CALIFORNIA
ENERGY
COMMISSION

2009 INTEGRATED ENERGY POLICY REPORT

DRAFT COMMITTEE REPORT

September 2009
CEC-100-2009-003-CTD

STATE OF CALIFORNIA
ENERGY COMMISSION

Arnold Schwarzenegger,
Governor

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Program Manager

Lynette Green
Project Manager

Jennifer Williams
Principal Author

Carolyn Walker
Editor

Donna Parrow
Project Secretary

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Acknowledgements

This Committee Draft *2009 Integrated Energy Policy Report* would not have been possible without the significant contributions of the following Energy Commission staff:

Bob Aldrich
Eileen Allen
Al Alvarado
Grace Anderson
Aniss Bahreinian
Kevin Barker
Sylvia Bender
Libbie Bessman
Avtar Bining
Steve Bonta
Leon Brathwaite
Gerald Braun
Martha Brooks
Denny Brown
Barbara Byron
Bill Chamberlain
Barbara Crume
Paul Deaver
Albert DeLeon
Rhetta DeMesa
Jacqueline Dockum
Pamela Doughman
Devorah Eden
Dale Edwards
Ryan Eggers
Marlena Elliott
Joseph Fleshman
Serena Fong
James Fore
Steven Fosnaugh
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Cathy Graber
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Daryl Metz
David Michel
Chuck Mizutani
Marla Mueller
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Brian Neff
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Valentino Tiangco
Chris Tooker
Claudia Uresti
David Vidaver
Malachi Weng-Gutierrez
Kerry Willis
Michael Wilson
Lana Wong
William Wood
Jim Woodward
Gerald Zipay
Kate Zocchetti

Please cite this report as follows:

California Energy Commission, *2009 Integrated Energy Policy Report*, Draft Committee Report, September 2009, CEC-100-2009-003-CTD.

Preface

The Committee Draft *2009 Integrated Energy Policy Report* was prepared in response to Senate Bill 1389 (Bowen, Chapter 568, Statutes of 2002), which requires that the California Energy Commission prepare a biennial integrated energy policy report that contains an integrated assessment of 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]). This report fulfills the requirement of Senate Bill 1389.

The report was developed under the direction of the Energy Commission's 2009 Integrated Energy Policy Report Committee. As in previous Integrated Energy Policy Report proceedings, the Committee recognizes that close coordination with federal, state, and local agencies is necessary to adequately identify and address critical energy infrastructure and related environmental challenges. In addition, input from state and local agencies is necessary to develop the information and analyses that these agencies need to carry out their energy-related duties. This Committee Draft *2009 Integrated Energy Policy Report* reflects the input of stakeholders and federal, state, and local agencies that participated in the Integrated Energy Policy Report proceeding. The information gained from workshops and stakeholders was essential in developing the recommendations in this report. The Committee would like to thank stakeholders for their participation and thoughtful contributions to the process.

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Abstract

The Committee Draft *2009 Integrated Energy Policy Report* evaluates overall supply and demand trends for electricity, natural gas, and transportation fuels in California, as well as issues associated with energy infrastructure, efficiency, reliability, and cost. The report describes the various energy policies currently affecting California's energy sectors and outstanding issues that will need to be addressed in each sector to maintain reliable, affordable, and environmentally benign sources of energy for the state's citizens. The report focuses on issues surrounding the integration of increased levels of renewable energy in both the electricity and transportation fuel sectors and makes recommendations on future actions the state should pursue.

Key Words

Assembly Bill 32, greenhouse gas emissions, loading order, transmission, resource adequacy, energy efficiency, demand response, Renewables Portfolio Standard, Renewable Energy Transmission Initiative, renewable energy, demand forecast, distributed generation, combined heat and power, nuclear, once-through cooling, emission credits, transportation, natural gas.

Executive Summary

Introduction

As California pursues its goal to address climate change by reducing greenhouse gas emissions, minimizing the environmental impacts of energy production and use continues to be the driving force for many of the state's energy policies. Assembly Bill 32 (Núñez and Pavley, Statutes of 2006), the Global Warming Solutions Act of 2006, established the goal of reducing greenhouse gas emissions to 1990 levels by 2020, and serves as the comprehensive framework for addressing climate change. However, many of the policies in place prior to passage of Assembly Bill 32 are also valued for their role in meeting the state's climate change goals.

One of these policies is the loading order for electricity resources, which calls for meeting new electricity needs first with energy efficiency and demand response; second, with new generation from renewable energy and distributed generation resources; and third, with clean fossil-fueled generation and transmission infrastructure improvements. Another policy in place prior to the passage of Assembly Bill 32 is the Renewables Portfolio Standard, established in 2002 and revised over time, which currently requires retail sellers of electricity to procure 20 percent of their retail sales from renewable resources by 2010.

More recently, Governor Schwarzenegger issued Executive Orders in 2008 and 2009 that established the Renewable Energy Action Team to develop a plan for renewable development in sensitive desert habitat, accelerated the Renewables Portfolio Standard renewable requirement to 33 percent by 2020, and directed the Air Resources Board to adopt regulations by July 31, 2010, to meet that requirement.

Greenhouse gas emissions are not the only environmental issue facing the electricity sector. The State Water Resources Control Board has issued a draft policy to phase out the use of once-through cooling in the state's 21 coastal power plants to reduce impacts on marine life from the pumping process and the discharge of heated water. Another issue is the lack of emission credits in the South Coast Air Quality Management District that makes it difficult to obtain the necessary permits to build reliable replacement power before aging power plants can be retired or repowered.

The transportation sector is the primary contributor to greenhouse gas emissions in California. Governor Schwarzenegger's Executive Order S-01-07 established a low carbon fuel standard for transportation fuels sold in California that will reduce the carbon intensity of California's passenger vehicle fuels by at least 10 percent by 2020. In addition, the Alternative and Renewable Fuel and Vehicle Technology Program created by Assembly Bill 118 is working to develop and deploy alternative and renewable fuels and advanced transportation technologies to help meet the state's climate change policies. Further, the federal government in June 2009, granted California's request for a waiver that allows California to enact stricter air pollution standards for motor vehicles than those of the federal government. The standards (Assembly

Bill 1493, Pavley, Chapter 200, Statutes of 2002) are expected to reduce GHG emissions from California passenger vehicles by about 22 percent in 2012 and about 30 percent in 2016, while improving fuel efficiency and reducing motorists' costs.

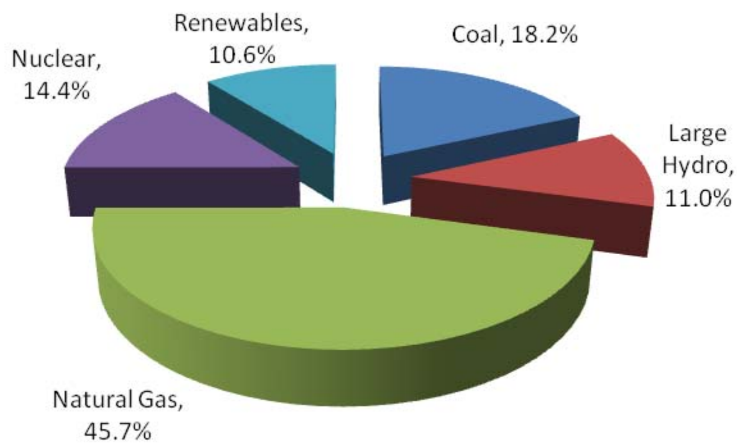
A major challenge to policy makers is the need to balance the state's environmental goals with the need for reliable and affordable energy supplies for its citizens. While the economic downturn has reduced energy demand in the short term, demand is still expected to grow over time as the economy recovers. It is essential that the state's energy sectors be flexible enough to respond to future upswings and downturns in the economy.

The Electricity Sector

Supply and Demand

Figure E-1 shows California's electricity generation supply mix in 2008. In-state generating facilities accounted for about 68 percent of total generation, with the remaining electricity coming from out-of-state imports.

Figure E-1: – California's Generation Mix (2008)

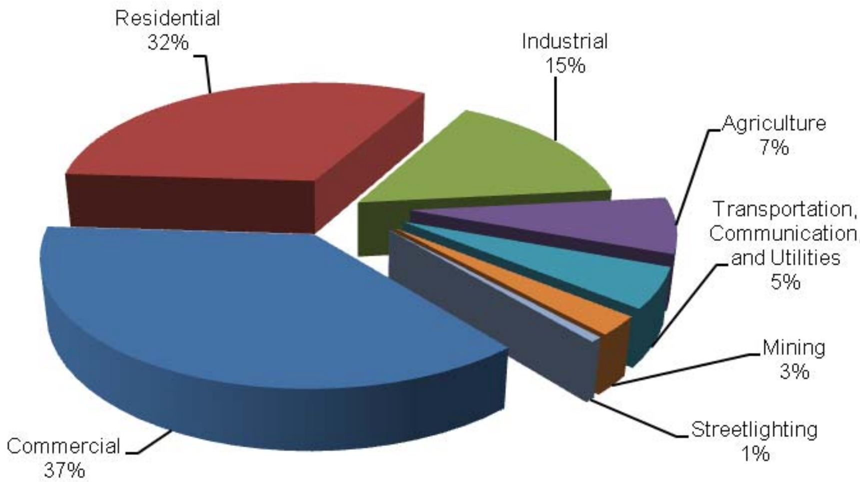


Source: California Energy Commission

Since deregulation in 1998, the Energy Commission has licensed more than 60 power plants: 43 projects representing 14,630 megawatts are online, 6 projects totaling 2,072 megawatts are under construction, and 13 projects totaling 6,511 megawatts are on hold but "available" for construction. In addition, the Energy Commission has a historic high level of more than 30 proposed projects under review totaling more than 13,000 megawatts, many of which are large scale solar thermal power plants with new and challenging environmental impacts to be considered.

On the demand side, Californians consumed 285,574 gigawatt hours of electricity in 2008, primarily in the commercial, residential, and industrial sectors (Figure E-2). The Energy Commission staff forecast of future electricity demand shows that consumption will grow by 1.1 percent per year from 2010–2018, with peak demand growing an average of 1.2 percent annually over the same period. The current forecast is markedly lower than the forecast in the *2007 Integrated Energy Policy* Report, primarily because of lower expected economic growth in both the near- and long-term as well as increased expectations of savings from energy efficiency.

Figure E-2: Electricity Consumption by Sector 2008



Source: California Energy Commission

Because of economic uncertainties surrounding the current recession and the timing of potential recovery, the IEPR Committee directed staff to look at alternative scenarios of economic and demographic growth and their impacts on electricity demand. Staff analyzed both optimistic and pessimistic scenarios and found only small differences in projected electricity demand as a result of those scenarios. Annual growth rates from 2010–2020 for electricity consumption and peak demand would increase from 1.1 percent and 1.25 percent, respectively, to 1.2 percent and 1.4 percent in the optimistic case and fall to 0.9 percent and 1.1 percent growth rates under the pessimistic scenario.

Energy Efficiency and Demand Response

Energy efficiency is a zero-emission strategy to reduce greenhouse gas emissions in the electricity sector. Energy efficiency and conservation programs can also reduce energy dependence, make businesses more competitive, and allow consumers to save money and live more comfortably. Energy efficiency programs can also play a major role in increasing reliability of the electricity system and reducing the cost of meeting peak demand during periods of high temperatures and high prices.

Thanks to the state's energy efficiency standards and programs and conservation, California's energy use per person has remained stable for more than 30 years, while the national average has steadily increased. However, stabilizing per capita electricity use will not be enough to meet the carbon reduction goals. To meet those goals, the state must increase its efforts to achieve 100 percent cost-effective energy efficiency. Much of these efforts is carried out by the investor-owned utilities and the publicly owned utilities, both of which have legislative and regulatory mandates to identify and develop energy efficiency potential and to set annual savings goals. The Energy Commission then uses those goals as the basis for developing its statewide energy efficiency goals.

Strategies to achieve 100 percent cost-effective energy efficiency, as well as the greenhouse gas emissions reduction goals, include zero net energy buildings, increasingly stringent building and appliance standards along with better enforcement of those standards, and the increased efficiency of the state's existing building stock.

A zero net energy building merges highly energy-efficient building construction, state-of-the-art appliances and lighting systems, and high performance windows to reduce a building's load and peak requirements and can include onsite solar water heating and renewable energy such as solar PV to meet remaining energy needs. The result is a grid-connected building that draws energy from, and feeds surplus energy to, the grid. Making zero net energy buildings a reality by 2020 for residences and 2030 for commercial buildings will require ongoing collaboration between the Energy Commission, the California Public Utilities Commission, and the Air Resources Board, as well as coordination with local governments that have the authority over land use development and planning.

California's building and appliance standards provide a significant share of energy savings from reduced energy demand. The 2008 Building Efficiency Standards will take effect on January 1, 2010, and will require, on average, 15 percent increased energy efficiency savings compared with the 2005 Building Efficiency Standards. The 2009 Appliance Efficiency Regulations became effective statewide on August 9, 2009, and, as required by Assembly Bill 1109 (Huffman, Chapter 534, Statutes of 2007), set new efficiency standards for general purpose lighting of a phased 50 percent increase in efficiency for residential general service lighting by 2018. The first phase takes effect January 1, 2010.

Existing residential and commercial buildings present a significant challenge to meeting the goal of 100 percent cost-effective energy efficiency. Over half of the single family homes in California were built before building standards went into effect. Retrofitting these homes can provide significant savings toward meeting the state's energy efficiency goals, but will require a coordinated effort between state and local agencies, utilities, and stakeholders. To address the existing building sector, the state needs to move beyond programs that target replacing incandescent bulbs with compact fluorescent bulbs. Comprehensive programs need to be designed that include building energy use performance labeling or benchmarking, well-designed comprehensive deep retrofit packages, marketing, outreach and education efforts in layperson terms, and creative funding mechanisms that have minimal impact on households' bottom line.

Recommendations

- To achieve the goal for all new residential construction in California to be zero net energy by 2020, and all new commercial construction net zero by 2030, the IEPR Committee recommends establishing a statewide task force that includes state agencies, local governments, utilities, industry, enforcement bodies, and technical experts to address the various issues, definitions, standards and roles necessary to achieve the goal. In addition, because the goal of zero net energy buildings will involve not just efficiency but also building-based energy supply, the Energy Commission's standards for building energy efficiency should be expanded to address building-scale renewable energy solutions.
- To improve the contribution of the state's building and appliance standards to statewide energy efficiency goals, the IEPR Committee recommends expanding the scope of the building standards to include high-energy-using commercial building types and expanding appliance standards to include consumer electronics, general lighting, irrigation controls, and refrigeration systems. In addition, the Committee recommends improving enforcement and compliance of the standards.
- To take advantage of the significant potential for energy efficiency savings from California's existing residential and commercial buildings, the IEPR Committee recommends that energy efficiency retrofits should be required at point of sale or point of remodel. Incentives such as refunds for inspections or caps on maximum expenditures should be used to avoid dissuading homeowners from selling or making improvements to their homes.
- To help the state meet its goal of reducing peak demand by 5 percent through demand response measures, the IEPR Committee recommends that all utilities, including publicly owned utilities, should install meters capable of recording hourly consumption and should publish their time varying electric rates in an actionable and open source format. Customers should have no-cost access to near-real time information about their energy use in a format that is both meaningful and easy to understand. In addition, the Energy Commission should continue its efforts to adopt a statewide load management standard requiring all utilities in the state to adopt some form of dynamic pricing for customers that have advanced meters.

Renewable Energy

Renewable energy is the first supply-side resource in the loading order and a key strategy for achieving a significant portion of the *Climate Change Scoping Plan* target for greenhouse gas emission reductions from the electricity sector. Increasing the amount of renewable energy in California's electricity mix also reduces the risks and costs associated with potentially high and volatile natural gas prices while also reducing the state's dependence on imported natural gas used to generate electricity. Renewable resources also provide other benefits such as economic development and new employment opportunities, benefits that are becoming increasingly important given the current recession.

Challenges with increasing the amount of renewable resources in California's electricity mix include uncertainty about the ability to meet Renewables Portfolio Standard goals, given progress to date, and the difficulty of integrating large amounts of renewable energy into the electricity system, barriers to the development of bioenergy resources, environmental concerns with the development of renewable facilities in the California desert, and the need to provide financial certainty to project developers to encourage development of new facilities.

The Renewables Portfolio Standard requires retail sellers (defined as investor-owned utilities, electric service providers, and community choice aggregators) to increase renewable energy as a percentage of their retail sales to 20 percent by 2010. State law also requires publicly owned utilities to implement the standard but gives them flexibility in developing specific targets and timelines. In November 2008, Governor Schwarzenegger raised California's renewable energy goals to 33 percent by 2020 in his Executive Order S-14-08. In July 2009, the California Public Utilities Commission reported that the three investor-owned utilities were supplying approximately 13 percent of their aggregated total sales from eligible renewable resources as of 2008, far below the 20 percent required by 2010. Publicly owned utilities are showing some progress in renewable energy procurement with expectations for the 15 largest publicly owned utilities of 12.4 percent of RPS-eligible renewable retail sales by 2011, but this progress is still far short of the renewable target.

Integrating the high levels of renewable resources required by the Renewables Portfolio Standard into California's electricity system will be a major challenge. Not all renewable generators provide the operating characteristics that the system needs to maintain local area reliability, and integrating certain renewable technologies can make it more difficult to operate the system reliably. While some renewable resources can provide baseload power, such as geothermal and biomass, intermittent resources like wind, hydro, and solar operate when nature provides and are therefore not always available to meet system needs during peak hours. Intermittent resources can also drop off or pick up suddenly, requiring system operators to quickly compensate for sudden changes. Energy storage technologies can assist with renewable integration by allowing better matching of renewable generation with electricity needs. These technologies can also reduce the number and amount of natural gas-fired power plants that would otherwise be needed to provide the firming characteristics the system needs to operate reliably. However, many of these technologies are still in the research and development stage, are relatively expensive, and will need further refinement and demonstration.

Governor Schwarzenegger's Executive Order S-06-06 further requires the state to meet 20 percent of the Renewables Portfolio Standard with biopower. However, new biomass facilities continue to face barriers to development. There is significant potential for renewable generation fueled by biomethane from the state's dairies, but the high cost of emissions controls can interfere with dairies' ability to obtain air permits. New solid fuel biomass facilities also face challenges in obtaining air permits, as well as the added challenge in the South Coast Air Quality Management District of obtaining permits to emit particulate matter. Existing biomass facilities, which provide a significant portion of the state's baseload renewable capacity, also face challenges from the expiration at the end of 2011 of the Renewable Energy Program, which provides production incentives to keep existing renewable facilities operating.

While renewable energy provides obvious environmental benefits by reducing greenhouse gas emissions and criteria pollutants associated with electricity generation, adding large amounts of renewable resources can have negative environmental effects. Efforts like the Renewable Energy Transmission Initiative are working to facilitate the early identification and resolution or to avoid land use and environmental constraints to promote timely development of California's renewable generation resources and associated transmission lines. Also, Governor Schwarzenegger's Executive Order S-14-08 establishes a process to conserve natural resources while expediting the permitting of renewable energy power plants and transmission lines. The Executive Order established the Renewable Energy Action Team, comprised of the Energy Commission, the Department of Fish and Game, the Bureau of Land Management, and the U.S. Fish and Wildlife Service, to identify and establish areas for potential renewable energy development and conservation areas in the Colorado and Mojave deserts to help reduce the time and uncertainty associated with licensing new renewable projects on both state and federal lands. As part of implementing the Executive Order, the agencies are developing the Desert Renewable Energy Conservation Plan.

To address the need for financial certainty when developing renewable projects, the Energy Commission recommended the use of feed-in tariffs —fixed, long-term prices for renewable energy — in both the *2007 Integrated Energy Policy Report* and the *2008 Integrated Energy Policy Report Update*. Feed-in tariffs can be based on a generator's cost of generation plus a reasonable profit, on the value that generator provides to the system (such as delivering during peak periods), or on a hybrid of the two. Opinions regarding the effects of feed-in tariffs vary, with some parties concerned that higher feed-in tariffs would be too costly and would increase electricity rates for utility customers. Others argue that providing clear up-front feed-in tariff guidelines would reduce the time and expense of obtaining a long-term contract by allowing pre-approval of projects that meet those guidelines. In addition, feed-in tariffs could reduce financing costs by providing increased certainty for investors.

Recommendations

- Because of the importance of achieving the state's RPS goals, the IEPR Committee reinforces the need for the California Public Utilities Commission to be committed to imposing penalties on investor-owned utilities for non-compliance with RPS targets.
- The Energy Commission should conduct further analysis to identify solutions for integrating rising levels of energy efficiency, smart grid infrastructure, and renewable energy while avoiding conditions of surplus generation and decreased reliability. In addition, there should be efforts to determine what value new, more flexible, and efficient natural gas technologies best fit into an electricity grid in transition.
- The Energy Commission should support the detailed analysis being conducted by the California Independent System Operator to identify specific system requirements such as local ramp rates, inertia, and the other transmission-related ancillary service functions.

- The Public Interest Energy Research Program should continue its research efforts on the appropriate specifications of energy storage systems needed to integrate intermittent renewables.
- The Governor's *Bioenergy Action Plan* should be updated to address continuing barriers to the development and deployment of bioenergy, including air quality permitting, expiring incentive programs, and non-existent private project financing. The *Bioenergy Action Plan* should also be expanded to identify issues and potential solutions related to biogas injection and gas clean up.
- The Energy Commission should explore options to ensure that existing biomass facilities continue to operate, including continuation of the Existing Renewable Facilities Program, subsidizing biomass feedstocks, or developing a feed-in tariff for existing biomass facilities.
- The Energy Commission should continue its efforts in the Renewable Energy Action Team to streamline and expedite permitting of renewable energy projects while conserving endangered species and natural communities through the Desert Renewable Energy Conservation Plan.
- The California Public Utilities Commission should complete efforts to implement technology-specific feed-in tariffs for wholesale distributed generation for projects 20 megawatt or less in size, including simplified and standardized contracts with price levels similar to feed-in tariff contracts that have achieved high levels of renewable energy at reasonable costs.
- The Legislature should consider changes in state law to require that utilities or the California Independent System Operator offer technology-specific feed-in tariffs designed to encourage development and integration of utility-scale renewable energy along renewable-rich transmission corridors.

Distributed Generation and Combined Heat and Power

Distributed generation resources are grid-connected or stand-alone electrical generation or storage systems, connected to the distribution level of the transmission and distribution grid, and located at or very near where the energy is used. The benefits of distributed generation go far beyond electricity generation. Because the generation is located near where it is needed, distributed generation reduces the need to build new transmission and distribution infrastructure and also reduces losses at peak delivery times. Customers can use distributed generation technologies to meet peak needs or to provide energy independence and protect against outages and brownouts.

California is promoting distributed generation technologies through such programs as the California Solar Initiative, which includes the New Solar Homes Partnership, through the California Public Utilities Commission's Self-Generation Incentive Program, and through the Energy Commission's Emerging Renewable Facilities Program, all of which support distributed generation on the customer side of the meter. Larger-scale distributed generation such as combined heat and power, also referred to as cogeneration, is an efficient and cost-effective form of distributed generation. The *Climate Change Scoping Plan* has a target of adding 4,000 megawatts of combined heat and power capacity to displace 30,000 gigawatt hours of demand and reduce greenhouse gas emissions by 6.7 million metric tons of carbon by 2020.

Despite the Energy Commission's clear policy preferences and consistent emphasis in the *Integrated Energy Policy Reports* of the need to address barriers to the development of combined heat and power facilities, little progress has been made. In an effort to push forward, the Energy Commission developed a new study of market potential for combined heat and power facilities that are smaller than 20 megawatts in size and do not typically have excess power to export to the grid. The study developed a base case (status quo) and four alternative cases that included various stimulus and incentive measures. The base case showed about 2,700 megawatts of combined heat and power market penetration toward the target of 4,000, primarily for facilities smaller than 5 megawatts in capacity. Implementation of all of the stimulus efforts and incentives used in the alternative cases would add another 3,500 megawatts of market potential.

Recommendations

- To support the goal of integrating increased quantities of both renewable and non-renewable distributed generation into the grid, the IEPR Committee recommends that the Energy Commission and the California Public Utilities Commission should open a joint proceeding to develop a comprehensive understanding of the importance of distribution system upgrades, not only to assure reliability, but also to support the cost-effective integration and interoperability of large amounts of distributed energy for both on-site use and wholesale export.
- To realize potential greenhouse reductions from the development of new combined heat and power facilities, the IEPR Committee recommends:
  - The Energy Commission and the Air Resources Board should structure combined heat and power programs to ensure development of both large (greater than 20 megawatts) and small (20 megawatts and smaller) systems that are dispatchable, appropriately located, and have a load profile that meets utility needs.
  - The Energy Commission and the Air Resources Board should establish minimum efficiency standards, GHG emission criteria, and monitoring and reporting mechanisms.
  - Electric utilities should develop programs and solicit projects to promote CHP as a strategy to replace boilers, increase energy efficiency, and reduce emissions.
  - The Self-Generation Incentive Program should reinstitute eligibility for combined heat and power systems with a generating capacity of 5 megawatts or less that meet minimum performance, monitoring and reporting standards, regardless of technology or fuel type.
- To mitigate the greenhouse gas emissions from California's organic wastes and increase the amount of renewable combined heat and power facilities in the state, the IEPR Committee recommends that the California Public Utilities Commission and the Energy Commission work together to support the market penetration of technologies that can co-digest multiple

waste streams from the agriculture, food, and dairy industries at wastewater treatment facilities.

Nuclear Power Plants

As part of the *2008 Integrated Energy Policy Report Update*, the Energy Commission developed *An Assessment of California's Nuclear Power Plants: AB 1632 Report,* as directed by Assembly Bill 1632 (Blakeslee, Chapter 722, Statutes of 2006). The report addressed seismic and plant aging vulnerabilities of California's in-state nuclear plants —Pacific Gas and Electric Company's Diablo Canyon Power Plant and Southern California Edison's San Onofre Nuclear Generating Station — including reliability concerns. In addition, the report identified a number of other issues important for the state's nuclear policy and electricity planning, including concerns about the "safety culture" at the San Onofre Nuclear Generating Station, evolving federal policy on long-term nuclear waste disposal, costs and benefits of nuclear power compared to other resources, and potential conversion from once-through cooling to closed-cycle wet cooling.

While the Nuclear Regulatory Commission is responsible for relicensing nuclear power plants, its license renewal application process determines only whether a plant meets its own criteria for license renewal. It is left up to state regulatory agencies to determine whether it is in the best interest of ratepayers for the nuclear plants to continue operating for an additional 20 years. The California Public Utilities Commission proceeding will consider those matters that are within the state's jurisdiction, including the economic, reliability, and environmental implications of relicensing.

The *AB 1632 Report* made a number of recommendations for additional studies that Pacific Gas and Electric Company and Southern California Edison should undertake as part of their license renewal feasibility studies for the California Public Utilities Commission, and also directed the utilities to provide a status report on their efforts in the *2009 Integrated Energy Policy Report*. In June 2009, the California Public Utilities Commission sent letters to both utilities emphasizing the need to address issues raised in the *AB 1632 Report* as part of the their license renewable feasibility assessments, such as seismic and tsunami hazards, local economic impacts of shutting down the plants, and waste storage and disposal. However, based on information submitted by the utilities in response to the Energy Commission's data request as part of the Integrated Energy Policy Report proceeding, it appears that the utilities are not on schedule to complete these activities in time for consideration by the California Public Utilities Commission and that they may not intend to make all their studies available.

The comprehensiveness, completeness, and timeliness with which the utilities provide the information identified in the *AB 1632 Report* will be critical to assess whether or not the utilities should apply to the Nuclear Regulatory Commission for license renewals for their nuclear plants.

Recommendations

- To help ensure plant reliability and minimize costs, Pacific Gas and Electric Company and Southern California Edison should complete and report in a timely manner on the studies recommended in the *Assembly Bill 1632 Report* that the California Public Utilities Commission identified for completion as part of license renewal review. These reports should be made available to the Energy Commission, as part of the Integrated Energy Policy Report process, and to the California Public Utilities Commission for its license renewal review. Once a utility completes the required studies and makes them available to the Energy Commission and the California Public Utilities Commission for review, the utility may then file license renewal applications with the California Public Utilities Commission CPUC and the United States Nuclear Regulatory Commission.

- The California Public Utilities Commission should assess the need to establish a San Onofre Nuclear Generating Station Independent Safety Committee patterned after the Diablo Canyon Independent Safety Committee.

- The Energy Commission, California Public Utilities Commission, and the California Independent System Operator should assess the reliability implications and impacts from implementing California's proposed once-through cooling policy and regulations for California's operating nuclear plants.

- To support the state's long-term energy planning, Southern California Edison and Pacific Gas and Electric Company should report, as part of the *2010 IEPR Update*, what new generation and/or transmission facilities would be needed to maintain voltage support and system and local reliability in the event of a long-term outage. The utilities should develop contingency plans to maintain reliability and grid stability in the event of an extended shutdown at San Onofre Nuclear Generating Station, Diablo Canyon Power Plant, or the Palo Verde Nuclear Generating Station in Arizona.

- The Energy Commission should continue to update information on the comprehensive economic and environmental impacts of nuclear energy generation compared with alternatives. These economic and environmental assessments should consider thorough or lifecycle impacts.

Transmission

The state's transmission and distribution system is another critical component of the electricity sector for serving California's growing population and integrating renewable energy. The *2009 Strategic Transmission Investment Plan* describes the immediate actions that California must take to plan, permit, construct, operate, and maintain a cost-effective, reliable electric transmission system that is capable of responding to important policy challenges such as achieving significant greenhouse gas reduction and Renewables Portfolio Standard goals. The plan makes a number of recommendations intended to make the critical link between transmission planning and permitting so that needed projects are planned for, have corridors set aside as necessary, and are permitted in a timely and effective manner that maximizes existing infrastructure and rights-of-way, minimizes land use and environmental impacts, and considers technological advances.

Recommendations

The IEPR Committee supports the many recommendations made in the *2009 Strategic Transmission Investment Plan*, and highlights the following recommendations:

- The Energy Commission staff should work with the recently formed California Transmission Planning Group and California Independent System Operator in a concerted effort to establish a 10-year statewide transmission planning process that uses the Strategic Plan proceeding to vet the plan described in Chapter 4 of the *2009 Strategic Transmission Investment Plan*, with emphasis on broad stakeholder participation.
- The Energy Commission staff should work with the California Independent System Operator, California Public Utilities Commission, and publicly owned utilities on a simplified need assessment process that fosters the use of common assumptions and streamlined decisions.
- The Energy Commission staff should continue to support the Renewable Energy Action Team's mission to streamline and expedite the permitting processes for renewable energy projects, while conserving endangered species and natural communities at the ecosystem scale in the Mojave and Colorado Desert regions through the Desert Renewable Energy Conservation Plan.
- The California Independent System Operator, the California Transmission Planning Group, and the Energy Commission should prioritize transmission planning and permitting efforts for renewable generation, as outlined in Chapter 6 of the *2009 Strategic Transmission Investment Plan,* and work on overcoming barriers and finding solutions that would aid their development.
- The Energy Commission should continue supporting ongoing activities related to the Renewable Energy Transmission Initiative, including the Coordinating Committee, Stakeholder Steering Committee, and working groups by providing appropriate personnel and contract resources.
- The Energy Commission staff should continue to coordinate with the Renewable Energy Transmission Initiative stakeholders group to incorporate new information in applying the method described in Chapter 6 of the *2009 Strategic Transmission Investment Plan* to reach consensus on the appropriate transmission line segments that should be considered for corridor designation to promote renewable energy development.

Coordinated Electricity System Planning

California needs to better coordinate its electricity policy, planning, and procurement efforts to eliminate duplication and to ensure that planners and policy makers understand the interactions and conflicts that may exist between state energy policy goals.

California has numerous agencies that are involved in electricity planning. While there is some degree of coordination between various agencies and processes, the state needs to find better ways to coordinate and streamline the collective responsibilities of those agencies to be able to achieve the state's greenhouse gas emission reduction, environmental protection, and reliability goals while reducing duplicative or contradictory processes.

Recommendations

To better coordinate electricity system planning, the IEPR Committee recommends that the Energy Commission should:

- Continue analyses begun in the 2009 IEPR proceeding toward developing both short-term (2013–2020) and long-term (2020–2050) "blueprints" laying out the role for different generation technologies in the future, given state policy goals to support high levels of renewable resources, expand energy efficiency efforts, and retire aging power plants that rely on once-through cooling while maintaining system reliability.
- Continue to work with the California Public Utilities Commission, the California Independent System Operator, and the State Water Resources Control Board to implement the joint energy agency proposal that establishes a schedule for complying with once-through cooling mitigation while addressing electric system reliability concerns.
- Conduct analysis to determine the amount of air credits needed in South Coast air shed and work cooperatively with the South Coast Air Quality Management District, the Air Resources Board, and other appropriate agencies to design new methods to allocate scarce air credits to proposed power plants that best meet system and local needs.
- Plan to undertake need conformance for power plants it licenses in a more organized and formal manner relying upon need assessments prepared in an integrated planning process to determine future power plant needs.
- Focus its forecasting, planning, and Integrated Energy Policy Report and Strategic Transmission Investment Plan processes on conducting the statewide integrated planning that is clearly now required. Efforts should be coordinated with those of the California Public Utilities Commission and California Independent System Operator to reduce duplication.
- Seek legislative authority for (1) an explicit need conformance process for the power plants it licenses directly; and (2) the Energy Commission's need assessment conclusions to be used by local and regional environmental agencies with final approval over power plants that the Energy Commission does not license.

The Natural Gas Sector

California's dependence on natural gas as a significant energy source for the foreseeable future magnifies the importance of maintaining a reliable natural gas delivery and storage infrastructure. A reliable infrastructure system will support the receipt and delivery of adequate supply to California's millions of natural gas consumers, keeping prices lower for the residential, commercial, industrial, and electric generation sectors. An expanding California natural gas infrastructure will allow for the efficient delivery to California of increasing domestic shale gas production and liquefied natural gas imports.

Recent technological advancements in exploration, drilling, and hydraulic fracturing have transformed shale formations from marginal natural gas producers to substantial and expanding contributors to the natural gas portfolio. Recoverable shale reserve estimates range as high as 842 trillion cubic feet, a 37-year supply at today's consumption rates. While natural gas production from shale formations has significantly increased domestic production, there is ongoing investigation of potential environmental concerns related to shale gas development, including carbon emissions and possible groundwater contamination.

As recently as two years ago, domestic natural gas production and imports to California were on the decline, and liquefied natural gas was seen as a source to better serve the natural gas needs of California. The recent development of natural gas shale formations has contributed to increased domestic production of natural gas, and liquefied natural gas does not seem to be a priority fuel for California at this time. If private investors are willing to invest in liquefied natural gas facilities without committing taxpayer or ratepayer funds, however, it should be considered a viable option. The IEPR Committee does not oppose development of liquefied natural gas -related facilities as long as liquefied natural gas development is consistent with the state's interests in balancing environmental protection, public safety, and local community concerns to ensure protection of the state's population and coastal environment.

While there is widespread agreement that the physical market factors of supply and demand are primary contributors to natural gas prices and volatility, there also is growing interest and concern about the influence financial market factors, particularly commodity speculation, have on natural gas prices and volatility. The growth in speculative commodity trading from non-traditional participants, such as pension funds, university endowments, hedge funds, and index portfolios, has changed the futures market. Unlike traditional participants like utilities and refiners who used the market to hedge against volatile energy costs, these new participants use the market as an opportunity for profit. Significant disagreement exists about the influence speculative trading has on the natural gas market, prices, and volatility.

Finally, past efforts to forecast natural gas prices have been highly inaccurate compared to actual prices, even when price volatility was largely dominated by traditional, physical market factors. Recent natural gas price volatility is at least partially explained by evolving, less traditional, financial market factors that are complicating efforts to accurately forecast future natural gas prices. Additionally, as the United States continues moving to a carbon-constrained existence, future greenhouse gas policies will further complicate these efforts, likely rendering future natural gas price forecasts even less accurate and more uncertain. The uncertainty associated with predicting major input variables and the resulting natural gas price forecasts brings into question the value in producing date specific, single-point natural gas price forecasts.

Recommendations

- California should work closely with Western states to ensure development of a natural gas transmission system that has sufficient capacity and alternative supply routes to overcome any disruption in the system, such as weather-related line freezes and pipeline breaks. The state should support construction of sufficient pipeline capacity to California to ensure adequate supply at a reasonable price.
- The Energy Commission should continue to monitor the potential environmental impacts associated with shale gas extraction, including carbon footprint, volume of water use and risk of groundwater contamination, and potential chemical leakages.

The Transportation and Fuels Sector

The transportation and fuels energy sector is responsible for producing the greatest volume of greenhouse gas emissions, nearly 40 percent of California's total. However, the challenges confronting this sector go far beyond climate change. Reducing California's dependence on petroleum in general and foreign crude oil in particular is also critical to reduce the effects that global demand, geopolitical events, crude oil refining capacity and outages, and petroleum infrastructure challenges have on fuel prices, the average cost of production of goods and services, and national security.

Assembly Bill 32 does not directly address greenhouse gas emissions reduction in the transportation sector. Instead, reductions are addressed at the state level through California's Low Carbon Fuel Standard, the Pavley regulations (Assembly Bill 1493 [Pavley, Chapter 200, Statutes of 2002]), and Assembly Bill 1007 (Pavley, Chapter 371, Statutes of 2005), and the Alternative and Renewable Fuel and Vehicle Technology Program. The policies and standards resulting from these mandates will ultimately change vehicle and fuel technologies in California and accelerate the market for low carbon fuels well beyond the current level of demand.

The current recession has had a significant impact on the state's transportation sector. Consumer demand for gasoline and diesel fuels continues to decline. California's average daily gasoline sales for the first four months of 2009 were 2.1 percent lower than the same period in 2008, continuing a reduction in demand observed since 2004. Daily diesel fuel sales for the first three months of 2009 were 7.7 percent lower than the same period in 2008, continuing a declining trend since 2007. Job growth and industrial production — drivers of air travel — are also declining, causing the aviation sectors to experience a drop in air traffic. Recent demand trends for jet fuel (8.9 percent decline in 2008) are similar to diesel fuel and reflect the impact of the economic downturn and higher fuel prices.

The early years of the Energy Commission's transportation fuel demand forecast show a recovery from the recession. Because the economic and demographic projections used in these forecasts indicate a return to economic and population growth, fuel demand in the light-duty, medium- and heavy-duty, and aviation sectors tend to resume historical growth patterns. However, the mix of fuel types is projected to change significantly as the state transitions from gasoline and diesel to alternative and renewable fuels.

California needs sufficient fuel infrastructure to ensure reliable supplies of transportation fuels for its citizens. Both petroleum and renewable fuels face significant infrastructure challenges from the wholesale and distribution level to the end users. The petroleum infrastructure is strained at the marine ports and throughout the distribution system and much of the infrastructure for renewable and alternative fuels that will soon be necessary is not even in place.

Recommendations

- The state should modernize and upgrade the existing infrastructure for alternative and renewable fuels to preserve past investments and to expand throughput capacity in the state.
- California should support the development of alternative and renewable fuels that can provide immediate greenhouse gas reduction benefits and a bridge to the introduction of fuels that will result in deeper greenhouse gas reductions in the future.
- The state should work to maximize the use of California's abundant waste stream, including agricultural waste, municipal solid waste, and forest waste to produce energy for transportation uses in a sustainable manner.

Land Use

Land use decisions are made on the local level, but increasingly community design decisions influence the state's transportation choices, its energy consumption and its greenhouse gas emissions. The *2006 Integrated Energy Policy Report Update* stated that the single largest opportunity to help California meet its statewide energy and climate change goals resides with "smart growth." The *2007 Integrated Energy Policy Report* further noted that to reduce greenhouse gas emissions, California must begin reversing the current 2 percent annual growth rate of vehicle miles traveled.

The Energy Commission is one of several state agencies helping local and regional governments make sustainable land use decisions. The California Department of Transportation coordinates local and state planning through its Regional Blueprint Planning Program. Senate Bill 375 (Steinberg, Chapter 728, Statutes of 2008) requires the Air Resources Board to set regional emissions goals by working with metropolitan planning organizations. Senate Bill 732 (Steinberg, Chapter 729, Statutes of 2008) recognizes the need for state agencies to more closely work together on this issue, creating the Strategic Growth Council, a cabinet level committee composed of agency secretaries from Business Transportation and Housing, California Health and Human Services, the California Environmental Protection Agency, and the California Natural Resources Agency, along with the director of the Governor's Office of Planning and Research.

These state agencies need to coordinate more closely to help local governments achieve the benefits of sustainable land use planning. State government must improve its outreach to local governments to better understand the problems they face before adopting new state policies. This includes taking into account and addressing the fiscal realities local governments face in these tough economic times.

Recommendations

The IEPR Committee makes the following recommendations related to land use planning and decisions:

- The state should assemble easy-to-use data and provide tool kits to help local land use planners make informed decisions about energy concerns and climate change.
- The state should establish a comprehensive funding mechanism to support efforts by local and regional governments to prepare and implement land use policies consistent with the requirements of AB 32 and that contribute significantly to achieving the state's 2050 greenhouse gas reduction target.
- The state should recognize that rural regions differ from urban ones and insure that new sustainability, greenhouse gas, and energy requirements address these differences.
- The state should encourage California's utilities to work with regional and local governments to promote climate friendly and energy efficient development in their service areas.

Chapter 1: California's Energy-Related Policies and Activities

California has implemented several comprehensive energy policies that are affecting consumers, the economy, and the environment. This chapter identifies and briefly describes policies affecting California's electricity, transportation, and natural gas sectors and the programs and efforts that exist to implement those policies. The purpose is to provide decision makers with the context for discussions in subsequent chapters of the challenges and opportunities associated with meeting California's energy policy goals. The description of the energy policy landscape may also help decision makers see how policies overlap or complement each other, as well as where gaps may exist that require additional action to ensure a clean, efficient, and affordable energy future for California.

In 2006, the Legislature passed and Governor Schwarzenegger signed Assembly Bill 32 (Núñez and Pavley, Chapter 488, Statutes of 2006), the Global Warming Solutions Act of 2006, which established the goal of reducing GHG emissions to 1990 levels by 2020. AB 32 was the first law of its kind to address climate change by implementing regulatory market mechanisms to achieve real and measurable GHG reduction targets. AB 32 is now a driving force for many of California's energy policies and programs described in this chapter. Many of the policies in place prior to AB 32's passage are now valued for their role in meeting the state's climate change goals.

The California Air Resources Board's (ARB) *Climate Change Scoping Plan* report, approved on December 12, 2008, outlines the main strategies for meeting AB 32's goals. The *Climate Change Scoping Plan* contains a range of GHG reduction actions including direct regulations, alternative compliance mechanisms, monetary and non-monetary incentives, voluntary actions, market-based mechanisms such as a cap-and-trade system, and an AB 32 cost of implementation fee regulation to fund the program. The ARB, and other state agencies, must adopt these reduction measures by the start of 2011. The ARB has already adopted a number of "early action" measures required by the *Climate Change Scoping Plan*, such as the Low Carbon Fuel Standard (LCFS), and is now working on the plan's other measures.[1]

In April 2009, the California Environmental Protection Agency (CalEPA) released the *Draft 2009 Climate Action Team Biennial Report to the Governor and Legislature* that describes the impacts of climate change on public health, infrastructure, natural resources, and the economy. In addition, the report describes research efforts to date.[2] The Energy Commission is a key agency for implementing actions in the ARB's *Climate Change Scoping Plan* and the *CAT Biennial Report* relating to energy. These actions and progress to date are described throughout this chapter.

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1 California Air Resources Board, *Climate Change Scoping Plan*, December 2008, available at: [http://www.arb.ca.gov/cc/scopingplan/scopingplan.htm].

2 *Climate Action Team Biennial Report to the Governor and Legislature*, March 2009, available at: [http://www.energy.ca.gov/2009publications/CAT-1000-2009-003/CAT-1000-2009-003-D.PDF].

Electricity Sector

The Loading Order

If AB 32 is the overarching policy influencing California's energy future, then the loading order can be viewed as the guidebook. California's loading order provides an overall framework for meeting the state's growing energy needs as well as achieving GHG emissions reduction goals as mandated by AB 32. It was originally adopted in the *2003 Energy Action Plan I,* a collaborative report from the Energy Commission, the California Public Utilities Commission (CPUC), and the California Power Authority (now defunct). The loading order calls for these goals to be accomplished by first increasing energy efficiency and demand response; second, with new generation from renewable energy and distributed generation resources; and third, with clean fossil-fueled generation and infrastructure improvements.

Energy Efficiency and Demand Response

Energy efficiency and demand response measures are the first resources in the loading order because they can meet climate change goals with little or no impact on the environment and with measurable benefits (for example, cost savings) to the consumer. Since the 1970s, the Energy Commission has been setting efficiency standards and forecasting future electricity demand to help the state with its resource planning.

The following policies in the area of energy efficiency and demand response provide the impetus to reduce energy demand and meet AB 32 goals:

- **Assembly Bill 2021 (Levine, Chapter 734, Statutes of 2006):** This bill requires the Energy Commission, in consultation with the CPUC and publicly owned utilities, to develop a statewide estimate of all potentially achievable cost-effective electricity and natural gas efficiency savings and establish statewide annual targets for energy efficiency savings and demand reduction over 10 years.
- **ARB's *Climate Change Scoping Plan***: The ARB outlines emission reduction measures in the electricity sector from maximizing building and appliance standards, implementing additional conservation and efficiency programs, increasing combined heat and power (CHP), and more utility programs. The plan also calls for the same type of reduction strategies for the natural gas sector by increasing installations of solar water heating systems throughout the state.
- **CPUC Long Term Energy Efficiency Strategic Plan:** In September 2008, the CPUC adopted California's first strategic plan for energy efficiency that provides a roadmap to achieve maximum energy savings across all sectors in California. The plan includes four specific programmatic goals, known as the "Big Bold Energy Efficiency Strategies": (1) all new residential construction in California will be zero net energy by 2020; (2) all new commercial construction in California will be zero net energy by 2030;[3] (3) heating, ventilation, and air

3 A zero net energy building combines building energy efficiency design features and clean onsite or near-site distributed generation of sufficient quantity on an annual basis to offset any residual purchases of electricity or natural gas from utility suppliers.

conditioning will be transformed to ensure that its energy performance is optimal for California's climate; and (4) all eligible low-income customers will be given the opportunity to participate in the low income energy efficiency program by 2020.

The state is using several strategies to meet the policy requirements described above. Assembly Bill 2021 is a key legislative strategy for the utilities to expand their energy efficiency programs. Under AB 2021, the Energy Commission is required to develop statewide estimates of energy efficiency potential and goals for California's private and public utilities. It also requires that the publicly owned utilities identify all potentially achievable cost-effective electricity energy savings and establish annual goals for energy efficiency savings and demand reduction for the next 10-year period. The Energy Commission reports on utility progress in meeting these goals as part of the biennial *IEPR*.

The 2008 progress report, *Achieving Cost-Effective Energy Efficiency for California: Second Annual AB 2021 Progress Report,*[4] found that during the CPUC's 2006–2008 efficiency program cycle, the investor-owned utilities (IOUs) exceeded their three-year energy efficiency goals. During these three years, the IOUs achieved more than 200 percent of their electric energy savings goal and 150 percent of their natural gas savings goal. However, measurement and verification studies completed for the 2004–2005 efficiency programs indicate the possibility of verified program savings being less than those reported. The progress report also found that efficiency savings recorded by publicly owned utilities increased substantially from 2007 to 2008, reaching 66 percent of AB 2021 adopted goals in 2008.

The Energy Commission's Public Interest Energy Research (PIER) program helps improve energy efficiency technologies and strategies and directed $180 million in funding to efficiency-related efforts from 1997–2007.[5] The PIER program funds research, development, and demonstration in the following energy efficiency program areas: Buildings End-Use Energy Efficiency, Industrial/Agriculture/Water End-Use Efficiency Program, Demand Response, and Distributed Energy Resources System Integration.[6] With the passage of the Energy Independence and Security Act (EISA) of 2007 (Title XIII), the evolution of the nation's Smart Grid provides new potential to obtain even more penetration of the energy efficiency and demand response technologies and capabilities. The PIER program is actively funding new research in the Smart Grid area to better define how to take advantage of all the capabilities the Smart Grid will offer California in the future.

In the area of demand response and load management, the Energy Commission's *2007 IEPR* recommended initiating a formal rulemaking process involving the CPUC and California

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4 California Energy Commission, *Achieving Cost-Effective Energy Efficiency for California: Second Annual AB 2021 Progress Report*, December 2008, CEC-200-2008-007, [http://www.energy.ca.gov/2008publications/CEC-200-2008-007/CEC-200-2008-007.PDF].

5 California Energy Commission, *PIER Annual Report*, March 2009, CEC-500-2009-064-CMF, available at: [http://www.energy.ca.gov/2009publications/CEC-500-2009-064/CEC-500-2009-064-CMF.PDF].

6 California Energy Commission, PIER program, available at: [http://www.energy.ca.gov/research/index.html].

Independent System Operator (California ISO) to pursue the adoption of load management standards under the Energy Commission's existing authority. In 2008, the Energy Commission opened a rulemaking on the development of load management standards including metering, rate design, enabling technologies, and software.

The Energy Independence and Security Act (EISA) of 2007 created the Energy Efficiency and Conservation Block Grant Program, which is funded by the American Recovery and Reinvestment Act of 2009 (ARRA).[7] As part of the increasing national focus on the importance of energy efficiency, ARRA is providing $351.5 million in funding to California. Of that amount, $302 million will go directly from the U.S. Department of Energy (DOE) to large incorporated cities and counties in California, and $49.6 million will be made available through the Energy Commission to 265 small incorporated cities and 44 small counties not eligible for direct grants from the DOE.

The Energy Commission adopted the *Block Grant Guidelines* on September 16, 2009, which describe the eligibility and procedural requirements for applying for program funds. Overall, this program is a crucial strategy for assisting small cities and counties in implementing projects and programs that reduce total energy use and fossil fuel emissions and improve energy efficiency in building and other appropriate sectors.

ARRA is also providing $226 million in funding to the Energy Commission for the State Energy Program. Earlier in the year, the Energy Commission held a series of informational workshops throughout the state to inform stakeholders of the funding guidelines and application process. The Energy Commission adopted the *State Energy Program Guidelines* on September 30, 2009, which describe implementation and administration of specific program areas funded by the State Energy Program. Overall, this program is an important strategy for making buildings and industrial facilities more energy efficient and will help finance such projects.

Renewable Energy

Second in the state's loading order is to meet new electricity needs with renewable energy resources. With the passage of Assembly Bill 1890 (Brulte, Chapter 854, Statutes of 1996), the Legislature established a public goods charge to support renewable energy development. Since then, the state has implemented other policies to expand renewable energy production goals in California. Some of these policies were implemented prior to passage of AB 32, but they all play a critical role in meeting the state's GHG emissions reduction goals:

- **Senate Bill 1078 (Sher, Chapter 516, Statutes of 2002)**: Established California's Renewables Portfolio Standard (RPS) requiring retail sellers of electricity (IOUs, community choice aggregators, electric service providers) to procure 20 percent of retail sales from renewable energy by 2017. The publicly owned utilities are encouraged, but not required, to meet the same goal. The bill delegated specific roles to the Energy Commission and CPUC.

7 See [http://www.recovery.gov/Pages/home.aspx]

- ***Energy Action Plans I (2003) and II (2005):*** The first *Energy Action Plan* recommended accelerating the RPS deadline to 20 percent by 2010, and the second recommended a further goal of 33 percent renewables by 2020.
- **Senate Bill 107 (Simitian, Chapter 464, Statutes of 2006):** Required the IOUs to meet the "20 percent by 2010" goal as recommended in the *Energy Action Plan I*. The bill expanded the RPS reporting requirements of the publicly owned utilities to the Energy Commission and expanded RPS eligibility of out-of-state renewable resources.
- **Executive Order S-06-06 (2006):** Established a biomass target of 20 percent within the established RPS goals for 2010 and 2020.
- **Executive Order S-14-08 (2008):** Established accelerated RPS targets (33 percent by 2020) as recommended in the *Energy Action Plan II*. The order also called for the formation of the Renewable Energy Action Team, comprised of the Energy Commission, Department of Fish and Game, Bureau of Land Management, and U.S. Fish and Wildlife Service. Through the team, the Energy Commission and the Department of Fish and Game are to prepare a plan for renewable development in sensitive desert habitat.
- **Executive Order S-21-09 (2009):** Directs the ARB to work with the CPUC, the California ISO, and the Energy Commission to adopt regulations increasing California's RPS to 33 percent by 2020. The ARB must adopt these regulations by July 31, 2010.

The state has implemented several key strategies and programs to increase renewable energy generation consistent with these policies. These include the Energy Commission's Renewable Energy Program, the RPS Program jointly administered by the Energy Commission and the CPUC, the Renewable Energy Transmission Initiative, the Desert Renewable Energy Conservation Plan, feed-in tariffs for renewable generators, the *Bioenergy Action Plan*, and multiple RD&D activities.

The Energy Commission's Renewable Energy Program has since 1998 encouraged investments in renewable energy by providing rebates and electricity production incentives for new and existing renewable facilities and emerging renewable technologies. The program has supported more than 5,000 megawatts (MW) of existing and new renewable capacity. Funding collection for the program is set to expire January 1, 2012.

Under SB 1078, the Energy Commission and the CPUC jointly implement the RPS for all but the publicly owned electric utilities, who implement their own RPS programs. The Energy Commission is responsible for certifying eligible facilities as "RPS eligible" and has certified 600 facilities since 2002. The Energy Commission is also responsible for tracking and verifying RPS procurement, and was instrumental in the development of the Western Renewable Energy Generation Information System (WREGIS) as the official accounting system for tracking renewable energy credits (also known as "RECs") in the Western Interconnection region.[8] The CPUC's responsibilities include approving IOU procurement plans and RPS-eligible contracts for IOUs, ensuring compliance, and setting benchmark pricing for IOU RPS contracts. The

8 For more information, see [http://www.wregis.org/].

CPUC also oversees RPS programs for electric service providers and small and multi-jurisdictional utilities. As of June 2009, the CPUC has approved 116 RPS contracts totaling 8,334 MW, with an additional 13 contracts for 5,941 MW under review.[9]

The Energy Commission and CPUC are responsible for tracking and verifying utilities' progress towards RPS goals. In July 2009, the CPUC reported that the three IOUs were supplying approximately 13 percent of their aggregated total sales from eligible renewable resources as of 2008. The Energy Commission has not yet verified RPS procurement for 2008. Publicly owned utilities are showing progress in renewable energy procurement, with expectations for the 15 largest publicly owned utilities of 12.4 percent of RPS-eligible renewable retail sales by 2011.

Meeting the RPS goals depends in large part on building new transmission lines to access remote renewable resources. To help address land use and environmental concerns, the state launched the Renewable Energy Transmission Initiative (RETI) in 2007 to identify areas where renewable energy could be developed economically and with minimal environmental impacts and the transmission projects needed to access those areas. RETI is a stakeholder collaborative supervised by a coordinating committee made up of the Energy Commission, the CPUC, the California ISO, and publicly owned utilities. RETI and other transmission-related issues are discussed in more detail in Chapters 2 and 3.

Another strategy to address environmental barriers is Governor Schwarzenegger's Executive Order S-14-08, which directs state agencies to work with federal agencies to prepare a Desert Renewable Energy Conservation Plan (DRECP) for the Mojave and Colorado Deserts of California. The science-driven DRECP is intended to become the state road map for renewable energy project development that will advance state and federal conservation goals while facilitating the timely permitting of renewable energy projects in these desert regions.

The DRECP efforts will be informed by multiple environmental and land use planning activities including the Bureau of Land Management's Solar Programmatic Environmental Impact Statement and RETI activities, such as the competitive renewable energy zones, and associated transmission line segments to access the zones in the Colorado and Mojave Desert regions. The DRECP will cover a range of activities related to the development of renewable energy projects and associated transmission needs, as well habitat conservation and mitigation strategies in the plan's study area.

An additional strategy to help the state meet its RPS targets is the use of feed-in tariffs – fixed, long-term prices for energy. Other countries such as Spain and Germany have implemented successful feed-in tariff programs, but this concept has been slow to gain momentum in California. The state made some progress when the CPUC adopted a feed-in tariff (Decision 07-07-027) in February 2008 for renewable energy systems at publicly owned water and wastewater treatment facilities. In the same decision, the CPUC expanded the feed-in tariff

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9 California Public Utilities Commission, *Renewables Portfolio Standard Quarterly Report*, July 2009, available at: [http://www.cpuc.ca.gov/NR/rdonlyres/EBEEB616-817C-4FF6-8C07-2604CF7DDC43/0/Third_Quarter_2009_RPS_Legislative_Report_2.pdf].

approach to any renewable system with a capacity up to 1.5 MW in the Southern California Edison (SCE) and Pacific Gas and Electric (PG&E) service areas.

Governor Schwarzenegger's Executive Order S-06-06 is part of a strategy to develop an integrated and comprehensive state policy on the use of biomass for electricity generation. In response, the Bioenergy Interagency Working Group[10] developed the *Bioenergy Action Plan for California* in 2006, which identified 63 action items for various state agencies to advance the use of bioenergy in California.[11]

The Executive Order required the Energy Commission to provide a progress report in the biennial *IEPR* on the 63 action items. To date, the Energy Commission has found that most of the items have been implemented or are on-going. For those that have not been put into action, many are no longer relevant, have been overtaken by other events, or have not been funded. In 2008, California met the goal of generating 20 percent of its renewable electricity from biomass sources. However, biomass capacity in the state has decreased since 2002, from 6,192 MW to 5,724 MW.[12] This decrease resulted from the expiration of standard offer contracts from the 1990s, while very few contracts have been signed for new electricity generation fueled by biomass and biogas. The existing fleet of biomass generators depends on financial support from the Energy Commission's Renewable Energy Program, funding for which expires in 2011. These findings will be provided in the Energy Commission's *2009 Draft Bioenergy Progress to Plan* report, anticipated to be completed in early November 2009.

Overall, RD&D continues to be another important strategy for expanding renewable energy development in California. From 1976-2007, the Energy Commission's PIER program has dedicated $131 million to renewable energy research. In addition, the PIER Transmission Research Program is focusing on specifically addressing the issues associated with renewable integration into the California transmission system, while research in other areas such as demand response, energy storage, and smart grid technologies will help with renewable integration.

Finally, one other strategy for meeting the RPS is the California ISO's Integration of Renewable Resources Program (IRRP), which involves working with the Energy Commission and other agencies to identify issues and solutions for the integration of large amounts of renewable

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10 The Working Group is lead by Commissioner Jim Boyd of the California Energy Commission, and includes the California Air Resources Board, California Environmental Protection Agency, California Public Utilities Commission, California Resources Agency, Department of Food and Agriculture, Department of Forestry and Fire Protection, Department of General Services, Integrated Waste Management Board, and the State Water Resources Control Board.

11 Bioenergy Interagency Working Group, *Bioenergy Action Plan for California*, July 2006, CEC-600-2006-010, available at: [http://www.energy.ca.gov/bioenergy_action_plan/index.html].

12 Presentation by Daryl Metz at the August 10, 2009, IEPR Staff Workshop on RD&D of Advanced Generation Technologies, "California Generation Portfolio," California Energy Commission.

resources into the California ISO Control Area.[13] The California ISO completed studies on 20 percent RPS by 2010 in July 2009 and is working on the 33 percent RPS by 2020 scenarios, which it expects to complete by December 2009.

Distributed Generation

Increased use of distributed generation is another strategy for meeting the state's GHG reduction goals. Distributed energy systems are complementary to the traditional electric power system and include small scale power generation technologies (for example, CHP, photovoltaic, small wind turbines) located close to where the energy is being used. Distributed generation has many advantages, including increased grid reliability, energy price stability, and reduced emissions, especially in industrial applications. California is leading the nation in implementing policies to encourage distributed generation development. The following policies were implemented to encourage the use of distributed generation systems as a way of meeting the state's climate change goals while increasing reliability:

- **Assembly Bill 1969 (Yee, Chapter 731, Statutes of 2006):** This bill authorized feed-in tariffs for small renewable generators of less than 1 MW at public water and wastewater treatment facilities. In July 2007, the CPUC (D. 07-07-027) implemented AB 1969 and expanded the feed-in tariffs to 1.5 MW and included non-water customers in the PG&E and SCE territories. The power sold to the utilities under feed-in tariffs can be applied towards the state's RPS targets. Senate Bill 380 (Kehoe, Chapter 544, Statutes of 2008) codified CPUC's expanded feed-in tariff to include all RPS-eligible generators 1.5 MW and below. The program cap was also expanded from 250 MW to 500 MW.
- **Assembly Bill 1613 (Blakeslee, Chapter 713, Statutes of 2007):** Also known as the Waste Heat and Carbon Emissions Reduction Act, this bill was designed to encourage the development of new CHP systems in California with a generating capacity of up to 20 MW, resulting in more efficient use of natural gas and reduced GHG emissions. The bill requires the CPUC and the Energy Commission to establish policies and procedures for the purchase of electricity from eligible CHP systems.
- **ARB's *Climate Change Scoping Plan*:** The ARB set a target of 4,000 MW of CHP that would displace 30,000 gigawatt hours of demand from other power generation resources with the overall goal of reducing CO_2 by 6.7 million metric tons.
- **Senate Bill 1 (Murray, Chapter 132, Statutes of 2006):** This bill enacted the Governor's Million Solar Roofs program with the overall goal of installing 3,000 MW of solar PV systems.

Increasing CHP is a key strategy for displacing conventional power sources. To help track the state's CHP goals, the ARB will report on the GHG emissions reductions resulting from the increase of electricity generated from CHP. Also, in December 2009, the Energy Commission is

13 California ISO, http://www.caiso.com/1c51/1c51c7946a480.html.

scheduled to adopt guidelines to establish the technical criteria for CHP system eligibility for programs developed by IOUs and publicly owned utilities.

To implement SB 1, the state officially launched Go Solar California in 2007, to bring customer awareness to the CPUC's California Solar Initiative (CSI) and the Energy Commission's New Solar Homes Partnership (NSHP), and solar incentive programs offered by publicly owned utilities beginning 2008. The CSI offers rebates to existing homes and non-residential energy customers installing solar systems in IOU service territories, with 226 MW of new solar installed as of June 2009.

The NSHP offers incentives for home builders to construct solar homes. The goals of the program are to achieve 400 MW of installed solar capacity by the end of 2016, create a self-sustaining solar market without the need for government incentives, and foster sufficient market penetration in the new residential market so that 50 percent or more of new housing built by 2016 and thereafter will include solar systems. However, with the recent extreme downturn in new home construction, program activity has been slow and is likely to remain so until the economy recovers.

Solar incentive programs offered by the publicly owned utilities must abide by the minimum guidelines established by the Energy Commission. These solar incentive programs have their own processes and requirements and are expected to achieve 700 MW of installed solar capacity by the end of 2016.

Another customer-side strategy is the Self-Generation Incentive Program, which is implemented by the CPUC through the IOUs and provides rebates for customers who install wind turbines and fuel cells. The program originally included microturbines, small gas turbines, wind turbines, solar photovoltaics, fuel cells, and internal combustion engines, but as of January 1, 2008, only fuel cells and wind energy technologies are eligible. As of December 2008, the IOUs have paid more than $600 million in rebates for more than 1,200 projects totaling more than 337 MW of generating capacity. The Energy Commission administers a similar program also limited to wind turbines and fuel cells, the Emerging Renewables Program.

Net metering is another strategy to help increase customer-side distributed generation technologies, particularly PV. Customers who install an on-site renewable energy system can apply for net metering, which is a special billing arrangement with the utility. The customer's electric meter tracks electricity generated by the renewable system versus electricity consumed, with the customer paying only for the net amount taken from the grid over a 12-month period.

Natural Gas and Nuclear Power Plants

Despite long-term efforts to promote preferred resources like energy efficiency, demand response, distributed generation, and renewable energy, California still relies on natural gas and nuclear power plants for about 60 percent of its electricity. Since deregulation in 1998, the Energy Commission has reviewed and licensed 66 electric generation projects, totaling 25,744 MW. Forty-seven of these licensed facilities, totaling 14,630 MW of capacity, have been built and are on-line.

The following are key policies affecting natural gas and nuclear power plants:

- **State Water Resources Control Board's (SWRCB) Once-Through Cooling (OTC) Resolution (2006):** The SWRCB passed a resolution to reduce marine impacts from OTC systems used by 21 coastal power plants in California, including natural gas and nuclear plants. This began a coordinated process between several government agencies to phase out the use of OTC.
- **Assembly Bill 1632 (Blakeslee, Chapter 722, Statutes of 2006):** This legislation directed the Energy Commission to assess the vulnerability of PG&E's Diablo Canyon Nuclear Power Plant (Diablo Canyon) and SCE's San Onofre Nuclear Generating Station (SONGS) to an extended shutdown due to a major seismic event or aging. AB 1632 also called for an examination of potential impacts from the accumulation of nuclear waste at both locations and an exploration of other key issues such as plant relicensing and worker safety.
- **Senate Bill 1368 (Perata, Chapter 598, Statutes of 2006):** This bill limited long-term investments in baseload generation by the state's utilities to power plants that meet an emissions performance standard (EPS) jointly established by the Energy Commission and the CPUC.
- ***2005* and *2007 IEPR* Policy on Aging Power Plants:** In both reports, the Energy Commission recommended that the CPUC require IOUs to procure enough capacity from long-term contracts to allow for the orderly retirement or repowering of aging plants by 2012. In the *2007 IEPR*, the Energy Commission recommended that California's utilities adopt all cost-effective energy efficiency measures for natural gas, including replacement of aging power plants with new efficient power plants. In addition, the *2007 IEPR* recommended the Energy Commission, the CPUC, the California ISO, and other interested agencies work together to complete studies on the impacts of retiring, repowering, and replacing aging power plants, particularly in Southern California.
- **ARB's *Climate Change Scoping Plan*:** The *Climate Change Scoping Plan* calls for industrial facilities, such as power plants, to implement cost-effective GHG emissions reduction strategies. Specifically, the *Climate Change Scoping Plan* requires a reduction in GHG emissions from fugitive emissions from oil and gas extraction and gas transmission.

The federal government's Clean Water Act (CWA), enacted in 1972, is the primary law governing water pollution in the United States The CWA implemented a permit system for regulating point sources (for example, industrial facilities) of pollution to be overseen by the U.S. Environmental Protection Agency (U.S. EPA) or states with approved permitting programs, such as California. Section 316(b) of the CWA addresses the adverse environmental impacts caused by cooling water intake structures from power plants and other industrial sources. This section requires that the location, design, construction, and capacity of cooling water intake structures reflect the best technology available for minimizing adverse environmental impacts.

In April 2006, the SWRCB issued a resolution to reduce OTC impacts from existing power plants to comply with the CWA. The SWRCB issued a preliminary proposal to phase out OTC cooling and provided it for review to the Energy Commission, California ISO, and the CPUC. The SWRCB received pertinent feedback from the energy agencies about the ability to maintain reliability while complying with OTC policy. The SWRCB issued a second proposal, but the energy agencies still had concerns under the proposed schedule. In June 2008, the SWRCB formed the Interagency Working Group to foster communication among seven government agencies. The three energy agencies - the Energy Commission, CPUC, and the California ISO - were encouraged to propose alternatives to the fixed compliance schedule.

The energy agencies submitted a final strategy in May 2009 that calls for replacing existing OTC facilities with some combination of repowered technologies onsite, new generation located in other areas, and/or upgrades to the transmission system. The SWRCB accepted the proposal and included references to it in its draft OTC policy on June 30, 2009. [14] The OTC concerns relating to grid reliability, with emphasis on Southern California, are discussed in more detail in Chapter 3.

In addition to marine impacts from OTC, the primary concerns regarding the state's nuclear plants relate to the potential for extended outages at the plants from seismic events or plant aging and the absence of a repository for storing the high-level radioactive waste produced at the plants. In addition, the plants pose a small risk of potentially severe impacts from acts of terrorism or accidents.

The Energy Commission's report, *An Assessment of California's Nuclear Plants: AB 1632 Report*,[15] adopted as part of the *2008 IEPR Update*, recommended that PG&E and SCE update studies on the seismic hazard at their nuclear plants, investigate plant seismic safety compliance with current codes and standards, describe plant repair plans and timeframes in the event of an earthquake, provide evidence of strong safety cultures (especially at SONGS), and report findings from these studies as part of their license renewable feasibility studies for the CPUC and in future IEPRs.

The strategies just described are meant to minimize reliability, economic, and environmental risks associated with California's operating power plants. SB 1368, on the other hand, applies to all new power generation. In 2007, the Energy Commission adopted regulations for publicly owned utilities to meet the Emissions Performance Standard as required by SB 1368. The regulations require a baseload standard for generation of 1,100 lbs CO_2 per megawatt-hour and establish a public review process to ensure compliance with the Emissions Performance Standard.

Transmission

The state's transmission and distribution system is another critical component of the electricity sector for serving California's growing population and integrating renewable energy. The

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14 Jaske, Michael R. (Energy Commission), Peters, Dennis C. (California ISO), and Strauss, Robert L. (CPUC), *Implementation of Once-Through Cooling Mitigation Through Energy Infrastructure Planning and Procurement*, California Energy Commission, July 2009, CEC-200-2009-013-SD, available at: [http://www.energy.ca.gov/2009publications/CEC-200-2009-013/CEC-200-2009-013-SD.PDF].

15 This report was based upon a consultant report by MRW and Associates, *AB 1632 Assessment of California's Operating Nuclear Plants*, Final Consultant Report, October 2008, CEC-100-2008-005-F, http://www.energy.ca.gov/2008publications/CEC-100-2008-009/CEC-100-2008-009-CMF.PDF.

following policies were implemented to improve and streamline the state's transmission and distribution planning process:

- **Senate Bill 1565 (Bowen, Chapter 692, Statutes of 2004):** In 2004, the Legislature addressed the need for an official state role in transmission planning with the passage of this bill. SB 1565 directed the Energy Commission to develop a Strategic Transmission Investment Plan (Strategic Plan), which identifies and recommends actions to stimulate transmission investments to ensure reliability, relieve congestion, and meet future growth in load and generation, including renewable resources, energy efficiency, and other demand reduction measures.
- **Senate Bill 1059 (Escutia and Morrow, Chapter 638, Statutes of 2006):** Under this bill, California continued to develop an integrated, statewide approach to electric transmission planning and permitting to address the state's critical energy and environmental policy goals. This bill provided a bridge between the transmission planning process and the permitting process by designating transmission corridor zones on state and private lands available for future high-voltage electricity transmission projects, consistent with the state's electricity needs identified in the *IEPRs* and *Strategic Transmission Investment Plans*.

The Energy Commission has prepared and published two strategic plans in response to SB 1565. The first was released in 2005 and the other in 2007. Both reports provided an overview of the significant transmission planning and system issues hindering development of a more robust high voltage grid and identified actions necessary to improve California's transmission system.

The joint IEPR and Siting Committees Draft *2009 Strategic Transmission Investment Plan (2009 Strategic Plan)*, prepared in support of the *2009 IEPR*, describes the immediate actions that California must take to plan, permit, construct, operate, and maintain a cost-effective, reliable electric transmission system that is capable of responding to important policy challenges such as achieving significant GHG reduction and RPS goals. The *2009 IEPR* provides the report's top priority recommendations in Chapter 4. The *2009 Strategic Plan* recommendations will be the subject of a joint Siting and IEPR Committee hearing on October 8, 2009.

In 2004, the PIER program established the Transmission Research Program to specifically address the research and development needs of California's transmission system. The program considers new and emerging technologies that can increase the capabilities of existing transmission lines and provide better understanding of system management issues associated with the penetration of high amounts of renewable generation and integrating new high-speed data collection technologies like synchrophasors.[16] Research continues in areas specifically

16 Synchrophasors can collect and report critical electrical measurements approximately 30 times per second, providing information about grid conditions to system operators so they can make time-sensitive decisions. As more renewable resources are integrated into the grid, operators need this kind of technology to respond to unpredicted changes in output that are characteristic of some renewable technologies.

addressing the issues associated with renewable integration into the California transmission system.

Natural Gas Sector

California's dependence on natural gas as a fuel for electricity generation and for heating and process industries requires the state to have reliable and cost-effective sources of supply and sufficient infrastructure to deliver that supply. During the 2009 IEPR proceedings, the IEPR Committee focused on natural gas issues relating to price volatility, supply, and infrastructure needs. Aside from GHG emissions reduction policies, other guiding policies regarding natural gas relate to forecasting, supply stability, and reliability. The following policies and regulations provide direction on natural gas programs and development:

- **California Public Resources Code:** Directs the Energy Commission to conduct assessments and forecasts of all aspects of energy industry supply, production, transportation, delivery and distribution, demand, and prices at least every two years and to identify impending or potential problems or uncertainties in the electricity and natural gas markets, potential options and solutions, and recommendations.
- **California Climate Change Policies:** The policies directing the state to meet climate change goals, such as the RPS and the ARB's *Climate Change Scoping Plan*, intend to reduce the state's dependence on fossil fuels—such as natural gas—and replace these with cleaner fuel resources.

California relies on natural gas for more than 45 percent of its total system power needs.[17] Eighty-five percent of natural gas supplies are imported via pipelines from the Southwest, Rocky Mountains, and Canada. This reliance on out-of-state natural gas leaves California vulnerable to supply disruptions and price volatility. Since 2000, the United States has experienced four major price spikes that impacted residential, commercial, and industrial consumers, as well as power generators and gas producers. During the 2000–2001 energy crisis, natural gas cost California $19.4 billion, more than double the price paid for similar amounts in the years just before the crisis.

California's strategy to address this issue has been to increase interstate pipeline delivery capacity, improve utilities' receiving ability, and enhance storage operations of utilities and independent storage owners to meet future high demand conditions. This has given California's utilities the flexibility to choose supply sources in their day-to-day operations, forcing natural gas production areas to compete for a share of the state's natural gas market. However, California is still part of an international natural gas market that includes Canada, the United States, and Mexico; a disruption in one area ripples through the rest of the market.

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17 California Energy Commission, Energy Almanac, available at: [http://energyalmanac.ca.gov/electricity/total_system_power.html].

As domestic production of conventional natural gas has declined, shale-deposited natural gas within the United States and Canada could provide California with a more stable supply in the future. In the last 20 years, technological innovations have eliminated the barriers that prevented the production of this resource. It is possible that this new supply could flow eastward and allow more natural gas from the Rockies and the Southwest to be sent to California. However, further analysis is needed on environmental concerns related to groundwater impacts and the carbon footprint from drilling, as well as market uncertainties based on investments and the infancy of shale development.

Importing LNG is another strategy that that could offset declining domestic production of natural gas. In the *2007 IEPR*, staff projected that as much as 20 percent of North American natural gas requirements might be met with LNG by 2017. However, development of new terminals appears to be slowing, and imports of LNG to the United States have been lower than projected. There is a new sense that the United States may not need to rely on LNG to make up previously projected supply deficits.

The *2007 IEPR* recommended that California should promote the use of pipeline-quality biogas from dairies and landfills as a strategy to diversify supplies of natural gas. At the 2009 IEPR Scoping Workshop in June 2008, the Natural Resources Defense Council recommended that the *2009 IEPR* pursue policies that encourage the replacement of natural gas with renewable resources. The Energy Commission examined this issue and found that there are still significant barriers hindering the in-state development of this resource, including Assembly Bill 4037 (Hayden, 1988), which discourages injection of biogas into natural gas pipelines by penalizing landfill gas and pipeline operators if vinyl chloride is found in the pipeline. This has resulted in pipeline operators purchasing from out-of-state sources that are not restricted under the law.

Transportation Sector

California has taken a clear policy stance of decreasing reliance on petroleum fuels and increasing the mix of alternative and renewable fuels. However, the state also recognizes that petroleum will continue to be the primary fuel source for California’s vehicles for at least the near term, so it must be factored into all policy decisions regarding infrastructure and fuel needs. As California relies increasingly on crude oil imports, the state is looking at ways to enhance and expand the existing petroleum infrastructure at in-state marine ports. The state has implemented some crucial policies in recent years for reducing petroleum dependency and achieving AB 32 climate change goals. The following policies were implemented to increase the use of renewable and alternative fuels and vehicles and accelerate the adoption of low carbon fuels through regulatory and funding mechanisms, as well as to improve the state’s infrastructure:

- **Assembly Bill 1493 (Pavley, Chapter 200, Statutes of 2002)**: Required the ARB to develop and adopt, no later than January 1, 2005, regulations to achieve the maximum feasible and cost-effective reduction of GHG emissions from motor vehicles.
- **2003 Integrated Energy Policy Report:** The Energy Commission showed that it is feasible to significantly reduce the state’s dependence on petroleum by increasing vehicle efficiency

and the use of alternative fuels and recommended that the state increase the use of non-petroleum fuels to 20 percent of on-road fuel consumption by 2020 and 30 percent by 2030 based on identified strategies that are achievable and cost-beneficial.[18]

- **2005 Integrated Energy Policy Report:** The Energy Commission examined petroleum reduction options and recommended that the state:
  1. Develop flexible overarching strategies that simultaneously reduce petroleum fuel use, increase fuel diversity and security, and reduce air pollution and GHG emissions.
  2. Implement a public goods charge to establish a secure, long-term source of funding for a broad transportation program.[19]
- **Executive Order S-3-05 (2005):** The executive order established statewide GHG emission reduction targets that preceded the enactment of AB 32:
  1. By 2010, reduce emissions to 2000 levels;
  2. By 2020, reduce emissions to 1990 levels;
  3. By 2050, reduce emissions to 80 percent below 1990 levels.
- **Assembly Bill 1007 (Pavley, Chapter 371, Statutes of 2005)**: Required the Energy Commission to prepare, jointly with the ARB, a plan to increase the production and use of alternative and renewable fuels in California based on a full fuel-cycle assessment of the environmental and health impacts of each fuel option. The *State Alternative Fuels Plan* (*Plan*) was adopted by the two agencies in December 2007. The *Plan* highlights the need for state government incentive investments of more than $100 million per year for 15 years and recommends that the state adopt alternative and renewable fuel use goals of 9 percent by 2012, 11 percent by 2017, and 26 percent by 2022.
- **Bioenergy Action Plan (2006):** The Energy Commission adopted this plan with the intent to maximize the contributions of bioenergy toward achieving the state's petroleum reduction, climate change, renewable energy, and environmental goals. The plan recommends a production target of a minimum of 20 percent of biofuels produced in California by 2010, 40 percent by 2020, and 75 percent by 2050.[20]
- **Executive Order S-06-06 (2006):** This order set targets for the production of biofuels based on the recommendations of the *Bioenergy Action Plan* and charged the Energy Commission, along with other commissions and departments, to identify and secure funding for research, development, and demonstration projects to advance the use of biofuels for transportation.
- **Executive Order S-01-07 (2007):** Governor Schwarzenegger's order established a LCFS for

18 California Energy Commission, *2003 Integrated Energy Policy Report*, available at: [http://www.energy.ca.gov/reports/100-03-019F.PDF]

19 California Energy Commission, *2005 Integrated Energy Policy Report*, available at: [http://www.energy.ca.gov/2005publications/CEC-100-2005-007/CEC-100-2005-007-CMF.PDF]

20 California Energy Commission, *Bioenergy Action Plan*, July 2006, CEC-600-2006-010,available at: [http://www.energy.ca.gov/bioenergy_action_plan/index.html]

transportation fuels sold in California. By 2020, the standard will reduce the carbon intensity of California's passenger vehicle fuels by at least 10 percent. The Executive Order directs the Secretary for the CalEPA to coordinate the actions of the Energy Commission, the ARB, the University Of California, and other agencies to assess the "life-cycle carbon intensity" of transportation fuels. ARB completed its review of the LCFS protocols and adopted it as an early action in October 2007. The ARB, through its rulemaking, adopted the new standard in April 2009.

- **Assembly Bill 118 (Núñez, Chapter 750, Statutes of 2007):** This bill created the Alternative and Renewable Fuel and Vehicle Technology Program. The statute, subsequently amended by AB 109 (Núñez, Chapter 313, Statutes of 2008), authorizes the Energy Commission to develop and deploy alternative and renewable fuels and advanced transportation technologies to help attain the state's climate change policies. The Energy Commission has an annual program budget of approximately $100 million and is required to adopt and update annually an Investment Plan that determines the funding priorities.
- **The Energy Independence and Security Act of 2007:** This federal legislation requires ever-increasing levels of renewable fuels – a *Renewable Fuel Standard*, or RFS – to replace petroleum. Primarily focused on ethanol, the law establishes the national goal of using 36 billion gallons of renewable fuel per year by 2022. An updated version of the standard, called RFS2, is due to take effect January 1, 2010.[21]
- **Senate Bill 375 (Steinberg, Chapter 728, Statutes of 2008):** This bill requires the ARB to develop, in consultation with metropolitan planning organizations, passenger vehicle GHG emissions reduction targets for 2020 and 2035 by September 30, 2010. Through the SB 375 process, regions will work to integrate development patterns, the transportation network, and other transportation measures and policies in a way that achieves GHG emission reductions while meeting regional planning objectives.

Under Assembly Bill 1493's authority, the ARB approved regulations to reduce GHGs from passenger vehicles in September 2004, with the regulations to take effect in 2009. However, in March 2008, the U.S. EPA denied the ARB's first waiver request to implement GHG standards. The denial was based on a finding that California's request did not show it was needed to meet "compelling and extraordinary conditions" as required under the federal Clean Air Act.

The regulations became the subject of automaker lawsuits and their implementation was stalled by the U.S. EPA's denial. In May 2009, parties on both sides entered an agreement to resolve these issues. The U.S. EPA granted ARB's waiver on June 30, 2009, and the ARB held a hearing on September 24, 2009 on proposed amendments to the regulations. It is expected that the Pavley regulations will reduce GHG emissions from California passenger vehicles by about 22 percent in 2012 and about 30 percent in 2016, while improving fuel efficiency and reducing motorists' costs.

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21 United States Senate Committee on Energy and Natural Resources, Summary and related documents available at:
[http://energy.senate.gov/public/index.cfm?FuseAction=IssueItems.Detail&IssueItem_ID=f10ca3dd-fabd-4900-aa9d-c19de47df2da&Month=12&Year=2007]

On April 22, 2009, the Energy Commission adopted its first investment plan for the Alternative and Renewable Fuels and Vehicle Technology Program.[22] The Investment Plan contains specific recommendations for expending the $176 million appropriated for the first two years of the Program (FY 08-09 and FY 09-10). The Investment Plan allocates $46 million for electric drive vehicles, $40 million for hydrogen fueling stations, $12 million for generation I biofuels (or ethanol), $6 million for generation II biofuels (or renewable diesel and biodiesel), $43 million for natural gas development including biomethane production plants, $2 million for propane medium duty vehicles (such as school buses), and $27 million for workforce training, sustainability studies, standards and certification, and public education.

In response to the federal ARRA of 2009, staff released a solicitation in April 2009 to offer cost share funding opportunities using AB 118 funds. Leveraging these federal dollars for projects consistent with the AB 118 funding goals should spur innovation and competition in the development of alternative fuels, technologies, advanced vehicles and alternative fuel infrastructure, leading to an eventual reduction in petroleum fuel usage. Projects resulting from this solicitation include the development of 55 E85 stations, more than 3,100 electric charging stations, 5 public access liquefied natural gas (LNG) stations, and the purchase of 442 LNG medium-duty trucks and 123 medium-duty hybrid electric trucks.

In addition to the ARRA cost share solicitation, the Energy Commission has entered into interagency agreements (IAs) with state entities that specialize in workforce training. The first of these is with the Employment Development Department (EDD) and determines program specific labor market information and delivers local workforce development and training through the EDD Workforce Development Branch offices. The second IA is with the California Community Colleges Chancellor's Office and provides needs assessments, advanced transportation industry studies, and curriculum development and delivery through the community colleges. These IAs support the transportation component of the California Clean Energy Workforce Training Program, a collaborative effort between the Energy Commission, the EDD, and the California Workforce Investment Board.

The paramount matter is the Energy Commission's progress in achieving the goals and objectives set forth in the State Alternative Fuels Plan. According to the Energy Information Administration (EIA), California's overall alternative fuel usage increased to 109,114 gge (thousand gasoline gallon equivalent) in 2007 from just over 70,000 gge in 2003. The number of alternative fuel vehicles in use also increased. The largest alternative fuel categories in use are compressed natural gas (CNG), liquefied petroleum gas (LPG), and liquefied natural gas (LNG), followed by ethanol (E-85). Federal, state, and local government agencies are the predominant consumers of alternative fuels. As the trend away from petroleum fueled vehicles grows, the reduction in GHG emissions will become more apparent. Since 2000, the growth in hybrid

22 California Energy Commission, *Investment Plan for the Alternative and Renewable Fuel and Vehicle Technology Program*, Final Committee Report, available at: [http://energy.senate.gov/public/index.cfm?FuseAction=IssueItems.Detail&IssueItem_ID=f10ca3dd-fabd-4900-aa9d-c19de47df2da&Month=12&Year=2007]

vehicles alone in California has contributed to a reduction in GHG emissions of about 60 million metric tons.

As for the in-state biofuels production goals, the state is not on track to meeting the 2010 target. The biofuels industry – in California as well as the rest of the country – entered a period of severe decline in 2009, a victim of tight credit, a glut of production capacity, dwindling demand, and low oil prices. Many business models for producing biofuel were based on oil being priced above $80 a barrel; with oil prices falling well below that benchmark, making ethanol became uneconomical. Plants producing ethanol from corn shut down across the country as corn prices spiked even as ethanol prices dropped. Many companies, including Sacramento-based Pacific Ethanol Inc., sought bankruptcy protection.

Companies making biodiesel from vegetable oil or animal fat suffered similar fates. Delayed federal rules on changing fuel mixes added to uncertainty for the biofuel industry. While congressional mandates allowing biodiesel blending and requiring the use of second-generation biofuels are slated to take effect in 2010, the U.S. EPA postponed issuing regulations needed to implement the requirements.

By the fall of 2009, two-thirds of United States biodiesel production capacity sat idle, according the National Biodiesel Board.[23] As of September 2009, 98 percent of California's ethanol production capacity was reported to be closed down.

The Energy Commission's PIER program is focusing RD&D efforts on vehicle technologies, alternative fuels, and transportation systems and has invested $5.8 million to date. These three focus areas will fund research to reduce petroleum consumption and GHG emissions while assisting economic development within California. The PIER program released a Program Opportunity Notice on April 22, 2009, using the ARRA cost share funding for the Alternative and Renewable Fuel and Vehicle Technology Program. Also, the PIER program's Energy Innovations Small Grant Program provides up to $95,000 for hardware projects and $50,000 for modeling projects to small businesses, non-profits, individuals, and academic institutions to conduct research that establishes the feasibility of new, innovative energy concepts, including those related to transportation technologies.

Local Government Assistance

Land use planning is a local issue, under the jurisdiction of local governments. Decisions about land use, however, directly affect energy use and the consequent production of GHG emissions in the state.

Since the 1950s, California's land use patterns have emphasized suburban development of large residential tracts located far from city centers and places of work or business. This land use planning has resulted in many citizens purchasing more affordable housing in the suburbs and commuting longer distances to the workplace. With transportation being a major contributor to

23 Wall Street Journal, August 27, 2009, available at:
[http://online.wsj.com/article/SB125133578177462487.html?mod=googlenews_wsj].

GHG emissions (40 percent) in this state, smart land use planning and growth is an increasingly important strategy to combat declining air quality and the loss of open space and wildlife habitat, and to improve the quality of life for California's residents. Nearly 26 million vehicles, most of which are powered by fossil fuels, along with a high rate of vehicle miles traveled (VMT), contribute significantly to California's GHG emissions and climate change issues. Projections show that the state cannot reduce GHG emissions to 80 percent of 1990 levels by 2050 unless VMT is reduced by at least 17 percent.[24]

Reducing VMT in a meaningful way requires replacing the existing suburban development model with one that encourages denser, more compact cities that offer better mass transit options and amenities that encourage walking or biking. Indeed, "smart growth" — applying development principles that make prudent use of resources and create low-impact communities demonstrating enlightened design and layout — was singled out in the *2006 IEPR* as the single largest opportunity to help California meet its statewide energy and climate change goals.

Housing, transportation planning, and local GHG reductions all require local and regional approaches. But smart growth has become an increasingly important issue after the California's Attorney General's office ruled that local jurisdictions must consider GHG emissions when submitting California Environmental Quality Act (CEQA) documents for planning projects.

To encourage smart growth and make it easier to accomplish, state agencies — including the Energy Commission — are offering assistance to local governments. California has enacted new policies that emphasize smart growth plans at the local level that incorporate energy, transportation, climate change, and housing needs. The following policies provide direction on local government assistance:

- **Senate Bill 375 (Steinberg, Chapter 728, Statutes of 2008):** This bill established mechanisms for the development of regional targets for passenger vehicle GHG reductions. Under SB 375, regions will work to integrate development patterns, the transportation network, and other transportation measures and policies in a way that achieves GHG emission reductions while meeting regional planning objectives.
- **Senate Bill 732 (Steinberg, Chapter 729, Statutes of 2008):** This bill established a five-member council to help state agencies allocate Strategic Growth Plan funds to promote efficiency, sustainability, and support the Governor's economic and environmental goals.
- **Senate Bill 372 (Kehoe, 2009):** This recently passed bill focuses on land use in state parks. If SB 372 is signed by the Governor, any proposed development incompatible with state park purposes may proceed only after a recommendation by the State Park and Recreation Commission's Director and the Legislature enacts legislation approving the recommendation.

As part of SB 375's strategy, the ARB is required to develop, in consultation with metropolitan planning organizations (MPOs), passenger vehicle GHG emission reductions targets for 2020

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24 California Energy Commission, State Alternative Fuels Plan, December 2007, CEC-600-2007-011-CMF, p. 75, available at: [http://www.energy.ca.gov/ab1007/index.html].

and 2035 by September 30, 2010. This policy also creates incentives for local governments and developers by providing relief from certain CEQA requirements for development projects consistent with regional plans that achieve the targets.

SB 375 requires the MPOs to incorporate a Sustainable Community Strategy as an element of their Regional Transportation Plans (RTP). The strategy will be effectively a blueprint-like set of planning assumptions that shape the land use component of the RTP. The goal is to promote development density near urban cores and transit centers.

Funding is a key part of assisting local government agencies with their RTPs. Since 2005 the California Department of Transportation (Caltrans) has coordinated local and state planning through its California Regional Blueprint Planning Program, a voluntary, competitive grant program encouraging MPOs and Councils of Government to conduct comprehensive scenario planning. The goal of the program is for regional leaders, local governments, and stakeholders to reach consensus on a preferred growth scenario — or "blueprint" — for a 20-year planning horizon (through 2025). Caltrans has awarded a total of $20 million in federal RTP funds since initiating the program in 2005. In 2009 alone, Caltrans granted $5 million to nine MPOs and nine rural regional transportation planning agencies.[25]

Local government building departments are responsible for enforcing the mandatory energy efficiency standards for buildings. These standards are Part 6 of the California Building Code (Title 24). The Energy Commission works with building departments to provide training and assistance to the key partners in achieving energy efficiency.

To support the goals of SB 375, the Energy Commission is conducting research to help determine the most effective ways to integrate land use and transportation with fuel use and emissions. Through the Energy Commission's PIER program, the *Assessment of New Transportation and Urban Development Patterns in a Climate-Constrained Future* study is helping to model how reducing the use of transportation fuels and cutting VMT will affect the state. Working with the UC Berkeley Global Metropolitan Center, PIER hopes to quantify the results that smart growth can bring to the fight against global climate change.

Through new legislation and adopted policies, California has become a leader in the worldwide search for solutions to the growing problem of climate change. Many of the state's energy policies highlighted in the *2009 IEPR* are being used as templates for other governments as they strive to protect consumers, the economy, and the environment.

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25 California Department of Transportation, California Regional Blueprint Planning Program, see [http://www.dot.ca.gov/hq/tpp/offices/orip/blueprint/index.html].

Chapter 2: Energy and California's Citizens

This chapter describes the important connections between the energy policies described in Chapter 1 and its citizens —individuals, small businesses, large industries, and all levels of government. Energy users have three basic priorities when it comes to energy: it must be reliable, affordable, and have minimal environmental impacts. These priorities apply equally to all of the state's three major energy sectors: electricity, transportation, and natural gas. Each energy sector is covered in a separate section that discusses existing status, including supply and demand, and environmental, reliability, and economic issues facing that sector.

Electricity Sector

California's electricity system is a giant machine with many moving parts that are constantly being maintained and upgraded. This system of electricity generators, delivery facilities, and energy consumers must constantly adapt so that the amount of electricity that is generated instantly and continuously matches the amount of energy that is consumed. This section provides an overview of the three main components of the system: transmission and distribution, supply, and demand. It then discusses the environmental, reliability, and economic issues associated with the various resources in the state's loading order that was described in Chapter 1.

Electricity Transmission and Distribution

The backbone of California's electricity system is the state's network of electric transmission and distribution lines that bring power from plants both in and out of state to California consumers. Following California's deregulation of the electricity system, the three major investor-owned utilities (Pacific Gas & Electric Company [PG&E], Southern California Edison [SCE], and San Diego Gas & Electric Company [SDG&E]) and several publicly owned utilities transferred operation of their transmission systems to the California Independent System Operator (California ISO).[26] These utilities continue to operate their own distribution systems, but rely on the California ISO to operate the overall transmission network. Several publicly owned utilities, including Sacramento Municipal Utility District (SMUD), the Los Angeles Department of Water and Power (LADWP), and the Imperial Irrigation District, still control and operate their transmission and distribution systems, although the systems are connected to the California ISO-controlled grid.

Figure 1 shows the bulk transmission system now in place in California. Key features are the extensive interconnections to the north and southeast that allow imports to flow into California. Through these lines California is interconnected to overall Western Interconnection covering

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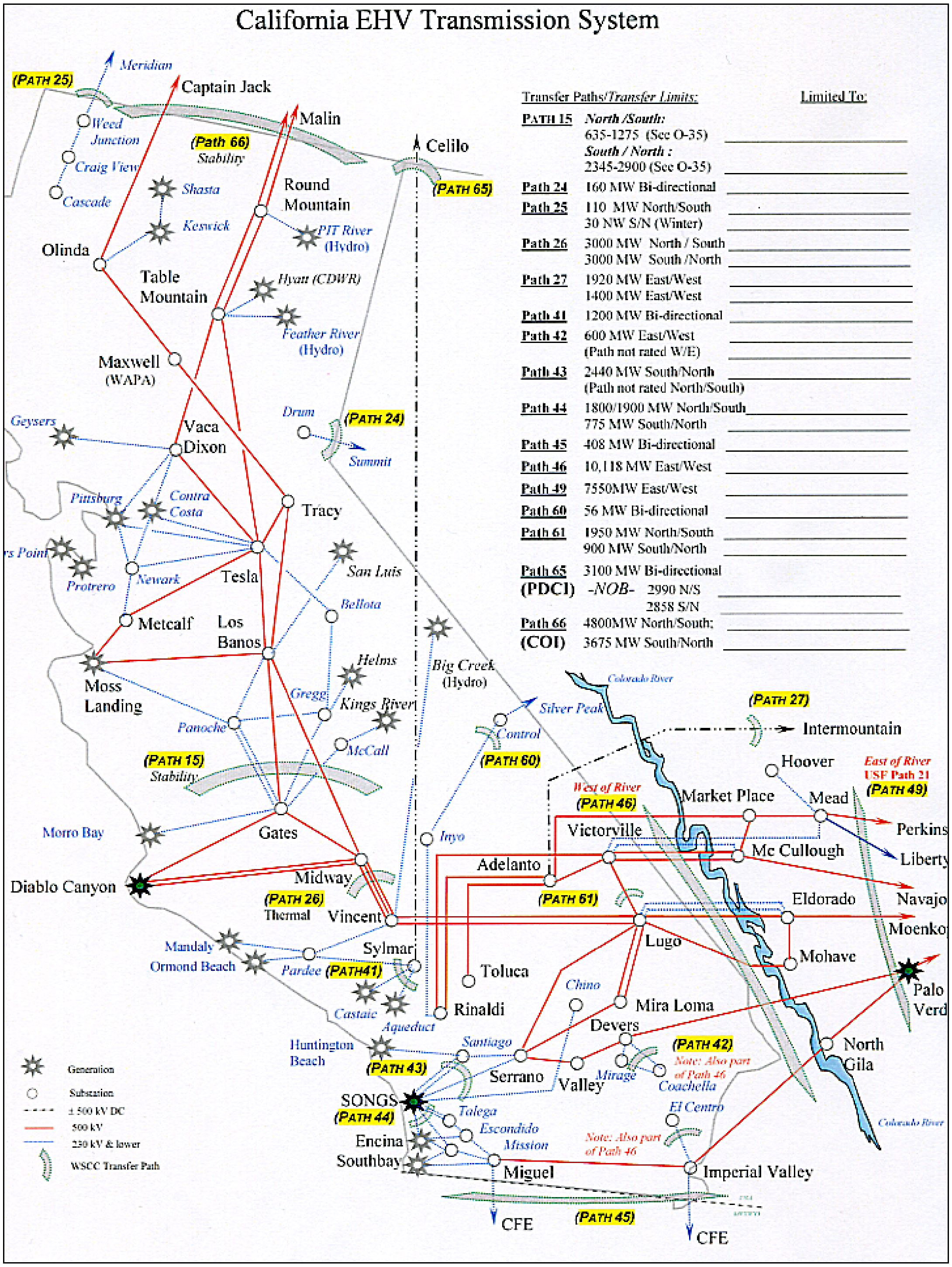
26 The California Independent System Operator is a Federal Energy Regulatory Commission regulated non-profit corporation tasked with ensuring competitive and non-discriminatory access to the California transmission system and is responsible for managing the flow of electric power for the majority of California.

most of western North America, from British Columbia and Alberta on the north to Baja Mexico on the south, and Colorado on the east.

Figure 1: Bulk Transmission System in California



Source: California ISO, 2008.

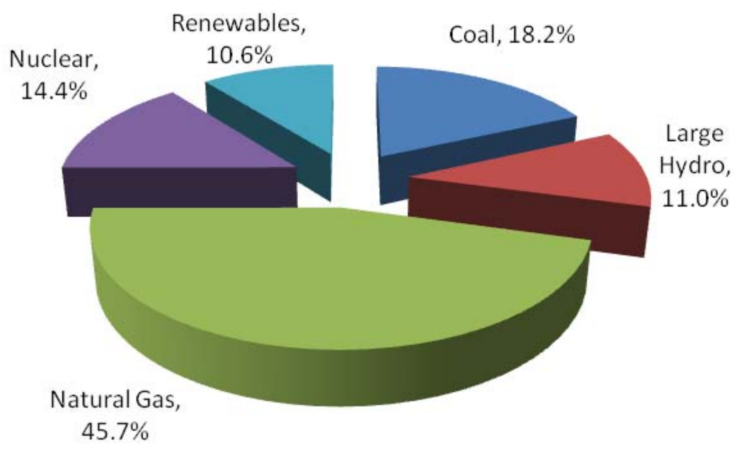
California's transmission and distribution infrastructure is an intrinsic component of the high-voltage Western Interconnection, making the state both an essential participant and a partner in various regional and federal planning and permitting initiatives that will alter the way transmission planning and permitting occurs in the future. The majority of these efforts encourage centralized transmission and distribution planning at the regional level, supplemented by federal incentives and regulation. Developers of new transmission are also focused on the Western United States, proposing over 30 enhancements and new projects that could increase the transfer capacity in various sub-regions and across the interconnection to bring renewable energy resources to market.

Electricity Supply

The second component of California's electricity system is the power plants that provide electricity supplies. California's system operators must constantly balance supply and demand in real time to provide reliable energy. The availability of generating resources depends on the lead-time involved. Some generators may need a full day to start up while others may be available within minutes. Other generators operate as "spinning reserves," generating less than their capacity but able to ramp up their generation relatively quickly to meet increased demand for electricity. Some resources, like nuclear, coal, geothermal, biomass, and cogeneration, usually run at or near full capacity when operating because of technical constraints, economics, or contracts. Other resources, like hydroelectric, wind, and solar, operate when conditions allow.

To match supply with demand, electricity systems rely on a portfolio of power plants with different operating characteristics. California relies on generating resources that include large hydroelectric, natural gas, nuclear, cogeneration, and renewables (see Figure 2). This mix can vary year-to-year, seasonally, daily, and even hourly.

Figure 2:– California's Generation Mix (2008)



Source: California Energy Commission

Table 1 shows the entire generation mix that served Californians in 2008. The in-state values listed are a reasonably accurate snapshot of the entire California power mix for the year. The imported power allocations for the Northwest and Southwest are estimated based on specific claims by energy service providers (retailers) and the general resource mix of those regions since there are no publicly available data-tracking mechanisms for the generation sources of imported power. The California Air Resources Board (ARB) is charged with addressing this issue in their implementation of Assembly Bill 32, including regulations for first jurisdictional deliverers to report on specified imports.[27]

Table 1: 2008 Total System Power (GWhs)

Fuel Type	In-State	Northwest Imports	Southwest Imports	Total System Power
Coal	3,977	8,581	43,271	55,829
Large Hydro	21,040	9,334	3,359	33,733
Natural Gas	122,216	2,939	15,060	140,215
Nuclear	32,482	747	11,039	44,268
Renewables	28,804	2,344	1,384	32,532
Biomass	5,720	654	3	6,377
Geothermal	12,907	0	755	13,662
Small Hydro	3,729	674	13	4,416
Solar	724	0	22	746
Wind	5,724	1,016	591	7,331
				0
Total	**208,519**	**23,945**	**74,113**	**306,577**

Source: Energy Information Agency, Energy Commission Quarterly Fuels and Energy Report Database, and Senate Bill 1305 Reporting Requirements

The resource mix for imports is based on the Energy Commission's *2008 Net System Power Report*.[28] The report represents the amount of electricity used by California customers for which no retailers specifically claimed a source of generation. In recent years, as California retailers specify larger and larger shares of their generation sources, the net system power has changed in two very important ways: it now represents a smaller share of total generation serving California (due to growing retailer claims on specific sources of generation), and it is characterized by a higher percentage of unclaimed coal and natural gas generation sources. Therefore, the total system power shown in Table 1 is used as an indicator of the sources of generation serving California end-users until the ARB begins collecting data from all first deliveries of power into California under AB 32.

27 First deliverer, or first seller, is the entity with ownership/title that first delivers power at a California point of delivery. For in-state production, the first seller is the generator; for imports, the first seller is the importer.

28 California Energy Commission, *2008 Net System Power Report*, July 2009, CEC-200-2009-010-CMF, available at: [http://www.energy.ca.gov/2009publications/CEC-200-2009-010/CEC-200-2009-010-CMF.PDF].

The Energy Commission has statutory responsibility to license thermal power plants 50 megawatts (MW) and larger. Since deregulation in 1998, the Energy Commission has licensed more than 60 power plants: 43 projects representing 14,630 MW are on-line, 6 projects totaling 2,072 MW are under construction, and 13 projects totaling 6,511 MW are on hold but "available" for construction. In addition, the Energy Commission has more than 30 proposed projects under review totaling more than 13,000 MW, which significantly exceeds historic workloads and is presenting challenges given existing staff resources.

Natural Gas-fired Generation

Natural gas plants (both in-state and out-of-state plants) provide about 46 percent of California's electricity needs. More than 14,600 MW of natural gas power plant capacity has come on-line since 1998. There are also 18 proposed natural gas-fired plants that are currently under review in the Energy Commission's power plant licensing process.

Of California's electricity sources, natural gas-fired plants tend to be the most flexible, allowing for peaking, cycling, and some baseload duty. Natural gas-fired generation is typically used to compensate for varying hydroelectric availability, and will likely be needed to help integrate higher amounts of renewable generation to meet the state's RPS goals. Emissions from natural gas generation account for a large portion of in-state greenhouse gas (GHG) emissions from the electricity sector, so it is essential for the Energy Commission to consider GHG impacts of natural gas plants in its power plant licensing process. However, because of the essential physical services provided by natural gas plants, California cannot simply retire all of its natural gas plants to meet its GHG emissions goals.

Hydroelectric Resources

Large hydroelectric power (larger than 30 MW in capacity) is a major source of California's electricity. In 2008, large hydroelectric plants produced 33,733 GWhs or 11 percent of total system power. California has nearly 400 hydro plants, most of which are located in the eastern mountain ranges, with total dependable capacity of about 14,000 MW. The state also imports hydro-generated electricity from the Pacific Northwest. While hydroelectric power offers the potential for low-cost baseload electricity, it is also subject to large annual fluctuations because of changes in rainfall and snowpack. For example, from 1995-1998, hydroelectric resources accounted for as much as 28 percent of California generation but in 2001 only provided 13 percent of total state generation.[29]

With current climate change concerns, there will be an increasing need to evaluate the possible impacts on California's hydropower resources. A recent draft paper by the California Climate Change Center looked at potential climate change effects on two hydroelectric facilities in California, the Upper American River Project, operated by SMUD in Northern California, and

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29 MRW and Associates, *Framework for Evaluating Greenhouse Gas Implications of Natural Gas-Fired Power Plants in California*, consultant report, May 2009, CEC-700-2009-009, available at: [http://www.energy.ca.gov/2009publications/CEC-700-2009-009/CEC-700-2009-009.PDF].

the Big Creek system, operated by Southern California Edison in Southern California.[30] The paper concluded that there could be a reduction in both energy generation and associated revenues from these facilities as a result of climate change. However, the results of the analysis also showed that the two hydroelectric facilities should still be able to supply peak power during the spring and early summer days in both Northern and Southern California, although there could be some difficulty in meeting increased power demand in late summer if there are increased occurrences of heat waves.

Nuclear

Generation from nuclear power plants represented 44,268 GWhs of California's total system power in 2008. California relies on three nuclear power plants for about 14 percent of the state's overall electricity supply:

- Diablo Canyon Power Plant: Pacific Gas and Electric owns and operates Diablo Canyon, which has a total generating capacity of 2,220 MW in two units. The Diablo Canyon facility is located near San Luis Obispo, along the coast between San Francisco and Los Angeles.
- San Onofre Nuclear Generating Station: Southern California Edison, San Diego Gas and Electric, and the City of Riverside are co-owners of the San Onofre Nuclear Generating Station, which is operated by Southern California Edison. The two operating units have a total capacity of 2,254 MW. The San Onofre Nuclear Generating Station is located near the boundary between Southern California Edison's and San Diego Gas and Electric's service territories near San Clemente, north of San Diego, in southern California.
- Palo Verde Nuclear Generating Station: Palo Verde is co-owned by Arizona Public Service Corporation, Southern California Edison, and five other utilities. Arizona Public Service Corporation operates the plant. Palo Verde's three units have an overall capacity of 3,810 MW. Palo Verde is located near Phoenix in Wintersburg, Arizona. California utilities own 27 percent of the plant.

These plants have been operating for roughly 20 years and are licensed to continue operating for through 2022 (SONGS) and 2024 and 2025 (Diablo Canyon Units 1 and 2, respectively). They provide benefits to California in the form of resource diversity, low operating costs, relatively low GHG emissions, and enhanced grid reliability. However, they also pose risks associated with nuclear waste storage, transport, and disposal, as well as potentially severe effects from accidents, acts of nature like earthquakes or tsunamis, or terrorism.

California has a moratorium on building new nuclear power plants until a means for the permanent disposal or reprocessing of spent nuclear fuel has been demonstrated and approved in the United States In 1978, the Energy Commission found that neither of these conditions had been met. In 2005, the Energy Commission reaffirmed these findings and also found that

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30 California Climate Change Center, *Climate Change Impacts on the Operation of Two High-Elevation Hydropower Systems in California*, draft paper, March 2009, CEC-500-2009-019-D, available at: [http://www.energy.ca.gov/2009publications/CEC-500-2009-019/CEC-500-2009-019-D.PDF].

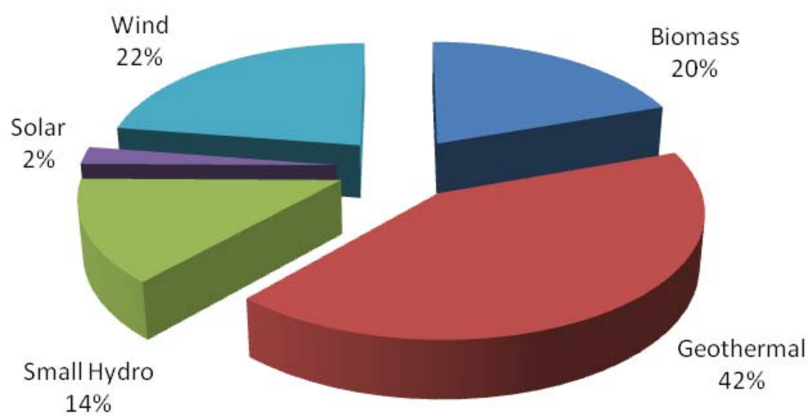
reprocessing remains substantially more expensive than waste storage and disposal and has substantially adverse implications for nuclear non-proliferation efforts.

Renewable Resources

California has a wide array of renewable resources, including biomass, geothermal, hydroelectric, solar, and wind. In 2008, renewable energy represented about 10.6 percent of California's total system power, supplying 32,532 GWhs. The breakdown of renewable energy by resource type is shown in Figure 3.

Much of California's renewable development arose from the federal Public Utility Regulatory Policies Act of 1978 (PURPA), which required utilities to purchase power from non-utility generators, including renewable generators, at the utilities' full avoided cost. PURPA was implemented in California through the use of "standard offer" contracts between utilities and non-utility generators. As a result of the availability of these contracts, about 5,000 MW of renewable capacity were added to California's electricity system between 1985 and 1990.

Figure 3: California Renewable Energy Generation by Technology, 2008



Source: California Energy Commission

California currently has roughly 7,400 MW of utility-scale renewable generating capacity, ranging in size from a few hundred kilowatts to large projects in the hundreds of MW.[31] In addition, the amount of grid-connected distributed photovoltaic systems continues to grow,

31 California Energy Commission, California Power Plant Database, see [http://energyalmanac.ca.gov/electricity/index.html].

with about 440 MW installed as of 2008.[32] The Energy Commission and the BLM are currently reviewing applications for power plant certification for about 6,000 MW of new solar capacity.[33]

Combined Heat and Power

A subset of California's natural gas-fired and renewable plants use combined heat and power. (CHP), also known as cogeneration. These plants provide approximately 9,000 MW to California's electricity supply portfolio. About half of existing CHP is in the industrial sector, primarily food processing and oil refining, and about a third is in enhanced oil recovery. The remaining CHP is in the commercial, mining, and agricultural sectors. CHP facilities can use a variety of fuel, from natural gas to renewable sources like biomass or biogas.

CHP plants provide significant benefits because they generate both mechanical energy (electricity) and thermal energy (heat). Since the thermal energy can be recovered and used for heating or cooling in industry or buildings, these systems are more efficient than those that generate electricity alone and therefore reduce GHG emissions associated with electricity generation. Given the GHG reduction benefits from these facilities, the ARB *Climate Change Scoping Plan* has set a target of 4,000 MW additional installed CHP capacity by 2020 to displace 30,000 GWhs of demand from other, less-efficient generation sources. Because of the significance of the amount of CHP envisioned to be added to the system, these resources must be carefully considered when looking at system integration issues.

Resource Adequacy

An important aspect of adequate electricity supply is having enough reserves to ensure reliable electricity service. The California Public Utilities Commission (CPUC), in consultation with the California ISO, has developed resource adequacy standards for investor-owned utilities (IOUs) and electric service providers to ensure that the state has enough electricity generating capacity to meet demand and required reserves during peak demand periods.

Publicly owned load serving entities in the California ISO control area must also meet basic requirements related to resource adequacy and reporting.[34] In 2008, publicly owned utilities represented 22.6 percent of California peak loads and 23.7 percent of energy needs. The largest 15 publicly owned utilities account for 94 percent of publicly owned utility peak load and 95 percent of energy requirements.

AB 380 (Núñez, Chapter 367, Statutes of 2005), requires the Energy Commission to report to the Legislature as part of the Integrated Energy Policy Report (IEPR) on the progress of the state's 54 publicly owned load-serving entities in planning for and procuring adequate resources to meet the needs of their end-use customers.

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32 California Energy Commission, Energy Almanac, available at: [http://energyalmanac.ca.gov/renewables/solar/pv.html].

33 California Energy Commission, Siting, Transmission, and Environmental Protection Division, see [http://www.energy.ca.gov/siting/solar/index.html].

34 There are 18 publicly owned load serving entities outside the California ISO control area that are not subject to formal requirements.

Fifty publicly owned utilities provided resource adequacy or resource plan filings to the Energy Commission in 2009. Based on those filings, the Energy Commission has found the publicly owned utilities to be resource adequate for both the year ahead and the long term. This finding is important for assuring that the publicly owned utilities will be able to provide reliable service to their customers during normal and peak conditions.

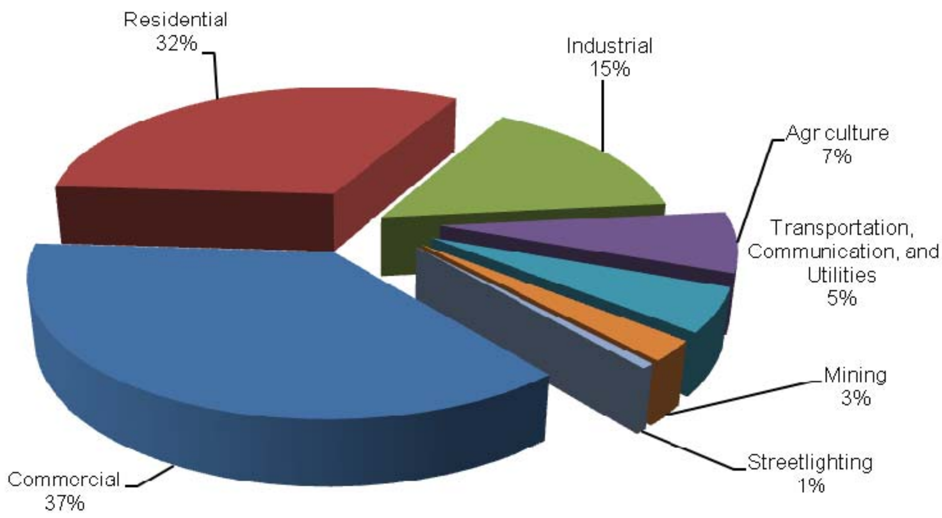
The publicly owned utilities also reported an increase in renewable contracts and decline in the use of coal resources as contracts with coal-fired power plants expire over time. This shift in resource types will contribute to statewide goals for reduced GHG emissions.

Electricity Demand

The most important component in California's electricity system is the electricity consumer. Demand for electricity varies over time, with daily, weekly, and seasonal cycles, and can fluctuate constantly even within a given hour. Demand is generally lower at night and on weekends and holidays, with the maximum demand generally occurring during the afternoon on a hot summer weekday. This maximum point is known as the peak and is an important factor in electricity and transmission planning since generation and transmission must be built out to capacity that can meet peak demand when needed.

Californians consumed 285,574 gigawatt hours (GWhs) of electricity in 2008, primarily in the commercial, residential, and industrial sectors (Figure 4).[35]

Figure 4: Electricity Consumption by Sector 2008 (GWhs)



Source: California Energy Commission

35 The difference between electricity consumption and total system power shown in Table 1 is due to line losses.

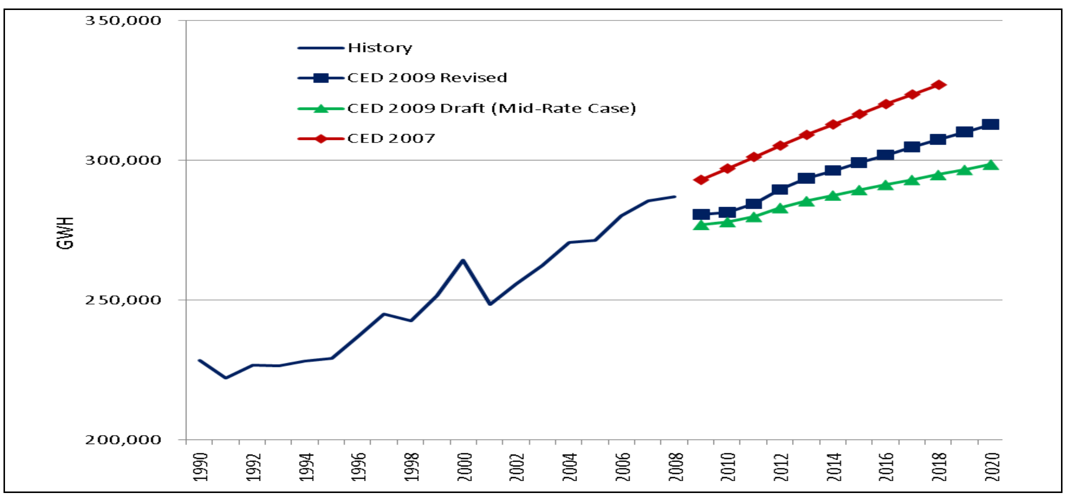
Electricity Demand Forecast

Forecasts of expected growth in electricity demand over time are an important tool for determining future electricity generation and transmission needs. Timely and accurate planning can ensure that California's citizens will have secure and reliable energy resources during normal and peak conditions. In addition, forecasts help the state plan for times of emergency (e.g. natural disaster), which is important for maintaining the health and safety of the general public.

In each two-year IEPR cycle, the Energy Commission forecasts electricity consumption over a 10 year period as well as expected peak demand during the same period. Once adopted by the Energy Commission, the forecast is used in various venues, including the CPUC procurement process, transmission planning studies, and by the California ISO in its grid studies.

Figure 5 compares three forecasts of statewide electricity demand: the *2007 IEPR* forecast (CED 2007), the draft demand forecast prepared by staff in the spring of 2009 (CED 2009 Draft Mid-Rate Case), and the revised demand forecast that reflects the IEPR Committee's direction in response to issues and concerns raised in IEPR workshops on the draft demand forecast (CED 2009). The CED 2009 forecast is the forecast proposed by the 2009 IEPR Committee for adoption.

Figure 5: Statewide Electricity Consumption



Source: California Energy Commission, 2009

Electricity consumption is projected to grow at a rate of 1.1 percent per year from 2010-2018, and peak demand grows an average of 1.2 percent annually over the same period. Although the CED 2009 revised forecast shows electricity consumption is higher than the earlier CED 2009 Draft (Mid-Rate Case), it is still markedly below the CED 2007 forecast. By 2018, electricity consumption is down by almost 6 percent and peak demand by around 4.5 percent compared to CED 2007. Two factors explain most of the difference: (1) lower expected economic growth not only in the near term but also in the longer term, and (2) increased amounts of energy efficiency impacts compared to what was included in the CED 2007 forecast. These changes reflect the increased emphasis on energy efficiency and increased level of efficiency expenditures now considered committed, as well as improved use of recent historic data that was not included in the CED 2007 forecast.

In the *2009 IEPR* cycle, staff focused on two primary topics related to the demand forecast. The first was the uncertainty of the economic and demographic projections used in the forecast, given the current economic recession which appears to be affecting California more than the rest of the nation. Second was quantifying the effect of energy efficiency programs in the demand forecast itself, particularly the expected impacts of uncommitted energy efficiency programs. Uncommitted programs are those that have not yet been approved or funded. In addition, parties continue to express concern about the amount of committed energy efficiency included in the forecast. The Energy Commission is attempting to resolve this uncertainty by distinguishing between committed and uncommitted energy efficiency programs. Committed program impacts are included within the demand forecast, while uncommitted program impacts are counted as a potential supply resource.

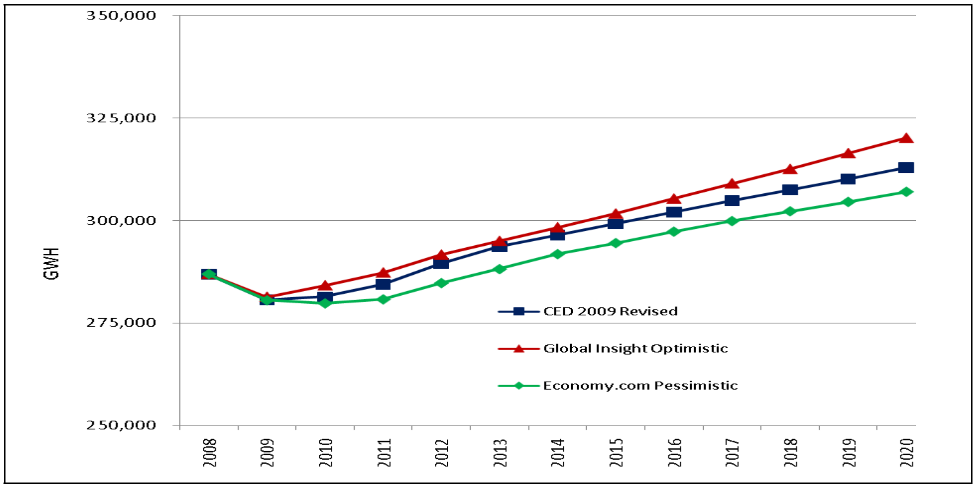
Economic Uncertainties

For the CED 2009 forecast, the IEPR Committee directed staff to investigate alternative scenarios of economic and demographic growth into the future and to quantify the impacts that a reasonable range of assumptions could have on electricity demand. Despite uncertainty about economic impacts from the current recession and about when and how California will recover, there is a surprisingly narrow band of electricity and peak demand resulting from alternative scenarios.

Staff examined the impacts of two alternative economic scenarios for California electricity demand: an *optimistic* case provided by IHS Global Insight and an Economy.com *pessimistic* case. Figure 6 shows the projected impacts of the optimistic and pessimistic scenarios on statewide consumption, and Figure 7 shows impacts on peak demand.

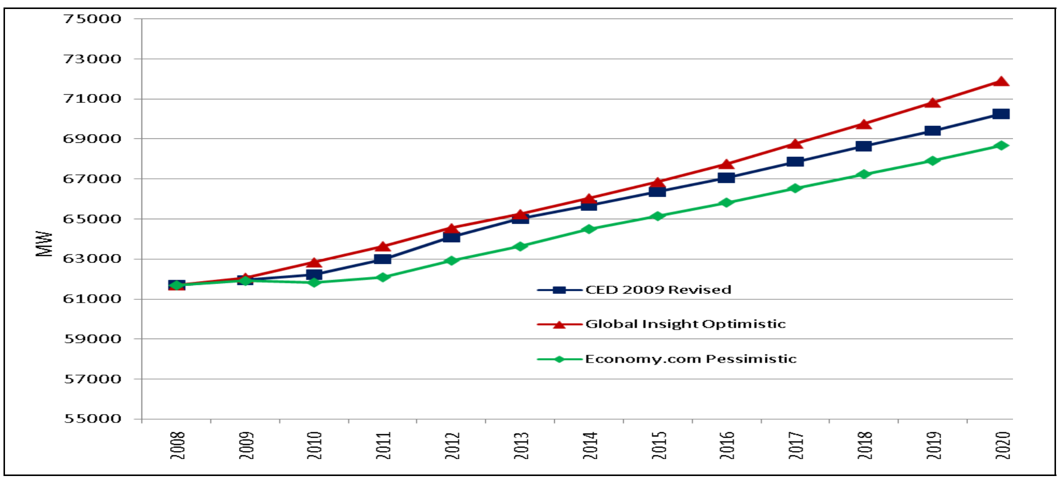
Electricity consumption is projected to be 2.3 percent higher in the optimistic economic case than in the CED 2009 forecast by 2020, and 1.9 percent lower in the pessimistic scenario. The peak demand forecast increases by 2.3 percent under the optimistic scenario by 2020 and falls by 2.2 percent in the pessimistic case. The percentage of peak reduction is higher than that of consumption in the pessimistic case because the relative decrease in consumption is projected to be higher for the residential and commercial sectors than for the industrial, which has a higher load factor (is less *peaky*). Annual growth rates from 2010-2020 for electricity consumption and peak demand increase from 1.1 percent and 1.25 percent, respectively, to 1.2 percent and 1.4 percent in the optimistic case, and fall to 0.9 percent and 1.1 percent under the pessimistic scenario.

Figure 6: Projected Statewide Electricity Consumption, CED 2009 Revised and Alternative Economic Scenarios



Source: California Energy Commission, 2009

Figure 7: Projected Statewide Peak Demand, CED 2009 Revised and Alternative Economic Scenarios



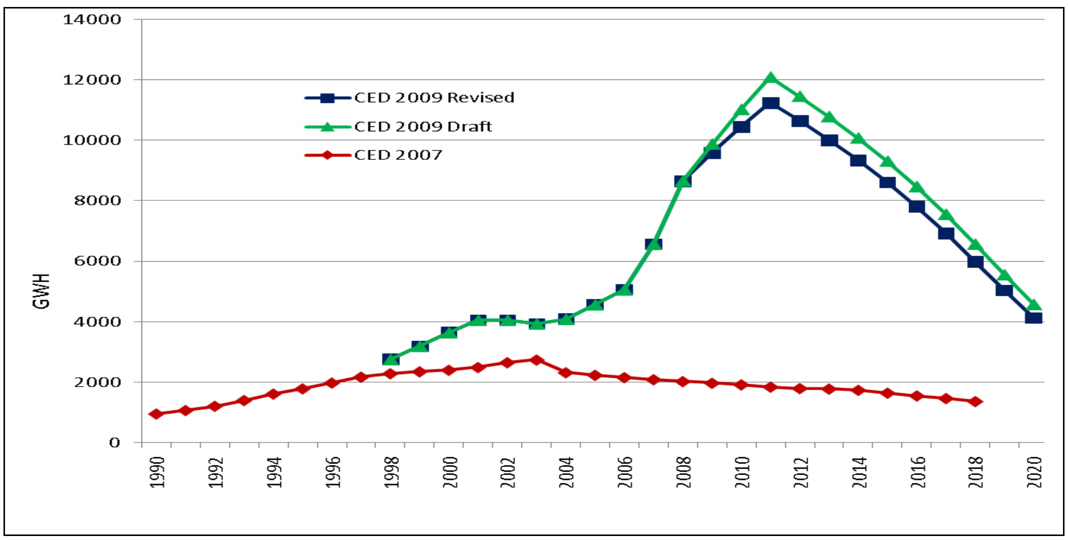
Source: California Energy Commission, 2009

Effects of Efficiency Programs on the Forecast

The importance of energy efficiency in reducing GHG emissions is being translated into conventional views of the future. This emphasis is reflected in near-term energy efficiency program proposals made by IOUs to the CPUC in the current proceeding to determine funding and program designs for 2009-2011. As a result, the amount of energy efficiency considered committed and therefore included in this baseline demand forecast is substantially higher than in the *2007 IEPR*, resulting in lower expected energy demand. Figure 8 shows the change in energy efficiency program impacts from all sources between the *2007 IEPR* and the staff's draft and revised forecast assumptions in this IEPR for the three IOUs. Some refinements moderate this pattern slightly for the revised staff demand forecast, but a similar pattern of increase is included in the revised demand forecast proposed for the larger publicly-owned utilities (SMUD and LADWP).

The steep drop off shown in 2012 and beyond reflects the short lifetime of some energy efficiency measures as well as conservative assumptions about whether impacts from utility programs continue beyond the life of the measures installed. There is great uncertainty about the nature of the consumer response to subsidized efficiency programs and whether savings from various measures translate into changes in consumer demand for electricity. For example, consumers may "take back" some of the benefits of the efficiency gains by increasing their energy use. It is also unclear whether consumers will voluntarily pay for a replacement measure when the subsidized measure wears out, although staff's analysis assumes that they will not in most cases.

Figure 8: Comparison of Committed Utility Program Consumption Impacts for IOUs



Source: California Energy Commission

Finally, it is possible that by the time an efficiency measure that was initially installed through a utility program subsidy wears out, the market will be transformed and less efficient options will no longer be available. One version of this transformation is the creation of mandatory efficiency standards assumed in the future even though they are not operative now. For example, staff has assumed that AB 1109 (Huffman, Chapter 534, Statutes of 2007), in conjunction with federal lighting standards, will cause the lighting measures to largely be replaced with efficient devices, with standards essentially eliminating inefficient bulb technologies.

The Energy Commission staff demand forecasting models have been developed in a manner that is especially appropriate to including efficiency standards, whether for appliances or for whole buildings. Including floor space or the vintage of housing and equipment for a given addition of floor space or housing in the models allows the requirements of standards to affect the limited proportion of the population subject to the standards in any year. Following the effective implementation date, standards gradually affect a larger and larger proportion of the total floor space or housing stock. Each cycle of increasingly tightened standards can be readily evaluated to determine the additional energy savings contributed from each vintage of standards, assuming that new housing stock or new appliance purchases would have been subject to the previous standards.

However, the emphasis of many utility programs – encouraging retrofit of existing floor space or equipment with more efficient devices – does not focus exclusively on newly built floor space or housing units, but upon the entire stock of floor space or housing units. Moreover, consumers voluntarily participate in utility programs, presumably following some combination of economic analysis to identify net benefits of the retrofit action and altruism such as wanting to "improve the environment." Energy Commission staff are adapting the forecasting models to better incorporate such retrofit actions, but only limited progress was made in the timeline of the *2009 IEPR* proceeding. With commitment to this effort, and improvements in access to measure-level data for multiple program years, further progress can be made following the *2009 IEPR* cycle.

Incremental Energy Efficiency

As described in the *2008 IEPR Update*, the Energy Commission has chosen to continue to distinguish between the impacts of energy efficiency programs considered committed and those which, although embodied in long-term goals, are classified as uncommitted because program designs are not complete and funding has not been authorized.[36] Thus, the baseline or reference demand forecast only includes committed impacts. These committed impacts can be from existing standards as they affect a growing proportion of the stock of buildings and/or appliances, or from utility programs for the period of time during which specific program designs have been approved or program funding has been authorized.

Beyond these impacts there are goals that have been set for which no specific program designs have been approved or actual program funding levels authorized. The CPUC in D.08-07-047established long-term energy savings goals encompassing the three electricity IOUs, currently adopted state and federal appliance standards, and state building codes resulting in zero net energy residential and commercial construction in 2020 and 2030. [37] The Energy Commission in the *2007 IEPR* established the goal of achieving 100 percent of cost-effective energy efficiency savings. Following input from the Energy Commission and CPUC, the ARB also established 2020 energy efficiency goals in its *Climate Change Scoping Plan*.

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36 The "taxonomy" paper developed initially by Itron and now being refined through the Demand Forecast Energy Efficiency Quantification Project Working Group process contains provisional definitions of these terms.

37 California Public Utilities Commission, Decision 08-07-047, available at: [http://docs.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/85995.htm].

Part of the foundation for determining incremental energy efficiency impacts – those impacts that are in addition to impacts already included in the baseline forecast – is improving the base demand forecasting models and analyses of committed energy efficiency programs. The Energy Commission staff demand forecast model is being modified to more explicitly incorporate the impacts of energy efficiency measures. Tracking the penetration of energy efficiency measures will provide more accuracy about what efficiency is included within the baseline forecast, thus improving the ability to determine the incremental impacts of higher levels of penetration of these measures.

The effort to directly capture utility program measure penetration in the Energy Commission's demand forecasting models for all IOU programs is too extensive for the resources and timeline available for the *2009 IEPR*, so the focus in this cycle has been on the most important of the program-induced measures: residential and commercial lighting, and heating, ventilation, and air conditioning measures. Energy Commission staff and the consulting firm Itron are collaborating to refine an existing energy efficiency projection capability to build off the level of energy efficiency measures in the baseline forecast to determine truly incremental impacts from further penetration of those or other high value measures. The Itron model SESAT, which was used for the CPUC's 2008 Goals Study,[38] is the starting point for this effort.

Itron adapted the existing SESAT model as part of its contractual support to the CPUC for the 2008 Goals Study. A model like SESAT can be configured to directly incorporate the non-programmatic assumptions of the baseline demand forecast or use alternative assumptions. Some assumptions, such as household growth in the residential sector, are easy to match, while others such as saturations for residential sector end-uses are not.[39] For example, the 2008 Goals Study implementation of SESAT did not allow saturations of end-uses to change through time. In contrast, the Energy Commission's demand forecast allows for such changes.

In developing incremental energy efficiency impacts relative to the Energy Commission's baseline demand forecast, all non-programmatic assumptions should be the same. However, to achieve this level of consistency requires substantial work to revamp the SESAT dataset used in the 2008 Goals Study and this would likely mean that the sum of the committed energy efficiency in the baseline demand forecast and the incremental energy efficiency quantified using SESAT would no longer exactly match the aggregate impacts adopted by the CPUC in the 2008 Goal Study decision. The degree of benching the incremental analyses to assure consistency has diminishing returns at some point.

Early in the *2009 IEPR* development process, the CPUC's Energy Division requested the Energy Commission to develop a demand forecast as well as projections of incremental energy efficiency for use in the forthcoming 2010 Long-Term Procurement Plan (LTPP) proceeding. The Energy Division requested that the Energy Commission evaluate previously established scenarios from the 2008 Goal Study as adopted in CPUC D. 08-07-047. Only the 2008 Goal Study

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38 California Public Utilities Commission, Decision 08-07-047, available at: [http://docs.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/85995.htm].

39 Saturation refers to the amount of diffusion or distribution of a product or measure within a market.

scenarios of medium and high goals are to be evaluated, since the low scenario diverges too much from current policies to merit evaluation. The IEPR Committee decided not to investigate other possible specifications of uncommitted energy efficiency, such as the levels included within the ARB *Climate Change Scoping Plan*, and to defer that analysis to other proceedings.[40]

Developing this incremental energy efficiency projection method and applying it to one or more of the existing statements of energy efficiency policy creates fresh estimates of the incremental impact of these policies relative to the baseline demand forecast. This effort is principally intended to reduce the uncertainty about overlap between the Energy Commission's demand forecast and other independently-developed estimates of uncommitted energy efficiency. The *2009 IEPR* and the CPUC's 2010 LTPP rulemaking are the arenas where the merits of these various estimates will play out. One could also consider updating the ARB *Climate Change Scoping Plan*, but the timeline for this effort is likely to follow that of the *2009 IEPR* or the CPUC's next goal-setting proceeding, at which point perhaps further improvements in energy efficiency projection method will be feasible.

The client for this initial product was the CPUC 2010 LTPP proceeding, with a focus on establishing the procurement authority for IOUs after accounting for preferred resource additions. It was not intended to establish a new policy for high levels of energy efficiency. The IEPR Committee, therefore, has allowed staff to implement the project on a schedule that satisfies the timing of the CPUC rather than *2009 IEPR* itself. Thus, at this writing the project is underway and scheduled to be completed by the end of the year. Once the draft results are completed, the IEPR Committee will conduct a workshop to receive comments and transmit a final product to the CPUC for its use.

Energy Efficiency

The first element in the state's loading order for meeting electricity needs is energy efficiency. Energy efficiency and demand response strategies are essential to reducing the GHG emissions associated with electricity generation. The ARB's *Climate Change Scoping Plan* calls for energy efficiency measures that would reduce electricity demand by 32,000 GWhs relative to "business as usual" projections for 2020. The ARB expects energy efficiency to reduce CO_2 emissions by 19.5 million metric tons by 2020.

Every day, California homeowners, factory managers, farmers, business people, and building operators make millions of energy-related decisions as they go about their daily activities without realizing how those decisions affect energy use and energy demand. Rather than making those decisions from the perspective of trying to be energy efficient, California's citizens

40 An obvious "home" for such an effort is the triennial Assembly Bill 2021 energy efficiency goal setting report required to be submitted to the legislature in 2010. Since this report requires goals to be established for both investor-owned and public utilities, and the California Public Utilities Commission itself intends to undertake another goal study in 2010, it is appropriate to defer examination of these more aggressive goals to allow staff's projection capabilities to be improved yet further.

are more concerned about being comfortable, cooling or heating their homes, and producing goods or offering services.

While energy conservation is cutting back on activities or doing without some creature comforts, energy efficiency is actually about using energy resources in a smarter and more effective way so those resources will go farther and have fewer negative consequences on the environment. Well designed energy efficiency and conservation programs can reduce energy dependence, make businesses more competitive, and allow consumers to save money and live more comfortably. Energy efficiency programs can also play a major role in increasing reliability of the electricity system and reducing the cost of meeting peak demand during periods of high temperatures and high prices.

Energy efficiency measures, including building and appliance efficiency standards and utility-sponsored incentive programs, reduce overall electricity demand and therefore the overall need for new power plants. Reduced electricity demand can also help system operators in several ways. First, it increases system reliability because less demand means less strain on the electricity system since less energy has to be generated and delivered. Second, because California's renewable energy goals are based on a percentage of retail sales of electricity, reducing overall electricity demand means fewer retail sales and therefore less renewable energy that must be generated. This means fewer renewable plants will need to be built, which will reduce the operational and reliability issues associated with those avoided plants.

Energy Efficiency and the Environment

California is a national leader in promoting energy efficiency. Due in part to a decades-long focus on energy efficiency, California has the lowest per capita electricity use in the United States. Our energy use per person has remained stable for over 30 years while the national average has steadily increased. However, stabilizing per capita electricity use will not be enough to meet the carbon reduction goals set in the ARB's *Climate Change Scoping Plan*. Very aggressive efforts will be needed in coming years to meet and exceed prior energy efficiency and demand response program goals. Efficiency contributions from utility programs have remained about the same since the mid 1980s, and this pattern needs to change in the next few years, or opportunities to reverse the CO_2 trend will be lost.

With the focus on reducing GHG emissions in the electricity sector, energy efficiency takes center stage as a zero-emissions strategy. Although the ARB's *Climate Change Scoping Plan* identifies electricity generation as the second largest source of GHG emissions in California after transportation, the GHG emissions from residential and commercial buildings are more than twice the emissions of all passenger cars, when the GHG emissions from the direct use of natural gas are included.

One of the strategies to reduce GHG emissions through energy efficiency is the concept of zero net energy buildings. In the *2007 IEPR*, the Energy Commission recommended increasing the efficiency standards for buildings so that, when combined with on-site generation, newly constructed buildings could be zero net energy by 2020 for residences and by 2030 for commercial buildings. As mentioned in Chapter 1, the CPUC's "Big Bold Energy Efficiency

Strategies" that were adopted as part of the CPUC's *Long Term Energy Efficiency Strategic Plan* includes these goals as well. A zero net energy building merges highly energy-efficient building construction and state-of-the-art appliances and lighting systems to reduce a building's load and peak requirements, and onsite renewable energy such as solar PV to meet remaining energy needs. The result is a grid-connected building that draws energy from, and feeds surplus energy to, the grid. The goal is for the building to use net zero energy over the year. The ARB recommends that energy efficiency measures in these buildings result in up to 70 percent savings relative to existing buildings, with on-site renewable generation to meet the remaining load.[41] The CPUC's *2007 Long Term Energy Efficiency Strategic Plan* contains a detailed implementation plan with goals, strategies, timelines, and recommendations.

In addition to the concept of zero net energy, there is also dialogue about the importance of net zero peak energy use, meaning that the building does not require extra energy during peak energy use times; and net zero carbon, meaning that the building generates more zero-carbon energy onsite than it uses from the grid in an average year. The ARB's *Climate Change Scoping Plan* also promotes zero-carbon footprint new homes, zero net energy homes, and green building standards.

Making zero net energy buildings a reality by 2020 for residences and 2030 for commercial buildings will require ongoing collaboration between the Energy Commission, the CPUC, and the ARB, as well as coordination with local governments who have the authority over land use development and planning. It will also require coordination between local, state, and industry players to promote and incentivize the installation of all cost-effective energy efficiency measures, expand the scope of and accelerate certification of highly efficient appliances, push for the incorporation of the cost of carbon in cost-effectiveness tests for new codes and standards and utility programs, encourage and expand green building programs, and promote and incentivize on-site renewable energy generation.

The Energy Commission has adopted several key strategies for achieving the goal of zero net energy homes by 2020 and commercial buildings by 2030. These efforts include reducing the "plug load" energy in buildings by broadening the range of appliances, such as more standards for consumer electronics covered by the Title 20 Appliance Efficiency Standards. It also includes building standards for water efficiency, improving education about existing standards and stepping up enforcement, and adopting voluntary "reach" building codes and standards that save energy beyond that required by mandatory, and implementing those reach standards through green building standards. Additionally, the Home Energy Rating System (HERS) Phase II program, effective September 1, 2009, adopted a home energy rating scale that starts at zero (0) to reinforce the long term goal of achieving net zero energy new homes by 2020.

To meet the goal of zero net energy buildings, the Title 24 Building Efficiency Standards will need to become increasingly stringent in each upgrade cycle. Because home electronics and other equipment and devices plugged into electrical outlets represent increasing loads compared to what are currently assumed in the standards, plug loads should be tested,

41 California Air Resources Board, *Climate Change Scoping Plan*, December 2008, p.42

modeled, and updated in building energy budgets and should be accounted for in Title 24 compliance software calculations. The scope of building efficiency standards should also be expanded to include process loads such as data centers as well as laboratories, refrigeration systems, and other common high energy using commercial building types. Continued research and development is also needed on building science technologies impacting the Title 24 Standards such as energy use modeling, energy use data collection, and in-home energy use monitors.

The goal of zero energy buildings requires not just energy efficiency but also on-site renewable energy generation. The Energy Commission has established guidelines for the New Solar Homes Partnership, which provides incentives for installing solar energy systems on new homes that meet specific energy efficiency requirements. The program's goal is to install 400 MW of solar electric generation by 2016. For existing homes, new and existing commercial buildings, and industrial, government, and non-profit buildings in the service territories of the IOUs, the CPUC administers the California Solar Initiative (CSI) program. The CSI program is required to meet Energy Commission established minimum energy efficiency requirements for newly constructed buildings, and the CPUC is exploring whether energy efficiency requirements for existing residential and commercial buildings should be increased.

However, as noted in the *2008 IEPR Update*, there are no active policies to deploy cost-effective and zero carbon renewable energy space heating and cooling technologies, which could contribute to the state's zero net energy goals. The potential value of renewable heating and cooling technologies could be very high, since California residential and commercial cooling accounts for approximately 30 percent of electric system peak load.[42] As recommended in the *2008 IEPR Update*, the Energy Commission's PIER program should develop a targeted program to address technical and infrastructure barriers to emerging renewable heating and cooling technologies.

Green building standards also offer an approach to reducing GHG emissions that impacts multiple sustainability objectives, including energy efficiency reductions in electricity, natural gas, water efficiency, recycling, waste reduction, and transportation/land-use planning. The ARB's *Climate Change Scoping Plan* identifies a green building strategy with specific goals based on building type for state, schools, commercial and residential buildings. Meeting the goals of the *Climate Change Scoping Plan* includes adopting a Green Building Standards Code for newly constructed buildings, achieving additional GHG reductions as cities and counties adopt local building codes that exceed the state standards, and retrofitting existing buildings.

The California Building Standards Commission adopted the "Green Building Standards" for newly constructed residential and commercial buildings in July 2008. This is the first statewide green building code in the nation. It contains both voluntary and mandatory green building measures, and sections of the Green Building Standards are intended to become mandatory standards in the next code cycle. The *Climate Change Scoping Plan* outlines the need to coordinate local government building codes and land use planning and development policies. The code

42 See [http://enduse.lbl.gov/info/LBNL-47992.pdf].

standardizes practices for reducing water use and electricity consumption and examines other aspects of typical construction practices. The update to the California Green Building Standards has been a collaborative effort with the Housing and Community Development. The Energy Commission actively advised the Building Standards Commission in the design of the voluntary tier levels of energy efficiency that are more stringent than the statewide Building Energy Standards, and has made them consistent with levels in the New Solar Homes Partnership. The Energy Commission should continue to expand its efforts to incorporate reach standards into the Green Building Standards.

Energy Efficiency and Reliability

By reducing demand, energy efficiency increases the reliability of the electricity system because there is less stress on existing power plants and transmission and distribution infrastructure as well as reduced need for new resources. By reducing the demand for new power plants, energy efficiency can also help reduce the state's dependence on natural gas. Reduced demand will also help soften potential reliability impacts on the electricity system from the retirement of the state's fleet of aging power plants and plants that use once through cooling. Finally, because less overall demand for electricity could mean that less renewable energy will be needed to meet California's Renewables Portfolio Standard, and energy efficiency can indirectly help reduce the impacts of integrating large amounts of renewables into the system.

California has pursued its energy demand reduction goals through two primary avenues: utility-sponsored programs that seek to reduce end-user consumption, and codes and standards designed to lower the energy use of buildings and appliances. In the mid 1970s, the Energy Commission developed the first comprehensive energy codes for new buildings and appliances, as well as utility-sponsored energy savings programs. By 2004, the state's building and appliance standards and energy efficiency incentive and utility sponsored education programs had cumulatively saved more than 40,000 GWh of electricity and 12,000 MW of peak electricity, equivalent to twenty-four (24) 500 MW power plants. More than half of the statewide savings due to energy efficiency has come from the building and appliance standards, with the balance resulting from programs implemented by the state's IOUs and publicly owned utilities.

Appliance Efficiency Standards

The first appliance efficiency regulations were adopted in California in 1976. The Energy Commission sets minimum efficiency thresholds that apply to appliances using a significant amount of energy, are based on feasible and attainable efficiencies, and are cost effective to consumers based on a reasonable use pattern over the design life of the appliances.

The Energy Commission adopted the 2009 Appliance Efficiency Regulations December 2008, which were approved by Office of Administrative Law in July 2009. They became effective statewide on August 9, 2009. These regulations set new efficiency standards for general purpose lighting as required by AB 1109 (Huffman, Chapter 534, Statutes of 2007) as a first step in achieving a 50 percent increase in efficiency for residential general service lighting by 2018. AB 1109 also set aggressive savings requirements for lighting for commercial buildings and outdoor lighting over the same time period. Meeting these saving requirements will require an ambitious program of increasing appliance efficiency standards, building efficiency standards, and other market transformation initiatives.

The Energy Commission continues to press the federal government for exemption from pre-emption of California standards for residential clothes washers, which result in substantial savings of both energy and water. The Energy Commission also must continue to pursue aggressive and expansive appliance standards for a wide variety of appliances and equipment, including but not limited to consumer electronics, lighting, water using equipment and irrigation controls, and refrigeration systems. More stringent codes and standards for appliances will be needed, and the associated technology and design research and development to support them.

Efficiency Standards for New Buildings

The Energy Commission established the nation's first energy efficiency standards for residential and nonresidential buildings in 1978. The standards apply to newly-constructed residential and nonresidential buildings, as well as additions and alterations to existing buildings, and are updated over time to reflect new energy efficiency technologies and methods. The Energy Commission adopted the 2008 Building Efficiency Standards in April 2008. The new standards will take effect on January 1, 2010, and will require, on average, 15 percent increased energy savings for newly constructed residential buildings compared with the 2005 Building Efficiency Standards. The updated standards also make many energy efficiency improvements for newly constructed nonresidential buildings and additions and alterations to both residential and nonresidential buildings; two examples of changes are increased requirements for cool roof products to help reduce air conditioning use in areas of the state with high summer peak load and requirements for higher performing windows.

The standards also focus on the problem that construction defects in the installation of energy efficiency features lead to reduced energy savings from those features. To address these construction defects, the Standards since 1998 have required measures that are prone to poor installation to be field-verified by a third-party home energy rater (HERS rater), using Energy Commission specified diagnostic testing and field verification protocols. In showing compliance with the energy budget, field-verified measures are given higher credit because they require onsite inspections and/or on-site testing to overcome their prevalence for construction defects. The emphasis on field verified measures helps educate the building industry and homeowners of the importance of higher quality workmanship and quality assurance to achieve higher performing buildings and lower energy bills. With each new update, the standards include expanded emphasis on field verification and diagnostic testing.

The Energy Commission is also developing "Reach" Standards for the Title 24 Building Standards. As part of the public process of developing building standards every three years, the Energy Commission will develop two levels of incremental improvements in building performance, a lower level that represents mandatory standards and a higher level that is voluntary. In each subsequent standards cycle, the higher level from the previous cycle would be considered for setting the new mandatory standards, and a new "Reach" Standard would be developed.

The City of Los Altos developed a *Green Building Regulations Ordinance*, effective July 2008, to conserve natural resources through sustainable design and construction practices. The ordinance requires all newly constructed residential and nonresidential buildings to be 15 percent more energy efficient than what is required by the 2005 Title 24 Building Standards. Much of the motivation and effort that went into developing and adopting the local standards was from a staff member of the City's Building Division, who is a Certified Energy Plans Examiner, Certified HERS rater, instructor at a local community college teaching the Building Energy Efficiency Standards, and provides periodic training to the City of Los Altos staff on enforcement requirements. The ordinance affects newly constructed residential, commercial and multi-family buildings in the city of Los Altos.

Adopting voluntary "Reach" Standards has many benefits. It allows proactive cities, counties, green building standards, incentive programs, and others to adopt the voluntary standards in their jurisdictions, which many cities and counties have already done. The "Reach" Standards also are adopted as the eligibility criteria for solar incentive programs, such as the CSI and NSHP programs, and as levels for qualifying for higher public goods charge incentives through utility new construction programs.

Currently, cities or counties may choose to adopt local energy standards that are more stringent than the statewide Title 24 Building Energy Efficiency Standards, and can enforce the standards on a voluntary or mandatory basis. Voluntary standards motivate the building community by offering incentives such as fast track permitting or reduced permit fees. Most mandatory local standards are intended as key climate change mitigation initiatives and to reduce electricity demand, especially during peak periods on hot summer afternoons. Recently local energy standards have been adopted as part of local comprehensive "green" ordinances, and include requirements related to land use, water use, recycling, indoor air quality, and GHG reduction goals as well as energy efficiency requirements.

Many local governments have adopted stringent local standards to address local building patterns or issues, local air, water, land use, or resource constraints, or to comply with state legislation or Executive Orders. Mandatory local standards that exceed the statewide standards must be approved by the Energy Commission. These cities or counties are recognized as being "early adopters" and include large and small cities and counties located in high density urban areas as well as lower density suburban regions. The Energy Commission commends the following cities and counties that have adopted energy ordinances requiring more stringent energy requirements than those set by California's 2005 Building Energy Efficiency Standards: Culver City, La Quinta, Los Altos, Los Altos Hills, Marin County, Mill Valley, Palo Alto, Palm Desert, Rohnert Park, City and County of San Francisco, San Mateo County, Santa Barbara, Santa Monica, and Santa Rosa**.** The Energy Commission is pleased that many of these governments are preparing to update their ordinances to be more energy efficient than the new 2008 Standards which go into effect January 1, 2010.

A major challenge with the building standards is achieving compliance and enforcement. The 536 local building departments in the state are responsible for enforcing the standards by issuing permits and conducting on-site inspections during construction. With the downturn in the economy and reduced budgets, many cities have downsized their building department staff to maintain other vital staff such as police or fire crews. Reduced staff, maintaining complex building standards to comprehensively address all important energy efficiency and climate change mitigation in our buildings, changes in architectural style, and insuring that the Warren-Alquist Act's emphasis on performance standards that provide flexibility in choice in energy using features and equipment are factors that affect compliance with and enforcement of the building standards. As a result, newly constructed residential buildings have been estimated to be potentially up to 30 percent out of compliance with the 2005 Title 24 Building Standards,[43] which could represent up to180 GWh per year[44] of lost energy savings and therefore lost opportunities for GHG emission reductions. The Energy Commission has actively sought sufficient staff resources to maintain a presence in the field to encourage improvements in compliance and enforcement and is actively working with the California Building Officials (CALBO) and California utilities to provide tools and information that will simplify Standards enforcement and provide expanded training for the industry and building officials.

Building standards also apply to additions to and remodels of existing buildings, which provide a critical opportunity to improve energy efficiency levels. Permits are required for any alteration that permanently changes the energy use of a building, including installation and change-out of HVAC equipment. Unfortunately, the HVAC industry is plagued by failure on the part of many installers to pull permits for HVAC change-outs. This unlawful activity is a major problem, placing homeowners at risk because the health and safety protections of pulling permits are bypassed and revenue that should be paid to local governments is not available to pay for resources needed by building departments to enforce all aspects of the building code, including the energy efficiency standards. Since projects where permits are not pulled, never get to building departments, the building departments are unable to complete their reviews and inspections to insure compliance. Failure to pull permits has very negative ramifications on the performance of the whole industry because in the highly cost-based competition in the market, installers who avoid the cost associated with pulling permits and complying with licensure laws and building codes represent unfair competition to contractors who follow the law by pulling permits and complying.

The rate of pulling permits issued for air conditioner change-outs is extremely low, and the HVAC industry estimates that 30 to 50 percent of central air conditioning systems are not being installed properly. The CPUC's *Long Term Energy Efficiency Strategic Plan* reported that fewer than 10 percent of installed HVAC systems pull permits, while the HVAC industry recently quoted a figure of less than 5 percent. This represents a major problem that makes it impossible for building departments to verify compliance, and represents a huge lost opportunity for energy efficiency savings.

To address challenges with compliance and enforcement, the Energy Commission develops and provides comprehensive and audience-specific education and outreach information on the Standards to improve local enforcement and building industry compliance. In addition to its Energy Standards Hotline, the Energy Commission is launching a California Building Standards Online Learning Center to assist building department personnel in understanding and

43 Quantec, LLC (merged with The Cadmus Group, Inc. in 2008), see [http://www.cadmusgroup.com].

44 BII & ConSol, July 2009, see [http://www.consolenergy.com/].

complying with the standards. The Energy Commission's Compliance and Enforcement Unit also investigates complaints and provides assistance to enforcement agencies, the public, and other energy professionals to increase compliance with the building standards. As part of this effort, staff works with various building departments throughout the state and also conducts regional outreach through International Code Council (ICC) chapters to increase communication and cooperation between building departments. In addition, there is certification and ongoing management of Home Energy Rating System (HERS) providers who train, manage and certify HERS raters and are responsible for field verifications of performance-based energy efficiency measures in the building standards.

To increase compliance with the building standards, the Energy Commission also is working with the Contractors State License Board to (CSLB) take action in investigating and disciplining unlawful activity by licensed as well as unlicensed contractors in relation to the standards. The Energy Commission is working with the HVAC industry, CSLB, and CALBO to focus the problems with failure to pull permits for change-outs. Education is also needed for property owners regarding the benefits of permits and code compliance to allow them to demand that the installers that work for them pull permits and that the quality of installations improve. The Energy Commission also has developed time-of–sale consumer information to educate consumers about the need for installers to properly pull permits and comply with the Standards requirements.

California has agreed to achieve a 90 percent compliance rate with state building energy codes within eight years in exchange for stimulus funds (by 2017). To meet this aggressive goal, the Energy Commission needs to develop a method to determine the level of compliance, enforcement, and quality of installations throughout the industry, and use this information as a benchmark against which to determine 90 percent compliance. Strategies should include auditing and scoring the 536 building departments in the state and providing them with education and tools to increase their compliance rate, with follow-up audits after some period of time to evaluate improvements.

Efficiency in Existing Buildings

Existing residential buildings present a significant challenge to meeting the goal of 100 percent cost-effective energy efficiency. Over half of the single family homes in California were built before building standards went into effect. Retrofitting these homes can provide significant savings toward meeting the state's energy efficiency goals, but will require a coordinated effort between state and local agencies, utilities, and stakeholders.

Utility rebate programs have not done enough to capture cost-effective energy savings in existing buildings. To begin to address the existing building sector, the state needs to move beyond programs that target single measure rebates, such as for replacing incandescent bulbs with compact fluorescent bulbs. Comprehensive programs need to be designed that include building energy use performance labeling or benchmarking; well-designed comprehensive deep retrofit programs; marketing, outreach and education efforts in layperson terms, and creative funding mechanisms that help building owners with the necessary capital to cover the cost of the retrofits with an affordable cash flow over the life of the measures to allow the energy savings to pay for the investment.

Point-of-sale and/or point-of-remodel legislation should be introduced to trigger retrofits at times of financial transactions or major construction projects. Innovative incentives, such as refunds for HERS Phase II inspections when a predetermined amount of expenditure will go into retrofits, or a cap on the maximum amount of expenditure required (2.5 percent of sale price, or 10 percent of estimated remodel costs) will safeguard against slowing a sale or dissuading homeowners from selling their homes or making improvements. This strategy will also require HERS providers to develop their training programs so that enough HERS raters will be available around the state.

In addition, legislation, utility incentives, or local ordinances should consider triggers such as point of sale or point of remodel to require HVAC equipment tune-up by qualified HVAC service technicians, similar to a DMV smog check requirement. Most homeowners do not know the benefits of HVAC maintenance, and the positive impacts on HVAC performance, and do not adequately maintain their HVAC systems.

Innovative financing options need to be explored and developed that offer competitive rates to finance whole-house energy retrofits. Recently emerging municipal financing, energy utility on-bill financing, waste collection on-bill financing, and water utility on-bill financing pilots around the country should be monitored and explored as possible mechanisms to allow payback out of energy savings and keep the debt with the property.

There is also significant potential for efficiency improvements in existing commercial buildings in the state. Building energy performance rating can set the stage for retro-commissioning and other energy efficiency improvement. Assembly Bill 1103 (Saldana, Chapter 533, Statutes of 2007) requires disclosure of non-residential building energy performance ratings at the time of lease, lending, or sale. The Energy Commission has opened and Order Instituting a Rulemaking to develop regulations for implementing AB 1103 that are expected to be adopted in early 2010. This historic building energy performance rating disclosure law provides an important opportunity to provide energy use data for commercial buildings at the time that purchase, lease and financing decisions are being made, which will allow decision makers to value energy efficiency as a building property asset. Building energy performance ratings will ultimately add value to commercial buildings in the form of increased resale value and increased marketability for energy efficient buildings.

One issue associated with implementing AB 1103 is that the national Energy Star Portfolio Manager rating system specified in the law will not provide a 1-100 rating for the majority of nonresidential buildings in California. Therefore, to fully implement this new energy performance disclosure law, the Commission has developed a California Commercial Building Energy Performance Rating System. A California specific rating can be disclosed to meet the intent of this law when a national rating is not available. The California specific rating may also be disclosed voluntarily by building owners who are disclosing the national rating.

Another challenge is that AB 1103 energy performance disclosure law applies only to entire buildings, not spaces within buildings. Many nonresidential buildings have tenant-leased spaces that are separately metered and have individual utility accounts. Future legislation should therefore address ways to obtain and disclose meaningful building performance ratings for tenant leased spaces.

The European Union's 2003 Energy Performance of Buildings Directive (EPBD) should be looked to as a model for commercial building energy performance rating methods. The EPBD established two types of performance ratings, operational ratings and asset ratings. Operational ratings, like Energy Star Portfolio Manager, can be used to track energy performance of buildings over time and to compare energy use to peer group buildings. Asset ratings, in contrast, judge the efficiency of only the permanent building energy systems that should be valued as part of a commercial property assessment. This asset rating system is analogous to the HERS for residential buildings. California should participate in and leverage the work begun at the national level to develop an asset rating system for commercial buildings.

Efficiency in the Industrial Sector

The state's energy efficiency standards for all new residential and nonresidential buildings built in California do not apply to industrial plants or their manufacturing processes. Consequently, no regulatory mechanism is in place to ensure energy efficiency implementation in the industrial sector. However, with approximately 50,000 industrial plants and related businesses, California's industrial sector consumes 15 percent of the state's total electricity and 50 percent of its natural gas, making it essential to address energy usage in this sector.

The Energy Commission objective is to increase operating efficiency in the industrial sector to enable plants to reduce their energy costs and lower their GHG emissions while remaining competitive. Since 2004, the Commission's Industrial Energy Efficiency Program (IEEP) has conducted industrial "Best Practices" training workshops in partnership with the United States Department of Energy (DOE), utilities, and industry. Initial survey results on the effectiveness of the training indicate that energy efficiency measures are being implemented by 60 percent of the plants.

The Energy Commission also conducts no-cost technical energy audits at industrial plants using DOE's Energy Savings Assessment protocol, software tools, engineering calculations and specialized measurement equipment. These assessments have resulted in estimated savings of 22 million therms of natural gas, 41,000 kilowatt hours of electricity, and 147,000 tons of carbon dioxide per year.[45] In addition to the energy savings, the assessments represent energy cost savings to industrial plants of $19 million per year. The Energy Commission expects to conduct approximately 10 assessments per year through 2012, with the goal of cumulative energy savings by 2012 of 50,000 MWhs per year of electricity and 40 million therms per year of natural gas.

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45 Presentation of Energy Commission staff Donald Kazama, Association of Energy Engineers' West Coast Energy Management Congress, Long Beach, California, June 11, 2009.

Publicly Owned Utility Success Stories:

Lodi Electric, with a customer base of less than 30,000, reported an increase in energy efficiency savings from 383,317 kWhs in 2007 to 3,090,527 kWhs in 2008. This quantum leap in savings was the result of a large commercial lighting program. Lodi Electric's efficiency program has also used Energy Star appliance rebates and energy audits as well as targeting specific customers with the "Keep-Your-Cool" refrigerator door gasket replacement program which has provided significant and savings for the customer with minimal upfront costs. This program was originally developed by Silicon Valley Power and shared with members of the Northern California Public Power Authority. Another well designed program is the HVAC system performance test which ensures that the customers' whole HVAC system is functioning efficiently before a rebate for new equipment is issued to maximize energy savings.

Truckee-Donner Public Utilities District, with a customer base of 13,000, reported an increase in energy efficiency savings from 603,611 kilowatt hours in 2007 to 4,455,607 kilowatt hours in 2008 mainly due to an increase in residential lighting savings. To maintain and increase customer participation during these difficult economic times, Truckee-Donner is focusing on direct installation and giveaway programs. For example, their LED holiday lighting exchange program has proven to be very popular. Customers exchange old incandescent holiday lighting for high efficiency LED holiday lights which are more than 80 percent more efficient than the older holiday lights. Like Lodi, Truckee-Donner has also had success with a direct install "Keep-Your-Cool" refrigerator door gasket replacement program.

An example of the potential for savings in the industrial sector is a food processing plant in central California that uses steam for dried fruit processing and compressed air for production machinery operations. The plant underwent an onsite technical audit of their steam and compressed air system. For a total project cost of $150,000, the plant was able to make energy efficiency improvements, saving the plant $46,000 per year in electricity costs, $23,000 per year in natural gas costs, and also reduced their water consumption, saving another $2,000 per year. Total costs savings per year exceeded $70,000 per year, for a total project simple payback of 2.1 years.

Publicly Owned Utility Efficiency Programs

Because publicly owned utilities represent about 22 percent of statewide electricity consumption, their contribution to meeting the state's energy efficiency goals is very important. AB 2021 (Levine, Chapter 734, Statutes of 2006) requires the Energy Commission to estimate statewide energy efficiency potential and establish targets for energy efficiency savings and demand reduction for California's investor and publicly owned utilities every three years, with the goal of reducing energy consumption by 10 percent over the next 10 years. The Energy Commission adopted the initial targets in 2007. In addition, the Energy Commission evaluates and reports on the annual progress of 39 publicly owned utilities' energy efficiency program investments and savings to the legislature as part of the IEPR.[46]

From 2007 to 2008, publicly owned utility expenditures in energy efficiency programs increased 65 percent and total $104 million. Annual efficiency savings increased by nearly 58 percent for energy and nearly 46 percent for peak hours compared to 2007. However, combined savings accomplishments of these utilities reached only 66 percent of the 2008 adopted target for energy savings. While the trend of increasing savings is encouraging, publicly owned utilities should continue to explore all

46 For details on publicly owned utility progress, see California Energy Commission, Achieving Cost-Effective Energy Efficiency for California: Second Annual AB 2021 Progress Report, June 2009, CEC-200-2009-008-SD, available at: [http://www.energy.ca.gov/2009publications/CEC-200-2009-008/CEC-200-2009-008-SD.PDF].

opportunities for increased efficiency savings to meet the targets adopted by the Energy Commission and contribute to meeting the statewide goal of achieving 100 percent cost-effective energy efficiency.

In 2008, the publicly owned utilities reported on the results of their program measurement and verification activities for the first time. While the results are preliminary at this time, publicly owned utility-verified savings appear to be consistent with reported program savings for 2008.

Publicly owned utilities face several challenges in increasing their efficiency savings. The current economic recession is affecting customers' willingness to participate in efficiency programs. At the June 9, 2009 IEPR workshop on publicly owned utility efficiency progress, one stakeholder noted, "...we can sit here all day and talk about how wonderfully cost effective these things are, but if I am sitting there as a customer and I have a choice between paying my mortgage and purchasing new windows….the windows are not going to win the game."[47] However, another stakeholder believed that energy efficiency measures can actually help customers: "Putting 20, 40, 60, 100 bucks in people's pocket every month through cost-effective energy efficiency can help…over the long term."[48]

An issue with many of the smaller publicly owned utilities is that they serve a relatively small customer base so their programs can reach saturation rather quickly. In addition, the smaller utilities typically have fewer staff and capital resources than the larger utilities, making it difficult to administer efficiency programs. And even the larger publicly owned utilities are facing challenges from a retiring workforce and bringing new staff up to speed quickly.

For the small utilities, success appears to be in large part due to careful consideration of their customers' needs when designing their efficiency programs. That knowledge, coupled with a commitment to personalized customer outreach and educational efforts, has helped some utilities succeed despite challenges. The state's publicly owned utilities are also working cooperatively through their representative associations, the Northern California Power Agency, the Southern California Public Power Authority and the California Municipal Utilities Association, to learn from one another's experiences.

Publicly owned utilities should continue to use their unique customer knowledge to focus attention on new customer segments, expand measures which are low or no-cost options, and market new incentive tools. The publicly owned utilities are encouraged to apply integrated resource planning to compare demand-side resources with supply-side resources using cost-effectiveness metrics. This approach, along with the willingness to fund energy efficiency from procurement sources, will increase future energy savings sufficiently to reach adopted targets.

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47 Oral comments by Scott Tomashefsky, Northern California Power Agency, June 9, 2009, IEPR workshop, transcript p. 51, available at: [http://www.energy.ca.gov/2009_energypolicy/documents/2009-06-09_workshop/2009-06-09_TRANSCRIPT.PDF].

48 Oral comments by Steven Poncelet, Truckee-Donner Public Utility District, June 9, 2009, IEPR workshop, transcript p. 104, available at: [http://www.energy.ca.gov/2009_energypolicy/documents/2009-06-09_workshop/2009-06-09_TRANSCRIPT.PDF].

Efforts to complete measurement and verification studies should continue. These studies provide an opportunity to improve program delivery and cost-effectiveness and to show that energy savings have been realized, and should be funded accordingly.

Energy Efficiency and the Economy

In the *2007 IEPR*, the Energy Commission recommended that the state adopt targets for the next 10-year period equal to 100 percent of total cost-effective energy efficiency savings to be achieved by a combination of state and local standards, utility programs, and other strategies. The targets are to be met through a combination of collaborative efforts by utilities, legislative mandates and regulatory standards. In addition, the CPUC's *California Long Term Energy Efficiency Strategic Plan* recommends maximum implementation of cost-effective energy efficiency.

The Energy Commission's 2007 Scenario Analyses Project found that regardless of the level of energy efficiency, the cost is negative. "[S]ociety is better off with…higher levels [of energy efficiency] than without…even without a carbon cost adder being included. Energy efficiency is less costly than the generating resources it displaces."[49] The combined economic potential to save energy in 2016 for California's three large IOU is estimated to be 40,700 GWh of electricity, higher than the ARB's demand reduction goal of 32,000 GWhs, and 6,800 MW of peak electrical demand. This does not include potential savings from emerging technologies.[50]

Achieving the goal of 100 percent cost-effective energy efficiency will be challenging and will require continued and accelerated collaborative efforts between state and local agencies and meaningful input from utilities and industry stakeholders. In addition, there is a need to accurately value carbon savings embedded in energy efficiency when determining the cost-effectiveness of energy efficiency measures. The IEPR Committee recommends that the definition of cost-effective energy efficiency should include a value for CO_2 and GHG emission reductions, consistent with the Title 24 Building Standards. Further, the CPUC should require utilities to include an externality value for CO_2 and GHG emission reductions in the evaluation of their energy efficiency program impacts.

In addition, the IEPR Committee recommends creating a taskforce comprised of state, local, utility, and industry stakeholders to work collaboratively to clarify definitions, set out strategies, identify potential hurdles and potential solutions, and set schedules and milestones to reaching the goals of 100 percent cost effective energy efficiency by 2016. The task force should develop a statewide strategic plan to serve as a "roadmap" of actions needed to achieve all cost-effective energy efficiency potential in California.

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49 California Energy Commission, 2007 Integrated Energy Policy Report, December 2007, CEC-100-2007-008-CMF, available at: [http://www.energy.ca.gov/2007publications/CEC-100-2007-008/CEC-100-2007-008-CMF.PDF].

50 Itron, California Energy Efficiency Potential Study, May 24, 2006, pp. ES-8 – ES10, [http://www.itron.com/pages/news_articles_individual.asp?nID=itr_008890.xml].

With the downturn in the national economy, energy costs are representing an increasingly larger share of consumers' budgets, including low income customers whose numbers are increasing as a result of the financial crisis. One of the goals of the CPUC's *Long Term Energy Efficiency Strategic Plan* is for all low-income homes to be energy efficient by 2020.[51] The CPUC issued a decision in November 2008 approving the Low Income Energy Efficiency (LIEE) 2009-2011 program budgets for the four major IOUs.[52] The goal is for all eligible customers in the low income sector, estimated at 4 million households, to have the opportunity to participate in the LIEE program. As part of achieving this goal, the CPUC is requiring the IOUs during 2009 to develop an integrated marketing, education, and outreach program for all energy efficiency programs, including LIEE. IOUs are also required to target their outreach to LIEE customers who are high energy users, have high energy burden, and/or have high energy insecurity, while also addressing low income customers with lower energy use. The Energy Commission applauds the CPUC's significant contribution to meeting the state's energy efficiency goals, particularly with regards to the significant impact the CPUC is making in the low income sector, recently swollen by the downturn in the economy. The energy demand forecast will be adjusted slightly for the final version of the *2009 IEPR* to incorporate the recent CPUC decision to move the 2009-2011 IOU efficiency program cycle to 2010-2012. Essentially, this adjustment entails shifting the first-year program savings estimated for 2009-2011 by one year and treating 2009 as a continuation of the 2006-2008 program cycle.[53]

Role of Local Governments

State energy agencies need to work closely with local and regional governments to provide assistance in meeting the challenges of adopting and implementing energy efficiency programs to reduce GHG emissions. Toward that end, the Energy Commission is updating its 1993 Energy Aware Planning Guide (Guide) in coordination with the Local Government Commission and other parties with a target release of fall 2009. The Guide will provide regional and local governments with a solid reference of energy conserving/GHG reducing planning ideas, policy language, program implementation options, environmental and economic effects, examples of programs in operation, and contact information.

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51 California Public Utilities Commission, California Long Term Energy Efficiency Strategic Plan, September 2008, available at: [http://www.californiaenergyefficiency.com/docs/EEStrategicPlan.pdf].

52 Decision 08-03-011 was approved 5-0 by the California Public Utilities Commission on November 6, 2008. The Decision approved budgets for the energy-related low income programs totaling approximately $3.6 billion for the four major investor-owned utilities: Pacific Gas & Electric, San Diego Gas & Electric, Southern California Gas, and Southern California Edison Companies.

53 California Public Utilities Commission, Proposed Decision, adopted on Sept. 24, 2009, see [http://docs.cpuc.ca.gov/PUBLISHED/AGENDA_DECISION/107378.htm].

Energy Conservation Assistance Account Program

The County of Contra Costa saw an opportunity to reduce energy use in several of its buildings after the 2001 electricity crisis. The county retrofitted and upgraded the HVAC systems in eight buildings. To finance the projects, the county borrowed $700,000 from the Energy Commission and used some of their own funds to pay the rest. The project was completed within 8 months and has reduced the county's annual energy use in those buildings by an average of 28 percent. In addition to the energy savings, these projects have made the buildings more comfortable for employees and reduced annual maintenance costs.

The Sacramento City Unified School District requested technical assistance to evaluate potential efficiency improvements in several of its high schools. Lighting retrofits, controls and LED exit signs were recommended at each of the schools, leading to reduced energy use and average savings of approximately $53,000 per year.

The Energy Commission also provides support to local governments through the Energy Conservation Assistance Account Program, a low-interest loan program established in 1979 for public non-profit schools and hospitals, public care institutions, and local governments. In coordination with the Energy Partnership Program, the program provides a wide range of assistance from identifying energy saving opportunities in planned facilities to audits and feasibility studies for improvements in existing facilities. The Energy Commission has successfully implemented this revenue bond program and continues to pursue revenue bonds as necessary to continue program operations. Since July 1, 2006, the program has provided technical assistance to 149 projects and awarded 31 low-interest energy efficiency loans. The program is expected to be augmented with American Recovery and Reinvestment Act (ARRA) funds.

The Energy Efficiency and Conservation Block Grant Program, created by the Energy Independence and Security Act of 2007, will provide $3.2 billion in ARRA funding to cities and counties throughout the United States. Of that funding, $302 million will go directly to large incorporated cities and counties in California, with another $49.6 million allocated through formula-based grants to 265 small incorporated cities and 44 small counties that are not eligible for direct grants from the DOE. The Energy Commission will distribute the funding to help cities and counties implement cost-effective projects and programs to reduce total energy use, reduce fossil fuel emissions, and improve energy efficiency in the building, transportation, and other appropriate sectors.

Local governments play critical roles in achieving expected energy efficiency. They are responsible to enforce the mandatory building energy efficiency standards, and some cities and counties have adopted local ordinances designed to exceed the required efficiency. Enforcement and local ordinance were discussed in earlier sections of this report.

Demand Response

Demand response efforts seek to slow the rising cost of electricity and improve the reliability of the electricity grid by improving the efficiency of the generation, distribution, and consumption of electricity. Demand response measures provide incentives and tools that enable customers to periodically reduce their consumption in response to system conditions. The demand for electricity varies with the time of day and the season of the year. Most California consumers demand more electricity during the day than at night, and more in summer than winter, due to the rapid increase in air conditioning and other consumer electronic use. The maximum peak load is projected to grow at a rate of 1.35 percent per year, faster than the overall demand

The Demand Response Research Center was launched in 2004 by the Energy Commission with the objective of researching and developing a broad knowledge of demand response technologies, capabilities and opportunities. The Center has been working toward developing many important technologies and technical capabilities necessary for a successful statewide demand response, including communication techniques and devices like two-way communicating utility devices in homes, commercial buildings and industrial plants. These communicating devices can be pre-programmed to react when the system sends signals that prices or demand are high, and can then turn off non-critical appliances (like washing machines, dishwashers, or unnecessary lights) or processes (like the defrost cycle of the refrigerator or preselected commercial or industrial processes) until the "event" is over and the price of energy or stress on the utility system goes down. Research efforts at the center also include development of open demand response communication standards between the utility and on site communicating devices and meters (Open ADR); methods to analyze behaviors and perceptions related to energy use as well as the most effective kinds of pricing signals (automatic control with optional override vs. a reminder phone call); structures for time-varying pricing; and methods to set appropriate DR program baselines and goals. The center has also field tested different kinds of communicating devices and has researched the potential for demand response to transition between sectors, such as from commercial to industrial facilities. Open Automated Demand Response has been identified as one of 16 potential national standards to support national smart grid development. Next steps include research studies of small commercial customer behavior and the potential impact of residential time-of-use rates.

growth rate. That peak load creates inefficiencies within the system. As electricity demand goes up at peak times, power companies generally dispatch power plants in decreasing order of efficiency; therefore as the load goes up, the overall efficiency of producing electricity goes down. As efficiency goes down, the cost to provide that power and the GHG emissions of that power go up. When demand falls, the opposite occurs. System operators must manage generation output in real time to match demand as it rises and falls to prevent excessive voltage and frequency changes which could interrupt or damage electrical devices.

Not only are peaking units generally less efficient, but because they operate only a few hundred hours per year, operators must pay for the unit's ownership and operating costs over a much shorter period. This results in much higher costs when compared with facilities that can spread their fixed costs over more hours of operation. Peaking units are necessary, however, to ensure that adequate amounts of power are available during peak times or to meet unexpectedly high load requirements. Successful demand response improves system efficiency, reduces the need for new electric generation capacity, and reduces fuel consumption at existing electricity generating stations.

Although the cost of providing electricity to consumers changes depending on the current load on the system, electricity rates have historically only been based on the total amount of energy consumed monthly rather than on when that electricity is actually used. These rates provide no signal of actual energy costs, nor do they provide incentives to reduce load during the few critical hours each year when high demand strains capacity, system stability is at risk, and electricity is the most costly to generate.

The CPUC has made significant progress toward making dynamic pricing available to all customers. In August 2008, the CPUC issued a decision (D.08-07-045) adopting a dynamic pricing timetable for Pacific Gas and Electric Company. Under this timetable, all nonresidential customers will be on a default time varying price by 2011. However, based on the restrictions of AB 1X, the CPUC timetable specifies that residential customers will default to flat prices and have to request time varying prices. In order to guarantee broad benefits of time varying pricing, they should be implemented as a default rate, and allow individual customers to opt-out if they choose.

In the state's *Energy Action Plans*, both the Energy Commission and the CPUC have supported time variant pricing. In the CPUC rulemaking (R.07-01-041) to evaluate the utilities' demand response programs, it sought to establish protocols for estimating load impacts, cost-effectiveness, and modifications to support the California ISO's efforts to incorporate these programs into market designs. A decision (D.08-04-050) regarding load impact estimations was issued in April 2008.[54] The Energy Commission joined in instituting the CPUC Rulemaking (R.02-06-001) "to develop demand response as a resource to enhance electricity system reliability, reduce power purchase and individual consumer costs, and protect the environment." The rulemaking focused on developing dynamic rates and demand response programs for large customers, and conducting research to evaluate the potential costs and benefits of building an advanced metering infrastructure to serve all IOU customers.

Research by the Demand Response Research Center indicates that with proper application, the new open automated demand response (open ADR) standard has the potential to substantially increase the amount of demand response capabilities that exist for grid operators in the future. As California implements the new smart grid, increased demand response capabilities can offset the need for increasing the number of conventional generating power plants in the future. A key element of open ADR is the ability of customers to pre-select and automate their desired demand response actions (lower air conditioning, lower lighting, reduce processes, etc.) and these actions will occur automatically when called upon unless overridden by the customer. Automated demand response actions can be signaled by an energy price or other signal indicating the grid is stressed and a pre-approved/coordinated load reduction is desired. Research indicates that customers readily accept this automated process and in the years of field testing customer comfort complaints have been negligible. In some cases, commercial businesses that have participated in pilots or programs have not only fully accepted the efforts but have also used their participation as a sign to their customers of their environmental stewardship and willingness to help California make the transition to a more efficient and lower GHG emitting future.

Renewable Energy

Renewable energy is the first supply-side resource in the loading order and a key strategy for achieving a significant portion of the ARB's target for GHG emission reductions from the electricity sector. Increasing the amount of renewable energy in California's electricity mix also reduces the risks and costs associated with potentially high and volatile natural gas prices while also reducing the state's dependence on imported natural gas used to generate electricity. Renewable resources also provide other benefits such as economic development and new employment opportunities, benefits that are becoming increasingly important given the current recession.

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54 CPUC, available at: [http://docs.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/81972.htm]

Renewable energy provides obvious environmental benefits by reducing air and water pollution. Adding large amounts of renewables can also have environmental effects on consumers. There could be conflicts between the broader goal of reducing GHG emissions and the specific environmental impacts of additional renewable infrastructure such as power lines to access renewable resources or new renewable power plants that can impact sensitive habitats or local communities. In addition, because some renewables are variable in nature, such as wind and solar, there is still a need for dispatchable generation, energy storage, and other technologies to provide the kinds of services the electricity and transmission systems need to operate reliably. Although new natural gas plants are more efficient and cleaner burning than older gas plants, some of the efficiency and emission benefits may be lost if these plants are frequently ramped up and down to firm up variable renewables.

While renewable resources can help reduce the climate change impacts of electricity generation, climate change itself will have impacts on the renewable energy sector. For example, climate change will affect snow pack and precipitation levels, which will in turn affect the availability of hydroelectric resources. Although large hydroelectric facilities are not eligible for RPS programs serving California's retail customers, they do provide important grid stabilizing services because they can be ramped up and down quickly. Changes in climate may also influence wind patterns and speeds, and could reduce available biomass feedstocks as a result of decreased water levels or risk of wildfires.

On the reliability side, increased use of renewables can reduce the demand for natural gas-fired generation, making consumers less vulnerable to the risks associated with natural gas supply disruptions. Renewables also diversify the system and reduce the state's dependence on natural gas. However, integrating large amounts of variable renewables into the system will require increased investment in resources needed for grid operators to provide reliable electric service, as discussed in more detail in Chapter 3.

Renewables also have economic benefits and costs. By decreasing natural gas use, renewables can make customers less vulnerable to natural gas price spikes and could also reduce natural gas prices as a result of reduced demand. Renewable resources provide economic benefits in the form of "green jobs," particularly important given current high unemployment levels. Individual customers can take advantage of financial incentives to install on-site renewables such as solar PV to reduce their electric bills. However, renewable resources can be more expensive than conventional resources, so adding high levels of renewables to the power mix could result in increased electricity rates. There will also be costs associated with adding new transmission and distribution lines to access renewable resources as well as costs from building new renewable power plants, including environmental mitigation costs for plants proposed in environmentally sensitive areas. In addition, there are costs related to adding new natural gas plants to provide the backup needed for variable renewables.

Renewable Energy and the Environment

California's Renewables Portfolio Standard (RPS), established in 2002, is an essential strategy to help the state reduce GHG emissions from the electricity sector. The RPS requires retail sellers (defined as IOUs, electric service providers, and community choice aggregators) to increase renewable energy as a percentage of their retail sales to 20 percent by 2010. State law also requires publicly owned utilities to implement an RPS but gives them flexibility in developing specific targets and timelines. In November 2008, Governor Schwarzenegger's Executive Order S-14-08 raised California's renewable energy goals to 33 percent by 2020, and in September 2009, his Executive Order S-21-09 directed the ARB to work with the CPUC, the California ISO, and the Energy Commission to adopt regulations by July 31, 2010, increasing California's RPS to 33 percent by 2020.

The 33 percent RPS target is expected to provide 15.2 percent of the total GHG reductions needed to meet the AB 32 goal of achieving 1990 emissions levels by 2020.[55] However, despite efforts to expand renewable generation, recent utility RPS procurement forecasts for 2010 and 2020 indicate that substantial challenges remain. As of June 2009, the CPUC has approved 116 RPS contracts totaling 8,334 MW; of that approved capacity, a little over 10 percent – 860 MW – has come on-line and is delivering energy to the grid. An additional 13 contracts for 5,941 MW are under review.[56] While the IOUs have made progress adding renewable contracts to their portfolios, they do not expect to meet the 2010 target and will be significantly below the 33 percent target in 2020 unless they add renewable resources at a much faster pace.

Recent estimates of the amount of renewable energy needed by 2020 to meet the 33 percent target range from 45,000 GWhs to almost 75,000 GWhs. This wide range reflects different assumptions about energy efficiency achievements, expected electricity demand and retail sales in 2020, and the amount of energy that will be provided by CHP, rooftop solar, and existing renewable facilities. Estimates of existing renewables vary from 27,000 GWhs to 37,000 GWhs, depending on the vintage of the estimate, the amount of out-of-state renewable generation attributed to publicly owned utilities, and the amount of unclaimed renewables (renewable generation not claimed as eligible for the RPS) included in the estimate. Energy Commission staff estimate that if the ARB *Climate Change Scoping Plan* goals are achieved for energy efficiency, CHP, and roof-top solar, the state will need 45,000 GWhs of additional renewable energy to meet the RPS goals.

Expanding Renewables Portfolio Standard Eligibility

Given the Governor's expanded goal of 33 percent renewables by 2020, the Scoping Order for the *2009 IEPR* identified the need to review eligibility criteria for the RPS. As part of its responsibilities under the RPS, the Energy Commission sets eligibility criteria and certifies facilities as RPS eligible. The Energy Commission currently defines eligible renewable resources by fuel source rather than by specific technologies, but state law related to the RPS law contains specific requirements relating to technology that must be considered when determining RPS eligibility.

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55 California Air Resources Board, Climate Change Scoping Plan, 2008, Appendix G, Table G-I-2, p. G-I-7, available at: [http://www.arb.ca.gov/cc/scopingplan/document/appendices_volume2.pdf].

56 California Public Utilities Commission, Renewables Portfolio Standard Quarterly Report, July 2009, available at: [http://www.cpuc.ca.gov/NR/rdonlyres/EBEEB616-817C-4FF6-8C07-2604CF7DDC43/0/Third_Quarter_2009_RPS_Legislative_Report_2.pdf].

An example is the use of municipal solid waste (MSW) to produce energy. Although the Energy Commission defines MSW as an RPS-eligible fuel, current law narrowly defines which MSW conversion technologies are allowed. To date, no MSW gasification facility has met these stringent requirements, particularly the requirement that the MSW conversion occur without the use of air or oxygen except ambient air to maintain temperature control.[57] Because the law requires proposed MSW facilities to obtain air permits, it may be difficult for such facilities, even if they meet RPS eligibility requirements, to be built in areas of the state such as the South Coast Air Quality Management District (SCAQMD) that are in non-attainment for federal air quality standards.

Most Western Electricity Coordinating Council (WECC) states do not explicitly allow MSW to be used for RPS compliance. California's RPS allows MSW that has undergone gasification or been converted to biodiesel to be used for RPS compliance, but combustion of solid unconverted MSW is not eligible (with the limited exception of facilities located in Stanislaus County and operational before Sept. 26, 1996). Similarly, Arizona allows only gasified MSW to be used for RPS compliance, but does not specifically permit combustion of solid MSW. Nevada is the only WECC state to explicitly allow unlimited or unrestricted combustion of solid MSW (as well as gasified MSW) to be used for RPS compliance. All other WECC states do not identify MSW of any form as eligible for RPS compliance.

As the space available for landfills becomes more limited in California, renewable energy developers have expressed interest in MSW gasification and are seeking clarification of rules for RPS eligibility of MSW conversion. In a 2006 report, the California Biomass Collaborative estimates that "biomass in the landfill disposal stream (23.1 million tons plus 2.6 million tons of green ADC [alternative daily cover]) could support about 1,750 MWe of electricity generation with another 900 MWe coming from the plastics and textiles components."[58] Given the state's aggressive renewable energy targets and the need for additional renewable energy to meet those targets, the IEPR Committee suggests that the Energy Commission and the California Integrated Waste Management Board should review emerging technologies to gasify MSW that most closely meet the intent of current RPS eligibility requirements as well as environmental considerations and, if appropriate, suggest modifications to applicable state statutes to allow such technologies to be RPS eligible.

Another eligibility issue is the delivery of renewable generation from out-of-state generators. Generation from a renewable power plant located outside of California is eligible for the state's

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57 April 21, 2009, IEPR workshop comments by Phoenix Energy: "There is no way you can do this without the presence of oxygen. Limited oxygen, yes, but if you follow the definition to the letter of the law, it can't be done.", transcript p. 74, see [http://www.energy.ca.gov/2009_energypolicy/documents/2009-04-21_workshop/2009-04-21_TRANSCRIPT.PDF].

58 California Energy Commission, April 2006, Biomass in Solid Waste in California: Utilization and Policy Alternatives, PIER Collaborative Report, Draft. Contract 500-01-016, p. 2, available at: [http://biomass.ucdavis.edu/materials/reports%20and%20publications/2006/MSW_Biomass_White_Paper_2006.pdf

RPS if the facility began operating after January 1, 2005, can demonstrate delivery of energy into California, and does not cause or contribute to any violation of a California environmental quality standard or requirement within California.[59] As of September 2009, the Energy Commission has certified only 24 out-of-state renewable facilities as eligible for the RPS, compared to more than 576 eligible in-state facilities.

The delivery requirement for out-of state renewable facilities is flexible, allowing delivery to occur "regardless of whether the electricity is generated at a different time from consumption by a California end-use customer."[60] This approach can allow out-of state renewables to be "firmed" or "shaped" to address issues like intermittency, inadequate transmission, or scheduling barriers. Firming and shaping can also provide greater value to the electricity system by converting off-peak renewable generation to on-peak energy delivery. Allowing out-of-state renewables to be firmed and shaped rather than immediately scheduled for delivery may also increase the availability of lower cost renewable resources. Firming and shaping may inadvertently allow non-eligible resources to be counted for RPS compliance. In addition, using large amounts of renewable energy from outside of California would reduce the in-state benefits of California's RPS, such as creating in-state jobs, enhancing California's air quality, and providing greater reliability.

As shown in Table 2, other states in the WECC area with RPS programs have their own delivery requirements. Arizona has the most restrictive electricity delivery policy, requiring that all electricity generated by the renewable resource being used for compliance with a utility's RPS target be physically delivered to that utility's service territory. Most other WECC states with an RPS program to some degree permit the use of unbundled renewable energy credits (RECs)[61] for RPS compliance. However, their use is often constrained by electricity delivery requirements, location requirements, or explicit caps. As a result, some of these states' policies are arguably more restrictive than California's in terms of geographic scope.

Limiting access to out-of-state renewable resources could create geographic inequities between California's utilities because there are more in-state renewable resources located in the southern regions of the state and transmission from south to north is limited. These inequities could be addressed by the use of tradable RECs. The CPUC issued a proposed draft decision authorizing tradable RECs for RPS compliance in December 2008, and issued a revised version in March

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59 If an out of state facility commenced commercial operations before January 1, 2005, it may still be eligible if it meets one of the following criteria: a) The electricity is from incremental generation resulting from project expansion or repowering of the facility on or after January 1, 2005, or b) the facility is part of a retail seller's existing baseline procurement portfolio as identified by the CPUC or part of a publicly owned utility's baseline as determined by Public Utilities Code section 387.

60 Public Resources Code § 25741(a).

61 As defined in California, a renewable energy credit is a certificate of proof, issued through the accounting system established by the Energy Commission, that one unit of electricity was generated and delivered by an eligible renewable resource. Unbundled renewable energy credits are those credits that are sold separately from the underlying electricity.

2009. If adopted, the revised proposed decision would "allow transfer of RPS credits without regard to constrained transmission pathways."[62]

Table 2: RPS Delivery and Location Requirements in Other Western States

State	Unbundled RECs Allowed	Delivery Requirements	Facility Location Requirement
Arizona	No	Delivered to the utility system	No requirement, but 1.5 multiplier for in-state solar installed before 2006 and for in-state renewables with components manufactured in-state and installed before 2006.
California	No	For out-of-state facilities, matching quantity of energy delivered to in-state zone or node. Facilities must have come on-line after January 1, 2005, if not included in the baseline procurement portfolio of a California IOU or publicly owned utility.	Must be interconnected to the Western Electricity Coordinating Council area (WECC)
Colorado	Yes	None	No requirement, but 1.25 multiplier for in-state generation.
Montana	Yes	Delivered to state if not located in-state. Out-of-state renewables must have commenced commercial operation after January 1, 2005.	None
Nevada	Yes	Delivered to the state	None
New Mexico	Yes	Delivered to the state, unless waived by the New Mexico Public Services Commission based on a determination "that there is an active regional market for trading renewable energy and renewable energy certificates in any region in which the [utility] is located." [c]	None
Oregon	Yes , subject to caps	*Unbundled RECs*: None *Bundled RECs*: Delivered to the transmission system of the utility, to Bonneville Power Administration, or to a designated point for subsequent delivery to the utility.	*Unbundled RECs*: WECC *Bundled RECs*: U.S. portion of WECC
Washington	Yes	Delivered to state only if not located in Pacific Northwest. If generator is located outside of the Pacific Northwest, the electricity must be delivered to the state "on a real-time basis without shaping, storage, or integration services."	*Unbundled RECs*: Pacific Northwest

Source: KEMA, Inc.

62 CPUC, Draft Proposed Decision Authorizing Use Of Renewable Energy Credits For Compliance With The California Renewables Portfolio Standard, ALJ Simon, March 2009, p. 14, available at: [http://docs.cpuc.ca.gov/efile/PD/99016.pdf].

Although tradable RECs do not necessarily maintain the local benefits of in-state generation, including environmental benefits, they could help California's RPS by avoiding transmission congestion barriers and their associated costs. The use of tradable RECs would add renewable energy to the grid on a regional, WECC-wide basis and could therefore place downward pressure on costs for electricity.

Environmental Impacts of Renewable Infrastructure

While Californians are generally supportive of renewable energy and its environmental benefits, many citizens are concerned about proposed renewable energy projects and associated transmission lines because of potential environmental impacts. For example, proposed solar plants located in the California desert may impact sensitive species habitat or require large amounts of water.

Initiatives are already underway to facilitate the early identification and resolution or to avoid land use and environmental constraints to promote timely development of California's renewable generation resources and associated transmission lines. The RETI collaborative process, discussed in more detail in the transmission section later in this chapter, has identified and prioritized preferred renewable resource development areas and associated transmission line links to deliver renewable power to load centers.

The *RETI Phase 2A Report* is used as one of the data sources for prioritizing the transmission projects to interconnect renewables that are in the state's best interests. It also forms the basis for the development of a draft method for identifying which of the RETI line segments should be considered for corridor designation in the Energy Commission's corridor designation process.

To help address potential impacts of new renewable power plants and related transmission lines, the Energy Commission and California Department of Fish and Game are implementing Governor Schwarzenegger's Executive Order S-14-08 which establishes a process to conserve natural resources while expediting the permitting of renewable energy power plants and transmission lines. The primary objectives are to identify and establish areas for potential renewable energy development and conservation areas in the Colorado and Mojave deserts to help reduce the time and uncertainty associated with licensing new renewable projects on both state and federal lands. As part of implementing the Executive Order, the two state agencies are working with federal agencies to develop the Desert Renewable Energy Conservation Plan (DRECP).

The DRECP will develop a conservation strategy that will use California's unique Natural Community Conservation Plan and may develop a federal Habitat Conservation Plan process to identify environmentally-sensitive areas compatible with economic renewable resource development. The DRECP will also seek to coordinate existing desert Conservation Plans within the Mojave and Colorado Deserts (i.e., the West Mojave Plan), renewable energy development project plans, the Bureau of Land Management (BLM) Solar Programmatic

Environmental Impact Statement, and Renewable Energy Transmission Initiative planning into an integrated framework for balancing natural resource conservation and renewable energy development within the Mojave and Colorado Deserts.

In November 2008, the Energy Commission, the Department of Fish and Game, the U. S. BLM and the U. S. Fish and Wildlife Service signed a Memorandum of Understanding formalizing the Renewable Energy Action Team, which has initiated the DRECP effort and is also addressing permitting issues associated with specific renewable energy projects. Federal participation is supported by the Secretary of the Interior's Secretarial Order 3285 (March 2009) directing all Department of the Interior agencies and departments (which include the BLM and USFWS) to encourage the timely and responsible development of renewable energy, while protecting and enhancing the nation's water, wildlife and other natural resources. State and federal agency representatives have met with county supervisors in the six-county region and have held three public workshops to solicit input from local agencies, environmental groups, utilities, and renewable energy developers; additional workshops are planned for late 2009 and throughout 2010.

Work on the renewable energy permitting elements of Executive Order S-14-08 is split up into six tasks including: (1) developing the DRECP Planning Agreement; (2) publishing a Best Management Practices Manual for the development of renewable energy projects by December 2009, (3) developing and gathering public stakeholder and independent scientific input; (4) developing the Draft DRECP Conservation Strategy by December 2009; (5) developing the Draft DRECP by December 2010; and (6) completing the final Draft DRECP environmental review and approval by June 2012.

With the Governor's direction in Executive Order S-06-06 to meet 20 percent of the RPS with biopower, it will be important to address potential air quality concerns associated with new biomass facilities in California. There is significant potential for renewable electricity generation fueled by biomethane from the state's dairies, but the high cost of emissions controls can interfere with dairies' ability to obtain air permits. California is the largest dairy state in the nation, with more than 1.7 million cows on about 1,800 farms. These cows produce 65 billion pounds of manure per year which could be used in digesters to produce biogas that can be burned to produce electricity.

In 2006, the Energy Commission approved grants for five new dairy digester projects in the San Joaquin air basin with generators to meet the dairies' electricity needs and, with approved power purchase agreements, to sell excess electricity to local utilities. However, because the air basin is an extreme non-attainment area, the San Joaquin Air Quality Management District imposed strict nitrogen oxide (NOx) requirements on these generators that required the use of advanced emission control systems. Because of low milk prices, the dairies were unable to meet the increased costs of installing emissions controls and could not agree to the conditions of the permit. Although discussions between the air district, the dairymen, the California Environmental Protection Agency, the ARB, local air districts, and other stakeholders resulted in conditional agreement on permits, these may have been the last ones issued for dairies with generators.[63]

New solid fuel biomass facilities also face challenges in obtaining NOx permits, as well as the added challenge in the SCAQMD of obtaining permits to emit particulate matter (PM). For example, a 25 MW solid-fuel biomass project would need permits for about 90 tons per day of PM-10 emission offsets or emission reduction credits. [64] At a cost of approximately $350,000 per pound per day (or $31.5 million), this requirement could make new biomass projects in the southern part of the state non-viable from a financial perspective.

Meeting California's renewable energy goals and aggressive GHG emission reduction targets will rely to a large degree on having transmission and distribution in place to access renewable resources. The Energy Commission's *Committee Draft Strategic Transmission Investment Plan* that was released for public review in September 2009 continues to support transmission projects identified in previous strategic plans but envisions the next step as a short-term, 10-year transmission plan focused on the statewide renewable energy goals and identifying transmission projects that will aid the attainment of the RPS targets.

Climate Change Effects on Renewable Infrastructure

Changes in the environment can also affect renewable energy.[65] Renewable energy depends on natural resources like water, biomass, wind, and the sun, so it can be more sensitive to climate variability than fossil or nuclear energy that relies on geological stores. The U.S. Climate Change Science Program has identified impacts of climate change on the country's renewable energy resources, including changes in availability of water, biomass, and incoming solar radiation as well as significant changes in established wind patterns

In August 2009, California's Natural Resources Agency released a comprehensive plan to guide adaptation to climate change, becoming the first state to develop such a strategy. Adaptation generally refers to adjustments in natural or human systems to actual or expected climate changes to minimize harm or take advantage of opportunities.

The 2009 California Climate Adaptation Strategy Discussion Draft summarizes the latest science on how climate change could affect the state and recommends adaptation strategies for the electricity sector.

The Natural Resources Agency's plan recommends encouraging renewable energy development in the least-sensitive environmental areas of the state to maintain natural habitats and healthy forests that will further buffer the environmental impacts of climate change.

63 April 10, 2009, letter from the Western United Dairymen to Governor Arnold Schwarzenegger, available at: [http://www.energy.ca.gov/2009_energypolicy/documents/2009-04-21_workshop/comments/Letter_from_Western_United_Dairymen_to_the_Governor_04-10-09_TN-51189.pdf].

64 California Air Resources Board, Facility details for Burney Mountain Power, available at [http://www.arb.ca.gov/app/emsinv/facinfo/facdet.php?co_=45&ab_=SV&facid_=42&dis_=SHA&dbyr=2007&dd=].

65 California Energy Commission, Potential Impacts of Climate Change on California's Energy Infrastructure and Identification of Adaptation Measures, January 2009, CEC-150-2009-001, available at: [http://www.energy.ca.gov/2009publications/CEC-150-2009-001/CEC-150-2009-001.PDF].

and potential effects on geothermal resources.[66] Climate change impacts that affect aspects of conventional energy facilities, such as power plant cooling and water availability, would also apply to certain renewable technologies such as biomass, geothermal, and solar thermal.

In California, only small hydroelectric facilities, those 30 MW or less in size, are eligible for the RPS. Small hydroelectric facilities provide about 1.5 percent of California's power but about 13.5 percent of total renewable generation,[67] so potential impacts on precipitation levels and the timing and rate of snowmelt could affect the amount of electricity provided by small hydro facilities and ultimately their contribution to the state's renewable goals.

Biomass generation sources include the wastes and byproducts from forestry and agriculture. If climate change results in drier conditions or variations in crop yield, it could affect the type and amount of biomass feedstocks available to existing and future biomass facilities. However, higher daily and seasonal temperatures can also affect insect pest and disease lifecycles as winters become milder, which could increase forest mortality, potentially making more biomass fuel available following disease outbreaks but reducing long-term supplies.

California has aggressive policies targeting rooftop photovoltaic systems, which depend both on the amount of incoming solar radiation and changes in temperature. Cases done outside of California have shown that a two percent decrease in solar radiation resulted in a six percent decrease in the electricity output of solar cells.[68]

Wind generation will most likely be affected regionally rather than uniformly throughout California. Analysis conducted by Breslow and Sailor suggest that average wind speeds in the United States will decrease by 1.0 to 3.2 percent in the next 50 years and will eventually decrease 1.4 to 4.5 percent over the next 100 years.[69] Meanwhile, geothermal resources could be affected by decreased efficiency due to the increased ambient temperature at which heat is discharged. According to the recent assessment by the U.S. Climate Change Science Program, "For a typical air-cooled binary cycle geothermal plant with a 330°F resource, power output will decrease about 1% for each 1°F rise in air temperature."[70]

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66 United States Climate Change Science Program, *Effects of Climate Change on Energy Production and Use in the United States*, February 2008, a report by the U.S. Climate Change Science Program and the subcommittee on Global Change Research, available at: [http://www.climatescience.gov/Library/sap/sap4-5/final-report/sap4-5-final-all.pdf].

67 California Energy Commission, Total System Power, see [http://energyalmanac.ca.gov/electricity/total_system_power.html].

68 Fidje A. and T. Martinsen, 2006: Effects of Climate Change on the Utilization of Solar Cells in the Nordic Region. Extended abstract for European Conference on Impacts of Climate Change on Renewable Energy Sources. Reykjavik, Iceland, June 5-9, 2006.

69 Breslow P. and Sailor J., Vulnerability of Wind Power Resources to Climate Change in the Continental United States, Tulane University, April 2001.

70 Bull, S. R., D. E. Bilello, J, Ekmann, M. J. Sale, and D. K. Schmalzer, Effects of Climate Change on Energy Production and Use in the United States, February 2008, a report by the U.S. Climate Change Science Program and the subcommittee on Global Change Research. Washington, D.C.

While large hydroelectric resources are not RPS eligible, it is a large source of carbon-free electricity in California. The state's hydroelectricity production relies on predictable water reserves. In 2008, 11 percent of California's electricity was produced from large hydroelectric power plants, presently the state's largest source of renewable energy, although large hydro is not eligible for the state's RPS. With changes in snow elevations, snowpack, and snowmelt, less water may be available for hydroelectric generation when it is needed most during the summer. When repeated dry years lead to a drought, reservoir levels can be too low for hydroelectric power generation.

Clearly, more research is needed on the effects of climate change on renewable and low and non-carbon resources, including: effects on biomass supplies and the influence that this would have on the optimal siting of a biomass facility; the California-specific impacts of climate change on photovoltaic technologies; and the location and scale of changes in California's wind patterns, especially in areas targeted for extensive wind energy development. In addition, the *2009 California Climate Adaptation Strategy Discussion Draft*[71] recommends using the Energy Commission's PIER regional climate modeling and related study efforts to assess the potential impacts of climate change on energy infrastructure from sea-level rise, precipitation, and temperature changes and other impacts.

Renewable Energy and Reliability

California has made significant progress in identifying areas of the state with high quality renewable resources, as well as areas with the least environmental impacts for both renewable power plants and transmission lines to access those resources. There are several ways renewable resources can affect energy reliability. Renewable resources help reduce the state's dependence on natural gas, making the state less vulnerable to natural gas supply disruptions. By reducing the amount of natural gas needed in the electricity sector, renewables could also free up more natural gas to be used for industrial processes or residential cooking and heating. In addition, diversifying the state's electricity portfolio reduces customer risk in much the same way that diversifying an investment portfolio reduces financial risk.

However, there could also be negative effects from adding large amounts of renewable resources to the electricity system. Not all renewables provide the operating characteristics that the system needs to maintain local area reliability, and integrating certain renewable technologies can make it more difficult to operate the system reliably. Necessary operating characteristics can include providing baseload power that can meet demand around the clock and throughout the year, peaking power that meet demand during hot summer months, ramping ability in response to changing demand, and voltage support.

Challenges associated with integrating renewables into the system are covered in more detail in Chapter 3. Simply put, California's system operators must constantly balance changing supply and demand to provide reliable electricity and to ensure that the electric grid remains stable.

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71 California Natural Resources Agency, 2009 California Climate Adaptation Strategy Discussion Draft, August 2009, available at: [http://www.energy.ca.gov/2009publications/CNRA-1000-2009-027/CNRA-1000-2009-027-D.PDF].

While some renewable resources can provide baseload power, such as geothermal and biomass, intermittent resources like wind, hydro, and solar operate when nature allows and are therefore not always available to meet system needs during peak hours. Intermittent resources can also drop off or pick up suddenly, requiring system operators to quickly compensate for sudden changes. For example, photovoltaic arrays are very sensitive to cloud cover, which can cause generation to drop substantially in less than a minute and jump back to full generation a few minutes later.[72]

Natural gas plants tend to provide the flexibility the system needs for peaking, cycling, and some baseload operation. Because of the engineering realities of how the system operates, natural gas plants can support the integration of renewable resources by providing the operational characteristics the system needs to operate reliably. The challenge will be to identify where and what types of natural gas plants will best allow renewables to be integrated into the system to meet renewable goals while maintaining reliability. Other solutions such as energy storage and hybrid renewable plants, are also possible and could be preferable in the longer term as more aggressive climate mitigation targets are addressed.

Another issue with integrating large amounts of renewables into the system is the potential for over-generation, particularly in the spring when there is a need to spill water stored in dams to make room for snow melt. Over generation is when generation exceeds demand despite the actions by the system operator to reduce generation. Over generation can lead to circumstances where market prices for electricity actually become negative as the system operator, to maintain system operations, must literally pay adjacent balancing authorities to take the excess energy.

One strategy to address the variability of renewable resources and over generation concerns is the use of utility scale and distributed energy storage, which is discussed in more detail in Chapter 3. Energy storage provides the ability to make best use of renewable generation facilities by addressing potential mismatches between generation and load while also addressing other issues like ramping rates and power quality. Large utility-scale energy storage technologies like pumped hydroelectric storage, compressed air energy storage, or large multi-megawatt battery storage systems can store renewable energy generated off-peak for later use during peak periods or to provide firming. Pumped hydroelectric storage uses water pumped from a lower elevation reservoir to a higher elevation using low-cost off-peak electric power (including renewable energy) to run the pumps. The water is then allowed to return and generate electricity during times when the renewable generation needs firming or to match the renewable load to the needs of the utility electrical system. Compressed air energy storage uses a compressor to pressurize a storage reservoir using off-peak energy and then releases the air

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72 Curtright, Aimee E. and Jay Apt. 2008. "Applications: The Character of Power Output from Utility-Scale Photovoltaic Systems." Progress in Photovoltaics: Research and Applications. 16: 241-247. [http://www.clubs.psu.edu/up/math/presentations/Curtright-Apt-08.pdf]. See also, Dan Rastler, EPRI, presentation at the April 2, 2009, IEPR workshop, available at: [http://www.energy.ca.gov/2009_energypolicy/documents/2009-04-02_workshop/presentations/0_3%20EPRI%20-%20Energy%20Storage%20Overview%20-%20Dan%20Rastler.pdf].

through a turbine during on-peak hours to produce energy. Large compressed air energy storage systems use underground caverns such as depleted natural gas mines to store the air and can provide energy storage for long periods of time. Battery energy storage technology has improved over time to the point where there are several emerging battery technologies that can provide utility scale energy storage.

Another tool to help reduce the impacts of renewable variability on the system is to improve the ability to forecast expected generation from intermittent resources. Progress has been made in reducing forecasting error in hour-ahead and day-ahead generation from wind facilities, but additional work is needed to improve forecasting capability for solar facilities.

Renewable Energy and the Economy

As economic concerns continue to dominate the daily news, the United States' new administration is shifting energy policy strategies to embrace a new clean energy economy, with development of renewable energy resources becoming part of the nation's economic recovery plan.

At the same time, California's citizens continue to face the risk of potential sustained high natural gas prices. In 2008, 45.7 percent of the state's electricity came from natural gas-fired generation, up from 36.5 percent in 2002. Because the electricity generation sector is the state's largest consumer of natural gas, price increases and volatility can have major effects on electricity prices and on the operating costs of existing and new natural gas plants that are needed to meet California's increasing electricity demand. Diversifying the electricity system by adding renewables helps to reduce these effects.

California has already invested billions of dollars to promote renewable energy. Senate Bill 1 (Murray, Chapter 132, Statutes of 2006) enacted a $3.35 billion set of solar incentive programs to achieve 3,000 MW of solar energy systems by offering incentives between 2007 and 2016. The programs are administered by the CPUC (about $2.1 billion), the Energy Commission ($400 million), and publicly owned utilities ($784 million). The CPUC is responsible for providing incentives to the nonresidential and existing residential markets in IOU service areas. The Energy Commission's New Solar Homes Partnership program offers incentives to encourage solar installations, with high levels of energy efficiency, in the residential new construction market for IOU utility service areas. Publicly owned utilities are responsible for solar incentive programs in their service areas.

In addition, the Energy Commission's Renewable Energy Program that was established in 1998 represents an additional $2.1 billion to support the continued operation of existing renewable facilities and the development of new renewable generating facilities and emerging renewable technologies.[73] The consumer education component of the Renewable Energy Program also

73 Funding for the New Solar Homes Program under the Renewable Energy Program is included in the total for the California Solar Initiative. See [http://www.energy.ca.gov/renewables/quarterly_updates/2009-1Q_FIANACIAL_SUMMARY.PDF] for a description of Renewable Energy Program funding expenditures as of March 2009.

funded the development of the Western Renewable Electricity Generation Information System, which tracks renewable generation in the Western Electricity Coordinating Council area to ensure that generation is counted only once for purposes of California's RPS.

Although the Renewable Energy Program was established prior to passage of the state's RPS, it is an important tool to help the state achieve its RPS and GHG emission reduction goals. The program has supported 4,500 MW of existing facilities and has helped develop nearly 500 MW of new large-scale generating capacity as well as about 130 MW from new customer-scale facilities. The program is also ensuring that California can reliably track and verify renewable generation claimed to meet the RPS. However, authorization to collect funds for the program is slated in to end January 1, 2012. Because of the importance of the Renewable Energy Program in helping to support the state's renewable energy goals, the IEPR Committee recommends that the Legislature extend the collection of public goods charge funding for the program through 2020.

New renewable power plants that are being proposed and developed in California to meet the state's RPS also represent a significant investment in renewable energy. As of August 2009, there were nine solar thermal projects under review by the Energy Commission and the BLM totaling more than 4,500 MW of new renewable capacity. An additional 19 solar thermal projects totaling 5,600-5,900 MW have been announced but have not yet applied to the Energy Commission for certification.[74] These projects represent billions of dollars of capital investments as well as significant job and tax benefits from the construction and continued operation of the projects themselves.

The earlier section on reliability impacts of renewables discussed some of the physical effects of integrating renewable resources into the electricity system. There are also potential economic consequences of moving to higher levels of renewables. To the extent that natural gas remains a low fuel cost, gas-fired generation can help the electricity system absorb the costs of transitioning to a higher level of renewable energy in our electricity system.

Determining the actual costs of increased levels of renewables is difficult. Cost studies done to date have widely varying assumptions, uncertainties, and approaches. However, study results are influenced by some common factors:

- Estimates of future natural gas prices
- Estimates of the cost of generation for gas-fired and renewable generating technologies, including the potential cost of GHG allowances for gas-fired generation, costs for siting and permitting, and the cost of capital to finance new renewable projects
- Availability of tax credits and other incentives for renewable generation

74 "Announced" refers to projects that have been publicly announced in the news media, have power purchase agreements pending with or approved by the California Public Utilities Commission, or have made official declarations of intent. See [http://www.energy.ca.gov/siting/solar/index.html] for a complete list of projects.

In June 2009, the Energy Division of the CPUC issued the preliminary results of a study on the impacts of the 33 percent by 2020 renewable target that examined four different potential scenarios and identified the costs and tradeoffs of each approach.[75] The study suggests that achieving 33 percent renewable energy could increase costs by about 10 percent compared to an all gas scenario and about 7 percent compared to simply maintaining 20 percent renewables through 2020. The study also indicated that the state needs to build four major new transmission lines at a cost of $4 billion for the 20 percent reference case, which holds renewable energy at 20 percent of retail sales through 2020. To meet a 33 percent by 2020 RPS target, the study indicates a need for seven additional transmission lines at a cost of $12 billion but assumes that the ARB's *Climate Change Scoping Plan* goals for energy efficiency, combined heat and power, and rooftop solar are not met.

Because of the importance of the cost of generation in studies evaluating the costs of moving to increased levels of renewables, the Energy Commission has continued to update its Cost of Generation Model to provide a consistent set of assumptions. The Cost of Generation Model was introduced in the *2003 IEPR* and has been revised in each IEPR cycle to improve the model's accuracy, flexibility, and transparency. The goal of the model is to have a single set of current cost estimates that can be used in energy program studies at the Energy Commission and elsewhere.

The Energy Commission's 2009 *Comparative Cost of California Central Station Electricity Generation Technologies Report* updated the estimates of levelized costs that were prepared for the *2007 IEPR.* Levelized, or annualized, costs are equal to the net present value of current and future annual costs, which allows technologies with different annual costs to be compared with each other. The current version of the model has been improved to capture long-term changes in technology costs over time. It also now includes ranges of costs for each technology, recognizing that the range of cost for a technology can be more significant than differences in average costs between technologies. Single-point estimates do not reflect actual market dynamics or the wide array of component costs, operational factors, or unpredictable future tax benefits.

For the *2009 IEPR*, the Energy Commission staff updated the levelized cost estimates for plants that could be developed by IOUs and publicly owned utilities, as well as merchant plants financed by private investors that sell electricity to the competitive wholesale power market. The update also included long-term changes in cost variables that determine levelized cost, the most significant of which is instant cost. Instant cost, sometimes referred to as overnight cost, is the initial capital expenditure

Based on initial capital expenditure, wind and solar technologies show a significant cost decline. Solar photovoltaic technology has shown dramatic cost changes since 2007 and is expected to

75 California Public Utilities Commission, 33% Renewable Portfolio Standard Implementation Analysis Preliminary Results, Anne Gillette, Jaclyn Marks, June 2009, available at: [http://www.cpuc.ca.gov/NR/rdonlyres/1865C207-FEB5-43CF-99EB-A212B78467F6/0/33PercentRPSImplementationAnalysisInterimReport.pdf].

show the most improvement of all the technologies evaluated in the model, bringing its capital cost within range of that of natural gas-fired combined cycle units.[76]

In general, IOU plants are less expensive than merchant facilities because of lower financing costs. However, the model indicates that merchant plants for some of the renewable technologies, such as the solar units, become less expensive because of the effect of cash-flow financing and tax benefits.

As part of the cost analysis, the Energy Commission compared its cost assumptions for renewable technologies with those used in the RETI process and in the CPUC's evaluation of the cost of RPS implementation. The Energy Commission's cost assumptions were generally consistent with the RETI assumptions with the exception of the cost of single-axis PV which was lower. Relative to the CPUC's cost assumptions, the Energy Commission's results were higher for solar thermal power plants and lower for wind.

Evaluation of the generation costs for renewable technologies is ongoing, and it is difficult at this point to draw concrete conclusions from the analyses to date. However, in looking at the inputs for determining the cost of renewable generation technologies, there is a clear need for future studies to also consider – either qualitatively or quantitatively – macroeconomic and externality factors associated with renewable generation that may influence costs. Factors that should be considered include:

- CO_2 abatement costs, including carbon capture and storage
- Environmental sensitivity and land-use constraints
- Permitting risk
- Transmission limitations and equity issues related to who bears the cost of new transmission
- System integration costs and system diversity benefits
- Availability of financing and tax credits
- Macro-economic benefits (jobs creation, security, fuel diversity, etc.)
- Natural gas price and wholesale price effects from increased penetration of renewables
- Costs of energy storage technologies

Because costs can change dramatically more often than the biennial IEPR cycle, there is a need for ongoing cost analysis efforts integrated across utility, community, and building scale applications of renewable energy technologies. Also, because levelized energy costs value each kWh delivered to the grid equally regardless of the time it is delivered and its impact on the remainder of the system, more comprehensive cost analysis should be complemented by value analysis that supports planning for least cost overall electric system operation.

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76 For detailed tables showing individual technology costs, see California Energy Commission, 2009 Comparative Cost of California Central Station Electricity Generation Technologies Report, August 2009, CEC-200-2009-017SD, p. 16-19, available at: [http://www.energy.ca.gov/2009publications/CEC-200-2009-017/CEC-200-2009-017-SD.PDF].

Recognizing that renewables often are more costly than conventional energy sources, the RPS law prior to 2008 set aside a fixed amount of public goods charge funding to offset potentially higher costs to the IOUs of procuring renewable energy. In 2008, legislative action transferred administration of these funds from the Energy Commission to the CPUC, refunded $462 million in unused funds to the IOUs, and eliminated the collection of that portion of the public goods charge. There is now a "cost limitation" for each utility that is equal to the actual amount of funding collected for this purpose from 2002 -2007 plus the projected amount that would have been collected from 2008 -2011.

Under the RPS law, once the cost limitation is reached, the CPUC cannot require IOUs to purchase any additional renewable energy that is more expensive than the benchmark "market price referent" price set by the CPUC. IOUs can, however, voluntarily procure renewable priced above the market price referent, and the CPUC is allowed to approve recovery of the above-market costs of those contracts through rates. As of May 2009, PG&E and SDG&E had reached their cost limitations ($381.9 million and $69 million, respectively), and as of September 2009, SCE appears to have reached its cost limitation as well.[77]Southern California Edison has 69 percent of its limitation remaining ($221.8 million).

With the cost limitation reached by two of the three IOUs, the state needs another approach to maintain downward pressure on the costs of renewables. Some recent studies suggest that well-designed feed-in tariffs – fixed, long-term prices for renewable energy – can help with the development of renewable resources at lower costs than other policies.[78] Feed-in tariffs can be based on a generator's cost of generation plus a reasonable profit, on the value that generator provides to the system (such as delivering during peak periods), or on a hybrid of the two. A cost-based approach can be most easily tailored to put downward pressure on costs, but a hybrid approach may be necessary because utilities and states may not have the legal authority to set wholesale electricity prices based on the cost of generation.[79] If a combined approach is

77 California Public Utilities Commission Resolution E-4253, September 24, 2009, page 2, [http://docs.cpuc.ca.gov/word_pdf/AGENDA_RESOLUTION/107332.pdf].

78 Studies include: Summit Blue Consulting, & Rocky Mountain Institute, (2007), an analysis of potential ratepayer impact of alternatives for transitioning the New Jersey solar market from rebates to market-based incentives (Final Report). Boulder, CO: Summit Blue Consulting, prepared for the New Jersey Board of Public Utilities, Office of Clean Energy; de Jager, David and Max Rathmann (Ecofys International, BV), Policy Instrument Design to Reduce Financing Costs in Renewable Energy Technology Projects. October 2008, PECSNL062979, International Energy Agency Implementing Agreement on Renewable Energy Technology Deployment, available at: [http://www.iea-retd.org/files/RETD_PID0810_Main.pdf]; Ragwitz et al (OPTRES), Assessment and Optimization of Renewable Energy Support Schemes in the European Electricity Market, Final Report, February 2007, European Commission, available at: [http://www.optres.fhg.de/OPTRES_FINAL_REPORT.pdf]; and NREL, Feed-in Tariff Policy: Design, Implementation, and RPS Policy Interactions, Karlynn Cory, Toby Couture, and Claire Kreycik, March 2009, p. 9, available at: [http://www.nrel.gov/docs/fy09osti/45549.pdf].

79 For more information, see California Public Utilities Commission Rulemaking (R.) 08-08-009.

used, care is needed to maintain transparency, certainty, and a clear link to the cost of generation for feed-in tariffs to stimulate development of renewable energy.

In setting feed-in tariffs, there are two important considerations. First, to keep downward pressure on costs, feed-in tariffs should not be "one-size-fits-all," but instead should be based on the size and type of renewable resource. For example, the cost of generating energy from a 100-MW wind farm is much less than the cost of generating energy from a 2-MW field of photovoltaic panels. Differentiating feed-in tariffs by type and size can ensure a good mix of new renewable energy projects and avoid paying too much for some technologies and too little for others. Setting a different feed-in tariff for each type of renewable energy technology can also stimulate competition among equipment manufacturers to bring costs down and maximize profit margins for project developers.[80] This approach is being used in Germany, where feed-in tariffs are stimulating development in a broad range of renewable energy types and project sizes.

Second, once a contract is signed, the original price should be set for the life of the contract to provide revenue certainty that is needed for projects to get financing. To encourage faster renewable development, lower tariffs could be offered for projects that come on-line in later years, with the rate of decline for each feed-in tariff revisited at specified intervals to ensure it is consistent with market conditions. For example, solid-fuel biomass facilities can invest in more efficient equipment to reduce their costs, but they have little control over the costs of collecting and transporting fuel to their facilities. If the cost of biomass fuel or transport rises significantly, the feed-in tariff may need to be revised to reflect market realities. On the other hand, if feed-in tariffs prove too successful at bringing renewable energy on-line faster than what is needed to meet the state's renewable goals, a cap could be used to contain costs. However, a capped feed-in tariff raises some doubts for developers about whether they will obtain a feed-in tariff contract. It can also create uncertainty for manufacturers regarding long-term market growth unless the cap is set as a long-term target.

The renewable energy data used in the Energy Commission's staff Cost of Generation Model could provide a good starting point for developing either cost-based or hybrid feed-in tariffs in California. A review of feed-in tariff rate-setting processes in Europe and the United States suggests that using cost-of-generation data to calculate feed-in tariff levels would require decisions on the following key criteria:

- The level of return on equity and/or debt consistent with the risk profile of the specific technologies.
- The ownership structure, if tariffs will be differentiated by owner type.
- The degree of leverage (debt versus equity).

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80 Grace, Robert, W. Rickerson, K. Corfee, K. Porter, and H. Cleijne (KEMA), California Feed-In Tariff Design and Policy Options. Final Consultant Report, prepared for the California Energy Commission, CEC-300-2008-009F, pp. 24-25, available at: [http://www.energy.ca.gov/2008publications/CEC-300-2008-009/CEC-300-2008-009-F.PDF].

- How costs are allocated for transmission, distribution, and interconnection.
- How to address the range of costs for each technology to balance costs to ratepayers against stimulating investment.
- How complex the rate-setting model will be and the optimal level of stakeholder involvement.

Over the past several years, the Energy Commission has explored the potential benefits of a feed-in tariff in California as a way to accelerate renewable energy generation and increase the likelihood of meeting California's RPS goals. The *2007 IEPR* recommended setting feed-in tariffs initially at the CPUC's market price referent for all RPS-eligible renewables up to 20 MW while continuing to explore feed-in tariffs for larger projects. The *2008 IEPR Update* reiterated this recommendation, adding that feed-in tariffs for larger projects should include must-take provisions as well as cost-based technology-specific prices that generally decline over time and are not linked to the market price referent.

Feed-in tariffs for smaller projects makes sense as an interim step toward broader development of feed-in tariffs because smaller projects can interconnect to the grid at the distribution level and typically do not require new transmission investment.[81] Also, smaller projects often do not require as extensive environmental reviews or as lengthy a permitting process as larger projects. Analysis in the RETI process has suggested that there is technical potential for as much as 27,500 MW of wholesale distributed PV projects up to 20 MW in size near substations.[82]

Opinions regarding the effects of feed-in tariffs vary. Some parties are concerned that higher feed-in tariffs would be too costly and would increase electricity rates for utility customers. Others argue that providing clear up-front feed-in tariff guidelines would reduce the time and expense of obtaining a long-term contract by allowing pre-approval of projects that meet those guidelines.[83] Feed-in tariffs could also reduce financing costs by providing increased certainty for investors.[84] And as with all strategies to reduce the impacts of climate change, determining the cost-effectiveness of feed-in tariffs to incentivize renewable energy must factor in the potential health and environmental costs of not meeting the state's GHG emission reduction goals.

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81 KEMA, *California Feed-In Tariff Design and Policy Options*, May 2009, CEC-300-2008-009-F, available at: [http://www.energy.ca.gov/publications/displayOneReport.php?pubNum=CEC-300-2008-009-F].

82 California Energy Commission, *RETI Phase 1B*, January 2009, available at: [http://www.energy.ca.gov/2008publications/RETI-1000-2008-003/RETI-1000-2008-003-F.PDF].

83 RightCycle and FIT Coalition, written Comments for May 28, 2009, IEPR workshop, available at: [http://www.energy.ca.gov/2009_energypolicy/documents/2009-05-28_workshop/comments/RightCycle_and_the_FIT_Coalition_Comments_TN_51944.pdf].

84 de Jager, David and Max Rathmann (Ecofys International, BV), Policy Instrument Design to Reduce Financing Costs in Renewable Energy Technology Projects, October 2008, PECSNL062979, International Energy Agency Implementing Agreement on Renewable Energy Technology Deployment, available at: [http://www.iea-retd.org/files/RETD_PID0810_Main.pdf].

Feed-in tariffs have already proven to be cost-effective in some European countries. In Germany, for example, the cost of the feed-in tariff for power customers in 2007 was quite small: only about 3 percent of the price of power for residential customers.[85] The National Renewable Energy Laboratory states that the European experience with feed-in tariffs shows that "renewable energy development and financing can happen more quickly and often more cost-effectively than under competitive solicitations."[86]

Within the U.S., the Gainesville Regional Utilities in Gainesville, Florida, has identified feed-in tariffs for solar PV as its least-risk and most cost-effective method for securing renewables, noting the low risk and guaranteed rate of return as favorable to investors and the minimal effect on its customer rates, which are about average for Florida.[87]

In California, IOUs have offered a feed-in tariff since 2008 for projects up to 1.5 MW based on the market price referent.[88] As of August 2009, this feed-in tariff has resulted in only 14.5 MW of contracted capacity, suggesting that the market price referent does not provide enough revenue to stimulate development of small-scale renewable projects. The CPUC is considering

Transmission remains one of the major barriers to meeting California's renewable energy goals, and while feed-in tariffs alone cannot resolve those issues, they could be structured to coordinate the development of renewable projects and the transmission lines needed to access those projects.

Several countries, including Germany, Spain, and France, have created feed-in tariffs to target specific locations and technologies. Under Germany's feed-in tariff, for example, developers receive higher incentives for developing off-shore wind in deeper waters and further from shore. China is also beginning to use a geographic approach to feed-in tariff development that uses competitive bidding to set feed-in tariffs for specific areas.

In California, utility solicitations for RPS energy do not coincide with the permitting or construction of transmission expansions or extensions required to access renewable resources. This can result in facilities being selected that will depend on transmission expansion that may not be actively pursued in a reasonable time frame. Tying feed-in tariffs to areas where transmission lines are permitted and construction funding is committed could help bring renewable generation on-line as soon as a new transmission line is commissioned, allowing the transmission and generation facilities to be developed in parallel.

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85 Hans-Josef Fell, member of the German Bundestag, March 2009, *Feed-in Tariff for Renewable Energy: An Effective Stimulus Package without New Public Borrowing*, p. 21, available at: [http://www.boell.org/docs/EEG%20Papier%20engl_fin_m%C3%A4rz09.pdf].

86 NREL, *Feed-in Tariff Policy: Design, Implementation, and RPS Policy Interactions*, Karlynn Cory, Toby Couture, and Claire Kreycik, March 2009, p. 9, available at: [http://www.nrel.gov/docs/fy09osti/45549.pdf], references listed on pp. 14-17.

87 Comments by John Crider, Gainesville Regional Utilities, May 28, 2009, IEPR workshop, transcript pp. 119-120, available at: [http://www.energy.ca.gov/2009_energypolicy/documents/2009-05-28_workshop/2009-05-28_TRANSCRIPT.PDF].

88 California Public Utilities Commission, "Summary of Feed-in Tariffs," available at: [http://www.cpuc.ca.gov/PUC/energy/Renewables/feedintariffssum.htm]. See also, California Public Utilities Commission Energy Division, Resolution E-4137, February 2008, [http://docs.cpuc.ca.gov/PUBLISHED/AGENDA_RESOLUTION/78711.htm].

expanding its feed-in tariffs to renewable projects as large as 10 or 20 MW.[89] A May 2009 ruling set the terms and conditions for the expanded feed-in tariff as very similar to the existing feed-in tariff offered for projects less than or equal to 1.5 MW in size. In September 2009, CPUC Energy Division staff developed a pricing proposal for a reverse auction process that encourages bidders with smaller renewable projects to price their projects competitively; that strategy could be an effective way to prevent systematic overpayment to generators.[90]

California's two largest publicly owned utilities are also developing feed-in tariffs. The LADWP is developing a feed-in tariff for solar on rooftops of public organizations that are not eligible for tax credits, such as the Los Angeles Unified School District, Los Angeles Community College District, the University of California, and California State University. [91] SMUD is also moving forward with a feed-in tariff beginning in January 2010 that is aimed at systems up to 5 MW connected to SMUD's local distribution system, with a system-wide cap of 100 MW.[92] The feed-in tariff applies to both renewable and fossil-fuel generation technologies.

Distributed Generation and Combined Heat and Power

Distributed generation and CHP are valuable resource options for California and a key element of California's loading order. Distributed generation resources are grid-connected or stand-alone electrical generation or storage systems, connected to the distribution level of the transmission and distribution grid, and located at or very near where the energy is used. The benefits of distributed generation go far beyond electricity generation. Because the generation is located near where it is needed, distributed generation reduces the need to build new transmission and distribution infrastructure and also reduces losses at peak delivery times. Customers can use distributed generation technologies to meet peak needs or to provide energy independence and protect against outages and brownouts.

California is promoting distributed generation technologies through such programs as the California Solar Initiative, the Self-Generation Incentive Program, the New Solar Homes Partnership program, and the Emerging Renewables Program, all of which support distributed generation on the customer side of the meter. On the utility side of the meter, efforts to support distributed generation include the feed-in tariff for small renewable generators (discussed in the earlier section on renewable energy resources) and the CHP tariff to be implemented under AB

89 See CPUC R.08-08-009, "Administrative Law Judge's Ruling on Additional Commission Consideration of a Feed-in Tariff," http://docs.cpuc.ca.gov/efile/RULINGS/99105.pdf and "Administrative Law Judge's Ruling Regarding Briefs on Jurisdiction in the Setting of Prices for a Feed-in Tariff," available at: [http://docs.cpuc.ca.gov/efile/RULINGS/101672.pdf].

90 California Public Utilities Commission, *System Side Renewable Distributed Generation Pricing Proposal,* Energy Division Staff Proposal, August 26, 2009, available at: [http://docs.cpuc.ca.gov/efile/RULINGS/106275.pdf].

91 Comments by Los Angeles Department of Water and Power at May 28, 2009, IEPR workshop, transcript p. 170.

92 Sacramento Municipal Utility District news release, July 17, 2009, available at: [http://www.smud.org/en/news/Documents/09archive/07-17-09_smud_feed-in-tariff.pdf].

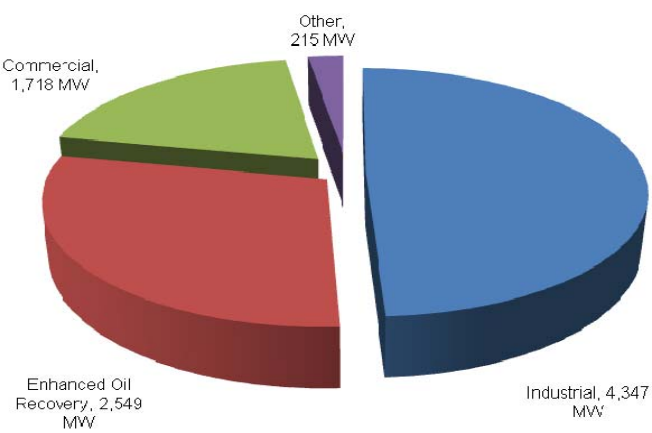
1613. The CPUC opened a rulemaking in June 2008 to implement the requirements of AB 1613, including establishing the policies and procedures for purchasing electricity from new CHP systems, and the Energy Commission is in the process of developing guidelines establishing technical eligibility criteria for programs to be developed by the CPUC and publicly owned utilities. AB 1613 requires the guidelines to be adopted by January 1, 2010.

CHP, also referred to as cogeneration, is the most efficient and cost-effective form of distributed generation, providing benefits to California citizens in the form of reduced energy costs, more efficient fuel use, fewer environmental impacts, improved reliability and power quality, locations near load centers, and support of utility transmission and distribution systems. In this sense, CHP can be considered a viable end use efficiency strategy for California businesses. Widespread development of efficient CHP systems will help avoid the need for new power plants or expansion of existing plants.

Existing Combined Heat and Power in California

California is one of the most prolific states in the country in terms of the amount of CHP in the state's energy mix. California has almost 1,200 sites representing nearly 9,000 MW of installed CHP (see Figure 9).

Figure 9: Existing Combined Heat and Power in California



Source: ICF International

The industrial sector represents the about half of existing CHP, the bulk of which is in food processing and refining. The remainder of the industrial sector is from process industries like chemicals, metals, paper, and wood products. About a third of existing CHP is in enhanced oil recovery because of the large steam load to produce heavy oil. Next is the commercial sector, which includes universities, hospitals, prisons, utility generation, water treatment, and other commercial applications. The remaining CHP is in the mining and agricultural sectors.

Existing CHP installations in California can also be characterized in terms of facility size, primary fuel, and technology (prime mover). Large installations make up most of the existing capacity, with systems smaller than 5 MW representing only 5.5 percent. Systems larger than

100 MW represent almost 40 percent of the total existing capacity. The market saturation of CHP in large facilities is much higher than for smaller sites, and much of the remaining technical market potential for CHP is for smaller systems.

By far the most important fuel used for CHP is natural gas, representing 84 percent of the total installed capacity. Renewable fuel makes up 4.5 percent of the total capacity, mostly in the wood products, paper, and food processing industries and in waste water treatment facilities.

Because of the concentration of large scale systems in the existing CHP population, the most common prime movers are gas turbines. In the very large sizes, these are often in combined cycle configuration. In intermediate sizes, simple cycle gas turbines are used. Renewable fuels or waste fuels are used in boilers driving steam turbines in the wood, paper, food and petrochemical industries. Most of the small systems are driven by gas-fired reciprocating engines; while total capacity is small (5 percent), the reciprocating engine technology represents the greatest number of CHP sites (62 percent).

Within existing CHP, there are approximately 6,000 MW under qualifying facility contracts with the utilities. The continued existence and viability of this power is a major issue; the *2007 IEPR* noted that as much as 2,000 MW of CHP capacity could shut down by 2010 as contracts expire.

Combined Heat and Power and the Environment

In December 2008, the ARB adopted its *Climate Change Scoping Plan* with a target of 4,000 MW of CHP to displace 30,000 GWhs of demand and reduce GHG emissions by 6.7 million metric tons of CO_2 by 2020. The Energy Commission has promoted the need to support CHP facilities because of their environmental benefits since the *2003 IEPR*. Because most electric thermal generation in the state does not make use of waste heat, average efficiency associated with the use of the fuel is still approximately 40 percent. A CHP facility produces electricity and utilizes the excess heat, thus increasing efficiencies and reducing GHG emissions.

For CHP to meet ARB's goals, a new generation of highly efficient CHP facilities must be encouraged and supported. Critical to achieving these efficiencies and meeting these targets will be the development of efficiency standards to guide development and operation of these facilities over time. AB 1613 (Blakeslee, Chapter 713, Statutes of 2007) is intended to encourage the development of new CHP systems in California with a generating capacity of not more than 20 MW. AB 1613 directs the Energy Commission to adopt guidelines by January 1, 2010 establishing technical criteria for eligibility of CHP systems for programs to be developed by the CPUC and publicly owned utilities. When these guidelines are adopted, they will set an efficiency standard for CHP facility development and assure that facilities are designed and operated in a way that reduces GHG emissions and will create a new benchmark for CHP efficiencies in California. As CHP technology continues to develop, efficiencies in the range of 75 to 80 percent can be expected to become standard and cost effective.

Another environmental benefit of CHP that is often overlooked has to do with water use. In California, central-station thermal, water-cooled power generators use enormous amounts of water for cooling. The National Renewable Energy Laboratory estimates that almost half a gallon of water is evaporated at central station thermoelectric plants for every kWh of electricity consumed at the point of use.[93] This issue is particularly important in California where water supplies are limited. CHP recovers and recycles thermal energy and generally does not use condensers or cooling towers, therefore, its water consumption is much lower.

CHP that uses renewable fuels provides additional environmental benefits to California. While the bulk of existing CHP capacity in the state is from systems that use natural gas as a primary fuel, there is market potential for doubling the renewable CHP at the state's wastewater treatment plants. Sludge from waste treatment plants can be fed into an anaerobic digester to create biogas (methane) which is then burned in a CHP system. The waste water treatment plants can also co-digest other biodegradable waste streams, such as the dairy and food processing industry and restaurant waste. Many waste treatment plants have begun exploring co-digestion to increase their biogas production and to take advantage of underused digester capacity. California's large dairy and food processing industry is also actively exploring co-digestion to solve the problem of waste disposal. Using these wastes for electricity generation also addresses the adverse impact of the GHG emissions from untreated wastes, as well as the GHG impacts from transporting wastes for disposal elsewhere. A recent report by the Energy Commission staff identified a market potential of 450 MW of CHP capacity from co-digesting sludge and other biodegradable waste.[94] There are, however, some economic and regulatory barriers, including streamlining the permitting process and providing some financing options that cash-starved municipally-owned waste treatment plants require.

A new assessment of statewide CHP technical and market potential, discussed in more detail below, suggests that the largest untapped market for CHP is in the commercial and institutional sectors (20 MW and under).[95] Unlike industrial sector CHP, these smaller systems will use distributed generation applications that will be located at or near existing customer's thermal loads. Because a CHP unit must be in close proximity to the facility where the waste heat will be utilized, new green space will not be needed to develop this new generation, meaning fewer environmental impacts. Additionally, most small CHP and distributed generation are interconnected to the distribution system. Developing generation closer to load centers instead of in remote areas miles from where it will be consumed, would help reduce the need to build new transmission infrastructure and thereby avoid the associated environmental impacts that must be dealt with when developing these projects.

The current and future state of CHP in California is a topic in a number proceedings, plans and activities at the Energy Commission, the CPUC, and the ARB. The most recent Energy Commission forecast of CHP technical and market potential under various scenarios was

93 National Renewable Energy Laboratory, *Consumptive Water Use for U.S. Power Production*, December 2003, NREL/TP-550-33905, available at: [http://www.nrel.gov/docs/fy04osti/33905.pdf].

94 California Energy Commission, *Combined Heat & Power Potential at California's Wastewater Treatment Plants*, Draft Staff Paper, July 2009, CEC-200-2009-014-SD; final staff paper scheduled for release in October 2009.

95 ICF Consulting, draft report scheduled to be released in October 2009.

completed in 2005.[96] None of the scenarios used in that assessment fully capture current economic and regulatory situations. With the passage of the AB 32 and the adoption of the ARB *Climate Change Scoping Plan*, the need for a more up-to-date evaluation of CHP market opportunities and drivers became apparent.

The 2005 study looked at industrial CHP facilities that were assumed to use gas turbines only. These facilities often have process steam loads that are fairly constant, so CHP systems sized to serve this steam load could have power capacities larger than on-site demand. The scope of the new assessment includes small CHP facilities (such as, commercial and institutional) facilities that are below 20 MW and do not typically have excess power for export to the grid.

Combined Heat and Power Technical Potential

The technical potential of CHP is an estimation of market size constrained only by technological limits – the ability of CHP technologies to fit customer energy needs. CHP technical potential is calculated in terms of CHP electrical capacity that could be installed at existing and new facilities based on the estimated electric and thermal needs of the site. The technical market potential does not include screening for economic rate of return, or other factors such as ability to retrofit, an owner's interest in using CHP, availability of capital or natural gas, and variations in energy consumption within customer application/size class. Identifying the technical market potential is a preliminary step in assessing actual economic market size and ultimate market penetration.

CHP is best applied at facilities that have significant and concurrent electric and thermal demands. In the industrial sector, CHP thermal output has traditionally been in the form of steam used for process heating and for space heating. For commercial and institutional users, thermal output has traditionally been steam or hot water for space heating and potable hot water heating, and more recently for providing space cooling through the use of absorption chillers.

Two different types of CHP markets were included in the evaluation of technical potential for this assessment. The first is the traditional CHP market where the electrical output meets all or a portion of the baseload needs for a facility and the thermal energy is used to provide steam or hot water. In this market, industrial facilities often have "excess" thermal load compared to their on-site electric load (meaning the CHP system will generate more power than can be used on-site if sized to match the thermal load). In the commercial sector, CHP almost always have excess electric load compared to their thermal load, so these facilities will use all power generated on site. In California, interest in the combined cooling, heating and power (CCHP) market could potentially open up the benefits of CHP to facilities that do not have the year-round heating to support a traditional CHP system. A typical system would provide the annual hot water load, a portion of the space heating load in the winter months, and a portion of the cooling load during the summer months.

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96 Electric Power Research Institute, *Assessment of CHP Market and Policy Options for Increased Penetration*, Draft Consultant Report, April 2005, CEC-500-2005-060D, available at: [http://www.energy.ca.gov/2005publications/CEC-500-2005-060/CEC-500-2005-060-D.PDF].

The previous two categories are based on the assumption that all of the thermal and electric energy is used on-site. Within large industrial process facilities, there is typically an excess of steam demand that could support CHP with significant quantities of export to the wholesale power system. The incremental export value of power from these facilities was quantified and evaluated as a separate market.

Table 3 shows the total technical potential for CHP in California for 2009. It indicates that there is more potential in commercial facilities than in industrial facilities, which is a switch from the traditional characterization of CHP target markets. There is also a heavy concentration of potential in the small size ranges, indicating that many large facilities already have CHP systems for their onsite needs, leaving the remaining large size system potential in the export market.

Table 3: Total CHP Technical Potential (MW) in 2009 by Market Sector

Market Type	Facility Size					
	50-500 kW	500 kW-1 MW	1-5 MW	5-20 MW	>20 MW	Total
Industrial Onsite	966	501	1,403	1,042	245	4,157
Commercial Traditional	297	133	124	15	0.0	568
Commercial Heating & Cooling	2,862	760	1,668	907	604	6,802
Export Existing	71	110	261	571	3,530	4,544
Total	4,197	1,504	3,456	2,535	4,379	16,071

Source: ICF International

The utility with the largest amount of CHP technical potential is PG&E, with SCE a close second. Since PG&E also has the largest amount of existing CHP installations, the remaining CHP potential indicates that SCE has more room for growth in CHP capacity as a percentage of current CHP installations. The LADWP also has a significant amount of remaining potential given the small size of its service area.

While the 2009 technical potential estimate is based on the facility data in the potential CHP site list, the 2029 estimate includes economic growth projections for target applications between 2009 and 2029 (Table 4). To estimate the development of new facilities and growth in existing facilities between the present and 2029, economic projections for growth by target market applications in California were used.[97] Due to recent economic factors, the outlook on growth

97 These growth projections were derived from data in the Annual Energy Outlook 2009 stimulus case developed by the U.S. Department of Energy's Energy Information Administration. The growth rates were used in this analysis as an estimate of the growth in new facilities or capacity additions at existing facilities. In cases where an economic sector is declining, it was assumed that no new facilities would be added to the technical potential for CHP.

rates for several industries are not as strong as they once were, leading to a lower amount of new technical potential additions in the forecast period.

Table 4: Total CHP Technical Potential Additions (MW) between 2009 and 2029 by Market Sector

Market Type	Facility Size					
	50-500 kW	500 kW - 1 MW	1-5 MW	5-20 MW	>20 MW	Total
Industrial Onsite	132	62	154	64	26	438
Commercial Traditional	47	15	19	4	0.0	85
Commercial Heating & Cooling	622	190	416	181	117	1,526
Export New Facilities	22	16	39	45	175	297
Total	823	283	628	294	318	2,346

Source: ICF International

Clearly, California contains significant technical potential for growth in CHP installations. Considering the market for both existing and new facilities, there is a total technical market potential that is over 18,000 MW. The most significant regions for growth are in PG&E and SCE service territory; however the other utilities in California also have significant room for growth.

Combined Heat and Power Market Potential

To determine the outlook for CHP market penetration in California, several factors were considered in the analysis:

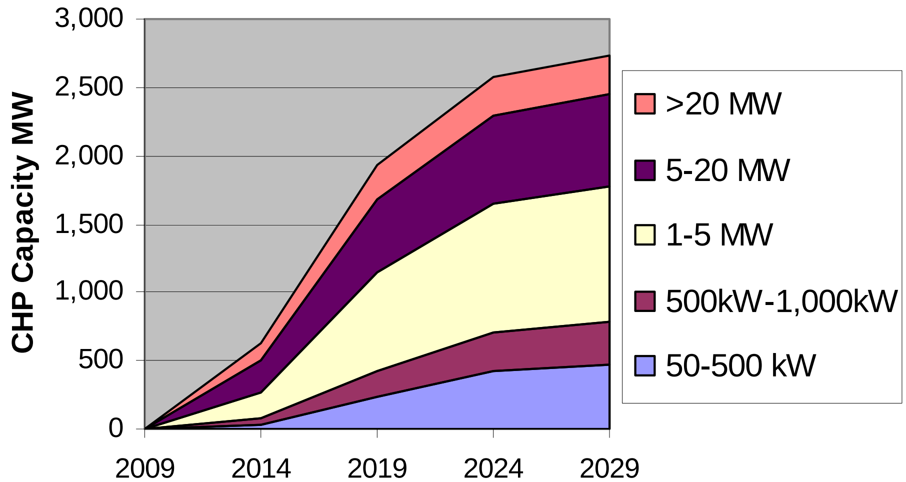
- The relationship of delivered natural gas and electricity prices, or spark spread.
- The cost and performance of the CHP equipment suitable for use at a given facility.
- The electric and thermal load characteristics of commercial, industrial, and institutional facilities in the State.
- Incentive payments to the CHP user that reflect societal or utility benefits of CHP.
- Customer decisions about the economic value that will trigger investment in CHP or the willingness to consider CHP.

All of these factors are accounted for in the forecasts of CHP market penetration between 2009 and 2029. A base case to reflect current market conditions and policies was developed first, followed by four alternative cases that include CHP stimulus measures including restoration of the Self Generation Incentive Program (SGIP), implementation of payments to CHP operators for CO_2 emissions reductions compared to separately purchased fuel and power, addition of an effective economic mechanism for the export power from facilities larger than 20 MW, and an "all-in" case that includes all of these measures combined.

Base Case Results

In the 20-year forecast period there is 2,731 MW of CHP market penetration. Figure 10 shows the market penetration by CHP system size. In the *Base Case* the largest share of the market penetration will be in sizes below 5 MW. This distributed generation CHP market makes up 65 percent of the total market penetration. The 5-20 MW size category makes up 25 percent of the market. Without a mechanism (such as a Qualifying Facility contract) for export of power in the greater than 20 MW size category, these large systems will make up only 10 percent of the new market penetration expected over the next 20 years.

Figure 10: Base Case Cumulative CHP Market Penetration by Size Category



Source: ICF CHP Market Model

Incentive Cases

The assessment of CHP potential included different incentive scenarios and an all in incentive case. Following are brief descriptions of the assumptions used for the incentive cases analyzed for this assessment.

- CO_2 Payments Case. CHP is a more efficient use of energy than purchasing boiler fuel and electricity separately. The CHP operator does not gain any special benefit from this fact, only from the reduction in operating costs at the site. Benefits of CHP that contribute to State or federal policy goals such as increased efficiency or CO_2 emissions reduction are external to the decisions to build and operate CHP. Providing CHP operators with a payment for reducing overall CO_2 emissions would internalize this benefit into the CHP deployment decision and stimulate the CHP market based on the social value of emissions reduction that is provided. An average value of $50/ton of CO_2 emissions reduction is provided for all CHP electric output and also for avoided electricity generation due to CHP supplied air conditioning as well.

- Restore the Self Generation Incentive Program eligibility. Restoration of eligibility of CHP for the Self Generation Incentive Program is under consideration in the Legislature (Senate Bill 1412). If this bill is enacted, the CPUC would be required to implement the Self Generation Incentive Program using its own discretion about program details. For this analysis it was assumed that all payments would be restored as they existed before they were suspended in 2007 and that the current phased expansion of benefits for projects up to 5 MW would be included as well.
- Basic Large Export Case. The AB 1613 CHP feed-in tariffs when they are finalized, will only apply to systems 20 MW or less. In the base case, no mechanism for exporting power from larger facilities (greater than 20 MW) was assumed. In this first of two expanded export scenarios, export of power from large facilities is assumed to be at a contract price reflecting the cost of power generation from a combined cycle power plant using the plant cost and performance assumptions defined by the Energy Commission Staff Report.[98]
- Strong Stimulus Large Export Case. A second contract price track for large export CHP projects was also evaluated that included an aggressive contract price.
- All Incentives Case. The all-in case represents a combination of restoration of the Self Generation Incentive Program, addition of CO_2 emissions reduction payments of $50/ton, and encouragement of large export projects with the aggressive contract pricing mechanism and accompanying CO_2 payments. The large export market contributes 2,714 MW to this case.

Incentive Case Results

Figure 11 shows the cumulative CHP market penetration for the incentive cases. The figures include both CHP generation and avoided air conditioning. The range of market penetration from the base case to the all-in case is from 3,000 to 6,500 MW. The case results can be summarized as follows:

- CO_2 payments increase market penetration by 244 MW.
- The restoration of the Self Generation Incentive Program for the next ten years increases market penetration by 497 MW.
- Expanding export contracting to facilities larger than 20 MW with a basic contracting mechanism increases market penetration by 1,441 MW. All of this increase in export market penetration is for facilities larger than 20 MW.

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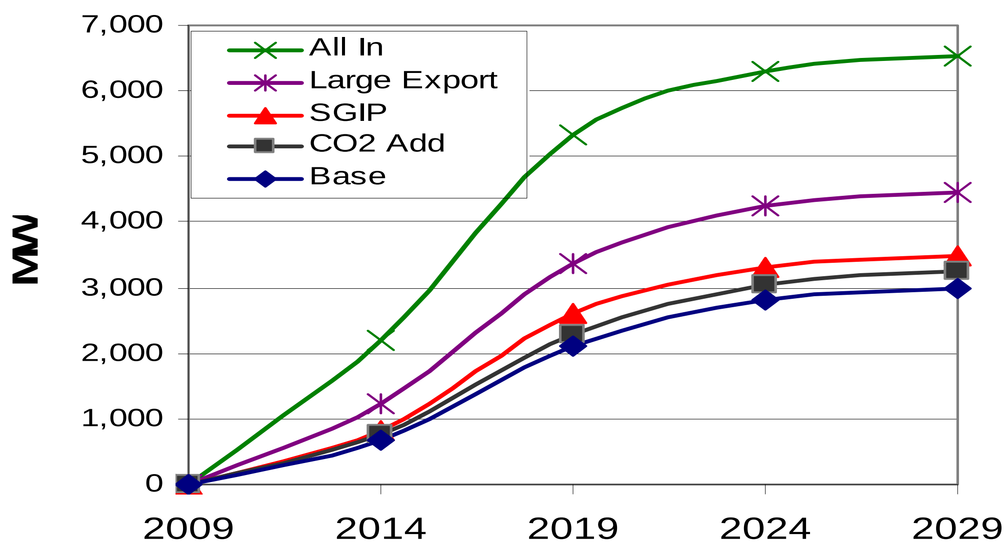
98 California Energy Commission, *Comparative Costs of Central Station Electricity Generation*, Draft Staff Report, August 2009, CEC-200-2009-017-SD, available at: [http://www.energy.ca.gov/2009publications/CEC-200-2009-017/CEC-200-2009-017-SD.PDF].

- In the all-in case which includes all measures plus a more aggressive large export contract price, the market increases by 3,521 MW, with 79 percent of this increase in the export market.

Figure 11: Incentive Cases Cumulative Market Penetration Results



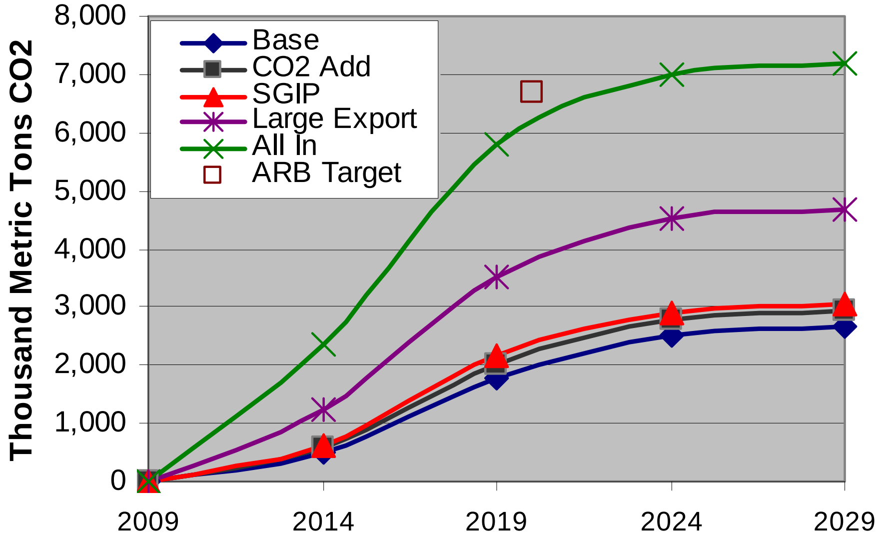
Source: ICF CHP Market Model

GHG Emissions Savings

For the updated assessment, emissions reductions by scenario were calculated and are shown in Figure 12. Annual GHG savings by the end of the forecast time horizon (2029) range from 2.7 million metric tons CO_2e to 7.0 million metric tons in the all-in case. The graph also shows the ARB target for CHP of 6.7 million metric tons reduction by 2020.

Table 5 compares the study results with the ARB target estimate of GHG emissions savings from CHP by 2020. In the base case, market penetration by CHP is only projected to be 56 percent of the ARB target estimate for additional CHP capacity market penetration, and actual power generation and avoided air conditioning from CHP is less than half of the ARB estimate. Finally, the emissions saving estimate is only 30 percent of the ARB estimate. In the all-in case, 2020 market penetration and generation both exceed the ARB estimates, but the expected GHG savings are only 90 percent of the target 2020 GHG emissions reduction.

Figure 12: GHG Emissions Savings by Scenario using ARB Avoided Central Station Emissions Estimate



Source: ICF CHP Market Model

Table 5: Comparison of Study Results GHG savings to ARB Target Estimate

Scenario	Capacity MW	Output GWh/year	Average Load Factor	Avoided CO_2 MMT/year	CO_2 Savings Rate lb/MWh
ARB 2020 Goal	4,000	30,000	85.6%	6.70	492
Base Case 2020	2,240	14,486	73.8%	1.93	294
Base Case 2029	2,998	18,293	69.6%	2.67	322
All In Case 2020	5,532	39,545	81.6%	6.05	337
All In Case 2029	6,519	45,779	80.2%	7.20	347

Source: ARB and ICF International

Because both the ARB estimates and this study are based on the ARB assumption for avoided GHG emissions, the differences to the unit emissions savings shown in the table – 492 lb/MWh for ARB and 294-347 lb/MWh for this study – are primarily due to changes in the operating profile and performance for CHP. The differences between this study's GHG estimates and ARB's are as follows:

- ARB assumes an 85 percent load factor for CHP, while the calculated value for the all-in case is 80.2 percent.
- ARB assumes an overall CHP efficiency of 77 percent, while the calculated value for the all-in case is 67.8 percent.

- Finally, there is one difference in the assumption regarding avoided central station emissions even using the ARB assumptions for this analysis. A total of 48 percent of the projected total market penetration in the all-in case will be in CHP export markets. The power output from these CHP sources will need to travel through the utility grid system for delivery to other customers. Therefore, it is not appropriate to credit this generation with avoiding the delivered GHG emissions of 1,045 lb/MWh as ARB did for all of their CHP power output; the appropriate comparison for export power is to the 963 lb/MWh generator emissions.

Combined Heat and Power and Reliability

As businesses, government facilities, and hospitals become increasingly dependent on sophisticated technologies and computers and information systems to run their operations, it is critical to provide protection from both short and extended power outages resulting from grid failures, natural disaster, terrorist attacks, or other disruptions. Hospitals in particular are vulnerable should power be interrupted. Reliable power is essential to keep cooling and ventilations system operating, high-tech diagnostic systems working, and electronic patient information available. Encouraging and supporting the development of CHP at hospitals throughout California will assure these essential services continue to operate reliably, even if there is a major disruption of regional power.

Traditionally, on-site diesel generators are used to protect facilities from utility power outages. However, recent events suggest that these generators may not be reliable and able to operate during both short and extended outages. During the August 2003 Northeast blackout, about half of New York City’s 58 hospitals experienced failures of their backup diesel generators. Even though periodic testing is required, infrequent use of conventional diesel backup generators increases the potential for failure when they are needed most.

In addition, if there is a prolonged outage, fuel supplies for diesel generators may also be a problem. After Hurricane Katrina, diesel fuel for backup generators could not be re-supplied for many reasons including blocked or destroyed roads and contaminated fuel supplies. Because CHP systems operate continuously (or for extended periods every day) and because they operate (typically) on natural gas, CHP systems eliminate many of these issues. During and after Hurricane Katrina, natural gas lines remained pressurized. As a result, natural gas was the only fuel available for several weeks afterwards.[99]

Encouraging and supporting the development of CHP at hospitals and other facilities or institutions that support essential health and safety functions for the state can provide a range of benefits beyond assured reliability. Benefits for hospitals include cost savings, improved patient service, and improved reliability and power quality to ensure expensive and sensitive electronics and equipment are not damaged when voltage fluctuates. From the state’s perspective, encouraging the installation of CHP in hospitals and other essential facilities will assure that if electric supplies are interrupted for hours, days, or weeks, as was the case when

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99 Gillette, Stephen F., *CHP Case Studies – Saving Money and Increasing Security*, available at: [http://www.chpcenternw.org/NwChpDocs/Microturbines_Capstone_overview_cases.pdf].

Hurricane Katrina devastated New Orleans, California citizens will be able to find a "safe haven" at hospitals and other similar institutions in the state that are equipped with CHP systems. A secondary benefit of increased use of CHP at hospitals throughout the state is the retirement of old diesel backup generators and the reduction of emissions associated with their operation.

Combined Heat and Power and the Economy

A facility with constant thermal load, constant electrical load, and hence a uniform "power-to-heat ratio" (or electrical load-to-thermal load ratio), is an ideal CHP prospect. However, many of the remaining CHP prospects have fluctuating loads and variable load profiles. For these facilities, electricity export loosens the operating constraints. A thermally matched CHP system will compete economically and environmentally with the separate production of electricity at a central station plant and the production of steam or heat on site. However, the following barriers limit the economic competitiveness:

- Uncertainty about the differential between the cost of buying electric power from the grid and the cost of natural gas.
- A required payback period of as little as two years and usually no longer than 5 years. The new assessment of CHP potential indicates that these facts imply a very high risk perception on the part of potential CHP project developers.
- The ability of a CHP system owner to offset only about 80 percent of the electrical retail rate because of standby and demand charges. Tariffs in other states provide higher offsets.
- Current tariffs do not fully account for the system and societal benefits that CHP provides.
- Facilities with fluctuating loads face additional technical economic and technical design challenges.

The variation in CHP market penetration forecasts under various economic assumptions illustrates the effects of those factors on the attractiveness of CHP. An export tariff would mitigate some of the barriers, depending on the tariff's simplicity, a term of at least 10 years, and prices that reflect capacity, energy, environmental values, and locational values. Restoration of the SGIP that provides up-front incentive payments to offset some of the capital costs of the CHP system and a CO_2 emission reduction payment for CHP electric output are all examples of economic incentives that can on their own or in combination promote CHP in California markets.

Natural Gas Power Plants

Natural gas plays a significant role in providing power to California citizens. In 2008, 46.5 percent of California's electricity came from natural gas. Citizens, community activists, and environmental groups have environmental and safety concerns with building new natural gas plants, but at the same time, Californians want reliable and affordable electricity for their homes and businesses. A balance between these competing objectives can be difficult to achieve, as almost every energy technology has costs and benefits.

Natural Gas Plants and the Environment

Natural gas has become California's fuel of choice for most new power plants because it is cleaner than other fossil fuels. Yet, emissions from natural gas generation account for (on average) 78 percent of the in-state electric GHG emissions.[100] However, natural gas power plants can also play a key role in meeting the state's climate change goals and RPS targets. The Energy Commission's *Framework for Evaluating Greenhouse Gas Implications of Natural Gas-Fired Power Plants in California* report identifies specific roles and expectations for gas-fired generation to support the integration of renewables under the policy mandates to reduce GHG emissions from the electricity sector. The report found that a natural gas plant providing support to integrate renewable energy under a 33 percent RPS will yield a GHG emission benefit if the addition raises the overall efficiency of the electric system, or if the new plant serves increased demand for electricity more efficiently than the existing power plant fleet. The analysis found that although a single natural gas-fired power plant produces GHG emissions, under certain circumstances the addition of a gas-fired plant may yield a system-wide GHG emission benefit.[101]

Marine impacts from once-through cooling (OTC) power plants are another major environmental concern with the state's natural gas and nuclear power plants. As part of an interagency working group, the Energy Commission, CPUC, and California ISO have been working with the State Water Resources Control Board (SWRCB) to outline a proposal to maintain electric grid reliability while reducing OTC in California's 21 coastal power plants. These plants together pump up to 17 billion gallons of ocean, bay, or estuary water each day.[102] The pumping process impinges on fish, invertebrates, and crustaceans, and destroys thousands of fish eggs and larvae, and the heated discharge water also harms marine organisms by increasing the water temperature. The SWRCB has issued a compliance schedule for retiring, refitting, or repowering OTC plants to comply with the federal water policy.

It is crucial that the state develop new generating capacity to replace OTC power plants that may retire in the near future. Plants most likely to retire are located in and around the Southern California area, which has some of the worst air quality in the nation. Replacement power sources will have to meet stringent local air quality requirements; however, emission offsets are in short supply in the SCAQMD, constraining the Energy Commission's ability to license new power plants in Southern California. Chapter 3 describes the system integration challenges

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100 MRW and Associates, *Framework for Evaluating Greenhouse Gas Implications of Natural Gas-Fired Power Plants in California*, consultant report, May 2009, CEC-700-2009-009, available at: [http://www.energy.ca.gov/2009publications/CEC-700-2009-009/CEC-700-2009-009.PDF].

101 Ibid.

102 State Water Resources Control Board, *Water Quality Control Policy on the Use of Coastal and Estuarine Waters for Power Plant Cooling*, March 2008, available at: [http://www.energy.ca.gov/2008publications/SWRCB-1000-2008-001/SWRCB-1000-2008-001.PDF].

associated with potential retirement of OTC plants as well as difficulties in providing replacement power due to limits on emission reduction credits.

On October 8, 2008, the Energy Commission adopted an Order Instituting Informational proceeding to solicit comments on how to satisfy its responsibilities under the California Environmental Quality Act (CEQA) related to GHG impacts of proposed new power plants. The Energy Commission's Siting Committee released its *Committee Guidance on Fulfilling California Environmental Quality Act Responsibilities for Greenhouse Gas Impacts in Power Plant Siting Applications* in May 2009 which outlined the power plant siting process during the interim period before the AB 32 regulations take effect. The Siting Committee recommended that the Energy Commission analyze each project according to basic CEQA precepts for determining (1) whether the project has a significant adverse cumulative effect, (2) if so, whether feasible mitigation can be required for the project, and (3) if not, whether the project has overriding benefits that justify licensing the project. The Siting Committee also recommended that the Energy Commission revisit this approach once the ARB's AB 32 regulations are in effect.

As California moves toward reducing GHG emissions associated with electricity generation, innovative strategies will be needed to address emissions from fossil plants that may be needed to support system operation or integration of renewable resources. One such strategy is CO_2 capture and storage, also known carbon capture and sequestration (CCS). As part of the *2007 IEPR*, the Energy Commission and the California Department of Conservation developed a report focused on geologic sequestration strategies for the long-term management of carbon dioxide, entitled, *Geologic Carbon Sequestration Strategies for California: Report to the Legislature.*[103]

There have been encouraging technology advancements and investments since publication of the *2007 IEPR*, and the emphasis of technology developers and policymakers examining potential CCS applications, costs, and benefits has expanded from an initial focus on coal (and petroleum coke) to natural gas (and refinery gas), the predominant fossil fuel used in California industrial facilities and electricity generation.

In terms of technology improvement, new and improved solvents are being commercially offered or tested that reduce the energy requirements of post-combustion closed loop absorber-stripper CO_2 capture systems. Such improvements are important because the cost of CO_2 capture is usually the most expensive element of CCS, particularly the energy cost associated with steam heating in the stripper reboiler. In addition, an expanding number of commercial developers working on multiple competing processes is indicative of a robust market that is more likely to achieve the necessary technology scale-up sooner and produce future cost-saving advancements. Nonetheless, CCS projects are large capital endeavors and multi-year testing of full-scale, integrated CO_2 capture, compression, pipeline transportation, and geologic injection systems is necessary before widespread commercial application can be expected.

[103] California Energy Commission and Department of Conservation, *Geologic Carbon Sequestration Strategies for California: Report to the Legislature*, February 2008, CEC-500-2007-100-CMF, available at: [http://www.energy.ca.gov/2007publications/CEC-500-2007-100/CEC-500-2007-100-CMF.PDF].

In the last two years, oxy-combustion CO_2 capture components and systems have been tested at ten times the size of previous pilot units, including California's Clean Energy Systems' rocket engine–derived gas generator. Pre-combustion CO_2 capture systems are now being proposed in commercial power plants based on solid fuel gasification, such as the Hydrogen Energy California project in Kern County (a joint venture of BP and Rio Tinto).

The U.S. Department of Energy (DOE) recently solicited proposals for large-scale industrial CCS projects at facilities fueled chiefly by non-coal energy; it is poised to award more than $1.3 billion in project co-funding authorized by the ARRA of 2009. Further, DOE has added funds to its cooperative agreement with the Energy Commission for the West Coast Regional Carbon Sequestration Partnership (WESTCARB; a public-private research collaborative involving more than 80 organizations) to work with PG&E to conduct an engineering-economic evaluation of CCS at natural gas combined cycle plants in California. WESTCARB also continues to work with the California Geological Survey and industry partners to characterize California deep saline formations suitable for commercial-scale CO_2 storage; two CO_2 storage field tests in the Central Valley are planned.

Although the cost of applying CCS to natural gas power plants or oil refinery furnaces is relatively high using proven technologies (about $75 per metric ton of CO_2 avoided),[104] the prospect of energy-saving technology improvements and the sale of captured CO_2 to oilfield operators for oil recovery has increased the likelihood that CCS can be economically competitive and, as a consequence, the interest of state agencies working on AB 32 compliance. Positive public comment was also cited as a contributing factor to increased discussion of CCS and support for near-term technology development in the ARB's *Climate Change Scoping Plan*. This momentum appears to be continuing, with an interagency group formed in August 2009 to develop recommendations on CCS-related policy issues.

Addressing policy questions in tandem with technology development and demonstration is particularly important for CCS because institutional barriers have been as much of an impediment as high cost. In many cases, the necessary regulatory and statutory frameworks are unclear or do not yet exist.[105] At the federal level, the U.S. Environmental Protection Agency in 2008 proposed new rules for wells used to inject CO_2 for long-term geologic storage.[106] These rules are expected to become final by early 2011, and further federal rules may be forthcoming restricting emissions of CO_2 as an air pollutant. However, many of the legal and regulatory issues needing resolution are within the domain of state rather than federal law.

In particular, legal clarity is needed on ownership of subsurface "pore space" where CO_2 is stored, the ability to independently transfer pore space rights and the dominance of such rights relative to surface and mineral rights, procedures by which access rights to multiple adjoining pore space "parcels" may be secured for CO_2 storage zones spanning multiple estates, and long-

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104 Ibid.

105 Ibid.

106 See [http://www.epa.gov/safewater/uic/wells_sequestration.html#regdevelopment].

term liability for stored CO_2. More than 30 states are currently wrestling these issues, with several states having passed laws that suggest approaches for consideration by the California Legislature.

Regulatory issues needing clarity include procedures by which operations permitted for CO_2-enhanced oil recovery become long-term CO_2 storage projects at the conclusion of oil-producing operations; CEQA responsibility and siting jurisdiction for power plant projects with CO_2 capture, pipeline transportation, and off-site geologic CO_2 storage (similar jurisdictional questions may arise for other industrial project types); responsibility for monitoring, reporting, and remediation (if necessary) when custody of captured CO_2 is transferred from a regulated industrial source to a subsurface storage site operator; and rules for offshore (sub-seabed) CO_2 storage projects. . Most of these issues require legislative solutions, although AB 32 rulemaking may provide some guidance. In the case of oilfield well conversion, U.S. EPA will have jurisdiction for geologic sequestration well permitting unless the state applies for primacy to administer the new "Class VI" well program (underground injection control for groundwater protection), as it does for "Class II" oil and natural gas exploration and production wells.

Resolution of legal and regulatory uncertainties will be crucial to helping spur CCS investment and further project development, but economic challenges will remain so long as the value of CO_2 emission allowances remains low. Cap-and-trade proposals with "safety valves" and other measures to limit the rate at which allowance prices rise to their expected long-term value will hamper private investment in CCS without some form of policy incentives. Given the expense and leadtime necessary for the large demonstrations needed to firmly establish CCS technology, and the social benefit of getting to the era of "learning by doing" cost reductions before widespread deployment becomes essential to maintaining progress toward California's long-term GHG reduction goals (such as, the period from 2020–2050), continued state investment in CCS R&D and demonstrations in tandem with investment by DOE and private industry is vital to realizing future dividends in GHG reduction cost-effectiveness.

Natural Gas Plants and Reliability

As the California's population continues to grow, the state will have to ensure that enough new power plants are built to meet the increase in energy demand. At the same time, state policy goals to increase the use of preferred resources, like renewables, along with policies to reduce the use of OTC and to retire aging power plants, will affect system reliability. The impacts of various state policies on reliability are discussed in more detail in Chapter 3.

The Energy Commission's, *Framework for Evaluating Greenhouse Gas Implications of Natural Gas-Fired Power Plants in California* found that as California's integrated electricity system evolves to meet GHG emissions reduction targets, the operational characteristics associated with increasing renewable generation will increase the need for flexible generation to maintain grid reliability. The report asserts that natural gas-fired power plants are generally well-suited for this role and that California cannot simply replace all natural-gas fired power plants with renewable energy without endangering the safety and reliability of the electric system. The report acknowledges that California will need to modernize its natural gas generating fleet to reduce environmental impacts, however. Overall, the report found that the future of natural gas plants will likely fill five auxiliary roles: 1) intermittent generation support, 2) local capacity requirements, 3) grid operations support, 4) extreme load and system emergencies support, and 5) general energy support. The question remains as to the quantity, type, and location of natural gas-fired generation to fill remaining electricity needs once preferred resource targets are achieved.

Given the role of natural gas power plants for electricity reliability and integrating renewable energy, efforts to mitigate OTC include a compliance schedule that maintains electric grid reliability and stability while reducing OTC in California's existing coastal power plants. It is likely that plant operators will choose retirement in the face of costly retrofits or repowering. If replacement resources are not built, this could greatly impact electricity reliability for the citizens of California. The compliance schedule focuses only on natural gas plants using OTC, as nuclear plants will require special studies.

Replacement of OTC plants is complicated by the current emission credit limitations in the South Coast Air Basin, as discussed in earlier in this section. These limitations are causing delay in environmental improvements that accompany investments in new and updated infrastructure and jeopardizing the long-term reliability of the region's electricity supplies. These issues related to emissions credits in the South Coast Air Basin are discussed further in Chapter 3.

Nuclear Power Plants

Major policy decisions that will be made in the coming years will shape the next three decades of nuclear energy policy in California. Nuclear plant owners and state officials will face decisions about plant license renewal and OTC at the same time that the federal government is reassessing its approach to nuclear waste disposal. In addition, California is addressing critical environmental issues associated with the electricity sector. The costs and benefits of nuclear power are being reexamined in California and nationwide because of major shifts in policies to limit GHG emissions and encourage new non-fossil fueled electric generation sources.

Nuclear power plants play a significant role in California's energy mix, providing about 14 percent of the state's total electricity in 2008 from two operating in-state facilities, PG&E's Diablo Canyon Power Plant (Diablo Canyon) and SCE's San Onofre Nuclear Generating Station (SONGS), and from the Palo Verde Nuclear Generating Station in Arizona. As part of the *2008 IEPR Update*, the Energy Commission developed *An Assessment of California's Nuclear Power Plants: AB 1632 Report*,[107] which addressed seismic and plant aging vulnerabilities of California's in-state nuclear plants, including reliability concerns. In addition, the report identified a number of other issues important for the state's nuclear policy and electricity planning. These include:

- Continuing Nuclear Regulatory Commission (NRC) concerns over safety culture, plant performance, and management issues at SONGS.

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107 California Energy Commission, *An Assessment of California's Operating Nuclear Power Plants: AB 1632 Commission Report*, November 2008, CEC-100-2008-108-CMF, available at: [http://www.energy.ca.gov/2008publications/CEC-100-2008-009/CEC-100-2008-009-CMF.PDF].

- The evolving federal policy on long-term waste disposal.
- Costs and benefits of nuclear power compared to other resources.
- Potential conversion from once-through cooling to closed-cycle wet cooling.

An overarching issue with the state's nuclear facilities is plant license renewal. The NRC operating licenses for California's nuclear plants are set to expire in 2022 (SONGS Units 2 and 3) and 2024 and 2025 (Diablo Canyon Units 1 and 2, respectively).[108] It is unknown whether the NRC will approve applications by PG&E and SCE for 20-year license renewals, but it has yet to deny a single application and has issued license renewals for 54 of the nation's 104 nuclear power reactors. SCE plans to file a SONGS license renewal application in late 2012. PG&E expects to be prepared to file the Diablo Canyon application in early 2010 but has not stated if it will make the filing in 2010 or at some future date.

> The NRC is in the final stages of considering changes in the way it assesses the probability of a crack forming through the wall of a reactor pressure vessel. If such a crack occurred, it could damage the reactor core or, in rare cases, release radioactive materials into the environment. The probability of crack formation relates directly to the extent of reactor pressure vessel embrittlement, which is the ability of metals that make up the reactor pressure vessel to withstand stress without cracking.
>
> Current regulations require licensees to demonstrate that reactor pressure vessel embrittlement does not exceed a screening limit corresponding to a one-in-200,000-year probability of through-wall crack formation. NRC's proposed regulations would expand this requirement to a one-in-a-million-year probability, but it would allow for the use of a less conservative methodology for assessing the probability. The NRC reports that, under the current methodology, ten reactors, including Diablo Canyon Unit 1, are likely to exceed the screening limit during the course of a 20-year license renewal, and, therefore, would not be eligible for license renewal unless they could reduce the embrittlement rate or demonstrate that operating the reactor would not pose an undue public risk.

The NRC license renewal application process determines whether a plant meets the NRC renewal criteria, not whether it should continue to operate. The NRC states, "Once an [operating license] is renewed, state regulatory agencies and the owners of the plant will ultimately decide whether the plant will continue to operate based on factors such as the need for power or other matters within the state's jurisdiction or the purview of the owners."[109]

The NRC license renewal proceeding focuses on plant aging issues, such as metal fatigue or the degradation of plant components, as well as environmental impacts related to an additional 20 years of plant operation. The NRC has consistently excluded from its proceedings issues raised by states and public interest groups that are not directly related to plant aging or to deficiencies in the environmental impact assessment. For example, during the license renewal proceeding for the Indian Point Power Plant in New York, the NRC dismissed from the proceeding most of the State of New York's contentions, including those regarding seismic vulnerability, plant vulnerability to terrorist attack, and

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108 Nuclear Regulatory Commission, Facility Information Finder, see [http://www.nrc.gov/info-finder.html].

109 Nuclear Regulatory Commission, "License Renewal Generic Environmental Impact Statement," NUREG-1437 Supplement 28, December 2006. The NRC has exclusive jurisdiction over the radiological aspects of nuclear power plants. States retain jurisdiction over electricity policy and planning issues, such as the economics of nuclear power, the reliability of the plants, and whether the plants are consistent with the state's policy goals and procurement needs.

the inadequacy of emergency evacuation plans for the plant.

Both utilities must obtain CPUC approval to pursue license renewal before receiving California ratepayer funding to cover the costs of the NRC license renewal process.[110] The CPUC proceeding will determine whether it is in the best interest of ratepayers for the nuclear plants to continue operating for an additional 20 years. The proceeding will address issues that are important for electricity planning but are not included in the NRC's application review.

The purpose of the CPUC license renewal review is to consider matters within the state's jurisdiction, including the economic, reliability, and environmental implications of relicensing. For example, the CPUC will consider the cost-effectiveness of license renewal, the role of nuclear power within the state's loading order, and replacement power options.

To initiate the CPUC license renewal review, PG&E and SCE are required to submit license renewal feasibility assessments to the CPUC.[111] In letters to SCE and PG&E in June 2009, the CPUC emphasized that the utilities must address in their feasibility assessments all the issues raised in the *AB 1632 Report*.[112] The CPUC specifically directed the utilities to undertake the following activities:

- Report on the findings from updated seismic and tsunami hazard studies and assess the long-term seismic vulnerability and reliability of the plants.
- Summarize the implications for Diablo Canyon and SONGS of lessons learned from the response of the Kashiwazaki-Kariwa nuclear plant to the 2007 earthquake.
- Reassess whether access roads surrounding the plants are adequate for emergency response and evacuation following a major seismic event.
- Study the local economic impact of shutting down the plants as compared to alternative uses for the plant sites.
- Report on plans and costs for storing and disposing of low-level waste and spent fuel through 20-year license extensions and plant decommissioning.
- Quantify the reliability, economic, and environmental impacts of replacement power options.
- Report on efforts to improve the safety culture at SONGS and on the NRC's evaluation of these efforts and the plant's overall performance (SCE only).

The comprehensiveness, completeness, and timeliness of these activities will be critical to the CPUC's ability to assess whether or not the utilities should apply to the NRC for license renewals. However, the utilities' reports to date indicate they are not on schedule to complete these activities in time for CPUC consideration and that they may not be planning to make all their studies available to the CPUC.

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110 California Public Utilities Commission, D.07-03-044 in proceeding A.05-12-002, March 15, 2007.

111 PG&E is required to submit its application by June 30, 2011. SCE has not been given a deadline. CPUC decision D.07-03-044.

112 Letter from CPUC to Alan Fohrer, CEO of Southern California Edison, June 25, 2009; Letter from CPUC to Peter Darbee, CEO of PG&E, June 25, 2009.

In October 2008, PG&E commented to the Energy Commission on the draft *AB 1632 Report* that it does not interpret the requirement to submit a license renewal feasibility study to the CPUC as including seismic safety, which it considers to be "outside the scope of license renewal," or those issues "that are not within the CPUC's jurisdiction."[113] PG&E also articulated its belief that the plan for the Energy Commission and the CPUC to review the costs and benefits of license renewal and to assess whether or not the utilities should pursue license renewal "improperly infringes upon the sole jurisdiction of the NRC to determine whether or not nuclear license should be extended."[114] PG&E reiterated this point in a letter to the CPUC, specifying that it would provide the information requested in the *AB 1632 Report*, subject to the CPUC's jurisdiction.[115] In its letter to PG&E, the CPUC indicated that the requested information is all subject to CPUC jurisdiction since it informs procurement planning.[116]

PG&E has not clarified whether it agrees or will refrain from submitting certain studies on account of jurisdictional concerns. PG&E is required to submit its license renewal feasibility assessment to the CPUC by June 30, 2011,[117] but does not expect to complete updates to the seismic hazard model and the seismic vulnerability assessment until 2012 and 2013, respectively.[118] Furthermore, PG&E said that it will require ratepayer funding to undertake the 3-D seismic mapping surveys recommended in AB 1632 and that it may use the CPUC license renewal review proceeding as an opportunity to request this funding. If this occurs, the results of these studies will likely not be available for CPUC consideration during this proceeding.

A similar issue arises with SCE. The utility plans to submit an application to the CPUC in late 2010 for funding to pursue an NRC license renewal application and to address issues from the *AB 1632 Report* and the CPUC.[119] However, SCE anticipates using this application to also request funding for completing AB 1632-recommended studies. Furthermore, SCE anticipates filing its CPUC application in the third quarter of 2010,[120] but does not anticipate completing the bulk of its studies until the end of 2010. As a result, SCE acknowledges that the application will likely not include results from all of the AB 1632 studies.[121]

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113 PG&E Comments on Draft Committee Report, California Energy Commission, *An Assessment of California's Nuclear Power Plants: AB 1632 Report*, October 22, 2008, p. 1.

114 PG&E, October 22, 2008, p. 4.

115 PG&E has not specified when it will file the CPUC application; however, PG&E has said that it expects to be prepared to file the NRC license application in early 2010. PG&E data request response L.02.

116 Letter from CPUC to Peter Darbee (PG&E), June 25, 2009.

117 CPUC decision D.07-03-044.

118 PG&E data request responses F.01 and F.03.

119 Letter from Alan Fohrer (SCE) to CPUC, August 4, 2009.

120 SCE data request response L.01.

121 SCE data request response L.01.

Nuclear Plants and the Environment

While nuclear power generates lower GHG emissions than power fueled by natural gas and other fossil fuels, it is not expected to contribute significantly to the state's near-term GHG emissions goals given the significant risk and expense of building a new nuclear power plant, the regulatory hurdles associated with licensing a new plant, and the environmental issues associated with this technology. These issues include nuclear waste disposal, leakage of radioactively contaminated water, and once-through cooling impacts on aquatic environments, as well as potential severe consequences from acts of terrorism, nature (earthquakes, tsunamis), or accidents. In addition, the nuclear power life cycle or "cradle-to-grave" impacts result in GHG emissions from uranium mining and enrichment, plant construction, decommissioning, and waste storage, transport, and disposal.

Even more so than with natural gas plants, citizens tend to be vocal about potential negative impacts of nuclear facilities operating near their communities. Concerns include issues with disposal of radioactive waste, plant safety, and the use of ocean water for power plant cooling.

Nuclear Waste Issues

After decades of federal efforts to establish a permanent geologic repository for spent nuclear fuel and high-level waste at Yucca Mountain, Nevada, development of the Yucca Mountain Repository Program is expected to be suspended in 2010. The program has long been challenged by scientific and technical uncertainty about its suitability for isolating the wastes from the environment and has faced staunch political and legal opposition.[122]

President Barak Obama's budget proposal eliminates all funding for development of Yucca Mountain, including further land acquisition, transportation development, and site engineering,[123] and the appropriations bills approved by the House of Representatives and the Senate both adopt his proposal.[124] These bills, which require conference committee reconciliation, would provide the DOE with $196.8 million in fiscal year 2010 for costs related to oversight activities and participation in the DOE's repository licensing application proceeding before the NRC. This resulted in a nuclear waste management budget cut of $91.6 million compared with fiscal year 2009,[125] demonstrating the Obama Administration's belief that the

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122 For an overview of the scientific concerns with Yucca Mountain, see the interview with Dr. Allison Macfarlane in David Talbot's "Life after Yucca Mountain," *Technology Review*, MIT, July/August 2009. For a longer discussion of the scientific and technical concerns and the legal and political challenges surrounding Yucca Mountain, see California Energy Commission's *Nuclear Power in California: 2007 Status Report*, CEC-100-2007-005-F, October 2007.

123 Terminations, Reductions, and Savings: Budget of the U.S. Government, Fiscal Year 2010, Office of Management and Budget, available at: [http://www.whitehouse.gov/omb/budget/fy2010/assets/trs.pdf. p.68]

124 H.R. 3183 and S. 1436.

125 FY 2009 Omnibus Bill, H.R. 1105, signed as Public Law 111-8 on March 11, 2009.

Yucca Mountain repository is not a workable solution to the problem of nuclear waste disposal.[126] This represents a major shift in U.S. nuclear waste policy.[127]

Halting development of Yucca Mountain would mean that the federal government has no clear policy in place for the long-term disposal of nuclear waste. Possible options include long-term dry cask storage either at reactor sites or at a few centralized storage facilities, and/or the development of commercial reprocessing.

Secretary of Energy Steven Chu announced in early 2009 that he intends to establish a Blue-Ribbon Commission of experts to investigate alternative solutions to nuclear waste disposal and make recommendations to the Administration. It is not clear how the Commission will be chosen and how extensive their investigations will be—the House Appropriations bill provides $5 million in funding for this commission, but the Senate bill is silent on the matter.[128]

The uncertainty surrounding U.S. nuclear waste disposal policy means that nuclear reactor operators, including PG&E and SCE, can no longer count on transferring spent fuel to a federal nuclear waste repository in the near or medium-term future. As a result, the utilities must continue to store spent nuclear fuel on-site. For California, this means that the 6,700 assemblies of spent fuel (2,600 metric tons of uranium) currently being stored at operating and decommissioned nuclear plants in-state will remain at these sites for the foreseeable future.[129]

PG&E and SCE have built intermediate-term waste storage facilities at their plants, known as independent spent fuel storage installations (ISFSIs). The ISFSIs at Diablo Canyon and SONGS are currently licensed for 20 years, but they may be eligible for multiple license extensions. The NRC allows spent fuel to be stored at reactor sites in above-ground storage for 100 years and is considering extending that limit by 20 years. PG&E and SCE report enough storage space at their respective nuclear plants for all spent fuel generated through the plants' current licenses.

The utilities have not reported plans to modify their spent fuel pools' racking to a less dense orientation, as the Energy Commission recommended.[130] However, the density of the spent fuels should decrease as the utilities move assemblies into dry cask storage. Thus far, PG&E has transferred 96 spent fuel assemblies to the Diablo Canyon ISFSI, and SCE has transferred 827 spent fuel assemblies to the SONGS ISFSI.

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126 Appendix: Budget of the U.S. Government, Fiscal Year 2010. Office of Management and Budget, p. 432, available at: [http://www.whitehouse.gov/omb/budget/fy2010/assets/appendix.pdf].

127 Although funding to continue development of Yucca Mountain may be eliminated, the federal government is still legally obligated to develop a permanent nuclear waste depository at Yucca Mountain pursuant to a 1987 amendment to the Nuclear Waste Policy Act that explicitly targets Yucca Mountain as the exclusive site for a nuclear waste repository. Congress would have to pass an amendment to the Nuclear Waste Policy Act before an alternate site could be developed as a permanent depository.

128 H.R. 3183 and S. 1436.

129 Utility responses to Energy Commission data requests, 2007 and 2009.

130 PG&E and SCE data request responses, C.15.

With the federal nuclear waste program in limbo, at-reactor storage continues to be the de-facto federal spent fuel storage policy. If Yucca Mountain is permanently abandoned, a federal permanent geologic repository or centralized dry cask storage facility likely will not be available for decades. Consequently, even if the plants' licenses are not renewed, it is likely that spent fuel will remain at the reactor sites for an extended period. As discussed in the *AB 1632 Report*, on-site ISFSIs would not necessarily restrict the decommissioning of the rest of the site and its conversion to commercial, retail, or other industrial purposes.

In addition to spent fuel, the nuclear plants generate low-level radioactive waste that must be disposed of at special facilities. In the past, the utilities shipped their low-level waste to several disposal facilities, but there is currently just one facility that will accept low-level waste from California reactors, and it accepts only the least radioactive grade of waste. As a result, PG&E and SCE are also storing higher-reactivity low-level waste at the reactor sites. Each plant generates around 150 cubic feet per year of this waste from regular operations.[131]

Once-Through Cooling

As discussed in the section on natural gas power plants, the SWRCB released a draft policy in June 2009 on the use of coastal waters for power plant cooling.[132] The cooling systems used by the state's operating nuclear power plants are viewed by the SWRCB as larger sources of biological harm to the marine environment than any of the cooling systems used by the state's other coastal plants. The proposed policy calls for coastal power plants to cut water intake by 95 percent to reduce the harmful impacts on marine life. To meet these requirements the nuclear plants would need to be retrofitted for wet cycled closed-cooling, dry cooling towers, or other cooling means. Previous studies have found that for California's nuclear plants, these options would be very expensive and possibly infeasible from an engineering perspective.[133] Therefore, the proposed policy would allow the nuclear plants to be exempted if the utilities demonstrated that the costs of compliance "are wholly disproportionate to the environmental benefits to be gained." The nuclear plants could also be exempted if the utilities demonstrated that full compliance would result in a conflict with the NRC's safety requirements. In both circumstances, the SWRCB could impose less stringent compliance requirements on the plants.

If the SWRCB's policy is approved, the agency will direct PG&E and SCE to commission independent studies of the alternatives to meet the policy requirements. The studies would assess the costs of alternative options for SONGS and Diablo Canyon to meet the requirements of the SWRCB's policy. These studies would be completed within three years of the effective date of the policy. SCE reportedly has its own engineering study underway to assess the options and costs for complying with the proposed policy. The IEPR Committee believes that

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131 Utility responses to Energy Commission data requests, 2009.

132 See [http://www.swrcb.ca.gov/water_issues/programs/npdes/cwa316.shtml].

133 California Energy Commission, *An Assessment of California's Nuclear Power Plants: AB 1632 Report*, pages 297-30, available at: [http://www.energy.ca.gov/2008publications/CEC-100-2008-009/CEC-100-2008-009-CMF.PDF]

these studies should be included in the cost-benefit assessment of the plants' license renewal feasibility studies.

Climate Change Impacts

One final environmental issue is the potential impact of climate change on the nuclear facilities. The Energy Commission staff report, *Potential Impacts of Climate Change on California's Energy Infrastructure and Identification of Adaptation Measures,* discussed potential impacts of climate change on power plant infrastructure. Power plants located along the coast could be impacted by sea level rise, with the Diablo Canyon nuclear power plant at greatest risk because it pumps cooling water through an intake pipe that takes the full brunt of northern swells from Pacific storms. To avoid shutting down or tripping the units, the facility has had to curtail power twice per storm season (on average) because of debris buildup on the intake screens. The shut downs can last anywhere from 18 hours to several days.

Nuclear Plants and Reliability

An issue of critical importance to the state for reliability planning is the possibility of a nuclear plant shutdown or even an extended outage, such as the multi-year outage at the Kashiwazaki-Kariwa plant in Japan following a major earthquake. The *AB 1632 Report* found that, given the current transmission system, a prolonged shutdown of SONGS could result in serious grid reliability shortfalls, whereas a prolonged shutdown of Diablo Canyon would generally not prose reliability concerns.[134] However, the *AB 1632 Report* also found that further reliability assessments are needed to fully understand the reliability implications of extended outages at the nuclear plants.

In a supporting document appended to the SWRCB's draft ocean cooling policy, the Energy Commission, CPUC, and California ISO noted the difficulties faced by regulators in evaluating the electric system reliability impacts of shutting down either SONGS or Diablo Canyon. Further studies are needed to understand what new generators, transmission lines, and/or demand response initiatives would be needed to prepare for the eventual shutdowns of the nuclear plants or to plan for possible extended outages while maintaining grid stability and local reliability. The need for and cost of these alternate resources should be considered in the cost-benefit assessment of the plants' license renewal feasibility studies and should also be considered in the context of CPUC and California ISO reliability planning. Given the long time frame required for permitting and building new generation and transmission resources, these studies should be completed soon.

Seismic Issues

Diablo Canyon and SONGS are located along California's seismically active coastline. The plants were designed to withstand large earthquakes without release of radiation or major damage; however, scientific understanding of the coastal fault zones has improved over the

134 California Energy Commission, *An Assessment of California's Nuclear Power Plants: AB 1632 Report*, pp. 23-24, available at: [http://www.energy.ca.gov/2008publications/CEC-100-2008-009/CEC-100-2008-009-CMF.PDF]

decades since the plants were designed, with a new fault discovered offshore of Diablo Canyon just last year. Plant components that do not serve a safety function were designed for less stringent seismic standards than the core of the nuclear plants. A large earthquake could cause enough damage to these components to necessitate extended plant shutdowns—five of the seven reactors at the Kashiwazaki-Kariwa plant in Japan remain shut down more than two years after being damaged by an earthquake.[135]

An extended plant shutdown would have economic, environmental, and reliability implications for ratepayers.[136] The CPUC will therefore consider the risk of an extended outage as part of its license renewal cost-benefit assessment. To support this assessment, the *AB 1632 Report* recommended that utilities update the nuclear plants' seismic assessments, including assessments of the earthquake and tsunami hazards at the plants, the vulnerability of non-safety related parts of the plants, and the time needed to repair the plants following an earthquake. It is crucial that the utilities complete these studies and submit them as part of the CPUC's license renewal review.

In July 2009, the utilities reported to the Energy Commission that they intend to complete these assessments. However, both utilities reported plans to use a probabilistic approach to their seismic hazard assessments rather than the deterministic approach recommended by the *AB 1632 Report*, and SCE did not commit to using some of the advanced mapping and survey techniques that were recommended.[137] Furthermore, SCE's tight schedule for completing the studies raises questions about how comprehensive its seismic assessment will be. As described above, the utilities do not intend to complete all the studies in time for submittal to the CPUC with their license renewal feasibility studies.

PG&E has begun to update the Diablo Canyon seismic hazard and vulnerability assessments and expects these assessments to be completed in 2013.[138] PG&E is using a number of advanced techniques to identify and better characterize fault zones near Diablo Canyon, including multi-beam bathymetry, high-resolution marine magnetics, and aeromagnetic surveys, and is purchasing industry seismic data in the vicinity of the plant.[139] PG&E is also sponsoring research on numerical simulations of near fault ground motions to improve ground motion models.[140] In addition, PG&E is planning to request ratepayer funding to undertake the three-

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135 World Nuclear Association, Nuclear Power Plants and Earthquakes, available at: [http://www.world-nuclear.org/info/inf18.html].

136 World Nuclear Association, Findings show the shutdown of the 8,000 MW Kashiwazaki-Kariwa plant cost the plant owner an estimated $5.6 billion in inspections, repairs, and replacement power during the first eight months of outage.

137 PG&E data request response F.09; SCE data request response F.01.

138 PG&E expects to complete the tsunami assessment by December 2009, the seismic reliability studies on non-safety related plant components by April 2010, the seismic hazard assessment in early 2011, and the seismic vulnerability assessment in 2013. The PG&E data request responses F.03, F.09, F.12, F.13.

139 PG&E data request response F.07.

140 PG&E data request response F.02.

dimensional geophysical seismic reflection mapping surveys recommended in the AB 1632 Report and required by AB 42 (Blakeslee).[141,142] PG&E will not include the United States Geological Survey National Hazard Mapping Project models in its studies because the models do not include detailed information pertinent to the Diablo Canyon area. Instead, PG&E believes that information developed in its own studies will inform the USGS databases.[143]

PG&E has already completed initial assessments of two specific seismic hazards in the area of Diablo Canyon, concluding that seismic activity that could be generated by the newly discovered Shoreline Fault is within the design margins of Diablo Canyon. (The NRC's preliminary assessment concurs with this conclusion.)[144] PG&E is conducting additional geophysical studies and will provide a final report in December 2010.[145] PG&E has similarly concluded that new estimates of the near fault ground motions from large strike-slip earthquakes, including directivity and maximum component effects, reveal a lower hazard than previously thought and therefore do not represent an increased hazard to Diablo Canyon.[146]

Research indicates that SONGS could experience larger and more frequent earthquakes than was anticipated in the original plant design and that additional research is needed to characterize the site's seismic hazard at the site. The *AB 1632 Report* recommended that SCE develop an active seismic research program for SONGS, similar to PG&E's Long Term Seismic Program, to assess whether the plant has sufficient design margins to avoid major power disruptions.

As of July 2009, SCE had not begun its updates to the SONGS seismic hazard and vulnerability assessments. Yet, the utility states that it expects to complete these by the end of 2010.[147] The studies are to include seismic source characterization, review of GPS data, probabilistic seismic hazard analysis modeling, review of earthquake recurrence relationships, ground motion updates for current attenuation relationships, review of new tsunami data from the University of Southern California and the National Oceanic and Atmospheric Administration, and an assessment of the reliability implications of the plant's non-safety related components.[148]

It is not clear whether SCE can complete all of these studies in a comprehensive manner by the end of 2010. Indeed, the utility has not committed to using three-dimensional geophysical

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141 PG&E data request response L.02.

142 As of September 14, 2009, the legislation was awaiting the governor's signature. The current status can be found at: [http://www.leginfo.ca.gov/].

143 PG&E data request response F.10.

144 Nuclear Regulatory Commission. "Preliminary Deterministic Analysis of Seismic Hazard at Diablo Canyon Nuclear Power Plant from Newly Identified 'Shoreline Fault'." Research Information Later 09-001. April 8, 2009.

145 PG&E data request responses F.01, F.06.

146 PG&E data request response F.02.

147 SCE data request responses F.01, F.13-F.15.

148 SCE data request responses F.01, F.12.

seismic reflection mapping and other advanced techniques as part of these studies or to installing a permanent GPS array. Instead, SCE committed only to evaluating the costs and benefits of these techniques,[149] an evaluation the Energy Commission has determined should be conducted by state agencies, not the utilities.[150] It remains to be clarified whether SCE plans to collect any new data on the seismic hazards in the SONGS region or whether it is planning simply to review currently available data.

SCE established a Seismic Advisory Board to guide and review the SONGS seismic studies.[151] SCE plans for the board to periodically review the seismic hazard at SONGS and to determine the need for new research and investigations into the plant's seismic setting. As currently structured, the board includes geologists from PG&E and private consultants in geology, seismology, and structural engineering who are familiar with the SONGS plant from previous work for SCE.[152] It includes just one expert not previously employed by SCE or currently employed by PG&E. This is unfortunate since a more independent advisory board would likely contribute to stronger studies.

Nuclear Plant Safety Culture

The state is concerned with a number of other issues that may affect the decision on whether the utilities should pursue plant relicensing. These include the reliability implications of lapses in the safety culture at SONGS and plans for emergency evacuations from both plants.

In 2007, the NRC identified a number of concerns about the safety culture at SONGS, particularly with respect to human performance and problem identification and resolution. Since then, SCE's management put a new leadership team in place at SONGS and instituted a series of safety reforms and monitoring programs.[153] For example, SCE implemented safety improvement plans and conducted extensive evaluations to identify the root causes of safety lapses. The utility also instituted weekly monitoring of core performance indicators, established weekly site-wide meetings on human performance and safety issues, set up a system for employees to voice their concerns regarding safety issues, and conducted a safety culture assessment.

The NRC recently concluded that these improvements were not adequate in addressing the overall safety culture at SONGS. The NRC was particularly concerned that it had identified problems in the areas of human performance and problem identification and resolution over the course of four consecutive assessments, including its most recent assessment in September

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149 SCE data request responses F.07, F.11.

150 California Energy Commission, *An Assessment of California's Nuclear Power Plants: AB 1632 Report*, p. 9, available at: [http://www.energy.ca.gov/2008publications/CEC-100-2008-009/CEC-100-2008-009-CMF.PDF]

151 SCE data request response F.05.

152 SCE data request response F.05. September 18, 2009.

153 SCE data request response, M.09.

2009.[154] During the September 2009 assessment, the NRC also identified an additional safety-related issue of "failing to use conservative assumptions" in decision-making.[155]

As a result of these safety culture failures, the NRC intends to maintain the additional oversight that it initially imposed over SONGS in December 2008. At that time, the NRC discovered that a battery used to power a backup generator at the plant had been inoperable since 2004. Although the NRC ranked this as a finding of low to moderate safety significance, the agency noted that the persistence of the problem for four years pointed to inadequate maintenance procedures for the plant overall. The NRC also expressed dissatisfaction that SONGS' self-evaluations had not identified seven other problems at the plant.[156]

In light of these performance lapses, Senator Barbara Boxer and California State Senator Christine Kehoe wrote to the NRC expressing concern about SCE's fall 2009 steam generator replacement project. The NRC responded by expressing confidence in SCE's ability to complete the project safely without any additional restrictions or NRC oversight. This is consistent with the NRC's position that, while SONGS' progress in improving safety culture has been inadequate, the plant continues to be operated in a safe manner.[157]

Lack of progress may also be evident in reduced plant performance. SONGS's 2008 capacity factor was just 81 percent,[158] significantly lower than the 92 percent industry average.[159] This relatively low level of availability was partially the result of Unit 3's refueling outage extending 66 days,[160] 28 days longer than the industry average.[161]

Improvements to the safety culture and plant performance at SONGS will be reflected in improved ratings by the NRC and INPO and by shorter outages and higher capacity factors. If

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154 Nuclear Regulatory Commission, Mid-cycle Performance Review and Inspection Plan – San Onofre Nuclear Generating Station, September 1, 2009, p. 1, available at: [http://www.nrc.gov/NRR/OVERSIGHT/ASSESS/LETTERS/sano_2009q2.pdf].

155 Nuclear Regulatory Commission, Mid-cycle Performance Review and Inspection Plan – San Onofre Nuclear Generating Station, September 1, 2009, p. 2.

156 Nuclear Regulatory Commission, Office of Public Affairs, "NRC to Provide Additional Oversight to San Onofre Nuclear Generating Station," December 22, 2008.

157 Nuclear Regulatory Commission, Mid-cycle Performance Review and Inspection Plan – San Onofre Nuclear Generating Station, September 1, 2009, p. 1.

158 Southern California Edison, *2008 Financial and Statistical Report*, p. 24, available at: [http://www.edison.com/files/2008_Financial&StatisticalRpt.pdf].

159 U.S. Energy Information Administration. U.S. Nuclear Statistics, see [http://www.eia.doe.gov/cneaf/nuclear/page/operation/statoperation.html].

160 Southern California Edison, *2008 Financial and Statistical Report*, p. 24, available at: [http://www.edison.com/files/2008_Financial&StatisticalRpt.pdf].

161 NEI, U.S. Nuclear Refueling Outage Days, available at: [http://www.nei.org/resourcesandstats/documentlibrary/reliableandaffordableenergy/graphicsandcharts/refuelingoutagedays/].

sufficient improvements are not demonstrated in the coming years, the implications of sustained safety culture lapses and the possible impact on reliability of the plants will need to be considered as part of the state's license renewal assessment for the plant.

An additional issue is emergency evacuation planning. The *AB 1632 Report* recommended that the utilities reassess the adequacy of plant roads for allowing access for emergency response teams and for allowing local communities and workers to evacuate. The report recommended that this reassessment be conducted as part of license renewal studies to ensure that plant assets would be protected in an emergency. PG&E has commissioned a study, to be completed in early 2010, on evacuation time estimates for Diablo Canyon.[162] SCE did not indicate whether it plans to conduct a study on SONGS's access roads and evacuation times.[163]

Nuclear Plants and the Economy

Nuclear power plants face a number of economic barriers, including high capital costs and long construction lead times. While nuclear plants are relatively cheap to run, construction costs are high. These costs are also highly uncertain since few nuclear plants have been constructed in the U.S. since the 1980s.[164]

During the late 1990s and early part of this decade, vendor estimates for new nuclear plants were on the order of $1,000-$1,500 per kW. However, these general estimates were not tied to particular projects. In recent years as some companies have begun to seriously evaluate options for new nuclear generation, vendor bids have been much higher, on the order of $4,000 - $6,000 per kW.[165] For a typical 2,200 MW nuclear plant, this amounts to $9-$13 billion in capital costs. Recently, several utilities reported even higher cost estimates of $14 billion ($6,300 per kW) for proposed plants,[166] and Moody's Investors Service estimated that costs for a new plant could potentially reach $7,000-$7,500 per kW.[167]

Until one or more new nuclear plants are constructed in the U.S., these estimates will remain preliminary, making construction of a new nuclear plant a risky endeavor. The risk of capital cost increases is compounded by the long length of time that it takes to get approval for and

162 PG&E data request response M.06.

163 SCE data request response M.06.

164 U.S. Nuclear Regulatory Commission. 2009-2010 Information Digest, page 36. [http://www.nrc.gov/reading-rm/doc-collections/nuregs/staff/sr1350/v21/sr1350v21.pdf]

165 KEMA. "Renewable Energy Cost of Generation Update." PIER Interim Project Report. CEC-500-2009-084. August 2009. Appendix A.

166 Florida Power & Light's Turkey Point plant, Georgia Power and Georgia Public Service Company's Vogtle plant, and Duke Energy's Lee Nuclear Station, see [http://progress-energy.com/aboutus/news/article.asp?id=20482]; [http://southerncompany.mediaroom.com/index.php?s=43&item=353]; [http://www.bizjournals.com/charlotte/stories/2008/11/03/daily19.html].

167 Moody's Corporate Finance. "New Nuclear Generating Capacity: Potential Credit Implications for U.S. Investor Owned Utilities." May 2008, pp. 1 and 15.

then construct a new nuclear plant, which raises the risk of cost increases due to regulatory delays, inflation, and increases to financing costs. As a result, Moody's cautioned that they "view new nuclear generation plans as a 'bet the farm' endeavor for most companies" and warned that companies that pursue new nuclear generation may face credit rating downgrades if they do not mitigate this risk.

Other cost issues relating to nuclear power plants include security (to protect sites from terrorism and theft), plant decommissioning, and nuclear waste storage, transport, and disposal. The federal Nuclear Waste Policy Act of 1982 made the federal government responsible for the permanent disposal of spent nuclear fuel and high-level waste. Since 1982, nuclear plant owners have been required to pay 0.1 cents per kWh of power generated from their plants into a Nuclear Waste Fund to finance federal efforts to build a permanent nuclear waste repository. In return for these payments, the DOE committed to opening a repository by January 31, 1998.

As of September 2008, the Nuclear Waste Fund contained $31.4 billion, with $1.4 billion from California. However, more than 11 years after the deadline, a repository has yet to be constructed. As a result, PG&E, SCE, and many other utilities have sued the DOE for breach of contract. PG&E claimed damages of $90.6 million through 2004 for costs at Diablo Canyon ($36.8 million) and Humboldt Bay ($53.8 million).[168] In October 2006, the U.S. Court of Federal Claims awarded PG&E $42.8 million. PG&E won an appeal on the award amount, and the lawsuit has been remanded to the U.S. Court of Federal Claims for a recalculation of damages. The DOE has conceded that PG&E is entitled to $75 million, but continues to contest $15.6 million of additional costs that are mostly related to onsite storage of Greater than Class C waste at Humboldt Bay. PG&E plans to file an additional claim to cover ISFSI-related costs incurred from 2005-2009.[169]

SCE claimed $150 million in damages through 2005. In addition to ISFSI licensing, construction, and operating costs, SCE is seeking additional compensation for payments made to General Electric for storage of Unit 1 spent fuel and investments in the proposed Private Fuel Storage facility in Utah.[170] A trial was conducted in late April 2009, and a decision is expected in late 2009 or early 2010.[171]

If a federal repository is established, spent fuel will need to be packaged for transport, aging, and disposal (TAD). Dry cask storage, an interim storage solution, could prove costly to utilities in the long-term, especially if they need to pay to transfer their fuel from their dry casks into federally approved TAD casks. The nuclear plants will also need to dispose of a substantial

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168 PG&E's initial damage claim was for $92.1 million. PG&E recalculated its claim based on the appellate court's decision.

169 PG&E data request response D.09.

170 MRW & Associates, Inc. "AB 1632 Assessment of California's Operating Nuclear Plants: Final Report" Prepared for the California Energy Commission. October 2008, pp. 220-221.

171 SCE data request response D.09.

quantity of low-level radioactive waste when they are decommissioned, and the cost to transport and dispose of this waste is expected to be hundreds of millions of dollars or more.

Transmission

Senate Bill 1565 (Bowen, Chapter 692, Statutes of 2004) requires the Energy Commission to adopt a strategic plan for the state's electric transmission grid as part of the IEPR proceeding. In further recognition of the importance of the state's role in transmission planning, Senate Bill 1059 (Escutia and Morrow, Chapter 638, Statutes of 2006) creates a link between transmission planning and permitting by authorizing the Energy Commission to designate transmission corridor zones (transmission corridors) on non-federal lands that will be available in the future to allow for the timely permitting of high-voltage transmission projects.

The *2008 IEPR Update* noted that the primary barrier to increased development of renewable generation continues to be the lack of transmission to access these resources, particularly those generating resources located (or proposed) in remote areas of the state. In particular, that report identified two major transmission-related barriers to achieving the state's renewables goals. First, there is a need for mechanisms to remove barriers to joint transmission projects between publicly owned utilities and IOUs. This issue is described below in the section on transmission and the economy. Second, with regard to transmission siting, the state must continue to actively address environmental, land use, and local public opposition issues by working closely with stakeholders during the planning process. This issue is described below in the section on transmission and the environment.

The joint IEPR and Siting Committees' Draft *2009 Strategic Transmission Investment Plan*, prepared in support of the *2009 IEPR*, describes the immediate actions that California must take to plan, permit, construct, operate, and maintain a cost-effective, reliable electric transmission system that is capable of responding to important policy challenges such as achieving significant GHG reduction and RPS goals. This section briefly summarizes some of the major issues covered in the plan.[172]

Transmission and the Environment

In the *2007 Strategic Transmission Investment Plan,* the Energy Commission identified the importance of early consideration of non-wires alternatives in statewide transmission planning processes. Essentially, non-wires alternatives are the preferred resources identified in the state's loading order and include energy efficiency, demand reduction measures (demand response and load management), and the use of small-scale and customer-level distributed generation resources and/or clean fossil-fired central station generation located within the load service area. Cost-effective energy efficiency is the resource of first choice for meeting California's energy needs; at the same time it is imperative that California reach its 33 percent RPS goals and expand distributed generation applications, particularly rooftop solar PV and CHP. Non-wires

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172 For additional detail, see California Energy Commission, *2009 Strategic Transmission Investment Plan*, September 2009, CEC-700-2009-011-CTD, available at: [http://www.energy.ca.gov/2009publications/CEC-700-2009-011/CEC-700-2009-011-CTD.PDF].

alternatives are increasingly identified as viable alternatives to new conventional generation and transmission facilities required to connect new generation to demand centers. The CPUC currently performs a project-specific, non-wires alternative analysis as part of its environmental review process for permitting transmission projects, initiated with the filing of a Certificate of Public Convenience and Necessity (CPCN).

As noted in the *2008 IEPR Update*, integrating land use and environmental concerns into transmission planning processes can be a challenge. Efforts are already underway to aid in the early identification and resolution or to avoid land use and environmental constraints to promote timely development of California's renewable generation resources and associated transmission lines. The RETI has proven to be a successful model for bringing together renewable transmission and generation stakeholders to link transmission planning and transmission permitting. This will ensure that needed projects are planned for, have corridors set aside as necessary, and are permitted in a timely and effective manner that minimizes environmental impacts, makes the best use of existing infrastructure and rights-of-way, and takes advantage of technological advances.

In August 2009, RETI released its Phase 2A Report which presents a conceptual transmission expansion plan to increase the capacity of the state's transmission grid to deliver renewable generation to load centers. It also forms the basis for the development of a draft method for identifying which of the RETI line segments should be considered for corridor designation by the Energy Commission. Next steps include a possible update of the Phase 2A report to address developments in the tax code that affect the economic rankings of competitive renewable energy zones (CREZs). Stakeholders are also considering participation in the California ISO Annual Transmission Plan proceeding and the electric utilities' California Transmission Planning Group (CTPG) [173]. Beyond this, the stakeholders are evaluating the benefits of conducting Phase 2B work to prioritize the transmission infrastructure identified in the conceptual transmission plan, address in greater detail out-of-state renewable resources and revise the transmission infrastructure accordingly, and develop an interim interconnection plan to exploit initial renewable generation opportunities that can rely on temporary fixes to the existing grid to be brought on line.

Another important effort to integrate land use concerns with transmission planning is the Energy Commission's transmission corridor designation process established under SB 1059. The transmission corridor designation process will help promote improved public involvement in transmission planning processes so that public concerns can be heard and addressed. In addition, early outreach by utilities to local governments and land use agencies will help with early identification of land use and environmental conflicts, which are typically the major impediments to securing any transmission permit. The corridor designation process can also provide better education to the public and local government agencies about why new

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173 The California Transmission Planning Group includes the California ISO, the California Municipal Utilities Association, the Imperial Irrigation District, the Los Angeles Department of Water and Power, Pacific Gas and Electric Company, Southern California Edison Company, San Diego Gas & Electric Company, and the Transmission Agency of Northern California.

transmission infrastructure is needed and how it will help the state meet its environmental goals.

Transmission and Reliability

As the demand for electricity increases, so does the need for new transmission to bring additional supplies of electricity to consumers. In addition, policy decisions like retiring aging power plants or OTC plants may require transmission solutions to maintain system reliability in the southern part of the state. Furthermore, the success in meeting RPS and GHG reduction goals will depend in large part on the ability to interconnect substantial amounts of new generation from renewable resources, much of which is located in remote parts of Southern California. The challenge regulators face is identifying the best mix of transmission projects to ensure a reliable network.

In the *2009 Strategic Transmission Investment Plan*, the IEPR and Siting Committees note that the highest priority is to continue to support the projects identified in previous strategic plans. The Energy Commission found that these projects met the criteria for strategic transmission resources because they provided statewide benefits. As currently planned, these projects would significantly increase the transmission network's ability to reliably connect renewable generation to California load centers. These projects include:

- Imperial Irrigation District Upgrades
- SCE Tehachapi Upgrades (Segment 1 – Antelope-Pardee; Segment 2 – Antelope-Vincent; Segment 3 – Antelope-Tehachapi; and Segments 4-11 – Tehachapi Renewable Transmission Project)
- SCE Devers – Palo Verde 2 (the entire California-Arizona interconnection, as well as the California-only variation)
- LADWP Tehachapi Upgrade (Barren Ridge Renewable Transmission Project)
- PG&E Central California Clean Energy Transmission Project (C3ETP)
- SDG&E Sunrise Powerlink Transmission Project
- Lake Elsinore Advanced Pumped Storage (LEAPS) Project – Transmission Portion
- Green Path North Coordinated Projects
- SCE El Dorado to Ivanpah Transmission Project (new project not in previous *Strategic Plans*)

A complete description of these projects and their current status is provided in Chapter 6 of the *2009 Strategic Transmission Investment Plan*.

The second priority should be transmission segments identified in the RETI process as "foundation" and "delivery" segments that limit environmental impacts by using or expanding existing transmission segments. Together with the first priority projects listed above, these segments would provide a strong system to move and deliver electricity throughout California. RETI has not performed the thorough planning studies that are required to move these projects forward toward permitting approvals. The detailed analysis of these projects should be conducted through RETI or the newly formed CTPG, described in more detail in the section on transmission and the economy.

Six conceptual transmission projects meet these two priority criteria. They are the "no regrets" RETI lines that could be built within an existing transmission corridor or by expanding an existing corridor. Two additional projects (Gregg – Alpha Four and Tracy – Alpha Four) do not meet these criteria but are needed to complete a link to Northern California load centers; without these two lines, the renewable energy would reach Fresno but not load centers in the Bay Area.[174]

The third priority should be to continue the analysis of the RETI renewable foundation and renewable collector lines that require new corridors and begin the planning work for the priority renewable areas outside Tehachapi, the Imperial Valley, and eastern Riverside County. Public outreach and corridor identification for the RETI "no regrets" lines that require new corridors should continue with local RETI forums, and the transmission planning should be developed through the CTPG. Which areas or CREZs should be given priority should be revisited because there are several factors that will affect the viability of the areas. The proposed national monument in the Mojave Desert area could reduce the size of several of the CREZs. The Solar PEIS currently being developed by the BLM will likely identify preferred solar development areas while removing other areas from development. The California ISO is completing its first clustered interconnection studies based on the new Generator Interconnection Process. While these studies will only identify transmission needs for a small part of the generation potential of many of the CREZs, the new studies will identify some of the transmission upgrades that are required to reliably connect proposed generators to the existing transmission grid, and the extent of these required upgrades could affect the development of renewable areas. All of these studies will help identify preferred renewable generation areas for California and will help prioritize the planning and permitting of future transmission needs.

Transmission and the Economy

Joint transmission projects between IOUs and publicly owned utilities promote economic efficiency by eliminating potentially redundant facilities, thereby reducing ratepayer expenses With respect to the issue of overcoming obstacles to joint transmission projects, the *2008 IEPR Update* recommended that the Energy Commission use the *2009 IEPR* and *2009 Strategic Transmission Investment Plan* processes as forums to identify and evaluate regulatory or policy changes that would reduce both legal and market obstacles to joint project development. Toward that end, two joint IEPR/Siting Committee workshops were held in support of the *2009 Strategic Transmission Investment Plan* that vetted the issue of coordinated statewide transmission planning to meet California's RPS goals. In the joint Committees' Draft *2009*

174 The eight second-priority conceptual transmission projects include five RETI Renewable Foundation lines (Kramer – Lugo 500 kV, Lugo – Victorville #2 500 kV, Devers – Mira Loma #1 and #2 500 kV, Gregg – Alpha Four 500 kV, and Tracy – Alpha Four 500 kV 1 & 2) and three RETI Renewable Delivery lines (Devers – Valley #3 500 kV, Tesla – Newark 230 kV, and Tracy – Livermore 230 kV.)

Strategic Transmission Investment Plan, the Committees recognize the formation of the CTPG and the significant progress the CTPG appears to be making toward establishing a coordinated statewide utility transmission planning process that could lead to joint IOU/publicly owned utility projects.

As described by the comments received under this proceeding by the CTPG,[175] the purpose of the CTPG is to find the best transmission solutions for meeting California's environmental, reliability, economic, and other policy objectives. Under the CTPG, electric utilities and the California ISO are planning to work together to avoid transmission duplication, optimize use of existing rights-of-way, reduce environmental impacts, and lower costs for consumers. The CTPG is intended, along with existing efforts, to fulfill the CTPG members' obligations and requirements under Order No. 890 issued by the FERC. Order No. 890 requirements include nine transmission planning principles that address many of the issues central to an open and inclusive planning process, including (1) coordination with customers and neighboring transmission providers; (2) open meetings available to all parties; (3) transparency in methodology, criteria, and processes; (4) opportunities to use customer data and methodological input; (5) the obligation to meet specific service requests of transmission customers on a comparable basis; (6) a clear dispute resolution process; (7) regional coordination; (8) study of economic effect of congestion and integration of new resources; and (9) a process for allocating costs of new projects.

The IEPR Committee supports the plans of the IOUs, publicly owned utilities, and the California ISO to work together to avoid transmission duplication, optimize use of existing rights-of-way, reduce environmental impacts, lower costs for consumers, and develop a process for cost allocation for joint projects. These actions could result in the development of joint transmission projects. Notwithstanding this progress, it is uncertain if the CTPG will be successful in implementing a true statewide planning process that will reflect broad stakeholder interests.[176]

Another high-priority economic issue for transmission is the broader cost allocation issue for interstate transmission projects. The *2007 Strategic Transmission Investment Plan* described the results of a PIER-funded study that examined cost allocation and cost recovery procedures in other regions of the country for insights that could apply to a California-western region context. The study also identified a number of basic principles for developing cost allocation procedures that could guide western planners.

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175 Post-Workshop Comments of Joint Parties Comments on Transmission Planning Information and Policy Actions, May 29, 2009, available at: [http://www.energy.ca.gov/2009_energypolicy/documents/2009-05-04_workshop/comments/Joint_Parties_Post-Workshop_Comments_052909_TN-51751.pdf].

176 For more information on the California Transmission Planning Group and its role in statewide transmission planning, see Chapters 2 and 4 of the 2009 Strategic Transmission Investment Plan, September 2009, CEC-700-2009-011-CTD, available at: [http://www.energy.ca.gov/2009publications/CEC-700-2009-011/CEC-700-2009-011-CTD.PDF].

Currently, there is a high degree of interest at the federal level in moving toward inter-connection-wide transmission planning and federal intervention in planning, permitting, and cost allocation. Congress is considering legislation that would establish new FERC authority for transmission siting and cost allocation. This issue is of concern to California because if FERC mandates a cost allocation method, California could be required to pay for projects not consistent with the California RETI effort, California RPS goals, and carbon reduction policies.

The Western Governors' Association (WGA) has recently asserted western policies that urge Congress to guide centralized regional transmission planning, implemented through actions and policies of federal agencies such as FERC, BLM, and DOE. Its policy letters explicitly urge Congress to require a regional transmission plan, chosen and approved by WGA, that could be enforced by DOE and FERC through mechanisms such as incentives, federal corridor designation, National Interest Electricity Corridor Designation, possible siting preemption/backstop authority, and prescriptive cost allocation under methods specified by the FERC.[177] The detailed implementation of the WGA policy statements will to a significant degree depend on what, if any, legislation is approved by Congress in 2009-10 (or beyond).

Another economic issue that is specific to the Energy Commission's transmission corridor designation process is California IOUs' uncertainty of cost recovery for land purchased within an Energy Commission-designated corridor for future transmission projects. The current FERC declaratory order requires that an IOU obtain a CPCN from the CPUC for a specific transmission project within a designated corridor to qualify for cost recovery for land purchases. This requirement is a potential barrier to the successful implementation of the Energy Commission's transmission corridor designation program. To eliminate this barrier the IOUs need assurance from FERC that they will be allowed to recover in their electric rates the cost of land purchased within an Energy Commission-designated corridor. The Energy Commission believes that FERC should allow an IOU to qualify for cost recovery if the land is set aside for one or more transmission projects that may be constructed 10-15 years in the future and is within an Energy Commission-designated corridor.

Natural Gas Sector

Natural gas provides almost one-third of the state's total energy requirements and continues to be a major fuel in California's supply portfolio. Natural gas is used in electricity generation, space heating for homes and commercial buildings, cooking, water heating, industrial processes, and as a transportation fuel.

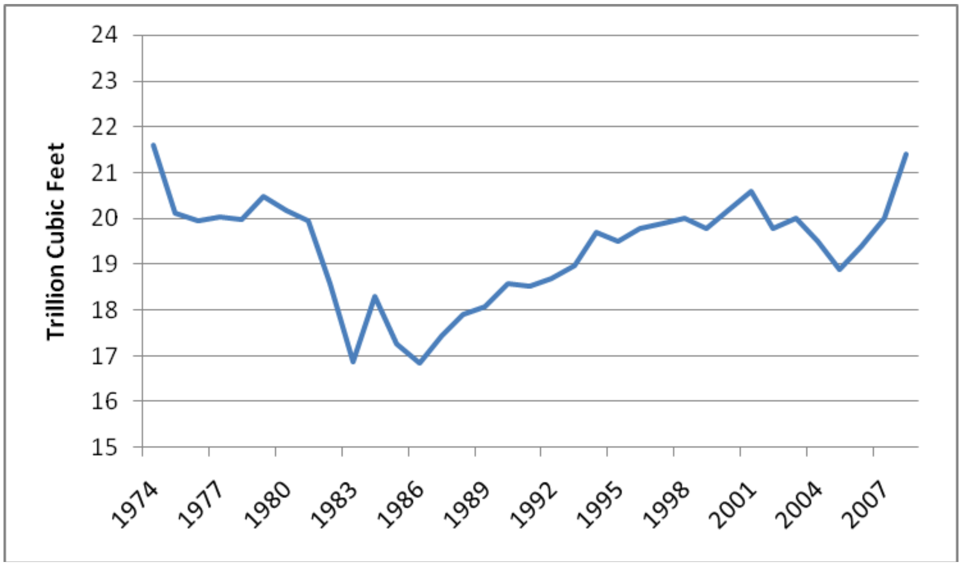
Natural Gas Supplies

California's supply of natural gas comes from four areas: in-state production, southwestern United States, the Rocky Mountain Region, and Canada, with 87 percent of the state's natural

177 Western Governors' Association Letter to the Honorable Jeff Bingaman, May 1, 2009, available at: [http://www.westgov.org/wga/testim/transmission5-1-09.pdf].

gas coming from out-of-state sources. After nearly a decade of relatively flat or declining U.S. natural gas production, domestic production in the lower 48 states began rising in 2006 and by 2008 returned to levels last seen in 1974 (Figure 13)[178].

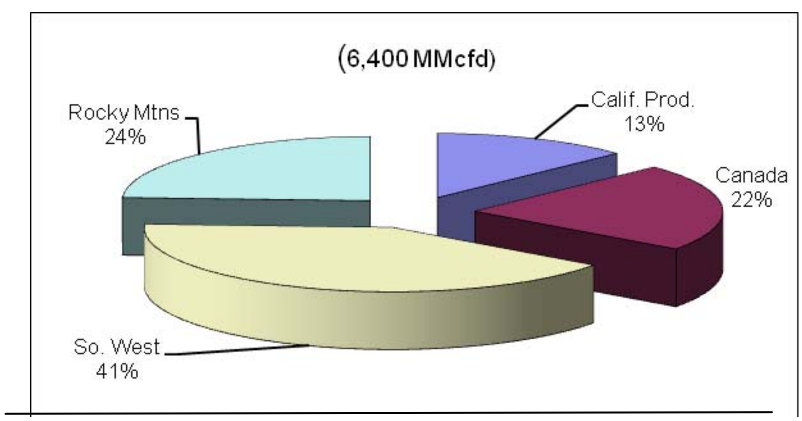
Figure 13: U.S. Domestic Natural Gas Production



Source: EIA AEO 2009 Early Release.

Twenty years ago, California produced 20 percent of the state's supply of natural gas, the Southwest provided nearly 60 percent, and the rest came from Canada and other basins. However, in-state natural gas production has been declining over time (Figure 14), and the downward trend may continue from the current 825 million cubic feet per day (MMcf/d) to possibly 700 MMcf/d by 2020.

Figure 14: 2007 California Natural Gas Receipts by Source



Source: Pipeline and Utility Filings with the California Energy Commission

178 Domestic natural gas production was 21.60 trillion cubic feet (Tcf) in 1974 and 21.40 Tcf in 2008.

Production from conventional natural gas basins that provided the majority of domestic supply began to decline in the late 1990s and early 2000s but as natural gas prices have increased, so have exploration and production. There have also been advances in horizontal drilling, a more efficient and cost-effective method for recovery of domestic unconventional natural gas reserves that provides the potential for greater gas production per well. Finding and development costs of a typical vertical well average $1.71 per thousand cubic feet (Mcf), while costs for a horizontal well average between $1.06/Mcf and $1.34/Mcf. [179]

Natural gas from out-of-state is delivered into California using the interstate natural gas pipeline system. Five interstate pipelines bring gas to California: Gas Transmission-Northwest pipeline (GTN) carries Canadian natural gas; El Paso, Transwestern, and Questar's Southern Trails transport gas from the Southwest; and the Kern River pipeline system moves Rocky Mountain production to market. Except for Southern Trails, each of these pipelines serves other customers before reaching California. Figure 15 shows natural gas pipelines and resource areas in western North America.

Interstate pipelines and California production currently have the capacity to supply California consumers up to 9,785 MMcf/d. However, because of upstream demand and utility multiple receiving points, the state can only rely on receiving 7,870 MMcf/d of supply from pipelines and native production. Simply because an interstate pipeline has a certain delivery capacity does not mean that all of its capacity is available to California. Each pipeline serving California has firm delivery contracts not only for California customers but also for customers upstream from California. Because of these upstream commitments, not all of a pipeline's capacity is available for delivery to the state.

179 California Energy Commission, *Shale-Deposited Natural Gas: A Review of Potential*, May 2009, CEC-200-2009-005-SD, available at: [http://www.energy.ca.gov/2009publications/CEC-200-2009-005/CEC-200-2009-005-SD.PDF].

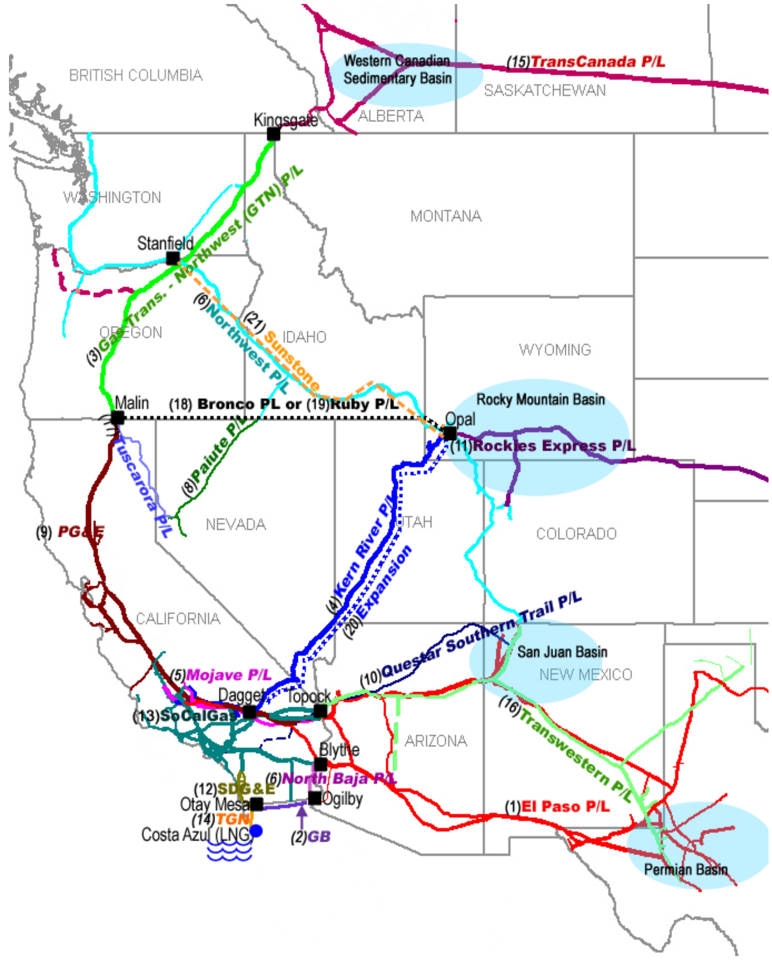
Figure 15: Natural Gas Resource Areas and Pipelines

In Operation:

1. El Paso Natural Gas
2. Gasoducto Bajanorte (GB)
3. Gas Transmission Northwest (GTN)
4. Kern River Pipeline
5. Mojave Pipeline
6. North Baja Pipeline
7. Northwest Pipeline
8. Paiute Pipeline
9. Pacific Gas Electric Company
10. Questar Southern Trail Pipeline
11. Rockies Express (REX)
12. San Diego Gas &Electric Company
13. Southern California Gas Company
14. Transportadora de Gas Natural (TGN)
15. TransCanada Pipeline
16. Transwestern Pipeline
17. Tuscarora Pipeline

Proposed:

18. Bronco Pipeline
19. Ruby Pipeline
20. Kern River Expansion
21. Sunstone Pipeline



Source: *2008 California Gas Report*

Once natural gas arrives in California, it is distributed by the natural gas utility companies. The three major utilities – Southern California Gas Company (SoCal Gas), SDG&E, and PG&E – collectively serve 98 percent of the state's natural gas customers. The remaining 2 percent are served by municipal and smaller or out-of-state utilites.

The amount of available natural gas storage is also important. PG&E's storage fields have the ability to cycle small quantities of gas through the year. The utility needs most of the injection period to fill its storage to meet winter demand. PG&E has indicated that it may maintain a 1,451 MMcf/d withdrawal rate through the winter. Although SoCal Gas has good natural gas cycling capabilities, the independent, non-utility Lodi and Wild Goose facilities have better cycling abilities. Each may withdraw and inject several times throughout the year and may also hold the same delivery levels as volumes of gas in storage are extracted. SoCal Gas asserts that it can maintain up to 2,225 MMcf/d[180] of gas withdrawals throughout all levels of storage

A potential additional source of natural gas supply is liquefied natural gas (LNG). In the near future, California could receive natural gas from an LNG facility located at Costa Azul, Mexico. The construction of the Costa Azul LNG Terminal was completed last year and still awaits the first of its commercial deliveries. LNG is available, but suppliers at the moment are reluctant to enter the lower-priced Pacific Coast market. When supply does start to flow, North Baja Mexico will have first choice to receive up to 300 MMcf/d to meet its industrial and power plant needs. Any excess in supply would add to California's supply mix. Under normal conditions, this would lead to price competition for market share. However, LNG is a price taker, meaning it does not set the price; with the reluctance for deliveries to the Pacific Coast, it is unclear what impact Costa Azul will have on supply and price.

Another option for new supplies of natural gas is shale gas.[181] Natural gas accumulates in three types of formations: limestone, sandstone, and shale. Before 1998, limestone and sandstone formations produced nearly all domestic supplies of natural gas. Exploration and production companies, however, have long known about the potential for natural gas in shale formations. This potential led the industry to pursue the engineering innovations needed to access these natural gas resources.

In the mid-1990s, shale-deposited natural gas provided about 1 percent of production in the lower 48 states.[182] The development of three-dimensional and four-dimensional seismic surveys, improved drilling technologies, and technological innovations in well completion and stimulation has increased the productivity of wells drilled into shale formations so that by mid-2008, shale production represented almost 10 percent of production from the lower 48 states (Figure 16). The Natural Gas Supply Association believes that production from the shales "…could double in the next 10 years and provide one-quarter of the nation's natural gas supply."[183]

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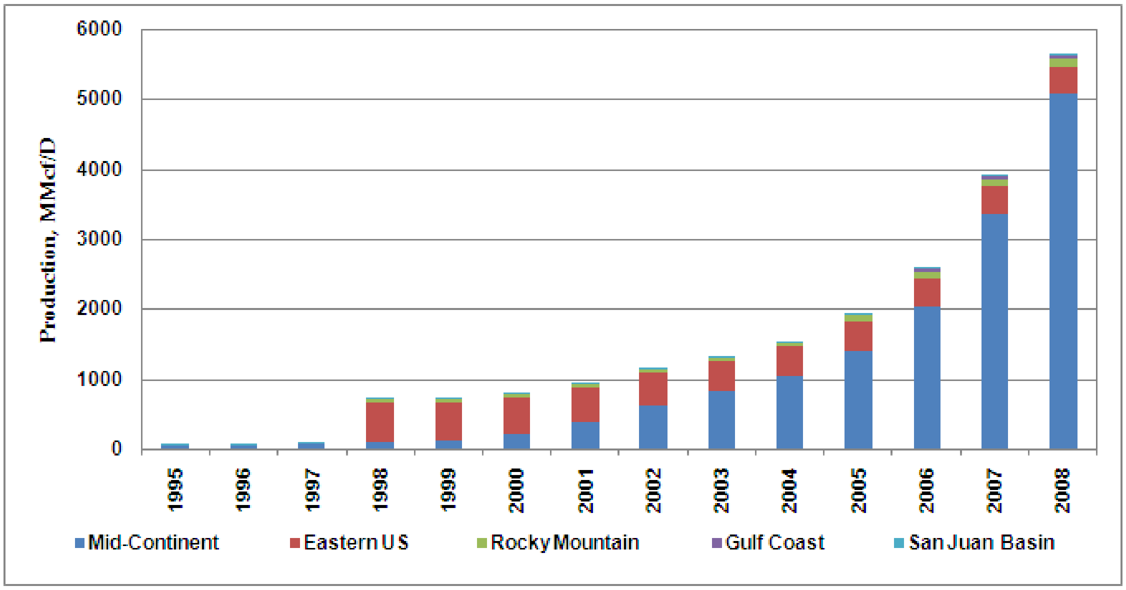
180 *2008 California Gas Report*, p. 90, available at: [http://www.socalgas.com/regulatory/documents/cgr/2008_CGR.pdf].

181 California Energy Commission, *Shale-Deposited Natural Gas: A Review of Potential*, draft staff paper, May 2009, CEC-200-2009-005-SD, available at: [http://www.energy.ca.gov/2009publications/CEC-200-2009-005/CEC-200-2009-005-SD.PDF].

182 "Lower 48"excludes Alaska and Hawaii.

183 Natural Gas Supply Association, News Release, October 8, 2008, "Natural Gas from Shale Could Double in Next Ten Years," available at: [http://www.ngsa.org/newsletter/pdfs/2008%20Press%20Releases/22%20-%20Natural%20Gas%20from%20Shale%20to%20Double%20w%20graphic.pdf].

Figure 16: Lower 48 Shale Natural Gas Production



Source: Lippman Consulting, Inc.

Natural Gas Demand

As a state, California is the second largest natural gas consumer in the United States, representing more than 10 percent of national natural gas consumption.[184] Customers in the residential and commercial sectors, referred to as "core" customers, accounted for 29 percent of the state's natural gas demand in 2008. Large consumers such as electricity generators and the industrial sector, referred to as "non-core" customers, accounted for about 71 percent of demand in the same year. California remains heavily dependent on natural gas to generate electricity, which accounted for more than 40 percent of natural gas demand in 2008.[185]

Most of the natural gas used in the residential sector is for space and water heating. Since 1970, the number of households in California has almost doubled, which has increased overall natural gas consumption, but as a result of California's building and appliance efficiency standards, the average amount of natural gas consumed per household has dropped more than 36 percent.

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184 Energy Information Administration, *Natural Gas Annual 2007*, available at: [http://www.eia.doe.gov/pub/oil_gas/natural_gas/data_publications/natural_gas_annual/current/pdf/table_002.pdf].

185 Southern California Gas Company, *2008 California Gas Report*, available at: [http://www.socalgas.com/regulatory/documents/cgr/2008_CGR.pdf].

In 2009, the Energy Commission staff prepared a comprehensive forecast of natural gas demand by end users (excluding electricity generation) as part of the *2009 IEPR*.[186] Table 6 compares the 2009 natural gas forecast with the 2007 forecast for selected years.

Table 6: Statewide End-User Natural Gas Consumption

	CED 2007	*CED 2009* (High-Rate Case)	Percent Difference
	(MM Therms)		
1990	12,893	12,893	0. 00%
2000	13,913	13,913	0. 00%
2007	13,445	12,494	-0.07%
2010	13,616	12,162	-10.68%
2018	14,058	12,894	-8.28%
Historic values are shaded			
	Annual Average Growth Rates		
1990- 2000	0. 76%	0. 76%	
2000- 2008	-0.43%	-0. 89%	
2008- 2010	0. 63%	-1.34%	
2010- 2018	0. 40%	0. 73%	

Source: California Energy Commission, 2009

The 2009 staff forecast is lower in the near term (2010) because of current economic conditions and because actual consumption in 2008, the starting point for the 2009 forecast, was lower than the forecasted 2008 consumption that was used in the 2007 forecast. By 2018, consumption is expected to be about 8 percent lower than in the prior forecast. As the economy recovers, projected annual growth in natural gas consumption is expected to exceed CED 2007 forecast growth for 2010–2018.

Although the method to estimate energy efficiency impacts has been refined, the staff draft forecast uses essentially the same methods as earlier long-term staff demand forecasts. A more detailed discussion of forecast methods and data sources is available in the *Energy Demand Forecast Methods Report*.[187]

Energy Commission staff also evaluated winter peak day natural gas demand trends and the effect of that demand on pipelines and natural gas storage, using demand data from the *2008 California Gas Report*[188] and from utility and pipeline filings made to the Energy Commission. Winter demand is driven primarily by heating requirements in the residential and commercial sectors, while natural gas for electricity generation represents about 14 percent of winter demand. Demand from the industrial sector has very little seasonal variation.

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186 *California Energy Demand 2010-2020, Staff Revised Forecast*, September 2009, CEC-200-2009-012-SF, available at: [http://www.energy.ca.gov/2009publications/CEC-200-2009-012/CEC-200-2009-012-SF.PDF].

187 *California Energy Commission, Energy Demand Forecast Methods Report,* June 2005, CEC-400-2005-036, available at: [http://www.energy.ca.gov/2005publications/CEC-400-2005-036/CEC-400-2005-036.PDF].

188 *2008 California Gas Report*, see [http://www.socalgas.com/regulatory/documents/cgr/2008_CGR.pdf].

The state is shifting to renewable energy sources to provide a larger share of the electricity generated to meet California's needs. Unless they are paired with on-site energy storage technologies, certain renewable generation technologies are not dispatchable to follow load and may not be available to meet peak day requirements. Solar thermal and photovoltaic generation better matches load than does wind generation. To insure reliable service during peak demand periods, natural gas fired generation will be needed to meet peaking requirements, provide load following and backup services for the renewable generation, and provide baseload services.

The type of natural gas unit needed to supplement renewable generation will affect the need for natural gas. While older units have heat rates in excess of 10,000 Btu per kWh, the newer combined cycle facilities are more efficient and operate at approximately 7,500 Btu per kWh. A 40 percent loss of renewable generation would be equivalent to an increase of 480 MMcf/d in combined cycle fuel use. However, peaking units are less efficient and, depending on the age of the unit, will use 50 to 100 percent more gas per MWh than a new combined-cycle unit. Replacing renewable generation with a peaker plant would therefore increase gas demand by 770 MMcf/d.[189]

Natural Gas and the Environment

The shift to a greater reliance on horizontal, rather than vertical, wells in shale formations elevates the issue of potential environmental impacts. While regulatory agencies and environmental groups highlighted these issues in the past, in the last 10 years the increased activities in shale formations brought greater focus on the potential environmental impacts, which can occur in any of five areas: surface preparation, drilling and completion, production and clean-up, transmission and distribution, and consumption. As a result, the increased development and production of natural gas in shale formations has raised three primary environmental concerns: surface disturbance, GHG emissions, and potential leakage of chemicals into the groundwater.

Surface preparation before drilling any natural gas well can create environmental stress in sensitive areas. The potential impact on wildlife habitat and wilderness areas has led to moratoriums on natural gas drilling in the Rocky Mountains and other sensitive areas of the lower 48 states. Drilling operations can also have significant impacts, and some states, including New York and Pennsylvania, have issued restoration requirement rules.

Because natural gas is made up mostly of methane (a GHG), small amounts of methane can sometimes leak into the atmosphere from wells, storage tanks, and pipelines. The Energy Information Administration says that methane emissions from all sources account for about 1 percent of total U.S. GHG emissions, but about 9 percent of the "greenhouse gas emissions based on global warming potential."[190]

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189 California Energy Commission, Natural Gas Infrastructure, May 2009, CEC-200-2009-004-SD, available at: [http://www.energy.ca.gov/2009publications/CEC-200-2009-004/CEC-200-2009-004-SD.PDF].

190 An indicator of the carbon dioxide equivalent.

The industry is attempting to address some of the environmental impacts of natural gas extraction by using smaller rigs that reduce surface disturbance. The use of horizontal and directional drilling allows producers greater flexibility about where drilling rigs are located.[191] The shift to horizontal drilling and away from vertical drilling can also lessen surface disturbance by requiring fewer wells to recover an equivalent amount of resource.

On a per million Btu (MMBtu) basis, total emissions from natural gas produced from shale formations differ little from those of natural gas from conventional sources. However, the carbon footprint of the horizontal wells used to extract shale gas far exceeds that of a typical vertical well since the drilling process, the completion process, and the production stimulation process (hydraulic fracturing) require more carbon-based fuels, more drilling mud, and more water. Further, running the required equipment and pumps produces more emissions.

Developing equivalent amounts of natural gas resources, though, requires two to three times more vertical wells than horizontal wells. For example, extracting 20,000 million cubic feet of natural gas may require up to 30 vertical wells but only 10 horizontal wells. The natural gas industry uses both well types to reach potential natural gas resources located thousands of feet beneath the Earth's surface, but each horizontal well recovers more natural gas on average than a vertical well. As a result, the overall carbon footprint for the entire development of a shale formation may not differ from that of an equivalent-sized formation developed using vertical wells.

There are also environmental issues associated with the water used in shale gas extraction. The hydraulic fracturing process used to extract natural gas from shale formations uses hundreds of thousands of gallons of water treated with chemicals. In the development of an entire field, the amount of water injected into a shale formation could reach into the hundreds of millions of gallons. The volume of water used in the development of natural gas from shale formations raises other environmental concerns, including the consumption of large water quantities and recovered water disposal. Although field operators retrieve most of the injected water once the hydraulic fracturing is completed, a significant quantity of water and chemicals remain within the formation.

When development of shale formations occurs near major population centers, environmentalists with concerns that potential leakage of chemicals used in the hydraulic fracturing process could pose a health and safety risk, are calling for stricter regulation. Some states have developed regulatory requirements for development of shale formations. For example, New York has issued regulations that include guidelines for the use and disposal of water, the protection of groundwater, and the use of chemicals.[192] Pennsylvania has also instituted rules governing the extraction of natural gas from shale formations, noting that "…developing our energy resources cannot come at the expense of our environmental resources

191 Natural Gas Supply Association, see [http://www.naturalgas.org].

192 Department of Environmental Conservation, New York State, *Final Scope for Draft Supplemental Generic Environmental Impact Statement on the Oil, Gas and Solution Mining Regulatory Program, February 2009*, available at: [http://www.dec.ny.gov/docs/materials_minerals_pdf/finalscope.pdf].

— our water, our land and our ecosystems."[193] In 2008, inspectors from the state's Department of Environmental Protection ordered the partial shutdown of two drilling sites after discovering violations of state regulations.[194]

Another natural gas supply source with potential environmental issues is LNG. LNG tends to contain higher-Btu-content hydrocarbons that have not been processed out as is typically done with domestically produced natural gas. This can cause increased particulate emissions and has raised some health and environmental concerns about the use of LNG. However, there appears to be a growing consensus that the carbon footprint for LNG, on a lifecycle basis, is smaller than that of coal-fired generation.[195]

In the Energy Commission's report, *Potential Impacts of Climate Change on California's Energy Infrastructure and Identification of Adaptation Measures,* staff reported potential impacts of climate change on the natural gas infrastructure. It appears that sea level rise as a result of climate change will have little impact on natural gas availability since most of the supply comes from basins located in Alberta, the Rockies, and the southwestern United States. Also, potential new sources of shale gas are located in regions that cannot be affected by rising sea levels. However, climate change could cause changes in consumer energy demand based on temperature (for example, increased need for air conditioning because of warming trends) and could decrease hydroelectric production because of changes to precipitation patterns and snowpack. A major change in consumer demand and hydro availability could affect the general pattern of natural gas withdrawal from storage facilities. If utilities cannot keep up with traditional storage levels, consumers could be impacted by higher costs.

Reducing the environmental footprint of natural gas use in California should follow the loading order approach used in the state's electricity system. First and foremost is improving residential, commercial, and industrial energy efficiency, as well as the efficient use of natural gas as a transportation fuel, to reduce emissions associated with consumption of natural gas. An example of California's successful energy efficiency efforts are the previously mentioned statistics that the average California home consumed 120 Mcf of natural gas per year forty years ago, but today consumes less than 50 Mcf per year. The second priority is to accelerate the adoption of clean alternatives to conventional natural gas resources, such as biogas for both the electricity and transportation sectors, as well as improved technologies. Finally, the performance and reliability of the natural gas system and infrastructure must be improved.

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193 Kathleen McGinty, Secretary of Pennsylvania's Department of Environmental Protection, speaking at a department-sponsored summit, June 2008.

194 Environmental News Service, June 16, 2008.

195 Jamarillo, P.; W. Griffin; H. Matthew, "Comparative Life-Cycle Air Emissions of Coal, Domestic Natural Gas, LNG, and SNG for Electric Generation," Environmental Science and Technology 2007, Vol. 41, No. 17, 6290 and PACE (2009). Life Cycle Assessment of GHG Emissions from LNG and Coal Fired Generation Scenarios: Assumptions and Results.

Natural Gas and Reliability

California's dependence on natural gas as an energy source requires the state to maintain a reliable natural gas delivery and storage infrastructure. Eighty-seven percent of California's natural gas supply is from out of state and delivered by pipelines that extend deep into Canada, the Rocky Mountains, and the U.S. southwest production areas.

California needs adequate delivery pipelines and utility receiving capacity to ensure the state has supply to meet its needs at competitive prices. The consequences of inadequate natural gas infrastructure were particularly apparent during the 2000–2001 energy crisis. Interstate pipelines delivering natural gas to California were running at or near capacity for more than a year. The utilities' receiving, local transmission delivery systems, and storage operations were at their limits. Because there were no supply options available, California incurred natural gas costs that were double those paid in the years just prior to the crisis.

During and after the crisis, California increased its interstate pipeline delivery capacity, utilities improved their receiving ability, and the utility and independent storage owners enhanced their storage operations to meet future high-demand day conditions. These improvements have given California utilities the flexibility to choose supply sources in their day-to-day operations, which has forced production areas to compete for a share of the state's natural gas market.

There are concerns about whether increased natural gas demand for electricity generation in the Southwest will reduce the amount of natural gas available for California. Along El Paso's southern pipeline system, more than 10,000 MW of natural-gas fired power plants have been built. If all of these plants ramp up at the same time to meet electricity demand, it could affect the ability of the pipeline to meet the natural gas demand for those plants, possibly leading to unstable natural gas supplies for California. Kern River pipeline also makes upstream deliveries in Utah and Nevada that effectively reduce its ability to deliver full capacity to California.

Natural gas storage is an important piece of California's natural gas infrastructure. Without it, the supply pipelines would have to increase in size to meet winter demand, leaving a huge investment standing idle during half of the year. Storage fields are basically depleted natural gas fields that have had injection and withdrawal wells already drilled and compression and processing equipment added to clean up extracted natural gas. Natural gas is withdrawn from storage during periods of high demand, such as in the winter for space heating and in the summer for power generation. Natural gas is injected into storage during the spring and fall when overall demand is low, making pipeline capacity available to bring in additional natural gas to fill the storage facilities.

California does have potential new sources of natural gas from an existing LNG import facility in Baja, Mexico, along with pipeline projects on the horizon. Three pipeline projects should significantly increase the flow of natural gas to the state:

- The Ruby Pipeline project is planning to deliver natural gas from Opal, Wyoming, to California at a rate of 1.2 billion cubic feet per day (Bcf/d). This pipeline is scheduled to be in service by 2011 and will deliver natural gas to Malin, Oregon.

- The Sunstone Pipeline plans to deliver 1.2 Bcf/d of natural gas from Opal, Wyoming to Stansfield, Oregon. This pipeline is planned to be on-line in 2011 and could displace much natural gas in Oregon, thus freeing up supplies for California.
- The Kern River pipeline expansion project will increase delivery of natural gas from Wyoming to Southern California by 0.2 Bcf/d. The expansion of the existing pipeline is scheduled to be completed in 2010.

In the *2007 IEPR*, staff projected that as much as 20 percent of North American natural gas requirements might be met with LNG by 2017. However, United States LNG imports in 2008 were significantly lower than the amounts projected by Energy Commission staff and others, owing to a range of market developments, both global and domestic. In addition, United States and West Coast LNG terminal development appears to be slowing, and there is a new sense that the United States may not have to rely on LNG to make up previously projected supply deficits. The number of LNG facilities previously proposed for California has been reduced to two, only one of which has filed applications for building permits.

Natural gas is also used in the transportation sector in a broad range of applications, including personal vehicles, public transit, commercial vehicles, and freight movement. Natural gas vehicles may use compressed natural gas or LNG. The number of California on-road, light-duty vehicles powered by natural gas has increased since 2001 from 3,082 to 24,810 in 2008. While these numbers are small compared to the total vehicle population, increasing alternative transportation fuels to help meet the state's GHG reduction goals will require careful evaluation of the impacts on the natural gas supply system.

Natural Gas and the Economy

Wide and frequent swings in natural gas prices affect natural gas consumers, producers, and investors. Natural gas price volatility, measured as the magnitude and rate of changes in a commodity price over a given period, affects the national economy as a larger portion of gross domestic product is consumed by rising energy costs. As natural gas prices rise, they can have a negative impact on residential consumers by consuming more of a household's discretionary income. Consumers are also affected because volatility adds uncertainty in the electricity generation industry, which ultimately affects the price of electricity. Volatility also makes budgeting and cost management more difficult for commercial and industrial consumers that use significant amounts of natural gas in their operations. For natural gas producers, volatility contributes to the boom-bust cycle of drilling activity, ultimately affecting available natural gas supplies. Natural gas price volatility also affects the energy planning process because the added uncertainty in predicting market movements affects the ability to accurately forecast natural gas prices.

During 2008, natural gas spot prices — the price of natural gas for next-day delivery at a specific location — traded as high as $13.32 per thousand cubic feet (Mcf) and as low as $5.63/Mcf. The large price fluctuations in 2008 increased the focus on price volatility and its impacts on natural gas market participants. Factors that influence natural gas prices and price volatility include weather, supply and demand imbalances, infrastructure issues, unreliable data, regional and global economic conditions, speculative trading, and market manipulation.

The impacts of natural gas price changes vary for different consumers. For example, residential and small commercial core customer demand tends to be somewhat less affected by price swings. Demand by these customers is largely driven by heating needs during cold weather, and because core customers are often unaware of natural gas price changes until a monthly bill arrives in arrears, there is little opportunity for them to reduce consumption in response to price changes. In addition, the rates that utilities charge these core customers are still subject to oversight by government agencies and are not subject to daily price changes.

However, longer-term wholesale price changes do affect the retail rates these customers pay when utilities receive approval to adjust their natural gas tariff rates to reflect a change in costs. These increased prices negatively affect core customers, especially low-income households, resulting in more residential customers that are unable to pay their monthly bills, increasing the number of consumers that require assistance through programs such as the Low-Income Home Energy Assistance Program.

Industrial, or non-core, consumers of natural gas tend to be much more sensitive to price volatility. These consumers typically purchase large quantities of natural gas directly from the market and are immediately affected by changing prices, making budgeting and cost management more difficult. For example, nitrogen fertilizer manufacturers use significant amounts of natural gas, the cost of which can account for 90 percent of the total manufacturing costs. Price volatility can therefore have a dramatic impact on their manufacturing operations. Also, because industrial consumers often are large users of natural gas, significant changes in natural gas prices can influence many operational decisions. If prices become too high or are extremely volatile, industrial users might consider switching to a different fuel if possible or even shutting down their operations.

While price volatility can have material consequences for the industrial sector, some large industrial consumers have the ability to take advantage of hedging opportunities to reduce risk. Large users potentially could purchase and store natural gas when prices are low, enter into long-term fixed price contracts, or use financial instruments like options to lower the risk and uncertainty of changing prices.

The electricity generation sector is the largest consumer of natural gas, both nationally and in California,[196] so natural gas price volatility significantly affects this sector and ultimately the price of electricity. Natural gas price volatility leads to increased uncertainty for both regulated utilities and merchant power firms about the ongoing costs of operating natural gas-fired power plants, both existing and new. Increased uncertainty also heightens concern regarding investment in new natural gas-fired plants, which may be seen as more risky when compared to other generation technologies that use coal or renewable fuels.

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196 Energy Information Administration, Natural Gas Consumption by End Use data, available at: [http://tonto.eia.doe.gov/dnav/ng/ng_cons_sum_dcu_nus_a.htm].

Natural gas producers are also affected by price volatility, making project evaluation and investment decisions less certain. Price volatility can trigger concerns by lenders and investors and increase the cost of capital as lenders and investors demand greater returns because of increased uncertainty. Price volatility also contributes to recurring boom-bust production cycles and associated operational problems, such as employee turnover and expensive start-up and shutdown costs. The current period of falling natural gas prices provides a good example. Natural gas production is largely a capital intensive venture during well development but has lower marginal production costs once the well is producing gas. During periods of low prices, active wells can remain profitable to operate but, in the longer term, declining prices can lead to reduced production when the number of drilling rigs is reduced in response to sustained lower prices. Since prices peaked in July 2008, United States drilling rig numbers dropped each week as prices continued to decline.[197]

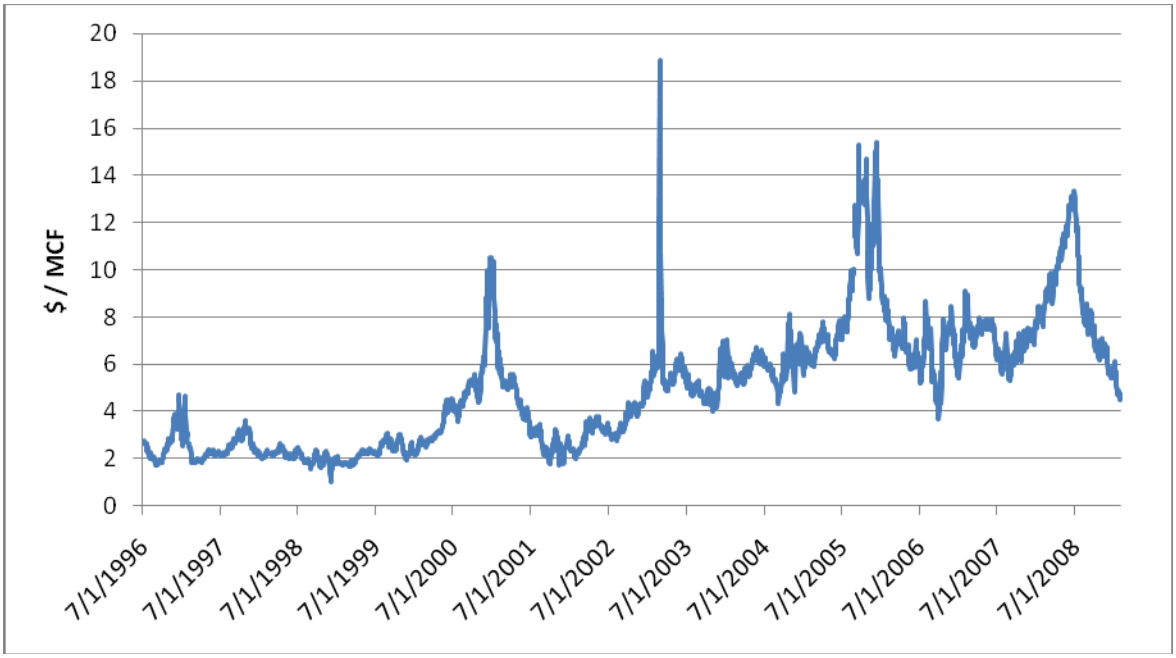
Figure 17 shows a period of relatively stable natural gas prices in the late 1990s, followed by several periods of large price spikes after 2000. Henry Hub[198] spot prices traded within a $2/Mcf to $3/Mcf band throughout the late 1990s and early 2000s, rose to $4/Mcf, and surpassed $6/Mcf by the middle of the decade. One key factor that caused price increases was the growth in domestic demand that exceeded United States domestic production capabilities because North American basins were maturing and producing less gas. The combination of increasing domestic demand and declining domestic production resulted in natural gas prices moving higher.

There have been four major price spikes since 2000 that were caused by many of the physical and financial market factors mentioned earlier in this section. However, each price spike was influenced to different degrees by the various factors. For example, a severe cold winter storm played the significant role in the February 2003 price spike, and back-to-back hurricanes played the significant role in the fall 2005 price spike. The price spikes of winter 2000–2001 and summer 2008 were the result of a number of different factors, including market manipulation and market speculation.

197 Energy Information Administration’s April 23, 2009, Natural Gas Weekly update reports that the domestic drilling rig count is down over 50 percent from its high in August 2008, reached in response to July 2008 peak prices.

198 Henry Hub is located in Louisiana and is North America’s main natural gas trading hub and most widely quoted natural gas pricing point. It interconnects four intrastate and nine interstate pipelines that can transport enough natural gas to satisfy about three percent of total United States demand.

Figure 17: Henry Hub Spot Prices 1996–2008



Source: Natural Gas Intelligence data

The flexibility from having extra infrastructure, coupled with supplies from lower-priced production areas, helps shield the state from the brunt of price volatility. Since California is part of an international natural gas market that includes Canada, the United States, and Mexico, a disruption in one area ripples though the rest of the market. California is not immune to the ripples, but the ripples are much smaller now when they reach the state. Prices of natural gas at California's border are among the lowest in the nation, with current prices considerably less than the Henry Hub price.

Fuels and Transportation Sector

Although the fuels and transportation energy sector is responsible for producing the greatest volume of GHG emissions—nearly 40 percent of California's total—the issues confronting this sector go far beyond climate change. Reducing California's dependence on petroleum in general and foreign crude oil in particular are equally pressing issues. Doing so would not only reduce GHG emissions, but would also mitigate the effects that global demand, geopolitical events, crude oil refining capacity and outages, and petroleum infrastructure challenges have on fuel prices and the average cost of production of goods and services, both of which directly affect the state's economy and gross state product.

AB 32 does not directly address GHG emissions reduction in the transportation sector, but legislation at both the state and federal level does. California's AB 1007 (Pavley, Chapter 371, Statutes of 2005), AB 118 (Núñez, Chapter 750, Statutes of 2007), AB 1493 (Pavley, Chapter 200, Statutes of 2002), California's Low Carbon Fuel Standard (LCFS), and the federal Energy

Independence and Security Act's (EISA) revisions to the Renewable Fuel Standard (RFS2) set policies and standards that will ultimately change vehicle and fuel technologies and accelerate the market for low carbon fuels well beyond the current level of demand.

The following section summarizes the Energy Commission's 2009 transportation supply and demand forecast. Providing this data will give decision makers a snapshot of the state's future fuel demand and supply for petroleum, as well as renewable and alternative fuels and vehicles. This data is imperative to understanding future fuel supply and infrastructure needs that could have a major impact on consumer reliability and the environment. In past *IEPRs,* the Energy Commission forecast has only included projections for petroleum transportation fuels. For the *2009 IEPR* cycle, staff expanded the list of transportation fuels to include demand forecasts for E85 (a blend of 15 percent gasoline and 85 percent ethanol), B20 (a blend of 80 percent diesel and 20 percent biodiesel), electricity, compressed natural gas (CNG), and liquefied natural gas (LNG), with more limited analysis of hydrogen and propane.

Transportation Fuels Supply and Demand

In its transportation forecasts, the Energy Commission analyzes trends of transportation demand related indicators, as well as demographic and economic variables. The transportation demand forecasts encompass four primary transportation sectors:

- Commercial and residential light-duty vehicles (under 10,000 pounds)
- Medium- and heavy-duty transit vehicles, including rail (over 10,000 pounds)
- Medium- and heavy-duty freight vehicles, including rail
- Commercial aviation

Each of these sectors is associated with a distinct forecasting model that estimates the demand for that transportation sector. The California Conventional Alternative Fuel Response Simulator, Freight, Transit, and Aviation models represent each of the corresponding transportation sectors. Staff used a range of fuel price cases, as well as economic and demographic projections from the Department of Finance (DOF) and Moody's Economy.com to cover the forecast period.

Demographics

Demographic growth trends are key indicators of future consumer travel demand. For the next 20 years, DOF forecasts growth in California's population of 25 percent and Moody's Economy.com forecasts growth in personal income of 76 percent. Between 2009 and 2030, population is projected to increase at an annual compound average rate of 1.15 percent, compared with a growth rate of 2.94 percent in real personal income over the same period. These growth rates indicate that travel demand in California will also likely increase over the forecast period.

To provide historical context, California's Gross State Product (GSP) increased by 40 percent in real terms from 1998 to 2008. During that same period, employment growth was only 10 percent. The impact of the economic recession is evident in that both GSP and employment lowered between 2008 and 2009. The GSP is projected to return to a positive growth rate by 2010, while total non-farm employment projections do not begin to exhibit positive growth until

2011. Non-farm employment is projected to grow by 20 percent during the forecast period of 2009–2029, in contrast with higher projected growth rates for both population and GSP.

The Energy Commission's draft staff report, *Transportation Energy Forecasts and Analyses for the 2009 Integrated Energy Policy Report* contains more details on these demographic findings.[199]

Fuel Supply and Demand

The current recession has had a significant impact on the state's transportation sector. Consumer demand for gasoline and diesel fuels continues to decline. Job growth and industrial production — drivers of air travel — are also declining, causing the aviation sector to experience a drop in air traffic. In response to this and higher fuel prices, the aviation sector has reduced the number of planes in service and taken the least efficient aircraft out of service. In addition, the freight sector (rail and trucking) is experiencing a decrease in container movement at the state's three major marine ports—Los Angeles, Long Beach, and the Bay Area.

The early years of the Energy Commission's transportation fuel demand forecast show a recovery from the recession. Because the economic and demographic projections used in these forecasts indicate a return to economic and population growth, fuel demand in the light-duty, medium- and heavy-duty, and aviation sectors tend to resume historical growth patterns. However, the mix of fuel types is projected to change significantly as the state transitions from gasoline and diesel to alternative and renewable fuels.

Petroleum

Although the state's 20 crude oil refineries processed more than 1.8 million barrels a day of crude oil in 2008, California crude oil production continues to decline, despite record crude oil prices and increased drilling activity greater than at any point since 1985. Since 1986, California crude oil production declined by more than 41 percent at an average rate of 3.2 percent per year over the last 10 years, and slowed to an annual average of 2.2 percent between 2006 and 2008. Figure 18 indicates the decline in California-sourced oil and the increasing reliance on marine imports, primarily from foreign sources as Alaska production also declines. The state's refinery capacity is expanding at a slower rate than that of the United States and the rest of the world. Refinery capacity growth, known as refinery creep, is relatively low and expected to increase at an annual average rate between 0 and 0.45 percent per year through 2030.

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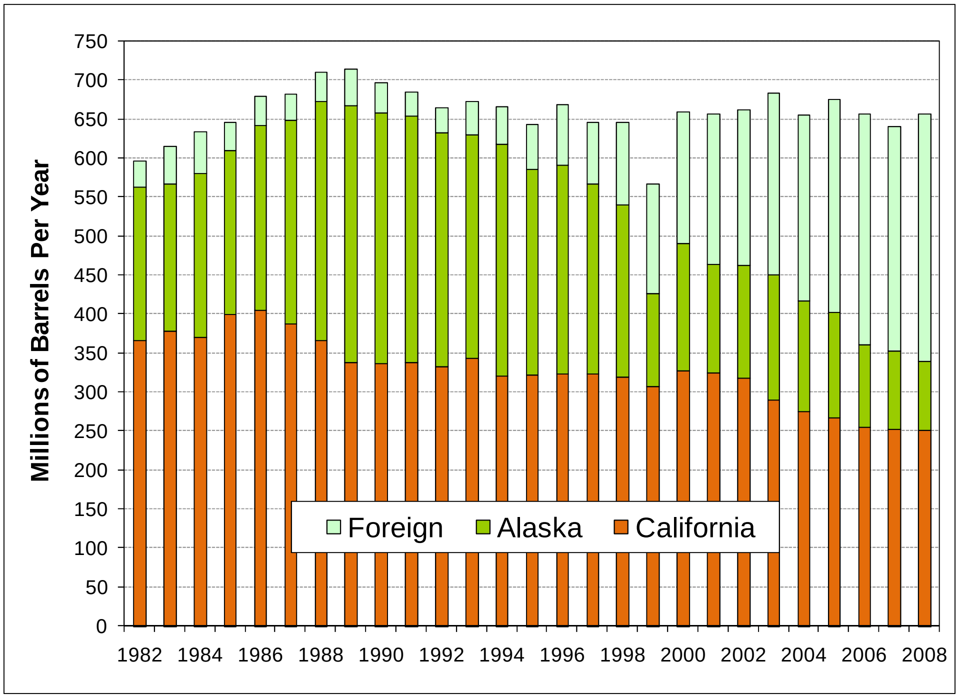
199 California Energy Commission, *Transportation Energy Forecasts and Analyses for the 2009 Integrated Energy Policy Report,* August 2009, CEC-600-2009-012-SD, available at: [http://www.energy.ca.gov/2009publications/CEC-600-2009-012/CEC-600-2009-012-SD.PDF].

Figure 18: Crude Oil Supply Sources for California Refineries



Source: Annual crude oil supply data from the Petroleum Industry Information Reporting Act database

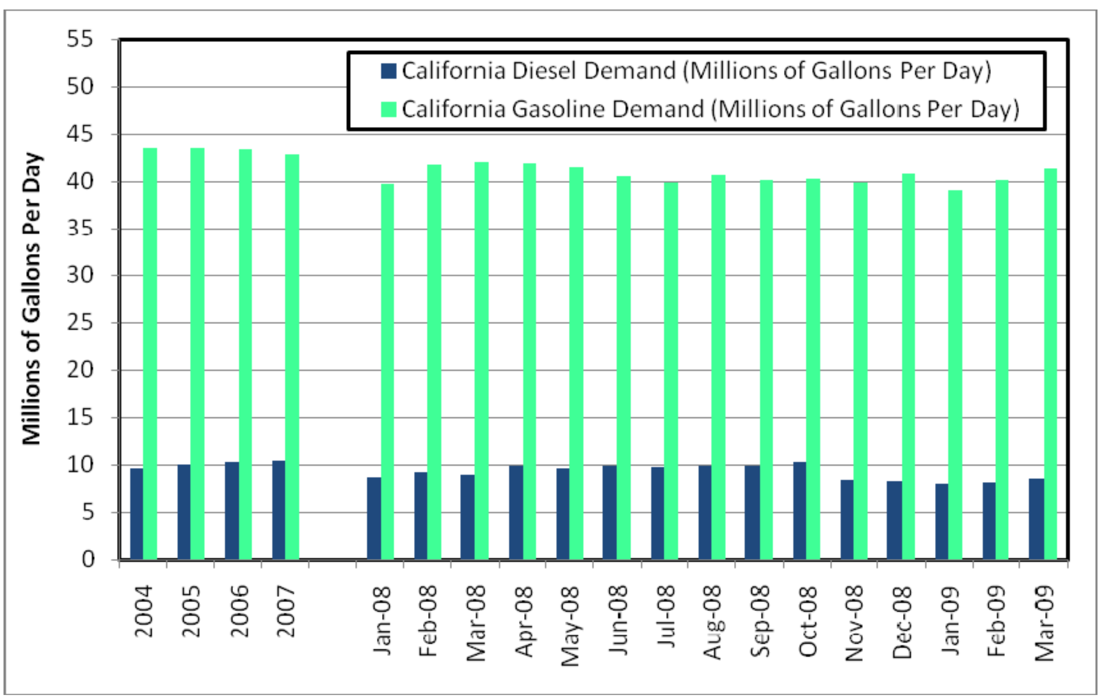
Increased exploration and drilling in state and federal waters could reverse the continuing decline of the state's crude oil production, but any significant production of off-shore oil would be at least a decade away. In 2008, the federal government lifted the moratorium on drilling in the Outer Continental Shelf off the coast of California. It is uncertain if off-shore drilling will proceed because of numerous environmental and economic concerns. If expanded off-shore exploration and development is allowed to proceed, crude oil production off the coast could increase from 110,000 barrels per day in 2008 to approximately 310,000 barrels per day by 2020 and 480,000 barrels per day by 2030.

Crude oil imports are determined by trends in consumer demand, California refinery output, and exports of petroleum products to neighboring states. In 2008, California refiners imported 406 million barrels of crude oil. Differences in crude oil import forecasts are results from contrasting assumptions on the production capabilities of California's refineries and the production of California crude oil. In the staff's Low Crude Oil Import forecast, refinery production capabilities remained constant over the forecast period and California crude oil production declined at a rate 2.2 percent. The High Crude Oil Import forecast assumes refinery production capabilities increased at a rate of .45 percent a year and California crude oil production declined at a rate of 3.2 percent. Under the Low Crude Oil Import projection, annual crude oil imports increase by 34 million barrels between 2008 and 2015, by 55 million barrels by 2020, and by 91 million barrels by 2030 (a 22.5 percent increase compared to 2008). Under the High Crude Oil Import projection, annual crude oil imports rise by 70 million barrels between 2008 and 2015, by 113 million barrels by 2020, and by 190 million barrels by 2030 (a 47 percent increase compared to 2008). It should be noted that most crude oil imports now come from foreign sources. This means that even under a low case scenario, the state's dependence on imported crude oil grows.

During the forecast period, the changes in levels of transportation fuel imports are determined by trends in consumer demand, California refinery output, and exports of petroleum products to neighboring states. The staff forecast shows that California's gasoline imports will decrease significantly over the next 15 years (under the High Petroleum Product Import Case), while imports of diesel and jet fuel will still rise to keep pace with growing demand for those products. Under the Low Petroleum Product Import Case scenario, the growing imbalances between gasoline and the other transportation fuels are even more extreme, resulting in a total net decline of imports of at least 116,000 barrels per day by 2025, whereby California's gasoline supply balance would switch from a net importer of over 51,000 barrels per day in 2008 to a net exporter of over 218,000 barrels per day in 2025. The latter outcome is unlikely since refiners will adjust operations to decrease the ratio of gasoline components produced from each barrel of crude oil processed.

The Energy Commission staff recently analyzed taxable fuel sales data from the Board of Equalization to determine consumption trends as shown in Figure 19.

Figure 19: Historic California Gasoline and Diesel Demand



Source: Energy Commission staff adjusted Board of Equalization sales data

Overall, California is experiencing a downward trend in sales for gasoline, diesel, and jet fuel. For example, California's average daily gasoline sales for the first four months of 2009 were 2.1 percent lower than the same period in 2008, continuing a reduction in demand observed since 2004. Daily diesel fuel sales for the first three months of 2009 were 7.7 percent lower than the same period in 2008, continuing a declining trend since 2007. Recent demand trends for jet fuel (8.9 percent decline in 2008) are similar to diesel fuel and reflect the impact of the economic downturn and higher fuel prices.

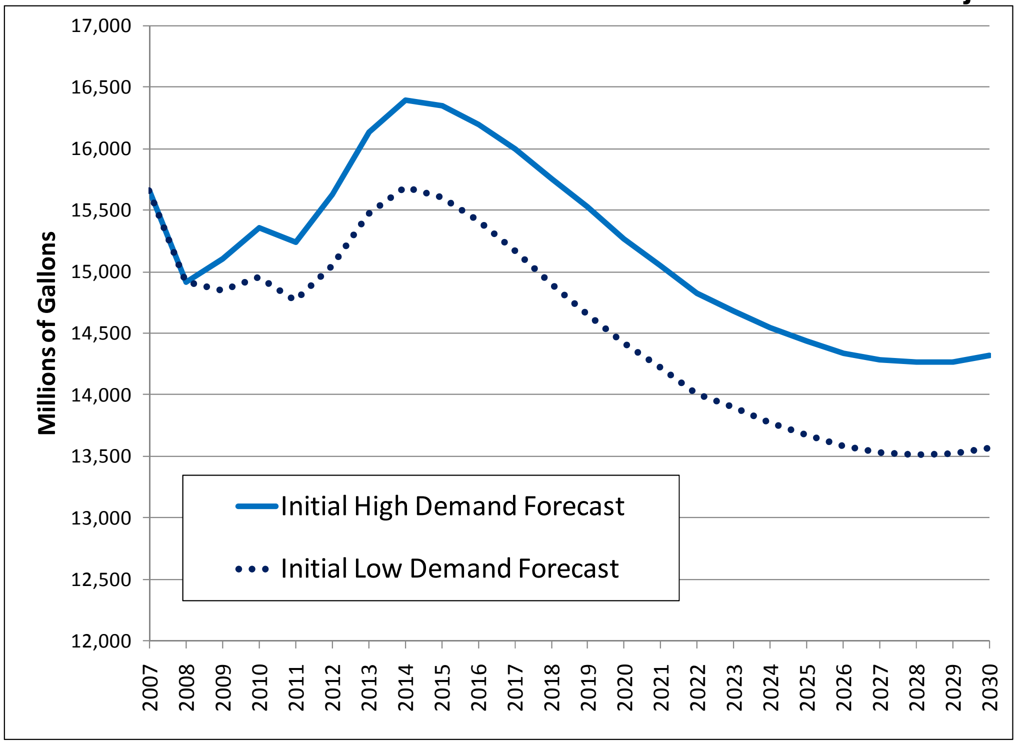
Staff expects annual gasoline consumption to decrease over the forecast period, largely because of high fuel prices, efficiency gains, competing fuel technologies, and mandated increases of alternative fuel use. The estimate of future gasoline and diesel fuel demand for California was the result of two distinct stages of analysis. The first step was to quantify demand levels using in-house computer models for both traditional fuels (gasoline and diesel fuel) and specific types of alternative fuels. The second step was to determine the impact of the federal renewable fuel mandates (discussed later in this section) that will likely result in even higher levels of ethanol and biodiesel use beyond the levels initially forecast during the first step of the analysis. Higher levels of renewable fuels calculated in the second step of the analysis will result in slightly lower levels of gasoline and diesel fuel demand for all modeling scenarios.

In the initial results of the forecast's Low Petroleum Price Case (High Demand), the recovering economy and lower relative prices lead to a gasoline demand peak in 2014 of 16.40 billion gallons before falling to a 2030 level of 14.32 billion gallons, 4.0 percent below 2008 levels (see Figure 20). The initial High Petroleum Price Case (Low Demand) forecast projects a gasoline demand peak of 15.69 billion gallons in 2014 before declining to 13.57 billion gallons by 2030, a decrease of 9.0 percent compared to 2008. Between 2008 and 2030, staff expects total diesel demand in California to increase 49.8 percent in the initial results of the High Petroleum Price Case (Low Demand) to 5.14 billion gallons and 57.4 percent in the Low Petroleum Price Case (High Demand) to 5.40 billion gallons. Between 2008 and 2030 staff expects that jet fuel demand in California will increase by 62.8 percent to 5.12 billion gallons in the High Petroleum Price Case (Low Demand), and 82.9 percent to 5.75 billion gallons in the Low Petroleum Price Case (High Demand).

Renewable and Alternative Fuels

Policies mandating increased renewable fuel use are projected to play a significant role in reducing the state's dependence on petroleum. At the federal level, the current Renewable Fuel Standard (RFS1) program, implemented under the Energy Policy Act of 2005 (EPAct), amended the Clean Air Act by establishing the first national renewable fuel standard. The Energy Independence and Security Act of 2007 made changes to the goals of RFS1, mandating increased use of ethanol and biodiesel. These new requirements, known as the RFS2, establish new specific volume standards for cellulosic ethanol, biomass-based diesel, advanced biofuel, and total renewable fuel that must be used in transportation fuel each year. The RFS2 also includes new definitions and criteria for both renewable fuels and the feedstocks used to produce them, including new GHG thresholds for renewable fuels. The U.S. EPA is in the process of a rulemaking and the target date for changes to take effect is January 1, 2010.[200]

Figure 20: Initial California Gasoline Demand Forecast – No RFS2 Adjustment



Source: California Energy Commission

Specifically, the RFS2 will require refiners, importers, and blenders to achieve a minimum level of renewable fuel use each year either through blending or purchasing of Renewable Identification Number (RIN) credits from other market participants who blend more renewable fuel than needed for their individual obligations. For 2009, the California RFS2 obligation is just over 10 percent and assumes that 11.1 billion gallons of renewable fuel will be blended into gasoline and diesel fuel nationally. Figure 21 depicts these renewable fuels obligations.

In recent years, the increased use of ethanol as a transportation fuel has resulted in an expanded domestic production capacity, fluctuating quantities of imports, and inventory build or draws as necessary to balance out demand. As of June 2009, there was an estimated 2.2 billion gallons of surplus ethanol production capacity in the United States. This oversupply of domestic ethanol is primarily responsible for the recent climate of sustained, poor production economics, which brought about the closure of several national and all California ethanol production operations. However, this development will likely be temporary as demand for ethanol is forecast to significantly increase over the next several years because of the RFS2 regulations.

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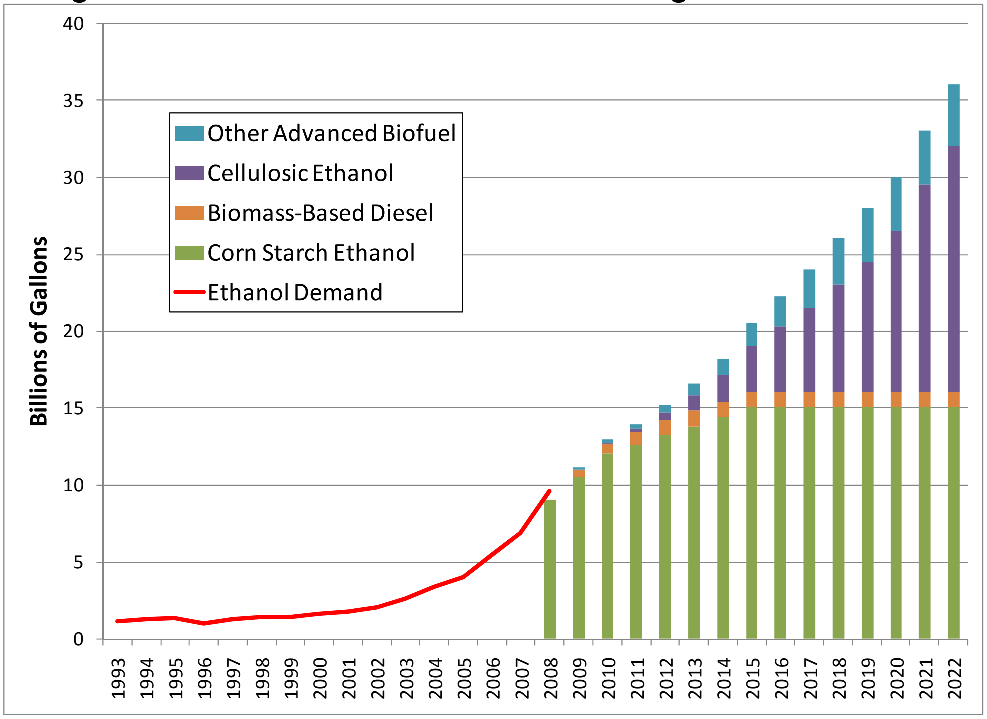
200 United States Environmental Protection Agency, see [http://www.epa.gov/OMS/renewablefuels/420f09023.htm].

Figure 21: U.S. Ethanol Use and RFS Obligations 1993-2022



Sources: Energy Information Administration, U.S. EPA, and California Energy Commission

This oversupply of ethanol, along with relatively low ethanol prices in the United States, reduced ethanol imports to modest levels. Imports of ethanol play a lesser role in California's supply picture, but this could change because of carbon intensity requirements, the state's LCFS, and the fuel obligations of RFS2. Specifically, California is expected to start importing more ethanol from Brazil, as it has lower carbon intensity relative to Midwest ethanol and will meet the LCFS policy requirements.

As for biodiesel, production has increased dramatically in the United States since 2005 in response to federal legislation that included a $1 per gallon blending credit for all biodiesel blended with conventional diesel fuel. As of July 2009, there was more than 2.3 billion gallons of biodiesel production capacity for all operating United States facilities, along with another 595 million gallons per year of idle production capacity, and another 289 million gallons per year capacity under construction. Even though the LCFS will greatly increase the use of biodiesel as a blending component (because of its lower carbon intensities), it appears there will still be sufficient domestic supply from biodiesel production facilities to meet the RFS2 blending requirements for several years.

Increased output of biodiesel, due to the blending credit and attractive wholesale prices, has resulted in increased United States exports to the European Union (EU). In 2008, United States producers exported nearly 70 percent of their supply to the EU. However, in July 2009 the EU officially imposed import duties on United States biodiesel for the next five years. Because of this ruling, United States exports to the EU are likely to decline dramatically.

As already shown, a projected impact of the RFS2 is that it will increase ethanol and biodiesel demand in California. Under the High Petroleum Price Case (Low Demand) for gasoline, staff forecast total ethanol demand in California to rise from 1.2 billion gallons in 2010 to 2.1 billion gallons by 2020. Under the Low Petroleum Price Case (High Demand) for gasoline, staff projects total ethanol demand in California to rise from 1.2 billion gallons in 2010 to 2.6 billion gallons by 2020. Staff also forecast that ethanol demand will exceed an average of 10 percent by volume in all gasoline sales between 2012 and 2013. However, because of various fuel specification and vehicle warranty limitations, it is unlikely that the low-level ethanol blend limit in California will be greater than the current 10 percent by volume (E10), even if the U.S. EPA ultimately grants permission for United States refiners and marketers to blend E15 gasoline.

To meet RFS2 requirements, the availability of E85 at retail sites will need to increase dramatically to ensure that sufficient volumes can be sold. This scenario would require significant increases in both the number of E85 dispensers and Flex Fuel Vehicles (FFV). For example, assuming a 10 percent ethanol blending limit, or "blend wall", E85 sales in California are forecast to rise from 2 million gallons in 2010 to 1.3 billion gallons in 2020 and 1.6 billion gallons by 2030 under the Low Petroleum Price Case (High Gasoline Demand). E85 consumption required to meet the RFS2 is shown in Figure 22; Figure 23 also shows the impact of the RFS2 on the final Low Gasoline Demand forecast. However, the pace of this expansion may still not be enough to achieve compliance because of specific infrastructure challenges and disincentives (see the Infrastructure Adequacy section below for more details).

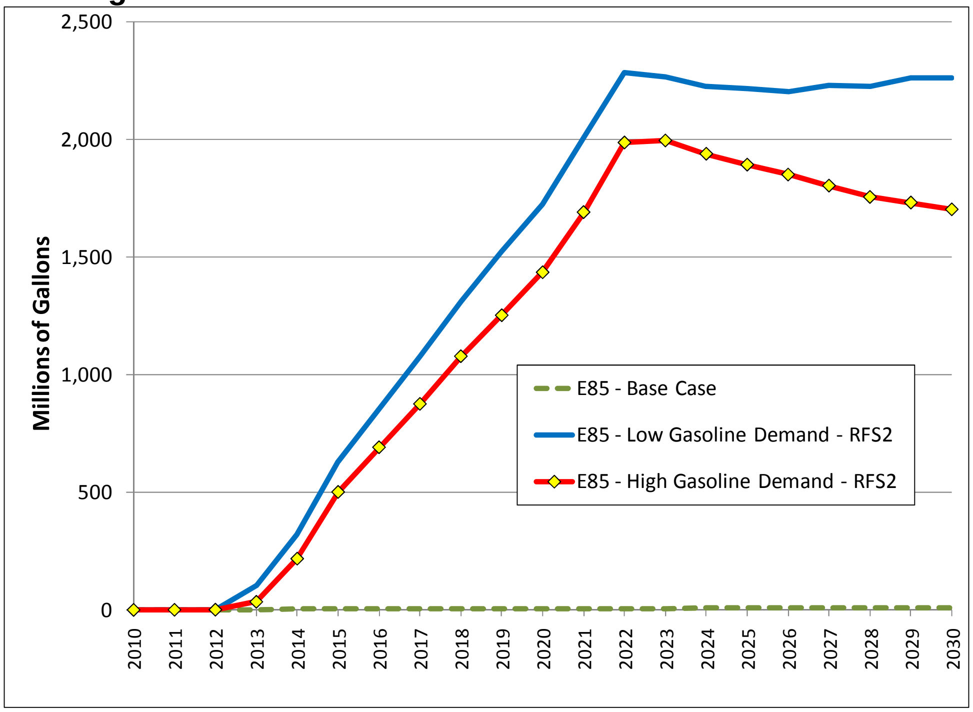
As for biodiesel demand, the High Petroleum Price Case (Low Demand) shows biodiesel "fair share," or California's share of mandated biodiesel use proportional to its share of total United States diesel use, will increase from 38 million gallons in 2010 to 57 million gallons by 2030. Under the Low Petroleum Price Case (High Demand), biodiesel "fair share" ranges from 37 million gallons in 2010 to 58 million gallons by 2030. Based on these projected volumes, California's average biodiesel blending concentration is not expected to be higher than 1.8 percent. However, California's LCFS requirements are anticipated to increase the level of biodiesel use to significantly higher levels that have yet to be fully quantified.

Infrastructure Adequacy

California needs sufficient fuel infrastructure to ensure reliable supplies of transportation fuels for its citizens. Petroleum, and alternative and renewable fuels face significant infrastructure issues from the wholesale and distribution level to the end users because of the anticipated rapid increase in demand associated with growing government ethanol mandates. Currently, petroleum infrastructure is strained at the marine ports and throughout the distribution system. In the case of alternative and renewable fuels, much of the infrastructure that will soon be necessary is not even in place. It is critical that the state expand upon the current petroleum fuel infrastructure to ensure a continued supply of transportation fuel for California and neighboring states, and that it build new infrastructure to ensure that California can meet its mandated renewable and alternative fuel goals.

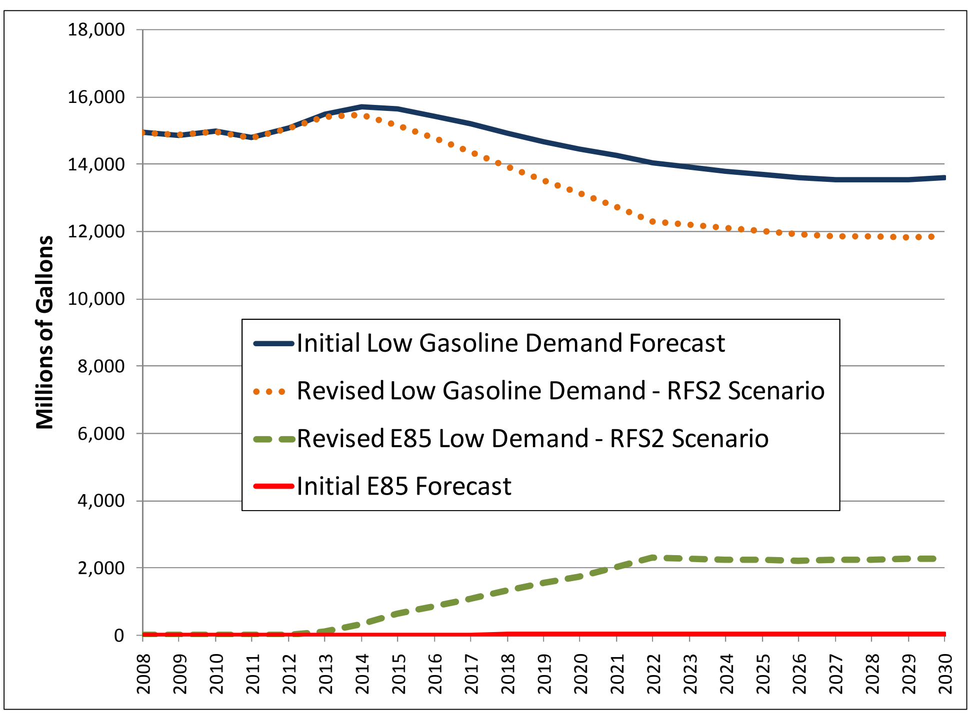
The following two sections describe the most pressing issues and barriers affecting development of the petroleum and renewable and alternative fuels infrastructure in California.

Figure 22: California E85 Demand Forecast 2010-2030



Source: California Energy Commission

Figure 23: Revised Low Demand Forecast 2010-2030



Source: California Energy Commission

Petroleum Infrastructure

The Energy Commission forecasts that crude oil imports will continue to increase, requiring expansion of the existing crude oil import infrastructure. This infrastructure is critical in ensuring a continued supply of feedstocks to enable refiners to operate their facilities and maintain a reliable supply of fuel for California and neighboring states.

The Energy Commission forecasts that the existing crude oil import infrastructure in Southern California must expand to avoid shortages in supplies for refinery operations. Although progress has been made on developing a facility at Pier 400, Berth 408 in the Port of Los Angeles, the permitting process to start construction has stretched to more than four years. In fact, Plains All-American (the project developer) still does not have all of the requisite approvals to start construction.

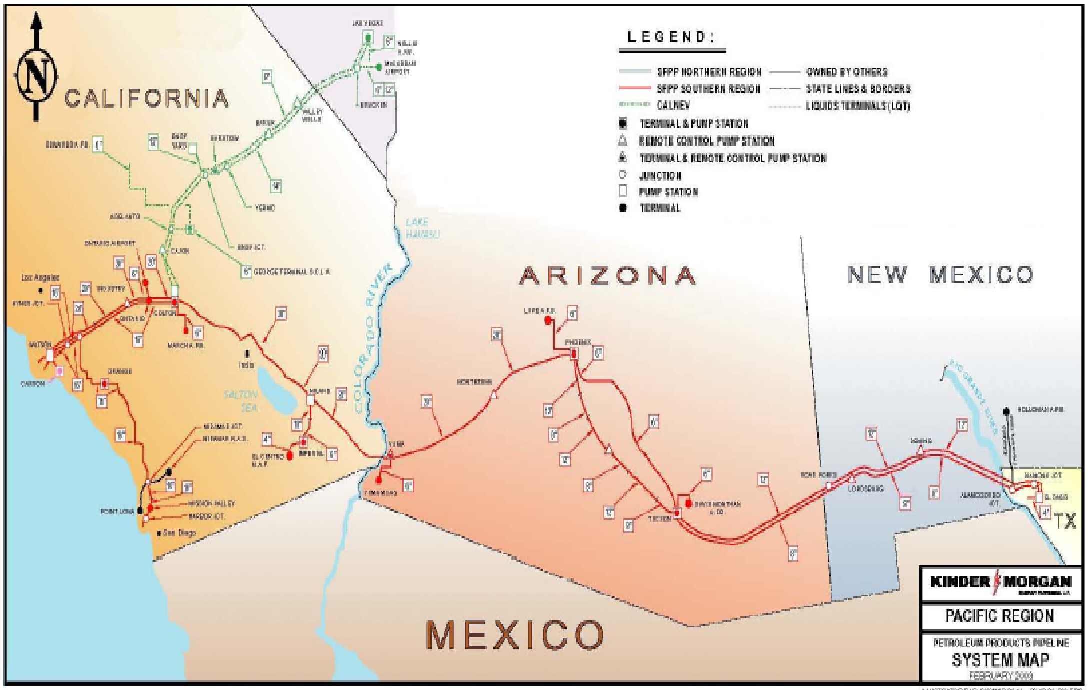
To add further strain (especially in Southern California), staff expects the increased imports of crude oil to result in a greater number of marine vessels arriving in California ports, with 46 to 272 additional arrivals per year by 2030. Additional storage tank capacity (beyond that already identified as part of Berth 408 project) must be constructed to handle the incremental imports and it is unclear where these can be located given the competition for land in and around the ports. Also, the opening of off-shore drilling along California's coast could require additional infrastructure in the way of platforms, interconnecting pipelines, crude oil trunk lines, and pump stations. It is recognized that some near-term offshore drilling projects using existing platforms or shore-based operations would mostly be able to use existing crude oil distribution infrastructure.

California exports large amounts of transportation fuels to Nevada and Arizona. Pipelines that originate in California provide nearly 100 percent of the transportation fuels consumed in Nevada and approximately 55 percent of fuels consumed in Arizona. Kinder Morgan's recent East Line pipeline expansion from Texas to Arizona (see Figure 24) caused a drop in Arizona's demand for California fuel exports in 2008 as refiners and marketers shifted to Texas and New Mexico for supply. If Kinder Morgan does not make additional expansions to the pipeline distribution systems, the continued growth of transportation fuel demand in Nevada could exceed pipeline capacity, but not until 2021. Overall, the near- and long-term forecast periods indicate that transportation fuel demand growth in Nevada and Arizona could place additional pressure on California's refineries and petroleum marine import infrastructure.

Renewable and Alternative Fuels and Vehicles Infrastructure

To meet the requirements of RFS2 and the LCFS, several issues must be resolved regarding the adequacy of additional biofuels supplies and the infrastructure needed to receive and distribute increased quantities of ethanol and biodiesel to California consumers. The primary challenges faced by makers of alternative fuel vehicles include a lack of infrastructure in both fuel production and refueling, the need to develop technologies to reduce battery costs, the need for standardized testing, and consumer acceptance of vehicles. Simply stated, the refueling infrastructure has to be in place when the vehicles arrive. Moreover, these refueling sites must meet consumer expectations for access, convenience, and fuel quality assurance.

Figure 24: Kinder Morgan Interstate Pipeline System

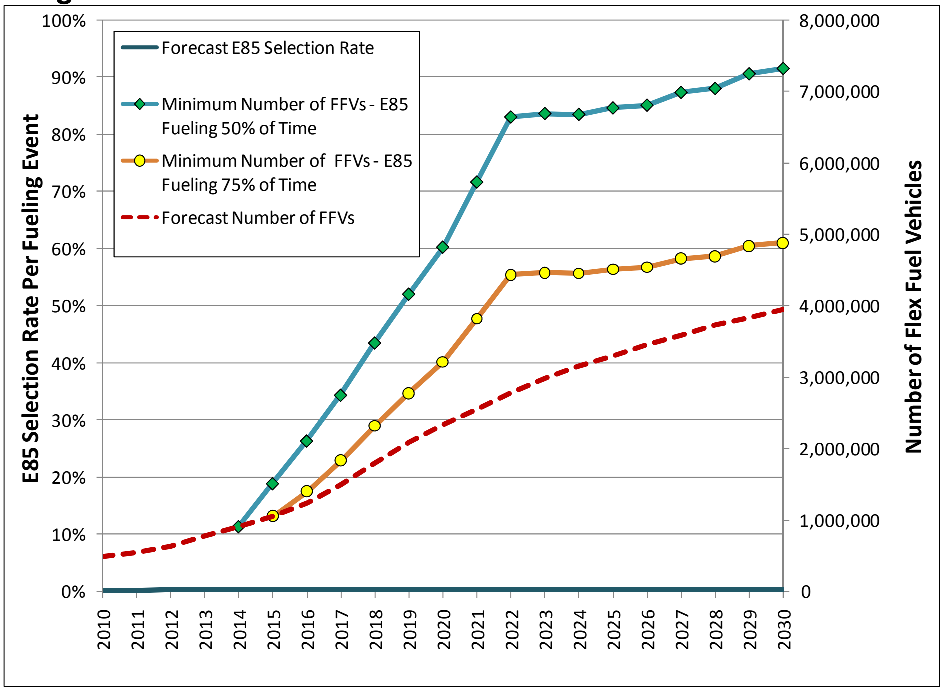


Source: Kinder Morgan Pipeline Company.

FFVs are designed to run with either gasoline or a blend of up to 85 percent ethanol (E85). As shown in Figure 25, California's number of registered FFVs must increase from a total of 382,000 vehicles in October 2008 to as many as 2.4 million by 2020 to provide demand for enough E85 to be sold to meet the RFS2. However, California's current retail infrastructure is not adequate to handle an increase in E85 sales. The general public only has access to about 25 E85 stations in California today, so a vast majority of FFV owners are fueling with regular gasoline. Retail station owners and operators are not required to make E85 available for sale to the public under RFS2.

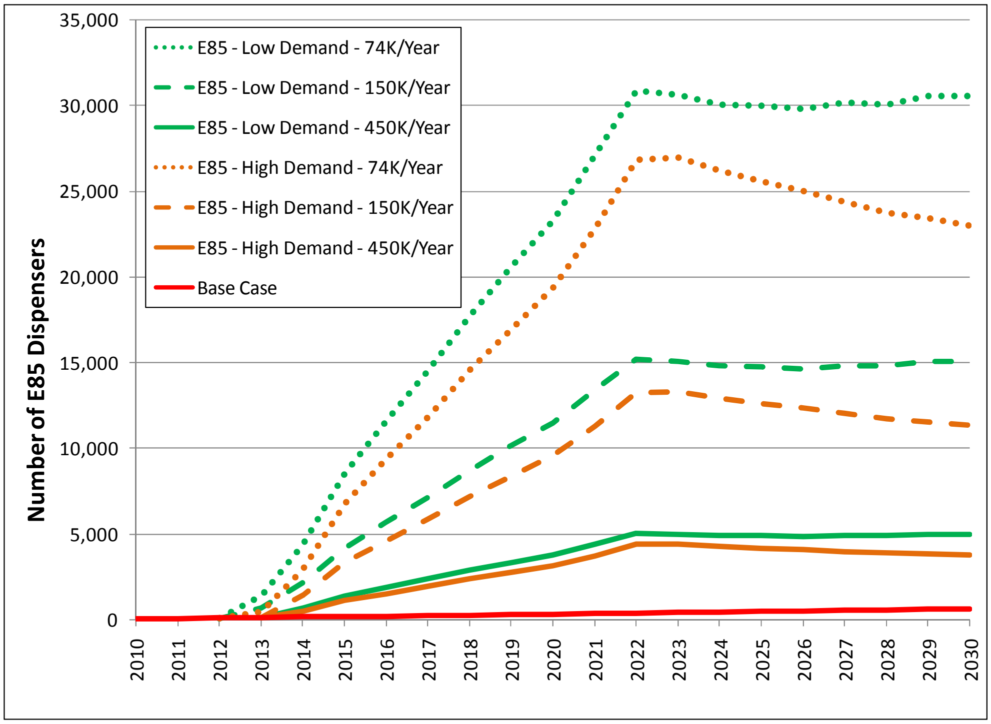
Consumers may continue to buy more FFVs, but that will have little impact on decreasing petroleum consumption or meeting RFS2 standards if E85 is not available at fueling stations. Depending on the average quantity of fuel sold by a typical E85 dispenser, California could require between 3,200 and 23,300 E85 dispensers by 2020 (Figure 26). E85 retail infrastructure is expensive. Costs for installing a new underground storage tank, dispenser, and associated piping range between $50,000 and $200,000. Statewide, the E85 retail infrastructure investment costs could be as low as $192 million, to upwards of $4.7 billion between 2009 and 2020. Between 2009 and 2030 the E85 dispenser infrastructure costs could range from $251 million to $6.1 billion. One approach to reduce this anticipated infrastructure cost is for the California Legislature to consider requiring new building code standards that all gasoline-related equipment (underground storage tanks, dispensers, associated piping and so on) be E85 compatible for construction of any new retail stations or replacement of any gasoline-related equipment beginning January 1, 2011. This approach would increase the likelihood of success of renewable fuel penetration policy goals.

Figure 25: California FFV Low Demand Forecast 2010-2030



Source: California Energy Commission

Figure 26: California E85 Dispenser Forecast 2010-2030

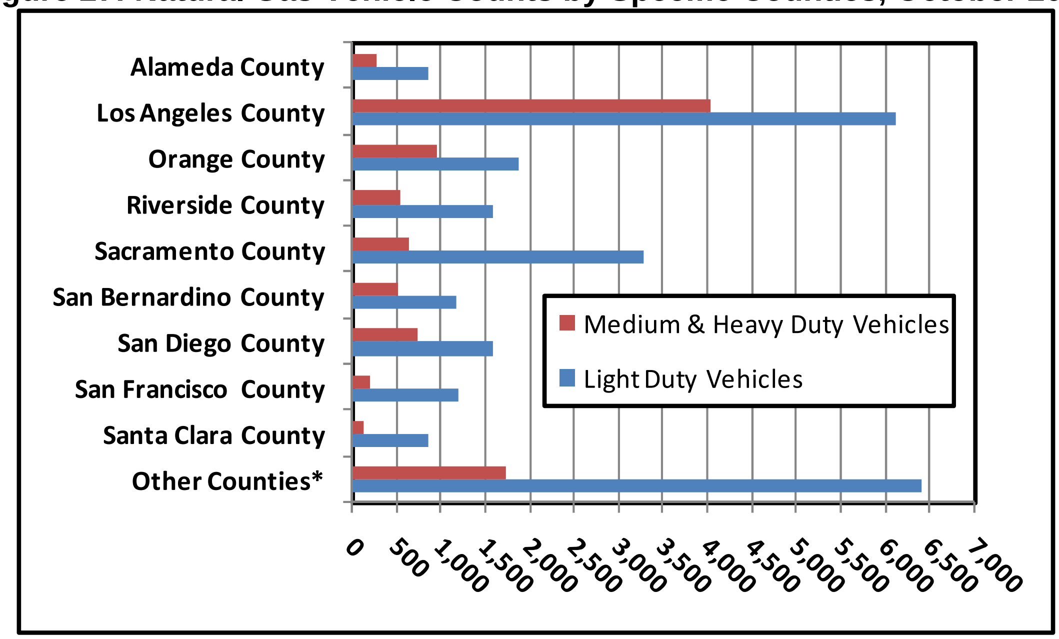


Source: California Energy Commission

The state's current retail infrastructure, however, can handle biodiesel blends at concentrations of five percent (B5) or less. On the wholesale and retail receipt and distribution levels, expanded use of biofuels (ethanol and biodiesel) can use the existing network of storage tanks and retail dispensers with little to no modifications for low-level blends (E10 and B5). However, higher concentrations of ethanol (E85) and biodiesel (B20) would require significant infrastructure modifications requiring the installation of thousands of new dispensers and underground storage tanks. In addition, wholesale distribution terminal operators would need to install additional storage tanks to enable the blending of biodiesel at B5 or B20 levels.

CNG or LNG vehicles run on natural gas and have been in use in California for more than 20 years. In 2008, there were 24,810 light-duty CNG vehicles registered and operating in California; half of these vehicles (10,747) were registered to individual owners.[201] This represents a significant increase over 2000 totals of 3,082; however, the light-duty natural gas vehicle population has been relatively flat since 2001. State and local governments accounted for 31 percent of the ownership of light-duty CNG vehicles with 78 percent of those vehicles existing in government vehicle fleets of 1,000 vehicles or more. In addition, there were 9,674 medium- and heavy-duty natural gas vehicles registered in California in 2008, with 7,144 of those vehicles being CNG-powered buses. Figure 27 illustrates natural gas vehicle counts for specific California counties.

Figure 27: Natural Gas Vehicle Counts by Specific Counties, October 2008



Source: Energy Commission analysis of DMV Vehicle Registration Database

*The Other Counties category is composed of counties with less than 500 light duty natural gas vehicles

The state had more than 460 natural gas stations at the beginning of 2009, with more than one-third of these stations offering public access.[202] Refueling options could be further increased

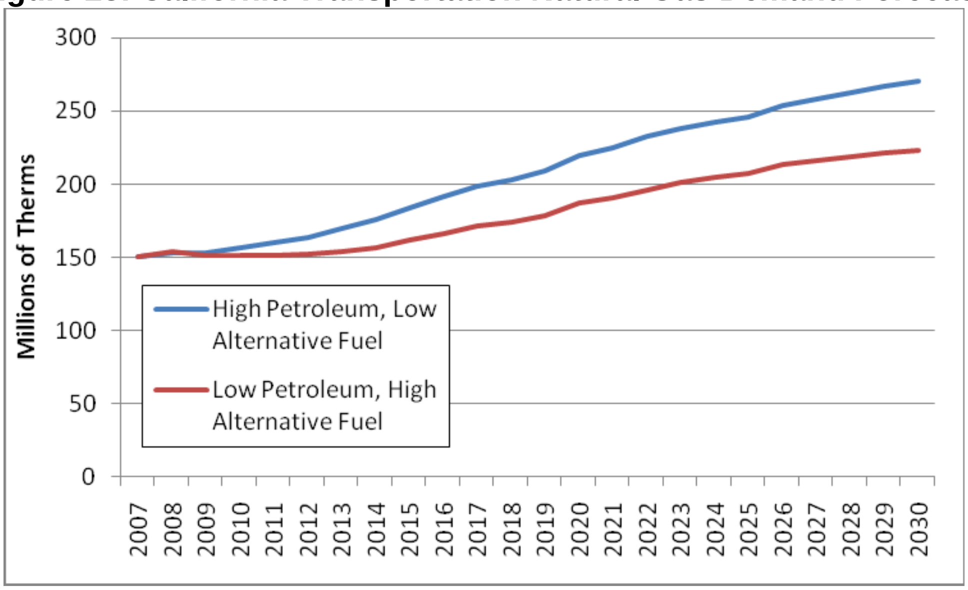
201 For this discussion, dual fuel CNG/gasoline vehicles are considered as CNG vehicles in vehicle counts. All vehicle counts come via the Department of Motor Vehicles database.

202 See [http://www.cngvc.org/why-ngvs/fueling-options.php].

through the use of a home refueling appliance which could be used to refuel a CNG vehicle tank at an owner's home.[203] This refueling process takes on average anywhere between 5 to 8 hours to fill 50 miles worth of natural gas and requires the owner to have access to a natural gas line.

California's use of natural gas in the transportation sector is forecasted to increase substantially. As measured in therms, the forecast shows demand rising from 150.1 million therms in 2007 to 270.3 million therms by 2030 under the High Petroleum Price Case (High natural gas Demand Case) and 222.9 million therms by 2030 under the Low Petroleum Price Case (Low natural gas Demand Case - see Figure 28). The number of compressed natural gas (CNG) vehicles is expected to grow from approximately 17,569 in 2007 to 112,025 by 2020 and 206,071 by 2030.

Figure 28: California Transportation Natural Gas Demand Forecast



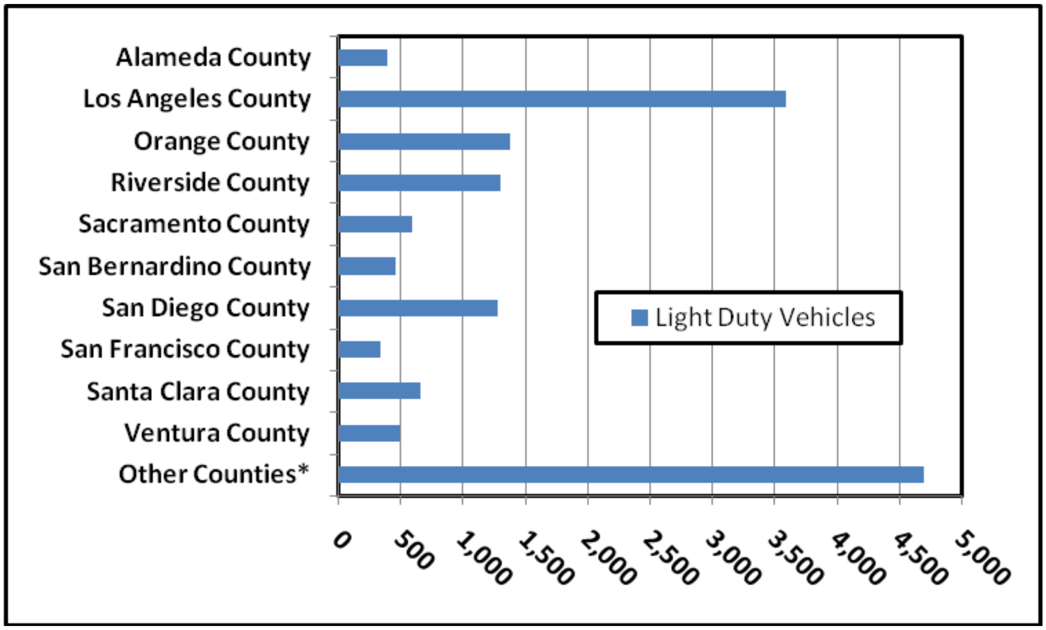
Source: California Energy Commission

There were 14,670 full electric vehicles (FEVs) operating in California in 2008. Although this is a substantial increase over the 2,905 operating in 2001, it is substantially less than the 23,399 in operation in 2003. Since 2004 this population has remained relatively flat. Primarily, these are neighborhood electric vehicles and sub-compacts. FEV counts for specific California counties are shown in Figure 29. According to SCE, the utility is expecting between 400,000 and 1.6 million electric vehicles by 2020.[204] Plug-in hybrid electric vehicles (PHEVs) combine the benefits of electric vehicles (that can be plugged in) and hybrid electric vehicles (that have an engine) and are scheduled for mass production as early as 2011. The Energy Commission forecasts the number of FEVs and PHEVs to reach nearly 3 million by 2030.

203 See [http://www.pge.com/myhome/environment/pge/cleanair/naturalgasvehicles/fueling/].

204 Testimony of Robert Graham, Southern California Edison, at the April 14, 2009, IEPR workshop, available at: [http://www.energy.ca.gov/2009_energypolicy/documents/2009-04-14-15_workshop/2009-04-14_Transcript.pdf].

Figure 29: Full Electric Vehicle Counts by Specific Counties, October 2008



Source: Energy Commission analysis of DMV Vehicle Registration Database

*The Other Counties category is composed of counties with less than 300 electric vehicles.

Several infrastructure barriers must be overcome to stimulate greater penetration of electric vehicles into the marketplace. Utilities will have to develop procedures, standardized equipment, and rates that meet the needs of vehicle users. Initially, utilities should probably focus on in-home recharging. Most consumers would be comfortable with home charging if time-of-use metering rates and equipment were available, as recharging could easily be accomplished mostly off-peak. Consumers could be further motivated if they were able to receive the carbon credits that accrued with the use of this energy source.[205]

As the electric vehicle population grows, the recharging system can expand to the workplace and to public recharging stations. Compatible and consistent standards will need to be developed for recharging connectors and other equipment, including 120/240 volt compatibility and smart chargers. Training of workers to install and service recharging equipment needs to increase, since today's expertise is limited to a few specialized technicians connected with electric vehicle dealers.[206] Additionally, utilities will need to evaluate and update their distribution infrastructure to accommodate the increased electricity demand.

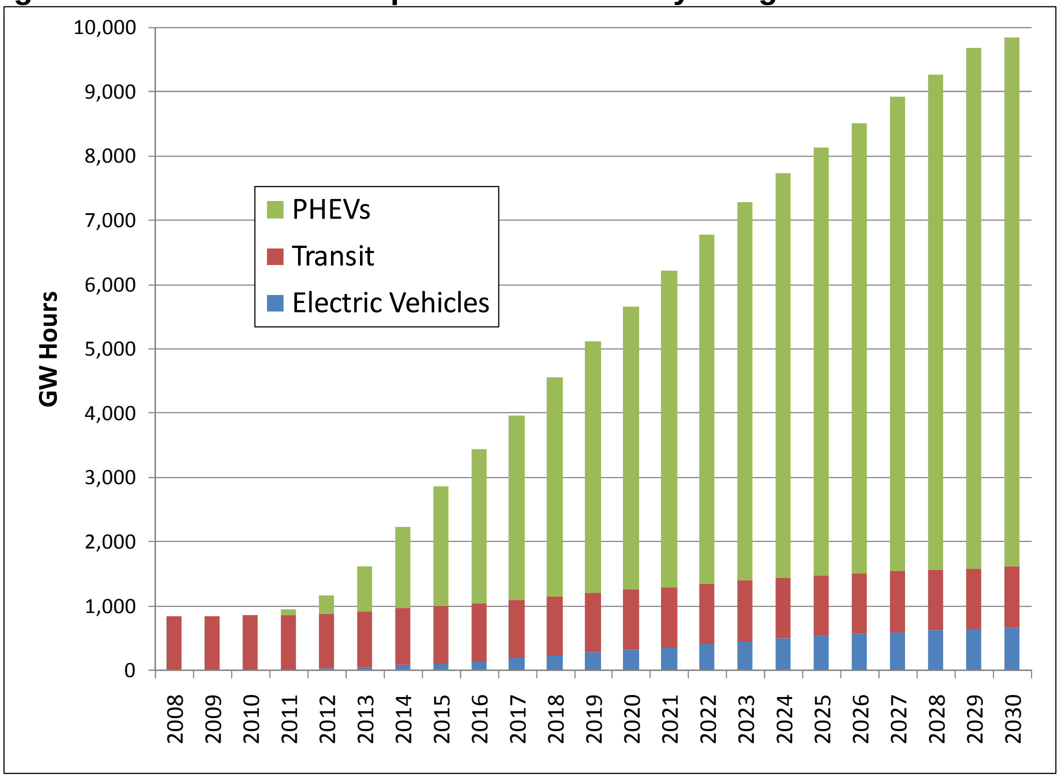
California's use of electricity in the transportation sector is forecast to increase substantially, primarily as a result of the anticipated growth in sales of PHEVs. As measured in GWhs, demand is forecast to rise from 828 GWhs in 2008 to nearly 10,000 GWhs by 2030. As Figure 30 illustrates, the surge in transportation electricity use under the High Petroleum Price Case

205 Ibid.

206 Ibid.

(High Electricity Demand Case) is mainly from PHEVs and to a lesser extent full electric vehicles. The number of PHEVs is expected to grow from 32,756 in 2011 to 1,563,632 by 2020 and 2,847,580 by 2030. Electricity use for transit is nearly flat over the forecast period. The transportation portion of statewide electricity demand is expected to rise from 0.29 percent in 2008 to between 1.57 and 1.79 percent in 2020.

Figure 30: California Transportation Electricity – High Demand Forecast



Source: California Energy Commission

There are 400 to 500 hydrogen powered vehicles in the United States,[207] with about 190 on the road in California.[208] These vehicles use stored hydrogen, which is combined with oxygen (from the atmosphere) through an electrochemical reaction in a fuel cell to produce electricity, that powers an electric motor. This technology is still relatively expensive because of high production costs of both fuel cells and the hydrogen, yet it is seen as an attractive technology because of its clean emissions capabilities.

While hydrogen has air quality benefits, it currently has no fuel quality or measurement standards for consumption and sale.[209] National and in-state standards need to be developed

207 Energy Information Administration, see [http://www.eia.doe.gov/oiaf/aeo/otheranalysis/aeo_2009analysispapers/ephev.html].

208 See [http://www.cafcp.org/sites/files/Action%20Plan%20FINAL.pdf].

209 Testimony of John Mough, California Department of Food and Agriculture, Division of Weights and Measures, at the April 14, 2009, IEPR workshop.

that address fuel quality, testing and certification methods, and sampling techniques, as well as the method of retail sale, dispensing facilities, and even the unit used to measure a sale. Fire regulations address most of the safety standards in the permitting process.

Currently, existing hydrogen stations in the state cannot sell hydrogen at their pumps because of the lack of metering systems and dispensing rules approved by California Department of Food and Agriculture's Department of Weights and Measures.

Transportation and the Environment

Currently, high fuel prices and the recession have contributed to a decline in petroleum fuel demand, which has benefitted the environment by lowering GHG emissions. In addition, these economic factors are causing more citizens to choose transit over vehicle travel. However, to significantly reduce petroleum consumption in the longer term and achieve the state's climate change targets, California must make large strides in making renewable and alternative fuels available for consumers.

The *State Alternative Fuels Plan* set targets for the use of alternative and renewable fuels in the California market and the *Bioenergy Action Plan* set aggressive goals to accelerate in-state biofuels production. These goals help to frame California's strong support for alternative fuels and a concerted and meaningful transition away from petroleum fuels and the attendant economic and environmental benefits.

Meeting the 2022 target in the *State Alternative Fuels Plan* would increase annual demand for alternative and renewable fuels to approximately 4 billion gallons. Reaching this goal would require the addition of more than 1 million gallons of new alternative and renewable fuels per day into the California market for the next 13 years. The Energy Commission recognizes that introducing these large volumes of alternative and renewable fuels carries the risk of encouraging or promoting environmentally and socially destructive production practices in California, North America, and throughout the world.

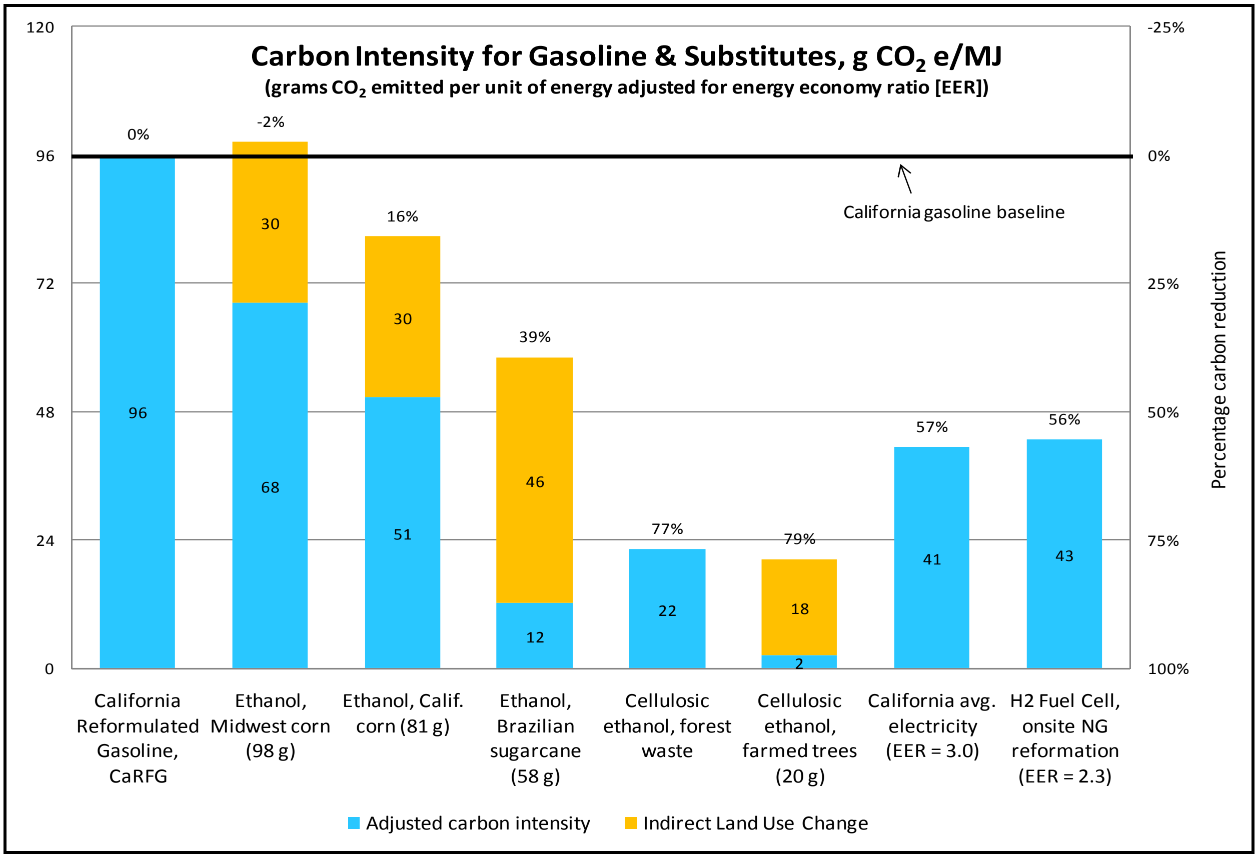
To gauge the environmental impacts of various transportation fuels, the Energy Commission employs a technique known as a "full fuel cycle assessment" or FFCA. Since 1989, the Energy Commission has relied on FFCA to develop policies supporting the use of alternative transportation fuels. The FFCA is used to evaluate and compare the full energy, environmental and health impacts of each step in the life cycle of a fuel, including, but not limited to, feedstock extraction, transport, and storage; fuel production, distribution, transport, and storage; and vehicle operation, refueling, combustion, conversion and evaporation. The Energy Commission and ARB have developed a common FFCA methodology that is used as a basis for investment decisions in the Alternative and Renewable Fuels and Vehicle Technology Program and the LCFS.[210] The focus of this FFCA work has been in comparing GHG emissions of alternative and renewable fuel options with those of gasoline and gasoline fuels.

The value of FFCA is determined by the underlying data, models, methodologies and treatment of uncertainties in the development, presentation and use of results. These areas are proving to

210 See [http://www.energy.ca.gov/2007publications/CEC-600-2007-004/CEC-600-2007-004-REV.PDF]

require additional work. A key area of interest to researchers is the treatment of indirect emissions in general and land use change emissions in particular. The inclusion of indirect GHG emissions in any FFCA can significantly alter the outcome and potential public policy support for various fuel options. This effect is illustrated in Figure 31.

Figure 31: Life-Cycle Analysis Carbon Intensity Values for Gasoline and Substitutes



Source: California Energy Commission

The nascent nature of this work creates uncertainty as to the best approach for treating indirect emissions in a policy, programmatic, regulatory, or market framework. In adopting its initial LCFS regulation in 2008, the ARB included indirect land use change emissions in determining carbon intensity values, but only for biofuel. However, all fuels must be evaluated equally. The ARB will reassess this aspect of the LCFS in 2010 and the Energy Commission and the ARB are continuing joint research into this topic.

As shown in Figure 31 above, not all biofuels are created equal. Depending on the origin of the fuel, the feedstock, and the type of energy used in its production, the GHG implications of a given biofuel on an FFCA basis can vary dramatically. Ethanol is currently the dominant biofuel of choice today, and will be needed to achieve federal energy and environmental policy mandates and goals. However, traditional corn-based ethanol originating from facilities in the midwest is estimated by ARB to have FFCA GHG emissions roughly equivalent to gasoline produced at California refineries.

To help achieve compliance with the LCFS, obligated parties will need lower carbon ethanol. Producing corn-based ethanol in California provides roughly a sixteen percent reduction in GHG emissions compared to gasoline. However, sugarcane-based ethanol (for example, produced in Brazil and imported to California) or "second generation" ethanol (for example, using biomass such as non-food parts of crops and municipal, agricultural, and forest waste material as a feedstock) will reduce GHG emissions by 79 percent over gasoline.

Similarly, biomass-based diesel fuel (including biodiesel and renewable diesel, as well as specific feedstock- and process-based diesels such as algae-based diesel, biomass-to-diesel, and diesel from thermal depolymerization of industrial and processing waste) could be significant contributors to reducing GHG emissions in California. Of these fuels, only biodiesel is commercially available in California and the United States today.

Biodiesel produced today in California reduces GHG emissions by 10-50 percent compared to conventional CARB diesel. These facilities use recycled cooking oil (yellow grease) as their lowest-cost feedstock option, but also use more expensive and abundant soybean, palm, and a variety of plant and animal oils. Moving beyond these oils and into "second generation" plants using cellulose, waste, and algae are necessary to achieve deeper GHG emission reductions. Depending on the feedstock, fuel production process, blend concentration, and vehicle type, these biodiesel and renewable diesel fuels could reduce GHG emissions by 61 to 94 percent compared to conventional CARB diesel fuel.

FEVs and PHEVs have numerous benefits that make them attractive in addressing carbon reduction and petroleum dependence. FEVs have the potential to reduce GHG emissions by 57 percent (PHEVs less due to the partial reliance on an internal combustion engine) based on the California average electricity mix. However, several utilities in California rely on electricity imports from out-of-state coal-fired plants. This will affect the GHG reduction potential and needs careful consideration in formulating broad public policies supporting FEVs and PHEVs. Use of substantial numbers of these vehicles would also provide localized air quality benefits by reducing criteria pollutant emissions compared to conventional vehicles.

Natural gas vehicles emit 30 to 40 percent less GHG emissions than gasoline and diesel-powered engines. The environmental profile of natural gas can be further improved through advancements in biomethane or biogas, which are renewable sources for the production of natural gas. Biomethane can be produced by capturing methane from landfills, dairy farms, and wastewater treatment plants and by anaerobic digestion of organic matter such as municipal solid waste. The use of biomethane in state-of-the-art natural gas vehicles has a much greater GHG benefit, reducing emissions by as much as 97 percent. California biomethane resource potential is estimated to provide transportation fuels for up to 250,000 vehicles per year from dairy operations, representing roughly one percent of the existing population of light-duty vehicles in the state as of October 2008.[211]

211 Biomethane Resource Potential, CALSTART, Steven Sokolsky, CEC IEPR Workshop, April 15,2009, slide 6

California's Leadership Role in Environmental Sustainability

California is one of the first states in the nation to use sustainability as a basis to fund energy projects. The Energy Commission is taking a leadership role in working closely with state partners and global organizations in advancing the state-of-science in this emerging field.

AB 118 was created to help transform California's transportation market by aiming to reduce California's dependence on petroleum and helping meet California's climate change reduction goals. But as some biofuel projects using palm oil, corn, or sugar cane around the world have discovered, producing new fuels can sometimes lead to unanticipated consequences that harm the environment. That's why, when creating the AB 118 program, the California Legislature directed the Energy Commission to include sustainability goals that would protect the state's natural resources.

To receive AB 118 funding, proposed projects must meet the sustainability goals and evaluation criteria outlined in the Alternative and Renewable Fuel and Vehicle Technology Program regulations. The first goal a proposed project must meet is to substantially reduce GHG emissions, and the second is to protect the environment while striving to achieve superior environmental performance. The third requirement is to achieve project goals in accordance with certified sustainable production practices.

Natural gas is currently the primary feedstock needed for manufacturing hydrogen and results in a reduction of GHG emissions by about 56 percent compared to gasoline. The use of electrolysis to produce hydrogen (a process where hydrogen is separated from water) has the potential of reducing GHG emissions even further. However, this technique depends on the source of the electricity used for the process. Renewable power has the greatest potential to reduce the emissions to near zero. Hydrogen can also be created from biomethane to further improve its environmental profile.

Propane is produced as by-product of refinery operations and is a co-product in the extraction of oil and natural gas. Propane reduces GHG emissions up to 19 percent compared to gasoline, slightly better than petroleum-derived propane. While not yet available commercially, studies are being conducted at Mississippi State University and Massachusetts Institute of Technology on the generation of renewable propane. Renewable propane can be derived from algae, row crops, and wood. While the GHG profile of renewable propane is not known at this time, production requires little additional energy and results in a product that contains the same energy content as propane derived from petroleum.

While considerable work is focused on understanding the carbon implications of various fuel options, an area that is not typically reflected in FFCA methodologies is the notion of "embedded carbon." Regulatory and market incentive policies typically encourage the introduction of new vehicles to achieve GHG emission targets. The importance of this strategy is clear, but manufacturing new vehicles induces GHG emissions via the energy and raw material inputs. This embedded carbon can take up to tens of thousands of miles to overcome through fuel savings. This also raises the question of the tens of millions of existing gasoline and diesel vehicles that will continue to emit carbon as new advanced vehicles are being introduced into the market place. A strategy that would provide incentives to retrofit segments of the existing fleet with low-carbon technologies should be examined from a public policy perspective.

Transportation and Reliability

As production from California's crude oil fields continue to decline, and as California's oil refineries continue to expand their production capacity, refiners will look to importing additional volumes from sources outside the state. Since Alaska crude oil production has declined at a greater rate than California production, refiners must seek substitute crude oil from foreign sources. There is concern about the political stability of oil-producing nations such as Iraq and Nigeria and the potential impact on crude oil availability. Offshore drilling could increase the domestic supply and help ensure reliability. However, environmental concerns with drilling activity in sensitive marine habitat could prevent or delay new production. These factors, along with an inadequate marine infrastructure, could significantly impact fuel security and reliability for California and neighboring states.

Uncertainty regarding the future supplies of crude oil represents an opportunity for the state to move more aggressively in expanding the use of alternative and renewable fuels. However, these fuels are not without uncertainty. Unless the state takes concerted steps to grow the alternative and renewable fuel industry domestically, policy-makers may be faced with similar potential supply interruptions from an overreliance on foreign sources of fuel and feedstock. To compound the issue, the LCFS could push industry to import commercial quantities of lower carbon-intensity fuels, further stressing California's marine infrastructure. Increasing reliance on foreign sources of renewable fuels also creates uncertainty as to the true carbon intensity of the fuel and therefore brings into question the suitability of the fuel for the California market.

Increasing imports of renewable and alternative fuels will require additional infrastructure including new off-take terminals, storage and distribution, and retail sites. Also, buyers of alternative and renewable fuel vehicles must be assured that the fuel or recharging stations are available and that they have access to vehicle parts, maintenance, and manufacturer warranties.

As California transitions from conventional biofuels to more advanced second generation biofuels, a great emphasis will be placed on identifying sustainable feed stocks. California's municipal, agricultural, and forest biomass waste stream is a massive unused resource that could be used as a feedstock for biofuels. California currently produces a total of 83 million gross bone dry tons per year (BDT/y) of combined biomass waste; this is projected to increase to 99 million BDT/y by 2020. However, only about 32 million BDT may be accessible as an energy feed stock because of economic and environmental limitations. At the current rate of use of just 5 million BDT annually, this is very under used resource. Still, biofuel producers will be competing with operators of biomass-fired power plants and users of non-energy bio-products. It is imperative to determine if there will be sufficient biomass waste to meet these growing and competing demands. Preliminary data suggests that there may be sufficient biomass waste in the near term for competing energy uses, but more thorough and in-depth analysis is needed for both the biofuels and electricity industry.

Alternatively, purpose-grown crops may be an important complement to biomass waste as an energy feed stock. Biodiesel can be derived from oil crops, cellulosic sources, and algae. The ethanol industry has been looking at sugar cane, sugar beets, sweet sorghum, grain sorghum, and cull fruits. These crops also may represent new sources of income in economically depressed communities. If energy crops are used as a biomass source, additional analysis will be needed to determine life cycle carbon implications, including both direct and indirect land use changes, and to ensure that crops are being grown in a certifiably sustainable manner using best management practices.

Transportation and the Economy

The economic recession has impacted the transportation industry at almost every level. At the consumer level, behavior changes are evident. Consumers are reducing vehicle trips and cutting back on personal spending in response to higher gasoline prices and the recession. In addition, as Table 7 shows, consumers are showing a purchasing trend of smaller cars, along with more FFVs and hybrids. This has resulted in an overall shift in production to more fuel efficient vehicles. In difficult economic times, price and fuel cost are significant factors in vehicle choice, suggesting that California consumers are aware of the tradeoff between these cost factors.

Table 7: Summary of California On-Road Light-Duty Vehicles

Light Duty Vehicle Counts						
	Gasoline	**Diesel**	**Hybrid**	**Flex Fuel**	**Electric**	**Natural Gas**
2001	22,779,246	316,872	6,609	97,611	2,905	3,082
2002	23,384,639	334,313	15,159	129,734	11,963	25,682
2003	24,516,071	364,411	24,182	183,546	23,399	17,228
2004	24,785,578	391,950	45,263	195,752	14,425	21,269
2005	25,440,904	424,137	91,438	269,857	13,947	24,471
2006	25,741,051	449,305	154,165	300,806	14,071	24,919
2007	25,815,758	465,654	243,729	340,910	13,956	25,196
2008	25,654,102	463,631	333,020	381,584	14,670	24,810
Compound Average Growth Rate	**1.71%**	**5.59%**	**75.06%**	**21.50%**	**26.03%**	**34.71%**

Source: California Energy Commission analysis of California DMV data

Consumers are particularly affected by fuel price volatility. Last year, crude oil prices rose to over $140 per barrel in July 2008, declined sharply to a level below $30 in December and then steadily climbed again to about $70 in September 2009. These events led to volatile gasoline prices, impacting consumers directly at the pump. At its highest peak, in June 2008, the U.S. Energy Information Administration reported the average price of California regular-grade motor gasoline was $4.48 per gallon. By December 2008, the price fell to $1.82, before rising again to $3.10 in September 2009. Consumers responded to this price volatility and overall economic conditions by reducing gasoline consumption; according to Board of Equalization data, California sales of gasoline fell by 6.2 percent from 2004 to 2008.

For the *2009 IEPR* transportation fuel forecast, staff developed high and low crude oil price forecasts for California transportation fuels and used these as the basis for California-specific high and low case regular-grade gasoline and diesel price forecasts. The Energy Commission's High Petroleum Price Case starts at $2.90 per gallon for gasoline and $3.09 for diesel in 2009, jumps to $4.36 and $4.43, respectively, in 2015, and then continues to rise to $4.80 and $4.87 by 2030 (all prices are in 2008 dollars to adjust for inflation). The Energy Commission Low Petroleum Price Case price forecasts start at $2.34 for gasoline and $2.42 for diesel per gallon in 2009, climb to $3.17 and $3.19, respectively, in 2015, and then hold constant until 2030. If the High Petroleum Price Case forecast holds true, then the state could see more consistent and sustained behavior changes in citizens related to driving patterns, gasoline demand, and vehicle purchasing decisions.

Cheaper fuel sources would be a major motivating factor for consumers to choose alternative fuel vehicles. The alternative fuel price forecasts show most of these fuels costing about the same (or sometimes more) than gasoline or diesel, but there are considerable uncertainties in these projections. Moreover, other factors, such as the efficiency with which the vehicle technology uses the energy in its fuel as well as insurance and maintenance costs, will also affect total operating costs. Finally, the purchase price of many alternative fuel vehicle types exceeds that of conventional gasoline vehicles.

The downturn of the economy has greatly affected the biofuels industry. All seven of the ethanol production plants in California are currently sitting idle. California ethanol producers cite the primary reason for ceasing production as poor market conditions and the economics of producing ethanol. On May 17, Pacific Ethanol (one of the larger California ethanol producers) filed Chapter 11 bankruptcy protection. Ethanol producers in other parts of the country, particularly the Midwest, are feeling strain from the economy, but the effects are not as detrimental as those felt in California. Midwest states support agriculture, corn production, and ethanol plants simultaneously, and California may need to take a similar role for its ethanol industry to survive. Also, companies have ceased construction on a number of biofuel projects because of their inability to secure financing. Financial institutions are not funding unique biofuel infrastructure projects, which all pose uncertain risks.

The California biodiesel plants are also struggling. The SWRCB prohibition of biodiesel in underground storage tanks (which was rescinded in May 2009) and the recession created detrimental economic hurdles. California has nine biodiesel plants with a combined 2009 theoretical capacity of 63 million gallons; these plants will likely produce less than 25 million gallons. Today, six biodiesel plants are idle.[212] The biodiesel industry has to work doubly hard to re-establish itself from the rescinded prohibition to store biodiesel in USTs during the recession. The added uncertainty from ARB's LCSF treatment of indirect emissions further exacerbates the lack of economic support for biofuels.

To move high levels of biofuels into California's predominantly gasoline market, incentives may be needed to stimulate in-state production as well as infrastructure investments. It is important that California efficiently maximize the benefits from federal grants as well as assistance with state funding and assistance resources. This will be a key aspect of leveraging AB 118 monies with federal stimulus funding.

212 Docket Comments by the California Biodiesel Alliance, February 16, 2009.

Economic barriers to wider-spread purchase of FEVs and PHEVs include the lack of commercially available models and delays in delivery, their higher price, and concerns about their size and range.[213] These perceptions of FEVs by potential vehicle purchasers may be intensified by a lack of familiarity with the technology and uncertainties over how the vehicles would be recharged or the expense of replacing batteries. Battery cost could be reduced through mass production of batteries, but there is still a great deal of RD&D taking place to improve vehicle range. Improving performance is important because as the technology currently stands, it is not possible to exceed vehicle range without a lengthy pause to recharge the battery. Overall, the initial costs of EVs are higher than for gasoline vehicles because of the additional cost of the battery and home recharging installation.

State and Federal Funding Efforts Stimulate Electric Vehicle Market

California is home to startup companies like Tesla Motors, Aptera Motors, and Fisker Automotive that are promising to bring upscale all-electric vehicles to market soon. Today, major manufacturers including Ford, Chrysler, BMW, Toyota, Mitsubishi, Subaru, and General Motors are actively exploring electric technology with the help of federal funding.

California is providing state funding support as well. Through AB 118, the Energy Commission is offering $9 million to manufacturers of electric vehicles and electric vehicle components willing to locate in California. The incentives will create several thousand green California jobs and help to boost local economies. Overall, AB 118 offers a total of $46 million in state funds to support electric transportation.

As automobile manufacturers in Asia, Europe, and the U.S. rush to capture a growing worldwide market for more efficient, environmentally-friendly vehicles, California and the federal government are helping American companies compete in the race to develop vehicles for the twenty-first century.

Several different vehicle manufacturers have produced light-duty CNG vehicles, but currently only the Honda GX CNG is offered for sale in the United States. A lack of vehicle offerings was identified by the *State Alternative Fuels Plan* as one of the primary hurdles to natural gas becoming a major publicly used transportation fuel in California.[214] Another barrier is that light-duty CNG vehicles often require more frequent refueling due to having approximately 25 percent less range than gasoline or diesel vehicles per one tank of fuel. And like electric vehicles, natural gas vehicles are so unfamiliar to the majority of consumers that they are unable to generate favorable impressions among many potential car buyers.

The price of natural gas fuel can be attractive to high-volume purchasers, but vehicle cost can be a barrier to more light-, medium-, and heavy-duty vehicle purchases unless alleviated by declining production costs, driven by on-board fuel storage needs or consumer incentives. The Energy Commission's *State*

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213 A recent study completed by the Government Accountability Office (GAO) describes the various challenges facing increased use of PHEVs, as well as elaborating on specific developments that would be necessary for PHEVs to be competitive. Government Accountability Office, *Plug-in Vehicles Offer Potential Benefits, but High Costs and Limited Information Could Hinder Integration into the Federal Fleet*, June 2009, GAO-09-493, available at: [http://www.gao.gov/new.items/d09493.pdf].

214 *State Alternative Fuels Plan - AB 1007 Report* - Docket # 06-AFP-1, see [http://www.energy.ca.gov/ab1007/index.html].

Alternative Fuels Plan - AB 1007 Report also identified several actions that would encourage the development of the industry: develop new utility rate structures for home refueling appliancess; stimulate the development of biomethane/biogas for use in natural gas vehicles and as a feedstock for hydrogen; improve on-board storage technology to improve the range and costs of natural gas vehicles; develop natural gas hybrid electric technology; and use the GHG emission benefit credits in investment and business operation plans.

The ARRA includes multiple elements to advance alternative fuel and vehicle technologies. For example, Ford received $5.9 billion in loans from the DOE to help it retool its plants to produce 13 fuel-efficient models, including as many as 10,000 EVs a year beginning in 2011. Nissan received $1.6 billion in loans to retool its Tennessee plant to make EVs. In August 2009, Ford, GM, Chrysler and others received $2.4 billion in federal grants to encourage the development of hybrid and EVs. The grants include $1.5 billion for battery makers, $500 million for companies developing electric motors and drive components, and $400 million to test a recharging system for electric cars. The grants are part of the federal government's $787 billion economic stimulus program.

As its population continues to grow, California must plan to make sure it has enough fuel to keep its economic engine running, while protecting the state's public health and natural resources. Regulations already in place demand that the state's energy supply becomes increasingly sustainable as Californians work to cut GHG emissions. Sustainability is becoming ever more important as the U.S. tries to wean itself away from constrained and rare resources like foreign oil. The state must avoid, however, trading one vulnerability for another, such as becoming dependent on electric automobile batteries that require rare lithium from other, perhaps less-than-friendly countries. The recession makes it increasingly important that California develops United States resources and provide United States jobs in a sustainable way.

Chapter 3: California's Electricity Infrastructure

Introduction

This chapter describes the important system integration challenges California's electricity sector is facing in meeting its energy policy goals. These goals include increasing the use of preferred resources (energy efficiency, demand response, renewable energy, combined heat and power, rooftop photovoltaic, and other distributed renewables), decreasing the use of once-through cooling (OTC) technologies in power plants, retiring aging power plants, and modernizing the state's system of power lines, while assuring reliability is maintained.

Overlaying all of these goals is the objective of reducing greenhouse gas (GHG) emissions in the electricity sector. Electricity generation is the second largest source of GHG emissions in California after transportation, making changes in the electricity sector a major component of the state's efforts to reduce its total GHG emissions. These issues underscore the need for a statewide "blueprint" for development of electricity resources and infrastructure given the often conflicting goals of minimizing environmental impacts while maintaining reliability and affordability for California's citizens.

California's electricity planning, procurement, and permitting processes must translate the state's policy goals into real actions. So far, the state's energy policy goals have been only weakly integrated, but it is essential to integrate policies to reconcile priorities, identify tradeoffs, and allow broadly framed objectives to be transformed into concrete measures. There is also a need for more efficient and coordinated transmission planning in the state to avoid contentious, lengthy, and ineffective processes that can delay transmission needed to meet the state's environmental goals.

California needs coordinated and integrated electricity infrastructure planning processes for electricity development in the 21st century. Such processes should reduce duplication among the state's energy agencies and provide a forum for integrating the various analyses and other efforts underway at those agencies. With a coordinated and integrated planning process, analysis and efforts by the state's energy agencies can complement and reinforce each other while minimizing duplication.

Issues Affecting the Power Plant Fleet in California

The Energy Commission, in its *2005 Integrated Energy Policy Report (IEPR)*, called for the retirement, replacement, and/or repowering of aging power plants, which include plants using OTC. The aging power plants operate at high heat rates when compared with new generation technologies, resulting in less efficient use of natural gas and higher levels of air pollutants, including GHG emissions. The Energy Commission also recommended that the California Public Utilities Commission (CPUC) ensure that long-term resource procurement explicitly takes into account the retiring, replacing, and/or repowering of aging power plants with cleaner, combustion-based technologies that operate at higher efficiencies, including aging power plants in the Los Angeles Basin. In its 2006 Long-Term Procurement Plan decision, D.07-12-052, the CPUC included substantial retirements in determining future investor-owned utility (IOU) needs.

In addition to this policy goal, the following three external forces continue to exert major influence over the electricity industry:

- Policies to reduce or eliminate the use of once-through cooling in power plants.
- The scarcity and high cost of emissions credits needed for new power plants.
- The need to shift the mix of resources toward demand-side resources and renewables and away from fossil power plants in response to global climate change initiatives.

Impacts of Once-Through Cooling Mitigation Policies

In June 2009, the State Water Resources Control Board (SWRCB) published a draft policy that establishes closed cycle wet cooling towers as the benchmark for compliance and proposes a compliance schedule based on a proposal by the Energy Commission, the CPUC, and the California Independent System Operator (California ISO) on how to address reliability concerns given the proposed timeline for OTC mitigation compliance.[215] The three energy agencies agreed that a fixed-year outer bound on OTC mitigation compliance can be established, provided it allows for the orderly development of necessary replacement infrastructure and can be amended if conditions such as permitting and construction delays indicate such change is needed to ensure reliability.

The proposed compliance schedule for each OTC plant is based on the timeline required to create replacement infrastructure. A wide range of circumstances exist among the OTC fleet. As new facilities become operational, some plants are losing their importance for local reliability. For others, the proposed schedule incorporates the construction timeline for replacement infrastructure when that is already underway. For many OTC power plants, substantial analysis of the options, decisions among the energy agencies, and then procurement, permitting, and construction create long lead times before replacement infrastructure can be operational. The complexities of these analyses differ from one region to another, with the Los Angeles Basin expected to be the most problematic given severe limitations on the air credits needed for new generation development. For this reason, the schedule of dates for replacement infrastructure typically is further into the future for the existing OTC plants located in the Los Angeles Basin.

It is critical to integrate the perspective of environmental regulators into reliability concerns. The SWRCB must establish a policy with a fixed deadline to force action by the plant operators and to also allow its regional boards to issue necessary permits to the existing plants with

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215 California Energy Commission, California Public Utilities Commission, and California Independent System Operator, *Implementation of Once-Through Cooling Mitigation through Energy Infrastructure Planning and Procurement*, July 2009, CEC-200-2009-013-SD, available at: [http://www.energy.ca.gov/2009publications/CEC-200-2009-013/CEC-200-2009-013-SD.PDF].

knowledge that OTC mitigation will occur on a fixed schedule. At the same time, the energy agencies strongly believe that implementation of an OTC mitigation policy for existing generators has to be integrated with planning and development of the replacement infrastructure necessary to support system reliability.

In the proposal to the SWRCB, the energy agencies provided estimated dates for new infrastructure being operational. The energy agencies must review and update these dates periodically, which must then be reviewed by the SWRCB. Where significant changes have been made, the SWRCB must use them as the basis for changing the permits for existing OTC plants. The energy agencies are committed to working together and with the SWRCB to achieve this objective.

Factors Affecting Replacement Infrastructure

Within the broad umbrella of linking OTC mitigation to the development of replacement infrastructure, the state could develop many alternative plans. State agency policies emphasize preferred resource types, including energy efficiency and demand response, renewables, and distributed generation. Including these resources in the analysis will likely result in a set of proposed replacement plants that do not rely strictly on conventional fossil power.

The energy industry's compliance with the California Air Resources Board's (ARB) *Climate Change Scoping Plan* regulations will presumably lead to a lower electricity demand forecast, because additional energy efficiency measures will reduce demand, and rooftop photovoltaic (PV) and other distributed generation will displace sales of electricity from the bulk power system to end users. A lower demand forecast would require fewer central station generating facilities within load pockets to satisfy reliability criteria. An Assembly Bill 32 (Núñez, Chapter 488, Statutes of 2006) compliance plan presumably also strengthens the role of renewable power generation, which encourages more transmission development to interconnect remote renewable resources, lessening the need for energy from traditional fossil generation but simultaneously increasing the need for dispatchable facilities, those that have the ability to control their output, to provide reliability services. Recognizing these likely consequences from AB 32 could lead to changes in both the mix and capabilities of fossil generation needed in load pockets, whether from repowered OTC plants or from new facilities that are electrically equivalent.

In addition, air permitting issues in the South Coast Air Quality Management District (SCAQMD), discussed in more detail in the next section, will also affect the type of replacement power that could be built. As a result of the Superior Court decision voiding the SCAQMD's Priority Reserve Rule, there will be serious limitations on power plant development in the South Coast Air Basin and nearby areas for some time.[216] SCAQMD's air quality permitting processes affect 7,500 megawatts (MW) of existing fossil capacity in the Los Angeles load capacity area of the California ISO and the Los Angeles Department of Water and Power

216 Natural Resources Defense Council, Inc., et al. vs. South Coast Air Quality Management District, Superior Court of the State of California, County of Los Angeles, Case No. BS 110792.

(LADWP) control area. New facilities totaling 1,750 MW in capacity have power purchase agreements with Southern California Edison (SCE) but cannot be licensed because they do not have access to the Priority Reserve. If this issue remains unresolved, these facilities will not be available to reduce the reliability threat from the proposed limitation on the use of OTC. This would significantly increase the challenge of siting new power plants needed to implement the OTC policy and require solutions to rely more upon transmission system upgrades to tap remotely located generation.

The state must also consider local capacity requirements (LCR) when discussing replacement power. The Energy Commission, CPUC, and California ISO are developing enhanced LCR analyses for each local capacity area, or load pocket, within the California ISO balancing authority area. Some areas lack excess capacity and must develop replacement capacity to meet increases in peak load or power plant retirements. Other areas have surpluses and could therefore tolerate some retirement. Based on load and resource assumptions, the LCR analyses will extend current requirements out to 10 years and identify the amount and various operating characteristics needed to plan for OTC retirement in some load pockets.

The results will be used as key inputs into an OTC power plant infrastructure replacement plan that would produce specific reliability designations, or dates that specific power plants could retire, as determined by the need for and expected timing of replacement infrastructure development. The plan would identify, for each region, the course of action required to eliminate reliance upon a power plant or unit using OTC. Most importantly, this plan would identify the complete set of infrastructure additions that, once operational, would allow OTC to be eliminated.

Recognizing these problems, the legislature proposed multiple bills in its 2009 session to address OTC mitigation and restoration of a functioning air quality credit mechanism for new power plants in the South Coast Air Basin. Of the proposed bills, only Assembly Bill 1318 (Perez, 2009) and Senate Bill 827 (Wright, 2009) passed through the legislature by the end of the session. AB 1318 would require the ARB, in consultation with the CPUC, the Energy Commission, the California ISO, and the State Water Resources Control Board, to submit a report to the Legislature and Governor evaluating the electric system reliability needs of the South Coast Air Basin and recommend strategies to meet those needs while ensuring compliance with AB 32, OTC mitigation requirements, state and federal air pollution laws and regulations, resource adequacy requirements, and renewable and energy efficiency requirements. AB 1318 would also authorize issuance of air credits to specific plants satisfying eligibility criteria. Similarly, SB 827 would authorize SCAQMD to issue needed air credits for a limited number of specific plants meeting eligibility criteria, but these criteria are not the same as those contained in AB 1318. Further, no study is required. These bills are awaiting action by the Governor.

Planning for Replacement Infrastructure

It will be necessary for the state to make significant planning decisions, procurement authorization, and permitting of specific energy infrastructure projects to accomplish the retrofitting, repowering, or retirement of more than 30 percent of the power generating capacity represented by OTC plants.[217] All of the 19 generation plants with OTC units are located in the California ISO and the LADWP control areas. Of the 16 OTC plants in the California ISO control area, 13 are located in transmission-constrained regions. Transmission constraints also influence the need for and options among refitting, repowering, and replacing the three OTC plants within the LADWP balancing authority. Thus, the CPUC, the California ISO, and the Energy Commission, rather than propose a fixed compliance schedule, have recommended that regions with less need for complex analyses and more advanced possible solutions to problems should be required to reduce OTC harm more quickly than those regions with more extensive constraints on implementing solutions.

The proposal submitted to the SWRCB encompasses three broad efforts. First, the agencies would conduct a series of studies examining the consequences of retiring individual or clusters of existing OTC power plants under a range of alternative futures and transmission system configurations to identify generation and transmission options for replacing each OTC facility. The Energy Commission would facilitate a review of the LADWP power plants, which are outside the jurisdiction of both the CPUC and the California ISO.

Second, the agencies would review key analytic results to determine a strategy that is compatible with broad energy policy preferences. When results are available, they would be entered into the 2010 or 2012 CPUC Long-Term Procurement Plan (LTPP) proceeding for further analysis by the investor-owned utilities (IOUs) and consideration by the CPUC, with the objective of issuing procurement guidance to IOUs to acquire resources, and to the California ISO annual transmission planning process to identify specific transmission projects.

Finally, the CPUC would approve necessary power plant additions and transmission projects. The Energy Commission would license the power plant projects. Staff of the energy agencies would monitor progress, periodically report to the SWRCB, and as appropriate, recommend changes.

Some power plant operators suggested that they might retrofit their power plant to satisfy SWRCB's proposed policy. For particular units, this might make sense, especially if the investments are lower than for repowering and the expected life of the unit makes such investments cost-effective to ratepayers. Since AB 32 now encourages deployment of renewables to the extent feasible, it makes sense to limit delays in California's aging power plant retirement policy to better link to renewable development schedules. The Energy Commission first articulated its policy in favor of retiring aging power plants in the *2005 IEPR* and then modified it to explicitly encompass repowering in the *2007 IEPR*. Therefore, it is appropriate that the Energy Commission modify the policy here to support limited retrofitting

217 Retrofitting or refitting refers to the installation of a cooling system that complies with the proposed SWRCB policy. Repowering entails replacement of the existing boiler with advanced generation technology – improving thermal efficiency – and installing a compliant cooling technology. Retirement may, and often does, require replacement of the foregone capacity with generation at another location.

of units that are most efficient and useful to integration of renewables and other system support functions. For the 2020 time horizon and beyond, the state should still pursue the goal of retiring or repowering these aging facilities.

Emission Credits for Power Plants

The second major issue affecting the electricity sector is the scarcity of emissions credits for new power plants. New generating capacity development to replace aging power plants or OTC plants is critical to achieving reduced GHG emissions from more efficient use of natural gas. However, recent court rulings limiting the supply of air emissions credits in the SCAQMD present new challenges for California to achieve its environmental goals while ensuring sufficient generating supplies for system resource needs and local area reliability.

Southern California air basins have some of the worst air quality in the nation, resulting in stringent local air quality requirements, including offsetting new sources of emissions with reductions in emissions from existing sources. These offsets, or emission credits, are in short supply in the SCAQMD, making it difficult to license new power plants or repower existing aging plants in Southern California. In 1990, the SCAQMD established a Priority Reserve of emission credits that were set aside for use by entities that serve a public interest, but did not explicitly include power generation as an industry eligible to use the credits.

In August 2007, the SCAQMD amended its Priority Reserve Rules to allow offsets to be purchased for new power plants licensed by the Energy Commission. The SCAQMD, under Rule 1309.1, limited these power plant credits, requiring developers to have a one-year power sales contracts and a license from the Energy Commission to construct their facility before the SCAQMD board would release any credits for that facility. Plants being proposed by municipal utilities were allowed only enough credits to build projects that serve their native load. The SCAQMD also limited the total amount of new electricity generating capacity that could access Priority Reserve credits to no more than 2,700 MW.

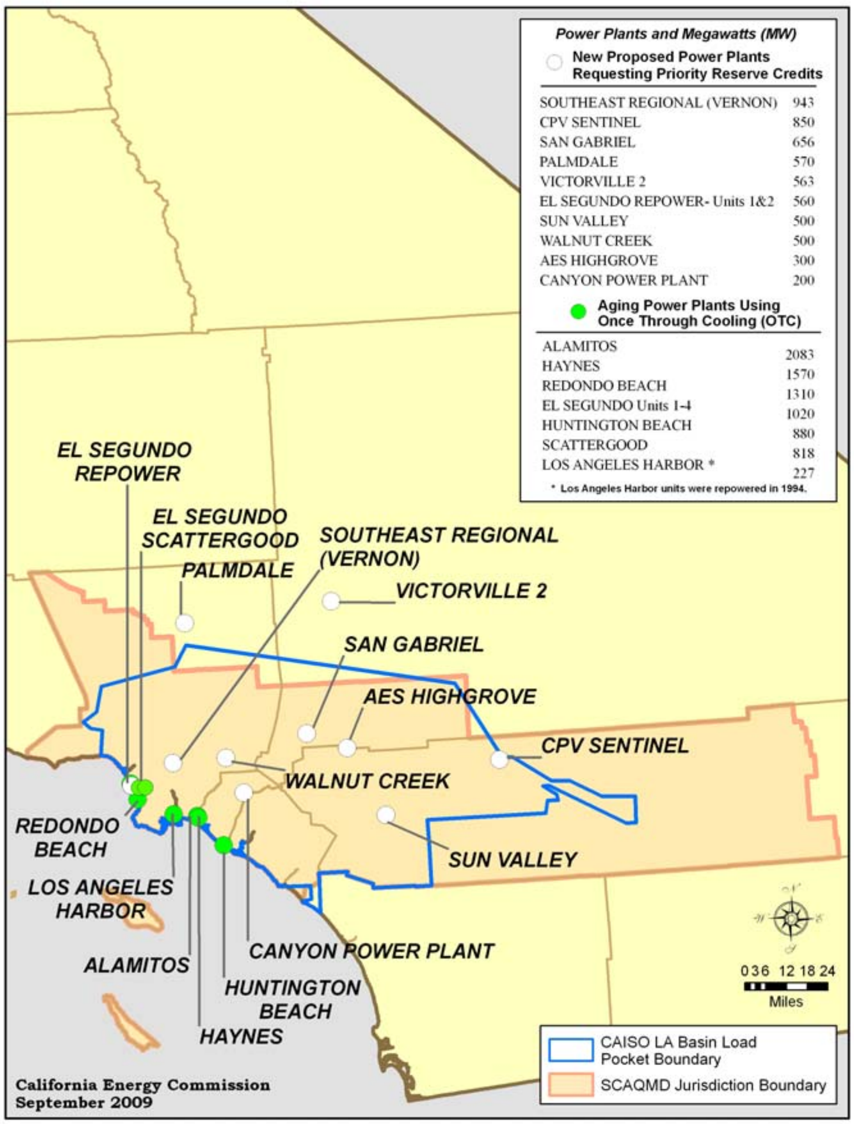
The SCAQMD Priority Reserve Rule was challenged in Los Angeles County Superior Court and in July 2008, the court decision found the air district's California Environmental Quality Act (CEQA) analysis inadequate and indicated that a sufficient environmental document would require significant new analysis that the SCAQMD believes it cannot reasonably provide. As a consequence, the SCAQMD is unable to issue any offsets for power plants or for any facilities requiring a permit for emissions. The SCAQMD is now working to modify its regulations to allow permits for non-power plant facilities, but has no specific plans to develop new rules specific to power plants. Instead, power plant proponents and SCAQMD authored several legislative fixes that would overturn the state court ruling.[218] Staff is conducting analyses to identify the need for resource additions in the Los Angeles Basin under various sets of future

218 Whether the two bills enacted by the Legislature will be signed by Governor Schwarzenegger is unknown as of the issuance of this report.

conditions that will allow a more analytically based debate about means to find the corresponding air credits needed. Initial results of this effort were discussed at a September 24 workshop.[219]

Figure 32 shows the geographic location of the existing OTC power plants impacted and those currently in the Energy Commission licensing process affected by the SCAQMD's Priority Reserve Rule.

Figure 32: Power Plants Affected by Priority Reserve Rule



Source: California Energy Commission

219 Energy Commission staff presentation, available at: [http://www.energy.ca.gov/2009_energypolicy/documents/index.html#092409].

If new gas-fired power plants cannot be licensed in the Los Angeles Basin because air emission credits from the SCAQMD Priority Reserve are unavailable and other rules favorable to power plant development are disallowed, system reliability will require continued and ongoing operation of aging, less efficient, higher emission power plants to maintain planning reserve margins between 15 and 17 percent. Most of these are also OTC plants, so the SWRCB's policy encouraging replacement by new infrastructure would likely be delayed. Eventually, the shortage of emission credits could have a negative impact on Southern California's ability to meet the California ISO summer peak and local capacity requirements if no new fossil plants can be built and if demand-side preferred resources cannot overcome load growth year after year. Local capacity requirements are designed by the California ISO to ensure that there is sufficient generation to provide uninterrupted service during all hours even if a major power plant or transmission line fails. In 2008, the Los Angeles Basin is meeting nearly half of its electrical load with local generating capacity, including aging power plants.

This analysis shows the strong interdependencies of the SWRCB's OTC mitigation policies are in conflict with the limitations of air credit availability to support new power plant development. The legislative solutions have not addressed the full issue, but have sanctioned use of air credits at a limited number of specific power plants already well into the licensing process. The workshop conducted September 24 revealed strong interest in a comprehensive solution to this issue, rather than a series of piecemeal attempts to license specific power plants. Staff's analytic project is on the right track and should be continued in conjunction with inputs from other stakeholders. Eventually legislation is probably required, but it should provide for a systematic, even-handed method for determining which power plants are able to obtain scarce air credits, while the environment is protected from excessive criteria pollutant emissions. That other sources in the Los Angeles air shed have to be regulated more tightly to allow for needed power plant capacity may be the price this region needs to pay to secure reliable electricity services.

Impacts on Power Plants Licensed by the Energy Commission

Three power plants licensed by the Energy Commission are located in the Los Angeles Basin load pocket and could, if developed, allow retirement of some of the existing aging power plants. Inland Empire (maximum capacity 800 MW) secured all its required emission reduction credits, including those from the Priority Reserve. Unit 1 became operational in early 2009, while Unit 2 has been delayed until January 2010.

- Sentinel Units 1 and 2 totaling 800 MW nameplate has completed its Energy Commission review, but was dependent upon Priority Reserve credits and is awaiting resolution of this issue. The owner of the existing El Segundo power plant, NRG Energy, secured a license for repowering of Units 1 and 2 from the Energy Commission in 2005 (nameplate capacity of existing units is 350 MW; license was granted for a repowered facility with nameplate capacity of 630 MW). In June 2007, NRG petitioned to amend its license so it could build a

560-MW facility. With the current change in facility size, NRG does not have sufficient emission reduction credits to move forward with construction of its El Segundo repower project with a nameplate capacity of 560 MW.

- Walnut Creek Energy Center (nameplate capacity 500 MW) received a permit from the Energy Commission in summer 2008 using the SCAQMD Priority Reserve credits. The facility is currently on hold with construction to start in late 2009 pending resolution of the Priority Reserve credit issues.

Other power plants currently in the licensing process at the Energy Commission could, if permitted and brought online, allow more aging power plant retirement. For example, CPV Sentinel (850 MW) has a power purchase agreement with SCE. Further, Sentinel is a "peaker" and would have lower overall levels of emissions than a baseload power plant of equal capacity due to its lower use on an annual basis. CPV Sentinel has applied to the SCAQMD for use of Priority Reserve credits to meet its obligation to mitigate particulate matter less than 10 microns in diameter (PM10) emissions.

Two other projects lie outside the Los Angeles Basin but still depend on Priority Reserve credits to go forward. In July 2008, the Energy Commission licensed the Victorville 2 gas/solar hybrid project (nameplate capacity 563 MW) in the Mojave Desert Air Quality Management District, adjacent to the South Coast Air Basin. Victorville used an inter-basin trading approach that depended on Priority Reserve credits. If the owners are not able to find acceptable replacement credits to use in the Mojave District, they may not be able to construct and operate. The Victorville 2 project currently has no power purchase agreement. The Palmdale project (nameplate capacity 617 MW), currently under Energy Commission review, is also outside the Los Angeles Basin.

Impacts on Specific Utilities

Any substantial delays in the construction of new fossil fuel facilities proposed in the Los Angeles Basin will impact the electricity supplies available to meet summer peak loads. SCE is the major utility in the Los Angeles Basin; however, many municipal utilities are also located there including: LADWP, Burbank Water and Power, Glendale Water and Power (all in the LADWP control area) and Anaheim, Riverside, Pasadena, and other smaller municipals in the California ISO control area. SCE will likely be the most affected by the SCAQMD ruling. The SCAQMD ruling threatens 1,757 MW of this capacity that had been expected to come online from 2010 to 2013 (Table 8).

Table 8: SCE Capacity Impacted by SCAQMD Rule

Year	Facility	Capacity (MW)	Cumulative (MW)
2010	Sentinel I	455	
2011	El Segundo Repower – Units 1&2	550	1,005
2012	Sentinel II	273	1,278
2013	Walnut Creek	479	1,757

Source: California Energy Commission

Energy Commission staff evaluated the supply-demand balance in the South of Path 26 region (SP26).[220] The resulting staff paper used Southern California Edison and other utility assumptions since the *2009 IEPR* had not yet been compiled. The paper computed two alternative retirement scenarios juxtaposed against the limited amount of new additions that could be permitted given the SCAQMD air credit limitations. An updated analysis using staff's planning assumptions and planning reserve margin calculations for the Southern California region over the next five years was presented at the September 24 workshop on SCAQMD air credit issues. The results using the CPUC procurement authorization assumptions are shown in Table 9. The Southern California portion of the California ISO control area has more capacity than necessary to sustain a 15 percent reserve margin through 2011, but falls below that level in 2012 and gets progressively worse. This increases vulnerability to situations like unexpected outages.

Table 9: Staff Planning Assumptions and Reserve Margin Results for Southern California Using High Retirements

Supply/Demand Element	2010	2011	2012	2013	2014
Peak Demand	27,880	28,289	28,794	29,221	29,553
Existing Generation	22,927	22,927	22,927	22,927	22,927
Net Imports	10,100	10,100	10,100	10,100	10,100
DR & Interruptible	1,491	1,512	1,534	1,547	1,551
New Thermal	995	1,707	1,992	1,992	1,992
New Renewable	162	251	533	965	1,157
Retirements	(354)	(354)	(354)	(354)	(708)
Total Generation	35,321	36,142	36,731	37,177	37,020
Reserve Margin w/o OTC Retire	27%	28%	28%	27%	25%
Surplus over 15%	3,259	3,609	3,618	3,573	3,034
SWRCB OTC Retirements	(1,850)	(3,050)	(4,500)	(5,350)	(5,350)
Reserve Margin w OTC Retire	20%	17%	12%	9%	7%
Surplus over 15%	**1409**	**559**	**(882)**	**(1777)**	**(2316)**

Source: California Energy Commission

However, revising the OTC retirement assumptions to match the schedule proposed by the energy agencies and accepted by SWRCB staff in its draft OTC policy reduces near-term retirements and produces surpluses throughout the five-year period. These results are shown in Table 10. The negative impacts of a fast retirement schedule, in light of air credit limitations on new power plant development, which the energy agencies were able to get SWRCB to accept, allows time for the air credit issues to be resolved.

220 California Energy Commission, *Potential Impacts of the South Coast Air Quality Management District Air Credit Limitations and Once-Through Cooling Mitigation on Southern California's Electricity System,* February 2009, CEC-200-2009-002-SD, available at: [http://www.energy.ca.gov/2009publications/CEC-200-2009-002/CEC-200-2009-002-SD.PDF].

Table 10: SCAQMD Impacts on Southern California Planning Reserve Margins

Supply/Demand Element	2010	2011	2012	2013	2014
Peak Demand	27,880	28,289	28,794	29,221	29,553
Existing Generation	22,927	22,927	22,927	22,927	22,927
Net Imports	10,100	10,100	10,100	10,100	10,100
DR & Interruptible	1,491	1,512	1,534	1,547	1,551
New Thermal	995	1,707	1,992	1,992	1,992
New Renewable	162	251	533	965	1,157
Retirements	(354)	(354)	(354)	(354)	(708)
Total Generation	35,321	36,142	36,731	37,177	37,020
Reserve Margin w/o OTC Retire	27%	28%	28%	27%	25%
Surplus over 15%	3,259	3,609	3,618	3,573	3,034
SWRCB OTC Retirements	0	0	0	0	0
Reserve Margin w OTC Retire	27%	28%	28%	27%	25%
Surplus over 15%	**3259**	**3609**	**3618**	**3573**	**3034**

Source: California Energy Commission

The SCAQMD court ruling has had similar impacts on publicly owned utilities in the Southern California portion of the California ISO control area. LADWP has three power plants totaling over 2,000 MW of capacity that use OTC, and apparently intends to repower most of the units in these plants in order to comply with SWRCB requirements. In securing air quality permits, LADWP has faced the same challenges as other entities within the SCAQMD's jurisdiction, since its ability to use SCAQMD's Rule 1304 exemption from providing air credits for its repowers was blocked by the court ruling. The legislative proposals embodied in AB 1318 (Perez, 2009) and SB 827 (Wright, 2009) would apparently restore repowering exemptions via Rule 1304.

Preferred Resource Additions

California has long pursued a path to use more environmentally sensitive technologies to satisfy consumer energy needs. Even during the enthusiasm for markets in the mid- and late-1990s, public goods charges were established to ensure that funding for energy efficiency and renewables would continue to achieve goals for these preferred resources. The Energy Action Plan process signaled inter-agency support for these technologies. The more recent motivation to mitigate climate change accentuates these past efforts.

Because the electricity sector represents a significant source of GHG emissions, it is viewed as a source for major emission reductions to satisfy the state's GHG emission reduction goals. California's continuing emphasis on energy efficiency and shifting the mix of generating resources from fossil plants to renewable resources will provide the bulk of the reductions from the electricity sector. Additional reductions will come from moving to more efficient fossil sources like combined heat and power (CHP) and state-of-the-art natural gas plants.

Uncommitted Energy Efficiency Goals

Since the original *Energy Action Plan*, energy efficiency has been assigned the highest priority among all preferred resources. Prior *IEPRs* and now the ARB *Climate Change Scoping Plan* hold out high aspirations for additional energy efficiency impacts beyond those included in the baseline demand forecast. The *2007 IEPR* called for "achieving all cost effective energy efficiency." In late 2008, the ARB adopted high goals for additional energy efficiency as part of its *Climate Change Scoping Plan*.[221]

The *2008 IEPR Update* described the review of the approach of segregating between committed and uncommitted energy efficiency and only including what the Energy Commission calls "committed" impacts in the baseline demand forecast. The Energy Commission did this to call attention to the need for numerous actions before broad, uncommitted goals can be achieved—for example, programs have to be designed and funded, utilities and other program administrators have to successfully implement programs, end users have to participate either voluntarily through utility programs or involuntarily through mandated standards, technologies must meet or exceed the technological development rates assumed in broad projections, and the general scope and pace of economic development has to continue as assumed when making estimates of program potential and participation. Many things can and do go awry when hundreds of thousands, or millions, of end-use customers have to participate in order to generate the savings estimated in potential studies and savings goal decisions.

As noted later in this chapter, the degree to which the high goals established for uncommitted energy efficiency are achieved interacts strongly with the goals for renewables. Simply said, the amount of renewable energy required under a 33 percent by 2020 Renewables Portfolio Standard (RPS) formula is nearly 50 percent higher without the impacts of additional efficiency. Assuming renewables are pursued in a reasonably logical manner of easiest, cheapest first, the success of energy efficiency aspirations determines whether the state has to construct the difficult and expensive subset of renewable potential. Thus, whether 33 percent renewables is even feasible by 2020 may depend on whether energy efficiency goals are achieved.

Chapter 2 described the efforts that Energy Commission staff is pursuing to develop estimates of the incremental impacts of three scenarios of uncommitted energy efficiency program initiatives derived from CPUC D.08-07-047. The CPUC wishes to use these estimates in its forthcoming LTPP proceeding as adjustments to the baseline demand forecast. The CPUC intends to require the IOUs to evaluate the alternative futures implied by these three "managed" demand forecasts (baseline less incremental, uncommitted impacts) when conducting its portfolio analyses. Examining three alternative futures is highly commendable, but these three do not reflect the full range of uncertainty about the incremental impacts of uncommitted energy efficiency. The three scenarios established by the CPUC reflect differences in the breadth of programs that are imagined to unfold through time via funding for utility programs, number and strength of ratchets in building standards, federal appliance mandates,

221 California Air Resources Board, *Climate Change Scoping Plan*, December 2008, available at: [http://www.arb.ca.gov/cc/scopingplan/document/scopingplandocument.htm].

and pursuit of net zero building designs. There are numerous other sources of uncertainty about incremental impacts that the staff's analytic effort is not examining. Among these are:

- Willingness of customers to participate in voluntary programs.
- The extent to which high efficiency buildings, appliances, and production processes encourage high levels of use thus "taking back" some portion of engineering estimates of savings.
- Measures of technological performance through time.

As the Energy Commission staff develops a capability to project incremental impacts of a less highly structured set of energy efficiency proposals, these other elements of uncertainty should be addressed in the method and assumptions used in making the projections.

On September 24, 2009, the CPUC unanimously adopted a $3.1 billion, three-year Strategic Plan for Energy Efficiency, to be administered by the state's IOUs. Implementing the plan will avoid the need for three additional 500-megawatt power plants. It will also create between 15,000 and 18,000 new jobs, launch the nation's largest home retrofit program, and provide $175 million to launch California's Big Bold Energy Strategies for zero net energy homes and commercial buildings. The plan was developed in close collaboration with the Energy Commission and was dedicated to Energy Commissioner Arthur Rosenfeld. This successful collaboration is an excellent model for California's energy agencies and bodes well for the state's clean energy future.

Renewable Integration

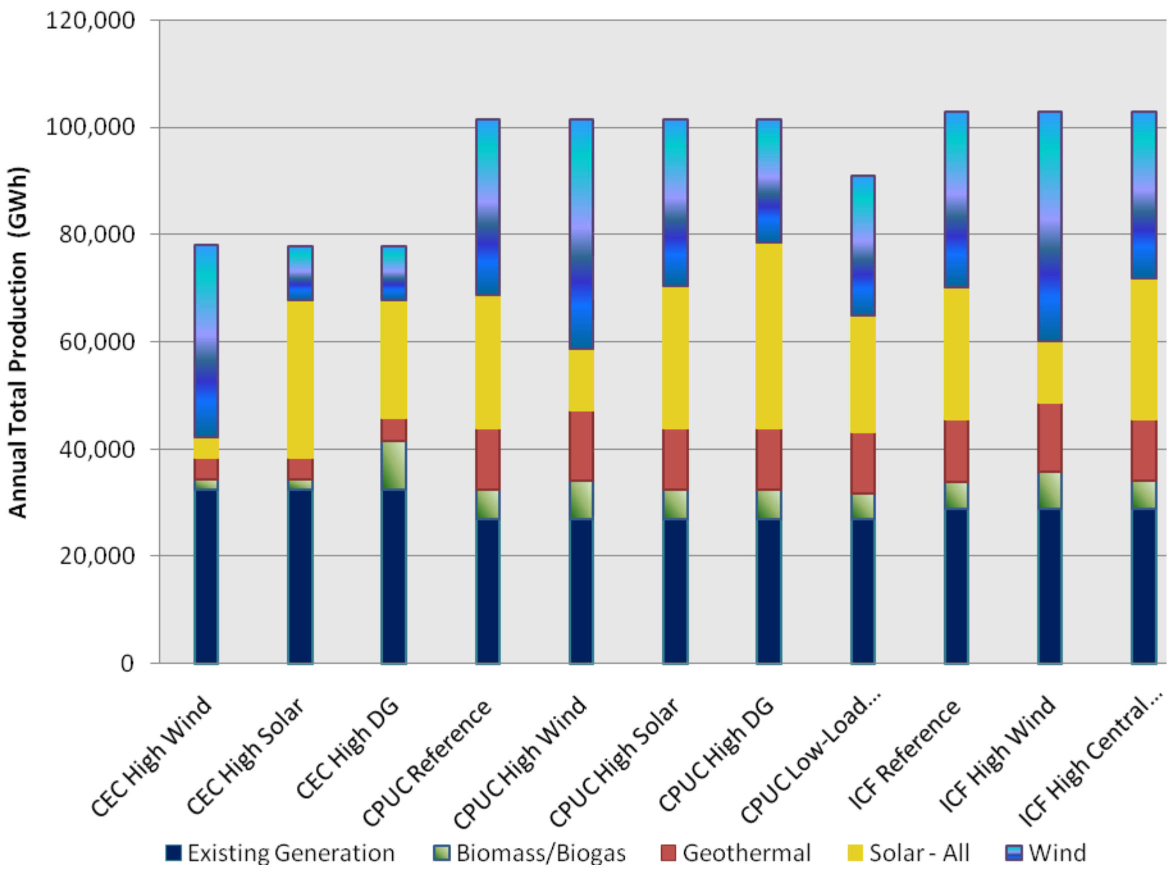
A major issue in implementing climate change policy is how to meet the RPS goal of 33 percent renewable energy by 2020, given the challenges of integrating such large amounts of renewable energy into the system.[222] While some renewable resources like geothermal and biomass can operate much like conventional baseload power plants, intermittent and remotely located renewable generation present new challenges for matching the power they produce with consumer demands. Intermittency of production means that capacity is derated from nameplate values as part of the resource adequacy process, and it also means that dispatchable resources are required to ramp up or down to match the characteristic daily patterns and sudden changes in electricity production from wind and solar resources. Integrating higher levels of renewables into the electricity system must also be integrated with other state policies to reduce the negative impacts of OTC, reduce waste through energy efficiency and combined heat and power, modernize the transmission and distribution grids, and use electricity as an alternative transportation fuel.

A primary question is determining the amount of added renewable energy needed to meet the RPS goal, referred to as the renewable "net short." This is an issue because the existing RPS law focuses on renewables as percentage of retail sales. Anything that reduces retail sales — energy

222 The challenges of accomplishing this integration are very similar whether the details of the program are defined by statute or by regulation.

efficiency program savings, rooftop solar PV and other customer-side-of-the-meter distributed generation — reduces the renewable requirement. As shown in Figure 33, assumptions about the resource mix of future renewable additions varies widely, and no studies have examined a scenario that would maximize the use of baseload biomass and geothermal resources rather than variable wind and solar technologies.[223]

Figure 33: Comparison of Recent Scenarios for Incremental Renewable Energy (33 percent by 2020)



Source: California Energy Commission

Recent estimates of the 2020 renewable energy net short vary from 45,000 gigawatt hours (GWhs) to almost 75,000 GWhs, depending on forecasted electricity demand along with the amount of expected energy efficiency, CHP, rooftop solar, and existing renewables included in the analysis. Since the RPS target is based on retail sales of electricity, estimates of the renewable net short will change over time as forecasts of electricity demand change. Similarly, meeting the

223 The Energy Commission study and presentations of the ICF International study are available at: [http://www.energy.ca.gov/2009_energypolicy/documents/index.html#062909]; the California Public Utilities Commission study, underlying calculator, and supporting white papers are available at: [http://www.cpuc.ca.gov/PUC/energy/Renewables/hot/33implementation.htm].

state's targets for energy efficiency, CHP, and rooftop solar will affect the amount of renewable energy ultimately needed.

Needed additions will also depend on how much renewable power is already flowing into the system. Estimates of existing renewable generation vary from 27,000 to 37,000 GWhs, depending on the vintage of the estimate, the amount of out-of-state renewable generation attributed to publicly owned utilities, and the amount of unclaimed renewables (renewable generation not claimed as eligible for the RPS) included in the estimate.[224] The wide variation between estimates illustrates the need for common assumptions and counting conventions so that the public can be confident in both the targets and reported progress.

Factors Affecting Renewable Integration

Implementing the OTC mitigation policies discussed earlier in the chapter will affect the integration of renewables because it is unclear what characteristics replacement power will have and therefore how it could support renewable integration. OTC units may need to be replaced within the same local capacity area, elsewhere on the grid, or not at all. Replacement plants could be combustion turbines with relatively few hours of operation or new, efficient combined cycle plants that would operate more hours per year than the plants they replace. In addition, the strict regulation of criteria air pollutants in the South Coast Air Basin will restrict the amount of in-basin replacement power, increasing the amount of generation needed from outside the area. The amount of energy imported to meet load in the South Coast Air Basin could be reduced with increased amounts of wholesale distribution-level renewables, although some amount of gas-fired generation or other types of "spinning reserves" may still be needed to allow transmission lines to continue to bring in electricity from outside the area.

Expiring coal contracts will also affect California's system mix and the operational attributes replacement plants will need. Coal contributed about 56,000 GWhs of energy in 2008, with more than 11,000 GWhs of coal-fired generation provided through contracts that will expire by 2020.[225]

Reserve margins are also an issue. To ensure system reliability, utilities are required to have a minimum planning reserve margin of 15 to 17 percent. Reserve margins cover uncertainties in load forecasting, forced and planned outages, largest single contingencies and other operational problems. Planners want enough reserves on hand to handle contingencies, but do not want so much extra capacity that ratepayers end up paying for unused generating units or transmission

224 The studies discussed at the June 29, 2009, IEPR workshop used the *2007 Net System Power Report* as the basis for their estimates of existing renewables, but varied in the way the data from the report was used. The California Public Utilities Commission had the lowest estimate of existing RPS renewable; the *RETI Phase 1B* report had the highest estimate.

225 Total utility out-of-state coal generation comes from the 2007 self-reported claims from the utilities for the Power Source Disclosure Program. Los Angeles Department of Water and Power claimed around 10,000 GWhs of imported coal generation from the Navajo plant, and California Department of Water Resources contracts around 1,300 GWhs of coal generation from Reid Gardner.

lines. Because resources like wind and solar may produce a large amount of energy at times other than system peak, conventional resources or storage may be needed to provide the necessary reserves.

Role of Natural Gas Plants

In designing a future low carbon electricity system, questions have been raised regarding why new natural gas units are needed, if they are needed in specific locales, if they are a help or a hindrance to the development of other preferred resources, and generally what role natural gas will play in the transformed electricity resource mix. The Energy Commission chose to investigate natural gas roles, both in its function as the siting agency for thermal units over 50 MWs and as part of its integrated resource planning infrastructure for generation, transmission, storage, and pipelines. Natural gas generation has many features which complement rather than compete with variable resources such as wind and solar and is therefore part of the suite of options to help create a low carbon system.

What type of natural gas facilities might be added and when they are needed is complicated. If high levels of energy efficiency are achieved, less overall energy will be needed, though capacity requirements may still be hefty. If combined heat and power units are built instead of central station gas generation, different system attributes will be affected. Finally, policies other than supporting incremental renewables are affecting the type and timing of new natural gas-fired units. These include reducing use of OTC at existing plants, meeting local area capacity requirements, and abiding by the criteria pollutant limits in the SCAQMD.

As part of the multi-agency efforts to understand the impacts of integrating higher levels of renewables into the grid, Energy Commission staff analyzed the potential impacts on natural gas use and generation.[226] The study used a reference case that did not include the ARB *Climate Change Scoping Plan* policies and only assumed that the 20 percent RPS goal was met by 2012 statewide. Two "bookend" cases were developed that included the *Climate Change Scoping Plan* policies and meeting the 33 percent RPS target by 2020. The two bookend cases included a high solar and a high wind case. By adding the demand-reducing policies from the *Climate Change Scoping Plan* and reducing the amount of incremental renewables required to reach 33 percent of retail sales, only 45,000 GWhs of incremental renewables were added compared to the 75,000 GWhs added in other studies that did not include the *Climate Change Scoping Plan* measures.

The study found that the potential impacts of adding large amounts of intermittent renewables on natural gas-fired generation were affected by two programs that had significant direct impacts on natural gas use and the type of plants to be built. The *Climate Change Scoping Plan*'s energy savings targets translated into an incremental 4,700 MW of CHP in the staff's model. By 2020, 20 percent of all California's natural gas used for power generation was consumed by CHP. This amount of CHP reduced electricity sales to end-use customers but did not create a

226 California Energy Commission, *Impact of Assembly Bill 32 Scoping Plan Electricity Resource Goals on New Natural Gas-Fired Generation*, June 2009, CEC-200-2009-011, available at: [http://www.energy.ca.gov/2009publications/CEC-200-2009-011/CEC-200-2009-011.PDF].

proportional reduction in natural gas use. It also added a large amount of baseload generation to Southern California, since this is where 60 percent of potential host sites for large CHP are located.

OTC policies also affected the potential impacts of intermittent renewables in the model because much of the generation that needs to be retrofitted or replaced serves local functions that continue to be supported by generation located in local reliability areas. Of the 15,069 MW of existing OTC units, 964 MW were retained, 1,450 MW have recently been repowered, and 7,758 MW were replaced with new, efficient units. By 2020, depending on the case, between 11 and 23 percent of natural gas-fired generation in California is from power plants associated with the OTC issue. Once CHP targets and OTC replacements were made, only a few new natural gas plants had to be added to meet local capacity and energy needs. Those were in the Sacramento Municipal Utility District, Turlock Irrigation District, and Imperial Valley control areas, which have no OTC and limited numbers of large host industrial or commercial facilities for new CHP.

The amount of natural gas units added did not change between the base case and the two bookend cases. This suggests that the CHP additions and those used for OTC policies provided enough gas flexibility so that more units were not needed even in the more intermittent wind cases. But the capacity factors for generic additions and OTC replacement combined cycles, which start out at normal baseload levels, drop much lower by 2020 in the two bookend cases, making the long-run cost-effectiveness of these combined cycles questionable. This suggests that the sample compliance path used in this study was not optimal if the large amount of CHP baseload is added. Baseload energy from "must take" CHP resources reduces need for energy from combined cycle merchant plants, thus shifting them into load following pattern of operations, which may not justify the incremental cost of combined cycle versus simple cycle combustion turbines. Thus, a key finding of the study is that none of these policies should be assessed in isolation. To test these conclusions, additional model runs could be done that lower the amount of must-take CHP and switch some of the OTC combined cycles to combustion turbines.

For electricity generation, the Western Electricity Coordinating Council (WECC) systemwide amount of natural gas did decrease by 15 percent in both of the bookend cases. However, the reductions were not distributed evenly, with at least 70 percent of the gas reductions occurring out of state. In-state gas-fired generation decreased by 10 percent in the high wind case and 13 percent in the high solar case. In contrast, out-of-state gas-fired generation dropped 21 and 20 percent, respectively. This suggests that out-of-state natural gas is the marginal resource and that in-state gas is used for local reliability or ancillary services.

The study also found that a resource mix with a high proportion of wind required more in-state natural gas generation than the high solar case. In addition, more impacts were seen in Southern California than in Northern California. While wind is distributed across the state, solar resources are almost completely concentrated in Southern California. OTC units and potential CHP sites are also concentrated in the southern part of the state. This indicates that there may be more system impacts and potential system stressors in the southern transmission grid.

While gas used for serving retail load dropped, total gas use increased. As Table 11 shows, between 2012 and 2020, total natural gas consumption rose slightly in all cases. The increases in the high wind and high solar cases were more modest, but still increased as large amounts of CHP fueled by natural gas were added to the system. Those increases were less in the high solar case than in the high wind case when compared to the reference case.

Table 11: California Use of Natural Gas in Power Plants in Billion Cubic Feet Per Day (Bcf/d)

	2012	2016	2020	2020 Change From Case 1
Case 1 Reference Case RPS	2.36	2.57	2.88	
Case 2 High Solar	2.34	2.45	2.52	-12%
Case 3 High Wind	2.34	2.48	2.60	-10%

Source: Energy Commission, Electricity Analysis Office

In contrast to the Energy Commission staff study, a recent study by ICF suggested that 33 percent renewables could lead to an increase of 3,000 MW of gas-fired capacity between 2009 and 2020, but a net decrease of 11,000 GWhs of in-state gas-fired generation. The different result in the two studies was the result of different modeling assumptions; for example, the Energy Commission study included local reserve and area reliability requirements, including publicly owned utility reserve requirements for new gas-fired capacity needed to modernize the OTC fleet. In addition, the Energy Commission study included 32,000 GWhs of gas-fired CHP, consistent with the target in the ARB's *Climate Change Scoping Plan*, while the ICF study did not add any CHP. Finally, ICF assumed that total natural gas use in the WECC would rise over the forecast period and that California would import more power generated using natural gas, but that the increase in total in-state use would exceed any increase in imports.

The Energy Commission staff study results indicate that at least three areas deserve further research because of the affect of study assumptions on the type of proxy generation needed to firm and backup intermittent renewables. First, alternative levels of CHP should be tested, since the addition of so much baseload power in state and in Southern California may be difficult to achieve with existing emission credit problems and the lack of a mechanism to make it happen. Second, alternative assumptions about compliance with OTC mitigation requirements should be tested because the interactions of all the *Climate Change Scoping Plan* programs lead to unrealistic capacity factors in the replacement of OTC combined cycles by 2020.

Finally, there are possible instances of over generation, a condition when more generation is provided than there is available load, which will require additional analysis. SCE noted this issue in the June 29, 2009 IEPR Committee workshop on renewable integrating issues, reporting that a study by Nexant suggests there may be an over-generation problem in April and May as the state moves to 2020 if there is high solar incidence in the desert, high generation of wind, and the need to spill water stored in dams to make room for snow melt. In addition, parties at the July 23, 2009 IEPR workshop on CHP issues noted the risk of over generation when large amounts of both renewables and CHP are added to the system mix.

Role of Energy Storage

To the extent that natural gas remains a low-cost fuel, gas-fired generation can help the electricity system absorb the costs of transitioning to higher levels of renewable energy. However, looking forward, some of the firming services provided by gas-fired generation will need to be provided by existing and emerging energy storage technologies that allow generators and transmission operators to fill the gap between the time of generation (off-peak) and the time of need (on-peak) for intermittent renewable energy. Energy storage systems can respond very quickly to the needs of the electric grid system (less than a second) when compared to conventional gas-fired generation (minutes to tens of minutes) and potentially reduce the overall amount of energy needed to balance the system needs. This fast response of energy storage also matches well with the variability of renewable energy systems such as wind and together the combination can allow the grid operators to use increased levels of renewable energy and still maintain the desired levels of reliability and control.

Examples of energy storage technologies that are currently commercially available and under development include advanced technology batteries, flywheels, compressed air energy storage, pumped hydroelectric energy storage, capacitors, and others. These technologies can provide value at each level in California's electric grid — generation, transmission and distribution, and end use — with storage technologies varying in type and size depending on the level of service needed. Generation-level energy storage focuses on the ancillary services market[227] and renewable integration, with grid frequency regulation becoming an area of interest of substantial technological advancements over the last few years. Storage at the transmission and distribution level focuses on load shifting, transmission congestion relief, reliability, and capital deferral. For end users, storage at commercial and industrial facilities can provide peak shaving, electricity backup, and increased reliability.

Using energy storage to help with renewable integration continues to be one of the more promising application areas to make renewable generation available when needed. Energy storage technologies will allow better matching of renewable generation with electricity needs as well as address the severe ramping rates observed with wind and PV. The use of energy storage technologies can also reduce the number and amount of natural gas-fired power plants that would otherwise be needed to provide the firming characteristics the system needs to operate reliably. Because energy storage systems can respond rapidly to the needs of the electric grid, research analysis completed by the Energy Commission indicates that smaller amounts of

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227 Ancillary services support the transmission of electricity from its generation site to the customer. Services could include load regulation, spinning reserve, non-spinning reserve, replacement reserve and voltage support.

energy storage can smoothly and effectively integrate renewable energy when compared to the amount of natural gas-fired power plants required to meet the same response times. California should seize this opportunity and encourage developers to install energy storage to support commercial scale solar and wind farms and reduce the need for new natural gas-fired plants as an energy-firming source.

California has opportunities to use storage in support of renewables in several applications. Storage can provide the ancillary services needed to integrate large amounts of renewables into the system that otherwise would have to be provided by conventional generating resources. Also, grid-connected utility-scale energy storage can be used to avoid cutting back on remote wind farm production in response to transmission limits. Another application is to use large-scale energy storage to shift renewable production to times of higher value and demand. This can help address over-generation issues by storing the excess renewable energy and providing it back to the grid when needed. Finally, fast-response storage can improve electricity system stability and reduce stability and frequency response issues that may occur with high penetrations of renewables.

Research completed by the Energy Commission indicates these utility-scale energy storage systems can provide the grid system a variety of benefits. The energy storage systems can respond rapidly to grid system reliability issues and improve the overall operation of the grid. They can also improve the dispatchability and availability of renewable generation systems by responding to the intermittent nature of wind and solar renewable systems. Additionally, energy storage systems can provide the grid operators ancillary services such as frequency response and spinning reserve. For grid operators to effectively manage the utility grid, a mixture of many types of generation, demand management, and energy storage capabilities are needed. When properly integrated, energy storage and automated demand response can provide critical capabilities currently provided by conventional natural gas generation.

Energy storage is typically measured as a combination of time increments and capacity (in kW or MW) and can range from a few minutes up to many hours. Examples of short-duration storage are batteries and flywheel systems that can be used to compensate for drops in PV generation when passing clouds block the sun, causing generation to drop substantially in less than a minute and jump back to full generation a few minutes later.[228] The Electric Power Research Institute reports that sodium sulfur batteries and lithium ion batteries can provide

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228 Curtright, Aimee E. and Jay Apt, *Progress in Photovoltaics: Research and Applications*, 2008, 16: 241-247, "Applications: The Character of Power Output from Utility-Scale Photovoltaic Systems", available at: [http://www.clubs.psu.edu/up/math/presentations/Curtright-Apt-08.pdf]. See also, presentation by Dan Rastler, EPRI, at the April 2, 2009, IEPR workshop, available at: [http://www.energy.ca.gov/2009_energypolicy/documents/2009-04-02_workshop/presentations/0_3%20EPRI%20-%20Energy%20Storage%20Overview%20-%20Dan%20Rastler.pdf].

frequency regulation to mitigate these kinds of fluctuations in PV generation.[229] In addition, the Energy Commission's Public Interest Energy Research (PIER) program has demonstrated where short-term energy storage systems such as flywheel technology can also provide this capability.

A recent PIER frequency demonstration project company has received Department of Energy (DOE) American Recovery and Reinvestment Act (ARRA) loan guarantees to permit it to construct a 20-MW facility. Other ARRA-related energy storage projects have been proposed to DOE that, if awarded, could result in several major utility-scale energy storage projects being constructed in California over the next few years.

For longer duration storage needs, pumped hydropower uses low-cost off-peak energy to pump water from lower to higher elevation reservoirs, and the water is then released during higher-cost peak times to generate electricity. However, most of the existing water infrastructure that could be used for this purpose must compete with irrigation, flood control, in-stream flow requirements, and other demands placed on the state's water systems. Developing dedicated reservoirs for pumped storage is extremely difficult. Also, under current tariff structures for energy services, there is inadequate support for pumped hydropower systems to cover costs, resulting in only a limited number of these systems being operational in California.

In IEPR workshops on energy storage and smart grid, stakeholders indicated that one significant barrier to increasing the amount of utility-scale energy storage in California is how to pay for the technologies. In many cases, energy storage systems provide utility grid services that cannot be recovered within existing rates and tariffs. Stakeholders recommended that the Energy Commission, California ISO, and the CPUC consider new rates and tariff options that will permit the energy storage system to be adequately reimbursed for all the services the technology provides to the grid. If this were to happen, system cost-effectiveness models can be developed that more accurately reflect the true value energy storage systems provide to the utility grid for renewable integration, system reliability improvements, and ancillary services markets.

To help in this effort, the PIER program is developing system performance models for several energy storage technologies to help identify more revenue sources for energy storage systems. Because energy storage is not considered generation, transmission, or load, new information is needed to properly integrate these technologies into the utility grid system. Once developed and demonstrated, these system performance models can be used to assist the California ISO in integrating them into the ancillary service and other potential markets they operate under the new Market Redesign Technology Upgrade grid management system. In addition to developing these models for energy storage technologies, the PIER program is also developing similar models for the load reduction capabilities provided by automated demand response systems.

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229 Transcript of the April 2, 2009, IEPR workshop, EPRI presentation, pp. 27-32, available at: [http://www.energy.ca.gov/2009_energypolicy/documents/2009-04-02_workshop/2009-04-02_TRANSCRIPT.PDF].

The California ISO has recognized the important role of energy storage in the integration of renewables into the electricity system, and in September 2009, released an issue paper about participation of non-generator resources, including energy storage resources, in ancillary services markets.[230] The California ISO has also started developing an energy storage pilot program to analyze the performance of storage devices and to identify and eliminate barriers to increased deployment.[231] This work should be further expanded in time to encourage installation of storage in the 2015 to -2020 timeframe as the state ramps up to the 33 percent level of renewable energy.

Role of Research and Development

The Energy Commission's PIER program is completing research, development, and demonstration (RD&D) efforts to help bring to market new and innovative solutions to the issues facing the California transmission system and the challenges caused by the integration of more renewables into the utility grid system. In addition to research on energy storage, automated demand response, distributed generation, CHP, and improved renewable technologies, the PIER program is leading a very aggressive effort to encourage the implementation of the California smart grid of the future, which will be driven by existing and future energy policies being implemented in California. Some of the current key policies are:

- 33 percent Renewables Portfolio Standard by 2020
- Implementing advanced metering infrastructure by the IOUs for residential customers. Current plans by CPUC include the IOUs installing more than 12 million "smart meters" in the next two to five years.
- Implementation of 100 percent of the cost effective energy efficiency by 2016.
- Demand response implementation goals.
- AB 32 GHG emission reductions goals.

In addition to these specific state policies, there are other technology improvements that are rapidly progressing in California, the nation, and the world. Some of these are:

- Substantial increase in the number of electric vehicles and plug-in-hybrid electric vehicles projected over the next decade.
- Commercial growth of home area network technologies in California residencies.
- Field implementation of a wide range of two-way communications technologies.

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230 California Independent System Operator, *Issue Paper for Participation of Non-Generator Resources in California ISO Ancillary Services Markets*, September 1, 2009, available at: [http://www.caiso.com/241c/241cd4af47ca0.pdf].
231 California Independent System Operator, see [http://www.caiso.com/2337/2337f16064bc0.pdf].

- Automation of demand response and implementation of a common Open ADR standard in California.
- Field implementation of high speed synchrophasor data collection and reporting systems.
- Advancements in the automated management of the utility distribution system.
- Increased emphasis on the need for new cyber security capabilities.

The California smart grid will take advantage of these and many more technologies and capabilities as the smart grid system is fully implemented over the next decade. The national smart grid effort is being driven by the requirements in the Energy Independence and Security Act (EISA) of 2007 and the efforts of DOE to implement a national smart grid. One key driver for the rapid expansion of these technologies is the amount of ARRA funding for smart grid. DOE is expected to fund more than $4 billion in smart grid projects nationally over the next 12 to 14 months, representing more than 10 times the normal rate of investments this area has seen in the past. California could easily receive $400 to$600 million in smart grid funding from DOE. Because projects require 50 percent match funding by the utilities and commercial companies requesting these funds, California could have more than $1 billion in smart grid projects over the next few years. This level of funding in California and the high level of national smart grid project funding will result in the very rapid growth of smart grid technologies and capabilities.

The implementation of the smart grid in California is expected to provide new opportunities to meet current and future energy policies goals such as:

- Increased utility system data reporting capabilities based on synchrophasor technology, advanced metering infrastructure, distribution automation, and new home area network technologies. These systems are expected to allow the utilities and California ISO to more rapidly recognize and analyze system problems, develop possible solutions, and repair or recover grid problem areas more quickly than with the current grid system. Consumers can expect the smart grid of the future to have fewer failures and faults, more rapid recoveries when problems do occur, and more efficient and cost-effective operation.
- The smart grid will provide new methods and technologies to implement energy efficiency and demand response capabilities in the future. The new data collections capabilities, increased two-way communications, smarter consumers, and wide range of energy savings tools and products will allow consumers to make much smarter individual energy management decisions.
- The smart grid will provide expanded abilities to integrate higher penetrations of renewable technologies. The management of energy storage, distributed generation, automated demand response, distribution level renewables and other capabilities will allow the grid to accept much higher amounts of renewables while maintaining high levels of reliability and controllability.
- The smart grid will allow high numbers of electric vehicles and plug-in hybrid electric vehicles on the roads and, with smart charging systems, permit these vehicles to operate

effectively without causing major disruptions on the utility grid. Some electric or plug-in hybrid vehicles could actually be used as grid assets and provide ancillary services for grid operators when parked in facilities where commercial energy service providers can aggregate their loads into one single energy response system.

- The smart grid will provide better tracking of GHG emissions and will help California meet future emission goals by increasing the use of renewables, energy efficiency, and electric vehicles and by reducing the number of power plants needed to support the grid by using demand response and energy storage as alternative sources of energy for the grid management.

One expected challenge for the smart grid is the how these rapidly deploying new technologies will interact. The PIER program is actively working with other state agencies, industry, and the academic community to identify key standards, protocols, and reference designs that will help ensure that the smart grid operates smoothly. The smart grid standards being implemented nationally will provide significant guidance in this area, but it is expected that California may lead the nation in the implementation of a smart grid and therefore will need to make some initial decisions to ensure the state has the interoperability and commonality needed in the future.

Another area where additional RD&D efforts are needed is renewable energy secure communities. Community-based energy systems are attracting investment, policy attention, and public support nationally and around the world, as community leaders respond to public interest in climate change, sustainable growth, job creation, reducing energy imports, and managing the economic impacts of fossil fuel price escalation and volatility. California is providing leadership in RD&D to identify technical solutions communities can use to optimize their energy supply and integrate building and community-scale energy sources with energy efficiency solutions and programs and smart grid capabilities. The Energy Commission held a solicitation for renewable energy secure community technical integration projects resulting in 50 proposals. The United States Department of Energy has followed suit with its own solicitation on this topic, and other states and countries are exploring policy mechanisms that allow communities to actively participate in the development of the best energy investment strategy for their individual community.

For utility-scale renewables, additional RD&D is needed on integration challenges with solar energy, since it now appears that solar will play a larger role than originally assumed when the Energy Commission completed its Intermittency Analysis Project. The Energy Commission's PIER program should define and complete a study that builds on previous utility-scale renewable energy integration studies.

PIER has adjusted the emphasis of its renewable energy RD&D investments to better address technical integration issues and solutions related to RPS implementation as well as the need for technical solutions enabling community- and building-scale renewable energy deployment. In addition, the Energy Commission is providing seed funding to the California Renewable Energy Collaboration for development of an integrated renewable energy systems program.

When fully funded, the program will conduct and coordinate cutting-edge studies addressing the major technical, economic, and policy questions facing the state as it deploys additional renewable energy supply throughout its electricity and energy end-use infrastructure.

Further research is also needed to understand what parts of the distribution system can best tolerate renewable generation and what role wholesale renewable distributed energy can play in providing local reliability. Research should also focus on the interaction of energy policies affecting the distribution grid, including on-site renewable generation, distributed energy storage, electrification of vehicles, energy efficiency, demand response, and zero net energy homes and buildings. For example, distribution lines may need to be reinforced with technology that can meet demand when on-site distributed renewable energy is not generating electricity. At the same time, upgrades, storage, or other resources may be needed to accommodate two-way flows from intermittent renewable power that is not dispatchable and is placed where it is convenient to the customer, but not to the grid.

Research should also focus on the technical feasibility of adding large amounts of wholesale distributed renewable energy to help the state meet 33 percent of retail sales with renewable energy by 2020, including review of the logistics of upgrading distribution grid infrastructure to meet this timeline. Better understanding of the amount of wholesale distributed renewable energy that is technically feasible by 2020 can help guide studies of market designs supporting smart grid communities, such as feed-in tariffs for CHP and renewable energy.

In addition, integrating increased quantities of distributed generation will require California's energy agencies to work together to develop a comprehensive understanding of the importance of distribution system upgrades not just to assure reliability but also to support the cost-effective integration and interoperability of large amounts of distributed energy for both on-site use and wholesale export. Utilities will need to assess where on their systems distributed generation both for on-site use and for export to the grid would be of the greatest value and provide that information to the energy agencies. These studies should identify which operational characteristics have the highest value; what tools, data, and criteria are used to select these locations; and what obstacles exist to deploying specific types of distributed generation.

Role of Other Renewable Technologies

Baseload renewable technologies such as biomass, biogas, and geothermal also will play an important role in reducing the potential need for gas-fired generation to firm up renewable energy.[232] Geothermal facilities currently provide 42 percent of California's renewable energy and generally operate as baseload; however, in combination with storage, geothermal facilities can offer load following or peaking services as well.

232 For example, see comments by ICF, IEPA, and Covanta Energy from the June 29, 2009 IEPR workshop, transcript, pp. 146, 172, and 190.

Biomass and biogas provide about 20 percent of California's renewable energy, with solid-fuel biomass providing the largest share. Executive Order S-06-06 requires meeting 20 percent of the state's RPS with bioenergy resources. Depending on the availability of fuel, biomass and biogas can provide baseload, load following, or peaking energy products.[233] Biopower could help displace the amount of new gas-fired generation needed to integrate higher levels of renewable energy, but because many of the existing biomass generators are operating at a financial loss under their current contracts, it is unclear whether providing load following or peaking support will be cost-effective for these facilities.

Role of Improved Production Forecasting

Another tool used by system operators to help integrate renewables into the system is production forecasting. Much as load forecasters use data analysis techniques to develop short-term load forecasts, system operators use production forecasting tools to anticipate the amount of renewable energy that will be delivered from various resources. Errors in load forecasting reduce the ability of system operators to anticipate the amount of energy needed to meet demand. If the amount of delivered renewable generation is different than the amount forecasted, system operators will need to increase or decrease generation from other sources of energy to make up the difference, which decreases the value of renewables to the system and increases costs.[234]

Work at the Energy Commission and the National Renewable Energy Laboratory has led to improvements in the characterization of wind areas for planning purposes. In addition, forecasting day-ahead and hour-ahead generation from wind facilities has improved, due in part to the California ISO's Participating Intermittent Resource Program (PIRP). A recent study by the North American Electric Reliability Corporation suggested that system operators expand their use of wind forecasting and conduct plant scheduling on intervals shorter than hourly to increase the ability of the electricity system to respond to changes in generation from wind energy resources.[235] Building on this progress, further work is needed to improve the accuracy of five-minute, hourly, and day-ahead forecasts for electricity demand and solar energy.

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233 "For solid-fuel biomass facilities, which are unique among renewables in having a significant fraction of their total cost of electricity production in the category of variable operating cost (mostly fuel cost), it might be possible to develop feed-in tariff contracts that have elements of load following that would increase their value to the utility at little or no cost to the biomass generator." Written comments by Green Power Institute, May 28, 2009, IEPR workshop, pp. 9-10, available at: [http://www.energy.ca.gov/2009_energypolicy/documents/2009-05-28_workshop/comments/Green_Power_Institute_TN-51936.PDF].

234 California Energy Commission, *2008 IEPR Update,* p. 21, available at: [http://www.energy.ca.gov/2008publications/CEC-100-2008-008/CEC-100-2008-008-CMF.PDF].

235 Center for Energy Efficiency and Renewable Technologies, June 29, 2009, IEPR workshop, transcript pp. 165-166. For further information, see North American Electric Reliability Corporation, *Special Report: Accommodating High Levels of Variable Generation*, April 2009, available at: [http://www.nerc.com/files/IVGTF_Report_041609.pdf].

Less progress has been made in the development of forecasting models for PV and solar thermal electric generation, which still result in large errors. Cloud cover can cause generation from PV systems to drop by 50 percent in a minute or less.[236] More data is needed to improve forecasting of solar energy generation, especially data on variation on the scale of five-minute intervals and minute-to-minute generation from large-scale PV fields. The need for advances in this area is becoming more urgent because of the increasing number of utility-scale PV fields under development and the growing interest in wholesale distributed PV systems. The California ISO plans to add solar to its PIRP program later this year.[237]

Beyond the needs of transmission system operators addressed above, real time web-based wind speed and solar radiation data and forecasts will be needed much more broadly throughout the state's future smart grid as communities- and building-based systems are operated in a way that responds to pricing signals and local and building demand. It is unlikely that current deployment of anemometry and radiation sensors will suffice to adequately support needs for accurate real time local forecasts. PIER has identified this long-term need and is developing plans to address it

Role of Distributed Resources

Although improvements are underway to streamline siting and permitting for transmission and renewable energy facilities, there is a substantial risk that a resource mix depending heavily on utility-scale solar electric projects in remote areas will be delayed beyond 2020. Shifting to a resource mix including both large-scale central station projects and distributed generation (DG) would help the state meet its goal of 33 percent of retail sales from renewable energy by 2020 and lay the foundation for achieving the Governor's Executive Order goal of 80 percent reduction in greenhouse gas emissions from 1990 levels by 2050.

Distributed renewable resources include ground-mounted solar projects up to 20 MW in size; distributed biogas capacity from wastewater processing, landfill gas, animal manure digester gas, and food processing; distribution-scale solid fuel biomass; other clean stand-alone technologies; and distribution-level CHP that reduces GHG emissions through the joint production of electricity and energy needed to meet industrial and commercial thermal loads. Renewable projects that interconnect to the grid at the distribution level can come online faster than large projects (greater than 20 MW) that interconnect to the transmission system directly. Typically they do not require new transmission investment, extensive environmental reviews, or a lengthy permitting process.

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236 This point was raised by Southern California Edison at the June 29, 2009 IEPR workshop, transcript p. 54. Clean Power Research, *Quantifying PV Power Output Variability*, Thomas E. Hoff and Richard Perez, May 2, 2009, available at:
[http://www.cleanpower.com/research/capacityvaluation/QuantifyingPVPowerOutputVariability.pdf].

237 For more information, see the California ISO Participating Intermittent Resource Program website at: [http://www.caiso.com/docs/2003/01/29/2003012914230517586.html], including California ISO PIRP Solar Telemetry Requirements, Draft Version 1.2, August 2009, available at:
[http://www.caiso.com/2403/2403c293428c0.pdf].

Recent studies indicate substantial technical potential for distribution-level generation resources located at or near load. A 2007 estimate from the Energy Commission suggests that there is roof space for over 60,000 MW of PV capacity, although the study did not factor in roof space that is shaded or being used for another purpose.[238] The California Renewable Energy Transmission initiative (RETI) Phase 1B report included a preliminary estimate suggesting that as much as 27,500 MW of 20-MW ground-mount PV projects could be located at substations in California.[239] The California Biomass Collaborative estimates that there is a technical potential for about 1,700 MW of distributed biogas capacity in California from wastewater processing, landfill gas, animal manure digester gas, and food processing.[240]

Studies by the CPUC and the Energy Commission have included scenarios of high penetration of distributed resources. The CPUC Energy Division Preliminary 33 Percent Implementation Analysis included a scenario with about 14 gigawatt (GW) of PV systems under 20 MW, and also included about 250 MW of distributed biogas capacity.[241] Energy Commission staff analysis included a scenario that met one-fifth of the 33 percent goal with biopower, consistent with the Governor's Executive Order S-06-06. This scenario included about 8 GW of distributed solar and about 190 MW of distributed biopower, although this excludes biomass projects identified by RETI Phase 1B report as having fuel to support more than 20 MW of solid-fuel biomass capacity.

Simulations and system analysis have shown that a significant amount of wholesale distributed renewable energy could be integrated into the California distribution grid. A recent analysis by E3 for the CPUC Energy Division found that approximately 69 percent of the California IOU substations can interconnect projects of 10 MW or smaller. Another study by GE on the effect of distributed renewable energy on feeder lines found that limits could range from 15 percent to 50 percent of feeder capacity depending on location and distribution. In addition, preliminary analysis by Navigant Consulting suggests that about 10 GW to 11 GW of wholesale distributed renewable energy could be connected at the distribution level, at substations, or on distribution feeders.

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238 California Energy Commission, *California Rooftop Photovoltaic (PV) Resource Assessment and Growth Potential by County*, September 2007, CEC-500-2007-048, available at: [http://www.energy.ca.gov/2007publications/CEC-500-2007-048/CEC-500-2007-048.PDF].

239 RETI Coordinating Committee, *Renewable Energy Transmission Initiative Phase 1B Final Report*, pp. 1-10, 6-23 through 6-25, January 2009, RETI-1000-2008-003-F, available at: [http://www.energy.ca.gov/2008publications/RETI-1000-2008-003/RETI-1000-2008-003-F.PDF].

240 California Biomass Collaborative, *An Assessment of Biomass Resources in California, 2007*, March 2008, available at: [http://biomass.ucdavis.edu/materials/reports%20and%20publications/2008/CBC_Biomass_Resources_2007.pdf].

241 California Public Utilities Commission, *33 Percent Renewables Portfolio Standard, Implementation Analysis*, *Preliminary Results*, June 2009, available at: [http://www.cpuc.ca.gov/NR/rdonlyres/1865C207-FEB5-43CF-99EB-A212B78467F6/0/33PercentRPSImplementationAnalysisInterimReport.pdf].

So far, the potential for distributed resources to contribute to the RPS goals remains largely untapped. As of July 2009, there are more than 560 MW of PV and more than 300 MW of biopower installed in California at the distribution level (20 MW or less per project). While most of the currently installed PV is not eligible for the RPS, much of the biopower is. IOUs have active RPS contracts for more than 180 MW of projects 20 MW and smaller; this is less than 2 percent of IOU RPS contracts. Publicly owned utilities have active RPS contracts for almost 150 MW of projects 20 MW and smaller; this is about 14 percent of publicly owned utility RPS contracts.

Although there is clearly potential for adding large amounts of distributed renewable generation on distribution systems throughout the state, doing so presents significant challenges. Currently, the state's electric distribution systems are not designed to easily accommodate large quantities of randomly installed distributed generation resources at customer sites. Accomplishing this objective efficiently and cost-effectively will require the development of a new transparent distribution planning framework that allows for the active participation of all stakeholders.

Transportation Impacts

Parties have raised the issue of how increased electrification of the transportation system may affect electricity demand and therefore the amount of renewable energy needed to meet statewide targets. Even though the demand forecasts adopted in this *2009 IEPR* include some limited amounts of plug-in hybrid electric vehicles (PHEV) and electric vehicle (EV) electricity loads, at this time the extent and pace of transportation and industrial electrification is highly speculative. Generally the impacts are viewed as largely beyond the 10-year time horizon that the electricity industry has become accustomed to using over the past decade or two. Stretching planning and analysis efforts out to 20 years and beyond seems necessary, and initial efforts to do so have begun, but it is less clear how decisions about time periods 10 to 20 years into the future should be made.

Issues Affecting the Transmission System

As population grows and electricity supply portfolios change, new transmission facilities will be needed to maintain system reliability and deliver electricity—including increasing amounts of renewable energy—to consumers. Conceptual planning identifies such potential transmission facilities for detailed study. Power flow modeling and production cost simulations performed by the California ISO and electric utilities then determine which projects are needed for reliability and make economic sense and how they must be configured electrically. An implementation plan is developed only after such detailed study and only after land use and environmental implications have been fully considered for specific transmission routes.

The *2009 Draft Strategic Transmission Investment Plan* released in September 2009 provides a detailed discussion of initiatives, trends, and drivers affecting California's transmission system and planning efforts, which are briefly summarized here. First among these is RETI. In August 2009, RETI released its Phase 2A conceptual transmission plan. Phase 3 of the project will focus on developing detailed plans of service for high-priority components of the statewide transmission plan.

The RETI conceptual transmission plan identifies additional transmission capacity needed to access and deliver renewable energy to meet the state renewable energy goals in 2020, and evaluates the relative usefulness of potential lines for accessing renewable energy. The plan identifies potential transmission network lines for further detailed study by the California ISO and electric utilities. Finally, the plan builds in environmental considerations and high level screening of conceptual transmission lines and incorporates a wide range of stakeholder perspectives.

The second issue affecting transmission planning is Governor Schwarzenegger's Executive Order S-14-08, which establishes an RPS target for California that directs all retail sellers of electricity to serve 33 percent of their load with renewable energy by 2020.[242] The order directs state government agencies "to take all appropriate actions to implement this target in all regulatory proceedings, including siting, permitting, and procurement for renewable energy power plants and transmission lines." Activities to implement the provisions of the Executive Order are being closely coordinated with RETI and with the Bureau of Land Management's Department of Energy Solar Programmatic Environmental Impact Statement (Solar PEIS).

The Solar PEIS is the result of requirements in the Energy Policy Act of 2005 for the Secretary of the Interior to plan for installing at least 10,000 MW of renewable generation capacity on public lands in six Western states. In 2008, the Bureau of Land Management (BLM) and the U.S. Department of Energy announced they were preparing a Solar PEIS to cover development of large-scale, grid-connected solar electric facilities in Arizona, California, Colorado, Nevada, New Mexico, and Utah. The Energy Commission is a cooperating agency for the Solar PEIS. The purpose of the Solar PEIS is not to eliminate the need for site-specific environmental review, but instead to identify best management practices and environmental mitigation strategies that proposed projects should follow. The Solar PEIS will also consider whether new transmission corridors are needed on BLM-managed land to interconnect solar electric facilities to the grid.

Another effort that will affect transmission is the CPUC's proceeding to consider issues related to the development of transmission infrastructure to provide access to renewable energy resources for California.[243] In February 2009, the CPUC held a prehearing conference and staff workshop to consider whether the output of the statewide RETI could be used to support cost recovery for transmission planning and the CPUC's standards for determining need within the

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242 Office of the Governor, Executive Order S-14-08, November 17, 2008, available at: [http://gov.ca.gov/executive-order/11072/].

243 California Public Utilities Commission, Order Instituting Rulemaking on the Commission's Own Motion to actively promote the development of transmission infrastructure to provide access to renewable energy resources for California, March 2008, available at: [http://docs.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/80268.htm].

transmission permitting process. In its comments, the California ISO noted that competitive renewable energy zones (CREZs) have been identified by RETI and may provide a basis for certification. The California ISO and other parties also addressed: (1) the use of RETI results in the California ISO long-term transmission planning process; (2) whether a rebuttable presumption of need should be afforded to renewable transmission projects studied and approved by the California ISO; and (3) how project development costs can be recovered by project proponents. The CPUC has not yet issued a proposed decision or subsequent notice.

The California Transmission Planning Group (CTPG), composed of electric utilities and the California ISO,[244] is working toward finding transmission solutions for meeting California's environmental, reliability, economic, and other policy objectives. The group plans to produce its draft 2009 Study Plan in December 2009, with a final report expected in January 2010.

California's transmission infrastructure is an intrinsic component of the high-voltage Western Interconnection, making the state both an essential participant and a partner in several regional and federal planning and permitting initiatives that will alter the way transmission planning and permitting takes place in the future.

New federal funding expected to be provided in 2010 for regional transmission planning will result in interconnection-wide 10-year and 20-year transmission plans for the WECC. These plans may identify projects and/or corridors that are needed, and these will become candidates for Federal Energy Regulatory Commission (FERC) ratemaking and possibly other federal incentives. It is critical that California engage in defining what these plans are and ensuring that they reflect California's policies and assumptions accurately.

- If advocates of federal legislation that would establish new FERC authority for siting and cost allocation succeed in passing a bill in 2009–2010, the pressure to site new interstate line(s) will increase, with associated controversy over siting processes and impacts on environmental resources (both in and out of state). If FERC mandates a cost allocation method, California could be required to pay for projects not consistent with RETI, RPS goals, and carbon reduction policies.
- In addition, transmission system upgrades and additions anywhere in the Western Interconnection will affect the operation of existing lines, including those owned by California utilities and private companies. Proactively participating in WECC analyses of new lines and path ratings is critical to ensuring continued high performance levels of key paths such as the California-Oregon Intertie.
- With federal funding, Western sub-regional transmission planning groups are taking on enhanced planning roles, including preparation of an integrated 10-year subregional transmission plan. Successful development and engagement of the CTPG and participation

244 The California Independent System Operator, California Municipal Utilities Association, Imperial Irrigation District, City of Los Angeles Department of Water and Power, Pacific Gas and Electric Company, Southern California Edison Company, San Diego Gas & Electric Company, and the Transmission Agency of Northern California.

of the California ISO are essential to find consensus on projects and analyses reflective of California interests.

- Greatly increased federal funding for the Western Governors' Association (WGA) Western Renewable Energy Zone (WREZ) Phase 3 and 4 projects (described below) will continue to promote geographically constrained low-carbon resources and large-scale transmission to move remote resources to distant loads. If California policy prefers to procure more resources locally, as reflected in RETI, conflict among states seeking to export and in-state development interests will emerge.
- Major project developers continue the trend of pursuing large transmission projects to deliver power to coastal and desert load centers. Significant resources are being spent to evaluate feasibility and siting for these projects. California needs to be involved in these efforts to provide feedback to project developers on whether these projects are needed or desirable for the state.

Investment in Desired Infrastructure

The hybrid electricity market established through Assembly Bill 1890 (Brulte *et al*., Chapter 854, Statutes of 1996) created multiple entities that invest in and operate specific facilities that are part of the overall electricity infrastructure in California. Merchant generation has a strong position in California. IOUs and various forms of publicly owned utilities continue to dominate the distribution and transmission elements of the electric grid, but even here niche participants have appeared. The Trans Bay Cable from Pittsburg to San Francisco is a good example of a transmission investment made by a public-private partnership. The large and growing number of distributed generation facilities satisfying end-user load, but exporting some of their production to the grid, represents an alternative type of investor. Each of these categories of investor makes decisions about securing capital and constructing facilities using different financial perspectives, accounting rules, tax liabilities, and risk mitigation preferences. Explicit legislation and regulatory agency decisions must guide these investors to make decisions compatible with the vision that the state has for the electricity grid.

Forward Energy or Capacity Markets

In the California ISO balancing authority area, the California ISO and the CPUC have established a one-year ahead forward capacity requirement for all load-serving entities under their various jurisdictions. By establishing a capacity requirement to satisfy reliability needs, a distinct value for capacity will emerge that covers a substantial portion of the investment in a power plant, and the needs for energy will be satisfied through less regulated market decisions. For several years the CPUC has been investigating whether this structure is adequate to provide signals to a competitive industry that additional generation is needed. Advocates of both a central capacity market and a bilateral forward market have put forward the merits of their proposals. At the July 28, 2009 IEPR workshop on OTC issues and in comments following, several generators urged consideration of their forward capacity market construct submitted to the CPUC. They asserted that this would be the best mechanism to surface replacement generation proposals.

Forward Generation Investment by Publicly Owned Utilities

The Energy Commission is required by AB 380 to oversee the resource adequacy efforts of all publicly owned utilities in California. The legislature has authorized a limited "review and report" form of oversight, which allows the Energy Commission to collect information from these utilities and biennially report results of its review as an adjunct to the *IEPR*. Energy Commission staff collected such information during 2009 and presented its results at a workshop on August 6, 2009.[245]

Collectively, and almost without exception, publicly owned utilities are resource adequate several years into the future. As integrated utilities responsible to oversight boards, the various publicly owned utilities have incentives to acquire resources to cover expected loads. As discussed elsewhere in this report concerning the various elements of demand-side or supply-side resource choice, publicly owned utilities have traditionally emphasized low cost options. As a consequence, their collective exposure to out-of-state coal, either through fractional ownership shares or wholly owned facilities, is now at odds with state policy to reduce GHG emissions. As state policy emphasizing preferred resource additions becomes more directly applicable to publicly owned utilities, a shift in resource mix is expected requiring publicly owned utilities to commit to long-term contracts or invest directly in such resources. This will increase total investment or credit requirements.

Investment in Transmission and Distribution

Utilities are expected to make sizeable investments in additional transmission infrastructure, both to facilitate use of remote renewables in satisfying load concentrated in urban centers and to upgrade transmission facilities within these urban centers to reduce local capacity requirements. At the July 28, 2009 IEPR workshop on OTC, SCE strongly cautioned that long lead-time transmission investments could be rendered not useful and thus not recoverable if short lead-time generation investments substituted for transmission at the last moment.[246] It appears that SCE wanted to communicate the message that the OTC replacement infrastructure proposal made jointly by the energy agencies to SWRCB needed to be followed through fully all the way to the final ratemaking actions by the CPUC.

The *2009 Strategic Transmission Investment Plan* provides an in-depth review of near-term and longer-term issues associated with transmission needed to achieve renewable development. However, as noted in this chapter, there are still many uncertainties affecting the transmission needed to support this renewable development. Among these are:

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245 The transcript and presentations from the August 6, 2009 IEPR workshop are available at: [http://www.energy.ca.gov/2009_energypolicy/documents/index.html#080609].

246 Comment by Pat Arons, Southern California Edison, at the July 28, 2009, IEPR workshop.

- The amount of renewable development that will be required to satisfy an RPS formula of 33 percent of retail sales by 2020 given various demand-side policy preferences.
- Whether, and to what extent, out-of-state renewables will be eligible to contribute toward RPS goals.
- What mix of renewable resource types, especially wind versus solar, is likely to emerge since the transmission lines and routing are largely different among various development scenarios.

Fortunately, the transmission revenue requirement issues associated with FERC treatment of transmission to support state energy policy goals seems to have been resolved. On January 25, 2007, the California ISO filed a petition with FERC for a declaratory order seeking conceptual approval of a new financing mechanism to aid the construction of interconnection facilities for location-constrained resources (primarily remotely located renewables). On April 19, 2007, FERC granted the California ISO's petition and accepted the design concepts proposed therein, thus paving the way for the California ISO to file tariff language implementing this initiative. The California ISO filed a tariff amendment for the Location Constrained Resource Interconnection on October 31, 2007. FERC approved the amendment on December 21, 2007.

The rollout of smart meters by IOUs and some publicly owned utilities and related smart grid technologies will also require substantial investments. While the infrastructure itself will be deployed by utilities (or commercial entities under long-run contract to utilities), once the system is in place end-use customers will need to make investment themselves to make full use of some of the new capabilities.

End-Use Customer Investments

Pursuing energy efficiency, customer-side-of-the-meter distributed generation, and demand response as preferred resources substituting for conventional generating facilities places substantial investment requirements on end-use customers. Customers are asked to make investments that will reduce expected energy purchase costs, hopefully saving money when all is said and done. The turmoil in credit markets stemming from the housing crisis of 2008–2009 and its spillover into the stock market and tightening of all forms of lending bodes ill for expectations that end users can easily provide the investment capital required. Early monitoring data from 2009 IOU energy efficiency programs suggests that IOUs are not making the energy savings goals established for them by the CPUC and that customers are simply not as willing to make the required investment despite the incentives provided through IOU programs authorized by the CPUC.

The energy agencies need to carefully review policies that depend upon consumer investments and determine whether new forms of assistance are required, how this might be provided, and what coordination among other state and local institutions is appropriate. If end-use customers cannot uphold expectations implicit in current demand-side program goals, then either programs need to be redesigned to increase incentives or program goals need to be scaled back either in the near term or long term.

Issues with Integrating State Policy Goals with Electricity Planning Processes

This chapter has outlined the numerous challenges that California faces in integrating the many overlapping and often conflicting energy policy goals related to the electricity sector. First there is the overarching goal of reducing GHG emissions from the electricity sector, through strategies such as achieving all cost-effective energy efficiency and demand response measures, meeting the state's RPS goals of 33 percent by 2020, adding 3,000 MW of solar through the California Solar Initiative by the end of 2016, and increasing CHP by 4,000 MW. Next are other environmental goals like retiring or repowering plants that use OTC to reduce the impacts of electricity generation on marine life, reducing the impacts of siting solar plants in the California desert, and improving air quality in non-attainment areas of the state such as Southern California. OTC mitigation is likely to reduce the amount of flexible fossil resources available to integrate renewables, so newly constructed power plants will be needed to support such integration. But air quality regulations strongly penalize new power plants compared to the continued operation of existing power plants, so licensing the amounts of new fossil generation needed for renewable integration will be extremely difficult in some regions of the state. Another potential area of conflict is the need for new transmission lines to access remote renewable resources that may have land use, environmental, visual, or cost impacts. Finally, there is the long-standing policy to reduce the state's dependence on natural gas and natural gas imports, as well as the Energy Commission's mandate to develop energy policies that ensure electric reliability, sufficiency, affordability, and public health and safety.

In the very large California ISO balancing authority area, formal resource adequacy requirements established by both the CPUC and California ISO provide a framework for evaluating reliability. However, the need for dispatchable power plants in specific locations to support the California ISO's local reliability needs remains analytically opaque and there is, as yet, no mechanism to ensure that the needed resources will be built. As the recent joint energy agency proposal to SWRCB concerning development of OTC replacement infrastructure makes clear, all these entities support reliability goals, but converting that common policy sentiment into concrete action steps resulting in operational power plants and transmission lines remains a challenge.

These GHG reduction, environmental protection, and reliability goals must be integrated so that the state can set priorities and better understand tradeoffs when goals are in direct conflict. Policy makers need to understand the interactions between goals and make decisions that reconcile or prioritize these goals. Planning processes must consider how realistic policy goals and their target dates are and whether they will be achieved in full and on schedule and if not, then plan accordingly. This could lead to more resources than are actually needed, which could be preferable to supply shortages that reduce system reliability or to resorting to expensive emergency actions in an attempt to "catch up."

At the same time, energy agency planning, procurement, and permitting decisions must consider technological, financial, and environmental constraints. On the engineering side, dispatchable power plants are needed to meet hourly, daily, and seasonal fluctuations in electricity demand and supply that can result from changes in weather, hydroelectric or natural gas supplies, variable renewable generation, planned outages for maintenance, or equipment failure. System operators also have to account for adequate electricity resources in specific areas of the state, known as "load pockets," so that transmission limitations into and out of those areas do not lead to operational problems or even outages. Also, transmission and generation are sometimes complementary, such as when transmission additions are needed to allow the development of remote renewable resources, and sometimes substitutes, as when transmission upgrades allow the retirement of certain power plants that provide local reliability functions in load pockets.

On the financial side, both electric utilities and private developers make decisions based on reasonable expectations of profits, which will affect how much investment in new infrastructure will be made at any one point in time. It is also a reality that all of California's preferred resources (energy efficiency, demand response, renewables, and distributed generation) have costs as well as benefits, and those costs must be taken into account when making decisions about policy tradeoffs. Further, since the state's overall industry structure is dependent upon private entities responding to state energy plans to motivate their investments, the state energy agencies need to provide clear and convincing messages about the type and timing of investments.

Planning in the Electricity Sector

There are numerous agencies within California involved in electricity planning. The Energy Commission, CPUC, and California ISO each conduct electricity planning processes that provide general guidance on policies and specific guidance on a limited range of electricity topics unique to the responsibilities of each agency. Some degree of coordination already exists. For example, the Energy Commission forecasts statewide electricity demand in its biennial *IEPR*, while the CPUC oversees investor-owned utility procurement of the resources needed to meet that demand. The California ISO analyzes and approves plans for the transmission needed to reliably bring those resources to customers and uses the Energy Commission demand forecasts in such analyses. However, while portions of the California ISO's analyses rely upon Energy Commission studies, other parts are less well-coordinated with state energy policy goals. In addition, publicly owned utilities conduct their own planning and procurement processes to meet resource needs in their service territories. Overlaying these planning processes, the ARB identifies strategies for achieving emission reductions in the electricity sector needed to help the state meet its GHG emission reduction goals.

State and regional environmental agency processes can also have a major effect on the electricity sector. For example, the SWRCB implements federal Clean Water Act provisions related to the use of ocean water in power plants, with the authority to approve and set conditions for permits without which those plants cannot operate. Withdrawing such permits can shut down an existing power plant, something that none of the energy agencies has authority to do. Another example is the SCAQMD, which determines which power plants get air credits. As noted earlier, current legal issues surrounding those credits have created a temporary moratorium on power plant licensing in the Los Angeles Basin.

On the transmission side, investor-owned utilities and publicly owned utilities plan for their own service territories. IOUs submit their planning considerations to the California ISO annual transmission planning process, while publicly owned utilities submit their future transmission priorities to the Energy Commission as part of the development of the *Strategic Transmission Investment Plan*.

The California ISO's annual plan addresses only the California ISO-controlled grid and is limited to electrical system planning requirements, so land use and environmental considerations are not included. The annual plan captures a 10-year time horizon and does not assess needs well into the future for a longer term view. The plan establishes the need for new transmission infrastructure proposals for IOUs who in turn seek permits for those facilities at the CPUC.

The Energy Commission is involved in transmission through the development and adoption of the *Strategic Transmission Investment Plan* as part of the requirements of the biennial *IEPR* to assess all aspects of energy supply, which includes transmission. The plan identifies and recommends actions needed to implement transmission investments needed for reliability, congestion relief, and future load growth. The plan also describes transmission challenges and provides recommendations to address those challenges and also identifies high priority transmission projects that are then integrated into the California ISO's annual transmission plans.

Lastly, the informal RETI process is influencing formal transmission planning. The electric utilities, the California ISO, and the Energy Commission have all committed to consider RETI results in their transmission planning processes. Because the RETI process only addresses the interconnection of renewable energy, it will not result in a complete and detailed California transmission plan of service. However, it is nonetheless a first step toward a detailed statewide transmission plan because it articulates the requirements associated with integrating renewable resources, which is the most important and difficult requirement for future transmission infrastructure in California. More importantly, it balances electric considerations with land use and environmental considerations in a stakeholder process to create broad support for new infrastructure needs.

All of these complementary and often overlapping electricity and transmission planning processes are only loosely coordinated among the many agencies involved. The CPUC's biennial long-term procurement planning (LTPP) proceeding uses information developed in the Energy Commission's IEPR to provide procurement guidance to the IOUs, and the CPUC's Energy Division staff has proposed expanding the scope of the LTPP to address "system requirements" rather than just IOU-bundled customer needs. If accepted as proposed, this "straw proposal" would be implemented during 2010–2011. The California ISO conducts an annual transmission planning process to evaluate both conceptual transmission developments and specific project proposals, and its study of local reliability is used to determine local capacity requirements for both CPUC-jurisdictional load serving entities and those publicly owned utilities governed by the California ISO's resource adequacy tariff. These key elements guide requirements for transmission owners and load-serving entities today.

Publicly owned utilities have their own processes that are even more loosely connected. Despite periodic efforts to coordinate these processes, the dynamics of independent institutions mean that only partial coordination has been sustained through time.

There have been some efforts to integrate the various statewide electricity planning processes. Senate Bill 1389 (Bowen and Sher, Chapter 568, Statutes of 2002) completely revised the electricity and natural gas planning responsibilities of the Energy Commission. It established the biennial *IEPR*, and directed the Energy Commission to consider the input of nine named state agencies in developing its assessments. It also requires these nine agencies to use IEPR information and analyses in carrying out their own energy-related activities. The CPUC then established a biennial long-term procurement plan process conducted in even numbered years to immediately follow upon the Energy Commission's *IEPR*. In a process known as integrated planning and procurement mechanism, the Energy Commission, CPUC, and California ISO negotiated how their respective planning and procurement activities would dovetail. By fall 2004, detailed flowcharts and narrative descriptions of process integration had achieved some degree of success. However, this process terminated by spring 2005 without reaching a formal agreement.

In decisions in 2004 and 2005, the CPUC directed that the *2005 IEPR* demand forecast be used as the basis for the 2006 LTPP proceeding and that the *2005 IEPR* policy recommendations be considered in the forthcoming CPUC LTPP rulemaking. The Energy Commission provided the CPUC with a special transmittal report containing the electricity demand forecast, net short results, and policy recommendations from the *2005 IEPR*. Despite opposition from IOUs and delays that deferred conclusion beyond the expected time frame, the CPUC issued a decision in the 2006 LTPP rulemaking to use the *2005 IEPR* demand forecast and accept the spirit of the aging power plant retirement policy established in the *2005 IEPR*. This process was not repeated for the *2007 IEPR* and the 2008 LTPP proceeding because the CPUC decided to devote the 2008 LTPP proceeding to reviewing and upgrading the methods used in LTPP portfolio analyses and other elements of the planning process that would then be used in the 2010 LTPP proceeding.

The next opportunity for coordination between the Energy Commission's *IEPR* and the CPUC's LTPP proceeding is the *2009 IEPR* and the 2010 LTPP. The CPUC has clearly stated its intention to use the demand forecast adopted in the *2009 IEPR*. Further, the CPUC has determined that it will use the Energy Commission's analysis of the incremental impacts of uncommitted energy efficiency projections as the source of modifications to the Energy Commission's baseline load forecast such adjustments to determine what amounts of additional energy efficiency reflecting previously established CPUC energy efficiency goals should be used to adjust the baseline forecast. The 2009 IEPR proceeding has agreed to provide such a product to the CPUC consistent with the CPUC's required schedule.

Although the discussions regarding coordination between the three energy agencies broke down in spring 2005, continuing discussions with the California ISO regarding coordinated planning resulted in proposals that the California ISO use the Energy Commission's long-term demand forecast as the basis for transmission planning. Since that time, the California ISO has used the *IEPR* demand forecast as the basis for its transmission planning studies and requires participating transmission owners to do the same. However, Energy Commission staff is unaware whether the California ISO modifies the baseline demand forecasts to reflect potential decreases in electricity demand as a result of the goals in the ARB's *Climate Change Scoping Plan* for increased energy efficiency and use of distributed generation resources. The California ISO also uses Energy Commission short-term demand forecasts in developing one-year-ahead local resource adequacy requirements, which the CPUC reviews and adopts each year as part of its resource adequacy requirements.

Statewide collaboration with regard to formal transmission planning does not exist and remains elusive. In the final analysis, transmission plans developed by formal transmission planning organizations in California are disjointed and uncoordinated and do not adequately address future transmission infrastructure requirements on a statewide basis. There is no single transmission planning process that addresses the state's complete transmission system or grid. None of the existing transmission planning processes adequately considers transmission line routing and related land use and environmental implications, and existing planning processes do not adequately consider long-term needs well beyond the 10-year time horizon.

Given the challenges facing California's electricity system in the next decade, the state requires tighter coordination among energy agencies to address these challenges and avoid unnecessary duplication of effort for both the agencies and the stakeholders they serve. Lack of this coordination, let alone full integration, means that some efforts are duplicated while others are inconsistent or not receiving the attention they deserve. For example, numerous efforts examining various implications of 33 percent by 2020 were presented at an Energy Commission IEPR workshop on June 29, 2009. However, the most fundamental work to understand the amounts of flexible, dispatchable resources to complement the intermittency of some renewables is still needed.

Another example is the use of alternative planning assumptions in various forums, including licensing proceedings, to evaluate specific generation or transmission projects. There are known discrepancies in these assumptions compared to state policy goals. Although the California ISO considers the Energy Commission adopted demand forecast in its annual transmission planning process, it does not modify the load forecast to account for the impacts of the demand-side resource goals adopted by the state for incremental energy efficiency, demand response reductions at peak, or distributed generation. Omitting these impacts leads to conclusions that electricity demand will be higher, thus making more projects cost effective. This conservative approach may make sense from a "reliability first" perspective, but it may increase the number of interventions in transmission licensing proceedings because some parties may feel proposed transmission lines would not be needed if the preferred demand-side policies were taken into account in the analyses.

Finally, no energy agency is systematically examining the long-term future. Electricity demand patterns may be very different 15 to 25 years into the future, and power plants that will be licensed and built in the ensuing years will still be viable and not yet fully depreciated. Transmission planning beyond the normal 10-year horizon is needed to prevent short-term infrastructure decisions from interfering with longer term needs or creating additional land use and environmental conflicts. Achieving the GHG emission reductions called for in Executive Order S-20-06 for 2050 will involve much more complex tradeoffs between fuels and electricity. Electricity demand may increase as a result of higher penetration of electric vehicles or increased electrification of industrial processes to help those sectors meet their GHG emission reduction goals. While it is too early to make firm commitments to power plants on the basis of this speculative electrification, it is not too early to begin identifying how larger electricity demand might be met by expanding the transmission system to access more sources, establishing transmission corridors to assure that transmission can be expanded in the future, and evaluating whether "energy parks" ought to be planned in advance to support electrification to the extent it is needed. Further, differences in demand patterns may alter the current mix of resources, relying either more or less than today on "peaking" resources that might be satisfied by storage technologies. Finally, a more electrified future could require higher reliability standards if more of society's eggs are in a single basket.

Need for Statewide Integrated Electricity and Transmission Planning

Finding ways to coordinate and streamline the collective responsibilities of the energy agencies will be essential in meeting the state's important policies and policy goals.[247] The most logical approach to effectively leverage and coordinate the respective functions of the Energy Commission, the CPUC, and the California ISO is an arrangement with lead responsibility for planning infrastructure requirements to reside in the Energy Commission's IEPR proceeding along with a description of the inputs from other agencies to be relied upon and the results provided to other agencies and the manner in which they are expected to be used.

Senate Bill 1389 intended the Energy Commission's *IEPR* to be the forum for establishing energy policy. The Energy Commission's forecasts and assessments are meant to be relied on by other agencies, including the CPUC, in carrying out their energy-related functions. There have been efforts to better link and coordinate the *IEPR* with the CPUC's LTTP. However, in recent years, the scope of the LTTP has grown in response to direct legislative mandates and under the CPUC's general interpretation that minimizing ratepayer costs requires it to make choices that balance resource preference goals with just and reasonable rates.[248]

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247 The Energy Commission staff prepared an integrated planning paper and distributed it among various agencies during August 2009. Feedback from these agencies has been mixed.

248 A California Public Utilities Commission Energy Division straw proposal for the 2010 LTPP cycle, released July 1, 2009, proposes to add a "system plan" element alongside direct IOU-bundled customer procurement to identify needed resource additions. The straw proposal explains that undertaking this new scope would add to the length and complexity of the LTPP proceeding.

Recently, the Legislature also gave the Energy Commission greater authority over publicly owned utilities to ensure they also follow the broad resource policy preferences established by the Energy Commission and CPUC or required by the Legislature. Similarly, the Energy Commission has been granted authority to designate transmission corridors to smooth the way toward specific transmission line projects in the future, which would presumably be evaluated, approved, and, once constructed, operated by the California ISO.

The Energy Commission has long required all load-serving entities with peak loads above 200 MW to submit their demand forecast and resource plans to the Energy Commission for review. This includes IOUs, publicly owned utilities, and CPUC-jurisdictional load-serving entities. The CPUC has similar requirements for the IOUs. While the CPUC's focus on IOUs is important, it does not cover efforts by its own regulated electric service providers or publicly owned utilities located in the transmission areas served by SCE or PG&E. Similarly, while the California ISO is the largest system operator and transmission planning organization in the state, there are four other balancing authorities in California that play similar roles.

Now that the joint agency proposal[249] has been accepted by SWRCB staff and incorporated into the draft OTC mitigation policy issued for formal public comment, the energy agencies need to confront the details of how the proposed analyses will be accomplished in a timely manner and how existing decision-making processes will be modified to make tough choices. While the proposal emphasized the broad steps leading to the product the SWRCB needs — a schedule for OTC power plant replacement — it did not lay out changes needed in planning process or decision-making practices to achieve the collaborative analyses and broad decisions about preferred options.

Creating Need Assessment and Need Conformance

Discussing broad blueprints for future resources that identify desired quantities of specific resource types and determining whether a specific project matches those needs requires common terminology to allow effective communication. Potential definitions are offered below:

- **Blueprint or Vision**: A qualitative plan, guide, or framework that juxtaposes resource policy preferences against reliability standards, reflects priorities among policy preferences, indicates which entities are guided by the plan, and establishes how agencies coordinate with one another.
- **Need assessment:** A process of quantitatively evaluating the state's blueprint or vision using current and expected electricity demand, new supply additions, possible retirements of existing power plants, operating requirements, and necessary

249 Jaske, Michael R. (Energy Commission), Dennis C. Peters (California ISO), and Robert L. Strauss (CPUC), *Implementation of Once-Through Cooling Mitigation Through Energy Infrastructure Planning and Procurement*, California Energy Commission, July 2009, CEC-200-2009-013-SD, available at: [http://www.energy.ca.gov/2009publications/CEC-200-2009-013/CEC-200-2009-013-SD.PDF].

transmission to guide decisions about the future energy system mix to determine the necessary attributes and locations of needed power plants, and in what time frame.

- **Need conformance:** The process of determining whether the expected operation of a specific plant matches the elements in a previously developed need assessment.

The Energy Commission is the permitting agency for thermal power plants greater than 50 MW in size. Although some renewable generating technologies are permitted by local agencies, the majority of power plant capacity additions still flow through the Energy Commission. Intervenors in recent cases have explicitly raised need issues even though the legal construct of the licensing process does not call out need assessment or need conformance. The Energy Commission itself is exploring need assessment issues through an Order Instituting Investigation concerning how to treat GHG emissions as part of the CEQA process for power plants it licenses.[250] This makes the Energy Commission's permitting process one of the principal clients of a need assessment product, especially if the Energy Commission is required to undertake need conformance as part of its permitting responsibilities. [251]

From the narrow perspective of providing a foundation for possible Energy Commission generation *need conformance* determinations for larger fossil power plants, the critical component of *need assessment* is analysis that indicates what fossil resources would be needed under different futures. The emphasis should be on conducting analyses of multiple, plausible futures (including futures in which 33 percent RPS or other policy goals are not reached "on a straight line"), estimating the magnitude of resources likely to be needed in the next 10 years, and defining what could be built over 5 to 8 years without regret.[252] Assumptions about the development of other system components will be essential to these analyses. Such analyses would translate into statewide planning guidance disaggregated and quantified to some set of defined areas, including perhaps the ISO control area, utility service areas, planning areas, and/or local reliability areas.

The need assessment should be broad in scope, yet detailed enough to be relevant for all jurisdictions that perform *need conformance* for all types and sizes of power plants. For example, a local air pollution control district evaluating a 49-MW geothermal plant — below the 50 MW size threshold of the Energy Commission's licensing jurisdiction — must recognize that the generation from such a plant would displace emissions from natural gas and coal power plants

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250 California Energy Commission, *Committee Guidance on Fulfilling California Environmental Quality Act Responsibilities for Greenhouse Gas Impacts in Power Plant Siting Application,* March 2009, CEC-700-2009-004, available at: [http://www.valleyair.org/programs/CCAP/documents/CEC-700-2009-004.pdf].

251 Senate Bill 696 (Wright, 2009) devised a "need conformance" construct for allocating scarce air emission credits within the South Coast air shed. The Energy Commission would have exercised this responsibility. In the most recent versions of this draft legislation all impacts on power plants have been removed. No bill with such provisions emerged from the 2009 legislative session.

252 "Without regret" means the amount of power plant development foreseen to be necessary under all reasonably likely sets of future conditions.

that have much greater GHG emissions per unit of production. Similarly, while major central station solar power plant proposals that use PV technologies are outside the Energy Commission's jurisdiction, many of the permitting issues the local agency must consider are the same as those considered by the Energy Commission for a solar thermal power plant. The statewide *need assessment* should guide these local entities in making their own *need conformance* decisions.

Need conformance also takes place in transmission development, mostly between the California ISO and the CPUC but also under ad hoc arrangements frequently created for specific projects. Even though the California ISO reviews specific transmission projects proposed by transmission owners and other entities and determines whether they are needed, larger transmission projects requiring a CEQA determination from the CPUC often encounter strong opposition in the permitting process, and *need conformance* is frequently a fundamental issue. As an example, opponents of the Sunrise Powerlink in San Diego asserted that urban rooftop PV could substitute for the transmission line and the power it would import. In their minds, the proposed transmission line was not needed. Another example is when publicly owned utilities proposing a transmission line from Northern California renewable developments to Central California encountered resistance from land owners who contested whether their land ought to be disadvantaged by a transmission line clearly intended to serve others that provided no policy or monetary benefit to the land owners along the route. From the opponents' perspective, the need for the line was not justified.

The *2009 Draft Strategic Transmission Investment Plan* presents a proposal for a consolidated statewide transmission plan that could help resolve some of these concerns. First, planning should be divided into two timeframes, a short-term 10-year planning horizon and a second timeframe that looks at the 10- to 30-year horizon. In the short-term planning process, each IOU would submit its planning perspective to the California ISO, and publicly owned utility balancing authorities would submit planned projects of statewide significance to the CTPG. Projects without statewide significance would go directly to permitting because they will not affect statewide planning. Next, the California ISO develops its Annual Plan, which addresses the California ISO-controlled grid.

The CTPG would then work together to develop a single statewide transmission plan, with the IOUs and the publicly owned utility balancing authorities acting in a fully coordinated manner. To adequately reflect stakeholder interests, the plan must have broad stakeholder support through all phases of plan development, particularly with regard to RETI. While consensus is not realistic on a statewide basis, the goal should be to achieve broad enough stakeholder support that transmission permitting will be less contentious and have a greater likelihood of success.

The CTPG statewide plan would then be submitted for evaluation to the Energy Commission's Strategic Transmission Investment Plan proceeding. The objective is to ensure that state interests regarding state policy goals and objectives are evaluated in a public forum. Projects conforming to state policy goals and objectives would be given greater weight in the permitting process. The *Strategic Transmission Investment Plan* also targets transmission projects for the Energy Commission's corridor designation process, and this step envisions recommending multiple projects identified in the CTPG statewide plan for simultaneous designation, rather than a piecemeal approach of one corridor designation proceeding at a time.

The final step is permitting, which is the most controversial stage of transmission development because it has the highest level of analysis and scrutiny. The CPUC has jurisdiction over IOU transmission line projects, and the publicly owned utility balancing authorities have jurisdiction over transmission line projects proposed for their publicly owned utility service territories. As pointed out, an inadequate transmission planning process compromises the transmission line permitting process because transmission owners seeking permit approvals for transmission line projects resulting from inadequate planning will likely fail for lack of support and because of active stakeholder resistance. This step assumes that need for new transmission is ultimately determined during the permitting process. However, this process envisions that analyses in support of need determination are being carried out during each of the preceding steps.

Assuming the CTPG statewide plan secures broad stakeholder support, this permitting step envisions stakeholders' support for transmission project permit applications that are consistent with the CTPG plan. For projects largely facilitating renewable development, the RETI stakeholders understand the benefits of such a project and can presumably be relied upon to express support for such projects. For others, however, such as upgraded transmission lines facilitating reduced reliance upon OTC power plants, support from stakeholders is less obvious and will have to be marshaled.

For longer term planning, it is impossible to produce a 30-year plan with the same level of detail as the 10-year California ISO Annual Transmission Plan. Instead, the long-term plan would build on the 10-year California ISO plan and CTPG statewide plan and would consider the RETI conceptual plan and WREZ initiative planning output. The Energy Commission would prepare and vet the long-term plan in the Strategic Transmission Investment Plan proceeding, with the cooperation of electric utilities and interested stakeholders. The long-term plan would feed back into subsequent RETI conceptual transmission planning cycles, which this planning approach assumes would be undertaken every two years. The objective of subsequent RETI cycles would be to update the conceptual transmission plan completed two years previously. In addition, like the 10-year transmission planning proposal, the long-term plan would signal transmission corridor needs for the Energy Commission's corridor designation program.

This type of far-reaching planning horizon would not seek precision, but it would offer a vision of possible future transmission needs for California significantly into the future. In addition, it would help ensure that shorter-term planning by the California ISO, electric utilities, and the RETI collaborative stakeholder process do not preclude or conflict with longer term transmission options for California beyond the customary 10-year planning horizon.

Integrated Generation/Transmission Planning

For too long, the generation and transmission planning processes have operated as parallel, not integrated, mechanisms. The RETI effort undertaken by stakeholders obviously brings together renewable generation development with the transmission lines needed to gather such power and move it to load centers. Assessing the options for retiring existing OTC generation is another area in which tradeoffs and complementary roles for generation and transmission have to be assessed. Part of the joint proposal of the Energy Commission, the CPUC and the Califonia ISO to the SWRCB is an agreement to conduct analyses to identify the options for retiring each OTC power plant and in terms of replacement infrastructure. Both the renewable generation and the OTC replacement topics illustrate both the need for and the beginnings of efforts to bring generation and transmission analyses together. What is now needed is a more explicit electricity infrastructure planning process in which decisions can be made that make use of such analyses. The Energy Commission intends to work toward developing such a process.

Chapter 4: Recommendations

Introduction

California's energy systems must constantly respond to changes in energy supply and demand, new policy priorities, and technological advances. As California's population increases, the state's energy systems become increasingly complex in order to serve increased demand. Although the current economic downturn has reduced projected energy demand in the short-term, demand is still expected to grow over time as the economy recovers. Energy system planning must be flexible to be able to respond to future upswings and downturns in the economy.

At the same time, California needs to maintain reliable and cost-effective energy supplies in the face of increasing environmental regulation. Policy makers need to consider the costs of providing clean and reliable energy to both energy providers and consumers and balance the short-term costs of doing so against the long-term costs and impacts of catastrophic climate change.

The primary policy driver for energy in both the short and long-term is the state's goal of reducing greenhouse gas (GHG) emissions. The state has identified near-term strategies for its 2020 goals, but more aggressive policies and actions will be needed to meet the longer-term goal of reducing GHG emissions to 80 percent below 1990 levels by 2050. To achieve this target will require fundamental changes in the way energy is produced and used, as well as extensive efforts to develop new technologies to meet the challenges that lie ahead.

As California moves toward less carbon-intensive energy sources to meet its climate change goals, the state needs to identify emerging technologies that can help address the challenges facing the various energy sectors. Because of the long lead times associated with research and development efforts, the state must begin now to identify the most promising areas of research and development on which to focus its efforts, and ensure that research and development activities are used to further the state's energy policy goals. In addition, the state needs to continue its research on how climate change will affect the state's energy infrastructure and its ability to serve the citizens of California.

Chapters 2 and 3 discussed some of the major issues facing California's transportation, electricity, and natural gas sectors. This chapter identifies recommendations that the Integrated Energy Policy Report (IEPR) Committee believes should be implemented immediately to ensure that California's energy systems continue to meet the needs of its citizens.

Recommendations for the Electricity Sector

Energy Efficiency and Demand Response

California needs to increase its efforts to achieve 100 percent cost-effective energy efficiency in the state to meet the GHG emission reduction goals in the California Air Resources Board's (ARB's) Scoping Plan. Strategies to achieve these goals include zero net energy buildings, increasingly stringent building and appliance standards along with better enforcement of those standards, and increasing the efficiency of the state's existing building stock. And with the prospect of increasing population growth in drier, hotter inland areas and the resulting increase in air conditioning loads, California needs to continue its efforts to reduce peak electricity demand to reduce the need for expensive and higher-emission peaking power plants. In addition, the Energy Commission needs to continue its efforts to accurately reflect energy efficiency impacts in its electricity demand forecast.

Zero Net Energy Buildings

To achieve the goal for all new residential construction in California to be zero net energy by 2020, and all new commercial construction net zero by 2030, the IEPR Committee recommends establishing a statewide task force that includes state agencies, local governments, utilities, industry, enforcement bodies, and technical experts to address issues such as:

- Definition of zero energy; for example, zero net energy, zero peak energy, or zero net carbon.
- Whether progress toward the goal should be measured by individual home, by neighborhood, by community, or by climate zone.
- The optimal level of energy efficiency needed before installing on-site renewable resources, and how to incorporate that into building codes.
- The most important aspects of home design and construction techniques that need the most attention in enforcement efforts and code upgrades to stay on the zero net path.
- Lessons learned from national efficiency code programs and appliance standards.
- The role of land use planning and neighborhood design and the need for continuing dialogue with local governments.
- The role of reach standards, green building codes, and other voluntary programs.
- Potential pilot program design and implementation.

In addition, because the goal of zero net energy buildings will involve not just efficiency but also building-based energy supply, the Energy Commission's standards for building energy efficiency should be expanded to address building-scale renewable energy solutions.

Building and Appliance Standards

To improve the contribution of the state's building and appliance standards to statewide energy efficiency goals, the IEPR Committee recommends:

- Expanding the scope of building standards to include process loads, laboratories, refrigeration systems, and other common high energy-using commercial building types.
- Better incorporating lighting and home electronic plug loads into Title 24 compliance software calculations.
- Expanding appliance standards to include consumer electronics, general lighting, irrigation controls, and refrigeration systems.
- Improving enforcement and compliance with building and appliance standards by working with building departments and providing them with the education and tools needed to increase their compliance rate.
- Collaborating with the Contractors State Licensing Board to take action in investigating and disciplining unlawful activity by licensed as well as unlicensed contractors in relation to the Energy Standards.

Efficiency in Existing Buildings

To take advantage of the significant potential for energy efficiency savings from California's existing residential and commercial buildings, the IEPR Committee recommends the following:

- Energy efficiency retrofits should be required at point of sale or point of remodel. Incentives such as refunds for inspections or caps on maximum expenditures should be used to avoid dissuading homeowners from selling or making improvements to their homes.
- Legislation, utility incentives, or local ordinances should consider triggers to require heating, ventilation, and air conditioning equipment tune up by qualified technicians to ensure appropriate maintenance and efficient operation.
- Innovative financing options need to be explored and developed that offer competitive rates to finance deep whole house energy retrofits. Utility on-bill financing, waste collection on-bill financing and water utility on-bill financing pilots around the country should be monitored and explored as possible mechanisms to design the payback out of energy cost savings and keep the debt with the property.
- For rating non-residential buildings as part of Assembly Bill 1103 performance disclosure requirements, the state should develop a California Energy Performance tool to provide a performance rating for energy usage by building size and type; an asset rating for the building shell, HVAC, boilers and other equipment; and a carbon rating for renewable energy generation onsite that offsets electricity or natural gas use. The European Union's "Energy Performance of Buildings Directive" should be considered as a model.

- Because the energy performance disclosure requirements under Assembly Bill 1103 apply only to entire buildings, regulations should be developed to address how to obtain meaningful building performance data for tenant leased spaces.
- To capture all cost-effective energy savings in existing buildings, the California Public Utilities Commission (CPUC) should encourage the energy and water utilities to transform the market from near-term savings to sustained long-term strategies and activities via performance based incentives, comprehensive packages of energy saving strategies, and decoupling of earnings from energy and water sales.

Publicly Owned Utility Energy Efficiency Programs and Reporting

To ensure that publicly owned utilities are making progress toward achieving the statewide goal of 100 percent cost-effective energy efficiency savings, the IEPR Committee recommends the following:

- Publicly owned utilities should apply integrated resource planning to compare demand-side resources with supply-side resources using cost-effectiveness metrics. This approach should result in increased funding for energy efficiency from utility sources beyond the Public Goods Charge, (that is, procurement) and increase future energy savings enough to reach adopted targets.
- To demonstrate this commitment, in their next annual report to the Energy Commission the publicly owned utilities should provide additional information on the role of energy efficiency in their integrated resource planning and the details of how increased funding will help to meet adopted energy efficiency targets.
- Each publicly owned utility should continue to complete evaluation, measurement, and verification studies to show that energy savings have been realized; and fund these studies consistent with their importance as a significant resource; and report on evaluation, measurement and verification plans, studies, and results in their next annual AB 2021 submittal to the Energy Commission.
- To provide confidence that publicly owned utilities are achieving their efficiency targets with bona fide program savings, publicly owned utilities should increase the transparency of information on energy efficiency activities, expenditures, savings estimations, and cost-effectiveness calculations. In addition, they should provide to the Energy Commission staff the data used to create their annual status reports. The Energy Commission will work toward developing protocols for the publicly owned utilities to provide information to explain 1) year-to-year differences in budget and savings accomplishments; and 2) methodologies and assumptions for estimating and verifying annual savings.

Demand Response

To help the state meet its goal of reducing peak demand by 5 percent through demand response measures, the IEPR Committee recommends the following:

- All utilities, including publicly owned utilities, should install meters capable of recording hourly consumption, and should publish their time-varying electric rates in an actionable and open source format.
- All customers should have no-cost access to near-real time information about their energy use in a format that is both meaningful and easy to understand.
- All utility price signals should use open source, non-proprietary, formats.
- The Energy Commission should continue efforts to adopt a statewide load management standard requiring all utilities in the state to adopt some form of dynamic pricing for customers that have advanced meters.
- The Energy Commission's Public Interest Energy Research Program should continue to pursue research and development that supports load management, such as mechanical and automatic devices and systems for the control of daily and seasonal peak loads, and complete the necessary research and development to implement open automated demand response for all customer classes.

Incorporating Efficiency in the Demand Forecast

- Energy Commission staff should actively participate in CPUC's evaluation, monitoring, and verification activities for the investor-owned utilities (IOUs) as well as similar activities for the publicly owned utilities to get insight into determinations of program savings and potential for future savings, which are closely related to Energy Commissioner demand forecast responsibilities.
- The Energy Commission should devote sufficient resources to become fully competent in making projections of energy efficiency savings from energy efficiency goals that are truly incremental to the savings in the demand forecast.
- Energy Commission staff should work closely with CPUC staff in establishing feasible energy efficiency goals as part of the periodic Assembly Bill 2021 requirements, as well as other forums.

Renewable Resources

Meeting the state's 33 percent RPS will be essential to achieving the ARB's target for greenhouse gas emissions reductions from the electricity sector. However, the state has not made sufficient progress toward meeting even the 20 percent by 2010 Renewables Portfolio Standard (RPS) goal, which will make achieving 33 percent renewables a challenge. Issues associated with meeting the target include integrating large amounts of renewable resources into the electricity grid, environmental permitting of both new renewable facilities and associated transmission lines, maintaining the state's existing renewable facilities, and providing the financial certainty needed by renewable developers to proceed with projects while continuing to keep downward pressure on renewable costs.

Renewable Portfolio Standard Targets

The *2006 IEPR Update* recommended that the state should maintain the per-kilowatt-hour penalties for investor-owned utility non-compliance with RPS goals consistent with California Public Utilities Decision 06-05-039, and eliminate the current per-utility cap on those penalties. In the *2008 IEPR Update*, the Energy Commission reported that while the CPUC had not eliminated the $25 million per-utility penalty cap established in Decision 03-06-071, the state was maintaining the authority to apply the penalties of 5 cents per kilowatt-hour for non-compliance with RPS goals. The *2008 IEPR Update* also noted the statutory change that addressed flexible compliance rules for the RPS and effectively extended the date for applying penalties for non-compliance beyond 2010 to 2013.

Because of the importance of achieving the state's RPS goals, the IEPR Committee reiterates the need for the CPUC to be committed to imposing penalties on IOUs for non-compliance with RPS targets.

Renewable Integration

To facilitate integrating renewable energy into California's electricity system while maintaining reliability, the IEPR Committee recommends the following:

- The Energy Commission should work with the CPUC, the California Independent System Operator (California ISO), the ARB, utilities, and other stakeholders to develop a clear implementation pathway to achieve the renewable, energy efficiency, and combined heat and power goals in the ARB's AB32 *Climate Change Scoping Plan* while addressing the need to reduce use of once-through cooling and operate within air quality restrictions in the South Coast Air Quality Management District. The implementation plan should create and capture opportunities for all energy-related state policies to complement one another rather than work at cross purposes.

- The Energy Commission should conduct further analysis to identify solutions to integrating rising levels of energy efficiency, smart grid infrastructure, and renewable energy while avoiding conditions of surplus generation. Potential solutions include better coordination of the timing of resource additions and the mix of resources added to efficiently meet customer needs and maintain system reliability. In addition, there should be efforts to determine what value new, more flexible and efficient natural gas technologies best fit into an electricity grid in transition.

- The Energy Commission should support the detailed analysis being conducted by the California ISO to identify specific system requirements such as local ramp rates, inertia, and the other transmission-related ancillary service functions.

- The Energy Commission's Public Interest Energy Research (PIER) program should develop tools to forecast operational performance of solar energy generation facilities and understand the interaction of forecasting errors in load, wind, and solar energy production. As part of this effort, PIER should develop a publicly available dataset of roof-top, community-scale, and utility-scale photovoltaic (PV) systems and solar thermal electric systems with and without storage.

- PIER should continue its research efforts on the appropriate specifications of energy storage systems needed to integrate intermittent renewable, with focus on the following issues:
    - Coordinating with the California ISO to determine whether storage can be allowed to participate in the ancillary services market and whether to create tariffs to allow for participation.
    - Researching the proper placement and sizing of new and existing storage technologies.
    - Investigating how storage could capture multiple revenue streams by providing multiple benefits since aggregation of these benefits is necessary for cost-effectiveness in many cases.
    - Developing control and operation of storage resources from dynamic stability enhancement to diurnal energy time shifting.
    - Investigating control requirements and smart grid integration requirements.
    - Continuing to deploy existing demonstration projects and initiate new projects to demonstrate the benefits of energy storage for renewable integration and increased system reliability.

Maintaining Existing Renewable Facilities

To help maintain California's baseline of existing renewable facilities, the IEPR Committee recommends the following:

- The Governor's *Bioenergy Action Plan* should be updated to address continuing barriers to the development and deployment of bioenergy. These barriers include air quality permitting, expiring incentive programs, and non-existent private project financing. The *Bioenergy Action Plan* should also be expanded to identify issues and potential solutions related to biogas injection and gas cleanup.
- The Energy Commission should explore options to ensure that existing biomass facilities continue to operate, including continuation of the Existing Renewable Facilities Program, subsidizing biomass feedstocks, or developing a feed-in tariff for existing biomass facilities.

Supporting New Renewable Facilities and Transmission

To facilitate permitting of new renewable facilities and securing the necessary transmission corridors and lines to access those facilities, the IEPR Committee recommends the following:

- The Energy Commission staff should continue to support the Renewable Energy Action Team's mission to streamline and expedite the permitting processes for renewable energy projects, while conserving endangered species and natural communities at the ecosystem scale in the Mojave and Colorado Desert regions through the Desert Renewable Energy Conservation Plan.

- Local air pollution districts should be encouraged to become involved in the Interagency Biomass Working Group since they have key regulatory authority over biomass projects. Furthering the dialogue between air districts, the state's energy agencies, the Governor, and the Legislature can result in innovative solutions to mitigate air pollution while enabling California to meet its biomass/biogas energy goals.

- The state should explore ways to leverage funding mechanisms to develop projects that simultaneously use biopower and biofuels. The Energy Commission's PIER Renewable-based Energy Secure Communities program should provide grants focusing on projects that capitalize on the synergies of co-locating electricity generation from biomass with the production of biofuel for use in the transportation sector.

- Energy Commission staff should actively participate in the CPUC Investigation and Rulemaking on Transmission for Renewable Resources and collaborate with the CPUC and other agencies to eliminate duplicative transmission needs determination and permitting processes.

- Energy Commission staff should conduct early outreach now to local governments and other land use agencies to inform them of the planning initiatives that are under way to facilitate the development of renewable generation and to encourage their timely participation in planning for and designating transmission corridors to help meet the state's energy policy objectives.

- The Energy Commission should continue to participate in the Renewable Energy Transmission Initiative (RETI) process to reach consensus on the appropriate transmission line segments that should be considered for corridor designation to facilitate renewable energy development.

Expanding Feed-In Tariffs

To facilitate lower-cost development of renewable resources, the IEPR Committee recommends the following actions to expand the use of feed-in tariffs in California:

- The CPUC should immediately implement technology-specific feed-in tariffs for wholesale renewable distributed generation for projects 20 megawatt (MW) or less in size, including simplified and standardized contracts and reasonable prices.

- The Legislature should consider changes in state law to require that utilities or the California ISO offer technology-specific feed-in tariffs designed to effectively spur development and integration of utility-scale renewable energy along renewable-rich transmission corridors.

- California should support clarification of federal law to ensure that states can implement cost-based feed-in tariffs for resources that help reduce health and environmental impacts of electricity generation, including greenhouse gas emissions.

Distributed Generation

The *2007 IEPR* identified the need to expand and upgrade California's distribution system to prepare for the resource mix needed to reach GHG emission reduction goals. With the state's policies to rely increasingly on preferred resources, the distribution system must be able to integrate and efficiently use distributed resources. With potentially billions of dollars being spent on distribution system upgrades, the state needs to ensure that those upgrades will facilitate meeting the goals for increased renewable resources.

To support the goal of integrating increased quantities of both renewable and non-renewable distributed generation into the grid, the IEPR Committee recommends:

- The Energy Commission and the CPUC should open a joint proceeding to develop a comprehensive understanding of the importance of distribution system upgrades, not only to assure reliability, but also to support the cost-effective integration and interoperability of large amounts of distributed energy for both on-site use and wholesale export. The proceeding should focus on the following:
    - Requiring utilities to provide an assessment of the areas/locations on their systems in which distributed generation for both on-site use and/or export would be of greatest value. The studies should report on operational characteristics that would have greatest value; tools, data and criteria used to select these locations; and obstacles to deploying specific types of distributed generation in these areas (for example, high density residential areas).
    - Reviewing and requiring the use of distribution system operational models and economic/capital investment models in utility rate cases.
    - Requiring utilities to use these tools to demonstrate that investments in advanced grid technologies will support grid modernization goals, including from a standpoint of cost effectiveness.
    - Implementing and validating open International Electrotechnical Commission (IEC) communication standards for distributed energy resources before proprietary solutions become established. Although these standards are not required in the United States, they are being implemented in Europe where most countries are mandated to use IEC standards. California can leverage European efforts to develop and implement these standards and ensure that the state benefits from the widespread use of communication standards. Once implemented for PV, the same communication standards can be used for other renewable systems, such as wind, fuel cells, biomass, as well as for distribution automation equipment.

Combined Heat and Power

Combined heat and power (CHP) provides benefits to the system through more efficient use of natural gas fuel, which also results in decreased GHG emissions. The barriers to increased penetration of CHP technologies have been identified repeatedly in past IEPRs, but little progress has been made. In addition, there is potential for renewable CHP at wastewater treatment plants using co-digestion of multiple biodegradable waste streams, such as municipal waste sludge, food processor waste, restaurant leftovers, and dairy manure, which can add as much as 450 MW to the CHP potential in California.

Meeting Scoping Plan Targets for CHP

Based on a 2005 CHP market forecast, the ARB set a target of 6.7 million metric tons of CO_2 emissions reduction from CHP by 2020 in its Climate Change Scoping Plan. This was translated into 30,000 gigawatt hours and 4,000 MW of new CHP. The new market forecast done for the 2009 IEPR found that 4,500 MW of new CHP could be installed by 2020 with various incentives, including export sales for CHP systems larger than 20 MW, but that the CO_2 emissions reductions would be only about half the ARB target. In addition, the future of existing qualifying facility contracts for CHP power (representing about 6,000 MW of existing CHP) is in question. Also, recession has altered the economic landscape – gas prices are low, economic growth estimates are reduced. Consequently the prospect for attaining system efficiencies, grid stability and GHG reduction seems to be in jeopardy unless a combination of remedial policies and programs are urgently implemented.

- The development of new CHP can lead to a reduction in carbon dioxide equivalent emissions of 4 million metric tons per year by 2020. To realize these reductions, the following implementation measures should be instituted:
    - The Energy Commission and the ARB should structure CHP programs to ensure development of both small CHP systems (20 MW and smaller) and large CHP systems (larger than 20 MW). Desirable CHP systems should be dispatchable, appropriately located, and have a load profile that addresses utility net short positions, and CHP tariffs should appropriately value these attributes.
    - The Energy Commission and the ARB should establish minimum efficiency standards, GHG emission criteria, and monitoring and reporting mechanisms.
    - Electric utilities should develop programs and solicit projects to promote CHP as a strategy to replace boilers, increase energy efficiency, and reduce emissions. Programs should include a mix of mechanisms such as energy audits, an electricity export sales tariff, and a pay-as-you-save pilot program for nonprofit organizations. Utility ownership is acceptable where it does not crowd out private investment.
    - Eligibility for CHP systems with a generating capacity of 5 MW or less that meet minimum performance, monitoring and reporting standards should be re-instituted in the Self Generation Incentive Program. The amount of the incentive should be based on efficiency and GHG reduction metrics rather than technology and fuel types.

Renewable Combined Heat and Power

Co-digestion of organic material at waste water treatment plants helps mitigate the GHG emissions emanating from California's multiple organic waste streams. A recent IEPR staff report shows that co-digesting multiple biodegradable waste streams such as municipal waste sludge, food processor waste, restaurant leftovers and dairy manure can add as much as 450 MW to the CHP potential in California. Research projects undertaken by the Energy Commission's PIER program and others have established the scientific and engineering feasibility of co-digestion; however, the technology is in the early stages of commercialization. Research and market assessments can improve the economics, efficiency and market potential from biodegradable waste in California. The IEPR Committee recommends the following:

- The CPUC and the Energy Commission should focus efforts toward increasing market penetration of technologies related to co-digestion of biodegradable waste streams, including:
  - Developing a web-based database to provide location and volume of available biodegradable waste material to promote logistically and economically sound exchange of waste suitable for co-digestion at wastewater treatment plants. This could be done on cost-share basis with industry associations.
  - Assessing the economic and technical potential of multiple biodegradable waste streams in a co-digestion mode. These waste streams should include the waste material from California's agriculture, food and dairy industries.
  - Developing methodologies for attaining and assessing GHG reduction, monitoring and verification of such reductions for biodegradable materials whose eligibility for GHG emission reduction credits is not established.

Coordinated Electricity System Planning

California faces challenges in implementing state policy goals to decrease the use of once-through cooling in power plants and retire aging power plants, given the need to maintain system reliability and limitations on emissions credits for replacement plants in the southern part of the state. At the same time, the state needs to better coordinate its electricity policy, planning, and procurement efforts to eliminate duplication and to ensure that planners and policy makers understand the interactions and conflicts that may exist between state energy policy goals.

California has numerous agencies that are involved in electricity planning. While there is some degree of coordination between various agencies and processes, the state needs to find better ways to coordinate and streamline the collective responsibilities of those agencies to be able to achieve the state's greenhouse gas emission reduction, environmental protection, and reliability goals while reducing duplicative or contradictory processes. The IEPR Committee recommends the following:

- The Energy Commission staff should continue the analyses begun as part of the 2009 IEPR proceeding toward developing both short-term (2013-2020) and long-term (2020-2050) "blueprints" laying out the role for different generation technologies in the future given state policy goals to support high levels of renewable resources, expand energy efficiency efforts, and retire aging power plants that rely on once-through cooling while maintaining system reliability. Analyses should evaluate:

- Generation additions in the South Coast Air Basin to satisfy demand growth and close or repower aging coastal facilities using once-through cooling technologies.
- Effect on future generation projects of transmission reinforcements, distributed generation applications, and the current lack of emissions offsets.
- In collaboration with the California ISO and CPUC, a detailed system analysis of new generation and transmission line additions needed for each load pocket.

- The Energy Commission should continue to work with the CPUC, the California ISO, and the State Water Resources Control Board to implement the joint energy agency proposal that establishes a schedule for complying with once-through cooling mitigation while addressing electric system reliability concerns.
- The Energy Commission should conduct analysis to determine the amount of air credits needed in South Coast air shed and work cooperatively with the South Coast Air Quality Management District, the ARB, and other appropriate agencies to design new methods to allocate scarce air credits to proposed power plants that best meet system and local needs.
- The Energy Commission should plan to undertake need conformance for power plants it licenses in a more organized and formal manner, relying upon need assessments prepared in an integrated planning process to determine future power plant needs.
- The Energy Commission should focus its forecasting, planning, IEPR, and Strategic Transmission Investment Plan processes on conducting the statewide integrated planning that is clearly now required. Efforts should be coordinated with those of the CPUC and California ISO to reduce duplication.
- The Energy Commission should seek legislative authority for (1) an explicit need conformance process for the power plants it licenses directly; and (2) its need assessment conclusions to be used by local and regional environmental agencies with final approval over power plants that the Energy Commission does not license.
- The Energy Commission's Cost of Generation model should be used where applicable as a transparent tool for upcoming integrated resource planning studies. A reasonable range of inputs should be used to generate a range of potential levelized cost estimates.

Nuclear Plants

- To help ensure plant reliability and minimize costs, PG&E and SCE should complete and report in a timely manner on the studies recommended in the *AB 1632 Report* which the CPUC identified for completion as part of their license renewal review. These reports should be made available to the Energy Commission, as part of the IEPR process, and to the CPUC for their license renewal review. Once a utility completes the required studies and makes them available to the Energy Commission and the CPUC for review, the utility may then file license renewal applications with the CPUC and the U.S. Nuclear Regulatory Commission (NRC). These studies should include:

- Reporting on the findings from updated seismic and tsunami hazard studies, including results of 3D seismic imaging studies, and assessing the long-term seismic vulnerability and reliability of the plants.
- Summarizing the implications for Diablo Canyon and San Onofre Nuclear Generating Station (SONGS) of lessons learned from the response of the Kashiwazaki-Kariwa nuclear plant to the 2007 earthquake.
- Reassessing whether plans and access roads surrounding the plants, following a major seismic event and/or plant emergency, are adequate for emergency response to protect the public, workers and plant assets and for timely evacuation following such an event.
- Studying the local economic impact of shutting down the plants as compared to alternative uses for the plant sites.
- Reporting on plans and costs for storing and disposing of low-level waste and spent fuel through 20-year license extensions and plant decommissioning using current and projected market prices.
- Quantifying the reliability, economic, and environmental impacts of replacement power options.
- Assessing the options and costs for complying with the proposed State Water Resources Control Board (SWRCB) once-through cooling policy. These studies should be included in the cost-benefit assessment of the plants' license renewal feasibility studies.
- Reporting on efforts to improve the safety culture at SONGS and on the NRC's evaluation of these efforts and the plant's overall performance (SCE only).

- The CPUC should assess the need to establish a SONGS Independent Safety Committee patterned after the Diablo Canyon Independent Safety Committee.
- The Energy Commission should continue to monitor Nuclear Regulatory Commission and the Institute of Nuclear Power Operations reviews of Diablo Canyon and SONGS, and in particular monitor plant performance and safety culture at SONGS.
- The Energy Commission should continue to monitor the federal nuclear waste management program and represent California in the Yucca Mountain licensing proceeding to ensure that California's interests are protected regarding potential groundwater and spent fuel transportation impacts in California.
- The Energy Commission should continue to participate in DOE and regional planning activities for nuclear waste transportation.
- The Energy Commission, CPUC, and the California ISO should assess the reliability implications and impacts from implementing California's proposed once-through cooling policy and regulations for California's operating nuclear plants.

- To support the state’s long-term energy planning, SCE and PG&E should report, as part of the *2010 IEPR*, what new generation and/or transmission facilities would be needed to maintain voltage support and system and local reliability in the event of a long-term outage at Diablo Canyon, SONGS or Palo Verde. The utilities should develop contingency plans to maintain reliability and grid stability in the event of an extended shutdown at SONGS, Diablo Canyon, or Palo Verde.
- The Energy Commission should continue to update information on the comprehensive economic and environmental impacts of nuclear energy generation compared with alternatives. These economic and environmental assessments should consider “cradle to grave” or lifecycle impacts.
- The SONGS’ Seismic Advisory Board should include greater representation from independent seismic experts, such as university or government scientists and/or engineers, with no current or prior employment with the plant owners or their consultants.
- The Diablo Canyon Independent Safety Committee should evaluate reactor pressure vessel integrity at Diablo Canyon over a 20-year license extension and recommend mitigation plans, if needed. This review should consider the reactor vessel surveillance reports for Diablo Canyon in the context of any changes to the predicted seismic hazard at the site.

Transmission

The *2009 Strategic Transmission Investment Plan* describes the immediate actions that California must take to plan, permit, construct, operate, and maintain a cost-effective, reliable electric transmission system that is capable of responding to important policy challenges such as achieving significant greenhouse gas reduction and RPS goals. The plan makes a number of recommendations intended to ensure that the critical link between transmission planning and transmission permitting is made so that needed projects are planned for, have corridors set aside as necessary, and are permitted in a timely and effective manner that maximizes existing infrastructure and rights-of-way, minimizes land use and environmental impacts, and considers technological advances.

The IEPR Committee supports the many recommendations made in the *2009 Strategic Transmission Investment Plan*, and highlights the following recommendations:

- The Energy Commission staff should work with the recently formed California Transmission Planning Group (CTPG) and California ISO in a concerted effort to establish a 10-year statewide transmission planning process that uses the Strategic Plan proceeding to vet the CTPG plan described in Chapter 4 of the *2009 Strategic Transmission Investment Plan*, with emphasis on broad stakeholder participation.
- The Energy Commission staff should work with the California ISO, CPUC, and publicly owned utilities on a simplified need assessment process that fosters the use of common assumptions and streamlined decisions.

- Prioritize transmission planning and permitting efforts for renewable generation at the California ISO, the CTPG, and the Energy Commission as outlined in Chapter 6 of the *2009 Strategic Transmission Investment Plan*; work on overcoming barriers and finding solutions that would aid their development.
- The Energy Commission should continue supporting ongoing RETI-related activities, including the Coordinating Committee, Stakeholder Steering Committee, and working groups by providing appropriate personnel and contract resources.
- The Energy Commission staff should continue to coordinate with the RETI stakeholders group to incorporate RETI's new information in applying the method described in Chapter 6 of the *2009 Strategic Transmission Investment Plan* to reach consensus on the appropriate transmission line segments that should be considered for corridor designation to promote renewable energy development.

Recommendations for the Natural Gas Sector

New technologies and resource finds have increased the availability of natural gas in North America. However, there are potential environmental impacts associated with exploration and development of shale gas as an additional source of natural gas supplies. Although there are no shale deposits in California, the IEPR Committee believes it is still important for the state to monitor the environmental impacts of shale gas extraction.

Plentiful supplies of natural gas will moderate prices and make natural gas an attractive option throughout the West as the electricity industry starts to build a less carbon-intensive infrastructure. Because California is at the end of the gas supply pipelines, demand for natural gas "upstream" of California could increase competition and therefore prices, and reduce supplies available to California.

The IEPR Committee recommends the following:

- The Energy Commission should continue to monitor the potential environmental impacts associated with shale gas extraction, including carbon footprint, volume of water use and risk of groundwater contamination, and potential chemical leakages.
- California should work closely with Western states to ensure development of a natural gas transmission system that has sufficient capacity and alternative supply routes to overcome any disruption in the system, such as a weather- related line freeze, pipeline breaks, and so on. The state should support construction of sufficient pipeline capacity to California to ensure adequate supply at a reasonable price.

Recommendations for the Transportation Sector

State and federal policies encourage the use of renewable and alternative fuels to reduce California's dependence on petroleum imports, promote sustainability and cut GHG emissions. The governor Executive Order S-06-06 established clear targets for increased use and in-state production of biofuels. California continues to work toward improving vehicle efficiencies, increasing the use of alternative fuels for clean air and energy security, and reducing vehicle miles traveled in efforts to achieve the 2050 GHG reduction targets.

Transportation Fuels and Technologies

Since the Energy Commission published the *2007 IEPR*, additional policies such as the *State Alternative Fuels Plan* (AB 1007) and California's Low Carbon Fuel Standard (LCFS) have been put in place to encourage renewable and alternative fuels. The federal government has granted a waiver allowing California to set emissions levels under AB 1493 Pavley legislation and is setting considerably higher fuel economy standards. The state has created the Alternative and Renewable Fuel and Vehicle Technology Program, a comprehensive program to provide funding to stimulate the deployment of innovative, low-carbon fuels and advanced vehicle technologies.

With these and other directives, the IEPR Committee believes that California has the regulatory tools and basic market mechanisms it needs to create a more sustainable transportation fuels system. What the state needs to do now is continue on the course already laid out, allowing the time and money to make those directives work.

In addition, the IEPR Committee recommends:

- The state should work to maximize the use of California's abundant waste stream, including agricultural waste, municipal solid waste, and forest waste to produce energy for transportation uses in a sustainable manner. For example, forest biomass from thinning and fire risk reduction efforts has the potential to create large volumes of woody biomass waste materials that can be used for transportation fuels. However, this strategy must be pursued carefully to ensure the sustainability of California's private and public lands forests, and to develop economic methods for the sustainable harvest and transport of woody biomass materials.

- To help ensure the availability of adequate biofuel infrastructure, the state should require new building code standards for all gasoline- and diesel-related equipment (underground storage tanks, dispensers, associated piping and so on) be E85 and B20 compatible for construction of any new retail stations or replacement of any gasoline- and diesel-related equipment beginning January 1, 2011.

- The state should support local economic development opportunities for producing alternative and renewable fuels from waste products and sustainable crops.

- The state should modernize and upgrade the existing infrastructure for alternative and renewable fuels to preserve past investments and to expand throughput capacity in the state.
- California should support the development of alternative and renewable fuels that can provide immediate GHG reduction benefits and a bridge to the introduction of fuels that will result in deeper GHG reductions in the future.

Land Use Issues

Land use decisions are made on the local level, but increasingly community design decisions influence the state's transportation choices, its energy consumption and its GHG emissions. The *2006 IEPR Update* stated that the single largest opportunity to help California meet its statewide energy and climate change goals resides with "smart growth." The *2007 IEPR* further noted that to reduce GHG emissions, California must begin reversing the current 2 percent annual growth rate of vehicle miles traveled.

The Energy Commission is one of the multiple state agencies helping local and regional governments make sustainable land use decisions. CalTrans coordinates local and state planning through its Regional Blueprint Planning Program. SB 375 requires the ARB to set regional emissions goals by working with metropolitan planning organizations (MPOs). SB 732 recognizes the need for state agencies to more closely work together on this issue when it created the Strategic Growth Council, a cabinet level committee composed of agency secretaries from Business Transportation and Housing, California Health and Human Services, the California Environmental Protection Agency, and the California Natural Resources Agency, along with the director of the Governor's Office of Planning and Research.

These state agencies need to coordinate more closely to help local governments achieve the benefits of sustainable land use planning. State government must improve its outreach to local governments to better understand the problems they face before adopting new state policies. This includes taking into account and addressing the fiscal realities local governments face in these tough economic times.

The IEPR Committee makes the following recommendations related to land use planning and decisions:

- The state should assemble easy-to-use data and provide tool kits to help local land use planners make informed decisions about energy concerns and climate change.
- The state should establish a comprehensive funding mechanism to support efforts by local and regional governments to prepare and implement land use policies consistent with the requirements of AB 32 and that contribute significantly to achieving the state's 2050 GHG reduction target.
- The state should recognize that rural regions differ from urban ones and insure that new sustainability, greenhouse gas, and energy requirements address these differences.

- The state should encourage California's utilities to work with regional and local governments to promote climate friendly and energy efficient development in their service areas.

Acronyms

ADR	—	Automated demand response
AB	—	Assembly Bill
ARB	—	California Air Resources Board
ARRA	—	American Recovery and Reinvestment Act of 2009
Bcf/d	—	Billion cubic feet per day
BDT/y	—	Bone dry tons per year
BLM	—	Bureau of Land Management
CALBO	—	California Building Officials
CalEPA	—	California Environmental Protection Agency
California ISO	—	California Independent System Operator
Caltrans	—	California Department of Transportation
CAT	—	Climate Action Team
CCHP	—	Combined cooling, heating, and power
CCS	—	Carbon capture and sequestration
CED	—	California Energy Demand
CEQA	—	California Environmental Quality Act
CHP	—	Combined heat and power
CNG	—	Compressed natural gas
CO	—	Carbon monoxide
CO_2	—	Carbon dioxide
CPCN	—	Certificate of Public Convenience and Necessity
CPUC	—	California Public Utilities Commission
CREZs	—	Competitive Renewable Energy Zones
CSI	—	California Solar Initiative
CSLB	—	Contractors State License Board
CTPG	—	California Transmission Planning Group
CWA	—	Clean Water Act
DOE	—	(United States) Department of Energy
DOF	—	Department of Finance
DRECP	—	Desert Renewable Energy Conservation Plan
EDD	—	Employment Development Depatment
EISA	—	Energy Independence and Security Act of 2007
Epbd	—	Energy Performance of Buildings Directive
EPS	—	Emissions performance standard
EU	—	European Union
EV	—	Electric vehicle
FERC	—	Federal Energy Regulatory Commission
FEV	—	Full electric vehicle

FFV	—	Flex fuel vehicle
FY	—	Fiscal year
GGe	—	Gallon gasoline equivalent
GHG	—	Greenhouse gas
GSP	—	Gross State Product
GTN	—	Gas Transmission-Northwest
GW	—	Gigawatt
GWh	—	Gigawatt hours
HVAC	—	Heating, ventilation, and air conditioning
HERS	—	Home Energy Rating System
IA	—	Interagency agreements
ICC	—	International Code Council
IEC	—	International Electrotechnical Commission
IEEP	—	Industrial Energy Efficiency Program
IEPR	—	Integrated Energy Policy Report
INPO	—	Institute for Nuclear Power Operations
IOUs	—	Investor-owned utilities
IRRP	—	Integration of Renewable Resources Program
ISFSI	—	Independent spent fuel storage installations
LADWP	—	Los Angeles Department of Water and Power
LCFS	—	Low Carbon Fuel Standard
LCR	—	Local capacity requirements
LEAPS	—	Lake Elsinore Advanced Pumped Storage
LIEE	—	Low Income Energy Efficiency
LNG	—	Liquefied natural gas
LPG	—	Liquefied petroleum gas
LTTPs	—	Long-Term Procurement Plans
Mcf/d	—	Thousand cubic feet per day
MMcf/d	—	Million cubic feet per day
MPO	—	Metropolitan planning organization
MSW	—	Municipal solid waste
MW	—	Megawatt
NOx	—	Nitrogen oxides
NRC	—	Nuclear Regulatory Commission
NRDC	—	Natural Resources Defense Council
NSHP	—	New Solar Homes Program
NWPCC	—	Northwest Power and Conservation Council
OTC	—	Once-through cooling
PG&E	—	Pacific Gas and Electric Company
PEIS	—	Programmatic Environmental Impact Statement
PHEV	—	Plug-in hybrid electric vehicle
PIER	—	Public Interest Energy Research
PM	—	Particulate matter

PURPA	—	Public Utility Regulatory Policies Act of 1978
PV	—	Photovoltaic
RD&D	—	Research, development, and demonstration
REAT	—	Renewable Energy Action Team
REC	—	Renewable Energy Credit
RETI	—	Renewable Energy Transmission Initiative
RFS	—	Renewable Fuel Standard
RIN	—	Renewable Identification Number
RPS	—	Renewables Portfolio Standard
RTP	—	Regional Transportation Plan
SCAQMD	—	South Coast Air Quality Management District
SCE	—	Southern California Edison Company
SDG&E	—	San Diego Gas and Electric Company
SMUD	—	Sacramento Municipal Utility District
SoCal Gas	—	Southern California Gas Company
Solar PEIS	—	Solar Programmatic Environmental Impact Statement
SONGS	—	San Onofre Nuclear Generating Station
SWRCB	—	State Water Resources Control Board
TAD	—	Transport, aging, and disposal
U.S. EPA	—	United States Environmental Protection Agency
VMT	—	Vehicle miles traveled
VOC	—	Volatile organic compounds
WECC	—	Western Electricity Coordinating Council
WIEB	—	Western Interstate Energy Board
WGA	—	Western Governors' Association
WREGIS	—	Western Renewable Energy Generation Information System
WREZ	—	Western Renewable Energy Zone