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ENERGY
COMMISSION

2007 Integrated Energy Policy Report

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STATE OF CALIFORNIA
ENERGY COMMISSION

Arnold Schwarzenegger, *Governor*

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M. Lorraine White
Program Manager

Susanne Garfield
Carolyn Walker
Yvonne Nelson
Principal Authors

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This report was prepared by the California Energy Commission's Integrated Energy Policy Report Committee as part of 2007 Integrated Energy Policy Report Proceeding - Docket # 06-IEP-1 and associated subdockets. The report will be considered for adoption by the full Energy Commission at its Business Meeting on November 21, 2007. The views and recommendations contained in this document are not official policy of the Energy Commission until the report is adopted.

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ENERGY COMMISSION STAFF

Jim Adams
McKinley Addy
Eileen Allen
Jameel Alsalam
Al Alvarado
Grace Anderson
David Ashuckian
Steve Baker
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Panama Bartholomy
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Gerry Bemis
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Bill Knox
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Kelly LaFave
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Jerome Lee
Heather Louie
Clint Lowell
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Nancy McKeever
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Madeleine Meade
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Daryl Metz
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Ross Miller
Sandy Miller
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Larry Myer
Chuck Najarian
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Keith O'Brien
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Jason Orta
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Adam Pan
Bill Pennington
Pat Perez
Terry Piotrowski
Michael Purcell
Heather Raitt
Anitha Rednam
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Paul Richins
Patty Rinaldi
Michael Ringer
Terry Rose
Rachel Salazar
Irene Salazar
A. Edalati-Sarayani
Rob Schlichting
Gordon Schremp
Diana Schwyzer
Mike Seaman
Rosella Shapiro
Margaret Sheridan
Julia Silvis
Tiffany Solorio

Arthur Soinski
Peter Spaulding
Linda Spiegel
Robert Strand
Gene Strecker
John Sugar
Angela Tanghetti
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Laurie ten Hope

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Lorraine White
Jennifer Williams

Lana Wong
William Wood
Jim Woodward
Dora Yen-Nakafuji
Rich York
Gary Yowell
Zhiqin Zhang
Kate Zocchetti

Student Interns
John Arndt
Michael Gazzolo
Abinet Kutie
Andrew Mrowka
Darren Nguyen
Michael Wilson

The Committee also acknowledges two former colleagues:

Kevin Kennedy, Ph.D., former Senior Advisor to Commissioner Jeffrey D. Bryon, California Energy Commission, currently with the Office of Climate Change, California Air Resources Board

Scott Matthews, retired Chief Deputy Director, California Energy Commission

ENERGY COMMISSION CONSULTANTS

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Altos Management Partners
- Dale M. Nesbitt,
- Howard T. Ash
- Thomas Y. Choi
- Theodore J. Foresman

Aspen Environmental Group
- Carl Livill
- Suzanne Phinney
- Carolyn Walker

Bates White, LLC
- Jonathan Lesser
- Paul Lowengrub
- Spencer Yang

Brattle Group
- Ahmad Faruqui,
- Ryan Hledik

R. W. Beck
- Catherine M. Elder
- Youssef Hegazy

Black and Veatch
- Richard O'Connell

Mark Bolinger, Independent Consultant

Center for Resource Solutions
- Galen Barbose
- Lars Kvale
- Jan Hamrin
- Meredith Wingate

Center for Sustainable Energy (CSE)
- Wilson Rickerson

Exeter Associates, Inc.
- Kevin Porter

Jensen Associates
- James T. Jensen

Global Energy
- Ann Donnelly
- Mike Donnelly
- Mayank Garg
- Gurider Goel
- Rich Lauckhart
- Bryan Swann

KEMA, Inc.
- Mark Bolinger
- Hans Cleijne
- Johan Enslin
- Paul Gripe
- Wilson Rickerson

Lawrence Livermore National Laboratory
- Elizabeth Burton

Robert Logan, Ph.D.

MRW & Associates
- Steve McClary
- Bob Weisenmiller
- Heather Mehta
- Laura Norin
- Andrew Davidson
- Briana Kobor

Navigant Consulting
- Dave Larsen
- Craig McDonald
- Ron Nichols

Sustainable Energy Advantage
- Bob Grace

Wiser Consulting
- Ryan Wiser

Preface

This *2007 Integrated Energy Policy Report* (*IEPR*) 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 (Pub. Res. Code § 25301[a]). This report fulfills the requirement of SB 1389.

The report was developed under the direction of the Energy Commission's 2007 Integrated Energy Policy Report Committee (Committee). As in previous IEPR 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 needed to develop the information and analyses that these agencies need to carry out their energy-related duties. This *2007 IEPR* reflects the input of stakeholders and federal, state, and local agencies that participated in the IEPR 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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CHAPTER 1: Meeting California's Energy Needs in a Carbon-Constrained World

Available, affordable, reliable, technologically advanced, and environmentally sound energy drives California's successful economy. Scientific consensus is that temperatures in the state are expected to increase during this century and precipitation patterns are predicted to change — threatening California's environmental quality and robust economy.

This temperature increase will result in widespread environmental consequences – worsening air pollution, intensifying heat waves, increasing coastal floods, reducing farmland productivity, increasing wildfires and pest infestations, decreasing fish populations and reducing snowpack, which means less hydropower and possible water shortages.

> ***"The debate is over. We know the science. We see the threat. And we know that the time for action is now."***
>
> Governor Arnold Schwarzenegger

Last year, Republican Governor Arnold Schwarzenegger and a Democratic Legislature passed the California Global Warming Solutions Act of 2006 (Assembly Bill 32, Nuñez, Chapter 488, Statutes of 2006), capping California's greenhouse gas emissions at the 1990 level by 2020. Achieving that goal requires about a 29 percent[1] cut in emissions below projected 2020 levels. The Governor's long-term target is far more ambitious and calls for reducing emissions to 80 percent below 1990 levels by 2050. This is the level of worldwide reduction believed necessary by many climate scientists to limit global temperature gains this century to 2-3 degrees Celsius.

AB 32 places reducing greenhouse gas emissions at the center of government and business agendas. Businesses are eager to show their "greenness," but require a clear, specific course of action if they are to help reach the state's goals. With AB 32, California's progressive energy policies must now also include reducing the state's *greenhouse gas footprint*[2] and stepping up the intensity of existing programs, standards,

[1] The 29 percent reduction of greenhouse gas emissions from a *business-as-usual* 2020 level is based on 174 million metric tons CO_2 equivalent as assessed by the Climate Action Team report, March 2006.

[2] G*reenhouse gas footprint*, commonly referred to as c*arbon footprint* is a measure of the impact of human activities on Earth's climate systems, directly or indirectly, as greenhouse gas emissions produced over the life cycle of a product, service or activity. These gases trap outgoing radiation that heats the atmosphere, increasing the *greenhouse effect* or global warming. The measure is usually expressed as tons of carbon dioxide (CO_2) equivalent. CO_2 accounts for about 84 percent

and regulations is mandatory to achieve aggressive carbon dioxide (CO_2) reduction.

California at the Forefront

From the rim of a thousand miles of spectacular Pacific Ocean coastline to the lip of the jagged Sierra Nevada mountain range, Californians live in an extraordinary environment that nurtures an imaginative, determined and forward-thinking population. For more than 150 years, California has represented the land of opportunity – and has been a land of challenges to overcome.

The Gold Rush of 1849 brought a flood of adventurous immigrants seeking better lives. A remote, wild California, geographically separated from the rest of the United States and the world, forced early settlers to solve problems in independent and innovative ways.

Our mild climate and fertile soil, coupled with some of history's most imaginative water projects at the time, earned California the reputation of the bountiful breadbasket to the nation, while the discovery of oil made us an energy pioneer. As early as 1910, our state was producing almost 78 million barrels of oil a year,[3] 22 percent of the entire world's oil production at the time.

Despite our early remoteness from most of the population centers in the United States, California has grown to become the most populous state in the union and the eighth largest economy in the world. Our diverse, mobile, dynamic and creative population has put us at the forefront of environmental, economic, technological, political, social and cultural development.

With a current population exceeding 37 million and projected to grow to more than 44 million by 2020,

Guiding Energy Policy

The California Energy Commission was created as the state's principal energy planning organization by then-Governor Ronald Reagan in 1974 to meet the energy challenges facing the state in response to the 1973 Oil Embargo. Six basic responsibilities guide the Energy Commission as it sets state energy policy: forecasting statewide electricity needs, licensing power plants to meet those needs, promoting energy conservation and efficiency measures, developing renewable energy resources and alternative energy technologies, RD&D and planning for and directing state response to energy emergencies.

The Governor appoints the five members of the Commission to five-year terms that require Senate approval. The Commissioners represent the fields of engineering and physical science, economics, environmental protection, the public and the law. The Energy Commission is unique among most governmental entities as all business is conducted in a public forum. A Public Adviser, also appointed by the Governor, ensures that the public and all interested parties are adequately represented at all Commission proceedings.

The Energy Commission receives its operational and administrative funding from an electricity consumption surcharge collected by the electric utilities through customers' utility bills, then transferred to the state's treasury. The surcharge is 2/10 of a mil, or a $0.0002, per kilowatt hour of electricity consumption or about 12 to 14 cents per month on an average bill.

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of human-caused greenhouse gas emissions in California, methane (CH_4), nitrous oxide (N_2O), and other manmade gases contribute the remainder of the gases.

[3] *Oil and Gas Production: History in California*, Department of Conservation, Division of Oil and Gas, ftp://ftp.consrv.ca.gov/pub/oil/history/History_of_Calif.pdf

California's already over-burdened infrastructure—roads, pipelines, ports, refineries, power plants and transmission lines—will be strained further to meet increasing demand for energy. Most of the population growth is occurring in the hotter interior areas of the state, increasing the demand for air conditioning. California's limited mass transit options, particularly in the inland areas, and the historic tendency toward suburban "sprawl" cause residents to rely more heavily on their cars, increasing individual vehicle miles traveled (VMT) and energy demand.

Environmental consciousness is not new to California. In 1947, Governor Earl Warren signed the Air Pollution Control Act, creating an air pollution control district for every county. And for over 30 years, the California Energy Commission has focused the state's energy policy on finding the most cost-effective, reliable and efficient resources while minimizing the environmental impacts of anticipated growth.

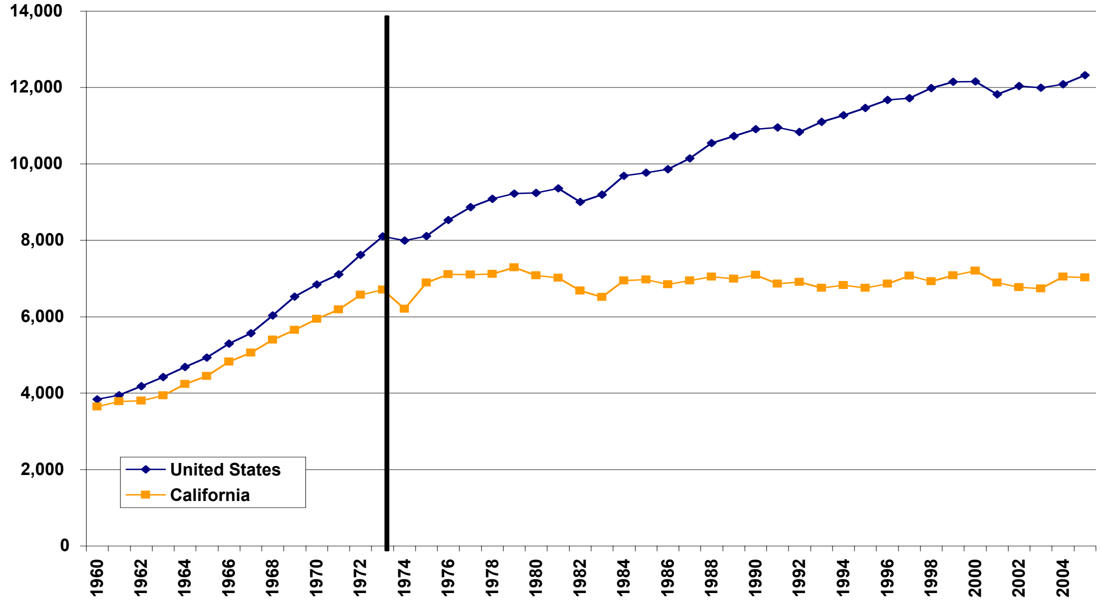
California leads the nation in the lowest electricity use per person. While the United States increased per capita electricity consumption by nearly 50 percent over the past 30 years, California's per capita electricity use remained almost flat due, in large part to a variety of cutting-edge energy efficiency programs and cost-effective Building and Appliance efficiency standards (Figure 1-1).

The state also changed the way it generates electricity. Before the oil crisis of the 1970s, petroleum was the fuel source for over half of the state's electricity. Today, cleaner-burning natural gas fuels over 41 percent of the state's electricity and renewables account for almost 11 percent.

Other than for use in power plants to generate electricity, California's use of natural gas has also decreased on a per capita basis. Our building and appliance standards have reduced the need for gas space heating and water heating for each home or business in the state.

Despite its passion for the automobile, California adopted stringent tailpipe emission standards as early as 1966, and in 1971 adopted the first automobile nitrogen oxides standards—both the first such standards in the nation. The California Smog Check Program, which assured the effectiveness of vehicle emission control systems, went into effect in 1984. In 1992, the first of many phases of reformulated clean burning gasoline was introduced to California, and in 1993 the state enacted new standards for cleaner diesel fuel.

Figure 1-1: California Holds the Line on Electricity Consumption (Per Capita Electricity Sales in Kilowatt Hours per Person)



Source: California Energy Commission

Improving vehicle fuel efficiency offers potentially dramatic reductions in petroleum demand and, hence tailpipe emissions; however, California's hands are tied by federal fuel efficiency standards that pre-empt state authority. The state has adopted regulations that limit the amount of greenhouse gases emitted by its vehicle stock but has not been able to implement those regulations pending federal government approval of a waiver.

Regardless of the federal response, California has continued to move forward. Assembly Bill 1007 (Pavley, Chapter 371, Statutes of 2005) directs the Energy Commission, in partnership with the California Air Resources Board (ARB), to develop and adopt a state plan to increase the use of alternative fuels in the transportation sector. The plan describes strategies; highlights market penetration growth; and recommends new standards, requirements, financial incentives, and other policy mechanisms to address petroleum and greenhouse gas reduction, and in-state biofuels production and use goals as articulated in the Governor's Executive Order S-06-06, which calls for California to produce a minimum of 20 percent of its biofuels within California by 2010, 40 percent by 2020, and 75 percent by 2050. The plan's first phase, a full fuel cycle analysis, forms the technical basis for the ARB's Low Carbon Fuel Standard that is designed to increase the use of transportation fuels that emit lower quantities of greenhouse gases on a life-cycle basis.

Yet, California's projected population increase will offset whatever gains existing efforts have made and continue to make in reducing emissions. The state currently emits almost 500 million metric tons of greenhouse gases, 28 percent from electricity generation and over 39 percent from transportation. California must step up efforts with every emission-saving technique in its substantial repertoire for transportation and electricity to reduce greenhouse gases in 2020 to the levels mandated by the AB 32 goals (Figure 1-2).

Meeting AB 32 Goals

Some have argued that a single dimensional approach, focusing on price such as a carbon tax or a cap and trade program, would be the simplest approach for California to meet its AB 32 greenhouse emission goals. Others argue that the state's existing programs for energy efficiency and demand side management along with the renewable portfolio standard should be expanded, as these programs will provide the earliest and most reliable emission reductions.

The Energy Commission believes that the most prudent avenue for addressing California's climate issues is to pursue both a pricing and program approach. The state must aggressively pursue and expand its energy efficiency and demand side management programs, as well as meet its 33% renewable portfolio standard. These important programs will provide early greenhouse gas emission reductions and serve as a solid foundation for cap and trade or carbon tax pricing.

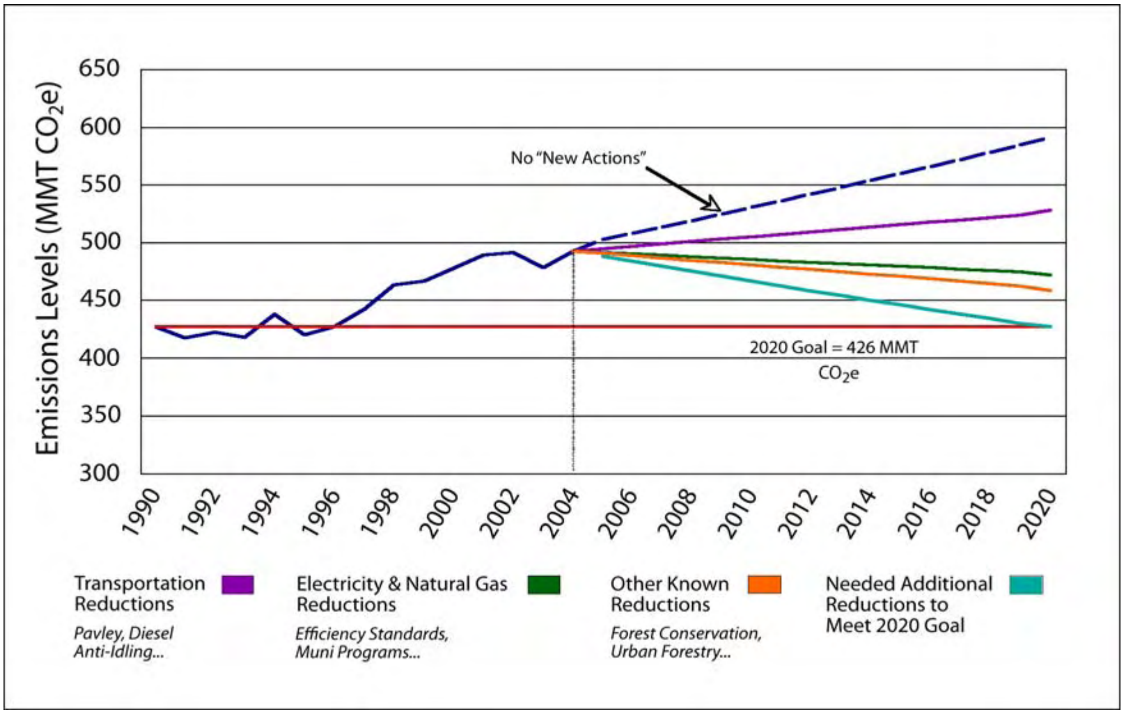
Greenhouse Gas Emissions

Climate change is the most important environmental and economic challenge of this century and greenhouse gas emissions are the largest contributors to global warming. California's greenhouse gas emissions are huge and growing. In 2004, we produced almost 500 million metric tons of CO_2 (greenhouse gas emission equivalent) – making us the second largest emitter of greenhouse gas emissions in the United States after Texas and about twelfth in the world.

The transportation sector is the single largest source of California's greenhouse gas emissions, producing over 39 percent of the state's total emissions in 2004 (Figure 1-3). Most of California's greenhouse gases, or 81 percent, are CO_2 produced from fossil fuel combustion, 2.8 percent were from other sources of CO_2, 5.7 percent were from methane, and 6.8 percent were from nitrous oxide.

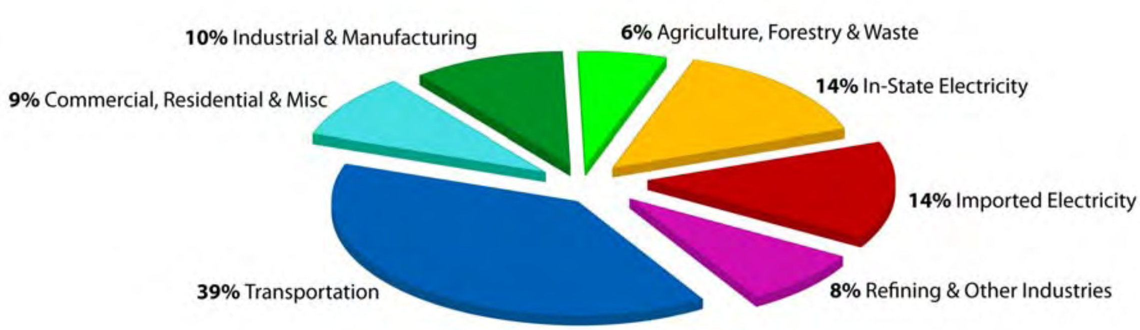
Electricity generation is the second largest source of greenhouse gas emissions after transportation. Out-of-state electricity generation from coal has higher CO_2 emissions than in-state generation. While imported electricity is a relatively small share of California's electricity mix, ranging from 22 to 32 percent of total electricity used, out-of-state electricity generation sources contribute 39 to 57 percent of the greenhouse gas emissions associated with electricity consumption in California.

Figure 1-2: Reaching for the AB 32 Target



Source: California Energy Commission, Climate Action Team data

Figure 1-3: California Greenhouse Gas Emissions in 2004



Source: California Air Resources Board, *Draft Greenhouse Gas Emissions Inventory*, August 2007

A significant percentage of electricity imported to California from the Southwest comes from coal-based generation, while imports from the Pacific Northwest are primarily hydroelectricity.

California's high level of greenhouse gas emissions is not surprising considering our nation-sized population. What is remarkable; however, is that California's greenhouse gas emissions per capita are one of the lowest in the United States. In 2001, California ranked fourth lowest in CO_2 emissions per capita and fifth lowest in CO_2 emissions per unit of gross state product. Nationally, emission trends per unit of gross state product are encouraging; most states have reduced their emissions per unit of gross state product over the 1990 to 2001 period.

California's ability to slow the rate of growth of greenhouse gas emissions will largely depend on the success of its energy efficiency and renewable energy programs, and a commitment to clean air and clean energy. In fact, the state's programs and commitments have lowered its greenhouse gas emissions rate of growth by more than half of what it would have been otherwise.[4] And California's energy programs and policies have had multiple benefits that include expanding energy diversity, lowering energy demand and improving air quality and public health.

Current Strategies to Reduce Emissions

Addressing the state's climate change goals requires meeting energy needs with zero or low-carbon energy sources to the extent possible. Since 2003, California's energy policy has relied on the loading order[5] to meet growing energy needs; first with energy efficiency and demand response, second with renewable energy and distributed generation, and third with clean fossil-fueled sources and infrastructure improvement. This strategy has had the benefit of reducing our CO_2 emissions and diversifying sources of energy supply.

Senate Bill 1078 (Sher, Chapter 516, Statutes of 2002), introduced a Renewable Portfolio Standard (RPS) requiring annual increases in energy generation from renewable resources equivalent to at least 1 percent of sales, with an aggregate goal of 20 percent by 2017. The 2003 *Energy Action Plan* adopted by the Energy Commission and the California Public Utilities Commission (CPUC) accelerated this target to 2010 and SB 107 put it in statute. Since 2004, the Energy Commission has recommended a further goal of

[4] National Resource Defense Council comments to the Energy Commission, April 5, 2005.

[5] The loading order, adopted as the state's energy policy, is the accepted protocol that describes the priority sequence for actions to address increasing energy needs.

33 percent renewables by 2020, and in 2005, Governor Schwarzenegger and the CPUC endorsed this enhanced target.

The RPS was designed to address California's growing dependence on natural gas for electricity generation and set the stage for long-term power purchase contracts that financial institutions require of renewable energy companies that intend to build generation projects. Hampered by complex rules, inconsistent application among retail sellers, and a lack of transparency in its application, the state's efforts to meet the RPS goals have not kept pace with the mandate. In this report and previous *Integrated Energy Policy Reports*, the Energy Commission has recommended a number of corrective measures to increase the role of renewables in our electricity mix.

As the second largest consumer of gasoline in the world (behind only the United States as a whole)— more than 16 billion gallons of gasoline and 4 billion gallons of diesel each year—California would like to replicate its success with electricity efficiency in transportation fuels. But federal law prohibits states from setting the minimum number of miles per gallon new cars and light trucks must achieve. Earlier this decade, the Energy Commission and the California Air Resources Board spent several years reviewing the technical and economic aspects of a major reduction in the petroleum dependence of California's transportation sector.[6] Based on this research, in 2005, Governor Schwarzenegger appealed to the United States House of Representatives "to establish new fuel economy standards that double the fuel efficiency of new cars, light trucks and SUVs."[7] In June 2007, the United States Senate voted to raise the fuel efficiency standard for cars to 35 miles per gallon by 2020. As of October 2007, the House had taken no action. The proposed 35 mile per gallon standard pales in comparison to Japan's current standard of 45 miles per gallon and Europe's more than 50 miles per gallon standard by 2012, and may ultimately be too little, too late to rescue American automobile manufacturers.

The California legislature also took advantage of a federal Clean Air Act provision that allows states to set their own emission standards (with a waiver from the United States Environmental Protection Agency (EPA))[8] and passed California's Clean Car Law - Assembly Bill 1493 (Pavley, Chapter 200, Statues of 2002), the first such regulation in the United States, to limit greenhouse gas emissions from passenger cars and light trucks. The Clean Car Law would cut greenhouse gas emissions by 30 percent by 2016 from all

[6] California Energy Commission and the California Air Resources Board *AB 2076 Report*, adopted 2003.

[7] May 13, 2005 letter from Governor Arnold Schwarzenegger to Pete Domenici, chairman, Energy and Commerce Committee of the U.S. House of Representatives and Jeff Bingaman, member, Energy and Commerce Committee, U.S. House of Representatives.

[8] < www.greencarcongress.com/2007/04/us_epa_opens_co.html > The EPA has historically granted all 53 such waivers previously sought by California.

cars sold in California starting in 2009. As allowed under federal law, 11 other states have adopted these California standards pending receipt of the EPA waiver. Unfortunately, the EPA has not acted on California's waiver request for nearly two years, declaring it lacks the authority to regulate greenhouse gases—a declaration rejected by the United States Supreme Court in their recent decision which states that EPA has the authority to regulate CO_2 emissions and should reconsider its refusal to do so.

The transportation sector is ripe to replicate the successes and improvements achieved in new buildings and appliances through energy efficiency regulations such as increased Corporate Average Fuel Economy (CAFE) standards. Current CAFE standards are 27.5 miles per gallon for new cars and 22.2 miles per gallon for light trucks, minivans and sport utility vehicles.

For the *2007 Integrated Energy Policy Report*, the first in the more complex post-AB 32 world of carbon constraints, staff has developed scenario analyses and a portfolio analysis. These two new approaches analyze in more depth the uncertainties that affect our ability to meet our future energy needs. The Scenario Analyses project examines the implications of energy policies that may help achieve AB 32 goals. In addition, staff revitalized and refined its cost of generation model—a classic levelized cost analysis—by collecting detailed information about actual power plant development costs and more systematically collecting and presenting information about new generating technologies that have limited track records. The Portfolio Analysis project studies how different resource additions perform economically and respond to changes in key variables such as fuel prices.

California's Energy System: Powering a Nation-State

Today one in eight Americans or over 37 million people live in the Golden State.

Our state has doubled its population since 1965, a growth rate faster than any other developed region in the world and already larger than Canada's (33 million) and Australia's (21 million).[9] If California was a nation our population would rank 33rd in the world. In fact, California's population exceeds the combined populations of our western neighbors – Oregon, Colorado, Wyoming, Montana, Idaho, Washington, Nevada, Arizona, Utah, New Mexico, Alaska, Hawaii, the Yukon Territory and British Columbia. The State Department of Finance predicts that California will add another 7 million people in the next dozen years, moving towards 60 million residents by 2050. The challenge we face is continuing to provide a quality environment, and reliable energy services to support a world-class economy.

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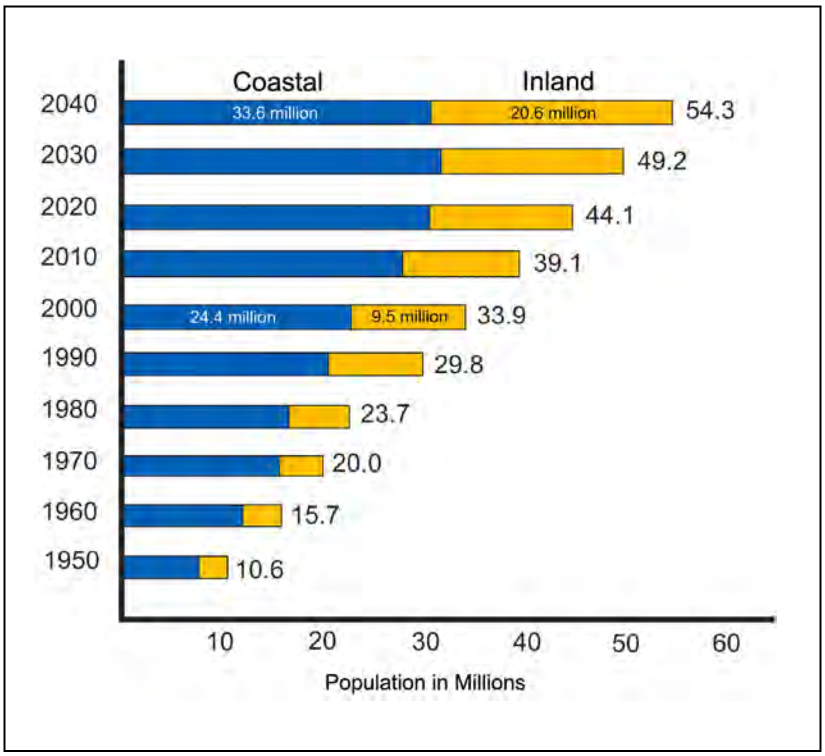
[9] *Western City Magazine*, "How Should California Grow?" Dr. Hans Johnson, July 2007.

To maintain this economic output and meet the energy service demands of our citizens, California requires a significant amount of energy. Energy represents nearly $100 billion in expenditures each year. Now, with the passage of AB 32, California has a stringent mandate to significantly reduce greenhouse gas emissions requiring government, consumers and businesses to take a hard look at exactly how energy is used in the state and ways to focus on choosing a system that is less carbon intensive. At the core of this energy system is a policy that the state's economy and environment are best served by energy efficiency measures and demand response programs first, then by renewable energy sources and a diversity of energy supplies. This approach has resulted in California using less electricity per person than any other state from the world's most diverse electricity generation supplies. Unfortunately our success in electricity has not been reflected in our transportation sector.

Inland Population Climbs

Figure 1-4: California's Inland Population Increases



Source: California Department of Finance, Demographic Research Unit projections and Public Policy Institute of California.

Ensuring energy supplies and an infrastructure to keep pace with such dynamic growth has been an ongoing challenge, but California planners must take more than just additional population into account. While today nearly 70 percent of the state's population lives in what is described as coastal California, the inland areas – the San Joaquin Valley, Southern California's Inland Empire, and the Sacramento area – are growing faster than the coastal areas (Figure 1-4). By 2040 almost 40 percent of the state's population, or over 20 million, will reside inland. This inland population growth drives demand for more electricity, but it also changes the energy use patterns for transportation fuels. Compared to the more temperate coastal zone, the inland climate is more extreme. In the summer, hotter inland areas require more air conditioning than coastal areas, which increases peak electricity use even faster than it pushes the overall demand for electricity.

The Inland Empire and the northern San Joaquin Valley are two of the fastest growing metropolitan areas in the United States. These cities often serve as bedroom communities for workers in the Los Angeles basin and the San Francisco Bay area. Growth in these inland areas means that transportation patterns change as more commuters drive more miles and longer distances to work each day, increasing the demand for transportation fuels.

Inland growth also increases environmental problems. The San Joaquin Valley and the Inland Empire already have some of the worst air quality in the nation, and as California's growing population continues its inland trek, growth will only make the situation worse. In 2040 there are more people projected to live in the California's inland areas than the state's total 1970 population.

Energy Consumption

California's overall energy consumption continues to be dominated by transportation. Over 40 percent of all energy consumed in the state is used to move people and goods – and almost all of this transportation energy is derived from petroleum (Figure 1-5).

Figure 1-5: Energy Use by Sector 2006

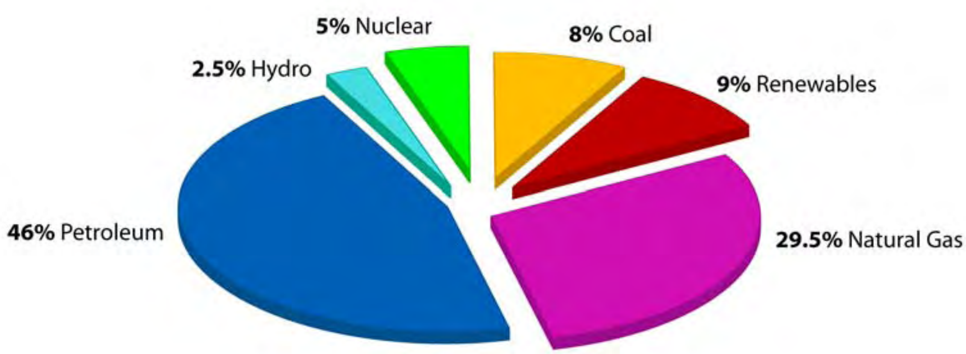
Source: California Energy Commission 2006

Despite California diversifying the mix of energy resources used to generate electricity, over 80 percent of the energy consumed in the state still comes from fossil fuels. This continuing dependence, combined with continuing population growth, places California's economic and environmental well being at risk.

Energy Supply

To understand the challenges California faces in cutting back on greenhouse gases, it is important to examine where the state gets its energy. Two primary fuels drive California's energy system: petroleum and natural gas (Figure 1-6). These resources are used in the transportation sector, to generate electricity, or for heating buildings and water.

Figure 1-6: California's Energy Sources 2006



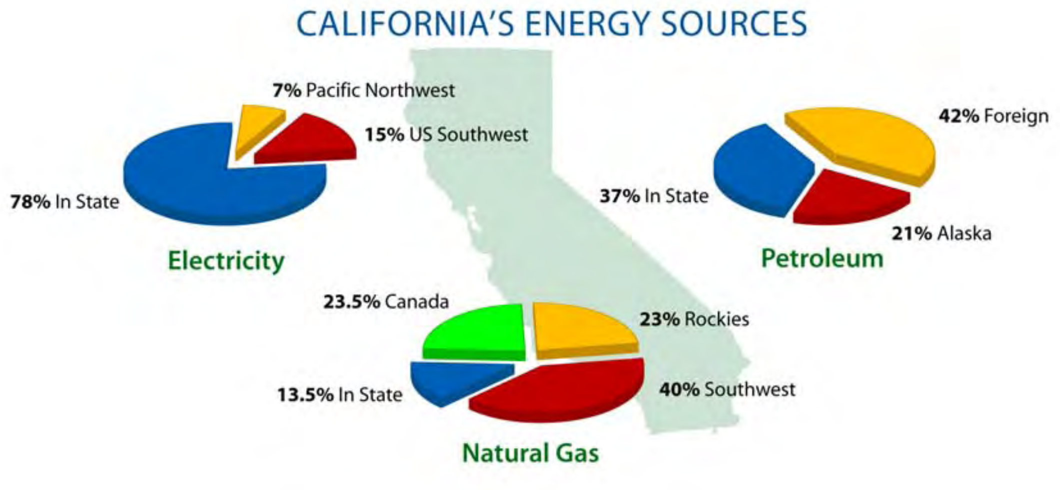
Source: California Energy Commission 2006

The state produces about 13.5 percent of the natural gas it uses, 37 percent of the petroleum and over three quarters of the electricity. The remaining amounts are electricity and natural gas purchases from other states and Canada and crude oil imports from Alaska and foreign sources (Figure 1-7). Importing energy means exporting state dollars. Energy efficiency can reduce these expenditures as well as conserve finite resources.

Electricity

New power plants licensed by the Energy Commission have added almost 13,000 megawatts to the state's grid since 1998 and new policies have stabilized the market. Virtually all of these new power plants burn natural gas. In 1991, a third of California's electricity came from natural gas- fired power plants. By 2006, this amount had increased to 41.5 percent.

Figure 1-7: California's Big Picture



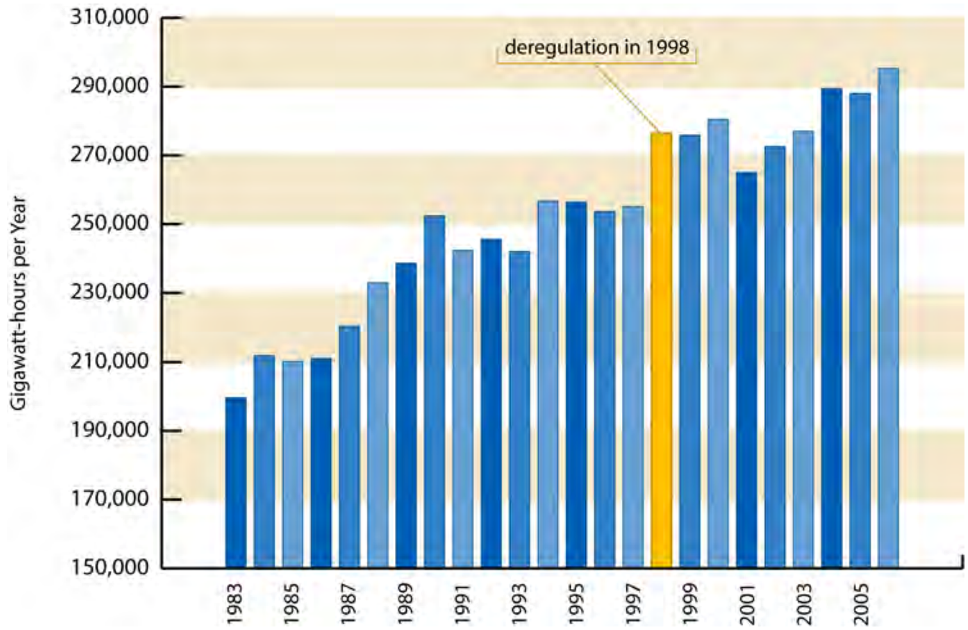
Source: California Energy Commission 2006

The lessons of the electricity crisis and the growing dependency on natural gas reinforce California's need to pursue a portfolio approach to electricity generation. Relying on a single fuel source for generation can be risky, as generators learned even before the 2000–2001 electricity crisis. At a time of high oil prices and tight supplies in the 1970s, oil-fired power plants supplied over half of the state's electricity. Today none of California's electricity comes from petroleum as the state turned to cleaner, less expensive sources of power.

The California electricity generation system is massive (Figure 1-8). After a period of flat to slow growth on the heels of the 2001 electricity crisis, California's demand is now on the rise, fueled by population growth and a robust economy. Electricity consumption is dominated by commercial and the residential use (Figure 1-9).

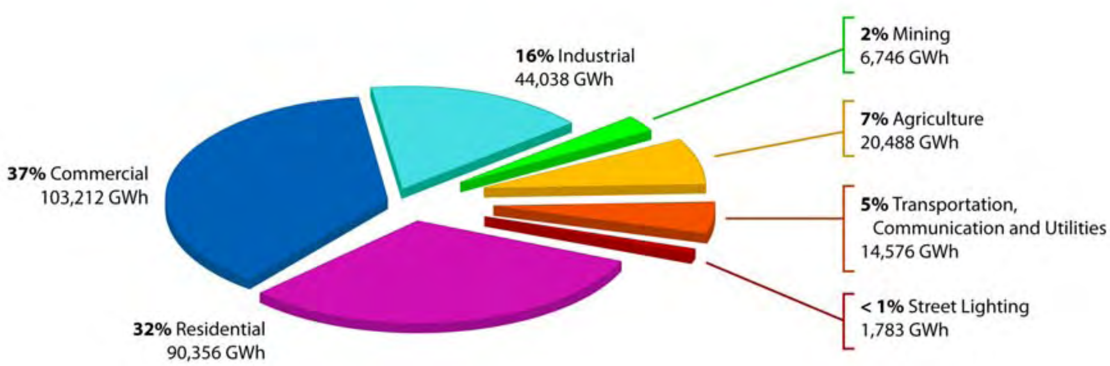
To diversify our electricity mix and reduce our output of greenhouse gases, California chose to significantly increase the amount of its electricity generation from renewable energy sources. The state adopted a Renewables Portfolio Standard (RPS) with a mandate of generating, by 2010, 20 percent of our power from renewable sources like biomass, geothermal, small hydro, solar and wind. Additionally, in Executive Order S-06-06, the Governor called for a 20 percent target within the RPS goals to be met with electricity from biomass and established the Bioenergy Action Plan to develop an integrated and comprehensive state policy on biomass. In 2006, renewable energy supplied about 11 percent of our electricity, and even with almost 400 new megawatts of renewables added to the system, load growth has matched these additions, and we remain at the same level (Figure 1-10).

Figure 1-8: California's Electricity Generation 1983 - 2006



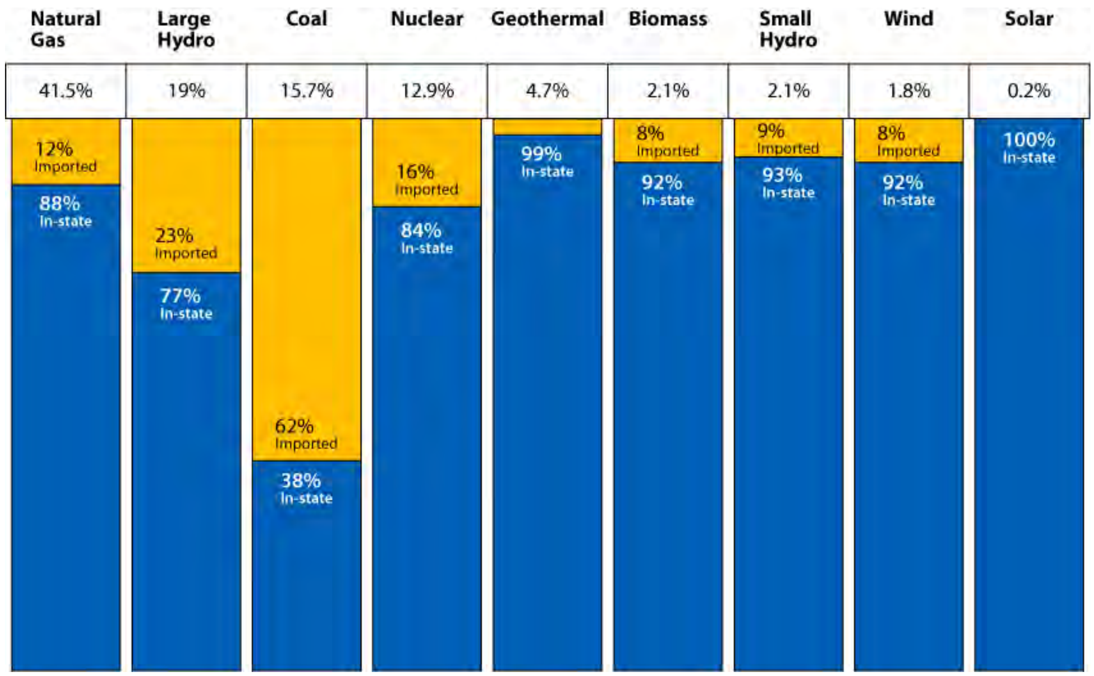
Source: California Energy Commission

Figure 1-9: Electricity Consumption by Sector 2006



Source: California Energy Commission

Figure 1-10: California's Electricity Mix – 2006



COAL: The in-state coal-fired generation includes electricity generated from several out-of-state coal-fired power plants that are owned by and reported by California utilities. There are other out-of-state generation facilities that are owned by California utilities, which are reported as imports.

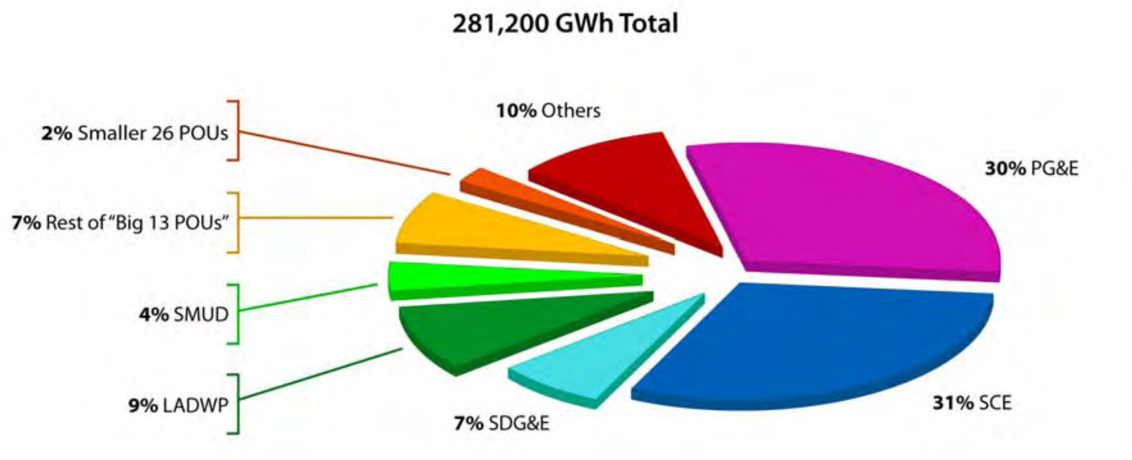
Source: California Energy Commission, *Gross System Power Report 2006*.

Governor Schwarzenegger, the Public Utilities Commission and the Energy Commission have called for 33 percent of our state's electricity to come from renewables by 2020, a daunting goal in light of current progress.

Wind farms, geothermal power plants and large solar facilities are often located well away from population centers where the electricity so cleanly generated is to be used. The state is upgrading its nearly 32,000 miles of transmission lines to bring more renewable energy to market.

Five major utilities provide about 80 percent of all electricity consumed in California: Investor-owned Pacific Gas and Electric (PG&E), Southern California Edison (SCE), and San Diego Gas and Electric (SDG&E) companies, and the publicly owned Los Angeles Department of Power and Water and the Sacramento Municipal Utility District (Figure 1-11).

Figure 1-11: Investor and Publicly Owned Utility Shares of California's Electricity Consumption - 2006



Source: California Energy Commission

The remaining 20 percent is provided by three smaller investor-owned utilities (Bear Valley, PacifiCorp and Sierra-Pacific Power) and 24 municipal utility districts; three rural cooperatives; about 12 irrigation or water districts and one state and one federal water agency (electricity is used for pumping water).

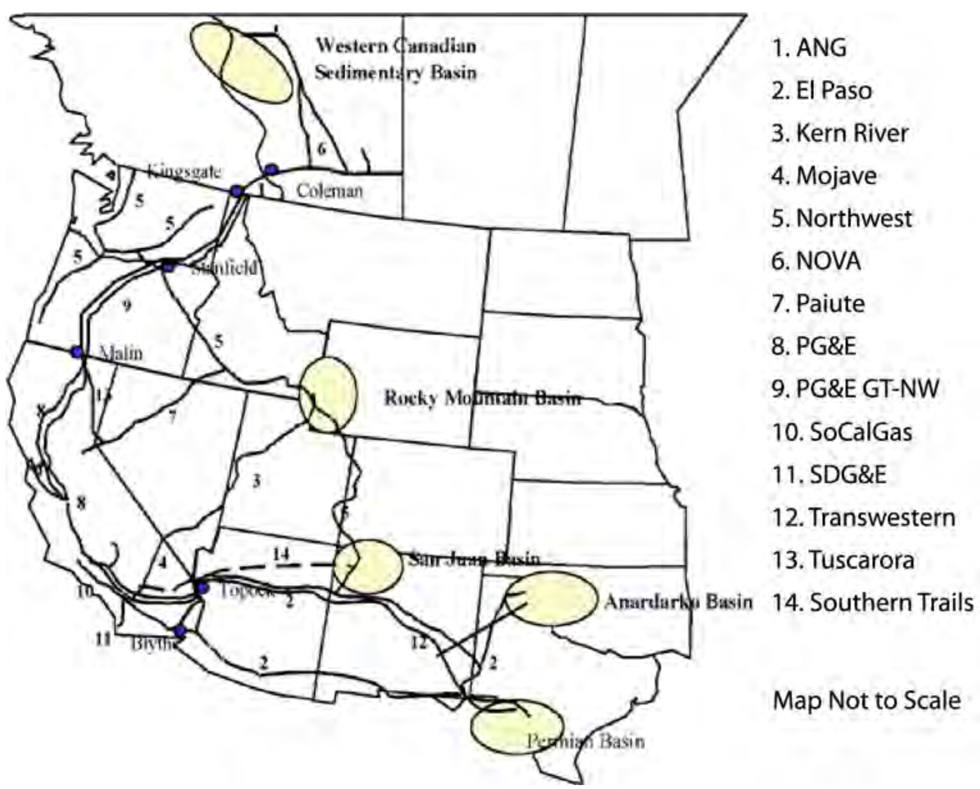
Under electric industry restructuring, the California Independent System Operator (California ISO) was formed to reliably and fairly control the electricity transmission system, or grid, meeting electricity demand and acting as the link between generators and the utilities that provide electricity to customers. The California ISO controls electricity transmission for the majority of the state: the major investor-owned utilities and two small city utilities – the cities of Vernon and Pasadena. Although the utilities still own transmission lines, the California ISO ensures equal access to power lines formerly under private control.

Almost 22 percent of the electricity used in the state is imported, coming from sources in 11 western states, Canada, and Mexico. In 2006, California enacted SB 1368, a law prohibiting utilities from making long-term commitments for electricity generated by plants that create any more CO_2 than clean-burning natural gas plants. Similar requirements have been adopted by Washington state. The law has discouraged the construction of new, dirty coal-fired plants in the West, and serves as another example of how California's clean energy decisions can drive the market in other states and other regions of the country.

Natural Gas

Only 13.5 percent of the natural gas California used came from in state production in 2006; the rest is delivered by pipelines from several production areas in the western United States and western Canada. California is at the end of those pipelines forcing us to compete with other states for supplies (Figure 1-12). Once the gas arrives in California, it is distributed by the state's three major gas utilities—SDG&E, Southern California Gas Company, and PG&E – that provide a collective total of 98 percent of the state's natural gas. Palo Alto is the only municipal utility in California that operates city-owned utility services for natural gas customers.

Figure 1-12: Natural Gas Resource Areas and Pipelines



Source: California Energy Commission

The largest user of natural gas is electricity generation, using about half of all natural gas in the state. The residential sector uses 22 percent of the natural gas. Of that amount, 88 percent is used by space and water heating.

Natural gas has become an increasingly important source of energy since more and more of the state's power plants rely on the fuel. While California's successful efficiency programs and our reliance on renewable sources of electricity should keep demand for natural gas growing slower here than in other parts of the nation, competition for supply is increasing. Our reliance on imported gas leaves us vulnerable to price shocks and supply disruptions.

Importing liquefied natural gas (LNG) by ship from foreign sources has the potential of furnishing new supply, but so far no LNG receiving terminals have been approved in California. A newly constructed Mexican facility in Ensenada, Baja California, however, is expected to begin operation as early as by the end of 2008. While 30 to 50 percent of this Sempra-owned plant is contracted for use in Mexico, the remainder should be available to California markets.

Since 1970, the number of households in California has almost doubled from 6.5 million to 12.5 million, pushing total residential natural gas consumption from about 5,500 million therms in 1970 to about 6,700 million therms in 2007. However, the average annual gas consumption per household has dropped over 36 percent, from 845 therms to 538 therms.

Petroleum

The early discovery of oil made California an energy pioneer. As early as 1910, our state was producing 73 million barrels of oil a year; 22 percent of the entire world's total oil output. Production in the state reached an all-time high in 1985 before beginning a gradual but steady decline. In 2004, California oil fields produced approximately 250 million barrels, a drop to levels not seen since the 1940s.

California is currently ranked fourth in the nation among oil-producing states, behind Louisiana, Texas and Alaska.

California's sources of crude oil have changed dramatically since the early 1990s. At that time the state imported 48 percent of its crude oil from Alaska and only five percent from foreign sources. Today, foreign imports – primarily from Saudi Arabia, Ecuador, Iraq and Mexico – contribute almost 42 percent of crude oil supplies and Alaska imports have declined to 21 percent as the North Slope oil field production declines.

With 60 percent of the oil used by California-based refineries and 10 percent of the refined petroleum products coming from outside of the state, marine facilities are a vital part of the state's petroleum infrastructure. Because no pipelines bring crude oil or petroleum products into California, all crude supplies and products must arrive by ship.

These marine facilities include terminals with docks for unloading both crude oil and finished petroleum products into storage tanks, through a network of pipelines. The same facilities are also used to export petroleum products to other states along the West Coast and to foreign destinations.

Facilities for importing or exporting crude oil and refined fuels are available at 46 marine terminals in California – 39 are located in the two major refining centers, Los Angeles and San Francisco Bay. The other seven marine terminals – in San Diego, Ventura, and Humboldt counties – are not directly linked to refineries, but are used to ship and receive refined products in areas not served by pipelines.

The network of pipelines within the state are another important component of the petroleum supply system, bringing California crude from import terminals and both onshore and offshore oil fields to refineries, and distributing finished fuels like gasoline, diesel and jet fuel to over 70 distribution terminals scattered throughout the state. Trucks deliver gasoline and diesel from these distribution centers to local stations.

Pipelines also help put California at the center of a regional petroleum market. Our refineries supply Nevada with almost 100 percent of its transportation fuels. Arizona gets over 60 percent of its fuel from California, while Oregon depends on our refiners for 25 to 35 percent of its fuel.

Currently, 21 petroleum refineries operate in California. Their combined crude oil distillation capacity totals more than 1.9 million barrels per day, ranking the state the third highest producer of transportation fuels in the nation. Ten of these refineries are located in the Los Angeles Basin and five in the San Francisco Bay Area. Between these two refining centers over 90 percent of California's crude oil input is processed. Of the remaining six refineries, three operate in Bakersfield, two in Santa Maria, and one in Oxnard. Just 14 of the 21 refineries produce California Air Resources Board (ARB) reformulated gasoline and diesel, while the remaining facilities produce non-fuel products such as lubricants and asphalt.

Until the mid-1990s, California refineries kept pace with the demand for gasoline and diesel fuel, but since then refiners have had to import more and more finished products. Californians used almost 16 billion gallons of gasoline in 2006, making us the second largest consumer in the world, behind the entire United States.

Demand for gasoline and diesel is normally expected to increase by 1 to 2 percent each year as a growing population registers more vehicles and drives more miles. While national demand grew by 1.5 percent in the first half of 2007 according to American Petroleum Institute figures, consumption in California actually dropped. Californians used nearly 1 percent less gasoline in April 2007 – 10.5 million fewer gallons – than the previous April, according to figures released by the California Board of Equalization. This was the fourth straight quarter in which Californians have used less gas than they did during the same period the year before.

Bioenergy

California has large, untapped biomass resources, including residues from forestry, urban, and agricultural wastes. Bioenergy cuts across all energy supply sectors because biomass can be used to create electricity, transportation fuels, and biogas. Using biomass to produce energy can reduce the waste stream in California's forests, landfills, and farmlands, and improve forest health while reducing the risk of catastrophic wildfires.

Because of the importance of this strategic fuel source, Governor Schwarzenegger issued Executive Order S-06-06 in April 2006 to establish specific biomass production and use targets for California. The Executive Order sets a target for biomass to comprise 20 percent of the state's Renewable Portfolio Standard for 2010 and 2020. In addition, the order states that California shall produce a minimum of 20 percent of its biofuels within the state by 2010, 40 percent by 2020, and 75 percent by 2050. The Executive Order also directed the Energy Commission to report on progress made toward achieving these targets in the *Integrated Energy Policy Report*.

Key issues that still need to be addressed include regulatory uncertainty and adequately valuing the public benefits of biomass energy. There are a number of state agencies with jurisdiction over different aspects of biomass production and use. Overlapping or conflicting regulations make it difficult for any individual agency to evaluate the overall environmental impacts and benefits of proposed projects. At the same time, bioenergy provides unique benefits not currently quantified in the marketplace. Recognizing and properly valuing these benefits would compensate project developers and help the biomass industry meet the Governor's goal for bioenergy in California.

California's Bioenergy Working Group, comprised of the ARB, the Energy Commission, the California Environmental Protection Agency, the Resources Agency, the California Department of Food and Agriculture (CDFA), the California Department of Forestry and Fire Protection (Cal Fire), the Department of General Services (DGS), the Integrated Waste Management Board (IWMB), the CPUC, and the State Water Resources Control Board (SWRCB), is continuing to evaluate strategies to remove barriers to meeting the Governor's bioenergy goals.

Bioenergy for Electricity Production

Biomass currently represents nearly 19 percent of the state's renewable resource requirements for 2010, close to the Governor's goal of 20 percent. Sustaining this progress beyond 2010, however, will require a concerted and coordinated effort by state government and the private sector. A number of these efforts are already underway:

- Under the Executive Order, the CPUC must initiate a new proceeding or build on an existing proceeding to encourage sustainable use of biomass and other renewable resources by the state's investor-owned utilities. A decision is pending in proceeding R06-05-027, under which the CPUC has asked parties to comment on how the unique benefits of biopower should be evaluated in resource procurement, particularly non-electric public benefits such as waste disposal, forest fire risk reduction, and cleaner air by avoiding open field burning.
- The CPUC has approved RPS biomass contracts totaling between 299 to 351 megawatts of new capacity since 2002. Meanwhile, the Energy Commission has supported 640 megawatts of existing biomass facilities with more than $150 million in production incentives, and has certified or pre-certified 117 biomass facilities as

eligible for California's RPS. In addition, the Energy Commission expanded RPS eligibility to include electricity generated from biogas injected into a natural gas transportation pipeline.

- The CPUC is also implementing a Renewable Power Purchase Tariff for renewable generation operated by a public water or wastewater facility, making 250 megawatts of small-sized biomass pilot projects (e.g., municipal wastewater treatment facilities, dairy digesters) eligible for the proposed tariff. In May 2007, Southern California Edison began offering a set of standard contracts for biogas and biomass generators as large as 20 megawatts.
- The CPUC's greenhouse gas emission performance standard for new long-term power contracts specifies a maximum rate of 1,100 pounds of CO_2 per megawatt-hour and is consistent with the Energy Commission's proposed standard for municipal utilities that expresses a preference for low carbon sources of electricity, such as biomass-based power.
- The Energy Commission is funding an economic study of dairy digesters for the SWRCB and has also installed 10 dairy digesters at sites throughout California with 2.5 megawatts of capacity. These efforts complement a Memorandum of Understanding signed on June 15, 2006, by the State of California with the government of Sweden, pledging cooperation on development of renewable energy and fuels, particularly biogas.
- CDFA Secretary A. G. Kawamura is working with 22 other states on the 25x25 Initiative, a coalition of states aimed at achieving the goal of 25 percent renewable energy from the nation's farms and forests by 2025. These efforts complement California's Renewable Portfolio Standard. Of particular interest to CDFA are efforts by California farmers to harness dairy and food wastes as a source of energy. CDFA has collaborated with the SWRCB and Regional Water Quality Control Boards and the farm community to strengthen water protection and discharge requirements for dairies, which can produce biogas while protecting water quality. CDFA has participated in the development of dairy digester reporting protocols by the Climate Registry, which will be adopted by ARB, and has worked with the CPUC to facilitate on-the-farm power sales and distribution.
- ARB is currently recommending emissions performance standards for the use of biomass and biofuels by local air districts in stationary sources, expected to be complete by mid-2008.
- CIWMB has completed its strategic plan that is intended to increase bioenergy production at landfills. As part of its strategic objectives, CIWMB has endorsed the goals to divert 10 percent of biomass wastes and 20 percent of organic residues from landfills by 2010, and 40 percent of waste and 60 percent of organic residues by 2020. As part of its statewide diversion strategy, CIWMB is also encouraging the production of landfill gas to biofuels at the state's waste disposal facilities. Statutory changes are needed to enable use of biomass residues through both combustion and

non-combustion technologies, such as gasification, fermentation, and pyrolysis, in current waste conversion technologies.

- Cal Fire is planning a small biomass cogeneration project at the Parlin Fork Conservation Camp and is in the process of identifying the most efficient means of harvesting and collecting the biomass to fuel that facility. Cal Fire is collaborating with the Climate Registry on urban forestry climate accounting protocols that encourage "best practices" for both forest management and resource conservation, while maintaining the state's forest lands as carbon sinks. Cal Fire is also working with the Tahoe Conservancy to secure state funding for a forest biomass demonstration program in the Lake Tahoe Basin. This program would demonstrate the significant benefits of reducing the risk of catastrophic wildfires and avoiding large fire suppression costs, while thinning the forests. Further, Cal Fire is partnering with the Energy Commission on the Western Carbon Sequestration Partnership to evaluate storing carbon in both geologic and terrestrial forms.
- Placer County released its strategic plan for biomass development based, in large part, on the Bioenergy Action Plan. Placer County has experienced four major forest fires since 2001 that have consumed over 30,000 acres of forest. The county is seeking financial and technical support from federal, state and private partners for its wildfire protection and woody biomass program. This program will improve air quality (by avoiding forest fires) and increase renewable energy production. If funding is be secured, the county plans at least one forest biomass-to-energy project in the Lake Tahoe Basin.
- SWRCB is committed to protecting water quality during the harvesting of biomass and the operation of biomass facilities. In particular, SWRCB is working to resolve permitting uncertainties for dairy digester projects in collaboration with the Regional Water Quality Control Boards. The Central Valley Regional Board has increased staffing for addressing dairy issues from seven to fourteen fulltime positions. The State Water Board estimates that anaerobic digestion of manure at dairies could produce up to 1,530 gigawatt hours of electricity. As a first step in addressing the costs of mitigating air, water and waste disposal impacts, the Board has arranged for an economic study of the effects of air and water quality regulation on proposed dairy digester projects in the Central Valley.

Bioenergy for Transportation

Biofuels, transportation fuels prepared from non-fossil feedstocks, are an essential component of California's petroleum reduction goals. The Governor's Executive Order calls for increasing amounts of California's biofuels to be produced in state. Activities underway to assist in meeting the Governor's goals include:

- In June 2007, the ARB adopted amendments to its California reformulated gasoline regulations that favor the use of E10 (10 percent ethanol blends) using the California Predictive Model. As part of ARB's effort to develop the Low Carbon Fuel Standard, it is using $2 million in research funding to evaluate the environmental impacts and emissions performance of a range of biofuels to establish fuel specifications for biodiesel blends ranging from 5 to 20 percent biodiesel.

- On October 31, 2007, the Energy Commission adopted its State Alternative Fuels Plan as directed by Assembly Bill 1007 (Chapter 371, Statutes of 2005). The plan, which was prepared in partnership with the ARB, includes a full fuel cycle analysis of the costs and benefits of various transportation fuels and also provides the analytic foundation for ARB's Low Carbon Fuel Standard. The Energy Commission has also awarded $3 million for energy conversion technologies using biomass; including projects for brown grease recovery, demonstration of an integrated biofuels and energy production system, and California's first cellulose-to-ethanol biorefinery project. In addition, in 2007 the Energy Commission-funded California Biomass Collaborative developed *A Preliminary Roadmap for the Development of Biomass in California,* a comprehensive strategy to guide research and development, address regulatory and permitting issues, and recommend appropriate public education programs.
- The Energy Commission's Agricultural Loan Program provides approximately $3 million in loan funds for the design, purchase and installation of eligible biomass technologies. Funding is available for fuel production from agricultural and forest residue, urban waste, food and beverage waste, waste grease, and purpose-grown energy crops. The California Department of Food and Agriculture is also working to influence federal funding opportunities in the 2007 Federal Farm Bill for conversion of agricultural residues and specialty crops to biomass power and fuels.
- DGS continues to purchase large numbers of flexible fueled vehicles for the state fleet, purchasing over 1,100 E-85 vehicles during the last two years. DGS purchases roughly 7,000 new state vehicles each year of the total 50,000 light and heavy duty vehicles in the state fleet. DGS plans to purchase more alternative fueled vehicles with the expectation that the fueling infrastructure will be established by the state's fuel suppliers. To date, none of these vehicles are being operated from fuels produced from biomass.
- The private sector and California universities have also contributed to the progress in reaching the state's bioenergy goals. Private industry, utilities, and venture capitalists have stepped up their efforts in California to finance the commercial development of biofuels projects, most notably, Pacific Ethanol's plant which is operating in Madera, California, and the proposed Blue Fire Ethanol project to be located at a southern California landfill.
- Other private sector activities include British Petroleum's new global business unit, BP Biofuels, which is developing transportation fuels using petroleum and agricultural feedstock. BP is addressing the challenges of cost, availability, quality and sustainability in pursuing technology solutions. Chevron, through its Biofuels Business Unit, is pursuing a two-phased approach; emphasizing ethanol blends in its

first generation of biofuels development. Amyris Biotechnologies is leveraging its own proprietary technology to develop hydrocarbon biofuels which perform like conventional gasoline, diesel, and jet fuels. Conoco Phillips, an integrated energy company, is producing a diesel fuel substitute, using agricultural, forestry, waste oils, wood, grass and cane. Neste Oil, an international fuel company with headquarters in Finland, is investing in renewable diesel fuel, derived from vegetable oils or animal fats that can be used in today's engines.

- Close collaboration with private companies, the federal government, and California's universities has resulted in considerable research funding for development of advanced biomass conversion technologies, commercial development of at least one biomass-to-ethanol project, and the creation of research centers at UC Davis and UC Berkeley on advanced biofuels. Other public/private research efforts include: a $500 million private grant from British Petroleum to UC Berkeley to establish the Energy Bioscience Institute; a $125 million grant to UC Berkeley and UC Davis from the United States Department of Energy for a Joint BioEnergy Institute to develop environmentally friendly biofuels; and a $25 million grant from Chevron Corporation to UC Davis for bioenergy research.

Powering the Future

As the world's eighth largest economy,[10] second largest consumer of gasoline, and twelfth largest emitter of greenhouse gases, California must be a leader in reducing greenhouse gases and a major participant in slowing global warming. Clearly the state requires an energy system that provides for its growing population in a way that is economically achievable within the rigorous environmental parameters mandated by state law. This *2007 Integrated Energy Policy Report* recommends energy policies that recognize this responsibility.

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[10] California Department of Finance, Top Countries Ranked by its Gross Domestic Product, California's World Ranking 2006.
http://www.dof.ca.gov/HTML/FS_DATA/LatestEconData/FS_Misc.htm

CHAPTER 2: Meeting California's Electricity Needs

California must provide a reliable supply of electricity for its citizens. A significant disruption in the flow of electricity would bring the California economy to an abrupt standstill, costing hundreds of millions of dollars to the state as well as to individual commercial and personal enterprises.

AB 32 forces California to determine how to meet our electricity needs in a way that leaves an ever-shrinking *greenhouse gas* footprint. Currently, electricity generation accounts for 28 percent of California's greenhouse gas emissions. Conventional generation natural gas and coal, which account for 57 percent of the state's electricity supply, present challenges to California's ability to meet the AB 32 mandate. Some of these challenges include:

> ***"There are risks and costs to a program of action. But they are far less than the long-range risks and costs of comfortable inaction."***
>
> John F. Kennedy

- California's aging power plants are extremely inefficient compared to current technologies that are 20-30 percent more efficient; these plants need to be either re-powered or retired and replaced with cleaner technologies that operate at higher efficiency to contribute to AB 32 goals.

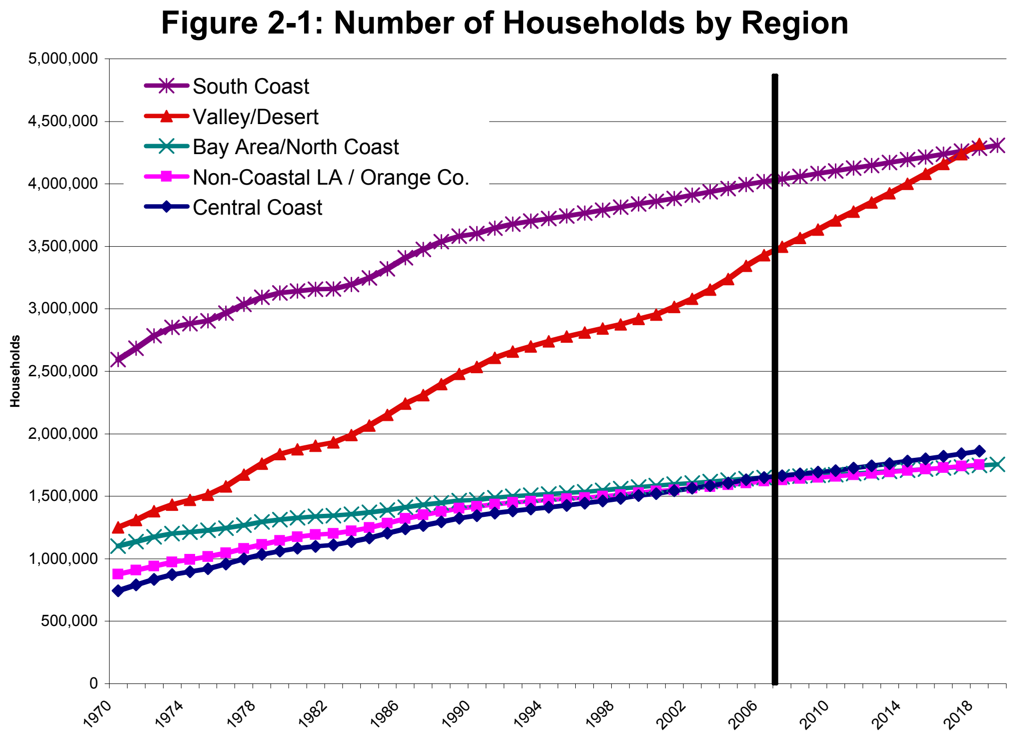
- Existing power plants that use once-through cooling are facing legal challenges, and new plants proposing to use once-through cooling face the risk of permitting delays or denials as a result of more stringent regulations on this technology.

- Carbon capture and sequestration for coal-fired generation and nuclear generation both face economic, environmental, and regulatory barriers that make them unlikely to be able to contribute significantly to the state's AB 32 goals by 2020.

Forecast of Electricity Demand

Reliable and current assessments of electricity demand growth are essential to system operators and policy makers in evaluating future infrastructure needs and resource options. Electricity use patterns reflect evolving trends in where and how people live and do business.

Population growth is a key driver for residential energy demand, and for commercial growth and demand for water pumping and other services. Even though the California Department of Finance (DOF) projects the *rate* of population growth will slow to 1.2 percent annually over the next 10 years (compared to average annual growth of 1.8 percent over the previous quarter century), the cumulative growth is significant, and that growth is occurring more in hotter areas of the state (Central Valley and desert areas) pushing up the peak demand for electricity (Figure 2-1). DOF expects this trend to continue.



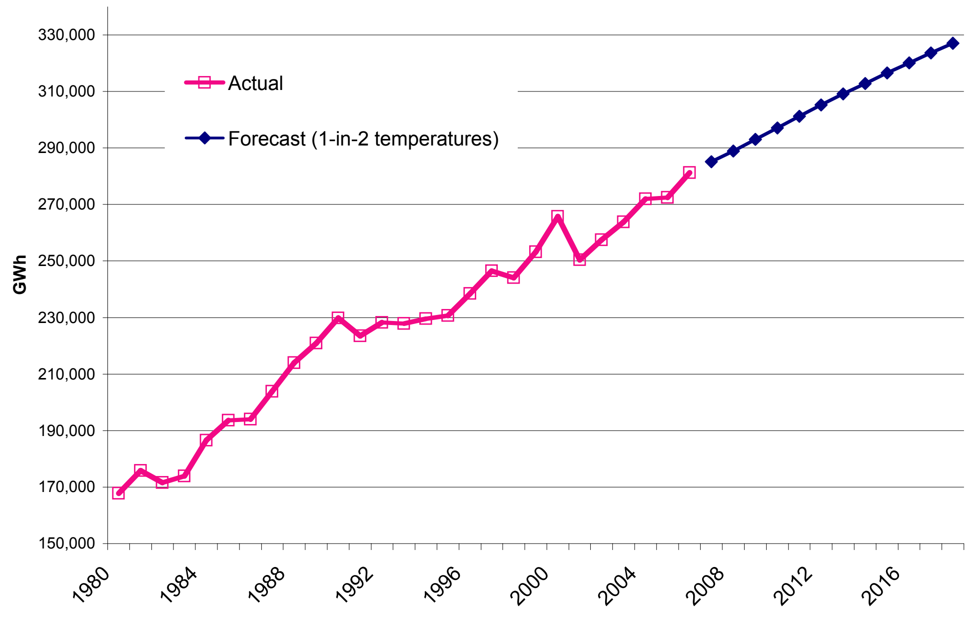
Source: Department of Finance (July 2007) and California Energy Commission

The historic data are actual consumption, while the forecast assumes average temperatures (Figure 2-2). The average temperatures are calculated as the average over the last 30 years.

While trends in population growth are relatively stable, economic trends are more cyclical and can drive swings in annual electricity use. Electricity consumption sharply increased in 1999 and 2000 during the technology boom but rapidly diminished with the 2001 electricity crisis and following recession. In 2005 and 2006, electricity use returned to pre-energy crisis levels. Statewide energy consumption is expected to grow at an average of 1.25 percent in the forecast period (2008–2018).

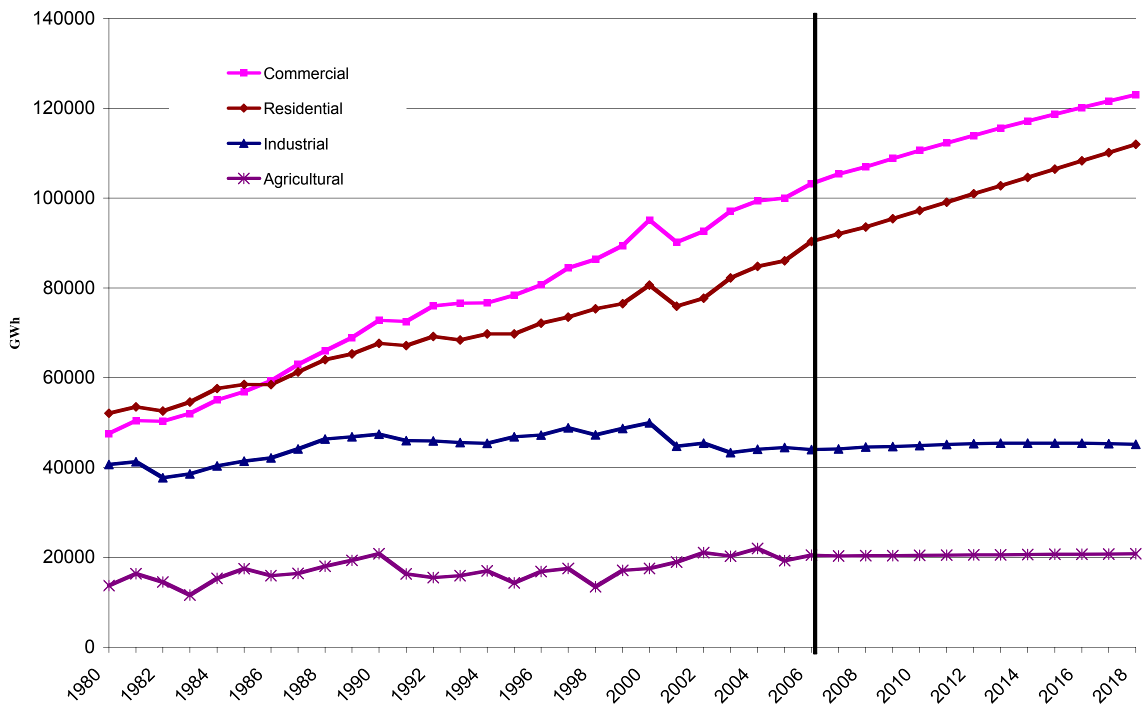
Electricity consumption by the commercial and residential sectors is expected to increase (Figure 2-3). During the last 25 years, the commercial sector had the highest growth rate, followed by the residential sector. In the forecast period, the residential sector continues to grow at the historic 1.8 percent rate, while the commercial sector slows slightly to 1.4 percent annual growth. Electricity use in the industrial sector remains relatively flat, although the economic value of output is projected to continue to increase at 0.8 percent annually.

Figure 2-2: Statewide Annual Electricity Consumption (Gigawatt Hours)



Source: California Energy Commission

Figure 2-3: Annual Electricity Consumption by Sector



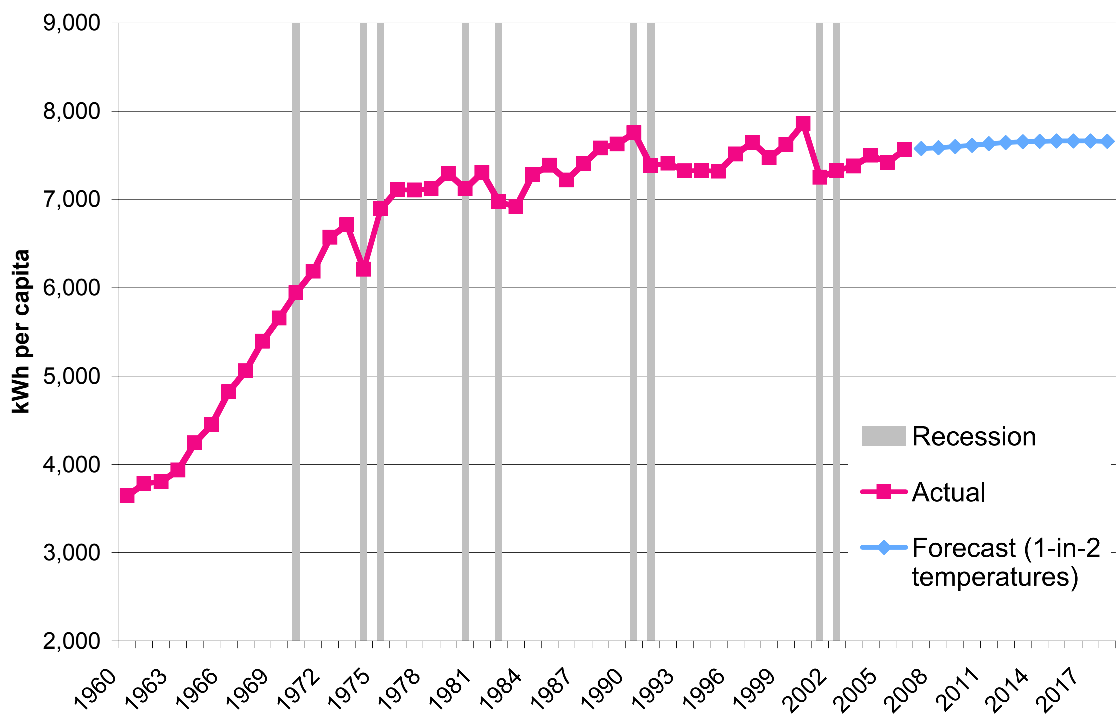
Source: California Energy Commission *California Energy Demand 2008–2018*, CEC-200-2007-015-SF

Overall, improvements in how efficiently we use electricity have helped to offset growth, so that per capita use has grown very slowly. Energy efficiency standards and programs have held per person electricity use essentially constant over the last 30 years, fluctuating between 7,200 and 7,800 kilowatt hours (kWh) per person, depending on economic and annual temperature conditions (Figure 2-4). Building and appliance standards have offset rising consumption from the increase in the number of different types of electronic equipment in homes and business.

This forecast includes the projected effects of currently adopted building and appliance standards and the investor-owned utility energy efficiency programs implemented or approved through 2008. Because the forecast is developed using data that reflects the effect of many past years of energy efficiency programs, it also implicitly includes some effects that can be attributed to post-2008 programs, to the extent those programs have similar strategies and level of effectiveness. The extent to which post-2008 targets contribute additional reductions in demand will depend on whether the new programs produce impacts beyond the *business-as-usual* effects accounted for in the forecast.

Economic conditions (shaded areas) directly impact electricity consumption. Since 1976, per capita use declined on average by 2 percent during recessions, while in non-recession years, use typically increased by .05 percent. In the forecast period, this trend of relatively constant use per capita is projected to continue at about 7,500 kWh per person.

Figure 2-4: Annual Electricity Consumption per Capita

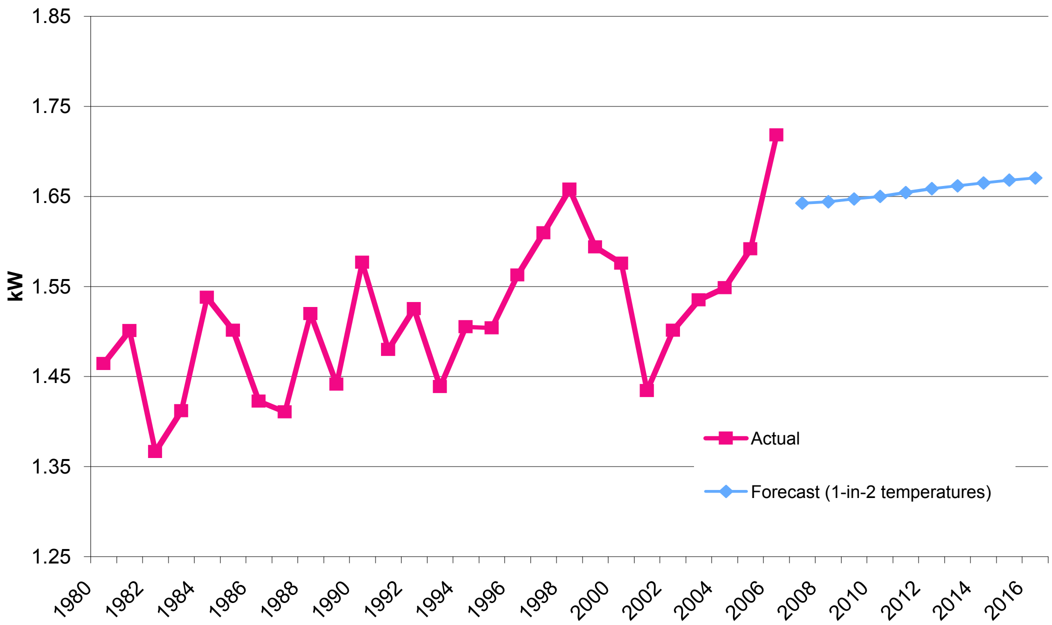


Source: California Energy Commission *California Energy Demand 2008–2018*, CEC-200-2007-015-SF

Peak Demand on the Rise

Peak electricity demand per capita, the highest hourly demand in each year, is growing slightly, rather than staying fairly constant as with energy use per capita (Figure 2-5). Generally, peak demand is extremely volatile and highly sensitive to temperature conditions and reflects the amount of installed cooling equipment in a region. To account for the effect of temperature on peak demand, daily temperatures from area weather stations, weighted by the distribution of residential air conditioning, are used to estimate response in each utility area. The average peak demand forecast assumes average annual maximum temperatures—those that have a 50 percent (1-in-2) chance of being reached in any given year. Because 2006 was hotter than normal, the starting point of the 1-in-2 forecast was lower than actual demand in 2006.

Figure 2-5: Peak Demand Per Capita



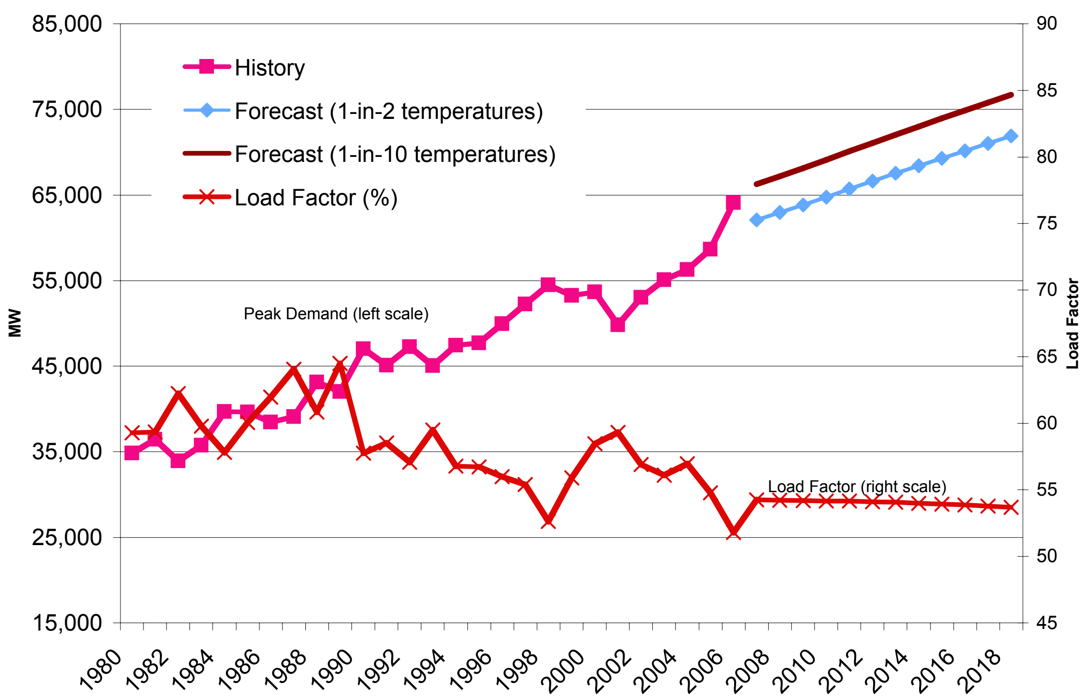
Source: California Energy Commission *California Energy Demand 2008–2018*, CEC-200-2007-015-SF

Statewide annual peak demand is projected to grow, on average, 850 MW per year for the next 10 years, or 1.35 percent annually (Figure 2-6). Population growth in California's drier, warmer areas increases peak demand more than it increases annual energy consumption. Another reason for the higher growth rate of the peak demand forecast compared to the electricity consumption forecast is the forecast's assumption that the 2005 federal air conditioning standards have no impact on peak, because they result in little, if any savings, during the hottest hours when California peak demand occurs. The federal seasonal energy efficiency ratio (SEER) performance number is based on outdoor temperatures which are far below the average annual maximum temperatures experienced in California and on more humid conditions and, consequently, does not accurately reflect efficiency improvements in California's hot, dry peak conditions. Therefore, while the electricity consumption forecast includes estimated energy savings from the 2005 standard's change to SEER 13, no impacts from the 2005 standards are feasible to include in the peak demand forecast. While these higher efficiency air conditioners probably do save energy during many summer afternoon hours, their impact during the hottest peak hours is suspect, at best.

The growth in peak demand is somewhat offset by projected increases in the electricity provided by self-generation, reflecting the effects of the California Solar Initiative (CSI), the New Solar Homes Partnership, and the Self-Generation Incentive Program. The peak demand forecast represents the net amount of load the electric grid must serve so that demand by self-generation reduces the electric system peak. In the forecast, the growth in photovoltaic and other self-generation installations is assumed to reduce peak demand by 650 MW by 2018, based on current costs and program performance. If the installed cost of photovoltaic systems declines significantly, either through reductions in component or installation costs or increases in federal/state tax credits, this projection could easily be exceeded.

Resource planners and system operators also need to know how much demand will increase under extreme temperature conditions. The Energy Commission applies its estimates of temperature response—how much peak demand increases as temperature rises—to develop demand forecasts for varying degrees of hotter-than-average temperatures. In the 1-in-10 temperature scenario, which has a 10 percent chance of occurring in any year, demand is increased by 8 percent in any given year (Figure 2-6).

Figure 2-6: Statewide Coincident Peak



Source: California Energy Commission *California Energy Demand 2008–2018*, CEC-200-2007-015-SF

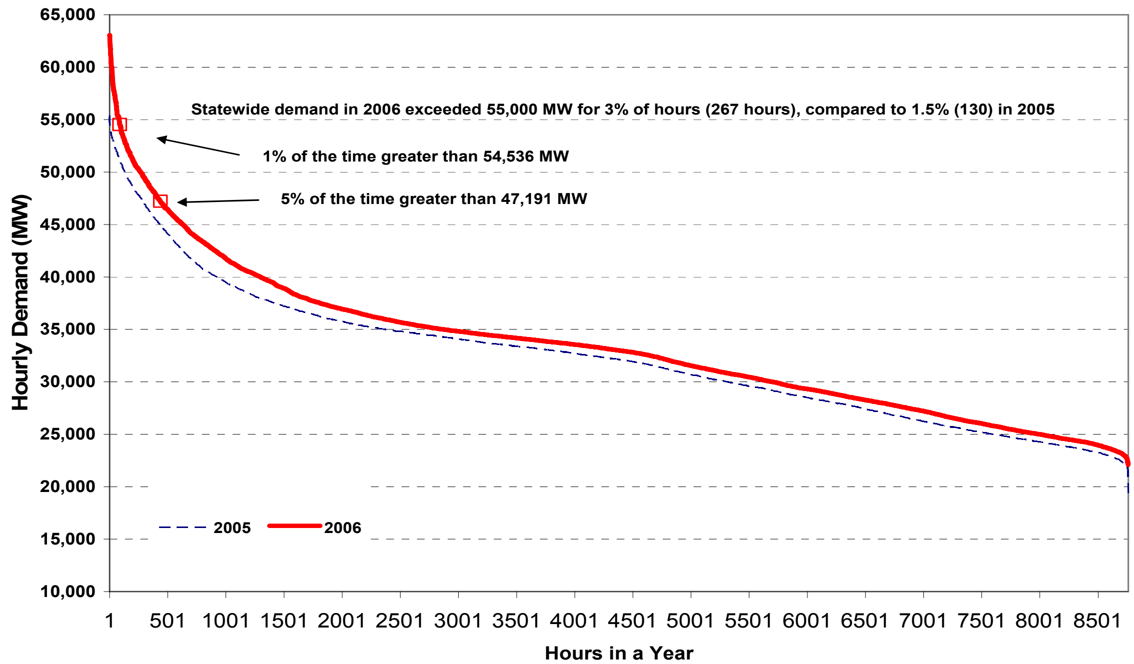
The actual and forecast load factor (using the 1-in-2 forecast) is also shown in Figure 2-6. The load distribution over the year is an important characteristic of demand. System operators must plan for sufficient electricity supplies or capacity to meet peak demand; however, in off-peak hours only a fraction of that capacity will be used. The load factor, defined as average demand relative to peak demand, measures the extent that capacity is being used. A load factor of 100 percent means demand is constant in all hours, so there is no unused capacity in any hour. Conversely, a low load factor means much of the resources needed to meet demand in the peak hour sit idle in other hours. Plant operators take advantage of some of these idle hours to perform essential maintenance but in many of these hours, no maintenance is needed.

Low load factors can be costly to California's electricity consumers. Load factors vary from year to year depending on weather. For example, 1998 was a cool year except for a brief hot spell, so average hourly demand was much less than in the peak hour, resulting in a load factor of only 52.7 percent. In 2001, the load factor reached 60 percent as businesses and consumers chose to use less air conditioning in response to the electricity crisis. In 2006, unusually hot weather simultaneously in Northern and Southern California produced a load factor of 52 percent.

While year-to-year temperature variations cause swings in the load factor, the decrease over time (historically and forecasted) reflects a number of continuing trends: more building is occurring in warmer, inland areas in the state resulting in more homes and businesses with central air conditioning; more homes with cooling equipment even in mild climates; and higher economic activity in the commercial rather than the industrial or agricultural sectors. Finally, many energy efficiency measures, such as more efficient residential lighting, can also contribute to the declining load factor by reducing overall energy use while having less of an impact on peak demand. Statewide demand in 2006 exceeded 55,000 megawatts for only 3 percent of the hours in that year (267 hours), compared to 1.5 percent (130 hours) in 2005 (Figure 2-7). The shift from 2005 to 2006 represents both warmer temperatures and load growth in 2006.

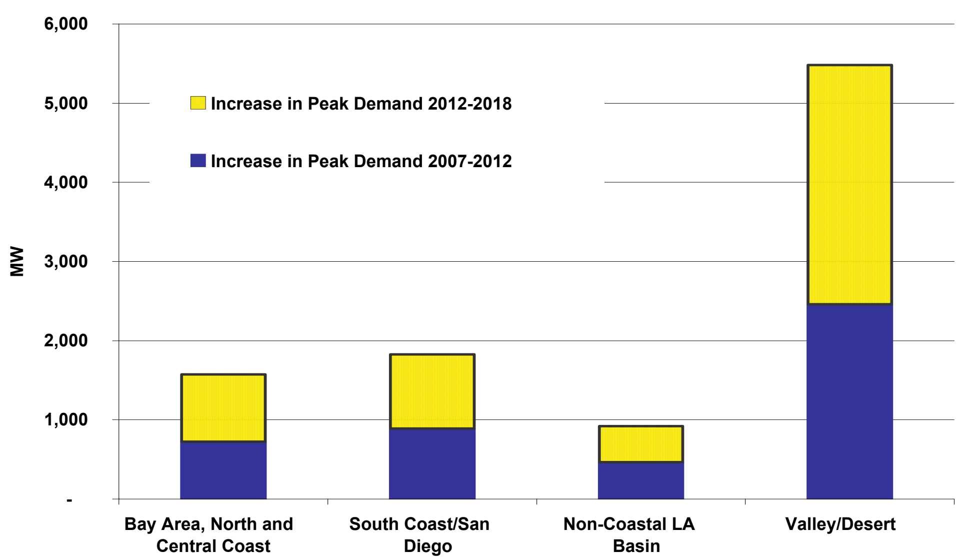
Transmission planning studies, supply/demand assessments, and other analyses of the electricity system often require load projections for individual utilities and small geographic areas. To support these studies, staff develops forecasts for 16 climate zones in the state, taking into account the climate, energy use characteristics, and projected economic and demographic trends for each area. Peak demand for regional clusters is forecasted to increase in all cases (Figure 2-8). In the entire Central Valley and desert regions of the state, demand is projected to increase by 5,500 megawatts during the forecast period. Forty percent of this (2,200 megawatts) is in the Inland Empire area served primarily by Southern California Edison (SCE) and Riverside Public Utility. The remaining, 2,300 megawatts, is growth in the Central and Sacramento Valley areas, served by Pacific Gas and Electric (PG&E), Sacramento Municipal Utility District (SMUD) and other utilities. Projected electricity demand growth, while doubling, is noticeably less in the more developed coastal areas served by PG&E and SCE than it is in the valley/desert areas.

Figure 2-7: Load Duration Curve 2006



Source: FERC Form 714 data compiled by Energy Commission staff

Figure 2-8: Regional Growth in Peak Demand (megawatts)

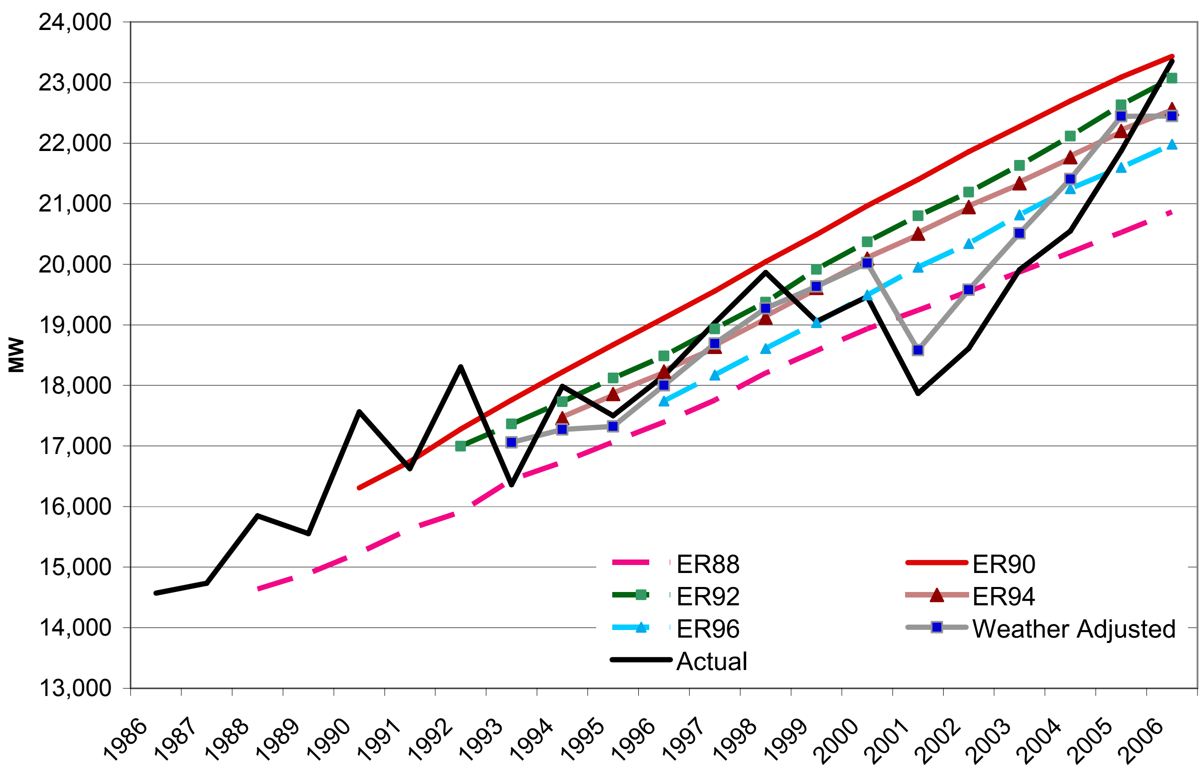


Source: California Energy Commission, *California Energy Demand 2008–2018*, CEC-200-2007-015SF.

The long-term economic and demographic projections used to forecast demand typically cannot predict the timing or magnitude of changes in the business cycle. So even if the predicted trend proves to be accurate over the forecast horizon, the forecast for any given year may be significantly inaccurate, for example, as shown for SCE (Figure 2-9).

For the five forecasts of demand in the SCE planning area adopted by the Energy Commission from 1988 to 1996, the average annual absolute error over the 5 to 12 year forecast horizon was 4 percent. This is the error when compared to weather-adjusted demand (what staff estimates demand would have been under average temperature conditions) and includes 2001.

Figure 2-9: Forecasted versus Actual Peak Demand in the SCE Planning Area



Source: California Energy Commission, *California Energy Demand 2008–2018*, CEC-200-2007-015SD.

Resource Adequacy

Reliable electricity service requires that the state must have enough electricity generation capacity to cover load and reserves during peak demand periods. In 2004, the CPUC established resource adequacy requirements (D.04-01-050) for load-serving entities under its jurisdiction, requiring that they own or contract with enough electricity generation to meet peak demand. In

September 2005, AB 380 (Nuñez, Chapter 367, Statutes of 2005) was enacted, resolving any disputes to the CPUC's authority to impose such requirements on retail electricity service providers. In June 2006, the California ISO established similar requirements for the publicly owned utilities located in its control area. These requirements have evolved over time to establish separate methods to address local capacity requirements, such as for the Los Angeles basin, and zonal procurement requirements, such as for Northern and Southern California. AB 380 requires the state's 54 publicly owned utilities, whether or not they are in the California ISO control area, must prudently plan for and procure adequate resources to meet their respective planning reserve margins. The publicly owned utilities are also required to provide the information necessary for the Energy Commission to evaluate and report their progress on resource adequacy.

The 18 public utilities outside the California ISO control area are not required by legislation or tariff requirements to buy, build, or contract for a specified amount of capacity (for example, an amount equal to 115 percent of their forecasted load during the summer peak in 2007).

The Energy Commission staff has collected and reviewed load and resource information from the publicly owned utilities throughout the state. Staff's assessment found that, in total, the utilities have resources sufficient to meet anticipated demands for the next several years. Even those public utilities that are not in the California ISO control area are generally adhering to self-imposed standards similar in rigor to those imposed by the California ISO.[11]

Scenario Assessments

Overview

The Energy Commission undertook the Scenario Analyses Project to assess key policy strategies for the electricity system, and specifically, to better understand how the actions necessary to achieve major reductions in greenhouse gases from the electricity. Rather than focusing on the range of uncontrollable external forces affecting the energy industry, staff developed scenarios that focused on the broad policy options available to decision makers. These "policy-driven" analyses demonstrate the greenhouse gas emission consequences of the scenarios. They provide a context for assisting the efforts now underway by the California Air Resources Board (ARB), the CPUC, and the Energy Commission to establish regulatory requirements for specific load-serving entities.

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[11] *Progress Report on Resource Adequacy Among Publicly Owned Load-Serving Entities in California* (http://www.energy.ca.gov/2007publications/CEC-200-2007-016/CEC-200-2007-016.PDF), Staff Report CEC-200-2007-016. August 2007.

Energy Commission staff examined the implications of resource plans featuring very high amounts of energy efficiency measures and renewable energy generation (both rooftop solar photovoltaic and supply-side generating technologies) in California and the Western Electricity Coordinating Council (WECC).[12, 13] The interesting variables included the effect of resource plans that reduce greenhouse gas emissions compared to resource plans with more conventional resources. These analyses look only at CO_2 because this component of greenhouse gas emissions comprises the overwhelming majority (at 98 percent) of total emissions from the electricity sector. In addition, the study investigated the impacts of a mix of resources to support load, system and production costs of different generation resources, fuel consumed in power generation, criteria pollutant emissions, and transmission additions required in each scenario. The staff effort did not attempt to devise the optimal amount of preferred resources, but, rather, explored how combinations of increases in amounts in California and the West affect greenhouse gas emissions, resource requirements, transmission requirements, and additional (or incremental) costs in those geographic areas.

The study used standard production cost models to simulate the results for a variety of scenarios composed of different levels of preferred resources—energy efficiency, roof top solar photovoltaic (PV), and supply-side renewable generating technologies—both for California and the balance of the Rest-of-WECC. The simulations were conducted to 2020 to correspond most closely to the AB 32 target. The production cost model was configured to use transmission zones (transareas) that modeled most of the major utility systems separately, but more detail was followed for California than for the Rest-of-WECC. The study addressed transmission in terms of the transfer capacity between transareas and modeled expansion of the transmission system when necessary in each of the scenarios. All production cost model analyses develop considerable detail on fuel costs, other variable operations and maintenance costs, and so forth, but this analysis also estimated the capital and fixed operations and maintenance costs of generation and transmission.

While staff developed nine basic scenarios to evaluate the preferred resource strategies, it examined more than 50 cases for the entire Western Interconnection by evaluating sensitivities for high and low fuel prices, plus high and low hydro-electric generation. This range of thematic scenarios allows preferred resource plans to be compared to what might be expected from resource plans with more conventional resources.

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[12] *Scenario Analyses of California's Electricity System: Preliminary Results for the 2007 Integrated Energy Policy Report*: Staff Draft Report, June 2007, CEC-200-2007-010SD.

[13] The Western Electricity Coordinating Council (WECC) encompasses 35 control areas, or balancing authorities, which are charged with maintaining system and voltage within narrow tolerances. Frequently these are closely aligned with a major utility within each one encompassing several smaller utilities. Modeling the detailed arrangements of hundreds of utilities is unwieldy, and for these policy assessment purposes, unnecessary. The topology of the production cost model used 29 transareas, which was judged to be a reasonable balance.

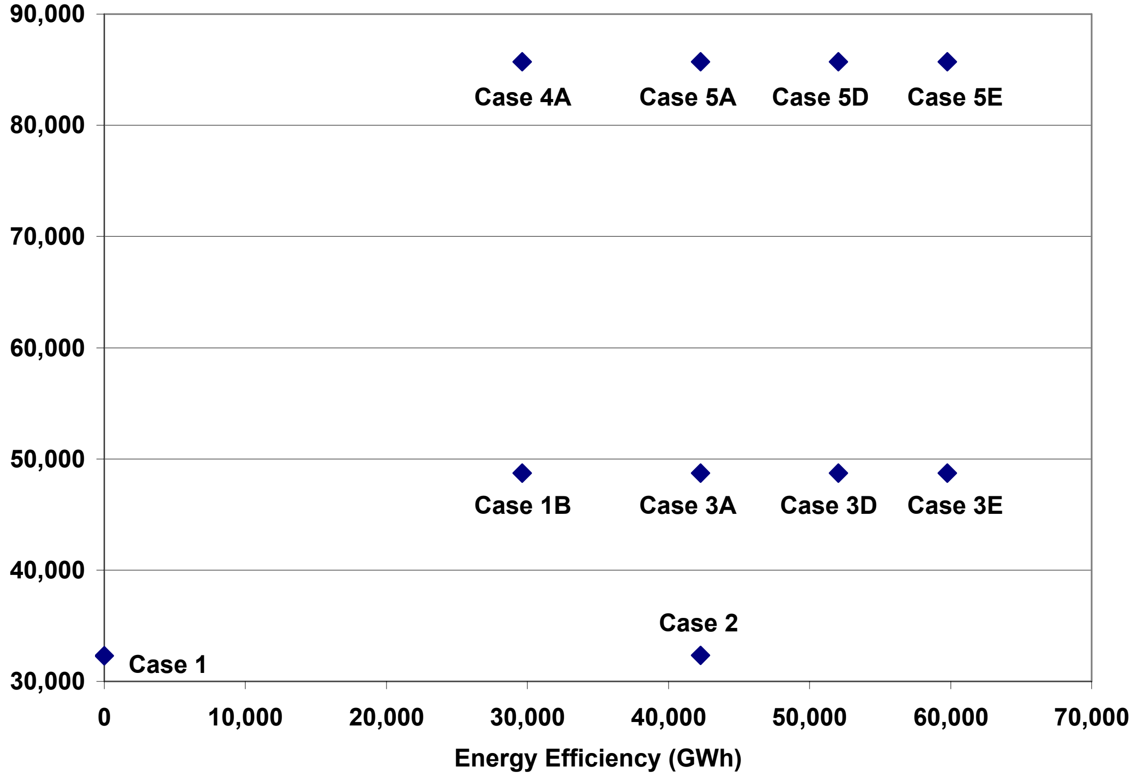
Study Design and Scenario Definitions

Staff's study was designed to focus on the broad implications of high levels of preferred resource additions. It was limited to the electricity sector and did not investigate measures like electrification of transportation or industrial processes that, while attractive to reducing greenhouse gas emissions, would necessarily increase emissions in the electricity sector as resources were added to accommodate increased loads. The study was limited to an analysis of the physical system and did not link loads and resources to specific load-serving entities. The study investigated the following thematic scenarios using both deterministic production cost modeling as well as sensitivity assessments for some of the variables thought to materially affect the results:

- Case 1 — Current conditions extended into the future implying minimal incremental amounts of preferred resources.
- Case 1B — Compliance with current requirements for preferred resources, both in California and in Rest-of-WECC.
- Case 2 — Utility industry resource decisions reflecting high sustained natural gas and coal prices, but minimal policy requirements from regulators.
- Case 3A, D, E — Three levels of increased energy efficiency, in California only, otherwise the assumptions of Case 1B.
- Case 3B, C — Two levels of increased energy efficiency, throughout the West, otherwise the assumptions of Case 1B.
- Case 4A — High levels of rooftop solar PV and supply-side renewable generating technologies, in California only, otherwise the assumptions of Case 1B.
- Case 4B — High levels of rooftop solar PV and supply-side renewable generating technologies, throughout the West, otherwise the assumptions of Case 1B.
- Case 5A, D, E — Three levels of increased energy efficiency (Case 3A, 3D, and 3E) and a high level of renewables, in California only, otherwise the assumptions of Case 1B.
- Case 5B — High levels of energy efficiency (Case 3B) and renewables (Case 4B) throughout the West.

Of these, Case 1B is the closest to reflecting the current energy efficiency goals, Renewable Portfolio Standard (RPS) requirements, and rooftop PV objectives both within California and across the West. In some respects it reflects continuation of recent policies without the incremental emphasis resulting from climate change concerns. The additional cases made use of the highest level of efficiency, renewables or PV that was developed in selected prior studies. The individual energy efficiency or renewables scenarios, and especially the combination scenarios, were intended to allow quantification of the greenhouse gas implications of these high levels of amounts of preferred resources.

Figure 2-10: Preferred Resource Composition of California Thematic Scenarios in 2020



Source: California Energy Commission Scenario Project

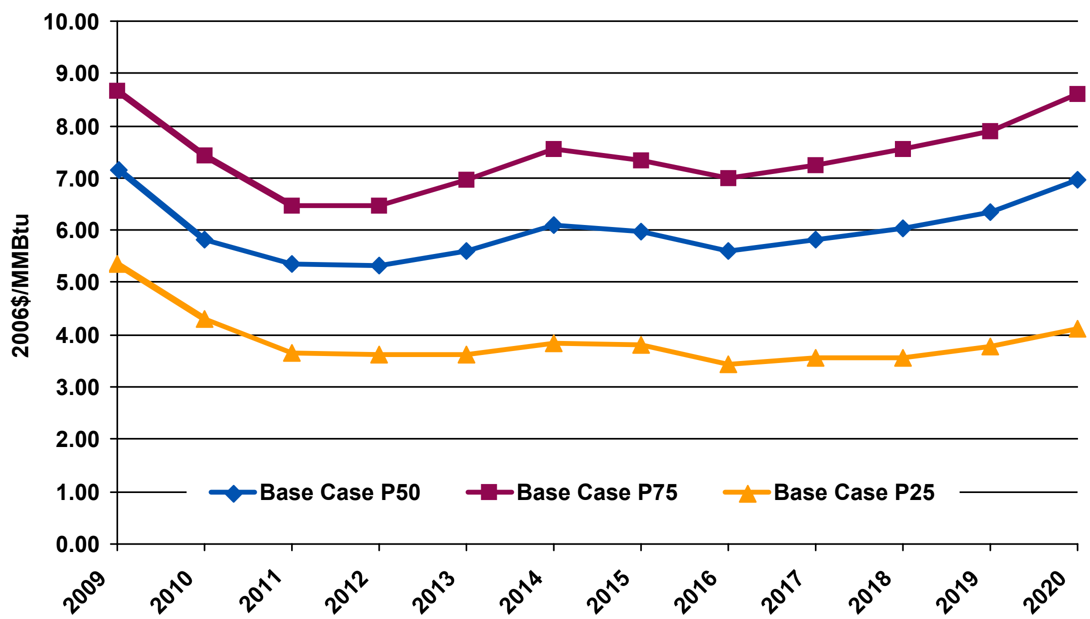
The differences among the 10 California-based scenarios by their reliance on energy efficiency and renewables range from a low of Case 1 with about 32,000 gigawatt hours of renewables and zero efficiency to a high of Case 5E with over 80,000 gigawatt hours of renewables and 60,000 gigawatt hours of energy efficiency (Figure 2-10).

Input Assumptions

Natural gas and coal fuel prices are a key input to any production cost modeling effort. Baseline projections used in the deterministic assessments and the alternative views used to investigate the consequences of higher or lower fuel prices were considered (Figures 2-11 and 2-12).[14]

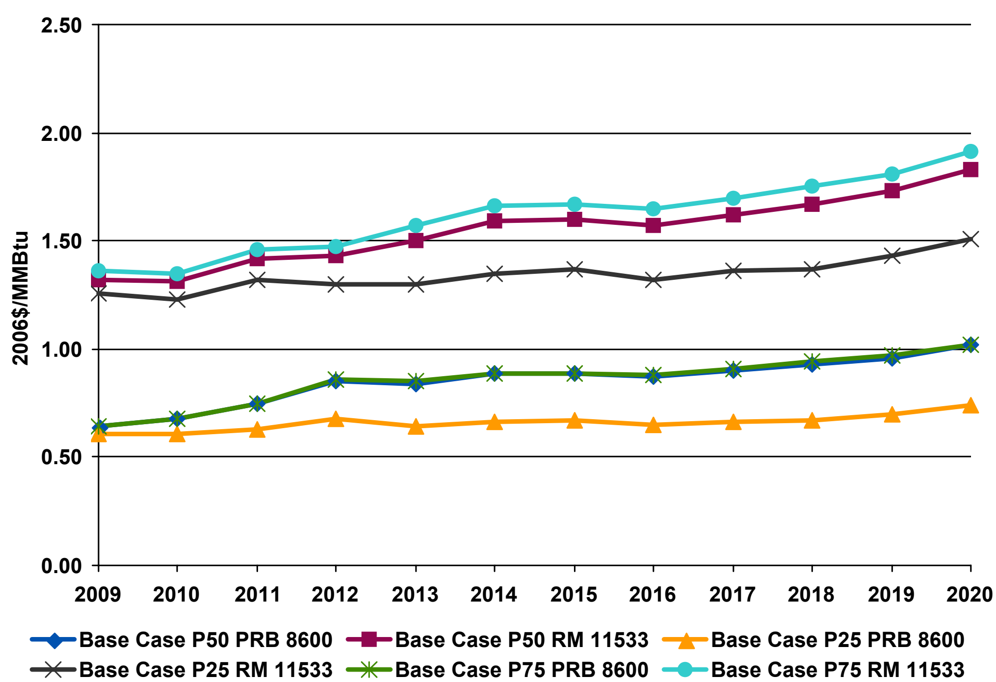
[14]*Scenario Analyses of California's Electricity System: Preliminary Results for the 2007 Integrated Energy Policy Report*: Staff Draft Report, June 2007, CEC-200-2007-010SD, pp. 97–99. Global Energy describes these alternative projections as encompassing 50 percent of the likely range, so that the high alternative exceeds 75 percent of the expected values while the low alternative exceeds only 25 percent of the expected values.

Figure 2-11: Expected Range of Natural Gas Prices ($2006)



Source: Global Energy

Figure 2-12: Expected Range of Coal Prices ($2006)

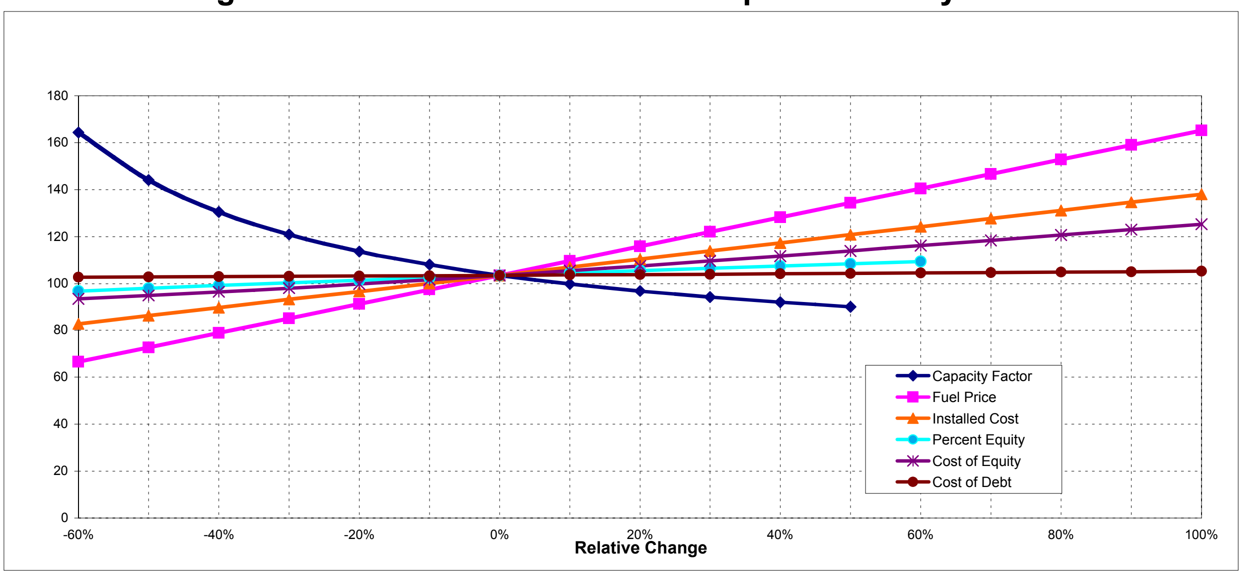


Source: Global Energy

Cost of Generation

As a step to improve the planning process for comparing alternatives and to increase the transparency of such analysis, the Energy Commission substantially overhauled its cost of generation model and input data. The Cost of Generation Model[15] uses capital, financing, and operational cost data to calculate levelized[16] costs of generation for various traditional and alternative electricity generating technologies. First introduced in the *2003 IEPR*, the cost of generation model has been extensively revised for the *2007 IEPR* to make it more accurate, user friendly, flexible, transparent, and better documented. The model has reasonable accuracy for gas-fired technologies (less information is available for renewable technologies), except for the extraordinary uncertainty of fuel price forecasts, and of capacity factors for specific power plants (Figure 2-13).

Figure 2-13: Cost of Generation Sample Sensitivity Curve



Source: California Energy Commission

The principal weakness of the revised model remains its lack of information as to how technology costs will evolve through time. This is a research-intensive and judgmental task that was beyond the scope of staff's resources in the 2007 IEPR cycle. Because of the increasing role that newer technologies—especially in the renewables sector—are likely to play in California's future generation mix, the Energy Commission commits to using the 2009 IEPR cycle to

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[15] *Comparative Costs of California Central Station Electricity Generation Technologies (2007 Update)*, draft staff report, June 2007, CEC-200-2007-011-SD provides a description of the cost of generation model, summarizes the calculated levelized costs, and provides the supporting data and a description of how that data was collected and processed.

[16] Levelized cost is the constant annual cost that is equivalent on a present value basis to the actual annual costs, which are themselves variable.

extensively refine the input data used for developing technologies and to establish a process, working with industry and academic experts, to include regularly update of technology costs over time.

Results of the Analyses

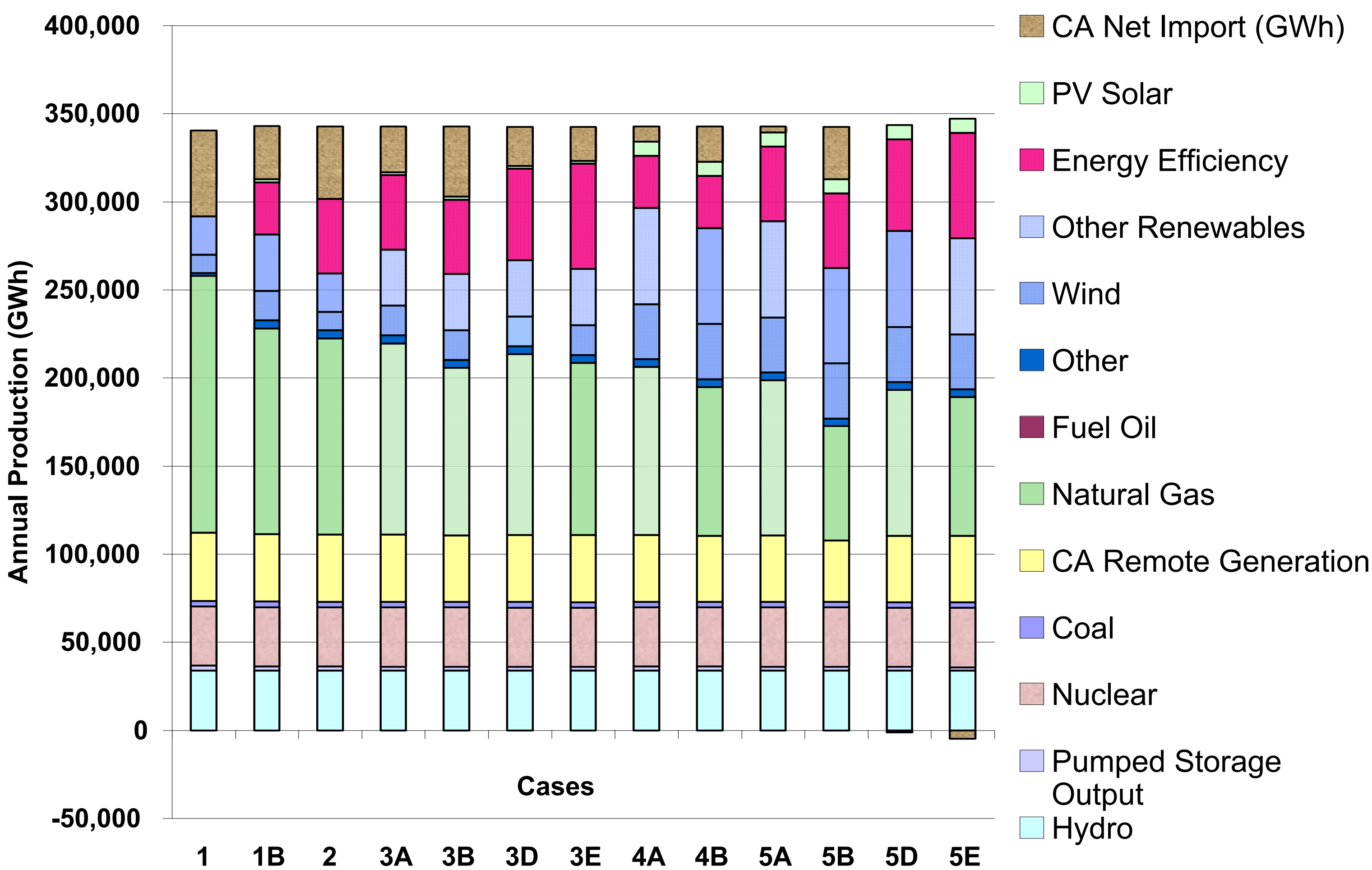
The results can be examined from multiple perspectives—generation by fuel type or technology, greenhouse gas emissions, power plant fuel use, reliability, corresponding transmission additions, and cost. Staff evaluated the 14 scenarios using a baseline set of assumptions. The baseline results assumed average or most likely conditions, while an extensive sensitivity assessment provided further insight as to the variation in the results for the variables tested. In response to workshop comments, staff assessed the implications of a CO_2 cost adder on the dispatch of the fleet of plants in two of the scenarios to assess the level of dispatch cost increase needed to alter reliance on existing coal facilities.

Generation Mix

Each of the California generating resource outputs corresponds to each of the same thematic scenarios for 2020 (Figure 2-14).[17] The conventional resource scenario on the left of Figure 2-14 has a much larger proportion of generation from natural gas than the scenario furthest to the right, which presumes a large increase in energy efficiency and supply-side renewable generation. Clearly, as the scenarios are designed, the increasing role of the preferred resources diminishes the generation from conventional power plant technologies. In California, natural gas generation is the principal source of instate greenhouse gas emissions, and is displaced as the preferred resources are added. Even in 2020, which affords the most time for the assumptions of Case 5B (the highest levels of both energy efficiency and renewables) to unfold, natural gas-fired electricity generation is still the largest single source of the electricity consumed in California in 2020 (Figure 2-14). Hydroelectric, nuclear and other fuel types or technologies are essentially unchanged across all scenarios.

[17] To simplify comparisons, incremental energy efficiency and roof top solar PV will be classified as resources, even though individual end-users might perceive the impact of these technologies to be load reductions and/or utility bill reductions.

Figure 2-14: Composition of California Resource Mix in 2020



Source: California Energy Commission Scenario Project

An important result of the analysis is the wide difference in level of imports (top of each bar) into California across these scenarios. These imports are limited to short-term market purchases that cannot necessarily be tracked to any specific generating plant.[18] Because of the influence of coal in supporting imports, both components of imports ("remote" plants and short-term market purchases) play a disproportionately large role in greenhouse gas emissions.[19]

Several notable results for Rest-of-WECC include large proportions of electricity from hydroelectric and coal generation when compared to California power plants (Figure 2-15). Contributions from hydroelectric and coal resources are almost unchanged across all of the scenarios, no matter how large the level of preferred resources. The addition of preferred resources displaces natural gas-fired electricity generation, just as in the case within California. What is surprising; however, is that the change in natural gas-fired electricity generation is even larger in Rest-of-WECC than it is for California. This results from the higher operating costs of out-of-state natural gas-fired plants, making their output the first to be displaced as preferred resources are added. Although electricity generated in Rest-of-WECC and exported to California is a noticeable share of California's electricity power sources, these "exports" are not important in the much larger Rest-of-WECC electrical system.

Greenhouse Gas Emissions

Each generating unit modeled was assigned an emission rate for CO_2, and the simulation results recorded CO_2 amounts based on the fuel burn of each unit. The total CO_2 emissions across the cases change as the energy generation changes. The California responsibility for CO_2 consists of three categories: (1) power plants located in California, (2) power plants owned by or under long-term contract to California load-serving entities, and (3) emissions from power plants located outside California that correspond to "spot purchases." Similarly, CO_2 emissions from the Rest-of-WECC consist of plants located in Rest-of-WECC, serving Rest-of-WECC loads as well as the share of the remote plants serving Rest-of-WECC loads. Power plants located in California and "remote" power plants located out of state, but controlled by California, have exact calculations of their emissions.

Except for "spot purchases," this portion of overall imports into California are allocated CO_2 emissions based on the average CO_2 profile of the annual average generation mix for Rest-of-WECC.

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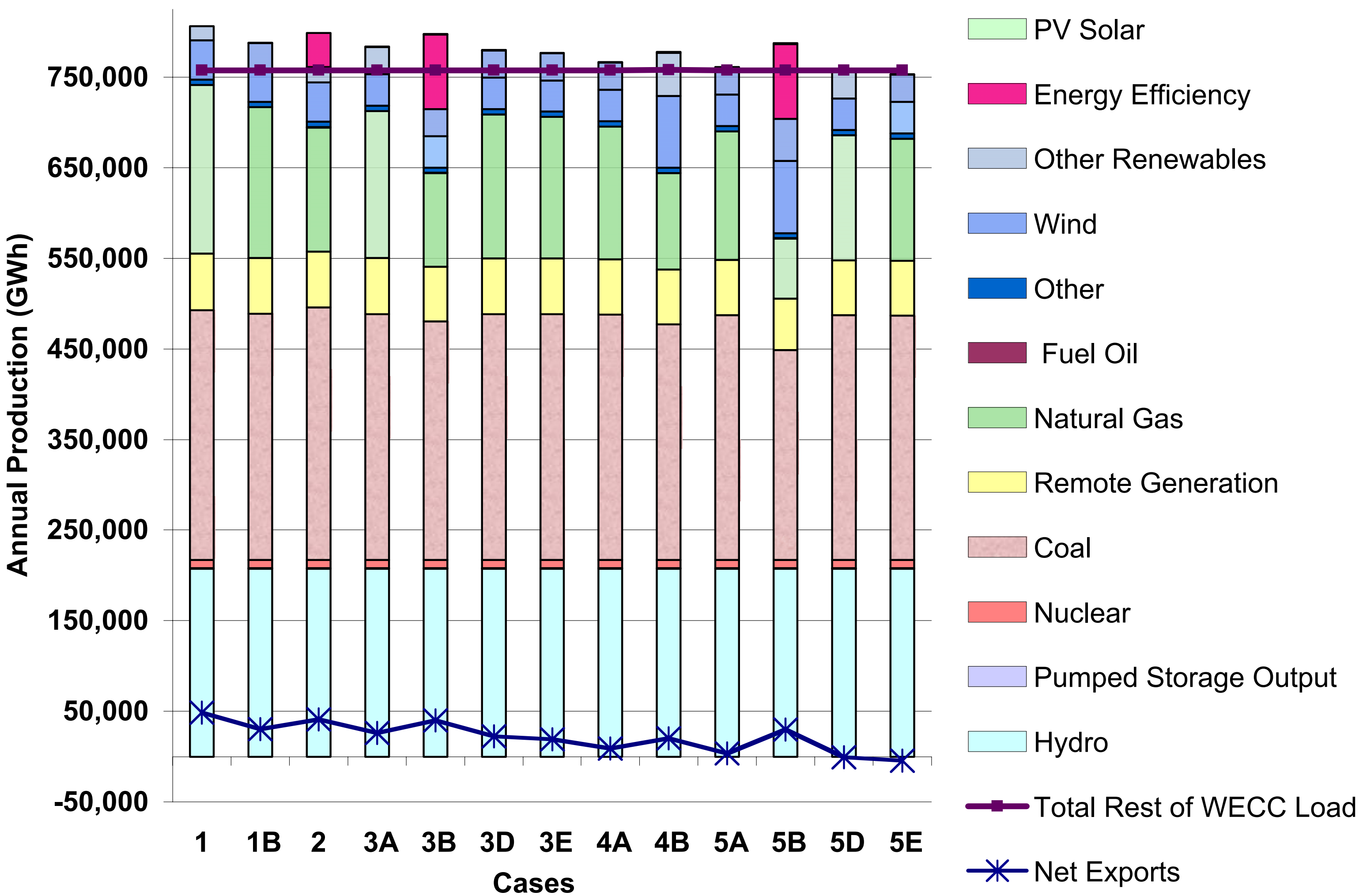
[18] The implications of these short-term market purchases have been discussed extensively in the AB 32 implementation processes, especially the joint proceeding between the CPUC and Energy Commission, because of the difficulties this sort of import creates for tracking and compliance systems.

[19] The physical system study design on which this analysis was conducted omits LSE-specific transactions, thus making it impossible to determine whether the limitations on baseload coal generation required by SB 1368 have been satisfied in all scenarios. Since only limited coal facilities are added in the entire Western Interconnection through 2020, the general intent to limit new coal contracts appears to be satisfied.

Figure 2-15: Composition of the Rest-of-WECC Generation in 2020



Source: California Energy Commission Scenario Project

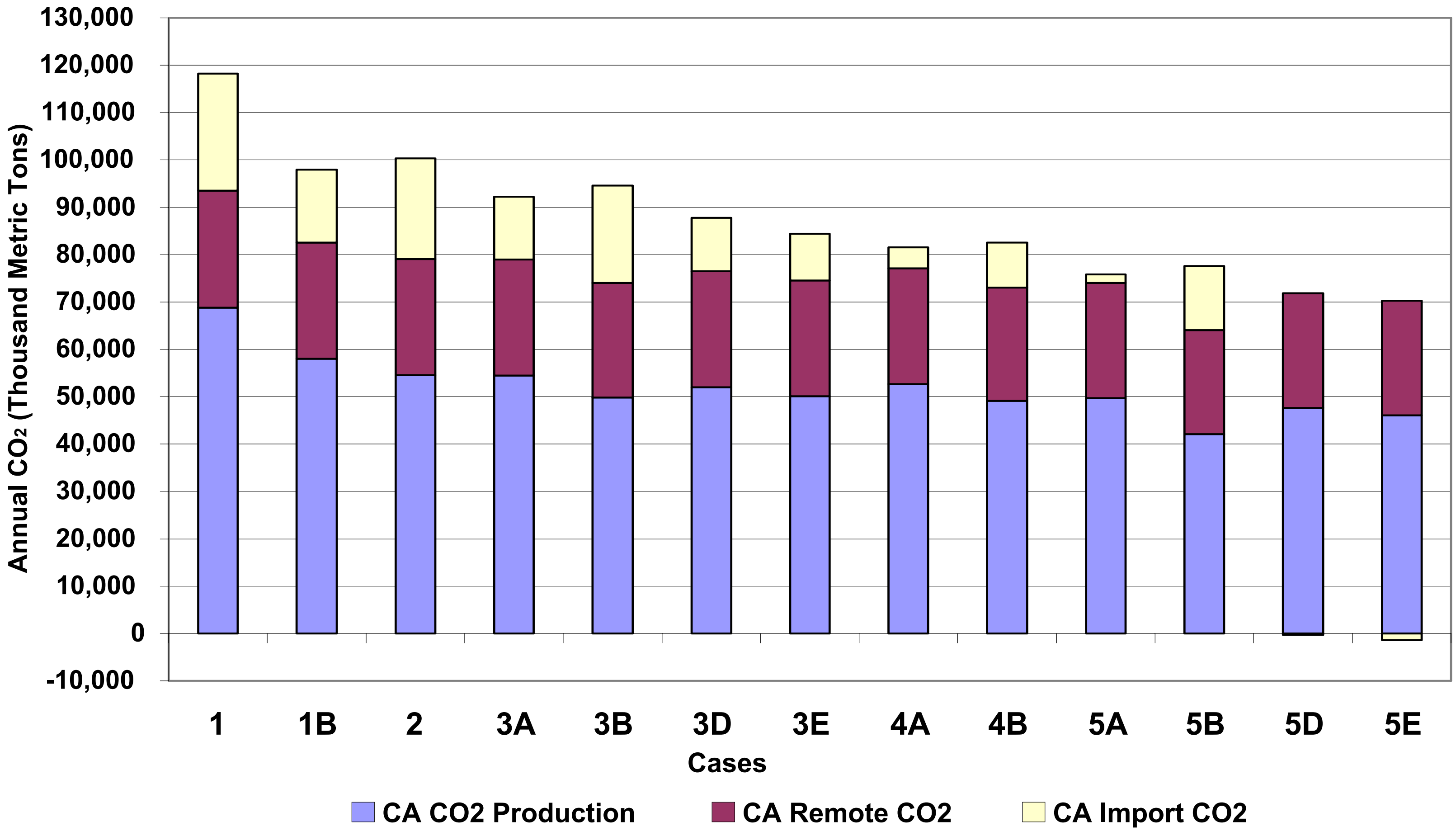
Changes in California CO_2 responsibility for 2020 in the scenarios are illustrated in Figure 2-16. A conventional resource mix in Case 1 has higher carbon emissions than Case 5E, the case with the largest amount of energy efficiency and renewables across the West. Even though the resource mix of Cases 5E and 5D are quite different regarding the amounts of natural gas consumed in California versus electricity imported into California, the level of CO_2 emissions are nearly the same. From a California responsibility perspective each of the pairs of cases—3A and 3B, 4A and 4B, and 5A and 5B—show slightly higher total emissions in the B version because of higher imports. This conclusion suggests that as long as power plant dispatch decisions continue to follow least-cost principles, and as long as CO_2 and other greenhouse gases remain un-priced attributes of electricity generation, the sources of California's CO_2 emissions are substantially affected by the resource mix and cost differences between power plants in California and those in the Rest-of-WECC.

The change over time of California in-state power plant CO_2 production is largely based on the change in natural gas-fired electricity generation. Since coal and oil are negligible sources of generation in California, only natural gas really matters as a greenhouse gas source for power plants located in- state. The "remote" power plants (in its inventory ARB refers to these as "specified imports") located outside California, but built for or contracted to serve California loads, hardly change in any scenario. Only spot market purchases (in its inventory ARB refers to those as "unspecified imports") are markedly reduced in the various preferred scenarios. Greenhouse gas emissions from imports are reduced because imports are reduced, not because the emission characteristics of imports from Rest-of-WECC make any great change.

It is important to consider California's responsibility for greenhouse gas emissions through 2020 (Figure 2-17). In Case 1, Current Conditions, natural gas-fired generation is added to meet future load growth while renewables and energy efficiency are only added in nominal amounts. As a result, the CO_2 production for Case 1 increases at a higher rate than any of the other cases with more preferred resources added. At the other end of the spectrum, Case 5E is comprised of a high level of energy efficiency and renewables in California. In this case, California in-state CO_2 emissions are the lowest and noticeably less than in Case 5B (a high energy efficiency and high renewables throughout the West.) There was no attempt to create an additional level of energy efficiency beyond Case 5B for Rest-of-WECC, because no data source to guide such a scenario was available.

It is instructive to see the difference between Case 1 (Current Conditions) and Case 1B (Current Preferred Resource Requirements). Case 1B reflects staff's interpretation of what would happen if current requirements for the three preferred strategies unfold through time. While these strategies have been pursued, in part, for reasons other than greenhouse gas emission reduction, they clearly have a profound effect. In fact, the Case 1 to Case 1B differential has a much larger effect than the incremental effect of further pursuit of these strategies.

Figure 2-16: Comparing California Carbon Dioxide Responsibility in Year 2020



Source: California Energy Commission Scenario Project

This figure also identifies how the electricity sector projections compare with an estimate of 1990 greenhouse gas emissions. The ARB has not finalized its inventory, and there are certain conventions ARB uses that do not match those of the Scenario Project, so minor adjustments to historic data have been made to assure consistency between the historic data and projected results. In making this comparison, staff does not assume ARB applies the statewide AB 32 greenhouse gas emission reduction goal proportionally to each of the five major emitting sectors. ARB will not make that decision until late 2008.

It is clear that several strategies pursued individually can satisfy the range of 1990 values (estimates prepared by the Energy Commission and ARB), if that is what ARB establishes as a goal for the electricity sector. Combinations of the preferred strategies at the levels investigated would reduce emissions below this range if ARB determines that the electricity sector should be controlled to a greater degree than other sectors.

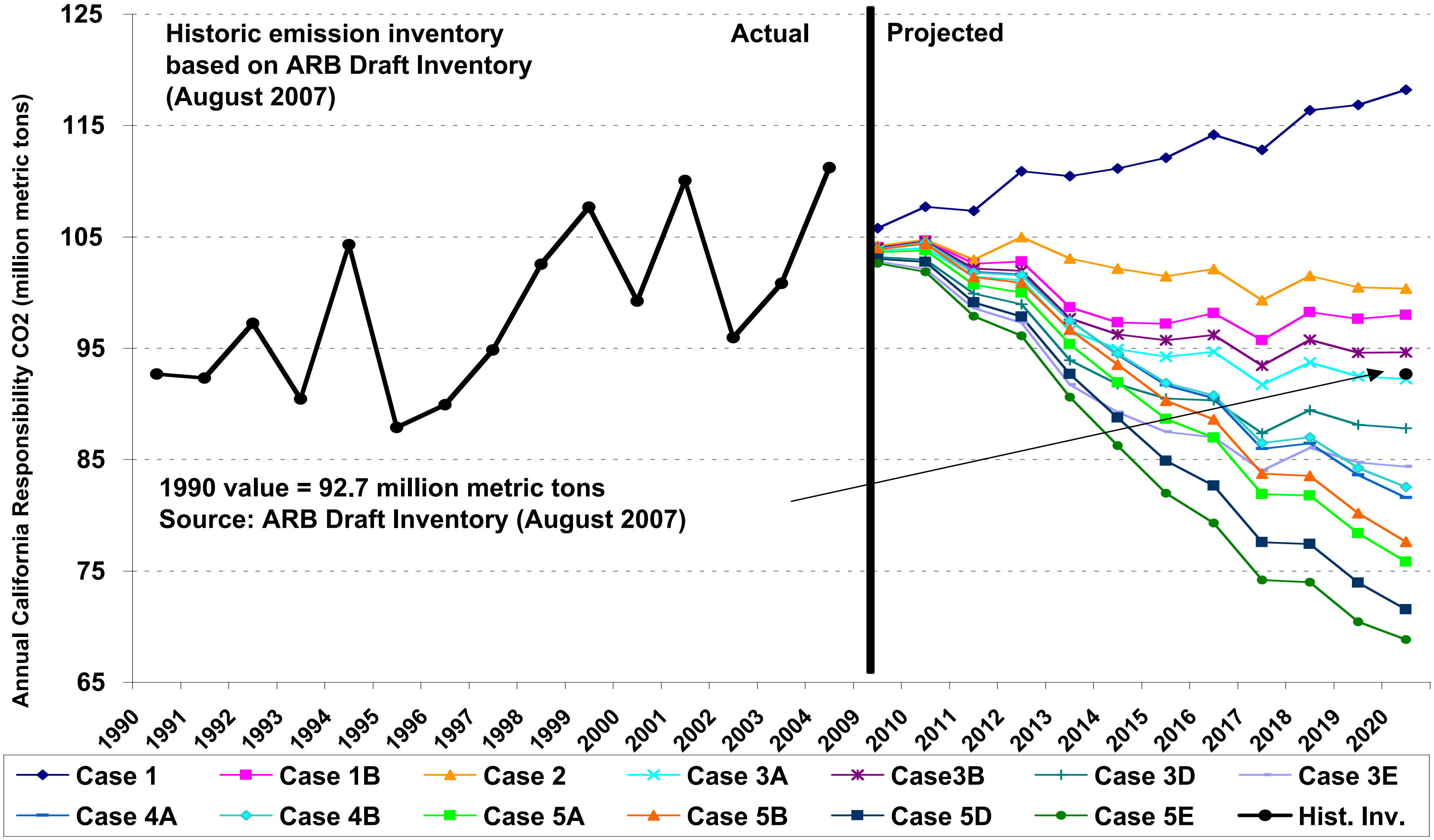
In addition, the volatility exhibited within the historic portion of Figure 2-17 makes clear the degree that hydroelectric variations can shift emissions from one year to the next. As noted in the staff analyses, any greenhouse gas compliance system has to recognize this volatility that is an inherent consequence of the generally beneficial use of hydroelectric generation in the Western electricity system.

Electricity Generation Fuel Use

Analyses were undertaken to look at the change in prospective natural gas demand as a power generation fuel in California and all the WECC (Figure 2-18). California and Rest-of-WECC natural gas use for electricity generation are comparable in volumes, even though it is proportionally more important in California. Gas consumption continues its historic increase in several scenarios, and only the ones involving more aggressive levels of both energy efficiency and renewables cause any decrease from current consumption levels.

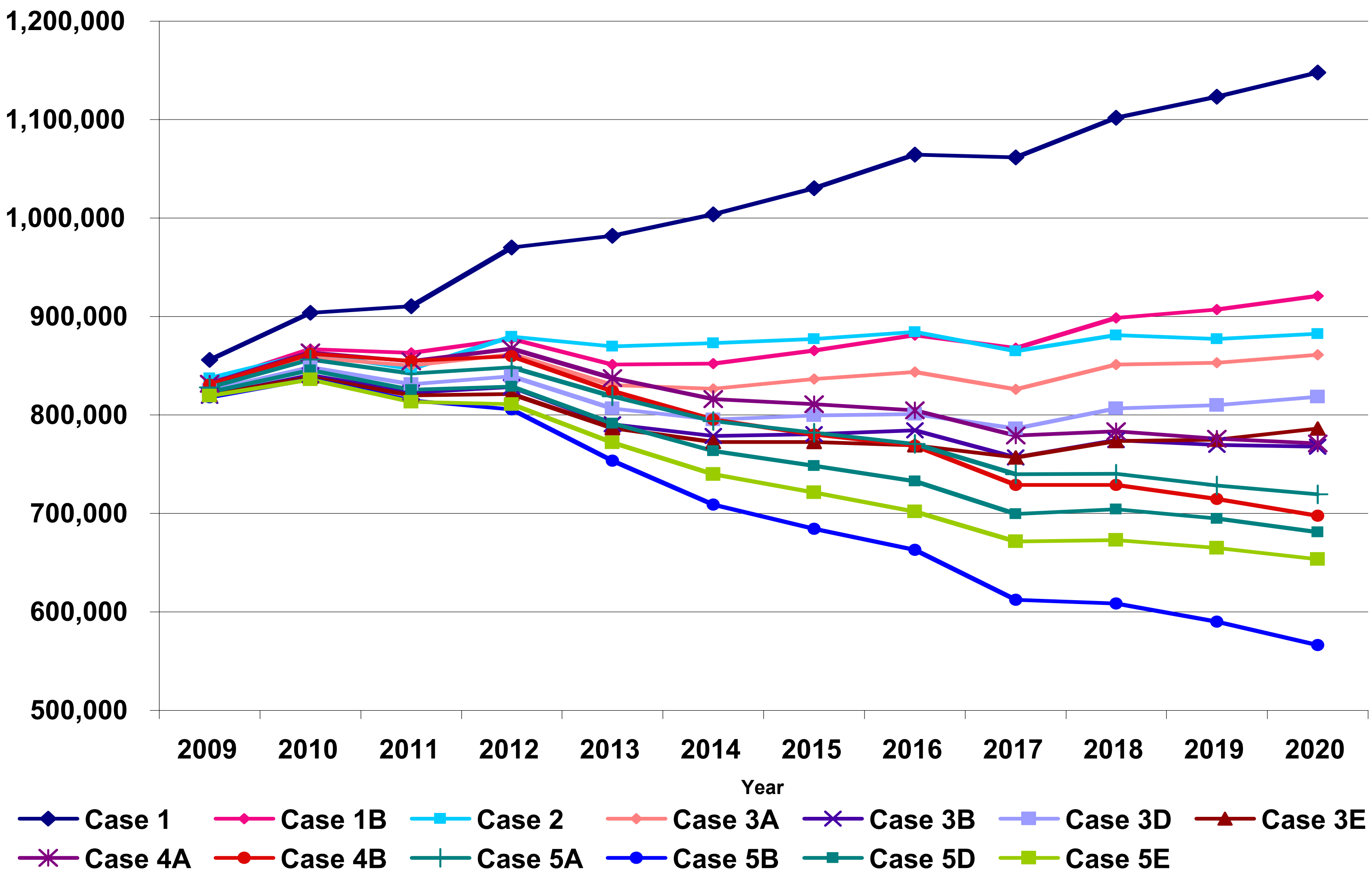
The WECC-wide coal consumption for power generation was assessed and in all scenarios but Case 5B (both high energy efficiency and high renewables on a West-wide basis) coal consumption continues to rise through time (Figure 2-19). Even in Case 5B, WECC-wide coal consumption only declines to current consumption levels. Although coal power plant development has increased somewhat in recent years, this effect is still modest, and the great majority of coal use stems from operations of existing coal plants. The coal prices described in Figure 2-12 are 5 to 10 times lower on a dollar per million Btu basis than the corresponding natural gas prices shown in Figure 2-11. Absent a carbon cost adder affecting dispatch, an actual carbon tax on usage, and/or explicit constraints on coal use, coal power generation prices are so much lower than natural gas prices that coal will continue to be dispatched regardless of resource additions promoted by policy makers.

Figure 2-17: California Carbon Dioxide Responsibility through Time by Case (Includes In-State Generation, Remote Generation, and Net Imports)



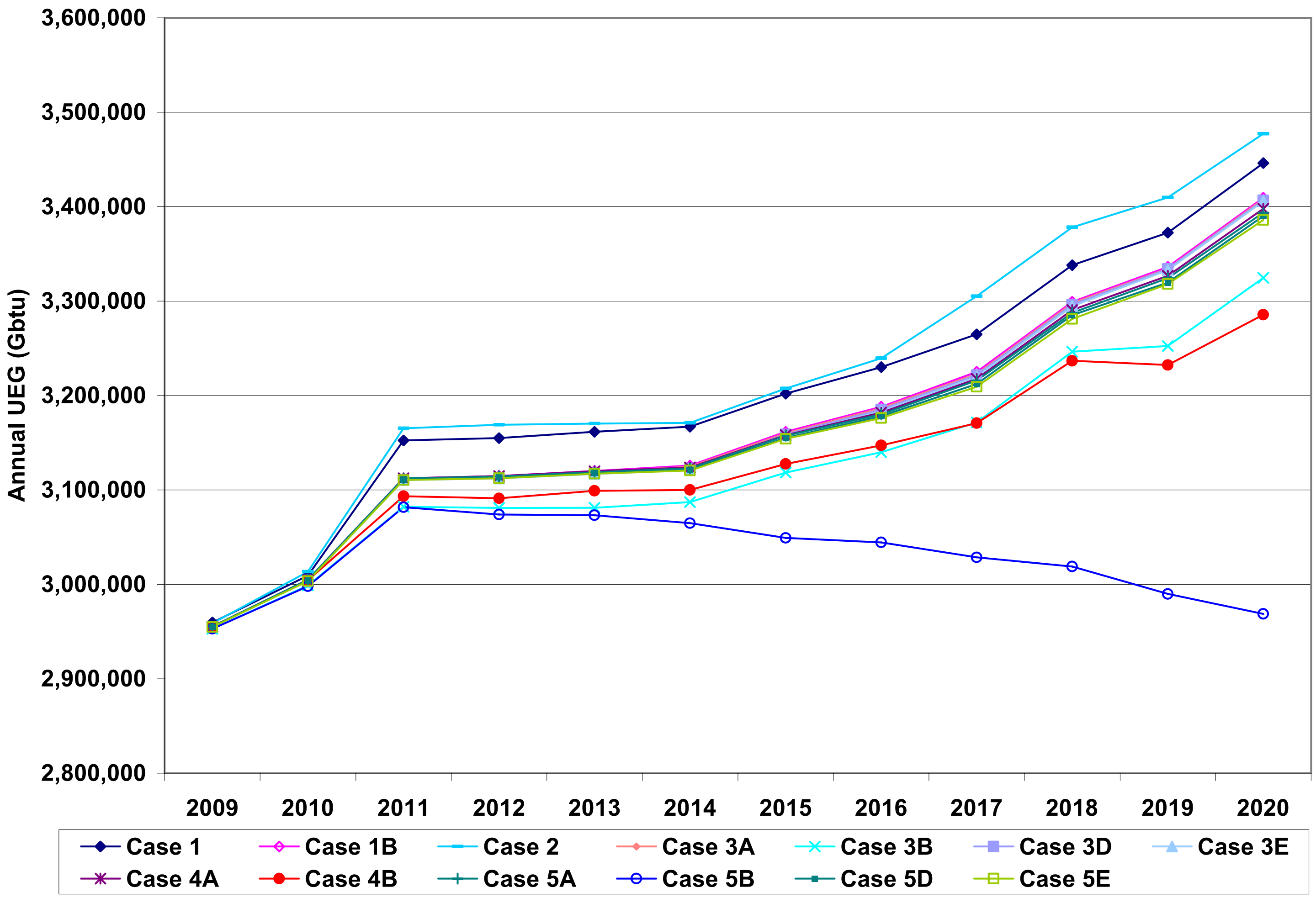
Source: Global Energy Decisions, Inc. and California Energy Commission

Figure 2-18: Total California Gas Consumption (Billion BTu)



Source: California Energy Commission Scenario Project

Figure 2-19: Total WECC Coal Consumption (Billion BTu)



Source: Global Energy

Reliability

Because of the large amounts of non-dispatchable capacity added in several scenarios, reliability was built into the design of the scenarios and tested. Staff used a simplified version of California's resource adequacy requirements to assure that each control area satisfied a 15 percent planning reserve margin while using dependable capacity values for wind and solar without backup. When dispatchable resources failed to satisfy the 15 percent threshold, combustion turbines were added or additions in transmission line capacity were made.

Staff tested reliability using standard loss of load techniques in Scenario 4B (the one most likely to confront these issues because of its reliance on high levels of renewables and high loads through no increased preference for energy efficiency), but found no expected un-served energy.[20] Further examination showed that actual resources exceeded planning reserve margin targets in all years, since the dependable capacity of the resources added exceeded the capacity of the generic resources removed when the scenarios were constructed.[21] This result suggests that adding renewable resources like in Case 4A or Case 5A, even though they are not dispatchable, does not create reliability problems. Staff's supplemental analyses of retiring aged power plants in Southern California, while problematic from the perspective of assessing retirement rather than repowering, found that some dispatchable capacity could be retired and not replaced and still satisfy reliability standards, if appropriate transmission upgrades were made to allow renewables to be more effective.[22]

Utilities remain concerned about operational issues, especially those connected to retirement of aging power plants and replacement with renewables located at a distance from load centers, and whether the full set of transmission line additions needed to support this pattern of resource build out has been adequately assessed.[23] As further discussed in Chapter 4, the Energy Commission supports more studies of the operational issues associated with renewables development. The Energy Commission believes such studies are critical to either dispel outdated concerns or to identify real problems with renewable development of the scale examined by these scenarios.

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[20] Expected un-served energy measures the annual amount of electricity consumption that end-users desired, but could not receive, through generation or transmission outages.

[21] Third Addendum Report, Chapter 4, and Appendix D.

[22] Second Addendum Report, Chapter 2, and Appendix A.

[23] SCE, *Aging Plant Retirements*, August 16, 2007 IEPR Committee Workshop.

Table 2-1: Summary of Transmission Additions by Scenario

		Case 1 Addition		Case 1B Addition		Case 4A Addition		Case 4B Addition		Case 5B Addition	
From Trans. Area	To Trans. Area	Year	Increase (MW)	Year	Increase (MW)	Year	Increase (MW)	Year	Increase (MW)	Year	Increase (MW)
Alberta N	Alberta S	2007	200	2007	200	2007	200	2007	200	2007	200
Alberta N	Alberta S	2009	1,200	2009	1,200	2009	1,200	2009	1,200	2009	1,200
PV	Arizona	2007	1,200	2007	1,200	2007	1,200	2007	1,200	2007	1,200
PV	Devers#2	2009	1,200	2009	1,200	2009	1,200	2009	1,200	2009	1,200
Alberta S	Montana			2008	300	2008	300	2008	300	2008	300
Alberta S	Montana			2014	500	2014	500	2014	500	2014	500
Alberta S	BC			2016	500	2016	500	2016	500	2016	500
Arizona	S. Nevada			2009	1430	2009	1430	2009	1430	2009	1430
BC	Northwest			2009	500	2009	500	2009	500	2009	500
IID	SCE			2009	1000	2009	1000	2009	1000	2009	1000
Imperial	SDG&E			2010	1150	2010	1150	2010	1150	2010	1150
Montana	Northwest			2011	500	2011	500	2011	500	2011	500
Montana	Northwest			2013	500	2013	500	2013	500	2013	500
SCE	SCE			2012	Tehachipi upgrades	2012	Tehachipi upgrades	2012	Tehachipi upgrades	2012	Tehachipi upgrades
SCE	SCE			2012	Pisgah upgrade #1	2012	Pisgah upgrade #1	2012	Pisgah upgrade #1	2012	Pisgah upgrade #1
Wyoming	Idaho			2010	700	2010	700	2010	700	2010	700
Wyoming	Utah			2011	500	2011	500	2011	500	2011	500
Wyoming	Idaho			2012	800	2012	800	2012	800	2012	800
Wyoming	Utah			2013	500	2013	500	2013	500	2013	500
IID	SCE					2015	500	2015	500	2015	500
SCE	LADWP					2015	500	2015	500	2015	500
SCE	SCE					2017	Pisgah upgrade #2	2017	Pisgah upgrade #2	2017	Pisgah upgrade #2
IID	IV-NG*					2015	700	2015	700	2015	700
Idaho	N Nevada							2018	500	2018	500
Montana	Wyoming							2018	500	2018	500
New Mexico	Arizona							2018	1600	2018	1600
Northwest	Idaho							2015	500	2015	500
Wyoming	Utah							2013	1200	2013	1200
Wyoming	Colorado (E)							2015	500	2015	500
Wyoming	Colorado (W)							2017	500	2017	500
New Mexico	Arizona									2013	900
Wyoming	Utah									2015	500

Transmission Additions

Load growth, merchant plant generation development patterns and supply-side renewable generating technology policy preferences imply various levels and configurations of transmission development. The scenario project identified necessary transfer capacity upgrades as part of each scenario (Table 2-1).

The emphasis on renewable generating development in Case 1B compared to Case 1 indicates that significant upgrades are needed between various transareas around the West and to a lesser extent within California. Despite its attractiveness from many perspectives, energy efficiency does not displace the need for these transmission additions. As an example, the two additions required in Case 5B are in addition to those of Case 4B because generic power plant additions still included in Arizona and Utah in that case can be displaced by imports from New Mexico and Wyoming with the additional transmission upgrades.

While the specific projects identified should not be considered for definitive planning studies, the variations on the chart reveal the strong interaction between generation development and transmission development. The Energy Commission is not the originator of this concept, but since its *2003 Integrated Energy Policy Report* has emphasized the need for increased attention for coordination among the entities responsible for transmission planning to make efforts to understand the nature of the generation build out framing transmission needs. Where there is clarity, transmission planning can proceed rapidly. Where there is ambiguity about generation development, multiple scenarios explicitly linking generation build out assumptions and complementary transmission needs must be prepared and provided to decision makers. The precise nature of the methodologies used to perform this linked analysis is less important than the need for linkage to be examined and understood.

Costs

Achieving these greenhouse gas emission reduction benefits is not without cost in some areas. Figure 2-20 provides the results of the analysis on levelized system costs for the scenarios under the control of California policy makers. These results assume that technology cost and performance stay constant through time, except for rooftop solar photovoltaic that is assumed to decrease by 50 percent.[24] With this significant caveat, total system costs tend to increase as greater proportions of renewables satisfy electricity requirements. Production costs tend to decrease as energy efficiency plays a larger role.

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[24] The Scenario Analyses project used capital and other fixed cost estimates by technology, except for coal generation, from the Cost of Generation Study, which is the most recent study available. That study found significant cost increases in recent years for a wide range of generating technologies.

The modeling results clearly reveal a capital cost versus production cost tradeoff that reflects total cost reductions for energy efficiency and total cost increases for renewables.

On a levelized cost basis, the three scenarios defined by higher energy efficiency are slightly less expensive than the current requirements case, but when the renewable component is added there is a noticeable increase in system costs per unit compared to what it would have been under current policies. This result stems in part from the higher costs assumed for the significant distributed rooftop PV included in these scenarios. Care must be taken when computing levelized cost and considering energy efficiency and end-user renewable resources because these activities reduce sales, thereby naturally raising levelized costs if only the remaining "purchased" electricity is considered. Figure 2-20 depicts energy efficiency and solar PV as resources, including their total energy contributions, which make the comparison more direct.[25] In addition, costs of these resources are partially covered by end-user contributions rather than entirely through general ratepayer cost recovery.

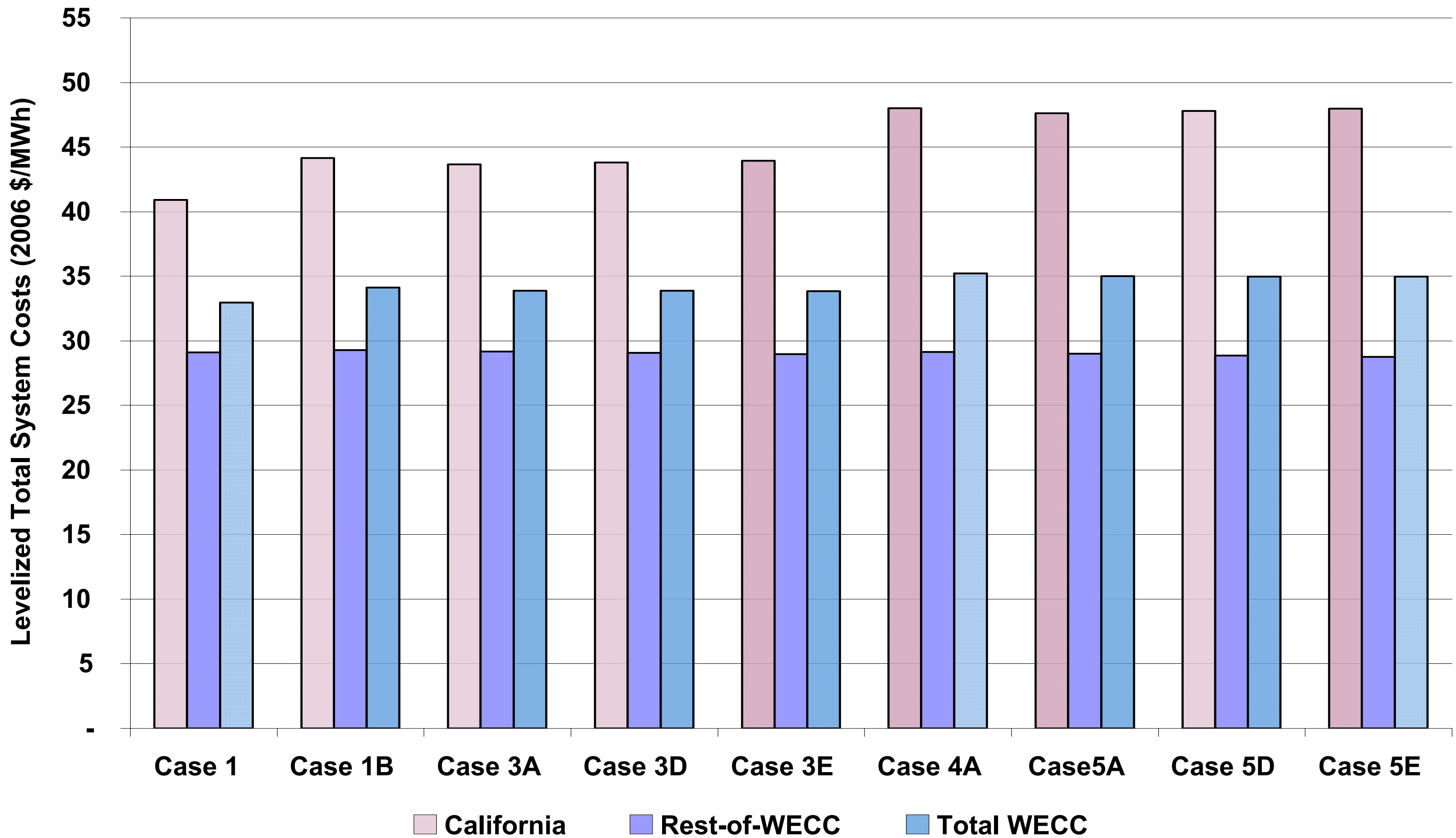
Sensitivities Revealing Implications of Uncertainty

Staff has rightly cautioned that many uncertainties affect the results. Most of them were not investigated for lack of time, resources, and data. However, staff believes the fundamental uncertainties that were addressed—fuel prices and hydroelectric generation—are sufficient to demonstrate that the results are sensitive to input assumptions.

A concise summary of the sensitivity of cost and greenhouse gas emissions relative to fuel price and hydroelectric generation were undertaken (Table 2-2). The hydroelectric generation range that staff examined is as extreme as it could be, the WECC-wide generation maximum corresponding to high hydro conditions and the lowest generation corresponding to adverse hydro conditions. Intuitively, costs are more sensitive to fuel price variations from baseline projections, while greenhouse gas emissions are more sensitive to the change in expected hydro-electric generation resulting from very dry or very wet precipitation patterns. A greenhouse gas emission reduction program must accommodate itself to the sort of swings in greenhouse gas emissions shown in California CO_2 column.

[25] Third Addendum Report, Table 8, p. 26.

Figure 2-20: Levelized System Costs ($2006/MWh)



Source: California Energy Commission Scenario Project

Table 2-2: Summary of California System Costs and Carbon Emissions for Year 2020

Thematic Scenarios		Calif. System Costs			Calif. Carbon Emissions		
		Low NG	Base	High NG	Low NG	Base	High NG
Case 1 - Current Conditions	High Hydro		16,164,681			69,142	
	Base	12,265,962	16,684,128	19,177,074	74,630	75,803	76,034
	Low Hydro		16,875,608			79,968	
Case 1B - Current Requirements	High Hydro		15,945,868			58,866	
	Base	13,004,270	16,354,098	18,224,842	63,100	63,907	63,850
	Low Hydro		16,507,640			67,441	
Case 3A - High EE in Calif. Only	High Hydro		15,299,757			55,124	
	Base	12,617,673	15,701,704	17,434,336	59,156	60,032	60,221
	Low Hydro		15,843,813			63,401	
Case 3B - High EE West-wide	High Hydro		15,077,660			49,691	
	Base	12,569,545	15,576,942	17,257,192	55,004	54,868	54,762
	Low Hydro		15,757,903			57,804	
Case 4A - High Renewables in Calif. Only	High Hydro		18,617,701			53,438	
	Base	16,452,327	18,935,010	20,318,987	57,233	58,078	58,338
	Low Hydro		19,039,752			60,914	
Case 4B - High Renewables West-wide	High Hydro		18,501,518			49,585	
	Base	16,443,014	18,904,156	20,272,379	53,804	54,172	54,268
	Low Hydro		19,055,587			56,826	
Case 5A - High EE and Rewables in Calif. Only	High Hydro		18,121,512			50,467	
	Base	16,184,232	18,407,604	19,636,497	54,047	54,836	55,030
	Low Hydro		18,491,545			57,592	
Case 5B - High EE and Rewables West-wide	High Hydro		17,799,534			42,429	
	Base	16,145,825	18,238,302	19,369,073	46,848	46,356	46,068
	Low Hydro		18,450,465			49,318	

Source: California Energy Commission

Initial Examination of Carbon Dioxide Cost Adder

At the IEPR Committee's request, staff conducted an abbreviated analysis of the impact of a carbon dioxide adder on the dispatch of a known resource mix. Such an analysis, of course, is not the comprehensive assessment of a carbon adder or carbon tax on the build out of the electricity system.

Figures 2-21 and 2-22 provide an overview of the degree to which resources are re-dispatched when a carbon dioxide cost adder of various levels affecting unit commitment and dispatch is imposed upon a given resource mix. Carbon dioxide cost adders from $10 per metric ton to $60 metric ton were explored, with only very slight responses when the carbon cost adder is at levels of $10 and $20 per metric ton. Both figures show that meaningful displacement of coal generated power begins when the adder reaches $30 to $40 per metric ton of CO_2.[26] Both the conventional resource mix (Case 1) and a resource mix with high levels of energy efficiency and renewables (Case 5B) show that natural gas-fired power plants increase generation to replace coal-fired generation.

Perhaps more importantly, since it once again illustrates the interconnectedness of the electricity system in WECC, natural gas-fueled plants in California are a principal means to displace generation from coal plants in Rest-of-WECC in this re-dispatch analysis. As natural gas plant use increases in California, this would increase both greenhouse gas and criteria pollutant emissions. Staff's initial analysis of this issue for 2020 shows that even in Case 5B (high energy efficiency and high renewables throughout the West) California natural gas-fueled plants would supply more than half of the entire increase in electricity generation displacing more expensive coal.

This initial result requires considerably more analysis, beyond the timeframe of the *2007 IEPR*, and it illustrates one of the themes flowing from the staff's assessment — that is, California is unlikely to accomplish its electricity sector greenhouse gas emission reduction goals in isolation from Rest-of-WECC. The Energy Commission should communicate these initial results to the ARB and CPUC and undertake additional studies to better understand the implications of various prices attached to CO_2 emissions in the future.

Implications of the Results

Table 2-3 provides an overview of the incremental effects of those cases that California policy makers could pursue alone (Cases 3A, 3D, 3E, 4A, 5A, 5D, and 5E) compared with Case 1B—essentially business as usual. Case 1B reflects staff's expectations of load-serving entity compliance with current requirements or current practice. All of the remaining cases compared to Case 1B reflect the cost and performance differences of these additional emphases on energy efficiency and renewables. Table 2-3 also computes a simple statistic of effectiveness. It measures greenhouse gas emission reductions per thousand dollars of expenditure.

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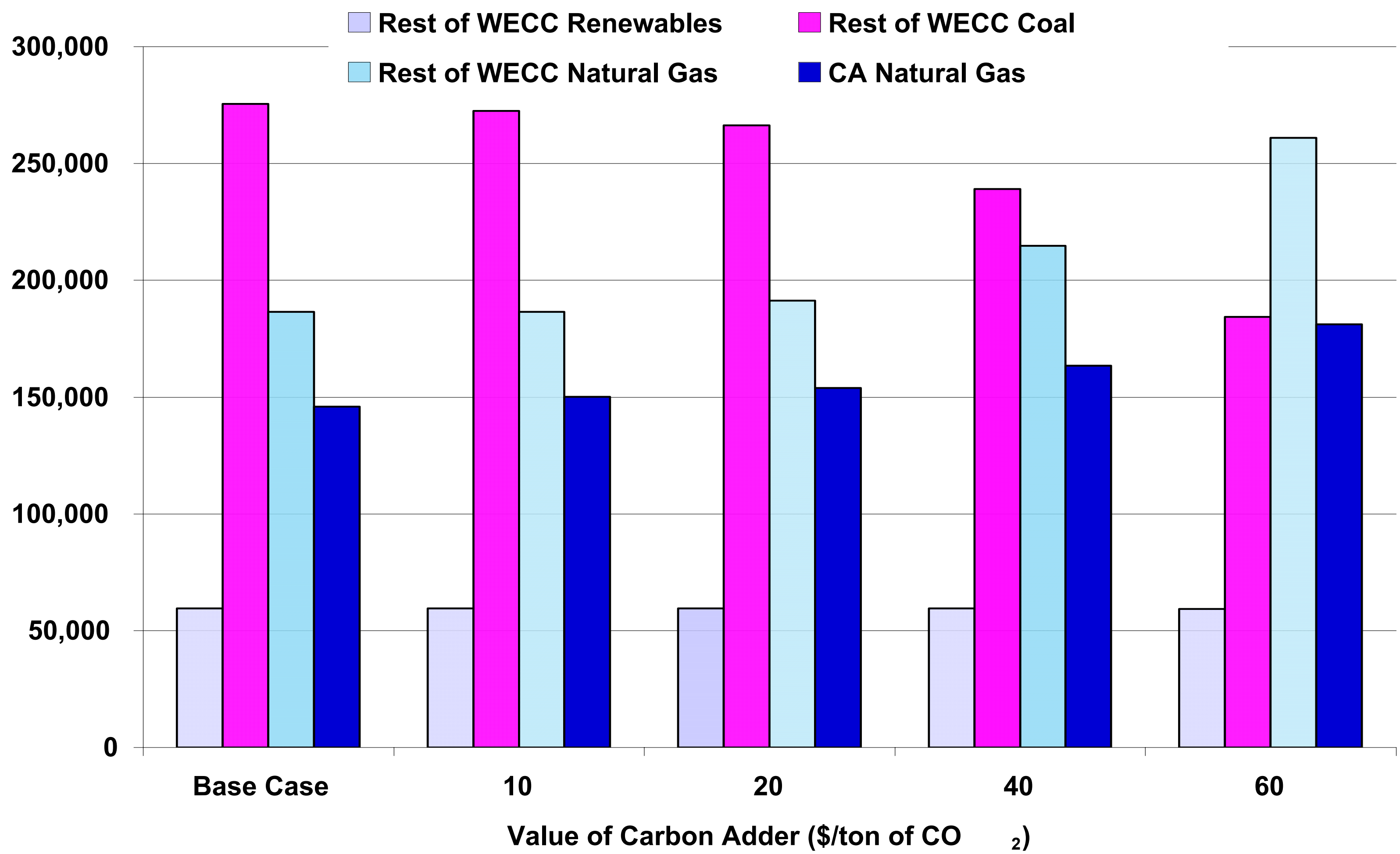
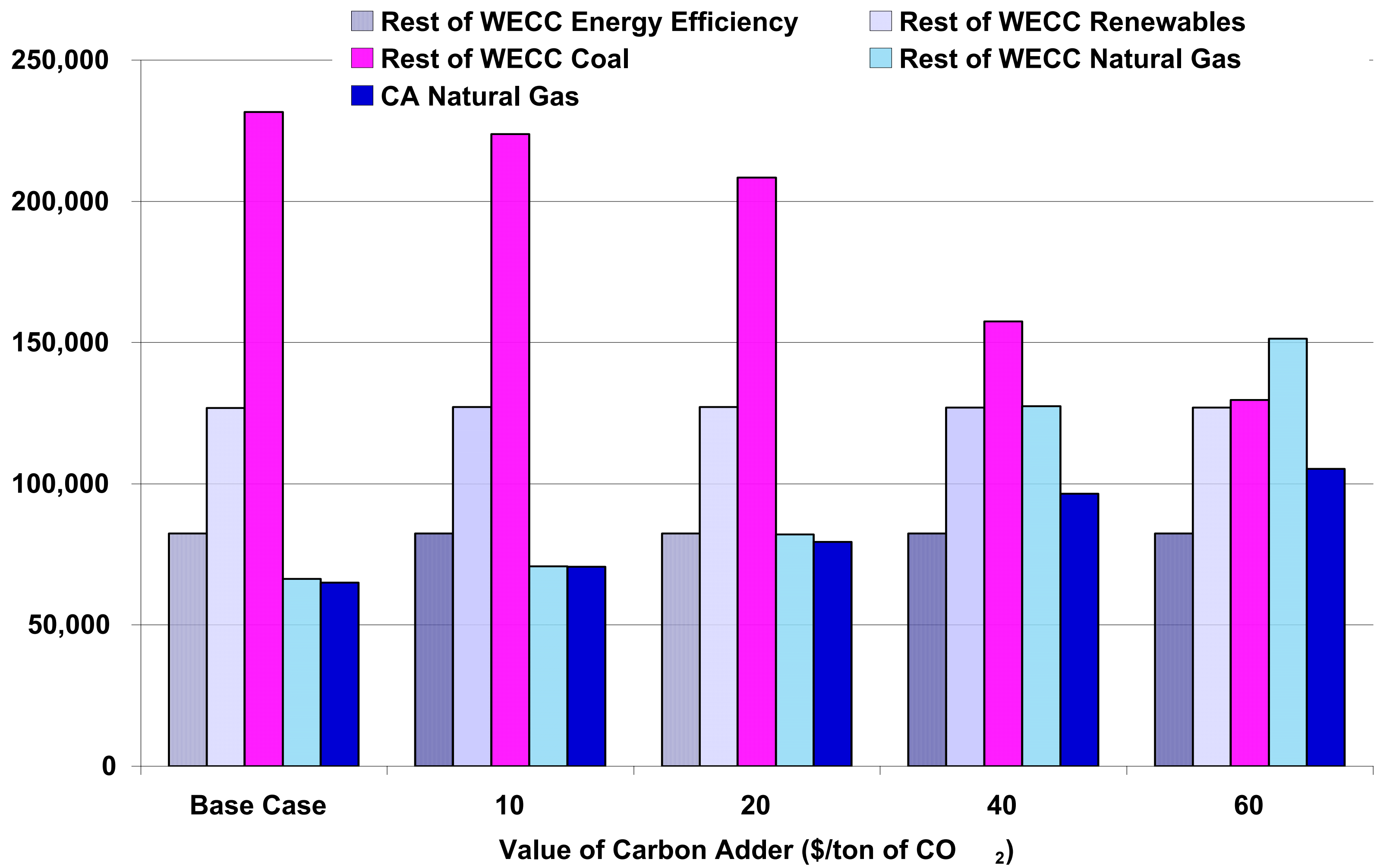
[26] Third Addendum Report, Chapter 3.

Figure 2-21: Case 1 Annual Generation (Gigawatt Hours) 2020



Source: Global Energy Decisions

Figure 2-22: Case 5B Annual Generation (Gigawatt Hours) 2020



Source: Global Energy Decisions, Inc.

Table 2-3: Measuring Cost Effectiveness of Strategies by Assessing Differences from Case 1B

	2020 System Cost Difference	2020 GHG Instate Emission Difference	2020 Reduction ($/ton)	2020 GHG California Responsibility Emission Difference	2020 Reduction ($/ton)
Case 1B	-	-	NA	-	NA
Case 3A	(652,394)	(3,876)	(168.34)	(6,324)	(103.17)
Case 3D	(1,172,584)	(6,624)	(177.01)	(11,196)	(104.73)
Case 3E	(1,569,955)	(8,691)	(180.63)	(14,994)	(104.71)
Case 4A	2,580,912	(5,829)	442.75	(18,085)	142.71
Case 5A	2,053,506	(9,071)	226.37	(24,429)	84.06
Case 5D	1,554,921	(11,411)	136.26	(29,105)	53.42
Case 5E	1,164,144	(13,140)	88.59	(32,100)	36.27

Source: Global Energy Decisions, Inc.

The three levels of energy efficiency (Cases 3A, 3D, and 3E) reflect successively increasing levels of greenhouse gas reduction by 2020. The cost per unit of greenhouse gas reduction from alternative levels of energy efficiency is relatively constant. Most importantly, the cost is negative, meaning that society is better off with these higher levels than without them even without a carbon cost adder being included. Energy efficiency is less costly than the generating resources it displaces, so not only does it provide a public good in emission reductions, it provides a collective good to the ratepayers funding the activities by saving more in direct fuel expenses and deferred capital cost recovery than the costs of the programs.

A renewables strategy (Case 4A) is clearly more costly per unit of greenhouse gas reduced than is an energy efficiency strategy alone. Here, the rooftop solar photovoltaic costs and benefits are combined with supply side renewable generating technologies. The combined cases (Cases 5A, 5D, and 5E) blend the reduced expenditures for electricity customers with the increased outlays of Case 4A to get both higher total greenhouse gas reductions as well as lower increases in aggregate electricity costs than those from Case 4A alone. From this perspective, Cases 5D and 5E are also preferred to Case 5A since the increased levels of energy efficiency dilute the out-of-pocket costs to electricity consumers while achieving greater aggregate greenhouse gas emissions reductions.

Table 2-3 also illustrates the distinction between instate power generation versus the broader view of California's responsibility for all generation that supports California loads. The California Responsibility columns of Table 2-3 always show much lower dollar per ton of savings results than the instate generation columns because the same expenditures necessary for the preferred measures affect both instate and out-of-state generation. For example, the Case 4A result for renewables measures greenhouse gas savings just for instate power plant greenhouse gas reductions costs over $400 per ton, while taking total power generation emission reductions into account reduces this cost per ton to only $140 per ton. Similar effects are shown for all of the cases in varying degrees, because the preferred strategies always have both in-state and out-of-state power generation greenhouse gas emission reductions.

The results have driven home the reality of California's interconnectedness with the rest of the West that is too easily forgotten in enthusiasm of greenhouse gas emission reduction strategies. It is critical in the near-term to solidify the regional framework initiated by Governor Schwarzenegger with other western states and Canadian provinces. The Energy Commission welcomes the formation of the Western Climate Initiative as noted in the recent joint CPUC and Energy Commission decisions implementing AB 32. The decisions California makes affect other areas of the West and vice versa.

The ARB process for implementing AB 32 should be grounded in the type of analysis conducted in this project. The CPUC modeling project that intends to identify a specific set of measures that individual load-serving entities can use to comply with the goals established for them by ARB appears to be making use of the analysis and placations developed at the Energy Commission. Staff should make every effort to develop cooperative working relationships with ARB and CPUC that can routinely illuminate the California-wide and WECC-wide consequences of greenhouse gas emission reduction strategies. This project and its successor editions complement the more emitter-specific analyses those regulatory agencies will conduct.

Findings of the Assessment

Although staff's study improves upon weaknesses of previous studies, the results suggest impacts rather than forecast them. The study findings are only indicative because of scientific, technological, and institutional uncertainties. Despite staff's caveats, the following findings of this study are sufficiently robust to communicate as part of this IEPR:

- Each of the policy-driven cases which increases the investment in efficiency and renewables beyond current requirements seems likely to fall within the range of 1990 CO_2 emissions. The more intensive preferred resource scenarios would enable a higher contribution to AB 32's 2020 goals than attaining 1990 levels.
- Reductions in fossil generation that result from increased penetrations of efficiency and renewables are attributable to the displacement of production from some existing fossil-fueled generation facilities as well as the deferral or elimination of some anticipated fossil facilities.[27]
- Unless costs affecting power plant dispatch are revised, or other dispatch priorities are otherwise affected, natural gas is found to be the swing fuel in nearly all cases, with coal-based electric generation little affected by simply increasing the levels of energy efficiency and renewables in the resource mix, either in California or Rest-of-WECC.[28]
- Given the assumptions inherent in this Scenario Analyses Project, existing coal generation will be affected by the imposition of a carbon dioxide "adder," whether by cap and trade or tax, but meaningful reductions (10 percent or greater) do not occur until the value reaches $30 to $40 per ton of CO_2.[29] The displaced coal generation would be replaced by higher generation from natural gas-fueled power plants, both in California and Rest-of-WECC.[30]
- Increased penetration of preferred resources that significantly reduces natural gas usage compared to the overall market can drive down natural gas market-clearing prices, but the magnitude of this result is sufficiently uncertain to be unreliable at this time.[31]

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[27] Results Report, Chapter 7.

[28] Results Report, p. 120.

[29] Third Addendum, p. 30.

[30] Third Addendum, p. 29.

[31] Second Addendum, p. 30.

Portfolio Analysis

Electricity industry restructuring, along with the changes in regulatory requirements and the financial and economic considerations it has effected, has greatly increased risks and added to the uncertainties that utilities and regulators must consider. In the days before industry restructuring, investor-owned electric utilities could construct, own, and operate new capacity to match their electricity generation and reliability needs. Utility ownership of generation and transmission, combined with an authorized rate of return, limited their financial risks. Although fuel costs could be a significant portion of total costs, they were relatively low and less volatile than they are today.

Today's environment calls for an electric resource planning process that includes the variety of options, risks, and uncertainties that utilities must consider in evaluating potential resource additions. Choosing a resource addition based on current lowest-cost projections is no longer adequate if the potential for dramatically higher prices is ignored. As Graves, et al., point out in their paper *Resource Planning and Procurement in Evolving Electricity Markets*:

> In particular, the old IRP (Integrated Resource Planning) model generally did not incorporate risk management considerations akin to those now central to utility planning. Perhaps a few scenarios were evaluated, but there was no need to measure and manage dynamically shifting probability distributions for future market prices or utility costs.[32]
>
> The new procurement and planning problem combines traditional least-cost goals with new risk-management objectives. Least-cost planning involves developing a portfolio of resources that has the lowest expected future cost (that is, on average), subject to achieving a given quality of service…Risk management, on the other hand, involves ensuring that the portfolio of power plants, contracts, and financial risk management instruments reduces foreseeable variance (or more generally, uncertainty) around the future expected cost.[33]

Current Investor-Owned Utility Practices

The CPUC recognizes the importance of managing risk by requiring investor-owned utilities to prepare risk reports for their existing portfolios based upon Value at Risk

[32] Graves, Frank C., James A. Read, and Joseph B. Wharton, The Brattle Group. 2007. *Resource Planning and Procurement in Evolving Electricity Markets*, p. 19. Prepared for Edison Electric Institute, January 21, 2007.

[33] Ibid., p. 21.

methods. However, these methods address primarily the level of short-term fuel-related risk to which the investor-owned utilities' existing portfolios are exposed and are used to provide guidance regarding the need for additional hedging activities over the short to mid term. They are not used for constructing and analyzing a variety of portfolios over the longer term, with the goal of providing guidance regarding the efficiencies of those portfolios and the acquisition of new resources.

As the *2005 IEPR* pointed out, investor-owned utilities currently use opaque least-cost, best-fit criteria to select bids from their solicitations, and the criteria ostensibly focus on ensuring that selected bids match the baseload, peaking, and other physical characteristics of system needs. Filing of procurement plans is required at the CPUC every two years. The plans describe planning and procurement activities the investor-owned utilities will undertake over the succeeding 10-year period. While these plans loosely conform to general requirements specified by Assembly Bill 57 (Wright), Chapter 835, Statutes of 2002, and CPUC orders, they vary greatly in their methodologies and assumptions.

Each investor-owned utility has developed its individual methods to calculate and weigh the criteria, including resource or market value, portfolio fit, credit, viability, transmission impact, debt equivalence, and non-price terms and conditions. Consequently, the criteria are not universally transparent and require a high degree of subjective interpretation and judgment.

As one example of the varying assumptions used by the different investor-owned utilities in their planning processes, Table 2-4 presents their estimates of the 95th percentile natural gas price from 2010 – 2016. In the near term (2010), investor-owned utility estimates of natural gas prices vary by as much as 67 percent. By 2016, projected prices vary by 84 percent. Investor-owned utility estimated gas price trends from 2010 to 2016 ranged from a decrease of 15 percent to an increase of 16 percent over the period.

Table 2-4: Reported Natural Gas Prices (95th Percentile, Nominal $)

	2010	2013	2016
PG&E	$17.09	$16.30	$17.21
SCE	$10.21	$10.61	$11.87
SDG&E	$11.06	$9.90	$9.36

Source: Investor-Owned Utility Long-Term Procurement Plans filed with the CPUC December 11, 2006.

The difference in the investor-owned utilities' estimated natural gas prices may reflect different methodologies or input assumptions (for example, historical period used for data, functional form) or, to a small extent, actual differences in the volatility of the gas price faced by each utility. Nevertheless, it is unrealistic that individual utilities could be exposed to such differences in the long-run cost of natural gas, one of the more fundamental planning assumptions; nor is such a wide divergence helpful in formulating statewide energy policy. Additionally, investor-owned utility gas costs are normally passed along to ratepayers; under current regulatory rules unexpectedly high prices do not unduly burden shareholders. The corrosive influence of "moral hazard," where decisions are made by entities that are financially insulated from the consequences of those decisions, should be obvious.

The impact of longer-run changes in the price of natural gas cannot be mitigated using traditional financial instruments, nor do longer-run changes have the predictability of short-run changes. The price of natural gas over the longer term will depend on technological, economic, and political factors whose joint impact cannot be easily ascertained. Long-run natural gas price volatility will likely increase over time for several reasons, including increased reliance on remote resources and the risk that consumption in the eastern U.S. could rise dramatically from the curtailment of coal-fired generation due to greenhouse gas concerns, which could further strain the tight U.S. natural gas supply.

If the underlying probability distributions for key drivers of ratepayer costs vary significantly by utility, these variations can be incorporated into an analysis of each utility's portfolios. For example, small differences in expected gas prices can be assumed if indicated, but the broader range of gas prices over which portfolios are evaluated should be similar for each utility. This will not only provide policy makers with a basis for comparing the performance of each portfolio under a common set of futures, but will encourage development of a wider range of portfolios to analyze. While the resource planning process should provide an opportunity for utilities to present evidence about the likely cost of a preferred resource, requiring a range of costs for that resource should facilitate the development and consideration of portfolios suggested over that range.

State-of-the-Art Practices

Over the past year, Energy Commission staff investigated utility resource planning methods and reviewed selected plans to seek information on the state-of-the-art. The resulting report[34] describes planning and evaluation methods used by the three major investor-owned utilities in California as well as other out-of-state utilities and entities.

Energy Commission staff found that a portfolio analytical approach based on modern portfolio theory is a better way to explicitly consider risk when analyzing different combinations of actions that utilities can take to meet future demand. Portfolio analysis enables a decision maker to assess the potential changes to an existing portfolio's risks

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[34] California Energy Commission. *Portfolio Analysis and Its Potential Application to Utility Long-Term Planning*. CEC-200-2007-012-SF. August 2007.

and costs brought about by adding assets with their own individual risk and cost profiles. The resultant risks and costs of various combinations of assets can then be quantified, and the most efficient portfolios recognized, on a curve referred to as the "efficient frontier." That is, for any given level of risk, decision makers can determine the least expensive portfolio. Conversely, for any given level of cost, they can determine the portfolio associated with the least risk. This method allows consideration of different risk preferences and the examination of various tradeoffs among risks and costs. Both the cost and risk of an efficient portfolio cannot be simultaneously lowered; costs can only be lowered with an increase in risk. Similarly, the risk of an efficient portfolio cannot be reduced without increasing costs. Indeed, without the explicit consideration of both metrics, it is not possible to forecast the effect of adding the lowest expected cost resource to a portfolio, and it is not possible to say whether or not the portfolio is "efficient."

As part of its investigation, Energy Commission staff reviewed the long-term procurement plans filed by California investor-owned utilities—PG&E, SCE, and San Diego Gas & Electric (SDG&E)—at the CPUC on December 11, 2006, and later amended. Staff also reviewed resource plans for 12 western utilities. In most of those cases, candidate resource portfolios were constructed by hand and featured resources that are regionally available and have passed initial cost or performance screening tests.[35] Although this selection of candidate portfolios may simplify the modeling process, it also allows human bias to influence the outcome by limiting the universe from which the optimal portfolio emerges.

Finally, staff also reviewed the Fifth Northwest Electric Power and Conservation Plan (May 2005 update) developed by the Northwest Power and Conservation Council (Council), an "interstate compact" agency comprising the states of Idaho, Montana, Oregon, and Washington. The plan was developed from a regional model that is rooted in portfolio analytical-based techniques. The Council's approach to developing the plan was to test a wide variety of possible resource development plans (portfolios) against 750 futures (scenarios) that describe the behavior of key sources of uncertainty during the planning period. The Council calls this approach to resource planning "risk-constrained least-cost planning." Given any level of risk tolerance, there should be a least-cost way to achieve that level of risk protection.

[35] Bolinger, Mark and Ryan Wiser. August 2005. *Balancing Cost and Risk: The Treatment of Renewable Energy in Western Utility Resource Plans*. Lawrence Berkeley National Laboratory Report LBNL-58450, p. 20.

Common Planning Assumptions and the Resource Planning Process

Based on the Energy Commission's review, California's investor-owned utilities use relatively primitive analytic methodologies for assembling their long-term procurement plans. Although characterized as "least cost, best fit" by the utilities, these plans fail to adequately address the interests of utility customers in reducing the long term risk of continued volatility in the price of natural gas. The methodologies tend to focus on projected costs attributed to individual technologies and ignore portfolio effects. They apply inappropriately high discount rates to future fuel costs, thereby understating the impact upon consumers. The net result is a systematic undervaluing of non-fuel-intensive procurement alternatives, such as efficiency and renewables, and an increasing dependence on gas-fired generation.

State policy directives on loading order priorities have yet to effectively alter the analytic paradigm for procurement planning. Application of Modern Portfolio Theory and the Capital Asset Pricing Model, the underpinnings of financial analysis for the past several decades (and the basis for the 1990 Nobel Prize awarded to Harry M. Markowitz, Merton H. Miller, and William F. Sharpe), to electric utility procurement decisions should better align utility and customer interests. Accordingly, the Energy Commission intends to make the development of a common portfolio analytic methodology a core focus of the *2008 IEPR Update*, with the clear objective of influencing the long-term procurement plans filed by the investor-owned utilities with the CPUC in December, 2008.

Various state laws and CPUC decisions define the landscape of procurement choices available to the IOUs. Consistent with these multiple requirements, the 2008 IEPR Update process will:

- Invite the close collaboration of the CPUC staff with the Energy Commission staff in developing a schedule and structuring required investor-owned utility submittals that will prove most useful to the subsequent long-term procurement proceeding at the CPUC.
- Use common planning assumptions to the maximum extent practicable, particularly for key risk drivers such as the underlying probability distributions for natural gas price trends, greenhouse gas mitigation costs, technology characteristics, etc.
- Extend over a 20 – 30 year period of analysis, even though the investor-owned utilities' procurement plans subsequently filed with the CPUC may be of shorter duration.
- Discount future fuel costs at the 3 percent social discount rate used by the Energy Commission in its standard-setting activities, unless the investor-owned utilities can demonstrate that these costs should be assigned to shareholders.
- Focus upon an "efficient frontier" of procurement portfolios from a consumer perspective utilizing a cost-based metric, with a sufficiently broad scope to incorporate environmental impacts.

- Engage multiple stakeholders in a transparent process of public workshops and hearings.

The Energy Commission envisions broadening this methodology and applying it to the larger publicly owned utilities in subsequent IEPR cycles. For purposes of the *2008 IEPR Update*, however, the emphasis will be upon the investor-owned utilities and the CAISO control area.

The Role of Conventional Resources in Meeting Demand and AB 32 Goals

Conventional generation resources that use natural gas, coal, and nuclear energy currently account for about 70 percent of California's electricity supply.[36] Even if California could achieve the maximum potential energy efficiency and renewable development opportunities identified to date, for the foreseeable future, the state will continue to rely heavily on these resources. However, each of these resources faces its own challenges.

Natural Gas

Since California's electricity market was restructured in 1998,[37] the Energy Commission has licensed 62 power plants totaling nearly 24,000 megawatts of new capacity (Figure 2-23). During that same period, another 2,600 megawatts of electric capacity was licensed by local agencies. Nearly all of this capacity (99 percent) will be fueled by natural gas. If built and operational, this new generation would be enough to supply more than 40 percent of the state's peak demand. However, only 36 plants—12,910 megawatts—have come on line, with an additional 2,278 megawatts currently under construction. Although 13 plants, totaling 8,361 megawatts, have been approved, they have not moved forward with construction because they lack power purchase agreements necessary for their financing. The problems created by continued sluggishness in utility long-term procurement were a focal point of the *2005 IEPR*.

Natural gas is cleaner than other petroleum-based fuels and has become California's fuel of choice for most new power plants because of its environmental benefits. It now provides more than 41 percent of the state's electricity. At the same time, volatility in natural gas prices can have severe financial impacts on California's economy because the regulatory process does not adequately value the price risk associated with natural gas

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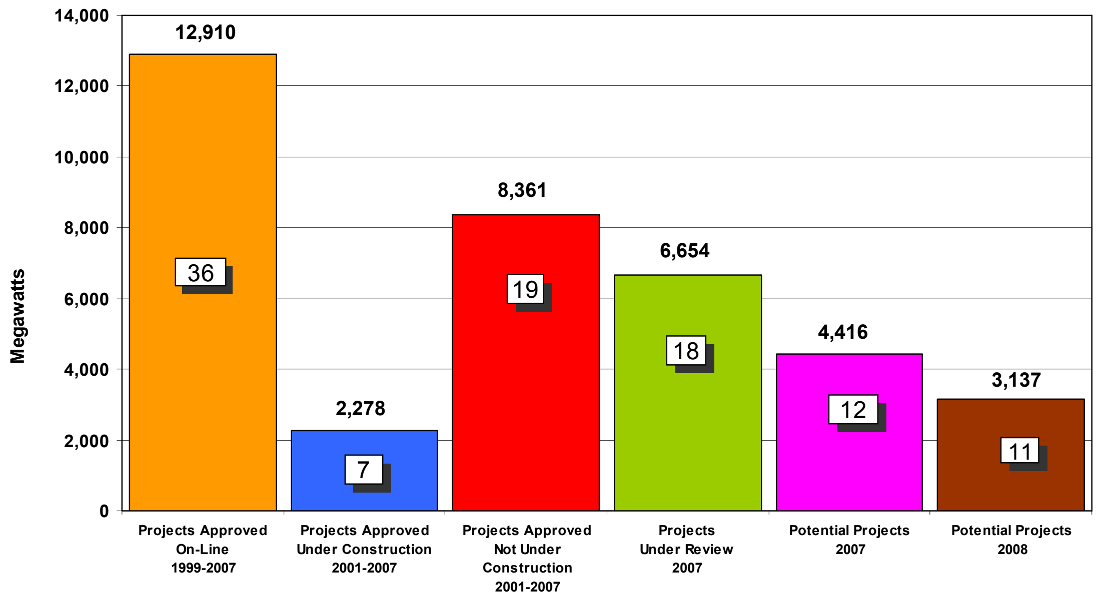
[36] California Gross System Power, 2006. The remaining 30 percent comes from renewables (11 percent) and large hydroelectric (19 percent).

[37] Assembly Bill 1890 (Brulte), Chapter 854, Statutes of 1996.

in its electricity portfolio. Portfolio analysis conducted for this IEPR suggests a strong tendency for utilities to under-invest in supply options like efficiency and renewables, which can hedge this gas price exposure over the long term. As the state's use of natural gas continues to increase, the tension between reducing the environmental impacts of electricity generation and reducing California's overwhelming dependence on a single fuel also increases.

Figure 2-23: Power Plant Application Status 1999–2008



Source: California Energy Commission.

Coal

California gets nearly 16 percent of its electricity from coal, almost exclusively from out-of-state facilities. Although coal power is cheap, it also emits large quantities of carbon dioxide (CO_2). As required by Senate Bill 1368 (Perata), Chapter 568, Statutes of 2006, the state has set a greenhouse gas emission performance standard for all new long-term investment in or purchases of baseload electricity generation by utilities. SB 1368 precludes new reliance on power plants with carbon emissions greater than 1,100 pounds per megawatt-hour similar to those of a modern natural gas combined cycle power plant.

The most likely way for coal plants to meet this standard is through the use of advanced coal technologies[38] combined with geologic carbon sequestration, where carbon emissions are captured and stored underground in geologic formations for hundreds of years. However, sequestration has not yet been demonstrated at a commercial scale and investor confidence in this technology appears low, making it unlikely that plants using this technology will be available to contribute to California's AB 32 goals for 2020.

AB 1925 (Blakeslee), Chapter 471, Statutes of 2006, requires the Energy Commission and Department of Conservation to develop "recommendations for how the state can develop parameters to accelerate the adoption of cost-effective geologic sequestration strategies for the long-term management of industrial carbon dioxide." In September 2007, the Energy Commission released *Geologic Carbon Sequestration Strategies for California: The Assembly Bill 1925 Report to the California Legislature.*[39]

The report concludes that, while technical challenges to CO_2 capture and sequestration remain, the primary barriers to progressing with initial projects are economic — with costs for CO_2 capture and compression estimated at \$50-\$90 per metric ton — and, more generally, statutory and regulatory.

The report also finds that while there is generally a large storage resource potential, more detailed site-specific study will be needed in many areas. Because of the need for appropriate infrastructure and expertise, it is likely to be more economic for carbon capture and sequestration projects to be affiliated with CO_2 enhanced oil recovery projects in oil and gas fields than to simply isolate CO_2 for long-term storage purposes.

Two proposed new power plants in California — the BP-Rio Tinto-Edison Mission Energy petroleum coke gasification project in Carson (Los Angeles County) and the Clean Energy Systems oxy-combustion plant in Kimberlina (Kern County) — include designs for CO_2 capture, with the prospect that the CO_2 could be sold for commercial purposes, including use in enhanced oil recovery.

Elsewhere in the United States, the federal Department of Energy has ongoing projects to facilitate carbon capture and sequestration, including seven regional partnerships that include about 40 states. These partnerships are conducting small scale sequestration demonstrations and providing assessments and databases of large emission sources and candidate storage sites within the United States.[40] The WESTCARB partnership, led by

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[38] Plant types considered "clean" include integrated gasification combined cycle; pulverized coal with "ultra-supercritical" main steam conditions, like a thermodynamic state well above the pressure and temperature of the critical point of water; and circulating fluidized-bed combustion plants with supercritical main steam conditions.

[39] California Energy Commission, CEC-500-2007-100-SD, September 2007.

[40] http://www.netl.doe.gov/technologies/coalpower/futuregen/EIS/.

the Energy Commission, includes California, Nevada, Oregon, Washington, Arizona, and Alaska, as well as British Columbia.

In addition, the FutureGen Project, the first project to combine coal gasification for electric power and hydrogen generation with carbon sequestration at a commercial scale, has recently completed its Environmental Impact Statement and risk assessments of candidate construction sites in Illinois and Texas.

Advanced coal technology with carbon sequestration is considered as a promising future low CO_2 source. This is particularly important to regions like the eastern United States or portions of the European Union with a high dependence on coal. Developing economies, like China and India, which intend to greatly expand their use of coal, may find it impossible to control their CO_2 emissions without breakthroughs in advanced coal technologies. However, investor confidence in these alternatives is presently low because sequestration technology is still under development and has not yet been demonstrated at a commercial scale. Emerging CO_2 markets' inability to establish a sufficiently high and sufficiently stable price for CO_2 complicates these prospects. Because an uncertain payment stream raises the cost of borrowing capital, uncertainty in the carbon markets can raise the cost of capital for cleaning up fuels with high greenhouse gas emissions.

Citibank recently downgraded its assessment of coal stocks, in part because of slow industry progress toward clean coal technologies. In its July 18, 2007, *North American Metals & Mining Newsletter*, Citigroup noted ". . . prophesies of a new wave of coal-fired generation have vaporized, while clean coal technologies such as integrated gasification combined cycle with CO_2 capture and coal-to-liquids remain a decade away, or more" and "We expect anti-coal politics to intensify, with carbon constraints almost certain to pinch." Coal stock prices dropped after HSBC and Citigroup downgraded.[41]

It is challenging to accurately assess the economics of CO_2 capture and sequestration because no policy exists to establish a price for CO_2 in the marketplace. Preliminary estimates for CO_2 capture and compression — by far the largest part of the entire cost of CO_2 capture and sequestration — are \$50 to \$90 per metric ton of CO_2 removed. This cost is sizeable given the \$8 per ton CO_2 adder established by the CPUC to be used by utilities for long-term planning and procurement. This does not include the cost of transporting CO_2 to the sequestration site. Other issues that could significantly increase costs include permitting, monitoring, acquiring property rights, and liability.

However, economists' estimates of the CO_2 price necessary to stabilize CO_2 concentrations at 550 parts per million, higher than the 450 parts per million levels

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[41] John Hill, *Coal: Missing the Window. Downgrading on Stubborn Stockpiles, Hostile Politics.* Citigroup, July 18, 2007. See also *UPDATE: Coal Stocks Tumble on Sweeping Citigroup Downgrade.* <http://money.cnn.com> accessed July 20, 2007.

recommended by the Intergovernmental Panel on Climate Change (IPCC),[42] range from $5 to $30 per metric ton by 2025. The IPCC came out with figures of $20-$50 per ton in 2020-2030. A $20 per ton CO_2 price could raise electricity prices in the United States by 14 percent, while a $50 per ton CO_2 price could raise prices by 35 percent.[43]

Because of the technological, economic, and regulatory barriers facing commercial-scale application of carbon capture and sequestration, the Energy Commission does not believe advanced coal with carbon sequestration will yield a significant amount of electricity generation in the 2020 timeframe. It does, however, remain an important national, and international, research and commercialization priority. The Energy Commission's detailed findings and recommendations on the topic are available in its report *Geologic Carbon Sequestration Strategies for California: The Assembly Bill 1925 Report to the California Legislature*.[44]

Nuclear

Nuclear power provides nearly 13 percent of California's electricity supply from three plants: the Diablo Canyon and San Onofre nuclear power plants in California, and the Palo Verde nuclear power plant in Arizona. Nuclear power has lower greenhouse gas emissions than fossil fuels and because fuel represents a small portion of their costs, nuclear plants are also largely insulated from fuel price volatility.

The United States is currently experiencing a "nuclear renaissance" as this technology is increasingly seen as a mitigation strategy for global climate change. Spurred by federal regulatory initiatives, financial incentives in the Energy Policy Act of 2005, increased volatility of fossil fuel prices, and continuing growth of energy demand, nuclear power is gaining greater visibility. About half of the nuclear power plants in the United States have received renewals to extend their operating licenses by 20 years, and some utilities and merchant generators have expressed interest in building new nuclear plants.

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[42] The Intergovernmental Panel on Climate Change reports a 450 ppm CO_2 equivalent as substantially reducing the expected magnitude, impact, and rate of climate change from business as usual scenarios. IPCC, 2007. Climate change 2007: Mitigation. Contribution of Working group III to the Fourth Assessment Report of the Intergovernmental Panel on Climate Change [B. Metz, O. R. Davidson, P. R. Bosch, R. Dave, L. A. Meyer (eds)], Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA. http://www.ipcc.ch/SPM040507.pdf, pp. 22-25.

[43] Richard Newell, Duke University, as cited in Economist.com, *The Final Cut,* May 31, 2007 <http://www.economist.com/surveys/displaystory.cfm?story_id=9217868>.

[44] California Energy Commission, CEC-500-2007-100-SD, September 2007.

However, nuclear power still faces a number of barriers, including high capital costs, uncertain construction timelines, regulatory risks associated with the use of once-through cooling, waste disposal and potentially severe effects from accidents, acts of nature, or terrorism. Within California, development and construction of any new nuclear power plants in the state are legally contingent on the demonstration and approval of the technologies needed to reprocess or dispose of the spent fuel generated in nuclear reactors.[45] In the *2005 IEPR*, the Energy Commission reaffirmed its finding made in 1978 that "a high-level waste disposal technology has been neither demonstrated nor approved." The report also found that "reprocessing remains substantially more expensive than waste storage and disposal and has substantial adverse implications for the United States effort to halt the proliferation of nuclear weapons."

Although California consumers have paid over $1 billion to support federal efforts to develop a permanent repository for spent nuclear fuel at Yucca Mountain, Nevada, the repository is not expected to open until 2021, if at all.[46] In the absence of a federal repository, California must plan for the continued accumulation and interim storage of high-level radioactive waste at existing reactor sites, even though none of the sites were originally designed for such long-term use. California needs a comprehensive assessment of the implications of indefinite reliance upon at-reactor interim spent fuel storage and should evaluate the viability of centralized interim fuel storage proposals.

Reprocessing of spent fuel is more expensive than waste storage and disposal and continues to have implications for United States nonproliferation efforts. While the federal government has proposed a major new reprocessing initiative (GNEP), significant questions remain regarding reprocessing technologies available today and those that GNEP proposes.

For example, a recent National Academies' panel concluded that the rationale for the GNEP program is unpersuasive, that the GNEP program should not go forward at its current pace, and that GNEP is relying upon technologies that are too early for commercial development (decades away) and too expensive (costing tens of billions of dollars or more). The panel further concluded that GNEP has had insufficient independent review and there are major uncertainties about its ability to address U.S. waste disposal issues.

Another barrier to the development of nuclear power is cost. Ironically, the recent surge in interest has prompted a sharp increase in the price of nuclear fuel in anticipation of a

[45] California Energy Commission reports related to this legislation are available on its website: http://energy.ca.gov/2007_energypolicy/documents/index.html#06252807

[46] Ibid.

large worldwide increase in demand. In addition, while nuclear plants are relatively cheap to run, they cost a lot to build and in the past have required extraordinary ratepayer guarantees to cover interest costs during construction. Development costs for new nuclear plants are uncertain, as very little reactor development has occurred in the U.S. for the past 20 years. However, the Watts Bar project in Tennessee, which began operations in 1996, took 23 years to complete at a cost of $6.9 billion.[47] Internationally, Finland's AREVA nuclear plant continues to experience delays — most recently announcing that on-line operations may be postponed from 2009 to 2011 — and is believed to be nearly $1 billion over budget.[48]

Unlike natural gas and coal power plants, which use modular components built at a factory and trucked to the site for assembly, reactor projects are built on site and require large capital investments and very long lead times. Developers of new plants could face extreme cost overruns comparable to the rapid inflation recently experienced in the construction industry that nearly doubled the price of building a coal plant between 2002 and 2006. Some developers and utilities, however, believe that new technologies, federal subsidies, standardized reactor designs, revised federal licensing procedures, and relatively low interest rates will combine to keep costs down.

Assembly Bill 1632 (Blakeslee, Chapter 722, Statutes of 2006) poses another challenge to the development of new nuclear power plants in California and perhaps to the license extensions for existing plants. The bill requires that the Energy Commission determine the potential vulnerability of existing large baseload generation facilities—1,700 megawatts or greater—to a major disruption due to plant aging or an earthquake. AB 1632's threshold applies to California's two operating nuclear power plants. It further directs the Energy Commission to assess the state and local costs and impacts from the accumulating waste at California's nuclear plants in the absence of a long-term, permanent federal waste disposal solution for these wastes. In light of the economic, environmental and regulatory obstacles involved in developing new nuclear power plants, the Energy Commission does not expect significant contributions from new nuclear plants toward the state's AB 32 goals by 2020.

Challenges Facing Southern California

As the state's demand for electricity increases, Southern California in particular continues to be vulnerable to supply shortages. Southern California utilities rely on electricity purchased from aging power plants under short-term contracts, threatening

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[47] "Atomic Renaissance," The Economist, September 8-14, 2007, p. 71.

[48] Energy Business Review, August 13, 2007, "Areva-Siemens Consortium Announces Delay of Finnish Nuclear Reactor," http://www.energy-business-review.com/article_news.asp?guid=80B1249C-4590-4A5A-A624-AC9AD3901FA2.

reliability in the area. In addition, 13 of the state's 19 coastal power plants – which face challenges from their use of ocean water for cooling as previously described – are located in the southern part of the state. Southern California air basins also have some of the worst air quality in the nation, resulting in stringent local air quality requirements and short supplies of emission credits for new electricity generators. This shortage will be exacerbated by the California ISO's Southern California local capacity requirements – enough generation to ensure uninterrupted service in all hours even if a major power plant or transmission line fails – which have increased such that in 2008, the Los Angeles Basin is required to meet nearly half of its electrical load with local generating capacity.

Aging Power Plants

In its *2004 IEPR Update*, the Energy Commission identified a study group of older power plants to evaluate the impacts of those aging plants on the state's resources. More than 75 percent of the aging capacity identified in the study was located in the southern part of the state, including 16 plants totaling 2,400 megawatts owned by publicly owned utilities. Nevertheless, the issue of California's aging plants is still a statewide concern. In the *2005 IEPR*, the Energy Commission urged the state's utilities to undertake long-term planning and procurement to allow for the orderly retirement or repowering by 2012 of the aging plants in that study group.

Currently, only PG&E has submitted a long-term procurement plan that contains enough new generation and transmission investments to avoid relying on aging plants after 2012. In contrast, SCE relies on these plants through 2016, and SDG&E's plan relies on the aging Encina facility throughout its planning period (although the Encina owner has announced plans to replace the old plant with a modernized design better suited to evolving loads and dispensing with ocean water cooling).

The Energy Commission submitted comments in the CPUC's long-term procurement proceeding recommending that the CPUC direct SCE and SDG&E to file an assessment of regional need that assumes the phased retirement of the aging plants identified in the *2005 IEPR's* Transmittal Report to the CPUC. Further, the Energy Commission recommended that the CPUC direct SCE and SDG&E to either (1) conduct solicitations aimed at replacing these aging plants or (2) identify transmission, demand response, energy efficiency, or renewable resources to replace or offset the generation needed from these plants.

In its Scenario Analyses Project, the Energy Commission evaluated specific retirements and replacements of older plants in the SCE service area. The results identify which plants might be more logical to repower, how replacement plants interact with the preferred loading order resources necessary to achieve the state's greenhouse gas goals, and what transmission upgrades are needed to eliminate some facilities.[49] Both SCE and the California ISO endorsed the assessment as a reasonable first step, but identified additional elements for further study.

The California ISO has also proposed a study related to reducing the state's reliance on aging plants and those that use once-through cooling technologies. The goal of the study is to develop plans that take into consideration a variety of scenarios to facilitate retirement and replacement of these facilities as well as alternative solutions such as transmission, distributed generation, and load management programs.[50] This study must address aging facilities owned by the investor-owned and publicly owned utilities and carefully consider issues surrounding once-through cooling and restrictions on emission credits in Southern California.

Once-Through Cooling

Nineteen coastal power plants in California use once-through cooling – the use of seawater to recondense superheated steam after it has been used to generate power. This practice can have significant impacts on marine organisms and ocean habitat.

Recognizing these impacts, the United States Environmental Protection Agency (U.S. EPA) in 2004, issued its 316 (b) Phase II rule to regulate once-through cooling systems for existing large power plants. The regulations established a series of "best technology available" options that created flexibility for facility owners to comply with the new regulations. The same year, the California Legislature enacted the Ocean Protection Act, which created the Ocean Protection Council to coordinate actions of state environmental regulatory agencies to improve the state of ocean ecosystems.

The *2005 IEPR* directed the Energy Commission to work with other state agencies and address once-through cooling issues in the broader context of protecting the state's fragile coastal marine ecosystem. Also in 2005, the State Water Resources Control Board (SWRCB) initiated a proceeding regarding the U.S. EPA's 316(b) regulations, followed in 2006 by a proposed SWRCB policy to strengthen regulation of cooling water intake structures.[51] SWRCB and the Ocean Protection Council have initiated their own studies of the power plants using ocean water for cooling, focusing principally on the aging

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[49] Second Addendum Report, Appendix A.

[50] *Mitigation of Reliance on Old Thermal Generation Including Those Using Once-Through Cooling Systems*, presentation by Larry Tobias, California ISO, September 21, 2007, http://www.caiso.com/1c5e/1c5edff632c50.pdf.

[51] *Scoping Document and Proposed Statewide Policy on Clean Water Act 316(b) Regulations,* California State Water Resources Control Board, June 13, 2006. http://www.waterboards.ca.gov/npdes/docs/cwa316b_scoping.pdf.

power plants in Southern California studied by the Energy Commission in its policy on repowering/retirement, and by the South Coast Air Quality Management District (SCAQMD) for emissions cleanup.

In 2007, the Second Circuit Court of Appeals approved a challenge to the 316(b) regulations in *Riverkeeper v U.S. Environmental Protection Agency*, determining that regulations for existing large power plants did not conform to the Clean Water Act.[52] The court upheld U.S. EPA's interpretation of "adverse environmental impact[s]" from once-through cooling and affirmed that the Clean Water Act requires such impacts to be minimized through the use of "best technology available." The decision also found that off-site restoration, cost benefit tests, and other exemptions to the technology requirements did not meet the intent of the Clean Water Act. As a result of this ruling, the U.S. EPA suspended its 316(b) regulations for large existing power plants and advised the states to use "best professional judgment" on specific permit renewals and new applications, with a new rulemaking planned to begin in late 2007.[53]

The Surfrider Foundation filed a legal challenge in July 2007 against the San Diego Regional Water Control Board and the SWRCB for their 2006 renewal of the National Discharge Elimination System permit for the Encina power plant in San Diego.

In September 2007, the Coalition for a Sustainable Delta, representing local water districts and irrigators, announced plans to sue Mirant Delta LLC and the United States Army Corps of Engineers over alleged violations of the Endangered Species Act due to the once-through cooling systems in the Pittsburg and Contra Costa power plants.

Some progress has been made in reducing the use of once-through cooling in the state. Five of the 19 power plants that use once-through cooling have proposed switching from once-through cooling: El Segundo, Encina, Gateway, Humboldt, and South Bay.

The Energy Commission has worked closely with the Ocean Protection Council, the SWRCB, State Lands Commission and other agencies involved with the once-through cooling issues to provide information on coastal power plant operations, resource adequacy and local reliability issues, including:

- Assessments of impacts to marine and estuarine environments from once-through cooling based on staff analysis of six coastal power plant licensing applications.

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[52] http://www.ca2.uscourts.gov:8080/isysnative/RDpcT3BpbnNcT1BOXDA0LTY2OTItYWdfb3BuLnBkZg==/04-6692-ag_opn.pdf#xml=http://10.213.23.111:8080/isysquery/irl981e/1/hilite

[53] "Discharge Permits: EPA Suspends Cooling Water Rule in Response to Second Circuit Decision," vol. 38, Env't Rep. (BNA), No. 27, at 1481 (July 6, 2007).

- Support from the Energy Commission's Public Interest Energy Research Program on ecosystem functions, species diversity and measuring impacts from once-through cooling in different ecosystems.
- Information from facility siting experience with inland and coastal plants to use air cooling.
- Information on coastal plant operations, resources adequacy and other energy issues associated with potential impacts to grid reliability from proposed regulatory changes on once-through cooling.

California's policy makers want to encourage retirement of the remaining steam boiler plants in California and encourage development at those sites of cleaner, combustion-based technologies that operate at higher efficiency and thereby reduce the demand for natural gas. However, planning for investment in capital-intensive projects like new power plants must incorporate the risk that applications could be substantially delayed or denied if once-through cooling is used.

In addition, existing facilities that currently use once-through cooling are likely to face significant legal challenges, particularly for permit renewals. Two-thirds of California's coastal power plants are located in the southern part of the state, which is already facing reliability challenges due to the number of aging power plants coupled with a shortage of emission credits available for new plants in the South Coast Air Basin.

Nuclear plants that use once-through cooling present special challenges. Because of their size, these facilities use more seawater than gas-fired plants use. The recently suspended 316(b) regulations for existing large power plants contain a safety exemption for nuclear plants that use once-through cooling. The court affirmed in *Riverkeeper II* that U.S. EPA had appropriately addressed the nuclear safety issue in *Riverkeeper I*, stating, "We defer to the EPA's determination that this compliance alternative ensures that any safety concerns unique to nuclear facilities will prevail over application of the general Phase II requirements."

However, the Nuclear Regulatory Commission (NRC) ruled, in April 2007, that the decision to allow the Vermont Yankee nuclear facility to discharge warmer water into the Connecticut River is a state issue, not a federal issue, concluding that the Clean Water Act, "precludes [the NRC] from either second guessing the conclusions in NPDES permits or imposing [its] own effluent limitations – thermal or otherwise."[54]

In addition, NRC officials testifying this summer at the Energy Commission's IEPR workshops on nuclear power indicated their intent to defer to SWRCB determinations.

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[54] NRC Docket 50-271-LR, Memorandum and Order, April 11, 2007, in the matter of Entergy Nuclear Vermont Yankee, LLC, & Entergy Nuclear Operation Inc., pp.4-5.

New Air District Rule Limits Use of Emissions Credits

In the South Coast Air Basin, limitations on the supply of emission reduction credits constrain the ability to either license new power plants or repower existing ones.[55] One option to address this constraint is the use of priority emission reserves—emission credits that have been set aside by the air district for use by entities that serve a public interest.

However, the South Coast Air Quality Management District (SCAQMD) recently adopted Rule 1309.1, which limits the use of priority reserve emission credits for power plants. The rule establishes stringent emission rates for nitrogen oxides (NOx) and coarse particulate matter (PM10) and a requirement that developers obtain a long-term (one year) power sales contract and a license from the Energy Commission before the SCAQMD board will decide whether to release priority reserve credits for that facility. In addition, municipal-owned plants will only be given credits enough to build projects that serve their native load. In addition to these constraints, the SCAQMD limited the total amount of credits available for in-district generation to 2,700 MW of generation, and requires each applicant to go before the board of directors prior to release of the credits.

The rule does allow the option for any power plant applicant to petition the SCAQMD board for a waiver of the requirement for a long-term contract or to go over the 2,700-MW limit provided the applicant can demonstrate that the power plant is needed in the Basin. In order to inform its decision-making, SCAQMD is funding its own study of supply/demand, potentially duplicating the Energy Commission's planning activities.

Grid Support/Local Capacity Requirements

Beginning in 2007, the California ISO identified the need for additional capacity in 2007 and 2008 in specific state geographic zones with constrained resources to meet local capacity requirements.[56] For 2007, the existing capacity needed to meet these requirements is 22,113 megawatts across 10 zones, many of which are coastal urban areas with older steam boiler facilities.[57]

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[55] SCAQMD severely limits the offsets a repowering facility can use to satisfy air quality permit requirements by only acknowledging the plant's recent operating history, not the permitted values for the original facility.

[56] These requirements replaced most direct reliability must run contracts between the California ISO and generators.

[57] *2008 Local Capacity Technical Analysis: Report and Study Results*, Table on pp. 43, California Independent System Operator, April 3, 2007. Specific plants to meet local capacity requirements are not named due to proprietary concerns.

However, it is important to distinguish between capacity reserves and operational levels. On an energy production basis, the coastal fleet contributed 22 percent of total 2006 in-state electricity sales. The two large nuclear plants account for 60 percent of that production; however, total electricity production from the coastal facilities has decreased by nearly half since 2001. In 2006, 11 of the 17 natural gas-fired power plants operated at or below a 15 percent capacity factor,[58] reflecting that most older steam boiler units were not being used for the baseload generation as they were designed to do. In fact, four large plants that ran above 50 percent capacity factors in 2001 – Contra Costa, Pittsburg, Morro Bay and Redondo Beach – all operated below five percent capacity factors in 2006.

For 2008, the existing capacity needed to meet local capacity requirements will increase to 22,899 megawatts. In addition, for 2008 and beyond, the California ISO convinced the CPUC to endorse another load pocket in the Ventura/Big Creek area, which will require more existing (and aged) Southern California facilities to be contracted for capacity. Also, Path 26 — a crucial link between SCE and PG&E electric grids — is now recognized as a constraint in resource adequacy. This further obligates entities serving loads in Southern California to contract with existing power plants located there, even if they are more expensive (and more polluting) than those located in Northern California. As a result of CPUC Decision 06-07-029,[59] beginning in 2008, additional emphasis will be placed on contracting with generators located within Southern California, highlighting the nexus between limited generation and transmission-constrained portions of the grid.

Next Steps

Conditions limiting generation development and technology choice in Southern California coastal areas require coordinated decisions and actions among all agencies to avoid reliability problems. Some current merchant electricity generators understandably question the *2005 IEPR* policy and want "market forces" alone to drive decisions on retirement or repowering.[60] But as discussed earlier in this chapter, existing barriers (including regulatory inertia) can allow "market forces" to protect an exceptional level of economic inefficiency. The *2005 IEPR* described at length the economic cost to utility customers of relying on outdated and inefficient steam boilers. More study is proposed, and California ISO technical staff has formed a transmission study group encouraging

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[58] Capacity factor means how much electricity a plant produces in a year relative to its potential production if it were to operate at full capacity for all 8,760 hours in a year.

[59] California Public Utilities Commission, July 20, 2006, <http://www.cpuc.ca.gov/published/Final_decision/58268.htm>.

[60] Comments of Mirant California on the California Energy Commission's August 16th Workshop on Aging Power Plants (Docket No. 06-IEP-1M), August 31, 2007.

the participation of all relevant stakeholders, but their work may not be complete until early 2009.

Concerted effort by the state's energy agencies is needed to ensure economic, reliable, and sufficient electric supplies in Southern California. At the same time, the state must step up its efforts to evaluate the impacts of retiring, repowering, or replacing aging generation resources with resources compatible with the state's air, water, and greenhouse gas goals, as well as the economic interests of its utility customers.

The Energy Commission recommends the following:

- The Energy Commission, the CPUC, the California ISO, and other interested agencies such as the Ocean Protection Council, State Water Resources Control Board and SCAQMD should work together to complete the studies needed to better understand the impacts of retiring, repowering, and replacing aging power plants, particularly in Southern California.
- As originally articulated in the 2005 IEPR, the CPUC should require that IOUs procure enough capacity from long-term contracts to allow for the orderly retirement or repowering of aging plants by 2012.

Retail Price Forecast

Retail prices are difficult to predict over time since they are subject to underlying costs and rate design choices made by regulators. Most retail price forecasts are simply current rate structures projected out over time and applied to forecasted changes in operating costs. The process of developing the 2007 IEPR retail price projection experienced the same over-simplification that plagued the 2003 and 2005 IEPR cycles. Although virtually all utility submittals to the Energy Commission call for real retail prices to fall, these forecasts do not consider the cost of infrastructure improvements and are based on extremely optimistic assumptions about the price of natural gas. The Energy Commission will re-evaluate the wisdom of expending state and utility resources on a process so vulnerable to public relations instincts.

Transmission Expansion

The achievement of state greenhouse gas policy objectives by the electricity sector will depend to a large degree on the interconnection and integration of renewable resources into the state's transmission grid. California must overcome ongoing transmission planning, permitting, financing, and integration barriers to accelerate the transition to a carbon-constrained generation base. In addition, California utilities must ensure that transmission projects that meet traditional reliability, congestion management, and economic objectives are developed in a timely manner. Actions are underway at the state and federal levels to address these barriers. The *2007 Strategic Transmission Investment Plan,* adopted by the Energy Commission in November 2007 and prepared in support of the *2007 IEPR* proceeding, describes the state's transmission challenges and provides recommendations to overcome them.[61] The report also makes recommendations regarding in-state transmission corridor planning and in-state transmission projects.

Recommendations

- The Energy Commission should include, in the *2009 IEPR*, a robust assessment of the effect of high levels of preferred resources on reducing natural gas prices.
- The staffs of the Energy Commission and CPUC should collaborate to integrate the portfolio analytical method into the Long-Term Procurement Planning process so that it can provide the basis for formulating and reviewing investor-owned utility portfolios.
- The Energy Commission should actively participate in the California ISO's study concerning aging power plants and those that use once-through cooling, with specific attention given to the challenges faced by the investor-owned utilities and the publicly owned utilities in Southern California.
- The CPUC should require that investor-owned utilities procure enough capacity from long-term contracts to allow for the orderly retirement or repowering of aging plants by 2012.
- The state should take an active role in the Yucca Mountain licensing proceeding, currently planned to begin in June 2008, to ensure that California's interests are protected.
- The state should challenge the U.S. Department of Energy's (DOE) inadequate response to potential impacts identified by California during the Yucca Mountain Environmental Impact Statement and review process.
- The Energy Commission should continue to participate in DOE and regional planning activities for nuclear waste shipments.
- The Energy Commission should work with federal and state regulators, nuclear plant owners, and Institute of Nuclear Power Operations (INPO) to develop a means to usefully incorporate INPO reviews and ratings of reactor operations into a meaningful public process while maintaining the value of the INPO reviews as confidential and candid assessments.
- Southern California Edison and San Diego Gas & Electric should, as part of their long-term procurement plans, develop a contingency plan to replace generation from Palo Verde should it be shut down for an extended period.

[61] California Energy Commission, *2007 Strategic Transmission Investment Plan*, http://www.energy.ca.gov/2007publications/CEC-700-2007-018/CEC-700-2007-018. pdf.

- The Energy Commission should continue to assess the reliability implications for California's operating nuclear plants of federal and state once-through cooling regulations.

CHAPTER 3: Meeting Energy Needs with Efficiency and Demand Response

For the past 30 years, California has led the nation in promoting and using energy efficiency programs. While the per capita electricity consumption in the rest of the country continues to escalate, California's per capita electricity consumption leveled off in the mid-1970s and has remained relatively flat – between 7,200 and 7,800 kilowatt hours per person – a success attributable in part to energy efficiency initiatives in the form of building efficiency and appliance efficiency standards and utility-sponsored incentive programs.[62]

> ***Energy conservation is the foundation of energy independence.***
> Tom Allen, U.S. Representative, R-Maine

Energy efficiency and demand response programs are key strategies for addressing climate change and meeting the AB 32 goals for greenhouse gas emissions. These programs can continue to reduce California's energy demand, make businesses more competitive, and allow consumers to save money and live comfortably. In addition, they play a major role in increasing the reliability of the current electricity system, as well as in reducing the costs of meeting peak demand during periods of high temperatures.

California continues to experience declining load factors.[63] The general decline in the load factor over the last 20 years is caused, in part, by a greater proportion of homes in warmer areas and more homes and businesses with central air conditioning. Today, close to 95 percent of single-family homes in the Sacramento area and many other parts of the Central Valley and the Inland Empire have central air conditioning. Forecasts suggest that most housing growth in California will continue to be in these hotter areas.

More temperate climates in California are also becoming increasingly dependent on air conditioning. The area around San Francisco, from Santa Rosa to San Jose, now has a central air conditioning saturation of nearly 50 percent – double previous estimates. More than 75 percent of new single-family homes in the area are projected to have central air conditioning. These trends foretell a continuing reduction in the state's load factor and continuing concern about meeting peak energy needs.

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[62] "Per capita consumption" is consumption across all of the electricity-using sectors – residential, commercial, industrial, and agricultural – totaled and divided by the state's total population.

[63] A load factor represents the relationship between average energy demand and peak demand: a low load factor means the peak is much higher than average hourly energy demand.

Energy efficiency tops the list of strategies for accomplishing California's significant greenhouse gas reduction targets because it is a relatively fast and inexpensive solution. In fact, it has what is called "negative abatement value" – by carrying out energy efficiency actions, energy consumers would both cut emissions and save money.

Using Efficiency to Meet California's Energy Needs

If energy efficiency is to play the critical roles envisioned for it under AB 32, the state needs to support expanded efforts in all programs. Scenario analyses have demonstrated that cost-effective efficiency programs can allow California to achieve at least a proportional reduction of carbon emissions from the electric sector. These analyses highlight the need to capture *all cost-effective energy efficiency.* The October 18, 2007, decision from the California Public Utilities Commission supports this goal and describes a course of action, involving programs under its jurisdiction and those under the Energy Commission's authority, to achieve it.

Since the 1970s, the Energy Commission has had the responsibility to establish and enforce energy efficiency standards for buildings and appliances. All construction of new buildings and major building modifications must meet the Energy Commission's standards, which are updated regularly to capture improvements in technologies, such as lighting and heating, ventilation, and air conditioning (HVAC) systems. In addition, the Energy Commission sets minimum efficiency standards for a range of appliances that use significant amounts of energy. The standards must, by law, be technically feasible and cost-effective.

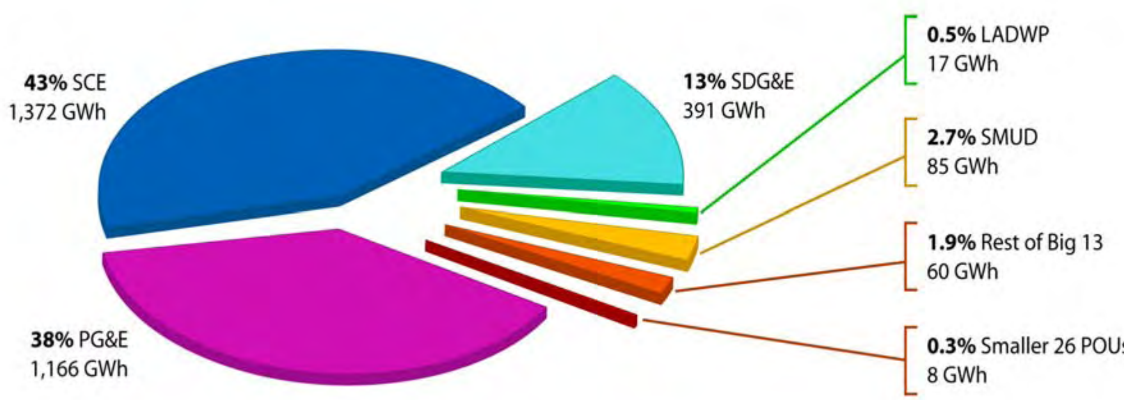
Besides the energy savings accumulated from these mandatory standards, the investor-owned utilities in California have offered ratepayer-funded programs of incentives and rebates to encourage customers to participate in savings programs or purchase efficient appliances. Many of the publicly owned utilities have offered similar programs for their customers although the significant differences in size among the publicly owned utilities affect their level of program development.

Each investor-owned utility and publicly owned utility customer pays a small public goods charge to support public programs for energy efficiency, low-income services, renewable energy, and public interest research and development. A natural gas surcharge provides similar support on the natural gas side. Since 2004, additional funding has been made available through the investor-owned utilities' procurement proceedings to pursue energy efficiency beyond what is funded by the public goods charge. In the 2004–2005 energy efficiency program cycle, the investor-owned utilities had a budget of nearly a billion dollars and reported energy efficiency savings of 4,773 gigawatt hours, 948 megawatts, and 77 million therms.

Like the investor-owned utilities, the publicly owned utilities administer a variety of energy efficiency programs for their customers. During fiscal year 2005–2006, all publicly owned utilities collectively spent over $54 million on energy efficiency and saved over 170 gigawatt hours and 53 megawatts of peak electricity.

Figure 3-1 shows the electric energy savings reported for 2005 for both investor-owned utilities and publicly owned utilities. Combined, the investor-owned utilities' programs command 95 percent of the savings. The two largest publicly owned utilities in the state, Sacramento Municipal Utility District (SMUD) and Los Angeles Department of Water and Power (LADWP), both of which have had programs as long as the investor-owned utilities, account for 3.2 percent of the statewide savings, but 60 percent of the publicly owned utility savings. SMUD expended $22 million for energy efficiency – close to half the entire amount spent for all 39 of the publicly owned utilities that supplied expenditure data. LADWP increased its expenditures to over $14 million in fiscal year 2006–2007, and is projected to spend $80 million in fiscal year 2007–2008.

Figure 3-1: Investor-Owned Utility and Publicly Owned Utility Share of Electric Energy Savings in 2005



Sources: *2006 Energy Efficiency Annual Reports* for the investor-owned utilities. California Municipal Utilities Association, *Energy Efficiency in California's Public Power Sector: A Status Report*, December 2006 for the publicly owned utilities.

Using Efficiency to Reduce Greenhouse Gas Emission Levels

Drawing on the efficiency potential described in a 2006 study from Itron,[64] the Scenario Analyses Project examined the greenhouse gas implications of resource plans featuring high penetrations of energy efficiency measures and renewable energy generation (both rooftop solar photovoltaic and supply-side generating technologies) in California and the Western states. A base case (Case 1) included the investor-owned utilities' 2004–2008 committed energy efficiency programs and the impacts of existing building and appliance efficiency standards, as accounted for in the Energy Commission's demand forecasts (Figure 3-2). No additional energy efficiency after 2008 was modeled in the base case. Four scenarios for energy efficiency were considered:

- Current practices (Case 1B) – For California, the energy efficiency resources reflect the goals summarized in the investor-owned utility 2006 procurement plans. For the rest of the Western states, the current energy efficiency programs were assumed embedded in the load forecasts (that is, the forecasts reflect sales net of reductions from energy efficiency programs).
- Aggressive development (Case 3A) – This case reflects aggressive expansion of energy efficiency programs beyond those of the investor-owned utilities. In California, this is equivalent to all cost-effective energy efficiency (minus the portion of the economic potential attributable to emerging technologies) from the California Energy Efficiency Potential Study (2006 Itron Study).
- Partial emerging technology deployment (Case 3D) – In addition to the aggressive energy efficiency included in Case 3A, approximately 55 percent of the economic emerging technology potential in California is included.
- Full emerging technology deployment (Case 3E) – This case includes the entire economic emerging technology potential in California.

The culmination of savings in each of the cases would be 30,000 gigawatt hours in Case 1B, 42,000 gigawatt hours in Case 3A, 52,000 gigawatt hours in Case 3D, and 60,000 gigawatt hours in Case 3E.

California retail load becomes relatively flat from 2016 through 2020 after including the impacts of energy efficiency (Figure 3-3). The net effect of these energy efficiency savings is virtually no growth in California retail loads in Case 3A, a decline in retail loads in Case 3D, and a further decline in retail loads in Case 3E as depicted in Figure 3-3. The

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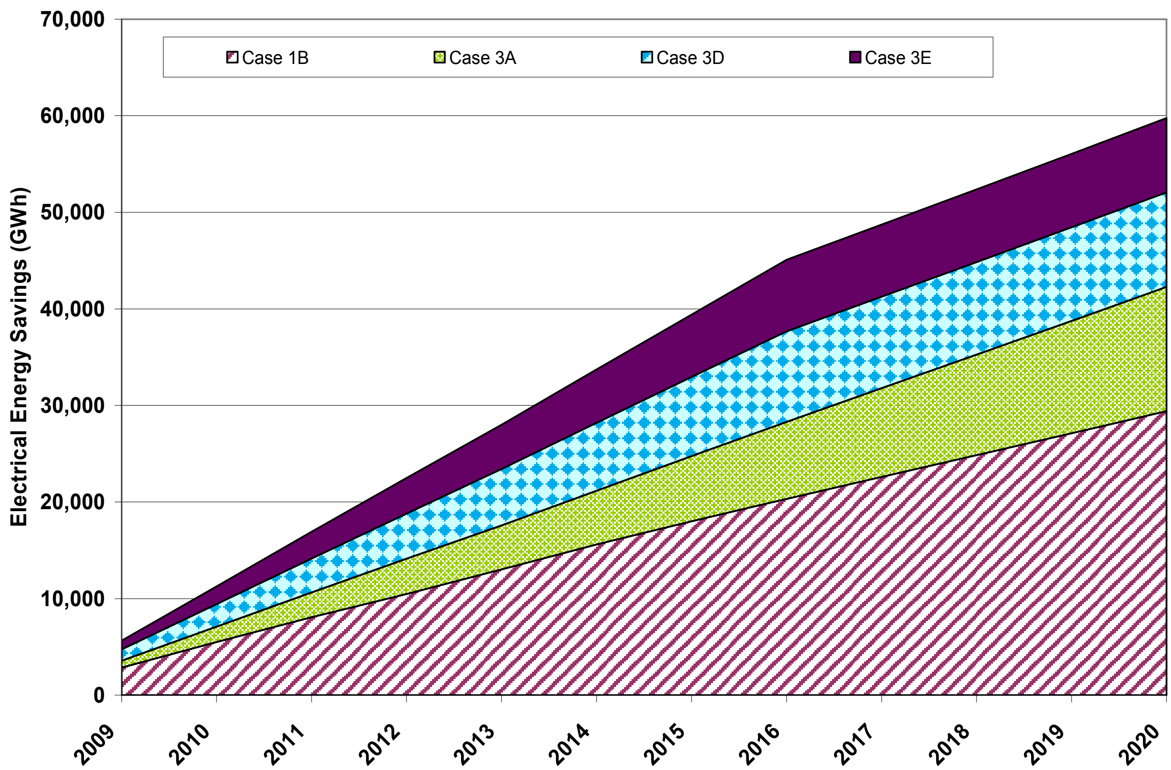
[64] Itron, California Energy Efficiency Potential Study, (three volumes), May 24, 2006. Available from http://www.calmac.org. This study projects electricity and natural gas efficiency potential through 2016 for the investor-owned utilities.

average annual decline between 2009 and 2020 is -0.3 percent in Case 3D and -0.5 percent in Case 3E.

Figure 3-2: Energy Efficiency through Time by Case



Source: Navigant Consulting, Inc.

The fundamental question is what impact the high efficiency cases will have on California's ability to reduce its overall greenhouse gas emissions to 1990 levels. Figure 3-4[65] shows the carbon emissions from the power generated to serve load in California, also known as the California Carbon Responsibility, for all 13 scenarios modeled in the Scenario Analyses Project. This figure also identifies how these electricity sector projections compare with estimated 1990 electricity sector greenhouse gas emissions. Minor revisions to the draft emissions inventory issued by the ARB have been made to this figure to make historic values compatible with the projections. ARB has not indicated that reaching the 1990 level would be a goal for individual greenhouse gas emitting sectors rather than as an overall goal for all greenhouse gas emissions.

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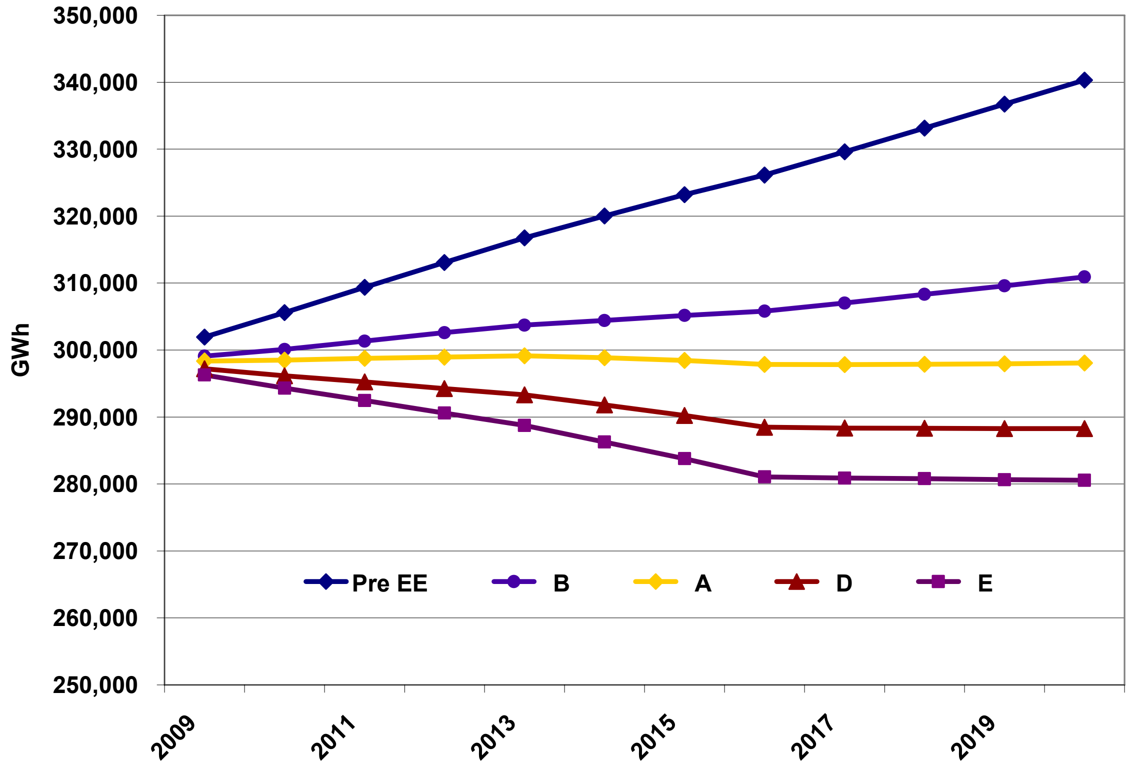
[65] For an explanation and discussion of Cases 4A and 4B, which represent high renewables only, see California Energy Commission, July 2007, *Scenario Analyses of California's Electricity System: Preliminary Results for the 2007 Integrated Policy Report,* staff draft report, CEC 200-2007-010.

Figure 3-3: Projected Cumulative Impacts on Net Energy for Load

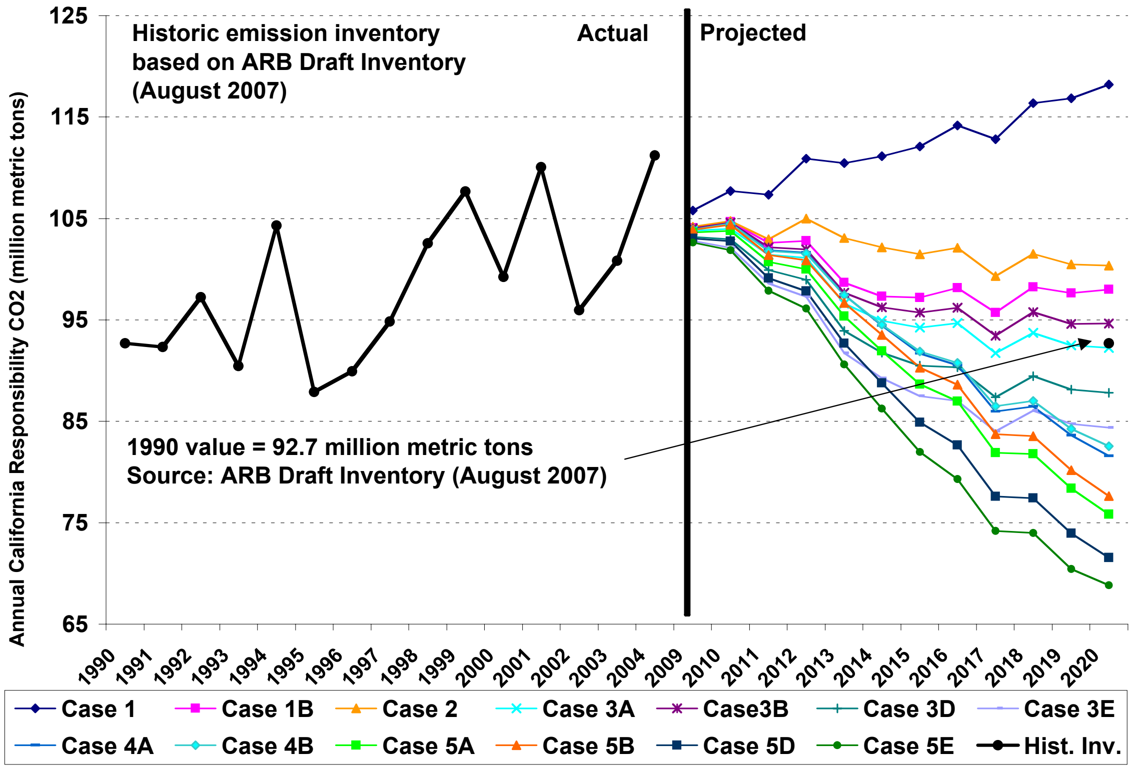


Source: Navigant Consulting, Inc.

The results show that even without significant contributions from renewable resources, the investment in energy efficiency within California included in Case 3A would reduce emissions within this range. Including the more aggressive energy efficiency investments envisioned in Cases 3D and 3E, the proportional contribution level is exceeded. Furthermore, all the cases with high renewables (Cases 4A and 4B) or high energy efficiency combined with high renewables (Cases 5A through 5E) exceed the proportional contribution – in the highest contribution cases, by a significant margin. The scenario results indicate that a more than proportionate contribution toward the AB 32 goals from the electricity sector is feasible and may even be necessary if the multi-sector goal is to be achieved.

Cases 3A, 3D, and 3E reflect successively decreasing levels of emissions by 2020 (Table 3-1). In them, the cost per unit of greenhouse gas reduction from alternative levels of energy efficiency is relatively constant and negative (Table 3-2). The energy efficiency modeled is less costly than the generating resources it displaces, so not only does it provide a public good in emission reductions, it saves direct ratepayer expenditures.

Figure 3-4: California Carbon Dioxide Responsibility through Time by Case (Includes In-State Generation, Remote Generation, and Net Imports)



Source: California Energy Commission. Adapted from Figure 8, *Scenario Analyses of California's Electricity System: Preliminary Results for the 2007 Integrated Energy Policy Report, Third Addendum*, p. 16. CEC-200-2007-010-AD3.

Table 3-1: Predicted Greenhouse Gas Emissions for California in 2020 (Thousand Tons of Carbon Dioxide per Year)

Annual CO_2 (000 metric tons)	Case 1B	Case 3A	Case 3D	Case 3E	Case 5A	Case 5D	Case 5E
Total California Responsibility	97,982	92,243	87,822	84,376	75,814	71,570	68,852

Source: California Energy Commission. Adapted from Table 4, Scenario Analyses of California's Electricity System: Preliminary Results for the 2007 Integrated Energy Policy Report, Third Addendum, p. 20. CEC-200-2007-010-AD3. September 2007.

Table 3-2: Measuring Cost Effectiveness of Strategies by Assessing Differences from Case 1B

	2020 System Cost Difference	2020 Greenhouse Gas California Responsibility Emission Difference	2020 Reduction ($/ton)
Case 1B	-	-	NA
Case 3A	(652,394)	(5,738)	(113.69)
Case 3D	(1,172,584)	(10,160)	(115.42)
Case 3E	(1,569,955)	(13,606)	(115.39)

Source: Global Energy Decisions, Inc.

The enhanced efficiency cases also depend on program designs that can achieve essentially all of the economic energy efficiency potential identified in the *2006 Itron Study*. Numerous studies have found that *actual* energy efficiency savings tend to be less than those identified in the economic potential studies. It is essential that the Energy Commission and CPUC combined efforts gain all cost-effective energy efficiency.

Achieving All Cost-Effective Energy Efficiency

Senate Bill 1037 (Kehoe, Chapter 366, Statutes of 2005) requires the CPUC, in consultation with the Energy Commission, to identify all potentially achievable cost-effective electric and natural gas energy efficiency measures for the investor-owned utilities, set targets for achieving this potential, and review the energy procurement plans of the investor-owned utilities to ensure the use of cost-effective supply alternatives. SB 1037 also requires all publicly owned utilities, regardless of size, to report investments in energy efficiency programs annually to their customers and to the Energy Commission.

Under Assembly Bill 2021 (Levine, Chapter 734, Statutes of 2006), the Energy Commission, in consultation with the CPUC and the publicly owned utilities, must produce a statewide estimate of "all potentially achievable cost-effective electricity and natural gas efficiency savings and establish targets for statewide annual energy efficiency savings and demand reduction for the next 10-year period."

Based on the *2006 Itron Study*, the remaining economic potential in 2016 for the investor-owned utilities and the publicly owned utilities is estimated to be 39,576 gigawatt hours, 6,597 megawatts, and 749 million therms, excluding the potential that might be available from emerging technologies. These values are indicated by a square on the next series of figures and are roughly equivalent to Scenario Case 3A. The emerging technologies represent an additional 12,000 gigawatt hours. In total, the savings targets proposed by the investor-owned utilities and publicly owned utilities for 2016 were 27,908 gigawatt hours, 5,880 megawatts, and 544 million therms.

With their current programs (extended through 2013), the investor-owned utilities would achieve savings equivalent to 71 percent of the identified electricity economic potential by the end of the 10 years. This ratio assumes that the CPUC will direct the investor-owned utilities to achieve savings at a rate at least equal to the annual savings in 2013, the last year covered by D.04-09-060, the governing decision.

Based on their targets proposed to the Energy Commission in June 2007, the publicly owned utilities intend to achieve 56 percent of their identified electricity economic potential by 2016. On a statewide basis, the investor-owned utilities and the publicly owned utilities, combined, are expecting to achieve 67 percent of their economic potential if they meet their proposed 10-year savings targets.

The Energy Commission has determined that a statewide efficiency target should be set at 100 percent of economic potential. The Energy Commission expects the state to achieve these targets through a combination of utility and non-utility programs coordinated at the state level by the Energy Commission and the CPUC. These efforts will include more expansive building standards, legislation or regulations requiring energy improvements at the time of a building's sale, local ordinances or codes affecting energy use, pursuit of emerging technologies, programs combining efficiency with renewables, new federal and state appliance standards, improved compliance mechanisms, and other programs that will result in long-term, sustainable savings.

The CPUC's October 18, 2007 decision concerning future savings goals from investor-owned utility programs orders a statewide energy efficiency strategic planning effort and greater statewide collaboration on energy efficiency and integration of program efforts and commits to working with the Energy Commission to achieve all cost-effective and feasible energy efficiency in the state. The decision expects that investor-owned utilities, in addition to their ongoing role as administrators of ratepayer-funded efficiency programs, would maximize the potential of their program efforts through collaboration with others planning and implementing programs to save energy. The publicly owned utilities should likewise maximize the potential of their program efforts through collaboration with the Energy Commission and other energy efficiency planning and implementing entities.

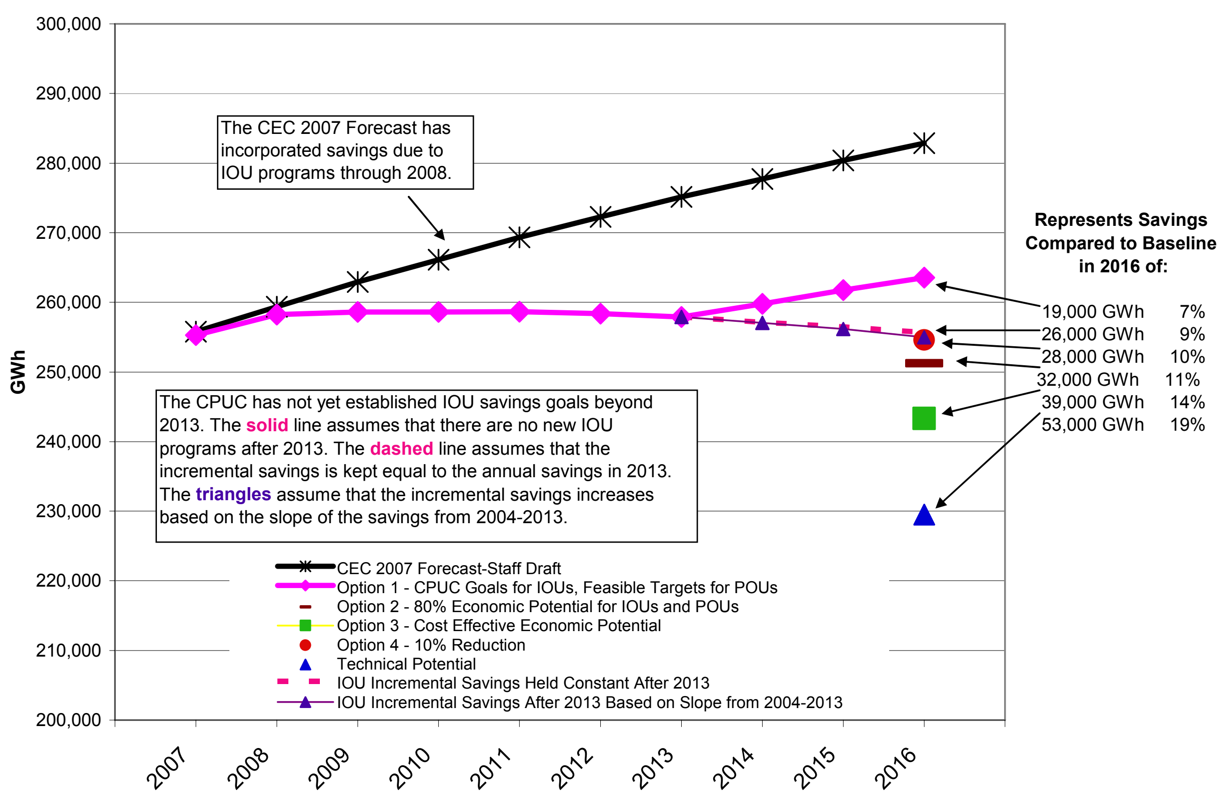
The CPUC's October 18, 2007 decision also advocates the use of utility efficiency program funds to support the Energy Commission's building standards efforts to achieve zero net energy residential buildings by 2020 and commercial buildings by 2030. The Energy Commission endorses these ambitious goals and will, with support from the

CPUC and the utilities, strive to achieve them through successive cycles of the building standards and appliance standards in combination with other program efforts.

New market-based approaches, such as "white tags" or "white certificates," which are the equivalent of renewable energy credits, should also be considered. Each certificate would represent 1 megawatt hour of energy savings and its associated carbon reduction. Renewable credits are tied to creating renewable generation and are measured by meter readings. "White tags" are created by reductions in energy use and are measured through software and control technology, but they can be sold or traded just as the renewable energy credits in a carbon market. This approach has not been extensively considered for California at this point but should be explored as an AB 32 compliance strategy. The Energy Commission and the CPUC should carefully study the role voluntary market instruments like white tags can play in closing the gap between utility programs, mandatory standards, and economic potential.

Figure 3-5 illustrates the impact of four possible savings targets on reducing forecasted statewide investor-owned utility and publicly owned utility customer electricity consumption.

Figure 3-5: Investor-Owned Utility and Publicly Owned Utility Electric Energy Consumption 2007–2016

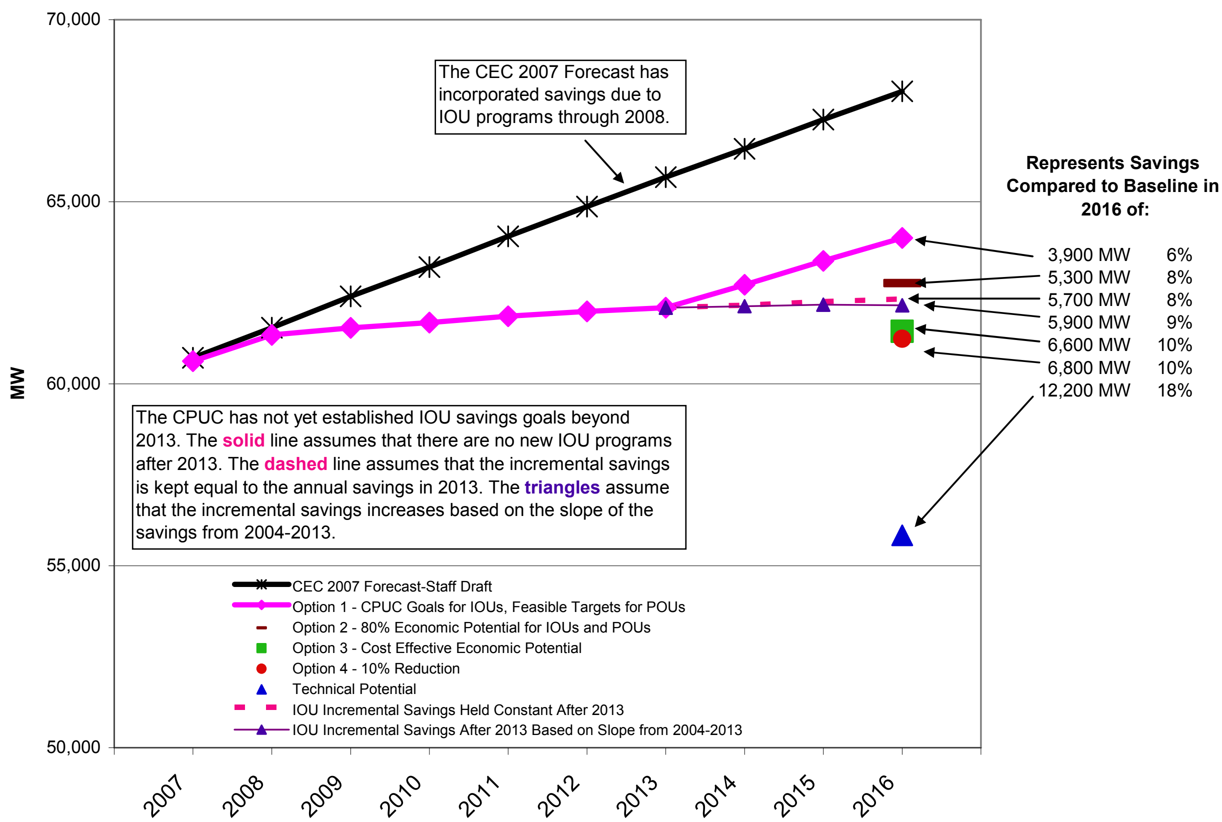


Source: California Energy Commission. From *Statewide Energy Efficiency Potential Estimates and Targets for California Utilities*, pp. 66-68. CEC-200-2007-019-SD, August 2007.

The top line shows the projected demand for electricity absent the effects of incremental investor-owned utility or publicly owned utility efficiency programs, for the period 2007–2016 for the publicly owned utilities and 2009–2016 for the investor-owned utilities. The dashed line shows the resulting statewide consumption if both the publicly owned utilities and investor-owned utilities are successful in meeting the energy savings targets proposed by the publicly owned utilities to the Energy Commission and adopted by the CPUC for the investor-owned utilities and extended at the incremental 2013 rate through 2016 (Option 1). The other lines and symbols on this graph show the potential impact of achieving the higher savings goal of the investor-owned utilities and publicly owned utilities obtaining 80 percent of their economic potential (Option 2), investor-owned utilities and publicly owned utilities achieving all cost-effective economic potential (Option 3), obtaining a 10 percent reduction in consumption in 2016 (Option 4), and achieving the total technical potential. Emerging technologies are not included.

Figure 3-6 illustrates the same cases for peak demand. For peak electrical demand, the investor-owned utilities' proposed goals would achieve 95 percent of the economic potential, while the publicly owned utilities are projecting to achieve 62 percent.

Figure 3-6: Investor-Owned Utility and Publicly Owned Utility Peak Demand 2007–2016



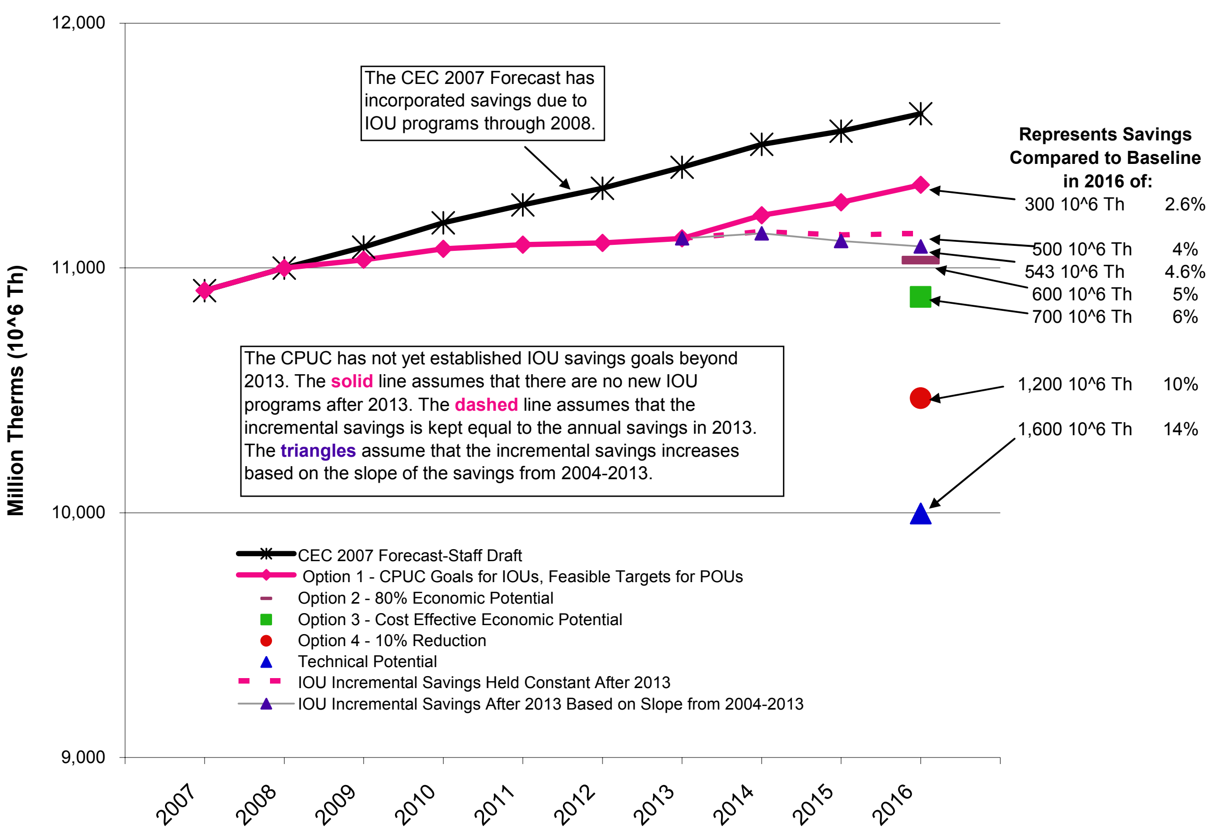
Source: California Energy Commission. From *Statewide Energy Efficiency Potential Estimates and Targets for California Utilities*, pp. 66-68. CEC-200-2007-019-SD, August 2007.

Combined, the investor-owned utilities and publicly owned utilities would achieve 85 percent of the remaining economic potential for peak electricity demand savings by 2016, excluding emerging technologies. This would reduce peak demand growth by 6 to 8 percent in 2016, depending on the investor-owned utility goals, or meet 70 percent of the expected growth over the next 10 years.

Natural gas efficiency targets are proposed in Figure 3-7 capture a smaller percentage of the economic potential than the electricity efficiency targets. The investor-owned utilities would achieve 65 percent of the economic potential and the publicly owned utilities, 21 percent. Since the overwhelming portion of the natural gas consumption is represented by the investor-owned utilities, the combined percentage is also 65 percent of the economic potential.

For natural gas, proposed savings targets (predominantly investor-owned utilities) will reduce forecasted consumption by 2 to 4 percent in 2016 and capture 68 percent of the growth between 2007 and 2016.

Figure 3-7: Investor-Owned Utility and Publicly Owned Utility Natural Gas Consumption 2007–2016



Source: California Energy Commission. From *Statewide Energy Efficiency Potential Estimates and Targets for California Utilities*, pp. 66-68. CEC-200-2007-019-SD, August 2007.

The publicly owned utilities have made considerable progress in developing estimates of economic potential, but there remains a wide variation in the proposed targets and program ramp-up rates for these utilities. Thirteen of the 39 publicly owned utilities account for 93 percent of the consumption. Using a metric of savings to sales (consumption) ratio annualized over 10 years, these utilities group into three natural clusters: one lower group clustering around 0.2 to 0.3 percent, a middle group clustering near 0.4 to 0.6 percent, and a higher group clustering between 0.7 and 1.5 percent. In some cases, the proposed annual increases in program budgets and expected savings exceed anything historically achieved by the investor-owned utilities. Given that other publicly owned utilities have experience with efficiency and know their customer base and local conditions well, and that they can learn from the experiences of the investor-owned utilities, the Energy Commission supports setting aggressive ramp ups.

AB 2021 gives the Energy Commission authority to make recommendations for improvements in publicly owned utility efficiency program strategies or targets if necessary in the intervening years. The Energy Commission expects to provide recommendations as appropriate and also expects to specifically describe acceptable evaluation measurement and verification techniques and define both methods and metrics for tracking progress toward the targets and reporting them.

New Solar Homes Partnership

At the direction of Governor Schwarzenegger, the California Solar Initiative was approved by the California Public Utilities Commission (CPUC) on January 12, 2006. The initiative creates a $3.3 billion 10-year program to put solar on a million roofs in the state. Under the initiative, the CPUC oversees a program to provide incentives for existing residential customers and all non-residential customers, while the Energy Commission manages a program to encourage solar in new home construction, the New Solar Homes Partnership (NSHP).

The NSHP is a 10-year, $400 million program that targets single family, low-income, and multi-family housing. The program incorporates high levels of energy efficiency and high-performing solar systems to help create a self-sustaining solar market in which home buyers demand energy-efficient solar homes.

By October 2007, the NSHP had received applications for 1,287 building structures, primarily in Northern California, and has approved applications for 575 structures totaling about 1.2 megawatts of capacity. Housing developments represent most of the applications and include large developers like Lennar, Centex, Meritage, and Christopherson and smaller developers like Coastal View Construction, Pacific Century, KD Development, and Armstrong Construction.

Energy Savings from Building Standards

The Energy Commission is in the process of developing the next version of building standards expected to be adopted in 2008. Some of the efficiency features that are expected to be in the final version of the standards include updated lighting and mechanical measures, cool roofs for residential applications, better controls for central hot water distribution, residential programmable communicating thermostats and nonresidential demand shedding controls for demand response capabilities, a new optional compliance tier for photovoltaic systems, and updated nonresidential outdoor lighting requirements.

The Energy Commission has coupled energy efficiency with promotion of solar photovoltaic systems through its New Solar Homes Partnership. To qualify for a photovoltaic incentive, the new home has to exceed the Title 24 building efficiency code by a minimum of 15 percent. This efficiency-first philosophy allows the photovoltaic system to cover more of the building's electric load. Builders are encouraged to exceed the code by 35 percent. These levels were selected so the builders could qualify for efficiency incentives from the utility programs.

Title 24 Building Codes and Standards: Considering a "Zero Net Energy" Future

SB 1 requires the Energy Commission to examine whether solar photovoltaics should be mandated in future building standards. This study must identify all life cycle costs and benefits and demonstrate that solar photovoltaic systems are cost effective in order to include them in the Title 24 building standards. Periodic updates are required.

The California Public Utilities Commission, through its "Big Bold Energy Efficiency Strategies," has adopted three programs designed to move all new residential and commercial construction to a zero net energy standard. The goal of this program is to reach zero net energy in residential construction by 2020 and in commercial construction by 2030.

Southern California Edison Chairman and Chief Executive Officer Alan J. Fohrer said that "significant additional progress will be made as a result of this new policy…Now the commission has made advancing customer energy efficiency the business of every department and employee of an investor-owned utility." The Energy Commission applauds the CPUC's significant advancement of energy efficiency programs. Together, success with these programs can result in changing the paradigm for energy growth in California.

For the building standards to reach the aggressive goals described in the various policy reports, initiatives, and legislation, the Energy Commission will have to consider vigorous efficiency coupled with technologies like solar photovoltaic systems. The Energy Commission recently initiated the investigative process required by Senate Bill 1 to determine whether solar photovoltaic systems should be mandated in future building standards.

Several bills were introduced, but failed to pass, this legislative session to encourage or mandate green building practices in the residential, commercial, and state building sectors. Nevertheless, both the Department of Housing and Community Development (for residences) and the California Building Standards Commission (for all building sectors) continue to be engaged in the goal of creating a green building guideline to publish in the California Building Code.

In view of the importance that expanded efficiency efforts will play in achieving the AB 32 goals, the Energy Commission will pursue legislation to require an on-site audit and an appropriate level of cost-effective efficiency improvements in existing buildings at time of sale. Absent that legislative authority at this point, the Energy Commission issued a booklet directed at homebuyers that provides information about home energy audits and rating programs. We are marketing this information through home warranty company websites.

Energy Savings from Appliance Standards

The Energy Commission is considering what appliances may be covered in the next round of appliance standards. The most recent round of standards improved efficiency for a variety of consumer audio and video equipment, power supplies for a variety of consumer equipment, and residential lighting, among other appliances. The next round of standards is likely to cover battery chargers, commercial lighting systems, and – most significantly – residential lighting efficiency.

Improving the efficiency of electric lighting in California offers a cost-effective path to reducing energy use and greenhouse gas emissions. The greatest opportunity for saving lighting energy in California residences lies in addressing the continuing prevalence of incandescent lamps. This is already done, in part, by the building standards for new and renovated housing, but it affects only a small proportion of all houses each year. The majority of sockets in existing houses are still occupied by incandescent lamps, which have an efficacy (amount of light provided per amount of electrical power consumed) in the region of 10–17 lumens per watt. When compared with the 45–70 lumens per watt of currently available in compact fluorescent lamps, incandescent lamps are clearly very inefficient.[66]

The efficacy of incandescent lamps could be increased by 30 percent with technology presently available, such as halogen capsules with infrared coatings. These technologies, while cost-effective in most uses, are significantly more expensive than standard incandescents. Industry stakeholders suggest that, with additional technological improvements, incandescent efficiency could even exceed 40 lumens per watt. Meanwhile, emerging light-emitting diode (LED) sources currently achieve 40 lumens per watt, could achieve 60 lumens per watt in a few years, and could even reach 100 lumens per watt some time in the next decade.[67] These sources currently cost significantly more than today's common lighting alternatives, but also have significantly longer lifetimes.

In residential construction, the Energy Commission's 2005 Building Standards increased requirements for fluorescent-level lamp efficiency in kitchens and required either high-efficiency or sensor-controlled lights in bathrooms, laundries, garages, and utility rooms. In addition, the Energy Commission's latest Title 20 appliance regulations require more efficient lamps for general purpose uses. These standards removed the least efficient incandescent general service lamps from circulation in 2006. In 2008, the next tier of requirements will take effect, reducing wattages of general service incandescent lamps by approximately 5 percent, encouraging manufacturers to pursue improvements in efficiency. In the Climate Action Team's early action report, the Energy Commission has

[66] Fernandes, L., *Efficiency Opportunities for Edison-Based Luminaires*, California Lighting Technology Center, September 12, 2007, p. 3.

[67] Ibid, p. 3

committed to updating its lighting standards by January 1, 2010, to address the challenge of further reducing greenhouse gas emissions.

This year, the Governor signed into law Assembly Bill 1109 (Huffman), which requires the Energy Commission to develop regulations to reduce the average energy used for residential general service lighting by 50 percent by 2018. Lighting industry support for this bill carries a potent message about the level of efficiency gain prudently achievable.

Other states have taken action to address lighting energy efficiency as well. In Nevada, in June 2007, the governor signed a bill (AB.178) banning lamps under 25 lumens per watt after 2012. Connecticut, Minnesota, New York, New Jersey, North Carolina, South Carolina, and Rhode Island have all introduced bills that in various ways restrict or ban the sale of incandescent lamps.

The Water-Energy Nexus

In the 2005 IEPR, the Energy Commission explored the relationship between water and energy in California, finding that "significant untapped potential for energy savings exists in programs focused on water use efficiency." Since 2005, there has been limited progress in expanding current utility energy efficiency programs to include water efficiency measures. In March of 2006, the CPUC committed to exploring inclusion of water efficiency measures in investor-owned utility programs, but has yet to implement the limited scope water-energy pilot projects planned to inform the 2009–2011 energy efficiency program cycle.

The Energy Commission reiterates the need to capture the energy savings benefits of water use efficiency, especially in light of climate change. Potential actions include:

- Standardizing and increasing the evaluation and monitoring of water efficiency programs to ensure the delivery of savings and benefits
- Implementing appropriate mandates, incentives, and funding to maximize the water efficiency potential of existing buildings and new construction
- Assessing the energy savings potential and associated greenhouse gas emission reductions from aggressive levels of water efficiency and recycling
- Identifying energy intensive water use by hydrologic region and alternatives for reducing energy intensity of water use in each region
- Fully incorporating water efficiency into the 2009–2011 energy efficiency program cycle
- Modifying CPUC or other state policies as necessary to allow for all energy savings associated with water efficiency or recycling to be included in any cost effectiveness analysis and developing accounting mechanisms as necessary to credit costs and savings appropriately

The Energy Commission is committed to using its Building and Appliance Efficiency Standards authority to save both water and energy. Most recently, Governor Schwarzenegger signed AB 662 (Ruskin, Chapter 531, Statutes of 2007) and AB 1560 (Huffman, Chapter 532, Statutes of 2007) expanding and reinforcing the Energy Commission's authority to establish water conservation and efficiency standards for both buildings and appliances. The Energy Commission will define a Water-Energy Research Development and Demonstration Strategic Plan and Roadmap that explores ways to reduce the energy intensity of the water use cycle and better manage the energy demands of the water system. These actions will be done in coordination with other agencies' efforts and those of the utilities to maximize the effectiveness of these efforts.

Federal Lighting Standards Proposals

The National Electrical Manufacturers Association has supported federal legislation to increase the minimum efficacy standards for incandescent lamps, corresponding to an efficacy increase of approximately 28 percent, to be gradually phased in until 2018. This would be accomplished by adopting halogen capsules, infrared coatings, and other technologies to provide similar light output with lamps that are required to have lower wattage.

Both the U.S. Senate and House of Representatives are considering legislation to improve the efficiency of residential, general purpose lighting. In the Senate, S.2017 (the Energy Efficient Lighting for a Brighter Tomorrow Act) would establish wattage caps for ranges of lumen output and deadlines for manufacturers to comply with the caps. S.2017 also includes a "second tier" of standards to be adopted by 2017 that would require general service lamps to achieve efficiencies of 50 lumens per watt by 2020.

The House of Representatives version of the energy bill (HR.3221) takes a similar approach. It requires minimum efficacies for several lumen ranges, phased in between 2012 and 2014. It also includes a "second tier" standard that would achieve efficiencies of about 45 lumens per watt after 2020, and it prohibits the sale of 100 watt incandescent lamps after January 1, 2012, unless their efficacy is at least 60 lumens per watt.

While both bills include preemption of state standards to improve general service lighting efficiency, HR.3221 provides more flexibility than S.2017. Specifically, the House bill would allow states to modify their standards to reflect the provisions in federal law with earlier enforcement dates.

Either of these approaches would improve the efficiency of residential lighting. The accompanying preemption provisions, however, are poor policy. Reasonable state standards do not present an undue burden to industry on a national level. Industries already routinely ship and distribute appliances with different performance characteristics to different regions of the country. In fact, the lighting market is an international marketplace, with a variety of standards efforts addressing general service lighting.

The federal proposals would not provide sufficient savings to achieve California's AB 1109 targets by 2018.[68] Achieving the goals of that legislation will require increased use of the most efficient lighting options and a concerted effort to increase the efficiency of existing incandescent technologies. Customer education and information, lamp appliance standards, incentives to encourage use of efficient technologies, and stricter building codes are all tools that could be employed to achieve these goals.

[68] Op cit., California Lighting Technology Center, p. 36.

International Lighting Standards Proposals

In February of this year, Australia put forth a proposal to impose stricter efficacy standards for the majority of general service lamps. Beginning in 2008, standard general service lamps in Australia must meet an efficiency curve that is about 18–22 lumens per watt, depending on lamp wattage. By 2014, other lamps such as candle shaped and round shaped lamps must meet the same standard. Australia would then consider a second tier of standards to become effective in 2016.

The Canadian government announced last April that it intends to phase out inefficient lighting by 2012, using non-technology-specific national standards. These standards are currently being developed, taking into account the potential effects on the Canadian lighting market.

In the European Union, under a 2005 European Commission directive to regulate products that have an energy and environmental impact, a study is ongoing to develop standards for office lighting (linear fluorescent and non-integrated compact fluorescent lamps), and a new study targeting residential lighting has been launched this summer. The standards are to be ready in 2008 and 2009, respectively. Meanwhile, the European Lighting Council – a European counterpart to the National Electrical Manufacturers Association – has made public a proposal for Europe-wide regulation that, although divided into two stages of increasing stringency, is quite similar to federal legislation in the United States with slight differences in efficacy levels. Independently of European Union-wide activity, individual European countries have proposed or taken measures to curb the least efficient types of lamps.

Investor-Owned Utility Efficiency Programs

In September 2004, the CPUC adopted the 10-year savings goals shown in Table 3-3 for the state's three electric and three natural gas investor-owned utilities. The CPUC is currently considering whether to update these goals for 2009–2013 and how to extend them to 2020.

Table 3-3: Approved 2004–2013 CPUC Goals for Investor-Owned Utilities

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
Total Annual Electricity Savings (GWh/yr)	1,838	1,838	2,032	2,275	2,505	2,538	2,465	2,513	2,547	2,631
Total Cumulative Savings (GWh/yr)	1,838	3,677	5,709	7,984	10,489	13,027	15,492	18,005	20,552	23,183
Total Peak Savings (MW)	379	757	1,199	1,677	2,205	2,740	3,259	3,789	4,328	4,885
Total Annual Natural Gas Savings (MMTh/yr)	21	21	30	37	44	52	54	57	61	67
Total Cumulative Natural Gas Savings (MMTh/yr)	21	42	72	110	154	206	260	316	377	444

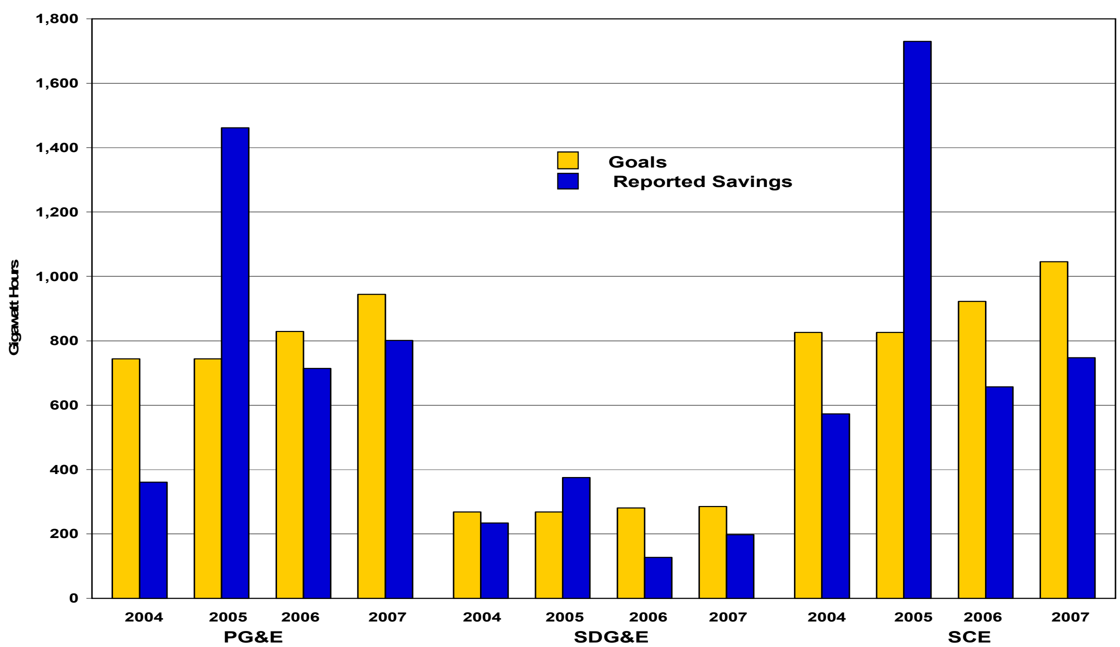
Source: CPUC Decision 04-09-060, September 23, 2004, *Interim Opinion: Energy Savings Goals for Program Year 2006 and Beyond*

The goals are based on a 2002 perspective on technologies, utility program designs, and price levels and may therefore understate the amount of future potential available in 2007. The adopted cumulative 2013 goal for net savings captures 91 percent of the "achievable" potential and 68 percent of the economic potential thought to be available based on the 2002 study. The 2002 potential studies that were used to set the existing goals, however, showed total economic potential to be less than 65 percent of the technical potential and the range (dependent on funding) of achievable potential through utility incentive programs to be from 20 to 60 percent of the economic potential.[69]

For the 2004–2005 program cycle, the investor-owned utilities planned energy efficiency savings of 4,600 gigawatt hours, 757 megawatts, and 42 million therms and a total expenditure of $965 million, of which they spent approximately $672 million. For the 2006–2008 efficiency program cycle, the investor-owned utilities budgeted a total of $2 billion for three years of efficiency programs for projected savings of 6,800 gigawatt hours in reduced annual electricity consumption, 1,000 megawatts in peak demand reduction, and 111 million therms of natural gas. As of July 2007, the investor-owned utilities have spent approximately $747 million of their $2 billion budget, with another $200 million in commitments.

Figure 3-8 compares the 2004–2007 program electric energy savings accomplishments to the goals. The utilities exceeded their goals in 2005, but did not meet their goals in 2004 or 2006.

Figure 3-8: Investor-Owned Utility Electricity Goals Compared to Reported Savings (2004–2007)

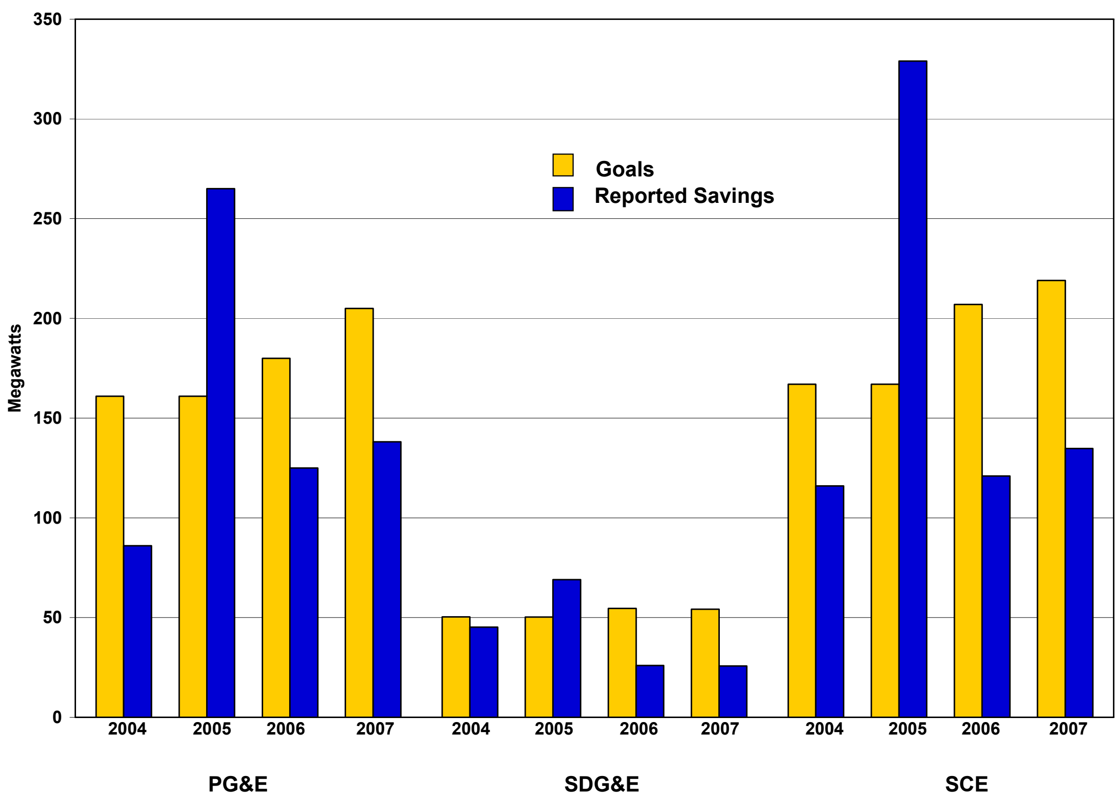


Source: California Energy Commission. Based on investor-owned utility quarterly reports to the California Public Utilities Commission.

[69] Kema-Xenergy, *California's Secret Surplus: The Potential for Energy Efficiency, Final Report*, submitted to Energy Foundation and Hewlett Foundation, September 23, 2002.

Slow program-start-up likely contributed to the failure to meet the goals in 2004 and 2006, each year being the first year in a new program cycle. Utilities did better in 2005 as the programs matured and savings committed in 2004 were actually realized. In fact, electricity savings in 2005 increased by more than 68 percent on average over savings achieved in 2004. The year 2005 represents the last year utilities were allowed to count commitments to install in a future year as part of their current year's reported savings. This change in rules contributes to sharp drop off in 2006, but may enhance the credibility of claimed savings levels. Program savings in 2007 are through July. Figure 3-9 compares the investor-owned utilities' yearly peak demand savings goals to their yearly reported accomplishments. None of the investor-owned utilities met their demand savings goals in 2004 or 2006, but all utilities exceeded their goals in 2005, the second year of a program cycle. Combining the two program years of 2004 and 2005, Southern California Edison exceeded its goals by nearly 60 percent. The 2006–2008 program cycle exhibits a similar increased rate of savings in the second year.

Figure 3-9: Investor-Owned Utility Peak Demand Goals Compared to Reported Savings (2004–2007)

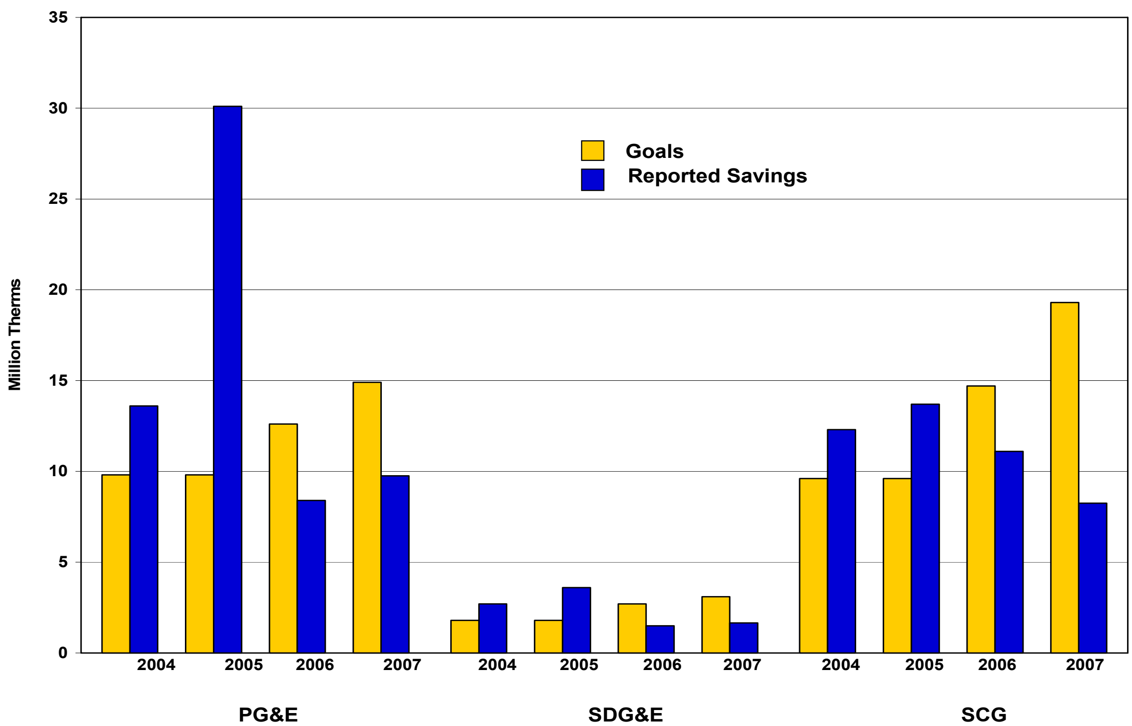


Source: California Energy Commission. Based on investor-owned utility quarterly reports to the California Public Utilities Commission.

Figure 3-10 illustrates first-year reported therm savings compared to investor-owned utility goals. All three gas utilities met their goals in 2004 and 2005, while none met their goals in 2006.

In 2004–2005, at least half of reported gigawatt hour savings came from lighting measures not already included in the Title 24 building standards. This share is as large as 80 percent in the residential sector, with the commercial sector being about half that amount. The smaller commercial share may reflect high commercial lighting accomplishments prior to this program cycle.

Figure 3-10: Investor-Owned Utility Therm Goals Compared to Reported Savings (2004 – 2007)

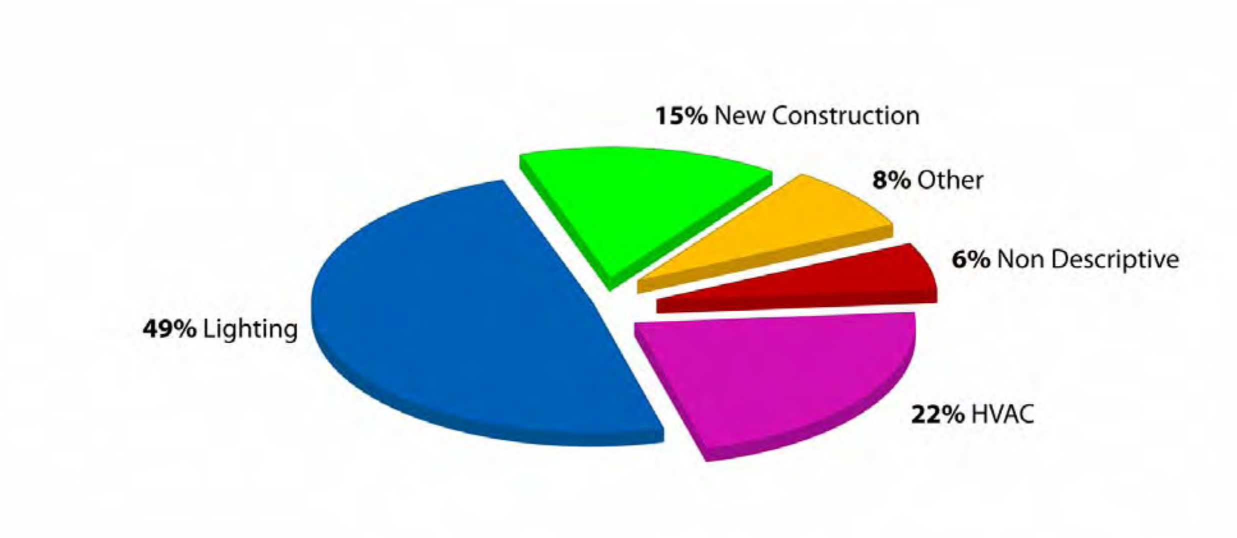


Source: California Energy Commission. Based on investor-owned utility quarterly reports to the California Public Utilities Commission.

The decline in the new construction and HVAC shares largely reflects changes in reporting rules; utilities are no longer allowed to record savings until measures are actually installed. Lead times for savings are longer in these two program areas.

Lighting accounted for a slightly smaller share of demand savings than energy savings – 49 percent in 2004–2005 – and continues to be the largest contributor in the next program cycle, rising to 60 percent of reported savings in the 2006–2008 portfolio (Figure 3-11). Commercial peak savings from lighting is nearly twice the size of residential savings.

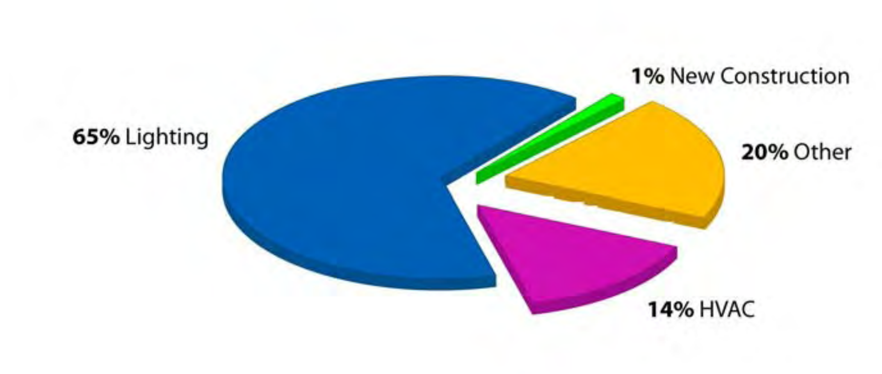
Figure 3-11: Investor-Owned Utility Reported Savings by End Use 2004–2005 (Megawatts)



Source: California Energy Commission. Based on investor-owned utility quarterly reports to the California Public Utilities Commission.

Peak savings from HVAC programs average 22 percent of the 2004–2005 savings, but in the current program cycle, the HVAC share has dropped to 14 percent of total peak savings as of July 2007. The lighting share of peak demand savings continues to increase (Figure 3-12).

Figure 3-12: Investor-Owned Utility Reported Savings by End Use 2006–2007(MW)



Source: California Energy Commission. Based on investor-owned utility quarterly reports to the California Public Utilities Commission.

On September 20, 2007, in decision D.07-09-043, the CPUC adopted a risk/reward incentive mechanism for investor-owned utility energy efficiency programs. The system will require each utility to achieve at least 85 percent of the adopted energy and peak savings targets for the period 2007–2008 before being eligible for performance-based incentives. All calculations of net benefits and savings are to be independently verified and will be based on cumulative achievements for the program cycle.

Earnings would be shared between shareholders and ratepayers and begin to accrue at 9 percent once 85 percent of the savings is verified. If 100 percent or more of the goal is reached, the earnings rate increases to 12 percent. This means, for example, that if a utility achieves 100 percent of the 2006–2008 savings goal, 88 percent of the verified net benefits or "performance earnings basis" (resource savings minus total portfolio costs) goes to ratepayers, and 12 percent goes to shareholders.

Utilities achieving below 65 percent of the goals would be subject to penalties (reductions in shareholder earnings) assessed at 5 cents per kilowatt hour, 45 cents per therm, and $25 per kilowatt. No earnings or penalties apply to performance that falls between 65 and 85 percent of efficiency goal achievement. This system is similar to the previous incentive system in place from 1992 to 1998, but provides a much lower incentive to the utility than previously when shareholders received 30 percent of the benefits and ratepayers received 70 percent. Earnings and rewards would be capped at $450 million for each program cycle.

Problems notwithstanding, evidence suggests that sufficient potential remains for utilities to achieve higher levels of savings. To do so, utilities, in collaboration with the CPUC and the Energy Commission, need to adopt innovative program designs and structures, such as combining efficiency with renewable programs, greater interconnection with statewide standards, and consideration of white tags.

The CPUC decision of October 18, 2007, directs the investor-owned utilities to prepare a "single comprehensive statewide long-term energy efficiency plan." Three programmatic initiatives form the centerpiece of an expanded "next generation" efficiency effort:

- All new residential construction in California will be zero net energy by 2020.
- All new commercial construction in California will be zero net energy by 2030.
- Heating, ventilation, and air conditioning will be reshaped to ensure optimal equipment performance.

Using Demand Response to Meet Electric System Peaks

Demand response can play a critical role as a resource in California's electricity planning mix. Price-responsive demand response, coupled with advanced metering infrastructure,[70] improves the level of service provided to electricity customers and has the potential to cost-effectively avoid incremental generating capacity costs, energy production costs, and transmission and distribution capacity costs. Despite its many advantages, price-responsive demand response is expected to reduce peak demand by only 2.2 percent in the summer of 2007, which is less than half of the goal of 5 percent laid out in the *Electricity Action Plan II.*[71]

In addition, reliability-triggered demand response promotes system reliability by providing the California Independent System Operator (California ISO) with tools to manage demand during peak days, as well as prevent brownouts and blackouts during emergency situations.

Potential Savings from Demand Response

The potential reduction in peak demand that can be achieved through price-responsive demand response programs depends on the amount of coincident demand that is reduced per customer and on the number of participating customers. As with energy efficiency programs, it is normal practice to assess three levels of demand impacts: technical potential, economic potential, and market potential.[72]

- "Technical potential" measures the outcome if all customers use the best available demand response technology. In the residential class, this is the gateway system, which allows homeowners to automatically manage electricity consumption at several points of end use, including stereos, appliances, and air conditioning units. The gateway system has the potential for lowering peak demand by 43 percent, as demonstrated by the advanced demand response system subset of the statewide

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[70] Advanced metering infrastructure refers to the hardware and software that allow utilities to remotely collect energy usage and status data from customers; transmit and receive information from utility servers to customer sites and potentially to third parties; and bill customers for their usage based on time-differentiated prices.

[71] If reliability-triggered programs are included as well, the utilities are expected to achieve a 5.7 percent reduction in peak demand. However, reliability-triggered programs are not part of the 5 percent target. This is elaborated upon in *The State of Demand Response in California*, by Ahmad Faruqui and Ryan Hledik, a draft consultant report prepared for the California Energy Commission, April 2007. That document is hereafter referenced as *State of Demand Response*.

[72] It should be noted that these projections are in addition to the current peak reductions achieved through reliability-triggered demand response. For a description of the distinction between price-responsive demand response and reliability-triggered demand response programs, see pp. 8–9 of *State of Demand Response*.

pricing pilot. In the commercial and industrial classes, automated demand response programs that control multiple end-use loads and leverage the energy management control system that is installed in most facilities are projected to reduce demand by 13 percent, as demonstrated by work carried out by the Demand Response Research Center. A weighted average over all customer classes leads to an estimate of roughly 25 percent for the technical potential of demand response.[73]

- "Economic potential" measures what would happen if all customers used a cost-effective combination of technologies rather than the best available technologies. This produces an estimate of the economic potential for demand reduction through demand response programs of approximately 12 percent. To illustrate this computation for the residential class: customers in the California experiment without an enabling technology lowered their peak usage by 13 percent. Those with a smart thermostat lowered peak usage by 27 percent, and those with the gateway system lowered peak usage by 43 percent. If 70 percent of the customers chose no enabling technology, 20 percent chose the smart thermostat, and 10 percent chose the gateway system, the result would yield a weighted average estimate of approximately 19 percent for the residential class. Corresponding values for the commercial and industrial classes are roughly 7 percent and 9 percent.
- "Market potential" (or "achievable potential") measures what would happen if a cost-effective combination of technologies is adopted at some assumed level of penetration in the marketplace. It differs from economic potential, which assumes that all customers accept dynamic pricing. Thus, the key unknown in estimating market potential is the number of participating customers. This, of course, depends on the conditions under which dynamic pricing is offered to customers. It is also contingent on the availability of advanced metering infrastructure, which is currently limited to customers above 200 kilowatts, but is likely to be deployed for all customers in the state during the next five years. Experience in other restructured states indicates that if the CPUC makes dynamic pricing the default rate, a larger fraction of customers would stay on it than they would if it were offered on an optional basis. The limited literature on the topic suggests that about 80 percent would stay on dynamic pricing if it is offered as the default rate and that a substantially smaller number, perhaps 20 percent, would select it on a voluntary basis. In its initial analysis, the staff assumes that the actual number is likely to be somewhere in the middle. This yields an estimate of approximately 5 percent. Obviously, programs that achieve greater customer participation will yield greater savings.

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[73] Much higher responses are possible in specific facilities that have time-flexible production processes, energy storage systems, and back-up generation. Since these are highly facility-specific, they have not been included in staff's estimate of technical potential.

Achieving even a 5 percent peak demand reduction would yield several benefits for California. Three of the benefits can be quantified in a preliminary projection. The first and most significant benefit would be the reduction in necessary peaking generation capacity. This would be a long-run benefit, consisting of the sum of avoided capacity and energy costs. It could be readily estimated based on the capacity cost of a combustion turbine. The second benefit would be the avoided energy cost that is associated with the reduced peak load. Third would be the reduction in needed transmission and distribution capacity.

The aforementioned avoided capacity cost benefit is calculated by quantifying and valuing the amount of capacity that would be avoided by the 5 percent reduction in peak demand. A 5 percent reduction in California peak demand of approximately 61,008 megawatts amounts to 3,050 megawatts of avoided peak demand. The amount of peaking capacity necessary to meet this peak demand can be computed by allowing for a reserve margin of 15 percent and line losses of 8 percent. This amounts to 3,789 megawatts, or roughly the output of 50 combustion turbines.[74] A conservative value of the avoided cost of generation capacity is $52 per kilowatt-year.[75] Thus, the total value of avoided generation capacity costs would be roughly $200 million per year.

Illustratively, the four combustion turbines installed by SCE this summer were more expensive – the same methodology would value that capacity at $101 per kilowatt year.[76] Using this as a benchmark, 3,100 megawatts of avoided generation capacity would be worth $380 million per year.

Using the relationship that was observed between annual generation capacity and energy benefits in a recent PJM Interconnection, LLC analysis of demand response, the annual value of avoided energy costs is estimated at around $20 million.[77]

In addition, there would be a reduction in transmission and distribution capacity needs. While these are system specific and depend on the coincidence between system and

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[74] These turbines come in sizes generally ranging from 50 megawatts to 100 megawatts.

[75] In R.02-06-001, the CPUC specified a value of $85 per kilowatt year. That value is widely accepted throughout the mainland United States. However, once the revenue stream associated with energy sales from the operation of the turbine is subtracted, a value of $52 per kilowatt year is obtained.

[76] The capital cost of the peakers is estimated at $245 million for 180 megawatts of capacity. We assumed a 7.6 percent discount rate and a 20-year life of the peakers. See *Comparative Costs of California Central Station Electricity Generation Technologies (2007 Update)*, draft staff report, June 2007, CEC-200-2007-011-SD, for the source of the financial assumptions.

[77] Sam Newell and Frank Felder, *Quantifying Demand Response Benefits in PJM*, study report prepared for PJM Interconnection, LLC and the Mid-Atlantic Distributed Resources Initiative, January 29, 2007.

local area peaks, they are unlikely to be zero. A conservative estimate is 10 percent of the savings in generation capacity and energy costs. Using this estimate would yield an estimate of roughly $20 million per year for savings in transmission and distribution costs.

Using the SCE peakers as the capacity benchmark, the benefits would be $470 million per year. Over a 20-year time horizon, the present value of demand response benefits could reach $3 billion or $5.5 billion measured against the SCE peakers.

Most of the barriers to adopting demand response measures are related to rate design issues, such as the need to deal with constraints created by the AB 1X residential rate freeze and customer acceptance issues. There are also analytical issues in this area, such as the need to modify existing cost-benefit methodologies for evaluating demand-side programs; to develop protocols for measuring demand response impacts; and to develop innovative rate designs that incorporate the risks of outages and high peak generation costs. Current efforts by the utilities and commissions to develop workable dynamic rate designs and effective protocols for measuring demand response impacts are steps toward solving these problems.

There is a dearth of customer understanding of the potential benefits from broad adoption of time-varying and dynamic rates, the impacts on their electricity costs from such a change, and the options they have for responding. In fact, the $3 billion calculated earlier as the present value benefit of a 5 percent demand response program can just as easily be seen as a measure of the hidden subsidies, which in the present time-insensitive rate structure provides that 5 percent of electricity demand that comes during peak load hours.

With well-designed rate designs in place, the focus must shift to overcoming the technological barriers to demand response. First is the need to install advanced metering infrastructure throughout the state. This is likely to happen over the next five years. To get the most from the advanced metering infrastructure investment, it may be necessary to equip the customer with enabling technologies and automation to facilitate reducing demand during critical peak times. The use of existing technologies that automate demand response should be integrated into program and tariff offerings, while further development of such technologies should continue.

Second, research has shown that customers provide a significantly higher level of demand response when equipped with enabling technologies that automate the response and facilitate the control of electricity consumption at multiple end-use points. Ultimately, these enabling technologies must be adopted on a large scale for California to approach its potential for demand response.

Establishing Load Management Standards

Since the 1970s, the Energy Commission has had the authority to establish and enforce load management standards for the state. The standards were created to provide the Energy Commission with the ability to develop programs for reducing peak demand and reshaping utility load duration curves. The Commission specifically is authorized to consider the following load management techniques, but its authority is not limited to these three:

- Adjustments in rate structure to encourage use of electrical energy at off-peak hours or to encourage control of daily electrical load. These adjustments in rate structure must be approved by the Public Utilities Commission in a proceeding to change rates or service and by publicly owned utilities for their service territories.
- End-use storage systems which store energy during off-peak periods for use during peak periods, such as thermal storage, pumped storage, and other storage systems.
- Mechanical and automatic devices and systems for the control of daily and seasonal peak loads.

The Energy Commission's load management authority is a valuable policy tool for the state to bridge the gap between the current level of demand response in California and its full cost-effective potential. In a joint IEPR and Electricity Committee workshop on demand response efforts on June 5, 2007, EnerNoc, Ice Energy, and Strategen Consulting encouraged the Energy Commission to use its load management authority to better achieve the state's demand response objectives. At the same workshop, Southern California Edison, San Diego Gas & Electric Company, and Pacific Gas and Electric Company all indicated support for the Energy Commission's effort to invoke its load management authority.

This policy tool may be particularly effective in two areas. One is modifying the default tariff, which could be changed to a dynamic tariff that reflects the higher cost of using electricity during critical peak hours and provides an incentive for lowering peak demand. The other is the adoption of technologies that enable customers to respond to the opportunities that dynamic pricing tariffs create.

Three illustrative load management proposals have been developed. One calls for replacing the default rate design with a dynamic pricing tariff, while the other two call for deploying enabling technologies directed at residential and non-residential customers.

In a scenario in which no load management standards are in place, dynamic pricing would probably be offered on an opt-in basis by the utilities as advanced metering infrastructure is rolled out to customers.[78] Once advanced metering infrastructure has

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[78] As proposed by Pacific Gas & Electric.

been fully deployed, dynamic pricing becomes feasible, but on an opt-in basis, it may not achieve a participation rate greater than 20 percent. In this scenario, customers would probably not be equipped with enabling technologies such as a smart thermostat. Under these assumptions, dynamic pricing could achieve a reduction in system peak demand of around 3 percent, representing over $1 billion in financial benefits over the next 20 years.[79]

In a second case in which a dynamic pricing standard is adopted in California, requiring that some form of dynamic pricing be offered as the default rate, 80 percent of customers are likely to stay on dynamic pricing, with the other 20 percent opting back to the old rate. Assuming that these dynamic pricing customers are not equipped with enabling technology, the peak demand reduction could increase to some 10 percent, representing financial benefits of nearly $6 billion. The incremental benefit of the dynamic pricing standard would be the difference between this and the previous calculation: an increase in peak demand reduction of roughly 7 percentage points and incremental financial benefits of around $4 billion.

If on top of the default dynamic pricing standard, another standard were imposed that required the installation of programmable communicating thermostats in all residential dwellings, the potential benefits would rise even further. The standard could require that all residential customers be equipped with programmable communicating thermostats that can receive price signals from the utilities and/or the independent system operator (California ISO) so their temperature setback would be raised by a few degrees during critical-priced periods. With this technology installed, the estimated peak reduction potential might increase incrementally by roughly 8 percentage points to around 18 percent.[80] The present value of the benefits would increase incrementally by around $5 billion to $10 billion.[81]

Finally, an automated demand response standard could be included with the programmable communicating thermostat standard and the dynamic pricing standard. This could equip commercial and industrial customers with system-wide automation, allowing them to leverage existing energy management control systems and automatically manage lights, air conditioning, and other sources of load during peak times. With this addition, the estimated peak reduction potential could increase

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[79] For the methodology behind these computations, consult Sidebar 1. Additionally, Monte Carlo simulations were performed to better understand the range of uncertainty around these estimates. For details, see Appendix A.

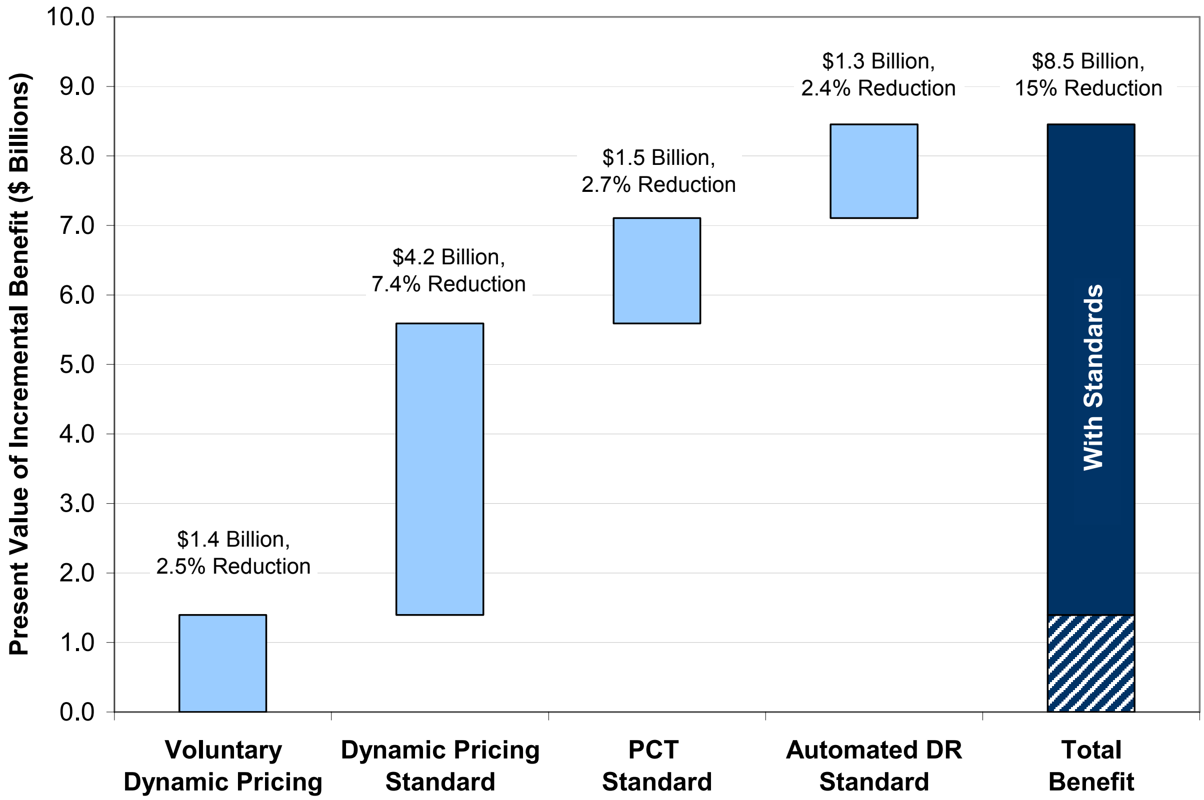
[80] Note that this estimate assumes that these benefits will accrue over a 20-year period during which all residential customers have programmable communicating thermostats installed in their homes. There would be an initial period during which the programmable communicating thermostats would have to be rolled out to customers.

[81] Note that some of the figures may not add up due to rounding.

incrementally by roughly 2 percentage points to approximately 20 percent. The present value of the benefits could increase incrementally by around $1 billion to $11 billion.

These approximate estimates of the benefits of new load management standards are summarized in Figure 3-13.

Figure 3-13: Incremental Benefits of Load Management Standards



Source: California Energy Commission. *California's Next Generation of Load Management Standards*, p. 28. CEC-200-2007-007-F, September 2007.

Recommendations

- Adopt statewide energy efficiency targets for 2016 equal to 100 percent of economic potential, to be achieved by a combination of utility programs, state and local standards, and other programs.
- Enlist publicly owned utilities in a collaborative relationship to aggressively ramp up energy efficiency programs. Publicly owned utilities need to use their local conditions and customer knowledge to craft new program ideas. In doing so, sufficient incentives have to be provided.
- Pursue legislation that would require a cost-effective level of efficiency improvements at the time of sale of a building.

- Initiate a formal rulemaking process involving the CPUC and California ISO in 2008 to pursue the adoption of load management standards under the Energy Commission's existing authority.
- Enact appliance standards to improve the efficiency of appliances sold in California, specifically targeting standards to increase the efficacy of general service lighting.
- Increase the efficiency levels of the building standards and combine them with on-site generation so that newly constructed buildings are net zero energy by 2020 for residences and 2030 for commercial buildings.
- Investigate market-based approaches to energy efficiency such as the "white tag" or "white certificate," also known as energy efficiency certificates or credits – the analog to renewable energy credits.

CHAPTER 4: Using Renewable Resources to Meet Energy Needs

California is a national leader in the development of renewable resources. Over the past 30 years, the state has built one of the largest and most diverse renewable generation portfolios in the world. Preceding AB 32, Senate Bill 1078 (Sher, Chapter 516, Statutes of 2002) established a Renewables Portfolio Standard (RPS) program in 2002, with the goal of increasing to 20 percent by 2017 the percentage of the state's electricity that is sold to retail customers and derived from renewable resources. The 2003 Energy Action Plan adopted by the Energy Commission and the CPUC accelerated that target date to 2010, and the *2004 Integrated Energy Policy Report (IEPR) Update* recommended expanding the target to 33 percent by 2020. The *2005 IEPR* and *2006 IEPR Update* reinforced that recommendation.

> ***"I'd put my money on the sun and solar energy. What a source of power! I hope we don't have to wait 'til oil and coal run out before we tackle that."***
>
> Thomas Edison

Increasing renewable energy to 20 percent of electricity sales by 2010 and 33 percent by 2020 is an essential part of reducing California's greenhouse gas emissions. Renewables currently account for only 11 percent of electricity generation, a course that is not on track to meet RPS or AB 32 goals. Meeting the 33 percent goal in 2020 *is* feasible, but it will require significant changes in infrastructure and significant changes in program structure.

Specifically, meeting the 33 percent goal will require:

- Investments in the state's transmission infrastructure to adequately access renewable-rich resource areas, both in state and out of state
- The ability to integrate large quantities of intermittent resources
- Changes to the RPS program to address its current complexity, lack of transparency, and undervaluing of renewables
- Legislative authority to require renewable procurement beyond 20 percent by 2010

California must determine how to meet its renewable and greenhouse gas emission reduction goals while minimizing the costs and risks borne by ratepayers for electricity generation. The first section of this chapter explores those two key drivers of renewable resource development, as well as discusses legislation that affects renewables development in California. The second section of the chapter discusses the feasibility of meeting the 33 percent renewables goal. That discussion responds to the Governor's signing statement for AB 1585 (Blakeslee, Chapter 579, Statutes of 2005),[82] which directed the Energy Commission to prepare and incorporate into the *IEPR* a report addressing the following topics related to the 33 percent goal:

- Needed transmission
- System reliability and dispatchability impacts
- Long-term planning requirements identified in electrical corporations' 2006 procurement plans
- Potential impacts on electric rates
- Progress made by California's public and private utilities and other entities that provide retail electricity in meeting the 20 percent by 2010 goal.

Finally, the chapter offers recommendations for using and developing renewable resources to meet California's energy needs.

Key Drivers for Renewable Energy and Recent Legislation

This section provides background on the two major policies driving renewable energy development—reducing greenhouse gas emissions and managing cost and risk to ratepayers—as well as an update on recent state legislation affecting renewable energy and a discussion of federal legislation that could preempt California's renewable energy programs.

Reducing Greenhouse Gas Emissions

As part of the state's loading order for electricity, renewable energy is essential to meet California's greenhouse gas emission reduction goals. This section summarizes recent trends in California, other states, and Europe, including the following topics:

- The California Global Warming Solutions Act of 2006 (AB 32)
- The Governor's Market Advisory Committee's view that renewable energy should not create offsets[83]

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[82] Assembly Bill 1585, which directed the Energy Commission to prepare an evaluation of the impacts of the 33 percent goal, was passed subject to the passage of Senate Bill 107 (Simitian, Chapter 464, Statutes of 2006) in 2005. Because SB 107 did not pass until 2006, AB 1585 did not become law until that time. The Governor clarified in his signing statement that regardless of whether SB 107 passed, the Energy Commission must report on specific items related to the state's 33 percent RPS goal.

- The need to separate RPS from a future carbon market for California

The California Global Warming Solutions Act of 2006

In consultation with other state agencies and with programs in other states, cities, regions, and countries, by January 1, 2009, the California Air Resources Board (ARB) must prepare a scoping plan "for achieving the maximum technologically feasible and cost-effective reductions in greenhouse gas emissions from sources or categories of sources of greenhouse gases by 2020" as defined by AB 32 (Health and Safety Code Section 38561 [a]). The plan must be updated at least every five years.

AB 32 requires the ARB to adopt a statewide greenhouse gas emissions limit to achieve 1990 levels by 2020. The ARB must adopt the limit and "emission reduction measures by regulation" by January 1, 2011, to be effective by January 1, 2012. The law requires that reductions pursued through any market-based compliance mechanism must be "in addition to any greenhouse gas emission reduction otherwise required by law or regulation, and any other greenhouse gas emission reduction that otherwise would occur."

AB 32 makes clear the intent of the Legislature to continue greenhouse gas emission reductions beyond 2020, maintaining the limit established in AB 32 and directing the ARB to recommend further actions to the Governor (Section 38551). The Governor's Executive Order S-3-05 underscores that long-term commitment, establishing a goal of 80 percent below 1990 levels by 2050.[84] Led by California Environmental Protection Agency (Cal/EPA), the California Climate Action Team prepares reports to the Governor recommending strategies to achieve the state's greenhouse gas emission reduction targets, including the target for 2050.

Market Advisory Committee: Renewables Should Not Create Offsets

The Governor created a Market Advisory Committee tasked with preparing a report for ARB on designing a market-based compliance program. In its report released on June 30, 2007, the Market Advisory Committee explained that renewable energy for electricity should not create offsets for a cap-and-trade[85] system for greenhouse gas emissions

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[83] Offsets refer to greenhouse gas emission reductions from a source in a sector or location that is not included in a cap-and-trade program. For more information, see http://www.climatechange.ca.gov/documents/2007-06-29_MAC_FINAL_REPORT.PDF, p. 61-62.

[84] Office of the Governor, Executive Order S-3-05, signed June 1, 2005.

[85] Cap-and-trade refers to a market-based compliance mechanism to lower allowable greenhouse gas emissions over time to achieve a specified limit. Each regulated source of greenhouse gas emissions gets a specified number of emission credits for each compliance period (e.g., per year). If a source finds it has more emission credits than emissions, it may sell the excess credits.

because that simply reduces the demand for allowances from regulated sources and does not provide additional reductions in greenhouse gas emissions.[86]

Furthermore, the report explains that a cap-and-trade system addresses the lack of a price signal for reducing greenhouse gas emissions, but does not address other impediments. A cap-and-trade system is best used to complement standards and incentives that address other impediments, such as the risk of a step-change in technology, fragmented supply chains, and high discount rates for investment by consumers. "By itself, a cap-and-trade program alone will not deliver the most efficient mitigation outcome for the state. There is a strong economic and public policy basis for other policies that can accompany an emissions trading system."[87]

Separating the Renewables Portfolio Standard from a Future Carbon Market for California

The California Climate Action Team report identified achieving 33 percent renewable energy by 2020 as one of the key strategies for reducing greenhouse gas emissions in California. To ensure the maximum contribution of this renewable energy target to greenhouse gas emission reduction, the number of allowances distributed under any future cap-and-trade system must exclude the amount of fossil-fuel energy displaced by achieving the RPS target.

As part of implementing AB 32, ARB will determine what quantity of greenhouse gas emissions is equivalent to the greenhouse gas emission reduction goal of 1990 levels by 2020. The ARB will also consider whether to establish a cap-and-trade system and allow offsets from entities in sectors not covered by the trading system. The quantity of allowances to be distributed under a cap-and-trade system will not be equivalent to the 1990 emissions level because all sources are not likely to be included within the system. At issue is what portion of the annual emissions target will be included in any allowance-based trading system. It is widely believed that an emissions trading system can be an efficient means of creating a price signal that encourages investment in additional greenhouse gas-reducing alternatives to meet California's growing energy demand.

The contribution of the 33 percent renewable goal to greenhouse gas emission reductions may not be clear if the expected carbon reductions that will emerge from this goal are not subtracted from the number of allowances distributed in a cap-and-trade system. The mechanism for reducing greenhouse gas emissions in a cap-and-trade system is a gradual reduction in the number of allowances. Adding renewable energy,

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[86] http://www.climatechange.ca.gov/documents/2007-06-29_MAC_FINAL_REPORT.PDF, accessed July 27, 2007.

[87] Ibid, p. 19.

without reducing the number of allowances distributed, will reduce the demand for allowances, but will not lower the total number of allowances. If the reductions were not subtracted, if one utility reduced its greenhouse gas emissions by adding renewable energy to meet the 33 percent by 2020 target, it would be able to sell its greenhouse gas allowances to another utility, producing no net greenhouse gas emission reduction. To avoid this perverse effect, any expected greenhouse gas emissions reductions from achieving the state's renewable energy goals should reduce the pool of available greenhouse gas allowances.

In addition, using renewable energy credits in a situation where they may actually result in no net greenhouse gas emission reduction could affect the value of the renewable energy credits.[88] Although some states allow the greenhouse gas emissions attribute to be separated from renewable energy credits used for their RPS programs, California's RPS does not. As defined by Public Utilities Code Section 399.12(g)(2):

> "Renewable energy credit" includes all renewable and environmental attributes associated with the production of electricity from the eligible renewable energy resource, except for an emissions reduction credit issued pursuant to Section 40709 of the Health and Safety Code and any credits or payments associated with the reduction of solid waste and treatment benefits created by the utilization of biomass or biogas fuels.

However, the exact quantification of these environmental attributes has not been assessed. Their value depends on the regulatory environment and the electricity that is displaced by the renewable energy credit.

In written comments for the March 13, 2007, IEPR workshop on wind repowering and best practices for coordinating the RPS with carbon market design, APX warned, "If renewable energy is managed outside the Cap and Trade mechanism and if the Cap is set without taking renewable energy emissions reductions into account, then it would significantly weaken any emission reduction claims of renewable energy credit purchases, whether for state RPS compliance or for voluntary green power programs."[89]

In a situation where renewable energy credits are used in such a way that they do not result in net greenhouse gas emissions reductions, the value of the renewable energy credit would depend on the supply of renewable energy credits, other low-greenhouse

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[88] As defined in California, a renewable energy credit is a certificate of proof that one unit of electricity was generated and delivered by an eligible renewable resource. For further information, see the RPS Eligibility Guidebook, http://www.energy.ca.gov/renewables/documents/index.html#rps.

[89] California Energy Commission, Integrated Energy Policy Report Committee Workshop on Incentives for Wind Repowering and Best Practices for Coordinating RPS with Carbon Market Design, March 13, 2007, Automated Power Exchange written comments.

gas resources, and greenhouse gas emission allowances in a trading system. For example, an increase in renewable energy use by one utility could allow the utility to sell some of its allowances, enabling an increase in fossil fuel use by another utility. This could yield no net greenhouse gas emission reduction and potentially cause an over-supply of allowances. As was evident in the first phase of the Emissions Trading System of the European Union, the excess supply of annual emissions allowances combined with the lack of carryover into Phase II of the European Union Emissions Trading System led the trading price to fall from 33 Euro to less than 1 Euro.[90]

In contrast, if renewable energy credits are taken off the top of the number of allowances, an increase in the use of renewable energy leads to a decrease in greenhouse gas emissions.[91] In this case, the amount of greenhouse gas emissions contained in a renewable energy credit would be a function of the electricity displaced by the generation of the renewable energy creating the renewable energy credit.

Taking 33 percent renewables by 2020 from the top of the quantity of allowances distributed under a cap-and-trade system reduces uncertainty and would create a price incentive for utilities to increase the pace of their investments in these long-standing, high priority alternatives.

Managing Risk and Cost to Ratepayers

California continues to be at risk from the potential for sustained high natural gas prices. In 2006, dependency on natural gas for electricity was 41.5 percent, up from 36.5 percent in 2002. California's growing dependence on natural gas for electricity generation has been a major theme of the *Integrated Energy Policy Reports* since 2003.

Another source of price risk associated with California's generation mix is the potential future cost of carbon emissions. The European Union instituted trading of carbon emissions allowances as part of its efforts to meet the Kyoto Protocol. In implementing

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[90] For reviews of the European Union Emissions Trading System see: http://ec.europa.eu/environment/climat/emission/review_en.htm and http://www.openeurope.org.uk/research/etsp2.pdf.

[91] Although combustion of biomass releases CO_2, it displaces the methane that would have been released through decay of the biomass. The greenhouse gas effect of methane is many times stronger than the effect of carbon dioxide. For further discussion, see Morris, G. 1999. *The Value of the Benefits of U.S. Biomass Power*. NREL/SR-570-27541. Golden, Colorado: National Renewable Energy Laboratory. In addition, Senate Bill 1368 (Perata), Chapter 598, Statutes of 2006 prohibits long-term financial obligations, including ownership and contracts five years or longer, with power plants, including biomass and biogas power plants, that exceed the state's greenhouse gas performance standard.

AB 32, California will adopt various strategies to limit greenhouse gas emissions, and fossil fuel generation is likely to incur costs based on such emissions.

In addition to the economic risk posed by volatile fuel prices and unknown emissions costs, global warming presents serious risks to public health and safety beyond costs associated with the consequences of climate change. Increasing renewable energy generation is critical in mitigating these risks.

Renewable resources are also subject to technology price risk, including investment cost risk, operations and maintenance risk, and risks associated with the intermittency of some technologies such as wind and solar. However, the volatility of the costs associated with these risks is much less than the volatility of the price of natural gas.[92]

Two important questions determine how we approach these risks. First, what portfolio of generation assets has the best combination of risk and expected cost for California's ratepayers? Second, what kind of premium is justified to accelerate renewable development in light of the dangerous effects of climate change?

To address the first question, the Energy Commission examined the use of portfolio analysis. Portfolio analysis allows the presentation of a range of portfolios, each with a different combination of expected cost and risk, allowing decision makers to choose one which matches the desired risk tolerance. The level of risk exposure is a policy decision. As discussed in the *2006 IEPR Update*, the current standard of comparison is based on stand-alone incremental engineering calculations of the future expected cost of electricity from a new baseload natural gas-fired combined cycle generation plant.

The resulting market price referent, [93] however, fails to properly consider the risk of price volatility. In the *2006 IEPR Update*, the Energy Commission discussed the weakness of relying on a particular natural gas forecast that represents a snapshot of potential future costs. Costs for most renewables generation (other than biomass) are independent of fuel price volatility and depend primarily on capital investment during project development. Thus, renewables generation has value as a hedge against fuel price volatility. However, in the current investor-owned utility solicitation process for long-term RPS contracts, SDG&E states that renewable energy developers tend to increase their bids if natural gas prices rise.[94] SCE is concerned that the demand for

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[92] Bates White, *A Mean-Variance Portfolio Optimization of California's Generation Mix to 2020: Achieving California's 33 Percent RPS Goal*, draft consultant report, July, 2007, CEC-300-2007-009/CEC-300-2007-009-D.PDF.

[93] A proxy for the market price of various electricity products, used to compare renewable products to meet a retail seller's Renewables Portfolio Standard obligations. Contracts with renewable generators at or below the market price referent are deemed reasonable with costs recoverable in rates.

[94] SDG&E 2007-2016 Long-Term Procurement Proceeding, Vol. 1, part 2 p. 211.

renewable energy is outpacing the supply and anticipates that prices for renewable energy will be 25 percent higher as the state moves to 33 percent by 2020. To avoid these results, changes in the structure of the RPS program could be designed to de-link prices paid for renewable energy from natural gas and thereby avoid a shortage of renewable energy. One way of doing so is through feed-in tariffs, discussed later in this chapter.

Investors in stocks and other assets know that diversification can mitigate or reduce risk. Increasing diversity by adding a less volatile asset reduces risk, more so when the values of the different assets are not perfectly correlated. A similar approach, focusing on expected costs and risk, should be used in determining the generation mix of most value to California's ratepayers. Modern portfolio analysis shows that adding higher cost assets can result in lowering total portfolio risk.

In addressing the second question, the cost of carbon emissions represents an additional risk that is difficult to estimate. In 2005, the CPUC directed the large investor-owned utilities to use a carbon adder[95] for resource planning and bid evaluation of $8 per ton of CO_2, escalating at 5 percent per year. However, other estimates of CO_2 emissions costs range from $0 to $58 per ton.[96] A recent Synapse report estimates that in 2020, CO_2 emission costs will be $10 to $33 per ton,[97] indicating that the $8 per ton figure may be too low. On October 4, 2007, the CPUC passed a resolution adding carbon adders to the 2007 market price referent, with values ranging from 0.271 to 0.972 cents per kilowatt hour ($2.71 to $9.72 per megawatt hour) depending on the contract length and contract start year.[98] These values are based on CPUC Decision 04-12-048, which says: "Consistent with established Commission policy, and the positions of several parties, including PG&E, we adopt a range of values to explicitly account for the financial risk associated with greenhouse gas emissions (which is called a 'greenhouse gas adder'), of $8 to $25 per ton of CO_2, to be used in the evaluation of generation bids."

The adopted values are based on approximately $8 per ton in 2004, escalating at 5 percent per year through 2023. These values are considerably lower than market trading

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[95] A price per ton of carbon used by utilities when evaluating options to meet future electricity demand. The adder is used for planning purposes as a proxy for potential future greenhouse gas emission reduction costs.

[96] 2006 IEPR Update, page 55. See footnotes for sources of various estimates.

[97] Synapse Energy Economics, Inc, "Climate Change and Power: Carbon Dioxide Emissions Costs and Electricity Resource Planning," prepared by Lucy Johnston, Ezra Hausman, Anna Sommer, Bruce Biewald, Tim Woolf, David Schlissel, Amy Rocshelle, and David White, June 8, 2006. Available at: http://www.synapse-energy.com/Downloads/SynapsePaper.2006-06.0.Climate-Changeand-Power.A0009.pdf.

[98] CPUC, Resolution E-4118, October 4, 2007, at http://www.cpuc.ca.gov/word_pdf/final_resolution/73594.pdf.

values for European Union Emissions Trading System credits for the year 2008. Since January 2006, European Union Emissions Trading System credits have been trading in the range of 15 to 26 Euros per metric ton, and were valued at 21.55 Euros on October 31, 2007, or $31.20 based on the October 31, 2007 exchange rate of $1.4479 per Euro. The European Union Emissions Trading System credit has varied between about $21 and $38 per metric ton since January 2006. The CPUC intends to consider greenhouse gas adders for future years' RPS solicitations in 2008.

Legislation Affecting Renewables in California

State Legislation

Five recently enacted bills affect California's RPS program: Senate Bill 1036, [99] which deleted the requirement for the Energy Commission to provide supplemental energy payments to cover above-market costs of renewables; Senate Bill 107,[100] which made significant modifications in California's RPS program; Assembly Bill 1969,[101] which requires IOUs to set a tariff to purchase renewable generation from small facilities operated by public water and wastewater agencies; Assembly Bill 1585,[102] which requires the Energy Commission to evaluate the feasibility of the 33 percent by 2020 renewable goal; and Assembly Bill 809,[103] which affects the RPS eligibility of small hydroelectric facilities.

- **SB 1036:** SB 1036 switches the responsibility for administration of funds above-MPR costs of renewable energy from the Energy Commission to the CPUC. By March 1, 2008, unencumbered funds from the New Renewable Resources Account of the Renewable Trust Fund will be returned to the utilities and held in accounts to be used for above-market costs of RPS generation. Funds will be allocated proportionally by load share to the utilities whose customers pay into the renewable public goods charge. Use of the funds must be approved by the CPUC through the advice letter and contract approval process currently used for RPS contracts.
- **SB 107**: This bill codifies the 20 percent by 2010 goal set by the Governor and state energy agencies. Several provisions of SB 107 serve to incorporate publicly owned utilities (POUs) more fully into the RPS. POUs are now required to report to the Energy Commission the resource mix they use to serve their customers using the categories defined as eligible for the RPS for the state's IOUs, electric service

[99] Senate Bill 1036 (Perata), Chapter 685, Statutes of 2007.

[100] Senate Bill 107 (Simitian), Chapter 464, Statutes of 2006

[101] Assembly Bill 1969 (Yee), Chapter 731, Statutes of 2006.

[102] Assembly Bill 1585 (Blakeslee), Chapter 579, Statutes of 2005.

[103] Assembly Bill 809 (Blakeslee), Chapter 684, Statutes of 2007.

providers (ESPs), and community choice aggregators. A summary of the data submitted by the POUs this year in response to this requirement is provided later in this chapter.

SB 107 also established a process that may lead to allowing unbundled renewable energy certificates to count toward meeting the RPS requirement, provided "the electricity is delivered to a retail seller, the Independent System Operator, or a local publicly owned electric utility."[104] Further, SB 107 continued the trend to relax deliverability requirements for renewable energy generated out of state. It allows electricity generated by an RPS-eligible[105] resource to be considered delivered "regardless of whether the electricity is generated at a different time from consumption by a California end-use customer."[106] This makes it possible for out-of-state wind and other intermittent resources that cannot normally be scheduled across control areas to meet deliverability requirements and count toward a utility's RPS target.

However, under SB 107, before the CPUC can authorize the use of RECs for RPS compliance, the CPUC and Energy Commission must jointly determine that a REC tracking system is operational and "can ensure that renewable energy credits shall not be double counted by any seller of electricity within the service territory of the Western Electricity Coordinating Council [WECC]."[107] The Energy Commission and other WECC entities developed the Western Regional Energy Generation Information System (WREGIS), which began operating in June 2007, to track renewable energy used for RPS programs in the WECC to prevent double counting. Also, a retail seller may purchase RECs from a POU only if the Energy Commission has determined that the POU is on track to meet its own RPS that is comparable to the standard applied to retail sellers.

- **AB 1969:** The purpose of AB 1969 is to bring in additional RPS-eligible energy from facilities that are too small to participate in utility RPS solicitations, either because they fail to meet minimum size requirements or because the process is too complex. In implementing AB 1969, the CPUC ordered IOUs to set a tariff under which qualifying generation from public water and wastewater facilities up to 1.5 megawatts is purchased at the MPR used for the RPS, until a statewide cap of 250 megawatts is reached under the program. Furthermore, the CPUC instituted a

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[104] Public Utilities Code Section 399.16(a)(3).

[105] For information on RPS eligibility, see the RPS Eligibility Guidebook, http://www.energy.ca.gov/renewables/documents/index.html#rps.

[106] Public Resources Code § 25741(a).

[107] Public Utilities Code Section 399.16(a)(1).

parallel program for about 230 megawatts that is open to customers other than public water and wastewater agencies.[108]

- **AB 1585:** In 2005, the legislature passed AB 1585, which would have required the Energy Commission to include "a review of the feasibility of increasing the RPS to 33 percent by 2020." However, the law was to go into effect only if SB 107 of the 2005-06 regular session was also enacted and became operative on January 1, 2006. SB 107 was enacted in September 2006 and went into effect January 1, 2007. In signing AB 1585 into law, the Governor directed the Energy Commission to conduct the review even though SB 107 did not go into effect on the date required. The Energy Commission's response to the Governor's direction is provided in this chapter.
- **AB 809:** AB 809 changes the definition of an "eligible renewable energy resource" to include conduit hydro of 30 megawatt or less under certain conditions, and allows small hydro facilities with efficiency improvements that increase their capacity above 30 megawatt to retain their RPS eligibility, also under specific conditions.

Federal Proposed Legislation

As of October 2007, legislation was pending in Congress that could negatively affect California's RPS program. While a federal RPS could help stimulate investment in renewable energy if it were designed as a minimum requirement, it would not serve this purpose if it effectively prevented states from increasing renewable energy beyond the federal standard, or allowed the higher standards in some states to offset procurement to the federal standard in other states.

A minimum standard could help overcome underinvestment in renewable energy resulting from a misallocation of risk. Utility procurements, as well as deregulated markets, tend to systematically under-invest in renewables and efficiency because the cost of fuel price volatility on customers is ignored.[109] A minimum federal standard would also require those electricity suppliers in the 25 states without a state RPS to meet certain minimum renewable energy purchase requirements, therefore expanding the nation's use of renewable electricity.

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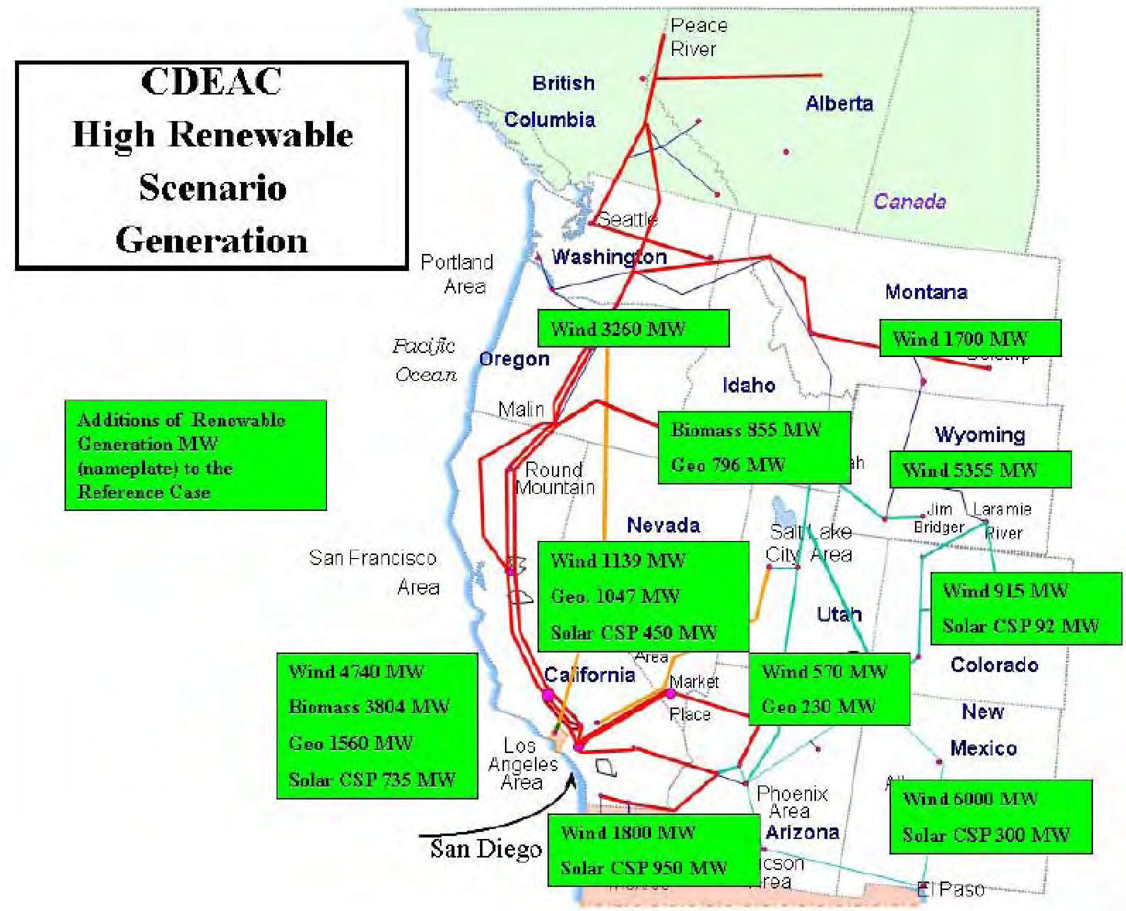
[108] California Public Utilities Commission, July 26, 2007, "Decision 07-07-027: Opinion Adopting Tariffs and Standard Contracts for Water, Wastewater and Other Customers to Sell Electricity Generated from RPS-Eligible Renewable Resources to Electrical Corporations," Rulemaking 06-05-027, http://www.cpuc.ca.gov/WORD_PDF/FINAL_DECISION/70660.PDF, accessed August 6, 2007.

[109] For a detailed discussion, see California Energy Commission, July 2007, A Mean-Variance Portfolio Optimization of California's Generation Mix to 2020: Achieving California's 33 Percent Renewable Portfolio Standard Goal, draft consultant report, CEC-300-2007-009-D. http://www.energy.ca.gov/2007_energypolicy/documents/index.html#071107, p. 1.

Also, a minimum standard would allow state and regional initiatives to take advantage of the diversity of resources across the states, allowing each state to decide how to meet electricity needs beyond the minimum standard. The Western states are rich in renewable resources, but the resource mix likely to be developed in the next 10 years varies widely from state to state. For example, the Western Governors' Association Clean and Diversified Energy Advisory Committee's Transmission (CDEAC) task force developed a scenario of renewable resources that are likely to be economically feasible to meet the WGA goal of 30,000 megawatts of clean and diversified energy by 2015 (Figure 4-1).

Figure 4-1: Clean and Diversified Energy Advisory Committee Transmission Task Force High Renewables Scenario for 2015



Source: http://www.westgov.org/wga/initiatives/cdeac/TransmissionReport-final.pdf.

The range of policies and requirements among the states in the West is readily accommodated in the Western Generation Information System (WREGIS), which can track renewable generation of member facilities in the WECC interconnect. To be eligible for the California RPS, generators must join WREGIS.

As discussed in Chapter 2, the Energy Commission published a study[110] showing the impact of a range of scenarios, including one scenario assuming about 30 percent renewable energy in California and a second scenario holding that amount of renewable energy in California constant while adding high levels of renewable development in the West, similar to the CDEAC scenario. The study suggested that high renewable energy development in the West displaces some new conventional generation additions and frees up some existing conventional generation. The study also finds that there may be increased levels of low-cost, high greenhouse gas -emitting resources into California. How to attribute greenhouse gas characteristics of power plants located out-of-state within the regulatory construct is one of the major unresolved challenges of greenhouse gas policy implementation.

However, out of state renewable generation may also help California realize its goals at lower cost to ratepayers.

Feasibility of 33 Percent by 2020: AB 1585 Review

Governor Schwarzenegger directed the *2007 Integrated Energy Policy Report* to review the feasibility of 33 percent renewable energy in California by 2020. The CPUC currently has legislative authority to require investor-owned utilities to purchase 20 percent renewable energy by 2010, subject to a cost limitation to be established by the CPUC on above-market costs of RPS contracts. To extend that authority to 33 percent will require additional legislation. Six topics identified in AB 1585[111] and related issues will affect the state's ability to achieve 33 percent renewable energy by 2020.

- Deliverability of electricity from eligible renewable energy resources to end users and any needed additions or upgrades to the transmission grid system

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[110] California Energy Commission, July 2007, Staff Draft Report: Scenario Analyses of California's Electricity System; Preliminary Results for the 2007 Integrated Energy Policy Report, Addendum, CEC-200-2007-010-AD1, http://www.energy.ca.gov/2007publications/CEC-200-2007-010/CEC-200-2007-010-AD1.PDF, p. 4-5.

[111] California, Office of the Governor, Signing statement for AB 1585 (Blakeslee), Chapter 579, Statutes of 2005: " … Unfortunately, this measure was joined to another measure requiring concurrent enactment and that measure did not pass the Legislature. By signing this measure I am directing the appropriate agencies to include the review required by this bill in the next update of the Integrated Energy Policy Report even though this measure will not be enacted." http://www.governor.ca.gov/govsite/pdf/press_release_2005/AB_1585_signing.pdf, accessed June 21, 2007.

- Dispatchability of electricity from eligible renewable energy resources and the consequences for the reliability of the electrical system
- Long-term planning requirements identified in the 2006 procurement plans for electrical corporations approved by the Public Utilities Commission pursuant to Section 454.5 of the Public Utilities Code
- Potential impacts upon the rates of electrical corporations and whether or not a renewable energy public goods charge is necessary to fund the above-market costs of electricity generated from eligible renewable energy resources
- The progress made by electrical corporations toward meeting the goal of procuring 20 percent of the electricity sold to retail customers per year by the year 2010, and the results of electrical corporation bid solicitations pursuant to a renewable energy procurement plan approved by the Public Utilities Commission pursuant to Section 399.14 of the Public Utilities Code
- The progress made by all load-serving entities other than electrical corporations, including the progress made by local publicly owned electric utilities as defined in subdivision (d) of Section 9604 of the Public Utilities Code, toward meeting the goal of procuring 20 percent of the electricity sold to retail customers per year by the year 2010

Deliverability and Transmission Upgrades Needed

The first topic in AB 1585 that affects the state's ability to achieve the 33 percent by 2020 goal is the need for transmission additions or upgrades to deliver renewable electricity. This section provides an overview of the status of new transmission to access areas rich in renewable resource potential, including:

- Delays facing key transmission projects
- Federal Energy Regulatory Commission support for transmission to multi-user location-constrained resources
- Potential involvement of the California ISO to facilitate equitable cost allocation of renewable generation through expanded feed-in tariffs
- In-state planning processes for renewables transmission
- Transmission to bring renewable energy from out of state
- Renewable Energy Certificates and deliverability
- Need for a "smart" transmission-distribution system (potential solutions are discussed in the *Dispatchability and Reliability* section below.)

Additional information and recommendations regarding transmission planning are provided in the *2007 Strategic Transmission Investment Plan*.

Delays Facing Key Transmission Projects

Key transmission projects to access the renewable resources in the Tehachapi Mountains and Imperial County are facing delays.

SCE is planning to build new transmission to allow up to 4,500 megawatts of wind from the Tehachapi Wind Resource Area to interconnect to the transmission grid. As of July 2007, the projected completion date is winter of 2013.[112] Segments capable of exporting 700 megawatts of wind from the area are scheduled for completion by the end of 2009.[113]

LADWP is expanding its transmission lines in the Tehachapi Wind Resource Area to accommodate at least 500 megawatts of wind and other renewables as part of a larger project that will add 1,150 megawatts of transfer capability for renewables and other transmission needs.[114] The Energy Commission encourages LADWP to coordinate its plans with SCE to avoid duplicative transmission development.

The Sunrise-Powerlink transmission project would provide access to about 1,000 megawatts of renewable energy. [115] The project has been delayed by debate regarding the path the transmission line should take from Imperial County to San Diego County.[116] In response to public comments, alternative paths have been proposed. The Energy Commission has no position regarding the path the line should take, but urges the

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112 Southern California Edison, Updated July 2007, *Fact Sheet: Tehachapi Renewable Transmission Project*, http://www.sce.com/NR/rdonlyres/96270562-668A-49F8-BCD4-B96A9D8E3F9E/0/TRTPFSJuly07.pdf, accessed July 20, 2007.

113 Southern California Edison Company, December 11, 2006, 2006 Procurement Plan Volume 1B (Public Version), https://www.pge.com/regulation/LongTermProcureOIR/Testimony/SCE/2006/LongTermProcureOIR_Test_SCE_20061211-02.pdf, p. 95

114 Department of Water and Power, City of Los Angeles, April 17, 2007, Renewable Transmission, presentation at April 17, 2007, IEPR workshop, Slide #5, accessed July 20, 2007, <http://www.energy.ca.gov/2007_energypolicy/documents/2007-04-17_workshop/public_comments/16%20Randy%20Howard%20LADWP.pdf>. LADWP's transmission plans are further described in its March 30, 2007, data response to the Energy Commission's Transmission Related Data Request.

115 CPUC, SDG&E’s Proposed Sunrise Powerlink Transmission Project, http://www.cpuc.ca.gov/static/hottopics/1energy/a0512014.htm, accessed July 20, 2007.

116 California Public Utilities Commission, San Diego Gas & Electric Company's Sunrise Powerlink Project(Applications A.05-12-014 and A.06-08-010), http://www.cpuc.ca.gov/environment/info/aspen/sunrise/sunrise.htm, accessed July 20, 2007. See also, J. Harry Jones, January 26, 2007, Public can weigh in on Sunrise project, San Diego Union Tribune, http://www.signonsandiego.com/news/northcounty/20070126-9999-1mi26sunrise.html, accessed July 20, 2007.

parties to find a workable solution as the Sunrise-Powerlink transmission project appears necessary for SDG&E to achieve the state's renewable energy goals of 20 percent by 2010 and 33 percent by 2020.

The Green Path Coordinated Projects, involving LADWP, Imperial Irrigation District, Citizens Energy, and SDG&E, would provide access to more than 2,000 megawatts of new renewable energy resources in the Imperial Valley. The Energy Commission supports these projects for their contributions to achieving the state's RPS goals. However, the Imperial Irrigation District has raised concerns that may delay completion of these projects.[117]

The proposed transmission development for the Tehachapi Wind Resource Area would capture much of the estimated economic potential for renewable energy development in that region, but the proposed transmission lines into the Imperial Valley could need expansion to accommodate the full renewable energy development of that region. An Energy Commission report identifies potential renewable energy in Tehachapi by 2020 as about 8,000 megawatts of wind, with 4,500

Environmental Challenges to Siting Solar Plants in California

As a result of California's aggressive RPS targets, developers are proposing many large solar energy projects. These projects, located largely in the California desert on U.S. Bureau of Land Management (BLM) land, could have major biological impacts because of the amount of acreage involved. As of August 2007, the BLM has received applications for solar thermal and photovoltaic projects in California totaling 38,000 megawatts. Based on solar thermal applications received at the Energy Commission, the acreage needed for these projects could be as much as 308,000 acres, or 480 square miles. For comparison, 1,288 acres have been impacted by 12,376 megawatts of power plants (primarily natural-gas fired) currently operating or under construction that have been permitted by the Energy Commission since 1996.

Identifying enough habitats to mitigate the potential impacts of these projects will be a challenge depending on the species impacted. For example, when the Energy Commission licensed the Luz SEGS solar thermal projects in San Bernardino County in the 1980s and 1990s, it required five compensating acres for every one acre impacted because the projects affected high-quality protected species. The California desert has many specialized species, with two species of particular concern being the desert tortoise and the Mojave ground squirrel. Both species have limited ranges which overlap with several areas under consideration in the Mojave Desert.

Because disturbed desert habitats recover very slowly, decommissioning and habitat restoration of solar project sites is of particular concern in these areas. When the Energy Commission licensed the Luz SEGS Unit 10 project in 1990, it required that $100,000 be set aside for a decommissioning fund during the first year of commercial operation. After putting in foundation piers and fencing, the project owner went bankrupt. Because Unit 10 was never completed, decommissioning funds were not collected and the fencing and foundations remain on the one square mile project site, representing an ongoing loss of habitat.

The Energy Commission staff is working with the BLM, California Department of Fish and Game, U.S. Fish and Wildlife Service, counties, and project owners to address decommissioning of solar projects and restoration of disturbed project-site habitat. Since solar thermal projects 50 megawatts or larger located on BLM land will require approval from both the BLM and the Energy Commission, these agencies have entered into a Memorandum of Understanding that outlines roles and responsibilities in conducting a joint environmental review of these projects.

[117] Jesse Montano, July 10, 2007, "Phase 1 Direct Testimony of Jesse Montano on Behalf of Imperial irrigation District, Before the CPUC, Application No. 06-08-010, In the matter of the application of SDG&E Company for a CPCN for the Sunrise Powerlink Transmission Project.

megawatts included in a scenario achieving 33 percent by 2020.[118] Estimates for Imperial County total more than 3,700 megawatts of near-term potential for new renewables, including about 1,000 megawatts of wind, about 2,400 megawatts of geothermal (1,900 megawatts more than existing), and large amounts of potential concentrating solar power. [119] RPS contracts have been signed for more than 800 megawatts of solar in Imperial County requiring new transmission.[120]

Federal Energy Regulatory Commission Support for Transmission

Since the *2006 IEPR Update*, the Federal Energy Regulatory Commission approved a concept proposed by the California ISO to provide a new financing mechanism for interconnecting location-constrained, multi-user resources, such as renewables, to the transmission grid. Under this concept, each generator that interconnects would be responsible for paying its pro rata share of the going-forward costs of using the line, but until the line is fully subscribed, all users of the grid would pay the cost of the unsubscribed portion of the line through the California ISO Transmission Access Charge. Once the facilities are built, generators would be allowed to interconnect and contract for unsubscribed capacity.[121] To implement this concept, the California ISO Board of Governors has approved making changes to its federal tariff, which was filed with Federal Energy Regulatory Commission October 31, 2007.[122] The Energy Commission applauds the California ISO's action and supports implementation of this concept as a needed mechanism for transmission to access renewable resources.

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[118] http://www.energy.ca.gov/pier/notices/2007-02-13_workshop/presentations/04_2007-02-13_DAVIS+DAHMAN+PATTEN.PDF, p. 85.

[119] Wind estimates are from http://www.energy.ca.gov/2007publications/CEC-500-2007-014/CEC-500-2007-014.PDF, p. 13. Geothermal estimate is from http://www.energy.ca.gov/2005publications/CEC-500-2005-070/CEC-500-2005-070.PDF, p. 8. For estimates of technical potential for concentrating solar power, see http://www.energy.ca.gov/2005publications/CEC-500-2005-072/CEC-500-2005-072-D.PDF, p. 19.

[120] California Energy Commission, April 6, 2007, Database of Investor-Owned Utilities' Contracts for Generation, Contracts Signed Towards Meeting the California Renewable Portfolio Standard Target. http://www.energy.ca.gov/portfolio/contracts_database.html, accessed July 20, 2007.

[121] Federal Energy Regulatory Commission, April 19, 2007, Order Granting Petition for Declaratory Order, Docket No. EL07-33-000, 119 FERC 61,061.

[122] California Independent System Operator press release, "Greening the Grid Gets Green Light," October 17, 2007. Also see http://www.caiso.com/1816/1816d22953ec0.html.

Connection between Transmission Options and Need for Cost Allocation Mechanism for Expanded Feed-In Tariffs

In Europe, feed-in tariffs typically offer a fixed, long-term price for renewable energy based on specific technologies.[123] In a number of European countries, the tariff levels are set to cover the cost of each eligible renewable technology plus a profit. The tariff can be designed to favor early actors, with generators coming on line in later years receiving a lower price. The tariff also can be varied by technology. Germany's tariffs are designed to favor both early actors and specific technologies.

This approach has benefits compared to California's ad hoc contract-by-contract subsidy decisions. By reducing uncertainty in a project's income stream, feed-in tariffs help developers obtain lower-cost financing and stimulate investment in a domestic renewable energy market.

In countries that offer feed-in tariffs, a strong home market has enabled renewable energy markets to show strong growth. This type of market is unlikely to develop from case-by-case decisions to allow above-market RPS contracts to be rolled into IOU rates . A number of other countries in Europe offer a feed-in premium on top of the electricity price, or a feed-in premium that varies with the market price to provide a set tariff to renewable projects. The former enables coexistence with a competitive market, but introduces market volatility to renewable developers, which could increase their costs. The latter removes this market volatility, while reducing the potential cost of feed-in tariffs.

To succeed on a statewide scale, the costs of feed-in tariffs need to be fairly distributed. One criticism of feed-in tariffs is that they cannot function in tandem with a competitive retail electricity market. The primary concern in this context is the lack of an obvious party to bear the electricity purchase obligation without destabilizing or skewing the competitive market landscape. Imposing an open-ended purchase obligation on competitive suppliers is not compatible with a market structure under which such suppliers contract to sell at fixed prices for varying terms to non-captive customers.

On the other hand, placing the obligation instead on just the regulated "provider of last resort" would not only burden a subset of customers disproportionately with the cost premium of supporting renewable energy, but could also accelerate customer migration to competitive alternatives, stranding the costs with an ever-shrinking subset of customers. As Wiser et al. point out, "feed-in laws are only competitively neutral if

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[123] European legislation requires renewables to be given priority in interconnection, but interconnection in some countries can be difficult. Spain and Ireland are two examples. In Germany there is an obligation to interconnect renewables.

applied to regulated elements of the industry or if a cost recovery and sharing mechanism is developed."[124]

In Europe, governments have developed mechanisms through which the costs of feed-in tariffs can be evenly redistributed.[125] In Germany, for example, regional transmission authorities evenly redistribute feed-in costs among national rate payers. In the U.S., Letendre suggests that a similar redistributive role could be played by regional transmission authorities or independent system operators.[126]

There are significant differences between the role played by the California ISO and that of European regional transmission authorities (transcos). In both Spain and Germany, grid access is guaranteed for generators responding to feed-in tariffs.[127] Germany's 2000 Ernueerbare-Energien-Gesetz (EEG) established a "countrywide compensation scheme . . . to help balance the costs [of renewable electricity] between the different electricity providers."[128] In 2004 the EEG was amended and the equalization provided for connection costs to be paid by plant operators and grid upgrade costs to be paid by the grid operator. In Germany, "The equalization provision in the EEG is aimed at the operators of transmission grids. (This is a small group with a limited number of players who will easily be able to handle the transactions associated with the equalization scheme, and will also be able to monitor each other.)"[129] In contrast, the California ISO has limited responsibility in allocating costs except for ancillary services.

However, given potential benefits of having a transmission agency guarantee renewable interconnection and play a role in cost equalization, the California ISO should consider its potential, as the control agency for transmission, to further accommodate and

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124 Wiser, R., Hamrin, J., & Wingate, M. (2002). Renewable energy policy options for China: A comparison of renewable portfolio standards, feed-in tariffs, and tendering policies. San Francisco, CA: Center for Resource Solutions. Prepared for the Center for Renewable Energy Development, Energy Research Institute, State Development Planning Commission.

125 Muñoz, M., Oschmann, V., & Tàbara, J. D. (in press). Harmonization of renewable electricity feed-in laws in the European Union. Energy Policy.

126 As quoted in Wilson Rickerson and Robert C. Grace, February 2007, The Debate over Fixed Price Incentives for Renewable Electricity in Europe and the United States, http://www.boell.org/docs/Rickerson_Grace_FINAL.pdf, p. 12-13.

127 Ragwitz, M. and Huber, C. *Feed-in systems in Germany and Spain: A comparison,* Fraunhofer Institute: Systems and Innovation Research, 2004, source for Table 5.1, page 54 in Mendonca, Miguel *Feed-In Tariffs: Accelerating the Deployment of Renewable Energy,* World Future Council, London, 2007.

128 Mendonca, Miguel *Feed-In Tariffs: Accelerating the Deployment of Renewable Energy,* World Future Council, London, 2007, page 32.

129 Ibid, page 35.

provide for equitable cost allocation of generation purchased should feed-in tariffs be adopted.[130] A Transco model, similar to that adopted in some European countries, was considered by Energy Commission staff during deregulation planning in the mid-1990s. Aspects of such a model may be adapted to California's current or potential electricity system to better integrate renewable generation, interconnection, transmission development, and scheduling of renewable electricity.

Several options should be evaluated as part of an Energy Commission white paper on feed-in tariffs prepared in collaboration with the CPUC to determine how best to allocate these costs. One option would be to allocate the costs through CPUC distribution rates. Another option would be to put in generation rates that allow stranded cost recovery from retail providers, as is currently done for qualifying facility renewable contracts. For additional discussion of feed-in tariffs, see *33 Percent by 2020 is Feasible with Changes in Program Structure* near the end of this chapter.

In-State Planning Processes for Transmission to Renewable Resources

One of the most important issues identified in the *2007 Strategic Transmission Investment Plan* is ensuring that transmission corridors are available to support the state's GHG emission reduction and RPS goals. Designating corridors can help streamline the transmission permitting process, building on improvements put in place by the CPUC and California ISO.

The Energy Commission, CPUC, California ISO, and publicly owned utilities have also created a new statewide inter-agency initiative, the California Renewable Energy Transmission Initiative (CRETI). The CRETI will assess competitive renewable energy zones in California, and possibly in neighboring states, to identify which zones can be developed most cost effectively and with the least environmental impacts. The CRETI will identify top-priority renewable energy zones and conceptual transmission plans for those zones, and initiate the permitting processes for projects identified in CRETI transmission plans.[131]

Noting the "land rush" in the Mojave Desert for potential concentrating solar energy development, the *2007 Strategic Transmission Investment Plan* recommends programmatic environmental impact reports/environmental impact statements (EIR/EIS) for California,

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130 Menanteau, P., D. Finon, and M.-L. Lamy, Prices versus quantities: Choosing policies for promoting the development of renewable energy. Energy Policy, 2003. **31**(8): p. 799-812. See also, Lewis, J. and R. Wiser, Fostering a renewable energy technology industry: An international comparison of wind industry policy support mechanisms. 2005, Lawrence Berkeley National Laboratory: Berkeley, CA. http://eetd.lbl.gov/ea/emp/reports/59116.pdf.

131 California Renewable Energy Transmission Initiative Mission Statement, July 11, 2007, http://www.ceert.org/ceert_reports/CRETI%20Mission%20-%20final.pdf, accessed July 24, 2007.

led by the Energy Commission and the Bureau of Land Management, with full participation from other state and local regulators. The programmatic EIR/EIS would formalize a roadmap of preferred renewable energy resource zones and the transmission needed to interconnect those areas to the electricity grid for permitting purposes, including both federal and non-federal land.

Another important part of the transmission investment process is the interconnection studies conducted by the California ISO to evaluate and allocate the transmission impacts of interconnecting new projects. The California ISO assesses renewable energy and other generation projects seeking interconnection to the transmission grid serving the state's investor-owned utility service areas and the service areas of many publicly owned utilities. This assessment takes place according to a proposed project's place in the California ISO interconnection queue, although clustered interconnection requests with common upgrades may be assigned without consideration of the queue position.[132] For projects that are not part of a cluster, if a project near the front of the queue drops out, interconnection studies for projects later in the queue must be redone.

Due to the California ISO's cost allocation procedures, it is financially difficult for projects to be interconnected ahead of other projects located in the same part of the transmission grid, unless they are considered as part of a cluster. As a result, a project that is delayed can hold up interconnection of other projects further down the queue. As of September 2007, SCE alone had 28,000 megawatts of renewables in the queue.[133] Most of the renewable energy projects in the current queue are fairly recent, although more than 700 megawatts of wind joined the queue before January 2004, including 300 megawatts of wind in Kern County that does not have an interconnection agreement.[134]

Transmission to Bring Renewable Energy from Out of State

The 2007 IEPR Committee is encouraged by the efforts of SCE and PG&E to develop transmission plans to bring renewable energy from out of state to California. The CPUC has authorized SCE to spend $4.5 million to assess resource zones in southeastern California and close-in border areas in Arizona and western Nevada and to participate in the CRETI process rather than perform those studies on its own.[135] PG&E received

[132] California ISO, FERC Electric Tariff, Third Replacement Volume No. II, Original Sheet No. 1005A, Effective March 1, 2006. http://www.caiso.com/1bf0/1bf0e846437e0.pdf, accessed July 20, 2007.

[133] Presentation by Ron L. Litzinger, Southern California Edison, at the Third Annual California Power Markets Forum, October 29, 2007.

[134] The latest update of the California ISO queue is available from http://www.caiso.com/docs/2002/06/11/2002061110300427214.html.

[135]California Public Utilities Commission, Energy Division, Resolution E-4052, approved August 23, 2007.

CPUC approval for $14 million in ratepayer money to study options for a major transmission line to bring up to 3,000 megawatts of renewable and other energy to Northern California. The earliest on-line date for the transmission line would be no earlier than 2013. Please see the *2007 Strategic Transmission Investment Plan* for discussion of additional renewable generation-transmission studies underway.

As of August 5, 2007, 55 of 64 new, repowered, or restarted RPS contracts signed since 2002 (about 80 to 85 percent of new, repowered, or restarted RPS capacity, depending on options exercised, and more than 90 percent of the associated energy) are priced below the market price referent, providing a significant economic benefit if this capacity becomes operational. Although out-of-state renewables have been eligible from the beginning of the RPS program, they have played a small part so far. As California moves to 33 percent RPS-eligible renewable energy, the state can maintain downward pressure on costs through a broad range of potential supplies in the WECC interconnection.

It is in California's interest to have better interconnection with other regions in the West. Such interconnection broadens the range of resources available to help meet California's greenhouse gas and renewable energy goals. As California moves to a carbon-constrained economy, there will likely be a higher value on environmental attributes of renewable energy without regard to location.

Renewable Energy Certificates and Deliverability

Recent changes to California's RPS are expected to encourage the development of out-of-state resources throughout the West. Although the California RPS currently requires retail sellers to procure renewable attributes and energy together as a "bundled" commodity — so that RPS-eligible energy is delivered to California consumers — these requirements have been made more flexible to make it easier to meet delivery requirements. However, renewable attributes, also referred to as "renewable energy credits" (RECs), that are sold separately from energy are termed "tradable" or "unbundled" and currently cannot be used to meet California RPS procurement requirements. To the extent unbundled RECs become eligible in the future, customers of the purchasing LSE will likely forego any supply diversity or price stabilizing benefits from the purchase because the LSE will still need to acquire a commensurate amount of conventional energy.

Provisions in SB 107 effectively allow "banking and shaping" of renewable energy by allowing RECs associated with out-of-state RPS-eligible facilities to be bundled with energy imported into California from electricity produced at a different time and from a different location. Previously, the Energy Commission required delivery to be scheduled directly from the RPS-eligible facility located out-of-state. The changes in the delivery requirements are expected to reduce the cost of importing RPS-eligible electricity, largely because of the flexibility in navigating transmission constraints. Further, these provisions allow intermittent resources to "shape" delivery with other resources and offer a firm product instead of energy "as available."

Another important amendment in SB 107 is allowing tradable RECs associated with energy produced from RPS-eligible resources to qualify toward RPS procurement requirements in the future, once certain conditions have been met. Tradable RECs may be allowed for RPS compliance after the CPUC and Energy Commission conclude that the WREGIS is operational, capable of independently verifying delivery of renewable energy to a retail seller, and can assure that RECs are not double counted by any seller within the WECC. Also, the CPUC may limit the amount of tradable RECs that a retail seller may procure to satisfy its RPS requirements. The CPUC is addressing RECs and other RPS implementation issues in its Rulemakings 06-05-027 and 06-02-012, and in subsequent RPS Rulemakings.[136]

Allowing tradable RECs for RPS compliance, including out-of-state RECs, could help increase the development of renewable energy WECC-wide, reducing the greenhouse gas emissions of system power. Also, it could encourage early action to build renewable energy that may otherwise be delayed by congestion on existing transmission lines bringing electricity into California, if that renewable energy can be effectively used locally.

Dispatchability and Reliability

AB 1585 also requires the Energy Commission to examine the consequences to electric system reliability from increased levels of renewable energy. This section discusses the impact of 33 percent renewable energy on the changing dynamics of reliable electricity supply in California. Intermittent renewable technologies, such as wind and solar, are a challenge to traditional reliability planning. The challenges must be addressed in part by changes in scheduling and services that support rapid changes in load and supply, such as improving the ability of systemwide and local capacity to ramp up and down rapidly.

Existing coal and nuclear plants and some recently built gas-fired baseload plants cannot ramp up and down as rapidly as needed to meet the increased peakiness of California's electricity load and the expected increased use of intermittent and must-take renewables to achieve 33 percent renewable electricity by 2020. At the same time, residential air conditioning demand is increasing. In California, the population is growing fastest in areas of the state with hot summer temperatures. In addition, a growing number of coastal homes are being retrofitted with air conditioning. To meet the growing demand for air conditioning, California needs greater quantities of electricity supply that can ramp up quickly.

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[136] California Energy Commission, *Renewables Portfolio Standard Eligibility Guidebook*, March 2007, http://www.energy.ca.gov/2007publications/CEC-300-2007-006/CEC-300-2007-006-CMF.PDF, p. 3.

As part of the 2007 IEPR proceeding, the Energy Commission published two reports assessing "stress" scenarios of the potential impact of expanded use of renewable electricity in California's 2020 generation mix:

- The *Scenario Analyses of California's Electricity System* report (Scenario Analyses Report) focused on scenario analysis in California and throughout the WECC region, creating scenarios that integrated high renewables and high levels of energy efficiency.[137] Some scenarios in this report used a resource mix of about 30 percent renewable energy in California.
- The *Intermittency Analysis Project Report* (IAP) analyzed renewable electricity scenarios for 2010 and 2020 and used a resource mix of 33 percent by 2020.

The Scenario Analyses Report divided the entire WECC area into 29 transmission zones, including 10 zones within California, to model transmission-constrained production costs. This analysis also used reserve margins as developed and required by the CPUC. More detail about the results of the Scenario Analyses Report is contained in Chapter 2.

The IAP studied the impacts of a 33 percent by 2020 scenario on system reliability and dispatchability in California and focused on in-state renewables using a more fine-grained approach than the Scenario Analyses Report, enabling study of the impacts of 33 percent renewable energy on local transmission requirements. Additional objectives of the IAP included quantifying both positive and negative impacts of a mix of 33 percent renewable technologies on transmission reliability and congestion (Table 4-1).

The study also attempted to develop a common perspective for evaluating different technologies, both fossil and renewable, that compete for limited system resources. The project was designed to provide a forum in which investor- and publicly-owned utilities, developers and regulators could work together to identify barriers, opportunities and benefits of strategically located renewable technologies.

The IAP relied on a systematic approach to identify statewide generation, transmission, and operations scenarios that satisfied 2010 and 2020 policy goals, beginning with developing a 2006 base case. The study accounted for grid-friendly technology changes by looking in detail at the electrical characteristics of modern state-of-the-art wind turbines and their impacts on performance, reliability, power quality and transmission system operation.[138] The study also used emerging wind and solar technologies and performance in selecting resource types and locations.

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[137] California Energy Commission, Scenario Analyses of California's Electricity System: Preliminary Results for the 2007 Integrated Energy Policy Report, Staff Draft Report, http://www.energy.ca.gov/2007publications/CEC-200-2007-010/CEC-200-2007-010-SD.PDF

[138] California Energy Commission, Impact on Past, Present and Future Wind Turbine Technologies on California Grid, CEC 500-2006-050, May 2006.

Table 4-1: Resource Mix Scenario for Intermittency Analysis Project (33 Percent Renewable Energy by 2020)

	2020
Total Geothermal, MW	5,100
Total Biomass, MW	2,000
Total Concentrating Solar, MW (Intermittent)	3,100
Total PV Solar, MW (Intermittent)	2,900
Total Wind, MW * (5,800 MW in Tehachapi Region) (Intermittent)	12,700
Total Renewable Capacity	25,800
Peak California Load, MW	80,742
Peak California ISO Load, MW	66,700
Intermittent Penetration in CA	23%
Intermittent Penetration in California ISO Service Territory	25%
Total Renewable Resource Penetration in California	32%

Source: California Energy Commission Intermittency Analysis Project[139]

*Intermittent penetration percentage for California ISO Control Area assumes 90 percent of statewide intermittent resources are located in that region.

In contrast to the Scenario Analyses Report, which used current 2006 cost of generation estimates from the Cost of Generation model with no assumed change in cost over time, the IAP study based future costs of renewables on present-day costs of energy and industry forecasts by entities such as the Electric Power Research Institute and Navigant. The economic analysis also accounted for the maturity of the technology and the length of time needed for development of a renewable energy project using that technology.

In preparing this scenario, the IAP team and stakeholders considered transmission upgrades, options for voltage reactive support (to protect equipment from voltage spikes and drops), and operational improvements to maintain local reliability. Investment will be needed in transmission, generation, and operations infrastructure to maintain reliability as the electricity system moves toward 33 percent by 2020.

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139 Porter, K. and Intermittency Analysis Project Team. 2007. *Intermittency Analysis Project: Summary of Final Results*. California Energy Commission, PIER Research Development & Demonstration Program. CEC□500□2007□081. , http://www.energy.ca.gov/2007publications/CEC-500-2007-081/CEC-500-2007-081.PDF, Tables 2-2 on page 18.

The IAP was designed to quantify in megawatts and megawatt-hours the potential impact of the 2010 and 2020 renewable energy goals on state-wide system operations. As part of the scenario analysis, IAP estimated the indirect costs of integration for regulation and load following for wind to be $0.69 per megawatt-hours and reported that emerging grid-friendly wind turbine technologies may reduce integration issues and costs.[140] Also, benefits of incorporating state-of-the-art wind energy forecasting techniques across the system were estimated at $4.37/ megawatt-hours.

The IAP did not focus specifically on estimating costs such as unit commitment or cost adders. The unit costs to manage and procure the megawatts and megawatt-hours variability created by increased renewable energy deployment will vary depending on the size of the utility service area and mix of resources. However, a joint project of the Northwest Power Planning Council (NWPPC) and other contributors reviewed several northwest utility studies of integration costs. The utility studies estimated costs from about $3.20 to $9.75 per megawatt-hours for 10 percent wind penetration, about $6 to $11.70 for 20 percent penetration, and about $8.85 to $16.15 for 30 percent penetration. [141] These estimates include additional incremental reserves needed to compensate for intermittency at a local utility planning scale, in addition to the costs of load following, regulation, and unit commitment. The NWPPC study states that the cost of wind integration depends primarily on the following factors:

- Size of the control area from which such services are procured relative to the amount of wind being integrated
- Geographic diversity of wind sites and resulting generation patterns
- Amount of flexibility available to the power system
- Access to robust markets for control area services and storage and shaping products[142]

The IAP final report estimates the number, type, and location of transmission upgrades needed for the report's renewable energy scenarios. These estimates do not include detailed land use or right-of-way costs, which could significantly increase costs.

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[140] Impact on Past, Present and Future Wind Turbine Technologies on California Grid by BEW Engineering, CEC 500-2006-050, May 2006. As reported in Porter, K. and Intermittency Analysis Project Team. 2007. *Intermittency Analysis Project: Summary of Final Results*. California Energy Commission, PIER Research Development & Demonstration Program. CEC-500-2007-081. , http://www.energy.ca.gov/2007publications/CEC-500-2007-081/CEC-500-2007-081.PDF, p. 3.

[141] Northwest Power and Conservation Council, *Northwest Wind Integration Action Plan*, pre-publication version, March 2007 at http://www.nwcouncil.org/energy/Wind/library/2007-1.pdf, p. 8

[142] Northwest Power and Conservation Council, *Northwest Wind Integration Action Plan*, pre-publication version, March 2007 at http://www.nwcouncil.org/energy/Wind/library/2007-1.pdf, p. 8.

However, the IAP analyzed only in-state renewable resources. In reality, out-of-state resources are likely to provide significant portions of California's RPS requirements, and these would imply different transmission upgrades and costs.

In addition, the transmission analysis of the scenarios studied in the IAP suggests that "wind variability may contribute to transmission congestion under certain renewable energy dispatch scenarios, and that transmission congestion patterns are more difficult to predict as the penetration of variable renewable energy resources increases."[143]

Regarding the technical feasibility of 33 percent by 2020, the IAP reached the conclusion that California can incorporate that amount of renewables, provided appropriate infrastructure, technology, and policies are in place. Specifically, this successful integration will require investment in transmission, generation, and operations infrastructure to support the renewable additions, appropriate changes in operations practice, policy and market structure, and cooperation among all regulatory participants.[144]

Another issue identified in the IAP 33 percent by 2020 scenario is the shape of California's overall wind generation profile, which is capable of producing large amounts of energy during low demand times. The combination of wind generation needed to meet RPS goals and existing baseload "must-run" plants such as qualifying facilities with must-run contracts and nuclear plants can contribute to an over-generation problem at these times. The IAP found that pumped hydro storage, better coordination of pumping by the State Water Project to increase load during low demand times, and other potential storage technologies discussed below can help accommodate low marginal cost wind.

The IAP suggests that there are opportunities to better use existing pumped storage to modify and increase load during off-peak times and provide ancillary services. New pumped storage, such as the proposed Lake Elsinore Advanced Pump Storage (LEAPS) facility in rapidly growing Riverside County and the Iowa Hill facility being considered by the Sacramento Municipal Utility District (SMUD) may provide further assistance for "storing" renewable energy generated on windy nights.[145][146]

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[143]Ibid.

[144]Ibid, p. 3.

[145] Porter, K. and Intermittency Analysis Project Team. 2007. *Intermittency Analysis Project: Summary of Final Results*. California Energy Commission, PIER Research Development & Demonstration Program. CEC-500-2007-081, http://www.energy.ca.gov/2007publications/CEC-500-2007-081/CEC-500-2007-081.PDF, p. 34-35.

[146] Confluence Newsletter, Summer, 2007, at http://hydrorelicensing.smud.org/IowaHill/News/Confluence%20News_Sumr07.pdf . See also SMUD's project description at http://hydrorelicensing.smud.org/IowaHill/iowa/Iowa_PD.pdf

In addition to the ability to ramp up or down on an hourly basis, the IAP suggests that an electricity mix for 2020 that includes 33 percent renewables will need a relatively modest average increase in regulation control resources (20 megawatts), such as automated demand response technologies, variable speed pumped hydro, and flywheel energy storage.[147] The IAP 33 percent by 2020 scenario also suggested a need for significant amount of volt-amperes reactive (VAR) compensation to maintain voltage stability.[148]

2006 Long-Term Procurement Plans for Investor-Owned Utilities

AB 1585 also requires the Energy Commission to discuss the long-term planning requirements for the state's IOUs. The CPUC directed PG&E, SDG&E and SCE to develop 2006 Long-term Procurement Plans (LTPP) to meet EAP II targets of 20 percent renewable by 2010 and 33 percent by 2020.[149] The CPUC stated that it "will not approve plans that lack realistic and implementable provisions for meeting the EAP II targets."[150]

However, as described below, the utilities' procurement plans contain considerable uncertainty about their ability to procure the amount of renewable energy equal to 20 percent by 2010. PG&E's 2006 LTPP did not include a scenario that would put the utility on track to meet 33 percent by 2020, and whether SDG&E's plan does so is subject to some debate. SCE did include such a scenario, but argued against adopting it.

The CPUC requires utilities to achieve 20 percent by 2010. This procurement requirement is defined as 20 percent of 2009 retail sales.[151] To be on track to achieve 33 percent by 2020, adding 1.3 percent per year to 20 percent in 2010, the Energy Commission estimates the need for 28 percent of retails sales in 2016, the end of the planning period covered by the 2006 LTPP.

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[147] Porter, K. and Intermittency Analysis Project Team. 2007. *Intermittency Analysis Project: Summary of Final Results*. California Energy Commission, PIER Research Development & Demonstration Program. CEC□500□2007□081. , http://www.energy.ca.gov/2007publications/CEC-500-2007-081/CEC-500-2007-081.PDF, p. 5.

[148]Ibid, p. 27.

[149] http://www.energy.ca.gov/energy_action_plan/2005-09-21_EAP2_FINAL.DOC

[150] CPUC, Scoping Memo on the Long-Term Procurement Phase of Rulemaking R.06-02-013. http://www.cpuc.ca.gov/EFILE/RULC/60186.htm, p. 17.

[151] CPUC, October 19, 2006, Decision 06-10-050, in Rulemaking 06-05-027, *Opinion on Reporting and Compliance Methodology for Renewables Portfolio Standard* Program, http://www.cpuc.ca.gov/WORD_PDF/FINAL_DECISION/61025.DOC.

Pacific Gas and Electric

PG&E's 2006 LTPP reports renewable energy in 2007 to be between 10,487 gigawatt-hours and 10,498 gigawatt-hours, 13.3 percent of the retail sales for 2006.[152] PG&E expects to have total retail sales between about 75,000 gigawatt-hours and 85,000 gigawatt-hours in 2010.[153] PG&E used 20 percent of 2009 retail sales to calculate the total renewable energy it needs to meet the 20 percent by 2010 target, about 15,000 gigawatt-hours to 17,000 gigawatt-hours with a renewable resource mix between 980 and 1,000 megawatts in size. PG&E used 25 percent of 2015 retail sales, forecast to be about 19,000-23,000 gigawatt-hours as a proxy for 33 percent by 2020, with between 2,800 megawatts and 5,000 MW of renewable resource capacity.[154]

PG&E's plan anticipates achieving about 18 to 19 percent renewable deliveries in 2010 and 20 percent in 2011 or 2012, depending on the scenario. Three of four of the scenarios prepared by PG&E do not achieve 28 percent of renewables by 2016. [155]

Assuming a 50 percent capacity factor to convert from energy (gigawatt-hours) into capacity (megawatts), the Energy Commission estimated PG&E's scenarios are short of achieving 20 percent renewables by 2010 by between 823 gigawatt-hours to 1611 gigawatt-hours (188 – 368 megawatts). Assuming 28 percent by 2016 is needed to be on track to achieve 33 percent by 2020, PG&E's scenarios are short by from 4,548 gigawatt-hours (1,038 megawatts) to 1,764 gigawatt-hours (403 megawatts).[156]

PG&E's LTPP recognizes that transmission is "increasingly becoming a critical element in meeting the state's RPS goals," and that most proposed renewable development is remote from PG&E's load centers.[157] PG&E assumes development of 2,400 megawatts of wind and 200 megawatts of geothermal resources which require transmission development and notes that there is "significant uncertainty regarding the availability of

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[152] Pacific Gas and Electric Company, 2006 Long-Term Procurement Plan, Vol. 1, public version, Tables IVC-7 and IVC-8.

[153] Ibid, p. IV-31.

[154] Ibid, p. IV-31.

[155] California Energy Commission, Prepared Direct Testimony of Heather Raitt on Behalf of the California Energy Commission Regarding the Issue of Renewable Energy Procurement Strategy as Addressed in the Long-Term Procurement Plan of Pacific Gas and Electric, pp. 16-17.

[156] Ibid, pp. 19-20.

[157] Pacific Gas and Electric Company, 2006 Long-Term Procurement Plan, Vol. 1, public version, p. V-49)

transmission capacity and consequent effect on wind [and geothermal] resource deliveries."[158]

To address the need for transmission, PG&E describes short-term (1 to 5 years), medium-term (next 5-10 years), and long-term (next 10-15 years) actions critical to support its procurement plan. The short-term projects are typically upgrades to existing facilities or transmission lines needed to reduce congestion such and expand PG&E's ability to deliver new renewable power from remote locations.[159] PG&E also identifies three medium-term projects with its schedules, recognizing that the timing may change depending on the results of environmental and technical studies: (1) Midway-Gregg 500 kV Line by 2012; (2) Bay Area 500 kV Station by 2013; and (3) Vaca Dixon-Fulton Connection by 2015.

For the long-term, PG&E states that it will continue to participate in regional planning efforts to access renewable resources in the Pacific Northwest. PG&E is contributing to a feasibility study for the Frontier Line, a proposed interstate, high voltage line to deliver renewable and coal energy throughout the West.[160] Also, PG&E has received approval from the CPUC to spend up to $14 million to study the feasibility of developing transmission to access renewable resources in British Columbia. Although PG&E did not include potential capacity from British Columbia in its forecasts of pending additional research,[161] it estimates that almost 9,900 megawatts of renewable resources—wind, hydro (including "medium" hydro which is not eligible for the California RPS), biomass, and geothermal—could be developed in British Columbia.[162]

PG&E states that it "…is planning to procure all available renewable resources, subject to market and transmission constraints until it meets its RPS targets, even if they are priced above market price. Once PG&E meets its RPS targets, it will implement the EAP loading order by pursuing all cost-effective renewable energy resources…"[163]

San Diego Gas & Electric

The Energy Commission's analysis determined that SDG&E's 2006 LTPP exceeds the 2010 RPS goal by approximately 334 gigawatt-hours (76 MW) in 2010, but is short of a trajectory toward 33 percent in 2020 by approximately 880 gigawatt-hours in 2016 (201

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[158] Ibid, p. IV-34 for wind, p IV-35 for geothermal.

[159] Ibid, p. V-50.

[160] Ibid, p. V-49.

[161] Ibid, pp. IV-33-34.

[162] Ibid, p. IV-37.

[163] Ibid, p. IV-27.

megawatts).[164] SDG&E contests these findings and states that its plan is on a trajectory to meet the 33 percent target as discussed below.[165]

SDG&E's 2006 LTPP states that it has contracts for 16.4 percent renewable energy under contract for delivery in 2010 and that it plans to procure the remaining approximately 3.6 percent needed to reach 20 percent (based on 2009 forecasted retail sales in accordance with the methodology approved by the CPUC in D.04-06-014).[166]

According to SDG&E, it plans to have 507 MW of renewable capacity in 2010 and 840 megawatts in 2016. SDG&E states that these resources would allow it to provide about 22 percent of its energy needs in 2010; it would then continue to increase its procurement of renewable energy over time. SDG&E cautions that the ability to meet the targets will depend on the availability of transmission.[167] SDG&E explains:

> There is some risk of contract failure associated with a number of power contracts, particularly those that are contingent on transmission additions. Should any of the signed contracts not materialize, then SDG&E would need to replace the power from an additional source with similar characteristics.[168]

The Energy Commission has expressed concern that SDG&E's margin of safety is not large enough to ensure that it meets the 20 percent by 2010 goal and has encouraged SDG&E to procure, through contracted or development of utility-owned facilities, RPS energy equivalent to 20 percent by 2010 plus a 20 to 30 percent margin of error. SDG&E has responded by noting that if all negotiations with a portfolio of counterparties were to be completed successfully, it could take SDG&E well beyond the recommended 30 percent safety margin if circumstances dictate a need for greater contracting. SDG&E has requested that the CPUC recognize that it is prudent to contract with renewables in excess of the 20 percent mandate to allow for unexpected contract failures or delays in the approval and construction of new transmission or renewable generation. SDG&E

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[164] California Energy Commission, Prepared Direct Testimony of Heather Raitt on Behalf of the California Energy Commission Regarding the Issue of Renewable Energy Procurement Strategy as Addressed in the Long-Term Procurement Plan of San Diego Gas & Electric, p. 19.

[165] SDG&E Opening Brief, pp. 82-83.

[166] SDG&E 2007-2016 LTPP Vol. 1 part 2 p. 190-191.

[167] SDG&E Vol. 1 Part 1, p. 169.

[168] SDG&E, December 11, 2006, 2007-2016 Long-term Procurement Plan, Volume 1, Public Version, https://www.pge.com/regulation/LongTermProcureOIR/Testimony/SDGE/2006/LongTermProcureOIR_Test_SDGE_20061211-01.pdf, p. 168.

envisions contracting for 24-26 percent of 2010 retail sales to be delivered from renewable resources.[169]

For 2016, SDG&E's plan calls for 840 MW of renewable capacity.[170] SDG&E states that it currently has renewable energy contracts for 19.5 percent of forecasted 2016 retail sales, explaining that actual growth in delivered renewable energy is likely to be "lumpy" and may be changed if the CPUC allows SDG&E to use unbundled RECs for the RPS, which SDG&E supports.[171]

The Energy Commission's testimony concluded that SDG&E's plan does not meet the 28 percent required to be on track to achieve 33 percent by 2020.[172] SDG&E, however, states that its plan actually shows reaching 29.4 percent renewable by 2016, consistent with reaching a 33 percent goal by 2020.[173]

Regarding transmission, SDG&E states that it needs the Sunrise Powerlink transmission project to achieve 20 percent by 2010 and "higher percentages in future years."[174] The Sunrise Powerlink would allow SDG&E to import an additional 1,000 MW from Imperial Valley to San Diego.[175] The Energy Commission supports this project as critical to SDG&E's ability to meet the 2010 RPS goal, ensure system reliability, and reduce congestion costs.[176]

Southern California Edison

The Energy Commission's analysis determined that SCE's 2006 LTPP exceeds the 2010 RPS goal by approximately 765 gigawatt-hours (175 megawatts) in 2010, but is short of a course toward 33 percent in 2020 by approximately 1358 GWh in 2016 (310 MW). These

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169 SDG&E August 1, 2007, Opening Brief, CPUC Rulemaking 6-02-013, Order Instituting Rulemaking to Integrate procurement Policies and Consider Long-Term Procurement Plans, https://www.pge.com/regulation/LongTermProcureOIR/Pleadings/SDGE/2007/LongTermProcureOIR_SDGE_20070801-01.pdf, pp. 83 – 84.

170 SDGE 2007-2016 LTPP Vol. 1 part 1, p. 178.

171 SDG&E 2007-2016 LTPP Vol. 1 part 2 p. 191-192.

172 California Energy Commission, Prepared Direct Testimony of Heather Raitt on Behalf of the California Energy Commission Regarding the Issue of Renewable Energy Procurement Strategy as Addressed in the Long-Term Procurement Plan of San Diego Gas & Electric, pp. 12-13, 15, 18.

173 Ibid, pp. 82-83.

174 SDG&E 2007-2016 LTPP Vol. 1 part 2 p. 192.

175 Ibid, p. 204.

176 California Energy Commission, Prepared Direct Testimony of Heather Raitt on Behalf of the California Energy Commission Regarding the Issue of Renewable Energy Procurement Strategy as Addressed in the Long-Term Procurement Plan of San Diego Gas & Electric, p. 16.

results reflect SCE's scenario that incorporates the Energy Commission's load forecast into SCE's "Best Estimate Plan," and the Energy Commission's assumption that renewable resources will have an average capacity factor of 50 percent.[177]

SCE's 2006 LTPP meets the 20 percent by 2010 RPS goal, with about 15,000 gigawatt-hours of renewable energy.[178] For 2006, SCE anticipated having 16.5 percent of its retail load met by output from eligible renewable resources.[179] In its LTPP, SCE states it may not be able to achieve 20 percent by 2010:

> … many uncertainties could potentially hamper the viability of this forecast, such as: potential fluctuations in load growth due to customer migration; potential fluctuations in renewable output resulting from resource depletion and contract attrition at levels higher than the 10 percent attrition rate assumed for the 33 percent scenario; delays in obtaining State or local transmission permits; missed milestones by project developers; and other unanticipated causes.[180]

To meet the 20 percent by 2010 goal and 33 percent by 2020 goal, SCE assumes the following transmission will be built:[181]

- Tehachapi (Phase I) 700 megawatts in 2010
- Tehachapi (Phase 2/3) 1,700 megawatts in 2013
- Tehachapi (Phase 4) 2,100 megawatts in 2015
- San Bernardino County 2,000 megawatts every two years starting in 2015 up to 10,000 megawatts
- Salton Sea 1,300 megawatts in 2017
- North of Lugo 975 megawatts in 2020

SCE's 2006 LTPP includes a Required Plan to put SCE on a path to achieving 33 percent renewables by 2020. SCE's scenario assumes a "chunky" development path, coming-on line as new transmission is built, showing about 25,000 gigawatt-hours in 2016, providing close to 33 percent of retail sales under the CEC Load Scenario, and about 30

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[177] California Energy Commission, Prepared Direct Testimony of Heather Raitt on Behalf of the California Energy Commission Regarding the issue of Renewable Energy Procurement Strategy as Addressed in the Long-Term Procurement Plan of Southern California Edison, p. 22.

[178] SCE's 2006 Procurement Plan, Volume 1B, public version, p. 78

[179] Ibid, p. 76.

[180] Ibid, pp. 85-86.

[181] Ibid, p. 77.

percent of retail sales under the SCE load scenario.[182] For comparison, SCE's 20 percent planning scenario shows about 20,000 gigawatt-hours of renewable energy in 2016.[183]

SCE identified new transmission to the following renewable resource areas as essential to achieving 33 percent by 2020: Western Nevada, Inyo County, the Salton Sea area in Imperial County, and Eastern San Bernardino County.[184]

However, SCE does not recommend this plan, stating that it would be expensive because of the transmission required to achieve this goal and increased demand for renewables.[185] In this Required Plan, for resources procured beyond the 20 percent plan, SCE assumes renewables will be priced at 25 percent above the MPR, arguing that "increasing demand by elevating the overall goal of the RPS program to 33 percent in a market already demonstrating resource shortages and consequently higher prices will likely lead to higher overall costs for the RPS program."[186] To avoid the expense, SCE asks the CPUC to approve its Best Estimate Plan, which does not meet 33 percent by 2020, stating "the Best Estimate Plan is the only plan that is realistically achievable and cost-effective." [187]

SCE's view of the cost of renewable energy is not supported by publicly available data from RPS solicitations. From the beginning of the RPS program in 2002 to August 2007, more than 80 percent of the new, repowered, or restarted renewable energy capacity and more than 90 percent of projected RPS energy deliveries contracted with IOUs is priced below the market price referent. Whether future costs remain below the MPR depends in part on whether manufacturing of wind turbines expands to meet demand; transmission is built to access renewable-rich areas; existing contracts (particularly for large amounts of solar) come on-line as planned; the future price of natural gas goes up or down, on average, compared to current prices; and the SEP/MPR structure is revised to incorporate modern portfolio theory and incorporate an appropriate greenhouse gas adder, or is changed to a feed-in tariff.

In addition, SCE assumes carbon regulation will cost $8 per ton of carbon dioxide. There is substantial risk that the value may be much higher. The *2006 IEPR Update* cited a study by Synapse Energy Economics forecasting a range of $8.5 to $30.8 per ton (p. 55). A July 2007 press release from Deutsche Bank anticipates carbon for 2008-2020 in Europe

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[182] SCE's 2006 Procurement Plan, Vol. 1B, public version, p. 85, 127.

[183] Ibid, p. 78.

[184] Ibid, p. 82.

[185] SCE's 2006 Procurement Plan, Vol. 1A, public version, page 5, lines 18-27.

[186] SCE's 2006 Procurement Plan, Vol. 1B, public version, p. 87-88.

[187] SCE's 2006 Procurement Plan, Vol. 1A, public version, page 5.

may be in the range of 35 Euro (about $48).[188] The 2008 allowances have been trading at about 20 to 30 Euro per metric ton CO_2 in the European Union Emission Trading Scheme.[189]

Potential Impact on Rates and Public Goods Charge

AB 1585 requires the Energy Commission to report on the potential impacts on electric rates of the 33 percent renewable goal. In November, 2005, the CPUC published a report prepared by the Center for Resource Solutions assessing the feasibility and cost impacts of a 33 percent renewable energy target. The report found 33 percent to be technically and economically feasible and slightly lower cost than business-as-usual in the long term. The report found an average rate impact of plus 0.57 percent over the 2011-2020 period. However, extending the analysis to 2011-2030, the report found the 33 percent by 2020 target was likely to provide a net savings.[190]

As part of the 2007 IEPR proceeding, the Energy Commission published several studies investigating potential impacts of 33 percent renewable energy on rates and public goods charge funds. Detailed findings from these studies are discussed later in this section.

The results of the Scenario Analyses Report show that a 2020 scenario with about 30 percent renewable energy may be achievable without a significant upward impact on rates.[191] As mentioned earlier, this study did not analyze potential changes in renewable technology costs over time. In addition, much of the increase in system costs in the high renewables scenario is associated with customer-funded distributed generation competing economically with retail rates, not contributing to them. In particular, the analysis of Case 4A showed a total increase of about $10 per megawatt-hour for both demand-side rooftop solar PV and total utility generation mix. The Scenario Analyses

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[188] Deutsche Bank, July 25, 2007, The European Union wants to cut Carbon Emissions by 20% by 2020, Deutsche Bank significantly upgrades Carbon Price Forecast, http://www.db.com/presse/en/content/press_releases_2007_3588.htm.

[189] 5 July 2007, EU carbon down, but solid above 20 Euros, http://www.carbonpositive.net/viewarticle.aspx?articleID=98 . See also, http://www.carbonpositive.net/viewarticle.aspx?articleID=137.

[190] Center for Resource Solutions, November 2005. *Achieving a 33% Renewable Energy Target*. Prepared for the CPUC. http://www.cpuc.ca.gov/word_pdf/misc/051102_FinalDraftReport_RenewableEnergy.pdf. p. 99-101.

[191] California Energy Commission, Scenario Analysis of California's Electricity System: Preliminary Results for the 2007 Integrated Energy Policy Report, CEC-200-2007-010-SD, June 2007

Report used total societal costs, including both rebates and PV purchase costs paid by homeowners and businesses. For that reason, and the fact that PV is more expensive than utility scale renewables, the expected $10 increase in total economic cost is consistent with a minimal or negligible increase in costs of utility generation that becomes part of the rate base.

A second, portfolio analysis study[192] suggests that there may be statewide generation portfolios with renewable content in excess of 33 percent by 2020 that provide lower or equivalent cost and lower risk for California ratepayers than maintaining 20 percent renewable energy. For example, the study models a generation mix with 45 percent renewables that has costs equivalent to a 20 percent renewable "business as usual" portfolio.

There is a wide range of uncertainty regarding forecasts of future electricity rates, which depend on future natural gas prices, potential cost of carbon regulation, generation costs in general, and upgrades to the transmission and distribution grids, among other factors. Major investments in transmission infrastructure will be needed to maintain system reliability and serve increasing electricity demand as California's population grows. Much of this investment would be needed even if the state were not committed to 33 percent renewable generation by 2020. Geographically, the areas with the most growth in housing are in the Central Valley and the southeastern counties.

Beyond the uncertainties affecting electricity rates in general, a different set of factors affects the future costs of renewable electricity. For example, there is currently a shortage of wind energy turbines, which is likely to drive up the price of energy from new wind facilities until manufacturing capacity expands to meet demand. The potential impact of 33 percent on rates and public goods charge funds also depends on the price mechanism used to contract for the additional renewable energy.

Currently, while there is considerable uncertainty regarding future costs of reaching California's renewable goals, preliminary analyses indicate that rates may not be greatly impacted. The Scenario Analyses Project found a clear tradeoff between higher capital cost and lower production costs with generation portfolios weighted toward renewables. However, several possible futures resulting in sustained very high natural gas prices could result in high renewable generation mixes that are less costly than mixes with more conventional generation. For example, country-wide turn away from high greenhouse gas-emission coal generation could put unprecedented upward pressure on gas prices.

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[192] Bates White, LLC, *A Mean-Variance Portfolio Optimization of California's Generation Mix to 2020: Achieving California's 33 Percent RPS Goal*, draft consultant report, July, 2007, CEC-300-2007-009-D.pdf.

Mean-Variance Portfolio Analysis Findings

In addition to the scenario analysis described above, the Energy Commission published a report using mean-variance portfolio analysis to assess potential future generation portfolios.[193] These scenarios suggest potential cost and risk impacts of at least 33 percent renewables by 2020. The report demonstrates how mean-variance portfolio analysis can be used to generate an "efficient frontier" of resource mixes for electricity generation. The mixes on this frontier indicate the least expensive options for a given amount of risk and the least risky options for a given cost.

This approach, commonly known as portfolio analysis, has been used by investors for decades. Investors typically seek a diversified portfolio that balances higher risk stocks with low risk assets such as government bonds. One reason that diversified portfolios have lower risk is that the likelihood of all assets declining in value at the same time is low. For example, expected returns for stocks are higher than for bonds; however, because stock prices are more volatile, bonds are a less risky investment. Studies of portfolio performance show that when bonds are added to a stock portfolio, the expected value of net risk-adjusted returns of the portfolio over time increases. Just as a diversified portfolio of investments can increase returns, a diversified portfolio of generation assets can reduce overall electricity costs paid by ratepayers.

The main findings of the portfolio analysis report include:

- Compared to a "business as usual" portfolio with 20 percent renewable resources in 2020, other portfolios exist that are less risky, less expensive, and that substantially reduce CO_2 emissions and dependence on energy imports.
- An optimal generating portfolio for California includes greater shares of renewable technologies that may cost more on a stand-alone basis.
- Adding a non-fossil, fixed-cost technology such as wind to a risky generating portfolio lowers expected costs at any level of risk. Adding too much renewable generation increases portfolio risk, but those levels are substantially greater than 33 percent in 2020.

The authors of the report noted a number of caveats and limitations associated with these findings:

- Realistic constraints on the amounts (upper and lower bounds) for each renewable and conventional technology type must be substituted for the proxy assumptions used in the report.
- A more complete analysis is needed that considers transmission and integration constraints, to regional and local levels.
- It may be difficult to constrain estimates of future volatility and covariance.

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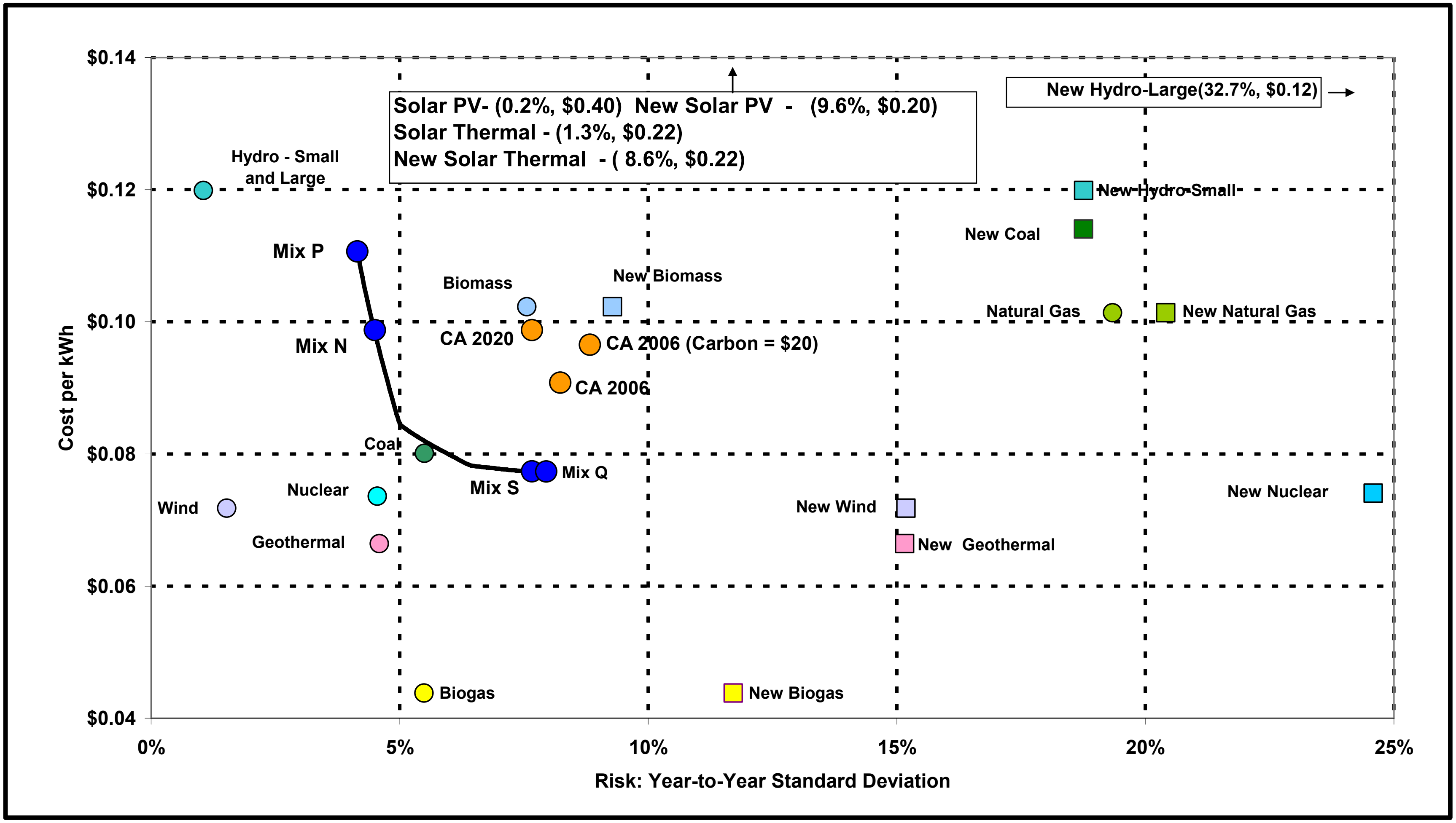
193 Ibid.

- The analysis ignored certain risks including wind resource intermittency and transmission stability issues and geothermal steam resource constraints
- Mean-variance portfolio analysis assumes that risks are symmetric, and that variance captures all risk attributes; however, risks associated with future generation costs may well not be symmetric.

Given these caveats, the report's results in terms of costs and risks associated with various portfolios are illustrative. Further analysis is needed to apply the concepts of portfolio analysis to models using more complete sets of inputs, such as those used in the Scenario Analyses Report and the IAP. Ultimately, integrating portfolio analysis concepts into state and utility long-term planning could be combined with other improvements that address the need to achieve state GHG goals while controlling ratepayer costs. Figure 4-2 shows the results from the preliminary portfolio analysis discussed in the report.[194] The vertical axis shows total portfolio electricity generation cost, while the horizontal axis shows portfolio risk. In the figure, the curve connecting

[194] Adapted from Bates White, LLC, Figure 8, p. 28.
http://www.energy.ca.gov/2007publications/CEC-300-2007-009/CEC-300-2007-009-D.PDF

Figure 4-2: Risk and Cost in Portfolio Analysis of California Business as Usual 2020 Generation Resources



Source: Bates White, A Mean-Variance Portfolio Optimization of California's Generation Mix to 2020: Achieving California's 33 Percent RPS Goal, Draft Consultant Report, July, 2007.

"Mix P" to "Mix Q" shows the location of portfolios with the best cost-risk combinations, indicating that the "business as usual" portfolio mix is not on the frontier.

Table 4-2 shows portfolios that fall on the efficient frontier shown by the curve in Figure 4-2. The proportions of each renewable technology in Portfolio N appear to be more practical than those in Portfolios S and Q. In addition to exceeding the 33 percent renewable generation goal, Portfolio N has lower risk, equivalent costs, and results in significantly less CO_2 emissions than the business-as-usual case.[195]

Table 4-2: Portfolio Mix Details for Portfolios P, N, S, and Q shown in Figure 4-2

	CA-2020 (BAU)	Portfolio P	Portfolio N	Portfolio S	Portfolio Q
RISK	7.7%	4.2%	4.5%	7.7%	8.0%
COST: cents/KWh	9.9	11.1	9.9	7.7	7.7
CO2: Mil-tonnes/Yr	78	47	47	19	19
Generating Resource	**Generating Shares**				
Coal	15%	15%	15%	5%	5%
Natural Gas	34%	5%	5%	5%	5%
Nuclear	12%	12%	12%	12%	11%
Hydro	20%	20%	20%	15%	15%
Wind	4%	2%	5%	22%	23%
Geothermal	7%	5%	11%	29%	29%
Biomass	3%	12%	12%	1%	1%
Biogas	1%	10%	10%	10%	10%
Solar Thermal	3%	10%	6%	0%	0%
Solar PV	0%	8%	4%	0%	0%
Renewables Share	20%	41%	45%	64%	64%

Source: Bates White, LLC, *A Mean-Variance Portfolio Optimization of California's Generation Mix to 2020: Achieving California's 33 Percent RPS Goal*, draft consultant report, July, 2007.

195 BW, p. 25-30.

In written comments on the portfolio analysis report, the IOUs indicated that they believe the report is based on too many simplifying assumptions. SDG&E states, "…we believe that the situation facing the utilities and the state in resource planning is far more complex than has been captured in the illustrative analysis presented as an example."[196] PG&E echoes the concern: "Conclusions suggested by the Bates White, LLC report are premature due to its methodological issues."[197]

SCE articulates a similar position: "SCE believes the analysis is a reasonable starting point for understanding the potential effects that a limited set of risk factors would have on the future costs and emissions of various hypothetical portfolios. However, the [Energy Commission's] analysis contains omissions in input data, risk factors, peer scrutiny, and other considerations that bring into question whether the results are a meaningful representation of the future outcomes."[198]

The Natural Resources Defense Council's (NRDC) written comments recognized the concerns voiced at the workshop regarding assumptions used in the report, but stated that, ". . . we believe that the value of portfolio analysis is clear." NRDC believes that the use of this approach is critical to understand[ing] the important role that energy efficiency and renewable energy can play in reducing total system risk" and recommends that "the [Energy] Commission work with the CPUC and the state's utilities to incorporate portfolio analysis techniques in the development of the 2008 Long-Term Procurement Plans."[199] The workshop comments and the acknowledged caveats to the mean-variant portfolio analysis study indicate that further study is needed to bring the benefits of portfolio concepts into analysis with a more complete set of assumptions.

The scenario and portfolio analyses approaches, along with the methodology used in the IAP, each have their strengths and weaknesses. None of these studies alone can definitively answer the question of the effect of 33 percent renewables on rates. Collectively, however, they corroborate the feasibility and desirability of the 33 percent in 2020 objective.

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[196] SDG&E, Comments, July 11, 2007 Integrated Energy Policy Report Committee Workshop on the Use of Portfolio Analysis in Electric Utility Resource Planning

[197] PG&E, Comments, July 11, 2007 Integrated Energy Policy Report Committee Workshop on the Use of Portfolio Analysis in Electric Utility Resource Planning

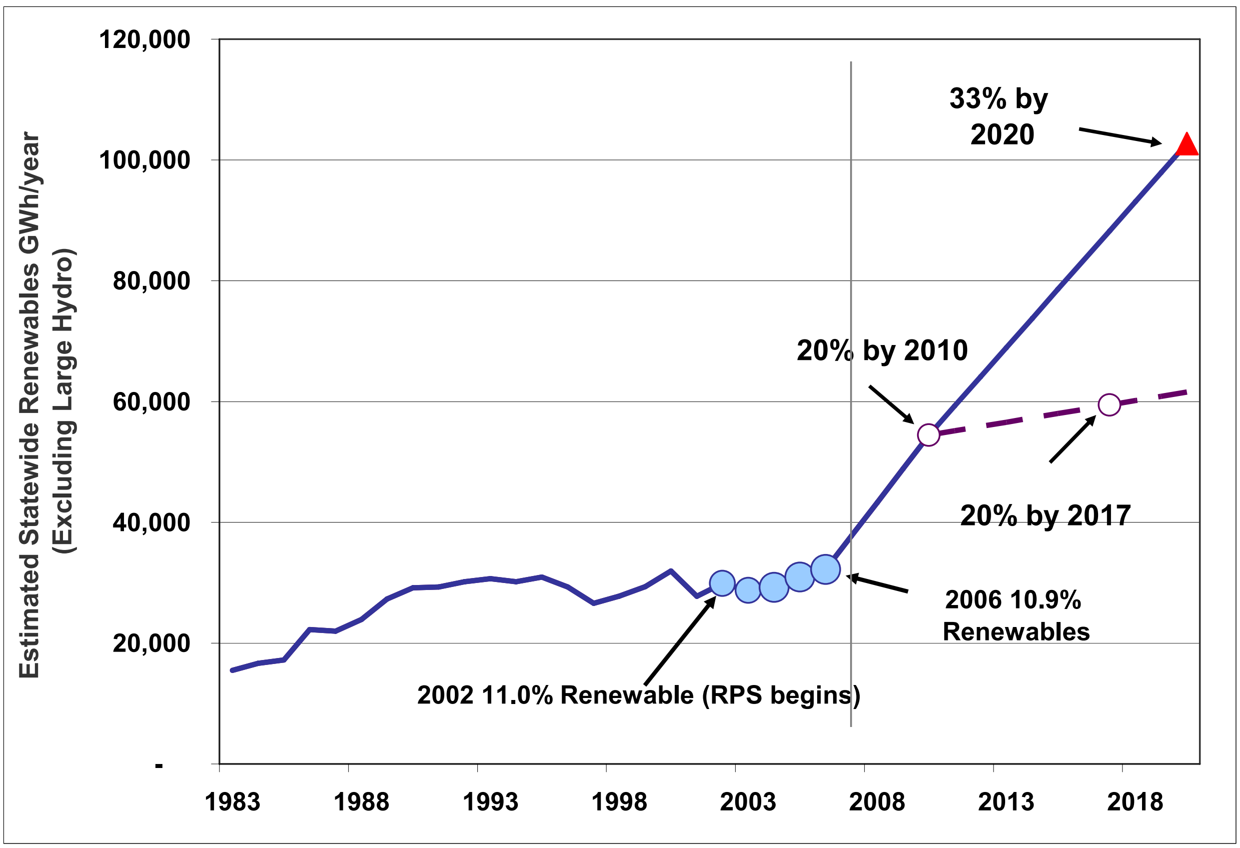
[198] SCE, Comments, July 11, 2007, Integrated Energy Policy Report Committee Workshop on the Use of Portfolio Analysis in Electric Utility Resource Planning

[199] Natural Resources Defense Council Comments, July 11, 2007 Integrated Energy Policy Report Committee Workshop on the Use of Portfolio Analysis in Electric Utility Resource Planning

Status of RPS Compliance: California Not on Track to Meet 20 Percent by 2010

AB 1585 requires the Energy Commission to evaluate the progress made toward the 20 percent renewable goal by all load-serving entities. Four years after legislative enactment of the RPS, insufficient progress has been made toward increasing the overall percentage of renewable energy deliveries in California's generation mix (Figure 4-3).

Figure 4-3: Progress Toward California's Renewable Energy Goals



Source: California Energy Commission.[200]

Renewable generation in 2006, for all entities serving retail load, was at 10.9 percent, just below the percentage in 2002 before the RPS began.[201] While delivered renewable energy has grown,

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[200] California Energy Commission, Gross System Power 1998-2005. Gross System Power renewable percentages are based on total reported generation and allow for consistent comparison of renewable generation across multiple years. Renewables Portfolio Standard targets are defined as renewable generation as a percentage of retail sales. In 2006, renewable generation in California represented approximately 11.9 percent of retail sales.

[201] California Energy Commission, Gross System Power 1998-2005,

load has also continued to grow, and delivered renewable energy has essentially kept even rather than increasing in percentage terms as required.

California's statewide RPS target of 20 percent by 2010 is defined as actual delivered renewable energy divided by retail sales. Although the percentage of renewable deliveries has been flat, there is a large amount of contracted renewable energy that is likely to come on line in the next two to five years as new transmission to the Tehachapi and Imperial Valley areas becomes available. Due to transmission constraints, growth of renewable energy is likely to be characterized by flat periods and periodic bursts of growth.

California's statewide targets are unlikely to be met without proportional contributions by all load serving entities, including IOUs, POUs and ESPs. Currently, mandatory RPS targets with consequences for noncompliance only apply to IOUs and ESPs, and rules for ESPs are less clear than for IOUs and have been only recently developed. POUs are "…responsible for implementing and enforcing a renewables portfolio standard that recognizes the intent of the Legislature to encourage renewable resources, while taking into consideration the effect of the standard on rates, reliability, and financial resources and the goal of environmental improvement.[202] Since the passage of SB 107, POUs will not be allowed to sell RECs in the future to IOUs unless they are on track to meet RPS targets comparable to those of the IOUs.[203]

Progress Made by Investor-Owned Utilities

Although IOUs have not sufficiently increased renewable deliveries since 2003, they have contracted for substantial quantities of renewable energy that they expect will become part of the generation mix soon after 2010. While an earlier discussion focused on the IOU's LTPPs and their expectations regarding future renewable deliveries, this section focuses on actual delivered energy (Table 4-3).

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http://energy.ca.gov/electricity/gross_system_power.html. Gross System Power renewable percentages are based on total reported generation and allow for consistent comparison of renewable generation across multiple years. Renewable Portfolio Standard targets are defined as renewable generation as a percentage of retail sales. In 2006, renewable generation in California represented approximately 11.9 percent of retail sales.

[202] Public Utilities Code Section 387, paragraph (a).

[203] Public Utilities Code Section 399.13, paragraph (d), as amended by SB 107 (Simitian), Chapter 464, Statutes of 2006, http://www.leginfo.ca.gov/pub/05-06/bill/sen/sb_0101-0150/sb_107_bill_20060926_chaptered.pdf.

Table 4-3: Investor-Owned Utility Renewable Generation (2003-2006)

	PG&E	SCE	SDG&E	Total
2003 Retail Sales (GWh)	71,099	70,617	15,044	156,760
2003 RPS Renewable Generation	8,828	12,496	550	21,874
2003 RPS Renewable Generation as % of Retail Sales	12.4%	17.7%	3.7%	14.0%
2005 Retail Sales (GWh)	72,727	75,302	16,002	164,031
2005 RPS Renewable Generation (GWh)	8,650	12,924	825	22,399
RPS Renewable Generation as % of Retail Sales	11.9%	17.2%	5.2%	13.7%
2006 Retail Sales (GWh)	76,692	78,863	16,847	172,402
2006 RPS Renewable Generation (GWh)	9,114	12,596	900	22,610
RPS Renewable Generation as % of Retail Sales	11.9%	16.0%	5.3%	13.1%

Source: Data for 2003 and 2005 from California Energy Commission 2005 RPS Verification Report (CEC-300-2007-001-CMF), except 2003 RPS Renewable Generation is from 2004 RPS Verification Report (CEC-300-2006-002-CMF). Data for 2006 submitted by IOUs in RPS Track Forms, to be verified in the forthcoming 2006 Verification Report

Comparing 2006 renewable generation (unverified data reported by the IOUS) with actual 2003 renewable generation shows that while overall IOU renewable deliveries has increased, particularly for SDG&E, overall procurement as a percent of retail sales has decreased by almost one percent. This means that renewable energy deliveries are not keeping up with load growth.[204] To reach 20 percent in 2010, PG&E and SDG&E will need to increase renewable deliveries by approximately 2 and 5 per cent per year, respectively.

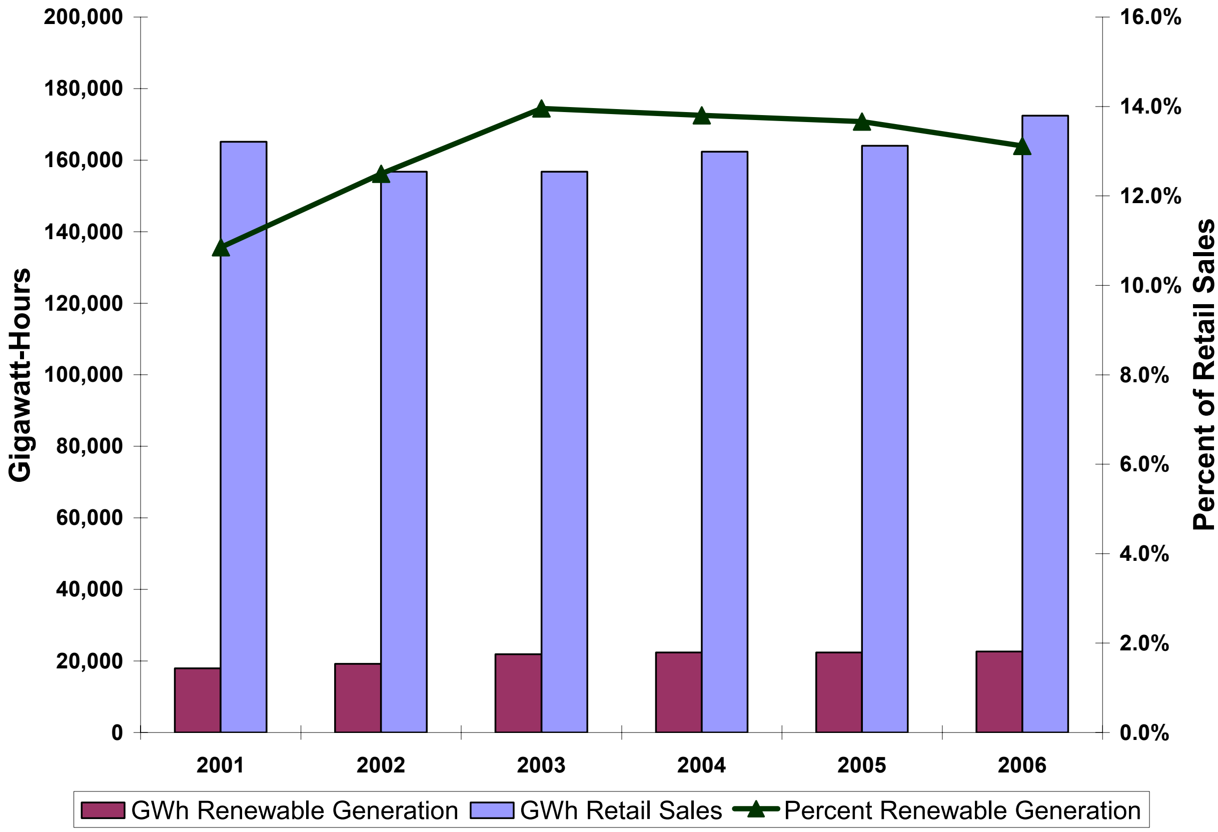
Figure 4-4 shows the progress of the three large IOUs toward the short-term RPS target of 20 percent renewable generation by 2010. The blue bars show combined total retail sales for PG&E, SCE and SDG&E, while the red bars show renewable generation. The yellow line shows renewable generation as a percentage of retail sales.

The three major IOUs added more renewable generation during each of the two years immediately preceding the start of the RPS at the beginning of 2003, although much of this added generation came from existing resources. Since 2003, the IOUs as a group have been

[204] Use of 2003 for a comparison reflects the CPUC's Decision 07-03-046 under Rulemaking 06-05-027 (the March 2007 Baseline Decision) that revises the methodology used to calculate the IOUs' Initial Baseline Procurement Amounts.

going in the wrong direction. The trend since 2003 is increasing load growth without the required increases in the amount of renewable generation.

Figure 4-4: Progress of Large Investor-Owned Utilities toward 20 Percent Renewable Energy by 2010 (GWh/year, Percent)

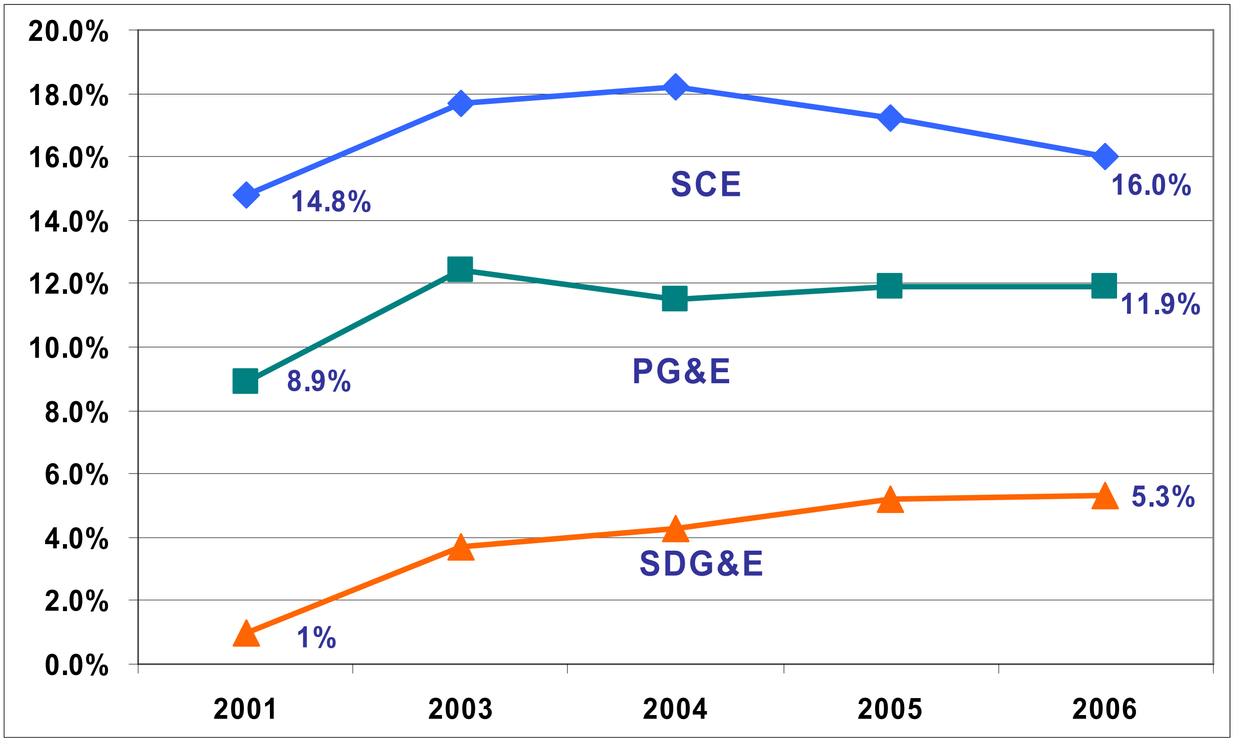


Source: California Energy Commission

Of the three major IOUs, SDG&E, starting with only one percent renewable generation and has made the most progress but will need to increase much more rapidly to meet the goal (Figure 4-5). SCE continues to decline in renewable generation, and will need to achieve about 1.5 percent per year to hit the target. PG&E's performance has also been flat over the last four years.

The three major IOUs have contracted (or are close to receiving CPUC approval for contracts) for sufficient renewable generation to meet 2010 goals if all contracts were to perform on schedule. Figure 4-6 shows the amount of renewable capacity the IOUs have contracted for each year since the RPS legislation took effect. According to the CPUC's RPS Procurement Status Report, submitted to the legislature in July 2007, RPS contracts approved or pending approval will result in the IOUs achieving about 25,000 GWh of renewable deliveries in 2010, provided contracts are not delayed.[205] This is equivalent to about 14 percent of retail sales.

Figure 4-5: Comparison of Investor-Owned Utility RPS Progress 2001–2006



Source: California Energy Commission 2004 and 2005 RPS Verification Reports and data submitted for 2006 RPS Verification reports. Data for 2002 is from AB 1305 submittals and IOU reports to the CPUC.

However, since June, the IOUs have requested CPUC approval for additional contracts that would deliver an additional 7,700 GWh by January 2011. These numbers are based on minimum quantities in the contracts in cases where there are options for additional build out. If all build-out opportunities were taken, there is sufficient energy contracted for the utilities as a group to meet the 20 percent goal. But the potential for contract failure and delay, discussed below, indicates that if current trends continue, the 20 percent target will be met after 2010.

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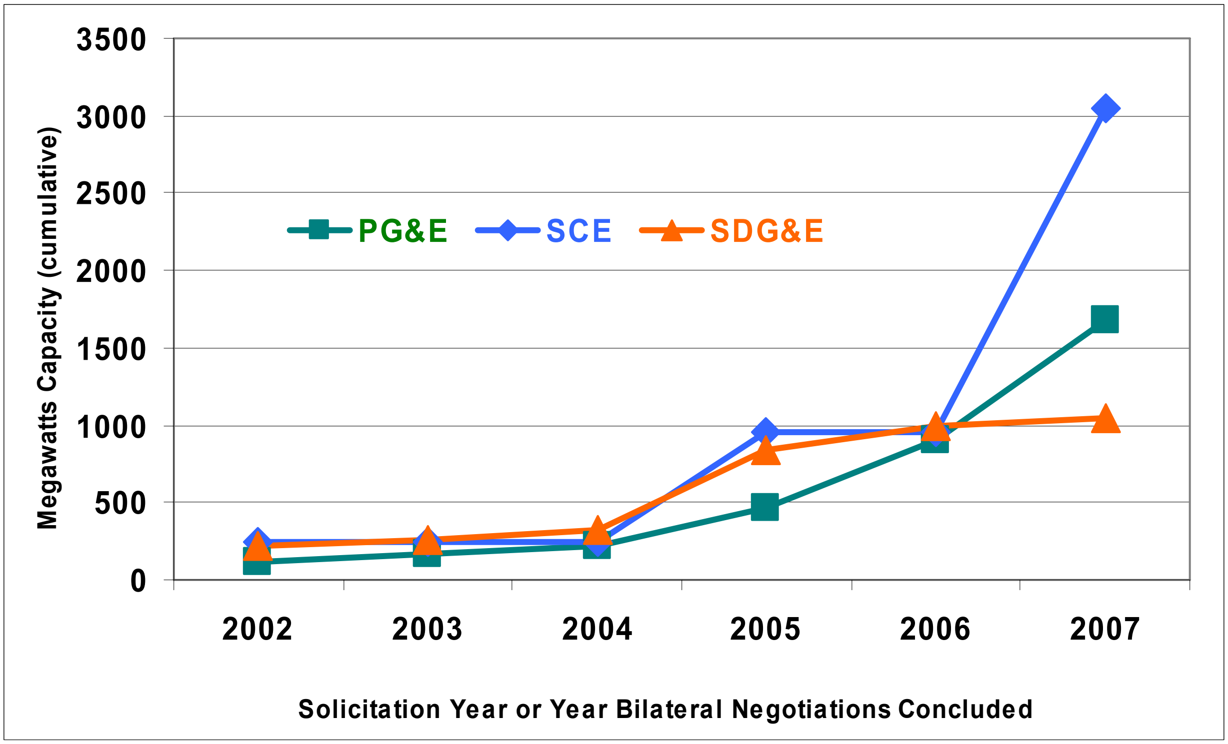
[205] CPUC, Progress of the California Renewable Portfolio Standard, July 2007, at http://www.cpuc.ca.gov/word_pdf/REPORT/69823.pdf. Quantities are based on Figure 1, p. 5.

Figure 4-6: Cumulative Contracted Renewable Capacity 2002–2007



Source: California Energy Commission, Contract Database at
<http://www.energy.ca.gov/portfolio/IOU_CONTRACT_DATABASE.XLS>.

IOU Contract Failure and Delay

The trend in failure and delay of IOU RPS contracts is not encouraging. As of March 2007, 50 percent of IOU RPS generation (GWh/year) under contract with new, repower, or restarted facilities was canceled or delayed (Table 4-4). Since then, new contracts have been signed for large amounts of energy, bringing the failure rate to 27 percent. It is too soon to tell what portion of these new projects will be cancelled or delayed. Similarly, as of March 2007, about 33 percent of the number of contracts signed since 2002 had been cancelled or delayed. In October 2007, contract failure by this measure had increased slightly, to 35 percent.

In terms of capacity, the March 2007 data show 1,410 MW of 2,283 MW, more than 60 percent of minimum capacity, was canceled or delayed. As of August 2007, 1,441 MW of 4,805 MW, about 30 percent of minimum capacity, was canceled or delayed.

Progress Made by Publicly Owned Utilities

POUs, including both municipal utilities and cooperatives, are required by state law to implement a renewables portfolio standard, but are given flexibility in developing specific targets and timelines.

This section describes efforts (through the end of July 2007) by the state's POUs in meeting their RPS requirements, including a summary of current POU RPS targets, progress towards achieving those targets, and recent contracts and solicitations. Despite some improvements to encourage more regular reporting of POU progress, the data that follow remain incomplete and somewhat uncertain in many respects.

Table 4-4: New, Repower, Restart Facilities with Investor-Owned Utility RPS Contracts

	Number of Contracts		Minimum Capacity (MW)		Energy (GWh/year)		Percent of Contracted Energy (%)	
	3/07	8/07	3/07	8/07	3/07	8/07	3/07	8/07
Canceled	8	9	162	207	724	1,039	9%	6%
Delayed	12 (4 of these on-line after delay)	15(4 of these on-line after delay)	1,248	1,234	3,415	3,323	41%	21%
Percent Canceled or delayed	33%	33%	62%	30%	50%	26%		
On schedule	39 (12 on-line)	49 (13 on-line)	860	3,364	4,093	12,147	49%	74%
Unknown	2	73	13	4,805	93	16,508	1%	100%
Total	61	9	2,283	207	8,325	1,039	100 %	6%

Source: Energy Commission, IOU RPS Contract Database (March and August 2007)

Data Sources for Tracking Publicly Owned Utility RPS Activities

POUs are required to report annually to the Energy Commission on the status of their RPS implementation and to provide data on specific purchases of eligible renewable electricity. Data submitted in accordance with these requirements were used if available to verify current RPS goals and timelines and to determine energy supplied from specific, Energy Commission eligible and POU-qualifying resources.[206]

Many POUs, however, did not submit all required data for 2006. Thus, a variety of other data sources were used in lieu of, or as a supplement to, information submitted to the Energy

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[206] "POU-qualifying" resources include deliveries from renewable resources that are eligible under a POU's RPS target but that are not Energy Commission-eligible (e.g., large hydro).

Commission, including: power content labels, press releases, annual financial reports, city council and utility board documents, and integrated resource plans or other planning documents prepared by POUs. Many of these data sources also provided information about recent POU renewable energy contracts and solicitations.

Several comments are worth noting regarding how these data sources were used:

- The amount of energy supplied by "Energy Commission-eligible" resources considers only resource eligibility criteria (e.g., no large hydro), but not deliverability-related eligibility criteria. That is, some renewable purchases indicated as "Energy Commission-eligible" represent resources that would not be eligible under the California RPS as applied to IOUs because of geographic location (out-of-state) and/or product type (e.g., RECs).
- Prior reports have presented data on each POU's supply of Energy Commission-eligible and POU-qualifying resources in 2003.[207] Staff re-calculated 2003 values based on data in the POUs' SB 1305 Annual Report Forms (if available) in order to maintain consistency with the 2006 values. In many cases, the re-calculated 2003 values were lower than those previously reported.
- If power content labels were used to determine the percentage of a POU's retail load supplied by Energy Commission-eligible or POU-qualifying resources, the percentages reported on the labels were adjusted to remove the renewable content associated with non-specific purchases.

Finally, staff notes that not all details presented here have been formally verified with POUs, and feedback on the accuracy of the data presented here is welcomed.

Current Publicly Owned Utility RPS Targets

At least 29 of the state's 47 POUs, representing 98 percent of statewide POU retail sales, have established some form of RPS commitment, although the details of their RPS policies vary considerably in terms of the target, timeframe, and resource eligibility rules (Table 4-5). Some of these targets are equally or more aggressive than the RPS targets applied to the state's IOUs (20 percent by 2010), while others are less so. At least 19 POUs that have developed RPS targets allow some hydropower projects to qualify that are not otherwise eligible under the IOUs' RPS requirements.

A number of the state's larger POUs have recently adopted more aggressive RPS policies. At least four POUs – the Los Angeles Department of Water and Power (LADWP), Riverside, Palo Alto, and Redding – have accelerated their existing 20 percent renewable energy targets to 2010 or sooner, in line with the timetable established by SB 107 for the state's IOUs. In addition, at least three POUs have increased their overall targets to levels greater than 20 percent, including LADWP (35 percent by 2020), the Imperial Irrigation District (30 percent by 2020), and Palo Alto

[207] KEMA, Publicly Owned Electric Utilities and the California RPS: A Summary of Data Collection Activities, November 2005, CEC-300-2005-023.

Table 4-5: Publicly Owned Utility Renewable Energy Targets and Deliveries (2003, 2006)

Utility Name	Total Retail Sales 2005 (MWh)	CEC Eligible 2003 (%)	CEC Eligible 2006 (%)	POU Qualifying 2003 (%)	POU Qualifying 2006 (%)	RPS Target	Large Hydro Included	RPS Timeframe
Los Angeles	23,400,472	1.6	3.9	4.2	6.6	20/35	Partial	2010/2020
Sacramento	10,485,723	4.8	10.9	4.8	10.9	20	No	2011
Imperial	3,108,748	n/d	6.7	n/d	n/d	20/30	Only "low impact"	2010/2020
Modesto	2,582,599	0.0	6.6	0.0	6.6	20	No	2017
Anaheim	2,553,464	0.1	4.5	4.3	8.6	20	Yes	2015
Santa Clara	2,496,836	23.5	21.2	63.1	51.4	No Specific	n/a	n/a
Riverside	1,989,207	13.4	13.1	13.4	13.1	20	No	2010
Turlock	1,808,573	6.7	8.0	6.7	8.0	20	No	2017
Pasadena	1,175,585	0.6	1.9	4.9	6.2	10/20	Existing large hydro only	2010/2017
Roseville	1,159,937	8.8	10.2	40.9	54.0	20	Yes	2017
Vernon	1,137,854	n/d	n/d	n/d	n/d	5/20	n/d	2009/2017
Glendale	1,104,909	7.4	10.7	13.4	16.7	20	Yes	2017
Burbank	1,093,700	0.3	0.6	0.3	0.6	10/20	Only "low impact"	2011/2017
Palo Alto	958,571	2.4	10.4	2.4	10.4	20/30/33	No	2008/2012/2015

Utility Name	Total Retail Sales 2005 (MWh)	CEC Eligible 2003 (%)	CEC Eligible 2006 (%)	POU Qualifying 2003 (%)	POU Qualifying 2006 (%)	RPS Target	Large Hydro Included	RPS Timeframe
San Francisco	782,758	n/d	n/d	n/d	n/d	n/d	n/d	n/d
Redding	769,947	4.8	8.1	39.3	61.6	20	Yes	2010
Lodi	455,238	27.1	22.9	48.6	34.4	20	Yes	2017
Alameda	378,333	54.7	48.7	90.9	86.1	40	Yes	Through 2020
Merced	345,224	1.6	2.9	1.6	2.9	15	No	2012
Colton	342,569	2.3	4.0	2.3	4.0	15	No	2017
Azusa	251,266	2.2	6.1	2.2	6.1	20	No	2017
Shasta Lake	194,897	n/d	n/d	n/d	n/d	20	n/d	2010
Corona	163,745	n/d	n/d	n/d	n/d	n/d	n/d	n/d
Plumas-Sierra	153,368	n/d	n/d	n/d	n/d	20	Yes	2017
Banning	144,447	n/d	n/d	n/d	n/d	20	Yes	2017
Truckee Donner	135,919	n/d	n/d	n/d	n/d	21	Yes	2010
Lompoc	133,838	30.3	n/d	54.1	n/d	20	Yes	Purchases limited to funds, load growth, and replacing retired resources
Lassen	127,996	n/d	n/d	n/d	n/d	n/d	n/d	n/d

Utility Name	Total Retail Sales 2005 (MWh)	CEC Eligible 2003 (%)	CEC Eligible 2006 (%)	POU Qualifying 2003 (%)	POU Qualifying 2006 (%)	RPS Target	Large Hydro Included	RPS Timeframe
Ukiah	111,894	55.0	50.3	90.6	67.1	n/d	Yes	n/d
Trinity	83,401	n/d	n/d	n/d	n/d	Only renewables to meet growth beyond that provided by the Trinity River	Yes	n/a
Surprise Valley	76,147	n/d	n/d	n/d	n/d	n/d	n/d	n/d
Healdsburg	72,569	54.7	49.8	n/d	n/d	20	n/d	n/d
Needles	62,277	0.0	0.0	n/d	n/d	n/d	n/d	n/d
Anza	42,460	n/d	n/d	n/d	n/d	n/d	n/d	n/d
Gridley	32,033	n/d	n/d	n/d	n/d	20	Yes	As resources added
Tuolumne	26,413	n/d	n/d	n/d	n/d	n/d	n/d	n/d
Biggs	19,144	n/d	n/d	n/d	n/d	20	Yes	As resources added
Valley Electric	6,796	n/d	n/d	n/d	n/d	n/d	n/d	n/d
Escondido	18	n/d	n/d	n/d	n/d	n/d	n/d	n/d

Utility Name	Total Retail Sales 2005 (MWh)	CEC Eligible 2003 (%)	CEC Eligible 2006 (%)	POU Qualifying 2003 (%)	POU Qualifying 2006 (%)	RPS Target	Large Hydro Included	RPS Timeframe
Hercules	n/d	n/d	n/d	n/d	n/d	n/d	n/d	n/d
City of Industry	n/d	n/d	n/d	n/d	n/d	n/d	n/d	n/d
McAllister Ranch	n/d	n/d	n/d	n/d	n/d	n/d	n/d	n/d
Moreno Valley	n/d	n/d	n/d	n/d	n/d	n/d	n/d	n/d
Pittsburg	n/d	n/d	n/d	n/d	n/d	n/d	n/d	n/d
Rancho Cucamonga	n/d	n/d	n/d	n/d	n/d	n/d	n/d	n/d
Victorville	n/d	n/d	n/d	n/d	n/d	n/d	n/d	n/d
Port of Oakland	n/d	n/d	n/d	n/d	n/d	20 Goal, 40 Objective	Yes	2017

Note: n/d indicates no data available, and n/a indicates not applicable.

Source: Form EIA-861; SB 1305 Annual Report Forms; Form CEC-POU-RPS; Power Content Labels; and information posted on utility and municipal websites, including annual financial reports, city council and utility board documents, and integrated resource plans or other planning documents.

(30 percent by 2012 and 33 percent by 2015). Anaheim, the state's fourth-largest POU, raised its RPS goal from 15 to 20 percent, while moving its target date forward from 2017 to 2015.

Though rules for resource eligibility and other policy details differ, it is instructive to compare the POUs' RPS targets to those of the IOUs in terms of the incremental need for renewable energy. Relative to their eligible renewable energy deliveries in 2003, the state's IOUs will – in aggregate – have to supply an additional 6 percent of retail sales with Energy Commission-eligible resources to meet their current 20 percent RPS target by 2010, and an additional 19 percent of retail load to meet the state's non-mandatory 33 percent goal by 2020.[208] In comparison, the 20 POUs for which data are available (representing 89 percent of statewide POU load) will have to increase their supply of POU-qualifying resources by 20.5 percent of retail sales (on an average, load-weighted basis) to meet their ultimate targets.[209] The POU targets vary in target year and target percentage. Although large POUs including LADWP, Imperial Irrigation District and Palo Alto have set ultimate goals of 35, 30 and 33 percent by 2020 or earlier, respectively, most POUs have not yet set 2020 goals comparable to those of the IOUs (Table 4-5)

Given POUs' widely varying compliance dates, however, it is also useful to compare the stringency of their goals relative to the IOUs' compliance dates in terms of average annual procurement needs, starting from 2003 levels. To meet their 20 percent target by 2010, the state's IOUs must add, on average, an additional 2 percent of load each year from 2007 to 2010 from eligible resources; to meet the 33 percent by 2020 goal will require an increase of 1.3 percent of retail sales per year from 2010 through 2020.[210] In comparison, the 20 POUs for which data are available (representing 89 percent of statewide POU load) will have to increase their supply of qualifying resources by 1.5 percent of retail sales per year (on a load-weighted basis) to meet their collective targets. These comparisons are not definitive, given different resource eligibility rules and enforcement approaches. However, because POUs began with lower levels of renewables, they must continue to add renewable resources at a much faster average rate than the IOUs in order to fulfill their proportional share of the overall state target.

Publicly Owned Utility Progress in Increasing Renewable Energy Deliveries

Since enactment of the state's RPS, progress by POUs towards achieving their individual RPS goals has been uneven, but increases in renewable energy deliveries are apparent.

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[208] Ibid.

[209] These 20 utilities consist of all those listed in Table 7 with available data on both RPS targets and POU-qualifying deliveries in 2003. Also included are Santa Clara and Healdsburg, both of which are considered to have no incremental need relative to 2003 levels.

[210] KEMA, Publicly Owned Electric Utilities and the California RPS: A Summary of Data Collection Activities, November 2005, CEC-300-2005-023.

Reasonably reliable data on deliveries by specific, Energy Commission-eligible resources in both 2003 and 2006 are available for 21 POUs, representing 89 percent of total POU retail sales. Among these utilities, deliveries of specific, Energy Commission-eligible resources increased by 3 percent of retail sales between these years, on a load-weighted average basis.[211]

Among these 21 POUs, deliveries of specific, Energy Commission-eligible resources declined from 2003 to 2006 for 7 utilities that represent 9 percent of total POU retail sales. However, at least 14 POUs, representing 80 percent of statewide POU retail sales, saw an increase in deliveries from Energy Commission -eligible resources over this timeframe equivalent to 3.5 percent increase per year. The following five utilities saw the largest percentage increases:

- Palo Alto increased its Energy Commission-eligible renewable percentage from 2.4 to 10.4 percent, primarily as a result of two new wind contracts (High Winds and Shiloh).
- Modesto increased its Energy Commission-eligible renewable percentage from 0 to 6.6 percent of retail sales by adding three new wind contracts to its portfolio (High Winds, Shiloh, and Big Horn).
- SMUD increased its Energy Commission-eligible renewable percentage from 4.8 to 10.9 percent as a result of new contracts for geothermal (Geysers), wind (High Winds), and small hydro (EBMUD) resources, and by expanding its owned wind project (Montezuma Hills).
- Anaheim increased its Energy Commission-eligible renewable percentage from 0.1 to 4.5 percent, largely as a result of new wind (High Winds) and geothermal (Heber) contracts.
- Azusa increased its Energy Commission-eligible renewable percentage from 2.2 to 6.1 percent as a result of a new wind project (High Winds).

LADWP, the state's largest POU, increased its Energy Commission-eligible renewable deliveries by 2.3 percent between 2003 and 2006, from roughly 1.6 percent in 2003 to 3.9 percent in 2006. This increase is associated largely with several new contracts with small hydro facilities in the Pacific Northwest, as well as a new wind contract (Pleasant Valley).

The 3 percent load-weighted average increase in Energy Commission-eligible renewable deliveries between 2003 and 2006 among the 21 POUs for which data exist can be compared to progress made by the three large IOUs over the same time period, as reported in the Energy Commission's 2004 and 2005 RPS Verification reports, and in RPS

[211] These 21 utilities consist of all those listed in Table 7 with available data on Energy Commission-eligible deliveries in both 2003 and 2006.

track reporting forms submitted by the IOUs that will be used in the 2006 RPS Verification report:[212]

- PG&E: Renewable deliveries as a percentage of retail sales from the same year decreased from 12.4 percent in 2003 to 11.9 percent in 2006 (a 0.5 percent decrease).
- SCE: Renewable deliveries as a percentage of retail sales from the same year decreased from 17.7 percent in 2003 to 16 percent in 2006 (a 1.7 percent decrease).
- SDG&E: Renewable deliveries as a percentage of retail sales from the same year increased from 3.7 percent in 2003 to 5.3 percent in 2006 (a 1.6 percent increase).

As a group, the IOUs have decreased Energy Commission-eligible renewable deliveries as a percentage of retail sales by an average of 0.1 percent per year between 2003 and 2006, compared to the 3 percent load-weighted average increase of the 21 POUs for which data are available. Thus, clearly the POUs were more successful than IOUs from 2003 to 2006 in increasing Energy Commission-eligible renewable energy deliveries.

Publicly Owned Utility Contracts and Solicitations

Since the beginning of 2003, POUs have contracted for approximately 1,600 MW of renewable electricity capacity, 1,300 MW of which is from new resources that began, or are expected to begin, operation after passage of the state's RPS law in 2002. The 1,300 MW includes approximately 900 MW of wind, 200 MW of geothermal, and 200 MW of biomass (including 100 MW of municipal solid waste to be developed by LADWP).

As of July 2007, over 550 MW of the contracted new capacity was online and delivering energy to the California POUs, while only 324 MW of new, repowered or re-started RPS capacity contracted by the IOUs was on line as of early August.[213] New POU wind projects make up almost all of this capacity, with the two largest projects located outside of California (Table 4-6).

Approximately 700 MW of new renewables projects are under contract (or in development) but not yet online. Included within this total are a number of contracts or projects announced since July 2006, including:

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[212] IOU Compliance reports submitted to the CPUC look at compliance defined, in part, as one year's RPS generation divided by the prior year's retail sales. This analysis compares renewable generation as a percent of the same years' retail sales. Energy Commission, Renewables Portfolio Standard 2005 Procurement Verification, CEC-300-2007-001-CMF, August 2007 and Renewables Portfolio Standard Procurement Frication Report, CEC-300-2006-002-CMF, February 2006.

[213] See the Energy Commission database of renewable energy contracts signed by the IOUs under the state's RPS, at: http://www.energy.ca.gov/portfolio/contracts_database.html

Table 4-6: New Renewable Projects Online (Publicly Owned Utilities)

Project	Technology	Capacity Under Contract to CA POUs (MW)	Location	Online	POUs Currently Receiving Deliveries
Big Horn	Wind	200	WA	2007	Modesto, Redding, Santa Clara
Pleasant Valley	Wind	127	WY	2003	Anaheim, Burbank, Glendale, LADWP
High Winds	Wind	104	CA	2003	Alameda, Anaheim, Azusa, Colton, Glendale, Merced, Modesto, Palo Alto, Pasadena, Roseville, SMUD
Shiloh	Wind	75	CA	2006	Modesto and Palo Alto
Montezuma Hills Phases I and II	Wind	39	CA	2003/ 2006	SMUD (owned-project)
Heber expansion	Geothermal	10	CA	2006	Anaheim, Banning, Glendale, Pasadena
Multiple projects	Landfill Gas	9	CA	2003-2006	Alameda, Burbank, Colton, Palo Alto, Riverside

Source: SB 1305 Annual Report Forms and information obtained through web searches, including press releases issued by utilities and project owners/marketers, annual financial reports, city council and utility board documents, and integrated resource plans or other utility planning documents

- The Milford wind project, located in Utah, for which contracts have been announced by Burbank (10 MW), LADWP (185 MW), and Pasadena (5 MW);
- Four municipal solid waste projects, totaling 100 MW, that LADWP has announced plans to develop;
- A 25 MW landfill gas project in Brea under contract with Anaheim Public Utilities; and
- A 25 MW biomass repowering project under contract with the Modesto Irrigation District.

Also since July 2006, at least seven solicitations have been announced through which the state's POUs are seeking additional renewable energy deliveries (Table 4-7). New contracts have yet to be announced from most of these solicitations. However, based on the amount of capacity solicited, additional resources procured through these efforts may add substantially to POUs renewable deliveries in future years.

Assuming that all contracts come to fruition, the 1,300 MW of new renewable sources currently under contract to the POUs is expected to meet 11 percent of 2003 POU load. This compares to roughly 4,640 to 6,330 MW of new renewable energy contracts signed by the state's IOUs as of July 2007, equivalent to 10 to 13.5 percent of aggregate IOU load in 2003. In other words, while POU progress in bringing new renewable energy projects on-line has so far exceeded the progress made by the state's major IOUs, projected future deliveries are similar if all contracts deliver as promised.

Progress Made by Electric Service Providers and Small and Multi-Jurisdictional Utilities

Although PG&E, SCE, and SDG&E began reporting their RPS procurement to the Energy Commission in 2005, the first year that other retail sellers were required to submit procurement data is 2007. The Energy Commission began collecting RPS data from ESPs and California's small and multi-jurisdictional utilities (SMJUs) in 2007, after the CPUC issued decisions establishing RPS rules for those entities.

Table 4-7: Renewable Solicitations Issued by Publicly Owned Utilities Since July 2006

Issued By	Date of Solicitation	Technologies Requested*	Capacity Solicited	Energy Solicited
Palo Alto	Jul-07	CEC Eligible	not stated	280 GWh/yr
SMUD	Apr-07	CEC Eligible	not stated	not stated
LADWP	Jan-07	CEC Eligible	not stated	2,200 GWh/yr
Turlock	Oct-06	CEC Eligible	not stated	260 GWh/yr
SCPPA	Sep-06	CEC Eligible	300 MW	not stated
NCPA	Sep-06	CEC Eligible	79 MW	not stated
SMUD	Aug-06	CEC Eligible	not stated	not stated

Notes: * Some of the Requests for Proposals do not explicitly identify Energy Commission-eligible as a requirement, but define eligible technologies to be largely consistent with Energy Commission rules. There are some modest exceptions. SCPPA's Requests for Proposals do not reference Energy Commission eligibility, but indicate "any certifiable renewable energy." Many of the solicitations provide greater delivery flexibility, or even allow renewable energy credits.

Source: Press releases and solicitations issued by utilities, posted on utility websites.

In Decision 05-11-025 (p. 14), the CPUC ruled that electric service providers are subject to the following RPS requirements:

- Achieve 20 percent renewable energy by 2010.
- Increase renewable sales by at least 1 percent of sales per year.
- Submit reports to the CPUC.
- Use flexible compliance mechanisms if needed.
- Subject to penalties and penalty processes.

In 2006, CPUC Decision 06-10-019 further clarified RPS rules and targets for retail sellers. In general, the same RPS requirements that apply to ESPs also apply to SMJUs. Following on the CPUC's decisions bringing all retail sellers into the RPS, the Energy Commission's RPS Guidebook requires ESPs, community choice aggregates, and SMJUs to report their RPS procurement for 2005 and 2006.

To date, 10 of 15 ESPs have either provided required reports or provided a partial response to the Energy Commission. In addition, all but one of the five SMJUs have responded. Therefore, the following discussion of ESP and SMJU progress is based on incomplete, unverified data. This preliminary data includes most of the total load served by ESPs and SMJUs.

The *2006 IEPR Update* reported that ESPs as a group served only about 0.25 percent of their retail sales from renewable sources immediately prior to 2006. In 2006, ESPs as a group increased their renewable energy to two per cent of retail sales. Of the six ESPs that reported both retail sales and RPS-eligible renewable energy, APS Energy reported the most (4.8 percent); the lowest percentage reported was just under 1 percent (Table 4-8). After a late start, ESPs have a long way to go to meet the 2010 goals.

Table 4-8: RPS-Eligible Energy as Percent of 2006 Retail Sales Reported by Electric Service Providers

Electric Service Provider	2006 RPS-eligible Renewable Energy as percent of 2006 retail sales
APS Energy Services	4.8
Calpine Power America	0.8
Commerce Energy, Inc	1.0
Pilot Power Group, Inc.	1.4
Sempra	2.4
Strategic Energy	1.0

Source: California Energy Commission

Two of California's five SMJUs are large utilities that serve bordering states as well as California, while three SMJUs are very small. Sierra Pacific Power, based in Nevada, reports procuring 31.8 GWh of renewable electricity in 2006 for its California load, or 5.9 percent of retail sales. PacificCorp reports 29.4 GWh of renewable energy, but has requested confidentiality for data on California retail sales. The state's three very small utilities have not provided complete reports, but represent only an extremely small portion of total state electric load.

Additional Barriers to Renewable Energy Market Development

In addition to the issues already discussed, two more barriers to renewable energy market development remain unresolved: a shortage of wind turbines; and the economic and permitting barriers to repowering and expanding existing wind facilities.

Shortage of Wind Turbines

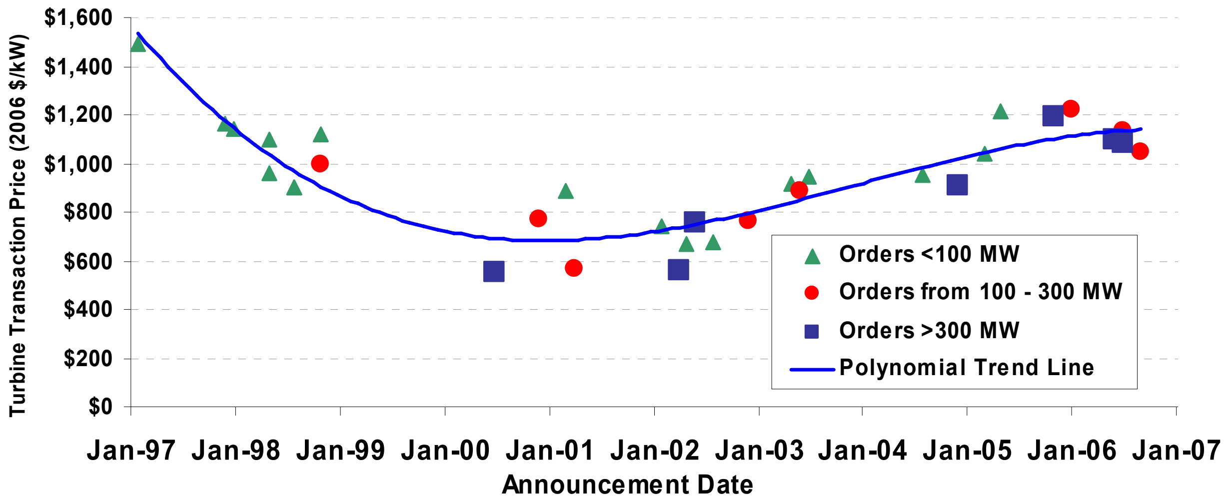
Global demand for wind turbines has increased dramatically in recent years, with annual installations growing from 6,800 MW in 2001 to more than 15,000 MW in 2006. With this rapid growth, demand for wind turbines has exceeded supply, and manufacturers of turbines and turbine components have struggled to scale-up manufacturing capability.

To secure wind turbines in this new environment, project developers have been required to enter into large orders for future turbine delivery and front substantial commitment fees. Smaller wind developers who typically purchase turbines as-needed for individual wind projects are unable to compete for turbines in this environment, so much consolidation has occurred within the development community.

One result of these trends is that wind turbine prices, and installed wind project costs, have increased substantially. Data from Lawrence Berkeley Laboratory, for example, show an increase in average wind turbine prices delivered to the U.S. market of roughly $400/kW between 2002 and 2006 (Figure 4-7). These increases have been caused by factors such as the declining value of the U.S. dollar relative to the Euro, increased materials and energy input prices, a general move by manufacturers to improve their profitability while demand exceeds supply, an up-scaling of turbine size (and hub height) and sophistication, and shortages in certain turbine components.

In this turbine-limited environment, some project developers have been unable to move their projects to fruition, and those developers with access to turbines dedicate them to the most-profitable wind projects in their pipeline. The evolving pricing environment has also made it difficult for developers to accurately predict delivered wind prices in competitive solicitations, sometimes requiring price revisions to already-signed wind power contracts as has already been seen with IOU solicitations in California. In locations where the project development cycle is lengthy – such as California, where many of the best sites are transmission-constrained – developers have been reluctant to commit to long-term pricing based on uncertain future turbine costs.

Figure 4-7: Wind Turbine Transaction Prices in the U.S. Market



Source: Wiser and Bolinger 2007.

Economic and Permitting Barriers to Repowering and Expanding Existing Wind Facilities

To achieve the state's renewable and GHG goals, existing as well as new renewable and transmission resources must be used efficiently. Some contracts have been signed to repower aging wind turbines, but more progress is needed.

An analysis by KEMA, Inc., on the economics of repowering estimated that replacing 1,000 MW of California's oldest existing wind projects with 1,000 MW of new wind turbines could result in more than 1,000 GWh/year of incremental wind power production, equivalent to about 350 MW of new (that is, greenfield) wind capacity.[214] The study did not assess expanding capacity at existing wind facilities, only switching out older turbines and replacing them with fewer, larger, more-efficient wind turbines. The Energy Commission would prefer to see capacity expanded at these prime sites,

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[214] California Energy Commission, (forthcoming 2007), Consultant Report: Scoping-Level Study of the Economics of Wind-Project Repowering Decisions in California, prepared by the following subcontractor team to KEMA, Inc.: Ryan Wiser, consultant; Ric O'Connell, Black & Veatch; and Mark Bolinger, consultant.

many of which were originally developed with significant investment of public resources.

The study also provided indicated economic trade-offs facing owners of existing wind turbines when deciding whether or not to repower. These trade-offs include whether the revenue likely to be earned by the repowered facility can at least match the profitability of the existing facility, and whether the existing project owner would be better off deploying new turbines in a greenfield rather than repowered project. The answers to these questions depend heavily on the profitability of the existing project, which can vary widely from project to project and is most strongly affected by the operation and maintenance costs of the existing turbines and their operating efficiency (capacity factor).

For example, poorly performing projects with high operating costs (i.e., marginally profitable existing projects) may find it economically advantageous to repower under reasonable assumptions about the amount of revenue (i.e., from power and REC sales) available to a repowered project. Conversely, adequately performing projects with relatively low operating costs may find that the amount of revenue available to a repowered project is insufficient to make up for the foregone profitability of the existing project. Furthermore, in some cases the most profitable outcome could be to continue to operate the existing project and, rather than repowering, deploy the new turbines in a greenfield project.

Although over time an increasing proportion of existing wind projects will be in the first category which is conducive to repowering, the report suggests that in the near-term, an economic incentive may be needed to accelerate the pace of repowering. Given the varying degrees of profitability among existing wind projects, a "one-size-fits-all" incentive approach may overpay some projects and underpay others, relative to the revenue needed to induce repowering. Furthermore, economic incentives alone may not be sufficient to stimulate repowering, which faces time-consuming environmental review procedures, limited turbine availability, and contracting barriers.

The KEMA report does not consider the cost of any transmission network upgrades that may be required (particularly to interconnect greenfield projects). But it does suggest that greenfield projects are likely to be more expensive than repowered projects, due to the latter's ability to use existing infrastructure. That said, continuing to operate an existing project while simultaneously deploying new turbines in a greenfield project may result in a lower power price (for the new capacity) than would be required for a repowered project. This is because when a project owner repowers, it foregoes the remaining profitability of the existing project, and presumably needs to make up for that lost profit (to induce repowering) by earning "above-normal" revenue from the repowered project. Instead, if a project owner continues to reap the benefits of the existing facility while at the same time devoting the new turbines to greenfield development, then it need only earn "normal" revenue from the greenfield project, which may result in a lower required power price for the greenfield project than for the repowered project, even though the former is more expensive to build than the latter.

At the March 13, 2007, workshop on incentives for wind repowering, there was little support for special economic incentives for repowering wind energy. SCE stated that the amount of incremental energy that could be gained from repowering wind would be about 1,100 GWh/year (roughly consistent with the KEMA estimate mentioned above), stating that this amount "is helpful, but not significant that it warrants special attention." (SCE comments for March 13, 2007, workshop, p. 2) In its calculations, SCE assumed that the total amount of installed capacity would remain unchanged, but did not explain what prevented expansion of the MW of wind installed at currently developed wind sites or what would be needed to overcome these barriers. As indicated above, the Energy Commission believes an expansion of capacity at these prime sites is desirable.

SCE explained that "as existing contracts near termination, the project owners will have significantly more incentive to repower." They also explained that transmission upgrades are needed to make repowering possible in the Tehachapi area.[215]

PG&E agreed that lack of transmission limits the rate of wind repowering, along with environmental study requirements, and "allocation of limited equipment to projects yielding greater return on investment."[216] "[T]he most profitable application …would be Greenfield development, rather than brownfield development." (PG&E comments for March 13 workshop, p. 7). This implies that building new transmission to remote areas far from load to develop new resources is more profitable than repowering and expanding premium, known wind resources close to load.

CalWEA's comments explain some of the circumstances that lead to this result. CalWEA explained that most existing wind projects have little economic incentive to repower, noting that 20-year old technology is functioning very well, transaction costs of a new contract are high because repower contracts are not standardized, and the permitting process is costly and time consuming.[217] CalWEA suggested a standard contract

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[215] Southern California Edison Company, March 19, 2007, Southern California Edison Company's Written Comments on the Workshop on Incentives for Wind Repowering and Best Practices for Coordinating RPS with Carbon Market Design; Docket Nos. 06-IEP-1c and No. 03-RPS-1078. http://www.energy.ca.gov/2007_energypolicy/documents/2007-03-13_workshop/comments/, accessed June 29, 2007.

[216] Pacific Gas and Electric Company, March 19, 2007, Post Workshop Comments of Pacific Gas and Electric Company on Incentives for Wind Repowering and Best Practices for RPS-Carbon Market Design, http://www.energy.ca.gov/2007_energypolicy/documents/2007-03-13_workshop/comments/PACIFIC_GAS_+_ELECTRIC_2007-03-20.PDF, accessed June 29, 2007.

[217] California Wind Energy Association, March 14, 2007, Comments of the California Wind Energy Association on Wind Repowering,

amendment that would allow repowered projects to be eligible for the federal production tax credit, removing "one of the main barriers to repowering."[218] Regarding transmission, CalWEA seeks a decision to ensure that repowered wind projects maintain existing interconnection rights if their generating capacity is not increased. Also, CalWEA states that avian issues in Alameda County and Contra Costa County are slowing repowers in the Altamont Pass, although at least one project is talking with PG&E about repowering.

The IEPR Committee encourages the repowering and expansion of existing wind energy sites to increase the efficient use of existing infrastructure and reduce environmental impacts.

As discussed below, the Committee supports efforts to reduce transaction costs for contract negotiation for all renewable energy, including repowered and expanded existing wind energy projects.

RPS Program Structure: Need for Greater Transparency, Less Complexity, and Full Valuation of Renewable Energy

As discussed in previous *IEPRs*, the RPS program structure needs greater transparency, less complexity, and full valuation of the system benefits of renewable energy. The areas most in need of change include the least-cost best-fit evaluation and the use of natural gas prices to calculate the market-price referent.

Least-Cost, Best-Fit Evaluation

The *2005 IEPR* noted that transparency is necessary to ensure that all parties can fully understand the rationale for allocation of public funds. Transparency is also needed so developers and transmission planners can know where renewable energy development has the greatest strategic and economic value. As noted in the discussion of the IAP, incorporating 33 percent renewables will require strategic placement of new generation and new transmission. The CPUC has taken some steps to increase transparency of the procurement process, including a workshop held on December 15, 2006. Despite these efforts, the procurement process remains in need of greater transparency and is subject to delays that are not clear to the public.

Each utility uses its own approach to least-cost best-fit evaluation, within the latitude granted by the CPUC. For example, SCE's least-cost-best-fit evaluation compares a base

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http://www.energy.ca.gov/2007_energypolicy/documents/2007-03-13_workshop/comments/CALIFORNIA_WIND_ENERGY_ASSOCIATION_2007-03-14.PDF, accessed June 29, 2007.

[218] Ibid.

case using "generic generation" to a base case using generic generation and an RPS project bid into a competitive RFP. SCE uses Global Energy Decisions' ProSym model to compare the total production costs of SCE's base resource portfolio ("project out") with the total production costs when each proposal is individually added to the base portfolio ("project in"). ProSym performs an hourly, least-cost dispatch with SCE's known resource portfolio and generic generation to meet customer demand. Because SCE's complete resource portfolio in the future is uncertain, generic generation is added to the portfolio to ensure that RPS and resource adequacy requirements are satisfied and customer load can be met. Each proposal is added to the resource portfolio as a no-cost, must-take hourly generation profile that is provided by the seller. The difference in total production costs between the "project in" and "project out" cases is the energy benefit for each proposal.[219]

SCE's analysis as described does not consider the combined effect of the RPS bids, or which combination of new bids and existing assets would best balance ratepayer costs and risk. So, the resulting mix may not, in fact, be the least cost portfolio at an acceptable level of risk, even if individual additions are declared to be "least-cost best-fit."

Without relying on the principles of modern portfolio theory as described in the portfolio analysis report, a portfolio cannot be judged to be efficient or inefficient; in the case of an inefficient portfolio, it may be possible to simultaneously lower both cost and risk, but without considering both, it is not even possible to tell.[220]

Natural Gas Prices and Market Price Referent

The risk to ratepayers of continued reliance on natural gas is not shared by the IOUs since fuel costs are passed through to ratepayers. The price of natural gas is one of the most volatile commodity prices. Linking the market-price referent to natural gas forecasts, rather than an estimate of fixed-cost conventional generation as required by law, does not adequately reflect the cost, risk, and carbon reduction value of renewable energy to the state's portfolio of generation resources. The CPUC in its draft 2007 market price referent has now included a carbon adder in the market price referent.[221] The CPUC expects to consider in more detail carbon adders for future market price referents.

The CPUC calculates market price referent values for a baseload proxy plant for use in RPS solicitations. The method of determining MPR values generally involves evaluating

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[219] SCE, July 30, 2007, SCE's Written Description of RPS Bid Evaluation and Selection Process and Criteria ("LCBF Written Report"), CPUC Rulemaking 06-05-027, p. 3.

[220] California Energy Commission, July 2007, Portfolio Analysis and its Potential Application to Utility Long-Term Planning, Draft Staff Paper, http://www.energy.ca.gov/2007publications/CEC-200-2007-012/CEC-200-2007-012-SD.PDF, p. 11.

[221] CPUC Resolution E-4118 rev. September 24, 2007.

(discounting) all project costs at the weighted average cost of capital. Finance-based approaches reflect cost and market risk.

Starting with the November 17, 2006, draft CPUC inputs to the MPR, Bates White calculated MPR values using finance-oriented valuation principles, based on the Capital Asset Pricing Model.[222] This approach relies on specific risk-adjusted discount rates for each project cost stream, as opposed to discounting all costs at the weighted average cost of capital as is done by the CPUC.

In this analysis, the Capital Asset Pricing Model-based approach assumed a baseload proxy plant could obtain a long-term natural gas fuel supply at a risk-free rate. This assumption treats natural gas fuel price risk quite favorably. It is likely that this price is less than what would be charged under long-term fixed price contracts, which are not available in practice. Tables 4-9 through 4-11 compare CPUC's weighted average cost of capital-based MPR values with Capital Asset Pricing Model-based MPR values. Despite this assumption, the Capital Asset Pricing Model suggests higher MPR values than those used by the CPUC.

Table 4-9: Weighted Average Cost of Capital-Based 2006 Market Price Referent Values

(Nominal - dollars/kWh)

Resource Type	10-Year	15-Year	20-Year
2007 Baseload MPR	0.08046	0.08176	0.08424
2008 Baseload MPR	0.07979	0.08195	0.08482
2009 Baseload MPR	0.07925	0.08223	0.08548
2010 Baseload MPR	0.07929	0.08295	0.08652
2011 Baseload MPR	0.07890	0.08307	0.08688
2012 Baseload MPR	0.07961	0.08420	0.08820
2013 Baseload MPR	0.08072	0.08566	0.08981
2014 Baseload MPR	0.08229	0.08746	0.09167
2015 Baseload MPR	0.08435	0.08964	0.09468

Source: CPUC November 17, 2006, "2006 MPR Model Draft Resolution E 4049_Distrib_11_17_06.xls."

222 Bates White analysis is based upon CPUC's MPR spreadsheet dated on November 17, 2006 ("2006 MPR Model_Draft Resolution E 4049_Distrib_11_17_06.xls"). Thus, the reported weighted average cost of capital-based MPR values are not exactly the same as the values reported in Resolution E-4049 dated on December 14, 2006.

Table 4-10: Capital Asset Pricing Model-Based 2006 Market Price Referent Values

(Nominal - dollars/kWh)

Resource Type	10-Year	15-Year	20-Year
2007 Baseload MPR	0.08371	0.08970	0.09610
2008 Baseload MPR	0.08299	0.09005	0.09584
2009 Baseload MPR	0.08241	0.08955	0.09687
2010 Baseload MPR	0.08244	0.09045	0.09828
2011 Baseload MPR	0.08192	0.09143	0.09977
2012 Baseload MPR	0.08260	0.09262	0.10335
2013 Baseload MPR	0.08370	0.09664	0.10510
2014 Baseload MPR	0.08699	0.09852	0.10707
2015 Baseload MPR	0.08928	0.10076	0.11143

Source: Bates White, August 2007.

MRP = market price referent.

Table 4-11: Difference Between Weighted Average Cost of Capital and Capital Asset Pricing Model-Based 2006 Market Price Referent Values

(Nominal - dollars/kWh)

Resource Type	10-Year	15-Year	20-Year
2007 Baseload MPR	0.00325	0.00794	0.01186
2008 Baseload MPR	0.00320	0.00811	0.01102
2009 Baseload MPR	0.00316	0.00732	0.01139
2010 Baseload MPR	0.00315	0.00750	0.01176
2011 Baseload MPR	0.00303	0.00835	0.01289
2012 Baseload MPR	0.00299	0.00841	0.01515
2013 Baseload MPR	0.00298	0.01099	0.01529
2014 Baseload MPR	0.00470	0.01106	0.01540
2015 Baseload MPR	0.00493	0.01112	0.01675

Source: Bates White, August 2007.

MPR = market price referent.

33 Percent by 2020 Is Feasible with Changes in Program Structure

Using renewable resources to provide 33 percent of retail sales by 2020 is feasible technically and economically, but concerted and coordinated support is needed from government, industry, and the public to make it happen. Changes are needed at least in the following areas:

- Planning and permitting processes need to be strengthened and streamlined through programmatic environmental impact report/environmental impact statements for renewable energy generation in coordination with state and federal transmission corridor planning.
- The transmission grid and distribution system need to be expanded and upgraded to access and prepare for the resource mix needed to bring the electricity sector's greenhouse gas emissions to 1990 levels.
- The MPR mechanism should be redesigned to allow developers to obtain lower-cost financing and encourage expansion of equipment production for renewable energy.

The first two items are addressed in the *2007 Strategic Transmission Investment Plan*. The third, related to use of supplemental energy payments now repealed by SB 1036, should be seen as a hallmark of the start-up phase of the RPS program. To scale the program toward reaching the 33 percent goal, California must move to a new system, such as the expanded use of feed-in tariffs.

Moving Forward with Feed-In Tariffs

Assembly Bill 1969 requires utilities to file tariff/standard contracts for renewable generation operated by a public water or wastewater facility. In July 2007, the CPUC adopted Decision 07-07-027 implementing this requirement. The decision requires that the standard contract use the appropriate MPR from the table of MPRs that are in effect on the date the contract is signed. However, in each solicitation year's table, the MPRs vary by start year. The decision requires that the actual MPR tariff paid be equal to the MPR for the start year during which the facility becomes commercially operational. Since MPRs used for a particular year's solicitation may trend up or down over the potential start years, either the utility or the generator, but not both, is at risk of the commercially operational date is delayed. Because for most solicitation years the MPR trends upward for later start years, the generator could have a small incentive to delay commercial operation.

Utilities are required to offer this tariff until they have purchased generation equal to a proportionate share of 250 megawatts, statewide. The CPUC expanded this program to require the same standard tariff for about 230 MW of additional "renewable resources from customers other than water and wastewater."[223]

In May 2007, SCE started offering a set of standard contracts priced at the 2006 MPR for biogas and biomass generators as large as 20 MW. The 2006 MPR is equivalent to approximately 7.960 to 9.393 cents per kilowatt-hour, depending on contract length (10, 15, or 20 years) and start date. Actual prices paid will also be adjusted for time of delivery, with higher prices paid during peak demand periods.[224] The contracts are available until December 31, 2007 up to a maximum of 250 MW.

This offer was prompted by the Governor's executive order S-06-06, issued in April 2006, which encouraged IOUs to increase sustainable use of biomass and other renewable resources.[225] There are three standard contracts, divided by project size and location as follows:

- Less than 1 MW of generating capacity in SCE's service territory.
- 1 MW to 5 MW in the California ISO Control Area.
- Greater than 5 MW to 20 MW under the operational control of the California ISO.[226]

SCE set the cut-off at 20 MW because it found that biogas and biomass renewable energy projects this size or smaller have been unable to participate in its competitive RPS solicitations.

The Energy Commission applauds SCE's leadership in the use of standard RPS contracts set at the MPR, making participation in the RPS feasible for smaller generators that cannot easily participate in the standard RPS process. Following the example set by

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223 California Public Utilities Commission, July 26, 2007, "Decision 07-07-027: Opinion Adopting Tariffs and Standard Contracts for Water, Wastewater and Other Customers to Sell Electricity Generated from RPS-Eligible Renewable Resources to Electrical Corporations," Rulemaking 06-05-027, http://www.cpuc.ca.gov/WORD_PDF/FINAL_DECISION/70660.PDF, accessed August 6, 2007. Attachment A, Item 11, and Conclusion of Law 25.

224 California Public Utilities Commission, June 22, 2007, AB 1969 Workshop Documents (Summary Matrix on Standard Terms and Conditions, Pacificorp Comments, and 250 MW allocation, Rulemaking 06-05-027, http://www.cpuc.ca.gov/EFILE/PD/69606.htm, accessed June 28, 2007.

225 Executive Order S-06-06 sets a target to increase the use of biomass for electricity to 20 percent of the state's renewable generation goals for 2010 and 2020, and directs the CPUC to encourage investor-owned utilities to pursue sustainable use of biomass and other renewable resources.

226 Southern California Edison, SCE Biomass Standard Contracts – Protocol, p. 4-5, in California Public Utilities Commission, June 22, 2007, AB 1969 Workshop Documents (Summary Matrix on Standard Terms and Conditions, Pacificorp Comments, and 250 MW allocation, Rulemaking 06-05-027, http://www.cpuc.ca.gov/EFILE/PD/69606.htm, accessed June 28, 2007.

CPUC implementation of AB 1969, the contracts offered by SCE should be expanded to other RPS-eligible renewables. Based on SCE's rationale, the size cut-off could be for systems as large as 20 MW, but SCE and the other investor-owned utilities should impose no cap on the total amount to be contracted and renew the offer each year.

Encouraging Solar Generation

Currently, Californians with a photovoltaic system that generates electricity in excess of their own consumption, provide it to the utilities for free. Recent experience with California's electrical system underscores a real need for reliable, zero emission electricity especially at peak usage times within the state's load centers. The Energy Commission believes that excess solar generation delivered to the grid should be compensated through a feed-in tariff. The price paid for each kWh delivered to the grid should be based on the RPS market price referent that includes a time-of-delivery adjustment. The Energy Commission and the California Public Utilities Commission should work together to establish an appropriate feed-in tariff for excess solar electricity.

Although the AB 1969 tariffs are not differentiated by technology type as are most feed-in tariffs, because they offer prices differentiated by time of delivery, they effectively result in different prices for different technologies due to differences in typical renewable generation profiles. For example, solar generation would be paid a higher average price per kilowatt-hour because deliveries generally coincide with peak times of delivery. SCE's tariff pays 3.28 times the base MPR for deliveries during the summer peak time of delivery period. In contrast, unless wind generation was able to supply electricity during a significant part of peak and shoulder periods, with little energy delivered at night and on weekends, the average price paid for wind would be less than the base MPR.

In general, feed-in tariffs can increase transparency, reduce complexity, and provide full valuation of renewable energy, addressing key problems of the current RPS structure. Feed-in tariffs can set different cost-based prices for different technologies, providing flexibility to account for technology-specific market conditions. Rickerson and Grace[227] report that "well-designed feed-in tariffs have been highly successful in driving a large percentage of the new renewable energy capacity installed around the world since the 1990s."

In many cases, feed-in tariffs in Europe and Canada are below California's 2007 market price referents for selected technologies. Considering 19 European countries, Ontario, and pending feed-in tariff legislation in Michigan, feed-in tariffs for facilities with high quality wind resources range from $0.062 to $0.128 per kilowatt-hour, with an average tariff of $0.097 per kilowatt-hour. In contrast, the 2007 MPR ranges from $0.09572 for 20 year contracts with facilities that begin commercial operations in 2008, to a levelized value of $0.11954 per kilowatt-hour if operations start in 2020. Feed-in tariffs range from $0.045 to $0.251 for solid biomass, from 0.036 to $0.251 for biogas-fired generation. Six

[227] Wilson Rickerson and Robert C. Grace, February 2007, The Debate over Fixed Price Incentives for Renewable Electricity in Europe and the United States, http://www.boell.org/docs/Rickerson_Grace_FINAL.pdf, p. 7.

European countries have feed-in tariffs for geothermal generation below $0.09 per kilowatt hour.[228]

The German feed-in tariff system is one of the most successful. Germany had 6.3 percent renewable electricity in 2000. In 2007, Germany met its goal for 2010 renewable electricity (12.5 percent) and states that new goals of 27 percent by 2020 and 45 percent by 2030 should be adopted.[229]

German feed-in tariffs are not linked to the cost of generation of wholesale electricity; rather, they are based on the cost of generation for each technology. The tariffs decline over time so facilities that begin operation in a future year receive a lower payment than facilities beginning operation in the current year.

Cost-based, technology-specific feed-in tariffs in Germany and other European countries have provided a mechanism to contain costs, while also lowering uncertainty to the developer, and stimulating expanded supply of renewable energy.[230]

Feed-in tariffs allow individuals, communities, and for-profit developers to generate renewable energy at a publicly known price. Feed-in tariffs are long-term and widely available, allowing developers to obtain financing at a lower cost.[231] In this supportive climate, equipment manufacturers can invest in expanded production.

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[228] European feed-in tariff data is from Klein, A, Held, A, Ragwitz, M., Resch, G. and Faber, T. (2006) *Evaluation of different feed-in tariff design options*, Best Practice paper for the International Feed-in Cooperation, available at http://www.feed-in-cooperation.org/images/files/best_practice_paper_final.pdf. and Mendonca, Miguel *Feed-In Tariffs: Accelerating the Deployment of Renewable Energy,* World Future Council, London, 2007. Data for Ontarios is from Contract Pricing as per OPA Renewable Energy Standard Offer Program Rules, version 2.0 at http://www.powerauthority.on.ca/SOP/Storage/32/2804_RESOP_Program_Rules_Version_2.0.pdf. For Michigan proposed legislation House Bill 5218, see http://www.legislature.mi.gov/(S(1jy314qsbq5nqqaohqvl0bva))/mileg.aspx?page=getObject&objectName=2007-HB-5218 European and Canadian feed-in tariffs have been converted to dollars per kilowatt-hour using the exchange rate of 1.1842 dollars per Euro as of 1/1/2006 to coincide with the same date used by Klein, et.al. to convert European national currencies to Euros.

[229] German Federal Ministry for the Environment, Nature Conservation and Nuclear Safety (BMU), July 5, 2007, Draft report on the Renewable Energy Sources Act (EEG). Only in German. http://www.bmu.de/files/pdfs/allgemein/application/pdf/erfahrungsbericht_eeg.pdf, p. 4.

[230] Commission of the European Communities, July 12, 2005, Communication from the Commission: The support of electricity from renewable energy sources, Com(2005) 627 final, http://ec.europa.eu/energy/res/biomass_action_plan/doc/2005_12_07_comm_biomass_electricity_en.pdf

[231] Presentation by Hans Cleijne at the May 21, 2007 *Integrated Energy Policy Report* Workshop, http://www.energy.ca.gov/2007_energypolicy/documents/2007-05-

At the Energy Commission's public workshop held on May 21, 2007 on this topic, participants supported further investigation of how best to tailor feed-in tariffs to California's renewable energy development goals, although the SCE and PG&E support continued use of the RFO process for large-scale renewable projects. Industry participants in the workshop supported cost-based feed-in tariffs, while SCE and PG&E recommended using an indicator of the wholesale market price for electricity considering the time-value of generation. SCE also stressed the need for safeguards to ensure long-term performance and maintenance of equipment. AES, a company with both fossil and solar thermal generation facilities, also supported a feed-in tariff that reflects the time value of electricity, noting the importance of peaking power to California. AES suggested a demonstration/transitional feed-in tariff for the 2008-2010 timeframe before moving to large-scale use of feed-in tariffs.

PG&E's comments on the Energy Commission's October 15th and 16th IEPR Hearings, supported the CPUC's decision to adopt 1.5 MW as the facility size under the AB 1969 tariffs, although the law had required a 1 MW cap with the larger size as an option. PG&E believes that "there may be a rationale for creating a feed-in tariff for units larger than 1.5 MW" and suggests that 20 MW may be too high and 5 or 10 MW facility size caps should be examined. Furthermore, "Although PG&E does not agree that a feed-in tariff for large generators will significantly affect renewable generation, PG&E agrees that . . . if feed in tariffs are to succeed, . . . the costs must be fairly distributed."[232]

In contrast, the Union of Concerned Scientists agrees that feed-in tariffs should be offered for RPS-eligible facilities less than 20 megawatts, but that "the MPR may not be the appropriate price for such a tariff." The Union of Concerned Scientists also recommends that the Energy Commission provide a white paper "analyzing the potential advantages and drawbacks of adopting feed-in tariffs" in California.[233]

21_workshop/presentations/Hans%20Cleijne-European%20feed-in%20tariffs%20without%20RPS.pdf, slide 11.

[232] PG&E, Post Workshop Comments, October 15-16, 2007, Integrated Energy Policy Report Committee Hearings on the Committee Draft Integrated Energy Policy Report, at: http://www.energy.ca.gov/2007_energypolicy/documents/2007-10-15_hearing/committee_report_public_comments/Guliasi_Les_Pacific_Gas_and_Electric_2007-10-19_TN-42932.pdf

[233] UCS, Post Workshop Comments, October 15-16, 2007, Integrated Energy Policy Report Committee Hearings on the Committee Draft Integrated Energy Policy Report, at: http://www.energy.ca.gov/2007_energypolicy/documents/2007-10-15_hearing/committee_report_public_comments/Guliasi_Les_Pacific_Gas_and_Electric_2007-10-19_TN-42932.pdf

The Natural Resources Defense Council recommended that "the IEPR include additional specific recommendations for how to .. . promote the use of biogas in California."[234] In March 2007, the Energy Commission adopted revisions to the Renewable Portfolio Standard Eligibility Guidebook to clarify how electricity generated from pipeline-quality biogas injected into the pipeline system can be eligible for the RPS.

In their comments on the committee draft IEPR, the three large IOUs recommended continued use of the current RFO process for large renewable projects, arguing that the current solicitation process will result in lowest costs. However, the use of the MPR, which has increased each year, may tend to set a floor price above the cost at which some renewable technologies can be profitably developed. The fact that several European countries that have rapidly and successfully increased wind generation have done so with feed-in tariffs below the MPR indicates that wind generation, at least in Europe, may be less expensive than in California under the current MPR-solicitation process.[235] Although a particular year's MPR is not made public by the CPUC until after that year's solicitation is closed, the methodology is publicly available and it is not difficult to estimate an upcoming MPR.

In considering how to develop small and large-scale feed-in tariffs, state agencies should design them to complement the state's plans to coordinate generation and transmission planning, through programmatic EIR/EIS, transmission corridor designation, and other measures discussed in the *2007 Strategic Transmission Investment Plan*.

To build the infrastructure needed to achieve the state's renewable energy goals, California utilities are building transmission lines to areas with large amounts of renewable energy potential. To make the most of this investment, the state needs to encourage development of renewable energy in these areas while safeguarding against the possible exercise of market power by renewable energy developers.

A competitive RFO does not protect the ratepayers against the risk of collusion by energy generators to ratchet up the price bid for RPS contracts in renewable resource zones with new infrastructure investment. Nor does it provide a transparent process for developers to easily know and anticipate what price they will receive for their energy. A

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[234] NRDC, Post Workshop Comments, October 15-16, 2007, Integrated Energy Policy Report Committee Hearings on the Committee Draft Integrated Energy Policy Report, at: http://www.energy.ca.gov/2007_energypolicy/documents/2007-10-15 hearing/committee report public comments

[235] See Table 5.1, page 54 in Mendonca, Miguel *Feed-In Tariffs: Accelerating the Deployment of Renewable Energy,* World Future Council, London, 2007. Developers and utility staff have speculated that the MPR may set a price floor above the cost of profitably developing wind generation in California.

technology-specific feed-in tariff can accomplish both of these goals and pay a price that reflects the value of the energy product provided by the renewable energy generator.

To fully examine the impacts of a renewable feed-in tariff in California, the Energy Commission, in collaboration with the CPUC, should develop a white paper investigating the use of feed-in tariffs to be completed in 2008. In the white paper, the Energy Commission and CPUC should consider a range of mechanisms for determining the appropriate price to pay for renewable energy in designated renewable resource zones, including the following:

- The RPS market price referent including the recently approved greenhouse gas adder.
- A technology-specific cost of generation plus a reasonable return on investment.
- The median price awarded in the all-source long-term procurement competitive RFO plus a premium.
- The median price awarded to all RPS contracts through 2010.

Outside of the designated renewable resource zones, there is greater competition among renewable energy developers, producing a lower risk of market power collusion in competitive RFOs. This might suggest less urgency for adoption of a feed-in tariff outside of the areas of targeted new transmission infrastructure if the state were on track toward achieving its RPS and 33 percent by 2020 goals. Although the Committee would like to see all of the signed contracts for renewable energy come to fruition, the historical record to date indicates this is unlikely to be the case. An expanded use of feed-in tariffs can stimulate the robust pace of renewable energy development needed to achieve 33 percent renewables by 2020.

Proximity to transmission can also affect the cost of renewable energy. The costs may differ among utilities, depending on the extent of new transmission needed to reach renewable resources. To address uneven impacts on ratepayers of the feed-in tariffs in Germany, the costs of the feed-in tariffs are distributed evenly to all ratepayers by the regional transmission authorities.[236]

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[236] Wilson Rickerson and Robert C. Grace, February 2007, The Debate over Fixed Price Incentives for Renewable Electricity in Europe and the United States, http://www.boell.org/docs/Rickerson_Grace_FINAL.pdf, p. 13.

Other Financing Assistance Options to Promote RPS Goals

As California's gateway to the capital markets, the State Treasurer's office should aggressively pursue all financial products that reduce the cost of capital for renewable energy projects in order to combat climate change. This office should work with Congress to help create a new renewable energy category for private activity bonds and help scale-up the financing capability of clean renewable energy bonds. The State Treasurer should lead the way in expanding renewable energy development through both the California Pollution Control Financing Authority and the California Alternative Energy and Advanced Transportation Financing Authority.

FEDERAL ACTION:

Private Activity Bonds: Add new category for renewable energy projects. Municipal bonds provide tax-exempt financing for governmental and qualified purposes such as the construction of airports, hospitals, industrial development, certain waste and recycling activities and twenty-six other designated public purposes. To extend this low cost of capital to renewable energy projects, the U.S. Internal Revenue Code should be amended to add a new category for renewable energy. This proposed legislation has no federal budget impact since each state is allocated a specified amount of bond financing authority each year based on population. In 2007, the State of California received a little over $3 billion in bonding capacity for private activities, of which $440 million was allocated by the state for solid waste and recycling projects.

Renewable Energy Bonds: Create special volume cap for renewable energy projects. Create special volume cap for tax-exempt bonds to finance renewable energy projects under the U.S. Internal Revenue Code. In addition to the Private Activity Bonds above, Federal legislation created an additional $ 15 billion special volume cap for tax-exempt bonds dedicated to highway and freight transfer facilities. Senators Salazar and Smith through SB 672 have similar legislation that would expand tax-exempt bond categories for renewable projects 40 MW or less. These projects would be exempt from the state volume caps for private activity bonds.

STATE ACTION:

California Alternative Energy and Advanced Transportation Financing Authority (CAEATFA): Issue tax-exempt bonds for renewable energy projects. If the federal tax code is amended to include a new category for renewable energy projects under private activity bond authority, then CAEATFA could issue tax-exempt bonds for renewable energy projects. CAEATFA finances facilities that use new energy sources and technologies, and finances development of advanced transportation technologies. CAEATFA is also authorized to own all or part of a project, and can lease the property back to the developer. This technique can be used to exempt projects from state sales taxes.

Clean Renewable Energy Bonds (CREBs): Package renewable energy projects through the California Pollution Control Financing Authority (CPCFA). CREBs are a new form of tax credit bond in which interest on the bonds is paid in the form of federal tax credits by the U.S. government. This allows borrowing at a zero percent interest rate. This would be an effective financing mechanism for renewable energy projects owned by municipal utilities or installed on government facilities. The total 2007 nationwide volume cap allocation was $1.2 billion. Issuers must apply to the IRS for an allocation for each location. The IRS currently allocates the volume cap based on the "smallest to largest" criteria. For 2007, CREBs allocations ranged from $23,000 to $3.1 million. Larger CREBs allocations are anticipated in pending Federal legislation which also removes the "smallest to largest" allocation requirement.

LOCAL GOVERNMENT ACTION:

City of Berkeley: Finance solar installations through property taxes. The City is considering a plan to finance solar installations for property owners with low-interest revenue bonds backed by a 20-year property assessment. At current IOU tiered rates, the annual savings in utility bills is greater than the annual assessment for systems sized to save only the top tiers. The goal is to install solar on 25% of the residences and reduce the City's carbon footprint by 2,000 tons per year.

Recommendations

To address the barriers to renewable development in the context of the state's GHG emission targets and the need to manage cost and risk to ratepayers for electricity, the Energy Commission makes the following recommendations:

- Build new transmission lines to renewable resource areas in California and the West is essential to achieving California's greenhouse gas and RPS goals. The CPUC has approved PG&E's transmission planning efforts in the Northwest, extending to British Columbia, Canada. In August 2007, the CPUC approved SCE's request for transmission feasibility planning for renewable resources in Western Nevada, Southeastern California (Inyo, San Bernardino, and Imperial Counties), and Western Arizona. The Energy Commission applauds the CPUC's support of these transmission planning efforts. To tie together the changing resource mix needed to meet California's greenhouse gas and RPS goals, utilities must incorporate new technologies into the transmission and distribution systems to create an electricity transmission/distribution system that accommodates a growing volume of intermittent renewable, distributed generation, and demand response technologies. This will require coordinated investment in generation, transmission, and support services. For additional recommendations related to transmission, refer to the *2007 Strategic Transmission Investment Plan.*[237] For recommendations related to the distribution system, refer to Chapter 6 of this document.

- Implement a feed-in tariff set, for the immediate future, at the MPR for all RPS-eligible renewables up to 20 MW in size, and begin a collaborative process with the CPUC to develop a white paper evaluating feed-in tariffs for larger projects to accelerate renewable development in the next decade. This process should recognize the value of a diverse mix of renewables considering differential costs of different renewable technologies and incorporate these values and the applicable features of the most successful European tariffs. Also, the joint Energy Commission-CPUC process should consider how to evenly allocate costs for renewable energy feed-in tariffs.
- Until a feed-in tariff system is in place, continue to update the MPR protocols to more fully reflect risk and market costs of long-term fixed-price power. The MPR for 2007 will include a small greenhouse gas adder, but still does not capture fully the benefits of renewables. The Energy Commission and CPUC should include the risk of price volatility and further develop greenhouse gas adders in the valuation of renewable energy.
- Coordinate the RPS with market-based compliance mechanisms for greenhouse gas emissions reduction. To be eligible for trade in any market-based compliance mechanism used to achieve the AB 32 emission greenhouse gas limit, AB 32 requires that greenhouse gas emission reductions be in addition to reductions required by existing policies. To avoid excess supply of tradable greenhouse gas emission reduction credits, this should be clarified to ensure that greenhouse gas reductions due to RPS are quantified and taken out of any allowance system for cap-and-trade purposes.
- Ensure that California's RPS goals are not negatively affected by any federal targets that may be developed for renewable energy. Congress has been considering

[237] California Energy Commission, CEC-700-2007-018, November 2007.

legislation that, if not carefully implemented could negatively affect California's RPS program. Though the Energy Commission supports a federal renewable portfolio standard, it does so only if such a standard does not pre-empt the authority of states to implement higher standards within their own jurisdictions in a manner that des not allow inappropriate spillover in the federal legislation.[238]

[238] John L. Geesman, Commissioner and Presiding Member, Renewables Committee, and Jackalyne Pfannenstiel, Chairman and Associate Member, Renewables Committee, June 18, 2007, Letter to the Honorable John D. Dingell, Chairman, Committee on Energy and Commerce and the Honorable Rick Boucher, Chairman, Subcommittee on Energy and Air Quality, U.S. House of Representatives. California Energy Commission, http://www.energy.ca.gov/papers/2007-06-18_CONGRESSMAN_DINGELL_LETTER.PDF, accessed July 20, 2007.

CHAPTER 5: California's Electric Distribution System

California's electric distribution system is essential to deliver power to consumers. Distribution systems transfer high-voltage power from the transmission grid through substations, where the voltage is reduced. From the substation, distribution lines deliver power to customers.

Electric distribution systems throughout California still use designs, technologies and strategies that were developed to meet the needs of mid-20th century customers. These large and complex systems have historically provided reliable electric power to tens of millions of customers throughout the state, although aging infrastructure coupled with modern demands is beginning to erode this capability. With California's strong commitment to distributed renewable energy, combined heat and power, demand response, and reduced production of greenhouse gases, the design of these systems will have to change to accommodate the integration of these new resources.

> ***"Never tell people how to do things. Tell them what to do and they will surprise you with their ingenuity."***
>
> George S. Patton

Ideally, the 21st century distribution grid should allow grid operators to detect and respond to problems quickly by being able to manage the grid in real time. It should provide for rapid two-way information exchange between utilities and customers. It should allow the use of distributed resources to support grid operation. And it should allow for the seamless integration of the full spectrum of 21st century technologies.

As California utilities invest billions of dollars to expand and replace aging distribution infrastructure in the next five to ten years, it is critical to develop a framework to guide these investments. Without a transparent planning process, the state will not realize the full benefits of these resources.

This chapter discusses the challenges facing California's distribution system along with the barriers to integrating distributed resources into that system.

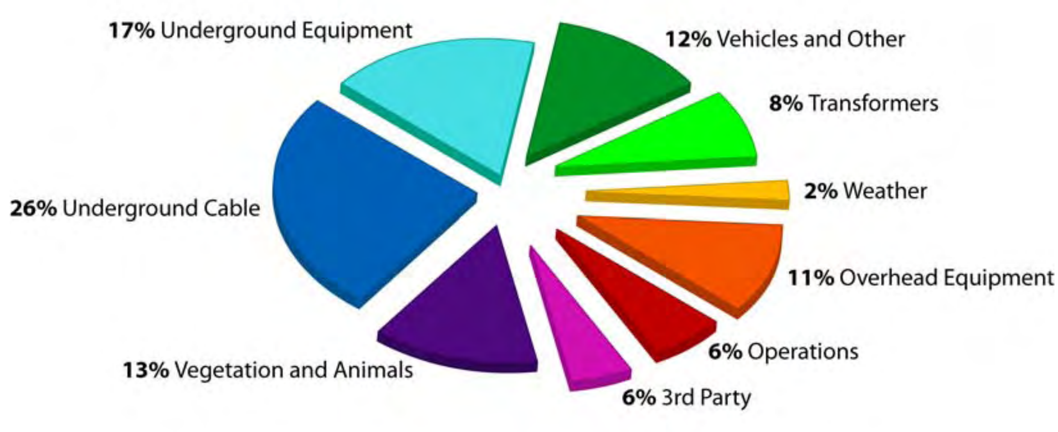
Existing Distribution Infrastructure in California

Each utility service territory is physically distinct and has its own unique challenges. Some utilities have large concentrations of urban customers and others serve rural areas. Some systems are relatively new, while others have served customers for more than a century.

Of the state's three major investor-owned utilities, Pacific Gas & Electric (PG&E) has the largest service area and serves approximately 15 million electric and natural gas customers in dramatically varying climate and weather conditions.[239] Serving 12 million people, Southern California Edison (SCE) provides electric service to central, coastal, and southern California, including larger urban population centers. [240] San Diego Gas and Electric (SDG&E) is the smallest of the three large investor-owned utilities, with 4,100 square miles of service territory, serving 1.4 million electricity customers in San Diego and southern Orange counties to the Mexican border.[241] One of the biggest challenges each of these utilities face when planning for the future is unprecedented load growth in the hot inland areas of their service territories.

About 90 percent of all customer interruptions and outages — both within California and throughout the U.S. — are caused by distribution problems or "events" (Figure 5-1). In four days in early September of 2007, an unprecedented 645,000 SCE customers suffered distribution-caused outages. Some of these events occur when poles or lines are impacted by people, equipment, high temperatures, balloons, or vegetation. Service can also be interrupted by weather related events such as wind and lightning. Another significant cause of outages is equipment malfunction and failure.

Figure 5-1. Distribution Failures



When interruptions do occur, it is often the customer who first alerts the utility. Utilities and researchers are working to improve problem detection and response and to develop sensors, smart meters, communications, and controls to enable them to detect problems and restore power quickly anywhere on the system.

239 http://www.pgecorp.com/corp_responsiblity/reports/2006/company_overview.html.

240 http://www.sce.com/AboutSCE/CompanyOverview/territorymap.htm.

241 http://www.sdge.com/aboutus.

Addressing California's Distribution Infrastructure Challenges

On May 10, 2007, the California Energy Commission's Integrated Energy Policy Report (IEPR) Committee and the Electricity Committee held a joint workshop to provide stakeholders and parties the opportunity to bring forward issues and challenges facing California's electricity distribution system.[242] During the workshop, presentations and discussions covered distribution challenges, San Diego Smart Grid Study research technologies, and research program activities.

Presentations by PG&E, SCE, and SDG&E at the workshop described in detail the operational challenges California's distribution utilities face on a daily basis. One issue highlighted at the workshop was the age of the existing underground cable system. Customer preference for underground cables is so high that the California Public Utilities Commission (CPUC) authorizes utilities to replace portions of overhead cable in areas of their service territory with underground cable every year.

Throughout the 1970s and 1980s SCE installed increasing amounts of underground cable, much of which is approaching the end of its design life (Figure 5-2). It will therefore need to be replaced in the near future to avoid failures. Depending on the amount and age of underground cable in their service territories, utilities report replacing underground cable at rates of 40 to 70 miles per year. Based on 43,108 miles of such cable, this is unlikely to prove an adequate replacement cycle. Even if the rate of replacement is increased, it is clear from the figure that in the SCE service territory, cable failures due to age are likely to measurably increase in the next 5 to 10 years, impacting reliability.

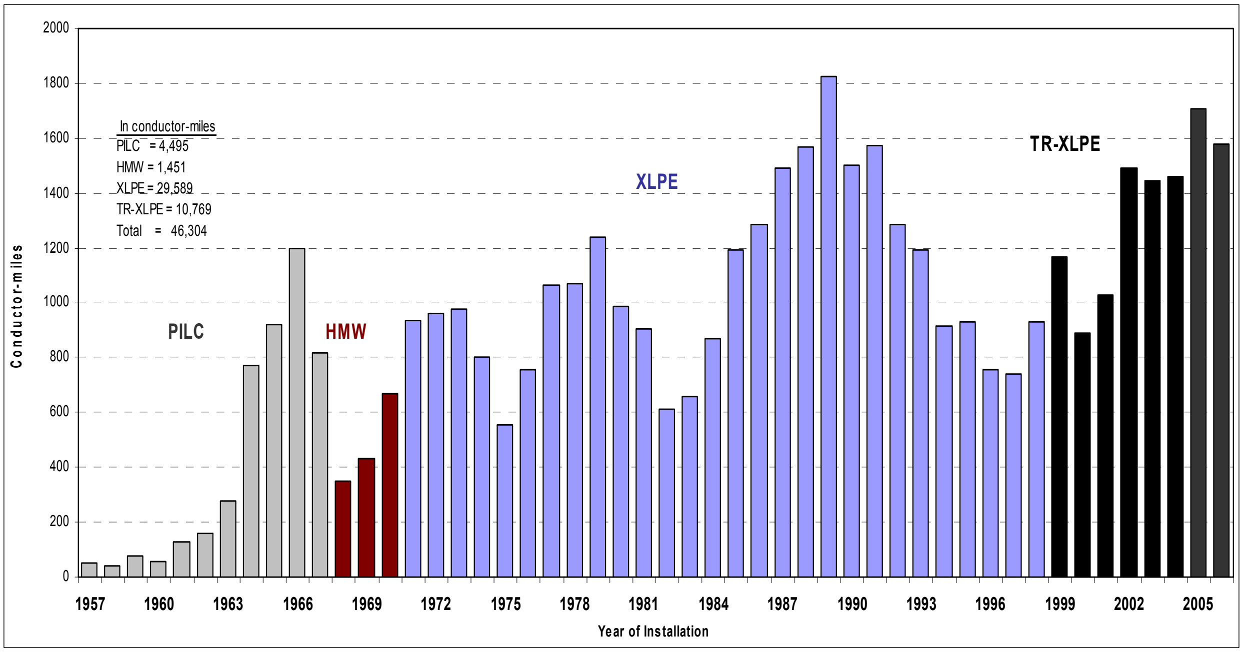
At the May 10 workshop, PG&E acknowledged that with 26,000 miles of underground cable and current replacement efforts at 70 miles per year, their efforts are equivalent to a 371-year replacement cycle.

One way to deal with this problem is to determine which lines are at greatest risk of failing and replace them first, since some older underground cables are still capable of performing reliably for some years into the future. However, an inexpensive and reliable diagnostic technique that can accurately determine the condition and remaining life of underground cables does not currently exist. With this type of diagnostic, utilities could prioritize the replacement of cable, rather than simply replacing it based on age. At the workshop, PG&E indicated that the average cost to replace one foot of underground cable for PG&E is $120. By determining what cables actually need to be replaced and when, substantial savings could be achieved without eroding reliability. These issues are

[242] California Energy Commission, Joint Committee Workshop on Addressing California Distribution Infrastructure Challenges, May 10, 2007.

not unique to California, as other utilities throughout the U.S. are struggling with the same reliability and technical challenges.

Figure 5-2. SCE Underground Primary Cable by Year of Installation



Note: PILC: Paper Insulated Lead Cable, old style cable with copper conductors wrapped in oil soaked paper covered in lead sheath. HMW: High Molecular Weight polyethylene cable, an early form of poly cable. XLPE - Cross Linked Polyethylene cable, the more modern form of poly insulation. TR-XLPE: Tree Retardant XLPE, where trace chemicals are added to XLPE to retard the growth of "trees," cracks in insulation due to moisture and voltage stress.

In spite of interest in automation and smart grid technologies, California utilities have very little regulatory incentive to design and build "smart" distribution infrastructure that can do more than assure that power is reliably delivered from distant central station power plants. Public policy should encourage investment in technology that supports flexibility. Utility engineers are clearly interested in designing new infrastructure that will meet the needs of their customers in the future, but the current regulatory approval process is not designed to allow the transparent side-by side evaluation of new technologies and traditional investments. Without regulatory approval, utilities will be reluctant to introduce new technologies into their systems.

Another issue that was highlighted in the workshop by SDG&E is the aging utility workforce and the inability of utilities to attract both new operational and engineering talent. As a career field, power engineering does not attract many students and the number of universities and colleges at which it is taught is declining. Attracting and keeping skilled field and construction staff are also issues. Over the next five years, this issue is expected to worsen and will impact the ability of utilities to rebuild their distribution systems and provide reliable service in the future. New technologies including automation, sensors, and controls will assure that staff resources are used as efficiently as possible.

At the workshop, the customer perspective was provided by the San Francisco Community Power Cooperative representative who indicated that the role of customers passively receiving and paying for electricity is changing. New laws and programs in California are providing incentives to customers to install renewable solar generation at their homes and businesses to meet some of their energy needs. A range of new technologies, tariffs (such as time-of-use and Critical Peak Pricing), and programs are being developed that will also encourage customers to control the amount of power they use during different times of the day. It can be expected in the coming years that, as new advanced metering infrastructure is installed throughout the state, this infrastructure will enable other technology applications and support the growth of a California customer-centric resource pool throughout the state. Customers will increasingly be in a position to provide valuable energy resources and services to utilities if the right programs and incentives are developed.

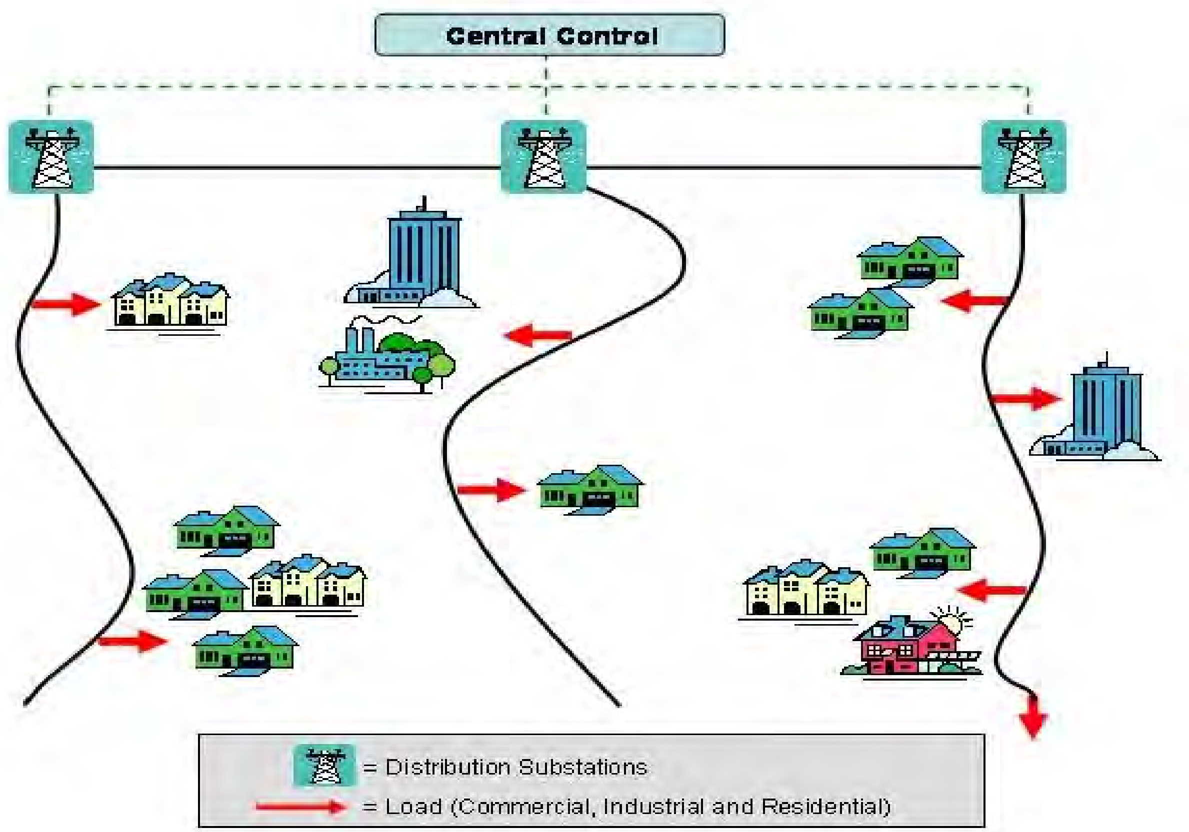
PG&E indicated that utilities are also working to understand and develop strategies to manage and utilize the growing penetration of customer resources on the distribution system. The utilities are addressing issues like the technical challenges and how the design of the distribution system should change to accommodate and optimize the use of emerging resources. Beyond the technical changes —for example, integrating automation and communications technologies into the existing power delivery system to coordinate new resources — it is critical to begin today to explore what must be done to encourage utilities and customers to work together to develop a more integrated and lower-carbon energy network that better meets everyone's needs in the future.

Distribution System Investments

Utilities spend approximately three-fourths of their total capital budgets on distribution assets, with about two-thirds spent on upgrades and new infrastructure in most years. These investments will be with us for 20-30 or more years. As utilities throughout the state plan to build new distribution assets and replace old assets, the magnitude of these investments suggests that we must understand what they are investing in and whether these investments will result in a distribution system that will serve customers in the future. Planning for investment in these assets should include requiring utilities, before undertaking investments in non-advanced grid technologies, to demonstrate that alternative investments in advanced grid technologies that will support grid flexibility have been considered, including from a standpoint of cost-effectiveness.

California's energy policies are shifting how the state will meet energy demand in the future. Legislation and new laws, as well as the state's Energy Action Plan, have made strong statements that new energy demand in California must increasingly be met by energy efficiency and demand response, the use of alternative fuels, and low carbon distributed generation resources such as solar, combined heat and power (CHP), and wind. With the advent of new advanced metering infrastructure, along with the increasing focus on distributed generation technologies and the high priority for demand response, the state needs a distribution grid that facilitates two-way communication while easily detecting problems and automatically adjusting for them. "Business as usual," where customers passively receive energy from utilities, must change. During the next 10 years, a whole range of new energy tariffs and programs will have to be developed to encourage utilities, customers and businesses to use new information and energy technologies through the distribution system so they can benefit from greater choice and lower costs.

Figure 5-3. Typical Distribution System

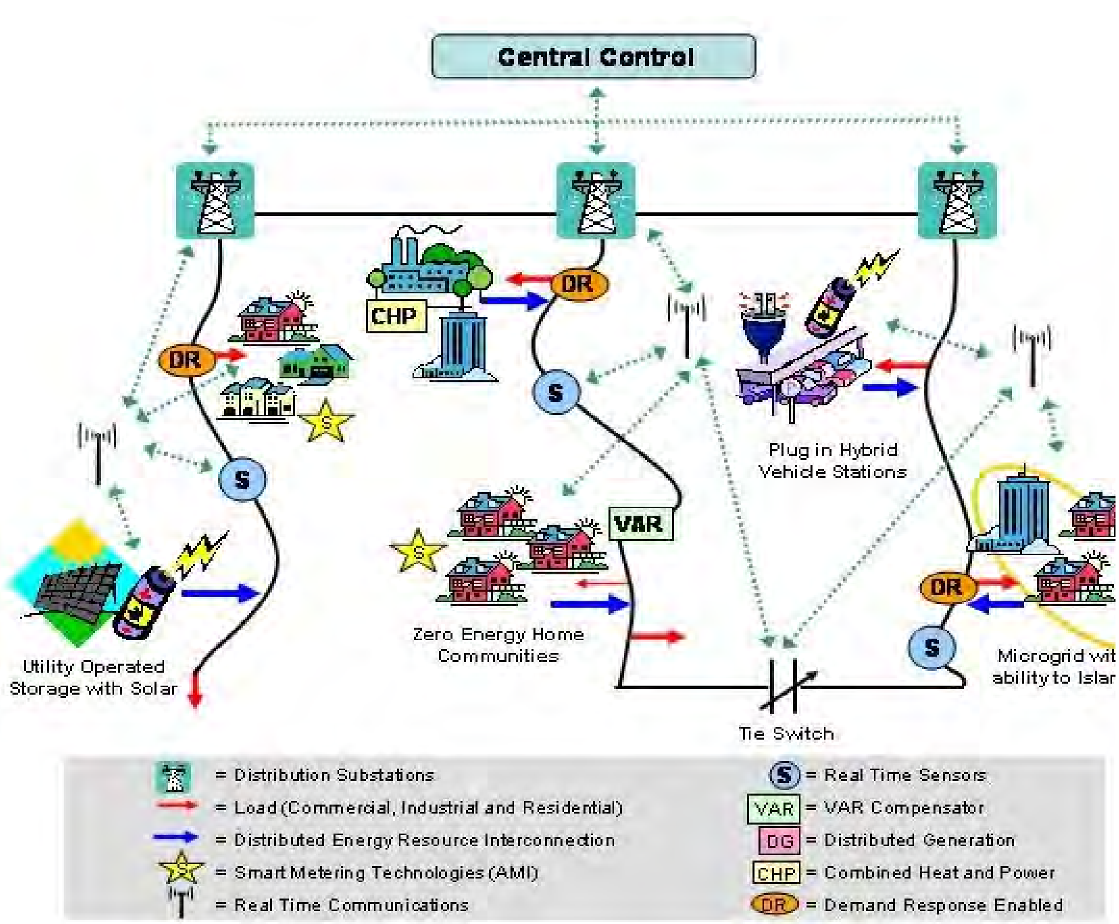


As the goals of state law are met over the next decade, the distribution system will be called on to integrate and efficiently use all the distributed energy resources that will be installed in California customers' homes and businesses. As California moves towards that utility investment should be channeled into appropriate technologies and equipment that will lead to the development of a modern and smart network. Utilities will be spending billions of dollars over the next 10 years rebuilding and expanding their distribution systems. It is essential that this massive capital flow be directed to where it can be most effective.

Today, distribution systems continue to be designed and built to accommodate one-way flow of power (Figure 5-3).

California continues, through legislation and regulation, to support its commitment to increased penetrations of renewable and highly efficient distributed generation, a trend likely to intensify as priority is placed on aggressively reducing greenhouse gas emissions. To assure maximum reliability and leverage benefits from these new distributed resources, the design of the electric distribution system must also evolve. Through increased use of distribution automation and communications and controls, utilities will no longer have to wait for customers to let them know there is a problem. New technologies, including Advanced Distribution Automation (ADA), will give distribution grid operators the ability to detect and respond to problems quickly and safely. Being able manage the grid in real time will allow utilities to better assure grid reliability, security, efficiency, affordability and power quality. These new systems will feature the free exchange of information between the utility and the customer and the customer and the utility (Figure 5-4).

Figure 5-4. 21st Century Distribution System



Distribution Research Program

The distribution system will play an increasingly important role in dealing with energy issues and challenges that California will face in the near future. The following issues and their solutions will require research to develop distribution level technologies, planning tools, models and business cases.

- Generation and transmission capacity constraints: Transmission and environmental constraints, along with continuing population growth, suggest that distributed generation will play an increasing role in meeting future capacity needs. Because these resources will be dispatched and used through the distribution system, this will require the distribution system to shoulder an increasing burden for meeting California's capacity needs.
- Integrated distributed energy resources: Integrating and leveraging resources, such as photovoltaics, combined heat and power, and energy storage, is a critical challenge for California to meet its environmental and energy reliability needs.
- End-Use Technologies: The development of increasingly diverse and sophisticated end-use technologies — including smart appliances, Plug-in Hybrid Electric Vehicles and demand response — will require a vibrant and modern distribution system.
- Energy Efficiency: The distribution system accounts for a higher share of delivery losses than transmission, and may offer a significant opportunity for improvements in efficiency.
- Transparent Planning: Customers are likely to play a greater role in meeting their own energy needs, and current approaches to planning may limit the potential benefits.

The Energy Commission's Public Interest Energy Research Program (PIER) has developed a Distribution Research Program intended to support technologies that provide efficient, reliable and affordable energy to customers through a low-carbon energy network, and to bring those technologies to market.

The Distribution Research Program completed a comprehensive assessment that identified critical research gaps. A program roadmap was then developed to identify milestones needed to reach target program goals. The program includes a Program Advisory Committee comprised of representatives from California's three major investor-owned utilities, a large out-of-state utility, Department of Energy, and the customer and manufacturing sectors, which provides advice and expertise to program managers. After careful analysis and study, the program developed a project portfolio emphasizing technologies that support reductions in greenhouse gases, improve distribution reliability and capability, and enable renewable energy resources, demand response and energy storage.

Currently, the program is developing and funding several projects to support integrating distributed energy resources, enable the optimization of these resources to improve and support reliability, reduce greenhouse gases and reduce costs to customers. Areas addressed by these projects are Advanced Distribution Automation, microgrids, distribution models and planning tools, and sensors.

Advanced Distribution Automation Research

Advanced Distribution Automation (ADA) has been identified as a focus area for the program due to the critical role it will play in establishing a modern distribution system. To support the development and deployment of ADA, the program has been conducting research to determine how ADA provides value to utilities, customers, and society. Two studies were commissioned to accomplish this. The first, "Value of Distribution Automation Applications,"[243] looks at the ways ADA has been applied by state, national and international utilities. This work provides a foundation for understanding how ADA adds value for improving operational efficiency, peak load management, and system restoration after failures. The second study, "The Value of Distribution Automation,"[244] presents an analytical framework that determines the potential value that ADA could provide if fully deployed in the service territories of California's investor-owned utilities. This study is nearing completion and will be available in the fall of 2007.

In parallel with these two studies, the DRP has been actively engaged with leading distribution experts from industry to fully vet and appropriately focus research in this area. As part of the first study, a large group of experts representing utilities, equipment suppliers and researchers held a workshop to discuss the ADA topic. The workshop reinforced the complexity of the distribution automation value proposition, and there was general agreement that a deeper understanding of the value of automation is needed to more fully use these types of technologies.

It is clear that ADA adds significant value for California stakeholders by increasing service quality (reliability), improving resource efficiency (including reducing energy losses), and reducing the cost of distribution service. It is also important to specifically note ADA's contribution to increasing the penetration of distributed generation, including PV. By understanding how various ADA functions benefit stakeholders, Distribution Research Program managers can make strategic decisions to support R&D that answers the following key questions:

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[243] California Energy Commission, *Value of Distribution Automation Applications*, PIER Final Project Report, Prepared by: Energy and Environmental Economics, Inc. and EPRI Solutions, Inc., April 2007, CEC 500-2007-028.

[244] California Energy Commission, *The Value of Distribution Automation*, PIER Final Project Report, Prepared by: Navigant Consulting, Inc., September 2007.

- How can we develop ubiquitous, low-cost sensors that can monitor the distribution network at a resolution sufficient for ADA?
- How can we ensure that a wide variety of new and legacy equipment can communicate reliably and operate in a coordinated fashion?
- How can we manage the large quantity of data associated with a full-scale deployment of ADA, and convert the data to useful information and databases that are actionable?
- How do we balance autonomous local control with central or regional coordination?
- How do we reduce the cost of ADA technologies to promote full-scale deployment?

The effective deployment of ADA technologies will be key to developing the distribution system of the future. By integrating and adding ADA technologies, utilities will be able to increase the reliability, efficiency and flexibility of the distribution system to respond to the evolving needs of customers. ADA will also make vital contributions to meeting California's energy challenges in the coming years, including integrating high penetrations of distributed generation, reducing greenhouse gases, and creating new approaches to infrastructure planning and development.

Microgrid Research

A microgrid is an integrated energy system consisting of interconnected loads and distributed energy resources, which as an integrated system, can operate in parallel with the grid or in an intentional island mode. The Energy Commission's PIER Program and DOE have been researching and developing this technology since 2000 to allow the safe operation of microgrids. Some of the value propositions for microgrid applications include:

- Reducing the cost of energy and managing price volatility
- Improving reliability and power quality
- Increasing the resiliency and security of the power deliver system by promoting (allowing) the dispersal of power resources
- Helping to manage the intermittency of renewables and promoting the deployment and integration of energy-efficient, environmentally friendly technologies
- Assisting in optimizing the power delivery system, including the provision of services
- Providing different levels of service quality and value to customers segments at different price points.

If it can be demonstrated that microgrids can operate safely, a whole range of new opportunities, and value propositions like those described above will become available for both customers and utilities. In particular, microgrids offer the opportunity for customers to develop "micro" systems that use clean generation technologies and support California's low carbon objectives. Working jointly with the Distributed Energy Resources Integration Program, the Distribution Research Program is developing major research demonstrations of microgrid technology that will feature innovative integrations of suites of clean technologies and energy storage. The research will focus on documenting the value of these integrated resources to provide local load reductions of at least 15 percent on utility distribution feeders and to efficiently coordinate generation and customers' resources.

Distribution Models and Planning Tools

California's distribution operators have limited ability to assess the benefits of distributed energy resources on the distribution system. Traditional power flow models and analysis have not been able to process system data on large distribution circuits. Some new distribution operational models are becoming available and can help operators better manage segments of their system, but distribution data challenges remain difficult.

This lack of system visibility also impacts the overall planning process and makes it difficult to assess and rank what additions or investments provide the maximum value. The Distribution Research Program currently has a contract with New Power Technology to develop a methodology using Optimal Technology's AEMPFAST to assess and rank system changes to improve operational efficiency. This tool will also be used to rank, from an operational perspective, the value of distributed energy resource additions. This research project has successfully processed huge amounts of distribution data into a working model for one of the largest systems within the SCE service territory. The model will recommend system reconfigurations and optimization strategies that will be applied and monitored to validate projected benefits. These types of models, which are routinely used to model transmission systems, have not been widely used to assess distribution systems. This research will validate the use of distribution planning models to determine high value locations for distributed resources and support a more transparent distribution planning process. The Department of Energy (DOE) is funding a complementary financial study that will compare the value of distributed resource options identified in the New Power Technology analysis to traditional utility capital investments (e.g. substation upgrades and other equipment replacements).

Sensors

Sensors are critical to determining the condition of equipment. Because communicating sensors remain relatively expensive and the distribution system is so expansive, developing small and extremely cheap communicating sensors using new technology would provide a whole range of new opportunities to better monitor the distribution system for faults and equipment failure. The Distribution Research Program will be issuing a Research Opportunity Notice in 2008 to explore innovative technologies to develop new applications for small inexpensive communicating sensors.

Sensors are also the focus of a unique research effort that is being managed through the Center for Information Technology Research in the Interest of Society at the University of California, Berkeley. The researchers will be developing a diagnostic tool or sensor that can reliably determine the remaining life of a distribution cable buried in the ground. The team and California utilities will use innovative and new scientific instruments and scopes to understand the reason for cable failure and explore new technologies that can sense and relay the condition of the cable to utility engineers without interrupting service on the cable. A conference to bring engineers and scientists from around the country and world to discuss possible solutions to this vexing problem will be held in Berkeley in January 2008. Failing underground cable is one of the most critical problems faced by utilities in California and the U.S. If new diagnostics are not developed, distribution system reliability will be negatively impacted because current rates of replacement of old cable will not be able to keep up with increasing age-related failures.

Integrating Distributed Generation

Distributed generation (DG) and combined heat and power (CHP) are valuable resource options for California. The Energy Commission has proposed policies to encourage development of DG resources, including CHP projects, for many years, beginning in the late 1990s with the formation of the California Alliance for Distributed Energy Resources and continuing with collaborative efforts with the CPUC to address barriers to DG development.

Despite these efforts, significant issues facing DG and CHP developers persist. In 2002, the Energy Commission developed a Distributed Generation Strategic Plan, noting:

> "…regulatory uncertainty in California continues to be a major concern for those considering the deployment of distributed generation. Utility rate design is confusing at best, including issues surrounding standby charges, interconnection fees, exit fees, and grid management charges. The timing of legislative mandates regarding rate design and the ultimate implementation of those policies also carry confusion and uncertainty to DG stakeholders."[245]

Both the 2003 and 2005 *Integrated Energy Policy Reports* recognized that focused policy direction would be needed for successful long-term deployment of DG and CHP. The *2003 IEPR* recommended that California "Create a transparent electricity distribution

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[245] California Energy Commission, *Distributed Generation Strategic Plan*, 700-02-002, June 2002, p. 16.

system planning process that addresses the benefits of distributed generation."[246] As part of the 2005 IEPR process, the Energy Commission assessed California's CHP market.[247] In that assessment, potential project developers indicated the policy options most likely to increase the likelihood of a CHP project going forward were:

- Modifying the CPUC's Self Generation Incentive Program to allow larger, natural gas fired projects that meet customers' requirements to participate
- Allowing CHP owners to sell excess power to the grid[248]

Opening the wholesale market for CHP projects was seen as the most important policy change for increasing the penetration of CHP, and for increasing societal benefits.[249] By allowing large CHP projects to find customers for their excess generation and to export power at wholesale prices, more than 2,400 megawatts of CHP generation output could be available for export. Because this reflects generation that is matched to facilities' heat loads, it is an efficient use of fossil fuel, mainly natural gas. The carbon-reduction paradigm established by AB 32 should place particular value on achieving these efficiencies rather than meeting electric and thermal loads separately.

In the 2005 assessment, some project developers suggested that the state consider measures to encourage investor-owned utilities to support rather than oppose CHP development.[250] Developers felt that CHP is seen as competing with the local utility, and the lack of incentives to encourage utility cooperation could result in utility foot-dragging.

Through a research project involving the Electric Power Research Institute (EPRI), California investor-owned utilities, and other states, the Energy Commission investigated the possibility of utility ownership of DG facilities, particularly CHP projects.[251] The goal was to develop a pilot application, testing alternative, "win-win" regulatory treatment of DG projects. However, utilities showed no interest in owning

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[246] California Energy Commission, *2003 Integrated Energy Policy Report*, publication no. 100-03-019, December 2003, p. 16.

[247] *An Assessment of California CHP Market and Policy Options for Increased Penetration*, CEC-500-2005-173, 2005.

[248] Ibid, p. XIII.

[249] Ibid, p. 4-25.

[250] Ibid, p. 3-21.

[251] California Energy Commission contract number 500-02-014, WA #121.

on-renewable projects. This result is consistent with findings of a 2007 DOE study[252] that concluded:

> There are several economic and institutional reasons why electric utilities have not installed much DG. For example, the economics of DG are such that financial attractiveness is largely determined on a case-by-case basis, and is very site-specific. As a result, many of the potential benefits are most easily captured by customers so that the incentives for customer-owned DG are often far greater than those for utility-owned DG. This has led to the current situation where standard business model(s) for electric utilities to invest profitably in DG have not emerged.

In the *2005 Integrated Energy Policy Report,* the Energy Commission found that, despite many years of articulated policy preferences, DG and CHP in California continues to face major barriers to market entry in the context of traditional utility cost-of-service grid management.[253] The *2005 IEPR* reiterated that California must improve access to wholesale energy markets and streamline utility long-term contracting processes so that CHP owners can easily and efficiently sell their excess electricity to their local utility. Availability of the wholesale market continues to be a significant consideration in encouraging DG and CHP.

In October 2007, Governor Schwarzenegger approved Assembly Bill 1613 (Blakeslee, Chapter 713, Statutes of 2007), which allows the CPUC to require utilities to purchase excess electricity from CHP systems sized at 20 MW or less. This legislation represents a step toward opening the wholesale market for smaller CHP projects and providing those operators with a market for their excess generation. However, because the bill does not compel the CPUC to impose this requirement on the utilities nor does it provide a date certain by which such a requirement would take effect, it stops far short of providing small CHP operators with the guaranteed access to wholesale markets recommended in the *2005 IEPR*.

AB 1613 also requires the CPUC to establish a "pay-as-you-save" pilot program. This program is intended to enable customers to finance the upfront costs for purchasing and installing a small (less than 20 MW) CHP system. Customers would repay those costs over time through on-bill financing at the difference between what they would have paid for electricity and the actual savings for a period of up to 10 years. This program will be available until the statewide cumulative capacity from CHP systems participating in the program reaches 100 MW statewide. Since the availability of

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[252] "The Potential Benefits of Distributed Generation and Rate-Related Issues that May Impede Their Expansion, a Study Pursuant to Section 1817 of the Energy Policy Act of 2005". U.S. Department of Energy, February 2007.

[253] California Energy Commission, *2005 Integrated Energy Policy Report,* CEC-100-2005-007-CMF, November 21, 2005, p. 76.

financing was not identified by stakeholders as a major barrier to CHP development, it is not clear how significant this provision will prove to be.

As part of the 2007 IEPR process, on May 7, 2007 the 2007 IEPR Committee held a joint workshop with the Energy Commission's Electricity Committee to discuss staff's proposed "Combined Heat and Power Policy Roadmap." The roadmap was developed to provide a long-term perspective for DG and cogeneration policy. The Roadmap includes a 2020 DG and Cogeneration Vision and a Pathway with detailed actions and milestones for implementing policies.

Oral and written comments from the workshop raised the same issues, which have characterized past discussions. Testimony by municipal utilities suggests that they welcome DG resources in their systems, but there is a continuing gulf between the perceptions of the investor-owned utilities and those of DG advocates regarding the risks and value of DG projects to those systems.

Investor-owned utilities continue to show little interest in accepting energy from customer-owned DG projects or in developing utility-owned DG or CHP projects. As a result, these options continue to struggle with major barriers to market entry. As noted in the *2005 IEPR*, many of the state's operating, large-scale CHP systems continue to run under the terms of generation contracts signed during the early 1980s. As these contracts expire, as much as 2,000 MW could shut down by 2010.[254]

On September 20, 2007 in D07-09-040, the CPUC adopted policies and pricing mechanisms applicable to the electric utilities' purchase of energy and capacity from qualifying facilities. Steps remain to implement this decision. In fact, on October 25, 2007, the three investor-owned utilities, Toward Utility Rate Normalization, and the CPUC's Division of Ratepayer Advocates filed an Application for Rehearing of the decision. However, this decision appears to be a major step toward ensuring that these CHP resources continue to serve California's electricity system.

The importance of keeping this DG capacity in the system is elevated by the state's need to reduce greenhouse gas emissions as part of AB 32. CHP in particular offers low greenhouse gas emissions rates for electricity generation taking advantage of fuel that is already being used for other purposes. These systems use waste heat for either process or electricity generation needs which results in very efficient use of fossil fuels. Large CHP units appear to offer the greatest fuel efficiency of available DG technologies. Because CHP systems are located close to the load, transmission and distribution line losses are minimized, further reducing greenhouse gas impacts.

[254] California Energy Commission, *2005 Integrated Energy Policy Report,* CEC-100-2005-007-CMF, p. 77.

As regulations for AB 32 compliance are finalized, the benefits of DG and CHP for the electricity system will become more quantifiable. This will reinforce the need to make DG and CHP projects a higher priority in utility resource mixes for both IOUs and publicly owned utilities.

DG can also play an important role in helping to meet local capacity requirements. The California ISO has encouraged the CPUC to include local capacity requirements in its procurement to replace "reliability must-run" (RMR) capacity that must operate, even if uneconomically, to preserve system reliability. This change lowers the costs of California ISO services and allows more than one year contracts.

Under the RMR contracts, plants had to be larger than one MW to participate. With the local utility now responsible for this reliability hedge, smaller plants, such as DG facilities, may participate, subject to utility and/or CPUC approval, improving local reliability and system efficiency.

The CPUC is beginning to act on the need for contracts that provide DG developers with the certainty needed to undertake projects. In October 2006, the CPUC approved SCE's request for approval of 61 fixed price energy agreements with existing renewable qualifying facilities for a five-year period through April 30, 2012.[255] The CPUC also adopted the PG&E/Independent Energy Producers Settlement Agreement in which 121 power projects entered into either a fixed or variable energy price agreement with PG&E. The power deliveries associated with the settlement agreement "represent over half of generation deliveries from all qualifying facilities currently under contract with PG&E." [256]

In April 2007, the CPUC released a proposed decision that would provide for contract terms as long as 10 years for DG projects that fit as qualifying facilities. Subsequently, the CPUC approved D.07-09-040, setting the stage to remove the major barrier of uncertainty that has helped to stall development of new distributed generation, especially combined heat and power projects.

However, this opening of longer-term, firm capacity contracts is offset by the possible imposition of as-yet-undetermined non-bypassable charges for departing load related to DG and CHP projects. Comments filed during the Energy Commission's DG workshop noted the uncertainty generated by CPUC-proposed, un-quantified departing load charges to be assessed on DG projects.[257] While the option for longer-term contracts

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[255] Ibid, p. 4.

[256] *Opinion on Future Policy and Pricing for Qualifying Facilities*, D.06-07-032, ALJ Halligan, April 24, 2007, p. 4.

[257] Comments Of The Cogeneration Association Of California And The Energy Producers And Users Coalition On The Distributed Generation And Cogeneration Policy Roadmap For California, May 3, 2007.

reduces uncertainty for project developers, this future non-bypassable charge has the opposite effect.

Given the expected growth in electricity demand in each procurement period along with the cyclical nature of the procurement process, it is possible to adjust resource procurement to load changes over time. It is not reasonable to subject one source of load changes to these charges, while ignoring the impacts of other sources of change, such as increased efficiency. This use of non-bypassable charges chills the market for DG and CHP projects, undermining the potential benefits these projects offer both to the environment and California's electricity system.

Recommendations

To address the challenges facing California's distribution system, the Energy Commission recommends the following:

- Develop state policy that articulates and supports modernizing California's distribution system
- Establish a transparent distribution planning process that is integrated with other resource procurement processes assuring that the intelligent electrical and communications infrastructures that will be required to support the integration and use of new low-carbon resources — renewables, demand response, efficient CHP, distributed generation, energy storage, advanced metering infrastructure, and plug-in hybrid electric vehicles — is developed during the same timeframe.
- Establish a Distribution Program, similar to the Energy Commission's Transmission Program, with adequate staff to assess distribution system adequacy and provide leadership in the area of distribution system modernization.
- Fund distribution research through the PIER program to develops and demonstrates technologies that will accelerate the transformation of the distribution grid into an intelligent and sustainable network.
- Develop policies and research to provide open data architecture supporting interoperability from transmission to generation, distribution, and customers and their meters and appliances.
- Develop a new rate design that encourages consumers and utilities to invest in promising technologies and participate in programs that provide value to them and the state (premium power quality, critical-peak and real-time pricing).
- Base a portion of each utility's profit on criteria related to performance, achieving designated goals, service reliability, and customer support and assistance to achieve

greater efficiency of electricity use, rather than basing that profit exclusively on investing in infrastructure.

- Requiring utilities, before undertaking investments in non-advanced grid technologies, to demonstrate that alternative investments in advanced grid technologies have been considered, including from a standpoint of cost-effectiveness.
- Recovering in a timely manner the remaining book-value costs of equipment rendered obsolete by the deployment of a qualified smart grid system, based on the remaining depreciable life of the obsolete equipment.

DG, especially CHP applications provide significant system and efficiency benefits to California's distribution system. The Energy Commission recommends the following:

- The CPUC's self-generation program incentives should be based upon overall efficiency and performance of systems, regardless of fuel type.
- The CPUC should complete a tariff structure to make DG and CHP projects "cost and revenue neutral", while granting owners' credit for system benefits, such as reduced congestion.
- The CPUC and the Energy Commission should work cooperatively to eliminate all non-bypassable charges for DG and CHP, regardless of size or interconnection voltage, and standby reservation charges for DG.
- The CPUC should continue the work of the "Rule 21" industry/utility collaborative working group to refine interconnection standards, provide third party resolution of interconnection issues and streamline permitting
- The CPUC should develop a DG portfolio standard, including CHP regardless of size or interconnection voltage, for electric utility procurement plans. Alternatively, the utilities could be required to treat DG and CHP, regardless of size or interconnection voltage, like efficiency programs.
- The CPUC should adopt revenue-neutral programs that would enable high efficiency CHP to more easily export power to interconnected utilities. These programs should not lead to additional non-bypassable charges and could include:
    - Providing the option for utilities to procure natural gas for combined heat and power plants at customer sites on the same basis they do for central power plants.
    - Counting combined heat and power plant output toward energy efficiency goals for utilities.
    - Providing a portfolio standard with steadily increasing requirements for combined heat and power plant generation.
- The CPUC and the Energy Commission should continue to work collaboratively to develop a methodology to estimate DG costs and benefits.
- The state should adopt greenhouse gas measures and regulations that fully reflect the benefits of CHP with separate production of thermal and electric energy.

CHAPTER 6: Meeting Natural Gas Needs

> ***"A nation behaves well if it treats the natural resources as assets which it must turn over to the next generation increased, and not impaired, in value."***
>
> Theodore Roosevelt

Almost 30 years ago, California's serious air quality problems placed natural gas as the fuel of choice for electricity generation. In the late 1970s for air quality and cost benefits, California moved away from petroleum, nuclear and out-of-state coal to natural gas for generating electricity. Natural gas was cleaner burning, relatively cheap and helped diversify our electricity generation system. Now, with global warming recognized as a serious world environmental concern, the rest of the United States, Canada and Mexico are following California's lead with a similar shift from an oil and coal-based electricity system.

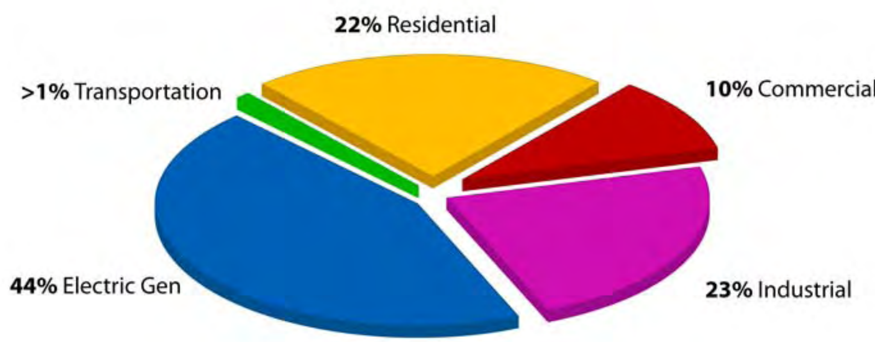
Today, California faces a new challenge. Burning natural gas contributes to greenhouse gas emissions and state law mandates that California's greenhouse gas emissions be reduced to 1990 levels by 2020. This reduction must be balanced with the understanding that natural gas is the fossil fuel of choice and will likely play an even more important role in California's energy future, despite policymakers' emphasis on efficiency and renewables. As discussed in the description of the scenario analysis in Chapter 2, increased natural gas fired generation in the California is a possible outcome of displacing coal generation in other western states. The magnitude of any such increase will depend on the cost attributed to CO_2 amount of efficiency and renewables across the Western Electric Coordinating Council (WECC).

Natural gas is critical to California's energy system, providing more than a third of the state's total energy requirements. Over 44 percent of the natural gas consumed in California is used to generate electricity. Natural gas is the primary and most efficient fuel for residential cooking, space and water heating and industrial processes (Figure 6-1).

In 2006, over 85 percent of our natural gas supplies are from sources outside of the state. This dependency poses an ongoing challenge in securing adequate and reliable supplies of natural gas at reasonable prices. This occurs, in part, because natural gas well productivity in the United States is declining and California is literally at the end of the interstate pipeline system, competing with a growing North American demand.

Natural gas demand in the power generation sector for the United States is projected to increase by 5.5 percent per year, putting pressure on California's ability to obtain stable supplies without paying more. Most of this projected growth is occurring in the states east of the Mississippi as they shift more from coal-based electricity generation to cleaner natural gas-fired generation to help reduce criteria pollutant emissions.

Figure 6-1: California Natural Gas Use in 2006



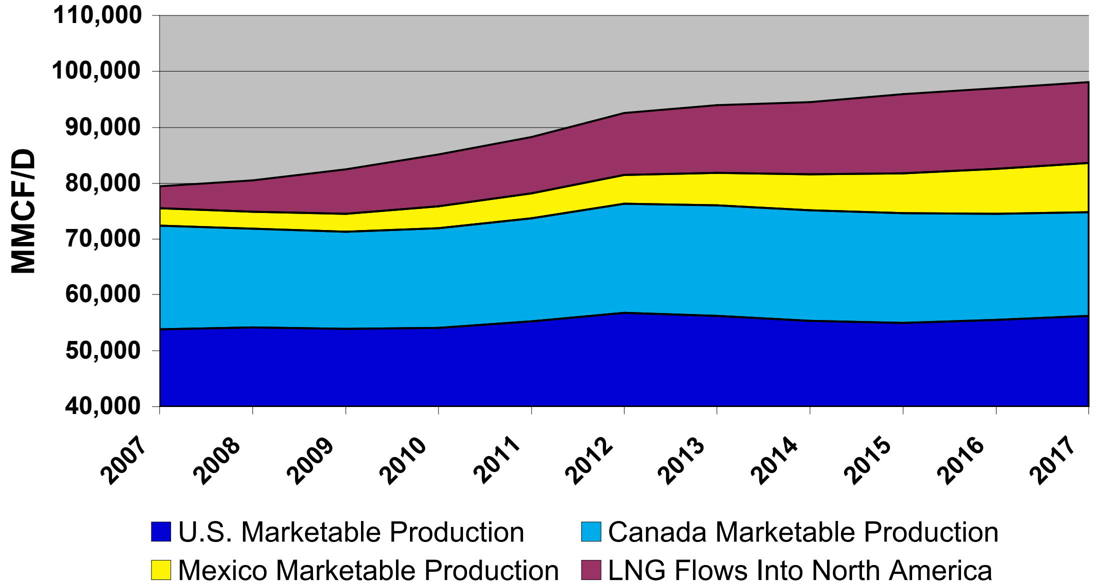
Source: Utility and pipeline filings to the California Energy Commission

Over the past several years, instate and interstate natural gas pipelines and storage facilities have been improved, strengthening the state's ability to bring in, store and distribute more supplies to reduce price volatility and meet demand. However, because California imports large volumes of natural gas by pipeline, we are vulnerable to weather related events throughout the United States that can either disrupt production, as in the case of hurricanes, or increase demand with cold temperatures. In either case supplies can be constrained, causing prices to spike. Cold winters in the East can drive up natural gas prices for California and hurricanes in the Gulf region can wreak havoc on natural gas production and distribution.

New natural gas supplies in the continental United States are increasingly difficult to find and produce. Despite more drilling activity, declining well productivity, shorter production life, smaller fields and more drilling regulations have all combined to keep North American production relatively flat and increase prices.

The decline in well productivity creates a widening gap between United States demand and domestic supplies. Additionally, the United States can rely less on pipeline imports from Canada as that country's domestic natural gas demand increases and field production declines. To fill this gap the Energy Information Administration (EIA) projects significant imports of natural gas from worldwide sources to increase over the next 20 years, shipped as liquefied natural gas (LNG) by tanker, not pipeline, requiring additional infrastructure. By 2017, 15 percent of North American natural gas supplies could be LNG (Figure 6-2).

Figure 6-2: Origins of Natural Gas Supply for North American



Source: California Energy Commission

The state's energy efficiency programs and the use of renewable energy for electricity generation have helped keep California's growing natural gas demand in check even though our population continues to climb by a half million people each year.

California's overall natural gas demand is projected to grow at less than one percent per year, mostly for electricity generation. Lacking similar national efficiency and renewable standards, the comparable United States annual 2.1 percent growth rate for natural gas to generate electricity is higher than California's.

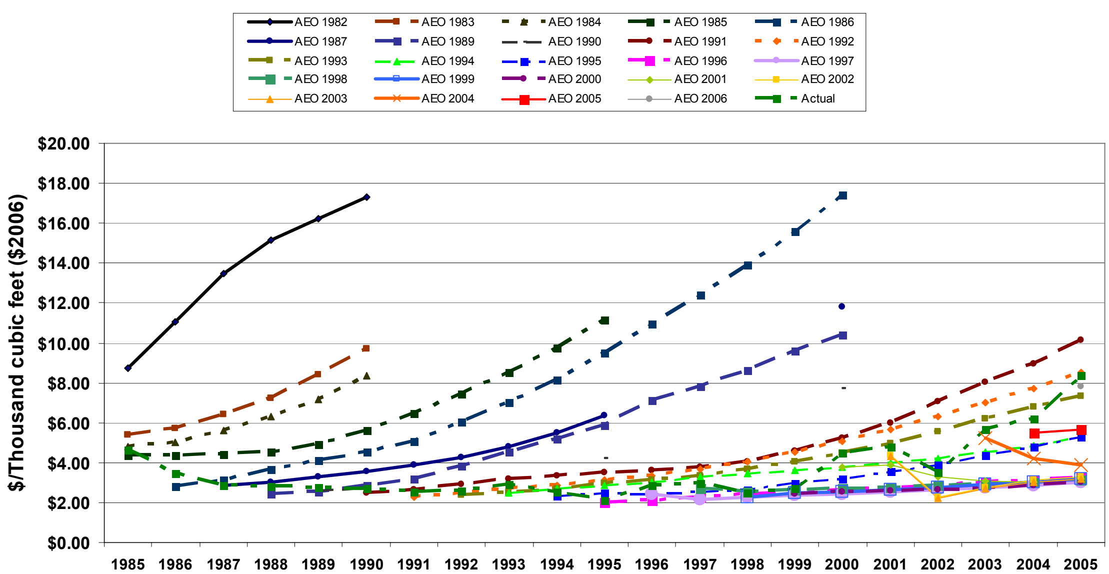
While California's average wholesale natural gas price is lower than in some regions of the United States, it has increased appreciably from $3.82 (2006 dollars) per thousand cubic feet in 2002 to $6.68 per million cubic feet in 2006. California consumers spent $18.8 billion for natural gas in 2006, double what they spent in 2002. As demand throughout North America grows, natural gas prices are likely to continue the upward trend. The impact on the economy is compounded because higher natural gas prices also lead to higher electricity prices.

Even with the uncertainties of domestic supplies and prices, California most likely will continue to build new natural gas power plants for years to come. Since 1998, the Energy Commission has approved over 23,000 megawatts of natural gas-fired facilities with about 13,000 megawatts of that amount constructed and on-line, and an additional 7,500 megawatts of gas-fired power currently in the review process. Newer natural gas power plants are more efficient than the existing aging natural gas power plants, using less natural gas for more electricity output. They also can ramp up and down more quickly to provide electricity to meet peak demand and system regulation requirements. Natural gas power plants are also the best complement to renewable resources since they have the ability to come on line quickly when wind or solar resources lose output due to lack of wind or sunshine. Despite numerous energy efficiency programs in California, electricity demand is expected to grow due to population increases in the hotter, inland areas that have high air conditioning loads. Natural gas power plants have proven to be reliable providers of electricity for California. They are also superior options to nuclear and coal-fired plants until those technologies resolve their environmental problems of waste disposal and carbon sequestration. As discussed in Chapters 2 and 5, however, the high price volatility for natural gas and the ability of electric utilities to be financially insensitive to fuel cost pass-through, has made California's increasing reliance on gas-fired electric generation problematic from a ratepayer perspective.

A Model Shift in Analysis

Mark Twain was correct when he said, "Prophesy is a good line of business, but it is full of risk." Attempting to forecast California's future natural gas demand, supplies and prices is laden with uncertainties. Clearly, the natural gas price forecasts developed by Energy Information Administration have been wildly inaccurate (Figure 6-3). There is no magic measuring stick that shows exactly what volume of natural gas reserves exist in North America or what the cost of these supplies will be. And two of the biggest unknowns are how many LNG facilities will be built in the United States and whether the United States will compete with developing economies in Asia for those remote supplies of natural gas.

Figure 6-3: Natural Gas Price Forecasts by Year Issued



Source: U. S. Department of Energy, Energy Information Administration, *Annual Energy Outlook Retrospective*, March 2007. DOE/EIA-0640(2006).

The scenario analysis work performed for the *2007 Integrated Energy Policy Report* was designed to expand the pinpoint analysis done in past years to address broader energy policy dynamics. This modeling approach addressed those measures that would meet carbon reduction goals.

What happens to natural gas demand if new environmental policies drive the United States, Canada and Mexico to switch from coal and oil for some or most of their electricity generation to reduce greenhouse gas emissions? How will these policies impact available natural gas supplies and prices?

How can we determine increasing natural gas use, if California decides that electricity is the "clean" fuel strategy of choice and replaces stationary diesel motors with electricity? Will plug-in hybrid vehicles grab the lion's share of the vehicle market? That would reduce gasoline consumption, but increase electricity demand, and subsequently increase natural gas demand to an unknown extent. Does following the European model by encouraging the use of compressed natural gas vehicles make sense?

Or can tankless water heaters be the solution to the continuous high temperature storage feature of current natural gas water heaters? What role will solar water heating, or space heating, play in the future?

These questions challenge the traditional forecasting methodology because they do not allow us to quantify the uncertainties and risks the state is facing with new energy policies. AB 32 shifts how California considers its natural gas future and challenges how we look at the consequences of our energy choices. Cutting greenhouse gas emissions means that the business as usual mode of using natural gas less efficiently for electricity generation and industrial processes will no longer meet our environmental goals. These necessary and difficult choices require new tools that help design a California future that uses natural gas in its most efficient way such as eliminating wasteful electricity generation from aging power plants and encourages uses that meet the state's environmental goals.

Rethinking Forecasting Methods

The California Energy Commission's Scenario Analyses Project took the first step in moving towards exploring a carbon-constrained future by expanding how we consider our energy choices from a policy-driven perspective and which combination of resources will help reduce greenhouse gases. The Scenario Analyses Project examined the implications of using various amounts of energy efficiency, rooftop solar photovoltaic (PV), and renewable electricity generating technologies to determine how these strategies would affect greenhouse gas emissions from the electricity sector. One of the variables evaluated in this assessment was the amount of natural gas used in electric power generation in each scenario. Staff studied these implications in a number of conventional and non-conventional scenario futures.

Scenario 1B, which reflects current efficiency and renewable policies, produced a California natural gas demand for power generation similar to the staff's most recent natural gas forecast. Natural gas demand would rise slowly as natural gas becomes a larger share of electricity generation. Although this scenario is the closest to meeting current efficiency goals and RPS requirements, it does not notably reduce greenhouse gases.

The scenarios that combined high amounts of energy efficiency and renewables, in contrast, indicated slow declines in natural gas use for electricity generation. This scenario concluded that employing very high levels of energy efficiency and renewables could substantially reduce 2020-projected natural gas used for power generation in California and drive down greenhouse gas emissions extensively below 1990 levels. More importantly, if the rest of the West pursued these preferred resources as aggressively as California, then natural gas demand for power generation could fall 51 percent from what it would otherwise be in 2020. This aggressive scenario future relies heavily on energy efficiency and renewables; and natural gas plants only where needed for reliability.

Rather than asking which of these views of the future is most likely, California and western states decision-makers should ask, which one is preferable? California has already embarked on a process to answer that question. Five other western states and two Canadian provinces have signed a Memorandum of Understanding to pursue a major decrease in greenhouse emissions. These policy debates, and their implications for substantial change compared to current energy use patterns will dominate analyses of demand for and supply of natural gas for several years to come.

Even with AB 32 requiring significant reductions in greenhouse gases, natural gas use will remain a major fuel in California's supply portfolio over the next several decades, and if California adopts electricity as the "fuel of choice strategy" for all sectors including transportation, natural gas use will likely increase until displaced by renewables, coal with carbon sequestration, or nuclear generation.

Natural Gas Supplies and Dependence on Imports

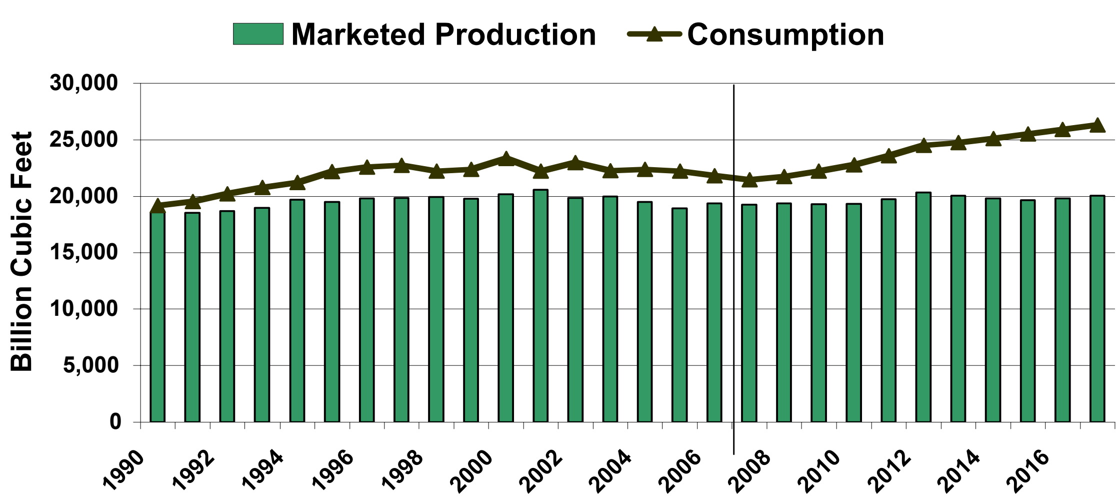
Starting in the late 1970s California altered the state's electricity generation system by switching to a cleaner burning fuel – natural gas. Driven by deteriorating air quality and an oil embargo, the state's utilities invested in cleaner burning natural gas. With only about 15 percent of California's supplies coming from in-state production, billions of cubic feet each year were imported to a hungry California electric generation market from the Southwest, Rocky Mountains and Canada. Suppliers were eager to get paid for gas that had no other market. Competition from other states was minimal and California effectively cornered the market for gas as a generation fuel and cornered it rather cheaply. Unfortunately, that's not the case today. The state no longer has a lock on natural gas supplies and California must compete with the rest of North America as demand increases and supplies become tighter. As natural gas has become the fuel of choice for electricity generators to reduce criteria air pollutants, competition for natural gas has intensified with concerns about greenhouse gas emissions across the United States.

California's natural gas supplies are tied to North American production with about 1.7 trillion cubic feet per year of natural gas imported to meet the state's demand. Because in-state production peaked several years ago and is slowly declining, and in-state natural gas demand continues to grow slowly but steadily, natural gas imports will have to increase to keep up.

Gas producers across the United States and Canadian are struggling to keep pace with growing demand. Although large volumes of natural gas have been discovered worldwide and production is increasing, United States production has been relatively flat since 1990 and most conventional domestic and Canadian natural gas production from mature basins is declining.

United States production is expected to remain around 53 billion cubic feet per day (20 trillion cubic feet annually) over the next decade (Figure 6-4). Growth in natural gas production from the Western Canadian Sedimentary Basin, the largest natural gas producing region in North America, has slowed considerably over the last five years and is expected to slightly increase from about current levels of about 18 billion cubic feet per day to only about 19 billion cubic feet per day by 2012, remaining flat afterwards. Supplies in North America are not able to meet growing demand despite high prices and higher levels of drilling.

Figure 6-4: United States Production and Consumption 1990-2017

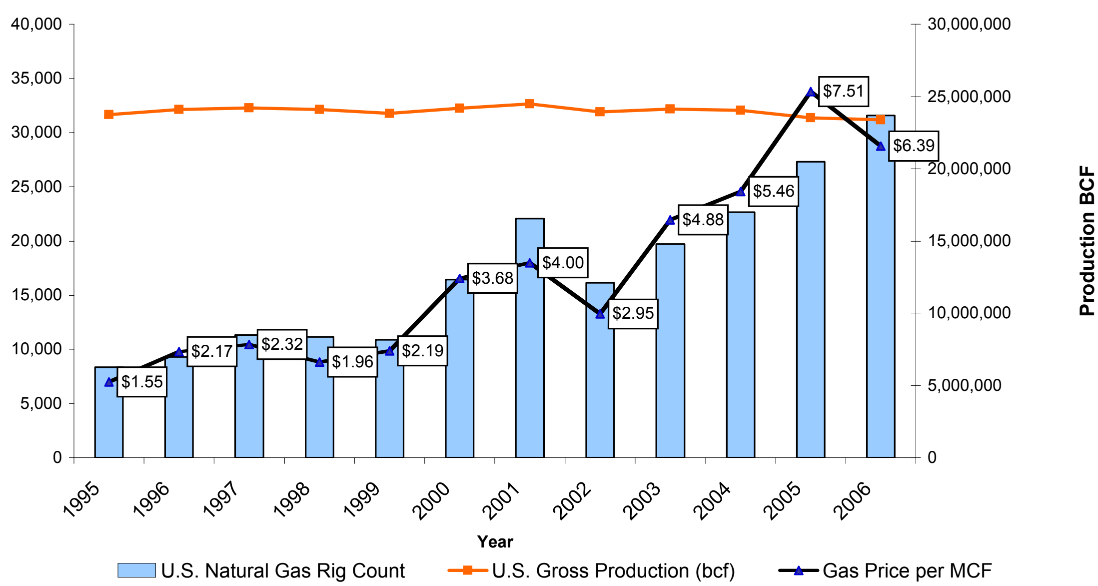


Source: Energy Information Administration

Since 1995, the number of natural gas wells completed in the United States has almost tripled from 8,400 to 31,000 wells in 2006. Had production per new well remained constant, this would have resulted in huge volumes of natural gas produced. Instead, despite intensive drilling, production increased only modestly and the easier-to-produce, less expensive supplies are dwindling. Nine years ago it took 15,427 wells to produce the same amount of gas that today requires 27,414 wells to produce.

Although higher natural gas prices have spurred more drilling, production has not increased and drilling costs are higher (Figure 6-5). If declines in productivity per new average well continue at the four percent per year rate experienced from 2000 to 2006, then 60,000 more new wells would have to be drilled in 2017 to satisfy demand in that year – a number that is not economically or physically likely.

Figure 6-5: United States Natural Gas Production, Price and Wells Drilled



Source: California Energy Commission

Newly found fields are usually smaller and more costly to develop and, over time, more effort is required to produce the same amount of gas. Advances in drilling technology allow producers to increase a well's first-year performance; but by extracting the gas more quickly, the well's annual production declines more rapidly in the following years. Also, as developers move to increased reliance on unconventional gas fields, the productivity per well continues to fall even as costs and prices continue rising.

Producers are on a treadmill of drilling just to keep pace with current demand and they will soon reach a point where they will no longer be able to maintain this level of output without extraordinary price increases or technological advances.

Although earlier forecasts projected rising gas production, the reality of falling production per well means that even by drilling more wells, we can achieve only slight increases in production over the next several years. And despite earlier optimism, natural gas resources previously slated for delivery from Artic Canada (Mackenzie Delta) and Alaska's North Slope into the North American gas market are not likely to be available until at least 2020.

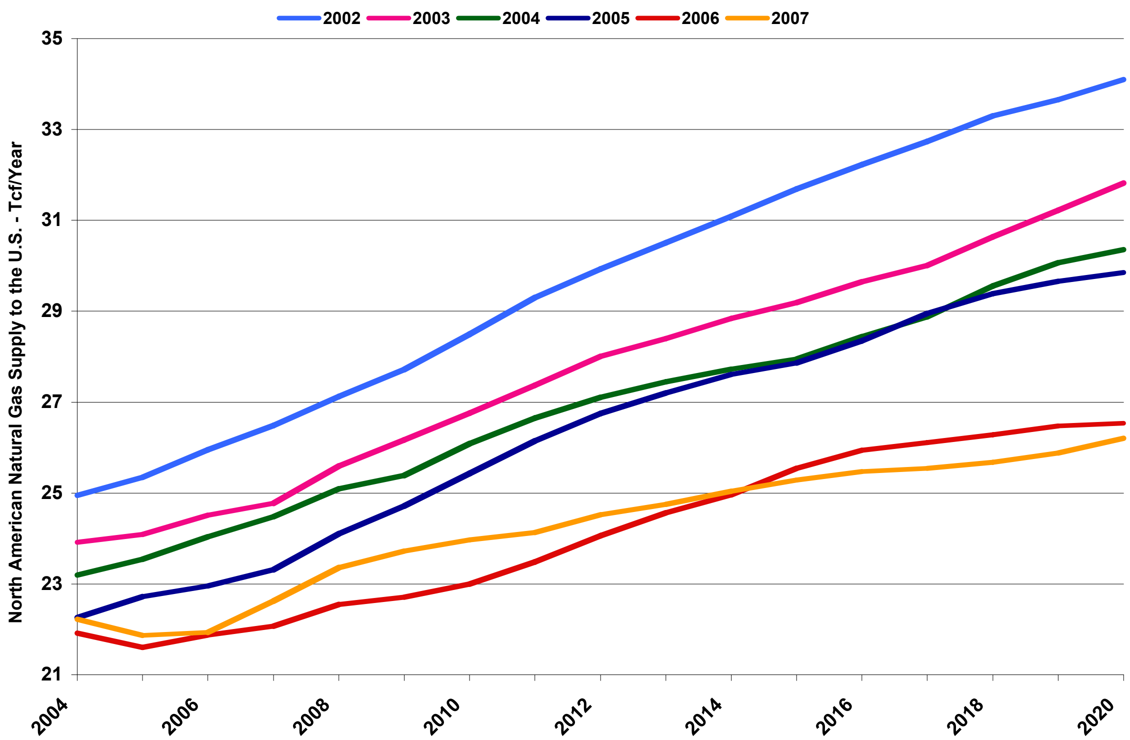
Supply Uncertainty

The Energy Information Administration publishes an annual projection of natural gas production for North America (Figure 6-6). The annual forecast of North American natural gas production has decreased each year since 2002, a difference of about eight trillion cubic feet a year. These forecasts have been unreliable and reflect a change in trends that the models were unable to capture. The modelers expected natural gas prices to stay cheap and abundant at $2 per thousand cubic feet but conventional resources went into decline and North America had to turn to more costly unconventional supplies.

Over time the forecasts finally started incorporating the industry's inability to produce additional North American natural gas, despite ever increasing drilling. Given the challenges in producing North American natural gas, we expect more downward adjustments in future forecasts. PG&E has publicly commented that they believe that western Canadian natural gas production will be less than predicted while Sempra/SoCalGas believes that several supply basins will produce less than forecasted.

The natural gas industry continues looking for more supplies – supplies that are more difficult and more expensive to produce. Production from newer supply basins in the Rocky Mountains, east Texas and in the Gulf of Mexico deep water has helped to slow this decline. Supplies from some of these areas; however, are produced from unconventional resources such as coal bed methane, tight sands gas, shale gas, or in very deep water, all of which cost more to develop and raise the relative costs of natural gas across North America. Based on the number of applications to construct liquefied LNG terminals in North America, some in the natural gas industry believe that it is more profitable to develop stranded natural gas supplies in remote corners of the world and ship it as LNG.

Figure 6-6: Dept of Energy EIA Natural Gas Supply Forecasts in North America (2004 – 2020)



Source: Energy Information Administration

Alternative Natural Gas Sources

LNG – A Controversial Supply

Being at the end of a long pipeline network with little in-state production, California must have access to a variety of stable sources. LNG is one potential supply of natural gas.[258]

LNG is already a natural gas supply source for North American users and is currently imported into the United States through five receiving and re-gasification terminals. None of these terminals is on the west coast, although Sempra's Costa Azul facility in Baja California will provide some United States supplies when it comes on-line in 2008.

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[258] LNG is natural gas that has been chilled, reducing it to a liquid form, condensing its volume by 600 percent. This significant reduction in bulk allows natural gas to be shipped worldwide by tankers before the liquid gas is re-vaporized back into its gaseous state.

Bringing natural gas into California as LNG will require infrastructure improvements including a re-gasification terminal.

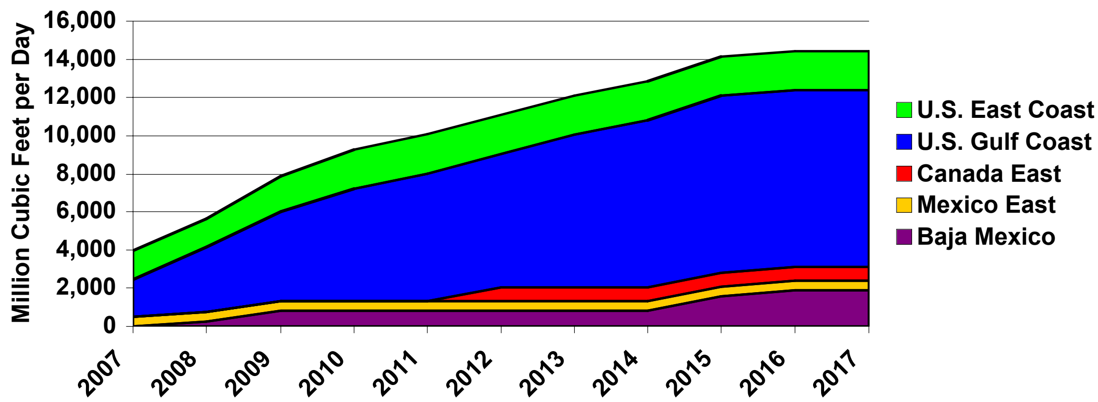
Imports of LNG to the United States are expected to increase almost 13 percent annually by 2017 to 11.3 billion cubic feet per day or about 20 percent of United States supplies, according to Energy Commission staff. Staff included only facilities that fall into the following three categories: currently operating (with any scheduled expansion), currently under construction, and currently permitted (high probability of construction).

Although much of these supplies will be shipped into the United States Gulf Coast region, they will help meet California's additional natural gas needs by increasing overall domestic supplies (Figure 6-7).

In its *2003 and 2005 Integrated Energy Policy Reports*, the Energy Commission found the construction of LNG import facilities important to natural gas supplies and infrastructure in North America. These facilities will increase natural gas supplies available to the United States over the next 10 years and help meet California's additional natural gas needs. The *2003 and 2005 Energy Reports* also highlighted the need to develop these facilities and their associated infrastructure to better serve the natural gas needs of California and the western United States. In 2007, that conclusion remains in escapable.

Twelve applications to build LNG re-gasification facilities are in various stages of review on the West Coast including four in California, four in Oregon, three in British Colombia and one in Mexico. California has already engaged in the LNG debate by participating in direct discussions with the Federal Energy Regulatory Commission, which manages the environmental review process for on-shore LNG facilities, and the Coast Guard, which is responsible for the offshore review. In addition, the Energy Commission coordinates the activities of the LNG Interagency Working Group, composed of the federal, state and local agencies responsible for overseeing the licensing of LNG facilities in California. It is the mission of the Energy Commission, and the LNG Working group, to help ensure that any LNG development is consistent with the state's interest in balancing environmental protection, public safety and local community concerns to ensure protection of the state's population and coastal environment.

Figure 6-7: LNG Imports into North America



Source: California Energy Commission

Currently, staff analysis anticipates receiving about 500 million cubic feet a day of natural gas from the almost completed Costa Azul facility on Mexico's west coast starting early in 2008. The Costa Azul facility is projected to import an average of roughly 800 million cubic feet per day when it reaches commercial operation. About 300 million cubic feet per day will serve electric power plants in Mexico and up to 400 million cubic feet per day will flow to San Diego through the SDG&E lines. The rest will flow through the North Baja line to Blythe and then north into California. Almost all the Mexican natural gas entering California will displace domestic Southwest supplies that currently come to California.

Currently, the North Baja pipeline provides natural gas to Baja. The California State Lands Commission recently approved the necessary permits for the pipeline to cross the Colorado River, which could allow the reverse the flow of the North Baja pipeline to import supplies to southern California from Costa Azul.

However, if the Costa Azul facility expands from 800 million cubic feet per day to double that amount, for California to access more natural gas from Mexico, additional or modified pipeline infrastructure will be required. If the expansion takes place, as much as an additional 1 billion cubic feet per day could enter southern California through the North Baja pipeline. There is no guarantee, however, that Costa Azul will expand. Another LNG facility may be built on the west coast instead. Market conditions and environmental review of the proposed sites will determine the outcome.

While there is no assurance that west coast LNG projects will lower natural gas prices to California, staff's modeling shows that LNG delivered to the United States is cheaper, on a cost basis, than the high-cost elements of newer North American production and would tend to keep prices lower than they would be if no LNG came to North America. Additional supplies, no matter where they come from, are expected to help stabilize California's supplies and prices.

Biogas

Diversifying the state's natural gas supply sources is important especially if it increases in-state biogas production facilities. California has a large amount of biomass resources that are suitable as feedstock for gasification technologies.[259] Natural gas produced from landfills in the state is growing and agricultural waste can be converted to synthetic natural gas. Greater use of combined heat and power systems fueled by biomass could also reduce demand for natural gas in process and industrial heat and cooling operations, helping to increase overall energy efficiency and reduce carbon impacts of the state. By 2050, nearly 100 billion cubic feet of biomethane per year could contribute to the state natural gas supplies.

Promoting Biogas

The Energy Commission believes that California should promote the use of pipeline-quality biogas from dairies and landfills. Pipeline-quality biogas injected into California's natural gas pipeline system should be compensated for through a feed-in tariff mechanism paid by the gas utilities. The Energy Commission and Public Utilities Commission should work together to establish an appropriate price per therm to be paid for pipeline-quality biogas along the lines of the market price referent used in the RPS program.

The Energy Commission has invested almost $94 million over the last five years in renewable facilities and agriculture biomass projects to help overcome some of the economic barriers and environmental impacts.

Natural Gas Infrastructure – A Vital Resource

The natural gas infrastructure system is critical to California's ability to provide a stable and reliable supply of gas since only 15 percent of our natural gas supplies are produced in state. Just as California looks for adequate supplies of natural gas, it must also ensure that its infrastructure can move and store supplies.

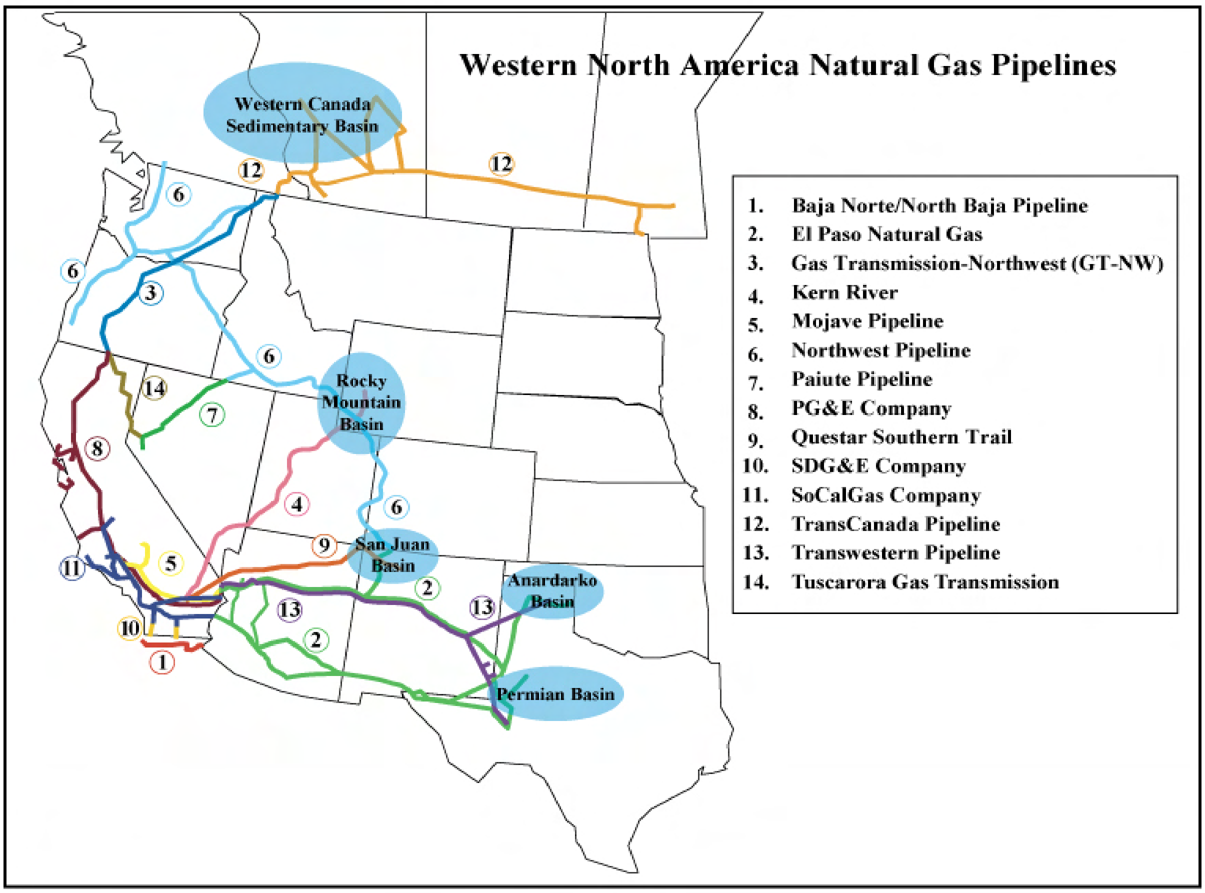
An extensive pipeline network, linking the state to several supply basins in North America, can satisfy California's average demand of over two trillion cubic feet of natural gas annually. (Figure 6-8) Since the 2001 electricity crisis, delivery capacity to California has expanded about 18 percent by 2006, climbing to about 9.2 billion cubic feet per day and ensuring that we will have adequate capacity for the next decade. The demands of residential, commercial, industrial and power generation customers sometimes display wide variation from month to month, even day to day. As has happened in the past, sustained cold winter days makes it difficult to satisfy all demand requirements by pipeline capacity. In these cases the state's storage facilities supply additional natural gas. As noted earlier, there will be two pipelines bringing natural gas from an LNG facility in Costa Azul, Baja Mexico into southern California.

If the Costa Azul LNG facility and the North Baja pipeline are expanded to import more natural gas into California, a surplus will occur at the southern California border. Competition between additional supplies from Wyoming delivered by the Kern River

259 *Bioenergy Action Plan for California,* The Bioenergy Interagency Working Group, July 13, 2006.

pipeline system and from the Southwest delivered by the Transwestern and El Paso pipeline systems will cause the price of natural gas at the Southern California border to drop below the price of natural gas in Northern California. If the price of this natural gas is 20 cents to 50 cents below the northern California gas price then most likely one of three options will occur. Since the existing south to north pipeline – Line 300 – is owned by PG&E and would be full, PG&E could expand the line; however, this option would take several years. Options 2 and 3 include either expanding the Kern Mojave and Mojave pipelines to allow additional natural gas supplies to move north, or power plant developers wanting access to the less costly gas will try to locate their power plants in the southern region.

Figure 6-8: Western North American Pipelines and Supply Basins



Source: California Energy Commission

Even though staff assumes Costa Azul will expand, PG&E suggested that other supply options could develop to the north of California, most likely brought to North America as LNG. According to PG&E, "California and in particular Northern California, see significant benefits in terms of price, extended use of installed capacity, and far lessened pressure to expand PG&E's Baja path."[260]

There are also concerns that when Sempra's Rocky Mountain Express Pipeline goes into operation in 2009, natural gas supplies currently transported to California could be shifted to the East. The original staff assessment estimated 1.5 billion cubic feet per day of natural gas capacity; however, this potential has increased as the Rocky Mountain Express Pipeline sponsor has reportedly received commitments from shippers for 1.8 billion cubic feet per day of capacity. A more detailed analysis of the Rocky Mountain Pipeline expansion will be provided in the *2009 Integrated Energy Policy Report* cycle.

California's natural gas storage has been instrumental to help guard against interruptions or severe weather changes, ensuring adequate supplies and making some contributions to more stable prices. Over the last several years, the state has added storage bringing total capacity to about 256 billion cubic feet. These storage facilities allow sustained additional gas withdrawals of about 4.9 billion cubic feet per day during peak demand periods.

Natural Gas Demand

Natural gas is critical in meeting the state's energy demand. California's growing population requires more natural gas for residential heating and cooking, industrial processing and - the big driver - electricity generation. Electric motors, natural gas-fueled vehicles and other technologies such as plug-in hybrids in transportation may also play a larger role in future demand.

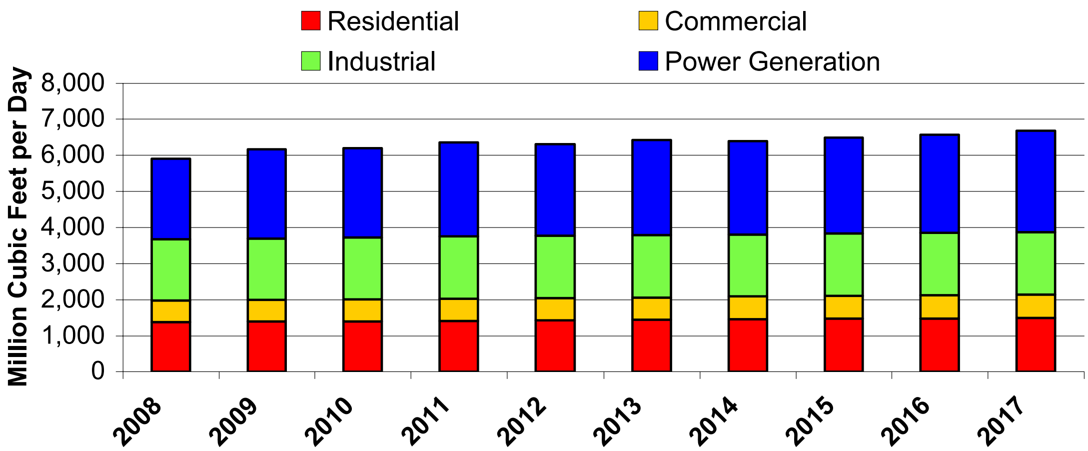
In fact, natural gas, like petroleum, has become a global commodity and California competes not just with the Mid-West and East Coast for access to less abundant natural gas supplies, but also with Western Europe and Asia Pacific consumers in a world market for natural gas, and at prices that are likely to continue increasing.

California Depends on Natural Gas

California's demand growth for natural gas in residential, industrial and commercial sectors has remained slow, with each sector expected to grow less than one percent each year in the next decade (Figure 6-9).

[260] Pacific Gas & Electric Company letter commenting on the August 16, 2007 IEPR Workshop.

Figure 6-9: Projected California Demand by Sector 2008-2017



Source: California Energy Commission

Peak electricity demand is expected to grow at about 1.35 percent each year through 2017 and will be the sector with the largest natural gas increase over the next decade. Before 1997, natural gas consumption for electricity averaged 500 billion cubic feet each year (1,400 million cubic feet per day); however, future demand is anticipated to average 2,500 million cubic feet each day. This forecasted increase in natural gas consumption does not take into consideration any impacts implementing the State Alternative Fuels Plan (AB 1007) would have on the transportation sector. If natural gas consumption occurs at the rate that the State Alternative Fuels Plan suggests, then natural gas consumption for transportation could increase from 37.2 million cubic feet per day in 2006 to as much in 2017 as 87.5 million cubic feet per day (conservative case), 154.2 million cubic feet per day (moderate case), or 239.1 million cubic feet per day (aggressive case). These increases could occur if all barriers to natural gas as a transportation fuels are overcome and no competition from other alternative fuels develop.

California no longer has the luxury to view natural gas from a "California demand only" perspective but must examine how the demands from our competitors are changing – the western states, Canada as well as the eastern United States.

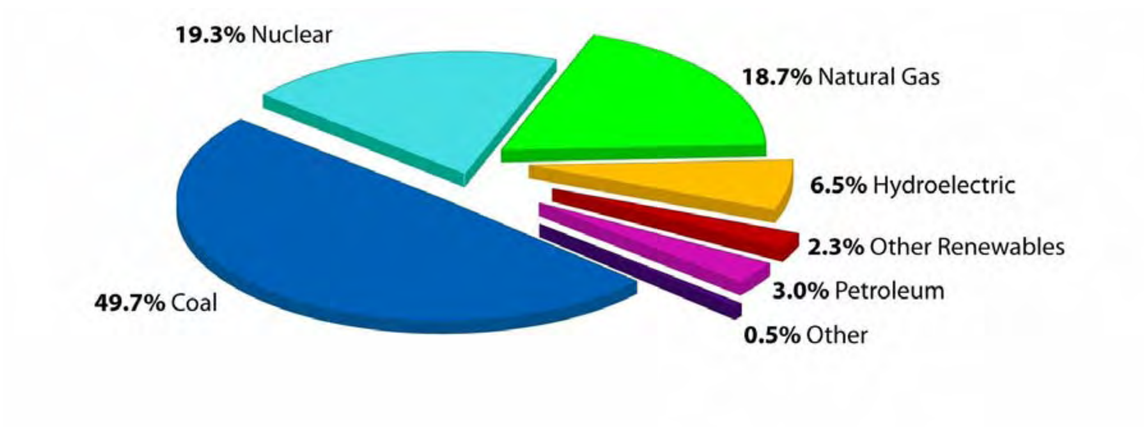
Currently, the United States, Canada and Mexico consume about 74.5 billion cubic feet of natural gas each day. This demand is expected to increase 2.3 percent each year, reaching over 89 billion cubic feet per day by 2017. Although the United States is the dominant consumer of natural gas, at 83 percent of total demand, it could experience the slowest growth rate of 2.1 percent each year over the next 10 years when compared to Canada and Mexico's combined demand growth at 3.1 percent each year.

Electricity Generation - the Driver Behind Robust Demand

Today coal makes up almost 50 percent of the United State electricity generation (Figure 6-10). As more states follow California's lead and substitute natural gas in the electricity generation sector to cut criteria pollutant and greenhouse gas emissions, this demand growth for natural gas will continue. Electric power generation in North America is projected to be the fastest growing end use for natural gas at 5.7 percent each year. By 2017, daily natural gas consumption for electricity generation will almost double from the current 17 billion cubic feet daily to 30 billion cubic feet each day.

If the eastern United States and Canada adopt more aggressive strategies to reduce greenhouse gas, demand may rise even faster as their coal plants are replaced with cleaner burning natural gas fired ones. More than 100,000 megawatts of merchant owned natural gas-fired generation facilities were constructed throughout North America over the last 10 years (Figure 6-11). Currently these facilities are using less than their full generating potential, increasing the possible likelihood for quick, large jumps in natural gas demand if a shift from coal and oil occurs. From 1998 to today, when North America constructed the majority of natural gas fired generating capacity, California added almost 13,000 megawatts of gas-fired generating capacity.

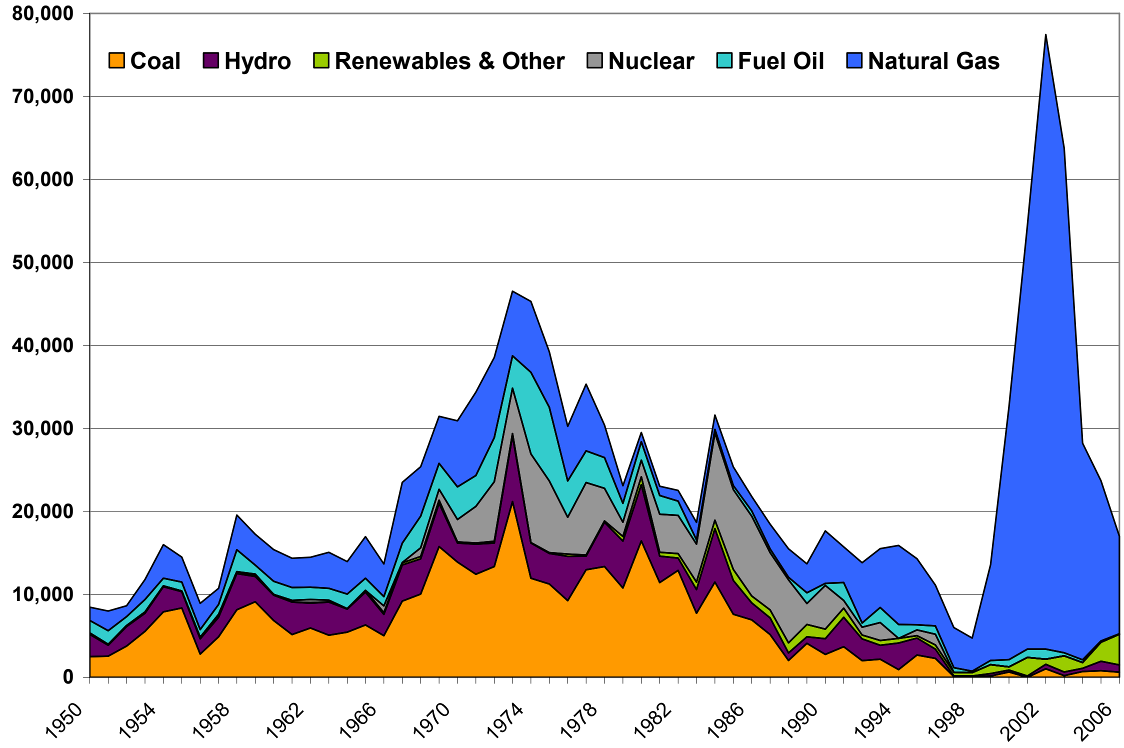
Figure 6-10. United States Electricity Production by Resource for 2005



Source: U.S. Energy Information Administration, Form EIA-880, “Annual Electric Generator Report.”

Even with this extra electricity generation potential there is still not enough capacity to meet growing demand in North America. The rest of the United States must begin choosing from a mix of coal, natural gas and renewable resources. Facing the anticipation of more stringent environmental regulations, more utilities coast to coast are abandoning their plans for coal plants because conventional coal plants are too dirty and the cost of cleaner facilities too high. Decisions made 25 years ago by the rest of the country about the fuel for their electricity generation system did not affect California. Today, these decisions do. And California has helped push those choices towards natural gas, with SB 1368 which prohibits California utilities from renewing or entering into new long-term contracts with out-of-state generators that are not providing electricity from plants as clean as natural gas-fired power plants. Given the national supply constraints, the more natural gas other states use, the less is available for California and the more prices could increase.

Figure 6-11: North American Electricity Capacity Additions Since 1950 in Megawatts



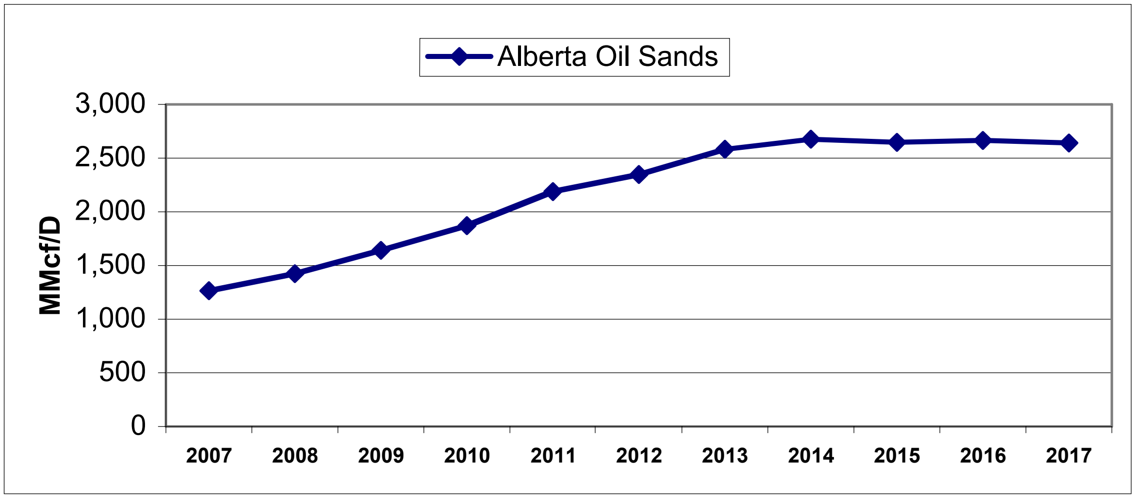
Source: 2007 Energy Information Administration Data.

Although demand throughout the world impacts California, there is a more immediate impact from natural gas demand in the western United States and western Canada. Expected natural gas demand in the western states and Canadian provinces has a direct influence on gas prices and the ability for California to secure its necessary supplies. By 2017, the western United States and western Canada will be consuming over 1.6 billion cubic feet more of natural gas each day to meet the growing needs of residential, commercial, industrial and electricity users. Most of this new demand will be to generate electricity.

Alberta Oil Sands Production Uses More Natural Gas

Western Canada accounts for roughly 98 percent of Canada's gas supplies. Production for the Western Canadian basin is expected to decline slightly over the next decade so any increase in demand for natural gas in Canada reduces available gas exports to the United States, which has a direct impact on California's supplies and prices.

Figure 6-12: Alberta Oil Sand Production Increases Natural Gas Demand



Source: California Energy Commission, 2006 Natural Gas Staff Assessment

Currently, Alberta oil sands are consuming approximately six percent of the natural gas produced in western Canada. Producing oil from these sands is costly and requires large quantities of natural gas; however, even in the $35 per barrel range, it is profitable to extract. With current oil prices hitting $90 per barrel, every effort is being made to produce as much as possible. More oil production means more natural gas from the western Canadian sedimentary basin consumed locally and less available for exporting. By 2017, the oil sands are projected to consume approximately 2.6 billion cubic feet per day or about 15 percent of the forecasted gas production in the basin. (Figure 6-12)

The Ontario region of eastern Canada is anticipating increased natural gas demand as coal-fired generation is curtailed to meet recent greenhouse gas reduction requirements.

This increase in natural gas demand in western and eastern Canada impacts the amounts of natural gas Canada will have available to export to the United States. The United States will have to either seek additional LNG imports or prices will have to increase enough to encourage more unconventional North American production.

Demand Impacts Natural Gas Prices

Natural gas prices ebb and flow with demand and supply - and demand for natural gas is increasing faster than supply throughout North America. Even though the record-breaking prices of $14 to $16 per thousand cubic feet caused by Hurricanes Katrina and Rita in 2005 have declined, wholesale prices are still much higher than five years ago. Natural gas prices that were expected to go back to pre-hurricane and pre-energy crisis levels have stayed high. Declining rates of finding new North American natural gas supplies, uncertainty over LNG imports, proposed carbon controls to reduce greenhouse gas emissions and a growing population have combined to push national prices higher.

Natural gas is not immune to wide price swings but it seems unlikely prices will return to the 1990s era of cheap natural gas.

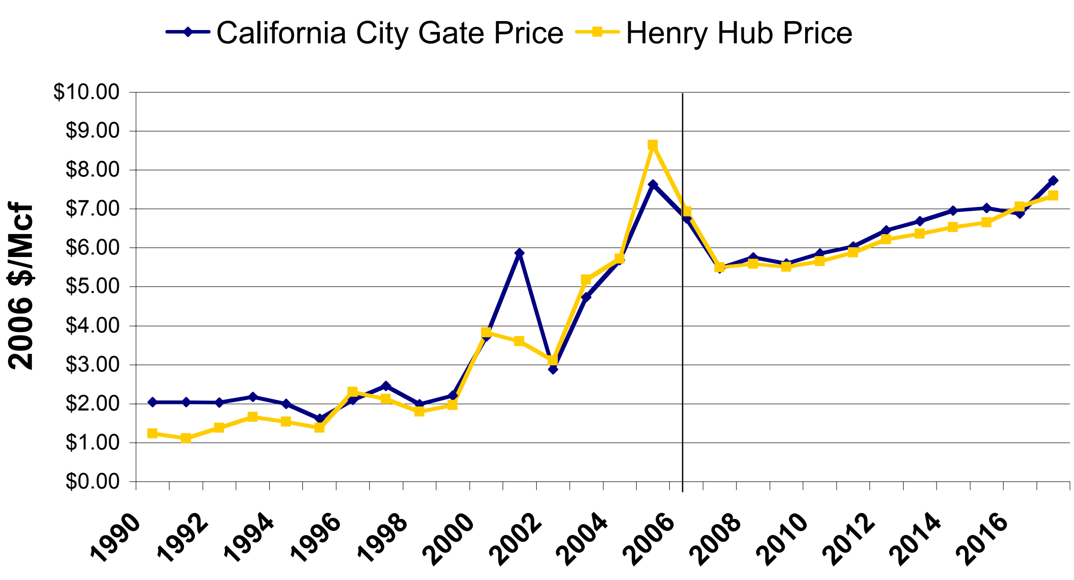
As noted earlier, there is basically one natural gas market in North America; however like any commodity, there are regional price variations that reflect different levels of demand, supplies and pipeline capacities. The Energy Commission staff estimates national wholesale prices ranging from $4.50 to $6.25 per thousand cubic feet in 2007 to increase 30 to 40 percent over the next 10 years to $6.75 to $8.25 per thousand cubic feet.

Higher natural gas prices can mean higher gas bills for customers if consumption stays the same, especially for those using natural gas to meet their heating needs. At the wholesale level, higher natural gas prices also mean higher costs to generate electricity, which translate into higher costs for electricity ratepayers.

The California City Gate Price, or price paid by the utilities before the gas is distributed, was relatively stable during the 1990s. But in recent years this price has become much more volatile as the state faces more competition for natural gas from its traditional supply sources just as many of the major producing basins in the west have peaked in their ability to increase production.

The forecast indicates an increasing California city gate price. Over the forecast period the City Gate price is expected to increase at a rate of 3.5 percent annually, slightly higher than the forecast annual increase for the Henry Hub price of 2.9 percent. (Figure 6-13) The Henry Hub is the wholesale price for natural gas processed in the Gulf Coast that serves the eastern United States.

Figure 6-13: Wholesale Natural Gas Prices – California Compared with Henry Hub (National)



Source: California Energy Commission

Even when California's own demand is moderate, in-state prices can spike in response to extreme weather conditions in other parts of the country. Although natural gas prices could decline slightly in the near term with the introduction of newer supplies into the market, Energy Commission staff projects a slow increase in national natural wellhead gas prices over the next decade as conventional sources are replaced by more expensive unconventional ones. This slow rise reflects the growing difficulty of producing natural gas in North America conventional production areas; however, it does not account for market volatility and short-term price spikes.

Over the next 10 years, the Energy Commission estimates that residential gas prices will fluctuate between $9.90 and $12.70 per thousand cubic feet or 99 cents and $1.27 per therm. Based on staff's forecast, this increase could be as much as $150 annually for the average residential household's gas bill. However, the impact will be reflected in electricity bills as well. According to a 2006 California Natural Gas Study Advisory Committee[261] report, if natural gas prices rose to $1 per therm, the average California household would experience a combined increase of $339 annually for natural gas and electricity.

Commercial customers can expect to pay between $8.90 and $11.70 per thousand cubic feet over the same period, depending on the service territory. Natural gas prices for industrial customers track similar trends as those for other California customers but at lower levels. Industrial customers usually purchase their gas directly, reducing delivery and storage costs for the utilities and could expect to pay between $7.10 and $9.80 per thousand cubic feet over the next decade. If the cost of doing business becomes too high for gas-intensive industries like fertilizer and chemicals to earn a profit, they may move their operations to other countries where costs are more affordable.

California's electricity generators are estimated to pay between $5.10 and $8.60 per thousand cubic feet through 2017 and prices vary based on whether or not the generator is served by a natural gas utility or takes its fuel supplies directly from another source, such as an interstate pipeline or local gas producer.

Unanticipated weather or political events that might influence demand are not considered in the Energy Commission's price projections. The model is based on long-term market fundamentals that drive the supply-demand balance in a normal, well-functioning market.

What Happens to Price if Production Drops?

Most experts agree that North American natural gas production will decline as well productivity continues to drop. And as discussed, it is difficult to imagine that the industry can complete the necessary 50,000 to 60,000 wells in 2017 for production to keep pace with demand. Staff examined a *scarcity case* that assumed that natural gas

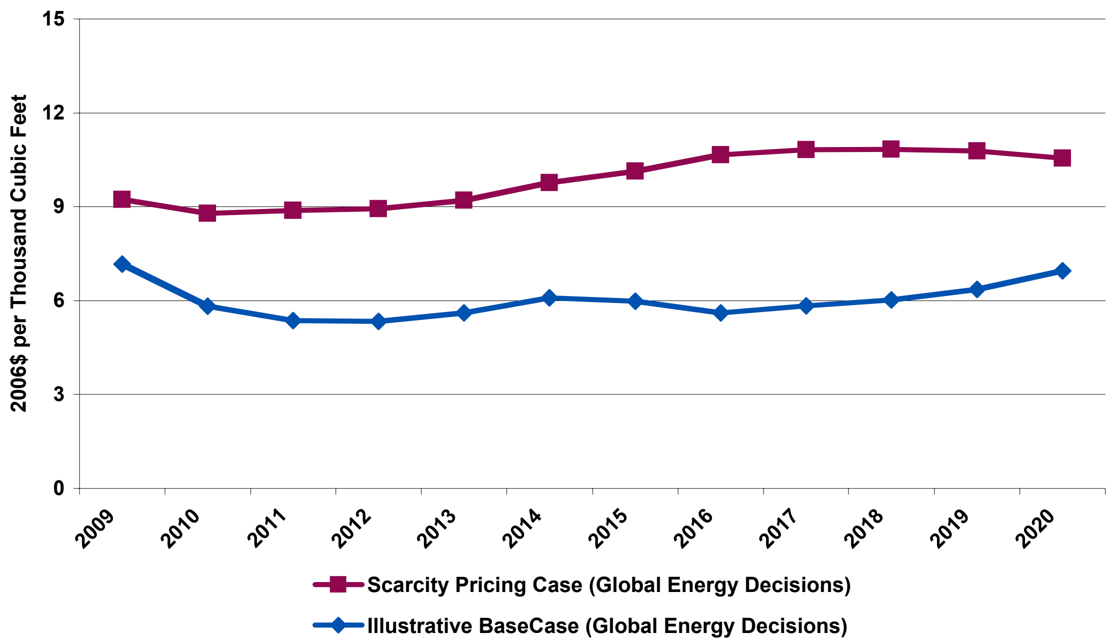
261 The Impacts of Natural Gas Prices on the California Economy by Global Insight, 2006

production would fall by 35 percent below the forecasted levels (Figure 6-14). The results show natural gas prices increase over 50 percent in each year from 2009 to 2020 and by 2015 the prices increase from $5.99 to $10.13 per thousand cubic feet. This scenario is not meant to predict but rather describe the consequences if a decline in North American natural gas production occurs. The case requires further adjustments and evaluation on the demand side of the model used before a complete understanding of the impact of low domestic natural gas supply is understood.

Given the consequences for California, the Energy Commission will monitor North American natural gas production for signs of decline or production difficulties. Unless the productivity of new natural gas wells stops deteriorating, the number of wells required just to maintain production will exceed what is likely to be economically or physically possible.

Alternatives to North American natural gas are essential, and will likely require increased amounts of the preferred resources of energy efficiency combined with renewables and other natural gas sources such as LNG.

Figure 6-14: Illustrative Scarcity Price Compared to Illustrative Base Case



Source: California Energy Commission based on Global Energy Decisions information

Natural Gas Demand and AB 32

Energy Efficiency

Energy efficiency has always been the most effective way to reduce demand and still increase productivity. It has played a major role in establishing California as one of the lowest per capita energy users in the nation. Even though today's homes are larger and have more appliances, California households use almost half the natural gas that households used in 1977. California's Building and Appliance Energy Efficiency Standards are the foundation of the state's energy efficiency policy and have been instrumental in helping to reduce natural gas use. The CPUC in recent years has authorized an additional $300 million for funding utility natural gas efficiency programs, setting aggressive goals to double annual natural gas savings by 2008 and triple savings by 2013.

Efficient Natural Gas-Fired Generation

New natural gas-fueled electricity generation technologies offer efficiency, environmental and other benefits to California, specifically by reducing the amount of natural gas used and with less natural gas burned, fewer greenhouse gas emissions. Older combustion and steam turbines use outdated technology that makes them less fuel- and cost-efficient than newer, cleaner plants. They waste two-thirds of the natural gas they use to make electricity – they are only 33 percent efficient. The state has about 16,000 megawatts of aging natural gas-fired electricity generating capacity, many of these units are between 26 and 62 years old and reaching the end of their assumed operational lifetimes. Because these facilities take too long to ramp up to provide electricity when needed, they are idled during the low demand season, burning natural gas and emitting greenhouse gas emissions but producing no electricity. Yet, as electricity demand grows, California remains dependent on these older plants for summertime peak power. California must take serious steps to retire these aging facilities that are being misused as peakers and replace them with newer technology that can more effectively provide electricity when needed without added emissions.

Today's natural gas-fueled electricity generation technology offers more efficient and reliable generation with about one and one-half times the increased efficiency, reducing the amount of natural gas consumed by 50 percent. These combined heat and power facilities can be particularly efficient when a heat recovery steam generator to power a conventional steam turbine in a combined cycle configuration captures waste heat from the gas turbine. They can also be run in a cogeneration configuration: the exhaust is used for space or water heating, or drives an absorption chiller for cooling or refrigeration. This type of cogeneration configuration can be over 90 percent efficient.

Combined heat and power facilities must provide a larger role in meeting California's electricity supply needs. The *2003 and 2005 Energy Reports* noted that the state could help reduce natural gas consumption for electric generation by taking steps to retire older, less efficient natural gas power plants and replace or repower them with new, more efficient combined heat and power facilities.

Natural gas efficiency is also a priority in the Energy Commission's natural gas research, development and demonstration program. In the last two years the Energy Commission established a Public Interest Energy Research Program on Natural Gas. With a 2007 budget of $18 million, this program has focused half of its funding on energy efficiency projects linked to the state's natural gas efficiency programs. Future reports will have more specific information on natural gas efficiencies from this program.

Renewables in Electricity Generation

Today, California generates almost 11 percent of its electricity from renewable resources – solar, wind, geothermal and biomass. Meeting California's Renewable Portfolio Standard (RPS), which requires that 20 percent of California's electricity supplies must be from renewable energy by 2010, is essential in reducing the growth in natural gas use for electricity generation and help in meeting the AB 32 goals. The state also has a goal of achieving 33 percent renewables by 2020. However, less than 400 megawatts of renewable resources have been brought on-line in the five years since the RPS was enacted, although nearly 5,000 megawatts of new contracts have been signed.

Coupled with expanding energy efficiency and demand response programs, California could reduce projected electric generator natural gas demand by 37 percent in 2020 if preferred energy efficiency and renewable resources are increased as described in Scenario 5A. And if the same assumptions were applied to California and the Western Electricity Coordinating Council (WECC) under Scenario 5B, California could reduce electric generator gas demand by 51 percent from projected 2020 levels.

The Effect on Natural Gas Prices by Reducing Demand

What happens to natural gas prices if demand for natural gas is reduced? Previous studies have found that reducing electricity demand through increased amounts of preferred resources lowers natural gas prices. This conclusion could help drive public policy to choose preferred resources over other conventional fuels. Staff's analysis looked at two models[262] from the Scenario Analysis Project; Case 1 using just enough efficiency and renewables to meet the RPS goals and Case 5B using high levels of efficiency and renewable energy in the WECC electricity resource mix. Results showed that the difference in natural gas demand for the electricity sector between Case 1 and 5B *averaged* a 36 percent decline from 2009 to 2020, as more preferred resources were incorporated into the WECC region's electricity supplies. The region's total natural gas demand for all sectors, including residential, commercial and industrial, decreased 2

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[262] Altos and Global Energy natural gas demand; Scenario Analysis Project - *Second Addendum Report*

percent in 2009 to 26 percent by 2020. And North American demand declines ranged from 0.2 percent in 2009 to 2.5 percent in 2020.

What did this mean for prices? The staff used two different models to answer this question. By lowering natural gas demand, the average wholesale (Henry Hub) price forecast for the WECC declined an average of 15 percent from $5.92 to $5.15 per thousand cubic feet in the first model compared to an average of just over 2 percent in the second model. Both these studies concluded that increasing energy efficiency and renewables in the electric sector reduces natural gas demand and may bring downward pressure on natural gas prices for all customers.

Natural Gas as a Complementary Strategy to Meet Greenhouse Gas Emission Reductions

As our population continues to grow, California manages to keep natural gas demand for residential, commercial and industrial customers to less than one percent growth each year respectively. Higher gas prices and aggressive efficiency and renewables programs have helped to slow demand, even in the electricity generation sector. Compared to the East Coast's projected growth rate of 6.4 percent each year for natural gas in the electricity generation, California's slower annual 1.4 percent increase in the electricity generation demand seems slight. However, electricity generation combined with the other sectors will add 827 million cubic feet more each day to California's natural gas demand – a total of almost seven billion cubic feet daily by 2017.

Growth in natural gas used to generate electricity may exceed even these estimates under certain greenhouse gas reduction measures. For example, scenario analysis calculated that if a $60 per ton of carbon price were attached to CO2 emissions, projected levels of coal-generated electricity in the WECC would decline by about 30 to 40 percent in 2020. As a result, natural gas burned to generate electricity in California would increase by about 20 to 70 percent depending on the amount of preferred resources. Natural gas consumption in the WECC would increase between 35 to 127 percent.

Reducing the amount of coal used to generate electricity with a combination of preferred resources and natural gas and in the context of $60 per ton of carbon charge increases natural gas use in California and throughout the WECC.

Natural gas is and will remain the major fuel in California's supply portfolio and must be used prudently as a complementary strategy to reduce greenhouse gas emissions. Not only does the state have a mandate to cut greenhouse gas emissions, we also have a responsibility to provide a reliable and affordable fuel source for home and business use.

Recommendations

- The Energy Commission advocates policies that allow California to secure alternative and diverse sources of natural gas to meet growing demand and energy security options, including support of liquefied natural gas facilities on the West Coast that can be licensed to meet environmental and public health and safety standards.
- The Energy Commission supports all cost effective energy efficiency measures for natural gas.
- The Energy Commission encourages renewable sources of energy to generate electricity, as well as sources—such as solar for water and space heating—that directly displace natural gas.
- The Energy Commission and CPUC should adopt a "loading order" for natural gas resources, similar to the one in place for the electric sector. This will encourage utilities to seek out low-carbon fuels before conventional sources of natural gas, with the first priority being all cost-effective natural gas efficiency and solar resources followed by renewable fuels like biomethane.
- The Energy Commission will continue to incorporate new analytical tools such as Scenario Planning and Portfolio Analysis in assessing and forecasting the state's natural gas supplies and demand to meet reduced greenhouse gas emission targets. The Energy Commission will encourage the Public Utilities Commission to participate in these analytic efforts.
- As the Energy Commission has determined that there are uncertainties in forecasting natural gas production, demand, and price, we will pursue the following actions in the 2009 Integrated Energy Policy Report cycle:

  - Conduct a rigorous verification of the models used to forecast natural gas supply and price by evaluating the reasonableness and economic and physical likelihood of the model results based on a range of factors including number of new wells, initial rates of production, depletion rates, and other variables.

  - Develop probabilities and quantify outcomes for demand scenarios to gain better insight into natural gas demand, including a) scenarios that assume an expanded consumption of preferred resources, b) adoption of electricity as the best fuel strategy, c) displacement of new coal plants with natural gas plants in the Western Electricity Coordinating Council and the eastern United States, and d) levy of a carbon charge on the use of coal to generate electricity:

  - The Energy Commission must pursue energy efficiency improvements through increased natural gas research and development.

CHAPTER 7: Meeting Transportation Needs

Perhaps no other population in the world has embraced the automobile as passionately, nor is any other state defined as much by the car, as California.

Cars give Californians the individual freedom and autonomy we crave. This freedom comes with a high price, both to the environment and consumer pocketbooks. Vehicles are the major contributor to global warming pollution. Almost 40 percent of carbon dioxide (CO_2) and other greenhouse gases in California come from burning transportation fuels, mainly gasoline and diesel in cars and trucks. We must change our relationship with automobiles and the way we view transportation - at a personal, as well as a state policy, level.

> ***"Embrace the future and recognize the growing demand for a wide range fuels or ignore reality and slowly—but surely—be left behind."***
>
> Mike Bowlin, Chairman and CEO of ARCO (now BP)

Decreasing California's reliance on petroleum fuels is critical. By 2020, at current trends, over 44 million Californians will consume more than 24 billion gallons of gasoline and diesel fuel each year. The consequences are clear: major investments in petroleum refinery and delivery infrastructure expansions, more dependency on foreign energy supplies, and decreased environmental and public health quality.

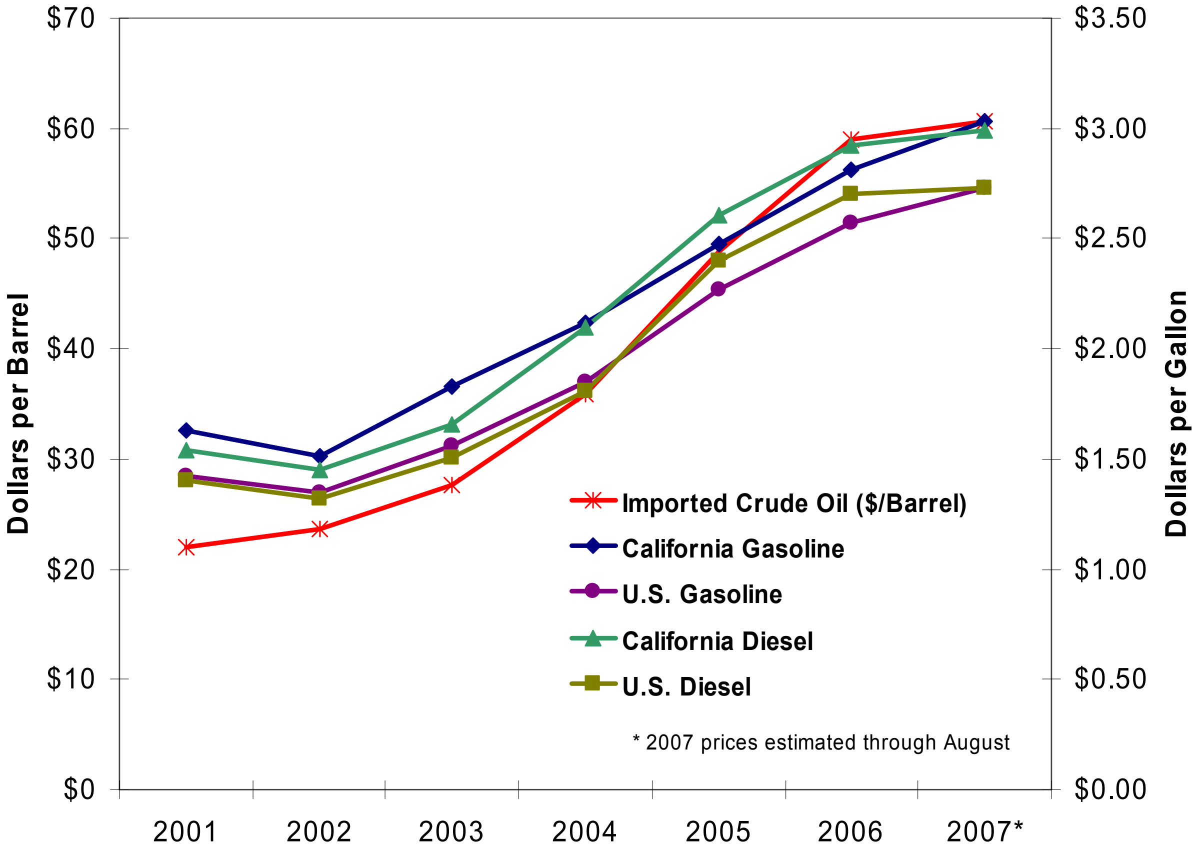
California's energy policy — the loading order — identifies energy efficiency, renewables and new infrastructure improvements as the state's priorities in meeting growing energy demand. These strategies also apply to transportation.

Improved efficiency of transportation energy use, in large part through vehicle standards, is the most effective and sustainable strategy for reducing our demand for transportation fuels. Applying these preferred strategies to transportation focuses first on the pursuit of maximum achievable energy efficiency. Efficiency improvements can be made in vehicle energy use, individual vehicle miles traveled, and goods movement.

More than 40 percent of all energy used in the state moves people and goods, and most transportation fuel demand is met by petroleum. The state's nearly 26 million registered vehicles consume about 380 million barrels of gasoline (16 billion gallons) and almost 100 million barrels of diesel (4 billion gallons) each year. California is the second largest consumer of gasoline in the world, behind the entire United States and just ahead of Japan.

Due to high oil prices and in-state refinery maintenance and breakdowns California's gasoline prices reached a record high of $3.46 per gallon during May 2007 (Figure 7-1). Consumers are unable to change their driving habits quickly; therefore when transportation fuel prices increase over a short period of time, consumers are left with less disposable income. In addition to the impact of high transportation fuel prices, increases in crude oil prices drive up the average cost of production of goods and services. This negatively affects the state's economy and gross state product.

Figure 7-1: Gasoline, Diesel and Crude Oil Prices



Source: California Energy Commission

Significant petroleum price increases; such as those experienced in 1973-74, 1979-80, and 1990; all led to national recessions.

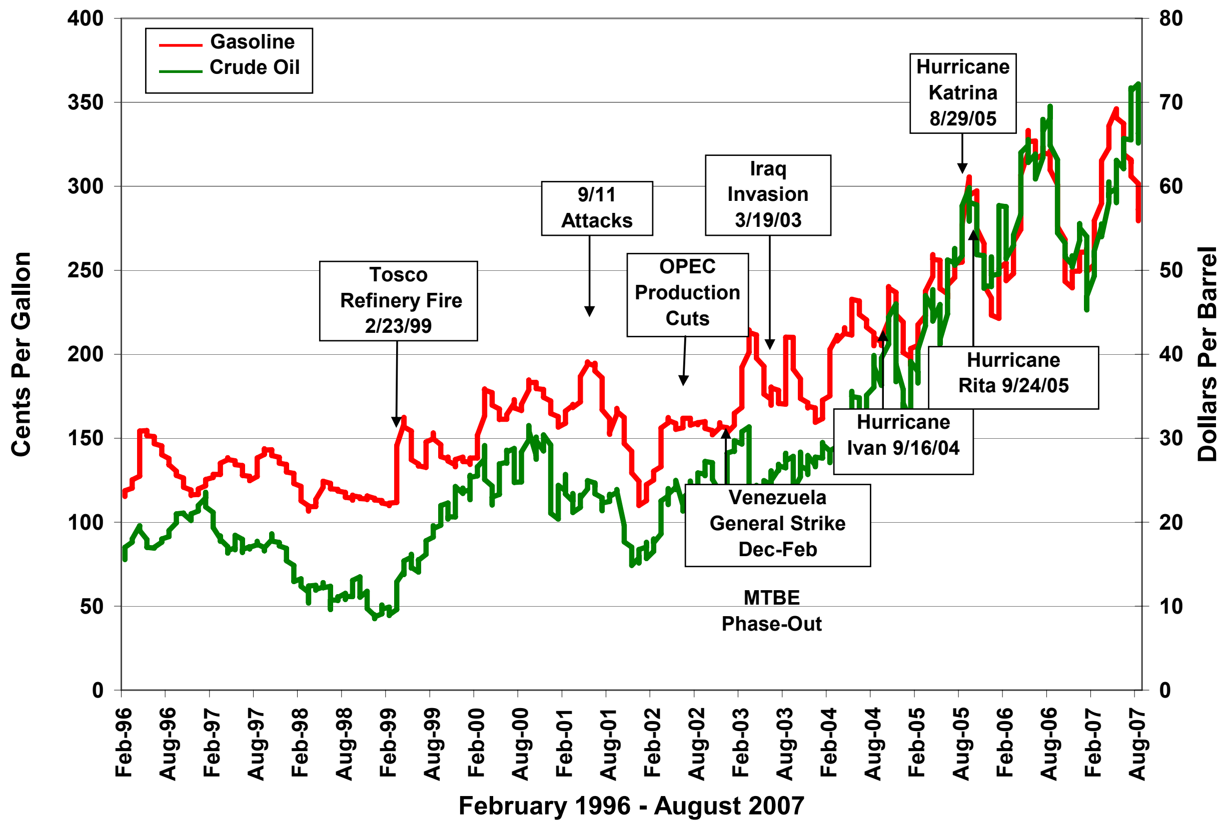
Crude oil is the single largest cost component in producing gasoline and diesel, accounting for between 42 and 56 percent of the price of regular gasoline in the last year. World oil prices have more than doubled since 2004 (Figure 7-2). Skyrocketing demand in China and other developing nations, along with current global conflicts, particularly in Nigeria and the Middle East, are exacerbating the situation. Other factors such as weather and geopolitical events also affect crude oil and transportation fuel prices.

By October 2007, crude oil prices had exceeded $90 per barrel. The price of crude oil, regardless of its origin, is affected by the worldwide price for benchmark crude oils, and these price trends emphasize the importance of reducing our growing dependence on foreign oil sources.

Twenty-five years ago, California received 94 percent of its crude oil supplies from in-state production and imports from Alaska; foreign sources contributed the remainder (Figure 7-3). By

2006, the situation had changed, with foreign imports making up 45 percent of crude oil processed by California refineries. Additionally, due to the limited refining capacity in California, the state must import ten percent of its refined blending components and finished gasoline and diesel to meet the growing demand.

Figure 7-2: California Gasoline and World Crude Oil Prices



Source: California Energy Commission

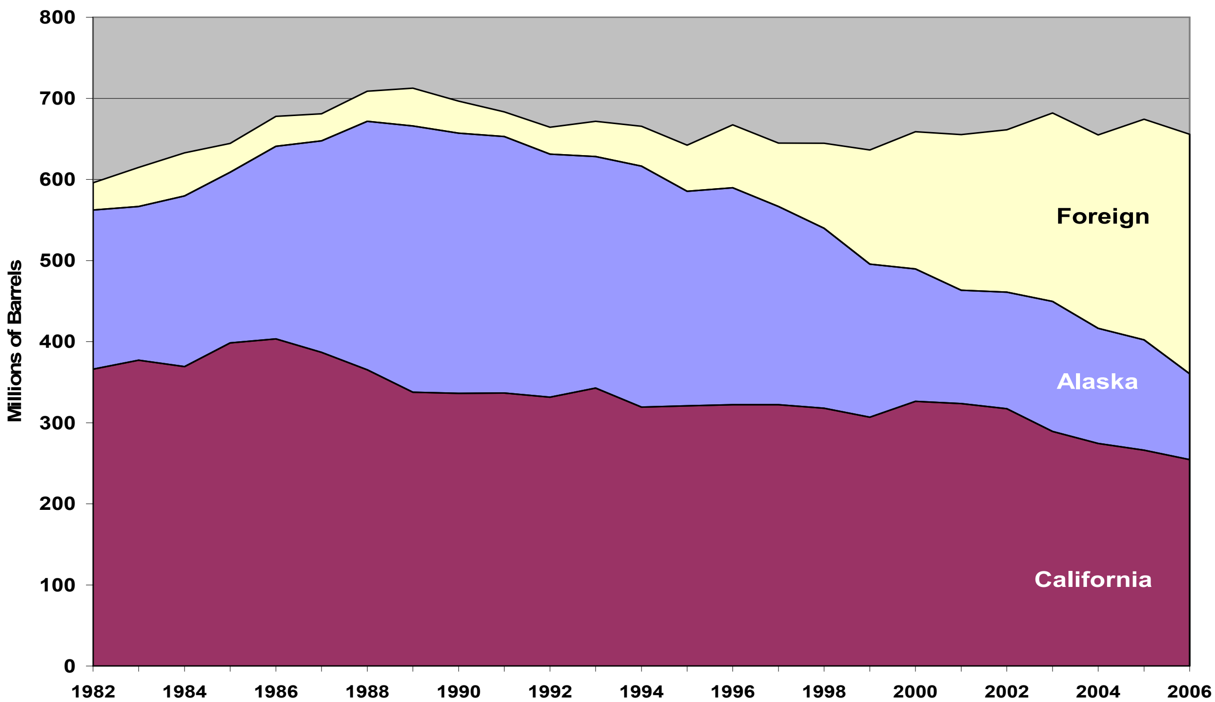
California's petroleum infrastructure operates at near capacity and the volume of imports is constrained by limited storage capacity and marine terminal capabilities at Southern California ports. This adds further challenges.

Unplanned outages at in-state refineries or pipeline facilities quickly tighten gasoline and diesel supplies, creating price spikes. California is not connected by pipeline to other domestic refining centers, and in-state refiners cannot readily procure gasoline, diesel, and other blending components when outages occur. Relying on imports of petroleum and finished product coming into the constrained import infrastructure creates a market conducive to extreme price volatility. This contributes to higher and more prolonged price spikes, as has been experienced in recent years.

Transportation Fuel Demand Trends

In the past 20 years, California's population has increased at an annual average rate of 1.7 percent and personal income has increased at 1.58 percent per year. Over the 2005 to 2030 time period, projections forecast a slowing of growth for both population and income, to 1.04 percent and 1.08 percent per year, respectively.[263] Nevertheless, California's population is estimated to exceed 44 million by 2020. Even if not climbing at historic high rates, the total growth will be considerable and result in substantial increases in transportation fuel demand for the state. The policies that result from the state's Assembly Bill 1007 (AB 1007) (Pavley, Chapter 371, Statutes of 2005) plan (discussed later in this chapter), from the programs that will be funded by Assembly Bill 118 (AB 118) (Nuñez, Chapter 750, Statutes 2007), and from California's overall AB 32 protocols will have a major impact on what fuels are used in the state to meet this rising transportation fuel demand.

Figure 7-3: California's Refinery Crude Input



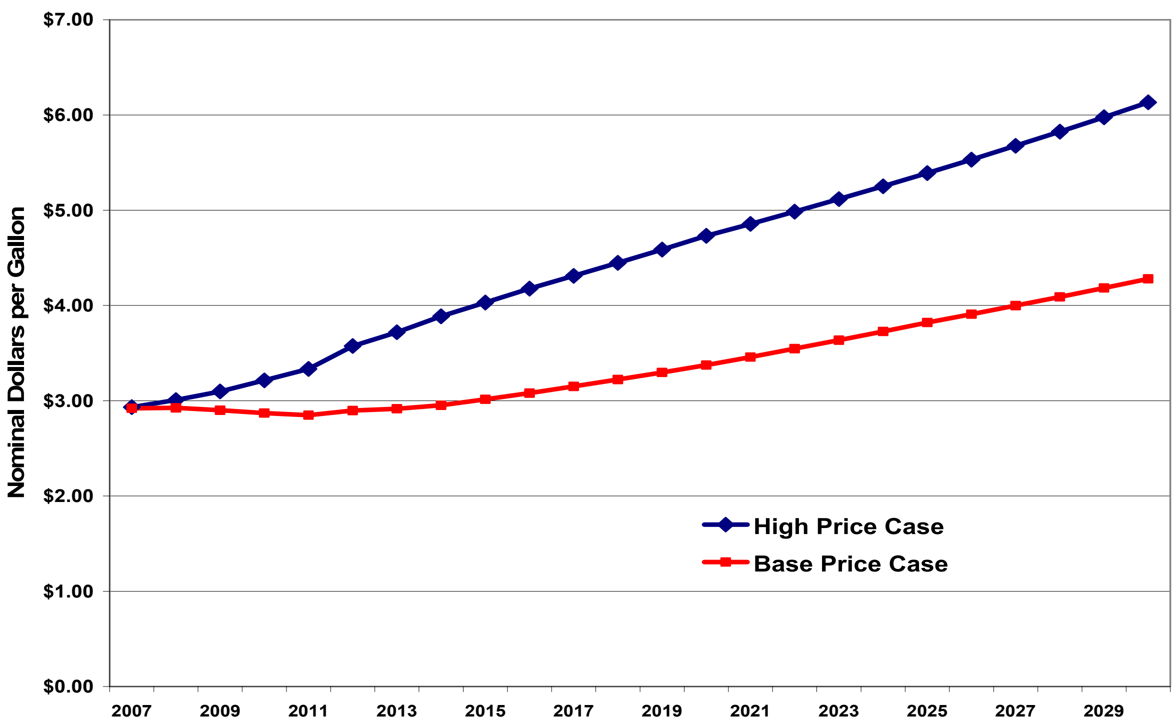
Source: California Energy Commission

[263] Based on population projection series from the Department of Finance's July 2007 report, *Population Projections by Race / Ethnicity for California and Its Counties 2000–2050* (population growth rate of 26% for the 2005-2030 timeframe) and demographic data obtained from California Energy Commission Demand Analysis Office.

Besides population growth, California's transportation fuel demand is affected by many other factors, including economic growth, fuel prices, and consumer behavior. Energy Commission staff developed several demand forecasts with different levels of transportation fuel consumption and several variable factors such as fuel prices, technology developments, and greenhouse gas reduction regulations. For petroleum supply and imports, staff developed cases that varied according to assumptions about crude oil production, refinery and pipeline expansion projects, port and marine terminal capacities, and California and neighboring state fuel demand.

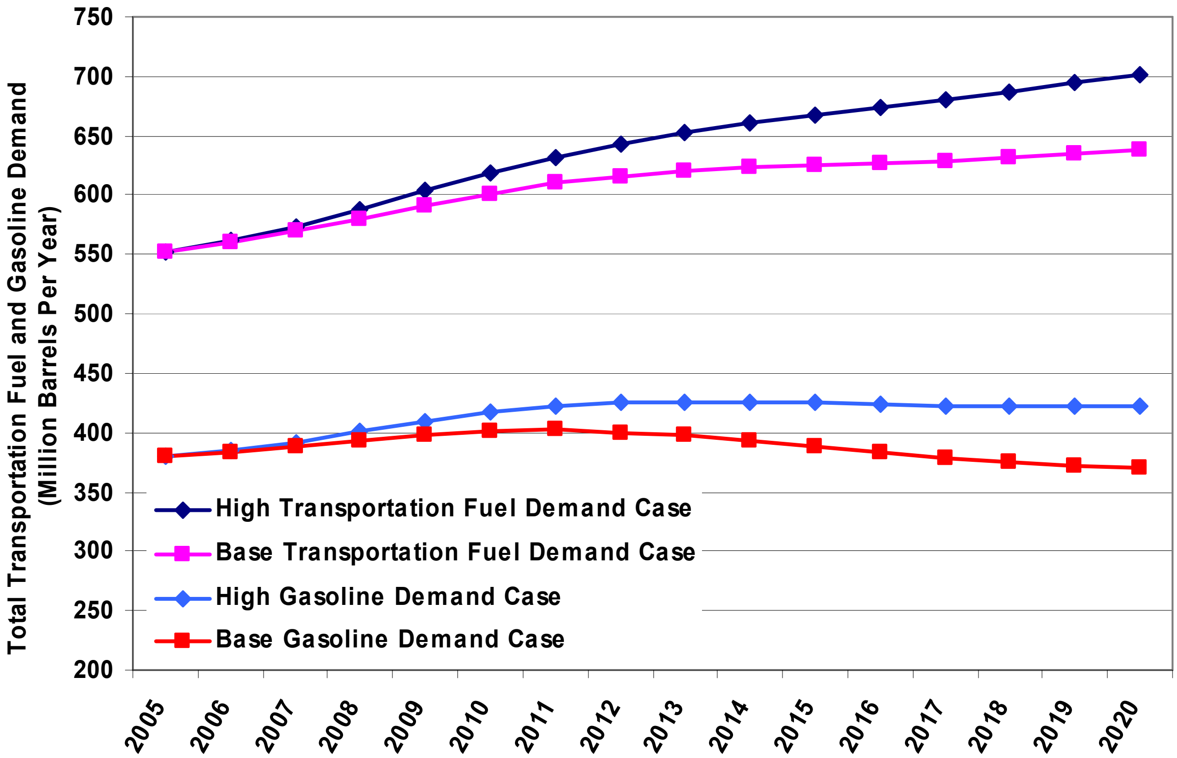
Increasing demand is one factor that affects gasoline prices (Figure 7-4). Potential growth for both gasoline and total transportation fuel demand (gasoline, diesel, and jet fuel) is illustrated for the High Demand Case and the Base Demand Case (Figure 7-5). California's gasoline use steadily increases at an average annual rate of 0.76 to 1.63 percent through 2012. From 2012 to 2020 gasoline demand grows at an average annual rate of 0.07 to 0.98 percent. This downturn in the rate of growth of gasoline demand occurs in both cases because more hybrid-electric and diesel light-duty vehicles are assumed to enter the fleet. In the Base Demand Case, greenhouse gas standards and higher fuel prices also reduce fuel demand growth. These projections reflect extrapolation from current conditions and market behavior, and will likely differ significantly as the policies put in place in response to AB 1007 and AB 118 are implemented.

Figure 7-4: Projected California Gasoline Prices



While gasoline demand is expected to peak and then fall, total transportation fuel demand will continue to increase through 2020. Total gasoline, diesel, and jet fuel demand increases at an average annual rate of between 0.96 and 1.61 percent by 2020, growing from 553 million barrels in 2005 to between 638 and 702 million barrels in 2020.

Figure 7-5: Transportation Fuel Demand



Source: California Energy Commission

Diesel fuel is expected to steadily increase its share of the transportation fuel market. Diesel consumption in freight, transit, and off-road uses is expected to continue to grow with population and economic growth. In these sectors, diesel use will also be largely insulated from dramatic changes in vehicle fuel efficiency. At the same time, diesel is poised to make major penetrations in the light-duty vehicle market because of its marked fuel efficiency advantages compared to gasoline vehicles. Total California diesel use is projected to grow at an annual average rate of 3 percent to 3.5 percent per year through 2020.

Commercial jet fuel use in California is estimated to grow at an annual average rate of 2.9 to 3 percent. Future commercial jet fuel use is calculated by using forecasts of the number of passengers boarding each plane and depends on population growth and projections of revenue per passenger mile. Different paths for future jet fuel prices may cause airlines to change the quantity of jet fuel used. However, federal projections of airport capacity at Los Angeles International, San Francisco International, and San Diego International airports indicate that constraints largely limit growth so that demand levels in the High and Base Demand cases do not differ very much through 2020. In addition, fuel prices are around 25 percent of total airline expenses, so the price signals that might otherwise alter demand are dampened.

California has been called an "island" in terms of petroleum markets, but is in fact an integral part of the larger West Coast and Pacific market regions. In addition to being partially integrated with refinery operations in Washington, California supplies virtually all of Nevada's transportation fuels and over 60 percent of Arizona's, as neither of these landlocked states have any refineries. California refineries also provide between 25 and 35 percent of Oregon's fuels delivered via marine tankers. These states have joined with California in collaborative arrangements to address greenhouse gases in the region. If these other states develop policies similar to those California is considering under AB 1007 and AB 32, their demand for petroleum products will likely differ from these projections.

Exports to Nevada and Arizona rely on pipelines that are linked to distribution terminals located in Reno, Las Vegas, and Phoenix. This network of interstate pipelines is owned and operated by the Kinder Morgan Pipeline Company (KMP). Demand for transportation fuels in each of these states is increasing rapidly. To meet this growing demand, pipeline exports from California to Nevada will increase at an average annual rate of 2.1 to 2.9 percent per year and exports to Arizona will increase at a rate of 2.4 to 2.6 percent per year from 2006. These additional pipeline exports will either need to be produced by California refineries or need to be imported through Southern California's increasingly constrained petroleum infrastructure.

California Ethanol Demand

Currently, about 6 percent ethanol is blended into the gasoline pool. In the near future, California ethanol demand is expected to increase, primarily from changes to California's gasoline regulations and other efforts to increase the use of alternative fuels, such as the Low Carbon Fuel Standard. Energy Commission staff believes the majority of California's gasoline market will contain 10 percent ethanol (E-10) by 2012. As such, ethanol demand in the state under the Base Case gasoline demand scenario is expected to increase from almost 23 million barrels in 2006 to approximately 40 million barrels in 2012, a 10 percent average annual rate of growth.[264] The additional imports needed to meet this anticipated growth will depend on how many additional California ethanol production facilities are constructed over the next few years.

As of July 2007, California had an ethanol production capacity of 1.8 million barrels per year. Based on additional projects already under construction, in-state ethanol production capacity is estimated to increase to at least 5.5 million barrels per year by 2009. If other projects in

[264] In the high gasoline demand and limited in-state ethanol production scenario, total imports of ethanol could grow to 36 million barrels per year by 2020 compared to 2006 import levels of 22 million barrels. Assuming lower gasoline demand and higher in-state ethanol production, total ethanol imports could decline to 21 million barrels by 2020.

advanced stages of planning and financing are also pursued to completion, annual in-state conventional ethanol production capacity could reach 16 million barrels by 2012.

The Energy Commission expects California's future transportation fuel demand to increase regardless of which price scenario and regulatory conditions are assumed. However, the magnitude of future contributions from various emerging alternative transportation fuels and technologies is unknown. These emerging fuels, such as ethanol and biodiesel, can potentially displace a significant volume of petroleum, which may change the mix of required infrastructure enhancements in the future. However, many of these alternative fuels, in particular renewable fuels, may also require their own additional segregated import facilities, including pipelines and storage tanks.

California must continue to meet its growing transportation fuel needs and must further consider the impacts of these needs while meeting the targets of reducing greenhouse gas emissions. To meet these needs the state must address two major areas of concern: the constrained petroleum infrastructure and options to reduce petroleum dependency – alternative fuels, and emission and vehicle standards – that reduce our carbon footprint.

California's Petroleum Infrastructure

California cannot reliably meet its increasing fuel demand without a robust petroleum infrastructure that includes refineries, storage, pipelines, distribution terminals and marine facilities. The *2005 Integrated Energy Policy Report* noted that although some necessary improvements have made to portions of the infrastructure, California must further expand its marine terminal capacity, marine storage and the pipelines connecting these facilities with the refineries and other pipelines if we are to meet our rising fuel demand.

Little has improved since the *2005 Integrated Energy Policy Report*; in fact, the outlook for improvements to the marine infrastructure has worsened. Staff projects that overall fuel demand will continue to grow, increasing imports through a marine infrastructure that is already congested and exceeding infrastructure capacity expansions currently under construction or to which the industry is committed.

Whether California consumers and businesses have adequate supplies of transportation fuels over the forecast period will be determined by existing spare capacity, the magnitude and timing of marine terminal expansion activity, and the actual demand that occurs. Several conclusions from the *2005 Integrated Energy Policy Report* are applicable today:

- Important segments of the state's existing fuels infrastructure are already being used at or near their capacity.
- The current capacity of existing marine infrastructure, particularly in the Los Angeles and Long Beach marine terminals, could decline as a result of pressure to remove petroleum facilities from port areas and requirements to meet seismic standards implemented by the State Lands Commission.

- Petroleum marine terminal capacity, marine storage, and gathering pipelines that connect marine terminals with refineries will have to expand to meet expected demand for fuels. Most of this expansion would occur in the Los Angeles Basin.
- Expansion of transportation fuel marine infrastructure will become more difficult in the Los Angeles Basin as available land becomes increasingly scarce and subject to competing uses and because residents, community groups, and local authorities have expressed substantial resistance to such expansion.

Effects of Competition for Existing Terminal and Storage Capacity

As transportation fuel demand and imports increase, facilities that accommodate the increased number of vessels carrying cargoes of crude oil, gasoline, diesel, and jet fuel must also expand. Without an adequate import infrastructure supplies of transportation fuels will not be sufficient for the state. Marine terminals are naturally limited in their ability to operate at their theoretical maximum capacity since it is difficult to precisely calculate a tanker's travel time and arrival (because of changing sea conditions) and unexpected delays in unloading cargo (lengthy inspections, processing delays in paperwork, and interruption of pumping operations during cargo discharge) automatically reduce the number of vessels a terminal can manage. Most marine terminals operate at 50 to 70 percent of their capacity, which is considered at or near maximum economic and safe operating levels. Having tankers wait at anchor in the harbor is impractical, from both economic and safety perspectives, and costly.

Vessels unable to unload cargoes despite an immediate need for the product not only impact the tankers' owners, with delay costs of $30,000 to $100,000 per day, but also consumers, with increased retail fuel costs. For example, a 10-cent per gallon increase in gasoline, diesel, and jet fuel prices can mean over $6 million per day increased direct consumer expenditures on these fuels, depending on demand levels.

Congestion also leads to additional tankers at anchor in the port or nearby, which raises risk of serious accidents and even spills, and possibly increased emissions. Many harbors and waterways in California already experience significant marine vessel traffic.

Over the past 15 years approximately 6 million barrels of storage tank capacity has been removed from Southern California. The potential loss of more existing marine terminal capacity from voluntary business decisions, involuntary forced closure due to current lease termination or refusal to renew existing marine terminal operating leases, erodes the ability to meet California's transportation fuel demand. Constrained storage capacity also limits increased imports of alternative fuels, in particular the biofuels necessary to meet the state's goals for reducing petroleum use.

Challenges to Developing Additional Capacity

Efforts to expand existing, or create additional petroleum infrastructure, specifically in the San Pedro Harbor, have been met with stiff resistance from some local community members, elected officials, and port representatives. Objections include concerns over increased air pollution, increased truck traffic, visual aesthetic opposition to the sight of storage tanks, perceived safety threats to nearby communities, and competition for diminishing spare land that is coveted by community members for park/recreational development and by port representatives for expansion of cargo container handling facilities.

Dredging and Maintenance Standards

Unlike facilities in the Los Angeles Basin, San Francisco Bay marine petroleum terminals face significant limitations caused by the relatively shallow depths of their shipping channels. The draft or depth that a vessel sits in the water, of modern very large crude carriers (VLCC) exceeds the depth of these shipping channels. This requires either more shipments by smaller tankers or transferring, called lightering, of loads from larger tankers that anchor in areas outside the constrained channels into smaller vessels that continue to the terminals. Lightering is strictly regulated by the Department of Fish and Game's Office of Spill Prevention and Response and the United States Coast Guard and incurs extra costs, inefficiencies, time delays, and risks that would be avoided by more direct access. In some cases, water depths near marine terminals are difficult to maintain at depths adequate for even smaller tankers.

Timely and reliable dredging of the Pinole Shoal sufficient to support marine shipments into the Carquinez Straits is an ongoing challenge. Environmental rules limit the time allowed when dredging activities can take place and where dredging spoils can be deposited. Most terminals in the San Francisco Bay area also require periodic maintenance dredging to offset silt deposits in nearby lanes. These logistical and permitting requirements do not prevent crude oil and transportation fuel deliveries but can lead to higher costs for producers and consumers. It is important that federal funding for Pinole Shoals dredging receive continuous high priority to ensure adequate shipping depths through the Carquinez Straits to upstream refinery marine terminals.

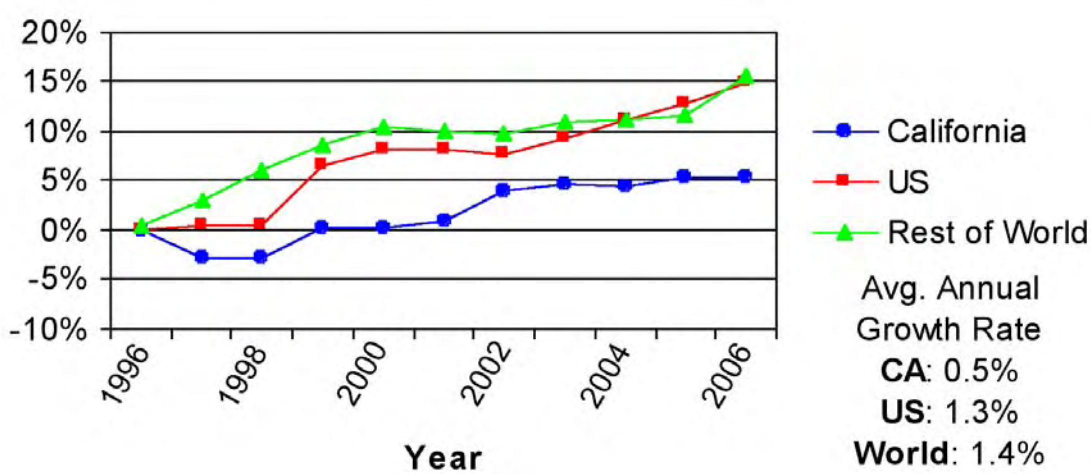
All California petroleum marine terminals are under a new set of regulations known as the Marine Oil Terminal Engineering and Maintenance Standards (MOTEMS), approved by the State Lands Commission in 2004. MOTEMS are a comprehensive standard for the design, construction, maintenance, inspection, and repair of petroleum marine terminals. The primary purpose of these standards is to prevent crude oil and petroleum product spills. Since the average age of most of these marine terminals is more than 50 years, their design and configurations have not been updated to accommodate the growth in vessel size or structures. Applying the MOTEMS will extend the life spans of these aging facilities and reduce their seismic, mooring, and berthing vulnerabilities.

Some of the state's marine terminal network, especially in Southern California, will require substantial upgrades to meet these standards. These costly investments may cause short operational disruptions; however, some terminals in the San Francisco Bay have already performed these seismic and structural upgrades on a much larger scale. The MOTEMS regulations include compliance flexibility and an implementation schedule with flexibility dependent on annual funding limits, environmental restrictions, and any other permitting or regulatory compliance issues. With some thought and good engineering, there should be almost no operational disruptions or fuels price impacts caused by MOTEMS compliance. It is important that Energy Commission staff continue to monitor progress toward compliance with MOTEMS as well as the actions by the ports to terminate leases of oil terminals in order to determine any potential impacts to the flow of crude oil and transportation fuels of these standards.

Refining and Storage Capacity

As the demand for transportation continues to grow throughout the world, refiners have responded by increasing their capacity to process crude oil. In 2005, California refineries processed 674 million barrels (1.8 million barrels per day) of crude oil; however, the state's refinery capacity is expanding at a slower rate than in the United States or the rest of the world (Figure 7‐7). Based on forecasted increases in future transportation fuel consumption in California and neighboring states, demand is growing faster than the ability of refineries to produce those fuels. California refinery capacity growth, known as refinery creep, is relatively low and only expected to increase at an annual average rate between 0.4 and almost 1 percent per year through 2020. The rate of refinery growth in the Pacific Northwest (Washington State), as well as potential future projects to increase the capability to produce California fuels will increase in importance since this region is a modest source of California transportation fuels. It is therefore likely that future IEPR work will expand to incorporate a larger regional outlook for refinery growth and individual state demand projections, compared to the three-state analysis (California, Arizona and Nevada) conducted for *2007 IEPR*.

Figure 7-6: Refinery Capacity Growth for U.S., California, and the World



Source: California Energy Commission; *2006 Price Spike Report*

Even this small, expected refinery growth requires more tankers than presently available to bring in refined products, congesting marine terminals, as well as requiring more marine port storage capacity. Coupled with the state's steadily declining crude oil production, even low refinery capacity growth rates will require increased levels of crude oil imports and storage capacity. Imports of crude oil into California are expected to rise at an annual average rate between 1.7 and 2.7 percent per year through 2020.

Additional storage tank capacity necessary to meet California's product storage requirements by 2020 ranges from 5.4 million to 13.1 million barrels and the additional crude oil storage capacity needed ranges from five to 17 million barrels. California must prepare for this range of additional storage capacity even as it develops and implements its alternative fuels plans under AB 1007. Additional infrastructure will be necessary to meet California's transportation requirements, even with alternative fuels meeting a greater percentage of those requirements.

Assuming planned storage capacity is built, crude oil import capacity in the Los Angeles Basin should be sufficient through 2015, but in the higher imports case, more capacity would be required by 2020. The Crude Oil Import Marine Facility Project at Pier 400 in the Port of Los Angeles has been significantly delayed. This facility is a critical element of the assumption of adequate capacity through 2015. Without an expansion of the existing crude oil import capability for the San Pedro harbor, refiners will eventually be forced to reduce production of transportation fuels as they run out of options to import additional crude oil. It is estimated that this spare crude oil import capacity could be used up as soon as 3 to 5 years from today. Further delay of the release of the draft EIR for the Pier 400 project by the Port of Los Angeles could extend the ultimate completion date long enough to put the oil industry's ability to import sufficient quantities of crude oil to operate their refineries at risk.

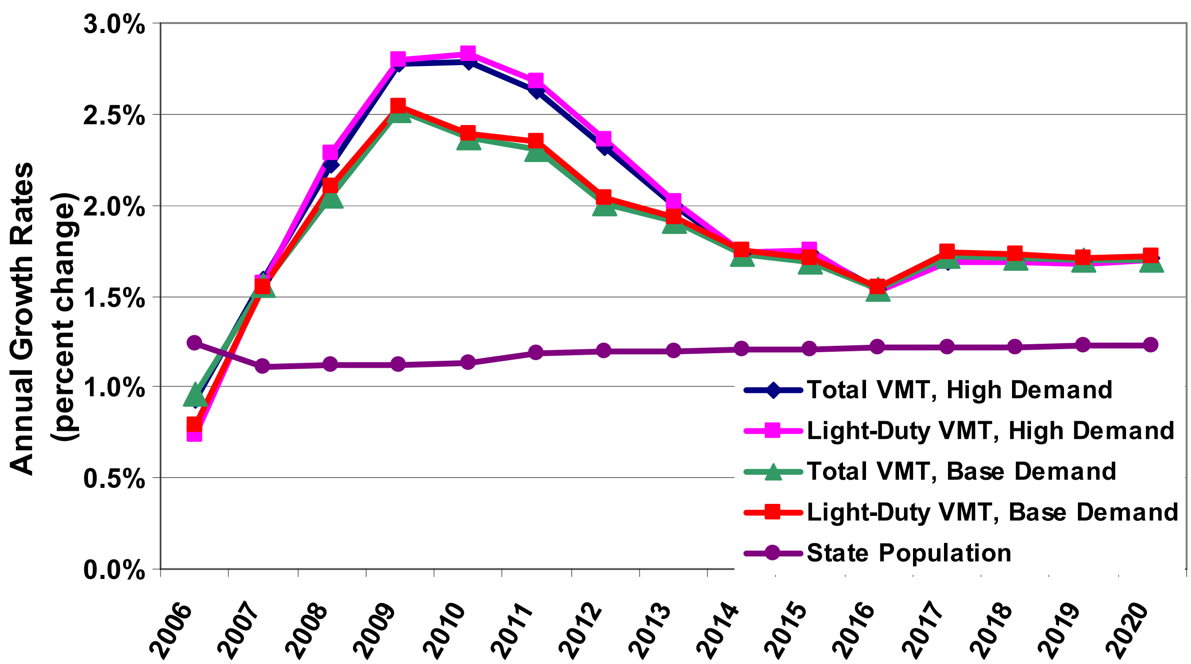
Crude oil tankers are considerably larger than product tankers - an average crude oil tanker load is about 700,000 barrels while an average product tanker load is around 300,000 barrels. By 2020, the number of additional crude oil tanker arrivals to California ports will range from 167 to 291 per year, depending on assumptions about state oil production and refinery capacity additions. Additional product tanker arrivals per year could range from as few as 214 to as many as 519, again depending on assumptions about product demand.

The proportion of criteria pollutants by various marine vessels from petroleum tanker emissions are marginally less than emissions from container ships per port visit. Overall, emissions from marine tankers in 2001 represented between 1.2 and 8.2 percent of air pollution from all sources in the Port of Los Angeles, depending on type of pollutant.

Providing Transportation Options With Efficiency And Alternative Fuels

Californians require mobility to conduct their everyday lives and attend to their business needs. For the most part, this mobility is achieved through use of a petroleum-fueled vehicle, typically with a single occupant, and is measured as Vehicle Miles Traveled (VMT). Figure 7-7 shows the narrow range of future travel demand expected under differing conditions of fuel prices and fuel efficiency standards. Travel demand is essentially a fixed requirement for individual consumers of transportation goods and services in a state as physically expansive as California, where distances are large and most metropolitan areas are extensive and poorly served by public transit. Reducing public access to work, recreation, and other travel cannot be achieved without disruption and economic loss. Moreover, population growth translates directly into increases in aggregate travel demand. Future land-use decisions will impact this relationship, as described in Chapter 8.

Figure 7-7: A Population on the Move



Source: California Energy Commission

Consumers must have a broader set of choices if they are to simultaneously reduce the environmental, social, and economic costs of transportation energy use while maintaining their mobility. Although conventional petroleum fuels will be the main source of transportation energy for the foreseeable future, over the next several decades California must pursue multiple complementary strategies that increase fuel efficiency, expand non-traditional fuel use, and ultimately realign consumer preferences to reduce demand for all transportation energy use as well as reduce trips and VMT.

Government mandates, policy directives, incentives, and increased concerns over the negative environmental and economic consequences of global climate changes all indicate that there will be an increase in the use of alternative fuels in California. The increased use of fuels with a lower carbon intensity than conventional petroleum fuels can help meet the mobility requirements of consumers while reducing the economic and environmental impacts of continued petroleum dependence. However, increased availability of alternative refueling infrastructure and changes in vehicle procurement processes need to support a broader concept of transportation choices under AB 32.

Even though fuel efficiency and greater use of alternative fuels can contribute to lower petroleum consumption, California cannot meet its long-range goals of reducing greenhouse gas emissions without fundamental changes to the way we meet our mobility needs. Changing the patterns that cities take as they grow so that destinations are closer to people's homes and channeling urban growth so that public transit can assume a larger burden of travel demand are elements of the longer-term strategy that the state must develop if gains made in other policy areas are not to be overwhelmed by future population growth.

While California must address its petroleum infrastructure problems and act prudently to secure transportation fuels to meet the needs of our growing population, this should be viewed as a strategy to allow time for the market and consumer behavior to adjust to alternative fuels and transportation choices. During this transition, California must be innovative and aggressive in finding more ways to make increased efficiency, greater renewable fuel use, and smart land use planning the most desirable consumer options.

High Speed Rail

With California's relentless population growth, demand for air travel will also increase—particularly between the northern and southern portions of the state. California's airports, however, are reaching their capacity to provide service, and proposals to expand San Francisco and Los Angeles airports have met with strong opposition from environmentalists and local communities.

Aviation accounts for about 10 percent of greenhouse gas emissions from transportation in the U.S., or about 2.7 percent of total national greenhouse gas emissions. Because international treaties prevent California from regulating aviation fuels, those fuels are not covered by the state's low carbon fuel standard.

At some point, California will need to provide an alternate means of travel between northern and southern California, one that also reduces greenhouse gas emissions. A potential option is a high-speed rail system, similar to those currently in use in Europe and Asia. The Center for Clean Air Policy estimates that high-speed rail in California could displace 1.3 million metric tons per year of CO_2 from airplane emissions.

The California High-Speed Rail Authority was created in 1996 to build a high-speed train network to transport passengers between the state's major metropolitan areas. The full system will cost more than $33 billion to build, and will take 8-11 years to develop and begin operation of an initial segment of the train.

Currently, a $10 billion bond measure to help pay for high-speed rail is slated for the November 2008 ballot. However, political leaders have suggested delaying the measure (which has been delayed twice before) to 2010 or 2012.

Corporate Average Fuel Economy (CAFE) Standards

The average, on-road fuel economy of cars and light-duty trucks in California increased from 12.6 miles per gallon (mpg) in 1970 to 20.7 in 1985 as a result of federal standards. These standards have not substantively changed in the last 22 years. Fleet averaged, on-road fuel economy has deteriorated steadily as consumers purchased more light trucks, especially sports utility vehicles (SUVs), which meet a lower mpg CAFE standard. With the implementation of small increases in CAFE requirements for light trucks as described below, this trend began to reverse in 2004 and the combined fleet's fuel economy has gradually improved by about two mpg.

The goal of the original 1977 federal CAFE standards for passenger cars was to double new car fuel economy to 27.5 mpg by model year 1985. Congress did not specify a target for the improvement of light truck fuel economy. Instead, it directed that they be established administratively, at the maximum feasible level for model year 1979 and each year after. The act gave the exclusive authority for establishing fuel economy standards to the federal government.

The National Highway Traffic Safety Administration (NHTSA) is responsible for establishing and amending the light-truck CAFE standards.

In April 2003, NHTSA adopted new, “reformed” light truck CAFE requirements, based on size (distance between front and rear axles times average wheel track width) with larger vehicles allowed to have lower fuel economy. The reformed light truck CAFE requirements increase the standard to 21.0 mpg in 2005, 21.6 mpg in 2006, and 22.2 mpg in 2007. These values assume the same market shares by vehicle size as previous sales. Additionally, the reformed CAFE requirements apply to medium-duty passenger vehicles (rated at 8,501 to 10,000 pounds gross vehicle weight).

Because CAFE standards have been largely unchanged until the modest improvements in 2003, most technological improvements to engines and vehicles have been used to increase performance and overcome weight gains from the larger vehicles, especially trucks and SUVs, rather than to improve fuel economy.

National experts, such as the National Research Council of the National Academy of Sciences and the American Council for an Energy Efficient Economy, have identified multiple pathways to achieve an on-road fleet average fuel economy of 30 to 45 mpg. Their analysis shows that, in most instances, increasing fuel economy creates consumer fuel savings that exceed the increased cost of the more fuel-efficient vehicle. In addition, society benefits from improvements to the environment and energy security.

Requiring vehicle manufacturers to improve fuel economy, however, is the sole domain of the federal government. The challenge for California policy makers is to work effectively with the federal government to improve new vehicle fuel economy.

In June 2007 the United States Senate voted to raise fuel efficiency standard for cars to 35 mpg by 2020. By November 2007, no action has been taken by the House of Representatives and the fate of any legislation to modify CAFE remains uncertain. This proposed legislation is a step in the right direction because United States manufacturers individually have only recently begun to see the value of improving their vehicles’ fuel economy as they lose market share to other companies. By instilling "fuel economy discipline" through more demanding CAFE requirements, manufacturers will be better able to compete with international companies in the world market. A recent analysis by the University of Michigan’s Transportation Research Institute has concluded that adopting size-based CAFE requirements similar to those adopted for light trucks would improve the competitive position of U.S. automobile manufacturers and workers.[265] CAFE improvements do not have to reduce vehicle safety or compromise performance; hybrid-electric vehicles are proof of this.

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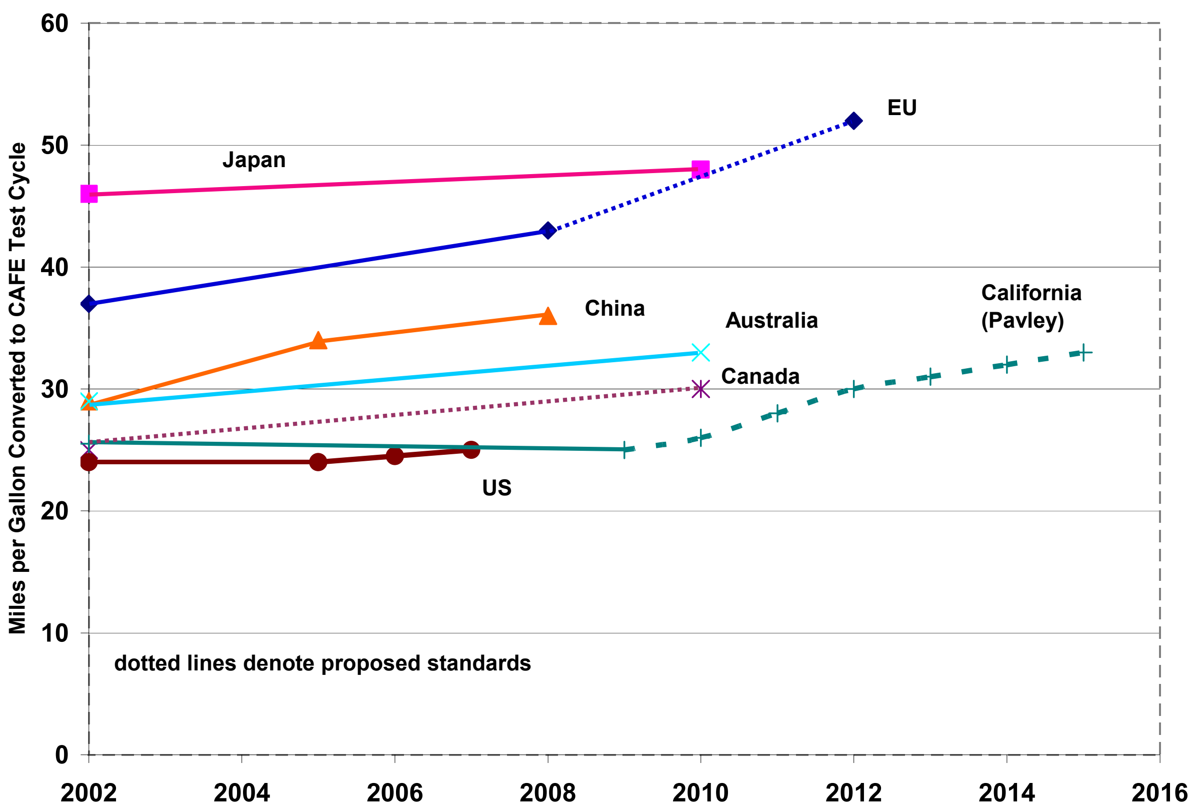
[265] Walter S. McManus, PhD. Director, Automotive Analysis Division, University of Michigan Transportation Research Institute, Ann Arbor, Michigan, July 2007, page 5.

Japan, the current leader in the auto industry, has a fuel economy standard equivalent to 45 mpg. Europe has recently passed legislation to raise its fuel economy standards to more than 50 mpg by 2012 and even China and Australia have higher fuel economy standards than California and United States (Figure 7-8).

Figure 7-8: Comparison of Fuel Economy of Passenger Vehicles



Source: Pew Center on Global Climate Change, Comparison of Passenger Vehicle Fuel Economy and Greenhouse Gas Emission Standards Around the World, December 2004

A study by the Union of Concerned Scientists found that a 35 mpg fleet would create as many as 170,800 jobs in 2020 - including 22,300 in the auto industry - and save consumers nearly $25 billion on gasoline with average prices at $2.55 per gallon. The increase in fuel efficiency would also decrease the demand for oil in the U.S. by close to 2.5 million barrels of oil per day.

Since over 39 percent of California's greenhouse gases come from transportation (on-road gasoline use is 27.7 percent, on-road diesel use is 5.8 percent and railroad, marine and aviation make up the remainder), it is important to address this problem at its source.

The *2003 Integrated Energy Policy Report* stated that California should work to build a coalition with other states and stakeholders to influence Congress and the U.S. Department of Transportation to once again double the fuel economy of new passenger cars and light trucks. Three proposals now active in Congress would implement reformed CAFE requirements for both passenger cars and light duty trucks and would require the overall U.S. market to improve from a 2005 base of 23.7 mpg to 32 to 35 mpg.[266] The modest improvements seen to date, and even the more aggressive targets in pending legislation, suggest that coalition building must continue.

The recommendation to double fuel economy as called for in the *2003 Integrated Energy Policy Report* was based on results of a joint Energy Commission/ARB study of options to reduce petroleum use, as directed by AB 2076 (Chapter 936, Statutes of 2000). This recommendation was by far the single most significant and cost-effective petroleum reduction strategy resulting from this joint study, which was based upon technologies either already on, or about to enter, the market.

Fuel Substitution Options - Assembly Bill 1007 Alternative Fuels Plan

Governor Schwarzenegger, in his response to the *2003 Integrated Energy Policy Report*, called upon the Energy Commission to craft a workable long-term plan to increase the use of alternative fuels. Recent legislation, AB 1007 directs the Energy Commission, in partnership with the Air Resources Board, to develop a State Alternative Fuels Plan (Plan) to increase the use of alternative fuels without adversely affecting air pollution, water pollution, and public health.

Assembly Bill 1007 specifically requires the State Alternative Fuels Plan to:

- Evaluate alternative fuels using a full fuel cycle analysis.
- Set goals to increase the use of alternative fuels in 2012, 2017, 2022.
- Recommend policies, such as standards, financial incentives, research and development programs, to stimulate the development of alternative fuel supply, new vehicles and technologies, and fueling stations.

The Energy Commission initiated a process involving over 50 multiple one-on-one meetings with key stakeholders and six public workshops conducted over the past year. The Plan, developed in partnership with the ARB, was adopted by the Energy Commission on October 31, 2007.

The Plan presents actions California must take to increase the use of alternative fuels and make alternative fuels a significant option to meet the state's transportation energy needs in an environmentally sound and sustainable way. Sustainability requires the state to meet its future transportation energy needs with a growing viable supply of alternative fuels, and to ensure that in accessing biofuels as alternative fuels, food access and energy crops needs are balanced, biodiversity is protected, and water demands and use of agricultural chemicals do not harm the environment.

The Plan recommends a combination of regulations, incentives, and market investments to achieve increased penetration of alternative and non-petroleum fuels. In addition, to accomplish

[266] Ibid., Table ES-2.

a longer-term vision for the year 2050, increased use of alternative fuels, vehicle efficiency improvements and significant reductions in vehicle miles traveled are needed. The Plan describes strategies, highlights actions, and recommends mechanisms to concurrently address multiple state policies in an integrated fashion:

- Petroleum reduction: joint recommendations by the Energy Commission and the Air Resources Board in response to Assembly Bill 2076 (Chapter 936, Statutes of 2000).[267]
- Greenhouse gas reduction: Assembly Bill 1493, Governor's Executive Order S-3-05 on Climate Change (2005), Assembly Bill 32, the Global Warming Act (2006), and Governor's Executive Order S-1-07 on the Low Carbon Fuels Standard.
- In-state biofuels production and use goals: California Bioenergy Action Plan and the Governor's Executive Order S-06-06 on Biomass.
- State air quality goal: on-going reductions in criteria pollutants and toxic air contaminants.

The Plan concludes that existing programs and regulations alone cannot achieve the state's multiple policy goals; the state needs a portfolio of alternative, low-carbon fuels to meet the multiple goals of petroleum use and greenhouse gas emission reduction, and biofuels production and use. The plan recommends multiple strategies which combine private capital investment, financial incentives, and technology advancement approaches.

Achieving the state's petroleum use reduction, climate change air quality, and biofuels goals will require substantial investment in fueling infrastructure, production facilities, vehicle components, and commercial development of "second generation" alternative fuels and advanced technology vehicles.

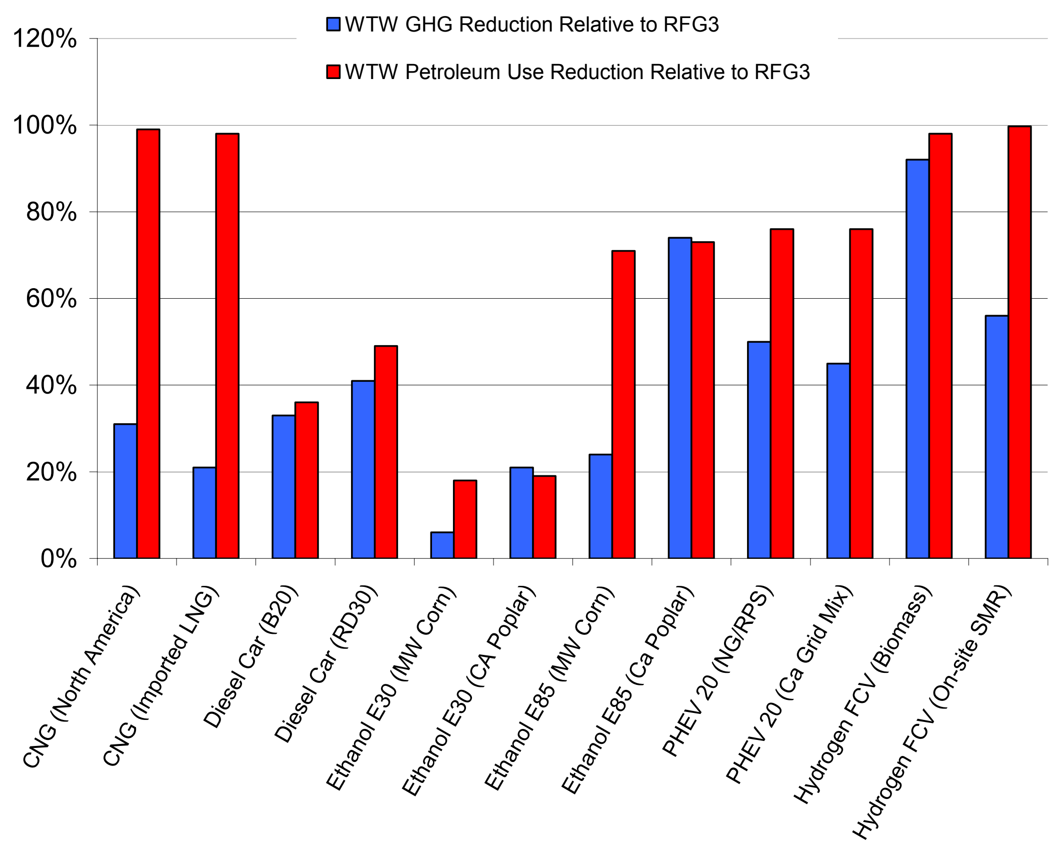
Federal and state incentives will be needed to complement mandates, standards and regulations, and they must be coordinated, sustained and consistent over the 20 to 30 year period. More importantly, substantial capital investment by the private sector must be properly directed toward advanced technology and infrastructure. With these strategies, the Plan identifies the potential for steady and substantial growth in the use of many alternative fuels, the mix of which will change and evolve over the near term (2007-2015), mid term (2016-2030,) and long term (2031-2050).

Full Fuel Cycle Evaluation

Figure 7-9 shows the greenhouse gas and petroleum reduction performance of new light-duty vehicles on a well-to-wheels (WTW) basis for selected alternative non-petroleum fuels as a function of feedstock, compared to Phase 3 Reformulated Gasoline (RFG3). The figure clearly shows the greenhouse gas emissions are dependent on feedstock origins and production pathways.

Results of the Plan's full fuel cycle WTW analysis demonstrates that alternative fuels can provide substantial greenhouse gas reduction benefits when used in mid-size passenger cars and urban buses. Depending on the fuel pathway chosen, fuels such as ethanol, natural gas, liquefied propane gas (LPG), electricity, and hydrogen have decided advantages over conventional gasoline and diesel fuels. Most of the alternative fuels have a 10 percent or better carbon intensity, when compared to petroleum fuels. The Energy Commission plans to update the full fuel cycle analysis in future cycles to address sustainability issues and land use conversion impacts of biofuels.

Figure 7-9: Vehicle GHG and Petroleum Reduction Performance



Source: California Energy Commission, Full Fuel Cycle Assessment, June 2007.

Alternative Fuel Goals

Goals for each fuel were developed using a scenario approach without expressing a policy preference for any single fuel or technology. Each scenario has a Business-As-Usual (BAU), Moderate and Aggressive case. The cases differ by the assumptions made about technology maturity, vehicle and infrastructure availability, fuel supply and fuel type. Alternative fuel and vehicle goals were not simply based on desired reductions in petroleum use and emissions, but were derived from assessments about the potential market expansion of each alternative fuel, informed by substantial research and discussions with the alternative fuel industries. Fuel use goals were determined by several approaches appropriate to the data available for the Assembly Bill 1007 candidate fuel or an appropriate analog for the fuel and vehicle technology combination.

Table 7-1. Alternative Fuels Use Goals

Alternative Fuels Case	Milestone Year		
	2012	2017	2022
AB 1007 Goals (Moderate Case)	9%	11%	26%

Source: California Energy Commission, *Alternative Fuels Plan*, October 2007.

Biofuels, produced from the state's agricultural, forestry, and urban waste residues, should be pursued in the short term, because of the resulting petroleum use reduction, waste reduction, and climate change benefits. Over the longer term, advanced biofuels, hydrogen, and plug-in hybrid vehicles are expected to play a role in meeting California's Low Carbon Fuel Standard.

Certain biofuels can provide large greenhouse gas reductions (up to 75 percent compared to gasoline) because CO_2 emissions are recycled through plant photosynthesis. Changes in agricultural land can have a dominant impact on biofuels pathways, however, and the potential land conversion effects need to be better quantified.

Key Findings and Conclusions

The Plan recommends a five-part strategy to achieve the state's petroleum reduction, biofuels and greenhouse gas reduction goals:

A multi-part strategy will maximize the use of alternative fuels, relying on increased alternative fuels use, blending biofuels, advanced fuels and vehicle technologies, improved vehicle fuel efficiency, and measures to reduce vehicle miles traveled.

The Plan established targets on a gallon of gasoline equivalent basis for alternative fuels use in the on-road and off-road sectors (excluding air, rail and marine), including but not limited to, electricity, natural gas, propane, hydrogen, ethanol, renewable diesel, and biodiesel of nine percent by 2012, 11 percent by 2017, and 26 percent by 2022.

These strategies can help achieve the 2050 future vision outlined in the Plan, and support the Governor's goal of reducing statewide greenhouse gas to 80percent below 1990 levels by 2050.

The combination of regulations or standards, financial incentives, and technology advancements are needed to achieve the state's multiple policy goals.

The Low Carbon Fuel Standard will achieve 30 percent of the transportation sector's proportional share of the greenhouse gas reductions; provide a durable framework for the production and use of alternative fuels; and stimulate technology innovation.

Private investment and state and federal incentive funding are needed to offset the cost difference between gasoline or diesel and alternative fuel use; share the cost of installing fueling stations; and fund the development and demonstration of clean and advanced transportation technologies to the extent that market competition and market mechanisms cannot fulfill this need.

Assembly Bill 118 (Nuñez, Chapter 750, Statutes of 2007) provides a source of state incentive funding to stimulate production and use of alternative fuels in California.

Recommendations

To continue to meet California's growing transportation fuels needs while also complying with the directives of AB 32, the Energy Commission should:

- Stress to local and state authorities the connection between infrastructure expansion requirements and measures that reduce demand for petroleum fuels, as shown in this report by the impact of the greenhouse gas regulations.
- Propose a new law that allows state appeals in the petroleum marine infrastructure lease renewal process at the Ports of Los Angeles and Long Beach.
- Monitor the impact on infrastructure development of the State Lands Commission Marine Oil Terminal Engineering and Maintenance Standards, especially on clean fuels marine terminals in the Ports of Los Angeles and Long Beach.
- Press for a firm federal funding mechanism to maintain an adequate depth for tanker traffic in the Pinole Shoal in San Francisco Bay.
- Update and reissue every to years, the State Alternative Fuels Plan, as part of the Energy Commission's biennial *Integrated Energy Policy Report*, to include specific recommendations, sate agency and private sector responsibilities, and timetables necessary to increase the use of alternative fuels in California.
- Work collaboratively with ARB, key stakeholders, and other relevant agencies to regularly update the full fuel cycle analysis in an open and transparent manner.
- Continue to refine the underlying economic analysis, assessment of alternative fuels current status and market potential for alternative fuels.
- Improved its analytical ability to better quantify the agricultural land conversion and water consumption effects of biofuels production.

- Develop and recommend sustainability standards to guide the future development of alternative fuels in California, in partnership with ARB.
- Move quickly to implement AB 118, beginning with forming the advisory body as directed in the legislation.
- Develop a strategic investment plan for alternative fuel and vehicle incentives, as required by AB 118 (Nuñez, Chapter 750, Statutes of 2007), to be updated annually.

CHAPTER 8: MITIGATING ENERGY NEEDS WITH SMART GROWTH

The neighborhoods we live in and the cars we drive around them are major contributors to greenhouse gas emissions. Adding 24 million new California residents by 2050 will push greenhouse gas emissions from vehicle and home energy use even higher – in direct opposition to the goals of AB 32 and the Governor's Executive Order S-3-05.

> ***"The oldest task in human history: to live on a piece of land without spoiling it."***
>
> Aldo Leopold, *Ecologist* (1887-1948)

The location and size of the average home in California have changed significantly in the past several decades. Returning World War II veterans married and flocked to the suburbs. A thriving economy increased automobile ownership, an expanded urban road network, and available land continued the trend. The result was a dispersed urban geography, often called sprawl, which characterized both suburbs and large cities like Los Angeles. More expensive housing and less land available for development have pushed suburbs even farther from city centers, with potential homeowners employing the "drive 'til you qualify" mortgage option in the hopes of finding affordable housing.

This 60-year legacy of suburban growth, increased auto use, and an inexpensive and reliable fuel supply have increased the miles we drive to work, to the grocery store, to soccer games, and social events. The resulting vehicle miles traveled (VMT) account for 27 percent of California's greenhouse gas emissions and are increasing at a rate markedly faster than the population.

Residential home styles have changed as well. Nationally, single-family homes have doubled in size from just less than 1,000 square feet in 1950 to 2,265 square feet in 2000.[268] Residential energy use (electricity and natural gas) accounts for 14 percent of California's greenhouse gas emissions.[269] Studies have shown that the type of housing (such as multi-family) and the size of a house have strong relationships to residential energy use. Residents of single-family detached housing consume over 20 percent more primary energy than those of multifamily housing and 9 percent more than those of single-family attached housing.[270]

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[268] America's Housing 1900-2000, A Century of Progress. National Association of Homebuilders, http://www.nahb.org/assets/docs/files/v5_513200312545PM.pdf

[269] http://www.climatechange.ca.gov/policies/1990s_in_depth/page5.html.

[270] Rong, Fang, 2006, Impact of Urban Sprawl on U.S. Residential Energy Use, University of Maryland, http://hdl.handle.net/1903/3848.

California's efforts to reduce greenhouse gas emissions lead the nation. Programs to replace petroleum with cleaner alternative fuels, reduce greenhouse gases from new cars sold in the state, and reduce the amount of carbon in our fuels are some of the leading edge policies the state is implementing to reduce the impact of transportation on California's climate.

But even these programs, added together, are not enough to meet AB 32 goals due to the significant expected increase in VMT, which is impacted by our community design choices. Given the long-term nature of neighborhoods, there are also likely significant indirect energy savings from improved infrastructure design attributes, such as narrower streets, more efficient street lighting, enhanced tree shading, reduced imperviousness of pavement, and maintenance of natural drainage courses that should be considered. A new land use dynamic is needed. Planning that results in a larger proportion of more compact and energy and resource-efficient homes close to transit, work and services — smart growth — must be a state priority.

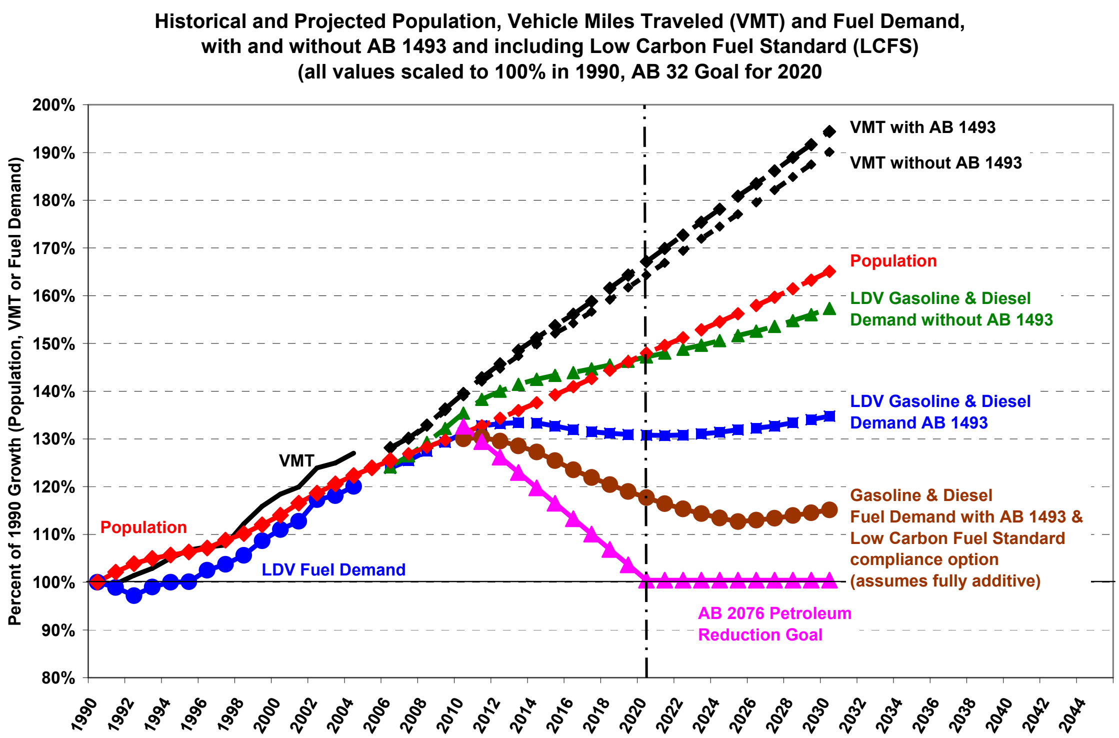
Impact of Land Use on Energy Consumption, Production, and Distribution

Urban growth patterns have caused California's VMT to increase at a rate of over 3 percent a year between 1975 and 2004, markedly faster than the population growth rate over the same period. This VMT created 130.9 million metric tons of CO_2 in 2004. The California Department of Transportation (Caltrans) estimates that VMT will continue to grow at nearly 3 percent annually into the foreseeable future. A continuing increase in VMT caused by California's expected growth is predicted to push CO_2 emissions to 152.6 tons by 2020, a 16.6 percent increase without AB 1493 (which requires the Air Resources Board to adopt regulations to reduce the emissions of greenhouse gases by motor vehicles) and the Low Carbon Fuel Standard (LCFS).

The degree to which transportation greenhouse gas emissions must be reduced is uncertain given the status of several approaches to reduce these emissions. However, it is apparent that reduced VMT growth will be required to meet greenhouse gas reductions goals. It is imperative that land use planning and infrastructure investments place a high priority on reducing VMT growth. Meeting Executive Order S-3-05's long-term goal, which requires a reduction by 2050 to 80 percent below 1990 emissions levels, would certainly require nearly carbon-free transportation and strong actions to reduce VMT.

Figure 8-1 shows California's growth in VMT, gasoline and on-road diesel consumption are indexed to the 1990 value, the year that AB 32 greenhouse gas control measures are required to be met by 2020. Figure 8-1 can also be used to view the historical growth in transportation fuel use (and associated greenhouse gas emissions) relative to VMT and the degree of reduction needed to return to 1990 levels. Also plotted in Figure 8-1 are projected gasoline and on-road diesel use and VMT projected by Energy Commission staff for the *2005 Integrated Energy Policy Report*. Transportation fuel use is plotted both with and without the effect of AB 1493, and one line shows the result with AB 1493 and with the LCFS, assuming it is entirely added to reductions obtained by implementing AB 1493.[271]

Figure 8-1: Historical and Projected Population, VMT, and Fuel Demand (2007)



Source: California Energy Commission

Since greenhouse gas emissions from gasoline are such a large portion of total state greenhouse gas emissions (27 percent), it is likely that these emissions will have to be controlled to meet the goals of AB 32. The goals have yet to be established for specific energy end-use sectors such as transportation, but the overall goal represents about a 29 percent reduction in projected 2020 emissions. This percentage can be used to compare

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[271] AB 1493 has an "alternative compliance option" that could include low-carbon fuel, and therefore, the low carbon fuel standard may not be entirely additive.

the historical and projected gasoline demand. From Figure 8-1 it can be seen that the gallons of transportation fuel used in 2004 grew 20 percent above 1990 usage. Projected usage in 2020 is about 45 percent over 1990 consumption, if AB 1493 is not approved by the courts, and about 31 percent if it is upheld and implemented on the schedule adopted by ARB.

Figure 8-1 also shows the effect of the LCFS, assuming implementation of the "linear" compliance schedule and assuming that these reductions are fully additive to fuel use reductions accomplished by AB 1493 and the Zero Emissions Vehicle Program. The LCFS technical report shows annually decreasing carbon intensity[272], but the effects of the LCFS are projected only to 2020. The additive effect of these strategies reduces future transportation fuel consumption such that by 2025 it is only about 15 percent above 1990 consumption. This indicates that even with AB 1493 and the LCFS, significant further efforts (roughly equivalent to the projected magnitude of AB 1493 or the LCFS) would be needed to reduce the transportation sector's fuel consumption and greenhouse gas emissions to their 1990 levels by 2020 as required by AB 32.

Land use patterns play a direct role in the rate and growth of VMT, influencing the distance that people travel and the mode of travel they choose.

A 2002 U.S. Environmental Protection Agency study[273] compared the impacts of compact and sprawling counties on transportation patterns. Sprawl was defined as:

- A population widely dispersed in low density residential development.
- A rigid separation of homes, shops, and workplaces.
- A lack of distinct, thriving activity centers, such as strong downtowns or suburban town centers.
- A network of roads marked by very large block size and poor access from one place to another.

Sprawl was measured for 83 of the nation's largest metropolitan areas. The research suggests that counties with an inverse proportion of the above sprawl characteristics had significantly less average vehicle ownership, daily VMT per capita, annual traffic fatality rate, and maximum ozone level days. At the same time, shares of work trips by transit and walk modes increased to a significant degree.

[272] Table 2-2 of the LCFS technical report.

[273] Ewing R., R. Pendall, and D. Chen, "Measuring Sprawl and Its Impact," Smart Growth America/ U.S. Environmental Protection Agency, Washington D.C., 2002.

Of the many factors that can be used to quantitatively analyze development and transportation interactions, density may have the most significant relationship to travel and transportation outcomes. Controlling for other factors, the difference between low and high density U.S. metropolitan areas is more than 40 percent daily per capita VMT. A doubling of neighborhood density can be expected to result in approximately a 5 percent reduction in both vehicle trips and VMT per capita.

Accessible, highly dense, mixed-use communities result in shorter length of vehicle trips. Of particular note is the difference between centrally-located developments and development along the outskirts of established areas. Areas of high accessibility—such as center cities[274]—seemed to produce substantially lower VMT than dense mixed-use developments in the exurbs.[275] Trip frequencies seem to depend mostly on socioeconomic and demographic factors, but overall VMT and vehicle trips declined as accessibility, density, and/or land-use mixing increased. As Dr. Reid Ewing noted in the June 26, 2007, Energy Commission workshop, "a smart growth development plan that increases average density by 30 percent, emphasizes infill, and mixes land uses to a high degree would be expected to reduce regional VMT by about 15 percent per capita over 30 years at an average metropolitan growth rate."

The length and number of work trips seem to be growing because of an imbalance between the availability and affordability of housing with the number and earning power of jobs. In the San Francisco Bay Area, average commuting vehicle miles grew by 23 percent between 1980 and 1990 as rising housing prices forced more and more people to move farther out and commute into San Francisco. If jobs were brought into balance with housing, "(all) things being equal, every 10 percent increase in the number of jobs in the same occupational category within four miles of one's residence (would be) associated with a 3.29 percent decrease in daily work-tour VMT."[276]

A balance of jobs and housing may reduce daily work VMT, which is important in managing congestion, but work trips account for a small and shrinking percentage of total travel. According to the National Household Travel Survey 2001 Highlights Report, 45 percent of daily trips were made for family and personal reasons, such as shopping and running errands, 27 percent were made for social and recreational purposes, and 15

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[274] A city's downtown and adjacent neighborhoods.

[275] Prosperous rural communities beyond the suburbs that become commuter towns for an urban area.

[276] Cervero, Robert and Michael Duncan, 2006, "Which Reduces Vehicle Travel More: Jobs-Housing Balance or Retail-Housing Mixing?", Journal of the American Planning Association, Autumn 2006, Vol. 72, No. 4, p. 482.

percent were made for commuting to work.[277] "Nonwork is the major reason for travel even in peak travel periods. It may also be linked to the rapidly increasing numbers of commercial vehicles in service."[278]

Non-work VMT is a large portion of travel, which may not respond to traditional methods of reducing VMT in the same way.

Transit-oriented developments, for example, may be more successful if they are designed to facilitate non-auto errand trips as well as transit commutes. The relationships between possible explanations and travel behavior are complex, and researchers are just beginning to try to understand them.

Unintended Tax Consequences

Land use patterns, and the VMT resulting from them, are influenced by the tax revenues available to local governments. One of the largest impediments to local governments' embracing of energy-efficient and climate-friendly growth patterns is the structure of local-government finance.

Proposition 13 significantly cut local tax revenue and altered the way local governments fund public services and infrastructure. In particular, it encouraged cities and counties to impose heavier exactions - sometimes known as developer fees or impact fees—to pay for roads, sewers, parks, and schools.

Local governments receive 1/7 of the state sales tax for sales in their local districts. So in addition to exacting fees on developers, local governments also started encouraging development that increased sales tax revenue; such as shopping malls, car dealerships, and hotels. By contrast, land uses that produce only property taxes and have a high public service cost, such as moderately priced housing, became less desirable. This caused counties and cities to favor sales tax-generating retail development rather than property-tax-bound residential uses, a circumstance commonly referred to as "the fiscalization of land use."

As a result of these tax policies, local land use planning and decision-making may demonstrate a bias toward tax revenue-driven development. Such development often may pit one community against another in an effort to attract businesses that generate sales tax. Local competition for retail and auto malls rarely balances community housing

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[277] U.S. Department of Transportation and Bureau of Transportation Statistics, 2003, NTHS 2001 Highlights Report, BTS03-05, Washington, D.C.

[278] Nelson, Dick and John Niles, January 9-13, 2000, "Observations on the Causes of Nonwork Travel Growth," Transportation Research Board 79th Annual Meeting, Washington, D.C., Paper No. 00-1242, p. 2.

needs with the benefits of non-retail business and industry and may exacerbate transportation and associated environmental problems.

The state should conduct a thorough review of the impact of tax policy on land use patterns in the California.

Residential Energy Supply and Use Offer Additional Opportunities

To ensure a reliable and secure source of electricity, and reduce residential greenhouse gas emissions, land use planning must also consider energy demand, supply and infrastructure. Increasing on-site production of renewable energy, using distributed generation, orienting residences in relation to the sun, increasing shading, incorporating roofs that reflect heat, and installing energy efficient appliances and more efficient streetlights are some measures that would produce significant energy savings at the individual building and community levels. Most developments, if they consider energy, do so in the context of building efficiency. However, much more is possible and necessary.

Local governments and utilities are joining forces to plan new communities from inception to full build-out. Military base closures and reuse present a particular opportunity to explore these concepts. For example, Southern California Edison and Southern California Gas Companies have joined forces with the City of Irvine, Lennar Corporation, and energy and land use experts to develop a new energy infrastructure for the proposed Irvine Great Park. The Great Park will use energy efficiency and fuel diversity to meet a goal of net zero energy use. The target is homes that use 40 percent less energy than required by California Building Energy Efficiency Standards (Title 24) and non-residential facilities that use 30 percent less energy than is required by the standards. In addition, the Great Park will incorporate advanced metering infrastructure, solar photovoltaics, district heating and cooling, distributed generation, transportation strategies, lighting technology, waste to energy and grid islanding.[279]

The Road to Better Land Use Planning

Currently, land use planning, although linked to transportation and air quality planning, is not integrated with these activities. Opportunities exist at all levels of government for integrated planning that would reduce energy demand and greenhouse gas emissions as well as eliminating redundant or conflicting efforts. At the local level, general plans and zoning codes are incorporating more growth management and energy measures. At the regional level, hundreds of millions of dollars are spent annually on transportation, land use, and air quality planning and better coordinating these efforts will reduce energy demand, for example, by tying transportation funding to smart growth land use plans. At the state level, policies and plans (the California Environmental Quality Act, the

[279] Irvine Great Park Energy Subteam Update, November 2006.

California Transportation Plan, housing element updates, the California Water Plan, and stormwater plans) and the state's purse strings can be used as levers to effect land use patterns.

Local Government Plans Need to Address Energy and Greenhouse Gas Emissions Reductions

The state has limited authority in direct land use planning, rather conducting activities that more indirectly influence land use decisions. Local governments hold the majority of land use authority in California and express their legally enforceable policies through required general plans and zoning codes. General plans set forth objectives, principles, standards, and proposals for development. State law requires these general plans to address land use, circulation, housing, open space, conservation, safety, and noise.

No state mandate requires that a general plan include an energy element — a part of the general plan that addresses energy demand and resource development of a community. Only about 10 percent of California's general plans include such elements, and over half of the state's jurisdictions have general plans more than 10 years old.[280]

Currently, there is no state guidance for how local governments should assess, report, avoid or mitigate greenhouse gas emissions resulting from their land use decisions.

The passage of SB 97 (Dutton, Statutes of 2007) requires the Governor's Office of Planning and Research to develop, and the Resources Agency to adopt, guidelines for the feasible mitigation of greenhouse gas emissions or the effects of greenhouse gas emissions. This will lead to local governments performing analysis of, and offering mitigation efforts for, the potential greenhouse gas emissions impacts of growth within their jurisdictions and will require them to address greenhouse gas considerations in their general plan and other planning efforts.

Issues such as housing, transportation and congestion, economic development and air pollution and greenhouse gas reduction lend themselves to, and in some cases require, a more regional approach. City and county boundaries and authority can limit an agency's ability to affect change as it may require collaboration from regional peers to effectively attain its policy goals. An example of this is the adoption of smart growth principles by a city attempting to reduce sprawl by limiting low-density development within its boundaries. If the city's regional partners do not support the city's efforts by adopting similar policies, and instead allow low-density, sprawling development in the jurisdiction, then the region could still suffer from the negative impacts (congestion, greenhouse gas emissions, etc.) of the development.

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[280] Roberts, T. 2006. Remarks presented at Land Use and Energy Workshop, California Energy Commission, September 22, 2006

Regional Blueprint Planning Efforts Show Promise

California's Regional Blueprint Planning Program[281] provides a model example of the potential benefits of regional planning. The program is based on the principles of regional collaboration, stakeholder involvement, more efficient land use patterns, and more housing and transportation choices. The Program provides funding to help regional governments create long-term growth plans consistent with the above principles. The Blueprint Learning Network coordinates state and regional agencies to share experiences and best practices in making better infrastructure investment decisions. As a result, nearly all of the state's metropolitan planning organizations (MPOs) are developing long-range growth and transportation plans.

The program involves the proactive engagement of all segments of the population, as well as critical stakeholders in the community, business, academia, developers, construction, and environmental organizations, to foster consensus on a vision and preferred land use pattern in a given region. The regional blueprint planning grants are intended to build capacity for regional collaboration and integrated planning that will, in turn enable regions to plan to accommodate all their future growth, thereby reducing sprawl.

If implemented aggressively, blueprint planning could reduce future VMT. For instance, projections to 2050 showed that the scenario preferred by Sacramento stakeholders and adopted by the regional governing body could use 46 percent less new land, reduce VMT by 12.3 miles per household per day, and produce 15 percent less CO_2 and particulate matter per capita, as compared to the business-as-usual case Base Case 2050 (see Table 8-1). However, even though VMT declines compared to the business-as-usual Base Case 2050, Sacramento total regional VMT per day grows from 43 million in 2000 to 53 million in 2050 because the number of households more than doubles during that timeframe.

281 http://calblueprint.dot.ca.gov/

Table 8-1: Key Statistics Comparing Sacramento Base Case Scenario 2050 and Regional Preferred Scenario 2050

PARAMETER	BASE CASE 2050	ADOPTED PLAN 2050	DIFFERENCE
VMT per household per day (excludes commercial vehicles)	47.2	34.9	12.3 fewer miles per household per day, a 25% reduction
People Living in Areas with Good Mix of Jobs and Housing	26%	53%	27% increase
Growth Near Transit	5% New Jobs 2% New Housing	41% New Jobs 38% New Housing	36% more new jobs near transit 36% more new homes near transit
Additional Urbanized Land	666 square miles	304 square miles	362 fewer square miles urbanized
Daily Vehicle Minutes of Travel (per household per day)	81 minutes	67 minutes	14 fewer minutes per day (more than two 40 hour work weeks per year)
Per Capita CO_2 and Small Particulate Emissions from vehicles (includes commercial vehicles)	Set at 100%	85% of Base Case	15% less than the Base Case per capita

Source: SACOG, Blueprint Program, 2005.

The completed Blueprints are in early stages of implementation and will need technical, financial, and regulatory assistance to achieve maximum results. Smaller MPOs, with less staff and modeling capability, could benefit from mentoring assistance from the larger MPOs that have been able to move faster and generally further with their Blueprint programs. The state can replicate best-practices completed in some Blueprint programs to help other regions to form a value-added data collaborative. These collaboratives could pull city and county geographic information system (GIS) data into one place where the members of the collaborative could cost-effectively update, coalesce and amend the data into one fully accessible, integrated database needed for quality Blueprint planning. Aggregated data increases the capacity of regional transportation planning, air quality planning and local general planning to coordinate for improved energy and greenhouse gas efficiency. Each of the MPOs is unique, with its own approach to travel modeling, VMT analysis and greenhouse gas emission quantification. Third-party review of the range of methods for the purpose of producing a set of research, data development, and modeling improvements to advance all MPO programs to a single, standardized level of excellence is needed as soon as possible. Model improvements will lend better accuracy to VMT quantification and enhance the state, regional and local ability to deploy resources to reduce energy use and greenhouse gas emissions.

Blueprint practitioners have requested state support to better assess new challenges presented by the land use demands of energy crops and the effect they have on long term food production, water demand, and land use patterns affecting VMT and greenhouse gases. Interagency support and funding is needed to develop a knowledge base and integrate it into land use planning programs for fully-informed decision making with energy, environmental, economic and social tradeoffs clearly defined.

The state must provide assistance to build the many levels of strong leadership necessary to shape land-use practices and to guide the development of methods to measure and track the effects of land use on the state's energy and climate goals. A state growth plan, prepared in conjunction with regional and local interests, is essential. A state plan should be composed of regional plans, developed by local governments, in a process facilitated by regional agencies, modeled on the Blueprint success. Once regional plans are adopted, the state should compile their data and programs into a statewide growth management plan. Upon adoption of such a plan, state policies and programs should be modified to align with and support the plan. The statewide plan should be updated every ten years, adding maturing regional and local data and plans, to keep the state plan current.

The State's Regulatory Authority and Purse Strings should be used to Better Advantage

The state took a major step toward encouraging smarter growth with the passage of AB 857 (Wiggins, Chapter 1016, Statutes of 2002), which laid out three planning priorities for state agencies: promote infill development and social equity in existing communities; protect and conserve environmental and agricultural resources; and achieve more efficient use of land, transportation, energy and public resources outside the infill areas. Unfortunately, AB 857 has had little effect. While it provided the framework for guiding state agency land use practices, there is no consequence for agencies that do not comply. Currently, the Governor's Office of Planning and Research only has the authority to collect annual reports of agencies self-reported compliance with the law.

While the state has limited land use authority, it does have some key leverage points (California Environmental Quality Act, housing elements, and others) that can be used to assist local governments in reducing energy use and greenhouse gas emissions that result from land use planning choices. T

The state can use the disbursement of transportation and housing funds to motivate collaborative planning at a regional level in an attempt to significantly reduce a community's greenhouse gas emissions. A common methodology for reporting and measuring greenhouse gas emissions contributions for communities is needed.

Infrastructure funding policies influence the design and use of local government infrastructure and development projects. California has a unique opportunity to direct infrastructure investments contained in the Governor's Strategic Growth Plan and approved by voters in November 2006 to those communities that reduce greenhouse gas emissions associated with given projects. The Strategic Growth Plan contained a few programs to encourage energy-efficient, climate-friendly land use but project funding criteria (where they exist) currently contain no energy or climate considerations. The funding criteria ultimately developed for Propositions 1B, 1C, 1D, and 84 will determine the extent to which bond monies contribute to less energy-intensive land use and reduce VMT. The state should build upon the Governor's Strategic Growth Plan by requiring that all state financing for infrastructure incorporate energy use reduction strategies and climate considerations

California Should Learn from Other States

Plans being developed in other states may be instructive to California. Oregon, New Jersey, and Maryland are conducting similar land use planning efforts, some of which are specifically targeted toward greenhouse gas emission reductions. Some of the states and regions within states have tied financial and technical assistance to smart growth planning areas. New Jersey has issued regulations that specifically integrate smart growth principles into utility service policies. Anyone building in state-determined non-smart growth areas must pay the full cost of utility line extensions. Some of the programs are already showing reductions in VMT: Portland residents decreased their daily per capita VMT by 4 percent between 1996 and 2005, while the nation and California both increased daily per capita VMT by 5.7 percent and 6.6 percent, respectively.

Utility Partnerships with Local Planning Efforts are Essential

While electric utilities have been instrumental in supporting local building energy efficiency measures, they have played a limited role in local government planning. Planning for intrastate transmission lines is underway and must address local and regional issues if future infrastructure has any hope of being developed. As mentioned above, utilities are partnering with local governments to plan new residential and commercial developments. The state's investor-owned utilities and municipal utilities need to play an even greater role in planning and development programs and projects. Investor-owned utilities have stated that their ability to do so is hamstrung by current energy efficiency program time and funding constraints.

Research is a Critical Tool for Ensuring Future Success

Land use impacts on energy demand, energy generation, and transmission and on greenhouse gas emissions are in the early stages of exploration. Further research and development is necessary to explain and quantify the effect land use has on energy systems. Research is needed to develop and update existing modeling and decision-support tools to improve the integration of energy considerations into future planning and development efforts. For example, differences in land development patterns result in differences in trip mode choice, number and length. Mechanisms to account for the Five Ds - *Density, Diversity, Design, Destination*, accessibility & Distance to transit — have been developed and successfully used to improve the ability of travel models to assess how VMT is affected by land use patterns. Many local governments and regional agencies, however, find that access to information and a lack of funding prevent them from improving their models to develop and implement climate-friendly and energy-efficient plans and programs. Other MPOs have used internal funding and grants to successfully integrate land use and transportation planning, embedding the Five Ds sensitivity into their travel models to better assess smart growth options. Best practice data, modeling and public education methods found in some California MPOs should be packaged and shared with all MPOs.

The *2006 Integrated Energy Policy Report Update* charged the Energy Commission's Public Interest Energy Research (PIER) group with providing tools and conducting research to assist the energy and greenhouse gas reduction planning efforts of local governments. A number of currently funded projects support this charge. In the next year, over $2 million will be allocated for sustainable communities research. This funding will support initiatives designed to better understand the interaction between energy demand and environmental design principles, to identify infrastructure design impacts on energy and the environment, and to identify design improvements that would reduce energy use in California. Land use modeling tools and methodologies are critical to these initiatives.

Transportation research also is underway through PIER funding, with research designed to reduce petroleum consumption and greenhouse gas emissions through increased vehicle efficiency and lower carbon fuels. Creation of new, and validation of existing, modeling tools used in these and similar research efforts are important elements. Understanding the role of smart communities - those that employ information technology to change how the community uses its physical space - in reducing VMT needs to be explored.

Recommendations

- The state should collect required regional plans and adopt a statewide growth management plan to align State planning, financing, infrastructure and regulatory land use policies and programs.
- The state should require regional transportation planning and air quality agencies to adopt 25-year and 50-year regional growth plans that provide housing, transportation and community services for expected population increases while reducing greenhouse gas emissions to state-determined climate change targets.

- The Air Resources Board should adopt regional greenhouse gas emission reduction levels to guide regional growth management plans in their AB 32 scoping plan. The Board should include in the scoping plan clear guidance on greenhouse gas emissions accounting for urban land use activities and a local government protocol for assessing and tracking greenhouse gas emissions in jurisdictions.
- The Air Resources Board should require local jurisdictions to adopt plans to reduce their greenhouse gas emissions.
- The Climate Action Team's Land Use Subgroup should convene a proceeding to develop recommendations for measuring and reducing vehicle miles traveled.
- The Legislature should mandate local governments to develop regional growth management plans that will accommodate 25-years and 50 years of housing, transportation and community service growth needs while meeting Air Resources Board-set regional greenhouse gas emission targets.
- The Legislature should:
  - Require regional growth management plans to be adopted through a joint process between a region's Municipal Planning Organizations and/or Council of Governments (MPO/COGs) and the local air quality management district (AQMDs).
  - Require local governments to adopt the portion of the regional plan and greenhouse gas emission reduction target that impact their jurisdiction into their General Plans. The plans should clearly identify areas where growth and development should and should not occur.
  - Require MPO/COGs and AQMDs to incorporate the plan and targets into their planning, financing and regulatory programs.
  - Require the Governor's Office of Planning and Research to collect the regional growth management plans and integrate them to create a statewide growth management plan.
  - Require state agencies to modify all programs and policies that affect land use, including but not limited to, planning, financing, capital outlay and compliance, to incorporate, and support, the statewide growth management plan. Colleges, universities and state buildings should also be required to be consistent with the growth management plan.
  - Require that the regional and statewide plans, and the local governments, MPO/COGs and AQMDs adoption of them, shall be updated on ten-year schedule.
- State infrastructure financing should encourage development that is consistent with the state's greenhouse gas emission and energy consumption goals.

- The Legislature should require all remaining Strategic Growth Plan bond programs to incorporate climate change and energy consumption reduction measures.
- If the state adopts growth management legislation as described above, all state infrastructure planning, financing and compliance programs should only allow resources, financial, technical or otherwise, to be spent for development of projects in identified growth areas.
- The Legislature should require that all state infrastructure planning, financing and compliance programs only allow resources, financial, technical or otherwise, to be spent for development of projects in complete consistency with regional Blueprints.
- The Legislature should require that all state infrastructure planning, financing and compliance programs not allow resources, financial, technical or otherwise, to be spent for development of projects in areas not consistent with existing regional Blueprint plans.

• The state should expand efforts to provide technical and financial assistance to regional agencies and local governments to facilitate climate-friendly and energy efficient planning and development.

- The state should continue to fund the Blueprint Regional Planning Grant Program and Blueprint Learning Network (the Network) to assist regional agencies and local governments in developing improved regional land use plans. The grant program should include energy consumption and greenhouse gas emission reduction as primary outcomes of the blueprints developed within the program.
- The state should work with the Network to develop new analytical capacity needed to better inform the long-term planning decisions presented by increased demand for energy crop land allocations, and the integrated environmental, energy, economic and social tradeoffs that will be presented to both rural and urban regional and local governments.
- The state should work with the Network to explore best practices and develop a set of recommendations to improve and to standardize the level of accuracy of VMT and greenhouse gas quantification produced by each MPO and to develop a standardized methodology for applying this information in climate change and energy action plans, Blueprint planning and local planning.
- When growth management legislation is passed, the Grant program and the Network should be modified to support development of the regional growth management plans as specified in the legislation.

- The Legislature should pass legislation that implements the Proposition 84 Sustainable Communities Program. The Program should focus on assisting regional and local governments in developing, implementing and incorporating into existing policies the above mentioned growth management plans, Blueprints and climate action plans.
- The Energy Commission should convene a group of stakeholders, both within and outside of State government, to update its Energy Aware Planning Guide to provide guidance for regional and local governments attempting to adopt local growth management, energy and climate action plans.
- Once the Sustainable Communities program is established and the Commission should coordinate with the California Department of Transportation's existing research efforts to convene a land use research group to identify research needs, carry out research and develop and disseminate tools and resources to land use stakeholders.

- State government should be a model for climate friendly and energy efficient development patterns.
    - The Legislature should pass legislation that builds upon AB 857's intentions by adding greenhouse gas emissions reduction and energy consumption as priority planning goals of the state. The legislation should require that state agencies engaging in or financing the development of infrastructure or capital outlay projects report on the project's compliance with state planning policies during each stage of its administrative and legislative budget approvals. The legislation should require that projects that do not meet the state planning priorities should not be funded except in situations where compliance would be proven infeasible by the sponsoring agency.
    - The Climate Action Team Land Use Subgroup should develop greenhouse gas emissions reduction and energy efficiency guidelines for state agency programs that affect land use. State agencies should adopt the guidelines to the greatest extent feasible.

- The state should determine the extent to which state and local tax policies affect and guide land use practices and correct polices that encourage growth inconsistent with the state's growth management plan.
    - The Governor's Office of Planning and Research, working with local governments, the building community, the university system and other stakeholders should conduct a study of the impacts of state and local tax policy on land use practices in the state. The report should contain recommendations for changing identified tax policy that leads to detrimental land use practices.

- California's utilities should play an active role in regional and local government planning and development efforts at both the plan and project level to encourage climate friendly and energy efficient development in their service areas.
    - The California Public Utilities Commission should allow utility-incentive and technical-assistance programs with longer lead times to enable greater collaboration by utilities with developers and local governments.
- The state should work with its Congressional delegation to ensure that future federal highway and other transportation and land use related legislation and programs include energy reduction and climate stabilization considerations.

APPENDIX A: Participants in the 2007 Integrated Energy Policy Report Process

Individuals from many government and private entities either attended public workshops and/or made comments to the proceeding. The Committee thanks those many individuals for their participation in the 2007 IEPR process.

GOVERNMENT ENTITIES

Anaheim Public Utilities, City of Anaheim
▪ Charles Guss
▪ Marcie Edwards
▪ Stephen J. Sciortino
Arizona Corporation Commission
▪ Steve Olea
Brookhaven National Laboratory
▪ Vasilis Fthenakis, Ph.D.
Burbank Water & Power
▪ Bruno Jeider
▪ Evilia Waloejo
California Air Resources Board
▪ Barbara Fry
California Department of Fish & Game
▪ Bronwyn Hogan
California Department of Forestry
▪ Doug Wickizer
California Department of Water Resources
▪ Jon Seehafer
California Electricity Oversight Board
▪ Eric Saltmarsh
California Geological Survey
▪ John Clinkenbeard
▪ Cameron Downey
California Department of Oil & Gas & Geothermal Resources
▪ Michael Stettner
▪ Bill Winkler
California Public Employees Retirement System
▪ Russell Read
California Public Utilities Commission
▪ John Bohn, Commissioner
▪ Rachelle Chong, Commissioner
▪ Valerie Beck
▪ Andrew G. Campbell
▪ Susannah Churchill
▪ Paul Clanon
▪ Laurence Chaset
▪ Tom Flynn
▪ Sean Gallagher
▪ Chloe Lukins
California State Lands Commission
▪ Martin Eskijian
California Transportation Commission
▪ John Barna
City of Azusa
▪ Bob Tang
City of Banning
▪ Fred Mason
City of Biggs
▪ City Council Members
City of Cerritos
▪ Vince Brar
City of Corona
▪ Yarek Lehr
▪ Kurt Duvall
City of Palo Alto Utilities
▪ Karl Knapp
▪ Debra Lloyd
City of Pasadena Water and Power Department
▪ Anthony S. D'Aquila
▪ Paul Lee
City of Shasta Lake
▪ Paul H. Eichenberger

City of Ukiah
▪ Elizabeth A. Kirkley
City of Vernon
▪ Donal O'Callaghan
Colton Public Utilities
▪ Jeanette Olko
County of Imperial
▪ Jurg Heuberger
County of Kern
▪ Lorelei Oviatt
County of San Bernardino
▪ David Dawson
▪ Jim Squire
Glendale Water and Power, City of Glendale
▪ Ramon Abueg
▪ Burhan AlShanti
▪ Ignacio Troncoso
Governor's Office of Planning & Research, State of California
▪ Terry Roberts
Hercules Municipal Utility
▪ Glen Reddick
Imperial Irrigation District
▪ Jorge Barrientos
▪ Carrie Downey
▪ Noe Gutierrez
▪ Juan Carlos Sandoval
Joint Policy Committee—Regional Planning Program
▪ Association of Bay Area Governments
▪ Bay Area Air Quality Management District
▪ Bay Conservation & Development Commission
▪ Metropolitan Transportation Commission
▪ Ted Droettboom
Lassen Municipal Utility District
▪ Frank Cady
Lawrence Berkeley National Laboratory
▪ Mark Bolinger
▪ Joe Eto
▪ Tom McKone
▪ Larry Myer
▪ Phil Price
▪ Michael Sohn
▪ Matt St. Clair
Lawrence Livermore National Laboratory
▪ S. Julio Friedmann
Los Angeles Department of Water & Power
▪ Oscar Alvarez
▪ Mohamed Beshir
▪ Mauricio Guardado
▪ Randy Howard
▪ John Kerrigan
▪ Brian Koch
▪ Rodney Luck
▪ Jeff Peltola
Merced Irrigation District
▪ Cindy Ardison
Modesto Irrigation District
▪ Greg Salyer
▪ Gerard N. Stillwagon
Moreno Valley Utility
▪ Michael McDonald
National Energy Center for Sustainable Communities
▪ City of Chula Vista
▪ Gas Technology Institute
▪ San Diego State University
Northern California Power Agency
▪ Matthew Foskett
▪ Kenneth C. Goeke
▪ David Reynolds
▪ Scott Tomashefsky
▪ Tony Zimmer
Placer County Biomass Project
▪ Brett Storey
Port of Los Angeles
▪ Dave Mawson
Port of Los Angeles Advisory Committee
▪ Janet Gunter
▪ Kathleen Woodfield
Port of Stockton

- Jeff Kaspar
- Don Smail
- Nick Zettel

Rancho Cucamonga Municipal Utility

- Lynn M. Haug
- Mike TenEyck

Redding Electric Utility

- Nick Zettel

Riverside Public Utilities, City of Riverside

- Ron Barry

Roseville Electric

- Philip McAvoy
- Michael Wardell

Sacramento Area Council of Governments

- Mike McKeever
- Gordon Garry

Sacramento Metropolitan Air Quality Management District

- Bridget Tollstrup

Sacramento Municipal Utility District

- Greg Brownell
- Bruce Ceniceros
- Steven M. Cohn
- Vicken Kasarjian
- Paul Lau
- Gary Lawson
- Ruth McDougal
- Susan Patterson
- James Shetler
- Robin Smutny-Jones
- Nate Toyama

Silicon Valley Power

- Michael Pretto

South Coast Air Quality Management District

- Barry Wallerstein

Southern California Association of Governments

- Hasan Ikhrata

Southern California Public Power Authority

- Manny Robledo

State of Montana, Office of the Governor/Economic Development

- Tom Kaiserski

State of Nevada

- Bob Halstead
- Robert R. Loux

State of Wyoming, Governor's Office

- Steve Ellenbecker

Trinity Public Utilities District

- Rick Coleman

Truckee Donner Public Utility District

- Stephen Hollabaugh

United States Air Force

- Gary Munsterman

United States Bureau of Indian Affairs

- Troy Burdick

United States Bureau of Land Management

- Duane Marti
- Scott Powers

United States Department of Energy

- Michael Brairton
- Jeremy Cusimano
- Timothy A. Frazier
- Eric Knox
- J. Gary Lanthrum

United States Environmental Protection Agency, Region 9

- George Robin

United States Forest Service

- Bob Hawkins

United States General Accountability Office

- Richard Cheston

United States Marine Corps

- Patrick Christman

United States Nuclear Regulatory Commission

- William Jones
- Samson Lee

University of California, Berkeley

▪ Per Peterson, Ph.D.

University of California, Santa Barbara, Bren School of Environmental Science and Management

▪ Robert Wilkinson

Western Area Power Administration

▪ John Goodin

▪ Jeanne Haas

▪ Russell Knight

▪ Havier Van Tran

▪ Hiroshi Kashiwagi

PRIVATE ENTITIES

Advanced Resources International, Inc.
▪ Vello Kuuskraa
Advocates for Clean Responsible Energy
▪ Neil W. Brown
▪ Edwin D. Sayre
▪ Robert F. Williams
AES Corporation
▪ Mark J. Skowronski
AJW Inc
▪ Sarah Wade
Alliance for Nuclear Responsibility
▪ Rochelle Becker
Alliance for Retail Energy Markets
▪ Carmen Baskette
▪ Rick Counihan
▪ Daniel W. Douglass
▪ Gregory S. G. Klatt
Alliance Real Energy, Inc.
▪ Kevin Best
▪ Phil Reese
Alameda Power & Telecom
▪ Mike Brown
▪ Meredith Owens
Amyris Biotechnologies
▪ Kinkead Reiling
APS Energy Services
▪ Jenine Schenk
APX, Inc.
▪ Reiner Musier
AREVA
▪ Alan S. Hanson
▪ Bruce Marlow
Arizona Electric Power Cooperative, Inc.
▪ Ann Alvarez
Arizona Public Service Company
▪ Bob Smith
A 2nd Opinion, Inc.
▪Cal Hodge
Ausra, Inc.
▪ John O'Donnell
Baker and O'Brien
▪ Dileep Sirur
Bevilacqua-Knight, Inc
▪ Richard Myhre
▪ Marian Stone
Border Power Plant Working Group
(member organization of Ratepayers for Affordable Clean Energy)

▪ Bill Powers
Braun & Blaising
▪ C. Anthony Braun
British Petroleum
▪ Ruth Scotti
Bull Moose Energy
▪ Erin Koch
Norman Burgess
Caithness, Western Development
▪ Joe Greco
CalCef
▪ Dan Adler
California Biomass Alliance
▪ Phil Reese
California Clean Distribution Generation Coalition
California Climate Action Registry
▪ David Olsen
California Farm Bureau
▪ Karen Mills
California Independent Oil Marketers Association
▪ Jay McKeeman
California Independent System Operator

▪ Robin Smutny-Jones
▪ Gary Deshazo
▪ Dave Hawkins
▪ Phil Pettingill
▪ Tom French
▪ Dariush Shirmohommadi
▪ David Withrow
California Institute for Energy & Environment

- Steve Schiller

California League of Women Voters
- Jane Turnbull

California Municipal Utilities Association
- C. Anthony Braun
- Bruce McLaughlin

California Natural Gas Vehicle Coalition
- Mike Eaves

California Solar Energy Industries Association
- Sue Kateley

California Wind Energy Association
- Nancy Rader
- Joseph Karp
- Karen Bowen

Calpine
- Dean Cooley

Center for Clean Air Policy
- Suzanne Reed

Center for Energy Efficiency & Renewable Technologies
- Richard Ferguson
- Rachel McMahon
- Paul Vercruyssen
- V. John White

Chevron Technology Ventures
- Paul F. Bryan

City Solar AG
- Steffen Kammler

Clean Energy Group
- Mark Sinclair
- Todd R. Campbell

Clearwater Port, LLC
- Billy Owens

Community Environment Council
- Tam Hunt

Coalition for a Safe Environment
- Jesse Marquez

Climate Protection Campaign
- Mike Sandler

Cogeneration Association of California and Energy Producers and Users Coalition
- Don Schoenbeck
- Nora Sheriff

Columbia University
- Richard Garwin, Ph.D., IBM Fellow Emeritus

ConocoPhillips
- Daniel Sinks

Constellation Generation Group
- John Tormey
- Joe C. Turnage, PH.D.

Constellation Energy
- Joe Turnage

Constellation NewEnergy, Inc
- Andrew B. Brown

Council on Foreign Relations
- Charles Ferguson, Ph.D.

Cultural Economist
- Ronald R. Cooke

Cummins Power Generation
- Eric R. Wong

Ecosystem Solar Electric Corporation
- Nick Panchev

Edison Mission Group/Carson Hydrogen Power, LLC
- Lawrence J. Kostrzewa

Electric Power Research Institute
- Richard Rhudy
- Bob Woehl

Ellison, Schneider and Harris
- Douglas Kerner

ENCO Utility Services
- Jack Stermer

Energy & Environmental Economics, Inc.
- Snuller Price
- C. K. Woo

Energy Investors Fund
- John E. Buehler, Jr.

EnerNOC, Inc.
- Carmen Baskette

Environmental Health Coalition

- Laura Hunter

enXco Development
- Greg Blue

Exergy Consulting
- Beverly Alexander

Florida Power & Light Energy
- John Seymour
- Diane Fellman

Flynn Resources Consultants
- Ed Chang

Fresno Nuclear Energy Group, LLC
- John Hutson
- Tom McClean

FTI Consulting
- Tom Lumsden

FutureGen Alliance, Inc
- Michael Mudd

Future Ports
- Elizabeth Warren

Gas Technology Institute
- John Kelly

George Mason University
- Allison Macfarlane, Ph.D.

Global Energy Decisions
- J. Richard Lauckhart

Golden State Water Co. (for Bear Valley Electric Service)
- David X. Kolk

Goldman Sachs
- Curtis Kebler

GPI
- Greg Morris

Green Party of San Diego County
- Lupita Jimenez

Green Power Institute
- Gregory Morris

Harding Consulting
- Jim Harding

Ron Hofmann Consulting
- Ron Hofmann

Hydro Company, Inc. (dba Nevada Hydro Co., Inc.)
- Rexford J. Wait

ICE Energy, Inc.
- Donald C. Liddell

Independent Energy Producers
- Steven Kelly
- Manny Robledo

Institute for Local Government
- Steve Sanders

INTERTIE, LLC
- Richard Mrlik

Bryce Johnson

Kern River Gas Transmission
- Brent Arnold

Kinder Morgan
- Donald C. Liddell

League of Women Voters
- Jane Turnbull

Levy Associates
- Roger Levy

Local Power
- Robert Freehling

London Economics International, LLC
- Serkhan Bahceci
- Steven Ostrover

Long Beach Citizens for Utility Reform & Californians for Renewable Energy
- Bry Myown
- Regina Taylor

M.Cubed
- Richard McCann

Marsh Alternative Risk Solutions
- Partho Ghosh

Massachusetts Institute of Technology Laboratory for Energy and the Environment
- Howard Herzog
- James Katzer
- Mort Webster

Doug McNea

Metropolitan Water District of Southern California
- Sydney B. Bennion
- Ernest Hahn
- Jon C. Lambeck

▪ Dianna Mahmud
MightyComm
▪ Tom Fulks
Milbank, Tweed, Hadley & McCoy
▪ Kevin McSpadden
National Academies
▪ Kevin Crowley
The National Center for Smart Growth, University of Maryland
▪ Reid Ewing
Natural Resources Defense Council
▪ Audrey Chang
▪ Thomas B. Cochran, Ph.D.
▪ George Peridas
▪ Devra Wang
▪ Eric Wanless
Navigant Consulting, Inc.
▪ Sean Biggs
▪ Lisa Frantzis
▪ Ryan Katofsky
▪ Jay Paidipati
▪ Forrest Small
Neste Oil Holding (U.S.A.), Inc.
▪ Henrik Erämetsä
▪ Neville Fernandez
▪ Doug Newman
North American Energy Credit and Clearing Corporation
▪ John Flory
North American Young Generation in Nuclear
▪ Ken Schrader
▪ Kristin Zaitz
Nuclear Energy Institute
▪ Marshall Cohen
▪ Mary M. Quillian
Oak Creek Energy Systems
▪ Hal Romanowitz
O'Connor Consulting Services
▪ Tod O'Connor
Ocean Power Delivery
▪ Des McGinnes
Ocean Power Technologies
▪ George Taylor
Pacific Gas & Electric Company
▪ Mike Alexander
▪ Antonio Alvarez
▪ Darren Bouton
▪ Lloyd Cluff
▪ Robert Cowden
▪ Kevin Dasso
▪ Frank DeRosa
▪ Les Guliasi
▪ Dede Harper
▪ Jack Keenan
▪ Hal LaFlash
▪ Jim Larson
▪ Eric Law
▪ Joe Lawlor
▪ Steve Metague
▪ Ben Morris
▪ Hugh Meriam
▪ Jill Scotcher
▪ Fong Wan
▪ Christopher J. Warner
PacifiCorp
▪ Jeremy Weinstein
PilotPower Group, Inc.
▪ Thomas R. Darton
Plains All American Pipeline, LP
▪ David Wright
Planning and Conservation League
▪ Gary Patton
Policy Communications
▪ Jim Sims
Powerex Corporation
▪ James D. Squeri
▪ Jeff Lam
Power and Water Resources Pooling Authority
▪ Bruce McLaughlin
Princeton University
▪ Frank von Hippel, Ph.D.
Public Policy Institute of California
▪ Elisa Barbour
RCM Biothane

- Eric Larsen

Robertson – Bryan, Inc. (for Delano-Earlimart Irrigation District & Eastside Power Authority)
- Stuart Robertson
- Dale R. Brogan

Rumla, Inc.
- Mohamed El-Gasseir

San Diego Gas & Electric Company
- Tom Acuna
- Rob Anderson
- Jim Avery
- Bradley Bentley
- Herbert S. Emmrich
- Teresa Farrelly
- Dave Geier
- Lad Lorenz
- Candace Potter
- William L. Reed
- Chris Terzich
- Lisa Urick
- Eddie Van Herik
- Timothy S. Vonder
- Leslie Willoughby

San Diego Association of Governments
- Susan Freedman

Science, Technology and Environmental Policy Program
- Clare Breidenich
- Michael Gillenwater

Sempre Energy Solutions, LLC
- Greg Bass

Sempra Energy Utilities (Southern California Gas Company)
- Bernie Orozco
- Wendy Keliani

Sempra Global Enterprises
- Alvin S. Pac

Sempra LNG
- Dale Kelly-Cochrane

SFA Pacific, Inc
- Dale Simbeck

Sierra Club
- Gene Frick
- Jim Metropulos
- Tom Politeo

Solar Millennium
- Rainer Aringhoff

Southwest Consortium for Environmental Research & Policy
- D. Rick Van Schoik

Southern California Edison Company
- Gary Allen
- Manuel Alvarez
- Patricia Arons
- Tom Burhenn
- Art Canning
- Frank J. Cooley
- Mary Deming
- Tambre Dreiling
- Russ Garwacki
- Frank Harris
- Stuart Hemphill
- Raquel Ippoliti
- Jacqueline Jones
- Cathy A. Karlstad
- John Leeper
- Bobby Little
- Mark Minick
- Nam Nguyen
- Larry Oliva
- Berj K. Parseghian
- Pedro J. Pizarro
- Richard Rosenblum
- Gary Schoonyan
- Gilbert Tam
- William V. Walsh

Starwood Energy Group
- Steve Zaminski

Stillwater Associates
- David Hackett

Stoel Rives, LLP
- Jerry R. Fish

Strategen Consulting, LLC
- Douglas C. Liddell

Strategic Energy, LLC
- Carl Boyd

Summit Blue Consulting
- Dan Violette

Tesoro
- Dwight Stevenson

TransCanada Corporation
- Bill Hosie
- Ken Tate

Transmission Agency of Northern California
- James Beck
- James Feider

Turlock Irrigation District
- Howard Shapiro
- Robert E. Jones

Union of Concerned Scientists
- Cliff Chen
- David Lochbaum

Utility Savings & Refund, LLC
- Charles Toca

US Renewables Group
- Thomas King

Valerio
- Steve Faichney

Valley Electric Association
- Terry Stagg

VRB Power Systems, Inc.
- Douglas C. Liddell

Wal-Mart Stores, Inc.
- Donald C. Liddell

Carl Walter

Waste Management, Inc.
- Chuck White

Wavebob
- Andrew Parish

Wave Energy
- Mirko Previsic

Western Electricity Coordinating Council
- Steve Cauchois

Western Power Trading Forum
- Gary B. Ackerman

Western States Petroleum Association
- Gina Grey
- Joe Sparano

Wind-Works
- Paul Gipe

Woodside Natural Gas
- Colin Coe
- Dane McQueen