (Greene 2013). For transitional market transformation support, the introduction of the technology could occur much earlier as a result of policy support mechanisms, such as ARFVTP, shown as area "B." Alternatively, if market conditions become favorable more quickly (for example, petroleum prices climb, or robust carbon policies are implemented), the new technology could attain a higher level of market saturation, as shown in area "C." The ultimate market saturation level depends upon a large number of uncertain and interdependent factors, including levels of government policy and financial support and market conditions.

Figure 21: Market Share Shifts for Transitional Market Transformations (Derived From Geller and Nadel 1994)



Source: National Renewable Energy Laboratory Benefits Guidance Report

Benefits of the ARFVT Program

In 2008, the Legislature passed Assembly Bill 109 (Núñez, Chapter 313, Statutes of 2008), which amended AB 118 to require the Energy Commission to include an evaluation of projects funded by the ARFVTP in the biennial *Integrated Energy Policy Report* (*IEPR*), including their expected benefits and contribution toward improving air quality, reducing petroleum use and GHG emissions, and transitioning to a diverse portfolio of clean, alternative transportation fuels. The

Energy Commission contracted with the National Renewable Energy Laboratory[407] (NREL) to develop a method to calculate expected benefits from of projects funded between 2009 and June 2013 from ARFVTP to 2025.[408] This section summarizes NREL's expected benefits findings of those 188 ARFVTP-funded projects through 2025 and provides updates on the numbers of jobs created through ARFVTP-funded projects and the number of workers trained through the Workforce Training Program. These are initial results and may be subject to revision.

NREL Methodology for Calculating ARFVTP Benefits

NREL used two main categories of benefits: expected benefits and market transformation benefits.

> **Expected Benefits:** These benefits include petroleum, carbon, and criteria emissions reductions resulting from ARFVTP investments in commercial-scale projects that are constructed and operational, or that have a high likelihood of being constructed in the near future. These types of projects include electric, hydrogen and natural gas fueling infrastructure, commercial biorefineries, and commercially available alternative technology cars and trucks.

> **Market Transformation Benefits:** These benefits are realized through efforts that help reduce market entry barriers for new technology companies, reduce the cost of advanced technology vehicles and vehicle components, increase consumer awareness, and remove consumer choice barriers associated with limited refueling availability. Examples of Market Transformation Benefits resulting from ARFVTP investments include market changes and increased consumer acceptance of electric-drive cars and trucks, hydrogen fuel cell cars, and natural gas or renewable natural gas fueling and vehicle systems. These benefits also represent the growth potential for the feasibility and demonstration-scale projects funded through ARFVTP.

The ARFVTP project portfolio includes technical projects, such as advanced technology vehicles, electric charging stations, biorefineries, and program support projects, such as workforce training grants and technical support contracts. NREL evaluated the 188 technical fuel, fueling infrastructure, and vehicle-related projects from the total portfolio of 233 funded projects through June 2013 that are shown on Table 16. The project data set for the Expected Benefit calculations includes about 60 percent of the 188 technical projects. The data set for the Market Transformation Benefits comprises the other 40 percent of the technical project portfolio, including manufacturing, battery development, advanced technology truck and component demonstrations, and feasibility and demonstration-scale biofuels projects. Results from the staff

407 California Energy Commission Agreement Number 600-11-002.

408 Marc Melaina, George Mitchell, Ethan Warner, Aaron Brooker, and Garvin Heath, (National Renewable Energy Laboratory), "Program Benefits Guidance: Analysis of benefits associated with projects and technologies supported by the Alternative and Renewable Fuel and Vehicle Technology Program," 2013, California Energy Commission, publication pending.

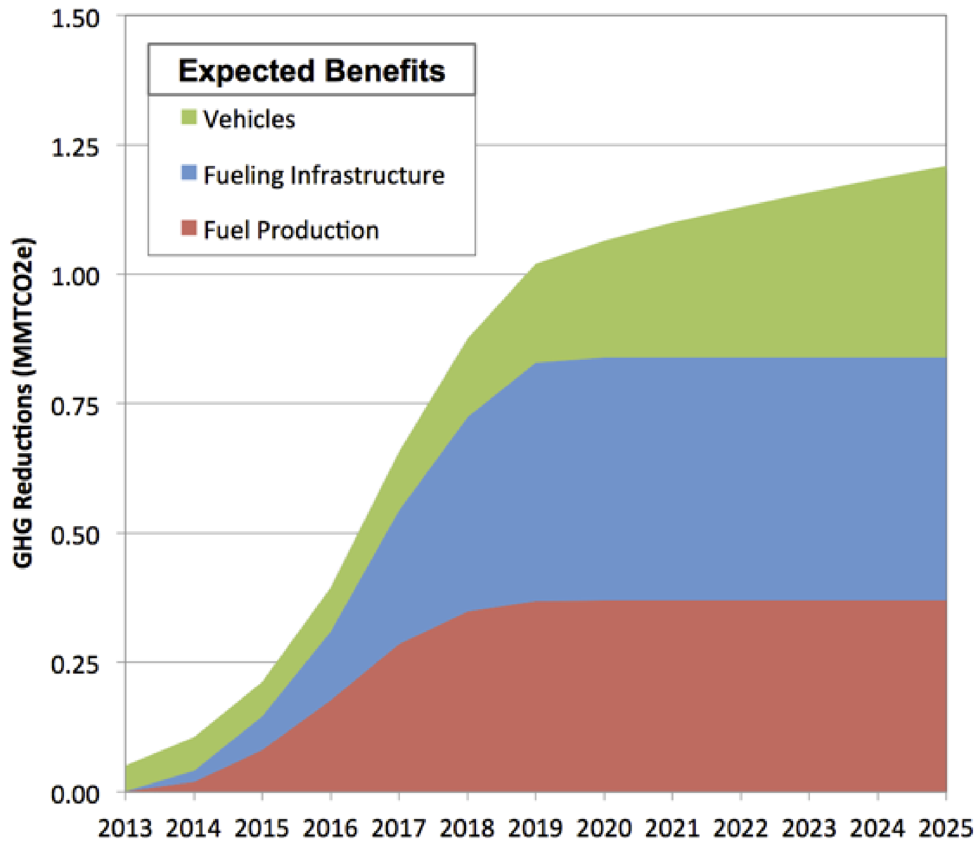
survey of all ARFVTP grant awardees also factor into the Market Transformation Benefit calculations.

Expected Benefits Results

To estimate the Expected Benefits of the current ARFVTP project portfolio, NREL tallied the estimated use levels for all of the commercial-scale projects that have been funded and assumed that each project will be built and operated according to grant agreement specifications. These projects include all commercial-scale biorefineries; hydrogen, CNG and E85 fueling stations; electric chargers; commercial vehicle support vouchers for heavy-duty CNG or propane trucks and buses; and light-duty CNG and electric vehicles. NREL then calculated the petroleum fuel and internal combustion engine vehicles and vehicle-miles that would be displaced through ARFVTP-funded alternative fuels, vehicles, and fueling stations.

As shown in Figure 22 and Tables 17 and 18, the expected benefits for commercial-scale projects from ARFVTP investments are estimated to be 1.22 million metric tons of GHG reduction in 2025 and 167.8 million gallons of petroleum reduction in 2025. For petroleum reduction, 49 percent of the reductions come from alternative fueling infrastructure, 28 percent from ZEV and low-carbon vehicles, and 23 percent from biofuel production projects. The high contribution from the alternative fueling station projects is a result of the high projected sales volumes and consumer acceptance of natural gas and E85 ethanol, which is due to the relatively low cost, widespread availability and compatibility of these fuels with current engine technologies.

Figure 22: Expected GHG Reduction Benefits through 2025 from Current ARFVTP Investments*



Source: NREL Benefits Guidance Report

*Current ARFVTP Investments are 188 technical projects funded between 2009 and June 2013.

For the 1.2 million metric tons of GHG emissions reduction benefits, 39 percent of the reductions are attributed to alternative fueling infrastructure, while biofuel production accounts for 31 percent of the reductions and alternative technology vehicles account for the remaining 30 percent of GHG reductions.

Nearly all of the expected benefits from ARFVTP investments in commercial-scale projects peak in 2020 when all current projects are expected to be operational, and then carry forward to 2025. In contrast, natural gas trucks achieve their peak petroleum and GHG reduction potential in 2015 and then taper to zero in 2025. This is because truck fleet operators tend to put new vehicles into the highest mileage duty cycles and then reduce and ultimately retire the trucks at the end of their commercial life.

Table 17 also shows that ARFVTP investments in ZEV truck technologies, through the manufacturing grants to electric truck companies like Electric Vehicles International, Motiv Power System, Transpower, and Boulder Electric, should yield potentially strong petroleum and GHG reduction benefits in 2020 to 2025 as those technologies mature, prices decline, and fleet operators purchase ZEV technology trucks for regulatory compliance obligations.

The Expected Benefits projections represent potential GHG and petroleum reductions from only those 188 technical projects funded to date. These projections explain why there is very little growth between 2020 and 2025; the projects are expected to attain peak use levels in 2020 (except for the natural gas trucks) and continue that level of service and operation through 2025, the end of the estimation period. Future growth or expansion of fueling stations or biorefineries funded through ARFVTP would require additional private or public financing. The Market Transformation benefit category captures some of those future investments.

Table 17: Expected Petroleum Reduction Benefits From Current ARFVTP Investments Through 2025 (Million Gasoline Gallon Equivalents [GGE] or Diesel Gallon Equivalents [DGE])

Expected Benefits: Petroleum Reductions (million GGE/DGE)		**2015**	**2020**	**2025**
Fueling Infrastructure	Biodiesel	0.5	8.5	8.5
-	Natural and Renewable Gas	7.0	39.2	39.9
-	Electric Chargers	3.2	6.2	6.2
-	E85 Ethanol	5.6	26.9	27.2
-	Hydrogen	0.2	1.1	1.2
Vehicle	Light-Duty BEVs and PHEVs	0.0	0.4	0.2
-	Electric Commercial Trucks	0.0	0.4	0.2
-	Gas Commercial Trucks	15.8	8.3	1.1
-	Manufacturing (ZEV Trucks)	0.4	19.0	45.8
Fueling Production	Biomethane	3.0	7.0	7.1
-	Diesel Substitute	3.4	16.4	16.4
-	Gasoline Substitute	1.9	13.9	13.9
Total	-	**41.0**	**147.3**	**167.8**

Sources: NREL Benefits Guidance Report

Table 18: Expected GHG Reduction Benefits through 2025 from Current ARFVTP Investments (Thousand Tonnes CO_2e)

Expected Benefits: GHG Reductions (thousand tonnes CO_2e)		2015	2020	2025
Fueling Infrastructure	Biodiesel	5.0	70.5	70.5
-	Natural and Renewable Gas	29.7	330.7	330.7
-	Electric Chargers	25.4	48.7	48.8
-	E85 Ethanol	2.3	11.1	11.1
-	Hydrogen	1.2	7.3	7.3
Vehicle	Light-Duty BEVs and PHEVs	0.0	2.9	2.0
-	Electric Commercial Trucks	0.0	3.0	1.4
-	Gas Commercial Trucks	64.3	27.3	4.6
-	Manufacturing (ZEV Trucks)	2.9	194.3	363.0
Fueling Production	Biomethane	33.7	81.1	81.1
-	Diesel Substitute	37.7	185.4	185.4
-	Gasoline Substitute	17.7	114.1	114.1
Total	-	**219.9**	**1,076.4**	**1,219.9**

Sources: NREL Benefits Guidance Report

Market Transformation Benefits

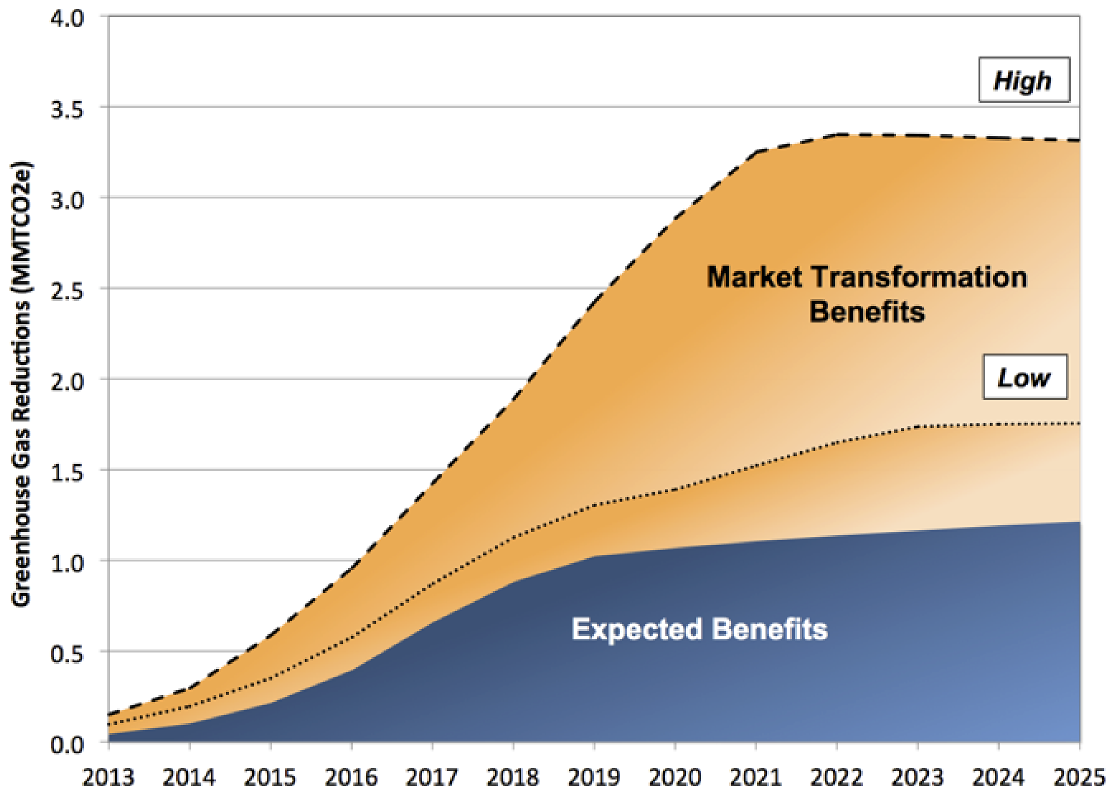
Market transformation benefits represent a range of future investments enabled or supported by the current project portfolio. For example, the continuing market expansion of battery electric and plug-in electric vehicles will be partially supported by current ARFVTP investments in electric charging infrastructure, battery and electric drivetrain technology, and light-duty vehicle purchase assistance through Clean Vehicle Rebate Project rebate vouchers. Similarly, new biofuel production technologies and capacity will be partially enabled through the successful production and sale of biofuel from the current ARFVTP portfolio, which will demonstrate to future investors that biofuel production and sale are a viable enterprise in California. NREL used a series of assumptions, techniques, and models to estimate these market transformation benefits, which are described in the forthcoming draft NREL Benefits Guidance Report. These are preliminary results that are subject to revision pending public review of NREL's draft report.

NREL estimates that market transformation benefits will range from 48.9 million to 235.8 million gallons in additional petroleum reductions by 2025, and from 0.54 million to 2.09 million additional metric tons in GHG reductions by 2025. This benefit category represents the future potential of ARFVTP projects that are in the demonstration and development phases, including ZEV truck technologies, battery and electric drive component development, ZEV vehicle manufacturing, and advanced technology, low-carbon biofuels from waste-based and alternative feedstocks.

ARFVTP investments in next-generation fuels and trucks account for the substantial majority of these future GHG and petroleum reduction benefits. For example, next-generation fuels account for 54 percent of the high range of Market Transformation GHG reduction benefits, followed by Vehicle Price Reductions, which account for an additional 26 percent. Tables E-1 and E-2 in Appendix E delineate the Market Transformation Benefits for GHG and petroleum reduction by investment category.

Figure 23 shows the estimated range of Market Transformation GHG reduction benefits between 2013 and 2025. These are shown as additive to the expected GHG benefit reductions. The total Expected and Market Transformation GHG Reduction Benefits are estimated to range from 1.8 million metric tonnes to 3.3 million metric tonnes.

Figure 23: Market Transformation GHG Reduction Benefits Combined with Expected GHG Reduction Benefits through 2025



Source: NREL Benefits Guidance Report

Interpreting Petroleum and GHG Reduction Benefits in the Context of Statewide Policy Objectives

As stated in the introduction to this chapter, California has an extremely large vehicle fleet of about 26 million cars and pick-ups and about 1 million medium- and heavy-duty trucks. This fleet consumes more than 18 billion gallons of fuel per year. Total on-road GHG emissions were

155.1 million metric tonnes in 2011.[409] Transportation GHG emissions represent 39 percent of the total GHG emissions from all California sectors.

While the ARFVTP investments result in modest decreases in terms of absolute total fuel consumption and GHG emissions, these targeted investments have resulted in measurable on-the-ground change and provided a basic foundation for further market growth of zero-emission vehicles. Today, California has the largest EV and hydrogen fueling station networks in the country and accounts for one-third of all battery and plug-in electric vehicle sales nationally.

Maintaining this momentum is a critical piece of California's policy framework for addressing transportation sector emissions. Significant work remains for the State to achieve the transportation sector carbon reduction goals described in Governor Brown's Executive Order B-16-2012, which targets 1.5 million ZEVs on California roads by 2025 and reduction of transportation sector emissions by 80 percent below 1990 levels by 2050. Continued targeted investments and strategic market support through ARFVTP, alongside the state's regulatory programs and planning efforts, will be needed to drive technologies to higher volumes, lower prices, and ultimately lasting markets that transform the transportation sector.

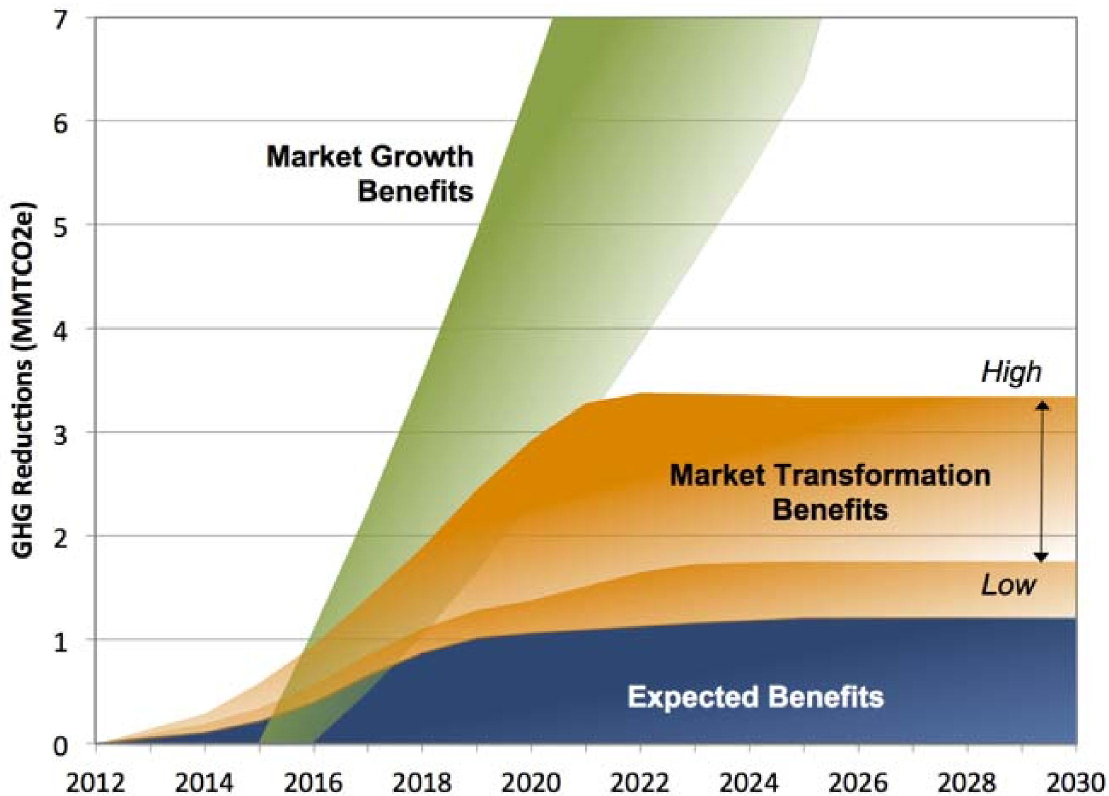
In interim terms, current ARFVTP investments are contributing in a meaningful way to the pace of petroleum and GHG emissions reductions needed to achieve the 80 percent reduction targets envisioned for 2050. Using the reduction scenarios for oxides of nitrogen (NOx) and GHG emissions described in the draft *Vision for Clean Air*,[410] NREL plotted a "Market Growth Benefits" curve that shows the range of GHG emissions reductions needed between 2015 and 2025 to keep pace with the total transportation sector reductions needed through 2050. It is a very steep curve. Figure 24 shows total estimated GHG emissions reduction benefits from ARFVTP through 2025 in the context of the GHG emissions reductions needed to stay apace of the needed Market Growth Benefits. The green shaded area represents the estimated range of GHG emissions reductions of just over 6 million metric tonnes needed between 2020 and 2025 to meet the Vision for Clean Air target trajectory toward 2050. The Expected Benefit GHG emissions reductions of 1.2 million metric tonnes represents about 20 percent of the progress needed in 2025, while the high range of Expected Benefit and Market Transformation reductions of 3.3 million metric tonnes represents 54 percent of the needed progress in GHG emissions reduction.

These are preliminary results, and Energy Commission staff plans further public review and discussion of the initial NREL benefits results as the Benefits Guidance Report becomes finalized.

409 *California Greenhouse Gas Inventory 2000 – 2011*, California Air Resources Board.

410 California Air Resources Board, South Coast Air Quality Management District, and San Joaquin Valley Unified Air Pollution Control District, *Vision for Clean Air: A Framework for Air Quality and Climate Planning – Public Review Draft*, June 27, 2012, http://www.arb.ca.gov/planning/vision/docs/vision_for_clean_air_public_review_draft.pdf.

Figure 24: Expected and Market Transformation Benefits in Context of Market Growth Benefits Needed to Meet Vision for Clean Air GHG Reduction Goals



Source: NREL Guidance Report

Public Health Benefits From ARFVTP Investments

The draft Benefits Guidance Report from NREL will also include estimates of criteria emissions and particulate matter reductions from ARFVTP investments. Using the commercial-scale ARFVTP projects that comprise the Expected Benefits category, NREL estimates cumulative statewide NOx emissions reductions of 3,421 short tons through 2025. The average annual NOx emissions reductions would be 380 short tons per year.

The U.S. Environmental Protection Agency's (U.S. EPA's) Region 9 Office in San Francisco[411] conducted a public health benefits estimate of these statewide NOx emissions reductions and estimates annual public health benefits of nearly $3 million per year. This monetized estimate of public health benefits reflects avoided mortality and morbidity from reduced criteria emissions, including avoided incidences of the following health effects: premature death, chronic bronchitis, upper and lower respiratory symptoms, asthma exacerbation, nonfatal heart attacks, hospital admissions, emergency room visits, work-loss days, and minor restricted activity days.

411 John Mikulin, U.S. EPA, Region 9 Clean Energy & Climate Change Office, http://www.epa.gov/air/benmap/sabpt.html and http://www.epa.gov/air/benmap/docs/BenMAP_Briefing_International.pdf.

This $3-million-per-year annual benefit is a conservative estimate based on national average health benefits associated with on-road NOx reduction. California-specific benefits in the severe non-attainment air basins would yield higher public benefit estimates. The U.S. EPA will assist on additional health benefit estimates as more results are available from NREL.

Job Creation and Workforce Training Benefits

Job Creation Benefits

While the primary policy goals of the ARFVTP are the reduction of petroleum fuel use, transportation GHG emissions and criteria emissions, economic development and job creation are important ancillary benefits.

To estimate job creation benefits, staff administered an electronic survey to recipients of all 188 technical project grants awarded since 2009. Staff did not include research, technical support, and program support grants and contracts in the survey. The response rate was nearly 100 percent, with just a handful of grantees who did not respond. 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, maintenance, sales, and administration.

Table 19 shows the estimated total number of jobs created through ARFVTP grant awards. Short-term jobs total 3,158 and long-term jobs total 3,216. Cumulative job creation to date is estimated to be 6,374. Construction-related jobs are the single biggest category for short-term jobs, accounting for 44 percent of the total. For long-term jobs, manufacturing and operations and maintenance-related jobs predominate, representing 32 percent and 25 percent of the total.

Table 19: Projected Job Creation by Category

-	**Administrative**	**Manufacturing**	**Construction**	**Engineering**	**Operation and Maintenance**	**Other**	**Total**
Short-term	433	541	1,406	371	284	123	**3,158**
Long-term	356	1,030	277	370	805	378	**3,216**
Totals	789	1,571	1,683	741	1,089	501	**6,374**

Source: Energy Commission Staff Survey

Energy Commission staff also requested information on the total number of businesses associated with all phases of project development, from sponsor and primary contractor to the subcontractor vendor level. ARFVTP grantees reported that a total of 2,189 businesses will be contractually engaged in development and implementation of the grant projects. California businesses totaled 1,645 companies and out-of-state businesses totaled 544 companies. Small businesses, defined as 250 employees or fewer, totaled 1,216 of the companies involved with the grant projects, or 55 percent of the total.

Workforce Training Benefits

Workforce training and development are vital to the Energy Commission's efforts to advance California's clean transportation market. Skilled workers are necessary to address the alternative fuels and advanced vehicle technology market in California.

The Energy Commission has three interagency agreements with California's workforce training agencies, including the Employment Development Department (EDD) at $7.25 million, the California Community Colleges Chancellor's Office (CCCCO) at $4.5 million, and the Employment Training Panel (ETP) at $10.25 million. These interagency agreements are structured to fund alternative fuel and low-emission vehicle-specific training as a portion of the partner agency's broader workforce projects. The ETP agreement funds training for incumbent workers while the EDD and CCCCO agreements provide workforce training development and support activities, including regional industry cluster support, planning grants, needs assessments for related industries and community college alternative fuel programs, curriculum development, and train-the-trainer support (including equipment purchases).

To date, these agreements have provided $22.0 million in training funds for 12,472 individuals and more than 135 businesses and municipalities, as shown in Table 20. The $4.5 million in CCCCO grants are not included in this table because they are not being used for direct training at this time.

Table 20: Workforce Training Funding

Partner Agency	Funded Training (in Millions)	Match Contributions (in Millions)	Trainees	Businesses Assisted	Municipalities Assisted
ETP	$10.25	$ 10.3	11,473	88	14
EDD	$ 7.25	$ 7.5	999	36	
Total	$17.50	$17.8	12,472	124	14

Source: California Energy Commission. Fund totals indicate completed training along with current and future contracts with estimated trainee participants. ~~The Energy Commission and NREL will estimate benefits in terms of petroleum reduction, carbon reduction, criteria emissions and particulate matter reduction, public health, and job creation. Additionally, NREL is providing guidance on estimating social, environmental, and market transformation benefits associated with projects supported by the Commission's ARFVT Program. For this draft of the *IEPR*, the Commission provides information on the methods and approach NREL is developing to estimate programmatic-level benefits through 2025 in Appendix E. *[** Note to reviewers, results from the NREL study will be summarized and included in the final draft, early December.]* Actual benefit estimates will be provided in a final *IEPR* and as a stand-alone Energy Commission Contractor Report. Commission staff will calculate job creation benefits, and the U.S. Environmental Protection Agency Region 9 will assist in the calculation of public health benefits from reduced petroleum fuel use.~~

Transportation Energy Trends

Trends show continuing declines in gasoline consumption. Since 2008, trends in California and the rest of North America show a sustained decline of gasoline consumption. Previous Energy Commission staff analysis from the 2009 and 2011 *IEPRs* identified this trend, showing a 6 percent decline in gasoline consumption, reflecting the effect of the national economic downturn and vehicle efficiency improvements. The Energy Commission and other experts expect this decline in gasoline consumption to continue for another decade because national vehicle economy standards (Corporate Average Fuel Economy or CAFÉ) require automobile and light truck manufacturers to increase average miles-per-gallon performance from 27.5 to

35.5 in 2016 and to 54.5 in 2025. As a consequence of improved vehicle efficiency, California should experience a 2-billion-gallon decline in gasoline consumption from 14.6 billion gallons per year in 2012 to 12.7 billion gallons per year by 2022. This change could affect production levels of some of the 20 existing crude oil refineries in California, 13 of which produce gasoline and diesel fuel for California vehicles.

Trends show increases in other transportation fuels. Since 2011, trends in California and the rest of North America show increases in crude oil and natural gas production. By 2012, North America experienced an upsurge in crude oil and natural gas production because horizontal drilling and hydraulic fracturing technology advances lowered exploration, drilling, and recovery costs as discussed in Chapter 7. The 2009 and 2011 *IEPRs* noted diesel fuel consumption demand growing at a rate of 1to 2 percent per year for 20 years. The economic recession interrupted this trend for four years, but the growth has been restored in 2012. Most of this change reflects growth in fuel consumption from the transport of freight in trucks. Natural gas trucks may also offer an option to address goods movement growth. By 2014, up to 20 new diesel models of passenger vehicles and light trucks should be available in North America, possibly accelerating a transition to diesel fuel from gasoline, improving vehicle fuel efficiency, and providing another market for biodiesel and renewable diesel. Also, although initially small, significant future growth is expected for electric and hydrogen vehicles.

Displacement of Petroleum and Potential Growth of Alternative Fuels in California

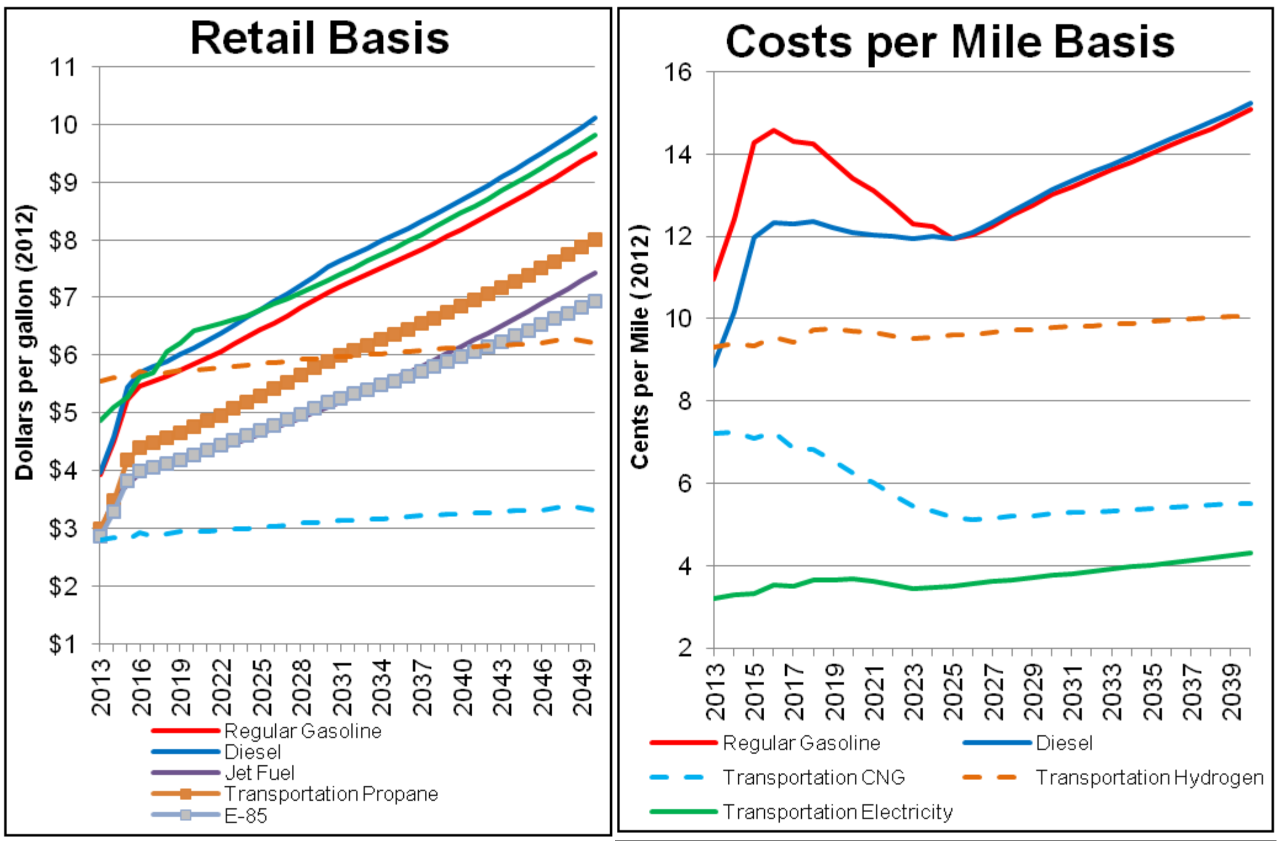
Alternative fuels include liquid and gaseous fuels and electricity used in cars, trucks, and buses. Liquid biofuels are blended with gasoline or diesel or, in some instances, replace gasoline (E85) or diesel (B100 or 100 percent biodiesel and renewable diesel). Biofuels are produced through several methods and technologies and are derived from dozens of purpose-grown crops (corn, sugarcane, and grain sorghum) and agriculture, forest, and urban waste residue. Natural gas fuel is also used in all types of vehicles as compressed natural gas (CNG) or liquefied natural gas (LNG), and electric and hydrogen vehicles have been introduced with expectations for significant growth. As discussed in Chapter 3, biomethane or biogas is another form of natural gas, and dimethyl ether (DME) produced from natural gas and biogas offers a clean-burning diesel alternative option. Electricity is produced from multiple sources including hydroelectricity, natural gas, nuclear, coal, and renewable resources (solar, wind, geothermal, and biomass).

By 2012, California experienced modest but notable increases in the use of alternative fuels. During the period from 2003 to 2012, alternative fuel market penetration grew to 7.3 percent of on road transportation fuel consumption. This growth is mainly due to an increase in ethanol blends in gasoline from 5.7 to 10 percent in 2008 and modest growth in natural gas and biodiesel fuel use in trucks and buses compared to a very small 2003 baseline. Several industry experts conclude that multiple factors increase the plausibility of alternative fuel growth within the next 10 years in North America and particularly in California.

Fuel Price Forecasts—Gasoline, Diesel and Alternative Fuels

The Energy Commission's transportation fuel price analysis shows that ~~For most of the U.S. Department of Energy's fuel price forecasts,~~ natural gas,[412] electricity, hydrogen, and some biofuels used in vehicles offer a cost advantage over petroleum fuels (Figures 25, 26, and 27).

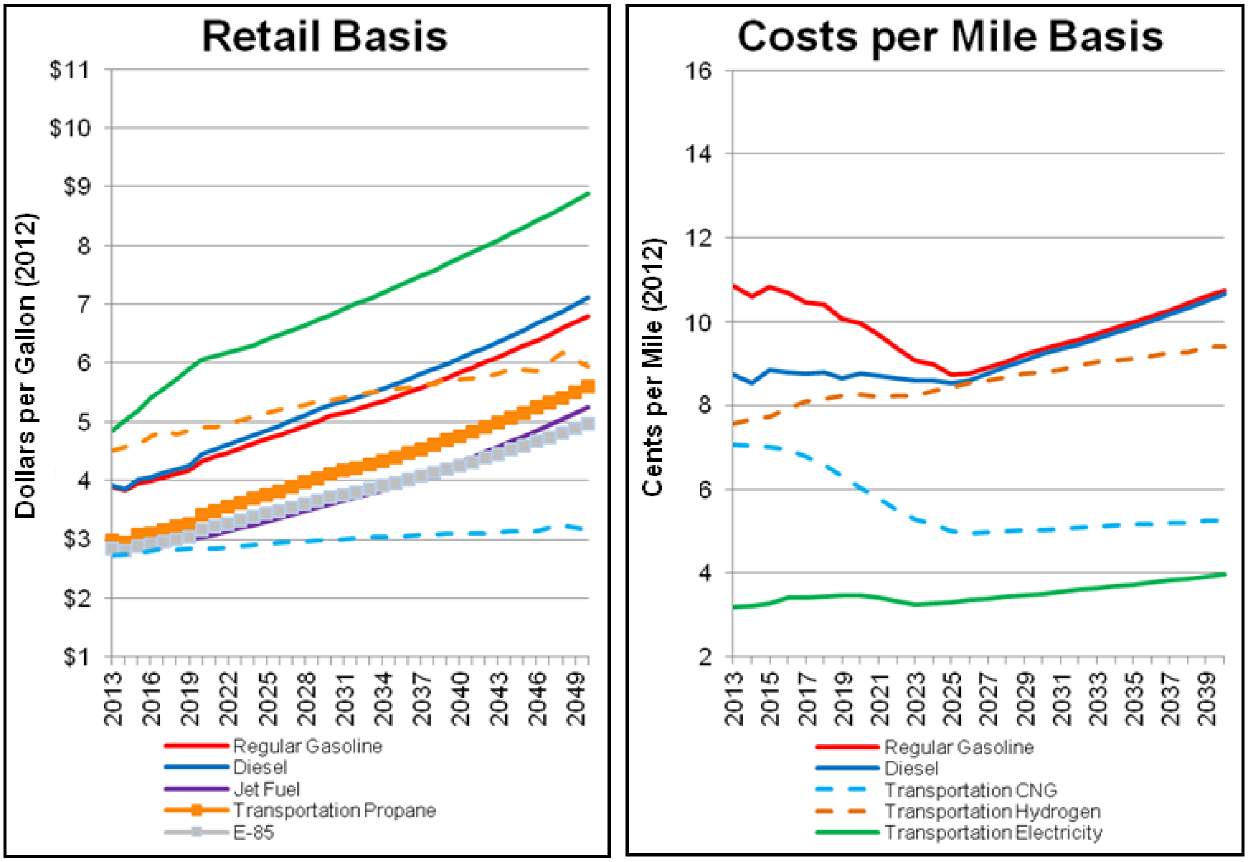
Figure 25: High Energy Price Common Case



Source: California Energy Commission

412 Natural gas prices discussed in this chapter are specific to transportation CNG, derived by an adjustment methodology to the Chapter 7 natural gas price forecast which represents a price forecast that considers power generation and other non-transportation uses.

Figure 26: Reference Common Case



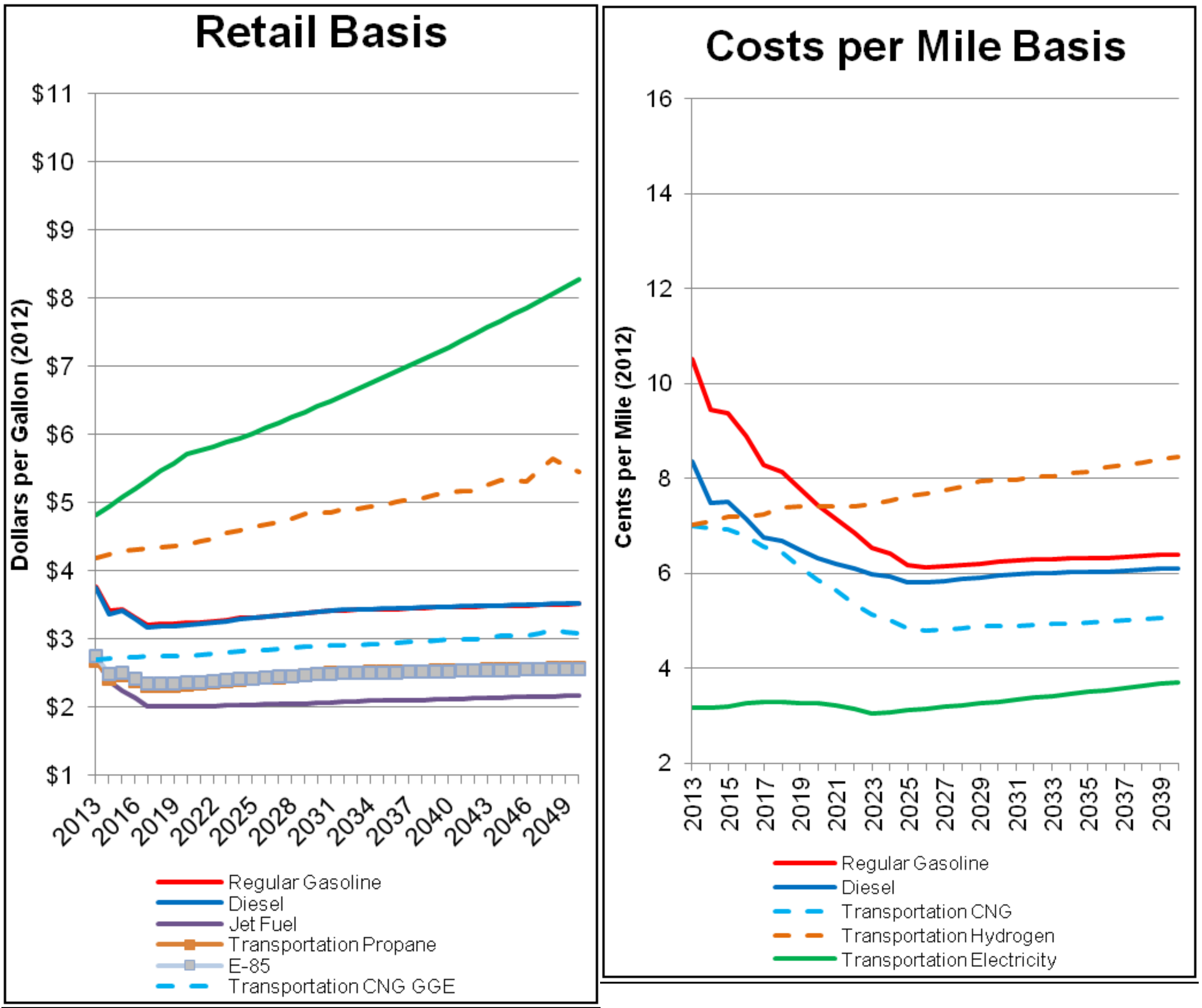
Source: California Energy Commission

~~Current~~ 2013 natural gas prices ~~of about $3.60~~under $4.00 per million British thermal unit (BTU) are $1.00 to $1.50 per gallon (gasoline per gallon equivalent—gge) below diesel and gasoline, and ~~U.S. Department of Energy~~DOE's natural gas price forecast scenario over the next 7 to 10 years~~,~~ are all lower than ~~its lowest~~ gasoline and diesel price projections.[413] Natural gas prices ~~are projected to stabilize~~ near $4.00 per million BTU over the next 7 to 10 years ~~and this stabilization in price~~ could trigger investment in a shift to this transportation fuel.

~~The impact of directional and horizontal drilling and hydraulic fracturing of natural gas shale structures led to substantial increases in natural gas supplies in North America. As a consequence, natural gas prices dropped, leading power plants in the Midwest and eastern states to switch from coal to natural gas fuels and creating opportunities for natural gas use in vehicles. Because natural gas pricing varies by continent and has not yet evolved to international commodity pricing, natural gas should remain moderately priced in North America for up to 10 years.~~

413 U.S. Department of Energy, http://www.eia.gov/forecasts/aeo/chapter, 2013.

Figure 27: Low Energy Price Common Case

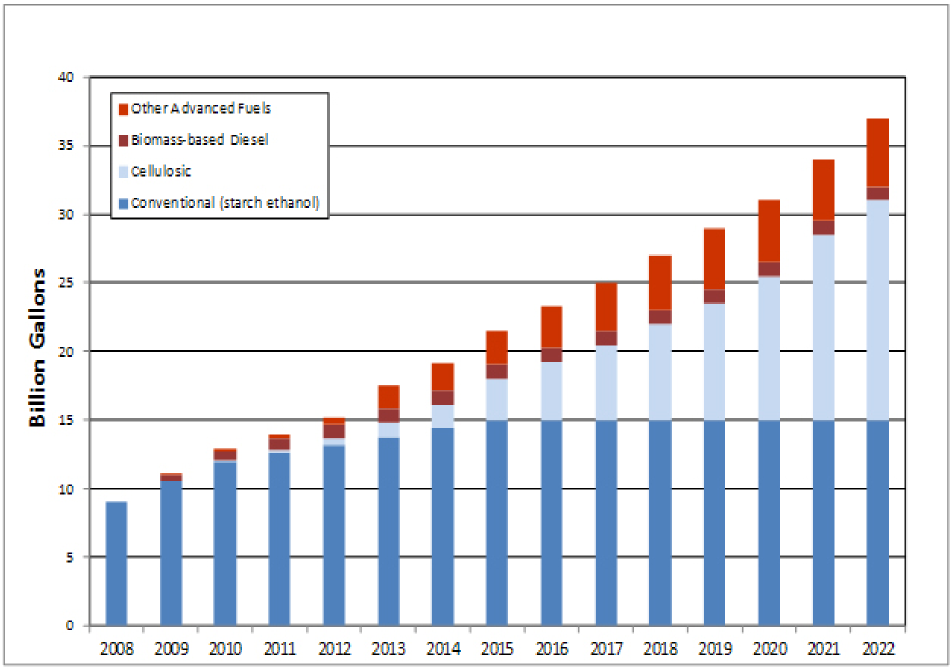


Source: California Energy Commission

Federal Regulations and Incentives

Renewable Fuels Standard: The federal Renewable Fuels Standard (RFS) requires fuel producers and ~~marketers~~ importers (obligated parties) to increase the use of renewable fuels to displace gasoline and diesel in the transportation sector. Biofuels eligible for RFS compliance include advanced biofuels, ethanol produced from corn and sugarcane, biodiesel, renewable gasoline and renewable diesel produced from soy, used cooking oil, tallow, and corn oil. Biomethane is also eligible as a renewable fuel for RFS compliance. The RFS also requires obligated parties to use low-carbon-intensity advanced biofuels at increasing levels each year (Figure 28). Obligated parties can demonstrate compliance by blending and/or obtaining excess~~produce or acquire renewable fuels themselves or buy credits from others who make renewable fuels available through~~ renewable identification numbers (RINs). These RIN credits have monetary value and can be packaged with compliance obligations or separated and sold or traded. For more information on RIN credits, please see Appendix F.

Figure 28: Renewable Fuel Standard Volumes by Year



Source: California Energy Commission

The Clean Air Act: An additional federal regulation, the National Ambient Air Quality Standards, administered by the U.S. Environmental Protection Agency, will require regions designated as nonattainment for the air quality standards to reduce emissions until the standards are met. The South Coast Air Quality Management District[414] concluded that to comply with this rule, the on-road vehicle fleet would have to be dominated by zero-emission vehicles displacing combustion fuels, such as gasoline, diesel, and natural gas. This conclusion has inspired and accelerated new research and early demonstrations of hybrid electric and all-electric drayage trucks for ports and other transport technologies.

Federal incentives continue to spur the development and use of alternative fuels. Furthermore, federal tax credits provide additional incentives for biodiesel and renewable diesel ($1.00 per gallon blender's credit through 2013), natural gas vehicles, and electric vehicles ($7,500 tax credit, which phases down and expires one year after each vehicle model achieves 200,000 in sales ~~for up to 200,000 of each vehicle model sold~~ in the country).

California Policies, Incentives and Regulations

414 Peter Greenwald, "The Need for Zero Emission Technologies—SCAQMD Zero Emission Transportation Technology Forum and Roundtable Discussion," April 20, 2011.

California laws, regulations, and executive orders increase the potential for alternative fuel growth. Beginning in 2003 with the passage of the Petroleum Reduction and Alternative Fuels Act, California government transformed transportation energy policy from a singular focus on reducing smog-forming tailpipe air emissions to more complex policies emphasizing multiple objectives. The Energy Commission and the ARB adopted goals to reduce petroleum consumption and increase alternative fuel use. Table 21 highlights a few of these key transportation energy initiatives, and the rest of this section features two of these initiatives: (1) the LCFS and (2) the ZEV Mandate.

Table 21: California's Transportation Energy Initiatives

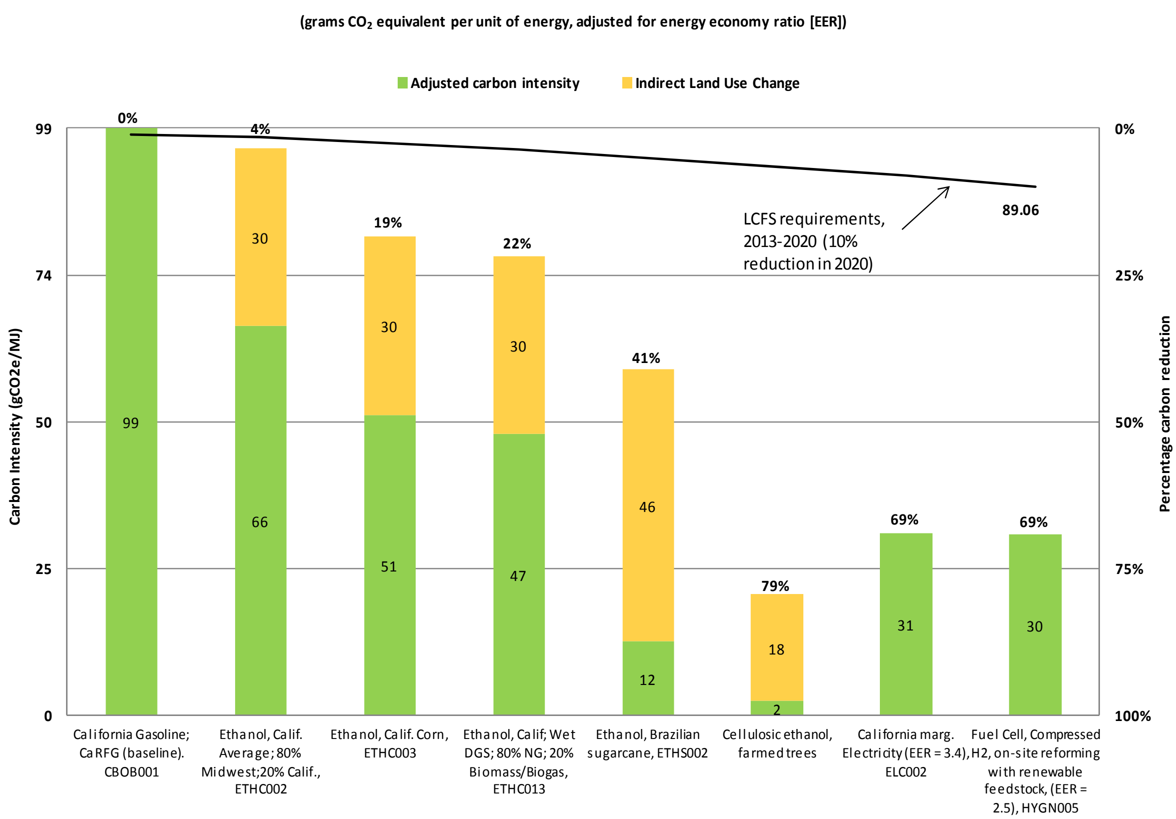
Policy/Law/Regulation	Quantified Objectives
Global Warming Act(2006)	Reduce GHG emissions to 1990 levels by 2020. ~~and 80 percent below 1990 levels by 2050.~~
Executive Order S-3-05	Reduce GHG emissions to 80% below 1990 levels by 2050.
Petroleum Reduction and Alternative Fuel Goals (2003) and Alternative Fuels Plan (2007)	Reduce petroleum fuel use to 15 percent below 2003 levels by 2020. Increase alternative fuel use to 9 percent of California's fuel consumption by 2012, 11 percent by 2017, and 26 percent by 2022.
Bioenergy Action Plan (2006)	Produce 20 percent of biofuels used in California from in-state sources by 2010, 40% by 2020, and 75 percent by 2050.
Low Carbon Fuel Standard (2009)	Reduce carbon intensity of transportation fuels sold in California by 10% by 2020.
Zero Emission Vehicle Mandate (2012)	Establish requirements for automakers to provide electric and hydrogen vehicles for sale in California by 2020 (regulation).
ZEV Executive Order (2012)	Ensure California has infrastructure to support 1 million ZEVs by 2020 and 1.5 million by 2025 (Executive Order).
AB 118, Carl Moyer, and Proposition 1B Incentives (2003, 2005 and 2007)	Energy Commission, ARB, and local air districts provide financial incentives to fund vehicles, infrastructure, and fuel production projects that reduce GHG emissions and air pollutants and increase the use of alternative fuels.

Source: California Energy Commission

The ARB adopted a LCFS regulation in 2009 requiring fuel producers and importers to lower the carbon intensity of fuel sold in California by at least 10 percent in 2020. The LCFS has separate requirements to reduce the carbon intensity values of gasoline and diesel, and the requirements are increased incrementally each year to achieve the total 10 percent reduction by 2020. Petroleum fuel producers can comply with the standard by reducing carbon intensity of petroleum fuels using several methods. Alternative fuels have carbon intensity values lower than petroleum fuels and are sources of carbon reduction that generate credits to help fulfill

LCFS compliance. As a consequence, the LCFS provides an incentive to develop and use alternative fuels. In some instances, the overall carbon intensities for many biofuel options vary because of differences in indirect land-use impacts. Figures 29 and 30 illustrate carbon intensity reductions of various alternative fuels compared to gasoline and diesel fuels.

Figure 29: Carbon Intensity for Gasoline and Substitutes



Source: California Energy Commission

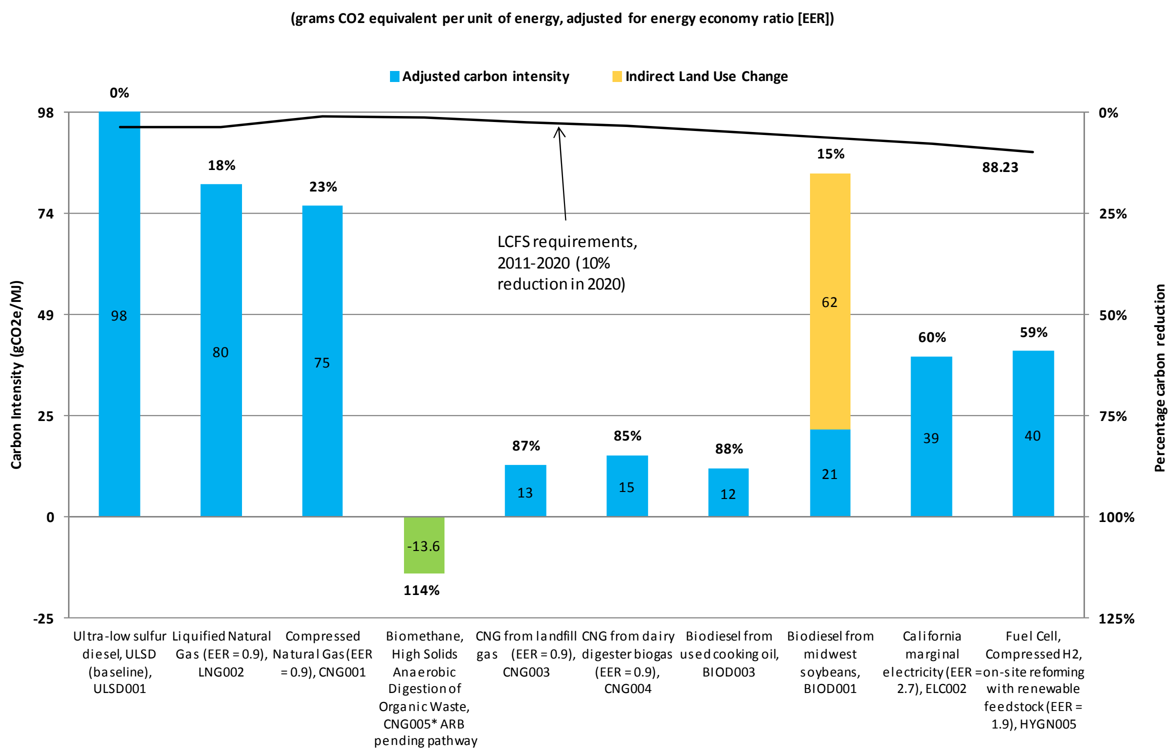
The Governor's ZEV Executive Order provides guidance to ensure that California has infrastructure in place to support 1 million ZEVs in 2020 and 1.5 million ZEVs in 2025. This Executive Order milestone supports the requirements in ARB's ZEV regulation. Figure 31 illustrates the expected annual ZEV sales to meet the requirements.

Transportation Energy Scenarios

The Energy Commission conducted a joint IEPR and Lead Transportation Commissioner workshop on July 31, 2013, to obtain insights on transportation energy scenarios from fuel developers, automakers, truck and bus experts, fueling infrastructure developers and owners, utilities, public interest groups, and industry associations. The participants provided growth projections to at least 2020 for all of the alternative fuels and diesel vehicles, presented key factors substantiating the growth, identified challenges that might impede growth, and recommended government actions needed to achieve the transportation energy goals. Energy

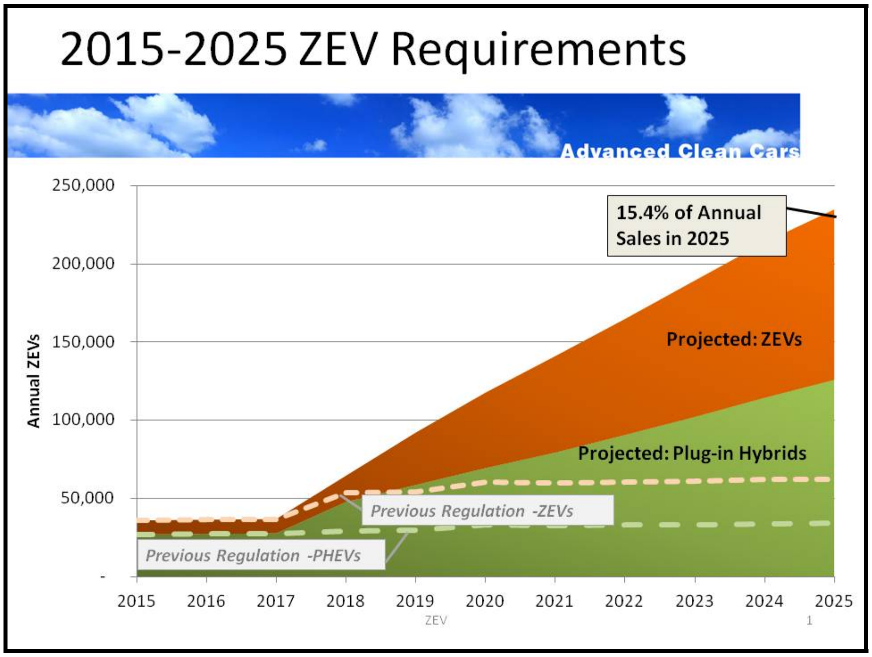
Commission staff evaluated the information provided by the participants and summarized the scenarios in Table 19. The information is listed in common units (gasoline gallons equivalent) for each option and reflect vehicle efficiency differences (energy efficiency ratios).

Figure 30: Carbon Intensity for Diesel and Substitutes



Source: California Energy Commission

Figure 31: 2015-2025 ZEV Requirements



Source: ARB, staff presentation at the January 2012 Board hearing.

To achieve California's 2020 goals noted in Table 18 to reduce GHG emissions, increase alternative fuel and vehicle use, and displace petroleum, aggressive market penetration of alternative fuels is needed compared to California's 2012 baseline. Table 22 represents the Energy Commission's current estimates of plausible growth for several low-carbon alternative fuel options. Existing government incentives and regulations combined with alternative fuel price advantages, expected economy-of-scale vehicle manufacturing, and technology advances could lead to at least threefold increase in each alternative fuel category by 2020. If this happens, California will achieve goals for petroleum displacement, in-stage biofuel production, and LCFS compliance. Key highlights and conclusions of the scenario projections are described below.

Biofuel Gasoline Substitutes

Existing gasoline-based substitutes are predominantly composed of ethanol produced from Midwest corn and Brazilian sugarcane. There are also several emerging low-carbon biofuel technologies on the horizon, most notably cellulosic ethanol, which can be made from agricultural, forest, and urban waste materials. The first wave of commercial-scale cellulosic facilities in the United States began producing in late 2012, and nationwide production of cellulosic ethanol is expected to increase from 20,000 gallons in 2012 to 5 million gallons in 2013. Biofuel producers are also developing other low-carbon ethanol sources from grain sorghum, sugar beets, and sweet sorghum. Ethanol is typically used as an oxygenate in gasoline to reduce exhaust tailpipe emissions from vehicles. In most areas in the United States, gasoline is blended with 10 percent ethanol by volume (E10). Ethanol is also used in a fuel commonly known as E85 which can be used in flexible fuel vehicles. There are about 500,000 flexible fuel vehicles operating in California today.

California uses roughly 1.5 billion gallons of ethanol per year, of which nearly 175~~50~~ million gallons per year are produced in California and the remainder is imported corn ethanol from the Midwest and foreign sources. The combination of RFS requirements for obligated parties, substantial RIN credit values, availability of sufficient biofuel resources, and California's LCFS will compel development of low-carbon biofuel projects in the state and a shift of low-carbon biofuels to California. Increased Brazilian sugarcane ethanol is the largest near-term contributor because it has a lower carbon intensity value compared to most corn ethanol and will displace 250 million to 400 million gallons per year of corn ethanol imports. Three operating corn ethanol plants in California have already begun a shift to lower-carbon ethanol by using grain sorghum in 2013, and a fourth plant, currently idle, could begin operating and using low-carbon biofuel feedstocks.

The Energy Commission has invested more than $150 million in several California advanced biofuel production plants using sweet sorghum, sugar beets, and agricultural and forest waste residue. These projects are expected to proceed to commercial-scale development in 2016 and 2017. The moderate scenario also assumes that at least one developer will successfully produce ethanol from a combination of sugar cane and other purpose-grown crops with high fuel conversion and low carbon intensity values in the Imperial Valley. In addition, it is anticipated that at least one cellulosic ethanol plant will be built in California by 2020.

Table 22: Alternative Fuel Growth Estimates

	Fuel Production/Calif. Consumption (Millions of Gallons - GGE and EER Factors)			
Fuel Type	2013	2015	2017	2020
Gasoline Substitutes				
Corn Ethanol Imports	1,150	1005	708	593
CA Corn/Grain Sorghum	150	180	220	220
CA Advanced Biofuels	2	63	100	180
CA Sugar Cane/Energy Cane			50	50
Brazilian Sugar Cane Imports	200	250	400	400
Cellulosic	1	5	25	60
Subtotal	1,503	1,503	1,503	1,503
Diesel Substitutes				
Palm Oil Imports	0	0	0	0
Soy Imports/CA Production	5	5	5	5
UCO/Corn Oil/Tallow	27	88	150	188
Renewable Diesel	103	157	310	310
Purpose Grown Crops (Camelina, Jatropha)			10	80
Algae			10	100
Cellulosic	1	5	25	60
Subtotal	136	255	510	743
Natural Gas				
CNG/LNG	150	300	500	900
Biomethane		1	2	4
Subtotal	150	301	502	904
Transportation Electric				
Light and Heavy Rail	44	45	45	45
Transit/Trolley	5	5	5	5
PEVs and Hydrogen FCVs	5	40	80	120
Subtotal	54	90	130	170
Propane	20	20	20	20
TOTAL	**1,863**	**2,169**	**2,665**	**3,340**

Source: California Energy Commission

Diesel Substitutes (Biodiesel and Renewable Diesel)

Diesel substitutes generally include biodiesel and renewable diesel. Historically, biodiesel was produced primarily from Midwest soybean oil, a co-product of meal/protein production~~s~~; however, because of LCFS requirements, biodiesel use in California has shifted to lower-carbon sources. California companies are producing greater volumes of biodiesel from used cooking oil, tallow, and corn oil which are inputs into broader fats and oils markets used to produce animal feed and other products. These feedstocks have ~~mostly waste products with~~ very low carbon intensities. California biodiesel plants have the capacity to produce approximately 50 million gallons per year of biodiesel, but current production is about half of the capacity. California's diesel consumption totaled approximately 3.3 billion gallons in 2012 for on-road vehicles and another 500 million for off-road farm and construction vehicles. Diesel fuel is used in 70 percent of California's 1 million trucks and buses and biodiesel is blended at multiple terminals.~~generally splash-blended at diesel fuel distribution centers.~~

Renewable diesel can be produced from the same feedstocks as biodiesel but the conversion process is different. Renewable diesel is chemically equivalent to diesel fuel and does not require separate blending infrastructure. In 2013, California received the first shipment of renewable diesel from Singapore and expects to see future growth. The Energy Commission expects at least a sixfold increase in biodiesel production to 188 million gallons per year and renewable diesel production and delivery to more than 300 million gallons per in California by 2020.

The RFS mandate, RIN credits, and the LCFS drive a major growth trend in the production of biodiesel and renewable diesel. Both can be derived from the same resources but use different technologies and conversion methods. Used cooking oil, tallow, and corn oil offer significant near-term growth contributions because they have lower carbon intensities than soy biodiesel and will displace the use of soy imports. The federal blender's tax credit will exist through 2013, providing an added incentive to develop biodiesel and renewable diesel fuels. These combined factors could push a fourfold increase in biodiesel and renewable diesel fuels by 2020.

A potential constraint is securing enough low-carbon-intensity feedstock to produce biodiesel and renewable diesel. Estimated potential for used cooking oil, tallow, and corn oil from within California is 100 million gallons of biodiesel or renewable diesel. The bulk of the renewable diesel is produced in Singapore and shipped to California. California will also attract imports of biodiesel produced from low-carbon feedstocks in other states. Resource constraints have triggered research and demonstration of purpose-grown crops such as jatropha and oil co-products from canola, and camelina to produce biodiesel. Several companies have developed pilot projects to produce renewable diesel from algae.

Biodiesel can be safely used at various 5 percent blend levels, and a new ARB alternative diesel fuel regulation being developed will guide the use of this fuel in California. The makeup of renewable diesel is undistinguishable from conventional diesel, so renewable diesel can be used in a variety of blends with diesel with no restrictions. Because automakers will introduce 20 new diesel passenger cars and pickup trucks over the next year, growth of biodiesel and renewable diesel fuel will not be limited to medium- and heavy-duty trucks.

Natural Gas Transportation

Natural gas has matured as a transportation fuel and is commonly used as CNG and liquefied natural gas in transit buses, trucks, waste haulers, and passenger cars. Several thousand natural gas vehicles operate in California, and more than 500 dispensing stations are operating in public access and fleet home base fueling centers. Because of the fuel cost advantage natural gas enjoys compared to diesel and gasoline, high-mileage vehicle owners have begun a shift to natural gas in long-haul trucks and taxis. The higher differential cost of natural gas engines and vehicles compared to diesel and gasoline vehicles can be offset by the lower cost of fuel if the natural gas trucks travel more than 80,000 miles per year and taxis more than 50,000 miles per year. The Energy Commission's natural gas rebate buydown program offers a mechanism to offset this cost and to increase market adoption of vehicles that do not have high-mileage annual use. Scale economy manufacturing of natural gas engines and vehicles should also have an impact on lowering the vehicle cost by 2020 or sooner. Heavy-duty engines powered by new natural gas engines offer a viable strategy to reduce nitrogen oxide and GHG emissions.

One automaker in the United States produces a dedicated natural gas passenger vehicle, but four others have developed dual-fueled gasoline/natural gas concept cars and may bring them to market in limited production within the next three years. Nearly 80 percent of transit buses in California have converted to natural gas fuels with funding from the U.S. Department of Transportation. A growth scenario representing a sixfold increase in natural gas vehicles and natural gas consumption from 2012 levels by 2020 is very possible. More aggressive growth may depend on the availability of more engines and vehicle models. California has installed more than 500 natural gas fueling stations, and developers have constructed natural gas fueling stations along highway corridors to enhance the use of LNG trucks. The LCFS is expected to help incentivize this growth because of the value of LCFS credits derived from natural gas used in transportation.

Electric Transportation

Many automakers produce an all-electric or plug-in hybrid-electric vehicle for sale or lease in California. As of mid 2013, 32,000 plug-in electric vehicles and an additional 14,000 neighborhood electric vehicles are on the roads.[415] More than 8,000 electric vehicle charge points have been funded by the Energy Commission and the air quality management districts in California. ~~installed. E~~Electric vehicles are 3.4 times more efficient than gasoline internal combustion engines. The Governor's ZEV Executive Order and the ARB's ZEV mandate, combined with a federal tax credit and incentives for electric vehicle rebates and electric charger installations, are advancing the electric vehicle market penetration in California. The Executive Order calls for California to ensure infrastructure is developed to support 1 million zero-emission vehicles by 2020 and 1.4 million by 2025. The Executive Order also reflects a 2050 goal to reduce transportation-related GHG emissions by 80 percent below 1990 levels by 2050 and concludes that electric and hydrogen fuel cell vehicles comprising greater than 80 percent of all passenger vehicles in 2050 will achieve that objective. The $7,500 federal tax credit begins to phase down and expires ~~when~~ one year after each electric vehicle model ~~exceeds~~ achieves 200,000 cumulative sales. California also provides up to $2,500 under the Clean~~alifornia~~ Vehicle Rebate Project for eligible electric vehicles. Electric vehicles offer a significant reduction in GHG emissions compared to gasoline or diesel-fueled vehicles today and this reduction increases only as ~~particularly if~~ renewable electricity is further added to the electricity mix~~the source of~~

415 http://www.energy.ca.gov/renewables/tracking_progress/documents/electric_vehicle.pdf.

~~vehicle charging~~. As a result, the Energy Commission expects exponential growth in the development and use of electric passenger vehicles.

Plug-in electric passenger vehicles represent the largest contributor to electric transportation, but other modes (transit, trucks, rail, and port electrification) are emerging as important electric transportation options. For example, the California High-Speed Rail project will connect Northern California to Los Angeles and eventually San Diego, will use renewable electricity, and is anticipated to displace a significant share of intrastate air travel. Electrification of the equipment used at ports is another example. Port electrification involves shifting from petroleum fuels to electricity sources to operate crane, yard tractors, onboard energy for vessels in ports and some container trucks, electric transit and trolleys, truck stop electrification, and shifting refrigerated trucks from diesel to electric power adds up to a significant contribution.

Hydrogen Fuel Cell Vehicles

Although a few hundred hydrogen fuel cell vehicles operate in California and new infrastructure is needed to fuel the vehicles, this option has tremendous potential because hydrogen and electric vehicles offer two of the best options to achieve the 2050 GHG emission reduction goals. Hydrogen is derived from natural gas reforming or electrolysis and the carbon intensity of the fuel is reduced because the vehicle is two to three times more efficient than gasoline or diesel vehicles. In addition, all hydrogen fuel sold from publicly funded stations must contain at least one-third renewable hydrogen, as required by SB 1505, which reduces the carbon footprint to a level equivalent to plug-in electric vehicles. Initial sales of hydrogen fuel cell vehicles are expected to occur in cluster areas in the San Francisco Bay Area and Southern California—establishing these as priority areas for fueling infrastructure. The California Fuel Cell Partnership Roadmap,[416] the preeminent study on hydrogen fueling for California, shows that an initial set of about 68 stations is needed by 2015-2017 to provide fueling infrastructure for 20,000[417] hydrogen fuel cell vehicles expected from automakers by this time frame. To help ensure a successful transformation of the transportation sector to ZEVs, the ARFVTP is providing incentives to help fund this initial set of hydrogen fueling stations.

Public incentives will be needed in the initial years of advanced vehicle deployment until they gain a sustainable foothold in the market. As specified in the new ARFVTP and AQIP reauthorization statute, the ARB and Energy Commission will assess the continuing need for hydrogen fueling station public incentives, the appropriate level of those incentives, and when an advanced technology has penetrated the market where incentives are no longer needed. The Energy Commission is directed to invest up to $20 million per year, or 20 percent of each year's investment allocation, until a network of at least 100 stations is constructed and operating in

416 http://cafcp.org/sites/files/A%20California%20Road%20Map%20June%202012%20%28CaFCP%20technical%20version%29_1.pdf.

417 The California Air Resources Board is resurveying the automakers on production and rollout plans of hydrogen fuel cell vehicles. Hydrogen fuel cell vehicle production numbers will be updated when available.

California. ~~The legislative goal as articulated in AB 8 is for the state to help develop a 100-station network.~~ A National Academy of Sciences study projects that hydrogen and electric vehicles will be less expensive than internal combustion engine vehicles after that point. Furthermore, increased hydrogen fuel sales is the key factor for fueling stations to cover operation costs and profit margin for fueling infrastructure to achieve market maturity and diminish the need for government incentives.

Transit, forklifts, and stationary fuel cell applications are growing markets for fuel cell uses and can provide complementary business models to accelerate hydrogen fuel cell technology improvements and increase hydrogen fuel sales, leading to scale economy manufacturing, reduced vehicle and infrastructure capital costs, and successful business practices.

Transportation Demand Forecast and Supply Demand Balance

The Energy Commission staff has prepared forecasts of transportation fuel demand to 2050 using demand forecasting models for commercial light-duty vehicle travel, urban and intercity travel (including public transit), freight movement, and passenger and freight aviation. Some of the key findings in the demand models that helped to inform the transportation fuel forecast are:[418]

- Light-duty vehicle travel: Vehicle attributes are expected to change over the next 30 years, assuming significant increases in fuel economy, full implementation of ARB's ZEV mandate, and an increase in passenger vehicle and light-truck stock from 27 million to between 42 million and 47 million vehicles in 2050.
- Urban Travel: Urban travel, trips of less than 50 miles, comprises 72 percent of the passenger miles traveled in California, and the number of passenger trips taken in light-duty vehicles is projected to increase from 17.8 billion to between 23.8 billion and 26.5 billion. Vehicle miles traveled are projected to increase from 136 billion miles in 2011 to between 182 billion and 202 billion miles in 2050. Transit miles are also expected to increase from 396 million in 2011 to between 653 million and 727 million miles in 2050.
- Intercity Travel: Intercity travel, trips of more than 50 miles, comprises about 28 percent of all passenger travel in California. Intercity passenger trips are expected to increase from 750 million in 2011 to 1.7 billion to 2.0 billion in 2050.
- Freight Movement: There are nearly 1 million trucks on California's roads with roughly 70 percent fueled by diesel, 29 percent by gasoline, and the remainder by alternative fuels. Trucking moves the majority of interstate freight *from* California *to* other states. Rail and intermodal move the majority of freight *from* other states *to* California.

These demand models are behavioral models that respond to changes in economic and demographic variables and to changes in vehicle attributes and fuel prices. These models use

418 Please see Appendix G for further information about the low, medium, and high cases and other details on these assumptions.

projected inputs from a number of sources to develop fuel demand forecasts. Estimating future transportation fuel demand requires staff to contend with uncertainties in future economic and market conditions, human behavior, and the regulatory and policy environment; therefore, the forecasts must be viewed in this context. Staff has developed multiple scenarios to allow for many of these uncertainties.

There are uncertainties in the projections of crude oil and transportation fuel prices, economic growth, and demographic and technological trends that are used in developing fuel demand forecasts. Moreover, many of the events that shape energy markets in the short term cannot be anticipated, including weather, geopolitical disruptions, and labor strikes. Nor can longer-term developments in transportation technologies, demographics, and resource markets be foreseen with certainty. Staff has developed scenarios that address key uncertainties in crude oil and transportation fuel prices, economic growth patterns, and federal and State regulations for current *IEPR* projections.

In addition to uncertainties inherent in the data and specifications used in estimating any forecasting model, there are also uncertainties associated with the public and private sector projections used as inputs to these models. Changes in consumer preferences, the regulatory environment, land-use patterns, and fuel and vehicle technology, as well as crude oil and transportation fuel price fluctuations, also add to the uncertainties of fuel demand forecasts in an increasingly globalized economy.

Fuel Price Forecast

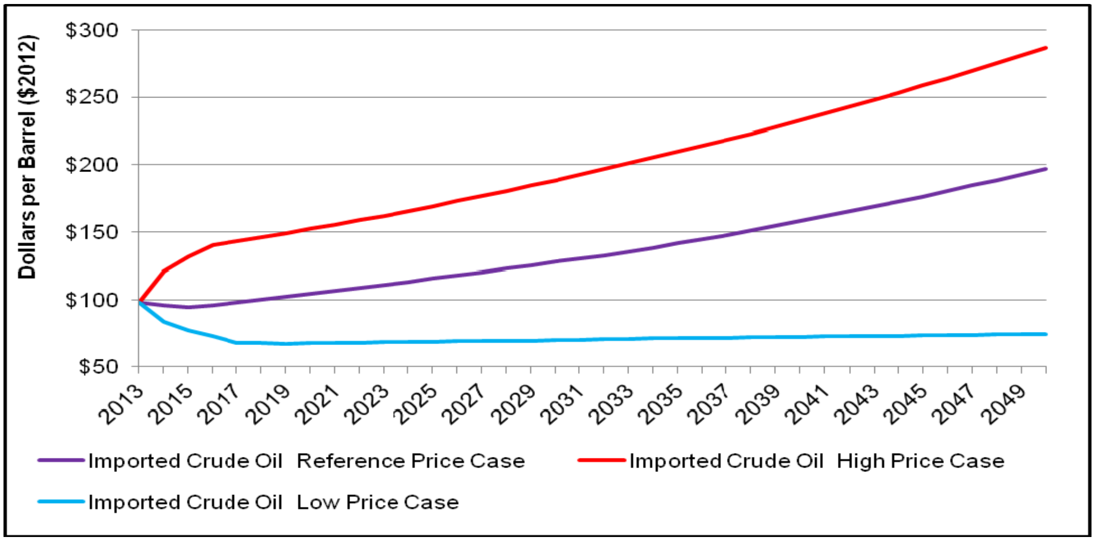
For the *2013 IEPR*, staff has developed California-specific Reference, High, and Low price cases for gasoline, diesel, and other petroleum price cases based on refiner acquisition cost (RAC) projections for U.S. refiners. RAC of imported crude oil, as defined and measured by the Energy Information Administration (EIA), is the weighted-average cost to refiners for obtaining an imported barrel of crude oil and is commonly used as a proxy for world crude oil prices. This index is historically roughly $3 to $10 per barrel less than the average for higher-quality light sweet oil, such as West Texas Intermediate, and has traditionally been a better predictor of crude oil prices for the California market than other benchmarks. For all three cases, staff obtained values for RAC from the *2013 Annual Energy Outlook* produced by the EIA. The *2013 Annual Energy Outlook* cases used by the Energy Commission were the Reference Case, High Oil Price Case, and Low Oil Price Case. Figure 32 displays the three RAC price cases in inflation adjusted 2012 dollars.

Consistent with EIA documentation, these cases have included the incorporation of the California LCFS and AB 32’s cap-and-trade program.[419] In all of these cases, West Coast production of crude oil (for which California is the largest producer) remains in decline, with it declining the most in the Low Price Case (-1.6 percent a year) and the least in the High Price Case (-0.3 percent a year).

419 http://www.eia.gov/forecasts/aeo/chapter_changes.cfm.

By 2040, in all cases, tight oil production forms a third of all U.S. production of crude oil, half of that production coming from onshore sources. Only in the Low Price Case does crude oil production in the U.S. decline.

Figure 32: Crude Oil Price Cases

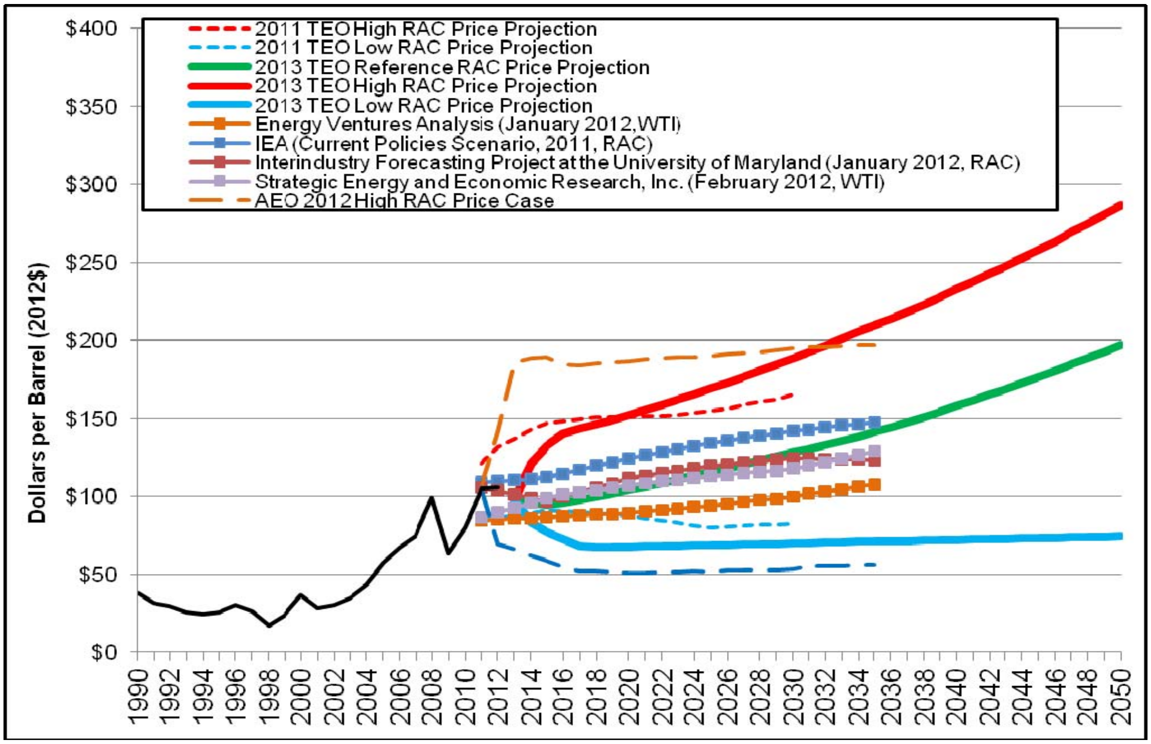


Source: California Energy Commission and the U.S. Energy Information Administration

Upon comparison of these projections and similar ones produced by other crude oil analysis firms, as seen in Figure 33, the Reference Case projection used by staff and the EIA is in the center of the largest clump of projections and represents a lowering of the average crude oil price in the near term before rising to its final price of roughly $200 a barrel in 2050. The Low Case falls to roughly $75 a barrel of oil and then maintains that price point. While not the lowest price on the chart, it is the second lowest with only the previous year's *Annual Energy Outlook* being lower. The High Case has a sharp near-term increase in prices followed by a lower rate increase past 2016 with a final 2050 price of roughly $290 a barrel. This forecast is on the upper end of the presented projections and represents a continued growth in prices similar to the 2002 to 2008 period.

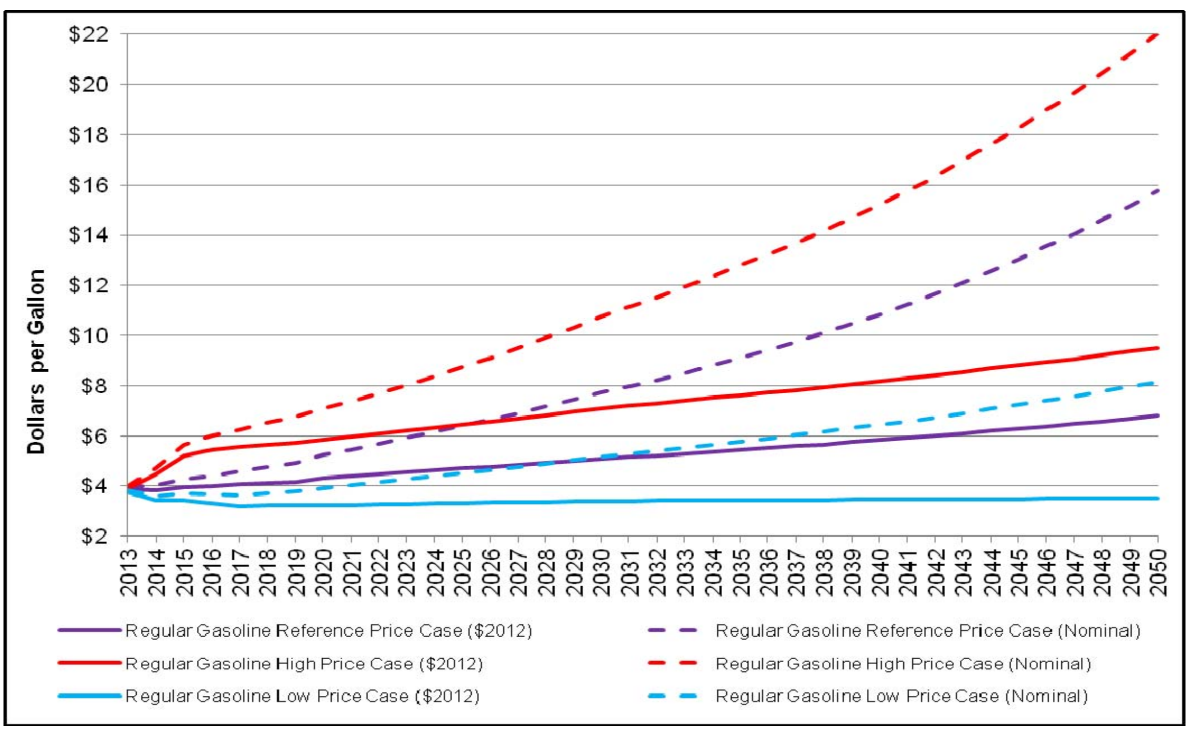
Figure 34 and Figure 35 show the California regular retail gasoline and retail diesel fuel price cases in 2012 dollars per gallon, as well as the common carrier price for jet fuel cases. These price cases are generated by adding the price margins and the corresponding tax estimates for each fuel type to the corresponding imported crude oil price cases. All prices included common-case assumptions regarding carbon prices used within both the natural gas and electricity market price and demand projections. In the inflation-adjusted price patterns, like the crude oil cases, deviation in the retail prices occurs in the near term of the projections with steady rises in the later portions of the projections. Once future price inflation is accounted for, in all cases actual prices likely seen by consumers will rise, with a doubling of the gasoline price occurring by 2025 in the High Case.

Figure 33: Recent Crude Oil Price Forecasts from Leading Energy Price Analysis Firms



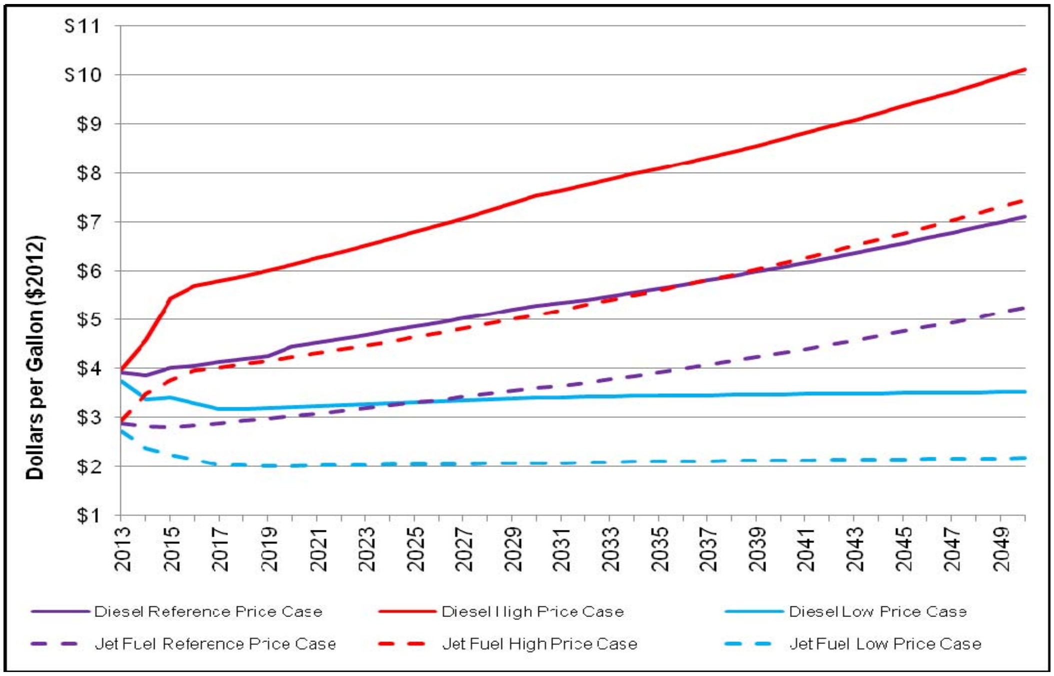
Source: California Energy Commission and the U.S. Energy Information Administration

Figure 34: *IEPR* 2013 Regular Gasoline Price Cases



Source: California Energy Commission

Figure 35: *IEPR* 2013 Diesel and Jet Fuel Price Cases (2012$s)



Source: California Energy Commission

Challenges to Achieving Alternative Fuel Growth Potential and Ensuring an Adequate Transportation Energy System

Potential changes in the regulatory landscape. Potential changes to regulations that require increases in alternative or low-carbon fuels, like the U.S. Environmental Protection Agency's Renewable Fuel Standard or the ARB's LCFS, can affect demand. To the extent that investments in biofuel production and infrastructure are based on current regulations, investment may be affected by the real or perceived risks that may be caused by uncertainty in those regulations.

More storage may be needed to accommodate higher volumes of domestic and imported fuels. As volumes of sugarcane ethanol increase to 250 million gallons a year or more, transport is more cost-effective by marine vessel shipment directly to California ports compared to shipments to Houston and transferring the fuel by rail cars to California. However, fuel terminal storage is limited in the California ports. Following the growth scenarios presented in Table 23, if no additional storage capacity is built, then limited storage could impede delivery of large amounts of this low-carbon fuel. Growth of low-carbon-intensity biodiesel could drive the need for additional storage and blending terminals, as well as retail sites.

Demand is outpacing availability of incentives. California incentives have spurred the growth of alternative fuels, and the increased growth depends on continuing incentives. However, the demand has begun to exceed the amount of government funds available in existing pools of state government funds. The alternative fuels industry is still in start-up phases with uncertain time frames to achieve technology and market maturity and develop sustainable business models. Incentives can help address and offset the real and perceived risks that private investors may see. Incentives can also help speed transition to new alternative technologies and fuels by bringing their costs closer to those of established technologies and fuels, helping California meet its climate, clean air, and energy security goals.

Integrating the transportation system into the electric grid. Electric transportation growth requires increased attention to balanced multiple objectives associated with that growth. These objectives include (1) ensuring electric grid and local distribution system safety, (2) maximizing renewable electricity use in electric vehicle charging and other transportation uses, balanced with electricity system load management, (3) enhancing community and utility readiness for vehicle charging and electricity system infrastructure for the growth of electric transportation, and (4) providing affordable electricity for household and business use of electric transportation. To help advance smart charging consistent with grid conditions, the California ISO is leading the development of a roadmap to include vehicle-to-grid and other technology options~~roadmap that is expected~~ to be completed by the end of the year.

Limited number of natural gas vehicle models. Even though natural gas enjoys a significant fuel price advantage compared to diesel and gasoline to help offset the higher vehicle cost, only one major engine manufacturer produces a natural gas engine for trucks and buses, and one automaker provides a dedicated natural gas passenger vehicle. Industry growth depends upon expansion to multiple vehicle and component manufacturers.

Scaling up infrastructure and vehicles for hydrogen. Automakers need greater certainty about the commitment to install hydrogen fueling stations near early adopter hydrogen fuel cell vehicle customers and station owners need assurances that vehicle owners will use their fueling stations. Numerous automakers, including Honda, Toyota, General Motors, Daimler, Hyundai, and Nissan state that they are planning to bring hydrogen fuel cell vehicles to market in the 2015-2017 timeframe. Currently 9 hydrogen fueling stations are operational and open to the public, and the Energy Commission has provided funding for 24 more new and upgraded stations. The Energy Commission facilitates the initial development of this industry by providing cofunding for the hydrogen fueling stations to offset investment risk until enough vehicle owners purchase hydrogen fuel at these stations to cover operating costs.

Changing trends in gasoline, diesel, and aviation fuel consumption. The decline in domestic and statewide gasoline consumption and the increase in diesel and aviation fuel demand may present challenges to some California refineries that would need to invest in reconfiguring their refineries. This situation could lead to refinery throughput reductions, possible closures, or consolidation to fewer refinery owners. These result could perhaps increase the state's vulnerability to supply disruptions and gasoline and diesel price spikes, although the state's diversified fuel mix—electricity, hydrogen, natural gas, and liquid biofuels—would certainly lessen that impact.[420]

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420 Joan Ogden, Christopher Yang, and Nathan Parker, "Transition Scenarios for the U.S. Light-Duty Sector," *Sustainable Transportation Energy Pathways*, UC Davis Institute of Transportation Studies, 2011.

Challenges tracking and evaluating alternative fuel growth. The hallmarks of alternative fuel growth trends include technology advances, vehicle cost reductions, scale economy manufacturing, commercial-scale fuel production and infrastructure projects, and competitive fuel pricing. Although the Energy Commission has authority to collect confidential information from the California petroleum industry, it has limitations on gathering information on the alternative fuels industry. The ARB has authority for information gathering under the ZEV mandate, the LCFS, and other regulations but lacks some details outside its regulatory jurisdiction. Although data limitations diminish capabilities to track the fast growth of alternative fuels and to evaluate the continued need, level, and appropriate mechanisms for economic incentives, continued cooperation between the Energy Commission and ARB is essential for gaining an overall understanding of the alternative fuels market.

Recommendations

To address challenges, the Energy Commission recommends initiatives and policy actions that will lead to measurable change, including recommendations to:

- **Help implement the *2013 Zero-Emission-Vehicle Action Plan* and California's high-speed rail.** Provide guidance to implement the *2013 Zero-Emission-Vehicle Action Plan* and use electricity and alternative fuels in the California High-Speed Rail Project.
- **Support national Renewable Fuel Standard Goals.** Confer with the U.S. Department of Energy, the U.S. Environmental Protection Agency, and Congress to advocate for a balance of stricter adherence by obligated parties to advanced, low-carbon, Renewable Fuels Standard goals and sustained federal government incentives that phase out as conversion technologies and commercial projects mature.
- **Evaluate fuel storage needs for low-carbon biofuels.** Investigate the need for investment, development, and permit approval of fuel storage terminals for imported and California-produced, low-carbon biofuels.
- **Develop a multiyear strategy to fund electric, hydrogen, and natural gas vehicle rebates.** The Energy Commission and California Air Resources Board should jointly prepare a multiyear strategy to estimate the need and amount of multiyear government funds required and revenue source options to fund electric, hydrogen, and natural gas vehicle rebates and incentives for related infrastructure.
- **Optimize incentives for alternative fuel production and fueling infrastructure.** The Energy Commission, in conjunction with the California State Treasurer's Office and the California Infrastructure and Economic Development Bank, should evaluate and recommend to the Governor and Legislature options to use State, federal, or other mechanisms to optimally configure existing incentives and explore strategies to leverage the value of carbon credits to increase private sector project financing of commercial-scale alternative fuel production plants and fueling and charging infrastructure.

- **Advance multiple objectives of transportation electrification.** The Energy Commission, the California Independent System Operator, and the California Public Utilities Commission (CPUC), the California Air Resources Board, and local air districts should jointly confer with investor-owned and publicly owned utilities and other public and private stakeholders to balance multiple objectives associated with the growth of transportation electrification and electric vehicle charging.

- **Evaluate factors affecting California's crude oil production and refining.** The Energy Commission shall consult with the California Environmental Protection Agency and California Department of Conservation to evaluate several factors that might reduce international imports of crude oil and change California's production and refining of crude oil and refining of crude oil from other states. The findings should be reported to the Governor and Legislature and include the following:

    - The Energy Commission shall consult with the California Environmental Protection Agency and California Department of Conservation to evaluate the magnitude, cost, and environmental impacts of producing crude oil from the Monterey shale formation and existing heavy oil fields in the San Joaquin Valley.

    - The Energy Commission should evaluate demand from other states and other countries for crude oil and petroleum products developed in California.

    - The Energy Commission should evaluate potential oil refinery industry and retail consolidation stimulated by a decline in gasoline consumption and increase in diesel and aviation fuel consumption.

    - The Energy Commission and California Environmental Protection Agency should evaluate reconfiguration of energy security goals to fuel diversity objectives if the trend continues toward a greater percentage of crude oil produced from domestic sources.

- **Expand joint data collection authority.** Expand existing authority for the Energy Commission and the California Air Resources Board to jointly gather annual information and data on alternative fuels, vehicles, and infrastructure from automakers and truck, bus, and engine manufacturers; wholesalers and marketers; and commercial infrastructure providers.

CHAPTER 9: Climate Change

In Governor Brown's talk at Tsinghua University in China, he said: "Shifting from the easy burning of fossil fuel to a leaner and more elegant energy production will cost money. It will take collaboration, it will take brain power, it will take research, and I'm very happy to say that California is in the forefront in many respects."[421] California remains a world leader in its efforts to address climate change by reducing greenhouse gas (GHG) emissions and identifying ways to prepare for and reduce ~~and adapt to~~ climate change impacts. Assembly Bill 32 (Núñez, Chapter 488, Statutes of 2006), the Global Warming Solutions Act of 2006, caps economywide California GHG emissions at 1990 levels by no later than 2020. This ~~aggressive~~ goal represents around an 11 percent reduction from current emissions levels and a nearly 30 percent reduction from projections of business-as-usual levels in 2020. In 2011, about 85 percent of GHG emissions in California are from the energy sector, with about 20 percent from electricity generation and 39 percent from transportation.

California's strategies to reduce GHG emissions in the energy sector include improving the energy efficiency of buildings and appliances, as well as reducing GHG emissions from the electricity sector by increasing the use of clean technologies such as renewable generation and demand-side resources Strategies to reduce GHG emissions in the transportation sector include the development of low-carbon renewable and alternative transportation fuels and vehicles. However, the energy sector will also be significantly affected by changes in climate. Atmospheric warming will increase electricity demand, decrease the efficiency of thermal power plants, and potentially change the availability of hydropower. Electricity reliability could also be affected by increased risk of wildfires that could damage power lines and by potential flooding in coastal power plants due to sea-level rise.

As part of the 2012 and 2013 *Integrated Energy Policy Report* (*IEPR*) proceedings, the Energy Commission held workshops to explore the effects of climate change on the California energy system and potential ~~adaptation~~ strategies to reduce climate risk. Energy Commission staff prepared a staff paper[422] based on information gathered through these and other climate-related workshops, three climate change assessments done in California since 2006, and state-sponsored climate change research. The staff paper ~~, scheduled for release in fall 2013,~~ focuses on the vulnerability of California's energy supply and demand infrastructure to the effects of climate change, research needed going forward to better understand those effects, ~~adaptation~~ options to prepare for climate risk, and key policy issues.

421 Governor Edmund G. Brown Jr., "Our Shared Path Toward Energy Innovation and Low Carbon Development," speech at Tsinghua University, Beijing, China, April 11, 2013, http://gov.ca.gov/news.php?id=17992.

422 David Stoms, Guido Franco, Heather Raitt, Susan Wilhelm, Sekita Grant, *Climate Change and the California Energy Sector*, 2013, California Energy Commission, CEC-100-2013-002, http://www.energy.ca.gov/2013publications/CEC-100-2013-002/CEC-100-2013-002.pdf.

This chapter discusses the Climate Consensus Document, California's GHG emissions, climate change research and projections relevant to California's energy sector, potential impacts on energy supply and demand, ~~climate readiness~~ strategies to safeguard the energy system from climate change impacts, and future research needed to continue to support California's GHG reduction and ~~readiness~~ safeguarding strategies. Also, to help support planning for the 2050 GHG reduction target, this chapter discusses how the Energy Commission staff is beginning efforts to evaluate changes needed to California's electricity system by 2030. The chapter concludes with recommendations for future work. The chapter sets the stage for the energy component of the fourth Climate Change Assessment and is part of a comprehensive, integrated California climate change policy that includes an evolving suite of policy documents such as the 2008 AB 32 *Climate Change Scoping Plan*, [423] the 2009 *Climate Adaptation Strategy*[424] and their updates, *The Safeguarding California Plan: Reducing Climate Risk*, [425] and other major state climate policy documents.

Climate Change Consensus Document

In May 2013, the Governor joined more than 500 world-renowned researchers and scientists in releasing a groundbreaking call to action[426] on climate change and other global threats to humanity. The 20-page consensus statement, produced at the Governor's urging and signed by scientists from ~~over~~ nearly 44 countries, translates key scientific findings from disparate fields into one unified message. The document aims to improve the nexus between scientific research and political action on climate change.

According to the consensus statement, "climate disruption, extinction, ecosystem loss, pollution, and population growth are serious threats to humanity's well-being and societal stability." By 2100, carbon emissions trends will likely cause average global temperature to rise between 4.3–11.5 degrees Fahrenheit. These trends would have devastating impacts. The impacts highlighted by the consensus statement include the following:

- By 2050, human quality of life will suffer substantial degradation if humanity continues down this path.
- By 2100, the 1-in-20 year hottest day is likely to become a 1-in-2 year event.
- Cities would experience the extent of damage caused by superstorm Sandy more frequently basis.

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423 http://www.arb.ca.gov/cc/scopingplan/document/adopted_scoping_plan.pdf.

424 http://resources.ca.gov/climate_adaptation/docs/Statewide_Adaptation_Strategy.pdf.

425 http://resources.ca.gov/climate_adaptation/docs/Safeguarding_California_Public_Draft_Dec-10.pdf.

426 *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-scientists.

- Decreasing snowpack ~~and slow spring melt~~ will adversely impact cities and farmland that rely on the seasonal accumulation of snowpack.
- Damage to coastal areas, flooding of ports, water shortages, adverse weather and shifts in crop-growing areas, creation of new shipping lanes, and competition for newly accessible arctic resources will all cost billions of dollars.

Relying on the science, the consensus statement concludes that the negative trends in climate disruption require scaling up carbon-neutral energy production. To stabilize atmospheric concentrations of carbon and potentially prevent global temperatures from rising more than 2 degrees Celsius~~percent~~, the world would have to decrease emissions by 5.1 percent per year for the next 38 years. This emissions decrease will require government policies that increase innovation and "realign the economic landscape for energy production."

California can be an important part of the solution, but California cannot do it alone. As Governor Brown said, "What's beautiful and exciting about climate change is no one group can solve the problem. Not the United States, not California, not Japan, not China. We all have to do it."[427]

California's Greenhouse Gas Emissions

This section presents some basic information about GHG emissions in California using the latest GHG Inventory data available from the California Air Resources Board. For the *IEPR*, the energy sector is defined as including all activities related to the extraction of energy (for example, oil and natural gas wells), transportation of fuels and energy (for example, oil and natural gas pipelines), conversion of one form of energy to another (such as production of gasoline and diesel from crude oil in refineries and natural gas combustion in power plants to generate electricity), and energy services (such as burning natural gas in homes and buildings for space heating and gasoline consumption in automobiles for transportation services). Under this broad definition, the energy system was responsible for about 85 percent of the gross[428] GHG emissions in 2011. This amount includes GHG emissions associated with out-of-state power plants providing electricity for consumption in California, which, as required by law, are counted in the California inventory.

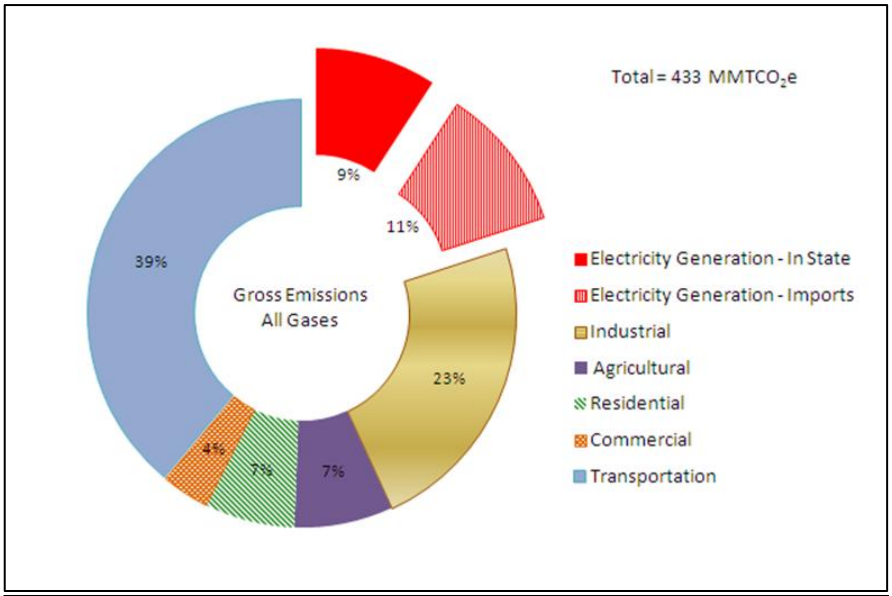
Figure 36 presents gross GHG emissions in 2011 from sectors of the economy. This figure shows that electricity generation contributed 20 percent of the total gross emissions in 2011. The percentage varies annually depending on factors including the availability of hydropower generation, the amount of renewable energy served, and other factors such as the shutdown of the San Onofre Nuclear Generating Station (San Onofre). This figure also shows that the

427 Governor Edmund G. Brown Jr., "Our Shared Path Toward Energy Innovation and Low Carbon Development," speech at Tsinghua University, Beijing, China, April 11, 2013, http://gov.ca.gov/news.php?id=17992.

428 The ARB 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.

transportation sector is the largest source of GHG emissions, contributing about 39 percent. Emissions from the industrial sector were slightly higher than from electricity generation, with substantial contributions from emissions associated with oil refineries (not shown). Figure 36 includes non-energy-related emissions such as nitrous oxide emissions from the use of nitrogen-based fertilizers in the agricultural sector or carbon dioxide emissions from the calcination[429] of raw materials in cement kilns, which are part of the industrial sector.

Figure 36~~33~~: 2011 GHG Emissions by Sector (Million Metric Tonnes of CO2 Equivalent)



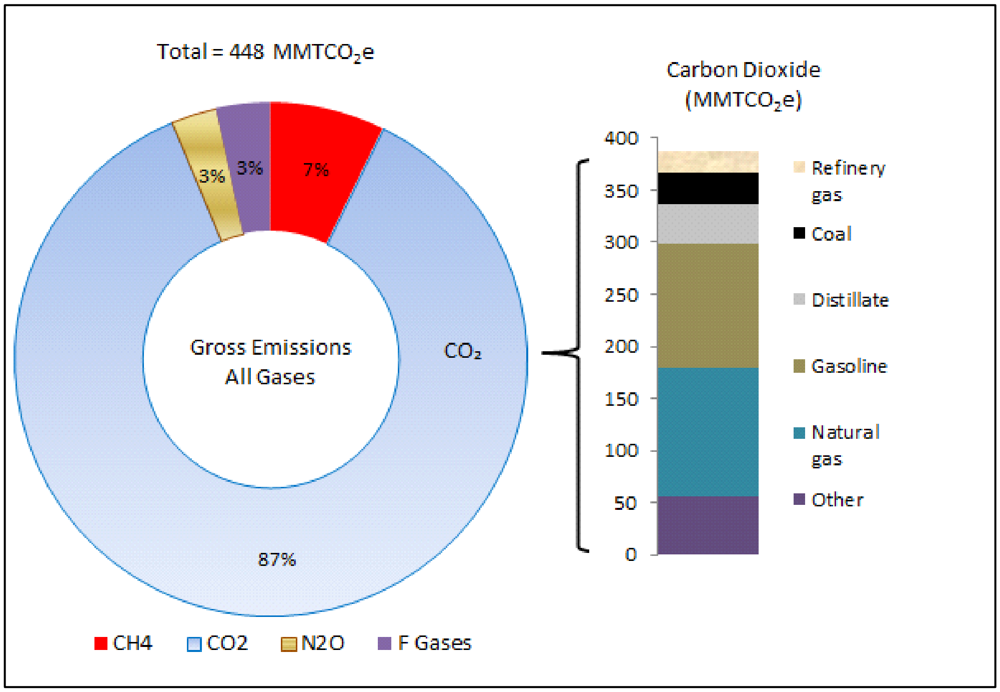
Source: California Energy Commission using data from California Air Resources Board GHG Inventory

Figure 37 shows emissions by GHG. Carbon dioxide (CO_2) is the main GHG emitted in California representing about 87 percent of total gross emissions. In turn, the combustion of fossil fuels is the major contributor of CO_2 emissions, as shown in the bar graph on the right of Figure 37. Refinery gas is produced and combusted in oil refineries in California and is attributable to the industrial sector. Emissions from the combustion of coal originate mostly from coal-burning electric power plants located outside California. Emissions from natural gas combustion are about equal to the emissions associated with gasoline consumption in the transportation sector. The "Other" category in Figure 37 includes carbon dioxide emissions from the combustion of minor fuels such as propane, kerosene, liquefied petroleum gas, and non-energy- related CO_2 emissions.

The F Gases in Figure 37 include fluorinated gases such as sulfur hexafluoride emitted from electrical equipment, such as transformers and other compounds used in the electronics industry. However, most F Gas emissions originate from refrigerant leaks from air conditioning units and chillers.

429 To heat a substance to a very high temperatures causing the loss of moisture and carbon dioxide from the decomposition of carbonates and other compounds.

Figure 37: 2011 GHG Emissions by GHG gas (Million Metric Tonnes of CO_2 Equivalent)



Source: California Energy Commission using data from California Air Resources Board GHG Inventory

Climate Change Research and Projections

State-sponsored research and assessments of climate change continue to advance the understanding of the sources of GHGs in the state and the potential effects of climate change on California, including effects on the energy sector. Since 2006, the state has sponsored a series of climate change assessments. The first showed that climate change is a function of global emissions of GHGs and that lowering emissions can reduce climate change effects. The second, released in 2009, concluded that ~~adaptation to~~preparing for the risks from climate change is a necessary and urgent complement to reducing emissions. The third assessment, released in 2012, explored local and statewide vulnerabilities to climate change and highlighted concrete actions to reduce climate change impacts. A fourth assessment is in the planning stages.[430]

The Energy Commission staff paper[431] prepared for the *2013 IEPR* synthesizes the results of the three climate change assessments, climate change reports and research through the Energy

430 Further information about each of the assessments can be found at http://www.climatechange.ca.gov/climate_action_team/reports/climate_assessments.html.

431 David Stoms, Guido Franco, Heather Raitt, Susan Wilhelm, Sekita Grant, *Climate Change and the California Energy Sector*, 2013, California Energy Commission, CEC-100-2013-002, http://www.energy.ca.gov/2013publications/CEC-100-2013-002/CEC-100-2013-002.pdf.

Commission's Public Interest Energy Research Program, *IEPR* workshops held in April 2012 and June 2013, and a California Climate Extremes Workshop held in December 2011 at the Scripps Institution of Oceanography. ~~The white paper sets the stage for the energy component of the fourth Climate Change Assessment and is part of a comprehensive, integrated California climate change policy that includes an evolving suite of policy documents such as the 2008 AB 32 *Climate Change Scoping Plan*, the 2009 *Climate Adaptation Strategy*, and forthcoming major climate change documents such as the 2013 Update to the AB 32 *Climate Change Scoping Plan*.~~

Analysis of historical data provides evidence of increasing temperatures in California and changes in the spring snowpack in the Sierra Nevada that are likely caused primarily by increased concentrations of GHGs in the atmosphere. Nighttime minimum temperatures in particular have been increasing in recent decades. Climate projections suggest that heat waves will be more frequent, last longer, start earlier in the year and end later, and be hotter than historical records. Precipitation in California is highly variable, and this high variability will continue to be a feature of the state climate in the future. Projections imply a potential for more frequent inland flooding in the future. As sea-level rises, the frequency and magnitude of extremes would increase markedly, with high sea-level surges that used to occur very infrequently in the historical period becoming very common by the end of this century and lasting for extended periods.

Impacts of Climate Change on Energy Supply

Climate change is likely to compromise electricity supplies, particularly during temperature spikes when demand for air conditioning will be high. The main effects on energy supply include less electricity output from thermal power plants, reduced capacity of the transmission and distribution infrastructure to deliver electricity, damage to energy infrastructure from extreme events like weather and wildfires, and changes in the availability and timing of renewable energy resources, such as hydroelectric power.

A study conducted by the Lawrence Berkeley National Laboratory (LBNL) for the 2012 California Climate Change Vulnerability and Adaptation Study[432] found that higher temperatures would decrease the capacity of thermal power plants (for example, natural gas, solar thermal, nuclear, and geothermal) to generate electricity during particularly hot periods. At higher temperatures, power plant cooling is less efficient, which, in turn, reduces the plant's efficiency and how much energy it can generate. California's gas-fired generating plants have a nameplate capacity of about 44,000 megawatts (MW). By the end of the century, this capacity could be reduced by as much as 10,000 MW on hot days, compared to a maximum of 7,600 MW in the 1961-1990 period. The LBNL study indicates that by the end of the century, energy supplies would need to increase by nearly 40 percent to meet increased demand from climate change and offset lower capacity of thermal generating plants and substations, assuming no technology advancements or population changes.

432 J.A. Sathaye, et al., "Estimating impacts of warming temperatures on California's electricity system," *Global Enviromental Change*, 2013, http://dx.doi.org/10.1016/j.gloenvcha.2012.12.005.

The energy system will also be increasingly vulnerable to extreme weather events, such as wildfires and coastal flooding.[433] ~~As many as 25~~About 20 coastal power plants and ~~86~~ about 80 substations face the risk of flooding or partial flooding because of sea-level rise. The Los Angeles Department of Water and Power has researched impacts of sea level rise on Los Angeles' coastal assets through the AdaptLA planning effort.[434] Their initial findings were that power services are not particularly vulnerable to sea level rise. The probability of wildfires occurring near large transmission lines is expected to increase dramatically in parts of California in some scenarios by the end of the century. The LBNL study found a 40 percent increased likelihood of wildfires near certain transmission lines, including the line that brings hydropower generation from the Pacific Northwest to California during periods of peak demand.

Climate change could also affect the amount and timing of energy generation from renewable resources over time.[435] Solar photovoltaic and wind energy are probably less vulnerable than conventional power plants, but the effects of climate change on wind and solar energy generation in California need to be investigated further.[436]

Hydropower contributes about 15 percent of California's in-state generation on average and provides low-cost, low-carbon power in the hottest months of the year when electricity demand is at its highest. Higher temperatures will mean that more precipitation falls as rain instead of snow, with remaining snowpack melting and running off earlier in the year. The system may not be able to store sufficient water for release in high-demand periods.[437] Many climate projections show a drier climate by late-century, although some suggest increased precipitation, especially in northern California.

Most research has focused on climate change effects on electricity infrastructure. Assessments will need to be expanded to include the vulnerability of California's transportation fuel supply and natural gas infrastructure—including refineries, pipelines, marine terminals, underground storage tanks, and fueling stations—to extreme weather events such as flooding, fire, and storms and to other potential climate effects like sea-level rise, coastal erosion, and rising temperatures.

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433 Jayant Sathaye, Larry Dale, Peter Larsen, Gary Fitts, Kevin Koy, Sarah Lewis, and Andre Lucena, *Estimating Risk to California Energy Infrastructure From Projected Climate Change*, California Energy Commission, 2012, CEC-500-2012-057.

434 Comments by LADWP in response to the *Draft 2013 Integrated Energy Policy Report*, October 29, 2013, http://www.energy.ca.gov/2013_energypolicy/documents/2013-10-15_workshop/comments/LADWPs_Comments_2013-10-29_TN-72304.pdf.

435 Edward Vine, "Adaptation of California's electricity sector to climate change," *Climatic Change*, 2012, pp. 75–99.

436 Ibid.

437 M., K. Guegan, and C. B. Madani, *Climate Change Effects on the High-Elevation Hydropower System with Consideration of Warming Impacts on Electricity Demand and Pricing,* California Energy Commission, 2012, CEC-500-2012-020.

Impacts of Climate Change on Energy Demand

Increasingly hot and longer summers are likely to increase demand for air conditioning, while warmer winters will decrease demand for heating in the cooler season. California's residential sector uses relatively little electricity for heating, but the overall demand for electricity will increase with more frequent operation of existing air conditioners and as more air conditioners are installed in areas of the state, such as the coastal regions, where there are currently few. Although technological advances could offset some of this increased demand, ~~higher temperatures in the next decade could increase demand by as much as 1 gigawatt during hot summer months. Also,~~ a 10 percent increase in peak demand is projected by the middle of the century.[438] This peak demand will occur at the hottest time of day when thermal power plants may not be able to deliver at full capacity.

To better understand the potential effects of climate change on peak energy demand, in 2011 the Energy Commission began factoring climate change into its electricity and natural gas demand forecast. This year, along with an updated peak demand analysis, the *2013 IEPR* ~~preliminary~~ demand forecast incorporates estimates of climate change impacts on electricity and natural gas consumption as discussed in Chapter 4. Higher temperatures by 2024 could increase peak electricity demand by around 950 MW in the mid demand case and around 1,550 MW in the high demand case.[439]

~~Climate Readiness~~ Strategies to Safeguard our Energy System From Climate Impacts

The energy sector is taking steps to increase its preparedness for potential climate change effects. First, energy generation resources are being diversified to reduce negative climate effects on any resource. California permitted more than 19,000 MW of renewable generating facilities from 2010-2012, and state incentive programs for customers who generate their own electricity have led to installation of nearly 4,000 MW of solar photovoltaic systems, small fuel cells, and small wind turbines that began operation between 2010 and 2012. Another 2,200 MW of new renewable generation is under construction.

Second, studies are being done to assess vulnerability and risk for energy infrastructure and to evaluate technological alternatives to ~~adapt to~~reduce risk from extreme weather conditions. The third Climate Change Assessment looked at vulnerability to increased temperatures, sea-level

438 J.A. Sathaye, et al., "Estimating impacts of warming temperatures on California's electricity system," *Global Enviromental Change*, 2013, http://dx.doi.org/10.1016/j.gloenvcha.2012.12.005.

439 Chris Kavalec, Nicholas Fugate, Bryan Alcorn, Mark Ciminelli, Asish Gautam, Kate Sullivan, and Malachi Weng-Gutierrez, *California Energy Demand 2014-2024 Final Forecast, Volume 1: Statewide Electricity Demand, End-User Natural Gas Demand, and Energy Efficiency*, 2013, California Energy Commission, Electricity Supply Analysis Division, CEC-200-2013-004-SF-VI.

rise, and increased risk of wildfire,[440] while new projects being funded by the Energy Commission are examining potential risks from flooding and sea-level rise in the Sacramento-San Joaquin Delta on energy infrastructure. Utilities are also assessing their vulnerability and incorporating climate change into their plans~~ning processes~~.

Third, the Energy Commission evaluates the impacts of climate change ~~effects~~ as part of a reliability analysis within its~~are being incorporated into~~ power plant siting and licensing processes. Within this analysis, the Energy Commission considers future risks of proposed power plant sites to extreme events. ~~as well as cumulative impacts of development and climate change on species of concern and other environmental factors. The state is developing new guidelines under the California Environmental Quality Act on~~ Research is also looking at ~~how climate change impacts such as sea level rise and flooding are to be assessed, and permit review processes will incorporate these guidelines once they are approved. Research is also looking at~~ how to assess the effects of new energy infrastructure in the context of a changing climate, since climate change will affect habitat conditions and migration patterns. Finally, decision support tools such as probabilistic forecasts are being developed to potentially reduce negative effects of climate change on California's hydropower by more effective management of reservoirs and hydropower units.

Future Climate Change Research Needs

California has developed an unmatched legacy of state-level research on climate change and its impacts. Nevertheless, new data, knowledge, and analytical capabilities dictate the need for continuing research to help the state achieve its existing and future policy goals. Energy Commission staff has identified several areas where research is needed.

Fourth Climate Change Assessment

A partial list of research areas the fourth Climate Change Assessment may address includes advances in fine-scaled probabilistic climate change projections; vulnerability to extreme events; economic impacts and costs of ~~adaptation~~preparing for climate risk; modeling and analysis of sectors and systems; funding mechanisms ~~for adaptation~~to reduce risks; how public and private sectors can implement climate considerations in their day-to-day activities; overcoming regulatory and legal barriers; supporting sustainable renewable generation; and evaluations of regions of the state not previously targeted for studies, such as the Central Valley and the desert/inland areas of southern California.

Effects of Extreme Events on the Energy Sector

In December 2011, Governor Brown hosted a ~~n invitation-only~~ conference in San Francisco focusing on the impacts of extreme climate events and how best to protect California from those impacts. The conference included experts from research, business, public health, local government, agriculture, energy, water, and other sectors. Specific research needs in this area

440 Jayant Sathaye, Larry Dale, Peter Larsen, Gary Fitts, Kevin Koy, Sarah Lewis, and Andre Lucena, *Estimating Risk to California Energy Infrastructure From Projected Climate Change*, California Energy Commission, 2012, CEC-500-2012-057.

include improved assessments to identify targeted ~~readiness~~ options to prepare for climate risks; development and testing of supply and demand forecasting methods; and innovative engineering design studies to identify when problems will materialize, what actions should be taken, and what alternatives are available.

Effects on Renewable Energy Goals

Research is needed to improve simulation of wind, solar radiation, relative humidity, cloud cover, and other variables that affect the amount of renewable generation that must be installed to meet state renewable goals. Also, effects of future climate conditions on wind and solar energy generation need to be further investigated. Further research is also needed on how to make up potential losses in hydropower generation.

Improve and Update Climate Change Indicators

Research is needed to improve indicators of climate change that help the state track, evaluate, and report on the outcomes of its efforts to reduce climate change effects. There are opportunities to improve current indicators and develop new ones to track the resilience and vulnerability of the energy sector. For example, wildfires are an important source of power interruptions in California, but additional data are needed on wildfires prior to 2002 to better understand the effects of such events.

Evolution of the Energy System

California's energy system must change drastically over the next few decades in response to policy goals to reduce GHG emissions and increase the amount of renewable energy in the electricity mix. This evolution will require information that helps create a more climate-resilient energy system. The Energy Commission is funding a project to enhance a newly developed model of the electricity system known as SWITCH (a loose acronym for Solar, Wind, Hydro, and Conventional Generation and Transmission Investment model). Energy scenarios developed with SWITCH will provide insight on strategies to achieve California's long-term GHG emission reduction goals for 2050 at minimum cost and will also help decision makers anticipate negative environmental impacts and develop mitigation strategies in advance. To meet these long-term goals, interim goals for 2030 are needed.

California's 2030 Electricity System

Research and planning are needed to help increase the resiliency of the energy system while transforming it to dramatically reduce GHG emissions. ~~California's energy sector contributes about 85 percent of the state's GHG emissions on a yearly basis, roughly 25 percent of which comes from the electricity sector, the remainder comes from natural gas systems, transportation services, and fuel infrastructure. Transportation represents the largest share, about 40 percent of the state's GHG emissions, meaning that transforming the transportation sector is an essential part of meeting the state's GHG goals.~~Realizing California's 2050 goal of reducing economywide GHG emissions to 20 percent of 1990 levels will require substantial decarbonization of the electricity and ~~electrification of the~~ transportation sectors. ~~Because there is so much uncertainty about~~In planning for a 2050 goal, the state must evaluate interim goals for 2030.

Decarbonization of California's electricity system must occur as demand from population and economic growth increases, combined with increased electrification of the industrial and transportation sectors to reduce their GHG emissions, which is expected to more than offset future improvements in energy efficiency. The effects of climate change will further complicate efforts to reduce GHG emissions.

An 80 percent reduction of GHG emissions by the electricity sector would limit 2050 emissions to 21.6 million metric tons of carbon dioxide equivalents (MMT CO_2).[441] ~~and require roughly a 70 percent reduction in electricity generation using fossil fuels.~~By 2030, California utilities will have divested themselves of coal-fired generation and will have met an RPS of 33 percent or more given that Governor Brown has consistently referred to a 33 percent RPS as being a "floor not a ceiling."[442] Replacing 21,000 GWh of coal-fired generation with renewable energy would yield a GHG emission reduction of 20 MMT CO_2.

The pathway to 2050 is all but certain to include the deployment of technologies now in the scale-up and demonstration phase, including fossil-fueled generation with CCUS, and advanced biofuels, as well as ~~Because widespread deployment of such technologies by 2030 cannot be assumed, however, California needs to consider how to meet interim GHG emission reduction and renewable resource development goals with~~ existing and mature technologies.

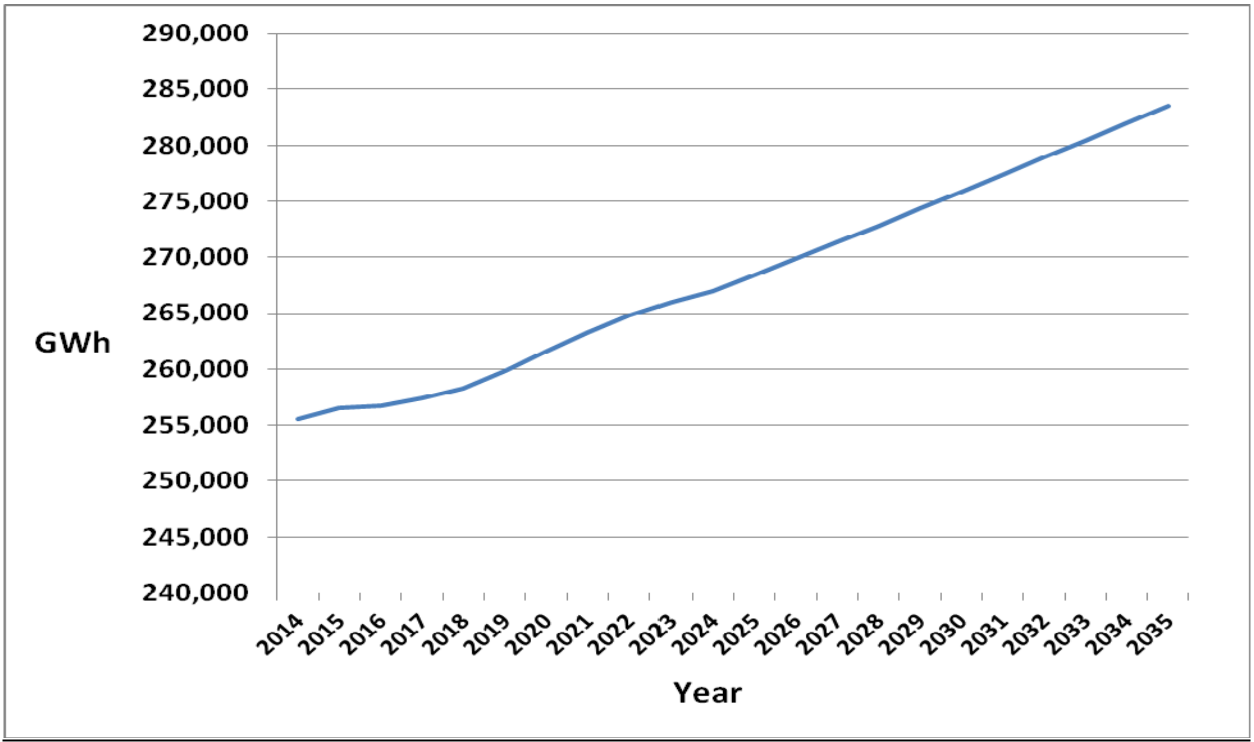
Electricity Demand in 2030

The ~~*Energy Commission's*~~*IEPR 2013* ~~preliminary~~ demand forecast, ~~for the next 10 years~~described in Chapter 4, is ~~substantially~~ lower than the *IEPR 2011* forecast ~~because of substantial~~due in part to reductions in projected population growth. Beginning with the *IEPR 2013* mid baseline demand forecast, staff developed a longer-term projection of RPS-eligible retail sales by adding additional achievable energy efficiency and extrapolating to 2035 based on 2018 – 2024 growth rates. Figure 38 illustrates this extended projection.~~Figure 34 illustrates the mid-case forecast for RPS-eligible retail sales with the mid- and low cases for achievable energy efficiency and extrapolates it to 2035 based on 2018 – 2024 growth rates, showing that growth in RPS-eligible retail sales from 2020 to 2035 will depend greatly on the extent to which energy efficiency savings are realized.~~

441 This value would be higher to the extent that offsets were used to meet GHG emission reduction goals. The cap-and-trade program developed by the California Air Resources Board allows for up to 8 percent of required emission reductions to be met with offsets. It is not expected that offsets will be used to the full extent allowed; see Elizabeth M. Bailey, Severin Borenstein, James Bushnell, Frank A. Wolak and Matthew Zaragoza-Watkins, *Forecasting Supply and Demand Balance in California's Greenhouse Gas Cap and Trade Market*, March 12, 2013.

442 Governor's signing statement for SB X1 2 (Simitian, Chapter 1, Statutes of 2011) in April 2011, and for AB 327 (Perea, Chapter 611, Statutes of 2013) on October 7, 2013, http://gov.ca.gov/docs/AB_327_2013_Signing_Message.pdf.

Figure 38: California Energy Demand ~~Revised Draft~~Final 2013 Forecast and Extrapolation to 2035, RPS Eligible Retail Sales, GWh



Source: California Energy Commission

Simply extending electricity demand for 2025 – 2030 and beyond based on forecasted trend growth from 2020 to 2024 may be misleading, however, because of uncertainty about the effects of various factors during the preceding decade. Several of these uncertainties relate to the magnitude of possible reductions in electricity demand, including:

- Development of new energy efficiency technologies, increased expenditures on utility efficiency programs, and increased adoption of efficiency measures because of higher electricity prices could lead to greater energy efficiency savings during the next two decades. While there is substantial technical potential for energy efficiency savings through 2030, the extent to which these savings will be realized is uncertain.
- Zero-net-energy requirements for new residential construction are expected to result from the 2020 building efficiency standards. The extent of savings by 2030 will depend on compliance rates and the extent to which the zero-net-energy target is met by energy efficiency savings rather than onsite solar photovoltaic generation. While the change in grid-supplied energy is unaffected by the latter consideration, the daily ramps that central-station generation, demand response programs, and storage must meet are altered.
- While a million new homes may be built during 2020 – 2030, energy efficiency savings of the magnitude needed to meet long-run GHG emission reduction goals will require

substantially reduced energy use in many more existing buildings, including rented and leased space.

- Development of efficient combined heat and power (CHP), a component of both the *Climate Change Scoping Plan* from Assembly Bill 32 (Núñez, Chapter 488, Statutes of 2006) and the Governor's Clean Energy Jobs Plan, could reduce the demand for grid-provided energy. Although estimates of economic potential are substantial,[443] the CPUC's assumption in its 2012 Long Term Procurement Planning proceeding—that there will be no incremental CHP development through 2022—reflects the numerous obstacles that CHP developers currently face. On the other hand, the return of cogenerators to utility service would increase the demand for electricity from utility-owned and merchant generators.~~On the other hand, the return of cogenerators to utility service would increase the demand for electricity from utility-owned and merchant generators.~~

Other uncertainties related to possible increases in electricity demand include the following:

- The ~~Energy Commission's 2013 preliminary~~ demand forecast assumes increased deployment of full electric and plug-in hybrid electric vehicles— more than 2 million vehicles by 2024~~ consuming 6,113 GWh~~. Although costs are expected to fall and performance characteristics improve, deployment through 2030 remains uncertain. ~~In addition, demand may increase with the development of high-speed rail and zero-energy vehicles for use in ports and goods transport.~~
- Electrification of the industrial sector to meet long-term GHG emission reduction goals is expected to accelerate as carbon prices rise and will at least partially offset any efficiency improvements. The extent to which this will occur by 2030 is uncertain, as is the role that nonutility supply—solar process heating and CHP—will play in meeting increased demand.
- Growth in demand from other sources such as plug loads and potential new sources such as desalination may markedly increase the demand growth rate.
- The effect of climate change on electricity demand will increase from 2025 – 2030, with higher average temperatures and more frequent extreme heat events increasing average and peak electricity demand, respectively.

Electricity Supply Through the Early 2020s

If electricity demand grows as slowly over 2024 – 2030 as indicated in Figure 35, the likely generation portfolio in 2024 provides an informative starting point for envisioning the system in 2030. This requires consideration of the renewable portfolio that is expected to meet the 33 percent RPS in the early 2020s, the nonrenewable resources to be added to provide reliable service given the retirement of San Onofre and once-through cooled facilities in southern California, and any additional resources needed to integrate intermittent renewable generation.

443 ICF International, *Combined Heat and Power: Policy Analysis and 2011-2030 Market Assessment*, February 2012, CEC-200-2012-002. The mid-case presented by ICF indicates a potential 13,730 GWh reduction in retail sales in 2030, the result of 3,443 MW of CHP generating at an 80 percent capacity factor with slightly more than 50 percent of the generation being consumed on site.

Renewable Development through the Early 2020s

Table 23 shows California's RPS-eligible renewable portfolio as of ~~the beginning of~~year-end 2012~~3~~. Slightly more than 35~~20~~ percent of this energy, 15,2~~1,6~~00 GWh, comes from resources that came on-line in 2012 and 2013.

~~Based on the Energy Commission's 2013 preliminary demand forecast, the~~Projections for meeting ~~projected energy required to meet~~ the 33 percent RPS in 2024 estimate that ~~will require~~ an additional ~~27,100~~13,154 GWh to ~~31,400~~37,427 GWh of renewable energy is needed.[444] The forecast projects that these resources will be accompanied by the development of an additional 3,000 MW of solar photovoltaics on the customer side of the meter, bringing the statewide total to an estimated 4,730 MW that will generate about 7,920 GWh of energy.

Table ~~20~~23: California's RPS Portfolio, December 2012

Technology	Projected Annual Energy (GWh)		
	In-State	Out-of-State	Total
Solar	8,272	1,415	9,687
Wind	13,404	8,158	21,562
Geothermal	12.790	1,198	13.988
Biofuels	6,982	562	7,544
Small Hydro	5,294	40	5,334
Total	**46,742**	**11,372**	**58,115**

Source: California Energy Commission. The figures do not include customer-side-of-the-meter solar photovoltaics (PV), installed as part of the California Solar Initiative and publicly-owned utility programs, estimated to be 1,596 MW, (http://www.californiasolarstatistics.ca.gov/, June 30, 2013) providing 2,420 GWh of energy (assuming a 17.1 percent capacity factor).

The CPUC and the Energy Commission have jointly developed renewable resource portfolios intended to reflect both environmental and land-use constraints and likely or potential development to satisfy the RPS during the current 10-year planning horizon. Under a May 2010 agreement, the agencies developed "commercial interest," "environmental," and "high distributed generation" portfolios, presented to stakeholders at a joint agency workshop in December 2012 for consideration in the California ISO's 2013/2014 Transmission Planning Process.[445] A majority of the renewable resources needed to meet the 33 percent RPS in 2020 have already been procured by the state's utilities and are under construction or about to begin.

444 The demand forecast coupled with the mid-case for additional energy efficiency yields an incremental need for renewable energy of 28,462 GWh. The development of 1,200 MW of new CHP resources beyond the small amount assumed in the forecast, assumed to operate at an 80 percent capacity factor and use the energy produced on-site, less line losses, reduces the renewable net short- the amount of renewable energy that remains to be procured to meet the RPS- to 26,289 GWh.

445 For a discussion of the development of these portfolios, see the letter from CPUC President Michael R. Peevey, Energy Commission Chair Robert B. Weisenmiller, and CPUC Commissioner Michael P. Florio to California ISO President and CEO Steve Berberich, February 7, 2013, available at http://www.caiso.com/Documents/2013-2014RenewablePortfoliosTransmittalLetter.pdf.

Others are likely—and assumed by planners—to be built, given CPUC-approved power purchase agreements with utilities and targets for such programs as the Renewable Auction Mechanism. The portfolio developed for use in Track 2 of the CPUC's 2012 LTPP proceeding is summarized in Table 24. This portfolio, like others developed for the CPUC's LTPP and Resource Adequacy proceedings and the California ISO's TPP, assumes development of a large amount of intermittent resources, especially solar.

Table 24: Projected Renewable Portfolio for California, 2022

Technology	Projected Annual Energy (GWh)			Nameplate Capacity (MW)
	In-State	Out-of-State	Total	
Solar	18,843	1,633	20,476	9,115
Wind	4,481	1,496	5,977	2,149
Geothermal	3,766	1,200	4,965	688
Biofuels	1,377	0	1,377	193
Small Hydro	0	0	0	0
Total	**28,468**	**4,328**	**32,796**	**12,144**

Source: California Energy Commission.

Nonrenewable Generation Development through the Early 2020s

~~Several studies are underway that will provide information for estimates of the need for nonrenewable generation resources in the California ISO balancing authority area through 2022.~~

<u>As noted in Chapter 4, the California ISO has undertaken several studies to estimate the potential need for gas-fired generation capacity in Southern California through 2020 due to: 1) the closure of San Onofre and 2) the retirement of gas-fired generation using once though cooling (OTC) in compliance with the policy established by the State Water Resources Control Board (SWRCB). These studies indicated replacement capacity needs of 4,100 MW – 5,500 MW in Los Angeles and San Diego, conclusions that are sensitive to assumptions regarding other, preferred resources that may reduce or satisfy capacity needs such as renewable generation, energy efficiency, demand response, CHP, and upgrades to the transmission system.</u>

~~The California ISO's 2012 LTPP Track 2 Studies estimate operational flexibility needs in 2022 given the expected portfolio of renewable resource additions. Expected to be completed in fall 2013, the studies will indicate the potential need for incremental operational flexibility given the retirements of San Onofre (2,246 MW) and OTC plants in both Northern and Southern California that have compliance deadlines through 2020 (11,524 MW) as well as expected retirements of other facilities in these areas before 2022. Building on this effort, the Energy Commission, CPUC, and California ISO staffs, in collaboration with Southern California Edison, South Coast Air Quality Management District (SCAQMD), San Diego Gas & Electric, the State Water Resources Control Board (SWRCB), and the California Air Resources Board, prepared a "Preliminary Reliability Plan for LA Basin and San Diego." The purpose of the plan is to ensure reliability in Southern California in light of the closure of San Onofre, the expected closure of 5,068 MW of gas-fired generation that uses OTC, and load growth. Recommendations from the~~

~~preliminary plan were presented by staff to the leaders of the state energy agencies, the California ISO, and SCAQMD during a workshop on September 9, 2013. Public comment will be taken and the plan will be revised as needed before it is submitted to the Governor.~~

Supply filings submitted by POUs outside of the California ISO's balancing authority area~~as part of the *2013 IEPR* proceeding by POUs in California's other balancing authority areas~~ indicate that new natural gas-fired resource development by these entities is expected to be minimal through 2020. The only major activity expected involves a change in the date of the Los Angeles Department of Water and Power's (LADWP's) divestiture of its Navajo entitlement (477 MW of coal) to the end of 2015.[446] The LADWP filing indicates that it expects to replace Navajo with a 300 MW combined-cycle facility.[447]

~~While these studies are not completed, it is likely that they will indicate that a substantial share of the capacity to be retired in the Los Angeles Basin and San Diego through 2020, perhaps 5,000 MW to 6,000 MW, will have to be replaced with flexible, dispatchable generation to meet local reliability needs.~~

Need for Operational Flexibility

As briefly discussed in previous chapters, the retirement of gas-fired power plants using OTC (discussed in Chapter 4 in the section on *The Need for New Electricity Infrastructure*) and the ramps created by a growing use of solar generation will lead to a need for increased operational flexibility through the mid 2020's (discussed in Chapters 2 and 4). Operational flexibility is provided through the availability of resources that can be started up quickly and ramp up and down as needed.

Various pathways are available for meeting the operational flexibility needs by 2024. Development of preferred resources such as targeted energy efficiency, demand response, storage, and in-basin renewable generation in the South Coast and San Diego basins could either reduce the need for operational flexibility or provide operational flexibility (for example, permanent load shifting or energy efficiency might reduce the evening peak while storage or demand response could act as flexible resources). Also, new gas-fired generation developed in Southern California to meet local reliability requirements could potentially provide enough operational flexibility to meet the growing need for flexible capacity. Alternately, the existing

446 http://www.ladwpnews.com/go/doc/1475/1727379/LADWP-Takes-Historic-Action-Toward-Clean-Energy-Future-for-Los-Angeles.

447 On December 3, 2013, the LADWP Board of Commissioners approved the purchase of the 527-MW, gas-fired Apex Power Project, a baseload resource located in Clark County, Nevada. The plant will provide replacement capacity for Navajo and assist in the integration of energy efficiency and renewable generation. An unspecified share of the plant's output will be available to other members of the Southern California .Public Power Authority. See California Energy Markets, No. 1261 (December 6, 2013), p. 11.

fleet of gas-fired resources could potentially provide the additional flexible capacity needed by reducing self-scheduling.[448]

Another option using existing resources is procurement of out-of-state generation from the regional energy imbalance market which will begin operation in 2014 (discussed further in Chapter 5 in the section on *Transmission Opportunities to Enable Higher Levels of Renewables*). ~~The California ISO's Track 2 study of operational flexibility needs in 2022 indicates that the expected amount of new solar generation on both the customer- and utility-side of the meter will create early-evening ramps of substantial size from November to March. This will result in up to 14,000 MW of load having to be met by dispatchable resources when solar output falls during late afternoon and early evening hours. The study also indicates the potential need to export energy during mid-morning hours in low-load months – months in which the Pacific Northwest has surplus hydroelectricity and the Southwest is meeting demand with coal resources, which cannot be turned off or ramped down. In addition, the "net load peak" – the point at which the need for dispatchable generation is greatest – is pushed back in summer months to 8:00 p.m. (an hour when very little solar generation is available) indicating that additional solar development, absent storage, would not markedly reduce the need for dispatchable capacity.~~

~~The CPUC and the California ISO are jointly developing ways to quantify the operational flexibility of generation and other resources such as demand response and storage, and to estimate the combined monthly system need for flexible resources, as well as resource adequacy protocols that will ensure California ISO control over the required amount of capacity. In the fall of 2014, the California ISO will inaugurate an energy imbalance market (EIM) that includes resources from both the California ISO and PacifiCorp balancing authorities. Resources bidding into this market will be scheduled on a 5-minute basis, which will increase the quantity and flexibility of resources the California ISO can draw on in real time to manage intrahour and longer ramps. The potential contribution of this market to meeting ramping requirements needs to be assessed to accurately estimate the amount of flexible generation available to California from out-of-state resources. Over the long term, technology advances and other factors will promote increased participation by demand response and energy storage resources in this and other markets (such as ancillary service markets), allowing for reduced need for gas-fired resources to balance the system.~~

Potential Supply Development From 2024 Through 2030

If electricity demand grows as slowly from 2024 – 2030 as indicated by the midcase for energy efficiency shown in Figure 35~~4~~, incremental capacity from nonrenewable sources to meet system wide and zonal reserve margins, local capacity requirements, and reliability needs will be

448 While generation owners can specify the price(s) at which the California ISO can induce changes in the amount of energy or ancillary services they provide, a self-scheduled generation resource does not specify such a price or prices, effectively precluding the California ISO from changing the amount delivered. For example, utilities—load-serving entities that own generation—will frequently self-schedule their own generation to satisfy their load and ancillary service requirements, thereby reducing the amount of capacity that the California ISO can (re)dispatch to meet operational needs.

driven as much by resource retirements as by changes in peak demand. The latter indicates an annual growth rate in electricity demand of 0.4 percent.

There are three major sets of retirements to be considered in the post-2020 period:

1. If Diablo Canyon is not relicensed in 2024 and 2025, the zero-carbon energy from 2,240 MW of generation capacity and an unknown share of the capacity itself will require replacement. The equivalent annual output of 17,300 GWh from an efficient fast-start, gas-fired, combined-cycle plant emits nearly 7 MMT CO_2.

2. LADWP and five smaller southern California POUs will have to replace the energy from their shares (1,777 MW) of the coal-fired Intermountain Generating Station in the late 2020s because of California's Emission Performance Standard. The utilities hope to accelerate the divestiture of their purchase obligations by two years: from 2027 to 2025, replacing a share of the energy with output from a natural gas plant that would replace all or part of the existing facility. The GHG emissions associated with California's share of the resource equal roughly 11 MMT CO_2; those associated with the replacement energy from the gas plant would be significantly smaller.[449]

3. LADWP units using once-through cooling technologies will have to comply with the SWRCB policy. Scattergood 1-2 (358 MW, end of 2024), Haynes 1-2 (444 MW, end of 2029), and the Harbor combined-cycle (215 MW, end of 2029) will likely be replaced with a comparable amount of efficient, flexible capacity onsite due to local reliability needs and the difficulties and costs associated with major transmission upgrades within the Los Angeles area that would allow for retirement without replacement.

Potential for Development of New ~~Nonrenewable~~ Zero- and Low-Carbon Technologies

Studies of pathways to a decarbonized electricity sector point to several generation technologies that may provide zero- or low-carbon electricity by 2050. These include coal and natural gas-fired generation using CCUS; nuclear generation, immature renewable technologies (offshore wind, tidal generation), and advanced biofuels, in addition to the mature technologies that make up the state's current renewable portfolio.[450]

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449 Average annual GHG emissions attributed to California utility shares of Intermountain over 2007 – 2010 were 10.86 MMT CO_2, according to the California Greenhouse Gas Emissions Inventory. Replacement of 50 percent of the energy from Intermountain with gas-fired generation and 50 percent with renewable energy would reduce the GHG emissions to 3.1 MMT CO_2.

450 In its study of potential resource portfolios for meeting 2050 GHG reduction goals, Energy and Environmental Economics, Inc. (E^3) presented various portfolios that relied upon renewable energy (74 percent of total energy), nuclear energy (55 percent), and fossil generation (natural gas and coal) with carbon capture and sequestration (CCS; 47 percent). See *Meeting California's Long-Tem Greenhouse Gas Reduction Goals*, Energy and Environmental Economics, Inc., November 2009. The California Council on Science and Technology develops similar portfolios in *California's Energy Future: The View to* 2050, California Council on Science and Technology, May 2011.

~~While advancement of immature technologies is all but certain by 2050, the pace at which it will occur is uncertain.~~ The rate at which coal- and natural gas-fired generation with CCUS and generation with advanced biofuels are developed will likely be influenced by the presence or absence of a national GHG policy, which would accelerate private sector research and development. Reductions in cost and improvements in CO_2 emitted per MWh (for CCUS technologies) will allow for the technology's widespread deployment by 2030.~~, it still may face public opposition.~~

Large-scale coal-fired generation with CCUS is at the demonstration and market-entry stage of development.[451] ~~It is unlikely that~~At this stage, existing coal plants, many of which will be 50 years old or more in 2030, ~~will be~~are not the best economic candidates for retrofitting with CCUS technology. However, according to the United States Environmental Protection Agency (U.S. EPA), CCUS can serve as an effective tool to reduce emissions in new coal- and gas-fired power plants. In proposed rules regulating new power plants, the U.S. EPA requires that new power plants burning coal use available clean energy technologies such as CCUS to reduce emissions.[452]~~Even if coal-fired generation with CCUS is cost-competitive with renewable resources by 2030, it is more likely that (1) such resources will be developed in neighboring states by local utilities in support of local loads, and (2) be supercritical and ultra-supercritical facilities that, due to engineering constraints, will have limited ability to cycle up and down in support of California's intermittent generation. Public opposition to "clean coal" in California may hamper its procurement. It is not unreasonable to imagine a future in which coal-fired generation with CCUS, while competitive with renewable generation with storage, is developed by out-of-state entities to exploit an indigenous resource but is largely rejected as an alternative by California because of incremental bulk transmission needs, questions regarding the integrity of sequestration, the desire to reduce the environmental impact and profitability of mining a fossil resource that is a candidate for export abroad, and a preference for renewable resources.~~

Natural gas-fired generation with CCUS is arguably a more likely candidate for widespread development in California by 2030. Estimates of the levelized cost of energy from such plants are 37 to 57 percent higher than the cost of conventional gas plants, requiring that a carbon price

451 The only utility-scale plant under construction in the United States is the Kemper County facility in Kemper County, Mississippi, which will produce 582 MW (524 MW gasified coal, 58 MW natural gas) when it comes on-line in 2014~~, at a cost of $6700/kW~~. The facility will capture and use 65 percent of its CO_2 emissions for enhanced oil recovery (EOR) in conjunction with long-term geologic storage. Hydrogen Energy of California (HECA) is seeking certification for an up to 43~~0~~0 MW (288 MW net) facility to be built at an estimated cost of $4.03 billion ~~($10,000/kW)~~. HECA also includes a fertilizer manufacturing plant and capture of 90 percent of its CO^2 emissions for EOR and long-term geologic storage.

452 U.S. EPA, *Standards for Performance for Greenhouse Gas Emissions from New Stationary Sources: Electric Utility Generating Units*, 40 CFR Part 60, http://www2.epa.gov/sites/production/files/2013-09/documents/20130920proposal.pdf.

be well above current levels to incentivize development.[453] CCUS costs are expected to fall, however, and a combination of high carbon prices and lower costs could lead to marked instate development by 2030. To the extent CCUS is developed, it is important that policies are in place to prevent the exploitation of resources, maintain the integrity of sequestration, and minimize environmental impacts.~~The farther CCUS development and operating costs decline, the lower the carbon price needed to encourage gas-with-CCUS development, and the lower the post-deployment carbon price will become.~~

Nuclear development in California is precluded by legislation, although California utilities can invest in out-of-state facilities. Public acceptance of nuclear generation in California is very low in the post-Fukushima era, and time lags for permitting and construction are very long, making development of nuclear resources by 2030 very unlikely. As noted above, the retirement of Diablo Canyon—whether due to operational concerns or a decision not to relicense it in 2024-2025—is a risk that must be managed.

~~Given the uncertainties associated with the deployment of fossil-fueled generation with CCUS and nuclear generation, further reductions in GHG emissions from 2024 to 2030 may have to come from the renewable technologies relied upon today.~~

Renewable Development from 2024 – 2030

When extrapolated to 2030, the Energy Commission's 2013 *California Energy Demand Final Forecast 2014-2024* ~~preliminary demand forecast~~ mid-case forecast and achievable energy efficiency scenarios jointly yield estimates of renewable energy needs in 2030 under a 33 percent RPS that are only slightly higher than in 2020 (Table 25; the values in parentheses represent the incremental renewable energy needed during the post-2020 period to meet different RPSs in 2030 and 2040).

The incremental renewable energy needed to maintain a 33 percent RPS during 2020 – 2030 is small because load growth is projected to be low due to a combination of slower population growth, the development of customer-side distributed generation, and energy efficiency savings. The incremental renewable energy needed to reach a 40 percent RPS, roughly 23~~5~~,000 GWh, is not substantial compared to the procurement of renewable energy over the past several years. Table 26 provides the MW of capacity that would be needed to provide 23~~5~~,000 GWh of energy from various renewable technologies.

453 Edward S. Rubin and Haibo Zhai, *The Cost of CCE for Natural Gas-Fired Power Plants*, presentation to the 10th Annual Conference on Carbon Capture and Storage, May 3, 2011.

Table 25: Renewable Energy Needs in 2030 by RPS Percentage, GWh

Year/RPS Target	Mid EE Case (GWhs)
2020 / 33%	85,043
2030 / 33%	88,866 (3,823)
2030 / 40%	107,716 (22,973)
2030 / 50%	134,645 (49,602)

Source: California Energy Commission. Numbers in parentheses represent estimated incremental renewable energy needs compared to 2020/33 percent.

Table 26: Capacity Needed to Provide 24,008 GWh of Energy, Selected Renewable Technologies

Technology	Capacity Factor	Required MW
Distributed Solar	24%	10,784
Central Station Solar	28%	9,244
Wind	32%	8,088
Geothermal	80%	3,235
Biomass/Biomethane	85%	3,045

Source: California Energy Commission

While the amount of incremental renewable energy procured in going from a 33 percent RPS in 2020 to a 40 percent RPS in 2030 is not large, acquiring a significant share of this energy from solar resources will exacerbate the operational concerns identified in the California ISO Track 2 Study. Developing such resources on the utility side of the meter will be in addition to customer-side distributed solar ~~projected~~ assumed to be developed in the 2013 *California Energy Demand Final Forecast 2014-2024*~~preliminary demand forecast~~ and capacity expected to be added as a result of zero-net-energy regulations arising out of 2020 standards for new home construction. It is questionable whether this level of development can occur without developing significant amounts of complementary resources, the most effective of which will be energy storage that is capable of absorbing energy during other hours, including the morning down-ramp, for use during the net peak hours of the early- and mid-evening.

Primary Research Topics for 2030 Analysis

Electricity system needs in 2030 are likely to resemble those of today. Without technological advances that would allow for the widespread deployment of such zero- and low-carbon generation technologies as coal-fired generation with CCUS, nuclear, and advanced biofuel generation until 2030 and beyond, increasing amounts of "conventional" renewable generation will likely be relied upon to achieve interim GHG emission reductions from the electricity sector. To the extent that these resources are predominantly intermittent, they will increasingly need to be accompanied by technologies such as gas-fired generation with CCUS, energy storage, or demand response to minimize the development and use of high GHG-emitting resources.

Uncertainties point to the importance of additional ~~the following~~ analysis to accurately assess ~~more accurately~~ possible resource needs through 2030, given increased deployment of intermittent generation resources. The scope of further 2030 analyses is discussed in more detail in the California Air Resources Board's *Climate Change Scoping Plan First Update*.

- ~~Development of reasonable bounding estimates for load growth over 2025 – 2030, including scenarios for the impact of zero-net-energy regulations arising from 2020 building standards for new home construction, specifically the extent to which energy use will be reduced though 2030 by energy efficiency measures as opposed to being offset by onsite generation, as these have different implications for complementary resource needs. Development of similar estimates for energy efficiency savings associated with existing buildings is needed; potential savings based on the number of existing buildings are much larger than for new construction, but more difficult to realize.~~
- ~~Estimation of changes in the net load shapeas solar is increasingly deployed over time, and its implication for the following:~~
    - ~~The quantity of complementary resources needed to meet morning and afternoon ramping requirements.~~
    - ~~Surplus generation.~~
    - ~~Hourly wholesale electricity prices and the value of specific energy efficiency programs, for example lighting, that would reduce demand in higher-priced and higher-ramp hours.~~
- ~~Estimation of gas-fired generation capacity that will be built to replace San Onofre, retiring OTC facilities, and other generation expected to retire through 2030.~~
- ~~Assessment of the potential for dispatchable resources in other California balancing authority areas and neighboring states to provide load-following services to the California ISO through an energy imbalance market during periods of the year and times of day in which they are most needed. The contributions of gas-fired generation in the Southwest during early evening hours, for example, may obviate the need for new capacity in California solely for the integration of intermittent renewable resources until sufficient energy storage can be developed. This assessment consists of evaluating both the surplus capacity in neighboring states that is likely to be available to participate in California markets and the need for internal generation and limits on imports into California during high-ramp hours. Similarly, increased renewable resource development in the remainder of the West can assist in balancing the California system with zero-carbon resources, to the extent that out-of-state resources have an output profile that compliments that of renewable resources in California.~~
- ~~The ability of neighboring states to absorb any excess energy that California may generate.~~

Recommendations

The Energy Commission supports the Governor's *Climate Change Consensus Document*[454] and recommends the following actions to help reduce the adverse effects of climate change to California's energy infrastructure:

- **Sponsor research on regional climate projections, energy sector vulnerability, and ~~adaptation~~ strategies to reduce climate risk.** Continue to sponsor climate change research on regional climate projections, the vulnerability of the energy sector, and ~~adaptation~~ strategies to reduce climate risk.
- **Fund research, development, and demonstration for technologies that reduce greenhouse gas emissions.** ~~Continue funding research, development, and demonstration on technologies that reduce greenhouse gas emissions and that need~~Continue funding public-interest research, development, and demonstration on technologies that reduce California's greenhouse gas emissions. ~~public support in California.~~
- **Support actions that provide both reductions in GHG emissions and preparation for climate risks~~climate change mitigation and adaptation benefits~~**. California should emphasize climate mitigation actions to reduce greenhouse gas emissions that also make the energy system more resilient, reliable, and efficient in the face of climate change.
- **Expand support for Cal-Adapt and CaLEAP tools that assist local planning.** Sustain and expand Cal-Adapt (a web-based interactive visualization tool developed to convey the risks of climate change to local decision makers and Californians who live in affected communities) and CaLEAP (a program that local governments use in preparing plans to ensure that key assets are resilient to disasters that affect energy). These tools have proven to be valuable aids to local communities in planning for climate change.
- **Assess the vulnerability of transportation fuel infrastructure to climate change.** The Energy Commission will assess the vulnerability of the transportation fuel infrastructure, such as refineries, pipelines, marine terminals, underground storage tanks, and fueling stations, to extreme weather events and other climate impacts.
- **Continue to coordinate climate change research by California agencies.** The Energy Commission will continue to provide coordination support to climate change research sponsored by state agencies in California via the Climate Action Team Research Working Group.
- **Support development of greenhouse gas reduction targets for 2030 and metrics to track progress.** The Energy Commission will work with the California Air Resources Board to develop potential greenhouse gas reduction strategies and goals for 2030 as part of the *Climate Change Scoping Plan First Update* development process. The agencies will also jointly develop metrics to track progress against the *Scoping Plan*.

454 http://mahb.stanford.edu/consensus-statement-from-global-scientists.

ACRONYMS

AAEE	—	Additional Achievable Energy Efficiency
AQIP	—	Air Quality Improvement Program
AQMD	—	air quality management district
ARB	—	California Air Resources Board
ARFVTP	—	Alternative and Renewable Fuel and Vehicle Technology Program
ASME	—	American Society of Mechanical Engineers
BAMx	—	Bay Area Municipal Transmission Group
BCF	—	billion cubic feet
BLM	—	Bureau of Land Management
BTU	—	British thermal unit
CAL	—	Confirmatory Action Letter
CaLEAP	—	California Local Energy Assurance Planning
California ISO	—	California Independent System Operator
CBD	—	Center for Biological Diversity
CCCCO	—	California Community Colleges Chancellor's Office
CCUS	—	carbon capture, utilization, and sequestration
CEQA	—	California Environmental Quality Act
CHP	—	combined heat and power
CMUA	—	California Municipal Utilities Association
CNG	—	compressed natural gas
CPUC	—	California Public Utilities Commission
DATC	—	Duke-American Transmission Company
DAWG	—	Demand Analysis Working Group
DE	—	design earthquake
DDE	—	double design earthquake
DFA	—	Development Focus Area
DGE	—	Diesel Gallon Equivalents
DOE	—	U.S. Department of Energy
DRECP	—	Desert Renewable Energy Conservation Plan
DRRC	—	Demand Response Research Center
EDD	—	Employment Development Department
EIA	—	Energy Information Administration
EIM	—	energy imbalance market
EIR	—	Environmental Impact Report
EIS	—	Environmental Impact Statement
EM&V	—	evaluation, measurement, and verification

EPA — Environmental Protection Agency
ERC — emission reduction credit
ETP — Employment Training Panel
FERC — Federal Energy Regulatory Commission
FIT — feed-in tariff
GEIS — Generic Environmental Impact Statement
GGE — gasoline gallon equivalents
GHG — greenhouse gas
GHP — geothermal heat pump
GIDAP — Generator Interconnection and Deliverability Allocation Procedures
GMC — ground motion characterization
GWh — gigawatt hour(s)
HERS — Home Energy Rating System
HVAC — heating, ventilation, and air conditioning
HVDC — high-voltage direct current
IDSM — Integrated Demand Side Management
IEPR — *Integrated Energy Policy Report*
IID — Imperial Irrigation District
IOU — Investor-owned utility
IPRG — Independent Peer Review Group
ISFSI — Independent Spent Fuel Storage Installation
LADWP — Los Angeles Department of Water and Power
LCFS — Low Carbon Fuel Standard
LCOE — Levelized Cost of Energy
LNG — liquefied natural gas
LTPP — Long Term Procurement Plan
LTSP — Long Term Seismic Program
MAOP — maximum allowable operating pressures
MM — Million
MMth — million therms
MW — megawatt(s)
NAS — National Academy of Sciences
NEPA — National Environmental Policy Act
NERC — National Electricity Reliability Council
NOx — oxides of nitrogen
NRC — Nuclear Regulatory Commission
NREL — National Renewable Energy Laboratory
NTTF — Near-Term Task Force

OII	—	Order Instituting Investigation
OIR	—	Order Instituting Rulemaking
OTC	—	once-through cooling
PGC	—	public goods charge
PG&E	—	Pacific Gas and Electric
POU	—	publicly owned utility
PPA	—	power purchase agreement
PSIG	—	pounds per square inch gauge
PV	—	photovoltaic
PSHA	—	probabilistic seismic hazard analysis
RAC	—	Refiner Acquisition Cost
RAI	—	request for additional information
RAM	—	Renewable Auction Mechanism
RCCo	—	reliability coordination company
RE	—	reliability entity
REAT	—	Renewable Energy Action Team
ReMAT	—	Renewable Market Adjusting-Tariff
RFS	—	Renewable Fuels Standard
RIN	—	renewable identification number
RPS	—	Renewables Portfolio Standard
RRTT	—	Rapid Response Team for Transmission
SAB	—	Science Advisory Board
SCAQMD	—	South Coast Air Quality Management District
SCE	—	Southern California Edison Company
SDG&E	—	San Diego Gas & Electric Company
SFP	—	Secondary Financial Protection
SMUD	—	Sacramento Municipal Utility District
SNF	—	spent nuclear fuel
SSC	—	seismic source characterization
SSCs	—	systems, structure, and components
SSHAC	—	Senior Seismic Hazard Analysis Committee
SWRCB	—	State Water Resources Control Board
SWUS	—	Southwest United States
TDV	—	Time-Dependent Valuation
TPP	—	Transmission Planning Process
TRTP	—	Tehachapi Renewable Transmission Project
TTG	—	Transmission Technical Group
TWE	—	TransWest Express Transmission Project

U.S. EPA	—	United States Environmental Protection Agency
VEA	—	Valley Electric Association
WECC	—	Western Electricity Coordinating Council
WREGIS	—	Western Renewable Energy Generation Information System
WSP	—	Westlands Solar Park Master Plan
~~**WTI**~~	~~—~~	~~West Texas Intermediate~~
WWD	—	Westlands Water District
ZEV	—	zero-emission vehicle
ZNE	—	zero-net-energy

GLOSSARY

Ancillary services market	The market for services needed to maintain system reliability
AutoDR	Short for automated demand response, refers to reducing or shutting down loads automatically through use of technology, rather than manual switching operations
Benchmarking	A measurement of the quality of an organization's policies, programs, or strategies, and the comparison with standard measurements or similar measurements of its peers
Building commissioning	The process of verifying, in new construction, all of the subsystems achieve the owner's project requirements as intended by the building owner and as designed by architects and engineers
Closed-loop geothermal system	System that continually circulates the same water and antifreeze solution through a closed loop
Cost-effectiveness protocols	Method to measure the cost-effectiveness of demand response programs, intended for evaluations of programs which provide long-term resource value
Direct load control	Activities that can interrupt load at the time of peak by interrupting power supply on consumer premises, usually applied to residential customers
Flexible resources	Resources that generate cost in proportion to the amount used
Load impact protocols	Protocols the California Public Utilities Commission uses to provide input on determining demand response cost-effectiveness and to assist in resource planning and long-term forecasting
Local capacity area requirements	Minimum quantity of local capacity necessary to meet the local capacity requirement criteria
Megajoule	Unit of energy expended in applying a force of one newton through a distance of one meter
Once-through cooling	Water that is withdrawn from the ocean or other water body is passed through a steam condenser one time, then returned to the water body some distance from the intake

OpenADR	Short for open *automated demand response*, this research and standards development effort for energy management is typically used to send information and signals to cause electrical power-using devices to be turned off during periods of high demand
Open-loop geothermal system	System that uses well or surface body water as the heat exchange fluid, returning it to the ground once it has circulated through the system
Port electrification	The process of transforming the power sources of the port from internal combustion to electricity
Reach standards	Standards in addition to efficiency levels that should be installed in any building project striving to be considered a "green" building
Rule 21	Formal language outlining the requirements for interconnection at the Distribution System level that applies to electric utilities in California that are under the jurisdiction of the California Public Utilities Commission
Rule 1315	South Coast Air Quality Management District rule that enables the district to replenish the District Account by allowing them to harvest as needed the 0.2 of the 1:2:1 offset ratio imposes by Rule 1303 on all offsets surrendered
Standard Capacity Product	Provides a mechanism that offers an incentive or disincentive to a resource based on resource availability, reflecting whether it is providing the capacity value that it was procured for
Synchronous condenser	A specialized synchronous motor whose shaft is not attached to anything, but spins freely, and whose purpose is to adjust conditions on the electric power transmission grid
Telemetry requirements	Requirements for automatic measurement and transmission of data by wire, radio, or other means from remote sources to receiving stations for recording and analysis
Time-dependent valuation	An alternative to source energy as the currency for evaluating building energy performance, time-dependent valuation accounts for when energy is used.
Time value of service	The value electricity customers place on the electricity used at a given time

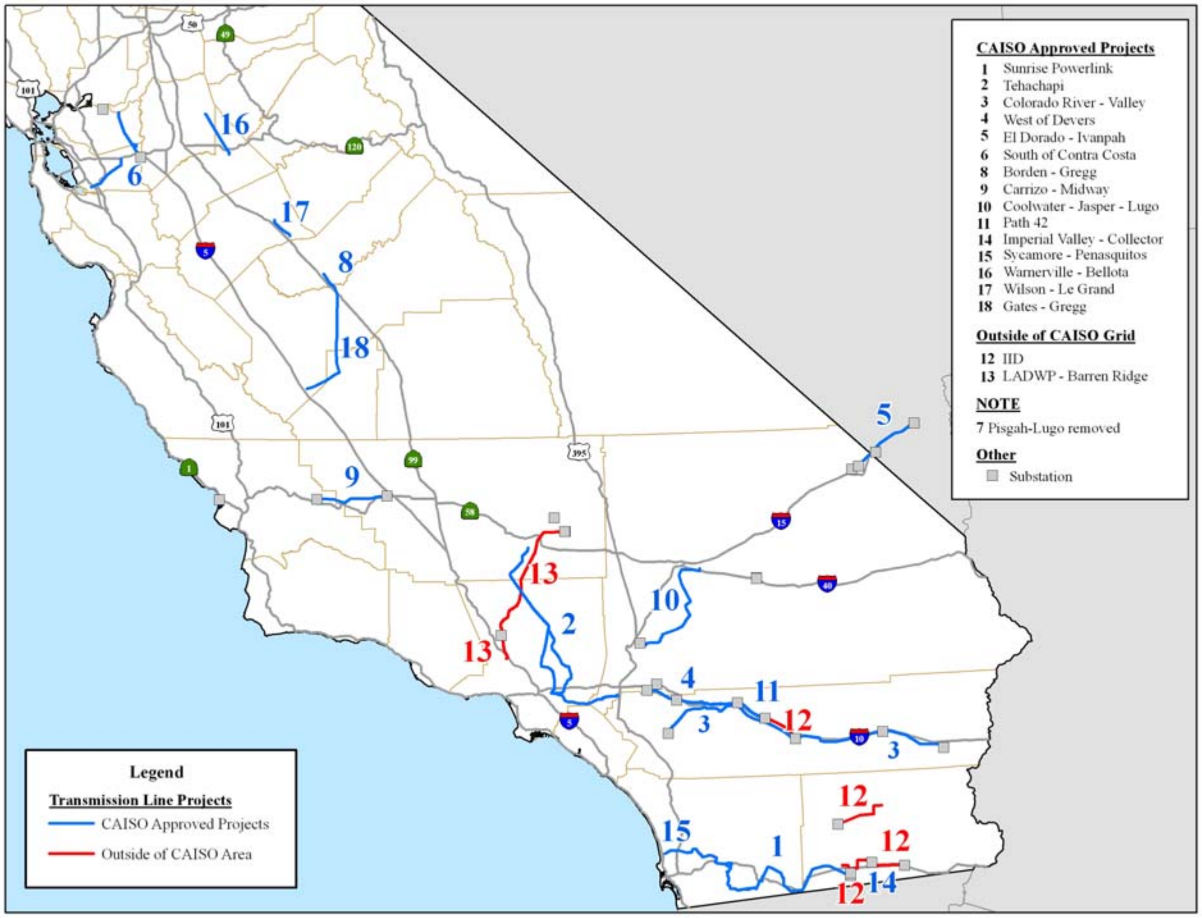
Truck stop electrification	The process of transforming the power sources of a truck stop from internal combustion to electricity
Use-limited resources	Resources that have operational or environmental restrictions that limit production hours but can operate for a minimum set of consecutive trading hours

APPENDIX A: Detailed Description of Approved Transmission Line Projects

As noted in Chapter 5, the California Independent System Operator (California ISO), the Imperial Irrigation District (IID) and the Los Angeles Department of Water and Power (LADWP) have identified and approved 17 transmission projects for the integration of renewable resources that will enable California to meet its 33 percent Renewables Portfolio Standard (RPS) goal by 2020. The status of these transmission projects are posted on the Energy Commission website.[455] Below are detailed descriptions of each project and key dates throughout the approval process. The projects are in presented in the same order as the spreadsheet posted on the website. The map below shows the approximate location of each transmission project.

455 The status of each transmission project is posted on the Renewables/Tracking Progress/Transmission Expansion page of the Energy Commission website at http://www.energy.ca.gov/renewables/tracking_progress/.

Figure A-1: Map of California ISO, IID and LADWP Approved Transmission Projects



Source: California Energy Commission

Sunrise Powerlink (1)

Description

On June 17, 2012, SDG&E completed construction and energized the 117-mile 500 kV Sunrise Powerlink transmission line that increases the import capability into San Diego from the renewable energy-rich Imperial Valley. Sunrise Powerlink combined with the Imperial Valley (IV) Collector Station and IV-Collector transmission line and Sycamore-Peñasquitos projects (discussed below), will increase the import capability by an additional 1,000 MW for a total of 1,700 MW. As of June 7, 2013, the California ISO Interconnection Queue[456] includes 2,045 MW of active renewable generation projects in Imperial County that can interconnect to the Sunrise Powerlink and provide power to SDG&E and the rest of California. More than 7,000 MW of

456 California ISO Interconnection Queue is located on the California website at http://www.caiso.com/planning/Pages/GeneratorInterconnection/Default.aspx.

renewable generation projects in Imperial County have withdrawn from the California ISO's queue. The Imperial Irrigation District's interconnection queue consists of 17 projects with proposed generation of 1,099 MW that could also use the Sunrise Powerlink.[457]

Key Dates

August 3, 2006: California ISO Board of Governors approved project.
August 4, 2006: SDG&E filed application with CPUC for a CPCN.
December 18, 2008: CPUC issued Decision 08-12-058[458] approving project.
January 20, 2009: BLM issued Record of Decision[459] approving project.
July 13, 2010: USFS issued Record of Decision[460] approving project.
December 9, 2010: SDG&E started construction.
June 17, 2012: In-service date.

Imperial Valley (IV) Collector Station and IV-Collector Line (14)

Description

In coordination with IID, the California ISO identified a policy-driven project with capital costs under $50 million for the Imperial Valley Area in the board-approved *2012-2013 Transmission Plan*.[461] The project was identified to help resolve transmission development and permitting issues, as well as commercial concerns of generators who desire to interconnect directly to the California ISO grid.[462] The elements of the project include an Imperial Valley 230 kV Collector Station and a 230 kV transmission line, about one mile, that will connect the Collector Station to the existing Imperial Valley Substation. The Collector Station and transmission line will provide

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457 Jamie Asbury, Imperial Irrigation District, comments on *2013 IEPR – Transmission Planning and Permitting Issues*, Docket No. 13-IEP-1E, May 21, 2013, p. 1, http://www.energy.ca.gov/2013_energypolicy/documents/2013-05-07_transmission_workshop/comments/Imperial_Irrigation_District_Comments_re_Transmission_Planning_and_Permitting_Issues_2013-05-21_TN-70922.pdf.

458 The CPUC Decision 08-12-058 approving the Sunrise Powerlink project can be found on the CPUC website at http://www.cpuc.ca.gov/environment/info/aspen/sunrise/D08-12-058.pdf.

459 BLM Record of Decision approving Sunrise Powerlink can be found on CPUC website at http://www.cpuc.ca.gov/environment/info/aspen/sunrise/rod.pdf.

460 USFS Record of Decision approving Sunrise Powerlink can be found on USFS website at http://www.fs.usda.gov/Internet/FSE_DOCUMENTS/stelprdb5320675.pdf.

461 California ISO Board approved 2012-2013 Transmission Plan, p. 12, http://www.caiso.com/Documents/BoardApproved2012-2013TransmissionPlan.pdf.

462 Jamie Asbury, Imperial Irrigation District, comments on *2013 IEPR* – Transmission Planning and Permitting Issues, Docket No. 13-IEP-1E, May 21, 2013, p. 2, http://www.energy.ca.gov/2013_energypolicy/documents/2013-05-07_transmission_workshop/comments/Imperial_Irrigation_District_Comments_re_Transmission_Planning_and_Permitting_Issues_2013-05-21_TN-70922.pdf.

an efficient means by which generation in the California ISO queue located in Imperial Valley can move forward to commercial operation. The project is contingent upon IID upgrading the IV-El Centro line (S line) and looping it into the new Collector Station. The IID upgrade will enhance its ownership rights at the IV substation. The Imperial Valley Collector Station and transmission line qualify for the competitive solicitation process.

Phase 3 of the California ISO's transmission planning process includes a competitive solicitation process for policy-driven and economically driven transmission projects, as well as for reliability-driven projects that provide additional policy and economic benefits. The bid window, where project sponsors can submit proposals to finance, construct, and own the IV Collector Station and IV-Collector line, was open from December 19, 2012, through February 19, 2013. On February 25, 2013, the California ISO posted the list of project sponsors that submitted proposals.[463] On July 11, 2013, the California ISO selected the Imperial Irrigation District as the approved project sponsor and accepted IID's offer of a cost cap of $14.3 million to construct the project.[464] The selected project sponsor will submit applications to state and federal regulatory agencies requesting project approval. California ISO's expected in-service date is no later than 2015.

Key Dates

December 14, 2012: California ISO management approved the project following a briefing to the California ISO Board of Governors.[465]
December 19, 2012 through February 19, 2013: Competitive solicitation bid window open.
February 25, 2013: California ISO posted the list of project sponsors that submitted proposals.
July 11, 2013: California ISO selected IID as the project sponsor.
No later than 2015: Expected in-service date.

Sycamore-Peñasquitos (15)

Description

The California ISO identified a policy-driven need for a 230 kV transmission line between SDG&E-owned Sycamore and Peñasquitos substations in its recently board-approved *2012-2013*

463 The list of project sponsors that submitted proposals for the IV Collector Station and IV-Collector line project can be found on the California ISO website at http://www.caiso.com/planning/Pages/TransmissionPlanning/2012-2013TransmissionPlanningProcess.aspx.

464 The California ISO's *Imperial Valley Policy Element Project Sponsor Selection Report* can be found on the California ISO website at http://www.caiso.com/Documents/ImperialValleyPolicyElement-ProjectSponsorSelectionReport_Jul11_2013.pdf.

465 The California ISO management briefing to the Board of Governors on the Imperial Valley Area policy driven transmission elements can be found on California ISO website at http://www.caiso.com/Documents/BriefingImperialValleyAreaPolicy-DrivenTransmissionElementsUnder50Million-Presentation-Dec2012.pdf.

Transmission Plan.[466] The policy-driven line will ensure delivery of generation needed to meet the 33 percent RPS as well as reliability benefits to the San Diego area. As part of the 2012-2013 Transmission Planning Process, the California ISO examined the reliability impact without the Diablo Canyon Power Plant (Diablo Canyon) and San Onofre Nuclear Generating Station (San Onofre). This study identified several transmission system upgrades that, in addition to generation replacement and mitigation measures already underway, would help manage future unplanned extended outages to the San Onofre plant. The upgrades included the installation of 650 MVAR of dynamic reactive support near the San Onofre and the Sycamore-Peñasquitos project. Construction of this project becomes more important in light of SCE's June 7, 2013, announcement of its decision to permanently retire San Onofre Units 2 and 3.[467] The project is eligible for competitive solicitation.

Phase 3 of the California ISO's transmission planning process includes a competitive solicitation process for policy-driven and economically driven transmission projects, as well as for reliability-driven projects that provide additional policy and economic benefits. The bid window, where project sponsors can submit proposals to finance, construct, and own the Sycamore-Peñasquitos 230 kV line, is open from April 1, 2013, through June 3, 2013. On June 6, 2013, the California ISO posted the list of project sponsors that submitted proposals for the Sycamore-Peñasquitos project.[468] The selected project sponsor will submit applications to state and federal regulatory agencies requesting project approval. California ISO's expected in-service date is 2017.

Key Dates

March 20, 2013: California ISO Board of Governor approved the *2012-2013 Transmission Plan.*
April 1, 2013, through June 3, 2013: Competitive solicitation bid window open.
June 6, 2013: California ISO posted the list of project sponsors that submitted proposals.
2017: Expected in-service date.

Tehachapi Renewable Transmission Project (2)

Description

SCE's Tehachapi Renewable Transmission Project (TRTP) will provide the electrical facilities necessary to integrate 4,500 MW of wind generation in Eastern Kern County to the Los Angeles Basin and accommodate planned or future solar and geothermal projects. TRTP addresses

466 California ISO Board approved *2012-2013 Transmission Plan*, pp. 296 and 374, http://www.caiso.com/Documents/BoardApproved2012-2013TransmissionPlan.pdf.

467 SCE's news release can be found on SCE website at http://edison.com/pressroom/pr.asp?id=8143.

468 The list of project sponsors that submitted proposals for the Sycamore-Peñasquitos project can be found on the California ISO website at http://www.caiso.com/Documents/List-ProjectSponsorProposalsReceived-SycamoreCanyon_Penasquitos230kVLineProposedPolicyDrivenElement.pdf.

reliability needs of the California ISO-controlled grid due to projected load growth in the Antelope Valley and the South of Lugo transmission constraints in Hesperia, California. TRTP 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. SCE submitted two applications to the CPUC for authorization to construct segments 1-3 (formerly known as Antelope-Pardee Transmission Project) and segments 4-11.

On October 17, 2011, SCE filed a Petition for Modification of Decision 09-12-044[469] to address the Federal Aviation Administration's (FAA) recommendations near Chino airport for segment 8, Phase 3. On April 11, 2013, the CPUC and U.S. Forest Service prepared a draft supplemental environmental impact report/environmental impact statement (Draft SEIR/SEIS)[470] for the proposed changes to the TRTP requested in SCE's Petition for Modification of Decision 09-12-044.

On November 10, 2011, the CPUC issued Decision 11-11-020[471] granting a construction stay for Segment 8A within Chino Hills, as modified on July 12, 2012, by the Decision 12-03-050.[472] The ruling of the Assigned Commissioner will continue until the CPUC makes a final determination on undergrounding options. Segment 8A undergrounding options are not the subject of the SEIR/SEIS. In April 2013, the Segment 8A undergrounding evidentiary hearings at the CPUC concluded. On June 11, 2013, CPUC Administrative Law Judge (ALJ) Jean Vieth issued Proposed Decision[473] denying the City of Chino Hills' petition for modification of Decision 09-12-044 regarding Segment 8A of TRTP finding that while the undergrounding of a transmission line is feasible, the cost is prohibitive and should not be borne by ratepayers. At the same time, President Michael Peevey issued an Alternate Proposed Decision[474] granting the City of Chino Hills' petition and ordering SCE to construct an underground, single-circuit, cross-linked polyethylene (XLPE) system, UG5, in Segment 8A. On July 11, 2013, the CPUC voted in favor of President Peevey's Alternate Proposed Decision and released the construction stay. The decision requires SCE to underground Segment 8A, a 3.5-mile, 500 kV transmission line, and

469 SCE's Petition for Modification of Decision 09-12-044 can be found on the CPUC website at ftp://ftp.cpuc.ca.gov/gopher-data/environ/tehachapi_renewables/PetForMod_2.pdf.

470 SCE and USFS Draft SEIR/SEIS can be found on the CPUC website at http://ftp.cpuc.ca.gov/gopher-data/environ/tehachapi_renewables/DSEIRS/Index.htm.

471 CPUC Decision 11-11-020 can be found on the CPUC website at http://docs.cpuc.ca.gov/word_pdf/FINAL_DECISION/151130.pdf.

472 CPUC Decision 12-03-050 can be found on the CPUC website at http://docs.cpuc.ca.gov/word_pdf/FINAL_DECISION/162534.pdf.

473 CPUC ALJ Vieth's Proposed Decision can be found on the CPUC website at http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M066/K068/66068597.PDF.

474 CPUC President Peevey's Alternate Proposed Decision can be found on the CPUC website at http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M065/K706/65706074.PDF.

remove the previously installed towers.[475] The expected in-service date for the remaining segments is late 2015 or early 2016.[476]

Key Dates

Segments 1-3

December 9, 2004: SCE filed application with CPUC for a CPCN.
January 11, 2005: SCE filed special use application with U.S. Forest Service.
March 1, 2007: CPUC issued Decision 07-03-012[477] approving the project.
August 23, 2007: USFS issued a Record of Decision[478] approving project.
2008: SCE started construction.
December 2009: Segments 1, 2, and 3A in-service.
Spring 2012: Construction started on 3B.
Fall 2012: Segment 3B in-service.

Segments 4-11

January 24, 2007: California ISO Board of Governors approved project.
June 29, 2007: SCE filed application with CPUC for a CPCN.
June 29, 2007: SCE filed special use application with U.S. Forest Service.
December 17, 2009: CPUC issued Decision 09-12-044 approving the project.
April 2010: SCE started construction.
October 4, 2010: USFS issued a Record of Decision approving project.
October 17, 2011: SCE filed a Petition for Modification of Decision 09-12-044 to address the FAA's recommendations near Chino airport for segment 8, Phase 3.
November 10, 2011: CPUC issued Decision 11-11-020 granting a construction stay for Segment 8A within the City of Chino Hills.
Spring 2012: Segments 4 and 10 in-service.
July 12, 2012: CPUC issued a Decision 12-03-050 modifying Decision 11-11-020.
Winter 2012: Segment 5 in-service.
April 11, 2013: CPUC and USFS prepared a Draft Supplemental EIR/EIS based on SCE's proposed modifications.

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475 CPUC Decision on TRTP Segment 8A can be found on CPUC website at http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M071/K423/71423831.PDF.

476 Manuel Alvarez, Southern California Edison, comments on *California Energy Commission Docket No. 13-IEP-1A: Draft 2013 IEPR*, October 29, 2013, p. 18, http://www.energy.ca.gov/2013_energypolicy/documents/2013-10-15_workshop/comments/Southern_California_Edisons_Comments_2013-10-29_TN-72296.pdf.

477 CPUC Decision 07-03-012 can be found on the CPUC website at http://docs.cpuc.ca.gov/published/FINAL_DECISION/65273.htm.

478 USFS Record of Decision can be found on the CPUC website at http://www.cpuc.ca.gov/environment/info/aspen/antelopepardee/record_of_decision.pdf.

June 3, 2013: Public comments period ends on draft Supplemental EIR/EIS.
June 11, 2013: CPUC ALJ Vieth Proposed Decision denying Chino Hills' petition for modification of Decision 09-12-044.
June 11, 2013: CPUC President Peevey Alternate Proposed Decision granting Chino Hills' petition for modification of Decision 09-12-044.
July 11, 2013: CPUC Decision favors President Peevey's Alternate Proposed Decision Chino Hills.
Late 2015 or early 2016: Expected in-service date for remaining segments.

Colorado River-Valley (and Red Bluff Substation) (3)

Description

SCE's Colorado River-Valley 500 kV transmission project includes the Colorado River to Devers project, also referred to as the California side of the Devers-Palo Verde 2 (DPV2) project, consisting of the following main components:

- New 500/220 kV Colorado River Substation near Blythe
- New Red Bluff Substation west of the Colorado River Substation
- 111-mile Devers-Colorado River 500 kV transmission line between Devers Substation and the Colorado River Substation that will parallel the existing Devers-Palo Verde transmission line
- 42-mile Devers-Valley No. 2 500 kV transmission line between Devers Substation and Valley Substation in Menifee that will parallel the existing Devers-Valley transmission line

The project will allow generators in eastern Riverside County to connect with the Devers Substation in Southern California. This project, along with the West of Devers upgrade (discussed below), will allow for delivery of about 4,000 MW from Riverside County.

Construction of all facilities are nearing completion, but the June 2013 target completion date will likely not be met because a timeline for mitigation measures for nesting birds has not been established, which could delay construction. On May 22, 2013, SCE completed construction on the Red Bluff Substation, ahead of SCE's target in-service date of July 2013.[479] On September 29, 2013, SCE completed and energized the Colorado River-Valley project.

Key Dates

February 24, 2005: California ISO Board of Governors approved the original Devers-Palo Verde 2 (DPV2) project. No further Board approval required for the Colorado River-Valley project.

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479 Manuel Alvarez, Southern California Edison, comments on *California Energy Commission Docket No. 13-IEP-1E Transmission Planning and Permitting Issues*, May 21, 2013, p. 5, http://www.energy.ca.gov/2013_energypolicy/documents/2013-05-07_transmission_workshop/comments/Southern_California_Edison_Comments_re_Transmission_Planning_and_Permitting_Issues_2013-05-21_TN-70920.pdf.

April 11, 2005: SCE filed an application with CPUC for a CPCN.
January 25, 2007: CPUC issued Decision 07-01-040[480] approving DPV2.
July 14, 2011: CPUC issued Decision 11-07-011[481] approving construction of the expanded Colorado River Substation.
May 14, 2008: SCE filed a Petition for Modification (PFM) of Decision 07-01-040 requesting the CPUC authorize SCE to construct only the California portion of the DPV2 facilities.
November 20, 2009: CPUC issued Decision 09-11-007[482] approving the PFM.
July 19, 2011: BLM issued Record of Decision[483] approving the project.
September 2011: SCE started construction on Colorado River and Red Bluff Substations.
January 2012: SCE started transmission line construction.
May 22, 2013: Red Bluff Substation completed.
September 29, 2013: In-service date.

West of Devers (4)

Description

The California ISO's Generator Interconnection Procedures identified SCE's West of Devers transmission lines as delivery network upgrades for the Blythe, Genesis, and Palen solar generating projects in Riverside County. The West of Devers project consists of removing and replacing nearly 48 miles of existing 220 kV transmission lines with new double-circuit 220 kV transmission lines between the existing Devers Substation (near Palm Springs), Vista Substation (in Grand Terrace), and San Bernardino Substation. SCE received approval from the Federal Energy Regulatory Commission (FERC) and the California ISO through acceptance of the nonconforming Large Generator Interconnection Agreement (LGIA) for the Blythe, Genesis, and Palen solar generating projects.

SCE is developing routes and gathering the environmental information needed to apply for required state and federal permits. Without the West of Devers upgrades, most of the renewable generation proposed in eastern Riverside County will be unable to meet the deliverability requirements in the power purchase agreements. On October 25, 2013, SCE filed an application

480 CPUC Decision 07-01-040 can be found on the CPUC website at http://docs.cpuc.ca.gov/published//FINAL_DECISION/64017.htm.

481 CPUC Decision 11-07-011 can be found on the CPUC website at http://docs.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/139770.htm.

482 CPUC Decision 09-11-007 can be found on the CPUC website at http://docs.cpuc.ca.gov/published/FINAL_DECISION/110360.htm.

483 BLM Record of Decision can be found on the CPUC website at http://www.cpuc.ca.gov/Environment/info/aspen/dpv2/record_of_decision_071911.pdf.

for a CPCN with the CPUC. If approved, construction will begin in 2016 with an expected in-service date of 2019.[484]

Key Dates

September 15, 2010: Energy Commission Decision[485] on Blythe Application for Certification (AFC).
September 29, 2010: Energy Commission Decision[486] on Genesis AFC.
December 15, 2010: Energy Commission Decision[487] on Palen AFC.
February 4, 2011: FERC Order[488] accepting Blythe LGIA.
February 17, 2011: FERC Order[489] accepting Palen LGIA.
October 20, 2011: FERC Order[490] accepting Genesis LGIA.
2011-2013: SCE in project planning and public outreach activities.
October 25, 2013: SCE filed an application for a CPCN with the CPUC.
2019: Expected in-service date.

Eldorado-Ivanpah (5)

Description

The California ISO's Generator Interconnection Procedures identified SCE's Eldorado-Ivanpah transmission project as delivery network upgrades for the Ivanpah Solar Electric Generating System. The Eldorado-Ivanpah project will provide the electrical facilities necessary to integrate

484 Manuel Alvarez, Southern California Edison, comments on *California Energy Commission Docket No. 13-IEP-1E Transmission Planning and Permitting Issues*, May 21, 2013, p. 5, http://www.energy.ca.gov/2013_energypolicy/documents/2013-05-07_transmission_workshop/comments/Southern_California_Edison_Comments_re_Transmission_Planning_and_Permitting_Issues_2013-05-21_TN-70920.pdf.

485 Energy Commission Decision on Blythe AFC can be found on Energy Commission website at http://www.energy.ca.gov/2010publications/CEC-800-2010-009/CEC-800-2010-009-CMF.PDF.

486 Energy Commission Decision on Genesis AFC can be found on Energy Commission website at http://www.energy.ca.gov/2010publications/CEC-800-2010-011/CEC-800-2010-011-CMF.PDF.

487 Energy Commission Decision on Palen AFC can be found on Energy Commission website at http://www.energy.ca.gov/2010publications/CEC-800-2010-010/CEC-800-2010-010-CMF.PDF.

488 FERC Order accepting Blythe LGIA can be found on California ISO website at http://www.caiso.com/Documents/Feb4_2011Orderconditionallyacceptingnon-conformingLGIAsanddenyingmotions-consolidate_docketER11-2329_etal_.pdf.

489 FERC Order accepting Palen LGIA can be found on California ISO website at http://www.caiso.com/Documents/February17_2011Orderconditionallyacceptingnon-conformingLGIAs_denyingmots_-consolidateindocketno_ER11-2451.pdf.

490 FERC Order accepting Genesis LGIA can be found on California ISO website at http://www.caiso.com/Documents/2011-10-20_ER11-4512_GenMcCoyLGIAorder.pdf.

1,400 MW of new solar energy generation in the Ivanpah Dry Lake area. The project's major components include:

- New Ivanpah Substation in San Bernardino County.
- Replacement of a portion of an existing 115 kV transmission line with a 35-mile double-circuit, 220 kV transmission line between the new Ivanpah Substation and the existing Eldorado Substation near Boulder City, Nevada.
- Installation of associated telecommunication infrastructure.

On July 1, 2013, SCE completed and energized the Eldorado-Ivanpah project.

Key Dates

May 28, 2009: SCE filed an application with CPUC for a CPCN.
September 22, 2010: Energy Commission Decision[491] on Ivanpah AFC.
March 15, 2011: FERC Order[492] accepting amendments to original 2010 Ivanpah LGIAs.
December 16, 2010: CPUC issued Decision 10-12-052[493] approving project.
May 25, 2011: BLM issued Record of Decision[494] approving the project.
March 2012: SCE started construction.
July 1, 2013: In-service date

South of Contra Costa (6)

Description

The California ISO's Generator Interconnection Procedures identified PG&E's South of Contra Costa reconductoring project as needed to deliver 300 MW of new wind generation in Solano County. The South of Contra Costa project includes reconductoring the following transmission lines:

- 18.3 miles of the Contra Costa Power Plant-Delta Pumps 230 kV transmission line
- 21 miles of the Las Positas-Newark 230 kV transmission line

491 Energy Commission Decision on Ivanpah AFC can be found on Energy Commission website at http://www.energy.ca.gov/2010publications/CEC-800-2010-004/CEC-800-2010-004-CMF.PDF.

492 FERC Order accepting amendments to original Ivanpah LGIA can be found on California ISO website at http://www.caiso.com/Documents/March15_2011LetterorderacceptingLGIAsbetweenISO_SCE__SolarPartnersindocketnos_ER11-2885_ER11-2899.pdf.

493 CPUC Decision 10-12-052 can be found on CPUC website at http://docs.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/128873.htm.

494 BLM Record of Decision can be found on the BLM website at http://www.blm.gov/pgdata/etc/medialib/blm/ca/pdf/needles/lands_solar.Par.91949.File.dat/EITP_ROD.pdf.

- 8 miles of the Kelso-Tesla 230 kV transmission line

Without reconductoring these lines, none of the renewable generation proposed in the Solano County area will be considered deliverable. The Kelso-Tesla 230 kV reconductoring was completed in November 2012. PG&E is in the engineering phase for the Contra Costa Power Plant-Delta Pumps and Las Positas-Newark 230 kV transmission lines is and has not yet filed applications to state and federal regulatory agencies requesting approval. PG&E's expected in-service date for these remaining projects is 2017.

Key Dates

July 6, 2012: PG&E submitted Advice Letter 4083-E[495] to CPUC for Kelso-Tesla line.
August 5, 2012: CPUC approved Advice Letter 4083-E.
November 2012: In-service date for Kelso-Tesla transmission line.
2017: PG&E's expected in-service date for remaining projects.

Pisgah-Lugo (7)

Description

SCE's Pisgah-Lugo project was identified by the California ISO as being needed for the interconnection of the 850 MW K Road Calico Solar Project. On June 20, 2013, K Road, LLC, filed a request with the Energy Commission to terminate the Calico Solar Project.[496] The California ISO noted that the project is not reflected in any other interconnection agreements. As a result, the Pisgah-Lugo project was removed from the CPUC portfolios and the California ISO 2012-2013 TPP. However, there remains a strong likelihood that the Desert Renewable Energy Conservation Plan will identify a Development Focus Area in the same location as the Pisgah-Lugo project to access solar resources in the Mojave Desert. At this time the Pisgah-Lugo project is not moving forward, but a similar project could be identified in the future by the California ISO as generator projects in its interconnection queue move forward.

Borden-Gregg (8)

Description

The California ISO's Generator Interconnection Procedures identified PG&E's Borden-Gregg 230 kV transmission line reconductoring project as a delivery network upgrade as needed for the delivery of 800 MW of new solar generation proposed in the Fresno area, specifically the Westlands area. According to PG&E, the project is on hold. Once the project moves forward,

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495 PG&E Advice Letter 4083-E can be found on PG&E website at http://www.pge.com/nots/rates/tariffs/tm2/pdf/ELEC_4083-E.pdf.

496 On June 20, 2013 K Road, LLC, filed a request with the Energy Commission to terminate the Energy Commission license for the Calico Solar Project, http://www.energy.ca.gov/sitingcases/calicosolar/compliance_2012/notices/2013-06-24_Notice_of_Receipt_of_Request_to_Terminate_License_TN-71374.pdf.

PG&E will submit applications to state and federal regulatory agencies requesting approval. PG&E's expected in-service date is 2016.

Carrizo-Midway (9)

Description

The California ISO's Generator Interconnection Procedures identified PG&E's Carrizo-Midway transmission project as a delivery network upgrade identified as needed for the delivery of 900 MW of solar generation in the Carrizo Plain area in San Luis Obispo County. On May 5, 2011, PG&E submitted a notice of exempt construction, Advice Letter 3842-E[497], to the CPUC for transmission facilities that would interconnect renewable generators in the Carrizo Plain. San Luis Obispo County issued permits for the switching stations as part of the Conditional Use Permits granted for two PV projects: the California Valley Solar Ranch Project (250 MW) and the Topaz Solar Farm Project (550 MW). The proposed project consists of the Caliente Switching Station in San Luis Obispo County and the Solar Switching Station in San Luis Obispo County, associated with the two solar PV projects and reconductoring roughly 35 miles of the existing Morro Bay-Midway double-circuit 230 kV transmission line. On September 14, 2011, the CPUC issued Resolution E-4434, approving PG&E's Advice Letter 3842-E. On March 20, 2013, PG&E completed reconductoring and energized the Morro Bay-Midway transmission line.

Key Dates

May 5, 2011: PG&E submitted Advice Letter 3842-E to the CPUC.
September 14, 2011: CPUC issued Resolution E-4434 approving Advice Letter 3842-E.
March 20, 2013: In-service date.

Cool Water-Lugo (Jasper Substation) (10)

Description

The California ISO's Generator Interconnection Procedures identified SCE's Coolwater-Lugo transmission project as a delivery network upgrade needed for the Abengoa Mojave Solar Project. The project will provide an additional 1,000 MW transmission capacity needed in the Kramer Junction and Lucerne Valley areas in San Bernadino County to support large-scale renewable generation development and to ensure system reliability. The project initially included a proposed Jasper Substation; however, SCE is developing the substation separately from the Coolwater-Lugo project. The expected in-service date of the Jasper Substation is 2015, prior to the Coolwater-Lugo project's expected in-service date of 2018. SCE intends to loop the Coolwater-Lugo transmission lines into the proposed Jasper Substation. The project includes:

- 34 miles of a 220 kV double-circuit transmission line from SCE's Coolwater Substation to the proposed Jasper Substation on a new right-of-way.

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497 PG&E Advice Letter 3842-E can be found on PG&E's website at http://www.pge.com/nots/rates/tariffs/tm2/pdf/ELEC_3842-E.pdf.

- Removal of 29 miles of existing Pisgah-Lugo No. 1 220 kV transmission line from Jasper Substation to Lugo Substation on an existing right-of-way and replace with
  - o 14 miles of 220 kV double-circuit transmission line.
  - o 17 miles of 500 kV single-circuit transmission line initially energized at 220 kV.
- Site for future Desert View Substation east of Apple Valley.
- Installation of a third high-voltage transformer bank at SCE's Lugo Substation.

On August 28, 2103, SCE filed a PEA with the CPUC and BLM. SCE's expected in-service date is 2018.[498]

Key Dates

September 8, 2010: Energy Commission Decision[499] on Abengoa AFC.
January 28, 2011: FERC Order[500] accepting Abengoa LGIA.
August 28, 2013: SCE filed a PEA with the CPUC and BLM requesting project approval.
2018: Expected in-service date.

SCE/IID Joint Path 42 (11/12)

Description

The SCE/IID Joint Path 42 project is a successful collaboration among the California ISO, SCE, and IID. 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's controlled grid.[501] Upgrading Path 42 requires improvements to facilities under the control of SCE and the California ISO, as well as facilities under IID control. On May 18, 2011, SCE's portion of the upgrade received California ISO Board of Governors approval as a policy-driven upgrade upon

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498 Manuel Alvarez, Southern California Edison, comments on *California Energy Commission Docket No. 13-IEP-1E Transmission Planning and Permitting Issues*, May 21, 2013, p. 6, http://www.energy.ca.gov/2013_energypolicy/documents/2013-05-07_transmission_workshop/comments/Southern_California_Edison_Comments_re_Transmission_Planning_and_Permitting_Issues_2013-05-21_TN-70920.pdf.

499 Energy Commission Decision on Ivanpah AFC can be found on Energy Commission website at http://www.energy.ca.gov/2010publications/CEC-800-2010-008/CEC-800-2010-008-CMF.PDF.

500 FERC Order accepting amendments to original Abengoa LGIA can be found on California ISO website at http://www.caiso.com/Documents/January28_2011Orderconditionallyacceptingnon-conformingLGIAs_denyingmots_-consolidateindocketno_ER11-2368.pdf.

501 Jamie Asbury, Imperial Irrigation District, comments on *2013 IEPR – Transmission Planning and Permitting Issues*, Docket No. 13-IEP-1E, May 21, 2013, p. 2, http://www.energy.ca.gov/2013_energypolicy/documents/2013-05-07_transmission_workshop/comments/Imperial_Irrigation_District_Comments_re_Transmission_Planning_and_Permitting_Issues_2013-05-21_TN-70922.pdf.

adoption of the *2010-2011 Transmission Plan*.[502] SCE's upgrade includes a 15-mile, double-circuit, 230 kV transmission lines between SCE's Devers and Mirage Substations.

On August 16, 2011, the IID Board of Directors approved its portion of the Path 42 upgrade.[503] The upgrade consists of replacing 20 miles of a double-circuit 230 kV transmission line (one conductor per phase) with a bundle of two conductors per phase conductors between SCE's Mirage and IID's Coachella Valley and Ramon Substations. On August 20, 2013, IID and SCE filed with BLM a Draft Mitigated Negative Declaration and Environmental Assessment/Initial Study for public review and comment. IID is the CEQA lead for the project.[504] The parties have been working with the BLM on remaining permitting issues. SCE's and IID's expected in-service date is April 30, 2014.[505]

Key Dates

May 18, 2011: California ISO Board of Governor approved the *2010-2011 Transmission Plan.*
August 16, 2011: IID Board of Directors initial approval of Path 42 upgrade.
August 23, 2012: IID Board of Directors reaffirmed approval of Path 42 upgrade.[506]
August 20, 2013: IID and SCE filed with BLM a Draft Mitigated Negative Declaration and Environmental Assessment/Initial Study
April 30, 2014: SCE and IID expected in-service date.

IID: Additional upgrades (12)

IID identified three additional upgrades needed for the interconnection of generating resources in its Transitional Cluster. The upgrades include El Centro-Highline, El Centro-Imperial Valley (S line), and Midway-Bannister. The El Centro-to-Highline project replaces existing 161 kV and 92 kV lines with a double-circuit, 230 kV transmission line. The El Centro-Imperial Valley

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502 California ISO Board approved *2010-2011 Transmission Plan*, p. 524, http://www.caiso.com/Documents/Board-approvedISO2010-2011TransmissionPlan.pdf.

503 IID Board of Directors Regular Meeting, August 16, 2011, p. 2, http://www.iid.com/Modules/ShowDocument.aspx?documentid=4970.

504 Manuel Alvarez, Southern California Edison, comments on *California Energy Commission Docket No. 13-IEP-1E Transmission Planning and Permitting Issues*, May 21, 2013, p. 6, http://www.energy.ca.gov/2013_energypolicy/documents/2013-05-07_transmission_workshop/comments/Southern_California_Edison_Comments_re_Transmission_Planning_and_Permitting_Issues_2013-05-21_TN-70920.pdf.

505 Jamie Asbury, Imperial Irrigation District, comments on *2013 IEPR – Transmission Planning and Permitting Issues*, Docket No. 13-IEP-1E, May 21, 2013, p. 2, http://www.energy.ca.gov/2013_energypolicy/documents/2013-05-07_transmission_workshop/comments/Imperial_Irrigation_District_Comments_re_Transmission_Planning_and_Permitting_Issues_2013-05-21_TN-70922.pdf.

506 See IID news release at http://www.iid.com/index.aspx?page=30&recordid=236&returnURL=%2Findex.aspx.

project, S line, replaces an existing 230 kV line with a double-circuit, 230 kV transmission line between jointly owned IID/SDG&E Imperial Valley Substation to IID's El Centro Switching Station. The Midway-Bannister project consists of nearly 8 miles of a new 230 kV transmission line between IID's Midway Substation and the proposed Bannister Substation. Depending upon developer need, IID would expect to commence the required upgrades by 2014.

LADWP: Barren Ridge (13)

Description

LADWP's Barren Ridge Renewable Transmission Project consists of:

- About 75 miles of two new 230 kV transmission lines from the Barren Ridge Switching Station to the proposed Haskell Canyon Switching Station located north of Santa Clarita.
- 12-mile, 230 kV transmission line on existing structures from Haskell Canyon to the Castaic Power Plant, a pumped-storage generating facility, where renewable energy can be stored until needed to meet utility customer power needs.

The project will provide additional transmission capacity to access 1,400 MW of wind, solar, and other renewable resources. LADWP's expected in-service date is 2016.

Key Dates

September 19, 2012: LADWP Board of Water and Power Commissioners approved final Environmental Impact Report.[507]
September 24, 2012: BLM issued Record of Decision[508] approving the project.
2016: Expected in-service date.

Warnerville-Bellota (16)

Description

The California ISO identified a policy-driven need for reconductoring the 230 kV transmission line between PG&E's Warnerville and Bellota substations in its recently board-approved *2012-2013 Transmission Plan*.[509] The policy-driven upgrade will allow for the delivery of renewable generation in the Greater Fresno, Central Valley North, Merced and Westlands zones needed to meet the 33 percent RPS. The Warnerville-Bellota, Wilson-Le Grand, and Gates-Gregg projects will allow for delivery of roughly 700 MW renewable generation. PG&E will submit

507 See LADWP news release at http://www.ladwpnews.com/go/doc/1475/1547235/.

508 BLM Record of Decision can be found on BLM website at http://www.blm.gov/pgdata/etc/medialib/blm/ca/pdf/ridgecrest/barren_ridge.Par.25255.File.dat/BRRTP_ROD_Final.pdf.

509 California ISO Board approved *2012-2013 Transmission Plan*, pp. 263 and 374, http://www.caiso.com/Documents/BoardApproved2012-2013TransmissionPlan.pdf.

applications to state and federal regulatory agencies requesting project approval. California ISO's expected in-service date is 2017.

Key Dates

March 20, 2013: California ISO Board of Governor approved the *2012-2013 Transmission Plan.*
2017: Expected in-service date.

Wilson-Le Grand (17)

Description

The California ISO identified a policy-driven need for reconductoring the 115 kV transmission line between PG&E's Wilson and Le Grand substations in its recently board-approved *2012-2013 Transmission Plan*.[510] The policy-driven upgrade will allow for the delivery of renewable generation in the Greater Fresno, Merced, and Westlands zones needed to meet the 33 percent RPS. The Wilson-Le Grand, Warnerville-Bellota, and Gates-Gregg transmission projects will allow for the delivery of roughly 700 MW renewable generation. PG&E will submit applications to state and federal regulatory agencies requesting project approval. California ISO's expected in-service date is 2020.

Key Dates

March 20, 2013: California ISO Board of Governor approved the *2012-2013 Transmission Plan.*
2020: Expected in-service date.

Gates-Gregg (18)

Description

The California ISO identified the need for a 230 kV transmission line between PG&E's Gates and Gregg Substations as a reliability-driven project with policy-driven benefits in its board-approved *2012-2013 Transmission Plan*.[511] The transmission line will be constructed as a double–circuit, 230 kV line with one side strung, facilitating future development requirements to supply load or integrate renewable generation while minimizing future right-of-way requirements. The Gates-Gregg, Wilson-Le Grand, and Warnerville-Bellota projects will allow for the delivery of nearly 700 MW renewable generation. The project is eligible for competitive solicitation.

Phase 3 of the California ISO's transmission planning process includes a competitive solicitation process for policy-driven and economically driven transmission projects, as well as for reliability-driven projects that provide additional policy and economic benefits. The bid window, where project sponsors can submit proposals to finance, construct, and own the Gates-

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510 California ISO Board approved 2012-2013 Transmission Plan, pp. 263 and 374, http://www.caiso.com/Documents/BoardApproved2012-2013TransmissionPlan.pdf.

511 California ISO Board approved *2012-2013 Transmission Plan*, pp. 149 and 376, http://www.caiso.com/Documents/BoardApproved2012-2013TransmissionPlan.pdf.

Gregg 230 kV line is open from April 1, 2013, through June 3, 2013. On June 6, 2013, the California ISO posted the list of project sponsors that submitted proposals for the Gates-Gregg project.[512] November 6, 2013, the California ISO selected the consortium of PG&E, MidAmerican Transmission, in conjunction with Citizens Energy Corporation, as the approved project sponsor to finance, own, construct, operate, and maintain the Gates-Gregg project. Selected project sponsor will submit applications to state and federal regulatory agencies requesting project approval. California ISO's expected in-service date is 2022.

Key Dates

March 20, 2013: California ISO Board of Governors approved the *2012-2013 Transmission Plan.*
April 1, 2013, through June 3, 2013: Competitive solicitation bid window open.
June 6, 2013: California ISO posted the list of project sponsors that submitted proposals.
November 6, 2013: California ISO selected the consortium of PG&E, MidAmerican Transmission, and Citizens Energy Corporation as project sponsor.
2022: Expected in-service date.

512 The list of project sponsors that submitted proposals for the Gates-Gregg project can be found on the California ISO website at http://www.caiso.com/Documents/List-ProjectSponsorProposalsReceived-Gates_Gregg230kVLineProposedPolicyDrivenElement.pdf.

APPENDIX B: Strategic Transmission Investment Plan Workshop Summaries

In light of the transmission-related recommendations from the *2012 IEPR Update* and emerging issues and opportunities since that report was published, the Energy Commission held two workshops to introduce and develop these issues with input from stakeholders and create recommendations consistent with the legislative mandate to produce a biennial *Strategic Transmission Investment Plan*. The IEPR and Siting lead commissioners conducted a workshop on the morning of May 7, 2013, on consideration of environmental and land-use factors in renewable scenarios for transmission planning and renewable energy project database issues.[513] The IEPR lead commissioner then held a workshop on transmission planning and permitting issues on the afternoon of May 7, 2013.[514]

May 7, 2013, (Morning) Joint IEPR/Siting Lead Commissioner Workshop

This workshop addressed Recommendation 9 in the Renewable Action Plan (Chapter 5 of the *2012 Integrated Energy Policy Report Update*), which directs the Energy Commission to ensure that environmental and land-use information developed through relevant sources is incorporated into renewable resource scenarios used in the California Public Utilities Commission (CPUC) Long-Term Procurement Plan (LTPP)proceeding and the California Independent System Operator (California ISO) Transmission Planning Process (TPP). Recommendation 9 also directs the Energy Commission to continue to develop its in-state and out-of-state renewable project databases via a public, transparent process that provides opportunities for stakeholder involvement. The purpose of this workshop was to discuss the goals and scope of this effort, data needs, possible sources of publicly available data, gaps in available information, data collection issues, and possible options.

Formal presentations at this workshop included a CPUC staff update on the CPUC's LTPP portfolio/scenario development process; an Energy Commission staff update on the Energy Commission's existing renewable energy project database and the environmental scoring method for LTPP renewable scenarios; and a CPUC staff presentation that provided background on the CPUC's RPS Calculator and consideration of long-term environmental/land-use data needs. Following the formal presentations, Energy Commission staff moderated a roundtable discussion on environmental/land-use data for scenario planning and renewable energy project database issues. Panelists included representatives from Energy Commission

513 See the complete workshop record at http://www.energy.ca.gov/2013_energypolicy/documents/#05072013-am.

514 See the complete workshop record at http://www.energy.ca.gov/2013_energypolicy/documents/#05072013-pm.

staff, CPUC staff, California Department of Fish and Wildlife, U.S. Bureau of Land Management, Los Angeles County, Western Electricity Coordinating Council, Natural Resources Defense Council, The Nature Conservancy, and SunPower Corporation. Four parties made public comments at the workshop. These included representatives for the Power Company of Wyoming, Large-Scale Solar Association, Pathfinder Renewable Wind Energy/Zephyr Power Transmission, LLC, and Defenders of Wildlife. Following the workshop, the Energy Commission received written comments on the workshop topics from the following organizations: Bay Area Municipal Transmission Group, Joint comments by The Nature Conservancy/Defenders of Wildlife/Sierra Club/Natural Resources Defense Council, supplemental comments by Natural Resources Defense Council, PG&E, Pathfinder Renewable Wind Energy/Zephyr Power Transmission, LLC, Power Company of Wyoming, and supplemental comments by The Nature Conservancy.

Two key issues emerged from the discussion, comments, and presentations of this workshop. The first issue that several participants articulated is a concern with the current environmental weighting in planning and/or the desire for placing greater weight on the environmental portfolio in the LTPP process and environmental impact in the TPP process.[515] The workshop generated several informative discussions and comments related to the types of environmental (and other) data that should be considered for use in the environmental scoring of projects. However, it appears any efforts to revise environmental scoring methodology itself or incorporate other datasets would have little effect on the transmission planning outcome because environmental score carries only a 10 percent weight in the commercial interest portfolio, which has been selected in past years and used in the main modeling for the LTPP at

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515 Erica Brand (The Nature Conservancy), Noah Long (Natural Resources Defense Council), Sarah Friedman (Sierra Club), and Kimberley Delfino (Defenders of Wildlife), *Joint Lead Commissioner Workshop on Environmental and Land-Use Factors in Renewable Scenarios and Database Development.* California Energy Commission, Docket No. 13-IEP-1E, May 21, 2013, http://www.energy.ca.gov/2013_energypolicy/documents/2013-05-07_siting_workshop/comments/Joint_Comments_to_the_Joint_Lead_Commissioner_Workshop_May_7_AM_2013-05-21_TN-70929.pdf; Barry Flynn and Pushkar Wagle (Bay Area Municipal Transmission Group), *Lead Commissioner Workshop on Transmission Planning and Permitting Issues,* California Energy Commission, Docket No. 13-IEP-1E, May 21, 2013, http://www.energy.ca.gov/2013_energypolicy/documents/2013-05-07_transmission_workshop/comments/Bay_Area_Municipal_Transmission_Group_Comments_2013-05-21_TN-70932.pdf; and David Smith (Power Company of Wyoming, LLC), *Joint Lead Commissioner Workshop on Environmental and Land-Use Factors in Renewable Scenarios and Database Development,* California Energy Commission, Docket No. 13-IEP-1E, May 21, 2013, http://www.energy.ca.gov/2013_energypolicy/documents/2013-05-07_siting_workshop/comments/Power_Company_of_Wyoming_LLC_Comments_re_the_Consideration_of_Environmental_and_Land_Use_Factors_2013-05-21_TN-70928.pdf.

present.[516] This issue of environmental score weighting remains a barrier to a more robust consideration of environmental data in the CPUC and California ISO planning processes.

CPUC staff reported its ongoing study and "back testing" of past environmental scoring and methods and possibly reevaluating the weighting to determine relevancy to renewable energy projects and the LTPP process.[517] Staffs of the CPUC and Energy Commission will collaborate as results from this CPUC study become available, and CPUC plans to hold a public stakeholder process if a new method is developed. Energy Commission staff would participate in that process and other opportunities to revisit environmental score weighting. CPUC had anticipated this process of potential new scoring method development and stakeholder vetting to be completed by late 2013 or early 2014. However, as of October 2013 due to CPUC shifting workload priorities and staffing constraints, the back testing effort is on hold. In addition, Commissioner Andrew McAllister mentioned his ongoing collaboration with the CPUC regarding needed resources and data collection, which are related to advancing issues related to both transmission planning and energy efficiency.[518]

To address the issue of environmental weighting in transmission planning, the Energy Commission recommends that the energy agencies (Energy Commission, CPUC, and California ISO) evaluate the environmental weighting process and policies associated with the LTPP and TPP processes. If attempts to significantly increase the weight on environmental scores are successful, many of the detailed data and methodology-related comments arising from this workshop could have more of an effect on planning outcomes and processes.

Renewable project database maintenance and improvement were the second main focus of the morning joint lead commissioner workshop. Energy Commission staff presented a summary of Energy Commission renewable data collection: (1) the Strategic Transmission Planning Office's siting-related tracking in the renewable energy project database (Renewable Energy Action Team [REAT] renewable generation database) and (2) the Renewable Energy Office's RPS Program-related tracking of verification, certification, and other data. Workshop participants

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516 Robert Strauss (CPUC), Transcript of the May 7, 2013 *Joint Lead Commissioner Workshop on Environmental and Land-Use Factors in Renewable Scenarios and Database Development*, California Energy Commission, Sacramento, California, p. 20, http://www.energy.ca.gov/2013_energypolicy/documents/2013-05-07_siting_workshop/2013-05-07_transcript_morning.pdf.

517 Carlos Velasquez (CPUC), Transcript of the May 7, 2013 *Joint Lead Commissioner Workshop on Environmental and Land-Use Factors in Renewable Scenarios and Database Development*, California Energy Commission, Sacramento, California, pp. 46-47, http://www.energy.ca.gov/2013_energypolicy/documents/2013-05-07_siting_workshop/2013-05-07_transcript_morning.pdf.

518 Andrew McAllister, Transcript of the May 7, 2013 *Joint Lead Commissioner Workshop on Environmental and Land-Use Factors in Renewable Scenarios and Database Development*, California Energy Commission, Sacramento, California, p. 68, http://www.energy.ca.gov/2013_energypolicy/documents/2013-05-07_siting_workshop/2013-05-07_transcript_morning.pdf.

provided feedback on the data fields of most interest to them and important characteristics of a publicly accessible database. The data fields of particular stakeholder interest that are already tracked by staff include geospatial linking data, capacity, acreage, technology type, status (project phase), facility on-line date, date of last project information update, and location.[519] Most participants provided recommendations regarding potential expansions to the scope of data tracking, including incorporation of other datasets for California and out-of-state resources. Some participants (for example, the Nature Conservancy and PG&E) noted difficulties in consolidating various online data sources and supported creation of a centralized renewable energy data clearinghouse, which is the subject of a separate, albeit relevant, recommendation under the Energy Commission's Renewable Energy Action Plan (RAP).[520] The Energy Commission's Electricity Supply Analysis Division staff is implementing RAP Recommendation 14 through participation in CPUC's Order Instituting Rulemaking (OIR)[521] and reported the scope of that OIR appears sufficiently broad to incorporate siting-related renewable project data useful for transmission planning. Staff agrees with PG&E's caution regarding the significant effort required to consolidate and maintain existing data and that "a new clearinghouse would provide little value if it duplicates data that already exist elsewhere."[522] The Energy Commission will continue to maintain the Renewable Energy Action Team renewable generation database on the Energy Commission web page and keep it updated quarterly to the extent possible. The Energy Commission will consider integrating some of the information from the other data sources mentioned (as feasible).

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519 Erica Brand (The Nature Conservancy), Noah Long (Natural Resources Defense Council), Sarah Friedman (Sierra Club), and Kimberley Delfino (Defenders of Wildlife), *Joint Lead Commissioner Workshop on Environmental and Land-Use Factors in Renewable Scenarios and Database Development*, California Energy Commission Docket No. 13-IEP-1E, May 21, 2013, http://www.energy.ca.gov/2013_energypolicy/documents/2013-05-07_siting_workshop/comments/Joint_Comments_to_the_Joint_Lead_Commissioner_Workshop_May_7_AM_2013-05-21_TN-70929.pdf; and Carl Zichella (Natural Resources Defense Council), *Joint Lead Commissioner Workshop on Environmental and Land-Use Factors in Renewable Scenarios and Database Development*, California Energy Commission Docket No. 13-IEP-1E, May 21, 2013, http://www.energy.ca.gov/2013_energypolicy/documents/2013-05-07_siting_workshop/comments/NRDC_Combined_Comments_TN-70973_TN-70974_TN-70975.pdf.

520 See Recommendation 14 in the *2012 IEPR Update*, Chapter 5 (Renewable Action Plan).

521 See http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M031/K744/31744124.PDF for scoping memo and decision and ftp://ftp.cpuc.ca.gov/13011516_EgyDataWorkshop for the latest posted workshop information.

522 Matthew Plummer (PG&E), *Joint Lead Commissioner Workshop on Environmental and Land-Use Factors in Renewable Scenarios and Database Development,* California Energy Commission, Docket No. 13-IEP-1E, May 21, 2013, http://www.energy.ca.gov/2013_energypolicy/documents/2013-05-07_siting_workshop/comments/PG_and_E_Comments_on_the_May_7_Joint_Lead_Commissioner_Workshop_2013-05-21_TN-70921.pdf.

May 7, 2013, (Afternoon) IEPR Lead Commissioner Workshop

The IEPR lead commissioner then held a workshop on transmission planning and permitting issues on the afternoon of May 7, 2013. This workshop contributes to development of the Energy Commission's 2013 IEPR proceeding. In particular, the workshop responded to the 2013 IEPR Scoping Order, dated March 7, 2013, which directs the Energy Commission to prepare a *Strategic Transmission Investment Plan* as required by Senate Bill 1565 (Bowen, Chapter 692, Statutes of 2004.) In addition, the workshop addressed implementation of Recommendation 10 (Monitor Status of California ISO-approved Transmission Projects to Ensure Timely Completion) and Recommendation 11 (Streamline Transmission Permitting in California) in the Renewable Action Plan (Chapter 5 of the *2012 Integrated Energy Policy Report Update*). Major workshop topics included western states transmission issues, status of approved transmission projects to meet the 33 percent Renewables Portfolio Standard, and synchronization of generation and transmission permitting to achieve renewable policy goals.

Presentations at this workshop included an Energy Commission staff presentation on Western Electricity Coordinating Council restructuring, a California ISO staff presentation on the California ISO Energy Imbalance Market Design Straw Proposal, a California ISO staff update on transmission planning to support the 33 Percent RPS mandate, and a presentation by Southern California Edison staff on Development Focus Area[523] Suitability and Transmission Planning. Following the formal presentations, Energy Commission staff moderated a roundtable discussion on synchronization of generation and transmission permitting to achieve renewable policy goals. Panelists included representatives from BrightSource Energy; Paul Hastings, LLP, for Abengoa Solar; Mangano Homes Inc. for Westlands Solar Park; SunPower Corporation; Southern California Edison; PG&E; California Municipal Utilities Association; CPUC staff; California ISO staff; Startrans IO, LLC; and Natural Resources Defense Council. Following the workshop, the Energy Commission received written comments from the Bay Area Municipal Transmission Group, Joint comments by California Consumer Alliance/Clean Coalition; Imperial Irrigation District; Large-Scale Solar Association; Wyoming Infrastructure Authority; Natural Resources Defense Council; PG&E; Pathfinder Renewable Wind Energy/Zephyr Power Transmission, LLC; Southern California Edison; and TransWest Express LLC.

523 *Development focus areas* represent the areas within which permitting of renewable energy development would be streamlined under the Desert Renewable Energy Conservation Plan.

~~APPENDIX B:~~
~~Strategic Transmission Investment Plan Workshop Summaries~~

~~In light of the transmission-related recommendations from the *2012 IEPR Update* and emerging issues and opportunities since that report was published, the Energy Commission held two workshops to introduce and develop these issues with input from stakeholders and create recommendations consistent with the legislative mandate to produce a biennial *Strategic Transmission Investment Plan*. The IEPR and Siting lead commissioners conducted a workshop on the morning of May 7, 2013 on the consideration of environmental and land-use factors in renewable scenarios for transmission planning and renewable energy project database issues. The IEPR lead commissioner then held a workshop on transmission planning and permitting issues on the afternoon of May 7, 2013.~~

~~May 7, 2013 (Morning) Joint IEPR/Siting Lead Commissioner Workshop~~

~~This workshop addressed Recommendation #9 in the Renewable Action Plan (Chapter 5 of the *2012 Integrated Energy Policy Report Update*), which directs the Energy Commission to ensure that environmental and land-use information developed through relevant sources is incorporated into renewable resource scenarios used in the California Public Utilities Commission (CPUC) Long-Term Procurement Plan (LTPP)proceeding and the California Independent System Operator (California ISO) Transmission Planning Process (TPP). Recommendation #9 also directs the Energy Commission to continue to develop its in-state and out-of-state renewable project databases via a public, transparent process that provides opportunities for stakeholder involvement. The purpose of this workshop was to discuss the goals and scope of this effort, data needs, possible sources of publicly available data, gaps in available information, data collection issues, and possible options.~~

~~Formal presentations at this workshop included a CPUC staff update on the CPUC's LTPP portfolio/scenario development process; an Energy Commission staff update on the Energy Commission's existing renewable energy project database and the environmental scoring method for LTPP renewable scenarios; and a CPUC staff presentation that provided background on the CPUC's RPS Calculator and consideration of long-term environmental/land-use data needs. Following the formal presentations, Energy Commission staff moderated a roundtable discussion on environmental/land-use data for scenario planning and renewable energy project database issues. Panelists included representatives from Energy Commission staff, CPUC staff, California Department of Fish and Wildlife, U.S. Bureau of Land Management, Los Angeles County, Western Electricity Coordinating Council, Natural Resources Defense Council, The Nature Conservancy, and SunPower Corporation. Four parties made public comments at the workshop. These included representatives for the Power Company of Wyoming, Large-Scale Solar Association, Pathfinder Renewable Wind~~

~~Energy/Zephyr Power Transmission, LLC, and Defenders of Wildlife. Following the workshop, the Energy Commission received written comments on the workshop topics from the following organizations: Bay Area Municipal Transmission Group, Joint comments by The Nature Conservancy/Defenders of Wildlife/Sierra Club/Natural Resources Defense Council, supplemental comments by Natural Resources Defense Council, PG&E, Pathfinder Renewable Wind Energy/Zephyr Power Transmission, LLC, Power Company of Wyoming, and supplemental comments by The Nature Conservancy.~~

~~Two key issues emerged from the discussion, comments, and presentations of this workshop. The first issue that several participants articulated is a concern with the current environmental weighting in planning and/or the desire for placing greater weight on the environmental portfolio in the LTPP process and environmental impact in the TPP process. The workshop generated several informative discussions and comments related to the types of environmental (and other) data that should be considered for use in the environmental scoring of projects. However, it appears any efforts to revise environmental scoring methodology itself or incorporate other datasets would have little effect on the transmission planning outcome because environmental score carries only a 10 percent weight in the commercial interest portfolio, which has been selected in past years and used in the main modeling for the LTPP at present. This issue of environmental score weighting remains a barrier to a more robust consideration of environmental data in the CPUC and California ISO planning processes.~~

~~CPUC staff reported their ongoing study and "back testing" of past environmental scoring and methods, and possibly reevaluating the weighting, to determine relevancy to renewable energy projects and the LTPP process. Staffs of the CPUC and Energy Commission will collaborate as results from this CPUC study become available, and CPUC plans to hold a public stakeholder process if a new method is developed. Energy Commission staff would participate in that process and other opportunities to revisit environmental score weighting. CPUC anticipated this process of potential new scoring method development and stakeholder vetting to be completed by late 2013 or early 2014. In addition, Commissioner Andrew McAllister mentioned his ongoing collaboration with the CPUC regarding resources needed and data collection, which are related to advancing issues related to both transmission planning and energy efficiency.~~

~~To address the issue of environmental weighting in transmission planning, Recommendation #1, item 2 recommends that the energy agencies (Energy Commission, CPUC, and California ISO) evaluate the environmental weighting process and policies associated with the LTPP and TPP processes. If attempts to significantly increase the weight on environmental scores are successful, many of the detailed data and methodology-related comments arising from this workshop could have more of an effect on planning outcomes and processes.~~

~~Renewable project database maintenance and improvement were the second main focus of the morning joint lead commissioner workshop. Energy Commission staff presented a summary of Energy Commission renewable data collection: (1) the Strategic Transmission Planning Office's siting-related tracking in the renewable energy project database (Renewable Energy Action~~

~~Team [REAT] renewable generation database) and (2) the Renewable Energy Office's RPS Program-related tracking of verification, certification, and other data. Workshop participants provided feedback on the data fields of most interest to them and important characteristics of a publicly accessible database. The data fields of particular stakeholder interest that are already tracked by staff include geospatial linking data, capacity, acreage, technology type, status (project phase), facility on-line date, date of last project information update, and location. Most participants provided recommendations regarding potential expansions to the scope of data tracking, including incorporation of other datasets for California and out-of-state resources. Some participants (for example, the Nature Conservancy and PG&E) noted difficulties in consolidating various online data sources and supported creation of a centralized renewable energy data clearinghouse, which is the subject of a separate, albeit relevant, recommendation under the Energy Commission's Renewable Energy Action Plan (RAP). The Energy Commission's Electricity Supply Analysis Division staff is implementing RAP Recommendation 14 through participation in CPUC's Order Instituting Rulemaking (OIR) and reported the scope of that OIR appears sufficiently broad to incorporate siting-related renewable project data useful for transmission planning. Staff agrees with PG&E's caution regarding the significant effort required to consolidate and maintain existing data and that "a new clearinghouse would provide little value if it duplicates data that already exist elsewhere."The Energy Commission will continue to maintain the Renewable Energy Action Team renewable generation database on the Energy Commission web page and keep it updated quarterly to the extent possible. The Energy Commission will consider integrating some of the information from the other data sources mentioned (as feasible).~~

~~May 7, 2013, (Afternoon) IEPR Lead Commissioner Workshop~~

~~The IEPR lead commissioner then held a workshop on transmission planning and permitting issues on the afternoon of May 7, 2013. This workshop contributes to development of the Energy Commission's 2013 IEPR proceeding. In particular, the workshop responded to the 2013 IEPR Scoping Order, dated March 7, 2013, which directs the Energy Commission to prepare a *Strategic Transmission Investment Plan* as required by Senate Bill 1565 (Bowen, Chapter 692, Statutes of 2004.) In addition, the workshop addressed implementation of Recommendation #10 (Monitor Status of California ISO-approved Transmission Projects to Ensure Timely Completion) and #11 (Streamline Transmission Permitting in California) in the Renewable Action Plan (Chapter 5 of the *2012 Integrated Energy Policy Report Update*). Major workshop topics included: western states transmission issues, status of approved transmission projects to meet the 33 percent Renewables Portfolio Standard, and synchronization of generation and transmission permitting to achieve renewable policy goals.~~

~~Presentations at this workshop included an Energy Commission staff presentation on Western Electricity Coordinating Council restructuring, a California ISO staff presentation on the California ISO Energy Imbalance Market Design Straw Proposal, a California ISO staff update on transmission planning to support the 33 Percent RPS mandate, and a presentation by Southern California Edison staff on Development Focus Area Suitability and Transmission~~

~~Planning. Following the formal presentations, Energy Commission staff moderated a roundtable discussion on synchronization of generation and transmission permitting to achieve renewable policy goals. Panelists included representatives from BrightSource Energy, Paul Hastings, LLP, for Abengoa Solar, Mangano Homes Inc. for Westlands Solar Park, SunPower Corporation, Southern California Edison, PG&E, California Municipal Utilities Association, CPUC staff, California ISO staff, Startrans IO, LLC, and Natural Resources Defense Council. Following the workshop, the Energy Commission received written comments from the Bay Area Municipal Transmission Group, Joint comments by California Consumer Alliance/Clean Coalition, Imperial Irrigation District, Large-Scale Solar Association, Wyoming Infrastructure Authority, Natural Resources Defense Council, PG&E, Pathfinder Renewable Wind Energy/Zephyr Power Transmission, LLC, Southern California Edison, and TransWest Express LLC.~~

APPENDIX C: California Independent System Operator *Demand Response and Energy Efficiency Roadmap*

The California ISO's *Demand Response and Energy Efficiency Roadmap* sets out a plan for how DR and energy efficiency will become integral, dependable, and familiar resources that support a reliable transition to an environmentally sustainable electric power system. The California ISO envisions that the strategies contained in this roadmap will form the core of an ongoing dialogue and interagency collaboration that will result in the optimal availability of these resources to help shape load, bolster resource sufficiency, and promote efficient and economical grid operations.

The roadmap is composed of four parallel and roughly concurrent paths that run from 2013 through 2020. The roadmap highlights specific areas where coordination and communication will build new market opportunities for DR and energy efficiency solutions to meet the needs of both end-use customers and the power system as a whole.

The **load reshaping path** focuses on the demand side of the balance equation to create a flatter system load shape. This path emphasizes programs and incentive mechanisms such as retail tariff structures that change consumer behavior and favorably alter the load shape, by making it more expensive to consume energy when demand is high and less expensive to consume energy when demand is low. This path also highlights activities for incorporating "load-modifying" DR programs into the demand forecast, such as providing locational and time-varying market signals to end users to elicit demand-side responses that align with system conditions. Such energy efficiency and DR programs could offset the need for new generating plants and could help in planning transmission upgrades and in determining future resource requirements. The California ISO is working with the Energy Commission, CPUC, and IOUs to clarify and standardize the terminology for classifying DR programs and resources so that all existing DR programs will be classified for the *IEPR* demand forecast.

The **resource sufficiency path** focuses on the supply side of the balance equation to ensure that sufficient resources with the needed operational characteristics are available in the right places at the right times. This path emphasizes the development of policies to guide and ease procurement of the needed DR resources through the procedures of each relevant agency and its jurisdictional load-serving entities. The California ISO will develop a catalog of DR resource types that includes typical DR operational attributes and capabilities and offers initial indications of which configurations could effectively offset or at least defer the need for a transmission upgrade. This information will inform the 2013-2014 transmission planning cycle and could provide study support for local resource procurement decisions in the 2014 LTPP proceeding. It will also form the basis for further ISO, CPUC, and Energy Commission coordinated efforts to arrive at consistent DR and energy efficiency assumptions to be used in future LTPP cycles. In addition, the California ISO will develop policy to replace the existing backstop procurement mechanism (Capacity Payment Mechanism) that expires on March 31, 2015, with a market-based mechanism that would provide revenue certainty and price transparency for fast developing resources as well as support investments in upgrades to existing resources.[524]

The **operations path** takes the perspective of the grid operator responsible for continuous system balancing and focuses on making the best use of the resources that are made available through resource sufficiency path activities. This path would change some existing policies, modify or develop new market products to expand market participation in DR, and address relevant technical and process requirements. Such policies, markets, and technologies include:

- *Rule 24*: Enables existing utility DR programs as well as third-party aggregators to participate fully in the California ISO's wholesale market and is set for completion by 2014. SCE has indicated that the implementation of Rule 24 with Reliability DR Resource (required for emergency DR to bid and be dispatched through the California ISO's market) should bring 1,100 MW of DR capacity into the California ISO market in the summer of 2014.
- *Participating load model*: Enables DR to participate in the California ISO markets by increasing and decreasing consumption. The nongenerating resource model, which enables energy storage to participate by either increasing load (charging) or providing power to the system (discharging), can be adapted through a stakeholder process to enable participating load to be a dispatchable demand resource to support the ability of participants to more fully reflect operating capabilities to the California ISO market.
- *Must-offer obligation*: Obliges DR resources to submit economic bids into the California ISO day-ahead and real-time markets. Ensures the ISO can access DR resources for normal or emergency operations. A stakeholder process to define the must-offer obligation for flexible resources including use-limited resources will begin in 2013 to support the recent CPUC decision for the IOUs to report RA showing for 2015 compliance.
- *Standard capacity product for DR*: Provides a mechanism that offers an incentive or disincentive to a resource based on resource availability, reflecting whether it is providing the capacity value that it was procured for.
- *DR market participation guide*: Includes the California ISO participation steps for DR aggregators who intend to get RA credit and therefore must participate in the ISO market. The California ISO also will streamline the current process for assigning resource IDs as well as registering the customer accounts to provide the basis to define requirements and develop an automated interface for supplying registration data to the ISO.

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524 The new capacity procurement mechanism procures capacity that is not already designated as resource adequacy capacity and is obligated to be available to the California ISO for scheduling and dispatch comparable to the obligations of resource adequacy capacity.

The **monitoring path** provides an essential feedback loop to the other three paths. This path ensures that from the beginning there are mechanisms in place for monitoring progress and outcomes and for providing feedback to the people and organizations responsible for the initiatives outlined in this roadmap. The goal of this path is that, with each stage of activity, this roadmap will foster a deeper understanding of the operational capabilities of DR resources, the effectiveness of DR and energy efficiency procurement programs in aligning with systemwide and locational needs, and the impacts of energy efficiency and other load-modifying programs to reshape the system demand curve. This path is a collaborative stakeholder process to assess the resource performance needs of the California ISO system in concert with the needs of consumers that will provide DR resources and cooperatively develop energy efficiency and DR programs and incentives that meet both sets of needs. By 2014, the California ISO, Energy Commission, and CPUC should reach consensus on a process to track the development of DR and energy efficiency programs, which will help ensure that DR and energy efficiency resources will be in service as alternatives to transmission upgrades.

APPENDIX D: California Public Utilities Commission Staff Comments on the Draft Demand Response and Energy Efficiency Roadmap

The CPUC overall agrees that the four paths laid out in California ISO's draft roadmap provide a clear mechanism to allow the California ISO and the CPUC to address the supply-side and demand-side demand response (DR) and energy efficiency issues effectively. However, the CPUC's DR goals will involve developing DR under two frameworks: 1) as a supply-side resource, which focuses on a reliable and flexible DR that meets system planning and operational requirements; and 2) as a demand-side resource, which focuses on sustainable customer participation and rates. (See Table D-1 for a comparison of the two plans.)

The CPUC's discussion of DR as a **supply-side resource** is covered in its comments of the California ISO's Resource Sufficiency and Operations paths. The CPUC notes that only supply-side DR would be counted for resource adequacy (RA) as a supply-side resource and that the CPUC DR Rulemaking would be the likely venue to determine classification of DR resources. The CPUC suggests that implementing the corresponding RA counting rules would be best suited for the 2015 RA proceeding, which will also address the must-offer obligation for flexible, use-limited resources. In addition, the CPUC staff agrees that recognition and acceptance of the differences between DR and conventional generation are important so that California ISO operators and DR providers are proceeding with common expectations about resource performance. Finally, the CPUC staff agrees that the California ISO needs to develop a Standard Capacity Product (SCP) for DR with transparent rules and penalties for performance consistent with RA rules for conventional generation resources. The CPUC and California ISO will need to coordinate closely in setting the appropriate RA rules during the transition period and determine whether the must-offer obligation should be required in absence of SCP for DR.

The CPUC's discussion of DR as a **demand-side resource** is covered in its comments of the California ISO's load reshaping path. The CPUC has adopted timelines for the three large IOUs to phase-in default critical peak pricing for most nonresidential customers by 2016 and is therefore on a path to have a significant portion of IOU load on rates well-aligned with grid conditions. In addition, the CPUC is considering what types of rates should be offered to residential customers and on what basis (opt-in, opt-out, and so forth). The CPUC recognizes that it needs to find ways to make more economically efficient rate designs acceptable and attractive to the public, and it states that new legislative changes are needed to reform rates.

In response to the monitory path, the CPUC staff agrees that monitoring of DR and energy efficiency resources is important to ensure that the initiatives described in the draft roadmap accomplish their objectives and to make appropriate modifications as needed. One additional question the CPUC and California ISO need to resolve is determining which agency will be responsible for determining the load impacts of third-party DR programs that bid into California ISO wholesale markets.

To summarize, the CPUC describes four main policy goals in its comments:

1. Integration of DR into wholesale market
2. Increased use of time-based rates and AMI-enabled devices
3. Increased Customer Participation
4. Improved DR metrics and goals

Finally, its procedural roadmap for DR is as follows:

- Finalize Rule 24 by Fall 2013
- Open New DR Rulemaking by September 2013. This involves:
    - Interagency coordination with California ISO and the Energy Commission to develop DR strategic plans.
    - DR evaluation and cost-effectiveness reform.
    - DR delivery model and cost recovery.
    - Bridge funding year for 2015.
    - Guidance for future DR program design.
- 2015 RA: Flexible Capacity Framework for DR by June 2014

Table D-1: Mapping of California ISO Four Paths and CPUC Vision

	California ISO Draft DR/EE Roadmap	**CPUC Vision for DR (June 17 Presentation at CEC IEPR Workshop)**	**How it will be accounted for in RA**
1	Load Reshaping Path	Customer-Focused Programs and Rates: • Load modifiers, e.g., dynamic rates, DR supporting programs, non-dispatchable DR	Resources will be reflected in the Energy Commission's load forecast
2	Resource Sufficiency Path	Supply-Side Resources: • Dispatchable DR o IOU Programs o 3rd Party Programs	Resources will qualify for RA/LTPP/TPP
3	Operations Path		
4	Monitoring Path	Evaluation, Monitoring, & Verification (EM&V): • Supply-Side Resources • Customer-Focused Programs and Rates	

Source: CPUC comments on the CAISO Roadmap, http://www.energy.ca.gov/2013_energypolicy/documents/2013-06-17_workshop/comments_to_caiso_dr_ee_roadmap/California_Public_Utilities_Commission_Comments_2013-07-24_TN-71704.pdf

APPENDIX E:
Approach to Estimating Alternative and Renewable Fuel and Vehicle Program Benefits

The Energy Commission has contracted with the National Renewable Energy Laboratory (NREL) for assistance in estimating the environmental, public health and economic benefits from the Alternative and Renewable Fuel and Vehicle Technology Program (ARFVTP). NREL has developed the method described in this appendix, and quantitative benefit estimates will be finalized later in 2013. NREL recommends using the characterization of distinct types of benefits, which in general fall into two categories: *Demonstrated Benefits* and *Expected Benefits*. These two general categories include various sub-categories:

Demonstrated Benefits

These benefits accrue as advanced technology vehicles are driven and alternative fuels are consumed. Two distinct types of Demonstrated Benefits are quantified:

- **Demonstrated Program Benefits:** The result from the deployment and use of vehicles or fuels that have received direct monetary support from ARFVTP.
- **Demonstrated Baseline Benefits:** These result from the deployment and use of vehicles or fuels that have not received direct monetary support from ARFVTP.

Expected Benefits

These benefits are more hypothetical in nature than *Demonstrated Benefits*, primarily because they are more uncertain and difficult to measure. There are two general categories:

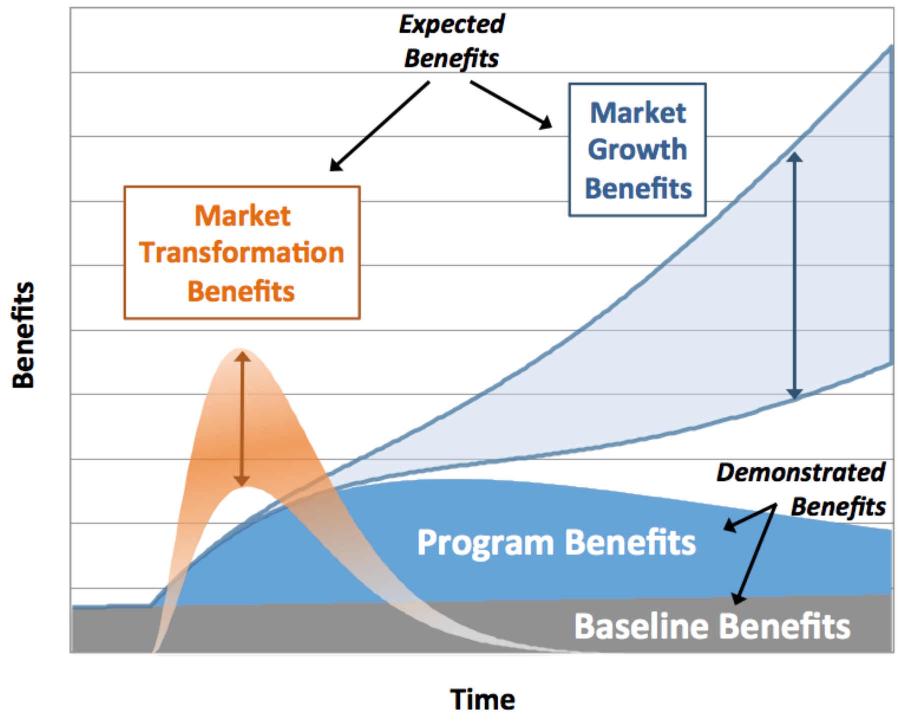
- **Market Transformation Benefits:** These benefits are realized through efforts that help reduce market entry barriers for new technology companies, increase consumer awareness, and remove consumer choice barriers associated with limited refueling availability. Examples of Market Transformation Benefits resulting from ARFVTP investments include market changes in electric-drive cars and trucks, hydrogen fuel cell cars, and natural gas or renewable natural gas fueling and vehicle systems.
- **Market Growth Benefits:** These benefits are estimated quantitatively with high and low market adoption projections for vehicles and fuels. For ARFVTP-funded projects, Market Growth Benefits would accrue when a demonstration or pilot-scale project is constructed at commercial scale.

Several projects supported by ARFVTP will result in additional expected benefits, such as outreach, education, standards development, and policy support. Although these additional expected benefits may be substantial, they are difficult to quantify due to unclear relationships between cause and effect. No attempt is made to estimate these other expected benefits at present.

Benefits Over Time

Figure E-1 is a schematic of the general relationships between these various benefit types as they might be realized over time.

Figure E-1: General Types of Benefits as a Function of Time



Source: National Renewable Energy Laboratory Benefits Guidance Report

The schematic is not intended to represent any particular vehicle-fuel combination. *Demonstrated Baseline Benefits* are shown as increasing slowly and linearly across the bottom of the figure, and are realized due to market growth likely to occur in the absence of ARFVTP or other state or federal programs. *Demonstrated Program Benefits* are indicated as a rapid increase in total benefits as new vehicles and fuels are introduced into the market. These benefits would decline over time as market success is achieved and additional funding is no longer required; vehicles funded directly would be used less often as they aged and eventually would be replaced, and fuel systems funded directly would be upgraded through new market-driven investments and eventually retired. These two types of Demonstrated Benefits can be estimated quantitatively and are indicated as additive benefits in Figure E-1.

Through the success of ARFVTP projects and other efforts, sustained market growth is an enduring benefit, achieved as advanced and renewable fuels and vehicles successfully compete in the market without substantial monetary government support. These Market Growth

Benefits are indicated as a range of high and low market projection trends that increase as total Demonstrated Program Benefits decline.

Finally, Market Transformation Benefits are achieved during the early phases of ARFVTP and early market growth, especially by increasing fueling availability for early niche markets. As demand increases, new investments in fueling infrastructure are market-driven and fueling availability becomes less of a market barrier for consumers.

Table E-1: Market Transformation Benefits – GHG Reductions Based on the 188 Projects Funded Through ARFVTP Between 2009 and June 2013

GHG Reductions (Thousand Metric Tonnes CO2e)		**2015**	**2020**	**2025**
Vehicle Price Reductions	High	270.0	614.0	556.2
-	Low	120.9	242.3	200.3
ZEV Industry Experience	High	13.1	38.0	46.8
-	Low	11.6	33.5	41.3
Next Generation Trucks	High	92.0	367.9	367.9
-	Low	4.47	17.9	17.9
Next Generation Fuels	High	-	791.7	1,123.0
-	Low	-	27.5	280.7
Total	**High**	**375.1**	**1,811.6**	**2,093.9**
-	**Low**	**136.9**	**321.1**	**540.2**

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Table E-2: Market Transformation Benefits – Petroleum Reductions Based on the 188 Projects Funded Through ARFVTP Between 2009 and June 2013

Petrol Reductions (Million DGE/GGE)		**2015**	**2020**	**2025**
Vehicle Price Reductions	High	33.1	81.2	83.5
-	Low	7.7	15.7	14.4
ZEV Industry Experience	High	1.7	5.0	6.9
-	Low	1.5	4.4	6.1
Next Generation Trucks	High	11.0	44.0	44.0
-	Low	-	3.1	3.1
Next Generation Fuels	High	-	72.0	101.4
-	Low	-	2.6	25.3
Total	**High**	**45.8**	**202.1**	**235.8**
-	**Low**	**9.2**	**25.9**	**48.9**

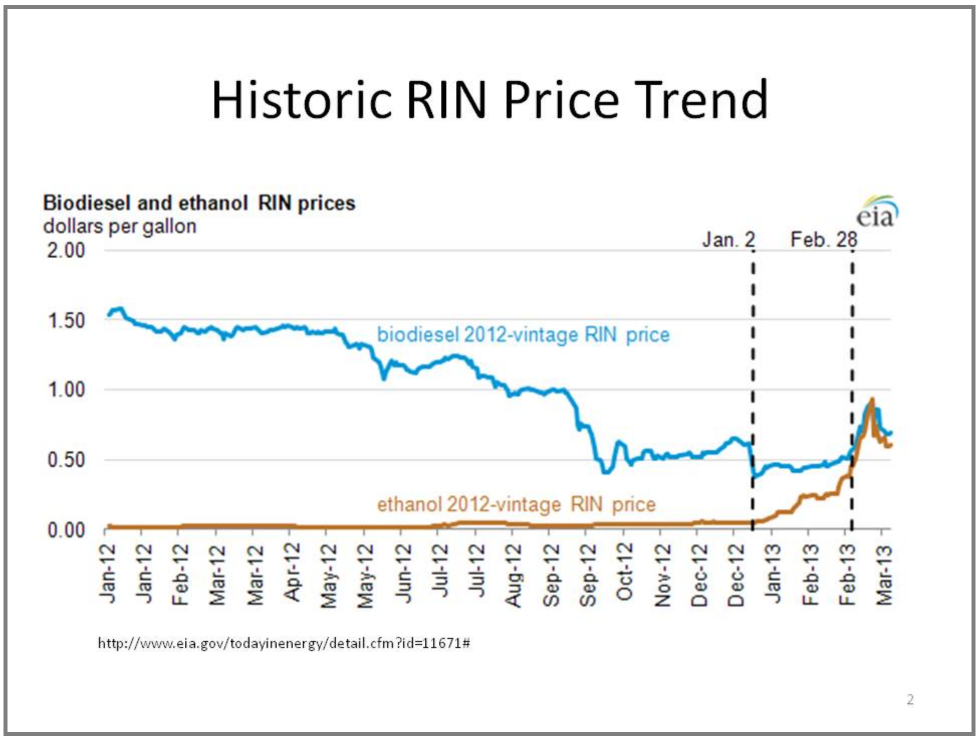
Source: NREL Benefits Guidance Report

The four categories indicated include a subset of all projects supported by ARFVTP. These include projects anticipated to have a significant impact on future market adoption rates, resulting in vehicle and fuel sales that are additive to those included in the Expected Benefits category. Vehicle Price Reduction benefits include additional vehicle sales associated with incentives provided through the Clean Vehicle Rebate Project, as well as estimates of sales increases due to EVSE and hydrogen stations installed with ARFVTP support. ZEV Industry Experience benefits include additional sales resulting from investments in vehicle production and manufacturing processes. The Next Generation Truck and Fuel categories include estimates of additional vehicle deployments and fuel production facility installations subsequent to those receiving direct support from ARFVTP.

APPENDIX F:
Renewable Identification Numbers Under the Renewable Fuels Standard

Figure F-1 illustrates fluctuations in Renewable Identification Number (RIN) credits, which reflect recent market conditions. RINS have different values for renewable fuels, advanced fuels, biodiesel and renewable diesel depending on the extent obligated parties can comply with annual RFS requirements, levels set or modified for each category, and the availability of credits generated by commercial sales of renewable fuels.

Figure F-1: Historical RIN Price Trend



Source: http://www.eia.gov/todayinenergy/detail.cfm?id=11671=

APPENDIX G: Transportation Demand Forecast and Supply/Demand Balance

Light-Duty Vehicles

The 2013 demand forecast for passenger vehicles and light trucks has been developed from surveys of consumers and commercial businesses. The Energy Commission staff used projected changes in vehicle attribute characteristics over the next 30 years to help estimate the forecast. Vehicle attribute changes included vehicle cost (manufacturer suggested retail price), fuel economy, vehicle miles traveled, income, and other factors. Vehicle information was gathered from a recent National Academy of Sciences (NAS) study, which showed that significant increases in fuel economy will occur in all cars and light trucks between 2011 and 2030. The study also concluded that internal combustion vehicles will increase in cost, but alternative fuel vehicles will see reduced costs over the same period. Table G-1 summarizes the NAS expected changes.

Table G-1: Forecasted Fuel Economy and Manufacturer Suggested Retail Price (2011-2030) (NAS Reference Case)

Vehicle Type		Fuel Economy Improvement	(MSRP) Increase>/Decrease<
Internal Combustion Engine	Car	61%	> 7%
	Light Truck	55%	> 6%
Compressed Natural Gas	Car	61%	NA
	Light Truck	55%	NA
Hybrid Electric	Car	49%	< 4%
	Light Truck	41%	< 4%
Plug In Electric	Car	61%	< 8%
	Light Truck	60%	< 10%
Battery Electric	Car	21%	< 24%
	Light Truck	16%	< 25%
Hydrogen Fuel Cell	Car	24%	< 13%
	Light Truck	20%	< 13%

Source: California Energy Commission and Sierra Research

Vehicle attribute assumptions include full implementation of California Air Resources Board's (ARB) zero-emission vehicle mandate reflecting the expected market penetration of electric and hydrogen electric vehicles associated with the ARB program. Furthermore, consumer transportation demand should begin to reflect the results of plans adopted by several metropolitan planning organizations under the state's "Sustainable Communities Energy Strategy" (SB 375) since 2009.

The passenger vehicle and light truck stock is expected to grow from 27 million vehicles in 2012 to a range of 42 million to 47 million vehicles in 2050 depending on petroleum fuel costs. Of the existing California light-duty vehicle stock in 2012, the top five vehicle classes of total vehicles on the road include midsize, compact, and subcompact cars and standard and compact pickup trucks. Standard pickup trucks and midsize cars represent 38 percent, making them the two largest categories of commercial vehicles.

Medium- and Heavy-Duty Trucks

Nearly 1 million trucks operate on California's roads, with nearly 70 percent using diesel fuel, 29 percent using gasoline, and the remainder representing alternative fuels. Trucks are categorized by weight and driving operations. Long-haul trucks that carry cargo primarily along major highways with mileage exceeding 100,000 miles per year are classified as class 7 and 8 trucks—most use diesel fuel with options to use biodiesel or renewable diesel blended with diesel. Natural gas (LNG) trucks have begun to replace some of the diesel trucks in these categories because of the lower natural gas fuel price compared to diesel costs. Refuse trucks, package and beverage delivery trucks, shuttle vans, and utility trucks are examples of other categories with different operation characteristics and varying annual mileage.

Freight movement

Freight movement data covering 1997 to 2011 from the Federal Highway Administration show a modest increase in goods movement within California from other states but a 50 percent increase in goods moved from California to other states. The same freight movement in ton-miles indicates domestic freight reflects the movement of lower value but massive goods, including lumber, minerals, and stone. California typically imports goods of higher value and lower mass.

Trucking moves the majority of interstate freight from California to other states. Rail and intermodal move the majority of freight from other states to California. The energy consumed by trucks to move a large volume of freight is significantly greater than the energy consumed moving the same volume by rail. For this reason, opportunities to shift freight from truck to rail can result in lower energy consumption.

California trucks moving within the state cover nearly two-thirds of the truck miles, with the remainder covered by interstate trucks. A larger share of the California trucks moving within the state are the smaller weight classes, while the interstate trucks tend to be the largest classes. Somewhat more of interstate truck movement is by trucks based in other states than trucks based in California.

The travel time index measures traffic congestion on average as the actual time required to make urban trips divided by the time required to make the same trips at times with no traffic congestion. The general increase in traffic congestion from the early 1980s to about 2007 was broken by the recession starting in 2008.

Urban and Intercity

Travel demand in California is forecasted by the Energy Commission's urban and intercity models. The Urban model is used to forecast passenger trips of fewer than 50 miles, while the Intercity model is used to forecast passenger trips greater than 50 miles. Population and income growth are the main drivers of travel demand in the state. Although population growth rates have declined, California will add 350,000 new people every year and urban traffic congestion has not abated. This is a significant factor because vehicle trips average 3.5 times per day for households, daily travel averages 35 miles per person, and vehicle occupancy shows no signs of decreasing. Congestion remains high in California's urban areas. Population growth means that more fuels will be needed, but consumption is offset by vehicle efficiency.

Urban Travel

Urban travel comprises 72 percent of passenger miles traveled in California, and urban trips average 1.5 passengers per vehicle. The number of passenger trips taken in light-duty vehicles is projected to increase from 17.8 billion to 26.5 billion during the forecast period in the high case, and 17.8 billion to 23.8 billion in the Low Case. The number of transit passenger trips is projected to increase from 529 million to 967 million during the forecast period in the high case and 529 million to 869 million in the Low Case.

Urban passenger miles follow a similar trend. Passenger miles in light-duty vehicles are expected to increase from 204 billion in 2011 to 304 billion in 2050 in the high case and increase from 204 billion in 2011 to 272 billion in 2050. An increase in transit passenger miles is also anticipated, with an increase from 8.7 billion in 2011 to 15.9 billion in the High Case, and 8.7 billion to 14.3 billion in the Low Case.

As expected, urban vehicle miles also experience a substantial increase. In the High Case forecast, light-duty vehicle miles increase from 136 billion in 2011 to 202 billion in 2050. In the Low Case, vehicle miles increase from 136 billion in 2011 to 182 billion in 2050. A significant increase in transit vehicle miles is expected in the High Case, with the number of miles almost doubling during the forecast period, from 396 million in 2011 to 727 million in 2050. In the Low Case, transit miles are forecasted to increase from 396 million in 2011 to 653 million in 2050.

Intercity Travel

Intercity travel comprises about 28 percent of all passenger travel in California. Automobile, air, bus, conventional rail, and high-speed rail represent the possible options for intercity travel. Auto trips average 1.9 passengers per vehicle.[525]

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525 *California Household Travel Survey*, California Department of Transportation, June 2013.

Intercity passenger trips are expected to increase from 750 million in 2011 to almost 2 billion in 2050 in the High Case. In the Low Case, passenger trips are expected to increase from 750 million in 2011 to 1.7 billion in 2050. In both the high and low projections, the number of intercity passenger trips more than double.

Likewise, intercity passenger miles more than double during the forecast period in the high case, as passenger miles are projected to reach 219 billion in 2050, increasing from 84 billion in 2011. In the Low Case, passenger miles are expected to rise from 84 billion in 2011 to 189 billion in 2050.

Future Direction of Urban and Intercity Travel

Transportation accounts for about 38 percent of greenhouse gas emissions in California, with cars and trucks accounting for almost three-quarters of those emissions. The primary intent of Senate Bill 375 (Steinberg, Chapter 728, Statutes of 2008) is to reduce pollution by improving land-use patterns and establishing a collaborative process between regional and State agencies to set regional targets for reducing greenhouse gas emissions.

California High-Speed Rail will provide an environmentally friendly interregional transportation system and help reduce greenhouse gas emissions, as well as deliver other environmental benefits. The initial section, between Merced and San Fernando, is expected to be operating by 2022. The corridor between San Francisco and Los Angeles will be completed by 2029.

In the San Francisco Bay Area, Caltrain plans to convert its diesel trains to electricity beginning in 2019 and to share a corridor with the high-speed rail system by 2029.

Based on diesel fuel consumption of more than 4 million gallons in 2011,[526] electrification of rail systems would remove between 6.9 million and 7.7 million gallons of diesel fuel in 2050 if ridership growth is proportional to projected statewide population and income growth in the same time frame.

526 Transit Agency Survey, California Energy Commission, 2012.

APPENDIX H: NRC Post-Fukushima Activities

Table H-1: NRC Post-Fukushima Activities

TIER 1 ACTIVITIES	DESCRIPTION	NRC ACTION
Mitigation Strategies	To enhance the capability to maintain plant safety during a prolonged loss of electrical power.	Order
Containment Venting System	To provide a reliable hardened containment vent system for boiling water reactors (BWRs) with Mark I or Mark II containment designs.	Order
Spent Fuel Pool Instrumentation	To provide a reliable wide-range indication of water level in spent fuel storage pools.	Order
Seismic Reevaluations	To reanalyze potential seismic effects using present-day information to determine if safety upgrades are needed.	Request for Information
Flooding Hazard Reevaluations	To reanalyze potential flooding effects using present-day information to determine if safety upgrades are needed.	Request for Information
Seismic and Flooding Walkdowns	To inspect existing plant protection features against seismic and flooding events, and correct any degraded conditions	Request for Information
Emergency Preparedness – Staffing and Communications	To assess staffing needs and communications capabilities to effectively respond to an event affecting multiple reactors at a site.	Request for Information
Station Blackout Mitigation Strategies	To enhance the capability to maintain plant safety during a prolonged loss of electrical power.	Rulemaking
Onsite Emergency Response Capabilities	To strengthen and integrate different types of emergency procedures and capabilities at plants.	Rulemaking
Filtration and Confinement Strategies	To evaluate potential strategies that may further confine or filter radioactive material if core damage occurs	Rulemaking
TIER 2 ACTIVITIES		
Spent Fuel Pool Makeup Capability	To provide a reliable means of adding extra water to spent fuel pools	Order (consolidated into Mitigation Strategies)
Emergency	To address three aspects of Emergency Preparedness	Order (1 and 2

Preparedness	for multi-reactor and loss of power events: 1. Training and exercises (drills) 2. Equipment, facilities, and related resources 3. Multi-unit dose assessment capability	consolidated into Mitigation Strategies) NRC-endorsed industry initiative (to address 3)
"Other" External Hazard Reevaluations	To reanalyze the potential effects of external hazards other than seismic and flooding events (which are being addressed under Tier 1).	Request for Information [planned]
TIER 3 ACTIVITIES		
Periodic Confirmation of External Hazards	To ensure external hazards, such as seismic and flooding effects, are periodically reanalyzed during the lifetime of a plant.	Rulemaking (planned)
Seismically-Induced Fires and Floods	To evaluate potential enhancements to the capability to prevent or mitigate seismically-induced fires and floods.	Longer-term evaluation
Venting Systems for Other Containment Designs	To evaluate the need for enhancements to venting systems in containment designs other than Mark I and II (which are addressed under Tier 1).	Longer-term evaluation
Hydrogen Control	To evaluate the need for enhancements to hydrogen control and mitigation measures inside containment or other plant buildings.	Longer-term evaluation
Emergency Preparedness	To evaluate additional enhancements to Emergency Preparedness (EP) programs that go beyond the Tier 1 and Tier 2 EP-related activities.	Longer-term evaluation
Emergency Response Data System (ERDS) Capability	To enhance the capabilities of the Emergency Response Data System (ERDS)	Longer-term evaluation
Decision-making, Radiation Monitoring, and Public Education	To evaluate the need for enhancements to Emergency Preparedness programs in the areas of decision-making, radiation monitoring, and education.	Longer-term evaluation
Reactor Oversight Process (ROP) Updates	To modify the Reactor Oversight Process to reflect any changes to the NRC's regulatory framework (which is being pursued under a separate activity).	Dependent on Regulatory Framework activity
Training on Severe Accidents	To enhance training of NRC staff on severe accidents and related procedures.	Dependent on outcome of Onsite Emergency Response Capabilities (Tier 1)
Emergency Planning Zone	To evaluate whether the basis for the size of the emergency planning zone needs to be modified.	Longer-term evaluation
Potassium Iodide (KI)	To evaluate the need to modify existing programs for the pre-staging of potassium iodide.	Longer-term evaluation
Expedited Transfer of	To evaluate the merits of expediting the transfer of	Longer-term evaluation

Spent Fuel to Dry Cask Storage	spent nuclear fuel from storage pools to dry cask storage.	
Reactor and Containment Instrumentation	To evaluate potential enhancements for instrumentation in the reactor and containment that can withstand severe accident conditions.	Longer-term evaluation

Source: Nuclear Regulatory Commission, http://www.nrc.gov/reactors/operating/ops-experience/japan-dashboard/priorities.html

APPENDIX I:
Summary and Status of *2011 IEPR* Nuclear Policy Recommendations

Table I-1: Summary and Status of *2011 IEPR* Nuclear Policy Recommendations

Seismic Issues			Status
2011-1	PG&E CPUC IPRP	PG&E should provide in a timely manner to the Energy Commission, the CPUC, and the Independent Peer Review Panel (IPRP) the technical details and any significant updates of their proposed seismic hazard study plans and findings for Diablo Canyon.	IPRP review of PG&E's seismic studies on-going. Report #6 issued 8/12/13.
2011-2	PG&E ASLB CPUC	PG&E should submit to the Atomic Safety and Licensing Board (ASLB), as part of PG&E's final seismic report to the ASLB in the Diablo Canyon license renewal proceeding, the findings and recommendations from the California IPRP on PG&E's seismic studies. These studies include PG&E's onshore and offshore seismic studies funded by CPUC Decision 10-08-003.	PG&E's completion of AB 1632 recommended seismic studies on-going~~–~~. PG&E has completed 2D/3D Low Energy Seismic Surveys and 2D Onshore High Energy Studies~~–~~. Data processing and interpretation are continuing. The final report is currently expected to be complete in June 2014 and will be provided to state and federal agencies~~PG&E's AB 1632 seismic studies on-going; NRC SSHAC analysis on-going and scheduled for completion March 2015.~~.
2011-3	SCE CPUC CAISO NRC	The CPUC should establish a San Onofre IPRP, comparable to Diablo Canyon's IPRP, to review San Onofre's seismic hazard study plans and findings as recommended in the *2008 IEPR Update*. SCE should provide in a timely manner to the Energy Commission, the CPUC, and the IPRP the technical details and any significant updates to their proposed seismic hazard study plans and findings for San Onofre. SCE should include the IPRP's evaluations, findings, and recommendations in its seismic hazard analyses and submittals to the NRC. California's IPRPs for PG&E's and SCE's seismic studies for Diablo Canyon and San Onofre should coordinate their seismic hazard evaluations.	San Onofre IPRG established 5/15/2012. IPRG review of SCE's seismic studies on-going. Report #2 issued 7/17/13.
2011-4	CPUC CAISO	SCE should include greater representation on its San Onofre's Seismic Advisory Board of independent seismic experts with no current or prior professional affiliation with utilities, including SCE or PG&E, or their consultants. The composition of SCE's San Onofre's Seismic Advisory Board of independent seismic experts should exclude those with a continuing	On 7/7/2013, SCE announced plans to permanently retire San Onofre Units 2 & 3. SSHAC process

		affiliation with SCE.	has replaced Seismic Advisory Board efforts.
2011-5	PG&E SCE	PG&E and SCE should provide updates on their progress in completing the AB 1632 Report-recommended seismic studies to the Energy Commission as part of the *2012 IEPR Update*.	Utilities' AB 1632 progress reporting in 2013 IEPR.
Spent Fuel Pool and Independent Spent Fuel Storage Installation			
2011-6	PG&E SCE	PG&E and SCE should investigate adding safety-related instrumentation (capable of withstanding design basis natural phenomena) to monitor in the control room key spent fuel pool parameters, for example, water level, temperature, and radiation levels, during a severe accident in which radiation levels within the spent fuel pool building are unsafe.	<u>PG&E prepared an Overall Integrated Plan for Reliable SFP Instrumentation, including equipment description and design criteria in response to the NRC's 3/12/12 Order EA-12-051, which mandated that all licensees equip SFPs with wide-range level instrumentation capable of withstanding a beyond-design-basis external event. This Plan was submitted to the NRC on 2/27/13. The equipment is scheduled to be installed in October 2015 for Unit 1, and May 2016 for Unit 2.</u>~~Action needed.~~
2011-7	PG&E SCE	To reduce the volume of spent fuel packed into storage pools, and consequently the radioactive material available for dispersal in the event of an accident or sabotage, PG&E and SCE should, as soon as practicable, transfer spent fuel from pools into dry casks, while maintaining compliance with NRC spent fuel cask and pool storage requirements and report to the Energy Commission in the *2012 IEPR Update* on their progress.	Action needed; no net change in storage density from transfers completed to date.
2011-8	PG&E SCE	PG&E and SCE should evaluate, as part of the *2012 IEPR Update*, 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.	Action needed.
Station Blackout			
2011-9	PG&E SCE	SCE and PG&E should report to the Energy Commission, as part of the *2012 IEPR Update*, on progress made in addressing the lessons learned from the station blackout at Fukushima and how well-equipped their plants are to withstand safely a station blackout lasting longer than seven days. This includes reporting on any significant changes, including estimated costs, associated with NRC requirements to address station blackout. It also includes arrangements for accessing emergency backup generation and fuel,	Efforts reported in 2013 IEPR Data Requests Responses/ 2013 IEPR Workshop.

		responding to multiple unit events, seismically and flooding protected equipment, and addressing the lessons learned from Fukushima.	
2011-10	PG&E SCE	PG&E and SCE should report to the Energy Commission on the adequacy of trained people, equipment, and external support, including written agreements, for providing emergency power equipment and fuel for handling an extended station blackout.	Efforts reported in 2013 IEPR Data Requests Responses/ 2013 IEPR Workshop.
Nuclear Plant Liability Coverage			
2011-11	PG&E SCE	Based on the Fukushima experiences, PG&E and SCE should provide a comprehensive study to the Energy Commission, as part of the *2012 IEPR Update*, on the adequacy of Price-Anderson Act liability coverage for a severe event at Diablo Canyon or San Onofre resulting in large offsite releases of radioactive materials.	Action needed.
Replacement Power and Reliability			
2011-12	CAISO PG&E SCE CPUC	To support long-term energy and contingency planning, the California ISO (with support from PG&E, SCE, and planning staff of the CPUC and CEC) should report to the Energy Commission as part of its *2013 IEPR* and the CPUC as part of its 2013 Long-Term Procurement Plan on what new generation and/or transmission facilities would be needed to maintain system and/or local reliability in the event of a long-term outage at Diablo Canyon, San Onofre, or Palo Verde. The utilities should report to the CPUC on the estimated costs of these facilities.	On-going.
2011-13	CAISO PG&E SCE CPUC	As a contingency in the event that Diablo Canyon and San Onofre experience a long-term outage following a major seismic or other event, California ISO with input from the Energy Commission and CPUC, in cooperation with PG&E and SCE, should further evaluate: (1) the uncertainties of a long-term loss of electricity from these plants, (2) the extent to which existing resources have an energy supply capability beyond that used in normal market conditions, and (3) the need for new resources or different types of resources to satisfy any remaining energy gap. If necessary, the long-term planning and procurement process at the CPUC should be modified to ensure that any replacement resources found necessary through these studies are acquired in a timely manner.	On-going.
Emergency Response Planning			
2011-14	CPUC CAL OES	The CPUC should approve funding for Cal EMA or the affected counties to evaluate the adequacy of current evacuation and emergency response plans, emergency planning zones, and training for Diablo Canyon and San Onofre, given the Fukushima accident and NRC's recommended 50-mile evacuation zone for U.S. citizens in Japan. This review should include the adequacy of plans for dealing with prolonged station blackouts (for example, powering communications equipment), multiple or multiunit events at one site, increased population densities and traffic flow configurations near the plants, and the possible loss of access roads and evacuation routes in a major event, such as an earthquake or flooding.	Action needed.
2011-15	DPH	The California Department of Public Health should evaluate the adequacy of equipment, staffing, aerial plume monitoring, and models for dealing with two-unit events at the Diablo Canyon or San Onofre sites involving radioactive releases.	Action needed.
Fukushima Lessons Learned			

2011-16	PG&E SCE	PG&E and SCE should report to the Energy Commission, as part of the *2012 IEPR Update*, and the CPUC on their progress and estimated costs in carrying out the recommendations of the *NRC Near-Term Fukushima Task Force Report*.	Efforts reported in 2013 IEPR Data Requests Responses/ 2013 IEPR Workshop.
2011-17	PG&E SCE	PG&E and SCE should report to the Energy Commission, as part of the *2012 IEPR Update*, on the adequacy of resources, training, and equipment to cope with severe plant events including a station blackout combined with natural or manmade events (earthquake, flooding, fires, or terrorist attack); for example, the availability of (1) seismically robust and flood protected essential safety systems and equipment; (2) suitably shielded, ventilated, and well-equipped facilities needed for the workers to manage the accident; (3) ability to respond to multiple events and multiple-unit events, and (4) trained onsite and offsite responders for a long-term station blackout or loss of all heat sinks.	Efforts reported in 2013 IEPR Data Requests Responses/ 2013 IEPR Workshop.
2011-18	NRC	The NRC should expeditiously move forward on the Post-Fukushima Task Force recommendations, particularly the urgent recommendations.	On-going.
Relicensing			
2011-19	PG&E SCE	To help ensure plant reliability and minimize costs, PG&E and SCE should complete the remaining AB 1632 Report-recommended seismic studies and make their findings available for consideration by the Energy Commission, CPUC, California Coastal Commission, and the NRC during their reviews of PG&E's (and SCE's, if they apply) license renewal application(s) and related certificates. SCE should not file a license renewal application with the NRC without prior approval from the CPUC.	On-going.
2011-20	NRC PG&E SCE CPUC	Since the regulatory changes and requirements recommended by the NRC Near-Term Task Force on Fukushima could result in higher costs, for example, seismic retrofits, PG&E and SCE should provide cost estimates to the CPUC for complying with NRC's requirements and the costs of potential replacement power in the event of an extended outage. The CPUC should consider these additional costs during its license renewal evaluations for Diablo Canyon (and San Onofre, if SCE applies for license renewal).	PG&E provided cost estimates for compliance with the NRC's Fukushima related requirements in its 2014 General Rate Case Application, A.12-11-009. There is currently no DCPP license renewal review pending at the CPUC~~Action needed.~~
2011-21	NRC	The NRC should delay its decisions on license renewal applications pending completion of the post-Fukushima lessons learned studies. NRC's license renewal review for Diablo Canyon and San Onofre (if SCE applies for license renewal) should examine updated site-specific information on seismic and tsunami hazards, emergency preparedness and evacuation timeliness, lessons learned from Fukushima, spent fuel storage options, and plant security. NRC should delay license renewal reviews to allow for consideration of findings from Fukushima studies.	On April 10, 2011, PG&E requested that the NRC defer issuance of renewed operating licenses until updated seismic studies were completed.
Plant Safety			
2011-22	PG&E SCE	PG&E and SCE should report, as part of the *2012 IEPR Update*, on their efforts to improve the safety culture at Diablo Canyon and San Onofre and on the NRC's evaluation of these efforts and overall plant performance.	Efforts reported in 2013 IEPR Data Requests Responses/ 2013 IEPR Workshop.

2011-23	CPUC	The CPUC should consider establishing a San Onofre Independent Safety Committee, modeled after the Diablo Canyon Independent Safety Committee, to provide an independent review of San Onofre safety, performance, and follow-up to the lessons learned from the Fukushima Daiichi plant accident.	On 7/7/2013, SCE announced plans to permanently retire San Onofre Units 2 & 3.
Continuing Activities			
2011-24	CEC	The Energy Commission will continue to monitor reviews of Diablo Canyon and San Onofre by the NRC and the Institute of Nuclear Power Operations; in particular, the Energy Commission will monitor plant performance and safety culture at both plants.	On-going.
2011-25	CEC	The Energy Commission will continue to monitor the federal waste management program and represent California in the Yucca Mountain licensing proceeding (in the event this proceeding resumes) to protect California's interests regarding potential groundwater and spent fuel transportation impacts to the state.	On-going.
2011-26	CEC	The Energy Commission will continue to participate in United States Department of Energy and state regional planning activities for nuclear waste transportation.	On-going.
2011-27	CEC	The Energy Commission will continue to update information on the comprehensive, "cradle-to-grave" or life-cycle economic and environmental impacts of nuclear energy generation compared with alternatives. These include impacts from uranium mining, reactor construction, fuel fabrication, reactor operation, maintenance and repair; reactor component replacement and disposal; spent fuel storage, transport and disposal; decommissioning; and "beyond design basis" accidents including an extended station blackout lasting longer than assumed.	Action needed.

Source: California Energy Commission