Framework for Evaluating Greenhouse Gas Implications of Natural Gas-Fired Power Plants in California

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Abstract

This consultant report provides a framework for assessing the implications of natural gas-fired facilities in the context of California's greenhouse gas reduction policy objectives. The California Energy Commission has an obligation to consider the potential environmental impacts of a proposed power plant in determining whether that power plant is in the best interest of the state. Electricity systems rely on a portfolio of power plants with a wide range of operating capabilities to ensure the instantaneous matching of supply and consumption. Large amounts of intermittent renewable generation will necessitate increases in flexible generation. Certain types of natural gas-fired power plants can be well-suited to meeting many operational requirements of an integrated electric system: support for intermittent generation such as renewables, meeting area-specific local capacity requirements, responding to sudden changes in load or system events such as transmission failures, or enhancing the efficiency of the existing utility system. Thus, as California expands renewable energy generation to achieve its GHG emissions reduction goals, it cannot simply retire natural-gas fired power plants, and in fact, new natural-gas fired power plants may be needed. This report explores the question of how much, what type, and where in California natural gas-fired generation may be needed in light of the need to cut GHG emissions, expand renewable energy, and continue protecting the state's environment.

Keywords

Greenhouse gas emissions, siting, electricity, transmission, renewable energy, wind, solar, natural gas, power plants, resource adequacy, reliability, AB 32, California Environmental Quality Act

Executive Summary

The California Energy Commission (Energy Commission) has licensing authority for all thermal power plants proposed for construction within the state that have a capacity of 50 MW or greater. The Energy Commission licensing process includes an environmental impact review that has been determined by the California Resources Agency to be the functional equivalent to the California Environmental Quality Act's (CEQA) environmental impact review process (Energy Commission 2009c, p.4). Therefore, the Energy Commission has an obligation to consider the potential environmental impacts of a proposed power plant.

The California Global Warming Solutions Act, or Assembly Bill 32 (Nuñez, Chapter 488, Statutes of 2006) (AB 32), passed by the legislature in 2006, mandates a statewide, multi-sector reduction in greenhouse gas (GHG) emissions. Specifically, AB 32 requires the California Air Resources Board (ARB) "to adopt a statewide greenhouse gas emissions limit equivalent to the statewide greenhouse gas emissions levels in 1990 to be achieved by 2020." (AB 32, p.1) In addition, Governor Schwarzenegger has set out a more aggressive goal of reducing GHG emissions to 80 percent of 1990 levels by 2050 (S-3-05), and similar targets are included in bills under consideration by the legislature. For the electricity sector, these ambitious goals will require a significant effort encompassing a wide range of measures to reduce GHG emissions over the next decade.

As part of the implementation of AB 32, ARB adopted a *Scoping Plan* in December 2008 that identifies a range of measures to be pursued in the electricity sector to achieve substantial cuts in GHG emissions. One of these measures is to add sufficient new renewable energy supplies to provide 33 percent of the state's electricity in 2020. Achieving this high level of renewable energy in the overall electricity supply mix will provide significant environmental benefits by reducing GHG emissions, but will also pose challenges to the operation of the integrated electric system.

Increased levels of renewable generation will necessitate increases in flexible generation. A defining characteristic of electricity is that generation must instantaneously and continuously match consumption. Electricity systems rely on a portfolio of power plants with a wide range of operating capabilities to ensure this instantaneous matching of supply and consumption. Specifically, balancing authorities will require generators with quick start, fast ramping and regulation capabilities and a wider operating range (lower minimum operation) to successfully integrate high levels of renewables (California ISO 2009c, p.32). Not all types of renewable energy resources are suited to providing the flexible generation that an integrated electric system needs to ensure a reliable supply of electricity. Solar and wind resources do not have the ability to provide the ancillary services that the California ISO requires.

Some natural gas-fired power plants, however, are well-suited to meeting many operational requirements of an integrated electric system. Certain gas-fired power plants are used to meet local reliability needs, to provide emergency system support, and to provide the range of ancillary services that are needed by the California ISO to keep the integrated electric system running reliably. California cannot simply retire natural-gas fired power plants to meet its GHG emissions goals, and in fact, new natural-gas fired power plants may be needed.

This report explores how much, what type, and where in California new natural gas-fired generation may be needed to cut GHG emissions, expand renewable energy, and to continue protecting the state's environment. The answer must take into account the policy framework that energy regulators and other stakeholders are pursuing for the electricity sector, the characteristics and operational requirements of the state's integrated electric system and some understanding of historical GHG emissions from the electricity sector. This report provides a first step toward answering the question by developing a qualitative framework that considers that multi-faceted context. More detailed, quantitative modeling is required to provide more definitive assessments of how much, what type, and where in California new natural gas-fired generation may be needed in the future.

The Policy Framework

The cornerstones of California's current and future energy policy framework are the Energy Commission's biennial *Integrated Energy Policy Report (IEPR)* and companion *IEPR Update*, the *Energy Action Plan*, and ARB's AB 32 *Scoping Plan*. The *IEPR* provides an analytical foundation that other state agencies can build upon when developing and carrying out energy-related policies and programs. Similarly, the *Scoping Plan* is a framework document that identifies the measures and tools the state intends to employ in its efforts to reduce GHG emissions. The Energy Action Plan is significant for establishing the state's preferred loading order of resources to meet electricity demand. Importantly, these foundational policies mandate that the state pursue all cost-effective and low GHG-emitting sources of electricity to meet electricity demand.

The first resource in the state's loading order is energy efficiency. Because energy efficiency reduces energy demand and/or slows future growth in demand, fewer power plants should be needed and overall GHG emissions should be reduced. ARB's *Scoping Plan* calls for energy efficiency measures that would yield energy demand reductions of 32,000 gigawatt-hour (GWh) relative to "business as usual" projections for 2020. Overall, the *Scoping Plan* looks to energy efficiency to contribute 19.5 million metric tons of CO_2-equivalent ($MMTCO_2E$) emissions reductions in 2020.

Renewable energy resources are the first supply-side resources in the loading order. California possesses an array of renewable energy resources, including wind, solar, geothermal, hydroelectric, and biomass. Increasing these resources should decrease the state's reliance on fossil fuels and reduce net GHG emissions from the electricity sector. Achieving a target of 33 percent renewable resources by 2020 is expected to account for nearly 20 percent of emissions reductions (ARB 2008b, Appendix G, Table G-I-2, pp.G-I-6 – G-I-8).

ARB's *Scoping Plan* also calls for wider implementation of demand response programs and increases in combined heat-and-power projects. The *Scoping Plan* envisions demand response contributing to energy efficiency-related demand reductions (ARB 2008b, p.41). Furthermore, it asserts that demand response can help facilitate the addition of intermittent renewable generation and provide grid reliability (ARB 2008b, p.45). The *Scoping Plan* also seeks to increase development of combined heat and power systems to displace demand from other power generation sources. The plan sets a target of 4,000 MW additional installed capacity by 2020, which would displace 30,000 GWh of demand (ARB 2008b, p.43).

An Integrated Electric System

Engineering realities and the limitations of current technologies require some conventional power plants, in particular natural gas-fired power plants, to meet the operational requirements of the state's electricity system. The operators of California's interconnected electric grid must plan for hourly, daily, and seasonal fluctuations in electricity demand and the available supply of electricity. California's current supply mix is dynamic, changing with weather and supply conditions and subject to large annual fluctuations in gas supplies and hydro production. The transmission grid is operated to account for these changes by employing a host of reliability services. Local resource adequacy must also be taken into account so that transmission constraints into and out of certain areas known as "load pockets" do not lead to operational issues or even outages. The electric system must be viewed as a continually changing, interwoven set of generators, delivery facilities, and consumers, with the entire system adapting constantly to match supply and demand.

Given these realities, the potential operational impacts of a new power plant must be considered in the context of the system as a whole. The reliability and dispatchability characteristics of the resource must be evaluated in relation to the existing resource mix. As California acquires resources and moves toward its renewable energy targets, it must focus on overall system operation in addition to specific resource attributes.

Transitioning to 33 Percent Renewable Energy

Renewable energy currently accounts for roughly 12 percent of California's electricity supply. If renewable energy resources are to supply 33 percent of California's electricity 11 years from now, the amount of renewable energy capacity connected to the grid will need to increase dramatically. Wind and solar resources are intermittent resources, characterized by both variability and unpredictability, can not be dispatched as can conventional generation. Several studies assume that intermittent generation, primarily wind, will account for most new renewable generation (California ISO 2007, p.2; CRS 2005, p.41; Energy Commission 2007h, p.17). According to the Energy Commission's *Intermittency Analysis Project* (IAP), almost half of the renewable energy that will be generated to meet a 33 percent Renewables Portfolio Standard (RPS) by 2020 will be from intermittent renewable generation, namely wind and solar. The report estimates that intermittent renewables will account for 12 percent of California's energy supply and 23 percent of California's generation capacity in 2020 (Energy Commission 2007h, p.18).

There are real and serious implications of adding substantial amounts of intermittent renewable resources for the operation of the integrated grid. First, intermittent renewable resources will increase the minute-to-minute and hourly variability of the electric system, which will require more ancillary services and ramping capabilities that permit the grid to operate reliably. For example, the maximum daily swing on the California ISO's system could increase by five percent in 2010 relative to 2004 under a 20 percent RPS. The California ISO forecasted that, under a 20% RPS, additional resources with short-start and fast-start capabilities will be needed to meet changes in morning and evening load and to accommodate increased wind generation. The maximum expected ramping requirement occurs during the summer months, when the combination of morning load increase and wind generation decrease is expected by the

California ISO to require commitment of 12,664 MW of capacity in the day-ahead market. Likewise, the maximum curtailment necessary would occur during the fall when the combination of load drop-off and increased wind production in the evening is expected by the California ISO to result in the need to curtail 13,483 MW of generation over a 3-hour period (California ISO 2007, p.65). Increasing renewable generation from 20 to 33 percent will increase these operational requirements.

Over-generation conditions and voltage stability are also concerns of grid operators as the amount of intermittent renewables connected to the grid increases. Over-generation conditions are most likely to occur in spring when hydro generation is operating at high levels. Voltage stability is likely to be a short-term challenge that will be mitigated as new wind facilities with dynamic reactive capacity are brought on line.

Currently no public studies provide estimates of amounts and types of ancillary services needed to support intermittent renewable generation under a 33 percent RPS. Such studies are necessary to provide a better understanding of the need for flexible generation in the next decade and beyond. The California ISO offered a preliminary prediction that integration problems and costs could more than double from a 20 percent RPS to a 33 percent RPS.

California policy goals extend beyond 2020 and include further GHG reductions to 80 percent below 1990 levels by 2050 (S-3-05). If California is to progress beyond the 2020 targets, ARB expects that existing programs involving further limitation under the cap-and-trade program, greater increases in renewable energy generation and increased energy efficiency and green building efforts must be established (ARB 2008b, p.119). Future technologies such as transportation electrification, advanced electric storage, and smart grid development may aid implementation of post-2020 goals. However, the extent to which specific policies and technologies will affect the electric system beyond 2020 is difficult to assess with any certainty.

Historical GHG Emissions

From 1990 to 2004 the overall GHG emissions associated with the electricity sector averaged 106 $MMTCO_2E$ and ranged from a low of 92 $MMTCO_2E$ in 1996 to nearly 120 $MMTCO_2E$ in 2004. On average, half of the total emissions were due to imported power, even though imports constituted only about 25-30 percent of total supplies. This is because a large proportion of imported power is from coal-fired power plants. Emissions from natural gas generators (both central station and cogeneration) dominated in-state emissions, accounting for an average 78 percent of the in-state electric GHG emissions.

The historical data shows significant year-to-year variation in GHG emissions associated with electricity in California. The year-to-year variations are due to several factors that must be accounted for when examining historical data and when forecasting the future based on the past. A fair comparison must account for the following variables:

- ***Demand,*** in particular as it is affected by weather. Weather extremes result in high energy use. Demand should be weather normalized before any benchmark comparisons.

- *Hydroelectric output.* Hydroelectric power accounts for 15 percent of the state's generation, but can vary by nearly a factor of two from year to year. These huge swings impact GHG emissions since production from fossil fuels – generally natural gas – increase when hydro production declines.

- *Nuclear output.* Nuclear power does not experience the wide swings in annual output that hydro does, however, it still accounts for a large percentage of in-state generation. Any reductions in nuclear output due to extended plant outages or to shutdown in response to relicensing issues will affect GHG emissions, since natural gas is the likely replacement generation source.

- *Mohave retirement.* The Mohave Generating Station (located in Southern Nevada) was the second-largest single emitter of GHG in the California electric system, after Los Angeles Department of Water & Power's (LADWP) Intermountain Power Plant (located in central Utah). Its retirement in 2005 must be considered when comparing current (and future) GHG emissions to this report.

- *Consistent Accounting of Imports.* Given the magnitude of imports, a consistent accounting protocol, for imported megawatt-hours and associated GHG emissions, is essential.

GHG Emissions under Different Policy-Driven Scenarios

The AB 32 mandate to cut GHG emissions by 2020 will be achieved through increased energy efficiency measures, greater use of renewable energy resources, and developing more CHP projects. These actions will impact the state's generation mix and the GHG emissions from the electricity sector. The most recent analysis of different policy scenarios was performed by Energy Commission staff as part of the *2007 IEPR* (*Scenario Analyses of California's Electricity System: Preliminary Results for the 2007 Integrated Energy Policy Report*). The likely impacts of several different policy-driven scenarios on the amount of new gas-fired generation that could be needed are summarized below.

Frozen Policy Case

Under this scenario, no additional combined cycle plants, beyond those in place and those additions specifically named in the Scenarios Report, are added by 2020, with a continued drop-off, but not elimination, of power from old steam turbine-based gas generators as well as a modest contribution by new combustion turbines. New peaking plants and quick-start capacity will be required beginning in 2011.

Increased Renewables Case

Under the "Increased Renewables" case the amount of gas-fired peaking (assumed to be combustion turbines) plants would be 3,700 MW less than under the Frozen Policy case. By 2020 power from in-state renewable resources will account for over 31 percent of the state's energy mix. This represents an 88 percent increase relative to the Frozen Policy Case generation in 2020 and a 175 percent increase compared to 2009 renewable generation.

The increase in renewable generation is offset by nearly equal decreases (on a GWh basis) of in-state gas generation and non-specified imports. This result, that increased renewable generation displaces gas-fired generation from combined cycles, and to a lesser degree, old gas-steam units, is consistent with the renewable generation integration studies conducted by the Energy Commission and the California ISO.

Increased Renewables and Accelerated Plant Retirement

Accelerated replacement of older gas-fired units could have a modest impact on GHG emissions. However, because they would likely be replaced by new gas-fired power plants, the net improvement is tied to increased efficiency as reflected in the overall system heat rate.

Expected Future Roles for Gas-Fired Generation

A single power plant within an integrated electric system provides one or more of three basic products to the electric system: energy, capacity, and ancillary services. The mix of generation resources that will provide these services will evolve over the next decades. Natural gas-fired power plants may be relied on less to provide energy or capacity, and at the same time be relied on more to provide certain ancillary services. Gas-fired power plants are most likely to fall into one of five categories:

1. Intermittent generation support,
2. Local capacity requirements,
3. Grid operations support,
4. Extreme load and system emergencies support, and
5. General energy support.

The role for a plant in each of these five categories as well as the major attributes for a plant in each category are identified in Table ES-1.

Table ES-1: Expected Roles for Gas-Fired Generation

Description	Role of Plant	Plant Attributes
Intermittent Generation Support	Support intermittent renewable generation	• Fast start-up capability (within 2 hours or less) • Rapid ramping capability • Can provide regulation • Can provide spinning reserve • Can provide non-spinning reserve
Local Capacity Requirements	Strategically located generation necessary to mitigate grid problems and potentially reduce need for new transmission infrastructure	• Able to satisfy/partially satisfy LCA resource requirements • Voltage support • May provide black start capability
Grid Operations Support	Support specific grid operational needs; plant is not necessarily located in a local capacity area.	• Fast start-up capability (within 2 hours or less) • Rapid Ramping • Can provide regulation • Can provide spinning reserve • Can provide non-spinning reserve • Black start capability • Load-following capability
Extreme Load / System Emergencies Support	Meet peak demand under extreme temperature conditions (for example, summer peak demand) or other system emergencies	• Fast start-up capability (within 2 hours or less) • May have low minimum load levels • Rapid ramping capability • Can provide regulation • Can provide spinning reserve • Black start capability
General Energy Support	To provide a reliable supply of cost-competitive energy to the grid; plant operates primarily based on economic dispatch, can provide energy in low hydro periods, extended nuclear outages, and seasonal low wind periods.	• Cost-competitive energy • Able to help a load serving entity (LSE) meet (RA) requirements • Not necessarily a quick start unit; start-up duration may be hours • Can provide limited regulation service • Can provide limited spinning reserve

An important step to understand how the electric system's net GHG emissions will change in the future was to identify specific roles that gas-fired generation would be expected to fulfill given the policy mandate to reduce GHG emissions from the electric sector. Given these expected roles, some preliminary qualitative assessments can be drawn as to how net GHG emissions could change with the addition of new gas-fired power plants. Net GHG emissions for the integrated electric system *will decline* under the following scenarios:

1. The addition of new gas-fired power plants necessary to permit penetration of renewable generation to meet the 33 percent target;

2. The addition of new gas-fired power plants that improve the overall efficiency of the electric system;

3. In some cases, GHG emissions could be reduced with the addition of a new gas-fired power plant or modernization/repowering of existing capacity that serves load growth or capacity requirements more efficiently than the existing fleet.

Extensive modeling is necessary to understand how the net GHG emissions of the electric system change under various future scenarios. The Energy Commission's Siting Committee reaffirmed a *2007 IEPR* finding that "new gas-fired power plants are more efficient than older plants, and they displace these older facilities in the dispatch order" (Energy Commission 2009a, p.20). The Energy Commission must review and consider an individual project application to make the appropriate judgments about a plant's ability to support the integration of renewable resources or otherwise provide important system benefits that outweigh any environmental impacts of building and operating a plant.

Although a single natural gas-fired power plant produces GHG emissions, under certain circumstances the addition of a gas-fired plant may yield a GHG emission benefit. The authors conclude that this would be the case if the plant provided support to integrate renewable energy under a 33 percent RPS, if the addition raised the overall efficiency of the electric system, or if the new plant served load growth more efficiently than the existing fleet.

CHAPTER 1: Introduction

The California Energy Commission (Energy Commission) has licensing authority for all thermal power plants proposed for construction within the state that have a capacity of 50 MW or greater. The Energy Commission licensing process includes an environmental impact review that has been determined by the California Resources Agency to be the functional equivalent to the California Environmental Quality Act (CEQA) environmental impact review process (Energy Commission 2009c, p.1). The Energy Commission has an obligation to consider the potential environmental impacts of a proposed plant in determining whether a power plant is in the best interest of the state.

The California legislature passed Assembly Bill 32 in 2006 (AB 32), which requires the California Air Resources Board (ARB) "to adopt a statewide greenhouse gas emissions limit equivalent to the statewide greenhouse gas emissions levels in 1990 to be achieved by 2020." (AB 32) In addition, Governor Schwarzenegger has set out the more aggressive goal of reducing greenhouse gas (GHG) emissions to 80 percent of 1990 levels by 2050 (S-3-05). These reduction mandates will be achieved in part by a substantial expansion of renewable energy to supply electricity and widespread adoption of energy efficiency measures. Renewable energy currently accounts for about 12 percent of the state's electricity supply mix. To help achieve the GHG emissions reductions targets and provide other environmental and economic benefits, state policymakers have set the target for renewable energy's share of the supply mix at 33 percent by 2020 (S-14-08).

Achieving these much higher levels of renewable energy in the overall electricity supply mix will pose challenges to the operation of the integrated electric system. California consumers are served by a diverse and integrated system that is operated to meet a number of sometimes-conflicting objectives. Consumers expect a reliable and adequate supply of electricity at all times; society expects the electric system to operate safely without endangering homes, businesses, and our environment. Over the years electricity system operators, owners and regulators have developed a set of principles and operating standards to achieve the objectives of a safe and reliable electric system. Many of these standards are now embodied in mandatory reliability standards with enforcement oversight within the United States by the Federal Energy Regulatory Commission (FERC).

As California's integrated electric system evolves to meet GHG emissions reduction targets, the operational characteristics associated with increasing proportions of renewable generation will create new challenges for the reliable operation of the grid. Large amounts of renewable generation will necessitate increases in flexible generation. Natural gas-fired power plants in general are well-suited to meeting many operational requirements of an integrated electric system, and may prove well-suited to complement large amounts of renewable generation. As California strives to achieve its GHG emissions reduction goals, and as it expands renewable energy for power generation, it cannot simply replace all natural-gas fired power plants with renewable energy without endangering the safety, adequacy, and reliability of the electric system. At the same time, California will need to modernize the gas-fired portions of its generating fleet to both enhance efficiency and also to reduce the environmental impacts of the electric sector – particularly once through cooling at some of the existing coastal plants. Thus, the question arises as to how much, what type, and where natural gas-fired generation should be part of California's strategy to achieve its GHG targets while maintaining a reliable electric power system.

Approach

The overarching objective of this report is to provide an assessment of GHG emissions attributable to the state's electric system under several future scenarios and in the context of the state's integrated electric system. In developing this assessment, the authors considered not only the operational requirements of the integrated electric system and the role that natural-gas fired power plants play in ensuring overall reliability of the system, but also the policy context established by California regulators.

The role of gas-fired power plants to support renewable energy is central to any assessment of GHG emissions from the electric sector. A number of recent studies and reports have analyzed the issues surrounding the integration of renewable energy resources into the overall electric system. This report draws heavily from those reports and does not attempt to provide new analyses of the operational and reliability issues surrounding renewable energy integration.

Report Structure

The remaining chapters of this report are organized as:

- Chapter 2 provides a summary of the legislative and policy initiatives in California that address state goals of reducing GHG emissions.
- Chapter 3 describes California's generation resource mix and provides an overview of key principles that underpin the integrated electric system.
- Chapter 4 examines potential operational requirements of the grid for the scenario of 33 percent renewable generation.
- Chapter 5 analyzes and quantifies historic levels of GHG emissions attributable to the electricity sector in California.
- Chapter 6 examines outcomes of several potential policy-driven futures.
- Chapter 7 discusses expected roles of natural gas-fired generation in a high renewables, low GHG emissions electric system.
- Chapter 8 examines potential developments in the electricity sector beyond 2020.

CHAPTER 2: Policies to Address Greenhouse Gas Emissions in the Electricity Sector

Electricity generation is the second largest source of GHG emissions in California after transportation. In 2004 electricity generation from power plants and distributed generation (DG) was responsible for approximately 120 $MMTCO_2E$ of GHG emissions (ARB 2008b, Appendix C, p.88). As a major contributor to the state's total GHG emissions, changes in the electricity sector must be a significant part of the solution in the state's efforts to reduce GHG emissions over the next decade. At the same time, efforts to reduce GHG emissions attributable to the electricity sector must not constrain the sector in such a way that electricity service is compromised.

Energy efficiency, demand response, and renewable energy resources are electricity resources that allow California to meet the carbon challenge the state faces. These resources will be the electricity resources of choice as California pursues its goals for a low-carbon future. Over the next decade and beyond, energy efficiency policies will be pursued to curb growth in electricity demand, and California's electricity supply mix will evolve to be more reliant on renewable energy and demand response.

Cornerstones of California's Energy Policy

The cornerstones of California's current and future energy policy framework are the Energy Commission's biennial Integrated Energy Policy Report (IEPR) and IEPR Update, the Energy Action Plan, and the California ARB's AB 32 *Scoping Plan*. These foundational policies mandate that the state pursue all cost-effective and low GHG-emitting sources of electricity to meet electricity demand. An overview of each of these is provided below.

Integrated Energy Policy Report

Senate Bill 1389 (Bowen, Chapter 568, Statutes of 2002) requires that the Energy Commission biennially prepare the Integrated Energy Policy Report (SB 1389). That report "shall contain an overview of major energy trends and issues facing the state, including... supply, demand, pricing, reliability, efficiency, and impacts on public health and safety, the economy, resources, and the environment" (CA PRC). The Energy Commission must also provide policy recommendations based on the analyses done in support of the IEPR (CA PRC). The statute requires state entities to carry out energy-related duties and responsibilities based upon the analyses and information provided in the IEPR documents. The first IEPR was completed in the fall of 2003. Subsequent IEPRs were prepared in 2005 and 2007. The Energy Commission prepares more narrowly focused updates of the IEPRs in the alternate years (that is, 2004, 2006, and 2008).

In the *2007 IEPR*, the last year in which a full IEPR was completed, the Energy Commission highlighted the need for the state to take aggressive actions to reduce GHG emissions. In particular, it noted that "[a]s the second largest emitter of greenhouse gases in the United States and about twelfth largest in the world, California's efforts to reduce its emissions will lead the way for other governments, as well as easing the severity of environmental and economic impacts experienced this century." (Energy Commission 2007a, p.1) At the same time that the state pursues aggressive actions to reduce GHG emissions, the Energy Commission recognized the state must continue to provide an adequate, reliable, yet cost-effective supply of electricity. To better understand how to achieve such a goal, the Energy Commission undertook an important analytical exercise to examine the implications of different resource plans on future GHG emissions. The analysis, the *Scenario Analyses Of California's Electricity System: Preliminary Results For The 2007 Integrated Energy Policy Report* (Scenarios Report), allowed the Energy Commission to consider how varying levels of energy efficiency and renewable energy generation penetration impact GHG emissions, while maintaining system reliability (Energy Commission 2007d, p.1). Chapter 6 discusses the Scenarios Report and its conclusions in more detail.

Energy Action Plan

California first adopted an Energy Action Plan in 2003. The energy crisis of 2000-2001 spurred cooperative action among the Energy Commission, the California Public Utilities Commission (CPUC), and the California Power Authority. The agencies collaborated to develop a single framework that would guide all stakeholders when making decisions about how to meet the state's electricity needs. The CPUC and the Energy Commission have continued the Energy Action Plan process pursuant to Senate Bill 1113 (Chesbro, Chapter 208, Budget Act of 2004) (SB 1113).[1]

Of most significance, the three agencies established a "loading order" for utilities' procurement of electricity resources. The objective for the loading order is to ensure that the state's electricity system is developed in a cost-effective manner while meeting the long-term interests of consumers, society as a whole, and the environment. The priorities established by the loading order are energy efficiency and other demand-side resources, followed by renewable energy, distributed generation, combined heat and power systems, and finally conventional generation (Energy Commission 2008d, p.1). This loading order marked a distinct move toward low-emission projects.

The initial 2003 Energy Action Plan has been followed by a second complete Energy Action Plan in 2005 and an update published in 2008. The *2008 Energy Action Plan Update* emphasizes the emergence of a "consensus that California must act to decrease its greenhouse gas emissions to reduce the impact of climate change," noting recent legislative developments and considering the implications of emissions reductions for the electricity sector (Energy Commission 2008d, p.2).

AB 32 Scoping Plan

ARB adopted its Proposed *Scoping Plan* pursuant to the Global Warming Solutions Act of 2006 (Assembly Bill 32, Nuñez, Chapter 488, Statutes of 2006) in December 2008 (AB 32). The *Scoping Plan* outlines how California will achieve a reduction in GHG emissions to 1990 levels by 2020 by proposing a comprehensive set of measures that will affect all sectors of California's economy. Even though the electricity sector accounts for only 23 percent of total statewide emissions, the electric sector is being asked to shoulder a substantial burden for the state's

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[1] The California Power Authority was eliminated in 2004.

efforts to reduce GHG emissions. The *Scoping Plan* envisions that the electricity sector will contribute about 40 percent of total statewide GHG emissions reductions (ARB 2008b, Appendix G, Table G-I-2, pp.G-I-6 – G-I-8, p.11).[2] Moreover, ARB will seek to reduce GHG emissions in the transportation sector by pursuing electrification of different forms of transportation (for example, plug-in hybrid electric vehicles and ship electrification at ports) (ARB 2008b, pp.29, 40). The potential impacts that electrification of transportation will have on the electric sector are discussed in Chapter 8.

Specific goals outlined in the *Scoping Plan* for the electricity sector include the expansion of energy efficiency programs and strengthening of appliance standards, with an electricity demand reduction target of 32,000 gigawatt-hour (GWh) in 2020; achieving a statewide target of 33 percent of electricity generated by renewable energy; a goal for increased use of combined heat and power technologies; and involvement of the electricity sector in a cap-and-trade program in California that will be able to link with the Western Climate Initiative to create a regional market for GHG emissions (ARB 2008b, pp.30-46). Table 1 shows the estimated emissions reductions by measure.

The *Scoping Plan's* aggressive energy efficiency targets rely heavily on programs included in the CPUC's long-term energy efficiency strategic, which seeks to maximize the utilization of cost-effective energy efficiency (ARB 2008b, pp.41-43). Meanwhile, collaborative efforts such as the Renewable Energy Transmission Initiative (RETI) are working to address the transmission additions, streamlined permitting process, and reliability measures necessary to accommodate a 33 percent RPS. (Chapter 4 discusses RETI in more detail.)

Combined heat and power (CHP), or cogeneration, may also play a prominent role. The *Scoping Plan* set a target of adding 4,000 MW of CHP capacity by 2020 to offset 30,000 GWh of electricity demand that would otherwise be met by traditional power sources (ARB 2008b, Appendix C, p.C-122).[3] ARB will continue to evaluate what actions addressing barriers to CHP will be necessary for meeting its goal in the context of actions by the Energy Commission and CPUC (ARB 2008b, p.44).[4] Additionally, the Waste Heat and Carbon Emissions Reduction Act (Assembly Bill 1613, Blakeslee, Chapter 713, Statutes of 2007) (AB 1613) was passed by the state legislature in 2007, authorizing the CPUC to require utilities to purchase excess electricity from CHP subject to a maximum limitation. It also required the CPUC to establish feed-in tariffs to facilitate the purchase of excess CHP-generated electricity (AB 1613, pp.1-2).

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[2] Electricity sector contributions are comprised of the total reductions sought from the "Building and Appliance Energy Efficiency and Conservation" and "Renewable Energy" categories, along with the reductions due to increased renewable energy production envisioned from the "Other" category.

[3] If transmission line losses are taken into account, adding 4,000 MW of CHP capacity displaces 32,000 GWh from the grid.

[4] The Energy Commission opened a proceeding in December 2008 to develop efficiency guidelines for CHP as required by AB 1613. The CPUC intends to initiate a proceeding that will consider a long-term policy for the procurement of energy from CHP systems by the IOUs.

Table 1: Estimated Emissions Reductions by Scoping Plan Measure

Measure	Estimated Emissions Reductions ($MMTCO_2E$ in 2020)
Energy Efficiency Initiatives	19.5
Increased Combined Heat and Power Use	6.7
33 percent RPS	21.3
California Solar Programs (including CSI)	2.1
Solar Water Heaters	0.14

Source: (ARB 2008b, Appendix G, Table G-I-2, pp.G-I-6 – G-I-8)

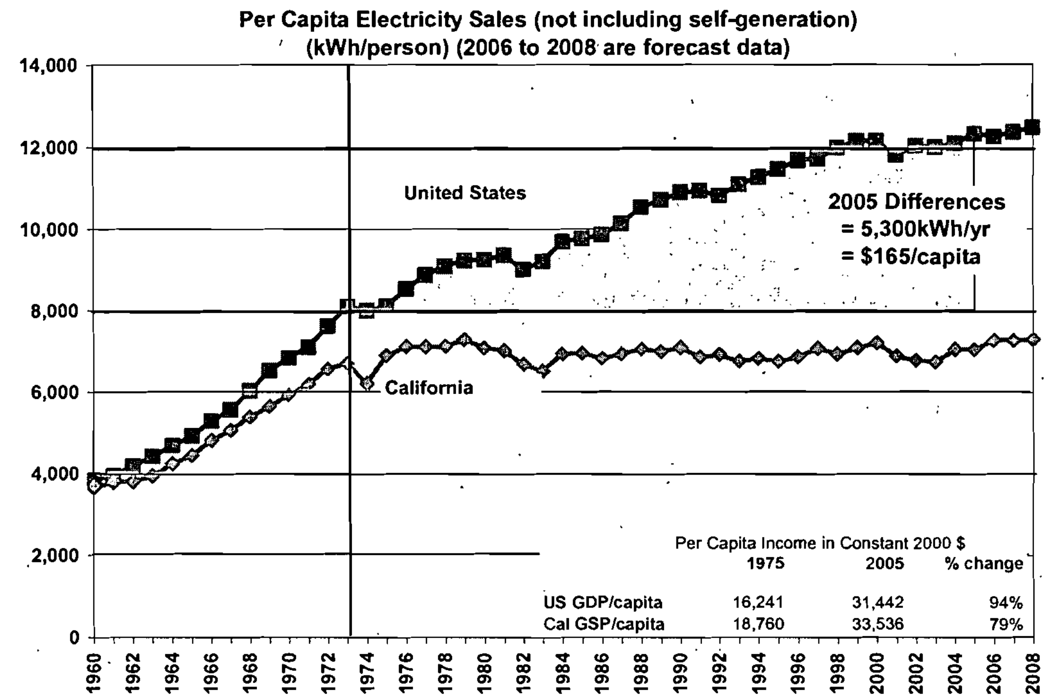
Mandating Energy Efficiency to Flatten Demand

"Cost-effective energy efficiency is the resource of first choice for meeting California's energy needs." (Energy Commission 2005b, p.3) Energy efficiency serves to reduce energy demand, such that fewer supply-side resources are needed to meet demand growth. Because energy efficiency avoids the operation of fossil fuel-fired plants, it lowers GHG emissions from the electricity sector. The Energy Commission's 2007 Scenario Analyses Project examined three levels of energy efficiency in three separate cases and found that regardless of the level of energy efficiency the cost is negative. "[S]ociety is better off with...higher levels [of energy efficiency] than without...even without a carbon cost adder being included. Energy efficiency is less costly than the generating resources it displaces."(Energy Commission 2007a, p.59) California's potential for savings is substantial. The combined economic potential to save energy in 2016 for California's three large investor-owned utilities (IOU) is estimated to be 40,700 GWh of electricity and 6,800 MW of peak electrical demand. This does not include the potential savings that might be available from emerging technologies (Itron 2006, pp.ES-8 – ES10).

Due in part to a decades-long focus on energy efficiency, California has the lowest per capita electricity use in the United States. As shown in Figure 1, California's per capita electricity use has remained mostly flat over the past 30 years, while the United States' per capita electricity consumption has increased by about 50 percent (Energy Commission 2007a, p.16). Moreover, California has reduced peak capacity needs by more than 12,000 MW since the mid-1970s, when California began pushing higher energy efficiency standards in buildings and new appliances and implementing utility-sponsored programs (Energy Commission 2005b, p.3). As a result, California avoided the need to build many new large fossil-fueled power plants.

A review of the resource plans prepared in 2006 by Pacific Gas & Electric Company (PG&E), Southern California Edison (SCE), and San Diego Gas & Electric Company (SDG&E) reveal the extent to which energy efficiency can eliminate the need for new supply-side resources. Over the first five years of their 2006 resource plans, energy efficiency as a percentage of forecasted load growth will equal 84 percent for PG&E, 50 percent for SCE, and 56 percent for SDG&E (LBNL 2008, p.6).

Figure 1: California per Capita Energy Sales



Source: (Energy Commission 2007i)

California's Energy Efficiency Framework

California has pursued its energy efficiency goals through two primary avenues: utility-sponsored programs that seek to reduce end-user consumption and codes and standards designed to lower energy requirements of buildings and appliances. In the mid 1970s, the Energy Commission developed comprehensive energy codes for new buildings and appliances, as well as utility-sponsored energy savings programs. The broader concept of pursuing "demand-side management" (DSM) to explicitly offset generation emerged in the 1980s. [5] After a drop in DSM funding in the early 1990s, the CPUC instituted a series of "shared-savings" incentive mechanisms linking payments to the utility to the performance of their DSM programs (CPUC 2003).[6] In late 1996, Assembly Bill 1890 (Brulte, Chapter 854, Statutes of 1996) established "Public Purpose Charge" funding for energy efficiency and shifted the focus of

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[5] In response to legislation, the Energy Commission adopted California's Appliance Efficiency Regulations in 1976, Title 20, and Part 6 of Title 24 of the California Code of Regulations, the Energy Efficiency Standards for Residential and Nonresidential Buildings in 1978. Both sets of standards are updated frequently to reflect new energy efficiency developments.

[6] For more information regarding shared-savings mechanisms; this decision can be found at the following internet address: http://docs.cpuc.ca.gov/published/Final_decision/30826.htm

conservation efforts from creating alternatives to supply resources to market transformation efforts intended to create markets for energy efficient products and services (AB 1890).

The 2000-2001 electricity crisis led to another shift in focus for energy efficiency programs. In late 2000, the CPUC returned to a focus on achieving peak savings, initially for the summer of 2001. Utility incentives were again explicitly tied to achieving savings. In 2004 the CPUC adopted explicit, numerical goals for electricity savings to be achieved by the state's largest IOUs. The CPUC established both annual and cumulative energy savings goals. At the time the goals were adopted, they were expected to meet from 55 percent to 59 percent of the IOUs' incremental energy needs over the period 2004-2013 (CPUC 2004, pp.2-3).

Senate Bill 1037 (Kehoe, Chapter 366, Statutes of 2005) required the CPUC to consult with the Energy Commission to identify all potentially achievable energy efficiency, to identify targets for an electrical corporation pursuant to its long term procurement plan, and to consider cost-effective alternatives when evaluating transmission facilities. Assembly Bill 2021 (Levine, Chapter 734, Statutes of 2006) went further and required the Energy Commission, in collaboration with the CPUC and IOUs, to set statewide targets for achieving all cost-effective energy efficiency for the next 10-year period (SB 1037; AB 2021; Energy Commission 2008d, p.7). Studies of the energy efficiency savings potential within the state showed that the targets established by the CPUC for the IOUs in 2004 and goals proposed by publicly owned utilities (POUs) were lower than the potentially achievable cost-effective electricity savings.

Thus, in 2007 the Energy Commission, pursuant to AB 2021, recommended that the state adopt targets for 2016 equaling 100 percent of total economic potential (that is, cost-effective energy efficiency savings) from utility and non-utility sources. The adopted savings targets proposed by the IOUs and POUs combined as of the *2007 IEPR* were 27,908 GWh and 5,880 MW (Energy Commission 2007a, pp.82-83; CPUC 2004).[7] Those targets are to be met through a combination of collaborative efforts by utilities, legislative mandates, and regulatory standards.

Also in 2008, the CPUC released its *Long Term Energy Efficiency Strategic Plan*. The plan was created in collaboration with the IOUs and numerous other stakeholders to guide efforts to achieve the aggressive energy efficiency goals set in ARB's *Scoping Plan*, AB 2021, and the Energy Action Plan II. The strategic plan followed on the Energy Commission's June 2008 *Strategic Plan to Reduce the Energy Impact of Air Conditioners*, completed under AB 2021 with a goal of decreasing the peak electricity demand of air-conditioning systems (Energy Commission 2008c, p.1). The CPUC's strategic plan lays out a vision for creating market-based energy efficiency measures that will not need ratepayer subsidies in the future. As part of this effort, the CPUC articulated a set of "Big Bold Energy Efficiency Strategies," which were supported by the Energy Commission's work pursuant to AB 2021. The strategies included were selected not only for their potential impact, but also their "easy comprehension and their ability to galvanize market players (CPUC 2008c, p.6)." These strategies included three major programmatic initiatives for the next decade and beyond (CPUC 2007a):

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[7] These targets reflect market potential based on incentives associated with the IOUs' programs as governed by D.04-09-060, which required savings of about 70 percent total economic potential . It was assumed that the CPUC would require utilities to target savings at a rate at least equal to their projected totals in 2013.

1. All new residential construction in California will be zero net energy by 2020;
2. All new commercial construction in California will be zero net energy by 2030;
3. Heating, Ventilation, and Air Conditioning (HVAC) will be reshaped to ensure optimal energy performance.

These initiatives will be supported by actions to encourage technological innovation in buildings, innovative financing options, and statewide education programs. For example, California's Building Standards Commission (BSC) adopted the state's first set of "Green Building Standards" for residential and commercial construction in July 2008 (CPUC 2008c, p.15). The plan also outlines a need for coordination of local government building codes and development policies, an effort likely to be led by the Energy Commission (CPUC 2008c).

Finally, in 2008 the CPUC reaffirmed the need for a framework to guide investments in energy efficiency over the long term (CPUC 2008e, pp.36-37). The CPUC established new targets for energy savings for the IOUs for the period 2012-2020, which for the first time included recognition of savings from state building standards, federal appliance standards, the Energy Commission's AB 2021 assessment, and the CPUC's Big Bold Energy Strategies (CPUC 2008e, p.2). If the IOUs achieve the new targets, they will save over 4,500 MW and over 16,000 GWh (CPUC 2008e, p.2). These targets constitute 100 percent of Total Market Gross energy savings goals based on the Itron Goals Update Study and the Itron 2008 IOU Energy Efficiency Potential Study, pursuant to AB 2021 and the *2007 IEPR* (CPUC 2008e, p.39).

California Utility Programs

California IOUs' 2006-2008 energy efficiency portfolio was based on a $2 billion investment by state ratepayers, and was the largest campaign in United States history.[1] Below are several examples of past, present, and future programs:

- Improved lighting efficiency, especially through the use of CFLs, comprises a significant portion of the IOUs' savings in residential and commercial buildings.
- IOUs offer the commercial sector incentives to meet or exceed Title 24 standards via the "Savings by Design" program.
- Over $1 billion of the budget for the IOUs' 2006 – 2008 programs is dedicated to commercial building retrofits.
- In the 2012 – 2015 period, IOUs will link their rebate programs to meeting a minimum Energy Star benchmark score, which will be based on a score determined during the 2009 – 2011 period.
- The CPUC provides low income customers energy efficiency and appliance testing and repair measures through the Low Income Energy

Role of Energy Efficiency from 2009-2020

In the *Scoping Plan,* ARB estimated that current efficiency and conservation programs will no longer be able to curb energy consumption in the face of population growth and expected changes in consumer behavior. New, more aggressive energy efficiency measures will be needed to limit per capita increases in energy consumption. ARB's *Scoping Plan* calls for energy demand reductions of 32,000 GWh relative to business as usual projections for 2020 (ARB 2008b, Appendix C, p.C-99).[8] Overall, the *Scoping Plan* expects all energy efficiency in buildings and appliances to contribute 19.5 $MMTCO_2E$ emissions reductions in 2020 (ARB 2008b, Appendix G, Table G-I-2, pp.G-I-6 – G-I-8).

In part to achieve this goal the Energy Commission, the CPUC, state agencies, utilities, the building industry, and others have come together to support a long-term statewide strategic vision for energy efficiency. The objective of this collaborative approach is to eliminate the fragmentation that previously existed across the IOUs, POUs, and the development of codes and standards by the Energy Commission.

One cross-cutting initiative that embodies the more collaborative, integrated approach to energy efficiency is the objective of "zero net energy" buildings. Both the Energy Commission and the CPUC have embraced this policy. To make zero net energy buildings a reality will require a combination of policies and codes that, for example, make on-site power generation cost-effective, make possible the use of combined technology HVAC systems, and allow the cost of carbon to be considered in cost-effectiveness tests for new codes and standards. The Energy Commission has estimated the potential cumulative savings from HVAC efficiency initiatives alone to be 1,216 GWh energy savings and 4,667 MW peak demand savings by 2020 (Energy Commission 2008c, p.36, Table A-7).

In addition, the Energy Commission has already begun several efforts that will be key to achieving the energy efficiency targets for 2020. These efforts include broadening the range of appliances (such as consumer electronics) covered by standards and developing standards for water efficiency, improving compliance with existing standards and stepping up enforcement, and tightening voluntary building codes and standards such as codes typically embraced by the green building community.

Expanding Renewable Energy in the Supply Mix

Where energy efficiency and other demand side resources are unable to meet California's energy needs, renewable resources provide the preferred option for electricity generation (Energy Commission 2005b, p.2). California possesses an array of renewable energy resources, including wind, solar, geothermal, hydroelectric, and biomass. Increasing use of such resources, consistent with California's loading order, should decrease the state's reliance on fossil fuels, and in doing so will reduce net GHG emissions from the electricity sector (ARB 2008b, p.44).

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[8] Note that this number is net of about 15,000 GWh of energy efficiency believed to be embedded in the Energy Commission's baseline demand forecast.

The state's efforts to increase the share of renewable energy in the electricity supply mix are essential to efforts to reduce GHG emissions. Based on ARB's expectations, renewable energy alone will account for nearly 20 percent of emissions reductions (ARB 2008b, Appendix G, Table G-I-2, pp.G-I-6 – G-I-8). These reductions are primarily based on achieving a 33 percent Renewables Portfolio Standard (RPS) by 2020. California's current RPS-eligible resources provide about 11.8 percent of the state's electricity, with geothermal providing the largest share at 4.5 percent (Energy Commission 2009e, p.3-37). As Table 2 illustrates, renewable energy's current share of California's total electricity generation is about 12 percent. Therefore, there is a need for significant new resource additions to meet the 33 percent RPS that ARB's *Scoping Plan* anticipates.

Table 2: Renewable Generation and Contribution to California's Electricity Supply

Resource	Energy Delivery (GWh)	Share of Total California Electricity
Biomass	6,236	2.1%
Geothermal	13,439	4.5%
Small Hydro	8,393	2.8%
Solar	675	0.2%
Wind	6,802	2.3%
Total	35,545	11.8%

Source: (Energy Commission 2009e, p.3-37)

Evolution of California's Renewables Portfolio Standard

California's Renewables Portfolio Standard (RPS) was first established by Senate Bill 1078 (Sher, Chapter 516, Statutes of 2002) in 2002 and subsequently modified by Senate Bill 107 (Simitian, Chapter 464, Statutes of 2006) in 2006 (SB 1078; SB 107). The RPS requires IOUs, energy service providers (ESPs), and community choice aggregators (CCAs) to add "1% of retail sales per year from eligible renewable sources until 20% is reached, no later than 2010 (CPUC 2008f, p.1)."[9] The Energy Commission and the CPUC in the second Energy Action Plan gave support to the more aggressive RPS of 33 percent by 2020. In October 2008, the CPUC and the Energy Commission recommended that ARB adopt a 33 percent RPS by 2020 as part of its plan to meet the goals of AB 32 (CPUC 2008f, p.2). Governor Schwarzenegger likewise voiced support for the 33 percent by 2020 target in Executive Order S-14-08 (S-14-08).[10] (The Executive Order also extended the RPS requirement to POUs in addition to IOUs.) ARB's *Scoping Plan* included the

[9] Most POUs have established their own renewable targets that are generally consistent with state policy. Under SB 107, POU governing boards must report annually on their progress implementing and attaining an RPS to customers and the Energy Commission.

[10] The order also directs the Energy Commission and CPUC to support the implementation of the RPS by facilitating the siting and permitting of renewable generation and the necessary transmission infrastructure through various policy initiatives and stakeholder forums.

33 percent by 2020 RPS as a key measure for meeting the state's GHG emissions reduction measures.

Table 3: Renewables Portfolio Standard Targets

Law or Other Policy Statement	RPS Standard	Date Adopted
SB 1078	20% by 2017	2002
SB 107	20% by 2010	2006
EAP II	33% by 2020	2005
S-14-08	33% by 2020	2008

Role of Renewable Energy in Meeting GHG Emissions Targets

Renewable energy will contribute a significant portion of ARB's targeted GHG emission reductions from the electricity sector. The 33 percent RPS standard alone is forecasted to contribute the bulk of these reductions; solar programs (including the California Solar Initiative) and solar water heaters will also provide reductions.

Table 4: Estimated Emissions Reductions from Renewable Programs

Measure	Reductions ($MMTCO_2E$ in 2020)	Percent of Total Reductions to Achieve 1990 Emissions Level by 2020
33 Percent RPS	21.3	15.2
California Solar Programs (3000 MW)	2.1	1.5
Solar Water Heaters (AB 1470 goal)	0.14	< 1

Source: (ARB 2008b, Appendix G, Table G-I-2, p.G-I-7)

Because of the importance of renewable energy to the overall success of the state's climate change goals, ARB has proposed new mechanisms to facilitate the development of renewable generation. First, ARB will evaluate the recommendation by the CPUC and the Energy Commission that revenues from the proposed cap-and-trade program be allocated to the electricity sector to support renewable energy, among other initiatives (ARB 2008b, pp.35-36). It also supports a feed-in tariff for RPS-eligible renewable facilities up to 20 MW to encourage development of small-scale generation (ARB 2008b, p.45).

Despite the myriad efforts to encourage the expansion of renewable generation, recent utility RPS procurement forecasts for 2010 and 2020 indicate that substantial challenges remain. Based on available demand data, procurement needs for RPS requirements of 20 percent in 2010 and 33 percent in 2020 are delineated in Table 5. While the IOUs have made progress adding renewable contracts to their portfolios, they will still fall somewhat short of the 20 percent target in 2010, and will be significantly below the 33 percent target in 2020 unless they add renewable resources at a much faster pace, as indicated by their net short data.

Table 5: IOU RPS Procurement Need (GWh)[11, 12]

Utility	PG&E		SCE		SDG&E		Total IOUs	
Compliance Year	2010	2020	2010	2020	2010	2020	2010	2020
RPS Requirement	16,230	30,893	16,142	31,403	3,613	6,964	35,985	69,260
Existing and/or Signed Contracts	11,719	6,639	13,271	13,123	1,680	2,024	26,670	21,786
Short listed/Under Negotiation/Pending Approval	959	5,322	299	1,920	965	1,339	2,223	8,581
Net Short	**3,552**	**18,932**	**2,527**	**16,360**	**968**	**3,601**	**7,092**	**38,893**
Equivalent Capacity assuming 25% CF (MW)[13]	**405** **1,622**	**2,159** **8,635**	**288** **1,153**	**1,865** **7,462**	**110** **442**	**411** **1,642**	**809** **3,235**	**4,435** **17,739**

Source: (PG&E 2008), (SDG&E 2008), (SCE 2008)

California Solar Initiative

The California Solar Initiative (CSI) was launched in January 2007 by the CPUC and is operated by the IOUs. The program provides upfront incentives for the installation of solar photovoltaic (PV) systems, with small systems receiving the full incentive upfront based on expected capacity and large systems receiving payments over five years based on actual performance during those years (CPUC 2008d, p.9).

In 2008, the program added 133 MW of solar PV capacity to the grid within the IOUs' service territories, and the CPUC expected it to remain strong in 2009 (CPUC 2008d, p.3). The programs' current pace of new installations is consistent with the goal of 1,750 MW installed by 2017 for this component of the 3,000 MW Million Solar Roofs program (CPUC 2008d, p.4). The other components of this program are as follows(CPUC 2008d, p.4):

- The Energy Commission administers the New Solar Homes Partnership, with a goal of 360 MW by 2017.
- The publicly owned utilities' incentive programs for solar-produced electricity have a goal of 700 MW by 2017.
- The CPUC's low-income residential program for solar-produced electricity has a goal of 190 MW.

[11] SCE and SDG&E's compliance reports have redacted demand data for 2010. These values have been estimated based on available demand data for these utilities.

[12] The 2020 RPS requirement given in the IOUs report is for a 20percent RPS. Here, the RPS requirement is calculated for a 33 percent RPS based on bundled retail sales.

[13] Number of megawatts needed assuming each megawatt had a 25 percent capacity factor.

Demand Response to Shave Peak Demand

California's peak demand is projected to grow at a rate of 1.4 percent per year from 2007 through 2018 (Energy Commission 2007b, Form 1.4, p.42). The growth in peak demand increases the state's need for peaking generation, which typically runs only a small number of hours per year in the summer. Peaking generation is generally less efficient and therefore contributes disproportionately to GHG emissions. GHG emissions from peaking generation can be reduced both by decreasing peak demand and by displacing conventional generation with renewable generation. ARB's *Scoping Plan* envisions demand response contributing to energy efficiency-related demand reductions (ARB 2008b, p.41). Furthermore, it asserts that demand response can help facilitate the addition of intermittent renewable generation and provide grid reliability (ARB 2008b, p.45).

The CPUC has been facilitating the implementation of demand response (DR) programs through a rulemaking proceeding and its proceedings to evaluate the IOUs' DR programs. Program structures and budgets for PG&E, SCE, and SDG&E for 2009 - 2011 are being considered in a consolidated proceeding (A. 08-06-001, -002, -003). In R. 07-01-041, the CPUC is seeking to establish protocols for estimating DR programs' load impacts, cost-effectiveness methodologies, specific goals and rules on goal attainment for 2008 and beyond, and modifications to support the California ISO's efforts to incorporate these programs into market design protocols (CPUC 2007b, pp.2-3). A decision regarding load impact estimations was issued in April 2008, and set for the protocols to be used in the 2009 - 2011 DR Program and Budget Applications discussed above (CPUC 2008a, p.2).

Conclusions

Ultimately, reductions in GHG emissions will depend upon how effectively the various policies identified above (or others) are implemented. It is clear, however, that California has set itself on a course that will fundamentally alter the state's electricity sector from both the supply and demand perspective.

Chapter 3: The Resource Mix in an Integrated Electric System

A fundamental defining characteristic of electricity is that generation must instantaneously and continuously match consumption. Electric utility systems rely on a portfolio of power plants and other resources that generate power, which is transmitted through a network of high voltage transmission and distribution systems to the load centers where it is used. This collection of power plants are operated or "dispatched" to respond to changing conditions, as loads vary and as power plants and transmission or distribution lines fail, subject to numerous technical and regulatory constraints. Thus the electric system must be viewed as a dynamically changing, interwoven set of generators, delivery facilities, and consumers, with the entire system adapting constantly to match supply and demand.

Historically, the primary goal of the design, operation and regulation of the electric utility system has been to respond to the challenges of providing reliable electricity at an acceptable cost. Increasingly, environmental constraints have also become important in electric system planning. For example, air emissions requirements may limit the hours of operation of gas-fired resources; fishery impacts can be a constraint on the operation of hydroelectric and some thermal power plants; and water availability and thermal impacts can be a constraint to the operation, construction and siting of thermal power plants. Going forward in California, GHG emissions will be an important additional consideration in the operation and planning of the utility system.

Generation resources in an integrated system can and do vary considerably in terms of cost, availability, ability to control output ("dispatchability"), and environmental impact. California relies on a diverse portfolio of generating resources that includes gas-fired power plants, cogeneration facilities, hydroelectric dams, nuclear power plants, and a host of renewable resources ranging from wind turbines and solar generators to biomass and geothermal plants. California also relies on power imported from outside the state for a substantial amount of its resource base. Each electricity source has its own unique operating characteristics, constraints, costs, and environmental impacts. At any given time, the operation of the system must take into account these combined characteristics to reach an optimum dispatch of resources to meet demand.

When considering the impacts of a new resource addition, the additional resource must be considered in the context of the system as a whole. Resource characteristics such as reliability and dispatchability must be evaluated in relation to the existing resource mix to assess the implications for the operation of the electricity system. Similarly, the economic and environmental consequences of an additional resource cannot be assessed in isolation. When one resource is added to the system, all else being held equal, another resource will generate less power. If the new resource has a lower cost or fewer emissions than the existing resource mix, the aggregate system characteristics will change to reflect the cheaper power and lower GHG emissions rate.

This chapter highlights the major integrated elements of the California electric system and notes qualitatively how resource additions might affect, or be affected by, each integrated element.

Elements that will be discussed include the transmission and distribution grid, supply resources, demand and demand resources, and reliability requirements. Impacts are discussed in planning and operations for the control-area and local level.

The Transmission Grid

The backbone of the electric system in California is the network of electrical transmission and distribution lines that instantaneously transmit power from power plants generating electricity in and out of California to consumers across the state. Following California's deregulation of the electrical system, the three major investor-owned utilities and several publicly-owned utilities transferred operation of their transmission systems to the California Independent System Operator (California ISO).[14] These utilities continue to operate their own distribution systems, but rely on the California ISO to operate the overall transmission network. Several POUs including Sacramento Municipal Utility District (SMUD), the Los Angeles Department of Water & Power (LADWP) and the Imperial Irrigation District (IID) have retained control over and continue to operate both their transmission and distribution systems. The POUs' systems connect to the California ISO-controlled grid, but are managed by the POUs themselves. Figure 2 provides a map of the balancing authority areas in California. Each of these areas undertakes to operate its portion of the overall Western Interconnection to satisfy system requirements and continuously balance supply and demand.

Movement of power throughout the transmission system is limited by system capacity and operating constraints. These constraints can affect specific locations on the grid and fall into two categories: congestion and reliability. When an operating constraint can be mitigated without load curtailment it is considered a congestion issue; if load curtailment is required, it is considered a reliability issue. In its 2009 Draft Transmission Plan the California ISO identified a total of 37 projects needed to address congestion and reliability issues on its system (California ISO 2009a, pp.173-183).[15] These projects address concerns at specific grid locations. They seek to ease constraints resulting from dominant directional flows and/or expand congested pathways to accommodate peak flows going to or from a certain local area.

Due to potential congestion, the location of plant interconnection onto the transmission grid is very important and can directly affect how, and how much a plant operates. Simply because a plant is efficient does not necessarily mean that it will operate at a high capacity factor. Plants located near load centers (that is, populated areas) avoid congestion issues but can face increased environmental constraints that can curtail operating hours or limit startup/shutdown cycles. Isolated plants are much less likely to be constrained by environmental issues but may not be able to operate as much as their economics might suggest due to transmission congestion. These and other operating issues are discussed below.

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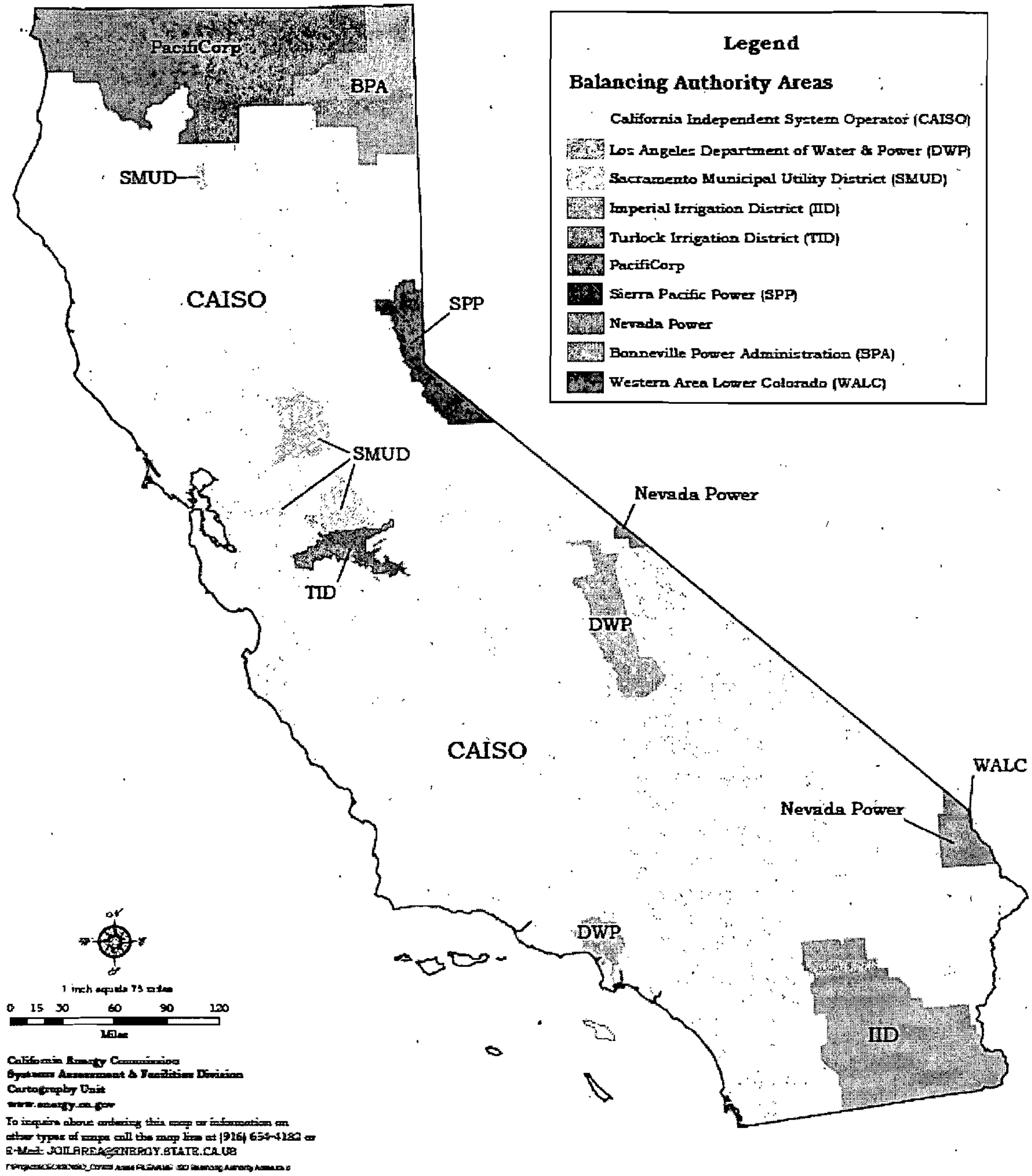
[14] The California ISO is a Federal Energy Regulatory Commission- (FERC) regulated non-profit corporation tasked with ensuring competitive and non-discriminatory access to the California transmission system and is responsible for managing the flow of electric power for the majority of California.

[15] Of these projects 22 are in the PG&E service area, 7 are in the SCE service area and 8 are in the SDG&E service area.

Figure 2: California Balancing Authority Areas



Source: (Energy Commission 2007c)

Demand in the California Electric System

Demand for electricity varies over time, following a daily, weekly, and seasonal cycle. Even within a given hour, demand will fluctuate constantly. Demand is generally lower at night and on weekends and holidays when minimum load conditions may occur.[16] The maximum demand for electricity in California will generally occur during the afternoon on a hot summer weekday. According to the Energy Commission forecast, maximum summer demand in 2010 is forecasted to be 64,216 MW and is expected to increase an average of 1.4 percent per year for the next five years (Energy Commission 2007b, Form 1.4, p.42; Energy Commission 2009b).

The point at which demand for electricity reaches a maximum is known as the peak and is an important factor in electricity and transmission planning. Load must be met by generation at all times. Thus, when demand reaches its peak, operating generators must be capable of generating that maximum quantity of electrical output and the transmission and distribution system must have the capacity to deliver to the consumer.[17] Both generation and transmission must therefore be built out at such a capacity to accommodate peak demand.

However, electricity use and peak demand need not be taken as a given in either transmission planning or power plant siting. For example, interruptible load can be curtailed in peak periods. Demand Response programs can mimic peaking supply-side resources by curtailing peak demand. In a joint vision statement released by the Energy Commission, the CPUC and the California ISO, policymakers have expressed the goal of fully integrating demand response and reliability planning into power markets such that demand response services can be bid into wholesale electricity and ancillary services markets alongside electric generation sources (CPUC 2008b).

Supply in the California Electric System

Demand for electricity in California is met by both in-state and out-of-state generation sources. Imported electricity accounts for roughly 31 percent of total electricity consumption in California. Figure 3 shows the breakdown of in- and out-of-state electricity by resource type. In 2007 California electricity demand was met by 45 percent natural gas, 15 percent nuclear power, 17 percent coal and roughly 12 percent each of large hydro and renewables (Energy Commission 2008b, p.5). As California continues to make steps towards GHG emission limits, this resource mix will evolve to include greater portions of renewable energy and reductions in the more carbon-intensive resources such as coal.

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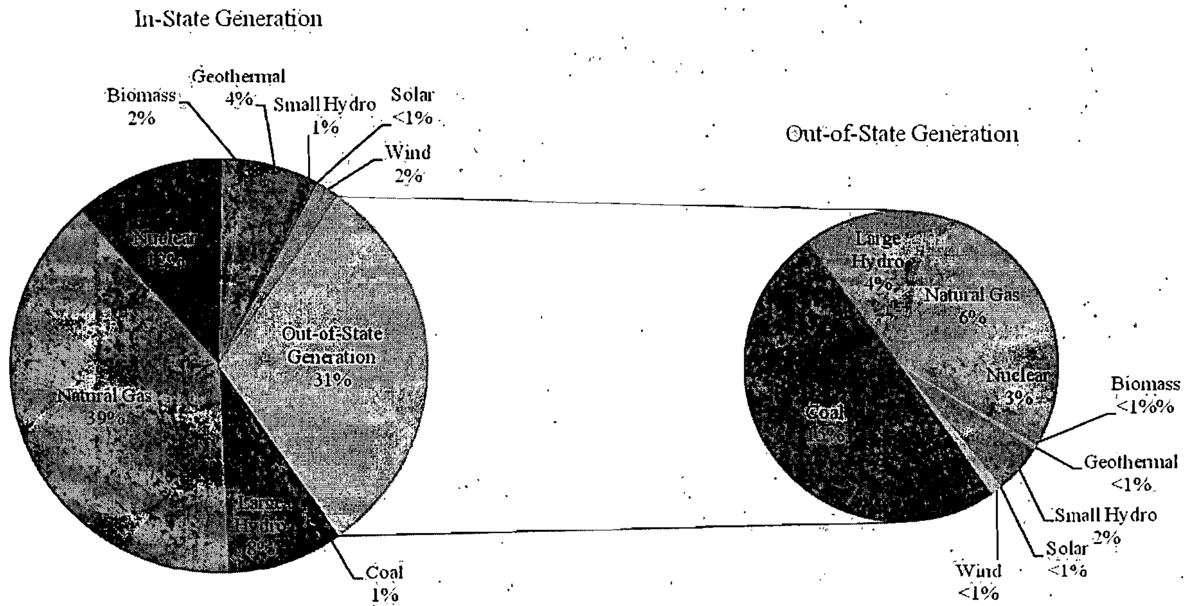
[16] Minimum load conditions exist when generation exceeds demand. Because generation must be continuously modified to match load, low levels of demand can create problems with over-generation. This concept is discussed in detail in Chapter 4.

[17] In addition to supplying generation at the level of demand, the system must carry sufficient generation to cover system losses and comply with resource adequacy requirements.

Figure 3: California Electricity Resource Mix in 2007 (percent of total energy)

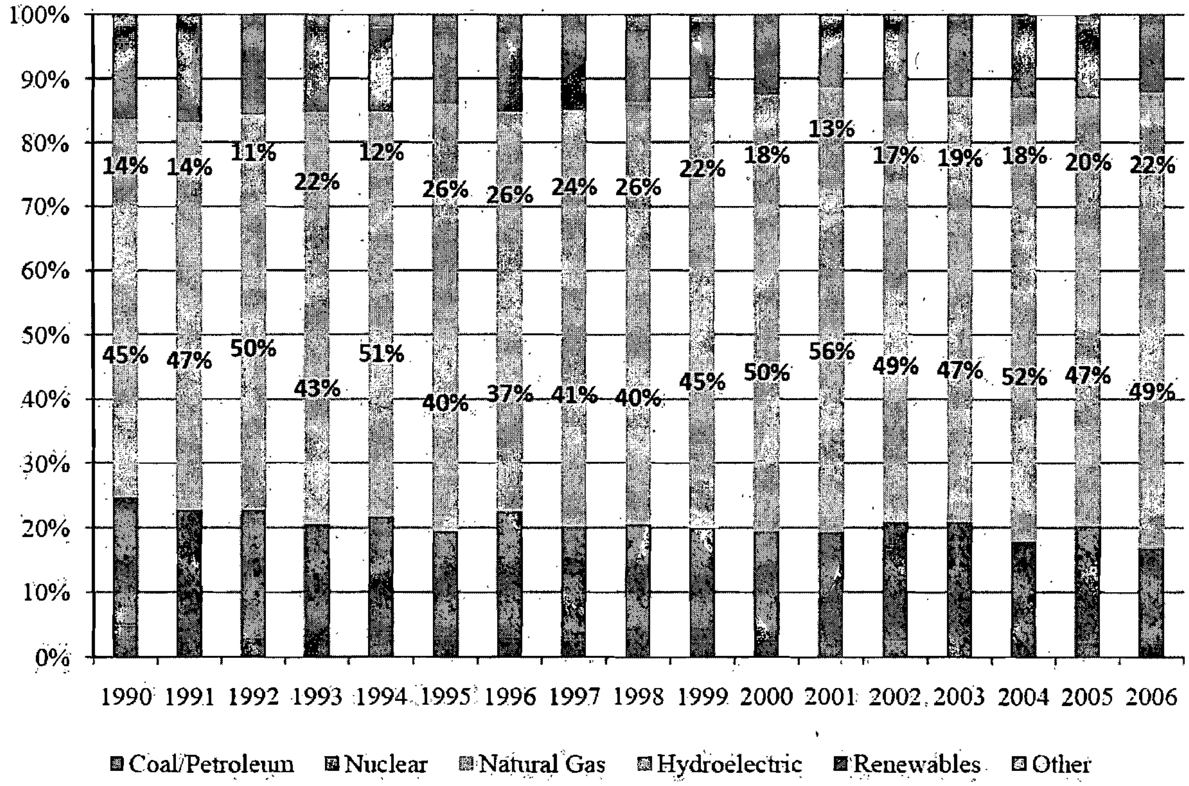


Source: (Energy Commission 2008b, p.5)

This mix is far from static and varies year-to-year, seasonally, daily and even hourly. For example, California tends to be a net power importer during the summer as the system reaches peak demand. Other regions, such as the Pacific Northwest and Canada experience peak demand in the winter. The seasonal exchange in imports and exports creates a shift in power flows throughout the year.

Hydroelectric power is one of California's primary energy sources. It is subject to large annual fluctuations that mirror changes in annual rain fall and snow pack. To a large extent, good hydro reserves are dependent on snow pack in the Sierras and subsequent runoff. Years in which snowfall is below average result in severely reduced spring reservoir levels, diminishing the amount of hydroelectric energy available. Figure 4 demonstrates the fluctuations in California's in-state generation mix from 1990-2006. From 1995 to 1998 hydroelectric resources accounted for as much as 28 percent of California generation. In 2001 hydro generation provided only 13 percent of total state generation (EIA). Natural gas-fired generation is typically the marginal generating resource, so it will produce more (or less) power to compensate for varying hydro availability.

Figure 4: California In-state Generation by Resource 1990-2006 (percent of total energy)



Source: (EIA)

Average generation values also miss a major element of the supply-piece of the integrated electric system: dispatch and duty cycle. Some plant types, due to technical constraints, economics or contracts, run at full capacity all the time (for example nuclear, coal, geothermal, cogeneration). Others, generally wind and solar, operate when nature allows. Gas-fired plants tend to be the most flexible, allowing for peaking, cycling, and some baseload duty. As such, they tend to be "on the margin".

Because natural gas-fired plants are frequently the marginal units in California, new more efficient power plants entering service will tend to displace generation from existing, older gas-fired plants. Thus, even if the plant emits CO_2, as long as the generation it is displacing, or perhaps even explicitly replacing, is less efficient (or uses a more carbon-intensive fuel), there will likely be a net decrease in system-wide GHG emissions.[18]

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[18] Displacement of an existing resource occurs when a new resource is dispatched that provides the same electricity products as an existing resource cheaper or more efficiently. Through economic dispatch, the new resource will be chosen over the existing one, causing it to operate less. Explicit replacement occurs when a resource is decommissioned as a result of new resource addition, which might involve a replacement or modernization of an older power plant. Note that the resulting GHG emission decrease discussed here is relative to the status quo generation mix.

As the fraction of renewable resources increase with the implementation of AB 32 and the state's RPS policies, gas plants, and in particular combined cycles and combustion turbines, may fill a new role: backstopping intermittent renewable resources. While wind and solar can provide a certain degree of dependable power when averaged across many locations, because of their intermittent nature, they will require other generation resources to be on line and available to cover their inevitable dips in output. Strategically located combined cycles can fill that role. Thus, a partially loaded combined cycle can, in principal lower system-wide GHG emissions—not only relative to the status quo generation mix but also absolutely—by allowing more intermittent renewable resources to operate without jeopardizing the stability of the transmission grid. Some hydro units and quick start combustion turbines may also be able to provide this backup service. Determining if a specific new resource provides this service would require extensive, probabilistic power flow and economic dispatch modeling.

Reliability Issues

A regulatory framework exists to ensure that resource decisions result in a reliable electric system. The key element of this framework is resource adequacy (RA) requirements, which are generally presented as reserve margins and can be roughly divided as follows: planning versus operational reserve requirements and local versus regional reserve requirements. In general, planning reserve margins are imposed on load serving entities (LSE) at the state level with regulatory oversight from the California Public Utilities Commission (CPUC) and operational reserve margins are the responsibility of the grid operator under regulations from the North American Electric Reliability Corporation (NERC) and the Western Electricity Coordinating Council (WECC)[19] with oversight from FERC.

The CPUC requires that LSEs within each control area meet certain procurement requirements that ensure that sufficient capacity will be available to meet changing loads. The planning reserve margin is the additional capacity required to cover load uncertainty, forced outages of power plants, and operating resources expressed as a percentage of the annual peak demand. It is a long-term planning tool that ensures that near-term capacity resources are able to maintain sufficient operating reserves.

NERC requirements seek to ensure that control areas maintain electric system reliability. The requirements address a number of standards that each control area must comply with such as resource and demand balancing, interchange scheduling and coordination, and transmission planning and operation standards (NERC 2008). These standards seek to ensure that transmission operation and planning results in a reliable electric system. The California ISO (and other regional grid operators) passes a certain amount of the responsibility for maintaining operating reserves down to the participating LSEs through power scheduling requirements.

[19] WECC is one of eight regional councils within NERC and may implement stricter reliability standards than NERC within its region.

Regional Resource Adequacy

To ensure that resources are available in real time, LSEs are required to procure sufficient resources to meet state-mandated planning reserve margins. These requirements seek to ensure that sufficient capacity will be available in the event of unpredictable circumstances such as higher than expected peak demand, generator outages or extreme weather events.

To reach planning reserve margin targets procured generation is assigned a net qualifying capacity (NQC) based on expected available capacity at the time of peak demand. Determining the NQC is relatively straightforward for generators able to modify output on command but is more difficult to assess for intermittent renewables such as wind and solar. The NQC assigned to these generators reflects a probabilistic assumption of the capacity that would be available at the time of peak demand.

Local Resource Adequacy

Local load pockets are defined by physical transmission constraints. If the transfer capability into a load pocket is less than the load demand within the area, then, depending on reliability criteria, additional generation capacity within the load pocket will be needed to satisfy demand.[20] This amount of generation capacity is the local capacity requirement (LCR). In simplest terms, the LCR study is the process of identifying the specific areas within the California ISO-controlled grid that have local reliability problems due to transmission constraints and, for each area so defined, determining the generation capacity, in megawatts (MW), that would be required to mitigate these local reliability problems.

LCR is defined as the amount of generating capacity that is needed within a local capacity area to reliably serve the load located within this area assuming the maximum amount of imported power into the local capacity area. The capacity requirements are determined by assuming electricity demand of 1 in 10 summer peak demand conditions.

Across its control area, the California ISO identifies the amount of generating capacity that must be available within a local area due to transmission constraints through the LCR study process. Based on its knowledge of operational history of the California ISO-controlled grid, the California ISO has identified 10 local areas in the state where local reliability issues exist. Seven local areas exist within PG&E's service territory, two are in SCE's region, and one local area falls within SDG&E's service territory.

In 2008 the CPUC adopted local capacity requirements for 10 local areas based on a study performed by the California ISO. The total LCR for all 10 areas is 27,915 MW in 2009, a slight decline from the total LCR in 2008 of 28,106 MW.

[20] There are actually a number of different criteria considered when examining local reliability. For example, for planning, an N-1/G-1 criterion is applied, which states that sufficient resources exist so that load can be met with the simultaneous loss of the largest importing transmission link and the largest in-area generator.

Table 6: 2009 Local Capacity Needs vs. Peak Load and Local Area Generation

	2009 Total LCR (MW)	Peak Load (1 in10) (MW)	2009 LCR as % of Peak Load	Total Dependable Local Area Generation (MW)	2009 LCR as % of Total Area Generation
Humboldt	177	207	86%	183	97%
North Coast/North Bay	766	1596	48%	945	81%
Sierra	2320	2126	109%	1780	130%
Stockton	726	1436	51%	541	134%
Greater Bay	4791	10294	47%	6773	71%
Greater Fresno	2680	3381	79%	2829	95%
Kern	422	1316	32%	677	62%
LA Basin	9728	19836	49%	12164	80%
Big Creek/Ventura	3178	4937	64%	5132	62%
San Diego	3127	5052	62%	3663	85%
Total	**27,915**	**50,181**	**56%**	**34,687**	**80%**

Source: (California ISO 2008a, p.21)

Because local load pockets are constrained as to the level of imports, some units within the pocket may be required to operate to meet load or maintain local grid stability in spite of the fact that they may be more expensive to operate than idle units outside the load pocket. These units were historically designated as reliability must-run (RMR) units and operated under single-year contracts with the California ISO. In 2006 the CPUC launched an effort to move away from costly RMR contracts by increasing RA procurement for load pockets. LSEs now emphasize signing contracts to meet specific local reliability needs. Since 2006, more than 7,800 MW of capacity has been released from California ISO RMR contracts as a result of greater reliance of LSE-procured LRA contracts (California ISO 2008b, p.2). Because most of the other balancing authorities in California are coterminous with an integrated utility, the elaborate process of dealing with multiple players to assure resource adequacy is not necessary

Operations

The pool of resources available for generation depends on the lead-time involved. Some generators may take a full day to start up while others may be dispatchable within minutes. Additional resources operate as spinning reserves, generating below their capacity with the capability of ramping up generation to meet load as required. NERC provides specific regulations dictating operational requirements to ensure that the electric system will be able to meet load on a day-to-day and minute-to-minute basis.

Beyond the regulated operational requirements, the California transmission system must account for several additional factors including seasonal shifts in supply and demand, temporary generator outages and the environmental consequences and limitations of power generation. These factors are external to the transmission planning process, but have large implications for grid operation, reliability and planning.

Economic Dispatch and Scheduling

When an LSE operates its own system, it will provide energy to meet load at the lowest cost while taking into account the multitude of operational requirements on the system. Economic dispatch will vary by timescale with dispatch decisions needed on the order of days down to minutes. Resource additions will affect the cost of system generation to the extent that generation from the additional resource will translate to modification of the generation profile of an existing source.

When a transmission operator such as the California ISO serves a large area including many LSEs, the dispatch and scheduling protocols are more complicated. The California ISO schedules generation to follow the daily load pattern. With the launch of the Market Redesign and Technology Upgrade (MRTU) on March 31, 2009, the California ISO created a day-ahead market that combines energy, ancillary services (operating reserves), and congestion management in an effort to better match what really happens when the electricity flows. According to the California ISO, the day-ahead market "determines the best use of resources available, while finding the least cost method of procuring required components" (California ISO 2006). MRTU seeks to move California towards a more fully economic market.

Ancillary Services

While LSEs schedule power to meet their anticipated needs on a day-ahead and hourly basis, the actual load will never exactly (or only coincidentally) match the sum of the scheduled load and associated supplies. Imbalances can arise due to fluctuations in demand, supply interruptions, or transmission line failures. The California ISO requires several types of ancillary services for its control area: regulation, spinning reserve, non-spinning reserve, and replacement reserves. The amount of each that is procured is sufficient to meet or exceed WECC and NERC performance standards. These ancillary services are used to meet real-time imbalances between actual and scheduled load and generation.

Generator and Transmission Outages

While electric generators and transmission lines are generally available for most of the year, they will experience outages, both scheduled (for maintenance) and unscheduled (due to equipment failure). Maintenance outages are scheduled so that they do not take place at the time of peak demand. However, if reserves are unexpectedly short, the California ISO can require that units refrain from shutting down for maintenance, even if an outage was scheduled. Typically, for planning purposes, each type of resource has an assumed forced outage rate and maintenance outage rate based on its historic operating performance.

Unscheduled outages provide a larger problem for transmission planning and are a principal motivation for resource adequacy planning. All generators and transmission lines carry a certain degree of risk that they will experience an unscheduled outage. Depending on the characteristics of the generator and the timing of the outage, if a generator trips offline unexpectedly there can be serious consequences for reliability. For example, if a large baseload plant were to go offline at the time of peak demand, system operators would likely struggle to supply power to meet demand, to maintain the proper operating frequency, and to avoid blackouts. In some cases the cause of an unexpected outage at a generator can be resolved within a short period of time, and the unit can be returned to duty quickly. In other cases, such as with nuclear power plants, an unexpected outage may be a symptom of a larger problem and may result in an outage on the order of months. Sometimes, even if the problem is simple, the operations of the plant may not allow for a quick return to service. While it is difficult to plan for unscheduled outages, a healthy transmission system—one which is in compliance with NERC requirements—will have contingencies to address these outages such as quick start combustion turbines available to provide backup.

Environmental Constraints

California's marginal power plants are typically gas-fired steam turbines and newer combined cycle plants. These plants respond to not only load conditions but the availability of other resources. Thus, these plants will operate significantly above average when there are outages at the nuclear plants, low hydro conditions, and during import limitations (that is, transmission line outages) etc. Operators of these plants have to comply with their environmental permits, which will limit air emissions (and thus operating hours and levels) and water discharge. In some cases operators of power plants may have operational flexibility through "bubbles" that aggregate emissions of multiple units or the ability to trade allowable emissions across power plants. During the height of the 2000-2001 California energy crisis, some power plant operators were faced with the dilemma of ignoring dispatch opportunities with the California ISO or exceeding their environmental emissions limits and facing steep fines from their local air quality regulators. Both LADWP and AES Southland faced fines from the South Coast Air Quality Management District (SCAQMD) for violating their air permits at that time.

New plants must meet prescribed new source emissions requirements and various other environmental operating constraints imposed upon them in the siting process. These constraints limit a plant's opportunity to offset the GHG emissions from older, less efficient plants or to firm up intermittent renewable generation. In setting the criteria air and water pollutant emissions levels, the regulators must therefore consider the trade-offs of GHG emissions for local criteria air or water emissions.

Conclusion

The integrated nature of California's electric transmission system has many implications for resource decisions. Electric demand varies constantly and must be met with supply at every moment. In addition, California's current supply mix is dynamic, changing with weather and supply conditions and subject to large annual fluctuations in gas and hydro production. The transmission grid is operated in such a manner to account for these changes by employing a host of reliability services and accounting for local resource adequacy issues. When assessing the impacts of an additional resource seeking to supply power to the integrated system, that resource must be considered in the context of the system as a whole. The reliability and dispatchability characteristics of the resource must be evaluated in relation to the existing resource mix to properly assess the implications. Similarly, the economic and environmental consequences of an additional resource cannot be assessed in isolation. As California acquires resources and moves toward its renewable energy targets, it must focus on overall system operation in addition to specific resource attributes.

CHAPTER 4: Transitioning to 33 Percent Renewable Energy

Renewable energy currently accounts for 12 percent of California's electricity supply. If renewable energy is to supply 33 percent of California's electricity, the amount of renewable energy capacity connected to the grid will need to increase dramatically. The four primary technologies that are likely to achieve the greatest penetration of the California market under a 33 percent RPS are geothermal, biomass, wind, and solar (both PV and solar thermal).[21] The grid implications of renewable resources vary by technology. Biomass and geothermal generation facilities behave in a similar fashion to conventional power plants, in that their output is dependent on fuel availability and/or operator decisions, rather than the weather conditions that drive wind and solar generation. Output from wind and solar generators is reliant on the availability of wind and solar radiation. These resources cannot be controlled to the same extent as output from conventional sources and are therefore considered separately.

Wind and solar resources are known as intermittent resources and are characterized by both variability and unpredictability. Some energy resources are variable but not necessarily unpredictable. Tidal energy, for example, is highly variable, but also almost perfectly predictable. Energy output from solar and wind, on the other hand, is not only highly variable but also much less perfectly predictable (Energy Commission 2007h, p.67). This intermittency does not allow wind and solar generation to be dispatched in the same sense as conventional generation.

It is unclear exactly which renewable technologies will come online to meet California's 33 percent RPS standard, however, several studies assume that intermittent generation, primarily wind, will account for the bulk of renewable generation in future scenarios (California ISO 2007, p.2; CRS 2005, p.41; Energy Commission 2007h, p.17). According to the Energy Commission's *Intermittency Analysis Project* (IAP), almost half of the renewable energy that will be generated to meet a 33 percent RPS by 2020 will be from intermittent renewable generation, namely wind and solar. The report estimates that intermittent renewables will account for 12 percent of California's energy supply and 23 percent of California's generation capacity in 2020 (Energy Commission 2007h, p.18).

As more renewable energy is connected to the grid and supplying energy, the state's integrated electric system will need to evolve in order to accommodate the modified generation mix. Because a large portion of the renewable energy is likely to come from intermittent generation sources, the transition to 33 percent renewable energy will have far-reaching implications for the reliable operation of the electric system in California.

This chapter will focus on the implications to the integrated electric system of transitioning to 33 percent renewable generation. Because wind and solar resources provide the greatest operational challenges for grid integration and are expected to provide large amounts of power, the discussion will focus on the particulars of these intermittent resources.

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[21] There is also the possibility that tidal or wave power may reach the market within the 2020 timeframe, but because these technologies have not yet reached commercial application they are not included in the analysis.

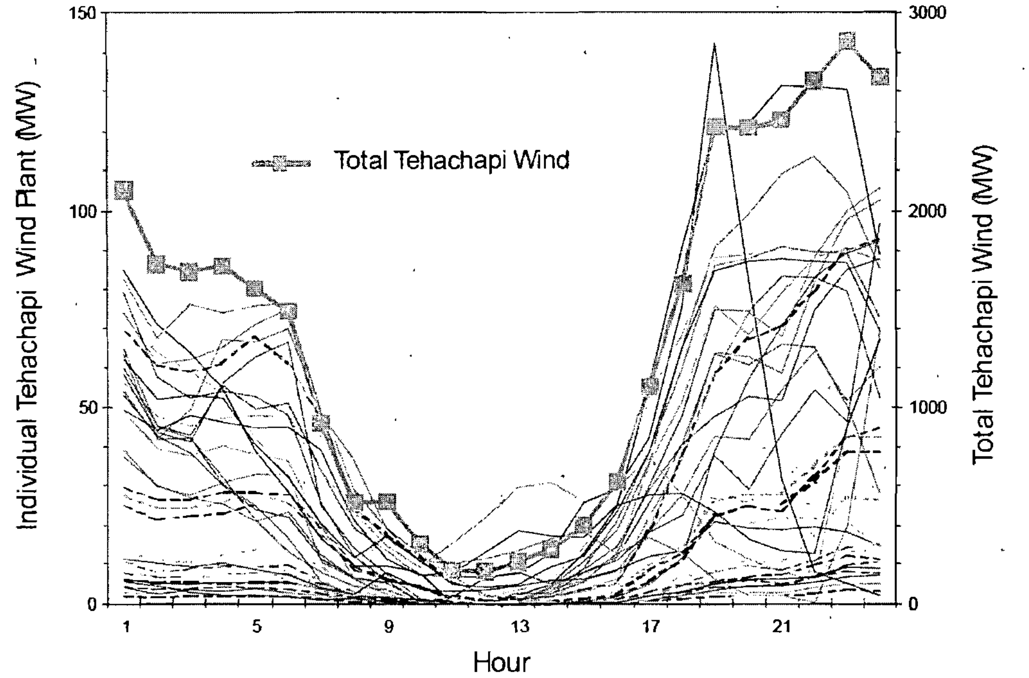
Challenges of Intermittent Renewable Energy Facilities

Wind and solar generating resources are classified as variable or intermittent resources because they rely on the availability of an external fuel source (that is, the wind or the sun) that cannot be controlled. Estimates have shown that wind is expected to be the primary source of renewable energy to meet California's RPS goals, potentially accounting for almost 50 percent of installed renewable capacity in 2020 (Energy Commission 2007h, p.18). In 2007, wind and solar accounted for 2.5 percent of energy from California's resource mix (Energy Commission 2008b, p.5). As the amount of renewable energy supplied to the grid nears the 33 percent target, wind and solar may provide roughly 12 percent of California's electricity supply (Energy Commission 2007h, p.18). In the near term the California ISO predicts that an additional 4,040 MW of wind generation will be installed to meet the 20 percent RPS requirement (California ISO 2007, 57).

Wind

Peak wind output tends to be lower in the summer and winter, and higher in the spring and fall (NERC 2009, p.17). Daily peak wind output generally occurs in the morning and evening. Over the short term, output from a single wind turbine or small wind plant can be highly variable on a minute-to-minute basis. However, as aggregate wind capacity increases and spatial variation is introduced, generation from wind sources may become less variable. The Tehachapi region in California, which encompasses over 500,000 acres, provides a good example of how aggregate wind generation installed over a large area is less variable than the output of a single plant. Figure 5 below shows individual as well as aggregate output from wind plants in the Tehachapi region. Within the Tehachapi region, individual plants experience very large hourly ramping, while total wind output is smoother. It is beyond the scope of this report to develop estimates of the extent to which volatility may be reduced as aggregate wind capacity increases across larger and larger geographic areas. Nevertheless, aggregating wind output across not just one large region, but state-wide or even across the Western region may dampen volatility.

Figure 5: Individual and Aggregate Tehachapi Wind Plant Profiles, July 21, 2003



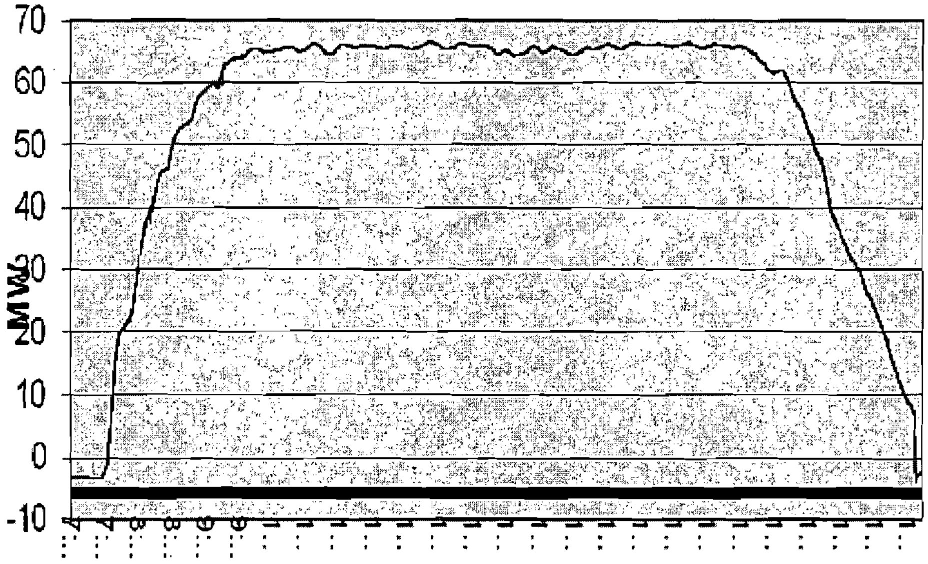
Source: (Energy Commission 2007h, p.29)

Solar

Solar power is generated by either solar thermal plants or solar PV arrays. Solar thermal plants collect solar energy to convert it into heat that is in turn used to generate electricity. Solar PV generators, on the other hand, convert sunlight directly into electricity. In general, solar thermal generators have much larger installed capacities than solar PV installations and are viable only in geographic areas with excellent solar resources. The major differences between the two types of solar technologies result in operational characteristics unique to each technology.

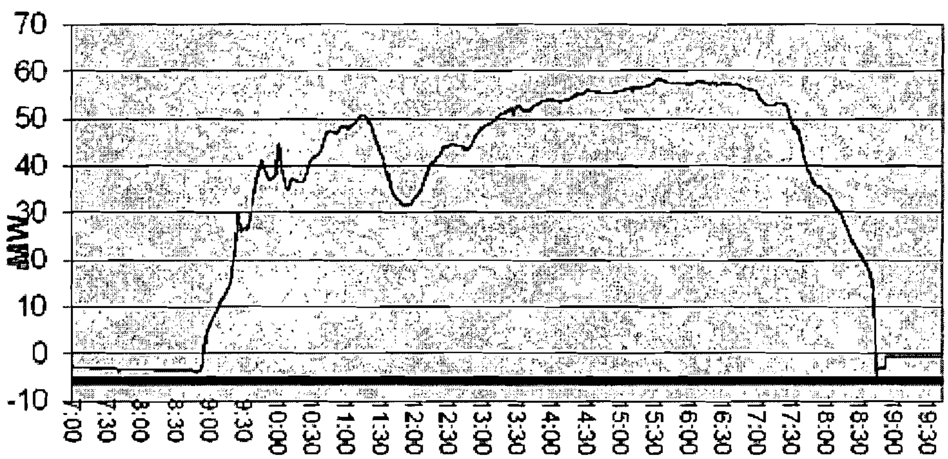
Solar thermal plants use solar radiation to heat a working fluid such as water or oil. This heat produces steam, which runs a steam-turbine and generates electricity. While incoming solar radiation can be highly variable, the thermal inertia retained in the working fluid aids in reliability and predictability over the short term (NERC 2009, p.25). As a result, solar thermal plants will experience less variability in electrical output on a minute-to-minute basis. In addition, while solar thermal generators may take some time after sunrise to begin to produce electricity, this thermal reserve will allow them to continue to operate for a certain period after sunset. Figure 6 and Figure 7 below show the output of a 64 MW solar thermal plant on a sunny day and a partially cloudy day, respectively.

Figure 6: Solar Thermal Output on a Sunny Day



Source: (NERC 2009, p.26)

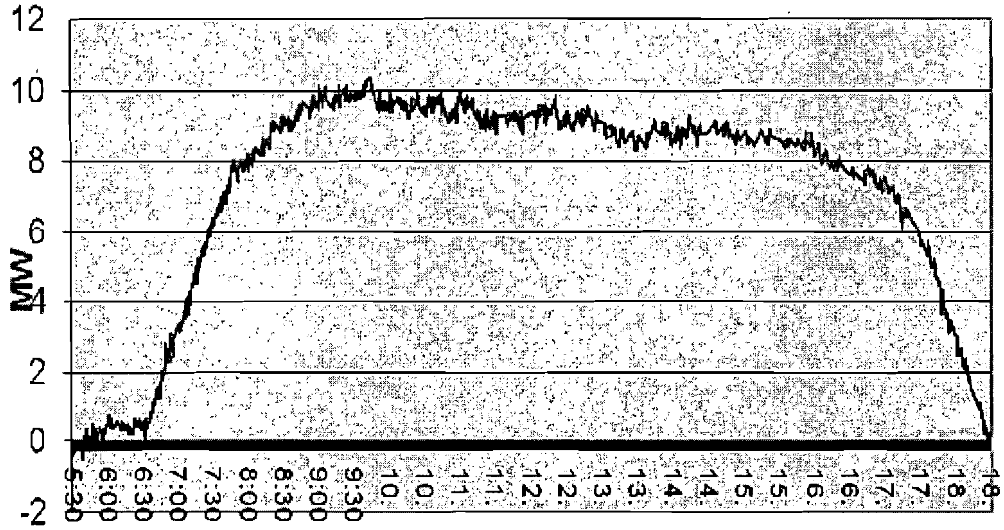
Figure 7: Solar Thermal Output on a Partly Cloudy Day



Source: (NERC 2009, p.26)

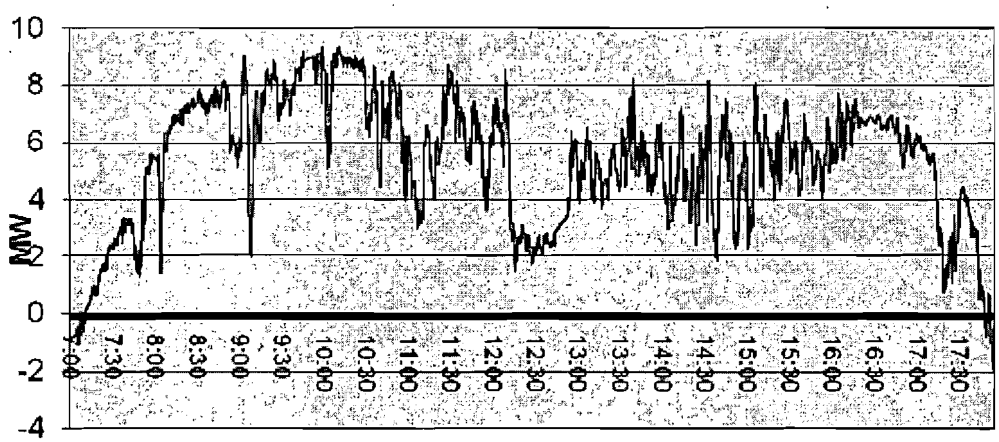
Because solar PV converts sunlight directly to electricity, it does not benefit from thermal inertia like a solar thermal plant. As a result, if all or part of a PV array is suddenly shaded by a moving cloud bank, PV output can experience ramping of +/- 50 percent in less than 90 seconds and +/- 70 percent in five to ten minutes (NERC 2009, p.27). Figure 8 and Figure 9 below show the output of a Nevada PV plant on a sunny day and a partially cloudy day, respectively.

Figure 8: PV Output on a Sunny Day



Source: (NERC 2009, p.28)

Figure 9: PV Output on a Partly Cloudy Day



Source: (NERC 2009, p.28)

Larger PV plants may be less susceptible to ramping due to the simple fact that they cover a larger area. Projects up to hundreds of megawatts in size have been proposed that may experience less variability. In addition, aggregation of solar plants across the state and/or Western region may lead to spatial variability benefits such as those shown for wind in Figure 5.

Intermittent Generation and Load

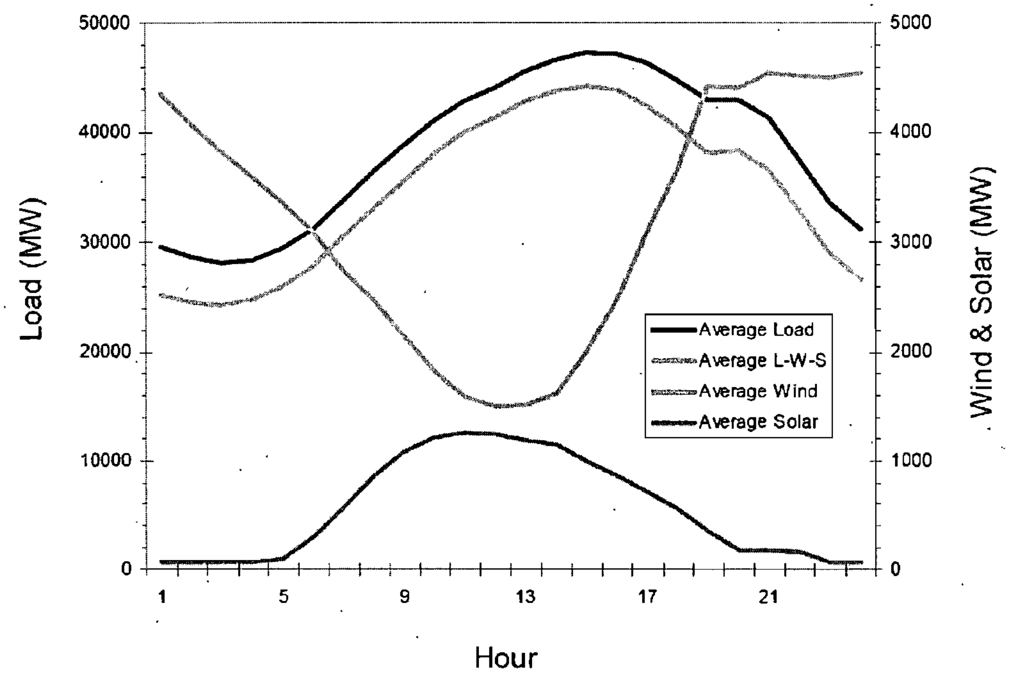
Introducing larger quantities of variable wind and solar generation to serve inherently variable load can have one of two effects. The variation among wind, solar, and load can offset each other, reducing overall system variability, or it can create additive variability. The timing of generation from wind and solar resources relative to the timing of load is an important factor in the assessment of the impact of these intermittent resources on grid operation. Wind will generally experience peak output in the mornings and evenings while solar will peak in the middle of the day.

Figure 10 and Figure 11 show the relationship between solar and wind generation and load on a sample day in July and in January, respectively. As shown in the figures, during the summer wind and solar generation can complement each other leading to a relatively consistent decrement in net load. Summertime wind generation is generally at its highest when demand is at its lowest, experiencing a large drop in output during the middle of the day. During the winter, output from wind generation becomes more consistent overall and experiences higher levels of generation coincident with the afternoon winter load peak.

Temporal changes in wind and solar generation may add to the variability of load. This effect is seen most clearly during the characteristic summer morning increase in load and the evening decrease. At the time of the morning increase in load, wind generation will typically be ramping down, while coincident with the afternoon decrease, wind generation will tend to ramp up (see Figure 10). The effect of these variations can be shown by examining the hourly change in load or output from one hour to the next (the delta) and comparing this across load and the net load resutling when wind and solar generation is subracted from load. Figure 12 below shows hourly load and net load in addition to hourly changes. Note that for the sample data shown below, during the morning increase between hour 7 and hour 10, net load including wind and solar generation experiences greater hourly variability than load alone. Similarly, during the evening drop around hour 22, net load experiences variability that is greater in magnitude than the variability of load itself. These occurences can be attributed to the diurnal shift in wind production (Energy Commission 2007h, p.39). Modeling in support of the IAP predicts that variability due to intermittent renewables will be 3-7 percent larger than variability from load alone (Energy Commission 2007h, p.78). [22]

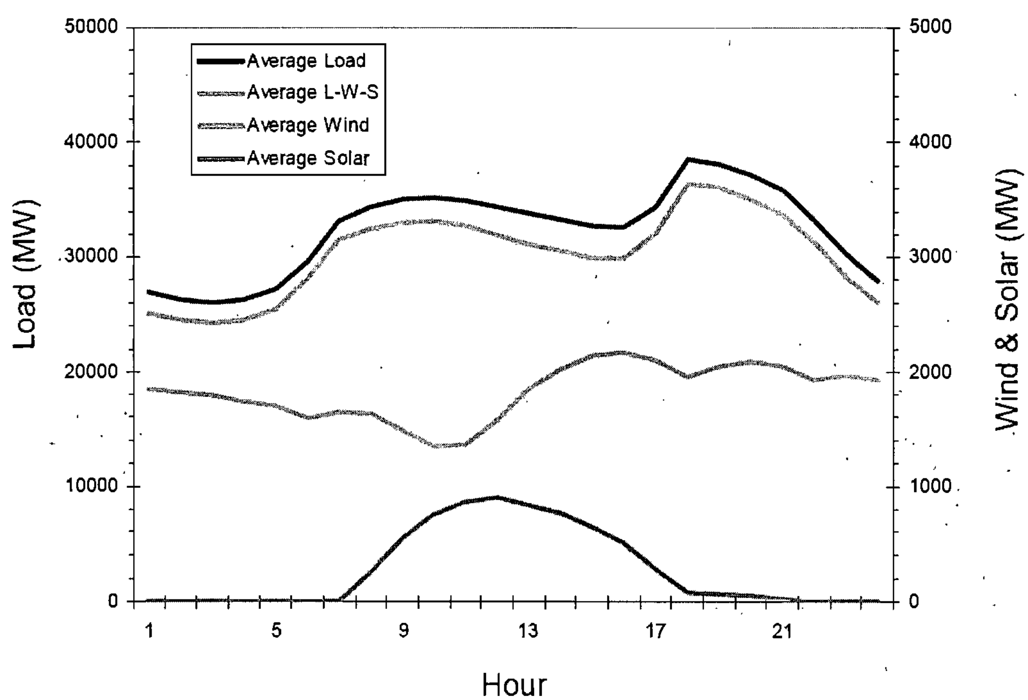
[22] Note that proportions of wind and solar that were observed in July 2003 may not be the same as proportions in future years. Therefore, the correlation of intermittent renewables with load shown in Figure 12 may change in the future.

Figure 10: California Average Output of Wind and Solar, Load and Net Load, July 2003



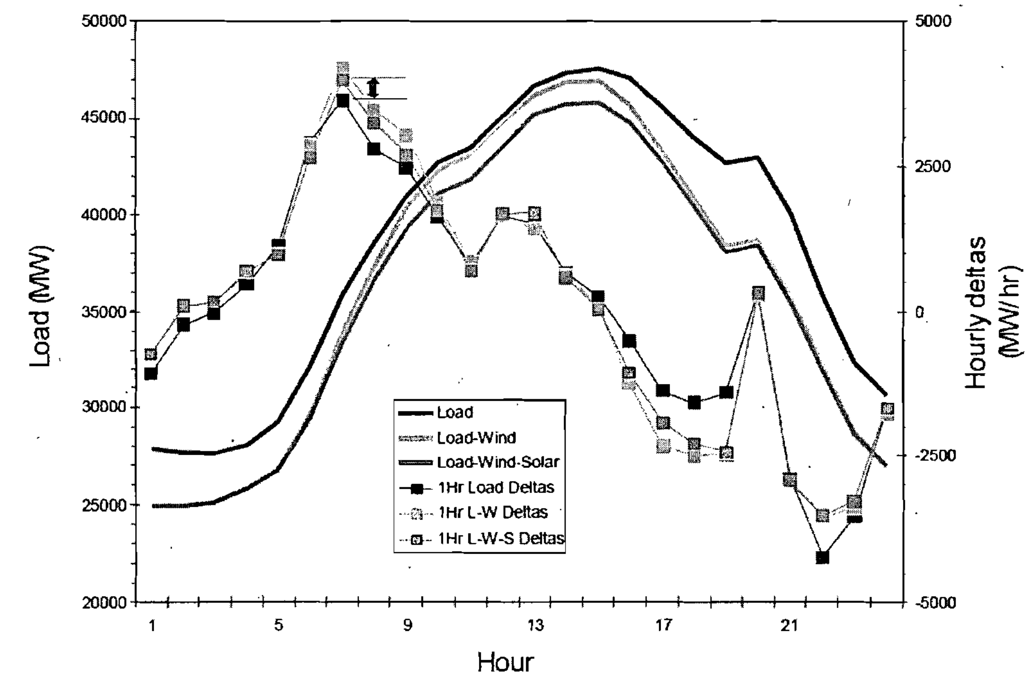
Source: (Energy Commission 2007h, p.24)

Figure 11: California Average Output of Wind and Solar, Load and Net Load, January 2003



Source: (Energy Commission 2007h, p.26)

Figure 12: Hourly Profiles and Hourly Variation, July 2002.



Source: (Energy Commission 2007h, p.40)

Forecasting Output of Intermittent Renewable Generation

A power system must be able to respond to variability in demand by changing output; its ability to accomplish this depends on advance knowledge of output requirements as well as an ability to reliably forecast output from intermittent renewables. At the current penetration level of intermittent renewable generation in the state, forecasting error does not create reliability issues. However, the California ISO anticipates that as the state moves toward its 20 percent RPS goal, there would be increased risk that uncertainties in day-ahead forecasting could create reliability challenges (California ISO 2007, p.49). This is due to the increasing magnitude of renewable generation and therefore the increasing magnitude of the associated error in the forecast. For example, if renewables were forecasted to produce 10 percent more than actual production but only 100 MW of renewables were online, forecast error would amount to 10 MW. If online renewables were to double, so would the resulting shortfall with a 10 percent over-estimation. As a result, over-forecast of renewable output during a given period could lead to insufficient dispatch of residual unit commitment resources, causing reliability issues. Developing more accurate forecasts of output will become increasingly important as renewable resources become a larger share of the state's energy mix.

Forecasting wind conditions requires an accurate knowledge of future weather conditions as well as an accurate model which can take weather data inputs and use these inputs to forecast future wind conditions. Error is introduced when either weather conditions are uncertain or when the forecast model is not correctly calibrated. Day-ahead forecasts characteristically contain larger error than hour-ahead forecasts. The IAP found that renewable forecasting errors contributed to roughly half of the measured day-ahead error and roughly 20 percent of the measured hour-ahead error (the remainder was attributable to load forecasting errors (Energy Commission 2007h, p.78).) Errors also were found to be dependent on load and wind generation magnitude. Uncertainty due to intermittent renewables was found to be three times greater than uncertainty due to load during moderate to light load conditions (Energy Commission 2007h, p.175).

Implications for Operational Requirements

The amount of dispatchable generation needed to meet performance standards is expected to increase as RPS requirements are met (Energy Commission 2007h, p.22). The California ISO expects that intermittent renewables installed to meet the interim 20 percent RPS goal will significantly increase minute-to-minute and hourly variability on the system (California ISO 2007, p.65). The reliability and resource adequacy measures of California's transmission system will need to evolve to keep up with this scale of renewable development.[23] The California ISO has determined that generators with quick start, fast ramping and regulation capabilities and a wider operating range (lower minimum operation) will be needed to successfully integrate high levels of renewables (California ISO 2009c, p.32)

Several studies have addressed the potential impact on operational requirements of increased renewable generation in California. In support of the *2005 IEPR*, the Electric Power Group (EPG) and the Consortium for Electric Reliability Technology Solutions completed an analysis of reliability and operational requirements under a 20 percent by 2010 RPS scenario relative to requirements in 2004 (EPG 2005). In addition, in support of the Energy Commission's IAP project, General Electric completed a study examining 20 percent and 33 percent renewable penetration relative to 2006 data (Energy Commission 2007h). Most recently, the California ISO has undertaken a similar analysis through its Integration of Renewable Resources Program, releasing a report (the IRRP Report) in November 2007 addressing potential requirements for 20 percent renewables in 2010 relative to requirements in 2006 (California ISO 2007). The results of these studies are highly dependent on the assumed renewable generation mix. This section utilizes the results of these reports to understand the potential operational issues that may arise in the future as the state increases renewable generation.

The California ISO is currently analyzing operational requirements for the California ISO-controlled grid under a 33 percent renewable RPS in 2020. Pending the outcome of this study, it is unclear what the exact requirements will be. The California ISO has stated preliminarily that the increase in intermittent generation associated with the shift from a 20 to a 33 percent RPS requirement will increase integration problems non-linearly and could more than double costs under the 33 percent RPS (California ISO 2007, p.14).

Multi-Hour Ramping and Ancillary Services

Ramping requirements and ancillary services help to meet load under variable and unpredictable conditions. With increased wind penetration, the generation requirement

[23] If the future renewable mix were to be modified to include less wind generation and more geothermal or biomass baseline generation, or more solar which experiences greater correlation with load changes, the relative requirements for additional controllable generation would be decreased (EPG 2005, p.23).

resulting from load requirements net of renewable generation is expected to become more variable. According to the EPG Study, the maximum daily swing (the difference between the maximum and minimum generation requirements) on the California ISO system would increase 5 percent in 2010 relative to 2004 assuming 20 percent renewable penetration (EPG 2005, p.22). This increase translates to a 1,100 MW increase in the maximum daily swing requirement and a 400 MW increase in the average daily swing requirement (EPG 2005, p.22).

The California ISO's IRRP Report concluded that additional resources with short-start and fast-start capabilities will be needed to meet morning and evening load and wind ramps due to intermittent resources installed to meet the 20 percent RPS requirement (California ISO 2007, p.65). The additional requirements result from the simultaneous morning increase in load and decrease in wind production as well as the opposite evening decrease in load and increase in wind production typical of the California system (see Figure 10 and Figure 11). The morning and evening ramps by season for 2006 and as expected in 2010 with 20 percent renewables are shown in Table 7.[24] The maximum expected ramping requirement occurs during the summer months, when the combination of morning load increase and wind generation decrease is expected to require commitment of 12,664 MW of capacity in the day-ahead market. Likewise, the maximum needed curtailment would occur during the fall when the combination of load drop-off and increased wind production in the evening is expected to result in the need to curtail 13,483 MW of generation over a 3-hour period (California ISO 2007, p.71). The resources required would need to be committed either in the day-ahead unit commitment process or the real-time unit commitment process with deficiencies to be met through load-following and/or regulation.

Table 7: California ISO Summary of Multi-Hour Ramping Requirements

(MW)	Spring	Summer	Fall	Winter
2006 Morning Ramps	6,860	10,090	7,229	6,979
20% RPS Expected Morning Ramps	8,494	12,664	8,995	8,631
Change due to Intermittency	955	1,529	1,023	926
2006 Evening Ramps	7,962	10,589	11,511	7,856
20% RPS Expected Evening Ramps	9,788	12,135	13,483	9,293
Change due to Intermittency	984	427	740	603

Source: (California ISO 2007, p.71)

In its review of the supplementary energy stack required to meet intra-hour load following and regulation needs with 20 percent renewable generation, the California ISO found that significant increases would be required for load following and additional increases would be required for regulation. For load following, the study estimated that the maximum hourly increase will be incremented by 800 MW and the maximum hourly decrease will be incremented by 900 MW (California ISO 2007, p.77). This large increase can be attributed to the

[24] Note that the numbers shown in Table 7 are highly dependent on assumptions about the future mix of renewable resources. In its analysis the California ISO assumed that 3,540 MW of wind would be installed in the Tehachapi area and 500 MW would be installed in the Solano wind park. The report additionally assumed that increases in concentrated solar would be small enough to not result in integration issues. Changing these assumptions would likely alter the expected ramping requirements. The same issues hold true for Table 8 below.

fact that in the hour-ahead time frame, the wind generation forecast error becomes comparable to the load forecast error compounding uncertainty and load-following requirements. In addition, regulation capacity increase would be incremented by a maximum of 250 MW and the decrease incremented by a maximum of 500 MW (California ISO 2007, p.82). The needed supplementary load-following and regulation capacity by season is summarized in Table 8.

Table 8: California ISO Load Following Capacity Needs in 2010 with 20 Percent Renewables

(MW)	Spring	Summer	Fall	Winter
Load-Following				
Increase due to Intermittency	+800	+800	+750	+700
Decrease due to Intermittency	-500	-600	-900	-750
Regulation				
Increase due to Intermittency	+240	+230	+170	+250
Decrease due to Intermittency	-300	-500	-275	-100

Source: (California ISO 2007, pp.77, 82)

The California ISO additionally predicts that load-following and regulation ramping requirements would increase. Load following ramping requirements increase by 40 MW per min both upwards and downwards while regulation requirements increase by roughly 20 MW per min (California ISO 2007, pp.75, 82). In a good hydro year the existing resource mix, which includes 12,651 MW of capacity certified for ancillary services, appears adequate to meet regulation needs. However, hydro facilities account for roughly 40 percent of this capacity including two-thirds of the regulation with ramp rates greater than 10 MW per min. During a low hydro year regulation may be slower due to increased reliance on thermal units with slower ramp rates and additional resources may be needed to meet regulation needs especially during the summer months (California ISO 2007, pp.75-76).

In comments on the report, PG&E and SCE expressed concern that the California ISO's analysis may underestimate integration needs (PG&E 2007a; SCE 2007a). Both utilities contended that the report may overestimate the ability of existing resources to compensate for the expected increase in intermittent renewable generation. SCE urged further consideration of the potential retirement of aging, flexible gas-fired generation and the subsequent stress on remaining generators. PG&E asserted that the study may overestimate the ability for hydro facilities to provide load-following and ramping services, noting that FERC requirements may not allow for greater flexibility in generation. In addition, PG&E called into question the ability for new conventional resources to provide sufficient operational flexibility because economics will tend to favor operation at or near full capacity and emissions issues may be encountered at partial load.

Over-Generation Conditions

Over-generation (or minimum load conditions) arises when generation exceeds load. Under normal operating conditions, whenever generation exceeds load the system operator will require generating units to move towards their minimum operating conditions, or in some cases will require that they be shut down if the units can be restarted and available to meet loads when necessary in the future (for example, the next day). In addition, the system operator will limit imports and seek to maximize exports. Over-generation conditions occur when these actions have been taken, but load continues to exceed generation. Under these circumstances market prices may turn negative as the system operator must literally pay adjacent balancing authorities to take the excess energy (California ISO 2007, p.82).

Over-generation conditions tend to occur when load is especially light such as in the spring when load drops to 22,000 MW or less. This situation is made more extreme when hydro is operating at high production levels, the nuclear plants are online at maximum production, and long-start thermal generators are operating because they are required for future operating hours (California ISO 2007, p.83). Because higher levels of wind generation are often coincident with lower load conditions (for example, a spring morning) and may increase unexpectedly, there is concern that large penetration of wind energy may exacerbate over-generation conditions.

Although wind generation has played a small role in historic over-generation events, it is anticipated that increased capacity to meet the 20 percent requirement will cause additional operational challenges during light load conditions (California ISO 2007, p.84). According to the EPG Report, minimum load conditions will worsen with renewable integration (EPG 2005, pp.85-86). In the most extreme cases, renewable generation was found to require additional reduction in generation output of up to 4,000 MW (EPG 2005, p.28). In some cases, the wind generators themselves may be able to curtail production as needed. The California ISO IRRP Report concluded that wind generation operators should be prepared to curtail a portion of their generation for up to 100 hours per year (California ISO 2007, p.87).

Voltage Stability

In the past wind generators have had issues meeting low voltage ride through standards, voltage control, and other large generator interconnection standards. However, new wind generators are expected to be free of these problems due in large part to the addition of dynamic reactive capacity. Not all new models of wind turbines have dynamic reactive capacity, but the majority of wind development is expected to possess these characteristics. The California ISO has indicated that it may consider requiring all new wind plants to have a minimum portion of the required power factor range be dynamic (California ISO 2007, p.26). As interconnection requirements evolve and are met by new types of wind generators, the problematic behavior of the older plants is expected to be relieved by the new generation (California ISO 2007, p.23).

The California ISO conducted a voltage stability analysis in which it assumed that 3,540 MW of wind capacity will likely be added to the existing 722 MW of wind generation in the Tehachapi area (California ISO 2007, p.57). If this new capacity meets WECC low voltage ride through criteria and has some dynamic reactive capacity, then the California ISO found that the proposed Tehachapi Transmission Project would allow integration of this level of wind generation without causing any transient stability concerns (California ISO 2007, p.26).

Voltage stability of the grid could also be threatened by looming retirement of many aging gas-fired plants. These plants contribute to local reliability by providing frequency control, voltage support, and voltage-ampere reactive (VAR) support (Energy Commission 2004, p.24). In many local reliability areas, few other resources are able to supply these services. The continued operation or replacement of these gas-fired facilities may be necessary to ensure that voltage stability is maintained.

Advanced Energy Storage

Energy storage technologies which can respond quickly to variations in the power system may play an important role in integrating intermittent renewable resources into the system. Energy storage has the potential to provide a myriad of benefits, including mitigating over-generation problems by acting as load when there is excess energy on the grid; mitigating large load and/or output ramps by quickly supplying energy to the system when needed; providing voltage support and regulating frequency; and shifting off-peak production to on-peak delivery.

At the current time, market-ready storage services are limited to pumped storage hydro, and pondage hydro capacity. Generally, there are limited additional opportunities to expand California's pondage hydro capacity and pumped storage capacity, so this section focuses on advanced energy storage options. Some of these opportunities might require retrofitting existing facilities with variable speed pumps. There are also several types of advanced energy storage technologies in the research and development pipeline that are being developed and evaluated for cost-effective wide-scale deployment. These include flywheels, hydrogen storage, flow batteries, lithium-ion batteries, super capacitors, compressed air storage and sodium sulfur (NAS) batteries (EPRI 2009).

Advanced storage technologies appear poised to take on new levels of development to aid in renewable energy integration. However, some barriers to the deployment of these technologies exist. These barriers include the nascent nature of some technologies and a need to further assess the true costs and values of the technology as well as the need for a defined role for storage within the regulatory arena (EPRI 2009). According to the California ISO, technology is not the major barrier for the construction of new storage facilities, but rather the lack of market mechanisms that recognize the value of the storage facilities and financially compensate the owners for the services and benefits they can provide (California ISO 2007, p.100).

Transmission Expansion and Upgrades

Much of California's existing transmission infrastructure was designed to move power from utility-owned power plants to load centers. Independent generators looked for locations which had ready access to the transmission system, obviating the need for substantial new infrastructure to deliver electricity into the system. In contrast, the majority of renewable resources are located in remote areas, far from the major load centers in the state, where no significant transmission infrastructure currently exists (RETI 2008, p.2-2). In its 2007 Strategic Transmission Investment Plan, the Energy Commission concluded that transforming California's transmission system to accommodate renewable generation in line with California's policy goals hinges on the following key factors (Energy Commission 2007g, p.48):

- Timely transmission corridor designation and subsequent utilization in permitting processes.
- Coordinated renewable generation and renewable transmission infrastructure planning and permitting.
- Emphasis on stakeholder involvement and the early identification of issues.

- Timely transmission interconnections.
- Removal of transmission system integration barriers.
- Use of state-of-the art planning tools.

The Energy Commission, the CPUC, the California ISO, and the state's publicly owned and investor-owned utilities formed the Renewable Energy Transmission Initiative with the goal of identifying the renewable resources and transmission investments necessary to meet California's renewable energy goals (RETI 2008, p.1-1). To date, RETI has calculated economic rankings for a number of renewable energy zones it analyzed including transmission costs.[25] RETI also estimated that meeting California's goal of 33 percent renewable electricity in the year 2020 would require additional renewable energy totaling about 68,000 GWh per year (RETI 2009, p.ES-4).

In May 2008 the Western Governors' Association and the U.S. Department of Energy formed the Western Renewable Energy Zone (WREZ) initiative. The WREZ initiative includes 11 states, two Canadian provinces and areas in Mexico that form the Western Interconnection.[26] The goal of the initiative is to foster discussion of how best to bring energy from remote renewable energy facilities to load centers throughout the West. The WREZ initiative will identify renewable energy potential in specific zones as well as conceptual transmission plans. The first phase of the project, which will identify renewable resource potential and associated generation and transmission costs, is expected to be completed in June 2009.

In addition to the recognized need to examine connection of renewable generation to the transmission system, a December 2008 Public Interest Energy Research (PIER) report additionally emphasized the need to study the delivery of renewable energy all the way to specific load centers (EPG 2008, p.15). The report highlighted the need to consider transmission gateways located at the connection between the state's backbone transmission system and local load centers. The import capability within a specific local area is a function of the portfolio of generators operating within the local zone. The report found that reduction of in-basin gas-fired generation through potential plant retirements and acceleration of dependence on external generation sources such as remote renewables will decrease ratings on the transmission system and accelerate the need for transmission upgrades (EPG 2008, p.32). In particular, the report found that more than two- thirds of new renewable generation expected under the RPS program would need to be delivered through the Los Angeles Basin area gateways (EPG 2008, p.37). It is estimated that between 13,000 and 17,000 MW of additional transmission capacity in addition to internal transmission upgrades will be needed at the LA Basin gateways alone (EPG 2008, p.30). To aid renewable integration, the report recommended that the California ISO

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[25] Where incremental transmission was required to deliver energy from a project, this cost was included in the economic analysis; incremental transmission included substation upgrades and additions, transmission to interconnect to the existing high voltage grid, and delivery to primary substations in load centers (RETI 2009, pp.3-16, 3-19).

[26] Members include Arizona, California, Colorado, Idaho, Montana, Nevada, New Mexico, Oregon, Utah, Washington, Wyoming, Alberta, British Columbia and Baja California.

expand the transmission planning horizon and initiate studies to expand transmission gateways and load center deliverability (EPG 2008, p.15).

Looking Beyond 2020

California's goals for reducing GHG emissions extend beyond the 2020 targets identified in AB 32. Governor Schwarzenegger's Executive Order that first defined the California target to reduce GHG emissions to 1990 levels by 2020 additionally called for a reduction to 80 percent below 1990 levels by 2050 (S-3-05). This target is consistent with the level of reduction that climate scientists estimate advanced economies must meet to stabilize the global climate in the latter half of the 21st century (ARB 2008b, p.117).

ARB's *Scoping Plan* focused primarily on the 2020 target, but examined the potential efficacy of the proposed measures towards continuing reduction beyond 2020. ARB found that to meet the 2050 reduction goal identified in Schwarzenegger's 2005 executive order, state-wide GHG emissions would need to be reduced to 85 $MMTCO_2E$ with an interim target of roughly 284 $MMTCO_2E$ by 2030 (ARB 2008b, p.118). The 2050 goal was considered too far in the future to be examined in detail, but ARB concluded that the *Scoping Plan's* recommended actions would place California on the right trajectory for achieving emissions reductions in 2030 that are in line with needed reductions to meet the ultimate 2050 target (ARB 2008b, p.118). Over the next 50 years, California will face the challenge of shifting its energy mix from primarily fossil fuels to a very low carbon mix.

If California is to progress beyond the 2020 targets, ARB expects that existing programs involving further limitation under the cap-and-trade program, greater increases in renewable energy generation and increased energy efficiency and green building efforts will need to be established (ARB 2008b, p.119). As California works towards further reduction, the targets must be reconciled with a large expected growth in population which is expected to rise 12 percent between 2020 and 2030 alone (ARB 2008b, p.118). The resulting requirement amounts to a per-capita emissions decrease of almost 5 percent per year from 2020 to 2030 (ARB 2008b, p.118).

Transportation Electrification

One of the pillars of ARB's AB 32 strategy involves the redesign and advancement of the transportation industry which currently accounts for 38 percent of California's GHG emissions (ARB 2008b, Appendix C, p.C-55). Much of the gains in the transportation sector will be the result of fuel switching—decreasing reliance on gasoline and diesel in part by increasing reliance on electricity (ARB 2008b, pp.3-4).[27] The actual effect that transportation electrification will have on the electric grid depends largely on the technologies adopted and measures put in place to control demand for electricity used for transportation.

One technology that is likely to be adopted to help meet the GHG challenges is the plug-in hybrid electric vehicle. Plug-in hybrids have a larger battery than traditional hybrids and can be recharged from the electric grid to minimize gasoline consumption. Widespread adoption of

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[27] The *Scoping Plan* also calls for additional transportation emission reduction measures including a low carbon fuel standard and vehicle efficiency measures.

plug-in hybrid vehicles will result in increased electric load. The important policy question is when and where the increased load would be expressed. A study by the Pacific Northwest National Laboratory found that if the cars were charged only during off-peak periods (the best-case scenario), there is sufficient excess off-peak electricity on the current system to charge 70 percent of the U.S. light-duty vehicle fleet, but only 23 percent of the fleet in California and Southern Nevada (PNNL 2007, pp.6-7). This means that even under the best-case scenario, new generation sources will likely be needed to accommodate large-scale adoption of plug-in hybrids in California. Further complications could result from the location of charging stations within local reliability areas. If the cars require charging within constrained load pockets there may be implications for local resource adequacy and the potential need for more in-basin resources.

The policy and pricing mechanisms related to charging plug-in hybrids need to be developed in such a way to encourage off-peak consumption. For practical purposes, however, it is unlikely that charging will be relegated only to off-peak hours. Recharge will depend on the range of the vehicle on a single charge and longer trips may require charging en-route. In addition, cars with faster recharge capabilities are more marketable as traditional car replacements, but must consume more electricity over a shorter period of time. With plug-in hybrid cars these issues may be partially mitigated through the use of the vehicle's gasoline engine, but as technology progresses towards the adoption of fully electric vehicles, recharge flexibility will decrease. The electric system must be prepared to take into account potential increases in peak and overall load due to the growth of transportation as a source of demand.

Adoption of Future Technologies

The ability of the electric system to accommodate policy measures that provide for reductions of GHG emissions beyond the 2020 targets will depend largely on the state of technological advancements. With even higher levels of intermittent renewable electricity generation, the electric system will need greater control over generation and load to reliably supply electricity to the state. Technologies that may be developed for these purposes include smart chargers in plug-in hybrids or electric vehicles, electric storage technologies, and smart-grid developments that aid demand response.

The batteries in plug-in hybrids and electric vehicles have the potential to aid system reliability by acting as a storage device for the electric grid. These batteries may be able to provide a useful sink for excess off-peak wind generation and may be developed with smart chargers that can automatically phase out charging when reserves become tight. In addition, there is potential for these batteries to supply electricity to the grid as needed and to directly supply power to a small local area in the event of a blackout. Energy used for this purpose may, however, limit the operation of the vehicle and will need to be evaluated accordingly.

There is also promise for development on the other side of the meter. Smart-grid technologies seek to allow real-time information about electricity usage to the system operator and may offer the ability to control load to dampen variability and decrease peak demand. However, there is a practical limit to any demand response program. At some level of reduction end-users will no longer be willing to reduce load but customers may be willing to operate appliances at different times with different price points for the right incentives. Thus, technological advancements in demand response may help to improve reliability and decrease the need for ancillary services provided by generation.

In addition to the technologies listed above, other developments such as smart growth and improved land use planning may additionally aid in achieving California's long-term GHG reduction goals. Included in this vein is the CPUC goal of zero net energy buildings for all new residential construction by 2020 and all new commercial construction by 2030 (CPUC 2008c, p.6). These goals could play a significant role in California's GHG efforts after 2020. To the extent that land use planning and smart growth can focus on building GHG-efficient communities from the ground up, additional reductions could be achieved.

While many resources are currently being put into the development of these technologies, it is difficult to speculate as to the level of adoption that may be seen over a certain time-frame. Successful development and deployment of some or all of these technologies will help California meet its GHG reduction goals in 2020 and beyond.

Conclusion

The addition of large quantities of renewable resources necessary to meet the state's renewables portfolio standard targets will create a challenge for reliable grid operation and necessitate evolution in grid planning and resource procurement. Intermittent renewable resources will increase the uncertainty and the variability of generation requirements and will need to be compensated for with complementary power products such as ancillary services. Energy storage may play a part in future grid integration, but large scale deployment is not likely in the near-future. As California progresses towards meeting its renewable energy goals, resource additions must consider the integrated nature of the system to ensure that generation characteristics needed to maintain grid reliability are provided in sufficient amounts. In the longer term California is faced with a challenge to meet the GHG emission reduction targets for 2050. To reach even higher levels of GHG emission reduction, new technologies and new institutions will be need to be developed. However, the extent to which specific policies and technologies will affect the electric system beyond 2020 is difficult to assess with any certainty at this time.

CHAPTER 5: Historic Greenhouse Gas Emissions

Greenhouse gas reduction targets are being set by benchmarking current and future emissions against historical emissions. This chapter examines reported GHG emissions from 1990 through 2004 associated with the California electricity generation sector, identifies the key drivers behind the variation in GHG emissions from year to year, and notes the key parameters and variables that need to be considered when comparing historical emissions year-to-year and against emissions from future scenarios.

Data Sources and Issues

There are two primary published sets of full California GHG emissions. The first is the *Inventory of California Greenhouse Gas Emissions and Sinks: 1990 to 2004*, published by the Energy Commission in 2006 (Energy Commission 2006). The Energy Commission Inventory estimated California's GHG emissions based on data from the U.S. Energy Information Administration (EIA), supplemented with Energy Commission fuel data from the California Energy Balances Report prepared by Lawrence Berkeley National Laboratories for the PIER Program (Energy Commission 2005a) and additional data collected by the Energy Commission staff. The report used GHG inventory accounting protocols from the Intergovernmental Panel on Climate Change and the U. S. Environmental Protection Agency.

The second set of data was compiled, and maintained, by the ARB. The ARB data set is presented in more detail than the Energy Commission's and includes all anthropogenic sources of CO_2, as well as the five other major gases with high global warming potential: methane (CH_4), nitrous oxide (N_2O), sulfur hexafluoride (SF_6), hydrofluorocarbons (HFCs), and perfluorocarbons (PFCs). With respect to GHG emissions in the electricity sector, ARB relies upon much of the same data as the Energy Commission: EIA Form EIA-906 and EIA-920 Databases, personal communications between ARB and EIA staff, and internal ARB calculations.

For in-state resources, both data sets use a bottoms-up approach to CO_2 accounting: multiply fuel consumption reported to the EIA by an assumed carbon conversion efficiency for each fuel and application. Neither set disaggregates either by utility or load serving entity or by geographic location within California. For imported electricity, the ARB first identifies specific plants, generally coal, which are owned by, or contracted to, California LSEs. For imports where an associated power plant is not identified, both ARB and the Energy Commission differentiated between imports from the Pacific Northwest, which would consist of a significant fraction of GHG-free hydroelectric power, and imports from the Southwest, which would contain more coal-generated power.

Because of its disaggregation, and the fact in 2007 AB 32 placed the responsibility of GHG inventory tracking with the ARB, the discussion and cursory state-level analysis here is based on the ARB data set.

Neither the ARB data set nor the Energy Commission Inventory report the power generation associated with the GHG emissions. (The ARB data set reported the assumed GWhs associated with unspecified imports from the Pacific Northwest and the Southwest, but not from any other sources.) To use historic data to project emissions levels into the future, the generation-GHG relationship is needed, and thus a source of generation statistics were required. Two were considered here: the California profile from the EIA and the 1983-2006 generation statistics spreadsheet from the Energy Commission. On average, the two sources agreed on in-state generation within two percent, although in some years they differed by five percent. With respect to the amount of imports, the two were, on average, within three percent of each other, but with very large year-to-year variations: from -20 percent to +28 percent.

The authors used here the EIA data for in-state generation, as its categories more closely aligned with those in the ARB emissions data set. For imports, the authors used the ARB-reported gigawatt-hour unspecified imports and derived an estimate of the specified imports (almost exclusively coal) from ARB's reported CO_2 emission rates and an estimated heat rate of 9,500 Btu per kWh. The import megawatt-hour (MWh) value derived in this way fell, on average, between the EIA and Energy Commission import values. Utility-level analysis and discussions are based on various filings made by the utilities and their reports in the California Climate Action Registry.

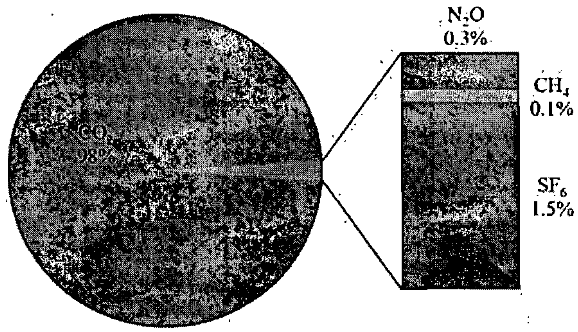
Greenhouse Gases Considered

While the ARB database tracks the six major greenhouse gases, electricity generation is not a significant source of all six of them. As shown in Figure 13, CO_2 emissions from direct combustion make up 98 percent of the GHG emissions from the electricity sector.[28] SF_6 is next greatest greenhouse gas from electricity production, comprising on average 1.5 percent of the GHG emissions. (SF_6 emissions are associated with fugitive emissions from transformers; due to tighter controls, SF_6 emissions have continuously declined.) Nitrous oxide (N_2O) constitutes about 0.3 percent of the emissions from the electric generating sector. CH_4 comprises about 0.1 percent of the GHG emissions.[29] HFCs and PFCs comprise the remaining *de minimus* fraction of a percent.

[28] All emissions percentages weighted by each gas' respective global warming potential.

[29] It does not appear that "lost and unaccounted-for gas" associated with gas-fired generation is allocated to electricity production. Doing so could markedly increase the fraction associate with methane. The "natural gas system" in the Energy Commission Staff Reports shows approximately 1.4 M $MMTCO_2E$ of CH4 emissions per year. If one assigns this to end users, electricity generation would receive about 1/3 (an additional ~0.5 $MMTCO_2E$), which would raise its average emissions to approximately the same as SF6.

Figure 13: California Electric Sector GHG Emission Fractions



Source: (ARB 2007)

Accounting for Emissions from CHP

Combined heat and power systems pose an allocation question: how much of the CO_2 emitted from a cogeneration plant should be allocated to and regulated as from power production, and how much should be allocated to and regulated as from thermal use. In the time frame of the historical data considered here, the analysis considered the thermal use to be generated at 80 percent efficiency, with the remaining fuel allocated to power. Therefore, for CHP, the CO_2 allocated to power production equaled the CO_2 associated with the fuel allocated to power per the following:

$$\text{Fuel(power)} = \text{Fuel(total)} - \text{useful thermal output}/80\%$$

The formula in use now for current reporting is more specific (ARB 2008a, pp.9-6 - 9-7):

$$E_H = \frac{H/e_H}{H/e_H + P/e_P} * E_T$$

And

$$E_P = E_T - E_H$$

Where:

E_H = CO_2 Emissions associated with thermal energy production

H/e_H = Useful thermal energy divided by the boiler efficiency

P/e_H = Power generated divided by the generator efficiency (in common units)

ET = Total CO_2 emissions

PH = CO_2 Emissions associated with thermal energy production

This formula effectively prorates the CO_2 by the amount of energy that each process—thermal energy generation and power—would have used were they created in a standalone fashion.

Accounting for Emissions from Imports

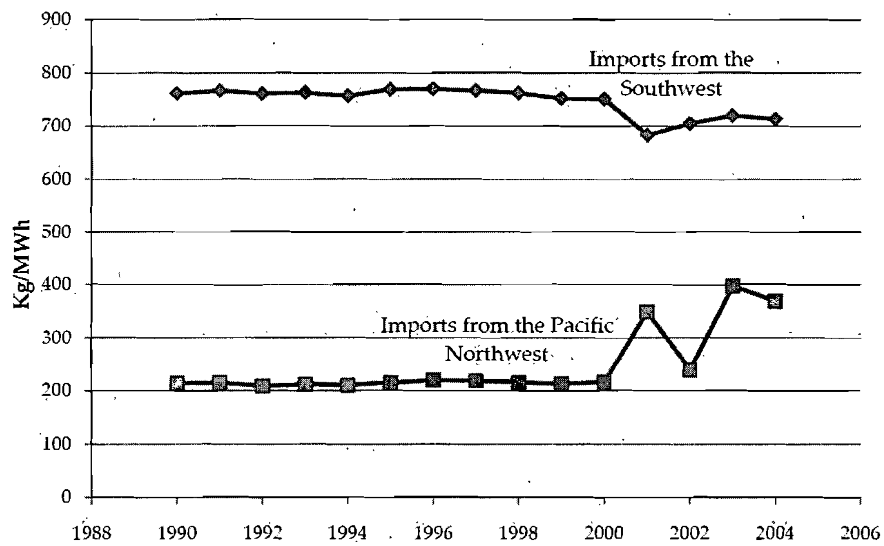
The Energy Commission Inventory Report notes that from 1990 to 2004, California imported 22 to 32 percent of its electric energy from nearby states. Given this large faction, tracking GHG emissions form imports is particularly important. But emissions associated with imported power are more difficult to track, as they cannot always be directly associated with a specific plant.

The Energy Commission Inventory Report estimated the 1990 through 1999 CO_2 emissions from Pacific Northwest non-specified electricity imports by assuming 20 percent was generated by coal and 80 percent from hydroelectricity. For electricity from the Southwest from 1990 through 1999, the Energy Commission Inventory Report assumed 74 percent was generated by coal and 26 percent was hydroelectricity (Energy Commission 2006, p.41).

Once the California wholesale market was restructured, tracking imports became much more difficult. For 2001 through 2004 the Energy Commission staff examined actual market transactions to estimate the fuel mix behind non-specified imports, and noted the ongoing Energy Commission effort to better characterize the fuel mix of, and GHG emissions from, imported power (Energy Commission 2006, p.41).

The ARB database documentation does not yet report the assumed underlying fuel makeup of the unspecified imported power but does differentiate between Pacific Northwest and Southwest imports and report the effective CO_2 rate from each region on an annual basis (ARB 2007). The effective emissions rates from the two regions, as reported by ARB, are shown in Figure 14 below. The increased volatility in the latter years corresponds to the opening of the California wholesale market and the change from a simple percent mix assumption—like that made by the Energy Commission—to a more nuanced analysis, akin to that in the Energy Commission Staff Paper, based on transactions.

Figure 14: ARB GHG Emissions Rates for Unspecified Imports

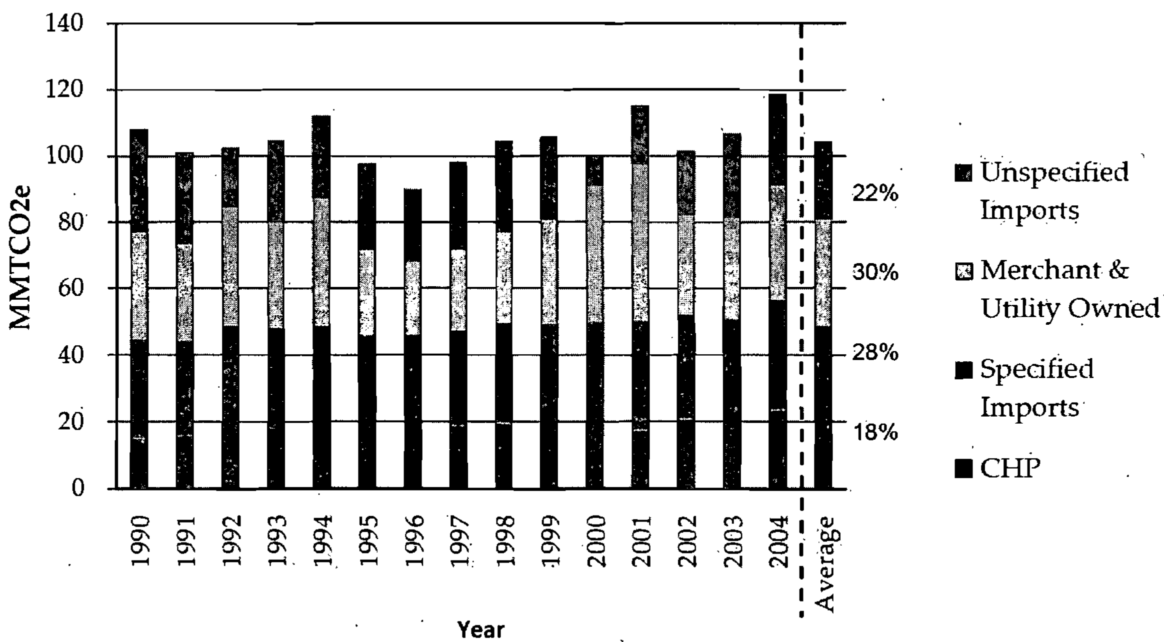


Source: (ARB 2007)

GHG Emissions from 1990 to 2004

From 1990 to 2004 the overall GHG emissions associated averaged 106 million metric tonnes CO_2 equivalent ($MMTCO_2E$) and ranged from a low of 92 million metric tonnes CO_2 equivalent ($MMTCO_2E$) in 1996 to nearly 120 $MMTCO_2E$ in 2004. Emissions attributable to imports made up on average half of the total emissions, even though imported power constituted only about 25-30 percent of total power. This is due to the high fraction of coal associated with the imports. Emissions from merchant and utility-owned generation, which is primarily natural gas-fired, contributed on average 30 percent of the GHG emissions, while cogeneration (combined heat and power) contributed less than 20 percent. Figure 15 shows historical GHG emissions by source for the period 1990 to 2004.

Figure 15: GHG Emissions by Source

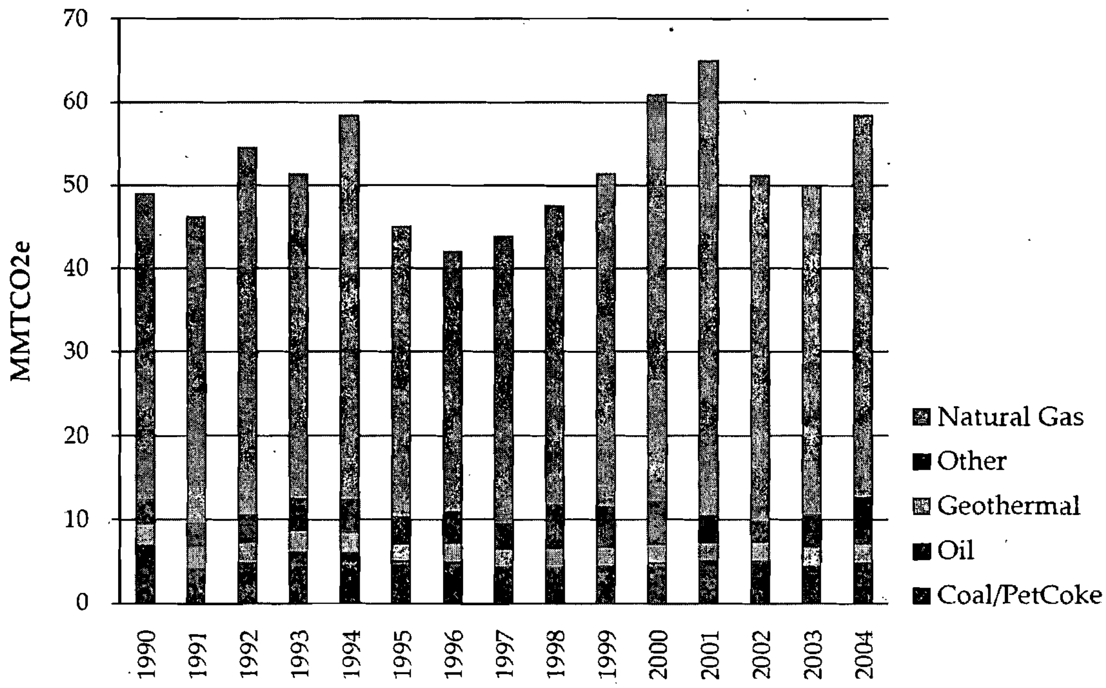


Source: (ARB 2007)

In-state GHG Emissions

Relative to GHG emissions from imports, GHG emissions from in-state generators are relatively stable. However, as shown in Figure 16, this stability is only relative to the wider variations in import-related GHG emissions. Over the 15-year period analyzed here, in-state electricity GHG emissions varied from 42 $MMTCO_2E$ in 1996 up to 65 $MMTCO_2E$ in 2001. Furthermore, as one would expect, emissions from natural gas generation, both central plant and cogenerated, dominate, accounting for, on average, 78 percent of the in-state electric GHG emissions. Of the remaining, emissions from pet coke and coal production account for 9 percent and "other" (mainly refinery gas, municipal solid waste, and landfill gas) account for another approximately 8 percent. Oil initially accounted for a notable fraction, but has since become negligible, while emissions from geothermal (CO_2 entrained in the steam and not reinjected) accounted for 4 percent of the GHG emissions.

Figure 16: In-state GHG Electricity-Related Emissions



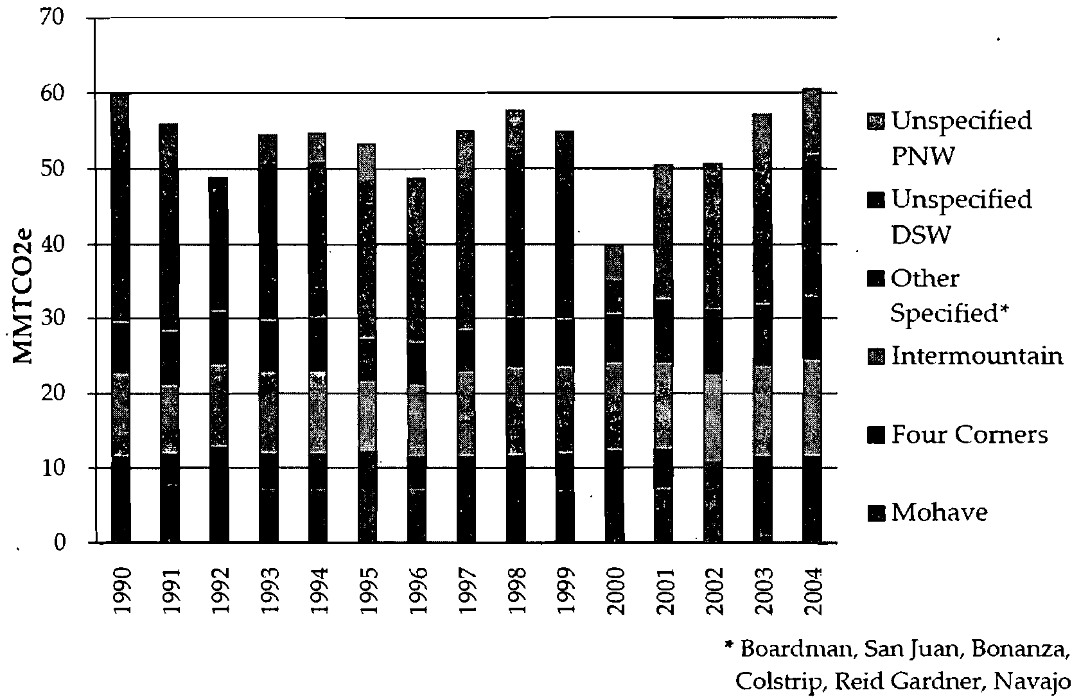
Source: (ARB 2007)

GHG Emissions from Imports

As noted above, imports were accounted for in three categories: specified imports (out-of-state plants directly owned or controlled by California utilities), unspecified imports from the Pacific Northwest, and unspecified imports from the Southwest. Unspecified imports accounted for half of the GHG emissions, with emissions associated with Southwest import imports dominating. Of the specified imports, three coal-fired plants--Intermountain in Utah, Mohave in Nevada, and Four Corners in New Mexico, accounted for three-fourths of the GHG emissions. The year 2000 shows a marked drop in imports relative to the other years, in particular for Southwest imports. This is likely caused by the 2000-2001 power crisis, with out-of-state suppliers reticent to sell to financially precarious California utilities. Figure 17 below shows the top out-of-state emitters and their average CO_2 emissions from 1990 to 2004.

The Mohave Generating Station, which accounted for 7 $MMTCO_2E$ per year, was retired in 2005. If that plant's output was replaced with power from a natural gas combined cycle, the emissions would be on the order of 3 $MMTCO_2E$ per year rather.

Figure 17: GHG Emissions Associated with Electricity Imports

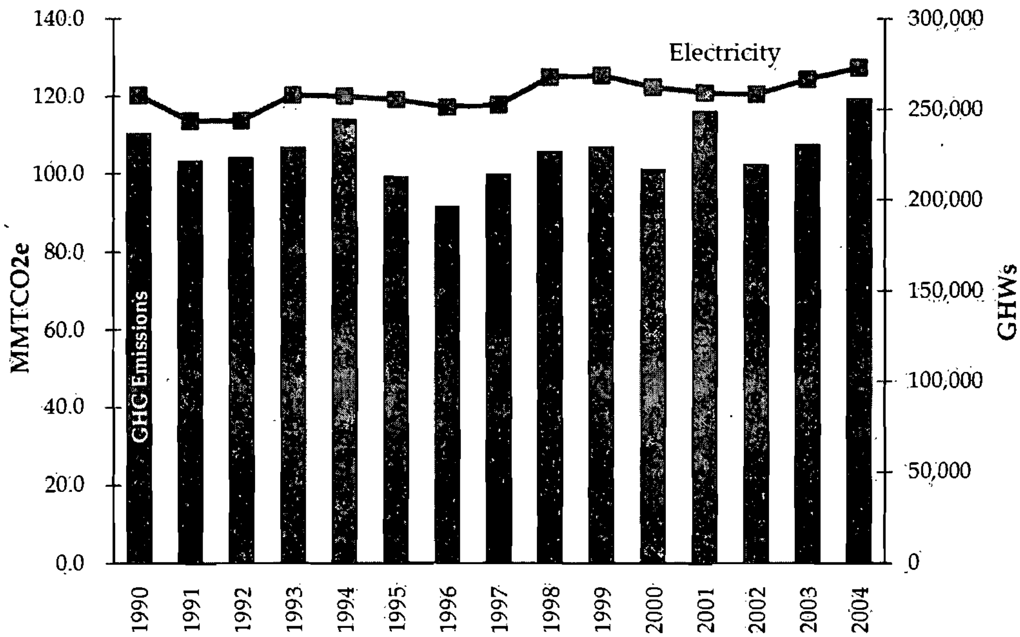


Source: (ARB 2007)

Explaining Annual Emissions Patterns

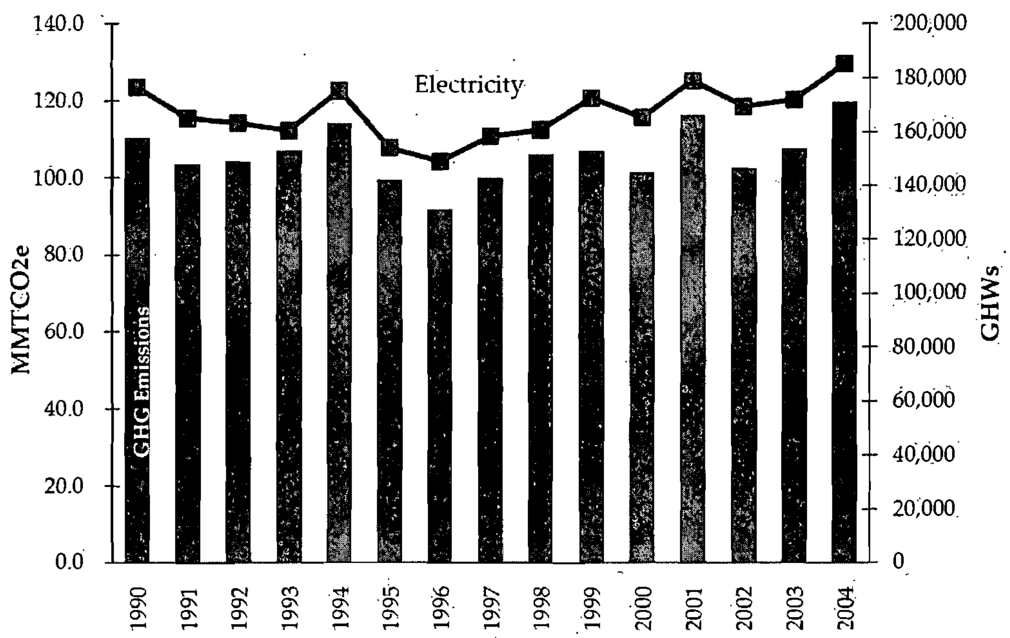
Conceptually, one would expect the GHG emissions from the electric sector to roughly follow demand growth with some variations due to hydroelectric production, major plant outages, and weather (as it affects demand). At first blush, the trends in GHG emissions during this period appear random. Figure 18 shows GHG emissions (columns) and electricity generation, including imports (line with diamonds). While the electricity generation line shows random variations, with general upward trend, it is not correlated to the GHG emissions columns. However, this figure does not account for the fact that one-third of California's generation comes from sources with negligible or no GHG emissions: hydroelectric, nuclear, and renewables. Considering only fossil resources, (Figure 19) the expected correlation emerges: GHG emissions follow fossil generation.

Figure 18: California Electricity Production and Associated GHG Emissions



Source: (ARB 2007)

Figure 19: California Fossil Electricity Production and Associated GHG Emissions

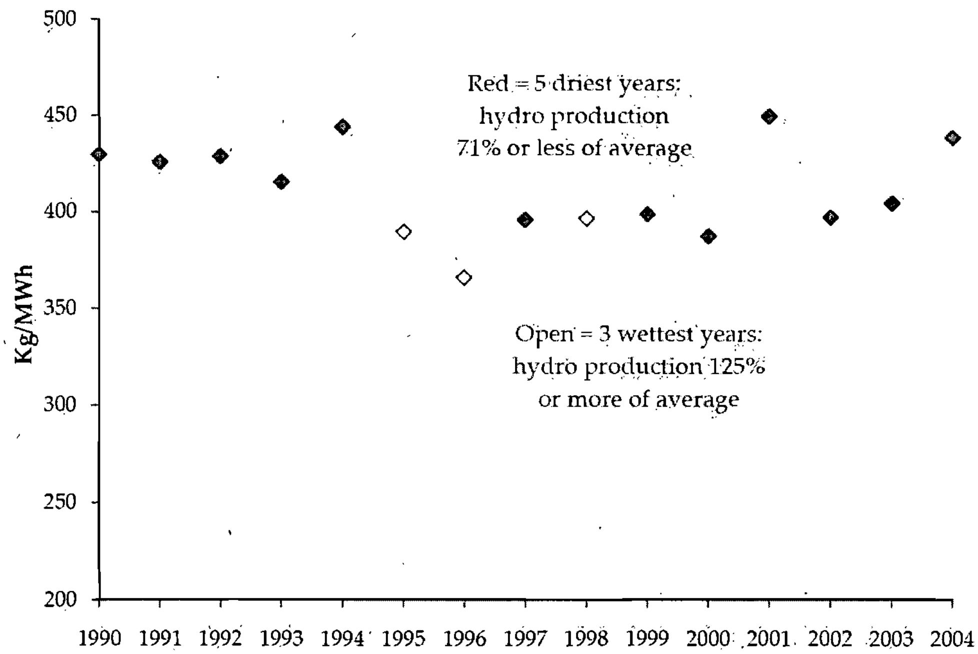


Source: (ARB 2007)

Variable emissions from non-fossil fuels explain the lack of correlation in Figure 18. Hydropower is the largest non-emitting electric resource in California. From 1990 to 2004, hydropower provided an average of35.6 million MWh or 14 percent of the state's power without GHG emissions. However, the year-to-year amount of hydropower varies considerably around this average. The worst year for hydropower production was 1992, in which only 20 million MWh were produced (43 percent less than average). At the other extreme, 1998 was the best year for hydropower production, with 48.5 million MWh generated (39 percent greater than the average).

Based on its sheer scale, one would expect the amount hydroelectric power in the state to inversely affect GHG emissions and explain much of the disconnection seen in Figure 18. The impact of hydro production on GHG emissions can be, to first order, observed in Figure 20, which graphs the average GHG emissions per MWh for each year from 1990 through 2004. Five of the six years with the highest GHG emissions rate corresponded to the five years with the lowest hydroelectric outputs, while three of the four years with the lowest average GHG emissions rates correspond to years with significantly greater-than-average hydro production.

Figure 20: Average GHG Emissions



Source: (ARB 2007; EIA 2007)

California's two nuclear powers, San Onofre Nuclear Generating Station and Diablo Canyon Power Plant, generate a similar amount of CO_2-free power as hydro: 33.2 million MWh or 13 percent. However, relative to hydro, nuclear production was relatively steady. At worst, the lowest nuclear production year, 1995, was only 9 percent less than the average, while the highest nuclear production year, 2003, was 7 percent above average. The variation in nuclear output should also in principal contribute to the variations in GHG emissions, but due to its relatively narrow variations, its impact is not obvious in the data analyzed here.

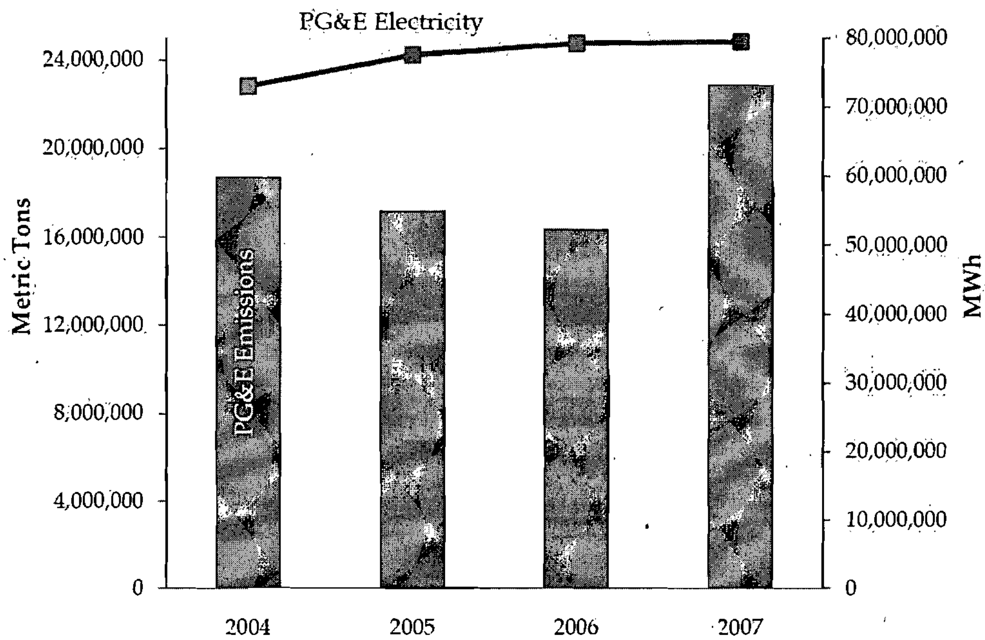
Utility Specific Historic Emissions

The California Climate Action Registry (CCAR) is a voluntary GHG registry in which members measure, verify, and publicly report their GHG emissions. Since 2001, the IOUs, LADWP, and SMUD have participated in public reporting of their GHG emissions through the CCAR. The CCAR data set for each utility includes the amount of energy delivered in the reported year, fuel sources, and the emissions associated with the electricity generated. The CCAR emissions data, along with the utilities' annual statistical reports and the Energy Commission's power content labels, form the basis of the analysis discussed below. Note that the CCAR protocols do not necessarily match the ARB data used in the state-wide discussion just presented, nor are each utility's interpretation of the CCAR protocols consistent with each other's.

PG&E

PG&E's GHG emissions, shown in Figure 21, are not closely correlated to the amount of electricity delivered to PG&E customers. Electricity usage increases steadily from 2004 to 2006, while remaining stable from 2006 to 2007. Emissions decrease from 2004 to 2006, while spiking upward in 2007.

Figure 21: PG&E Electricity vs. Emissions

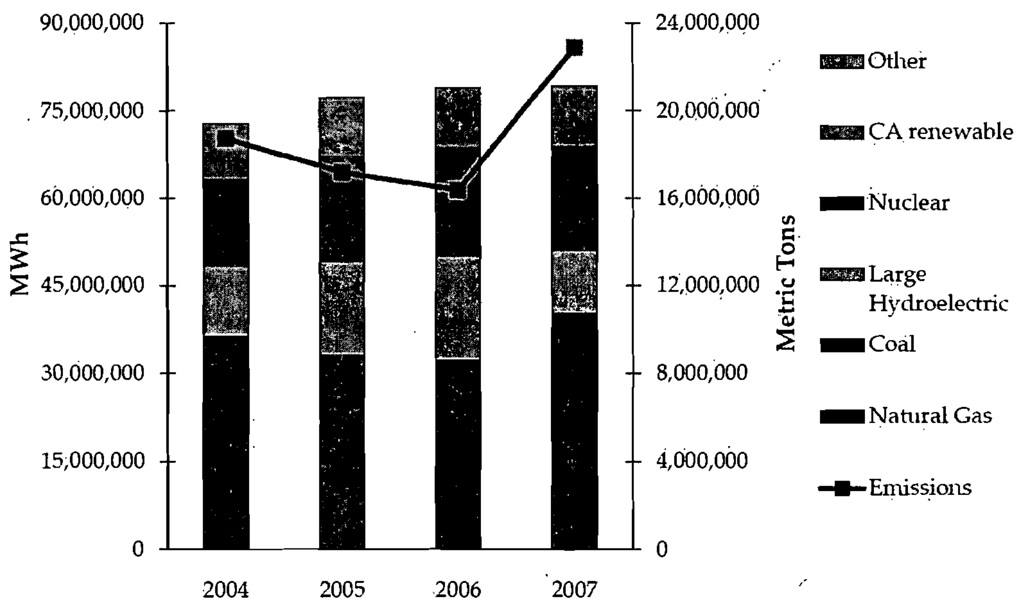


Source: (CCAR)

The expected correlation between emissions and electricity generation emerges when fuel sources are taken into consideration (see Figure 22); emissions rise and fall with the amount of electricity generated from fossil fuel resources.

Other trends are made apparent when electricity is disaggregated by fuel source. The amount of natural gas burned tends to be inversely related to the amount of electricity generated from large hydroelectric generating facilities. This relationship explains how electricity output increased from 2004 to 2006 while emissions decreased over the same time period; total electricity output during this time period grew from 73.0 million MWh to 79.2 million MWh, but output from large hydro and nuclear went from 27.0 million MWh to 36.4 million MWh. This increase in non-emitting electricity production more than met the increase in energy consumption during this time period, allowing PG&E to burn less natural gas while still meeting its energy requirement. This is further illustrated in 2007; although electricity output remained stable, emissions increased from approximately 16.4 MMTCO₂E to 22.9 MMTCO₂E, an increase of 39.9 percent, coinciding with a 40.7 percent decrease in hydroelectric energy output.

Figure 22: PG&E Electricity by Source vs. Total Emissions



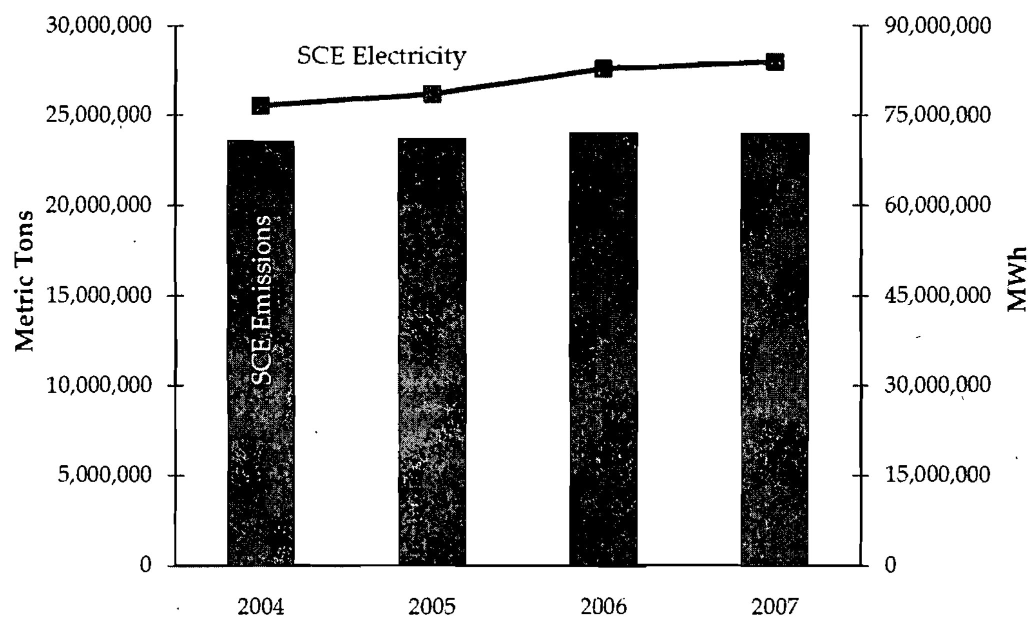
Source: (CCAR; PG&E 2004; PG&E 2005; PG&E 2006; PG&E 2007b)

SCE

SCE's emissions and electricity output tend to move in the same direction; as electricity output increases, emissions also tend to increase (see Figure 23).

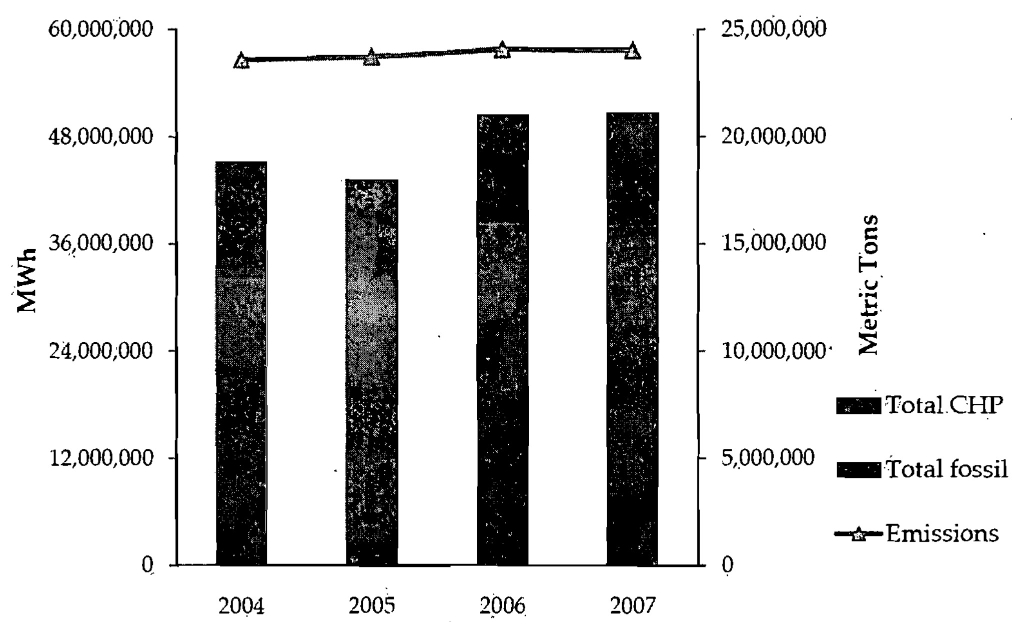
However, electricity output and emissions do not always change to the same degree. For example, from 2004 to 2005, SCE's electricity output increased by 2.5 percent while emissions increased by 0.5 percent. From 2005 to 2006, SCE electricity output increased by 5.4 percent accompanied by a 1.5 percent increase in emissions. Isolating SCE's fossil fuel-fired generation does not completely explain the changes in SCE's emissions, as seen in Figure 24. Though total fossil fuel-fired generation decreased in 2005, emissions rose slightly, and in 2007, fossil fuel-fired generation increased while emissions decreased slightly.

Figure 23: SCE Electricity vs. Emissions



Source: (CCAR)

Figure 24: SCE Fossil Fuel-Fired Electricity vs. Total Emissions



Source: (CCAR)

The CCAR data does not disaggregate fossil fuel-fired energy by fuel source, but SCE's power content label shows that the proportion of coal in SCE's power mix increased slightly from 2004 to 2005, and decreased slightly from 2006 to 2007 (SCE 2006; SCE 2007b). The changing ratio of coal to natural gas in SCE's fossil fuel-fired generation may explain the changes in emissions observed above. Differences in reporting protocols between the two sources make it difficult to asses whether or not this is a sufficient explanation for the unexpected variance between fossil fuel-fired electricity and emissions.

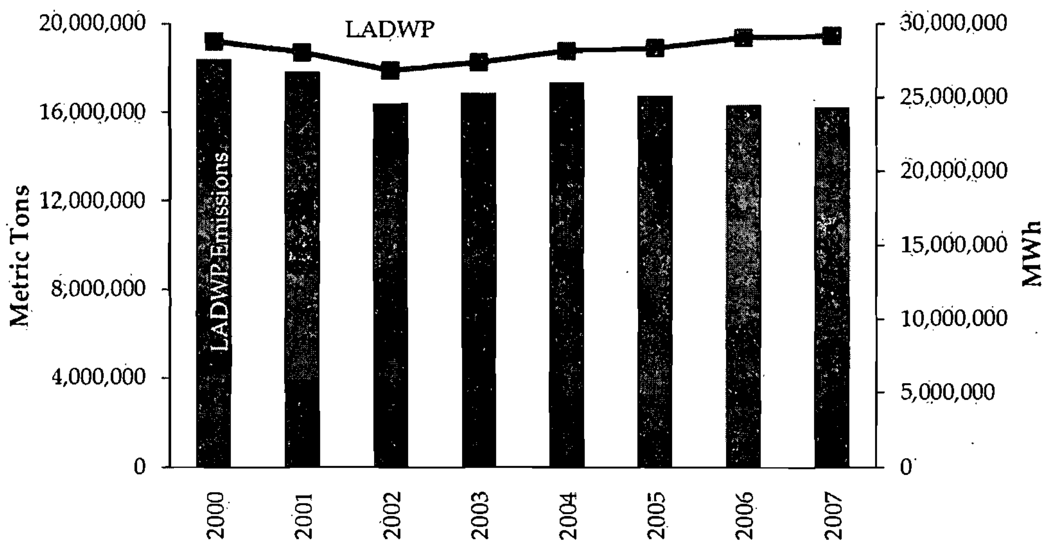
SDG&E

The CCAR data for SDG&E prior to 2006 is not consistent due to evolving reporting protocols in SDG&E's reports. As a result, a comparative analysis of SDG&E's energy output and emissions based on CCAR data is not possible. SDG&E's 2007 CCAR data reports 20.4 million MWh delivered, with 22.7 percent of it coming from carbon-free sources and 77.3 percent coming from a mix of natural gas, coal, and CHP, for a total of 7.5 MM CO_2E of GHG (CCAR).

LADWP

LADWP's emissions are well correlated with its electricity output from 2000 - 2004. However, from 2005 to 2007, electricity output increased while emissions decreased (see Figure 25).

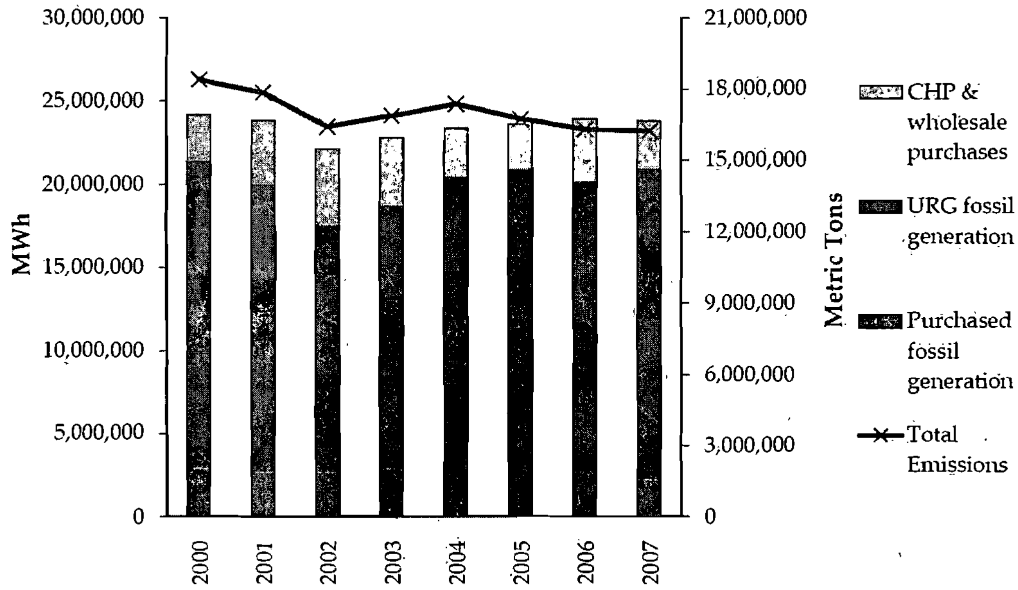
Figure 25: LADWP Electricity vs. Emissions



Source: (CCAR)

The CCAR data for LADWP shows significant increases in energy output from renewable sources from 2004 through 2007. While this helps to explain how energy output could increase while emissions decreased, an increase in renewable energy does not by itself explain the contradictory trend between electricity and emissions. Figure 26 shows emissions plotted against fossil fuel energy. Years 2005 through 2007 show a seemingly conflicting trend between fossil fuel energy and emissions. While fossil fuel energy increased in 2005, emissions decreased. The same trend is observed in 2006. In 2007, fossil fuel energy decreased slightly by 0.6 percent, while emissions decreased by 5.3 percent.

Figure 26: LADWP Fossil Fuel-Fired Electricity vs Emissions



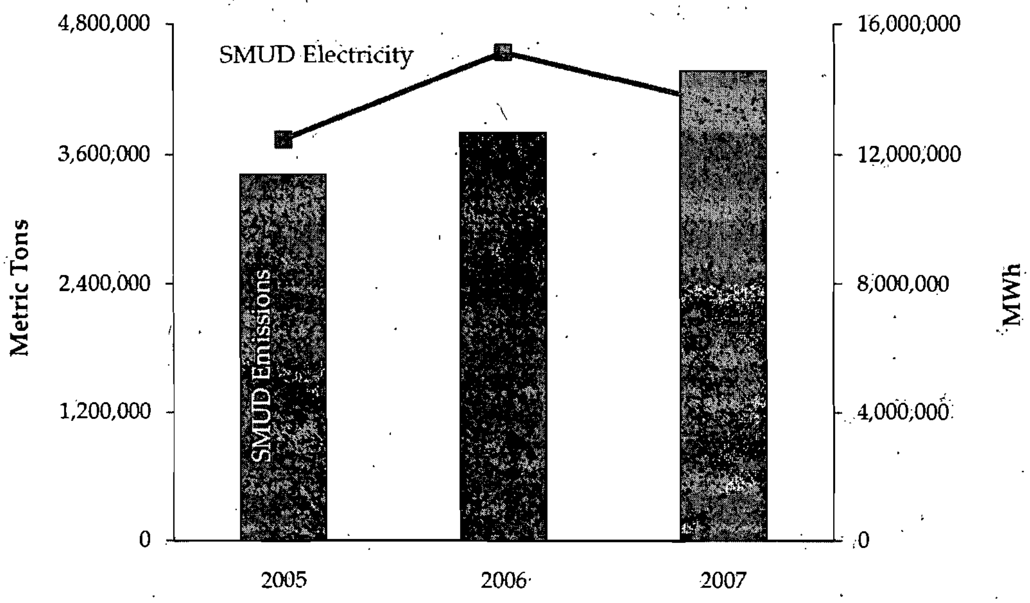
Source: (CCAR)

This seemingly contradictory trend is explained by the LADWP's changing mix of fossil resources. The Energy Commission's power content label for LADWP shows that LADWP's power content became less coal intensive over this same time period; In 2004, LADWP's power mix was 52 percent coal and 26 percent natural gas (LADWP 2004). In 2007, LADWP's power mix was 45 percent coal and 33 percent natural gas (LADWP 2007). The changing generation mix of LADWP's fossil fuel-fired energy output helps to explain the contradictory trend observed above.

SMUD

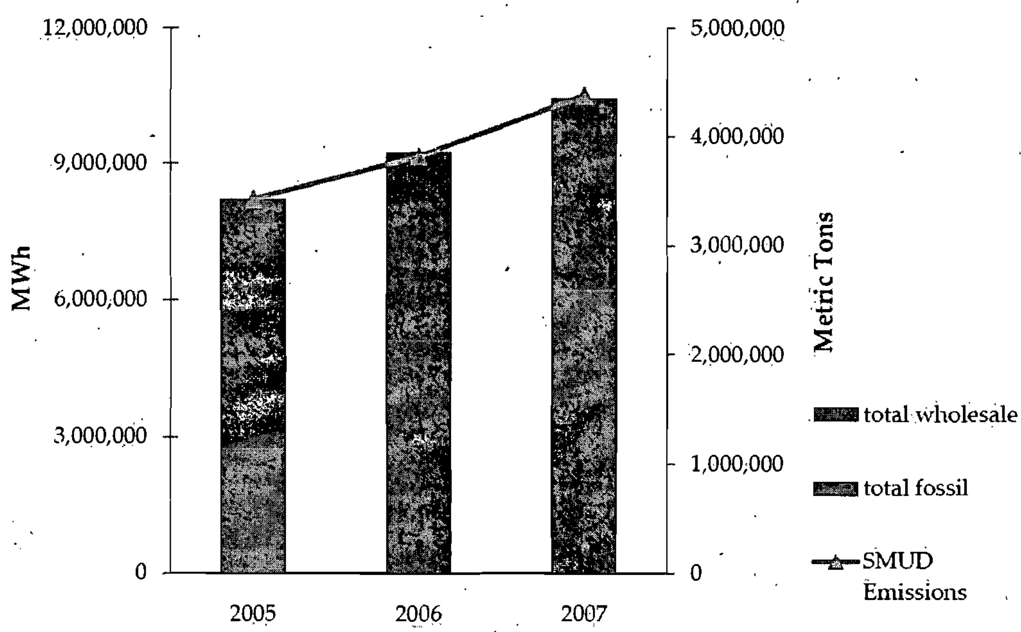
SMUD's energy output is not well correlated with its emissions, as seen in Figure 27. However, disaggregating the electricity by fuel source shows a strong correlation between fossil fuel and wholesale energy and emissions, as seen in Figure 28. From 2005 to 2007, energy from fossil fuel generation and wholesale purchases increased by 21.3 percent, while emissions increased by 21.8 percent. Emissions increased by 13.0 percent from 2006 to 2007 despite a 12.0 percent decrease in electricity because a 149 percent decrease in hydroelectric energy caused a need to add a greater proportion of fossil fuel to the resource mix in 2007.

Figure 27: SMUD Electricity vs. Emissions



Source: (CCAR)

Figure 28: SMUD Fossil Fuel-Fired Electricity vs. Emissions



Source: (CCAR)

Issues Using These Data

The historical data shows considerable year-to-year variation in GHG emissions associated with electricity in California. The year to year variations are due to a number of factors that must be accounted for not only when examining historical data, as but also when comparing the future to the past. Modeling exercises, like that developed by Energy and Environmental Economics, Inc. (E3), for the GHG proceeding at the CPUC, must make assumptions concerning key variables. To have a fair comparison, the following variables need to be explicitly accounted for:

- ***Demand,*** in particular as it is affected by weather. Weather extremes result in high energy use. Demand should be weather normalized before any benchmark comparisons.
- ***Hydroelectric output.*** Hydroelectric power accounts for 15 percent of the state's generation, but can vary by nearly a factor of two from year to year. These huge swings impact GHG emissions since fossil fuels—generally natural gas—increase when hydro production declines.
- ***Nuclear output.*** Nuclear power does not experience the wide swings in annual output that hydro does, however, it still accounts for a large percentage of in-state generation. Any reductions in nuclear output, due to extended plant outage or, in the future relicensing issues, will affect GHG emissions, since like hydro, natural gas is the marginal generation source.
- ***Mohave retirement.*** The Mohave Generating Station (located in Southern Nevada) was the second-largest single emitter of GHG in the California electric system, after Los Angeles Department of Water & Power's (LADWP) Intermountain Power Plant (located in central Utah). Its retirement in 2005 must be considered when comparing current (and future) GHG emissions to this report.
- ***Consistent Accounting of Imports.*** Given the magnitude of imports, a consistent accounting protocol, for imported megawatt-hours and associated GHG emissions, is essential.

CHAPTER 6: Exploring Policy-Driven Futures

The 2020 GHG emissions reduction mandate is expected to be achieved in part by a substantial expansion of renewable energy to supply electricity and widespread adoption of energy efficiency measures. Achieving the much higher levels of renewable energy needed to meet the 33 percent renewables goal and GHG reductions will require changes in the operation of the integrated electric system. As noted in earlier chapters, natural-gas fired power plants can have operational characteristics that make them well-suited to meeting many operational requirements of an integrated renewable-rich electric system, and many renewable energy resources are ill-suited to perform these same operational roles.[30]

This chapter begins to explore the impact on the state's generation mix and electric sector GHG emissions through 2020 assuming different policy scenarios. It addresses the question as to how much, what type, and where additional natural-gas fired generation should be part of California's strategy to address its GHG emissions reduction targets while maintaining a reliable electric power system. This question is not definitively answered in this chapter; rather, emerging trends are identified along with additional analysis that is needed to understand the changes needed in the electricity system to meet the state's goals for renewables and GHG emissions.

Data Sources and Issues

For this chapter, MRW relied on recent studies by the Energy Commission and other public agencies rather than perform any independent production cost modeling, capacity expansion assessment, and transmission planning. The primary source is the work supporting the *2007 IEPR*, specifically the *Scenario Analyses Of California's Electricity System: Preliminary Results For The 2007 Integrated Energy Policy Report* (the Scenarios Report) (Energy Commission 2007d). The authors also reviewed the California Ocean Protection Council and State Water Resources Control Board report on once through cooling (OPC/SWRCB 2008), and Energy Commission and California ISO reports on integrating renewables into the California grid (California ISO 2007; CWEC 2006). The authors also note the parallel effort that has been ongoing at the California Public Utilities Commission.[31]

The Scenarios Report examined "the implications of resource plans featuring very high penetrations of [...] energy efficiency measures and renewable energy generation in California and the Western Interconnection," focusing on the "effect of reducing greenhouse gas emissions compared to what might be expected from resource plans with more conventional resources." (Energy Commission 2007d, p.1) The report considered numerous scenarios, only a few of which are relevant here:

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[30] As discussed above in Chapter 4 storage technologies can also meet some of the operational characteristics lacked by intermittent renewables, but were not explicitly considered here in Energy Commission scenarios.

[31] The CPUC retained the firm Energy and Environmental Economics to develop a GHG modeling tool to use in exploreing some GHG policies. This model is based on a set of production cost model reference cases for two years developed by PLEXOS. The results are tweaked in the E3 model spreadsheet based on different policy levers. The Energy Commission's Scenarios Report conducted more dispatch model runs for a greater number of years to more explicitly model the impacts of various policies.

- Case 1b, a retrograde "baseline" which assumed then-current GHG emissions regulations and renewable energy policies.
- Case 4a, a case that accelerates renewable generation penetration and approximates a higher—albeit short of 33 percent—renewable requirement in 2020.[32]
- Cases 1b and 4a plus accelerated fossil plant retirements, as addressed in Addendum 2.

The energy efficiency in the two cases discussed here was based on the IOUs' long-term procurement plans for 2009 through 2016(Energy Commission 2007d, p.27). After 2016, the cases assumed the same savings as percentage of sales as in 2016. The cumulative energy efficiency savings for 2006-2020 exceeded the "Full Incentives" potential savings identified in the 2006 Energy Efficiency Potential Study (Energy Commission 2007d, p.27).[33] Because the energy efficiency savings in their cases were already aggressive, the authors chose not to use the High Energy Efficiency plus Renewables cases presented in the Scenarios Report (Energy Commission 2007d, p.39).[34]

The Scenarios Report examined: (a) the interaction between increased penetration of preferred resources (renewables and efficiency) and the associated transmission and fossil generation requirements needed to maintain system reliability at an inter-transmission area level of analysis; (b) the interaction between increased penetrations of preferred resources in California and increased penetrations in the West, especially the dispatch of fossil power plants; (c) the GHG emissions implications of high penetrations of the preferred resource types; (d) the effects of the interaction between increasing penetrations of renewable energy and the natural gas market; and (e) the relative cost effects of increasing penetrations of preferred resources in California and the West (Energy Commission 2007d, p.1).

The Scenarios Report provided an excellent framework for considering various policy-driven futures; however, the underlying analysis had some limitations. These limitations were clearly discussed in Chapter 9 of the Scenarios Report and are summarized here:

- **Transmission detail.** The Scenarios Report did not consider local reliability issues. "Although an attempt was made to ensure system reliability by imposing a simplified version of resource adequacy requirements (15 percent planning reserve margin and derating capability using dependable capacity procedures) in the construction of the scenario datasets, the broad nature of the trans[mission] areas means that capacity to satisfy local reliability requirements cannot be identified" (Energy Commission 2007d, p.222).

- **Renewable performance and penetration.** The report did not attempt to forecast changes in renewable costs of performance, nor did it attempt to optimize the mix of renewables added in the high renewables cases.

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32 The Scenarios Report explicitly notes that it did not model a 33 percent renewables RPS, but instead a "high penetration" case, which ended up with approximately 25 percent renewable generation in 2020. Note that side calculations conducted after the release of the report showed Case 4a to achieve approximately 31 percent renewables (Jaske 2009). Different accounting of losses and a few other minor factors account for the difference.

33 Citing to Itron, KEMA, RLW and AEC, "California Energy Efficiency Potential Study." May 2006.

34 Case 5a. The High Energy Efficiency cases assumed the achievement of full economic potential savings, net savings associated with "speculative" emerging technologies.

- **Limited stochastic modeling.** In general, the cases were single-run "what ifs" rather than a full stochastic analysis.[35] Given the magnitude of the modeling effort, this is quite reasonable, but it would miss key operational issues such as coincident drops in wind/solar output.
- **Does not track GHG emissions associated with imports:** The modeling assumed economic dispatch throughout the WECC, without regard to generation ownership or contractual arraignment. Except for assets owned by California LSEs, GHG emissions could be tracked only at a state level or a WECC-wide level. Thus, emissions from non-specified imports were not addressed.

In addition, the modeling supporting the Scenarios Report is based on expectations in 2006 concerning grid configuration, fuel prices, load growth, generation additions, renewable development policies, etc., many of which have changed. In each of the scenarios that follow, the authors note which of these roles the incremental gas-fired generation plays.

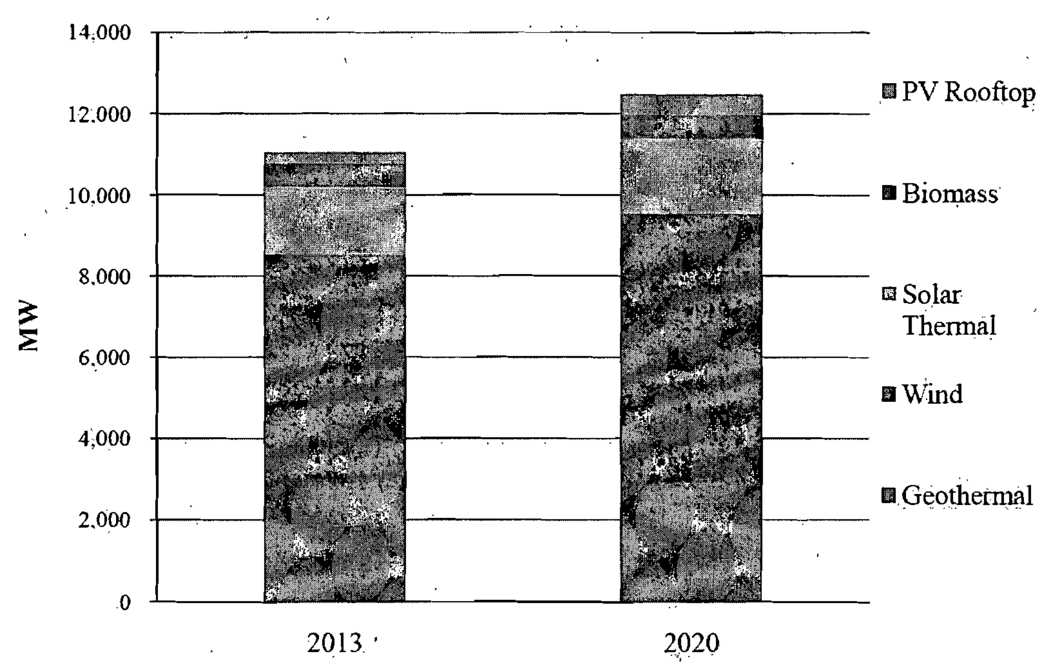
"Frozen Policy" Case

The Scenarios Report's Case 1b represents a "Frozen Policy" case. It is based on, as of the time of the study in late 2006-early 2007, the IOUs' energy efficiency goals, expected demand response program expansions, the ongoing California Solar Initiative program targets, and the then-current RPS targets, all as reflected in the IOU's 2006 Procurement plans (Energy Commission 2007d, pp.22, 23, 27). Therefore, Case 1b is outdated in that it doesn't reflect current policy directions embodied in AB 32, recent once-through cooling policy proposals, nor the recession's impacts on fuel prices and electricity demand. Nonetheless, it can serve as a reasonable benchmark of sorts against which the more aggressive cases can be compared.

Figure 29 shows the breakdown of renewable nameplate capacity by resource in 2013 and 2020. Wind and geothermal together make up over 75 percent of the renewable capacity in both years. Note that that resource additions were based on the judgment of the Scenarios Report's authors and do not represent a least cost, or least cost, best fit resource portfolio. They also do not reflect the results of the on-going RETI process, the California ISO interconnection queue, or even the IOUs' signed renewable contracts.

[35] For example, Monte Carlo runs with probabilistic outputs from intermittent resources, forced outages, etc.

Figure 29: Frozen Policy Case Renewable Capacity



Source: (Energy Commission 2007e)

Some basic energy statistics are shown in Table 9. The Scenarios Report assumed annual load would grow by about 24,000 GWhs from 2013 to 2020 (prior to accounting for incremental energy efficiency). More than half of the assumed load growth is met by increased energy efficiency, with the remainder mainly met by in-state gas-fired generation. The modeling also showed a drop in non-specified imports (which, like demand, is countered by the energy efficiency and in-state gas generation). Renewables meet only 10 percent of the load in 2010 and gradually ramp up to meet 13.5 percent of the load in 2020.

Table 9: Frozen Policy Case Energy Balance Statistics

(GWhs)	2013	2017	2020
Demand	315,927	328,890	339,831
Energy Efficiency (decrement to demand)	13,107	22,768	29,638
California Gas	104,808	109,204	116,771
California Renewables	41,927	44,615	45,586
California Hydro	33,913	33,916	33,910
California Nuclear	34,368	36,662	33,694
Other (mainly specified coal imports)	47,936	49,726	50,036
Non-specified Imports	39,869	32,178	30,197

Source: (Energy Commission 2007e)

Natural Gas-Fired Retirements and Additions

The Scenarios Report included major generation additions as shown in Table 10. Many of these projects have been delayed beyond the startup year anticipated in the Scenarios Report and at least two projects have been canceled (Eastshore Energy and Bullard); however, a similar amount of new gas-fired generation can be expected to be online by 2013, the first year considered.

Table 10: Near-Term Major Capacity Additions Assumed in the Frozen Policy Case (Scenarios Report Case 1b)

Plant	Capacity (MW)	Year	Region or CAISO Local Reliability Area
Niland CTs	94	2008	IID*
Potrero CTs	147	2008	Greater Bay Area LRA
Salton Sea #6 Geothermal	215	2008	IID*
Inland Empire 1 & 2	810	2008	SCE**
Pacific Wind	206	2008	SCE**
Panoche GTs	400	2008	NP15
Humbolt Bay ICs	160	2008	Humboldt LRA
Eastshore Energy ICs	116	2009	Greater Bay Area LRA
El Centro CC	120	2009	IID*
EIP Bullard CT	196	2009	NP15
Starwood Firebaugh CT	120	2009	NP15
Contra Costa 8 a & b	470	2009	NP15
Otay Mesa CC	510	2009	San Diego LRA
PG&E Colusa CC	660	2010	NP15
Russell Center CC	620	2010	Greater Bay Area LRA

* outside of the California ISO

** SCE area, outside of the LA Basin LRA

Source: (Energy Commission 2007f, Appendix B-3)

Beyond these additions, the Scenarios Report's Case 1b includes the addition of sufficient renewable generation—primarily concentrating central station solar and wind, plus gas peakers —after 2015 to maintain the reserve margins dictated by the state's resource adequacy requirements.

The report also assumed that plants were retired at 55 years of service (Energy Commission 2007e, p.3). Retired power plants were replaced with equivalent dependable capacity to the extent that a simplified resource adequacy protocol required aggregate capacity to satisfy system-wide planning reserve requirements (Energy Commission 2007e, p.3). Table 11 shows the plants and the assumed timeframes of their retirements.

Table 11: Retirements Assumed in Frozen Policy Case (Scenarios Report Case 1b)

		MW Retired		
Plant	**Unit**	**through 2012**	**2013 through 2016**	**2017 through 2020**
Greater Bay Area Local Reliability Area (LRA)				
Contra Costa	6	-	-	335
	7	-	-	337
Hunters Point	4	163	-	-
	GT1	52	-	-
Pittsburg	5	-	312	-
	6	-	317	-
Potrero	3	206	-	-
	4	52	-	-
	5	52	-	-
	6	52	-	-
Humbolt LRA				
Humboldt Bay	1	52	-	-
	2	53	-	-
Mobile GT	2	15	-	-
	3	15	-	-
LA Basin LRA				
Alamitos	1	175	-	-
	2	175	-	-
	3	-	332	-
	4	-	-	335
	5	-	-	485
Broadway	3	-	-	73
El Segundo	3	-	-	335
	4	-	-	325
Etiwanda	3	-	-	320
	4	-	-	320
Huntington Beach	1	-	226	-
	2	-	226	-
	3M	-	225	-
	4M	-	227	-
Redondo Beach	5	179	-	-
	6	175	-	-
Big Creek/Ventura LRA				
Mandalay	1	-	215	-
	2	-	215	-

(Continued on next page)

Plant	Unit	MW Retired through 2012	2013 through 2016	2017 through 2020
San Diego LRA				
Encina	1	100	-	-
	2	104	-	-
	3	-	110	-
South Bay	1	-	146	-
	2	-	-	150
	3	-	-	175
Other, Non-Constrained California ISO Areas				
Coolwater	1	-	63	-
	2	-	-	81
Morro Bay	3	-	-	337
IID (Outside of the California ISO)				
Brawley GT	1	-	-	11
	2	-	-	11
El Centro	3	42	-	-
Yuma Axis	ST1	-	75	-
LADWP (Outside of the California ISO)				
Grayson	3	21	-	-
	4	-	44	-
	5	-	-	44
Haynes	1	-	-	222
	2	-	-	222
	5	341	-	-
	6	341	-	-
Olive	1	-	42	-
	2	-	-	55
Scattergood	1	-	179	-
	2	-	179	-
Grand Total		2,365	3,133	4,509

Source: (GED 2006)

Table 12 shows the energy production from key gas plant types in 2013, 2017 and 2020. The table shows that by this study, no additional combined cycle plants, beyond those in place and those specifically named in the study are needed in 2020. It also shows a continued drop-off, but not elimination, of power from old steam turbine-based gas generators as well as a modest contribution by new combustion turbines. The increase in in-state gas generation is offset by the reduction in non-specified imports; output from specified imports — primarily southwest coal plants such as LADWP's Intermountain — increase.

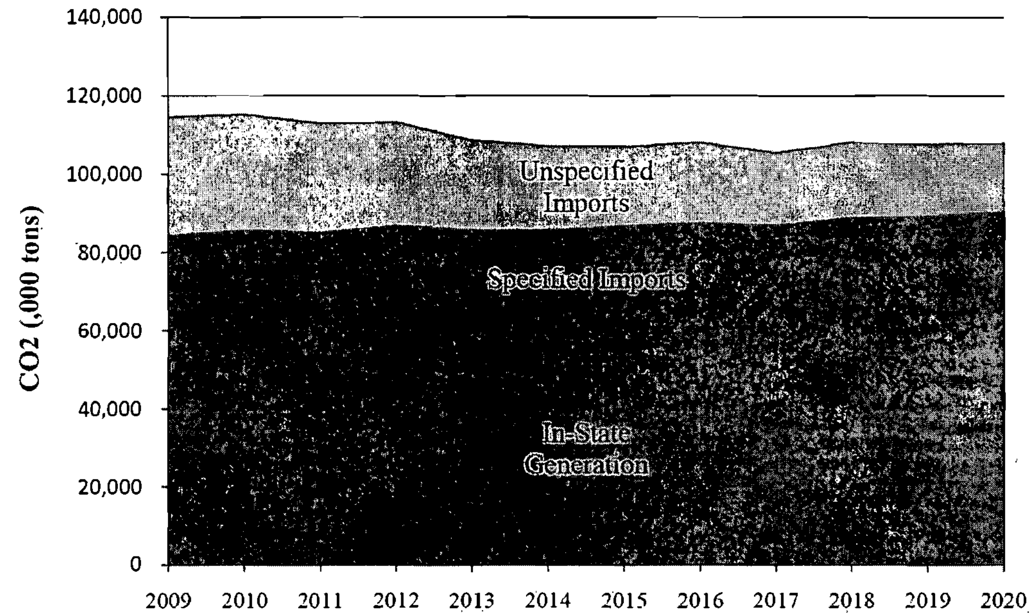
Table 12: Frozen Policy Case Fossil Plant Production

(GWhs)	2013	2017	2020
Existing/Planned NGCC	82,963	88,498	95,334
Existing/planned NGCT	17,674	17,102	17,041
Existing NG steam plant	4,163	879	1,100
New, generic NGCC	0	0	0
New, generic NGCT	0	2,495	3,197
Total In-state Gas	104,808	109,024	116,771
Specified Imports	37,351	38,372	38,307
Non-specified Imports	39,869	32,178	30,197

Source: (Energy Commission 2007e)

With respect to GHG emissions, the Frozen Policy Case results in GHG emissions associated with California electricity consumption decreasing by about 5 percent relative to 2009 by 2020 (Figure 30).[36] The decrease is mostly associated with the reduction in the volume of unspecified imports, which are, on average in this analysis, much more carbon-intensive than the new gas-fired generation that is occurring in-state.

Figure 30: Frozen Policy Case CO_2 Emissions



Source: (Energy Commission 2007e)

[36] Note that due to differing counting conventions concerning unspecified imports and combined heat and power, the values shown here CANNOT be directly compared to the historic emissions shown earlier in this report.

Plausibility and Implications

The Frozen Policy Case (Scenarios Report Case 1b) is technically plausible: its penetration of renewables is not overly aggressive, nor does it rely upon unproven technologies. However, the case reflects neither the current policy goals of the state nor the resource commitments resulting from these policies.

Furthermore, the retirement algorithm does not take into account local reliability needs nor reflect system optimization. This lack of system optimization and consideration of LCR could have a discernable impact on system costs by incurring capital costs to replace plants which it may not be economic to retire or conversely keeping in service plants that economically should be retired. However, replacing the output of an older plant with a low capacity factor with generation from a newer, more efficient plant will have a minimal, albeit positive, impact on the system's GHG emissions. The emissions impact of accelerated or delayed retirement is discussed in the Accelerated Retirement section later in this chapter.

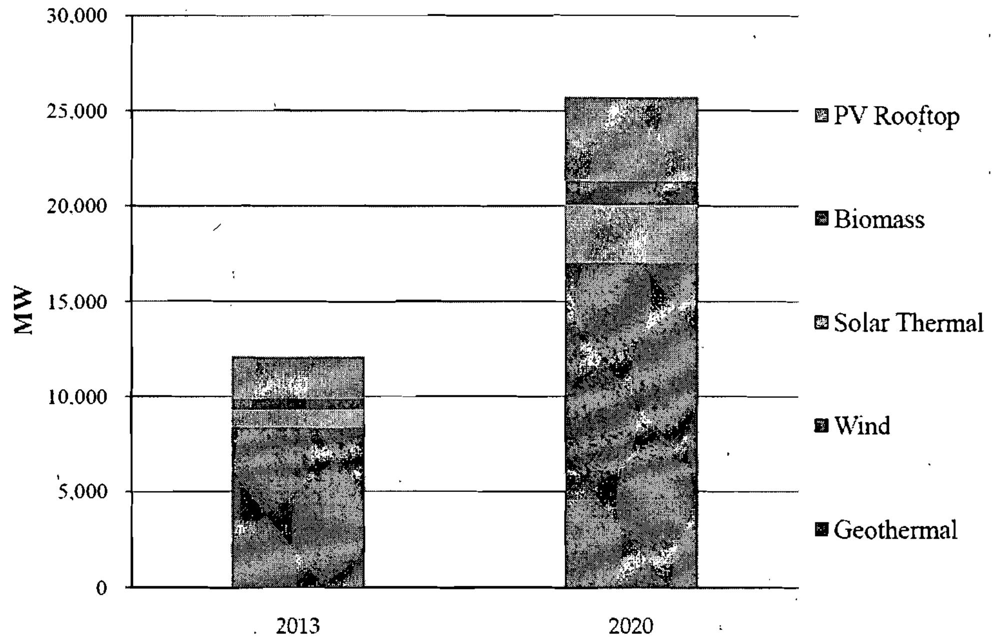
Increased Renewable Generation Case

The "Increased Renewable Generation" Case corresponds to the Scenarios Report Case 4A. This case was developed to "examine a major policy initiative to increase California reliance upon renewable generating technologies," but not explicitly meet any particular RPS target such as the 33 percent by 2020 RPS. Electricity demand levels, gas plant retirements, and non-California WECC generating mix remained the same from the Frozen Policy Case.

Figure 31 shows the breakdown of renewable nameplate capacity by resource in 2013 and 2020. The largest difference between this case and the Frozen Policy Case is the marked increase in renewable capacity by 2020: a near doubling to over 25,000 MW. Similar to the Frozen Policy Case, the renewables capacity in 2013 is predominantly wind and geothermal. In 2020, wind generation is still the dominant capacity resource, but now rooftop PV accounts for nearly as much capacity as geothermal.[37]

[37] Resource additions were based on the judgment of the authors of the Scenario Report and do not represent a least cost or least cost/best fit resource portfolio.

Figure 31: Renewable Capacity Assumed in the Increased Renewables Case



Source: (Energy Commission 2007e)

Some basic energy statistics are shown in Table 13 below. In this study annual load is assumed to grow by about 24,000 GWhs from 2013 to 2020 (prior to accounting for incremental energy efficiency). In this case, the load growth is met by increased energy efficiency and renewables. The modeling also showed a decrease in gas generation and a dramatic drop in non-specified imports, which are both made up for by increased renewable production. Renewables meet 10 percent of the gross load in 2010 and gradually ramp up to meet 25 percent of the gross load in 2020.

Table 13: Increased Renewables Case Energy Balance Statistics

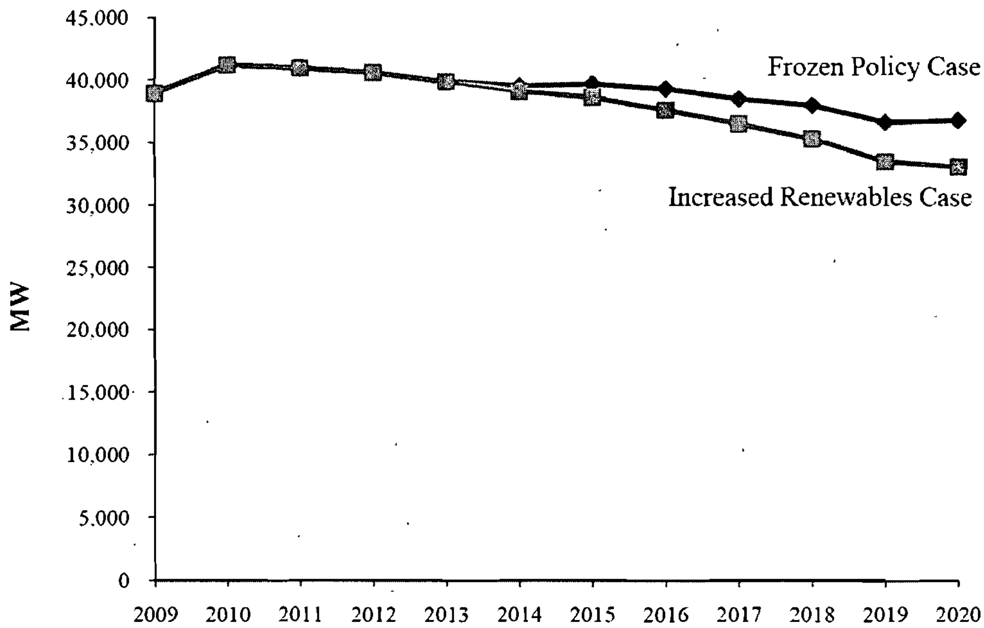
(GWhs)	**2013**	**2017**	**2020**
Demand	315,927	328,890	339,831
Energy Efficiency (decrement to demand)	13,107	22,768	29,638
California Gas	102,905	96,238	95,282
California Renewables	43,935	61,794	79,438
California Hydro	33,913	33,916	33,910
California Nuclear	34,368	36,662	33,694
Other (mainly specified coal imports)	37,316	38,057	37,855
Non-specified Imports	39,184	19,407	8,784

Source: (Energy Commission 2007e)

Natural Gas-Fired Retirements and Additions

The Increased Renewables Case contains the same 10,000 MW of gas plant retirements as the Frozen Policy Case. However, as shown in Figure 32, starting in 2015 it adds fewer megawatts of gas-fired peakers. By 2020, the "Increased Renewables" Case contains 3,700 fewer megawatts of gas-fired peaking plants than the Frozen Policy Case.

Figure 32: Total California Gas-Fired Capacity



Source: (Energy Commission 2007e)

Table 14 shows the changes in energy production from key gas plant types in 2013, 2017, and 2020 relative to the base case. In this scenario, by 2020, power from in-state renewables accounts for over 25 percent of the state's power consumption. This represents an 88 percent increase relative to the Frozen Policy Case generation in 2020 and a 175 percent increase relative to 2009 renewable generation. The increase in renewable generation is offset by nearly equal decreases (on a GWh basis) in in-state gas generation and non-specified imports. This result, that increased renewable generation displaced gas-fired generation from combined cycles, and to a lesser degree, old gas-steam units, is consistent with the renewable generation integration studies conducted by the Energy Commission and the California ISO.

Table 14: Changes in Energy Production in Increased Renewables Case

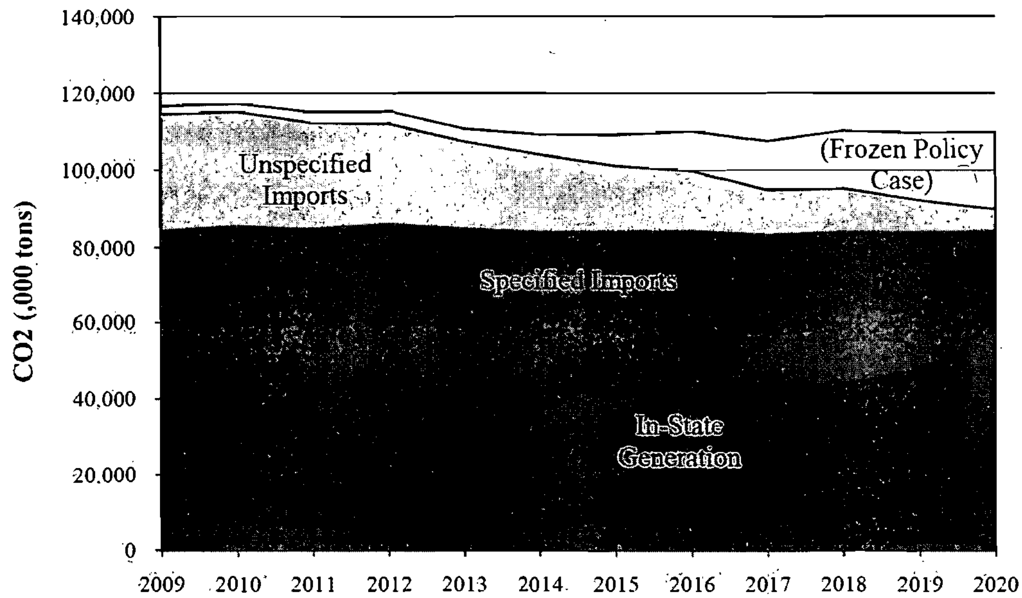
(GWhs)	**2013**	**2017**	**2020**
Increased generation from renewables	2,008	22,982	40,124
Reduced generation from:			
Existing/Planned NGCC	-1,560	-10,951	-18,249
Existing/planned NGCT	-136	-240	-486
Existing NG steam plant	-208	835	382
New, generic NGCC	0	0	0
New, generic NGCT	0	-2,431	-3,136
Total In-state Gas	-1,903	-12,787	-21,488
Specified Imports	-35	-316	-452
Non-specified Imports	-685	-12,771	-21,413
Percent Changes			
Increased generation from renewables	5%	52%	88%
Reduced generation from:			
Existing/Planned NGCC	-2%	-12%	-19%
Existing/planned NGCT	-1%	-1%	-3%
Existing NG steam plant	-5%	95%	35%
New, generic NGCC	0%	0%	0%
New, generic NGCT	0%	-97%	-98%
Total In-state Gas	-2%	-12%	-18%
Specified Imports	0%	-1%	-1%
Non-specified Imports	-2%	-40%	-71%

Source: (Energy Commission 2007e)

With respect to GHG emissions, the "Increased Renewables" Case results in GHG emissions associated with California electricity consumption decreasing by about 20 percent relative to 2009 by 2020 (Figure 33).[38] The decrease is mostly associated with the reduction in the volume of unspecified imports, which are, on average in this analysis, much more carbon intensive than the new gas-"fired generation that is occurring in-state.

[38] Note that due to differing counting conventions concerning unspecified imports and combined heat and power, the values shown here **cannot** be directly compared to the historic emissions shown earlier in this report.

Figure 33: "Increased Renewables" Case CO_2 Emissions



Source: (Energy Commission 2007e)

Plausibility and Implications

The "Increased Renewables" Case suggests that significant reductions in GHG can be achieved by moderately aggressive renewable development. Even though this case does not meet the 33 percent renewables target currently being considered for the state, it nonetheless achieves a 20 percent reduction in GHG emissions relative to 2009. Furthermore, these results are not based on an optimized resource mix; it contains a very high penetration of rooftop solar PV, which while an important resource, is relatively costly and does not have as high of a capacity factor as other renewables.[39] If a fraction of the PV investment assumed in the Scenario Report's "Increased Renewables" Case were shifted to other renewables, a greater reduction in GHG emissions could occur.

Figure 33, above, shows that much of the GHG reduction is due to reduced unspecified imports. This suggests that further GHG reductions beyond that achieved here would have to come at the expense of reduced specified imports (mainly cheap coal power from highly depreciated plants) or from a reduction in in-state gas generation. The amount that in-state gas generation can be reduced will likely be limited by the grid configuration, as discussed in the following section, local plants are needed for grid reliability and peaking purposes.

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[39] On the other hand, the PV level assumed in the Increased Renewables Case is consistent with the RETI Phase 1b Update, which points to the Go Solar California initiative's 2020 target of 4,200 MW. Furthermore, a sensitivity assessment of reduced solar costs in the RETI Phase 1b Report, assuming thin-film manufacturer cost targets as the basis for the solar capital cost, suggests that that" large amounts of distributed solar PV resources could be economic"(RETI 2009, pp.1-10)

Increased Renewables and Accelerated Plant Retirement

One way of reducing GHG as well as improving system reliability is replacing older, less efficient gas-fired plants with newer, more efficient ones or with renewable generation. Table 15 below shows the older gas-fired plants in the state, along with their location on the grid and their status as RMR. While there are significant megawatts of old plants, their capacity factors are relatively low (due primarily to their poor heat rates and to a lesser degree on operating restrictions due to emissions and water use). Thus, these plants are being maintained primarily, if not exclusively, for reliability purposes; either providing local capacity in load pockets (that is, they are designated RMR), providing peaking capacity during the few hours of system peak, or acting as an insurance policy for low hydro, extremely hot weather, or sustained outages of major power plants.

As the 2006 Capacity Factor column in Table 15 shows, none without RMR designation operated at capacity appreciably over 12 percent, while most were in the single digits. The table also notes which plants use once-through cooling. The State Water Resource Control Board made a policy decision to reduce or eliminate use of seawater at coastal power plants by 2015 or 2018, depending on capacity factor.

Table 15: Aging Power Plant Statistics

Plant	Unit	Year in service	MW	2007 Capacity Factor	RMR 2007	Once-Through Cooling
Greater Bay Area California ISO Local Reliability Area						
Contra Costa	6	1964	340	1%		yes
	7	1964	340	3%		yes
	subtotal		680			
Pittsburg	5	1960	325	3%		yes
	6	1961	325	2%		yes
	7		720	1%		yes
	subtotal		650			
Potrero Power	3		207	26%	yes	yes
	subtotal		363			
Humbolt						
Humboldt Bay	1	1956	53	90%		yes
	2	1958	54	28%		yes
	subtotal					
LA Basin						
Alamitos	1	1956	175	2%		yes
	2	1957	175	2%		yes
	3	1961	326	19%		yes
	4	1962	324	10%		yes
	5	1964	485	9%		yes
	6	1966	485	7%		yes
	subtotal		1,970			
El Segundo	3	1964	335	9%		yes
	4	1965	335	9%		yes
	subtotal		670			
Etiwanda	3	1963	320	14%		no
	4	1963	320	9%		no
	subtotal		640			
Huntington Beach	1	1958	215	21%		yes
	2	1958	215	6%		yes
	subtotal		430			
Redondo Beach	5	1954	179	1%		yes
	6	1957	175	2%		yes
	7	1967	493	6%		yes
	8	1967	496	4%		yes
	subtotal		1,310			
Big Creek/Ventura						
Mandalay	1	1959	218	9%		yes
	2	1959	218	15%		yes
	subtotal		436			
Ormond Beach	1	1971	806	5%		yes
	2	1973	806	9%		yes
	subtotal		1,500			

(Continued on next page)

Plant	Unit	Year in service	MW	2007 Capacity Factor	RMR 2007	Once-Through Cooling
San Diego						
Carlsbad (Encina)	1	1954	107	6%	yes	yes
	2	1956	104	5%	yes	yes
	3	1958	110	8%	yes	yes
	4	1973	300	8%	yes	yes
	5	1978	330	12%	yes	yes
	subtotal		951			
South Bay	1	1960	136	9%	yes	yes
	2	1962	136	10%	yes	yes
	3	1964	210	13%	yes	yes
	4	1971	214	8%	yes	yes
	subtotal		696			
California ISO Outside of Constrained Local Areas						
Coolwater	1	1961	65	1%		no
	2	1964	81	1%		no
	3	1978	241	16%		no
	4	1978	241	21%		no
	subtotal		628			
Morro Bay	3	1962	300	11%		yes
	4	1963	300	8%		yes
	subtotal		676			
Moss Landing	6	1967	702	6%		yes
	7	1968	702	10%		yes
	subtotal		1,478			
IID (Outside of the California ISO)						
El Centro	3	1952	44	11%		yes
	4	1968	74	20%		yes
	subtotal		118			
LADWP (Outside of the California ISO)						
Grayson	3	1953		N/A		no
	4	1959		5%		no
	5	1969		30%		no
	8	1977		N/A		no
Haynes	1	1962		29%		yes
	2	1963		22%		yes
	5	1966		4%		yes
	6	1967		17%		yes
	subtotal		1606	24.7%		
Burbank (Outside of the California ISO)						
Olive	1	1959	24	1		no
	2	1964	55	N/A		no
	subtotal		79			

Source: (Energy Commission 2003; Energy Commission 2008a; OPC/SWRCB 2008).

2007 IEPR Scenarios Report Examination of Accelerated Retirements in the SCE System

To explore what it would require for these plants to be removed from service in an accelerated fashion, the Scenarios Report Second Addendum (and associated appendices) explored the generation and transmission implications of different retirements on the Southern California Edison system (Energy Commission 2007e). In the main Scenarios Report, aging power plants were retired at 55 years of service life. Some power plants reached this benchmark before the 2012 year identified in the *2005 IEPR* policy as the time for retirement, while for others retirement came between 2012 and 2020. A few more plants were not retired by 2020 at all. When the power plants were retired, they were replaced with equivalent dependable capacity according to a simplified resource adequacy protocol.

The majority of the aging power plants identified in previous Energy Commission studies, totaling 4,140 MW, are located in the transmission planning area of SCE. As part of the *2007 IEPR*, staff, assisted by its consultants, undertook a study of the retirement and replacement of these power plants, including the interactions of retirement, replacement, and changes to the transmission system. The results of this study were reported in the Scenarios Report Second Addendum.

The Second Addendum analysis took Case 1b (the "Frozen Policy" Case here) and Case 4a (the "Increased Renewables" Case here) and considered the following (Energy Commission 2007e, pp.3-4):

- Retiring all 4,140 MW of aged capacity in the SCE system by 2012. Replacement capacity was identified that satisfied a simplified version of local capacity requirements allowing for changes in the transmission system. Transmission system contingency assessments identified overloaded transmission lines and suggested mitigation measures for the transmission system through time.
- A similar set of retirements, replacements, and transmission system upgrades that linked retirement and replacement with the underlying development of energy efficiency program savings and renewable generation development in each of the cases. In general, this was a slower pace of retirements compared with assuming mass retirement in 2012, but it had the benefit of linking replacements with unconventional generating resource development patterns and partially deferring transmission upgrades.

The remaining aged gas capacity and new gas capacity explicitly added to the SCE area are shown in Table 16 below. (No "new" capacity is shown for the comparative columns from the main Scenarios Report, as the locations of specific additions were not considered in sufficient detail to incorporate here). A number of insights can be gleaned from this table. First, comparing the Retire All in 2012 and the Phase Out per Need sensitivities in the Frozen Policy Case shows minimal difference in the added capacity by 2020. However, this is not true in the "Increased Renewables" case: the Phased-Out sensitivity case required 1,500 fewer megawatts in 2020 than the Retire All in 2012 case. This is due to the added renewable resources in the region as well as the assumption that local transmission upgrades could be made prior to aging plant retirement (Energy Commission 2007f, Addendum B, Appendix A) In effect, delaying retirement allows for the development of renewables and the needed transmission upgrades. .

Table 16: Changes in Gas Capacity in Accelerated Retirement Cases

	Main Scenarios Report		Per Addendum 2			
	55-year Retirement Rule		Retire All in 2012		Phased Out per Need	
	2012	2020	2012	2020	2012	2020
Case 1B (Frozen Policy)						
Total Aged Plants Online	6,325	2,991	2,510	2,510	3,110	2,510
New Peaking Capacity	n/a		2,802	3,144	2,800	3,146
New Combined Cycle Capacity			3,688	3,688	3,138	3,688
Total New Thermal Capacity			6,490	6,832	5,938	6,834
Case 4A (Increased Renewables)						
Total Aged Plants Online	6,325	2,991	2,510	2,510	4,330	2,510
New Peaking Capacity	n/a		3,305	3,045	2,810	2,742
New Combined Cycle Capacity			3,138	3,138	1,870	1,870
Total New Thermal Capacity			6443	6183	4680	4612

Source: (Energy Commission 2007d; Energy Commission 2007e, Table A-4)

Table 17 shows the generation by resource for the two scenarios in the original study and in the sensitivity runs. In all cases, the amount of renewable generation does not change in the sensitivity runs. However, both sensitivity runs show moderate increases in the amount of in-state gas generation on the order of five to ten percent. This increase is counterbalanced by a decrease in unspecified imports.

With respect to GHG emissions, the two sensitivities show only very modest changes in GHG emissions relative to the analogous scenarios in the Scenarios Report. In 2020, the in-state GHG emissions were less than one percent lower in the sensitivity cases that the original cases. This is due to the fact that the old gas generation is, for the most part, displaced by new gas generation, with some additional reduction in non-specified imports.

In addition to the broader impacts discussed here, there are detailed operational and ancillary service issues that must be taken into account. As noted in a recent PEIR report on renewable resource integration, "If new renewables are non-dispatchable, then load following, regulation, ramping and other operational attributes to run the power system and meet NERC's mandatory reliability standards will need to be provided by other resources and demand management (Energy Commission 2008e)." For instance, Southern California Edison's part of the California ISO control area already imports the majority of its power requirements through the eight major transmission lines feeding the region. However, generally a minimum of 40 percent of SCE's load has to be covered by in-basin generation and the exact amount and location of that needed generation changes depending on the loading of each of the eight transmission lines feeding the region. This means that some power plants not only have to be available to start up to cover emergencies but some need to be synchronized and ready to ramp up immediately to follow loads to assure frequency control and voltage support (OPC/SWRCB 2008, p.21)."

Table 17: Changes in Generation in Increased Retirement Cases

	Main Scenarios Report 55-year Retirement Rule		Per Addendum 2 Retire All in 2012		Per Addendum 2 Phased Retirements	
	2012	2020	2012	2020	2012	2020
Case 1B (Frozen Policy)						
Generation From (GWhs)						
In-state Renewables	41,927	45,586	41,927	45,586	41,927	45,586
Total In-state Gas	104,808	116,771	108,606	122,267	109,189	122,220
Specified Imports	37,351	38,307	37,182	38,164	37,178	38,116
Non-specified Imports	39,869	30,197	36,236	24,890	35,661	24,993
Percent Changes						
In-state Renewables	n/a		0%	0%	0%	0%
Total In-state Gas			-4%	-5%	-4%	-5%
Specified Imports			0%	0%	0%	1%
Non-specified Imports			9%	18%	11%	17%
Case 4A (Increased Renewables)						
Generation From (GWhs)						
In-state Renewables	43,935	79,438	43,936	79,438	43,936	79,438
Total In-state Gas	102,905	95,282	106,910	99,303	105,549	97,932
Specified Imports	37,316	37,855	37,171	37,676	37,168	37,766
Non-specified Imports	39,184	8,784	35,337	4,995	36,700	6,279
Percent Changes						
In-state Renewables	n/a		0%	0%	0%	0%
Total In-state Gas			-4%	-4%	-3%	-3%
Specified Imports			0%	0%	0%	0%
Non-specified Imports			10%	43%	6%	29%

Source: (Energy Commission 2007e)

Retirement of Coastal Plants Using Once-Though Cooling

At approximately the same time as the *2007 IEPR Scenarios Report*, the California Ocean Protection Council (OPC) and California State Water Resources Control Board commissioned a study to examine the economic and reliability impacts of the Control Board's then pending policy decision concerning use of seawater for once-through cooling (OTC) at coastal power plants (OPC/SWRCB 2008). In addition to the aging plants noted in Table 15, the state's two nuclear power plants, San Onofre and Diablo Canyon, as well as the new Moss Landing combined cycles use OTC. Unlike the scenarios report, which didn't include a load flow study, the OTC analysis included running both "(a) economic chronological hourly unit commitment and dispatch models for determining power supply economics [...] and (b) standard AC load flow models for determining reliability (OPC/SWRCB 2008, p.36)."

Under the Water Board's proposed policy, OTC plant owners can continue operating the present facilities with retrofitted non-OTC cooling, repower and add non-OTC cooling, or retire the plant. At face value, OTC plant owners seem to have considerable incentive to repower their facilities, using some other form of cooling than OTC. However, various constraints, such as incompatible land uses around a given site, could greatly affect the ability to repower certain sites. This has, in fact, been the case for a number of repowered proposals that have attempted

Applications for Certification (AFC) before the commission (for example, El Segundo, Morro Bay, and South Bay). These efforts have not borne fruit due to local opposition, and/or difficulty obtaining OTC water permits and air emission offset credits to compensate for the impact of air emissions from a repowered facility (OPC/SWRCB 2008, p.28).[40]

The modeling in the OTC Report examined a wide range of retirements and time frames for policy enactment. The modeling ranged from a no retirement case, through various assumptions concerning repowering and operating limitations, through a case with all OTC plants, including the nuclear plants, in 2015.

In the extreme case of all OTC plants retiring in 2015, including the nuclear units, the OTC report showed that substantial new transmission system upgrades to maintain reliability would be needed at a cost range from about $314 million to about $1 billion (OPC/SWRCB 2008, p.3). Removing all current OTC generation would also require adding ~4,000 MW of new generation in the Western U.S. plus additional transmission capacity to access that generation, at an estimated cost range of $3-11 billion (OPC/SWRCB 2008, p.3). All the other more moderate cases showed relatively modest cost increases compared to the no retirement case, and in most instances actually showed a modest cost reduction compared to the Energy Commission Scenario Report Case 1b baseline (The Frozen Policy Case discussed earlier).

With respect to emissions, all but the nuclear retirement case showed very minor decreases to the net CO_2 emissions (OPC/SWRCB 2008, p.45). This makes intuitive sense, in that the generation from the less efficient aged OTC steam-plants is replaced by generation from new, more efficient plants. The cases with the nuclear plant retire result in an additional 18 percent increase in in-state (and specified import) CO_2 emissions, as the CO_2-free power from SONGS and Diablo Canyon would have to be made up by gas-fired generation (OPC/SWRCB 2008, Table 4-2 and p.45).

Implications of Increased Renewables and Distributed Generation

Another policy option would be to increase the penetration of distributed generation in parallel with increasing renewables. This option was not explicitly considered in the Scenarios Report. Conceptually, a case with additional distributed generation would have the following impacts:

- Reduced conventional generation: As DG would not be dispatched, it would effectively be either a load reduction (if behind the meter) or must-take generation resource (such as directly connected PV selling on a feed-in tariff). Given California's resource mix, increased DG would displace conventional, generally gas-fired, generation.

- Potentially positive impact on transmission and distribution investment: DG, which would likely be concentrated in load centers, could offset or defer new, or upgrades to, transmission and distribution infrastructure.

[40] The South Coast Air Quality Management District has decided to award offsets related to a repowering based on that plant's recent emissions, rather than historical highs.

- Neutral or negative impact on grid operation. As DG would not be dispatchable, it would not contribute ancillary services. In fact, if its output were intermittent and not predictable on a local basis, such as solar PV, increased penetration of DG could increase the need for various ancillary services and complicate grid operations.
- Neutral to positive impacts on GHG emissions. As DG would displace conventional generation, the extent to which it would reduce net greenhouse gas emissions would be a function of the emissions characteristics of the DG relative to the displaced gas generation. If the DG was renewable or efficient combined heat and power, then the impact would be positive—reduced CO_2 emissions. If, on the other hand, the DG was not renewable and used a more carbon intensive fuel or used gas and was less efficient than the displaced generation, then net CO_2 emissions would increase.
- Unknown local criteria emissions impacts. The net local air emissions of criteria pollutants would depend upon the emissions characteristics of the DG as well as the location and emissions characteristics of the displaced generation.

At least with respect to overall displaced generation and GHG emissions, the Scenarios Report Case 5a can approximate a case with increased renewables and behind-the-meter DG. Case 5a modeled increased renewables plus increased energy efficiency. By broadly assuming that the displaced demand associated with the higher energy efficiency was instead a result of clean, behind-the-meter DG, then the Scenarios Report Case 5a can approximate a scenario with increased renewables and DG.

A comparison of the 2020 basic results in the "Increased Renewables" Case (Scenarios Report 4a) and the approximated "Increased Renewables plus DG" Case (Scenarios Report 5a) is shown in Table 18. This table suggests that generation from DG would displace a combination of in-state gas generation and non-specified imports. If the DG were carbon-free, then the net CO_2 emissions would be 7 percent less than the "Increased Renewables" alone. However, this GHG emissions impact represents a maximum; in practice, some DG, namely combined heat and power, is not carbon-free and would therefore increase the emissions from the "Increased Renewables Plus DG" Case and lower the net GHG savings.

Table 18: Impacts in 2020 of Approximated "Increased Renewables Plus Clean DG" Case

	Increased Renewables	Increased Renewables	Difference	
(GWhs)	Case	"+ DG Case"	GWh	Pct.
Energy Efficiency	29,638	42,263	12,625	43%
Renewable	85,710	85,707	(3)	0%
Total In-state Gas	95,282	88,108	(7,174)	-8%
Specified Imports	37,855	37,757	(98)	0%
Non-specified Imports	8,784	3,414	(5,370)	-61%
CO_2 Emissions, 000 tons	89,861	83,547	(6,314)	-7%

Source: (Energy Commission 2007f, Appendix C)

Conclusion

The Scenarios Report supporting the *2007 IEPR* and the subsequent Once-Through Cooling study provide some high-level insight as to new gas generation that might be needed under alternative policy futures. The Scenario Report modeling suggests that:

- Even without aggressive renewable or GHG policies (the Frozen Policy Case here), given the combination of the State's aggressive energy efficiency goals, natural turn-over of older gas plants, and some increase in renewables, electric-sector greenhouse gas emissions can be held at least through 2020 at approximately 2009 levels. (Comparisons to historic emissions cannot readily be made, given the differing protocols for assigning CO_2 emissions to imported power between the data presented in Chapter 5 and in Chapter 6.)
- Even in this case without aggressive renewable policies, the need for new gas generation will be primarily for peaking and quick start capacity in 2011 and beyond.
- With more aggressive renewable and GHG policies—albeit only up to 31 percent renewables by 2020 rather than 33 percent—("Increased Renewables" Case), CO_2 emissions from the electric sector can decline on the order of 20 percent relative to 2009 by 2020.
- Accelerated replacement of older gas-fired units could have a modest impact on GHG emissions, however as they would likely be replaced by new gas units, the improvement is tied simply to the improvement in the efficiency of the overall system heat rate.
- Increased clean DG (or energy efficiency) would displace gas-fired generation and have a marked reduction in electric sector GHG emissions.

These results, however, do not fully take into account local reliability constraints, transmission and transmission gateway issues, nor the increased ancillary service needs the system would face with a large injection of intermittent resources and the loss of strategically placed older gas plants. As noted in the Scenarios Report as well as in many places and by various parties, additional studies explicitly addressing these local reliability, transmission and intermittent resource operational issues are needed before one can more firmly determine the needs for type, role and location of, new gas generation in the state.

CHAPTER 7: Expected Roles for Gas-Fired Generation in a High-Renewables, Low-GHG-Emissions Electric System

Chapter 1 asked where, how much, and for what purpose new natural gas-fired generation should be added to California's portfolio of generation resources. This question arises in large part because of a potential conflict between natural gas-fired generation, which emits greenhouse gases, and the state's goal to reduce GHG emissions to 1990 levels by 2020 and to 80 percent of 1990 levels by 2050. This question is also relevant in light of other major policy goals including the twin goals of expanding reliance on energy efficiency and increasing the renewable energy share of the state's electricity mix to 33 percent by 2020. These goals are embodied in the preferred loading order of resources to meet future electricity demand and if successfully achieved will most likely reduce the state's overall reliance on natural gas-fired generation. How these policies ultimately shape California's electricity sector has long-term implications for the future role of natural gas-fired power plants in the state.

Because the Energy Commission is responsible for reviewing and approving the siting of new thermal power plants in California with generating capacities of 50 MW and larger, it necessarily must grapple with the environmental impacts posed by new natural gas-fired generation within the context of meeting the state's energy and environmental policies. Even highly efficient gas-fired power plants emit greenhouse gases and other air pollutants, and thus could have an impact on the environment. Given the expected long service life of a new gas-fired power plant, decisions made in the near term about new resource additions could have long-term environmental ramifications.

In the long run, as ARB translates its broad *Scoping Plan* into specific regulations, the market and the regulatory environment may clarify the question of where, how much, and for what purpose new gas-fired generation should be built in the state. But in the short run, when AB 32-related regulations have yet to be implemented, the Energy Commission must consider this question and its appropriate answer. Any answer must be one that does not threaten the reliability of the electric system and that minimizes direct economic costs and overall environmental impacts. Ideally, California would minimize its reliance on natural gas-fired generation with its associated GHG emissions as well as minimize its environmental footprint. California needs some gas-fired generation to satisfy reliable grid operations, local capacity requirements, and growth in demand for power. There are uncertainties around the achievable levels of energy efficiency, renewable energy, and combined heat and power and the feasible expansion of the transmission grid. Thus, the Energy Commission must weigh the expected benefits of each new power plant against the potential environmental impact of a new natural gas-fired power plant.

This chapter will consider what roles may exist within the state's integrated electric system for new natural gas-fired generation in light of current state energy and environmental goals. In addition, this chapter includes a qualitative, preliminary assessment of how the net GHG emissions of the electric system may change with the addition of new natural gas-fired generation to fulfill the roles.

Why Focus on Gas-Fired Power Plants

Natural gas-fired power plants are one of many resource types that could be built in California, and they are not alone in creating environmental impacts. However, their unique role in accommodating renewable resource development and maintaining system reliability and operational flexibility,.combined with other factors lead to the focus of this chapter on their future role in California's integrated electric system.

The current portfolio of proposed projects awaiting the Energy Commission's review and approval includes proposals for new gas-fired projects with a total capacity of approximately 8,000 MW.[41] The applications that will be actively pursued and, if approved, those actually built will depend on many factors. For example, few if any true merchant power plants that would sell their output exclusively or principally into short-term energy markets will be built; most power plants that are ultimately developed will be financed based on long-term power purchase agreements with utilities or other load-serving entities. Contracts with investor-owned utilities likely will be awarded only after thorough, multi-year regulatory assessments by the Energy Commission in the IEPR proceeding and the CPUC in its Long-Term Power Procurement proceeding. Nevertheless, in the near term the Energy Commission will review numerous applications to build natural-gas fired power plants.

Coal-fired power plants are not included in this discussion because the carbon sequestration technologies that would place them in the state's loading order of preferred resources have yet to be developed for large-scale generation. SB 1368 effectively prohibits California's utilities from owning or contracting for power from a coal-fired power plant unless that plant uses carbon capture and sequestration technologies. An application for a "clean coal" project that would gasify petroleum coke or a blend of coal and petroleum coke was submitted to the Energy Commission in July 2008, but this project and the technology it will use is currently in an early phase of being studied by the project proponent.[42] While the ARB *Scoping Plan* calls for more research into carbon sequestration technology, it is unlikely that a coal-fired plant that meets state requirements with respect to GHG emissions would be developed during the time frame considered by this report will be.

Renewable energy generation and CHP projects are excluded from this discussion for several reasons. First, such plants are already part of ARB's *Scoping Plan* measures to reduce GHG emissions reductions. Chapter 6 confirmed that expanding renewable energy generation from 20 percent to 33 percent of the state's electricity supply will reduce GHG emissions from the utility system. Second, wind, hydro, and solar PV are not thermal generation resources, and thus do not fall under the siting jurisdiction of the Energy Commission. Geothermal and some solar thermal power plants, which as thermal plants would fall under the Energy Commission's siting jurisdiction at capacities above 50 MW, do emit carbon dioxide but at very low levels

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[41] This figure does not include hybrid natural gas and solar-powered generation.

[42] The application is for the Hydrogen Energy California (HECA) plant. The proposed technology is integrated gasification combined cycle with carbon capture and sequestration. SCE recently filed an application with the CPUC (A.09-04-008) in which it seeks cost recovery for Phase 1 studies that will "determine initial feasibility" of the project.

compared to fossil fuel plants. The GHG emissions from a biomass facility are highly dependent on the fuel source and method of combustion; they could be a net source or sink for GHG emissions. A full consideration of the GHG emissions from a biomass plant would be more appropriately done within a specific project's siting application.[43] Finally, CHP projects, like renewable energy projects, are part of ARB's *Scoping Plan* measures to reduce GHG emissions.

Expected Roles for Gas-Fired Generation

A single power plant within an integrated electric system provides one or more of three basic products to the electric system: energy, capacity, and ancillary services.[44] As California pursues its various policies to reduce the carbon intensity of the electricity supply system and mitigate the environmental impacts of once-through cooling, the mix of generation resources that provide energy, capacity, and ancillary services to the grid will necessarily change. Natural gas-fired power plants may be relied on less overall to provide energy or capacity. However, there will be a greater need for gas-fired power plants to provide certain ancillary services because the preferred resources of energy efficiency and renewable energy generally are not dispatchable and because storage technologies are not yet sufficiently mature to provide these services.[45] For this reason, it is necessary to consider what roles gas-fired generation will play in the future. The authors identified five roles that gas-fired power plants are most likely to fulfill in the future:

1. Intermittent generation support
2. Local capacity requirements
3. Grid operations support
4. Extreme load and system emergencies support
5. General energy support

These categories look into the future when operational flexibility and strategic location will be as valuable from a grid operator's perspective as energy and capacity. Table 19 shows these expected roles for generation and the services that characterize each role. As the table makes clear, certain services are characteristic of more than one role (such as spinning reserve is a service listed for more than one category). This suggests that a new plant could potentially fulfill more than one of the five identified roles. This is a benefit to the grid in that redundancy of capabilities becomes built into the grid. A discussion of the different roles is presented after the table and an accompanying text box.

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[43] For example, an application for a combined solar/biomass plant, the San Joaquin Solar 1 LLC and San Joaquin Solar 2 LLC, is currently pending before the Energy Commission.

[44] The California ISO currently procures five distinct ancillary services: regulation (up and down), spinning reserve, non-spinning reserve, voltage support, and black start capability. Although there has been discussion of the need for a "load following" service, such an ancillary service does not yet exist as a formally defined service in the California ISO's markets.

[45] Detailed modeling would be needed to show how gas-fired generation's share of energy could fluctuate over all the hours in a year under various future scenarios.

Table 19: Expected Roles for Gas-Fired Generation

Description	Role of Plant	Plant Attributes
Intermittent Generation Support	Support intermittent renewable generation	• Fast start-up capability (within 2 hours or less) • Rapid ramping capability • Can provide regulation • Can provide spinning reserve • Can provide non-spinning reserve • Can provide energy when intermittent resources are unavailable
Local Capacity Requirements	Strategically located generation necessary to mitigate grid problems and potentially reduce need for new transmission infrastructure	• Able to satisfy/partially satisfy LCA resource requirements • Voltage support • May provide black start capability
Grid Operations Support	Support specific grid operational needs; plant is not necessarily located in a local capacity area.	• Fast start-up capability (within 2 hours or less) • Rapid Ramping • Can provide regulation • Can provide spinning reserve • Can provide non-spinning reserve • Black start capability • Load-following capability
Extreme Load / System Emergencies Support	Meet peak demand under extreme temperature conditions (for example, summer peak demand) or other system emergencies	• Fast start-up capability (within 2 hours or less) • May have low minimum load levels • Rapid ramping capability • Can provide regulation • Can provide spinning reserve • Black start capability
General Energy Support	To provide a reliable supply of cost-competitive energy to the grid; plant operates primarily based on economic dispatch, can provide energy in low hydro periods, extended nuclear outages, and seasonal low wind periods.	• Cost-competitive energy • Able to help an LSE meet RA requirements • Not necessarily a quick start unit; start-up duration may be hours • Can provide limited regulation service • Can provide limited spinning reserve

The textbox below, Electric Attribute Definitions, provides definitions for the terms contained in Table 19. These definitions are provided to ensure a common understanding of the expected roles, recognizing that these terms often are used with slightly varying meanings from situation to situation. The definitions are drawn from the California ISO's tariff unless otherwise noted.

Electric Attribute Definitions

Ancillary Services: Regulation, Spinning Reserve, Non-Spinning Reserve, Voltage Support and Black Start...to support the transmission of Energy from Generation resources to Loads while maintaining reliable operation of the California ISO Controlled Grid in accordance with WECC standards and Good Utility Practice.

Black Start: The procedure by which a Generating Unit self-starts without an external source of electricity thereby restoring a source of power to the California ISO Balancing Authority Area following system or local area blackouts.

Fast Start Unit: A Generating Unit that has a Start-Up Time less than two hours and can be committed in the RTUC [Real-Time Unit Commitment] and STUC [Short-Term Unit Commitment].

Local Capacity Area Resources: Resource Adequacy Capacity from a Generating Unit listed in the technical study or Participating Load that is located within a Local Capacity Area capable of contributing toward the amount of capacity required in a particular Local Capacity Area.

Non-Spinning Reserve: The portion of generating capacity that is capable of being synchronized and Ramping to a specified load in ten minutes (or Load that is capable of being interrupted in ten minutes) and that is capable of running (or being interrupted).

Ramping: Changing the loading level of a Generating Unit in a constant manner over a fixed time (e.g., Ramping up or Ramping down). Such changes may be directed by a computer or manual control.

Regulation: [The service provided by generators capable of delivering energy] in an upward and downward direction to match, on a Real-Time basis, Demand and resources.[...] Regulation is used to control the Power output of electric generators within a prescribed area in response to a change in system frequency, tie line loading, or the relation of these to each other so as to maintain the target system frequency and/or the established Interchange with other Balancing Authority Areas within the predetermined Regulation Limits. Regulation includes both the increase of output by a Generating Unit or System Resource (Regulation Up) and the decrease in output by a Generating Unit or System Resource (Regulation Down). Regulation Up and Regulation Down are distinct capacity products, with separately stated requirements and ASMPs in each Settlement Period.

Spinning Reserve: The portion of unloaded synchronized generating capacity that is immediately responsive to system frequency and that is capable of being loaded in ten minutes, and that is capable of running for at least two hours.

Voltage Support: Services provided by Generating Units or other equipment such as shunt capacitors, static VAR compensators, or synchronous condensers that are required to maintain established grid voltage criteria. This service is required under normal or System Emergency conditions.

Source: (California ISO 2009b)

Intermittent Generation Support

Earlier chapters of this report discussed how certain policy goals, if achieved, will reshape the state's electricity system into one that relies on a much higher percentage of renewable resources in the coming decades. The implications of this policy for the role of natural gas-fired generation are twofold. First, higher levels of intermittent renewable energy facilities connected to the grid will increase the need for flexible generation sources to accommodate the resulting increase in short-term fluctuations in the output of the electric system (over periods of a few minutes to two to four hours). These fluctuations need to be managed with the increased use of selected ancillary services:

- Very short-term fluctuations (minute-to-minute) in the aggregate output of intermittent renewable resources increase the need for regulation services, which require dispatchable generation under AGC.
- Fluctuations over slightly longer periods (that is, 5 minutes to 2 hours) require dispatchable resources that can provide spinning reserve. Effective provision of this service is facilitated by a resource that can ramp up and down quickly over the widest range of output; cost-effective provision of this service by a unit requires that it be able to do so without a substantial drop in efficiency. Quick-start units are needed to provide non-spinning reserve to handle changes in aggregate wind output over the 30 minute to two hour range.
- Predicable changes in aggregate wind output over the course of the day increase the need for resources designed to cycle daily, ramping on and up in the morning and down and off in the evening. As discussed in Chapter 4, wind resources are counter-cyclical, exacerbating the need for resources that are brought on- and off-line as load rises and falls over the day.

Second, the ability of renewable energy resources to count toward resource adequacy requirements is significantly reduced if the resource has limited ability to provide output coincident with peak demand. This is the case for wind resources where wind facilities often do not operate at their specified qualifying capacity at the time of daily peak demand. To the extent that these resources do not provide reliable capacity during periods of extremely high demand - at levels commensurate with their capacity value during other peak hours - additional dispatchable fast-start resources may needed to ensure reliable service during summer peaks.

LCA Resource Requirements Fulfillment

A number of power plants will need to be built in California in the coming years to ensure local area reliability. These resources must be located in specifically designated areas to accommodate existing grid problems when investments in new transmission infrastructure are too expensive or the timelines to license and construct such transmission upgrades are too lengthy.

There are two primary reasons why such strategically located plants will be needed. First, local reliability needs could change, for example, due to load growth or to backup transmission line loading, such that new capacity must be added to operate the grid in accordance with WECC and NERC standards. Second, all but 2,000 MW of the 13,600 MW of aging generation capacity that uses ocean water for once-through-cooling is currently providing local reliability services. Plants using OTC may be shut down under a proposed policy put forward by the State Water Resources Control Board (SWRCB). That March 2008 policy proposal called for reductions in ocean-cooling by retrofitting with wet cooling towers or the equivalent in sea water usage. To meet these requirements, much of the capacity of these plants will need to be replaced in the same or nearby locations.[46] The Energy Commission, the CPUC and the California ISO "have proposed an alternative implementation proposal to the SWRCB that links shutdown of OTC facilities to creating a replacement infrastructure, most likely a combination of new power plants, repowering of some OTC facilities, and new transmission lines reducing the need for capacity (Energy Commission 2009d, p.7)."

Grid Operations Support

As was discussed elsewhere in this report, the safe and reliable operation of an integrated electric grid requires a portfolio of power plants that can be operated in a manner that supports constantly changing demand and supply conditions while satisfying specific reliability criteria. Central station renewable generating technologies and customer-side-of-the-meter distributed generation do not possess the ability to ramp up and down or respond to other dispatch instructions. New power plants with specific technological capabilities and operational agreements establishing the means to respond may be needed in the future specifically to support the operational requirements of California's integrated grid. These plants essentially will provide the ancillary services and voltage support that the California ISO needs to keep the grid operational.

Extreme Load and System Emergencies Support

Historically the critical role of meeting the peak demand of an electric system has fallen to power plants called peaking plants. Although peaking plants operate very few hours in a year, they are critical to meeting the peak demand of an electric system. Demand response initiatives also help to meet a system's peak demand (by curtailing demand), but peaking plants will still be needed in the future. Such plants may also be needed to respond when transmission lines carrying renewable energy from remote areas experience outages, such as periodically occurs in southern California due to wild fires. A plant built to fulfill this role should also be capable of providing black start capability to the grid to enable the grid to cope with a system emergency. For example, SCE's planned peaking plant at Oxnard will offer black start capability, enabling it to provide the power necessary for other nearby generating plants to restart following a widespread outage.

General Energy Support

California's preferred resource choices are encapsulated in the loading order, which calls for the state to rely first on energy efficiency, then demand response, renewable energy, and combined

[46] Requiring the refitting of these aging plants with cooling towers is expected to lead to their retirement. A substantial share of the capacity retired will have to be replaced to meet both system-wide and local capacity requirements.

heat and power in that order. Each of these resources will play an important role in meeting electricity demand while also helping to reduce GHG emissions to meet AB 32's 2020 targets. However, the amounts of these preferred resource choices may not be sufficient to meet the state's future energy demand. In addition, some of the state's existing generation fleet is aging and inefficient and will need to be shut down. Generation may also be needed during a lengthy nuclear plant outage or during periods of low hydroelectric production. For these reasons, new gas-fired power plants may need to be built to provide cost-competitive energy to the grid.

The Energy Commission's Siting Committee recently concluded that the GHG emission impacts of a new power plant should be analyzed in terms of the overall net impact on the integrated electric system. Such an approach more accurately captures the displacement effect on GHG emissions that occurs when new, more efficient power plants are added and older plants run less frequently. A new gas-fired power plant should cause a less efficient plant to be pushed further back in the dispatch order based on its higher operating costs. The net effect should be an overall reduction in GHG emissions.

GHG Emissions Implications

An important step in trying to understand how the electric system's net GHG emissions will change in the future was to identify specific roles that gas-fired generation would be expected to fulfill in the future given the policy mandates being pursued by the state to reduce GHG emissions from the electric sector. Given these expected roles, some qualitative, preliminary assessments can be drawn as to how net GHG emissions could change with the addition of new gas-fired power plants. The authors would expect that the net GHG emissions for the integrated electric system *will decline* under the following scenarios:

1. The addition of new gas-fired power plants to the extent that is necessary to permit the penetration of renewable generation to the 33 percent target.
2. The addition of new gas-fired power plants that improve the overall efficiency of the electric system.
3. The addition of a new gas-fired power plant or modernization/repowering of existing capacity that serves load growth or capacity needs more efficiently than the existing fleet.

Extensive modeling would be needed to understand precisely how the net GHG emissions of the electric system change under various specified future conditions. (In Chapter 6 the authors examined some of this type of assessment performed by the Energy Commission). The California ISO is currently undertaking an extensive modeling effort to understand how much, what type, and where gas-fired generation will be needed to enable the integration of at least 33 percent renewable energy into the California system.

Conclusions

California's loading order for new electricity supply resources pledges the energy agencies to achieve goals of adding large amounts of renewable energy resources to the state's supply mix. Governor Schwarzenegger's Executive Order S-14-08 provides further concrete steps the state's agencies will take to achieve this goal. Renewable energy can deliver carbon-free or very low carbon-intensity power to the grid. Renewable energy in combination with energy efficiency and new combined heat and power plants are important tools in the state's efforts to reduce GHG emissions from the electricity sector. Thus, it should be consider as a given that the state is striving to add as much renewable energy to its supply mix as is feasible over the next several years.

The challenge the state faces in increasing its reliance on renewable energy is that some amount of gas-fired generation will most likely be needed to support the integration of these resources. In the long run, as ARB translates its broad *Scoping Plan* into specific regulations, the market and the regulatory environment may clarify the question of where, how much, and for what purpose new gas-fired generation should be built in the state. But in the short run, when AB 32-related regulations have yet to be implemented, the Energy Commission must consider this question and the appropriate answer to it.

This chapter identified key attributes, or services, that gas-fired power plants are expected to provide to the state's integrated grid in the future. Although these attributes are identifiable, the limited scope of this report does not permit the detailed modeling that might allow conclusions to be drawn as to very specific plant needs and locations. Nevertheless, gas-fired power plants that enhance the grid's operational flexibility are necessary. The Energy Commission will need to review and consider an individual project's application to make the appropriate judgments about a plant's ability to support the integration of renewable resources or otherwise provide important system benefits that outweigh any environmental impacts of building and operating a plant.

Although a single natural gas-fired power plant produces GHG emissions, under certain circumstances the addition of a gas-fired plant may yield a GHG emission benefit. The authors conclude that this would be the case if the plant provided support to integrate renewable energy under a 33 percent RPS if the addition raised the overall efficiency of the electric system, or of the new plant served load growth more efficiently than the existing fleet.

Acronyms and Abbreviations

AB	Assembly Bill
AFC	Application for Certification
ARB	California Air Resources Board
BSC	Building Standards Commission
California ISO	California Independent System Operator
CEQA	California Environmental Quality Act
CH_4	methane
CHP	combined heat and power
CO_2	carbon dioxide
CPUC	California Public Utilities Commission
CSI	California Solar Initiative
CT	combustion turbine
DG	distributed generation
DSM	demand side management
E3	Energy and Environmental Economics, Inc.
EIA	U.S. Energy Information Administration
Energy Commission	California Energy Commission
EPG	Electric Power Group
FERC	Federal Energy Regulatory Commission
GHG	greenhouse gas
GWh	gigawatt-hour
HFC	hydrofluorocarbon
HVAC	Heating, ventilation, and air conditioning
IAP	*Intermittency Analysis Project*
IC	internal combustion
IEPR	Integrated Energy Policy Report
IID	Imperial Irrigation District
IOU	investor-owned utility
IRRP	Integration of Renewable Resources Program
LADWP	Los Angeles Department of Water & Power
LCR	local capacity requirement
LRA	Local Reliability Area
LSE	load serving entity
MMTCO2e	million metric tonnes CO_2 equivalent
MRTU	Market Redesign and Technology Upgrade
MW	megawatt
MWh	megawatt-hour
N_2O	nitrous oxide

NAS	sodium sulfur
NERC	North American Electric Reliability Corporation
NQC	net qualifying capacity
OPC	California Ocean Protection Councils
OTC	once-through cooling
PFC	perfluorocarbon
PG&E	Pacific Gas & Electric Company
PIER	Public Interest Energy Research
POU	publicly-owned utility
PV	photovoltaic
RA	Resource Adequacy
RETI	Renewable Energy Transmission Initiative
RMR	reliability must-run
RPS	Renewables Portfolio Standard
SB	Senate Bill
SCAQMD	South Coast Air Quality Management District
SCE	Southern California Edison
SDG&E	San Diego Gas & Electric Company
SF_6	sulfur hexafluoride
SMUD	Sacramento Municipal Utility District
SWRCB	State Water Resources Control Board
WECC	Western Electricity Coordinating Council
WREZ	Western Renewable Energy Zone

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