R.12-03-014

Table of Contents - Exhibits Supporting Testimony of Robert Sparks and Mark Rothleder

Exhibit No.	Title of Document
ISO - 07	2011-2012 Transmission Plan - Chapter 3
ISO - 08	Supplemental Testimony of Robert Sparks in docket no. A.11-05-023
ISO - 09	Addendum to Board-Approved 2011-2012 Transmission Plan Section 3.4.2.1 Assembly Bill 1318 Sensitivity Reliability Study Results
ISO - 10	California Energy Commission *2009 Integrated Energy Policy Report*
ISO - 11	California Energy Commission Committee Report *Incremental Impacts of Energy Efficiency Policy Initiatives Relative to the 2009 Integrated Energy Policy Report Adopted Demand Forecast*
ISO - 12	California Energy Commission *2011 Integrated Energy Policy Report*
ISO - 17	Errata to Track I Direct Testimony of Mark Rothleder Includes Exhibits 1 through 4

Rulemaking	12-03-014
Exhibit Nos.:	ISO – 07 through ISO – 12, and ISO – 17
Witnesses:	Robert Sparks and Mark Rothleder

Order Instituting Rulemaking to Integrate and Refine Procurement Policies and Consider Long-Term Procurement Plans.	Rulemaking 12-03-014

EXHIBITS SUPPORTING PREPARED DIRECT TESTIMONY, AND SUPPLEMENTAL TESTIMONY OF ROBERT SPARKS AND EXHIBITS SUPPORTING PREPARED DIRECT TESTIMONY OF MARK ROTHLEDER ON BEHALF OF THE CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION

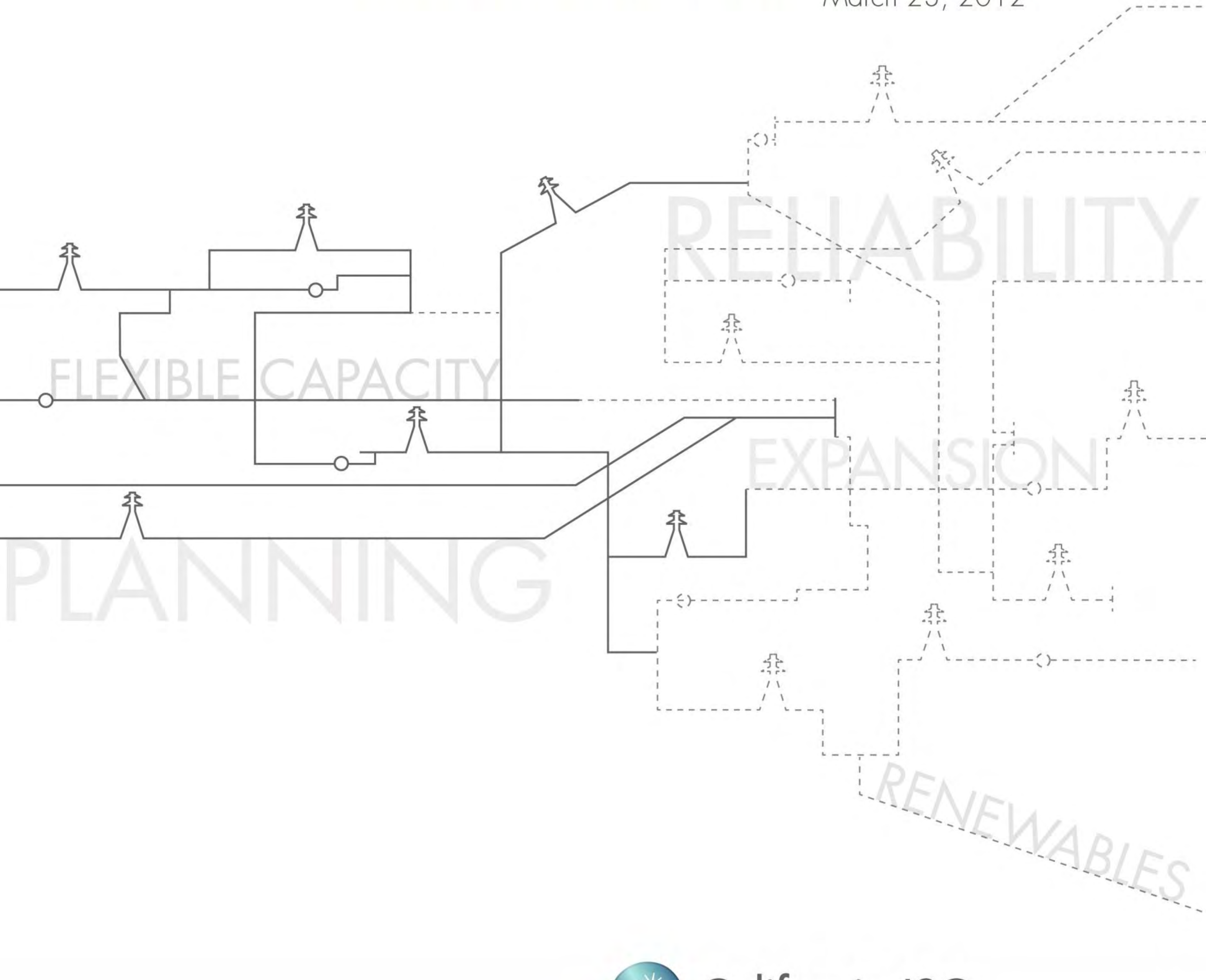
Rulemaking	12-03-014
Exhibit No.:	ISO - 07
Witness:	

2011 – 2012 Transmission Plan

Chapter 3

2011-2012 TRANSMISSION PLAN

March 23, 2012



California ISO

Shaping a Renewed Future

Prepared by: Infrastructure Development

Approved by ISO Board of Governors

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Chapter 3

Special Reliability Studies and Results

3.1 Overview

The special studies discussed in this chapter include ones of transmission projects identified in the ISO tariff that have not been addressed elsewhere in the transmission plan. These comprise projects that may be needed to maintain long-term congestion revenue rights feasibility, local capacity technical analysis and location constrained resource interconnection facilities (LCRIFs). In addition, the ISO also performed reliability assessments under various load and resource scenarios that may result from the state's other environmental policies. This includes the State Water Resources Control Board's (SWRCB) policy on once-through cooling (OTC) power plants and Assembly Bill 1318. AB 1318 requires coordination between various state energy agencies and the ISO under the leadership of the California Air Resources Board (CARB) to assess potential emission offset needs for fossil power plant development to maintain electric reliability in the South Coast Air Basin's jurisdiction.

3.2 Reliability Requirement for Resource Adequacy

Sections 3.2.1 and 3.2.2 summarize the technical studies conducted by the ISO to comply with the reliability requirements initiative in the resource adequacy provisions under Article 5 of the ISO tariff. The local capacity technical analysis addressed the minimum local capacity requirements (LCR) on the ISO grid. The Resource Adequacy Import Allocation study established the maximum resource adequacy import capability to be used in 2012.

3.2.1 Local Capacity Requirements

The ISO conducted short and long-term local capacity technical (LCT) analysis studies in 2011. A short-term LCT analysis was conducted for the 2012 system configuration to determine the minimum local capacity requirements for the 2012 resource procurement process. The results were used to assess compliance with the local capacity technical study criteria for the local capacity areas as required by the ISO tariff section 40.3. This study was conducted January-April through a transparent stakeholder process, with a final report published on April 29, 2011. A long-term LCT analysis was also performed to identify local capacity needs in the 2016 period, and a report was published at the end of January 2012. The long-term analysis was performed to provide participants in the transmission planning process with future trends in LCR needs for up to five-years. This section summarizes study results from both the short-term and long-term LCR need.

As shown in the LCT Report and indicated in the LCT Manual, 10 load pockets are located throughout the ISO-controlled grid as shown in Table 3.2-1 and illustrated in Figure 3.2-1 below.

Table 3.2-1: List of LCR areas and the corresponding PTO service territories within the ISO BA area

No	LCR Area	PTO Service Territory
1	Humboldt	PG&E
2	North Coast and North Bay	
3	Sierra	
4	Greater Bay Area	
5	Stockton	
6	Greater Fresno	
7	Kern	
8	Los Angeles Basin	SCE
9	Big Creek/Ventura	
10	San Diego	SDG&E

Figure 3.2-1: Approximate geographical locations of LCR areas

Each load pocket is unique and varies in its capacity requirements because of different system configuration. For example, the Humboldt area is a small pocket with total capacity requirements of approximately 200 MW. In contrast, the requirements of the Los Angeles Basin are approximately 10,000 MW. The short- and long-term LCR needs from this year's studies are shown in Table 3.2-2.

Table 3.2-2: Local capacity areas and requirements for 2012 and 2016

LCR Area	Existing LCR Capacity Need (MW) 2012	2016
Humboldt	190	198
North Coast/North Bay	613	901
Sierra	1685	1033
Stockton	389	326
Greater Bay Area	4278	4565
Greater Fresno	1899	2166
Kern	297	682
Los Angeles Basin	10865	10380
Big Creek/Ventura	3093	2348
Greater San Diego/Imperial Valley	2849	2982
Total	26158	25581

For more information about the LCR criteria, methodology and assumptions please refer to the ISO website at: http://www.caiso.com/18a3/18a3d40d1d990.html.

For more information about the 2012 LCT study results, please refer to the report posted on the ISO website at: http://www.caiso.com/Documents/Local%20capacity%20technical%20analysis/Final2012LCTStudyReportApr29_2011.pdf.

For more information about the 2016 LCT study results, please refer to the report posted on the ISO website at: http://www.caiso.com/Documents/Final2016LCTStudyReportJan30_2012.pdf.

3.2.2 Resource Adequacy Import Capability

In accordance with ISO tariff section 40.4.6.2.1, the ISO has established the maximum RA import capability to be used in year 2012. This data can be found at: http://www.caiso.com/Documents/2012%20Import%20allocations/ISOMaximumResourceAdequacyImportCapability_Year2012.pdf. For more information regarding the entire 2012 import allocation process, please see this link: http://www.caiso.com/1c44/1c44b2dd750.html.

In accordance with Reliability Requirements BPM section 5.1.3.5.1, the ISO has established the target maximum import capability (MIC) from the Imperial Irrigation District (IID) to be 1,500 MW in year 2021 to accommodate renewable resources development in this area. The import capability from IID to the ISO is the combined amount from the IID-SCE_BG and the IID-SDGE_BG.

The ISO also confirms that all other import branch groups or sum of branch groups have enough MIC to achieve deliverability for all external renewable resources in the base portfolio along with existing contracts, transmission ownership rights and pre-RA import commitments under contract in 2021.

The 10-year increase in MIC from the IID area is dependent on transmission upgrades in both the ISO and IID areas as well as new resource development within the IID and ISO systems. Table 3.2-3 shows the ISO estimates of how the increase in MIC will be achieved. The allocation of the MIC increases between the IID-SCE_BG and the IID-SDGE_BG can vary as long as the total does not exceed the amounts shown, and is limited by the maximum operating transfer capability (OTC) for each branch group in the appropriate year.

Table 3.2-3: ISO estimate of total policy driven MIC

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
IID-SCE_BG	517	517	1000	1000	1000	1000	1500	1500	1500	1500
IID-SDGE_BG	0	0								

The 2014 increase is dependent on the in-service dates for:

a) Path 42 upgrades to both the SCE as well as the IID system;

b) completion of the entire scope of the West of Devers interim upgrades (reactors and SCE and IID area SPS).

The 2018 increase is dependent on the in-service date for the West of Devers reconductoring project.

The future outlook for all remaining branch groups can be accessed at:

http://www.caiso.com/Documents/Advisory%20estimates%20of%20future%20resource%20adequacy%20import%20capability.

3.3 Once-Through Cooling Generation Retirement Studies

3.3.1 Background, Methodology and Assumptions

Approximately 30 percent of California's in-state generating capacity (gas and nuclear power) uses coastal and estuarine water for once-through cooling. On May 4, 2010, the State Water Resources Control Board adopted a statewide policy on the use of coastal and estuarine waters for power plant cooling. The policy establishes uniform, technology-based standards to implement federal Clean Water Act section 316(b), which requires that the location, design, construction and capacity of cooling water intake structures reflect the best technology available for minimizing adverse environmental impact. The policy was approved by the Office of Administrative Law on September 27, 2010 and became effective on October 1, 2010. It required the owner or operator of an existing non-nuclear fossil fuel power plant using once-through cooling to submit an implementation plan to the SWRCB on April 1, 2011. In most cases, the implementation plans selected an alternative that would achieve compliance by a date specified for each facility identified in the policy.

Nuclear units may also seek to establish site-specific requirements for best technology available. The policy directs Pacific Gas and Electric Company and Southern California Edison to conduct special studies to investigate alternatives for the nuclear units to meet the requirements. The studies are to include the costs for these alternatives. The SWRCB requires that the report on these special studies be submitted by October 1, 2013.

The ISO anticipates that the SWRCB policy will force the majority of gas-fired generating units using once-through cooling either to come off-line to retrofit or repower using alternative cooling technologies, or retire. The ISO needs to assess the reliability impacts to the ISO grid that may result from these actions.

Another consideration arising from the SWRCB policy is the connection between generating units using once-through cooling and renewable integration. Many of the units using once-through cooling technology have characteristics that would support renewable integration. Replacement infrastructure will need to retain or improve these capabilities (whether by the repowered plants or replacement capacity). Additionally, because of the contribution of these units to system operations, it will be essential to plan any retrofit or repowering efforts or retirements in a manner consistent with the operational requirements created by an expanding portfolio of renewables. Such requirements may be higher in some years than in others, because of the mix of renewables on the system. The process of complying with the once-through cooling policy is thus another factor to consider in preparing the power system for higher levels of renewable resources.

For purposes of the 2011/2012 transmission planning process, the ISO continued its collaborative study efforts with various state agencies and stakeholders. In 2010, with assistance from the CPUC and CEC, the ISO posted a load and resource analysis tool. The ISO uses the tool to screen and identify potential time frames in which local resources are less than the projected resources needed to maintain local reliability under a range of resource scenarios. The ISO also performed technical evaluations using power flow and transient stability programs for various RPS scenarios (i.e., trajectory, environmentally constrained, ISO base case, cost-constrained and time-constrained) to determine long-term (2021) local capacity requirements for areas that currently have OTC generating units. These areas are the Greater Bay Area, Big Creek/Ventura, the Los Angeles Basin and San Diego. The following is an outline of the studies for this planning cycle:

3.3.1.1 Long-Term LCR and Zonal Assessments

The ISO performs a reliability assessment (i.e., power flow and stability analyses) using the 2021 RPS study cases as seed cases to develop long-term LCR and zonal study cases.

- Using 2021 LCR cases prepared for the Greater Bay Area, Big Creek/Ventura, LA Basin and San Diego local areas, the ISO performed reliability assessments. The assessments determined the range of generation requirements — including OTC generation — that are needed to maintain applicable LCR reliability criteria for these areas under four different RPS portfolios (i.e., trajectory, environmentally constrained, ISO base case, and time-constrained).
- The ISO also performed a reliability assessment for the zonal area, particularly for the South of Path 26 area. This assessment identified reliability concerns, particularly with a potential minimum level of OTC generation modeled in the studies. If reliability concerns were identified in the zonal area, potential mitigation measures were identified, either with generation or transmission solutions.

3.3.1.2 Screening Evaluation Using Load and Resources Tool

- ISO performed a load and resource evaluation using the tool to determine which years would have a deficiency of resources for local capacity areas as well as zonal areas (i.e., NP 26 and SP 26) or ISO balancing authority. For this effort, the ISO evaluated the unavailability of affected generating units based on the following: the compliance years set forth in the SWRCB policy; or the years generator owners identify in their implementation plans to come off-line to take steps to comply with the policy.
- In addition, the ISO also evaluated resource adequacy in the zonal or balancing authority using inputs from the results of the long-term LCR assessment (Step 1 above) to identify any resource concerns. This type of assessment is similar in concept to the annual summer assessment that the ISO performs.

3.3.1.3 Evaluation of Potential Reliability Mitigations

The following potential mitigation measures were evaluated on a high level in order to maintain local or zonal reliability:

- identifying generation need;
- identifying potential transmission mitigation measures; and
- identifying potential demand side management or other contracted resources such as combined heat and power.

3.3.2 Once Through Cooling Reliability Assessment – Study Results

In this section, the following assessment results are reported:

- Reliability assessment of the local capacity requirement (LCR) areas that have once-through cooling power plants — this includes the Greater Bay Area, Big Creek/Ventura, Los Angeles Basin and San Diego. The purpose of this study is to identify whether there is a reliability need to run OTC plants, and if there is, what OTC generation level is needed.
- Transient stability assessment for on-peak and off-peak load conditions — for on-peak load conditions, the assessment was performed for the trajectory and environmentally constrained RPS portfolios. For the off-peak conditions, the assessment was performed for the environmentally constrained portfolio to determine if this portfolio, with significantly more distributed generation modeled, would still meet the WECC transient stability reliability criteria.
- Loads and resource assessment for zonal (NP26 and SP26) and ISO balancing authority — this assessment provides preliminary long-term evaluation of the adequacy of future generation to serve loads in the 2021 time frame under two load scenarios, 1-in-2 year and 1-in-10 year heat wave load conditions. This is similar to the ISO annual summer assessment, except that it looks ten years into the future, whereas the annual summer assessment evaluates the adequacy of resources for the next summer condition.

3.3.2.1 New Conventional Generation and Major Transmission Projects Assumed in the Studies

The starting power flow base cases were obtained from the power flow base cases for the four RPS portfolios: trajectory, environmentally constrained, ISO base case and time-constrained. These cases were then stressed further to include 1-in-10 heat wave load projection for the LCR areas under evaluation. Utilizing the same study process from the annual LCR studies, the following LCR areas that have OTC generation were modeled with 1-in-10 year heat wave load projections:[20]

- Greater Bay Area;
- Big Creek/Ventura Area; and
- Southern California Area (for studying LA Basin and San Diego areas).

Since the study base cases started with the RPS study cases, they have the same assumptions of the new conventional generation and major transmission projects. Please refer to the policy-driven write-up for details on these new conventional generation and major transmission project assumptions.

[20] The 1-in-10 year heat wave load projections were obtained from the official CEC-adopted demand forecast, which is the 2009 CEC-adopted demand forecast. A review of the CEC's 2011 preliminary demand forecast indicates that the long-term forecast is actually similar to or higher than the 2009 adopted forecast for the high net load conditions.

3.3.2.2 *Summary of Study Results*

In this section, the following study results are summarized:

- LCR assessment for the four local areas having once-through cooling generation: Greater Bay Area, Big Creek/Ventura, LA Basin and San Diego;
- transient stability assessment for trajectory and environmentally constrained RPS portfolios at peak load conditions and for environmentally constrained portfolio at off-peak load conditions; and
- preliminary supply and demand outlook assessment in 2021 for trajectory and time-constrained RPS portfolios for 1-in-10 year and 1-in-2 year heat wave load projections.

LCR Study Results

Detailed LCR assessments are discussed further in the following sections. Table 3.3-1 provides a summary of generation requirements in the main LCR areas where OTC generating units are currently located. Both distributed generation and non-distributed generation (i.e., centralized generating stations) are listed. The total generation requirements include both generation categories. If distributed generation does not materialize as indicated, its projected capacity needs to be replaced with other generation with equivalent capacity level.

Table 3.3-1: Summary of long-term (2021) LCR study results

<table>
<tr><th rowspan="2">LCR Area</th><th colspan="4">Local Capacity Requirements (MW)</th><th colspan="4">New Generation Need? #
If Yes, Range of New Generation Need (MW)</th></tr>
<tr><th>Trajectory</th><th>Environmentally Constrained</th><th>ISO Base Case</th><th>Time Constrained</th><th>Trajectory</th><th>Environmentally Constrained</th><th>ISO Base Case</th><th>Time Constrained</th></tr>
<tr><td>Greater Bay Area</td><td>5,773</td><td>4,728</td><td>5,778</td><td>6,572</td><td colspan="4">No</td></tr>
<tr><td rowspan="2">Big Creek/Ventura (BC/V) Area</td><td rowspan="2">2,371</td><td rowspan="2">2,604</td><td rowspan="2">2,438</td><td rowspan="2">2,653</td><td colspan="4">Yes (for Moorpark, a sub-area of the Big Creek/Ventura LCR area)</td></tr>
<tr><td>430</td><td>430</td><td>430</td><td>430</td></tr>
<tr><td>LA Basin (this area includes sub-area below)</td><td>13,300</td><td>12,567</td><td>12,930</td><td>13,364</td><td rowspan="2">2,370 – 3,741</td><td rowspan="2">1,870 – 2,884</td><td rowspan="2">2,424 – 3,834</td><td rowspan="2">2,460 – 3,896</td></tr>
<tr><td>Western LA Basin (sub-Area of the larger LA Basin)</td><td>7,797</td><td>7,564</td><td>7,517</td><td>7,397</td></tr>
<tr><td>San Diego / Imperial Valley (this area includes sub-area below)</td><td>3,291</td><td>3,104</td><td>2,968</td><td>3,272</td><td colspan="4">Yes (*Lower values correspond to new generation need # when including SDG&E-proposed generation for LTPP)</td></tr>
<tr><td>San Diego **</td><td>2,883</td><td>2,854</td><td>2,864</td><td>2,856</td><td>531* - 950</td><td>231*- 650</td><td>231*- 650</td><td>421*- 840</td></tr>
</table>

Notes: *Lower values correspond to new generation need when including SDG&E-proposed generation for Long Term Power Plan (LTPP) process
** Load curtailment of 366 MW is included for G-1/N-2 contingency (Otay Mesa / Sunrise + SWPL outage)
# New generation need (i.e., repowering) assuming existing OTC generation is to retire

Transient Stability Assessments

A key concern is whether future generation portfolios that include significant penetration of renewable generation, coupled with potential shutdown or retirement of some OTC generating units would contribute to the deterioration of inertia needed to maintain transient stability under critical contingencies. To address this concern, the ISO performed dynamic stability assessments for the trajectory study case for the peak load and for the environmentally constrained study cases for the peak load and off-peak load conditions. A minimum amount of OTC generation was modeled for these study cases. Environmentally constrained study cases represent stressed cases because of the presence of significant amount of distributed generation (i.e., photovoltaic generation) and less conventional generation than other portfolios.

The following tables provide summaries of transient stability study results. Critical contingencies in the WECC system were performed to see whether system performance met WECC transient stability reliability criteria (refer to table 3.3-2).

Table 3.3-2: Summary of transient stability studies for peak load conditions

Contingencies	Trajectory Portfolio Case		Environmentally Constrained Case	
	Met WECC Voltage Criteria?	Met WECC Frequency Criteria?	Met WECC Voltage Criteria?	Met WECC Frequency Criteria?
Diablo G-2	√	√	√	√
Diablo – Midway 500kV N-2	√	√	√	√
IPPDC Bi-polar	√	√	√	√
Los Banos North 500kV N-2	√	√	√	√
Los Banos South 500kV N-2	√	√	√	√
Lugo South 500kV N-2	√	√	√	√
Lugo – Vincent 500kV N-2	√	√	√	√
Midway-Vincent 500kV N-2	√	√	√	√
PDCI Bipolar	√	√	√	√
Palo Verde G-2	√	√	√	√
SONGS G-2	√	√	√	√
Table Mtn.-Tesla+VacaDixon-Tesla 500kV N-2	√	√	√	√
Sunrise + SWPL N-2	√	√	√	√
Vincent – Antelope 500kV N-2	√	√	√	Does not meet for Correct 66kV substation

Table 3.3-3: Summary of transient stability study results for off-peak load conditions

Contingencies	Environmentally Constrained Case	
	Met WECC Voltage Criteria?	Met WECC Frequency Criteria?
Diablo G-1	√	√
Diablo – Midway 500kV N-2	√	√
IPPDC Bi-polar	√	√
Tesla – Metcalf 500kV line	√	√
Vincent – Antelope 500kV N-2	√	√
Lugo South 500kV N-2	√	√
Lugo – Vincent 500kV N-2	√	√
Midway-Vincent 500kV N-2	√	√
PDCI Bipolar	√	√
Palo Verde G-2	√	√
SONGS G-1	√	√
Vincent – Mesa 230kV N-2	√	√
Sunrise + SWPL N-2	√	√

Based on the results above, the studied portfolios with minimum OTC generation met WECC transient stability reliability criteria. The environmentally constrained portfolio for the peak load conditions did result in a frequency excursion beyond the WECC minimum frequency limit (i.e., 59.0 Hz) for one sub-transmission load substation in the SCE service territory. However, the frequency excursion occurred for a radial load system and did not affect network facilities.

Estimated Summer 2021 Supply and Demand Outlook

To address concerns as to whether generation supplies are adequate for zonal areas (i.e., NP26 or SP26) or ISO balancing authority in the long-term (i.e., 2021 time frame), an estimated supply and demand assessment was performed for two load conditions: 1-in-2 and 1-in-10 heat wave load projections. This approach is similar to the ISO annual summer assessment in which a supply and demand outlook is provided for the next summer. The difference is that this provides a long-term outlook compared to the short-term outlook provided under the annual summer assessment. In addition, the assessment reported here is based on import assumptions using projected 2021 Maximum Import Capability (MIC). The 2021 long-term assessment is considered informational only because the official long-term supply and demand outlook is typically carried out under the CPUC Long-Term Procurement Plan (LTPP) process with significant participation from various stakeholders. The ISO assessment is intended to be used for informational purposes to provide an indication of potential trends or areas of concerns for stakeholders to investigate further in future regulatory or planning studies.

The following tables are summaries for the summer 2021 supply and demand outlook for the trajectory portfolio for the 1-in-2 and 1-in-10 heat wave load projections with projected 2021 MIC import assumption. From these assessments, it appears that there is no resource deficiency identified for 1-in-2 heat wave load projections. For 1-in-10 heat wave load projections, it appears that the operating reserve margins for ISO system and SP26 zonal areas are thin at about 3%.

Table 3.3-4: Estimated summer 2021 supply and demand outlook (1-in-10 load conditions) — trajectory portfolio with 2021 MIC estimates

Summer 2021 Loads and Resources Outlook - Trajectory Portfolio

1-in-10 Demand and 1-in-10 Generation & Transmission Outage Scenarios

Summer 2021 Outlook - RA Imports (Using Projected MIC for ISO BAA)			
Resource Adequacy Conventions	ISO (MW)	SP26 (MW)	NP26 (MW)
Existing Generation (2012 NQC)	50,427	24,677	25,750
Retirements			
(Known & OTC Gen determined not needed for LCR Area)	(8,939)	(5,106)	(3,833)
High Probability Capacity Additions			
(thermal generation under construction or have PPA)	5,305	2,009	3,296
Total Projected Renewable Generation Additions			
(NQC Values)	8,920	6,936	1,984
- Wind Generation	809	638	171
- Non-Wind Renewable Generation	8,111	6,298	1,813
Hydro Derates - only used for drough year	0	0	0
Outages (1-in-10 Generation & Transmission)	(6,844)	(3,872)	(3,616)
Net Interchange	11,225	10,132	4,843
Total Net Supply (MW)	60,093	34,776	28,424
DR & Interruptible Programs (use 2012 figures)	2,296	1,721	576
Demand (1-in-10 summer temperature)	60,773	35,507	26,760
Surplus/(Deficiency) (MW)	1,616	990	2,239
Operating Reserve Margin	2.7%	2.8%	8.4%

Table 3.3-5: Estimated summer 2021 supply and demand outlook (1-in-2 load conditions) – trajectory portfolio with 2021 MIC estimates

Summer 2021 Loads and Resources Outlook - Trajectory Portfolio

1-in-2 Demand and 1-in-2 Generation & Transmission Outage Scenarios

Summer 2021 Outlook - RA Imports (Using Projected MIC for ISO BAA)			
Resource Adequacy Conventions	ISO (MW)	SP26 (MW)	NP26 (MW)
Existing Generation (2012 NQC)	50,427	24,677	25,750
Retirements			
(Known & OTC Gen determined not needed for LCR Area)	(8,939)	(5,106)	(3,833)
High Probability Capacity Additions			
(thermal generation under construction or have PPA)	5,305	2,009	3,296
Total Projected Renewable Generation Additions			
(NQC Values)	8,920	6,936	1,984
- Wind Generation	809	638	171
- Non-Wind Renewable Generation	8,111	6,298	1,813
Hydro Derates - only used for drough year	0	0	0
Outages (1-in-2 Generation & Transmission)	(4,698)	(2,033)	(2,677)
Net Interchange	11,225	10,132	4,843
Total Net Supply (MW)	62,239	36,615	29,363
DR & Interruptible Programs (use 2012 figures)	2,296	1,721	576
Demand (1-in-2 summer temperature)	56,029	32,467	24,940
Surplus/(Deficiency) (MW)	8,507	5,869	4,999
Operating Reserve Margin	15.2%	18.1%	20.0%

Conclusions

To evaluate the reliability impacts to ISO controlled grid due to implementation of the SWRCB's Policy on Once through Cooling Plants (the Policy), various assessments were performed for local reliability areas, zonal areas and ISO Balancing Authority Area (BAA). Once-through cooling generation need was determined for the local reliability areas and served as foundational OTC generation need before zonal and ISO BAA assessments.

1. Local area assessments:

Reliability assessments using LCR methodology were performed for the local reliability areas that have OTC generation to determine grid reliability impacts to these areas and subsequently the ranges of once-through cooling generation needed for maintaining local reliability. The local areas that currently have OTC generation that are subject to the SWRCB's Policy include the Greater Bay Area, Big Creek/Ventura, Los Angeles Basin and San Diego areas. The generation owners of the OTC plants in these areas have submitted their implementation plans to the SWRCB, but because these plans are still uncertain subject to whether they will receive long-term Power Purchase Agreements (PPAs) or whether these plans will receive permit for construction from the CEC, the ISO provided the results of OTC generation need in ranges for the LCR areas. The low level of the range corresponds to the generation located in more effective locations, and vice versa for the high level need. If a sub-area has only one OTC generation power plant, then the reporting would be done without the ranges (i.e., Moorpark sub-area of the Big Creek/Ventura area). If the OTC generation was considered alongside an LSE-proposed generation development plan, the ranges include the OTC generation need with and without the LSE's new generation plan (i.e., San Diego area).

The following table summarizes the ranges of OTC generation need for studied LCR areas. The generation at the existing OTC generation locations can comply with the SWRCB's Policy by either repowering or replacement with Best Technology Available (BTA) cooling technology (i.e., closed cycle wet cooling). The other option, which is yet to be considered and approved by the SWRCB, is implementing Track 2 option, which would involve reducing impacts to aquatic life by other means.

Table 3.3-6 – Summary of OTC Generation Need

LCR Area	Trajectory (MW)	Environmentally Constrained (MW)	ISO Base Case (MW)	Time Constrained (MW)	Notes
Greater Bay Area	0	0	0	0	No OTC generation need identified
Big Creek/Ventura (Moorpark Sub-area)	430	430	430	430	
West LA Basin / LA Basin	2,370 – 3,741	1,870 – 2,884	2,424 – 3,834	2,460 – 3,896	W. LA Basin is part of larger LA Basin
San Diego	531* - 950	231*-650	231*-650	421*-840	*The lower range corresponds to the use of SDG&E-proposed generation included in its LTPP to the CPUC

2. Zonal Area and ISO BAA Resource Assessment

After evaluation of the local areas, the ISO performed loads and resource assessments for zonal areas (i.e., NP26, SP26) and ISO BAA under one-in-two and one-in-ten year heat wave load conditions. The objective of these assessments is to identify any resource concerns for zonal areas and ISO BAA, similar to the ISO annual summer assessment. The ISO included in these resource assessments the needed OTC generation capacity, identified in the individual LCR assessments. In these assessments, only the lower ranges of OTC generation were included. If the OTC generation was to be repowered at less effective locations, then higher ranges of OTC generation, as identified in the above table, would need to be updated for the zonal and ISO BAA loads and resource assessments. For the OTC generation that was not identified as needed for the LCR areas, it was included as potential retirement generation (or unavailable generation) due to uncertainty in obtaining long-term PPA from the LSEs. Four RPS portfolios were evaluated, but the resource concerns for SP26 were identified for the trajectory and time-constrained portfolios. Based on the results in Tables 3.3-4 and 3.3-5, the following potential resource concerns for the ISO BAA and SP26 for the trajectory RPS portfolio were identified:

- For 1-in-10 heat wave load projections, it appears that the operating reserve margins for ISO system and SP26 zonal areas are thin at about 3%, which is a threshold value in which load curtailment may be needed if the margins are declining further.

3. Transient Stability Assessment

Transient stability studies were performed and the following were found:

- System response met WECC reliability criteria for trajectory portfolio under peak load conditions for critical contingencies; for environmentally constrained portfolio, a radial load bus in SCE was found to be outside of WECC frequency limit criteria. However, this is still acceptable as it does not cause transient stability impact to other areas other than this radial facility.
- System response met WECC reliability criteria for environmentally constrained portfolio under off-peak load conditions for critical contingencies.

The studies described here were intended to identify capacity needs for meeting applicable reliability planning purposes. For operational needs, such as ramping and regulation, the reader is advised to follow the ISO renewable integration study work for those requirements.

3.3.2.3 Detailed LCR Studies

The starting power flow cases originated from the policy-driven cases for the four RPS portfolios: trajectory, environmentally constrained, ISO base case and time-constrained. These power flow cases were then adjusted further to have 1-in-10 year heat wave loads for Greater Bay Area, Big Creek/Ventura, LA Basin and San Diego.[21] Since LA Basin and San Diego areas peak almost at the same time, these two areas share common study cases with 1-in-10 heat wave load projection.

Because the LCR power flow cases originated from the policy-driven power flow cases, they have the same major new transmission and conventional generation projects.

The following once-through cooling generating units were assumed to be in service in the starting LCR study cases:

- Diablo Canyon and San Onofre Nuclear Generating Station: The SWRCB has a separate but parallel process for review of the nuclear power plant compliance with the OTC policy. This process, overseen by the SWRCB's Review Committee, requires special studies to be performed by an independent third party to evaluate various compliance options and associated costs. The special studies report is required to be submitted to the SWRCB by October 1, 2013.
- Moss Landing Units 1 and 2: These are relatively new combined cycled power plants that came on line in 2002. Similar to other new combined cycled projects, these power plants are efficient in running generation. When these power plants went through the CEC environmental review process, other cooling technology options were evaluated, but they were rejected because they were deemed environmentally infeasible.[22] The CEC approved the environmental permit for Dynegy to proceed with construction of the power plants. As part of its implementation plan submittal to the SWRCB on April 1, 2011, Dynegy claimed that it employs best technology available for cooling of the plant, which is yet to be resolved and agreed to by the SWRCB.

3.3.2.3.1 LCR Study Results — Greater Bay Area

To determine whether OTC generation is needed, and if it is, what level would be required for the Greater Bay Area in 2021, an LCR analysis was performed for the four RPS portfolios. The following area and sub-areas were examined for generation requirements:

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[21] The ISO uses the latest CEC-adopted load forecast for LCR studies. The latest Commission-adopted forecast is obtained from the 2009 adopted demand forecast. The CEC's 2011 demand forecast is preliminary and is not yet adopted by the Commission. For long-term forecast (i.e., ten years out), based on the CEC preliminary forecast for each respective utilities, the new forecast is either similar or higher than the 2009 adopted forecast for 1-in-2 heat wave load projection (http://www.energy.ca.gov/2011publications/CEC-200-2011-011/CEC-200-2011-011-SD.pdf)

[22] See Table 1 in the following document: (http://www.swrcb.ca.gov/water_issues/programs/ocean/cwa316/powerplants/moss_landing/docs/ml_ip2011attch_c.pdf)

- San Francisco sub-area;
- San Jose sub-area;
- Peninsula sub-area;
- Mission sub-area;
- East Bay sub-area;
- Diablo sub-area;
- DeAnza sub-area; and
- Overall GBA area.

None of the areas was determined to have any need for OTC generation.

Area Definition for Greater Bay Area

The transmission tie lines into the Greater Bay Area are as follows:

1. Lakeville-Sobrante 230 kV line;
2. Ignacio-Sobrante 230 kV line;
3. Parkway-Moraga 230 kV line;
4. Bahia-Moraga 230 kV line;
5. Lambie SW Sta-Vaca Dixon 230 kV line;
6. Peabody-Birds Landing SW Sta 230 kV line;
7. Tesla-Kelso 230 kV line;
8. Tesla-Delta Switching Yard 230 kV line;
9. Tesla-Pittsburg #1 230 kV line;
10. Tesla-Pittsburg #2 230 kV line;
11. Tesla-Newark #1 230 kV line;
12. Tesla-Newark #2 230 kV line;
13. Tesla-Ravenswood 230 kV line;
14. Tesla-Metcalf 500 kV line;
15. Moss Landing-Metcalf 500 kV line;
16. Moss Landing-Metcalf #1 230 kV line;
17. Moss Landing-Metcalf #2 230 kV line;
18. Oakdale TID-Newark #1 115 kV line; and
19. Oakdale TID-Newark #2 115 kV line.

The substations that delineate the Greater Bay Area are as follows:

1. Lakeville is out, Sobrante is in;
2. Ignacio is out, Crocket and Sobrante are in;
3. Parkway is out, Moraga is in;
4. Bahia is out, Moraga is in;
5. Lambie SW Sta is in, Vaca Dixon is out;
6. Peabody is out, Birds Landing SW Sta is in;
7. Tesla and USWP Ralph are out, Kelso is in;
8. Tesla and Altmont Midway are out, Delta Switching Yard is in;
9. Tesla and Tres Vaqueros are out, Pittsburg is in;
10. Tesla and Flowind are out, Pittsburg is in;
11. Tesla is out, Newark is in;
12. Tesla is out, Newark and Patterson Pass are in;
13. Tesla is out, Ravenswood is in;
14. Tesla is out, Metcalf is in;
15. Moss Landing is out, Metcalf is in; and
16. Oakdale TID is out, Newark is in;

Total 2021 bus load within the defined area is 10,700 MW. Each RPS portfolio has different line losses. The following Table 3.3-7 is a Greater Bay Area load and resource summary for all four portfolios.

Table 3.3-7: Loads and resource summary in GBA

Itemized Details	Trajectory (MW)	Environmentally Constrained (MW)	ISO Base Case (MW)	Time-Constrained (MW)
Total 1-in-10 Load + losses	10,949	10,920	10,951	10,938
Generation				
Existing Non NQC (2012)	5,285			
Existing OTC Capacity (2012)	1,303			
New Generation	2,308			
Distributed Generation	43	892	101	269

Critical Contingency Analysis Summary

Sub Areas

Each sub-area was evaluated for its own LCR, and the corresponding requirements were incorporated into the overall Greater Bay Area.

Since no OTC generation is needed in the sub-areas, the OTC need was then evaluated for the overall Greater Bay Area.

Overall Greater Bay Area

The most critical contingency for the overall Greater Bay Area is common for all four RPS scenarios, namely the environmental, base, trajectory and time-constrained portfolios. The outage is a combination of N-1/G-1 with Tesla-Metcalf 500 kV line and Delta Energy Center. The limiting element is a voltage collapse condition.

This common constraint establishes the following LCR for the four portfolios:

Table 3.3-8: LCR for the four portfolios in the Greater Bay Area

Portfolio	LCR (MW)
Trajectory	5,773
Environmental	4,728
Base	5,778
Time	6,572

LCR Summary by Portfolios

The following table summarizes the OTC and LCR requirements for each portfolio. The table also lists the worst contingencies and limiting elements.

Table 3.3-9: Trajectory portfolio — LCR and OTC requirements in the Greater Bay Area

Portfolios	Area	LCR			Existing OTC Units Needed?	Constraint	Contingency
		Non-D.G. (MW)	D.G. (MW)	Total (MW)			
ISO Base case	GBA	5,677	101	5,778	No	Voltage Collapse	Tesla-Metcalf 500kV Line + DEC
Environmentally constrained		3,836	892	4,728	No		
Time-constrained		6,303	269	6,572	No		
Trajectory		5,730	43	5,773	No		

Conclusions

It was determined that there is no need for OTC generation across all four RPS portfolios. Table 3.3-10 below is a summary of LCR and OTC generation requirements for the overall Greater Bay Area.

Table 3.3-10: Summary of LCR and OTC requirements in Greater Bay Area

LCR Area	Trajectory (MW)	Environmentally constrained (MW)	ISO Base Case (MW)	Time-constrained (MW)
Overall GBA	5,773	4,728	5,778	6,572
OTC Gen. Need	0	0	0	0

3.3.2.3.2 LCR Study Results — LA Basin Area

To determine the level of OTC generation requirements for the LA Basin in 2021, an LCR study was performed for the four RPS portfolios. The following areas and sub-areas were examined for generation requirements:

- Overall LA Basin;
- Western LA Basin;
- Ellis sub-area; and
- El Nido sub-area.

The Western LA Basin and Ellis sub-area drive the need for OTC units. The Ellis sub-area needs these units to mitigate a voltage collapse issue. The Western LA area needs these units to mitigate an overloading issue. The overall LA Basin generation requirements also incorporate the need for this OTC generation.

Area Definition for Overall LA Basin

The transmission tie lines into the LA Basin are:

1. San Onofre-San Luis Rey #1, #2, and #3 230 kV lines;
2. San Onofre-Talega 230 kV line;
3. San Onofre-Capistrano 230 kV line;
4. Lugo-Mira Loma #2 & #3 500 kV lines;
5. Lugo-Rancho Vista #1 500 kV line;
6. Sylmar-Eagle Rock 230 kV line;
7. Sylmar-Gould 230 kV line;
8. Vincent-Mesa Cal #1 and #2 230 kV lines;
9. Vincent-Rio Hondo #1 and #2 230 kV lines;
10. Devers-Red Bluff #1 and #2 500 kV lines;

11. Mirage-Coachella valley 230 kV line;
12. Mirage-Ramon 230 kV line; and
13. Mirage-Julian Hinds 230 kV line.

These sub-stations form the boundary surrounding the LA Basin:

1. San Onofre is in, San Luis Rey is out;
2. San Onofre is in, Talega is out;
3. San Onofre is in, Capistrano is out;
4. Mira Loma is in, Lugo is out;
5. Rancho Vista is in, Lugo is out;
6. Eagle Rock is in, Sylmar is out;
7. Gould is in, Sylmar is out;
8. Mesa Cal is in, Vincent is out;
9. Rio Hondo is in, Vincent is out;
10. Devers is in, Red Bluff is out;
11. Mirage is in, Coachella Valley is out;
12. Mirage is in, Ramon is out; and
13. Mirage is in, Julian Hinds is out.

The total 2021 substation load (bus bar level) within the defined area is 22,686 MW. Each portfolio has different losses. The following table is the LA Basin load and resource summary for all four portfolios.

Table 3.3-11: Loads and resource summary in LA Basin area

Itemized Details	Trajectory (MW)	Environmentally Constrained (MW)	ISO Base Case (MW)	Time-Constrained (MW)
Total 1-in-10 Load + losses	22,867	22,838	22,872	22,862
Generation				
Existing NQC (2012)	12,083			
Existing OTC Capacity (2012)	5,166			
Distributed Generation	339	1,519	271	687

Critical Contingency Analysis Summary

Overall LA Basin

The most critical contingency for the overall LA Basin for all four portfolios is an N-1/T-1 contingency of Chino-Mira Loma East #3 500 kV line and Mira Loma West 500/230 kV bank #2. The limiting element is Mira Loma West 500/230 kV bank #1 (24-hour rating). This constraint establishes the LCR numbers for the four RPS portfolios in Table 3.3-14 below:

Table 3.3-12: LCR for overall LA Basin with contingency affecting Mira Loam AA transformers

Portfolio	LCR (MW)
Trajectory	13,300
Environmental	12,567
Base	12,930
Time	13,364

Mira Loma West 500/230 kV bank #1 has a 1-hour emergency rating. This emergency rating can be utilized by assuming up to 600 MW of either load curtailment or load transfer within 1 hour. If this mitigation is feasible, the next worst contingency for the overall LA Basin area is the outage of Sylmar S-Gould 230 kV line and Lugo-Victorville 500 kV line. The limiting element is Eagle Rock-Sylmar S 230 kV line. This constraint establishes LCR numbers for the four RPS portfolios as noted in the table below:

Table 3.3-13: LCR for overall LA Basin with contingency affecting Eagle Rock – Sylmar 230kV line

Portfolio	LCR (MW)
Trajectory	10,743
Environmental	11,246
Base	11,010
Time	12,165

Generation Effectiveness Factors

The following table shows units that have at least 5 percent effectiveness on the Eagle Rock-Sylmar 230 kV line constraint for the overall LA Basin.

Table 3.3-14: Units with at least 5 percent effectiveness on Eagle Rock-Sylmar 230 kV line constraint for overall LA Basin

Generator	Eff. Factor (%)
PASADNA1 13.8 #1	24
PASADNA2 13.8 #1	24
BRODWYSC 13.8 #1	24
MALBRG3G 13.8 #S3	15
MALBRG2G 13.8 #C2	15
MALBRG1G 13.8 #C1	15
CHEVGEN1 13.8 #1	13
CHEVGEN2 13.8 #2	13
MOBGEN1 13.8 #1	13
MOBGEN2 13.8 #1	13
LA FRESA 66.0 #10	13
NRG ELS7 18.0 #7	13
NRG ELG5 18.0 #5	13
NRG ELG6 18.0 #6	13
ARCO 5G 13.8 #5	12
ARCO 1G 13.8 #1	12
ARCO 2G 13.8 #2	12
ARCO 3G 13.8 #3	12
ARCO 4G 13.8 #4	12
ARCO 6G 13.8 #6	12
LBEACH34 13.8 #3	12
LBEACH34 13.8 #4	12
LBEACH12 13.8 #2	12
LBEACH12 13.8 #1	12
HARBOR G 13.8 #1	12
HARBOR G 13.8 #HP	12
CARBGEN1 13.8 #1	12
HINSON 66.0 #1	12
THUMSGEN 13.8 #1	12
CARBGEN2 13.8 #1	12
HARBOR 230.0 #F1	12
BRIGEN 13.8 #1	11
CTRPKGEN 13.8 #1	11
SIGGEN 13.8 #D1	11
ALMITOSW 66.0 #D3	10
ALAMT1 G 18.0 #1	9
ALAMT2 G 18.0 #2	9
ALAMT3 G 18.0 #3	9
HILLGEN 13.8 #D1	9
EME WCG1 13.8 #1	9

Generator	Eff. Factor (%)
EME WCG3 13.8 #1	9
EME WCG4 13.8 #1	9
EME WCG5 13.8 #1	9
EME WCG2 13.8 #1	9
ELLIS 66.0 #12	8
ELLIS 66.0 #11	8
HUNT1 G 13.8 #1	8
HUNT2 G 13.8 #2	8
BARRE 66.0 #11	8
BARRE 66.0 #10	8
BARPKGEN 13.8 #1	7
SANTIAGO 66.0 #1	7
COYGEN 13.8 #1	7
ANAHEIMG 13.8 #1	6
S.ONOFR2 22.0 #2	5
S.ONOFR3 22.0 #3	5
CHINO 66.0 #E1	5
DELGEN 13.8 #1	5
DELGEN 13.8 #1	5
SANIGEN 13.8 #D1	5
CIMGEN 13.8 #D1	5
SIMPSON 13.8 #D1	5

OTC Generation Needed

The need for OTC units in the overall LA Basin area is established specifically by the Western LA Basin and Ellis sub-areas. The following table establishes the lower range of OTC generation capacity is required across all four portfolios to mitigate respective reliability issues in areas. Lower ranges of OTC generation requirements correspond to OTC generation located in more effective locations. This OTC capacity is counted toward the total LCR need for the overall LA Basin. The OTC requirements for the overall LA Basin by portfolios are as noted in the following table:

Table 3.3-15: OTC requirements for overall LA Basin to mitigate reliability issues

Portfolio	Min OTC Need (MW)
Trajectory	2,370
Environmental	1,870
Base	2,424
Time	2,460

Western LA Basin Sub-Area

Area Definition for Western LA Basin

The transmission tie lines into the LA Basin are:

1. San Onofre - San Luis Rey #1, #2, and #3 230 kV Lines
2. San Onofre - Talega #1 and #2 230 kV Lines
3. Serrano – Lewis #1 and #2 230 kV Lines
4. Serrano – Villa PK #1 and #2 230 kV Lines
5. Mira Loma – Walnut 230 kV Line
6. Mira Loma – Olinda 230 kV Line
7. Sylmar - Eagle Rock 230 kV Line
8. Sylmar - Gould 230 kV Line
9. Vincent - Mesa Cal #1 and #2 230 kV Line
10. Vincent - Rio Hondo #1 and #2 230 kV Line

The most critical contingency for the Western sub-area is the loss of Serrano-Villa Park #1 or #2 230 kV line followed by the loss of the Serrano-Lewis 230 kV line or vice versa, which would result in thermal overload of the remaining Serrano-Villa Park 230 kV line. This constraint establishes the LCR numbers for the four RPS portfolios as listed in the table below:

Table 3.3-16: LCR for Western LA Basin with identified contingencies

Portfolio	LCR (MW)
Trajectory	7,797
Environmental	7,584
Base	7,517
Time	7,397

Generation Effectiveness Factors

The following table shows generating units that have at least 5 percent effectiveness on Serrano-Villa Park 230 kV line constraint for Western LA Basin.

Table 3.3-17: Units with at least 5% effectiveness on Serrano-Villa Park 230 kV line constraint for Western LA Basin

Generator	Eff. Factor (%)
BARPKGEN 13.8 #1	32
BARRE 66.0 #11	32
BARRE 66.0 #10	32
ANAHEIMG 13.8 #1	32
ALAMT5 G 20.0 #5	24
ALAMT6 G 20.0 #6	24
ALAMT3 G 18.0 #3	24
ALAMT4 G 18.0 #4	24
ALAMT1 G 18.0 #1	23
ALAMT2 G 18.0 #2	23
ALMITOSW 66.0 #D3	23
ALMITOSW 66.0 #D2	23
ALMITOSW 66.0 #D1	23
ALAMT7 G 16.0 #R7	23
HUNT1 G 13.8 #1	23
HUNT2 G 13.8 #2	23
ORCOGEN 13.8 #1	23
ELLIS 66.0 #12	23
ELLIS 66.0 #11	23
ELLIS 66.0 #10	23
SANTIAGO 66.0 #1	17
COYGEN 13.8 #1	17
LITEHIPE 66.0 #10	16
BRIGEN 13.8 #1	16
LBEACH5G 13.8 #R5	16
LBEACH6G 13.8 #R6	16
LBEACH7G 13.8 #R7	16
HARBOR 230.0 #F1	16
HARBOR G 13.8 #1	15
HARBOR G 13.8 #HP	15
HINSON 66.0 #D8	15
HINSON 66.0 #D7	15
HINSON 66.0 #D6	15

Generator	Eff. Factor (%)
HINSON 66.0 #D4	15
HINSON 66.0 #D3	15
HINSON 66.0 #D1	15
CARBGEN1 13.8 #1	15
SERRFGEN 13.8 #D1	15
THUMSGEN 13.8 #1	15
CARBGEN2 13.8 #1	15
HINSON 66.0 #1	15
LBEACH12 13.8 #2	15
LBEACH34 13.8 #3	15
LBEACH8G 13.8 #R8	15
LBEACH9G 13.8 #R9	15
LBEACH34 13.8 #4	15
LBEACH12 13.8 #1	15
ARCO 1G 13.8 #1	15
ARCO 2G 13.8 #2	15
ARCO 3G 13.8 #3	15
ARCO 4G 13.8 #4	15
ARCO 5G 13.8 #5	15
ARCO 6G 13.8 #6	15
CENTER 66.0 #D1	15
SIGGEN 13.8 #D1	15
CTRPKGEN 13.8 #1	15
LCIENEGA 66.0 #D1	14
VENICE 13.8 #1	14
MOBGEN1 13.8 #1	14
OUTFALL1 13.8 #1	14
OUTFALL2 13.8 #1	14
PALOGEN 13.8 #D1	14
REDON1 G 13.8 #R1	14
REDON2 G 13.8 #R2	14
REDON3 G 13.8 #R3	14
REDON4 G 13.8 #R4	14
LA FRESA 66.0 #10	14

Generator	Eff. Factor (%)
LA FRESA 66.0 #D9	14
LA FRESA 66.0 #D8	14
LA FRESA 66.0 #D7	14
MOBGEN2 13.8 #1	14
CHEVGEN1 13.8 #1	14
CHEVGEN2 13.8 #2	14
ELSEG4 G 18.0 #4	14
ELSEG3 G 18.0 #3	14
REDON5 G 18.0 #5	14
REDON7 G 20.0 #7	14
REDON8 G 20.0 #8	14
REDON6 G 18.0 #6	14
NRG ELG5 18.0 #5	14
NRG ELG6 18.0 #6	14
NRG ELS7 18.0 #7	14
FEDGEN 13.8 #1	12
REFUSE 13.8 #D1	12
MALBRG3G 13.8 #S3	12
MALBRG2G 13.8 #C2	12
MALBRG1G 13.8 #C1	12
MESA CAL 66.0 #D7	11
BRODWYSC 13.8 #1	10
PASADNA1 13.8 #1	9
PASADNA2 13.8 #1	9
OLINDA 66.0 #1	7
EME WCG1 13.8 #1	7
EME WCG3 13.8 #1	7
EME WCG4 13.8 #1	7
EME WCG5 13.8 #1	7
EME WCG2 13.8 #1	7

OTC Generation Needed

The following lists the level of OTC generation capacity that is needed for the respective four RPS portfolios in order to mitigate the Serrano-Villa Park 230 kV constraint. These values correspond to the lower range of OTC generation need as they are located in more effective locations. The OTC requirements for the Western LA Basin are listed in the table below:

Table 3.3-18: OTC requirements for Western LA Basin to mitigate reliability issues

Portfolio	Minimum OTC Need (MW)
Trajectory	2,370
Environmental	1,870
Base	2,424
Time	2,460

Ellis Sub-Area

The most critical contingency for the Ellis sub-area is the loss of the Barre-Ellis 230 kV line followed by the loss of the Santiago-San Onofre #1 & #2 230 kV lines, which would cause voltage collapse

This constraint establishes the LCR numbers for the four RPS portfolios as noted in the table below:

Table 3.3-19: LCR for Ellis sub-area with identified contingencies

Portfolio	LCR (MW)
Trajectory	531
Environmental	597
Base	511
Time	556

Generation Effectiveness Factors

The generators inside the sub-area have the same effectiveness factors.

OTC Generation Needed

To mitigate voltage collapse issues in the Ellis sub-area, 450 MW of OTC are required in all four portfolios.

El Nido Sub-Area

The most critical contingency for this area in all four portfolios is an N-2 outage of La Fresa-Redondo #1 and #2 230 kV lines. The limiting element is La Fresa-Hinson 230 kV line. This constraint establishes the LCR numbers for the four RPS portfolios, as listed in the table below.

Table 3.3-20: LCR for El Nido sub-area with identified contingencies

Portfolio	LCR (MW)
Trajectory	619
Environmental	585
Base	568
Time	620

Generation Effectiveness Factors

The generators inside the sub-area have the same effectiveness factors.

OTC Generation Needed

No OTC units are required to mitigate reliability concern in the El Nido sub-area.

LCR Summary by portfolios

The following four tables summarize the OTC and LCR requirements for each portfolio. The tables also list the worst contingencies and limiting elements.

Table 3.3-21: Trajectory portfolio — LCR and OTC requirements in LA Basin and its sub-areas

Portfolios	Area	LCR			Existing OTC Units Needed?	Constraint	Contingency
		Non-D.G. (MW)	D.G. (MW)	Total (MW)			
Trajectory	Overall LA Basin	12,961	339	13,300	Yes	Mira Loma West 500/230 Bank #1 (24-Hr rating) **	Chino-Mira Loma East #3 230 kV line + Mira Loma West 500/230 kV Bank #2
		10,404	339	10,743	Yes	Eagle Rock-Sylmar S 230 kV line	Sylmar S-Gould 230 kV line + Lugo-Victorville 500 kV line
	Western	7,529	268	7,797	Yes	Serrano-Villa PK #1	Serrano-Lewis #1 / Serrano-Villa PK #2
	Ellis	472	59	531	Yes	Voltage Collapse	Barre-Ellis 230 kV line + SONGS - Santiago #1 and #2 230 kV lines
	El Nido	614	5	619	No	La Fresa-Hinson 230 kV line	La Fresa-Redondo #1 and #2 230 kV lines

Table 3.3-22: Environmentally constrained portfolio — LCR and OTC requirements in LA Basin area and its sub-areas

Portfolios	Area	LCR Non-D.G. (MW)	LCR D.G. (MW)	LCR Total (MW)	Existing OTC Units Needed?	Constraint	Contingency
Environmentally Constrained	Overall LA Basin	11,048	1,519	12,567	Yes	Mira Loma West 500/230 bank #1 (24-Hr rating)**	Chino-Mira Loma East #3 23 0kV line + Mira Loma West 500/230 kV bank #2
		9,727	1,519	11,246	Yes	Eagle Rock-Sylmar S 230 kV line	Sylmar S - Gould 230 kV line + Lugo - Victorville 500 kV line
	Western	6,695	869	7,584	Yes	Serrano-Villa PK #1	Serrano-Lewis #1 / Serrano-Villa PK #2
	Ellis	473	124	597	Yes	Voltage Collapse	Barre-Ellis 230kV Line + SONGS - Santiago #1 and #2 230 kV lines
	El Nido	494	91	585	No	La Fresa-Hinson 230 kV line	La Fresa-Redondo #1 and #2 230 kV lines

Table 3.3-23: ISO Base portfolio — LCR and OTC requirements in LA Basin and its sub-areas

Portfolios	Area	LCR Non-D.G. (MW)	LCR D.G. (MW)	LCR Total (MW)	Existing OTC Units Needed?	Constraint	Contingency
Base	Overall LA Basin	12,659	271	12,930	Yes	Mira Loma West 500/230 Bank #1 (24-Hr rating) **	Chino-Mira Loma East #3 230 kV line + Mira Loma West 500/230 kV bank #2
		10,739	271	11,010	Yes	Eagle Rock-Sylmar S 230 kV line	Sylmar S-Gould 230kV line + Lugo-Victorville 500 kV line
	Western	7,325	192	7,517	Yes	Serrano-Villa PK #1	Serrano - Lewis #1 / Serrano - Villa PK #2
	Ellis	472	39	511	Yes	Voltage Collapse	Barre-Ellis 230kV Line + SONGS-Santiago #1 and #2 230 kV lines
	El Nido	544	94	568	No	La Fresa-Hinson 230 kV line	La Fresa-Redondo #1 and #2 230 kV lines

Table 3.3-24: Time-constrained portfolio — LCR and OTC requirements in LA Basin and its sub-areas

Portfolios	Area	LCR Non-D.G. (MW)	LCR D.G. (MW)	LCR Total (MW)	Existing OTC Units Needed?	Constraint	Contingency
Time-Constrained	Overall LA Basin	12,677	687	13,364	Yes	Mira Loma West 500/230 bank #1 (24-Hr rating) **	Chino - Mira Loma East #3 230 kV line + Mira Loma West 500/230 kV bank #2
		11,478	687	12,165	Yes	Eagle Rock-Sylmar S 230 kV Line	Sylmar S-Gould 230 kV line + Lugo-Victorville 500kV line
	Western	6,954	443	7,397	Yes	Serrano-Villa PK #1	Serrano-Lewis #1 / Serrano-Villa PK #2
	Ellis	495	61	556	Yes	Voltage Collapse	Barre - Ellis 230 kV line + SONGS-Santiago #1 and #2 230 kV lines
	El Nido	589	31	620	No	La Fresa-Hinson 230 kV line	La Fresa-Redondo #1 and #2 230 kV lines

Conclusions

The main drivers behind OTC generation need in the LA Basin are the Western LA Basin area and the Ellis sub-area. The OTC generation needed across all four portfolios ranges from 1,870 MW to 2,460 MW, assuming most effective units are selected. The ‘HIGH’ or ‘LOW’ OTC levels are determined by using less effective or more effective OTC units, respectively. The following table is a summary of LCR and OTC requirements for the overall LA Basin and sub-areas.

Table 3.3-25: Summary of LCR and OTC requirements in LA Basin and its sub-areas

LCR Area	Trajectory		Environmental		ISO Base Case		Time-Constrained	
	High (MW)	Low (MW)	High (MW)	Low (MW)	High (MW)	Low (MW)	High (MW)	Low (MW)
LA Basin	10,743	10,263	11,246	10,891	11,010	10,516	12,165	11,663
Western LA Basin	9,168	7,797	8,482	7,468	8,831	7,421	8,833	7,397
Ellis	531		597		511		556	
El Nido	619		585		568		620	
OTC	3,741	2,370	2,884	1,870	3,834	2,424	3,896	2,460

3.3.2.3.3 LCR Study Results — Big Creek/Ventura Area

To determine the OTC generation requirements for the Big Creek/Ventura area in 2021, an LCR study was performed for the four RPS portfolios. The following areas and sub-areas were examined for generation requirements:

- Overall Big Creek/Ventura;
- Moorpark sub-area;
- Rector sub-area; and
- Vestal sub-area.

Out of all these areas, only the Moorpark sub-area drives the need for OTC units. These OTC needs are also incorporated in the generation requirement for the overall Big Creek/Ventura area.

Area Definition for Big Creek

The transmission tie lines into the Big Creek/Ventura area are as follows:

1. Antelope 500/230kV banks #1 and #2;
2. Sylmar-Pardee #1 and #2 230 kV lines;
3. Vincent-Pardee #1 and #2 230 kV lines;
4. Vincent-Santa Clara 230 kV line.

These substations form the boundary surrounding the Big Creek/Ventura area:

1. Antelope 230 kV bus is in, Antelope 500 kV is out;
2. Pardee 230 kV bus is in, Sylmar 230 kV is out;
3. Pardee 230 kV bus is in, Vincent 230 kV is out; and
4. Santa Clara 230 kV bus is in, Vincent 230 kV is out.

The total 2021 substation load (bus bar level) within the defined area is 4,851 MW. Each portfolio has different line losses. Table 3.3-26 is the load and resource summary in the Big Creek/Ventura area for all four portfolios:

Table 3.3-26: Loads and Resource summary in Big Creek/Ventura area

Itemized Details	Trajectory (MW)	Environmentally Constrained (MW)	ISO Base Case (MW)	Time-Constrained (MW)
Total 1-in-10 Load + losses	4,947	4,946	4,948	4,942
Generation				
Existing NQC (2012)	5,232			
Existing OTC Capacity (2012)	2,075			
Distributed generation	4	419	61	95

Critical Contingency Analysis Summary

Overall Big Creek/Ventura Area

The most critical contingency for the overall Big Creek/Ventura area for the environmentally constrained and base portfolios is an N-1/T-1 contingency of Magunden-Omar 230 kV line and Antelope 500/230 kV bank #1 or #2. The limiting element is the remaining Antelope 500/230 kV bank. For the trajectory and time-constrained portfolios, the most critical contingency is the outage of Sylmar S-Pardee #1 or #2 line and Lugo-Victorville 230 kV line. The limiting element is the remaining Sylmar-Pardee 230 kV line. These two constraints establish the LCR numbers for the four portfolios as listed in the table below:

Table 3.3-27: LCR for overall Big Creek/Ventura area with identified contingencies

Portfolio	LCR (MW)
Trajectory	2,371
Environmental	2,604
Base	2,794
Time	2,653

Generation Effectiveness Factors

The following table shows units that have at least 5 percent effectiveness on Eagle Rock-Sylmar 230 kV constraint for the overall Big Creek/Ventura area:

Table 3.3-28: Units with at least 5% effectiveness on Eagle Rock-Sylmar 230 kV constraint for overall Big Creek/Ventura

Generation	Effectiveness Factor (%)
RECTOR 66.0 #10	46
LAKEGEN 13.8 #1	45
ULTRAGEN 13.8 #1	45
VESTAL 66.0 #10	45
VESTAL 66.0 #E1	45
PANDOL 13.8 #1	45
PANDOL 13.8 #2	45
B CRK3-1 13.8 #1	44
B CRK3-1 13.8 #2	44
B CRK3-2 13.8 #4	44
B CRK 8 13.8 #81	44
B CRK 8 13.8 #82	44
B CRK2-3 7.2 #5	44
B CRK2-3 7.2 #6	44
B CRK2-1 13.8 #1	43
B CRK2-1 13.8 #2	43
B CRK2-2 7.2 #3	43
B CRK2-2 7.2 #4	43
B CRK1-1 7.2 #1	43
B CRK1-1 7.2 #2	43
B CRK1-2 13.8 #3	43
B CRK1-2 13.8 #4	43
PORTAL 4.8 #1	43
EASTWOOD 13.8 #1	43
EDMON8AP 14.4 #13	35
EDMON8AP 14.4 #14	35
EDMON2AP 14.4 #2	35
EDMON1AP 14.4 #1	35
EDMON3AP 14.4 #3	35
PSTRIAG1 18.0 #G1	35
OSO A P 13.2 #1	34
OSO B P 13.2 #8	34
ALAMO SC 13.8 #1	34
WARNE1 13.8 #1	29
WARNE2 13.8 #1	29
SAUGUS 66.0 #11	23
SAUGUS 66.0 #10	23
TENNGEN1 13.8 #D1	23
TENNGEN2 13.8 #D2	23
PITCHGEN 13.8 #D1	23
APPGEN1G 13.8 #1	23

Generation	Effectiveness Factor (%)
APPGEN2G 13.8 #2	23
APPGEN3G 13.8 #3	23
MOORPARK 66.0 #10	22
GOLETA 66.0 #E1	21
ELLWOOD 13.8 #1	21
S.CLARA 66.0 #E1	20
CHARMIN 13.8 #1	20
OXGEN 13.8 #D1	20
PROCGEN 13.8 #D1	20
CAMGEN 13.8 #D1	20
MANDLY1G 13.8 #1	19
MANDLY3G 16.0 #3	19
MCGPKGEN 13.8 #1	19

OTC Generation Needed

The need for OTC units in the overall Big Creek/Ventura area is established specifically by the Moorpark sub-area. Approximately 430 MW of OTC capacity is required across all four RPS portfolios to mitigate reliability issues in the Moorpark sub-area. This OTC capacity is counted towards the total LCR need for the overall Big Creek/Ventura area. The OTC generation requirements for the overall Big Creek/Ventura area by portfolios are listed in the table below.

Table 3.3-29: OTC requirements for Moorpark sub-area to mitigate reliability issue

Portfolio	Min OTC Need (MW)
Trajectory	430
Environmental	430
Base	430
Time	430

Moorpark Sub-area

The most critical contingency for the Moorpark sub-area is the N-1 outage followed by N-2 outage-loss of Pardee-Moorpark #1 230 kV line and Pardee-Moorpark #2 and #3 230 kV lines. This would result in a voltage collapse. To mitigate this voltage collapse, about 430 MW of OTC units are required as part of the LCR for this sub-area. This constraint establishes the LCR numbers for the four portfolios as listed in the following table:

Table 3.3-30: LCR for Moorpark sub-area with identified contingencies

Portfolio	LCR (MW)
Trajectory	735
Environmental	642/857
Base	651/781
Time	673/803

Generation Effectiveness Factors

Generators inside this sub-pocket have the same effectiveness on this limiting constraint.

OTC Generation Needed

Approximately 430 MW of OTC capacity is needed across all four portfolios in order to mitigate the voltage collapse concern. The OTC requirements by portfolios are listed in the table below.

Table 3.3-31: OTC requirements for Moorpark sub-area to mitigate reliability issues

Portfolio	Min OTC Need (MW)
Trajectory	430
Environmental	430
Base	430
Time	430

Rector Sub-Area

The most critical contingency for the Rector sub-area is the L-1/G-1 outage of Vestal-Rector #1 or #2 230 kV line and Eastwood generation. The limiting element is the remaining Rector-Vestal 230 kV line. This constraint establishes the LCR numbers for the four portfolios as noted in the table below.

Table 3.3-32: LCR for Rector sub-area with identified contingencies

Portfolio	LCR (MW)
Trajectory	653
Environmental	618
Base	600
Time	573

Generation Effectiveness Factors

The following table shows units that have at least 5 percent effectiveness on Vestal-Rector 230 kV constraint for the Rector sub-area:

Table 3.3-33: Units with at least 5% effectiveness on Vestal-Rector 230 kV constraint for Rector sub-area

Generation	ID	Effectiveness Factor (%)
KAWGEN	1	45
EASTWOOD	1	41
B CRK1-1	1	41
B CRK1-1	2	41
B CRK1-2	3	41
B CRK1-2	4	41
PORTAL	1	41
B CRK2-1	1	40
B CRK2-1	2	40
B CRK2-2	3	40
B CRK2-2	4	40
B CRK 8	81	40
B CRK 8	82	40
B CRK2-3	5	39
B CRK2-3	6	39
B CRK3-1	1	39
B CRK3-1	2	39
B CRK3-2	3	39
B CRK3-2	4	39
B CRK3-3	5	39
MAMOTH1G	1	39
MAMOTH2G	2	39
B CRK 4	41	38
B CRK 4	42	38

OTC Generation Needed

No OTC units are required to mitigate reliability concern in the Rector sub-area.

Vestal Sub-Area

The most critical contingency for this area in all four RPS portfolios is an L-1/G-1 outage of the Magunden-Vestal 230 kV #1 or #2 line and Eastwood generation. The limiting element is the remaining Magunden-Vestal 230 kV line. This constraint establishes the LCR numbers for the four RPS portfolios as noted in the following table.

Table 3.3-34: LCR for Vestal sub-area with identified contingencies

Portfolio	LCR (MW)
Trajectory	786
Environmental	835
Base	773
Time	806

Generation Effectiveness Factors

The following table shows units that have at least 5 percent effectiveness on Magunden-Vestal 230 kV constraint for the Vestal sub-area:

Table 3.3-35: Units with at least 5% effectiveness on Magunden-Vestal 230 kV constraint for Vestal sub-area

Gen Name	Gen ID	Effectiveness Factor (%)
LAKEGEN	1	46
PANDOL	1	45
PANDOL	2	45
ULTRAGEN	1	45
KR 3-1	1	45
KR 3-2	2	45
VESTAL	1	45
KAWGEN	1	45
EASTWOOD	1	24
B CRK1-1	1	24
B CRK1-1	2	24
B CRK1-2	3	24
B CRK1-2	4	24
B CRK2-1	1	24
B CRK2-1	2	24
B CRK2-2	3	24
B CRK2-2	4	24
B CRK2-3	5	24
B CRK2-3	6	24
B CRK 8	81	24
B CRK 8	82	24
PORTAL	1	24
B CRK3-1	1	23
B CRK3-1	2	23
B CRK3-2	3	23

OTC Generation Needed

No OTC units are required to mitigate reliability concern in Vestal sub-area.

LCR Summary by Portfolios

The following four tables summarize the OTC and LCR requirements for each portfolio. The tables also list the worst contingencies and limiting elements.

Table 3.3-36: Trajectory portfolio — LCR and OTC requirements in Big Creek/Ventura area

Portfolios	Area	LCR			Existing OTC Units Needed?	Constraint	Contingency
		Non-D.G. (MW)	D.G. (MW)	Total (MW)			
Trajectory	Overall Big Creek Ventura	2,367	4	2,371	No	Remaining Sylmar-Pardee 230 kV line	Sylmar-Pardee #1 and #2 + Pastoria Generation
	Moorpark	735	0	735	Yes	Voltage Collapse	Pardee-Moorpark #1 230kV + Pardee-Moorpark #2 and #3 230 kV lines
	Rector	653	0	653	No	Vestal-Rector #1 or #2 line	Vestal-Rector #1 or #2 line + Eastwood gen
	Vestal	786	0	786	No	Magunden-Vestal 230 kV #1 or #2 line	Magunden-Vestal 230 kV #1 or #2 line + Eastwood gen

Table 3.3-37: Environmentally Constrained LCR and OTC requirements in Big Creek/Ventura area

Portfolios	Area	LCR			Existing OTC Units Needed?	Constraint	Contingency
		Non-D.G. (MW)	D.G. (MW)	Total (MW)			
Environmentally constrained	Overall Big Creek Ventura	2,185	419	2,604	No	Antelope 500/230 kV bank #1 or #2	Antelope 500/230 kV Bank #1 or #2 + Magunden-Omar 230 kV line (and the associated generation)
	Moorpark	502	140	642/857	Yes	Voltage Collapse	Pardee-Moorpark #1 230 kV + Pardee-Moorpark #2 and #3 230 kV lines
	Rector	489	129	618	No	Vestal - Rector #1 or #2 line	Vestal - Rector #1 or #2 line + Eastwood gen
	Vestal	677	158	835	No	Magunden-Vestal 230 kV #1 or #2 line	Magunden-Vestal 230 kV #1 or #2 line + Eastwood gen

Table 3.3-38: ISO Base portfolio — LCR and OTC requirements in Big Creek/Ventura area

Portfolios	Area	LCR			Existing OTC Units Needed?	Constraint	Contingency
		Non-D.G. (MW)	D.G. (MW)	Total (MW)			
Base	Overall Big Creek Ventura	2,377	61	2,794	No	Antelope 500/230 kV Bank #1 or #2	Antelope 500/230kV bank #1 or #2 + Magunden- Omar 230 kV line (and the associated generation)
	Moorpark	637	14	651	Yes	Voltage Collapse	Pardee-Moorpark #1 230kV + Pardee-Moorpark #2 and #3 230 kV lines
	Rector	584	16	600	No	Vestal-Rector #1 or #2 line	Vestal-Rector #1 or #2 line + Eastwood gen
	Vestal	755	18	773	No	Magunden-Vestal 230 kV #1 or #2 line	Magunden-Vestal 230 kV #1 or #2 line + Eastwood gen

Table 3.3-39: Time portfolio — LCR and OTC requirements in Big Creek/Ventura area and its sub-areas

Portfolios	Area	LCR			Existing OTC Units Needed?	Constraint	Contingency
		Non-D.G. (MW)	D.G. (MW)	Total (MW)			
Time	Overall Big Creek Ventura	2,558	95	2,653	No	Antelope 500/230 kV Bank #1 or #2	Antelope 500/230 kV bank #1 or #2 + Magunden-Omar 230kV line (and the associated generation)
	Moorpark	632	41	673/803	Yes	Voltage Collapse	Pardee-Moorpark #1 230 kV + Pardee-Moorpark #2 and #3 230 kV lines
	Rector	555	18	573	No	Vestal-Rector #1 or #2 line	Vestal-Rector #1 or #2 line + Eastwood gen
	Vestal	785	21	806	No	Magunden-Vestal 230 kV #1 or #2 line	Magunden-Vestal 230kV #1 or #2 line + Eastwood gen

Conclusions

The main driver for OTC generation need in the Big Creek/Ventura area is the local capacity requirement for the Moorpark sub-area. Minimum OTC need across all four portfolios is 430 MW. The following table is a summary of LCR and OTC requirements for the overall Big Creek/Ventura area.

Table 3.3-40: Summary of LCR and OTC requirements in Big Creek/Ventura area and sub-areas

LCR Area	Trajectory (MW)	Environmental (MW)	ISO Base Case (MW)	Time-Constrained (MW)
Big Creek / Ventura	2,371	2,604	2,794	2,653
Rector	474	597	511	556
Vestal	638	585	568	620
OTC	430	430	430	430

3.3.2.3.4 LCR Study Results — San Diego Area

To determine the OTC generation need for San Diego area in 2021, an LCR study was performed for the following four RPS portfolios: trajectory;

- environmentally constrained;
- ISO Base; and
- time-constrained

The following areas were examined for LCR generation requirements:

- San Diego overall; and
- Greater Imperial Valley – San Diego (IV-San Diego)

Area Definition for San Diego

The transmission tie lines forming a boundary around San Diego include the following:

1. Imperial Valley-Miguel 500 kV line;
2. Imperial Valley-Central 500 kV line;
3. Otay Mesa-Tijuana 230 kV line;
4. San Onofre-San Luis Rey #1 230 kV line;
5. San Onofre-San Luis Rey #2 230 kV line;
6. San Onofre-San Luis Rey #3 230 kV line;
7. San Onofre-Talega #1 230 kV line; and
8. San Onofre-Talega #2 230 kV line.

The substations that delineate the San Diego area are:

1. Imperial Valley is out, Miguel is in;
2. Imperial Valley is out, Central is in;
3. Otay Mesa is in, Tijuana is out;
4. San Onofre is out, San Luis Rey is in;

5. San Onofre is out, San Luis Rey is in;
6. San Onofre is out, San Luis Rey is in;
7. San Onofre is out, Talega is in; and
8. San Onofre is out, Talega is in.

The total 2021 substation load (bus bar level) within the defined area is 5,590 MW. Each portfolio has different losses. The following table shows the load and resource summary in the San Diego area in 2021 for all four RPS portfolios:

Table 3.3-41: Loads and resource summary in San Diego area

Itemized details	Trajectory, MW	Environmentally Constrained, MW	ISO Base, MW	Time-Constrained, MW
Total 1-in-10 Load + Losses	5,745	5,751	5,745	5,741
Generation				
Existing NQC (2012)	3,049			
Existing OTC NQC (2012)	950			
Distributed generation	52	402	104	81

Critical Contingency Analysis Summary
Overall San Diego Area

The most limiting contingency in the San Diego area is described by the outage of the 500 kV Sunrise Powerlink and Southwest Powerlink (SWPL) overlapping with an outage of the Otay Mesa combined-cycle power plant (603 MW). A post-contingency import limit of 3,500 MW is not the most limiting element for this condition. The limiting constraint for this contingency is the South of SONGS Separation Scheme. This constraint establishes LCR requirements for the four portfolios as shown in the table below.

Table 3.3-42: Overall San Diego area LCR requirements

Portfolios	LCR, MW			OTC Need, MW	Constraint	Contingency
	Non-D.G.	D.G.	Total			
Trajectory	2,852	31	2,883	950	South of SONGS separation Scheme	Otay Mesa (G-1) + SWPL + SRPL
Environmentally constrained	2,660	194	2,854	650		
ISO Base	2,822	42	2,864	650		
Time-constrained	2,791	65	2,856	840		

Generation Effectiveness Factors

All units within this area have the same effectiveness factor. Units outside of this area are not effective for the contingency considered above.

Greater Imperial Valley — San Diego Area

The most limiting contingency in the Greater Imperial Valley-San Diego (IV-San Diego) area is described by the outage of 500 kV SWPL between Imperial Valley and N. Gila substations overlapping with an outage of the Otay Mesa combined-cycle power plant (603 MW), while staying within the South of San Onofre (WECC Path 44) non-simultaneous import capability rating of 2,500 MW. This constraint establishes LCR requirements for four portfolios as shown in the table below.

Table 3.3-43: Greater IV-San Diego area LCR requirements

Portfolios	LCR (MW)			OTC Need (MW)	Constraint	Contingency
	Non-D.G.	D.G.	Total			
Trajectory	3,260	31	3,291*	0	P44 rating of 2500 MW	Otay Mesa (G-1) + IV-NG
Environmentally Constrained	2,910	194	3,104	0		
ISO Base	2,926	42	2,968	0		
Time Constrained	3,207	65	3,272*	210		

* Assuming a fix for voltage deviations in Western Arizona sub transmission.

Generation Effectiveness Factors

All units within this area have the same effectiveness factor. Units outside of this area are not effective.

Conclusions

The LCR study for the San Diego area has shown the need for OTC generation units. The need was driven by the South of SONGS Separation Scheme for all portfolios and Path 44 rating of 2,500 MW for only the time-constrained portfolio.

The following table is a summary of LCR and OTC generation requirements for the San Diego and IV-San Diego areas.

Table 3.3-44: Summary of LCR and OTC generation requirements

LCR Area	Trajectory (MW)	Environmentally Constrained (MW)	ISO Base (MW)	Time-Constrained (MW)
San Diego	2,883**	2,854**	2,864**	2,856**
IV – San Diego	3,291	3,104	2,968	3,272
OTC Range*	531* - 950	231* - 650	231* - 650	421* - 840

*Lower OTC range value corresponds to the use of SDG&E-proposed generation included in the Long-Term Procurement Plan.

**Load curtailment of approximately 370 MW was simulated to achieve stability under G-1/N-2 contingency.

3.4 Assembly Bill 1318 (AB1318) Reliability Studies

3.4.1 Background, Methodology and Assumptions

Assembly Bill 1318 (AB 1318, Perez, Chapter 285, Statutes of 2009) requires the CARB, in consultation with the ISO, CEC, CPUC and the SWRCB to prepare a report for the governor and legislature that evaluates the electrical system's reliability needs within the South Coast Air Basin. The report is required to include recommendations regarding the most effective and efficient means of meeting reliability needs while ensuring compliance with state and federal law. In collaboration with the state agencies, in 2010, the ISO prepared an interim report: *Draft Work Plan on the Assessment of Electrical System Reliability Needs in South Coast Air Basin and Recommendations on Meeting those Needs*.[23] This report summarizes existing reliability studies for the ISO-controlled grid in the South Coast Air Basin and provides an overview of studies to be performed in the ISO's 2011/2012 transmission planning cycle to meet AB 1318 objectives. The following discussion provides the details of the study scope.

For the AB 1318 study, CARB is interested in determining the maximum credible range of offsets rather than a single "most likely" range. An advantage of the maximum range approach is that it could be determined using *a priori* knowledge by strategically evaluating the ranges of assumptions and modeling conventions to provide potential maximum or minimum values, which would encompass the most likely range scenario. A most likely range would probably require more time to debate and reach consensus among various competing interest groups and may not result in a deliverable product for CARB by the end of the year. Given the dynamics of renewable generation development, as well as the challenge of demand side management, it is more logical to evaluate the maximum and minimum range of potential emission offsets at this time

[23] http://www.arb.ca.gov/energy/esr-sc/0215-workshop/ab_1318_draft_work_plan.pdf

until further clarity of the RPS and demand side management development trend is known. Although the goal is to identify and assess various assumptions that lead to high and low offsets, the analytical plan also calls for sensitivity investigations. If all combinations of input assumptions are examined, there are still many cases contributing to the two study scenarios, and much additional time and resources would be required to assess them. This proposal suggests an approach that identifies the most important cases for near-term analyses.

The analytic approach uses power flow models to determine thermal violations, and transient and post transient stability analyses. The results of these studies were examined applying the ISO's techniques for determining local capacity area requirements.[24] The outcomes provided minimum capacity additions to satisfy local and zonal reliability standards. With the capacity additions for each scenario established, supplemental analyses will be performed by CARB staff, working in conjunction with the CEC, to translate the capacity additions into offsets associated with that capacity development.

3.4.1.1 High End of Emission Offset Range

The purpose of this study is to identify the upper end of the offset range for non-nuclear thermal generation in the L.A. Basin under various 33 percent renewable generation and OTC development scenarios utilizing the latest CEC adopted demand forecast. Offsets are both emission reduction credits (ERCs) and internal bank credits that would have to be surrendered for capacity that elected to use South Coast Air Quality Management District (SCAQMD) Rule 1304(a)(2). Comments identify remaining issues that may be resolved in future transmission planning study cycles if they cannot be resolved at this time. This approach is used because of the need to complete the capacity requirements studies for CARB this year. Four high end scenarios were studied for the high net-load conditions (i.e., CEC's adopted 1-in-10 year heat wave load without incremental energy efficiency or demand responses).

Study Combinations = [1 load (latest official CEC-adopted demand forecast)* 4 RPS scenarios * 1 OTC generation scenario[25]] = 4 cases

3.4.1.2 *Low End of Emission Offset Range*

The purpose of this study is to identify the lower end of the offset range if policy-driven demand side management measures (i.e., incremental energy efficiency, combined heat and power, demand response) were to materialize. The CPUC and the CEC refer to this load condition as the mid net load scenario. In many cases, the values chosen are the opposite of those selected for the high end of the offset range scenario. One low end scenario was studied:

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[24] ISO, *2013-2015 Local Capacity Technical Analysis: Final Report and Study Results*, December 2010.

[25] Local capacity requirement scenario: This scenario will determine the minimum OTC generation need that enables the load serving entities to meet applicable national, regional and ISO reliability requirements.

- Combinations = 1 load (mid net load[26])* 1 RPS (environmentally constrained) * 1 OTC generation study scenario = 1 case.

Like the study described in the section above, to provide data inputs to CARB staff for further estimates of emission offset needs, this study will be performed for the environmentally constrained case to provide the lower end of the emission offset range.

3.4.2 AB 1318 Reliability Assessment — Study Results

Because OTC and AB 1318 reliability studies share some common study objectives for the LA Basin (the area in which SCAQMD has jurisdiction), please refer to the write-ups in section 3.3.2 (OTC Reliability Assessment) for related study results for the AB 1318 reliability assessment. The following is a summary of the study scope for AB 1318 reliability assessment:

1. Reliability assessment of the LA Basin LCR area for four RPS portfolios at peak load conditions (high net load): The four portfolios are trajectory, environmentally constrained, ISO base case and time-constrained. The purpose of these studies is to identify whether there is a reliability need to run OTC plants, and if there is, what is the OTC generation level needed during peak load conditions. Studies at peak load conditions establish local capacity requirements for higher bound conditions. Additionally, these assessments utilized the official CEC-adopted demand forecast for 1-in-10 year heat wave load projection. The CEC demand forecast includes committed energy efficiency.
2. Per the request from the state agencies (CARB, CEC and CPUC), the ISO also performed an LCR assessment for mid net load conditions for the environmentally constrained study case as sensitivity studies: The results for this study provide for lower bound condition for informational purposes. For this study, the ISO utilized uncommitted incremental energy efficiency, modeled at specific load buses, as provided by the CPUC and CEC. Incremental demand resources are treated as potential resources, if they materialize. Because of the uncommitted nature of these programs, the ISO considers these studies as sensitivity studies.
3. Transient stability assessment for on-peak and off-peak load conditions. For on-peak load conditions, the assessment was performed for the trajectory and environmentally constrained RPS portfolios. For the off-peak condition, assessment was performed for the environmentally constrained portfolio to determine if this portfolio, with significantly more distributed generation modeled, would still meet the WECC transient stability reliability criteria.
4. Loads and resource assessment for zonal (NP26 and SP26) and ISO balancing authority: The purpose of this assessment is to provide preliminary

[26] Mid net load scenario includes uncommitted incremental energy efficiency, demand response and combined heat and power.

long-term review of the adequacy of future generation to serve loads in the 2021 time frame under two load scenarios: 1-in-2 year and 1-in-10 year heat wave load conditions. This is similar to the ISO annual summer assessment, except that it looks out ten years into the future, whereas the summer assessment evaluates adequacy of resources for the next summer condition. For this assessment, the minimum OTC generation requirement was modeled. In addition, NQC

5. values for renewable generation at peak load and some demand response was modeled.

3.4.2.1 Study Results

The results of study items #1, 3 and 4 are provided in Section 3.3.2 (OTC Reliability Assessment Study Results). In this section, only new study results for item #2 above are reported. The following table includes assumptions provided by the CPUC and CEC in regards to assumptions of incremental uncommitted energy efficiency and demand response values.

Table 3.4-1: State energy agencies' provided assumptions on incremental EE & DR

Load Serving Entities	2021 Incremental EE (MW)	2021 Demand Response (MW)
PG&E	2,275	1,523
SCE	2,461	2,829
SDG&E	496	283

The next table provides the summary study results for the mid-net load assumptions with incremental uncommitted energy efficiency and demand response. The results indicated that, if incremental energy efficiency and demand response were to fully materialize as assumed, the resulting OTC generation need would be about 42 percent of the need under high-net load condition for the same RPS portfolio (environmentally constrained), or about 33 percent of the highest OTC generation need under a different RPS portfolio (time-constrained).

For study conclusions, please refer to section 3.3.2.

Table 3.4-2: Summary of sensitivity assessment of the mid net load condition for the CPUC environmentally constrained portfolio

Portfolios	Area	LCR			Existing OTC Units Needed?	Constraint	Contingency
		Non-D.G. (MW)	D.G. (Mw)	Total (MW)			
Environmentally Constrained (Mid Net Load Condition)	LA Basin Overall	9,242	1,519	10,761	No	Mira Loma West 500/230 Bank #1 (24-Hr rating) *	Chino - Mira Loma East #3 230kV line + Mira Loma West 500/230kV Bank #2
	Western LA	5,589	869	6,458	Yes	Serrano - Villa PK #1	Serrano - Lewis #1 / Serrano - Villa PK #2
	Western LA OTC Range		802 - 1,275 MW				OTC need ranges from most effective to less effective generation
	Ellis	470	124	594	Yes	Voltage Collapse**	Barre - Ellis 230kV Line + SONGS - Santiago #1 and #2 230kV Lines
	El Nido	336	91	427	No	La Fresa-Hinson 230 kV line	La Fresa-Redondo #1 and #2 230 kV lines

Notes:

* Mira Loma 500/230kV Bank #2 has a 1-Hr emergency rating of 1792 MVA (assuming up to 600 MW load shed/transfer after 1-Hr). If this rating is utilized then Path 26 flow becomes the next limiting constraint.

** In addition to generation requirements, three 79 MVAR shunt capacitors were modeled to mitigate voltage collapse concern. The voltage concern was caused by less dispatch of generation due to lower load that was off-set by the state agencies' assumptions of uncommitted energy efficiency for the mid net load level.

Rulemaking	12-03-014
Exhibit No.:	ISO - 08
Witness:	

Supplemental Testimony of Robert Sparks on Behalf of the California Independent System Operator Corporation

Application No.: A.11-05-023
Exhibit No.: ____________
Witness: Robert Sparks

Application of San Diego Gas & Electric Company (U902 E) for Authority to Enter into Purchase Power Tolling Agreements with Escondido Energy Center, Pio Pico Energy Center and Quail Brush Power	Application 11-05-023

SUPPLEMENTAL TESTIMONY OF ROBERT SPARKS ON BEHALF OF THE CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE

STATE OF CALIFORNIA

Application of San Diego Gas & Electric Company (U902 E) for Authority to Enter into Purchase Power Tolling Agreements with Escondido Energy Center, Pio Pico Energy Center and Quail Brush Power	Application 11-05-023

SUPPLEMENTAL TESTIMONY OF ROBERT SPARKS ON BEHALF OF THE CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION

Q. What is your name and by whom are you employed?

A. My name is Robert Sparks. I am employed by the California Independent System Operator Corporation (ISO), 250 Outcropping Way, Folsom, California as Manager, Regional Transmission.

Q. Have you previously submitted testimony in this proceeding?

A. Yes, I have. On March 9, 2012 I submitted initial testimony addressing the need for generating resources in the San Diego area.

Q. Why have you submitted this supplemental testimony?

A. Specifically, after my initial testimony was served, SDG&E told the ISO that the newly revised WECC criterion for common corridor circuit outages would result in a reclassification of the Sunrise/IV Miguel double outage as a Category D contingency because the towers on the two lines are spaced less than 250’ apart for less than 3 miles (which is the new WECC criteria). This re-categorization of the common corridor circuit outage as a Category D contingency required the ISO to re-assess its local studies. The purpose of my supplemental testimony is to describe the results of this re-assessment. In addition, in response to questions posed to me during an all-party conference call held on March 21, 2012, I will present some additional information about the ISO's local capacity studies.

Q. Were all of the local capacity area studies described in your initial testimony revised as a result of this change in the WECC criterion?

A. In my initial testimony, I described the results of the ISO's 2012 LCR study, which is an annual assessment conducted through a stakeholder process during the first two quarters of each year. I also discussed the ISO's once through cooling (OTC) study results for the year 2021. This study was conducted in cooperation with several state agencies as part of the 2011/2012 transmission planning process. Finally, I discussed a mid-term local capacity area study, conducted for 2016, that was posted separately on January 31, 2012 but discussed in the 2011/2012 transmission plan.

The ISO revised the OTC results for 2021 and I describe these results below. The ISO recently completed its 2013 local capacity studies with the G-1/N-2 and with the N-1-1 as the limiting contingency. Therefore, I am addressing the results of these studies in lieu of updating the 2012 results. In addition, as noted in the 2016 local capacity study report, the differences in results between the 2012 results and the 2016 results are due to load growth only which is a fairly predictable change. Therefore the change in 2016 study results can be reasonably extrapolated based on the change in 2013 study results provided below.

Q. Please explain how the change in the WECC criterion impacted the ISO's OTC local capacity studies for 2021 for the San Diego area.

A. Prior to the change in the WECC criterion, the most limiting contingency for the determination of LCR needs in the San Diego area was the simultaneous outage of the 500 kV Sunrise Powerlink and the Imperial Valley-ECO 500 kV line overlapping with an outage of the Otay Mesa combined-cycle power plant (G-1/N-2). The limiting constraint for this contingency is the South of SONGS Separation Scheme. With this change to the WECC criterion, the most limiting contingency for San Diego sub-area is the loss of Imperial Valley-Suncrest 500 kV line followed by the loss of ECO-Miguel 500 kV line (N-1-1).

The table below shows the difference in study results between the two different limiting contingency scenarios.

LCR Area	Contingency	Limiting Constraint	Traject (MW)	Env (MW)	ISO Base (MW)	Time (MW)
San Diego	G-1/N-2 (Assuming load shed)	8000 Amp limit on P44	**LCR = 2,883** OTC = 531* - 950**	**LCR = 2,854** OTC = 231* - 650**	**LCR = 2,864** OTC = 231* - 650**	**LCR = 2,856** OTC = 421* - 840**
		7800 Amp limit on P44 (2.5% margin)	LCR = 2,939** OTC = 520* - 939	LCR = 2,922** OTC = 299* - 718	LCR = 2,930** OTC = 299* - 718	LCR = 2,911** OTC = 470* - 889
San Diego	N-1-1 (No load shed)	8000 Amp limit on P44	LCR = 2,680 OTC = 318* – 737	LCR = 2,625 OTC = 0* - 402	LCR = 2,669 OTC = 218* - 637	LCR = 2,633 OTC = 201* - 620
		7800 Amp limit on P44 (2.5% margin)	LCR = 2,735 OTC = 373* – 792	LCR = 2,702 OTC = 60* - 479	LCR = 2,694 OTC = 243* - 662	LCR = 2,691 OTC = 260* - 679
		Voltage Collapse (accounting for 2.5% margin)	**LCR = 2,646 OTC = 311* – 730**	**LCR = 2,524 OTC = 0* - 300**	**LCR = 2,663 OTC = 211* - 630**	**LCR = 2,553 OTC = 121* - 540**

* Lower OTC range value corresponds to the use of SDG&E-proposed generation included in the Long-Term Procurement Plan. The numbers in the table identified as OTC refer to an incremental local capacity need in the San Diego area driven by the loss of OTC generation in the San Diego area. This need could be met by repowering the existing OTC generation or by other new generation that is connected to an electrically equivalent location.

** Load curtailment of approximately 370 MW was simulated to achieve stability under G-1/N-2 contingency.

As can be seen in the results table, the continuing need for generation at the existing OTC site (Encina) or in an electrically equivalent location is reduced from 950 MW to 730 MW for the Trajectory 33% RPS portfolio study scenario. This assumes that the 8000 Amp limit due to the SONGS separation scheme is removed from being a binding constraint. With the 419 MW of SDG&E proposed generation procurement, the need amount is reduced from 531 MW to 311 MW. Need amounts are also provided with the 8000 Amp limit on the Path 44 (SONGS separation scheme) as a binding constraint and with a 2.5% margin from hitting that constraint. Need amounts based on the other three 33% RPS portfolio study scenarios are also provided in the table.

Q. Did this change cause the ISO to change its LCR study methodology in any way?

A. No. However, because the G-1/N-2 contingency is a severe contingency we conceptually assumed that an automatic load shedding scheme (SPS) would be installed and available to prevent voltage collapse for that contingency in our earlier results. With the more likely N-1-1 contingency we did not think it would be prudent to plan the system that would rely on the same type of load shedding SPS.

Q. Please explain how the change in the WECC criterion impacted the ISO's 2013 local capacity studies for the San Diego area.

A. Similar to the OTC 2021 studies, prior to the change in the WECC criterion, the most limiting contingency for the determination of LCR needs in the San Diego area was the simultaneous outage of the 500 kV Sunrise Powerlink and the Imperial Valley-ECO 500 kV line overlapping with an outage of the Otay Mesa combined-cycle power plant (G-1/N-2). The limiting constraint for this contingency is the South of SONGS Separation Scheme. With this change to the WECC criterion, the most limiting contingency for San Diego sub-area is the loss of Imperial Valley-

Suncrest 500 kV line followed by the loss of ECO-Miguel 500 kV line (N-1-1). The table below shows the difference in 2013 LCR study results between the two different limiting contingency scenarios.

Area	Contingency	Limiting Condition	LCR (MW)
San Diego	G-1/N-2: Otay + Sunrise + SWPL (No load shed)	Voltage Collapse	2863
San Diego	N-1-1: Sunrise followed by SWPL (No load shed)	Voltage Collapse	2570 (Accounting for 2.5% margin for N-1-1)

As can be seen in the results table, the San Diego area LCR needs were reduced from 2863 MW to 2570 MW. It is important to note that these studies assumed that both SONGS units were operating.

Q. Were the results for the IV-San Diego area and the Encina sub-area affected by the change in WECC criterion for Sunrise Powerlink/IV-Miguel?

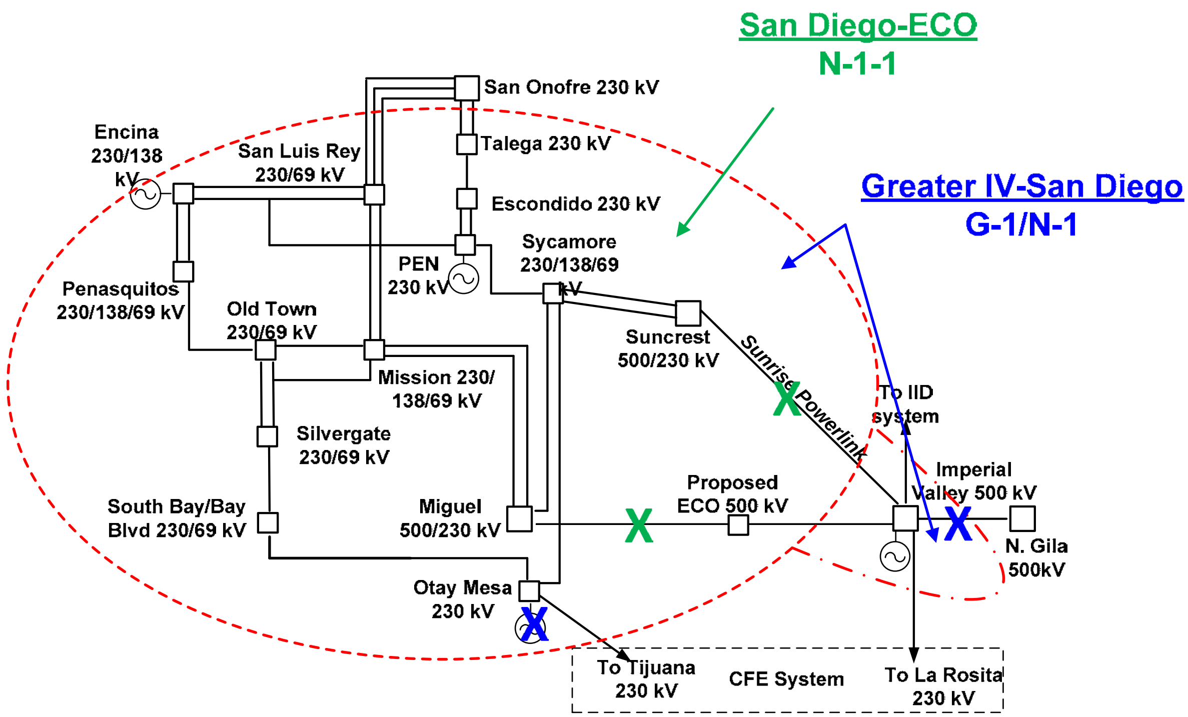
A. No. The most limiting contingency in the Greater Imperial Valley-San Diego (IV-San Diego) area is described by the outage of 500 kV SWPL between Imperial Valley and N. Gila substations overlapping with an outage of the Otay Mesa combined-cycle power plant (603 MW), while staying within the South of San Onofre (WECC Path 44) non-simultaneous import capability rating of 2,500 MW. The most limiting contingency for the Encina sub-area of the San Diego local capacity area is the loss of Encina 230/138 kV transformer followed by the loss of the Sycamore-Santee 138 kV line which could thermally overload the Sycamore-Chicarita 138 kV line. Neither of these limiting contingencies is affected by the new WECC criterion, and therefore the results of the studies were not affected in either of these areas.

Q. If the South of SONGS separation scheme were removed as a binding constraint, would the revised study results be affected?

A. The 2013 LCR study results are driven by a voltage collapse constraint, so those results would not change. The 2021 study results are provided with and without the SONGS separation scheme as a binding constraint. With the N-1-1 as the limiting contingency, removing the SONGS separation scheme as the binding constraint would reduce the LCR needs by about 30 to 180 MW, depending on the 33% RPS scenario.

Q. Why is there a San Diego local area and a San Diego/IV local area?

A. The most limiting contingency in the Greater San Diego-Imperial Valley area is described by the outage of 500 kV Southwest Power Link (SWPL) between Imperial Valley and N. Gila Substations over-lapping with an outage of the Otay Mesa Combined-Cycle Power plant (603 MW) while staying within the South of San Onofre (WECC Path 44) non-simultaneous import capability rating of 2,500 MW. The most limiting contingency for San Diego sub-area is the loss of Imperial Valley-Suncrest 5000 kV line followed by the loss of ECO-Miguel 500 kV line. The limiting constraint is post-transient voltage instability or the South of SONGS separation scheme. These two contingencies are depicted in the following diagram.



As shown in the diagram the difference between the two areas is determined by the different separation points which result from the two different limiting contingencies. The San Diego area limiting contingency separates the Imperial Valley substation from the rest of the San Diego area, whereas the IV-San Diego limiting contingency does not. This is why the Imperial Valley substation is not in the San Diego area and is in the IV-San Diego area.

Q. **In your initial testimony you described the sensitivity study conducted in the transmission planning process that considered the Pio Pico, Quail Brush and Escondido Energy Center resources under consideration in this proceeding (pages 10-12). Can you provide further information about this study?**

A. Yes, I can. It is important to remember that the sensitivity study included two changes to the study assumptions. First we assumed that the Encina generation would be completely retired, and that Carlsbad Energy Center would not be built.

Second we assumed that Pio Pico, Quail Brush and Escondido Energy Center resources would be built. The additional transmission upgrades identified in the sensitivity study are driven by the combination of these two assumptions. If Carlsbad were added to the sensitivity case with Pio Pico and Quail Brush then the additional overloads identified in the sensitivity study would be eliminated except for the Miguel-Bay Boulevard 230 kV line overload. However, as stated above, this overload can be mitigated by stringing additional conductor on the currently empty side of the double circuit tower line.

Q. Does this conclude your supplemental testimony?

A. Yes, it does.

Rulemaking	12-03-014
Exhibit No.:	ISO - 09
Witness:	

Addendum to:
Board-Approved 2011/2012 Transmission Plan

Section 3.4.2.1 Assembly Bill 1318
Sensitivity Reliability Study Results

California ISO
Shaping a Renewed Future

Addendum to: Board-Approved 2011/2012 Transmission Plan

Section 3.4.2.1 Assembly Bill 1318 Sensitivity Reliability Study Results

June 12, 2012

Addendum to Board-Approved 2011/2012 Transmission Plan Section 3.4.2.1 Assembly Bill 1318 Sensitivity Reliability Study Results

This Addendum to the Board-approved ISO 2011-2012 Transmission Plan (March 23, 2012 version) updates the study results for the LCR ***sensitivity*** analyses of the mid net load scenario conducted at the request of the state agencies (CARB, CEC, and CPUC) as set out in Section 3.4.2, page 254 of the 2011/2012 ISO Transmission Plan.

In that sensitivity analysis of the mid net load scenario, incremental uncommitted energy efficiency and additional combined heat and power, as provided by the state energy agencies (i.e., CPUC and CEC), were modeled in the 2021 environmentally constrained portfolio study case. The Addendum provides updated study results for the incremental uncommitted energy efficiency scenario, and new results for additional combined heat and power assumptions. The updates results also reflect the modeling of the Board-approved Del Amo – Ellis 230kV loop-in project that has been advanced to be in service in 2012. The Del Amo – Ellis 230kV loop-in project was not yet an approved project when the previous analyses took place, and was originally targeted to be in service in 2013.

As mentioned at the ISO's December 8, 2011 stakeholder meeting, the ISO treats these studies in which incremental uncommitted energy efficiency and additional combined heat and power as ***sensitivity studies***, which were requested by the state energy agencies (i.e., the CPUC and CEC) to evaluate the impact to potential generation need in the LA Basin area had these programs materialized. The ISO considers these studies as sensitivity studies due to the uncertain nature of these programs whether they would materialize at the forecasted locations.

The following section 3.4.2.1 replaces and supersedes previous section 3.4.2.1 (pages 255 – 256) in the ISO 2011-2012 Transmission Plan (March 23, 2012 version).

3.4 Assembly Bill 1318 (AB1318) Reliability Studies

3.4.2.1 Study Results

The results of study items #1, 3 and 4 are provided in Section 3.3.2 (OTC Reliability Assessment Study Results). In this section, only new study results for item #2 above are reported. The following table includes assumptions provided by the CPUC and CEC in regards to assumptions of incremental uncommitted energy efficiency (EE) and combined heat and power (CHP) values for SCE and SDG&E.

Table 3.4-1: State energy agencies' provided assumptions on incremental uncommitted EE & CHP

Load Serving Entities	2021 Incremental Uncommitted EE (MW)	2021 Incremental Uncommitted CHP (MW)
SCE	2,461	209
SDG&E	496	14

The following presents a series of ***sensitivity*** study results with incremental uncommitted EE and/or additional CHP modeled for SCE and SDG&E. The study results are provided step by step to provide information regarding the incremental impacts of EE, CHP and the Del Amo-Ellis 230 kV loop-in project, respectively.

Table 3.4-2 provides a summary of study results with incremental uncommitted EE only and without the Del Amo – Ellis 230kV loop-in project[1]. These changes are triggered by the following:

LA Basin's total LCR requirements:

- For this update, the ISO dispatched additional base-load generation in San Diego LCR area[2] to adequately mitigate a voltage instability concern under an N-1-1 contingency condition (i.e., Sunrise Powerlink and Southwest Powerlink). This minimum level of generation need in San Diego for this sensitivity study was modeled to ensure that we would not underestimate the generation need in the LA Basin LCR area. Previous studies had generation at a lower level in the San Diego area after modeling of the incremental uncommitted EE; however, this lower generation level turned out to be inadequate for mitigating the critical N-1-1 contingency voltage stability concern. Due to the interaction between LA Basin and San Diego LCR areas, the updated generation adjustment in turn resulted in having lower overall LCR requirements for the larger LA Basin.

Western LA Basin's new local generation requirements:

- In the previous sensitivity studies, the ISO inadvertently monitored the Serrano – Villa Park #2 230kV line, which has higher rating than its parallel Serrano – Villa Park #1 230kV line. In this updated study, the ISO correctly monitored the lower rated constrained line (i.e., Serrano – Villa Park #1 230kV line). This resulted in higher new local generation requirements[3] to mitigate identified overloading concerns. The generation adjustment above for San Diego LCR area was included in this analysis for the Western LA Basin.

[1] The Del Amo – Ellis 230kV loop-in of Barre substation project was accelerated for summer 2012 due to extended outage of the San Onofre nuclear generation. This project brings Del Amo – Ellis 230kV line into Barre Substation, creating Del Amo – Barre and second Barre – Ellis 230kV lines.
[2] The total generation within San Diego LCR area for this sensitivity study is approximately 1,900 MW.
[3] The definition of new generation requirements in this section refers to the repowering of once-through cooled generation with acceptable cooling technology.

Table 3.4-2: Summary of sensitivity assessment of the mid net load condition for the CPUC environmentally constrained portfolio with incremental EE

Portfolios	Area	LCR			New Gen. Required ?^	Constraint	Contingency
		Non-D.G. (MW)	D.G. (Mw)	Total (MW)			
Environmentally Constrained (Mid Net Load Condition)	Western LA	5,847	869	6,716	Yes	Serrano - Villa PK #1	Serrano - Lewis #1 / Serrano - Villa PK #2
	LA Basin Overall	7,135	1,519	8,654	Yes %	Mira Loma West 500/230 Bank #1 (24-Hr rating) *	Chino - Mira Loma East #3 230kV line + Mira Loma West 500/230kV Bank #2
	Western LA OTC Range		868 - 1,437 MW plus SONGS				New generation need ranges from most effective to less effective locations
	Ellis**	434	124	558	Yes	Voltage Collapse**	Barre - Ellis 230kV Line + SONGS - Santiago #1 and #2 230kV Lines
	El Nido	327	91	418	No	La Fresa-Hinson 230 kV line	La Fresa-Redondo #1 and #2 230 kV lines

Notes:

^ This has assumptions of new generation coming from repowering of OTC units.

% New generation need for the LA Basin is carried over from the Western LA area new capacity need (i.e., OTC plant repowering)

* Mira Loma 500/230kV Bank #2 has a 24-hour emergency rating of 1,344 MVA

** In addition to generation requirements, two 79 MVAR shunt capacitors (Johanna & Santiago) and 140 MVAR at HB were modeled to mitigate voltage collapse concern to maintain load. If Santiago N-2 SPS is used (drop Santiago load), then no new unit is needed (i.e., no OTC repowering), but two shunt caps are still needed.

Table 3.4-3 provides a summary of study results with incremental uncommitted EE and incremental uncommitted CHP. With the additional uncommitted CHP modeled for the LA Basin as well as the San Diego LCR area, the need for new generation requirements in the Western LA Basin LCR area is lower than the scenario in Table 3.4-2. However, the total LCR needs in the larger LA Basin increase slightly, due to the lower effectiveness of the additional CHP.

Table 3.4-3: Summary of sensitivity assessment of the mid net load condition for the CPUC environmentally constrained portfolio with incremental uncommitted EE and CHP

Portfolios	Area	LCR			New Gen. Required ? ^	Constraint	Contingency
		Non-D.G. (MW)	D.G. (Mw)	Total (MW)			
Environmentally Constrained (Mid Net Load Condition)	Western LA	5,895	869	6,764	Yes	Serrano - Villa PK #1	Serrano - Lewis #1 / Serrano - Villa PK #2
	LA Basin Overall	7,203	1,519	8,722	Yes %	Mira Loma West 500/230 Bank #1 (24-Hr rating) *	Chino - Mira Loma East #3 230kV line + Mira Loma West 500/230kV Bank #2
	Western LA OTC Range	782 - 1,301 MW plus SONGS					New generation need ranges from most effective to less effective locations
	Ellis**	388	124	512	Yes	Voltage Collapse**	Barre - Ellis 230kV Line + SONGS - Santiago #1 and #2 230kV Lines
	El Nido	284	91	375	No	La Fresa-Hinson 230 kV line	La Fresa-Redondo #1 and #2 230 kV lines

Notes:

^ This has assumptions of new generation coming from repowering of OTC units.

% New generation need for the LA Basin is carried over from the Western LA area new capacity need (i.e., OTC plant repowering)

* Mira Loma 500/230kV Bank #2 has a 24-hour emergency rating of 1,344 MVA

** In addition to generation requirements, two 79 MVAR shunt capacitors (Johanna & Santiago) and 140 MVAR at HB were modeled to mitigate voltage collapse concern to maintain load. If Santiago N-2 SPS is used (drop Santiago load), then no new unit is needed (i.e., no OTC repowering) but two shunt caps are still needed.

Table 3.4-4 provides a summary of study results with incremental uncommitted EE, uncommitted CHP and the Del Amo – Ellis 230kV line loop-in project modeled. With the loop-in project in service, it eliminates the need for local generation in the Ellis sub-area for the mid net load sensitivity analyses. However, because the loop-in project has the effects of reducing impedance in the southern Orange County area, it causes more power flow through the area, thus increasing the overload on the Serrano – Villa Park #1 230kV line under an N-1-1 contingency. Therefore, more local generation would be needed to mitigate this overloading concern.

Table 3.4-4: Summary of sensitivity assessment of the mid net load condition for the CPUC environmentally constrained portfolio with incremental uncommitted EE, CHP and Del Amo – Ellis 230kV loop-in project

Portfolios	Area	LCR			New Gen. Required ? ^	Constraint	Contingency
		Non-D.G. (MW)	D.G. (Mw)	Total (MW)			
Environmentally Constrained (Mid Net Load Condition)	Western LA	6,155	869	7,024	Yes	Serrano - Villa PK #1	Serrano - Lewis #1 / Serrano - Villa PK #2
	LA Basin Overall	7,288	1,519	8,807	Yes %	Mira Loma West 500/230 Bank #1 (24-Hr rating) *	Chino - Mira Loma East #3 230kV line + Mira Loma West 500/230kV Bank #2
	Western LA OTC Range		1,042 - 1,677 MW plus SONGS				New generation need ranges from most effective to less effective locations
	Ellis	0	0	0	No	None	Barre - Ellis 230kV Line + SONGS - Santiago #1 and #2 230kV Lines
	El Nido	274	91	365	No	La Fresa-Hinson 230 kV line	La Fresa-Redondo #1 and #2 230 kV lines

Notes:

* Mira Loma 500/230kV Bank #2 has a 24-hour emergency rating of 1,344 MVA.

^ This has assumptions of new generation coming from repowering of OTC units.

% New generation need for the LA Basin is carried over from the Western LA area new capacity need (i.e., OTC plant repowering).

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Witness:

California Energy Commission
2009 Integrated Energy Policy Report

CALIFORNIA ENERGY COMMISSION

2009 INTEGRATED ENERGY POLICY REPORT

CEC-100-2009-003-CMF

ARNOLD SCHWARZENEGGER
GOVERNOR

We dedicate the 2009 Integrated Energy Policy Report to

DR. ARTHUR ROSENFELD

Energy Commissioner
April 2000 – January 2010

A living legend who is widely recognized for his dedication to the cause of energy efficiency and whose leadership in scientific research, technology development, and public policy innovation leaves a lasting and profound legacy.

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Che McFarlin
Jim McKinney
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Daryl Metz
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Brian Neff
Terry O'Brien
Gary Occhuizzo
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Tiffany Solorio
Gene Strecker
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PREFACE

The 2009 Integrated Energy Policy Report was prepared in response to Senate Bill 1389 (Bowen, Chapter 568, Statutes of 2002), which requires that the California Energy Commission prepare a biennial integrated energy policy report that contains an integrated assessment of major energy trends and issues facing the state's electricity, natural gas, and transportation fuel sectors and provides policy recommendations to conserve resources; protect the environment; ensure reliable, secure, and diverse energy supplies; enhance the state's economy; and protect public health and safety (Public Resources Code § 25301[a]). This report fulfills the requirement of SB 1389.

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

The *2009 Integrated Energy Policy Report* proposes policy and program direction to address the many challenges facing California's energy future that are discussed throughout the body of the report. Specific recommendations are presented in Chapter 4, but the Energy Commission believes that certain policies and programs have priority and even urgency if California is going to address its diverse set of energy goals. The Executive Summary therefore identifies those actions and policies that the Energy Commission considers to be of highest importance.

EXECUTIVE SUMMARY

As California pursues its goal to address climate change by reducing greenhouse gas emissions, the driving force for the state's energy policies continues to be maintaining a reliable, efficient, and affordable energy system that minimizes the environmental impacts of energy production and use. Although the economic downturn has reduced energy demand in the short-term, demand is expected to grow over time as the economy recovers. It is essential that the state's energy sectors be flexible enough to respond to future fluctuations in the economy and that the state continue to develop and adopt the "green" technologies that are critical for long-term reliability and economic growth.

Assembly Bill 32 (Núñez, Chapter 488, Statutes of 2006), the Global Warming Solutions Act of 2006, established the goal of reducing greenhouse gas emissions to 1990 levels by 2020, and serves as the comprehensive framework for addressing climate change. However, many of the policies in place prior to passage of AB 32 are also valued for their role in meeting the state's climate change goals. One of these policies is the loading order for electricity resources, which calls for meeting new electricity needs first with energy efficiency and demand response; second, with new generation from renewable energy and distributed generation resources; and third, with clean fossil-fueled generation and transmission infrastructure improvements. A second important policy in place prior to the passage of AB 32 is the Renewables Portfolio Standard, established in 2002, which currently requires retail sellers of electricity to procure 20 percent of their retail sales from renewable resources by 2010.

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

While reducing greenhouse gas emissions is of paramount concern, it is not the only environmental issue facing California's electricity sector. The State Water Resources Control Board has issued a draft policy to phase out the use of once-through cooling in the state's 19 coastal power plants to reduce impacts on marine life from the pumping process and the discharge of heated water. Another issue is the lack of emission credits in the South Coast Air Quality Management District that makes it difficult to obtain the necessary permits to build reliable replacement power before aging, less-efficient power plants can be retired or repowered.

The transportation and building sectors are primary contributors to greenhouse gas emissions in California. Governor Schwarzenegger's Executive Order S-01-07 established a low carbon fuel standard for transportation fuels sold in California that will reduce the carbon intensity of California's passenger vehicle fuels by at least 10 percent by 2020. In addition, the Alternative and Renewable Fuel and Vehicle Technology Program created by AB 118 (Núñez, Chapter 750, Statutes of 2007) is working to develop and deploy alternative and renewable fuels and advanced transportation technologies to help meet the state's climate change policies. Further, the federal government in June 2009, granted California's request for a waiver that allows California to enact stricter air pollution standards for motor vehicles than those of the federal government. The standards (AB 1493, Pavley, Chapter 200, Statutes of 2002) are expected to reduce greenhouse gas emissions from California passenger vehicles by about 22 percent in 2012, and about 30 percent in 2016, while improving fuel efficiency and reducing motorists' costs.

This Executive Summary focuses on the policy recommendations that the Energy Commission believes should be the state's top priorities for meeting the goal of providing reliable, efficient, and cost-effective energy supplies for its citizens. Additional recommendations for specific actions needed in the various energy sectors are provided in Chapter 4.

Electricity

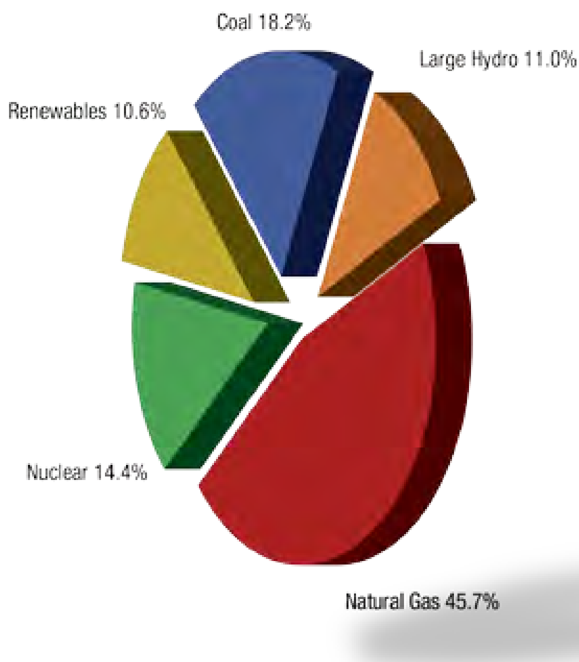
Supply and Demand

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

Since deregulation in 1998, the Energy Commission has licensed more than 60 power plants: 44 projects representing 15,220 megawatts are on-line, 6 projects totaling 1,578 megawatts are under construction, and 12 projects totaling 6,415 megawatts are on hold but available for construction. In addition, the Energy Commission has a historic high level of more than 30 proposed projects under review, totaling more than 12,000 megawatts, many of which are large-scale solar thermal power plants that present new and challenging environmental impacts that must be considered.

On the demand side, Californians consumed 285,574 gigawatt hours of electricity in 2008, primarily in the commercial, residential, and industrial sectors (Figure E-2). The Energy Commission staff forecast of future electricity demand shows that consumption will grow by 1.2 percent per year from

FIGURE E-1: CALIFORNIA'S GENERATION MIX 2008



Source: California Energy Commission

2010–2018, with peak demand growing an average of 1.3 percent annually over the same period. The current forecast is markedly lower than the forecast in the *2007 Integrated Energy Policy Report*, primarily because of lower expected economic growth in both the near and long term as well as increased expectations of savings from energy efficiency.

Because of economic uncertainties surrounding the current recession and the timing of potential recovery, the Integrated Energy Policy Report (IEPR) Committee directed staff to look in its forecast at alternative scenarios of economic and demographic growth and their impacts on electricity demand. Staff analyzed both optimistic and pessimistic scenarios and found only small differences in projected electricity demand. Annual growth rates from 2010–2020 for electricity consumption and peak demand would increase from 1.2 percent and 1.3 percent, respectively, to 1.3 percent and 1.4 percent in the optimistic case and fall to 1.1 percent each under the pessimistic scenario.

Energy Efficiency and Demand Response

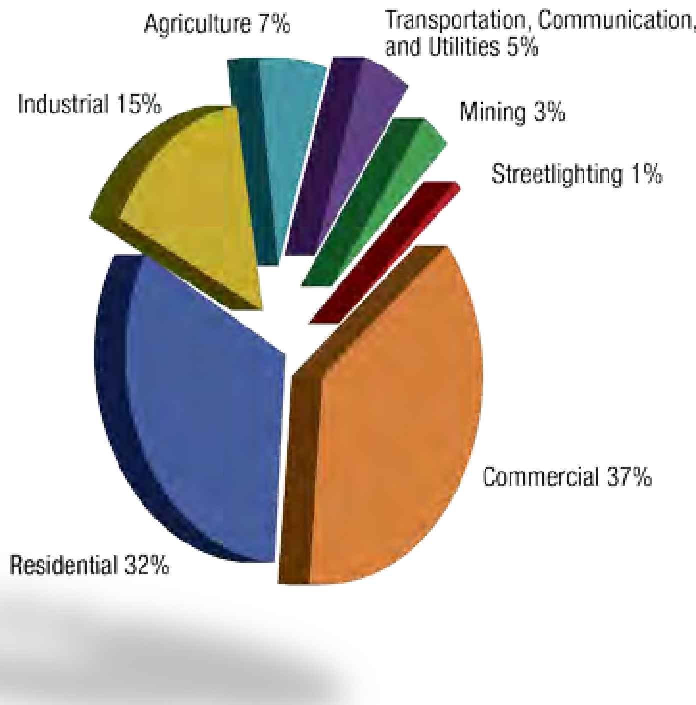
Energy efficiency is a zero-emission strategy to reduce greenhouse gas emissions in the electricity sector. Energy efficiency and conservation programs also reduce energy costs, which makes businesses more competitive and allows consumers to save money. In addition, energy efficiency reduces the cost of meeting peak demand during periods of high temperatures and high prices. By reducing the demand for electricity, energy efficiency programs also play a major role in increasing reliability of the electricity system by reducing stress on existing power plants and the transmission system and reducing the demand for new power plants and transmission infrastructure.

Because of the state's energy efficiency standards and efficiency and conservation programs, California's energy use per person has remained stable for more than 30 years while the national average has steadily increased. However, stabilizing per capita electricity use will not be enough to meet the carbon reduction goals of AB 32. To meet those goals, the state must increase its efforts to achieve all cost-effective energy efficiency. Many of these efforts will be carried out by the investor-owned utilities and the publicly owned utilities, both of which are governed by legislative and regulatory mandates to identify and develop energy efficiency potential and to set annual savings goals. The Energy Commission then uses these goals as the basis for developing its statewide energy efficiency goals.

Strategies to achieve all cost-effective energy efficiency and greenhouse gas emissions reduction goals include promoting the development of zero net energy buildings, increased building and appliance standards, and better enforcement of those standards.

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

FIGURE E-2: ELECTRICITY CONSUMPTION BY SECTOR 2008



Source: California Energy Commission

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

Another issue associated with energy efficiency is how to incorporate the expected energy savings from meeting the state's long-term energy efficiency goals into the Energy Commission's electricity and natural gas demand forecast. Not all of the specific efforts and programs to achieve those goals are in place, since utility programs and efforts are only approved by the California Public Utilities Commission in three-year cycles. However, it is important to understand the impacts of these expected incremental savings as part of the Energy Commission's demand forecasting efforts.

Recommendations

■ The Energy Commission will adopt and enforce building and appliance standards that put California on the path to zero net energy residential buildings by 2020 and zero net energy commercial buildings by 2030.

■ The Energy Commission and the California Public Utilities Commission should work together to develop and implement audit, labeling, and retrofit programs for existing buildings that achieve all cost-effective energy efficiency measures, maximize the benefit of existing utility programs, and expand the use of municipal and utility on-bill financing opportunities.

■ The Energy Commission will use the 2009 adopted forecast as a starting point to estimate the incremental impacts from future efficiency programs and standards that are reasonably expected to occur, but for which program designs and funding are not yet committed. Staff is planning to use and possibly modify Itron's forecasting model, SESAT, for this new purpose, with Itron providing training for the model in early 2010. The Energy Commission, in cooperation with the California Public Utilities Commission, the investor-owned utilities, and the publicly owned utilities, will devote sufficient resources to develop in-house capability to differentiate these future energy efficiency savings from energy efficiency savings that are already accounted for in the demand forecast.

Renewable Energy

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

Challenges with increasing the amount of renewable resources in California's electricity mix are plentiful. They include the difficulty of integrating large amounts of renewable energy into the electricity system; uncertainty on the timeline for meeting Renewables Portfolio Standard goals; environmental concerns with the development of renewable facilities and associated transmission; difficulty in securing project financing; delays and duplication in siting processes; time and expense of new transmission development; the cost of renewable energy in a fluctuating energy market; and maintaining the state's existing baseline of renewable facilities.

The Renewables Portfolio Standard requires retail sellers (defined as investor-owned utilities, electric service providers, and community choice aggregators) to increase renewable energy as a percentage of their retail sales to 20 percent by 2010. State law also requires publicly owned utilities to implement the standard but gives them flexibility in developing specific targets and timelines. In November 2008, Governor Schwarzenegger raised California's renewable energy goals to 33 percent by 2020 in his Executive Order S-14-08, and in September 2009, Executive Order S-21-09 directed the Air Resources Board to develop regulations by July 31, 2010, for a 33 percent Renewable Energy Standard.

In July 2009, the California Public Utilities Commission reported that the three investor-owned utilities were supplying approximately 13 percent of their aggregated total sales from eligible renewable resources as of 2008, far below the 20 percent required by 2010. Publicly owned utilities are showing some progress in renewable energy procurement with expectations for the 15 largest publicly owned utilities of 12.4 percent of Renewables Portfolio Standard-eligible renewable retail sales by 2011, but this progress still falls far short of the renewable target.

Not all renewable generators provide the operating characteristics that the system needs to maintain local area reliability, and integrating certain renewable technologies can make it more difficult to operate the system reliably. While geothermal and biomass resources can provide baseload power, resources like wind, hydro, and solar are intermittent and not always available to meet system needs during peak hours. Intermittent resources can also drop off or pick up suddenly, requiring quick action by system operators to compensate for the sudden changes. Significant energy storage will be required to integrate future levels of renewables, thus allowing better matching of renewable generation with electricity needs. These technologies can also reduce the number of natural gas-fired power plants that would otherwise be needed to provide the characteristics the system needs to operate reliably. However, many storage technologies are still in the research and development stage, are relatively expensive, and need further refinement and demonstration.

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

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

Recommendations

- The Energy Commission, the Air Resources Board, the California Public Utilities Commission, and the California Independent System Operator must continue to work together to implement a 33 percent renewable electricity policy that applies to all load-serving entities and retail providers.

- To reduce regulatory uncertainty for market participants and ensure a long-term and stable renewable energy policy framework for California, the state should pursue legislation to codify the 33 percent renewable target that was identified in Governor Schwarzenegger's Executive Orders S-14-08 and S-21-09.

- The Energy Commission will work with the California Public Utilities Commission, the California Independent System Operator, the federal Bureau of Land Management, the California Department of Fish and Game, and other agencies to implement specific measures to accelerate permitting of new renewable generation and the transmission facilities needed to serve that generation. These measures include the elimination of duplication, shortened permitting timelines, and planning processes such as the Renewable Energy Transmission Initiative and the Desert Renewable Energy Conservation Plan that balance clean energy development and conservation.

- To meet the Governor's target of 20 percent of the state's renewable energy goals from biomass resources that was identified in Executive Order S-06-06, the Energy Commission will facilitate and coordinate programs with other state and local agencies to address barriers to the expansion of biopower, including regulatory hurdles and project financing. The Energy Commission will also encourage additional research and development to reduce costs for biomass conversion, biopower technologies, and environmental controls.

- The Energy Commission will conduct further analysis to identify solutions to integrate increasing levels of energy efficiency, smart grid infrastructure, and renewable energy while avoiding infrequent conditions of surplus generation, or overgeneration, in which more electricity is being generated than there is load to consume it. Potential solutions include better coordination of the timing of resource additions and the mix of resources added to meet customer needs efficiently and maintain system reliability, as well as additional research, development, and demonstration of existing and emerging storage technologies. In addition, there will be efforts to determine what new, more flexible, and efficient natural gas technologies best fit into an electricity grid in transition. The Energy Commission will complete an initial study of the surplus generation issue to identify specific resource and data needs as part of the *2010 Integrated Energy Policy Report Update*, with an in-depth analysis forthcoming in the *2011 Integrated Energy Policy Report*.

Distributed Generation and Combined Heat and Power

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

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

Despite consistent emphasis in past *Integrated Energy Policy Reports* on the need to address barriers to the development of combined heat and power facilities, insufficient progress has been made. In an effort to push forward, the Energy Commission developed a new study of market potential for combined heat and power facilities that includes facilities smaller than 20 megawatts in size that do not typically have excess power to export to the grid. The study examined market penetration over the next 20 years for a base case (status quo) and four alternative cases that included various stimulus and incentive measures. The base case showed about 3,000 megawatts of combined heat and power market penetration, including both generation capacity and avoided electric air conditioning. (The study included alternative incentive scenarios, one of which made available an additional 497 megawatts of combined heat and power for addition to the base case in the event of the passage of SB 412 [Kehoe, Chapter 182, Statutes of 2009]. The bill became law in October.) Implementation of all of the stimulus efforts and incentives used in the alternative cases would more than double market penetration over the next 20 years to about 6,500 megawatts, exceeding the Air Resources Board's 4,000 megawatt target for capacity additions.

Recommendation

■ The Energy Commission will work with the Air Resources Board in the development of combined heat and power to meet the state goals for emission reductions from this technology. Actions include mandates to remove market barriers to the development of combined heat and power facilities and the provision of analytical support on efficiency requirements and other technical specifications so that combined heat and power is more widely viewed and adopted as an energy efficiency measure.

Nuclear Power Plants

As part of the *2008 Integrated Energy Policy Report Update*, the Energy Commission developed *An Assessment of California's Nuclear Power Plants: AB 1632 Report*, as directed by AB 1632 (Blakeslee, Chapter 722, Statutes of 2006). The report addressed seismic and plant aging vulnerabilities of California's in-state nuclear plants – Pacific Gas and Electric Company's Diablo Canyon Power Plant and Southern California Edison's San Onofre Nuclear Generating Station – including reliability concerns as well as concerns over safety culture, plant performance, and management issues at San Onofre. The *AB 1632 Report* also recommended additional studies that Pacific Gas and Electric Company and Southern California Edison should undertake as part of their license renewal feasibility studies for the California Public Utilities Commission and directed the utilities to provide a status report on their efforts toward implementing the recommendations in the *AB 1632 Report* in the *2009 Integrated Energy Policy Report*.

Major policy decisions that will be made in the next several years will shape the next three decades of nuclear energy policy in California. An overarching issue with the state's nuclear facilities is plant license renewal. The Nuclear Regulatory Commission operating licenses for San Onofre Units 2 and 3 are set to expire in 2022, and for Diablo Canyon Units 1 and 2, in 2024 and 2025, respectively. Pacific Gas and Electric announced on November 24, 2009, its intention to file a license renewal application for Diablo Canyon, and Southern California Edison plans to file for license renewal for San Onofre in late 2012.

The Nuclear Regulatory Commission license renewal application process determines whether a plant meets its renewal criteria, but not whether the plant should continue to operate. The Nuclear Regulatory Commission specifically states that it "has no role in the energy planning decisions of State regulators and utility officials as to whether a particular nuclear power plant should continue to operate." It is left to state regulatory agencies to determine whether it is in the best interest of ratepayers and cost effective to continue operation of their state's nuclear plants.

Although the California Public Utilities Commission does not approve or disapprove license applications filed with the Nuclear Regulatory Commission, both Pacific Gas and Electric and Southern California Edison must obtain the California Public Utilities Commission's approval to pursue license renewal before receiving California ratepayer funding to cover the costs of the Nuclear Regulatory Commission license renewal process. The utilities' submission of license renewal feasibility assessments to the California Public Utilities Commission initiates the California Public Utilities Commission's license renewal review proceedings. The California Public Utilities Commission proceedings will not only consider energy planning issues and whether continued operation of the nuclear power plants is in the ratepayers' best interest, but will also consider matters of state jurisdiction such as the economic, reliability, and environmental implications of relicensing.

The California Public Utilities Commission's General Rate Case Decision 07-03-044 required Pacific Gas and Electric to incorporate the Energy Commission's AB 1632 assessment findings and recommendations in its license renewal feasibility study and to submit the study to the California Public

Utilities Commission no later than June 30, 2011, along with an application on whether to pursue license renewal for Diablo Canyon. Letters on June 25, 2009, from the president of the California Public Utilities Commission to Pacific Gas and Electric and Southern California Edison reiterated the requirement for each utility to complete the *AB 1632 Report's* recommended studies, including the seismic/tsunami hazard and vulnerability studies, and report on the findings and the implications of the studies for the long-term seismic vulnerability and reliability of the plants. These studies are necessary to allow the California Public Utilities Commission to properly undertake its obligations to ensure plant and grid reliability in the event that either Diablo Canyon or San Onofre has a prolonged or permanent outage and for the California Public Utilities Commission to reach a decision on whether the utilities should pursue license renewal. However, the utilities' reports to date indicate they are not on schedule to complete these activities in time for California Public Utilities Commission consideration. In addition, both utilities have indicated objections to providing some of the studies and/or requirements indicated by the *AB 1632 Report* and the California Public Utilities Commission General Rate Case Decision.

The Energy Commission believes that the comprehensiveness, completeness, and timeliness with which both utilities provide the studies identified in the *AB 1632 Report* will be a critical part of the California Public Utilities Commission and Nuclear Regulatory Commission reviews of the utilities' license renewal applications.

Recommendation

- Pacific Gas and Electric Company and Southern California Edison should complete all of the studies recommended in the *AB 1632 Report*, should make their findings available for consideration by the Energy Commission, and should make their findings available to the California Public Utilities Commission and the U.S. Nuclear Regulatory Commission during their reviews of the utilities' license renewal applications.

Transmission and Distribution

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

Recommendations

The Energy Commission supports the many recommendations made in the *2009 Strategic Transmission Investment Plan* including those identified below.

- The Energy Commission staff will work with the recently formed California Transmission Planning Group and the California Independent System Operator in a concerted effort to establish a 10-year statewide transmission planning process that uses the Energy

Commission's Strategic Plan proceeding to vet the California Transmission Planning Group plan described in Chapter 4 of the *2009 Strategic Transmission Investment Plan*, with emphasis on broad stakeholder participation.

■ The Energy Commission staff will work with the California Independent System Operator, the California Public Utilities Commission, investor-owned utilities, and publicly owned utilities to develop a coordinated statewide transmission plan using consistent statewide policy and planning assumptions.

Coordinated Electricity System Planning

California has numerous agencies that are involved in electricity planning. While there is some degree of coordination among various agencies and processes, the state needs to find better ways to coordinate and streamline the collective responsibilities of those agencies to achieve the state's greenhouse gas emission reduction, environmental protection, and reliability goals while reducing duplicative or contradictory processes. California needs to better coordinate its electricity policy, planning, and procurement efforts to eliminate duplication and to ensure that planners and policy makers understand the interactions and conflicts that may exist among state energy policy goals.

Recommendation

■ The Energy Commission will work with the California Public Utilities Commission and California Independent System Operator, along with other agencies and interested stakeholders, to develop a common vision for the electricity system to guide infrastructure planning and development. Such coordinated plans can be used to guide each agency's own infrastructure approval and licensing responsibilities and thus maximize coordinated action to achieve state energy policy goals.

Addressing Procurement in the Hybrid Market

At the October 14, 2009, Integrated Energy Policy Report Committee Hearing on the draft *IEPR*, the IEPR Committee solicited comments from parties on how the state should address the current hybrid electric procurement market (a market split between utility-owned generation and contracted third party generation) and improve the investor-owned utility procurement process for electric generation. These issues are critical to state energy policy but did not receive sufficient analysis throughout the 2009 IEPR process. The Independent Energy Producers Association submitted comments expressing support for an examination of the hybrid market structure to determine if it is functioning properly and achieving its original goal of providing a level playing field for utility-owned and independent power generation. In addition, the Western Power Trading Forum submitted comments expressing concerns that utility domination of infrastructure investment is potentially detrimental to competitive wholesale and retail markets and therefore potentially detrimental to technological innovation. The Forum asserts that the existing hybrid market structure requires ratepayers to bear the financial and operational risks associated with new investment and ignores the market's capabilities to actively manage and hedge those risks, and it believes that improving competition at the wholesale and retail levels would create downward pressure on prices.

Recommendation

- The Energy Commission believes these issues deserve a fuller vetting, including an assessment of alternative market models that would better serve the goal of reduced cost to customers. The Energy Commission will invite the California Public Utilities Commission to participate in a more complete evaluation of the existing hybrid market structure as part of the *2010 Integrated Energy Policy Report Update* to identify possible market enhancements and changes to utility procurement practices that would facilitate the reemergence of merchant investment.

Natural Gas

Natural gas is the cleanest of the fossil fuels used in the state and will continue to be a significant energy source for the foreseeable future. Maintaining a reliable natural gas delivery and storage infrastructure is therefore important to support the receipt and delivery of adequate supply to California's millions of natural gas consumers and keep prices low for the residential, commercial, industrial, and electric generation sectors. An expanding California natural gas infrastructure also will allow for the efficient delivery to California of increasing domestic shale gas production and liquefied natural gas imports.

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

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

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

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

Recommendations

■ California should work closely with western states to ensure development of a natural gas transmission and storage system that has sufficient capacity and alternative supply routes to overcome any disruption in the system, such as weather-related line freezes and pipeline breaks. The state should support construction of sufficient pipeline capacity to California to ensure adequate supply at a reasonable price.

■ The Energy Commission will continue to monitor the potential environmental impacts associated with shale gas extraction, including carbon footprint, volume of water use and risk of groundwater contamination, air pollution, and potential chemical leakage. Specifically, the Energy Commission staff will coordinate and exchange information with energy agencies in states with shale gas development, such as New York, Texas, and other midcontinent states, and will report new findings in the *Integrated Energy Policy Report* and other Energy Commission forums.

Fuels and Transportation

State and federal policies encourage the development and use of renewable and alternative fuels to reduce California's dependence on petroleum imports, promote sustainability, and cut greenhouse gas emissions. Governor Schwarzenegger's Executive Order S-06-06 established clear targets for increased use and in-state production of biofuels. California and the federal government also have policies to improve vehicle efficiencies and to reduce vehicle miles traveled in efforts to achieve 2050 greenhouse gas reduction targets of 80 percent below 1990 levels as directed in the Governor's Executive Order S-3-05. Until new vehicle technologies and fuels are commercialized, petroleum will continue to be the primary fuel source for California's vehicles, and the state must enhance and expand the existing petroleum infrastructure, particularly at in-state marine ports, while at the same time working to develop an alternative fuel infrastructure.

The fuels and transportation energy sector is responsible for producing the greatest volume of greenhouse gas emissions – nearly 40 percent of California's total. AB 32 does not directly address greenhouse gas emissions reduction in the transportation sector. Instead, reductions are addressed through California's Low Carbon Fuel Standard, AB 1493 (Pavley, Chapter 200, Statutes of 2002), AB 1007 (Pavley, Chapter 371, Statutes of 2005), and AB 118, the Alternative and Renewable Fuel and Vehicle Technology Program. The policies and standards resulting from these mandates will ultimately change vehicle and fuel technologies in California and accelerate the market for low carbon fuels well beyond the current level of demand.

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

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

California needs sufficient fuel infrastructure to ensure reliable supplies of transportation fuels for its citizens. Reliance on foreign oil imports increasingly puts the state's fuel supply at risk, not only because of security and reliability concerns, but also because the marine ports are not expanding to meet expected growth in demand. Alternative and renewable fuels could face the same constraints at the ports should the state begin to rely on imports of those fuels to meet state and federal renewable fuel standards. In fact, renewable and alternative fuels face even more serious infrastructure issues, as much of the infrastructure that will soon be needed is not even in place. Both petroleum and renewable fuels face infrastructure challenges from the wholesale and distribution level all the way through to the end user.

Recommendations

- With the advent of new California programs such as the Alternative and Renewable Fuel and Vehicle Technology Program (a comprehensive investment program to stimulate the development and deployment of low-carbon fuels and advanced vehicle technologies), the Low Carbon Fuel Standard, and a federal waiver allowing California to set its own carbon dioxide motor vehicle emission standards, California is well positioned to develop a system of sustainable, clean, alternative transportation fuels. The state should continue on its present course of action by providing responsible agencies with the time and funding to implement these programs.

- The Energy Commission will collaborate with partner agencies and stakeholders to develop policy changes to address regulatory hurdles and price uncertainty for alternative fuels, particularly biofuels, in California.

- To maintain energy security, state and local agencies need to ensure that there is adequate infrastructure for the delivery of transportation fuels. The state should modernize and upgrade the existing infrastructure to accommodate alternative and renewable fuels and vehicle technologies as they are developed and to address petroleum infrastructure needs to preserve past investments and to expand throughput capacity in the state.

- The Energy Commission believes that transportation energy efficiency should be pursued through increased federal vehicle fuel economy standards and more sustainable land use practices in conjunction with local governments.

Land Use and Planning

Although land use decisions are made on the local level, they often have statewide implications by directly influencing consumer transportation choices, energy consumption, and greenhouse gas emissions. The *2006 Integrated Energy Policy Report Update* stated that the single largest opportunity to help California meet its statewide energy and climate change goals resides with smart growth – development that revitalizes central cities and older suburbs, supports and enhances public transit, promotes walking and bicycling, and preserves open spaces and agricultural lands. The *2007 Integrated Energy Policy Report* further noted that to reduce greenhouse gas emissions, California must begin reversing the current 2 percent annual growth rate of vehicle miles traveled.

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

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

Recommendations

- To reduce energy use and support the transportation greenhouse gas emission reduction goals of SB 375, state agencies in collaboration with the Strategic Growth Council and local and regional governments will continue to conduct research, develop analytical tools, assemble easy-to-use data, and provide assistance to local and regional government officials to help them make informed decisions about energy opportunities and undertake sustainable land use practices, while recognizing the different needs of rural and urban regions.

The Potential of Carbon Capture and Sequestration

California will need innovative strategies to address greenhouse gas emissions associated with energy production and use. One such strategy is carbon capture and storage, also known as carbon capture and sequestration. The *2007 IEPR* focused on geologic sequestration strategies for the long-term management of carbon dioxide, but there have been encouraging technology advancements and investments since then. Technology developers and policy makers who are examining carbon capture and sequestration applications have expanded from an initial focus on coal and petroleum coke to natural gas and refinery gas, the predominant fossil fuels used in California power plants and industrial facilities.

Recommendation

■ The Energy Commission recommends that, as a mechanism for achieving state energy and environmental objectives, it continue to support and conduct carbon capture and sequestration research to demonstrate technology performance and facilitate interagency coordination to develop the technical data and analytical capabilities necessary for establishing a legal and regulatory framework for this technology in California.

Achieving Energy Goals

California needs reliable, affordable, and clean supplies of energy to serve its citizens and maintain a strong economy. The state's electricity, natural gas, and transportation sectors must continuously respond to changes in supply and demand, new policies and technologies and their associated challenges, and increasing environmental regulation. California must bolster its current energy foundation with an aggressive and wide-ranging agenda that will continue to reduce energy demand, promote development of renewable energy resources, ensure development of cleaner fossil resources, give consumers more energy choices, and build the necessary infrastructure to protect the state from future supply disruptions and high prices.

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CHAPTER 1
CALIFORNIA'S ENERGY POLICIES

In 2006, the Legislature passed and Governor Schwarzenegger signed Assembly Bill 32 (Núñez, Chapter 488, Statutes of 2006), the Global Warming Solutions Act of 2006, which established the goal of reducing greenhouse gas (GHG) emissions to 1990 levels by 2020. AB 32 was the first law of its kind to address climate change by implementing regulatory market mechanisms to achieve real and measurable GHG reduction targets. AB 32 is the driving force for California's energy policy and programs, and the state must integrate many existing policies and legislation into a symbiotic whole under AB 32's broad umbrella.

At the same time, it is important to recognize that AB 32 is one of many policies that guide energy development, production, and use in California. Many policies and programs in existence prior to passage of AB 32 helped the state make steady progress toward more responsible stewardship of the planet and its resources. These are discussed later in the chapter and include the goal of achieving all cost-effective energy efficiency, the Renewables Portfolio Standard, the California Solar Initiative, the power plant Emission Performance Standard, and regulations to reduce GHG emissions from motor vehicles. While many of the energy policies in place are complementary, there can also be overlap or conflict among those policies because they are often designed to address different problems.

In addition to the challenge of integrating new and existing policies, laws, and regulations, there are challenges in coordinating the various agencies that implement those policies.

The Energy Commission, the California Public Utilities Commission, California Independent System Operator, the California Air Resources Board, California Environmental Protection Agency, and the State Water Resources Control Board all have very specific missions, jurisdictions, and expertise. Working collaboratively is a challenging and ongoing goal, as agencies strive to integrate policies to establish priorities and transform broadly framed objectives into concrete, efficient, and coordinated programs and actions.

This chapter provides background on and a brief status of current policies and programs that affect California's three major energy sectors – electricity, transportation, and natural gas – as well as those that affect land use and planning. The purpose is to provide decision makers with the context for the more detailed discussions in subsequent chapters of the various policy efforts underway and the challenges associated with meeting California's energy policy goals. The description of the energy policy landscape may also help decision makers see how policies overlap or complement each other, as well as where gaps may exist that require additional action to ensure a clean, efficient, and affordable energy future for California.

AB 32 Framework

Assembly Bill 32 legislation charged the California Air Resources Board (ARB) with developing regulations and developing market mechanisms to ultimately reduce California's GHG emissions by 25 percent by 2020. The ARB's *Climate Change Scoping Plan* report, approved on December 12, 2008, outlines the main strategies for meeting that goal. The *Climate Change Scoping Plan* contains a range of GHG-reduction actions including direct regulations, alternative compliance mechanisms, monetary and nonmonetary incentives, voluntary actions, market-based mechanisms such as a cap-and-trade system, and an AB 32 cost of implementation fee regulation to fund the program. The ARB and other state agencies must adopt these reduction measures by the start of 2011. The ARB has already adopted a number of "early action" measures required by the *Climate Change Scoping Plan*, such as the Low Carbon Fuel Standard, and is now working on the plan's other measures.[1]

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

Electricity

California's loading order provides an overall framework for meeting the state's growing electricity needs while achieving the GHG emissions reduction goals mandated by AB 32. The loading order was originally adopted in the *2003 Energy Action Plan I*, a collaborative effort by the Energy Commission, the California Public Utilities Commission (CPUC), and

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

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

the California Power Authority (now defunct). The loading order calls for California's electricity needs to be met first with increased energy efficiency and demand response; second, with new generation from renewable energy and distributed generation resources; and third, with clean fossil-fueled generation and infrastructure improvements. The policies and programs affecting the electricity sector are presented below in the same general sequence as the loading order.

Energy Efficiency and Demand Response

Energy efficiency and demand response measures are the first resources in the loading order because they can contribute to meeting climate change goals with little or no impact on the environment and with measurable benefits (for example, cost savings) to the consumer. Since the 1970s, the Energy Commission has set efficiency standards for buildings and appliances to reduce energy demand and increase savings from energy efficiency.

The following mandates and plans in the area of energy efficiency and demand response will contribute toward reducing energy demand and meeting the AB 32 goals:

Assembly Bill 2021 (Levine, Chapter 734, Statutes of 2006): This bill requires the Energy Commission, in consultation with the CPUC and publicly owned utilities, to develop a statewide estimate of all potentially achievable cost-effective electricity and natural gas efficiency savings and establish statewide annual targets for energy efficiency savings and demand reduction over 10 years.

Assembly Bill 758 (Skinner, Chapter 470, Statutes of 2009): This bill requires the Energy Commission to establish a regulatory proceeding by March 1, 2010, to develop a comprehensive program to achieve greater energy savings in existing residential and nonresidential buildings.

CPUC Long Term Energy Efficiency Strategic Plan: In September 2008, the CPUC adopted California's first strategic plan for energy efficiency that provides a road map to achieve maximum energy savings across all sectors in California. The plan includes four specific programmatic goals, known as the "Big Bold Energy Efficiency Strategies": 1) all new residential construction in California will be zero net energy by 2020; 2) all new commercial construction in California will be zero net energy by 2030;[3] 3) heating, ventilation, and air conditioning will be transformed to ensure that its energy performance is optimal for California's climate; and 4) all eligible low-income customers will be given the opportunity to participate in the low-income energy efficiency program by 2020.

ARB's *Climate Change Scoping Plan*: The plan outlines emission reductions in the electricity sector from maximizing building and appliance standards, implementing additional conservation and efficiency programs, increasing combined heat and power (CHP), and more utility programs. The plan also calls for similar strategies in the natural gas sector such as increased installations of solar water heating systems throughout the state.

Strategies and Progress

AB 2021 is a key legislative strategy for the utilities to expand their energy efficiency programs. Under AB 2021, the Energy Com-

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

mission is required to develop statewide estimates of energy efficiency potential and goals for California's private and public utilities. The Energy Commission reports on utility progress in meeting these goals as part of its biennial *Integrated Energy Policy Report* (*IEPR*).

The 2008 progress report, *Achieving Cost-Effective Energy Efficiency for California: Second Annual AB 2021 Progress Report*,[4] found that during the CPUC's 2006–2008 efficiency program cycle, the investor-owned utilities (IOUs) exceeded their three-year energy efficiency goals. During this period, the IOUs achieved more than 200 percent of their electric energy savings goal and 150 percent of their natural gas savings goal. However, these savings have not yet been verified, and measurement and verification studies completed for the 2004–2005 efficiency programs indicate that verified program savings could be less than those reported. The progress report also found that efficiency savings recorded by publicly owned utilities increased substantially from 2007 to 2008, reaching 66 percent of AB 2021 adopted goals in 2008.

There are various efforts underway to increase energy efficiency savings in California. The Energy Commission's Public Interest Energy Research (PIER) program helps improve energy efficiency technologies and strategies, with $180 million devoted to efficiency-related efforts from 1997–2007.[5] The PIER program funds research, development, and demonstration (RD&D) in the following efficiency program areas: buildings end-use energy efficiency, industrial/agriculture/water end-use efficiency, demand response, and distributed energy resources system integration.[6] With the passage of the Energy Independence and Security Act (EISA) of 2007 (Title XIII), the evolution of the nation's smart grid provides new potential to achieve higher penetration of energy efficiency and demand response technologies and capabilities. The PIER program is actively funding new research in the smart grid area to better define how to take advantage of all the capabilities the smart grid will offer California in the future.

In the area of demand response and load management, the Energy Commission's *2007 IEPR* recommended initiating a formal rulemaking process involving the CPUC and California Independent System Operator (California ISO) to pursue the adoption of load management standards under the Energy Commission's existing authority. The Energy Commission opened an informational proceeding and rulemaking on load management standards in January 2008. In November 2008, the Energy Commission's Efficiency Committee published a draft analysis that focused on advanced metering, time variant rate design, and demand response enabling technologies. The Efficiency Committee and staff held workshops and discussions with stakeholders from December 2008 through March 2009. Since that time, the National Institute of Standards and Technology has taken up the issue of demand response communication standards for possible federal action. In addition, most California utilities have aggressively expanded their advanced metering infrastructure rollouts and the U.S. Department of Energy has directed smart grid American Recovery and Reinvestment Act of 2009 (ARRA)

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

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

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

funding toward demand response issues like advanced metering infrastructure.[7] In light of these significant developments, Energy Commission staff is currently working with the Efficiency Committee to evaluate the necessity of a formal regulation to achieve state demand response and load management policy goals.

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

The Energy Commission adopted the Energy Efficiency and Conservation Block Grant *Block Grant Guidelines* on October 7, 2009, which describe the eligibility and procedural requirements for applying for program funds, and released the grant solicitation and application package on October 8. The Energy Commission held a series of application development clinics throughout California to assist eligible small cities and counties with their applications. Applications are due on January 12, 2010. Overall, this program is a crucial strategy for assisting small cities and counties in implementing projects and programs that reduce total energy use and fossil fuel emissions and improve energy efficiency in building and other appropriate sectors.

ARRA is also providing $226 million in funding to the Energy Commission for the State Energy Program. Earlier in the year, the Energy Commission held a series of informational workshops throughout the state to inform stakeholders of the funding guidelines and application process. The Energy Commission adopted the *State Energy Program Guidelines* on September 30, 2009, which describe implementation and administration of specific program areas funded by the State Energy Program. As of November 2009, the Energy Commission had allocated $25 million to the Department of General Services' Energy Efficient State Property Revolving Loan Program, $25 million to the Energy Conservation Assistance Act 1% Low Interest Loans, and $20 million to the Green Jobs Workforce Training Program. In addition, the Energy Commission is in the process of making $95 million available for energy projects focused on residential and commercial building retrofits for energy efficiency measures and installing on-site photovoltaic systems. Under this program, local jurisdictions, nonprofits, or private organizations can create partnerships and apply for program funding under a competitive solicitation process for three different areas: the California Comprehensive Residential Building Retrofit Program, the Municipal and Commercial Building Targeted Measure Retrofit Program, and the Municipal Financing Program for programs related to AB 811 (Levine, Chapter 159, Statutes of 2008), which authorizes all cities and counties in California to designate areas where willing property owners can enter into contractual assessments to finance installation of distributed renewable generation, as well as energy efficiency improvements.

Overall, this program is an important strategy for making buildings and industrial facilities more energy efficient and will help finance such projects.

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

Renewable Energy

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

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

***Energy Action Plans I* (2003) and *II* (2005):** The first *Energy Action Plan* recommended accelerating the RPS deadline to 20 percent by 2010, and the second recommended an accelerated goal of 33 percent renewables by 2020.

Senate Bill 107 (Simitian, Chapter 464, Statutes of 2006): Required the IOUs to meet the "20 percent by 2010" goal as recommended in the *Energy Action Plan I*. The bill expanded the RPS reporting requirements of the publicly owned utilities to the Energy Commission and expanded RPS eligibility of out-of-state renewable resources.

Executive Order S-06-06 (2006): Established a biomass target of 20 percent within the established RPS goals for 2010 and 2020.

Executive Order S-14-08 (2008): Established accelerated RPS targets (33 percent by 2020) as recommended in the *Energy Action Plan II*. The order also called for the formation of the Renewable Energy Action Team, comprised of the Energy Commission, Department of Fish and Game, Bureau of Land Management, and U.S. Fish and Wildlife Service. Through the team, the Energy Commission and the Department of Fish and Game are to prepare a plan for renewable development in sensitive desert habitat.

Executive Order S-21-09 (2009): Directs the ARB to work with the CPUC, the California ISO, and the Energy Commission to adopt regulations increasing California's RPS to 33 percent by 2020. The ARB must adopt these regulations by July 31, 2010.

Strategies and Progress

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

The Energy Commission's Renewable Energy Program has, since 1998, encouraged investments in renewable energy by providing rebates and electricity production incentives for new and existing renewable facilities and emerging renewable technologies. The program has supported more than 5,000 megawatts (MW) of existing and new renewable generating capacity with approximately $2 billion in funding over the life of the program. Funding collection for the program is set to expire January 1, 2012.

Under SB 1078, the Energy Commission and the CPUC jointly implement the RPS for all but the publicly owned electric utilities, who implement their own RPS programs. The Energy Commission is responsible for certifying eligible facilities as "RPS eligible" and has certified 600 facilities since 2002. The Energy Commission is also responsible for tracking and verifying RPS procurement and was instrumental in the development of the Western Renewable Energy Generation Information System as the official accounting system for tracking renewable energy credits (also known as RECs) in the Western Interconnection region.[8] The CPUC's responsibilities include approving IOU procurement plans and RPS-eligible contracts for IOUs, ensuring compliance, and setting benchmark pricing for investor-owned utility RPS contracts. The CPUC also oversees RPS programs for electric service providers and small and multi-jurisdictional utilities. As of November 2009, the CPUC had approved 129 RPS contracts totaling 10,271 MW, with an additional 30 contracts for 4,605 MW under review. About 900 MW of these approved contracts are online and delivering energy to the grid.[9]

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

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

9 California Public Utilities Commission, *Renewables Portfolio Standard Quarterly* Report, November 2009, available at: [http://www.cpuc.ca.gov/NR/rdonlyres/52BFA25E-0D2E-48C0-950C-9C82BFEEF54C/0/FourthQuarter2009RPSLegislativeReportFINAL.pdf].

with expectations for the 15 largest publicly owned utilities of 12.4 percent of RPS-eligible renewable retail sales by 2011. In addition, the Los Angeles Department of Water and Power recently set goals to divest entirely from coal-powered generation and increase its renewable energy portfolio to 40 percent by 2020.

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

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

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

An additional strategy to help the state meet its RPS targets is the use of feed-in tariffs – fixed, long-term prices for energy. Countries such as Spain and Germany have implemented successful feed-in tariff programs, but this concept has been slow to gain momentum in California. The state made some progress when the CPUC adopted a feed-in tariff (Decision 07-07-027) in February 2008, for renewable energy systems at publicly owned water and wastewater treatment facilities. In the same decision, the CPUC expanded the feed-in tariff approach to any renewable system with a capacity of up to 1.5 MW in the Southern California Edison (SCE) and Pacific Gas and Electric (PG&E) service areas.

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

The Executive Order required the Energy Commission to provide a progress report in

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

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

the biennial *IEPR* on the 63 action items. To date, the Energy Commission has found that most of the items have been implemented or are ongoing. For those that have not been put into action, many are no longer relevant, have been overtaken by other events, or have not been funded. In 2008, California met the goal of generating 20 percent of its renewable electricity from biomass sources. However, biomass capacity in the state has decreased since 2002, from 6,192 MW to 5,724 MW.[12] This decrease resulted from the expiration of standard offer contracts from the 1990s, while very few contracts have been signed for new electricity generation fueled by biomass and biogas. The existing fleet of biomass generators depends on financial support from the Energy Commission's Renewable Energy Program, funding for which expires in 2011. These findings are provided in the Energy Commission's *2009 Draft Bioenergy Progress to Plan* report, with anticipated publication in January 2010.

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

Finally, one other strategy for meeting the RPS is the California ISO's Integration of Renewable Resources Program, which involves working with the Energy Commission and other agencies to identify issues and solutions for the integration of large amounts of renewable resources into the California ISO Control Area.[13] The California ISO completed studies on 20 percent RPS by 2010 in July 2009, and is working on the 33 percent RPS by 2020 scenarios, which it expects to complete by December 2009.

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

13 California Independent System Operator, see [http://www.caiso.com/1c51/1c51c7946a480.html].

Distributed Generation

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

Assembly Bill 1969 (Yee, Chapter 731, Statutes of 2006): This bill authorized feed-in tariffs for small renewable generators of less than 1 MW at public water and wastewater treatment facilities. In July 2007, the CPUC (D. 07-07-027) implemented AB 1969, expanded the feed-in tariffs to 1.5 MW, and included nonwater customers in the PG&E and SCE territories. The power sold to the utilities under feed-in tariffs can be applied toward the state's RPS targets. Senate Bill

380 (Kehoe, Chapter 544, Statutes of 2008) codified CPUC's expanded feed-in tariff to include all RPS-eligible generators 1.5 MW and below. The program cap was also expanded from 250 MW to 500 MW. As of August 2009, 14.5 MW of contracted capacity had resulted from the tariff.

Assembly Bill 1613 (Blakeslee, Chapter 713, Statutes of 2007): Also known as the Waste Heat and Carbon Emissions Reduction Act, this bill was designed to encourage the development of new CHP systems in California with a generating capacity of up to 20 MW, resulting in more efficient use of natural gas and reduced GHG emissions. The bill requires the CPUC and the Energy Commission to establish policies and procedures for the purchase of electricity from eligible CHP systems.

ARB's Climate Change Scoping Plan: The ARB set a target of 4,000 MW of CHP that would displace 30,000 gigawatt hours of demand from other power generation resources with the overall goal of reducing carbon dioxide (CO_2) by 6.7 million metric tons.

Senate Bill 1 (Murray, Chapter 132, Statutes of 2006): This bill enacted the Governor's Million Solar Roofs program with the overall goal of installing 3,000 MW of solar photovoltaic (PV) systems.

Senate Bill 32 (McLeod, Chapter 328, Statutes of 2009): This bill requires each local publicly owned electric utility with 75,000 or more retail customers to offer a feed-in tariff for eligible renewable energy facilities up to 3 MW in size until the utility meets its proportionate share of a total statewide cumulative cap of 750 MW. The feed-in tariff price is to reflect the value of every kilowatt hour of electricity generated based on the time of delivery. The price may be adjusted based on other attributes of renewable generation. SB 32 also requires IOUs to expand their current feed-in tariffs for eligible renewable energy facilities from 1.5 MW to 3 MW until the utility meets its proportionate share of a total statewide cumulative cap of 750 MW. Prior to this bill, the statewide cap was 500 MW. The feed-in tariff shall provide performance guarantees for any generator greater that 1 MW.

Strategies and Progress

Increasing CHP is a key strategy for displacing conventional power sources. To help track the state's CHP goals, the ARB will report on the GHG emissions reductions resulting from the increase of electricity generated from CHP. Also, in January 2010, the Energy Commission is scheduled to adopt guidelines to establish the technical criteria for CHP system eligibility for programs developed by IOUs and publicly owned utilities.

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

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

Solar incentive programs offered by the publicly owned utilities must abide by the minimum guidelines adopted by the Energy Commission in December 2008. These solar incentive programs have their own processes and requirements and are expected to achieve 700 MW of installed solar capacity by the end of 2016.

Another customer-side strategy is the Self-Generation Incentive Program, which is implemented by the CPUC through the IOUs and provides rebates for customers who install wind turbines and fuel cells. The program originally included microturbines, small gas turbines, wind turbines, solar photovoltaics, fuel cells, and internal combustion engines, but as of January 1, 2008, eligibility was limited to fuel cells and wind energy technologies. However, SB 412 (Kehoe, Chapter 182, Statutes of 2009), signed in October 2009, expands program eligibility to include "distributed energy resources that the [CPUC], in consultation with the State Air Resources Board, determines will achieve reductions of greenhouse gas emissions." As of December 2008, the IOUs have paid more than $600 million in rebates for more than 1,200 projects totaling more than 337 MW of generating capacity. The Energy Commission administers a similar program, the Emerging Renewables Program, which continues to be limited to small wind turbines and fuel cells that use renewable fuels.

Net metering is another strategy to help increase customer-side distributed generation technologies, particularly PV. Customers who install an on-site renewable energy system can apply for net metering, which is a special billing arrangement with the utility. The customer's electric meter tracks electricity generated by the renewable system versus electricity consumed, with the customer paying only for the net amount taken from the grid over a 12-month period. As of October 2009, the CPUC reports that more than 90 percent of the 509 MW of grid-connected solar in IOU territories are net metered.[14] In addition, in October 2009, PG&E committed to increase the amount of net metering for rooftop solar in its territory from 2.5 percent to 3.5 percent to ensure that investment in solar continues to grow.[15]

Natural Gas and Nuclear Power Plants

Despite long-term efforts to promote preferred resources like energy efficiency, demand response, distributed generation, and renewable energy, California still relies on natural gas and nuclear power plants for about 60 percent of its electricity. Since deregulation in 1998, the Energy Commission has reviewed and licensed 66 electric generation projects, totaling 25,744 MW. Forty-seven of these licensed facilities, totaling more than 15,000 MW of natural gas-fired capacity, have been built and are on-line.

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

State Water Resources Control Board's Once-Through Cooling Resolution (2006): The State Water Resources Control Board (SWRCB) passed a resolution to reduce marine impacts from once-through cooling (OTC) systems used by 21 coastal power plants in

14 California Public Utilities Commission, *California Solar Initiative Staff Progress Report*, October 2009, Table 7, [http://www.cpuc.ca.gov/NR/rdonlyres/4B614602-0E76-4533-A03A-BC01B6A89831/0/ProgrReportOct09Final_3_withcover.pdf].

15 Office of the Governor, October 26, 2009, press release, "Governor Schwarzenegger Secures Commitment to Continue Net Metering for Solar," [http://gov.ca.gov/press-release/13731/].

California, including natural gas and nuclear plants. This began as a coordinated process between several government agencies to phase out the use of OTC.

Assembly Bill 1632 (Blakeslee, Chapter 722, Statutes of 2006): This legislation directed the Energy Commission to assess the vulnerability of California's largest baseload plants, PG&E's Diablo Canyon Nuclear Power Plant (Diablo Canyon) and SCE's San Onofre Nuclear Generating Station (SONGS), to an extended shutdown due to a major seismic event or aging. AB 1632 also called for an examination of potential impacts from the accumulation of nuclear waste at both locations and an exploration of other key issues such as plant relicensing and worker safety.

Senate Bill 1368 (Perata, Chapter 598, Statutes of 2006): This bill limited long-term investments in baseload generation by the state's utilities to power plants that meet an emissions performance standard jointly established by the Energy Commission and the CPUC.

***2005* and *2007 IEPR* Policy on Aging Power Plants:** In both reports, the Energy Commission recommended that the CPUC require IOUs to procure enough capacity from long-term contracts to allow for the orderly retirement or repowering of aging plants by 2012. In the *2007 IEPR*, the Energy Commission recommended that California's utilities adopt all cost-effective energy efficiency measures for natural gas, including replacement of aging power plants with new efficient power plants. In addition, the *2007 IEPR* recommended the Energy Commission, the CPUC, the California ISO, and other interested agencies work together to complete studies on the impacts of retiring, repowering, and replacing aging power plants, particularly in Southern California.

ARB's *Climate Change Scoping Plan*: The *Climate Change Scoping Plan* calls for industrial facilities, such as power plants, to implement cost-effective GHG emissions reduction strategies. Specifically, the *Climate Change Scoping Plan* requires a reduction in GHG emissions from fugitive emissions (for example, from leaks in plant equipment like valves, seals, and so on) from oil and gas extraction and gas transmission.

Assembly Bill 1318 (Perez, Chapter 285, Statutes of 2009): Under existing law, air pollution control districts or air quality management district governing boards are required to establish emission reduction credit systems that are to be used to offset certain future increases in the emission of air contaminants. These must be banked prior to use to offset future increases in emissions. This bill exempts certain actions on emission credits undertaken by the South Coast Air Quality Management District (SCAQMD) to be exempt from the California Environmental Quality Act (CEQA).

Senate Bill 827 (Wright, Chapter 206, Statutes of 2009): This bill authorizes SCAQMD to issue permits under specific circumstances notwithstanding the court decision on CEQA.

Strategies and Progress

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

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

The energy agencies submitted a final strategy in May 2009, that calls for replacing existing OTC facilities with some combination of repowered technologies onsite, new generation located in other areas, and/or upgrades to the transmission system. The SWRCB accepted the proposal and included references to it in its draft OTC policy on June 30, 2009.[16] The OTC concerns relating to grid reliability, with emphasis on Southern California, are discussed in more detail in Chapter 3.

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

The Energy Commission's report, *An Assessment of California's Nuclear Power Plants: AB 1632 Report,*[17] adopted as part of the *2008 IEPR Update*, recommended that PG&E and SCE update studies on the seismic hazard at their nuclear plants, investigate plant seismic safety compliance with current codes and standards, describe plant repair plans and time frames in the event of an earthquake, provide evidence of strong safety cultures (especially at SONGS), and report findings from these studies as part of their license renewal feasibility studies for the CPUC and in future *IEPRs*.

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

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

17 Available at: [http://www.energy.ca.gov/2008publications/CEC-100-2008-009/CEC-100-2008-009-CMF.PDF]. The report was based on a report prepared by MRW & Associates for the California Energy Commission, *AB 1632 Assessment of California's Operating Nuclear Plants*, October 2008, CEC-100-2008-005-F, available at: [http://www.energy.ca.gov/2008publications/CEC-100-2008-005/CEC-100-2008-005-F.PDF].

Transmission and Distribution

The state's transmission and distribution system is another critical component of the electricity sector for serving California's growing population and integrating renewable energy. The state has implemented several key legislative mandates addressing transmission planning and permitting, and recent passage of legislation requiring a "smart grid" deployment plan reflects the growing importance of these technologies in improving efficiency, reliability, and cost-effectiveness of the state's electrical system.

Senate Bill 1565 (Bowen, Chapter 692, Statutes of 2004): In 2004, the Legislature addressed the need for an official state role in transmission planning with the passage of this bill. Senate Bill 1565 directed the Energy Commission to develop a *Strategic Transmission Investment Plan* which identifies and recommends actions to stimulate transmission investments to ensure reliability, relieve congestion, and meet future growth in load and generation, including renewable resources, energy efficiency, and other demand reduction measures. The *Strategic Transmission Investment Plan* is a companion document to the *Integrated Energy Policy Report* and is adopted by the Energy Commission along with that report.

Senate Bill 1059 (Escutia, Chapter 638, Statutes of 2006): This bill required the Energy Commission to designate transmission corridor zones on state and private lands available for future high-voltage electricity transmission projects, consistent with the state's electricity needs identified in the *Integrated Energy Policy Reports* and *Strategic Transmission Investment Plans*.

Senate Bill 17 (Padilla, Chapter 327, Statutes of 2009): This bill requires the CPUC (in consultation with the Energy Commission, the California ISO, and other key stakeholders) to determine the requirements for a smart grid deployment plan consistent with the policies set forth in the bill and federal law by July 1, 2010. The bill requires the smart grid to improve overall efficiency, reliability, and cost-effectiveness of electrical system operations, planning, and maintenance. Each electrical corporation must develop and submit a smart grid deployment plan to the CPUC for approval by July 1, 2011.

Strategies and Progress

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

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

In 2004, the PIER program established the Transmission Research Program to specifically address the research and development needs of California's transmission system. The program considers new and emerging technologies that can increase the capabilities of existing transmission lines and provide better understanding of system management issues associated with the penetration of high amounts of renewable generation and integrating new high-speed data collection technologies like synchrophasors.[18] Research continues in areas specifically addressing the issues associated with renewable integration into the California transmission system.

Natural Gas

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

California Public Resources Code: The code directs the Energy Commission to conduct assessments and forecasts of all aspects of energy industry supply, production, transportation, delivery and distribution, demand, and prices at least every two years and to identify impending or potential problems or uncertainties in the electricity and natural gas markets, as well as potential options and solutions and recommendations.

California Climate Change Policies: The policies directing the state to meet climate change goals, such as the RPS and the ARB's *Climate Change Scoping Plan*, intend to reduce the state's dependence on fossil fuels – such as natural gas – and replace them with cleaner fuel resources.

Strategies and Progress

California relies on natural gas for more than 45 percent of its total system power needs.[19] Eighty-seven percent of natural gas supplies are imported via pipelines from the Southwest, the Rocky Mountains, and Canada. This reliance on out-of-state natural gas leaves California vulnerable to supply disruptions and price volatility. Since 2000, the United States has experienced four major price spikes that affected residential, commercial, and industrial consumers, as well as power generators and gas producers. During the 2000–2001 energy crisis, natural gas cost California $19.4 billion, more than double the price paid for similar amounts in the years just before the crisis.

This issue has been addressed by new expansions of interstate pipelines, improvements in utilities' receiving ability, and the enhancement by utilities and independent storage owners of their storage operations to meet future high demand conditions. These efforts have given California's utilities the flexibility to choose supply sources in their day-to-day operations and have forced natural gas production areas to compete for a share of the state's natural gas market. However, California is still part of an international natural gas market that includes Canada, the United States, and Mexico. A disruption in one

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

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

area ripples through the rest of the market.

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

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

The *2007 IEPR* recommended that California should promote the use of pipeline-quality biogas from dairies and landfills as a strategy to diversify supplies of natural gas. At the 2009 IEPR Scoping Workshop in June 2008, the Natural Resources Defense Council recommended that the *2009 IEPR* pursue policies that encourage the replacement of natural gas with renewable resources. The Energy Commission examined this issue and found that there are still significant barriers hindering the in-state development of this resource, including AB 4037 (Hayden, Chapter 932, Statutes of 1988), which discourages injection of biogas into natural gas pipelines by penalizing landfill gas and pipeline operators if vinyl chloride is found in the pipeline. This has resulted in pipeline operators purchasing from out-of-state sources that are not restricted under the law.

Fuels and Transportation

California has taken a clear policy stance of decreasing reliance on petroleum fuels by increasing the mix of alternative and renewable fuels and improving fuel efficiency. Petroleum will continue to be the primary fuel source for California's vehicles, at least in the near term, so it must be factored into all policy decisions regarding infrastructure and transportation supply and demand. As California relies increasingly on crude oil imports, the state is looking at ways to enhance and expand the existing petroleum infrastructure, particularly at in-state marine ports. California has adopted the following policies affecting the transportation sector.

Assembly Bill 1493 (Pavley, Chapter 200, Statutes of 2002): The bill required the ARB to develop and adopt, no later than January 1, 2005, regulations to achieve the maximum feasible and cost-effective reduction of GHG emissions from motor vehicles.

***2003 Integrated Energy Policy Report*:** The Energy Commission showed that it is feasible to significantly reduce the state's dependence on petroleum by increasing vehicle efficiency and the use of alternative fuels and recommended that the state increase the use of nonpetroleum fuels to 20 percent of on-road fuel consumption by 2020, and 30 percent by 2030, based on identified strategies that are achievable and cost-beneficial.[20]

***2005 Integrated Energy Policy Report*:** The Energy Commission examined petroleum reduction options and recommended that the state develop flexible overarching strategies that simultaneously reduce petroleum fuel use, increase fuel diversity and security, and reduce air pollution and GHG emissions and that it implement a public goods charge to establish a secure, long-term source of funding for a broad transportation program.[21]

Executive Order S-3-05 (2005): The executive order established statewide GHG emission reduction targets that preceded the enactment of AB 32: by 2010, reduce emissions to 2000 levels; by 2020, reduce emissions to 1990 levels; and by 2050, reduce emissions to 80 percent below 1990 levels.

Assembly Bill 1007 (Pavley, Chapter 371, Statutes of 2005): This bill required the Energy Commission to prepare, jointly with the ARB, a plan to increase the production and use of alternative and renewable fuels in California based on a full fuel-cycle assessment of the environmental and health impacts of each fuel option. The *State Alternative Fuels Plan* was adopted by the two agencies in December 2007. The plan highlights the need for state government incentive investments of more than $100 million per year for 15 years and recommends that the state adopt alternative and renewable fuel use goals of 9 percent by 2012, 11 percent by 2017, and 26 percent by 2022.

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

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

***Bioenergy Action Plan* (2006):** The Energy Commission adopted this plan with the intent to maximize the contributions of bioenergy toward achieving the state's petroleum reduction, climate change, renewable energy, and environmental goals. The plan recommends a production target of a minimum of 20 percent of biofuels produced in California by 2010, 40 percent by 2020, and 75 percent by 2050.[22]

Executive Order S-06-06 (2006): This order set targets for the production of biofuels based on the recommendations of the *Bioenergy Action Plan* and charged the Energy Commission, along with other commissions and departments, to identify and secure funding for RD&D projects to advance the use of biofuels for transportation.

Executive Order S-01-07 (2007): Governor Schwarzenegger's order established a Low Carbon Fuel Standard (LCFS) for transportation fuels sold in California. By 2020, the standard will reduce the carbon intensity of California's passenger vehicle fuels by at least 10 percent. The Executive Order directs the secretary for the Cal/EPA to coordinate the actions of the Energy Commission, the ARB, the University of California, and other agencies to assess the "life-cycle carbon intensity" of transportation fuels. ARB completed its review of the LCFS protocols and adopted them as an early action in October 2007. The ARB, through its rulemaking, adopted the new standard in April 2009.

Assembly Bill 118 (Núñez, Chapter 750, Statutes of 2007): This bill created the Alternative and Renewable Fuel and Vehicle Technology Program. The statute, subsequently amended by AB 109 (Núñez, Chapter 313, Statutes of 2008), authorizes the Energy Commission to develop and deploy alternative and renewable fuels and advanced transportation technologies to help attain the state's climate change policies. The Energy Commission has an annual program budget of approximately $100 million and is required to adopt and update annually an investment plan that determines the funding priorities.

The Energy Independence and Security Act of 2007: This federal legislation requires ever-increasing levels of renewable fuels – a Renewable Fuel Standard (RFS) – to replace petroleum. Primarily focused on ethanol, the law establishes the national goal of using 36 billion gallons of renewable fuel per year by 2022. An updated version of the standard, called RFS2, is scheduled to take effect January 1, 2010.[23]

Senate Bill 375 (Steinberg, Chapter 728, Statutes of 2008): This bill requires the ARB to develop, in consultation with metropolitan planning organizations, passenger vehicle GHG emission reduction targets for 2020 and 2035 by September 30, 2010. Through the SB 375 process, regions will work to integrate development patterns, the transportation network, and other transportation measures and policies in a way that achieves GHG emission reductions while meeting regional planning objectives.

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

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

Strategies and Progress

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

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

On April 22, 2009, the Energy Commission adopted its first Investment Plan for the Alternative and Renewable Fuels and Vehicle Technology Program.[24] The Investment Plan contains specific recommendations for expending the $176 million appropriated for the first two years of the program (fiscal years 2008–09 and 2009–10). The Investment Plan allocates $46 million for electric drive vehicles, $40 million for hydrogen fueling stations, $12 million for generation I biofuels (or ethanol), $6 million for generation II biofuels (or renewable diesel and biodiesel), $43 million for natural gas development including biomethane production plants, $2 million for propane medium-duty vehicles (such as school buses), and $27 million for workforce training, sustainability studies, standards and certification, and public education.

Another $83.45 million from ARRA federal stimulus funds will be added to this effort, as well as training and workforce development needs in the transportation sector. Leveraging these federal dollars for projects consistent with the AB 118 funding goals will spur innovation and competition in the development of alternative fuels, technologies, advanced vehicles, and alternative fuel infrastructure, leading to an eventual reduction in petroleum fuel usage.

In response to the federal ARRA of 2009, staff released a solicitation on April 22, 2009, titled *American Recovery and Reinvestment Act of 2009 Cost Share: Alternative and Renewable Fuel and Vehicle Technology Program* to offer cost share funding opportunities using AB 118 funds. Projects resulting from this solicitation include the development of 55 ethanol (E85) stations, more than 3,100 electric charging stations, 5 public access LNG stations, and the purchase of 442 LNG medium-duty trucks and 123 medium-duty hybrid electric trucks.

In addition to the ARRA cost share solicitation, the Energy Commission has entered into interagency agreements with state entities that specialize in workforce training. These agreements support the transportation component of the California Clean Energy Workforce Training Program, a collaborative effort among the Energy Commission, the Employment Development Department, and the California Workforce Investment Board.

The paramount matter is the Energy Commission's progress in achieving the goals and objectives set forth in the *State Alternative Fuels Plan*. According to the Energy Informa-

24 California Energy Commission, *Investment Plan for the Alternative and Renewable Fuel and Vehicle Technology Program*, commission report, April 2009, CEC-600-2009-008-CMF, available at: [http://www.energy.ca.gov/2009publications/CEC-600-2009-008/CEC-600-2009-008-CMF.PDF].

tion Administration (EIA), California's overall alternative fuel usage increased to 109,114 gasoline gallon equivalent (GGE) in 2007 from just over 70,000 GGE in 2003. The number of alternative fuel vehicles in use also increased. The largest alternative fuel categories in use are compressed natural gas, liquefied petroleum gas, and LNG followed by E85. Federal, state, and local government agencies are the predominant consumers of alternative fuels. As the trend away from petroleum-fueled vehicles grows, the reduction in GHG emissions will become more apparent. Since 2000, the growth in hybrid vehicles alone in California has contributed to a reduction in GHG emissions of about 60 million metric tons.

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

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

By the fall of 2009, two-thirds of United States biodiesel production capacity sat idle, according to the National Biodiesel Board.[25] In September 2009, 98 percent of California's ethanol production capacity was reported to be closed down.

The Energy Commission's PIER transportation subject area is focusing RD&D funding on vehicle technologies, transportation systems, and alternative fuels to help reduce petroleum consumption and GHG emissions while assisting economic development within California. In 2009, PIER transportation subject area solicitations invested over $5.8 million in advanced heavy duty natural gas engine development and advanced biofuels development. The PIER-funded vehicle technology and alternative fuel research can be deployed through the Alternative and Renewable Fuels and Vehicle Technology Program.

PIER transportation also offers small grants that address transportation concept feasibility research. Research guidance is provided by PIER transportation's three focus areas and road maps. Successful projects can receive additional funding from the PIER program to further develop proven concepts. The Energy Commission conducted the first two transportation small grant solicitations and received a total of 45 proposals. Proposal concepts include research addressing vehicle efficiency improvements, batteries, electric vehicles, and sustainable communities modeling.

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

Land Use and Planning

Land use planning is a local issue, under the jurisdiction of local governments. Decisions about land use, however, directly affect energy use and the consequent production of GHG emissions in the state. In addition, local government building departments are responsible for enforcing the mandatory energy efficiency standards for buildings.

Since the 1950s, California's land use patterns have emphasized suburban development of large residential tracts located far from city centers and places of work or business. This land use planning has resulted in many citizens purchasing more affordable housing in the suburbs and commuting long distances to the workplace. With transportation being a major contributor – approximately 40 percent – to GHG emissions in this state, smart land use planning and growth are increasingly important strategies to combat declining air quality and the loss of open space and wildlife habitat and to improve the quality of life for California's residents. Nearly 26 million vehicles, most of which are powered by fossil fuels, along with a high rate of vehicle miles traveled, contribute significantly to California's GHG emissions and climate change issues. Projections show that the state cannot reduce GHG emissions to 80 percent of 1990 levels by 2050 unless vehicle miles traveled are reduced by at least 17 percent.[26]

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

Housing, transportation planning, and local GHG reductions all require local and regional approaches. But smart growth became an increasingly important issue after the California Office of the Attorney General ruled that local jurisdictions must consider GHG emissions when submitting CEQA documents for planning projects.

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

Senate Bill 375 (Steinberg, Chapter 728, Statutes of 2008): This bill established mechanisms for the development of regional targets for passenger vehicle GHG reductions.

Senate Bill 732 (Steinberg, Chapter 729, Statutes of 2008): This bill established a five-member council to help state agencies allocate Strategic Growth Plan funds to promote efficiency and sustainability and support the Governor's economic and environmental goals.

Strategies and Progress

Senate Bill 375 requires metropolitan planning organizations to incorporate a Sustainable Community Strategy as an element of their Regional Transportation Plans. The strategy will be effectively a blueprint-like

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

set of planning assumptions that shape the land use component of the Regional Transportation Plans. The goal is to promote development density near urban cores and transit centers. Senate Bill 375 creates incentives for local governments and developers by providing relief from certain CEQA requirements for development projects consistent with regional plans that achieve the targets.

Funding is a key part of assisting local government agencies with their Regional Transportation Plans. Since 2005, the California Department of Transportation (Caltrans) has coordinated local and state planning through its California Regional Blueprint Planning Program, a voluntary, competitive grant program encouraging metropolitan planning organizations and councils of government to conduct comprehensive scenario planning. The goal of the program is for regional leaders, local governments, and stakeholders to reach consensus on a preferred growth scenario – or "blueprint" – for a 20-year planning horizon (through 2025). Caltrans has awarded a total of $20 million in federal Regional Transportation Plan funds since initiating the program in 2005. In 2009 alone, Caltrans granted $5 million to nine metropolitan planning organizations and nine rural regional transportation planning agencies.[27]

To support the goals of SB 375, the Energy Commission is conducting research to help determine the most effective ways to reduce fuel consumption and emissions through integrated land use and transportation planning. Working with the University of California, Berkeley Global Metropolitan Center, PIER expects to quantify the impacts that smart growth can bring in reducing the effects of global climate change. PIER-funded research includes a project titled Assess New Transportation and Urban Development Patterns in a Climate-Constrained Future that will analyze how various policy options would mitigate transportation GHG emissions given California's expected population growth.

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

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

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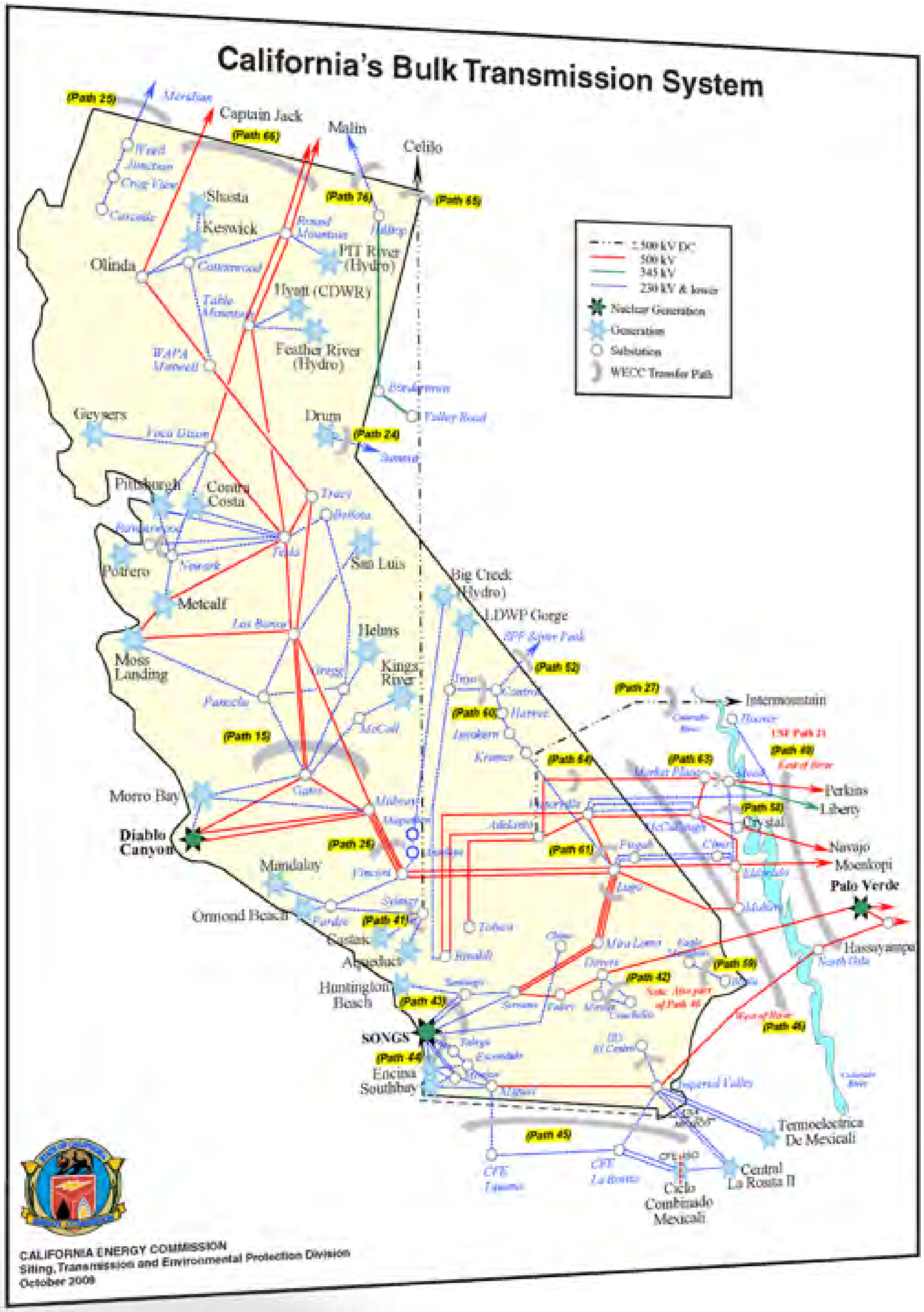
CHAPTER 2
ENERGY AND CALIFORNIA'S CITIZENS

California's energy policies have tangible and direct effects on energy consumers – individuals, businesses, industries, and government. The state's citizens have three basic priorities when it comes to energy: it must be reliable and affordable and have minimal environmental impacts. These priorities apply equally to each of the state's three major energy sectors: electricity, transportation, and natural gas. Each sector is covered in a separate section that describes supply and demand trends along with the environmental, reliability, and economic issues facing that sector. The electricity sector is further broken down based on the loading order elements of energy efficiency, renewable energy, distributed generation, conventional resources, and transmission infrastructure.

However, important overlaps exist between each sector. Natural gas remains the predominant fuel for electricity generation, so circumstances that affect natural gas supplies and prices will also affect the electricity system. Changes in natural gas supplies and prices can also affect the transportation sector as the state moves toward increased use of alternative transportation fuels like compressed natural gas. Similarly, increased electrification of the transportation system will affect electricity demand, which could increase the need for energy efficiency as well as the amount of renewable energy needed to meet the state's renewable energy goals. Increased use of renewable energy could affect demand for natural gas and, therefore, natural gas prices and the need for new natural gas infrastructure.

FIGURE 1: BULK TRANSMISSION SYSTEM IN CALIFORNIA



Source: California Energy Commission, 2009.

While this chapter characterizes various issues in each sector as relating primarily either to reliability, the environment, or the economy, there are no distinct lines among these categories and, in fact, most issues affect all three to some extent.

Electricity

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

California's electricity needs are satisfied by a variety of load-serving entities, including investor-owned utilities (IOUs), publicly owned utilities, electric service providers, and community choice aggregators. In the October 14, 2009, hearing on the draft *2009 Integrated Energy Policy Report (IEPR)*, several parties noted the need for equitable treatment of publicly owned and investor-owned utilities in all energy policy areas but particularly in energy efficiency evaluation, measurement, and verification as well as in meeting the state's renewable energy goals. The Energy Commission agrees that equal treatment is important given that energy policy goals are statewide goals and should therefore apply to all load-serving entities, but also recognizes that a "one size fits all" approach may be problematic given the unique needs and circumstances of some utilities.

Electricity Transmission and Distribution

The backbone of California's electricity system is the state's network of electric transmission and distribution lines that brings power to California consumers from generators both in and out of state. Following California's deregulation of the electricity system in 1998, the three major investor-owned utilities (Pacific Gas and Electric Company, Southern California Edison, and San Diego Gas & Electric Company) and several publicly owned utilities transferred operation of their transmission systems to the California Independent System Operator (California ISO).[28] These utilities continue to operate their own distribution systems, but rely on the California ISO to operate the overall transmission network. Several publicly owned utilities, including Sacramento Municipal Utility District (SMUD), the Los Angeles Department of Water and Power (LADWP), and the Imperial Irrigation District, still control and operate both their transmission and distribution systems, although the systems are connected to the California ISO-controlled grid.

Figure 1 shows the bulk transmission system now in place in California. Key features are the extensive interconnections to the north and southeast that allow imported electricity to flow into California. Through these lines California is connected to the overall Western Interconnection covering most of western North America, from British Columbia and Alberta to the north, Baja Mexico to the south, and Colorado to the east.

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

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

Electricity Supply

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

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

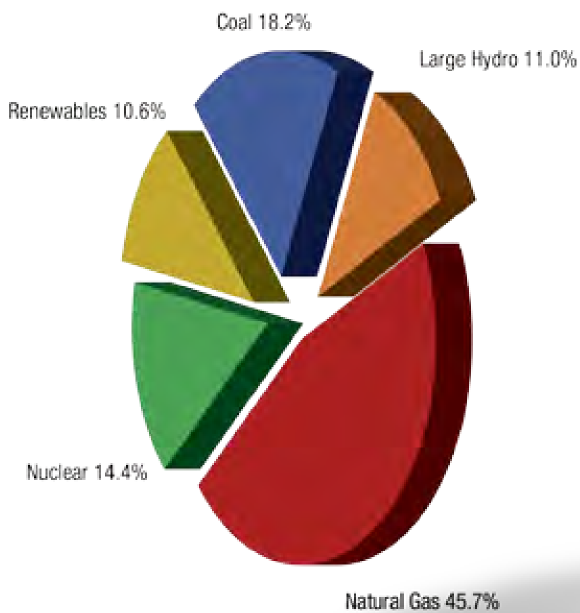
Table 1 shows the entire generation mix that served Californians in 2008. The in-state values listed are a reasonably accurate snapshot of the entire California power mix for the year. The breakdown of power imported from the Northwest and Southwest is an estimate based on specific claims by energy service providers (retailers) and the general resource mix of those regions since there are no publicly available data-tracking mechanisms for the generation sources of imported power. The California Air Resources Board (ARB) is charged with addressing this issue in its implementation of AB 32, (Núñez, Chapter 488, Statutes of 2006) including regulations for first jurisdictional deliverers to report on specified imports.[29]

The resource mix for imports is based on the Energy Commission's *2008 Net System Power Report*.[30] The report represents the amount of electricity used by California customers for which no retailers claimed a specific source of generation. In recent years, as California retailers have increasingly identified larger shares of their generation as coming from specific sources, the net system power has changed in two very important ways: it now represents a smaller share of total generation serving California (due to growing retailer claims on specific sources of generation), and it is characterized by a higher percentage

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

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

FIGURE 2: CALIFORNIA'S GENERATION MIX 2008



Source: California Energy Commission

of unclaimed coal and natural gas generation sources. Therefore, the total system power shown in Table 1 is used as an indicator of the sources of generation serving California end users until the ARB begins collecting data from all first deliverers of power into California under AB 32.

The Energy Commission is responsible for licensing in-state thermal power plants 50 megawatts (MW) and larger. Since deregulation in 1998, the Energy Commission has licensed more than 60 power plants: 44 projects representing 15,220 MW are on-line, 6 projects totaling 1,578 MW are under construction, and 12 projects totaling 6,415 MW are on hold but "available" for construction. In addition, the Energy Commission has 30 proposed projects under review (both conventional and renewable) totaling more than 12,000 MW, which significantly exceeds historic workloads and is presenting challenges given existing staff resources.

Natural Gas-Fired Generation

Natural gas plants (both in-state and out-of-state plants) provide about 46 percent of California's electricity needs. More than 15,000 MW of natural gas power plant capacity has come on-line since 1998. There are also 18 proposed natural gas-fired plants that are currently under review in the Energy Commission's power plant licensing process.

Of California's electricity sources, natural gas-fired plants tend to be the most flexible, allowing for peaking, cycling, and some baseload duty. Natural gas-fired generation typically is used to compensate for varying hydroelectric availability and likely will be needed to help integrate higher amounts of renewable generation to meet the state's Renewables Portfolio Standard goals. Emissions from natural gas generation account for a large portion of in-state greenhouse gas (GHG) emissions from the electricity sector, so

TABLE 1: 2008 TOTAL SYSTEM GENERATION (GIGAWATT-HOURS)

FUEL TYPE	IN-STATE	NORTHWEST IMPORTS	SOUTHWEST IMPORTS	TOTAL ENERGY SYSTEM
Coal	3,977	8,581	43,271	55,829
Large Hydro	21,040	9,334	3,359	33,733
Natural Gas	122,216	2,939	15,060	140,215
Nuclear	32,482	747	11,039	44,268
Renewables	28,804	2,344	1,384	32,532
Biomass	5,720	654	3	6,377
Geothermal	12,907	0	755	13,662
Small Hydro	3,729	674	13	4,415
Solar	724	0	22	746
Wind	5,724	1,016	591	7,331
Total	**208,519**	**23,945**	**74,113**	**306,577**

Source: Energy Information Agency, Energy Commission Quarterly Fuels and Energy Report Database, and Senate Bill 1305 Reporting Requirements it is essential for the Energy Commission to consider GHG impacts of natural gas plants in its power plant licensing process. However, because of the essential physical services provided by natural gas plants, California cannot simply retire all of its natural gas plants to meet its GHG emissions goals.

Hydroelectric Resources

Large hydroelectric power (larger than 30 MW in capacity) is a major source of California's electricity. In 2008, large hydroelectric plants produced 33,733 gigawatt hours (GWhs) or 11 percent of total system power. California has nearly 400 hydro plants, most of which are located in the eastern mountain ranges, with total dependable capacity of about 14,000 MW. The state also imports hydro-generated electricity from the Pacific Northwest. While hydroelectric power offers the potential for low-cost baseload electricity, it is also subject to large annual fluctuations because of changes in rainfall and snowpack. For example, from 1995–1998, hydroelectric resources accounted for as much as 28 percent of California generation but only provided 13 percent of total state generation in 2001.[31]

With current climate change concerns, there will be an increasing need to evaluate the possible impacts on California's hydropower resources. A recent draft paper by the California Climate Change Center looked at potential climate change effects on two hydroelectric facilities in California: the Upper American River Project, operated by SMUD in Northern California, and the Big Creek system, operated by Southern California Edison in Southern California.[32] The paper concluded that these facilities could experience a reduction in both energy generation and associated revenues as a result of climate change. However, the results of the analysis also showed that the two hydroelectric facilities should still be able to supply peak power during the spring and early summer days in both Northern and Southern California, although meeting increased power demand in late summer could be difficult if the occurrence of heat waves increases.

Nuclear Generation

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

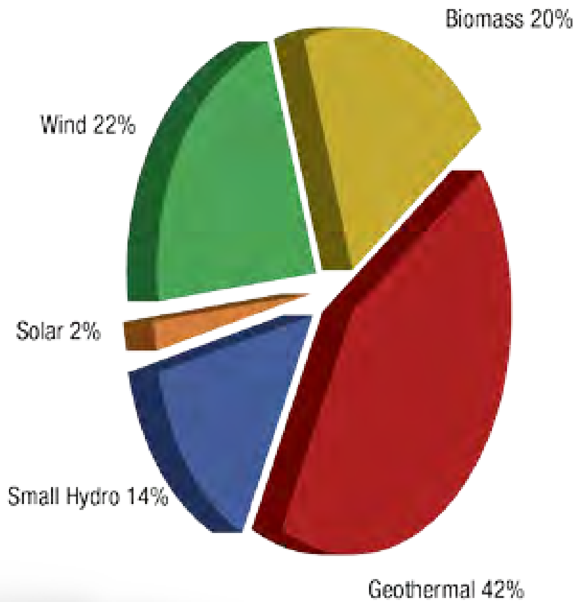
- Diablo Canyon Power Plant: Pacific Gas and Electric (PG&E) owns and operates Diablo Canyon, which has a total generating capacity of 2,220 MW in two units. The Diablo Canyon facility is located near San Luis Obispo, along the coast between San Francisco and Los Angeles.

- San Onofre Nuclear Generating Station (SONGS): Southern California Edison (SCE), San Diego Gas & Electric (SDG&E), and the City of Riverside are co-owners of the San Onofre Nuclear Generating Station, which is operated by SCE. The two operating units have a total capacity of 2,254 MW. The San Onofre Nuclear Generating Station is located near the boundary between SCE's and SDG&E's service territories near San Clemente, north of San Diego, in southern California.

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

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

FIGURE 3: CALIFORNIA RENEWABLE ENERGY GENERATION BY TECHNOLOGY, 2008



Source: California Energy Commission

- Palo Verde Nuclear Generating Station: Palo Verde is co-owned by Arizona Public Service Corporation, SCE, and five other utilities. Arizona Public Service Corporation operates the plant. Palo Verde's three units have an overall capacity of 3,810 MW. Palo Verde is located near Phoenix in Wintersburg, Arizona. California utilities own 27 percent of the plant.

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

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

Renewable Resources

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

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

California currently has roughly 7,400 MW of utility-scale renewable generating capacity, ranging in size from a few hundred kilowatts to large projects in the hundreds of megawatts.[33] The Energy Commission and the Bureau of Land Management (BLM) are currently reviewing applications for power plant certification for about 6,000 MW of new solar capacity.[34] In addition, the amount of grid-connected distributed photovoltaic systems continues to grow, with about 440 MW installed as of 2008.[35]

Combined Heat and Power

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

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

Resource Adequacy

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

Publicly owned load-serving entities in the California ISO control area must also meet basic requirements related to resource adequacy and reporting.[36] In 2008, publicly owned utilities represented 22.6 percent of California

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

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

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

36 There are 18 publicly owned load-serving entities outside the California Independent System Operator control area that are not subject to formal requirements.

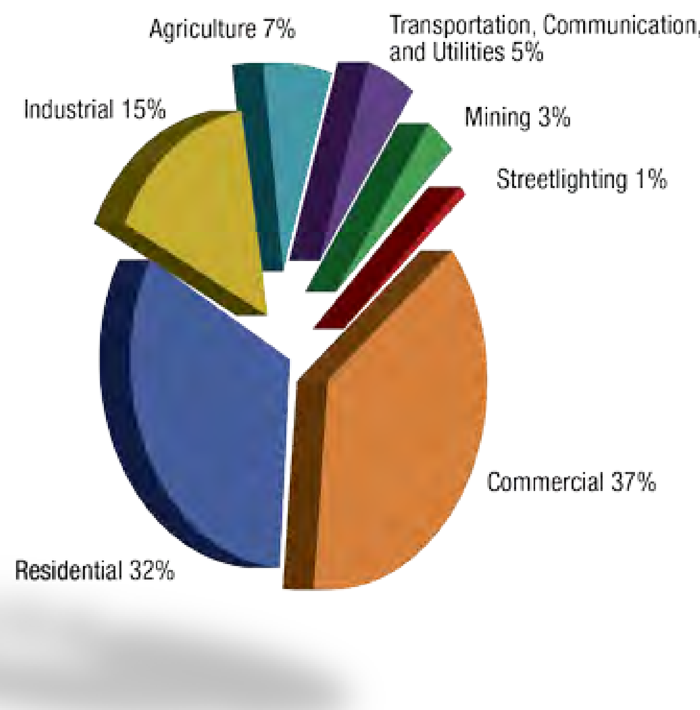
peak loads and 23.7 percent of energy needs. The largest 15 publicly owned utilities account for 94 percent of publicly owned utility peak load and 95 percent of energy requirements.

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

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

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

FIGURE 4: ELECTRICITY CONSUMPTION BY SECTOR 2008 (GIGAWATT-HOURS)



Source: California Energy Commission

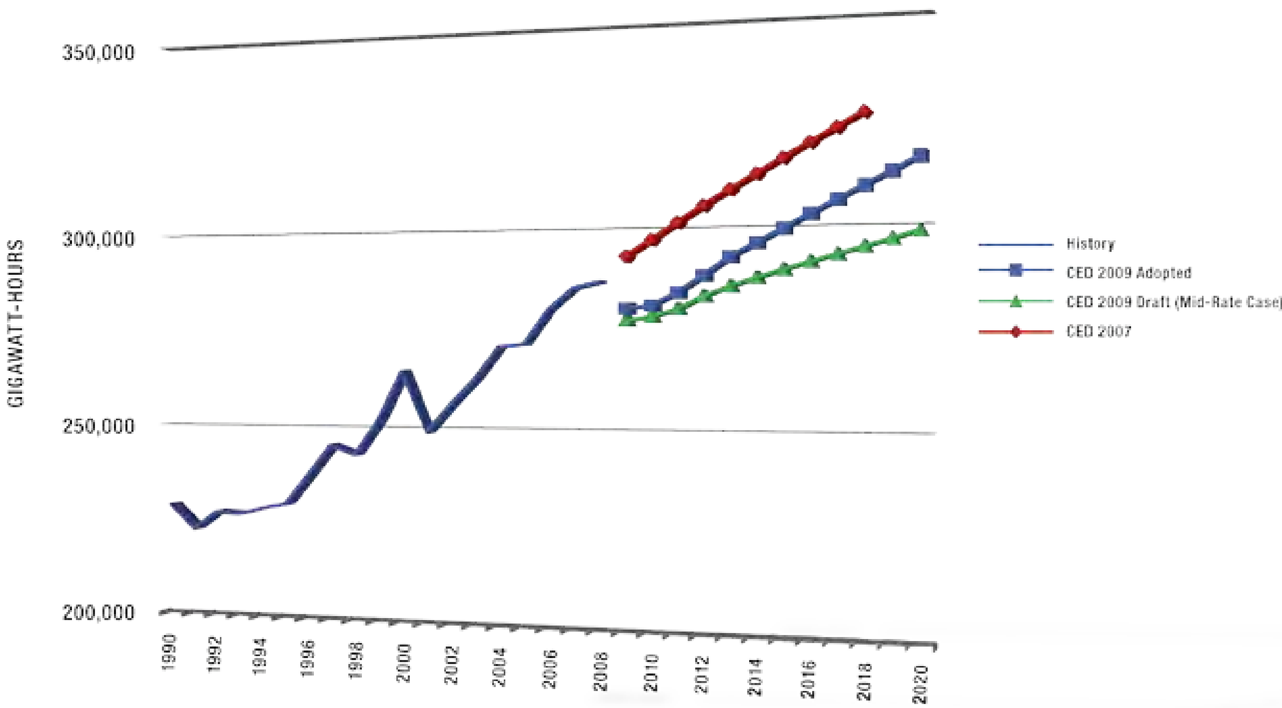
Electricity Demand

Californians consumed 286,771 GWhs of electricity in 2008, primarily in the commercial, residential, and industrial sectors (Figure 4).[37]

Demand for electricity varies over time with daily, weekly, and seasonal cycles and can fluctuate constantly even within a given hour. Demand is generally lower at night and on weekends and holidays, with the maximum demand generally occurring during the afternoon on a hot summer weekday. This

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

FIGURE 5: STATEWIDE ELECTRICITY CONSUMPTION



Source: California Energy Commission, *California Energy Demand 2010–2020 Adopted Forecast*, December 2009, CEC-200-2009-012-CMF.

maximum point is known as the "peak" and is an important factor in electricity and transmission planning since generation and transmission must be built out to capacity that can meet peak demand when needed.

Electricity Demand Forecast

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

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

Figure 5 compares three forecasts of statewide electricity demand: the *2007 IEPR* forecast (California Energy Demand [CED] 2007), the draft demand forecast prepared by staff in the spring of 2009 (CED 2009 Draft Mid-Rate Case), and the Energy Commission's adopted demand forecast (CED 2009 Adopted) that reflects the IEPR Committee's direction in response to issues and concerns raised in the IEPR workshop on the draft demand forecast. The CED 2009 forecast report was adopted by the Energy Commission on December 2, 2009.

Electricity consumption is projected to grow at a rate of 1.2 percent per year from 2010–2018, with peak demand growing at an average annual rate of 1.3 percent over the same period. Although the CED 2009 adopted forecast projects electricity consumption to be higher than the earlier CED 2009 Draft (Mid-Rate Case), it is still markedly below the CED 2007 forecast. By 2018, electricity consumption is forecast to be down by more than 5 percent and peak demand by around 3.5 percent compared to CED 2007. Two factors explain most of the difference: lower expected economic growth, not only in the near term but also in the longer term, and increased energy efficiency impacts compared to what was included in the CED 2007 forecast. These changes reflect the increased emphasis on energy efficiency and increased level of efficiency expenditures now considered committed and therefore included in the forecast, as well as improved use of recent historic data that was not available for the CED 2007 forecast.

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

New legislation (Senate Bill 695, Kehoe, Chapter 337, Statutes of 2009) allows the expansion of direct access service to individual retail nonresidential end-use customers, with a maximum level of annual kilowatt-hours supplied by electric service providers and the phase-in period to be determined by the CPUC. Since many more of California's customers will have this option available, the Energy Commission will incorporate direct access in future *IEPR* forecasts. In addition, since passage of SB 695 will likely affect the CPUC's 2010 Long-Term Procurement Plan (LTTP) process, Energy Commission staff plans to prepare a supplemental analysis that disaggregates the *2009 IEPR* planning area demand forecasts into bundled and direct access segments in early 2010.

The Effect of Economic Uncertainties on the Demand Forecast

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

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

FIGURE 6: PROJECTED STATEWIDE ELECTRICITY CONSUMPTION, CALIFORNIA ENERGY DEMAND 2009 ADOPTED AND ALTERNATIVE ECONOMIC SCENARIOS

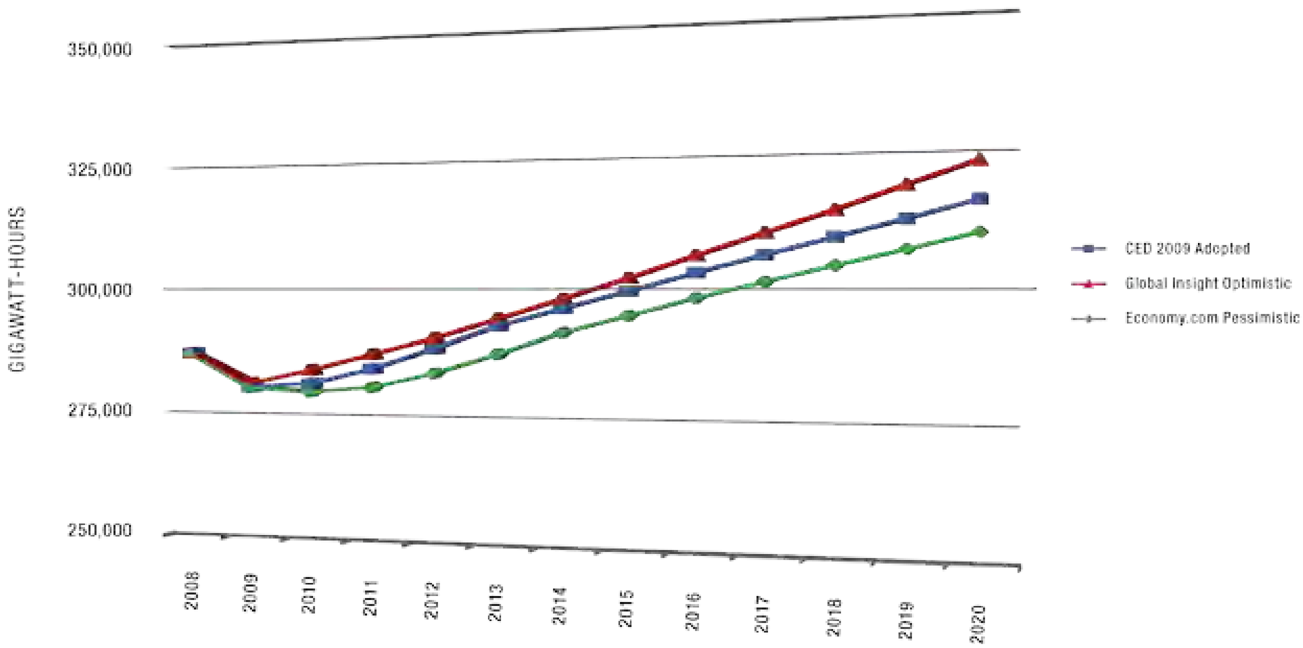
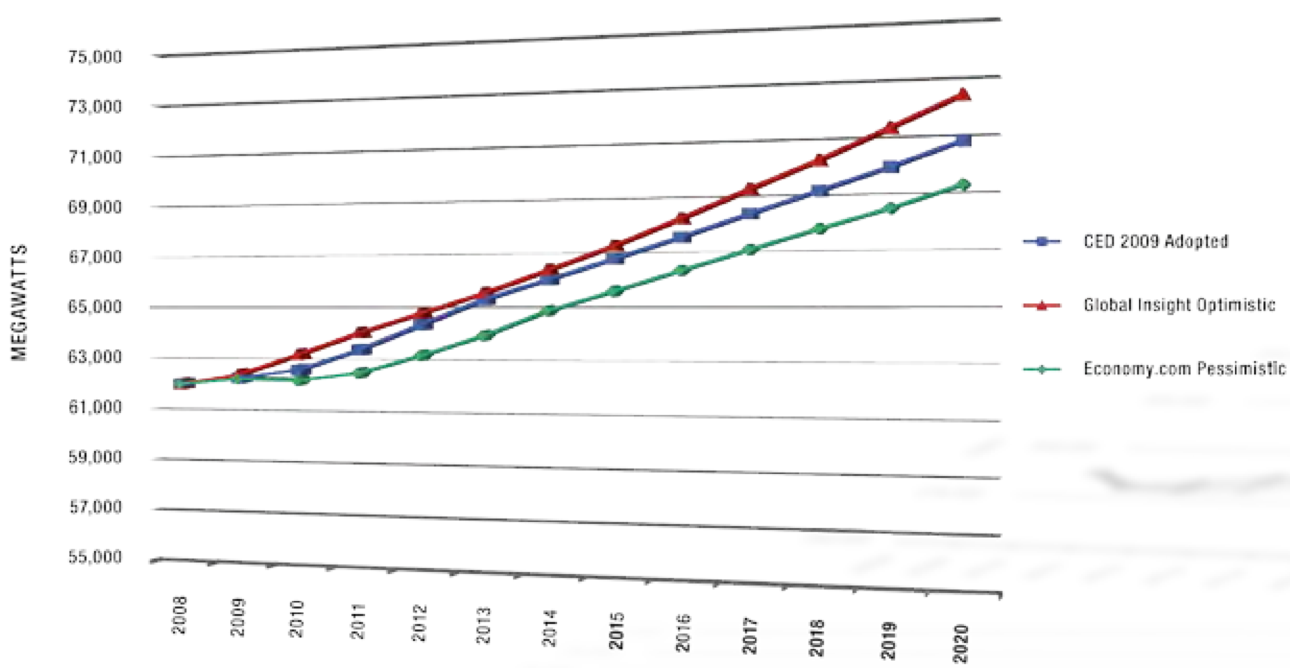


FIGURE 7: PROJECTED STATEWIDE PEAK DEMAND, CALIFORNIA ENERGY DEMAND 2009 ADOPTED AND ALTERNATIVE ECONOMIC SCENARIOS



Source for figures: California Energy Commission, *California Energy Demand 2010–2020 Adopted Forecast*, December 2009, CEC-200-2009-012-CMF.

Electricity consumption is projected to be 2.3 percent higher in the optimistic economic case than in the CED 2009 forecast by 2020, and 1.9 percent lower in the pessimistic scenario. The peak demand forecast increases by 2.3 percent under the optimistic scenario by 2020 and falls by 2.2 percent in the pessimistic case. The percentage of peak reduction is higher than that of consumption in the pessimistic case because the relative decrease in consumption is projected to be higher for the residential and commercial sectors than for the industrial, which has a higher load factor. Annual growth rates from 2010–2020 for electricity consumption and peak demand increase from 1.2 percent and 1.3 percent, respectively, to 1.3 percent and 1.4 percent in the optimistic case and fall to 1.1 percent each under the pessimistic scenario.

Energy Efficiency

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

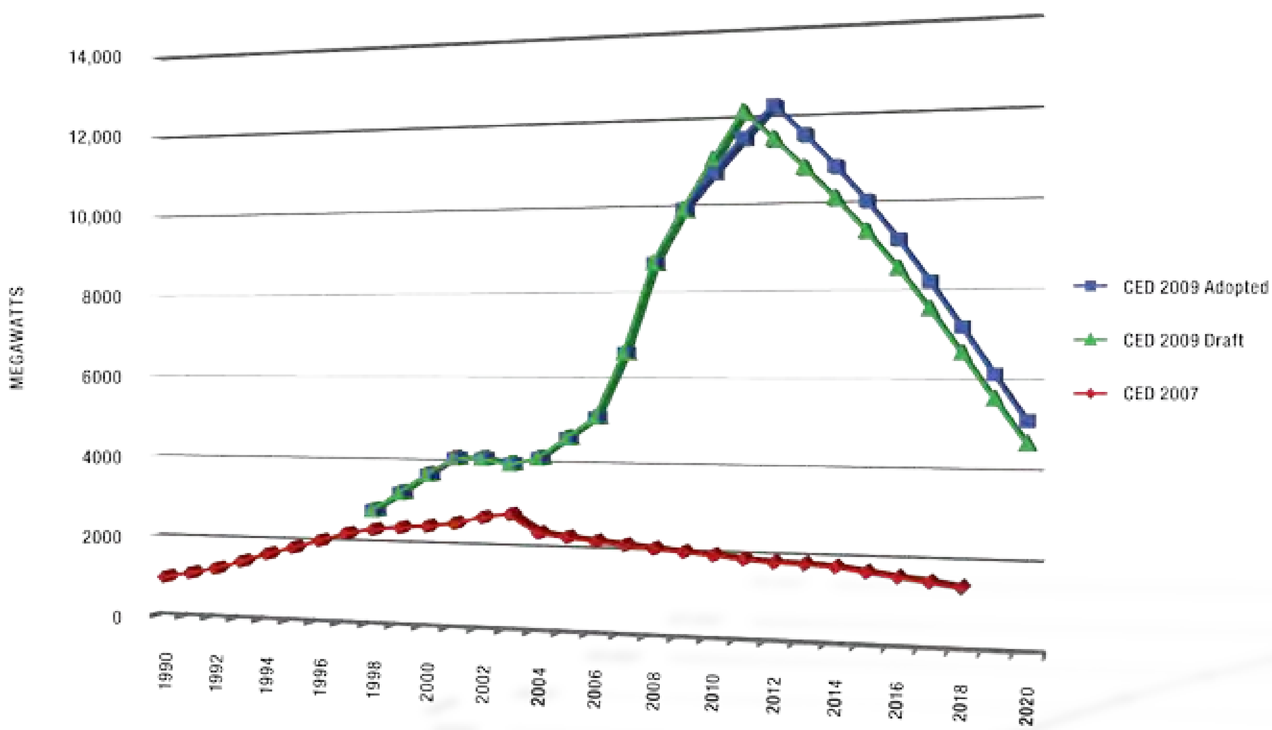
Every day, California citizens and businesses make millions of energy-related decisions as they go about their daily activities without realizing how those decisions affect energy use and energy demand. While some consumers may perceive energy conservation or efficiency as cutting back on activities or doing without creature comforts, conservation and efficiency are actually about using energy resources in a smarter and more effective way so those resources will go farther and have fewer negative consequences on the environment. Well-designed energy efficiency and conservation programs can reduce energy dependence, make businesses more competitive, and allow consumers to save money and live more comfortably. Energy efficiency programs can also play a major role in increasing reliability of the electricity system and reducing the cost of meeting peak demand during periods of high temperatures and high prices.

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

Energy Efficiency and the Demand Forecast

The importance of energy efficiency in reducing GHG emissions is influencing both near-term program funding and the future treatment in the demand forecast of efficiency resulting from programs. This influence is reflected in near-term energy efficiency program proposals made by IOUs to the CPUC in the current proceeding to determine funding and program designs for 2010–2012. As a result of historic high levels of funding for the 2010–2012 program designs in CPUC Decision (D.) 09-09-047, the amount of energy efficiency considered committed and there-

FIGURE 8: COMPARISON OF COMMITTED UTILITY PROGRAM CONSUMPTION IMPACTS FOR INVESTOR-OWNED UTILITIES



Source: California Energy Commission, *California Energy Demand 2010–2020 Adopted Forecast*, December 2009, CEC-200-2009-012-CMF.

fore included in the Energy Commission's baseline demand forecast is substantially higher than in the *2007 IEPR*, resulting in lower expected energy demand.

While progress has been made to delineate energy efficiency program impacts as presented in the Energy Commission's adopted demand forecast, numerous uncertainties remain. The energy efficiency attributions noted below are preliminary, based on the best available information and analysis to date, and will require further analysis to more clearly and completely understand the interactions among codes and standards, naturally occurring savings, and utility programs.

Figure 8 shows the change in IOU energy efficiency program impacts between the *2007 IEPR* and the staff's draft and Energy Commission-adopted forecast assumptions in this *2009 IEPR* for the three IOUs. The adopted forecast incorporates the recent shift in the CPUC efficiency program cycle from 2009–2011 to 2010–2012. A similar pattern of increased utility program impacts is included in the adopted demand forecast for the larger publicly owned utilities (SMUD and LADWP).

The steep drop off shown in 2013 and beyond reflects the short lifetime of some energy efficiency program measures, uncertainties about whether impacts from utility programs continue beyond the life of the measures installed, and reconciling these programmatic questions with the traditional price elasticity response when electricity rates are assumed to increase steadily into the future. There is also great uncertainty about the nature of the consumer response to subsidized efficiency programs and whether savings from various measures translate into actual changes in consumer demand for electricity. For example, the financial benefits of increased efficiency may induce some consumers to "take back" some of the efficiency gains by increasing their energy use. It is also unclear whether consumers will voluntarily pay for a replacement measure when the subsidized measure wears out, although staff's analysis assumes that they will not in most cases.

For some measures, by the time an efficiency measure that was installed through a utility program subsidy wears out, the market likely will be transformed as a result of new efficiency options, such as the virtual disappearance of single-pane windows from home improvement stores. For other measures, replacement is governed by mandatory efficiency standards. An example is staff's assumption that AB 1109 (Huffman, Chapter 534, Statutes of 2007) combined with federal lighting standards will result in the replacement of lighting measures with efficient devices and accompanying standards that essentially eliminate inefficient bulb technologies.

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

However, the emphasis of many utility programs – encouraging retrofitting of existing floor space or equipment with more efficient devices – does not focus exclusively on newly built floor space or housing units, but upon the entire stock of floor space or housing units, which is not as readily addressed by this modeling approach. Moreover, consumers voluntarily participate in utility programs, presumably based on some combination of perceived financial benefits and altruism (wanting to "improve the environment"). In recognition of the uneven ability of its models to treat utility programs, Energy Commission staff are adapting the forecasting models to better incorporate such retrofit actions, but only limited progress was made in the timeline of the 2009 IEPR proceeding.

As an interim step, staff worked with the CPUC Energy Division and utilities to obtain more complete evaluation, measurement, and verification data for IOU program savings. Since the CPUC Energy Division itself has made more progress in estimating firm savings from programs than in the past, these new data sometimes portray IOU programs in a different light than do previously available self-reported, first-year savings data that have not been adjusted based on in-depth measurement studies. However, these detailed evaluation, measurement, and verification data *ex post* results are only available for recent years, which required staff to make assumptions about the performance of programs and measures funded in earlier years. Further effort to develop a consensus about historic measure performance is needed. With commitment to this effort and improvements in access to measure-level data for multiple program years, further progress can be made following the 2009 IEPR cycle.

As described in the *2008 IEPR Update*, the Energy Commission has chosen to continue to distinguish between the impacts of energy efficiency programs considered committed and those which, although part of long-term goals, are classified as uncommitted because program designs are not complete and funding has not been authorized.[38] Thus, the baseline or reference demand forecast only includes committed impacts. These committed impacts can be from existing standards as they affect a growing proportion of the stock of buildings and/or appliances, or from utility programs for the period of time during which specific program designs have been approved or program funding has been authorized.

Beyond these impacts there are efficiency goals that have been set by the CPUC, the Energy Commission, and the ARB for which no specific program designs have been approved or actual program funding levels authorized. The CPUC, in D.08-07-047, established long-term energy savings goals encompassing the three electricity IOUs, currently adopted state and federal appliance standards, and state building codes resulting in zero net energy residential and commercial construction in 2020 and 2030.[39] The Energy Commission in the *2007 IEPR* established the goal of achieving 100 percent of cost-effective energy efficiency savings. Following input from the Energy Commission and CPUC, the ARB also established 2020 energy efficiency goals in its *Climate Change Scoping Plan.*

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

The effort to directly capture savings from utility efficiency programs in the Energy Commission's demand forecasting models for all IOU programs is too extensive for the resources and timeline available for the *2009 IEPR*, so the focus in this cycle has been on the most important of the program-induced measures: residential and commercial lighting and heating, ventilation, and air conditioning. Energy Commission staff and the consulting firm Itron are collaborating to refine an existing energy efficiency projection capability to build off the level of energy efficiency measures in the baseline forecast to determine truly incremental impacts from further penetration of those or other high value measures. The Itron model SESAT, which was used for the CPUC's 2008 Goals Study,[40] is the starting point for this effort.

Itron adapted the existing SESAT model as part of its contractual support to the CPUC for the 2008 Goals Study. A model like SESAT can be configured to directly incorporate the nonprogrammatic assumptions of the baseline demand forecast or use alternative assumptions. Some assumptions, such as household growth in the residential sector, are easy to match, while others such as saturations for

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

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

40 Ibid.

residential sector end uses are not.[41] For example, the 2008 Goals Study implementation of SESAT did not allow saturations of end uses to change through time. In contrast, the Energy Commission's demand forecast allows for such changes.

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

Early in the 2009 IEPR development process, the CPUC's Energy Division requested that the Energy Commission develop a demand forecast as well as projections of incremental uncommitted energy efficiency for use in the forthcoming 2010 LTPP proceeding. The Energy Division requested that the Energy Commission evaluate previously established scenarios from the 2008 Goal Study as adopted in CPUC D. 08-07-047, including high, medium, and low cases. The IEPR Committee decided not to investigate other possible specifications of uncommitted energy efficiency, such as the levels included within the ARB *Climate Change Scoping Plan*, and to defer that analysis to other proceedings.[42]

Developing this incremental energy efficiency projection method and applying it to existing energy efficiency policies creates fresh estimates of the incremental impact of these policies relative to the baseline demand forecast. This effort is principally intended to reduce the uncertainty about overlap between the Energy Commission's demand forecast and other independently developed estimates of uncommitted energy efficiency. The *2009 IEPR* and the CPUC's 2010 LTPP rulemaking are the arenas where the merits of these various estimates will play out.

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

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

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

The incremental efficiency efforts for the *2009 IEPR* focused on evaluating electricity efficiency and conservation. Staff did not update natural gas efficiency impacts from those estimated in the *2007 IEPR* forecast. Future forecasts, however, will expand the efficiency analysis to fully account for embedded natural gas efficiency.

Energy Efficiency and the Environment

California is a national leader in promoting energy efficiency. Due in part to a decades-long focus on energy efficiency, California has the lowest per capita electricity use in the United States, with energy use per person having remained stable for more than 30 years while the national average has steadily increased. However, stabilizing per capita electricity use will not be enough to meet the carbon reduction goals set in the ARB's *Climate Change Scoping Plan*. Very aggressive efforts will be needed in coming years to meet and exceed prior energy efficiency and demand response program goals.

With the focus on reducing GHG emissions in the electricity sector, energy efficiency takes center stage as a zero-emissions strategy. One of the primary strategies to reduce GHG emissions through energy efficiency is the concept of zero net energy buildings. In the *2007 IEPR*, the Energy Commission recommended increasing the efficiency standards for buildings so that, when combined with on-site generation, newly constructed buildings could be zero net energy by 2020 for residences and by 2030 for commercial buildings. As mentioned in Chapter 1, the CPUC's Big Bold Energy Efficiency Strategies that were adopted as part of its *Long-Term Energy Efficiency Strategic Plan* include these goals as well. A zero net energy building merges highly energy-efficient building construction and state-of-the-art appliances and lighting systems to reduce a building's load and peak requirements and includes on-site renewable energy such as solar PV to meet remaining energy needs. The result is a grid-connected building that draws energy from and feeds surplus energy to the grid. The goal is for the building to use zero net energy over the year. The ARB recommends that energy efficiency measures in these buildings provide as much as 70 percent savings relative to existing buildings, with on-site renewable generation to meet the remaining load.[43] The CPUC's *2007 Long-Term Energy Efficiency Strategic Plan* contains a detailed implementation plan for zero net energy buildings with goals, strategies, timelines, and recommendations.

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

Making zero net energy buildings a reality by 2020 for residences and 2030 for commercial buildings will require ongoing collaboration among the Energy Commission, the CPUC, and the ARB, as well as coordination with local governments that have the authority over land use development and planning. It will also require coordination among local, state, and industry players to promote and incentivize the installation of all cost-effective

43 California Air Resources Board, *Climate Change Scoping Plan*, December 2008, p.42, available at: [http://www.arb.ca.gov/cc/scopingplan/document/adopted_scoping_plan.pdf].

California Business on the Cutting Edge of Energy Efficiency Research

Adura Technologies is a San Francisco-based wireless lighting controls company founded in 2005 to commercialize research conducted at the University of California, Berkeley's Center for the Built Environment. The original idea for wireless lighting controls was developed at UC Berkeley with the help of a PIER research grant. The resulting study indicated potential energy savings from 65 to 70 percent for lighting, and Adura Technologies was formed to commercialize the technology. Since then, Adura has partnered with PIER's Lighting California's Future research program to integrate motion and daylight sensing technology into its system.

Adura's wireless lighting controls have enormous energy efficiency implications for the commercial building sector. Besides avoiding the costs of re-wiring existing buildings, these lighting systems can reduce energy demand and associated CO2 emissions. There may be additional potential benefits as wireless building control systems expand to other market segments and operating functions like heating, daylight shading, and demand response programs.

Adura is considered one of the most exciting clean tech/energy efficiency companies in Silicon Valley. Following its inception, Adura has built on its role as a manufacturing partner and has raised more than $7.5 million in venture capital funds. Adura won a Flex Your Power Award (2005), the Clean Tech Open (2006), and a UC/CSU/CCC Sustainability Award (2008). Adura's wireless lighting control system was named one of Buildings Magazine's Top 100 products for 2009. Adura currently employs 30 Californians and is directly involved in educating electricians and electrical contractors on lighting control strategies and technologies through its involvement in the California Advanced Lighting Controls Training Program.

energy efficiency measures; expand the scope of and accelerate certification of highly efficient appliances; push for the incorporation of the cost of carbon in cost-effectiveness tests for new codes and standards and utility programs; encourage and expand green building programs; and promote and incentivize on-site renewable energy generation.

The Energy Commission has adopted several key strategies for achieving the goal of zero net energy homes by 2020 and commercial buildings by 2030. One such effort, aimed at reducing "plug load" energy in buildings, includes broadening the range of appliances covered by the Title 20 Appliance Efficiency Standards to include consumer electronics and other appliances as they emerge on the consumer market. Other efforts include building standards for water efficiency; education about existing standards and increased enforcement; the adoption of voluntary "reach" building codes and standards that save energy above and beyond already mandated savings; and implementation of those reach standards through green building standards. Another effort is the Home Energy Rating System (HERS) Phase II program, effective September 1, 2009, which adopted a home energy rating scale that starts at zero consistent with the long-term goal of achieving zero net energy new homes by 2020.

Meeting the goal of zero net energy buildings will require increases in the Title 24 Building Efficiency Standards during each upgrade cycle. Because home electronics and other equipment and devices plugged into electrical outlets represent higher loads than those currently assumed in the standards, plug loads must be tested, modeled, and updated in building energy budgets and accounted for in Title 24 compliance software calculations. The scope of building efficiency standards will also need to be expanded to include process loads such as data centers, laboratories, and refrigeration systems. Continued research and development is also needed on building science technologies like energy use modeling, energy use data collection, and in-home energy use monitors.

The Buildings End-Use Energy Efficiency program area within the Energy Commission's Public Interest Energy Research (PIER) program focuses on lowering building energy use in both new and existing buildings in residential and commercial applications. By developing lower first-cost options for energy efficient products and helping to lower operating costs for energy-consuming systems, the PIER program helps increase the adoption of energy efficiency measures in California. Other research and development efforts within PIER that can help the state reach its goal of zero net energy buildings include those in agriculture, food processing, demand response, water-related energy consumption, demand shifting, metering and sub-metering, tariff analysis, urban planning, sustainable communities, codes and standards, water heating, data processing, building energy use benchmarking, motors, and process heating, among others. PIER's research and development also supports private sector research efforts and helps move technologies and tools into the market.

The goal of zero net energy buildings requires not just energy efficiency but also on-site renewable energy generation. For new residential construction, the Energy Commission's New Solar Homes Partnership provides incentives to install solar energy systems on new homes that meet specific energy efficiency requirements. For existing homes, new and existing commercial buildings, and industrial, government, and nonprofit buildings in the service territories of the IOUs, the CPUC's California Solar Initiative includes minimum energy efficiency requirements for newly constructed buildings; the CPUC is currently exploring whether energy efficiency requirements for existing residential and commercial buildings should be increased.

The *2008 IEPR Update* identified the need for active policies to deploy cost-effective and zero carbon renewable energy space heating and cooling technologies, which could contribute to the state's zero net energy goals. The potential value of renewable heating and cooling technologies could be very high, since California residential and commercial cooling accounts for approximately 30 percent of electric system peak load.[44] As recommended in the *2008 IEPR Update*, the Energy Commission's PIER program needs to develop a targeted program to address technical and infrastructure barriers to emerging renewable heating and cooling technologies.

Green building standards are another tool to help achieve the goal of zero net energy buildings, as well as to reduce GHG emissions that impact the environment. The California Building Standards Commission adopted Green Building Standards for newly constructed residential and commercial buildings in July 2008, which are the first statewide green building codes in the nation. The Green Building Standards contain both voluntary and mandatory green building measures, and sections of the standards are intended to become mandatory in the next code cycle. The code standardizes practices for reducing water use and electricity consumption and examines other aspects of typical construction practices. The Energy Commission advised the Building Standards Commission in the design of the voluntary levels, or tiers, of energy efficiency that are more stringent than the statewide Title 24 Building Energy Standards and will continue to expand its efforts to incorporate reach standards into the Green Building Standards.

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

Energy Efficiency and Reliability

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

California has pursued its energy demand reduction goals through two primary avenues: utility-sponsored programs to reduce end-user consumption, and codes and standards designed to lower the energy use of buildings and appliances. By 2004, these efforts had cumulatively saved more than 40,000 GWhs of electricity and 12,000 MW of peak electricity, equivalent to twenty-four 500-MW power plants. More than half of the statewide savings has come from the building and appliance standards, with the balance resulting from programs implemented by the state's IOUs and publicly owned utilities.

Appliance Efficiency Standards

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

The 2009 Appliance Efficiency Regulations became effective statewide on August 9, 2009. These regulations set new efficiency standards for general purpose lighting as required by AB 1109 (Huffman, Chapter 534, Statutes of 2007) as a first step in achieving a 50 percent increase in efficiency for residential general service lighting by 2018. AB 1109 also set aggressive savings requirements for lighting for commercial buildings and outdoor lighting over the same time period.

The Energy Commission continues to press the federal government for an exemption to exceed federal standards for residential clothes washers, which will result in substantial savings of both energy and water. The Energy Commission will also continue to pursue aggressive and expansive appliance standards for other appliances and equipment, including but not limited to consumer electronics, lighting, water-using equipment and irrigation controls, and refrigeration systems.

Efficiency Standards for New Buildings

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

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

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

Adopting voluntary reach standards has many benefits. It allows proactive cities, counties, green building standards, incentive programs, and others to adopt the voluntary standards in their jurisdictions, which many cities and counties have already done. The reach standards also are adopted as the eligibility criteria for solar incentive programs, such as the California Solar Initiative and New Solar Homes Partnership programs, and as

Building Regulations Ordinance Uses Sustainable Design and Construction

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

levels for qualifying for higher public goods charge incentives through utility new construction programs.

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

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

Compliance with and enforcement of the building standards are major challenges. Newly constructed residential buildings have been estimated to be as much as 30 percent out of compliance with the 2005 Title 24 Building Efficiency Standards,[45] which could represent up to 180 GWhs per year[46] of lost energy savings and therefore lost opportunities for GHG emission reductions. The 536 local building departments in the state are responsible for enforcing standards by issuing permits and conducting on-site inspections during construction. With the economic downturn and reduced budgets, however, many cities have downsized their building department staff in order to maintain other vital staff such as police or fire crews. Other factors that affect compliance with and enforcement of building standards include the complexity of the building standards, the effects of changes in architectural style, and the need for performance standards to provide choice in energy-using features and equipment. The Energy Commission has actively sought sufficient staff resources to maintain a presence in the field to encourage improvements in compliance and enforcement and is working with the California Building Officials and California utilities to provide tools and information that will simplify standards enforcement and provide expanded training for the industry and building officials.

Building standards also apply to additions to and remodels of existing buildings, which provide a critical opportunity to improve energy efficiency levels. Permits are required for any alteration that permanently changes the

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

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

energy use of a building, including installation and change-out of heating, ventilation, and air conditioning (HVAC) equipment. Unfortunately, many installers fail to obtain the proper permits for HVAC change-outs. This not only places homeowners at risk by bypassing the health and safety protections associated with permits, but it also reduces revenues that fund enforcement activities of local governments. In addition, without permits, building departments are unaware of the HVAC change-outs and therefore do not review and inspect the systems to ensure compliance with building codes and standards. Failure to obtain permits also has negative effects on the entire HVAC industry because installers who avoid the cost associated with permits and complying with licensure laws and building codes may charge less than contractors who follow the law, which represents unfair competition.

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

To address challenges with compliance and enforcement, the Energy Commission develops and provides comprehensive and audience-specific education and outreach information on the standards to improve local enforcement and building industry compliance. In addition to its Energy Standards Hotline, the Energy Commission is launching a California Building Standards Online Learning Center to assist building department personnel in understanding and complying with the standards. The Energy Commission's Compliance and Enforcement Unit also investigates complaints and provides assistance to enforcement agencies, the public, and other energy professionals to increase compliance with the building standards. As part of this effort, staff works with various building departments throughout the state and also conducts regional outreach through International Code Council chapters to increase communication and cooperation between building departments. In addition, there is certification and ongoing management of HERS providers who train, manage, and certify HERS raters and are responsible for field verifications of performance-based energy efficiency measures in the building standards.

To increase compliance with the building standards, the Energy Commission also is working with the Contractors State License Board to take action in investigating and disciplining unlawful activity by licensed and unlicensed contractors in relation to the standards. In addition to the board, the Energy Commission is working with the HVAC industry and California building officials to focus on the problems with failure to obtain permits for change-outs. Further, to help property owners understand the benefits of proper permitting and code compliance, the Energy Commission has developed educational time-of-sale consumer information.

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

Efficiency in Existing Residential and Commercial Buildings

Existing residential buildings present a significant challenge to meeting the state's energy efficiency goals. Over half of the single-family homes in California were built before building standards went into effect, and retrofitting these homes could provide significant savings. At the same time, utility rebate programs have not done enough to capture cost-effective energy savings in existing buildings. To address the existing building sector, the state must move beyond programs that target single-measure rebates, such as replacing incandescent bulbs with compact fluorescent bulbs, and instead design comprehensive programs that include building energy use performance labeling or benchmarking; comprehensive deep retrofit programs; marketing, outreach, and education efforts presented in layperson terms; and creative funding mechanisms that help building owners with the necessary capital to cover the cost of the retrofits with an affordable cash flow over the life of the measures to allow the energy savings to pay for the investment.

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

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

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

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

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

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

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

Efficiency in the Industrial Sector

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

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

The Energy Commission also conducts no-cost technical energy audits at industrial plants using DOE's Energy Savings Assessment protocol, software tools, engineering calculations, and specialized measurement equipment. These assessments have resulted in estimated savings of 22 million therms of natural gas, 41,000 kilowatt hours of electricity, and 147,000 tons of carbon dioxide per year.[47] In addition to the energy savings, the assessments represent energy cost savings to industrial plants of $19 million per year. The Energy Commission expects to conduct approximately 10 assessments per year through 2012, with the goal of cumulative energy savings by 2012 of 50,000 MWhs per year of electricity and 40 million therms per year of natural gas.

An example of the potential for savings in the industrial sector is a food processing plant in central California that uses steam for

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

dried fruit processing and compressed air for production machinery operations. The plant underwent an on-site technical audit of its steam and compressed air system. For a total project cost of $150,000, energy efficiency improvements at the plant are saving $46,000 per year in electricity costs, $23,000 per year in natural gas costs, and $2,000 per year in reduced water consumption. Total costs savings per year exceeded $70,000, for a total project simple payback in 2.1 years.

Efficiency from Publicly Owned Utility Programs

Because publicly owned utilities represent about 22 percent of statewide electricity consumption, their contribution to meeting the state's energy efficiency goals is very important. AB 2021 (Levine, Chapter 734, Statutes of 2006) requires the Energy Commission to estimate statewide energy efficiency potential and establish targets for energy efficiency savings and demand reduction for California's investor and publicly owned utilities every three years, with the goal of reducing energy consumption by 10 percent over the next 10 years. The Energy Commission adopted the initial targets in 2007. In addition, the Energy Commission evaluates and reports on the annual progress of 39 publicly owned utilities' energy efficiency program investments and savings to the Legislature as part of the *IEPR*.[48]

From 2007 to 2008, publicly owned utility expenditures in energy efficiency programs increased 65 percent and totaled $104 million. Annual efficiency savings increased by nearly 58 percent for energy and nearly 46 percent for peak hours compared to 2007. However, combined savings accomplishments of these utilities reached only 66 percent of the 2008 adopted target for energy savings. While the trend of increasing savings is encouraging, publicly owned utilities should continue to explore all opportunities for increased efficiency savings to meet the targets adopted by the Energy Commission and contribute to meeting the statewide goal of achieving 100 percent cost-effective energy efficiency.

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

Publicly owned utilities face several challenges in increasing their efficiency savings. The current economic recession is affecting customers' willingness to participate in efficiency programs. Another issue is that many of the smaller publicly owned utilities serve a relatively small customer base so their programs can reach saturation rather quickly. In addition, the smaller utilities typically have fewer staff and capital resources than the larger utilities, making it difficult to administer efficiency programs. Even the larger publicly owned utilities are facing challenges from a retiring workforce and bringing new staff up to speed quickly.

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

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

Publicly Owned Utility Success Stories

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

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

California Municipal Utilities Association, to learn from one another's experiences.

Publicly owned utilities need to continue to use their unique customer knowledge to focus attention on new customer segments, expand measures that are low- or no-cost options, and market new incentive tools. The publicly owned utilities are encouraged to apply integrated resource planning to compare demand-side resources with supply-side resources using cost-effectiveness metrics. This approach, along with the willingness to fund energy efficiency from procurement sources, will increase future energy savings sufficiently to reach adopted targets. Efforts to complete measurement and verification studies should continue. These studies provide an opportunity to improve program delivery and cost-effectiveness and to show that energy savings have been realized, and they should be funded accordingly.

Energy Efficiency and the Economy

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

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

When determining the cost-effectiveness of energy efficiency measures, the Energy Commission believes there is a need to accurately value carbon savings embedded in energy efficiency. The definition of cost-effective energy efficiency should include a value for carbon dioxide (CO_2) and GHG emission reductions, consistent with the Title 24 Building Efficiency Standards. Utilities should also include an externality value for CO_2 and GHG emission reductions in the evaluation of their energy efficiency program impacts.

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

With the downturn in the national economy, energy costs represent a larger share of consumers' budgets, including low-income

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

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

customers whose numbers are increasing as a result of the financial crisis. One of the goals of the CPUC's *Long-Term Energy Efficiency Strategic Plan* is for all low-income homes to be energy efficient by 2020.[51] The CPUC issued a decision in November 2008, approving the Low-Income Energy Efficiency (LIEE) 2009–2011 program budgets for the four major IOUs.[52] The goal is for all eligible customers in the low-income sector, estimated at 4 million households, to have the opportunity to participate in the LIEE program. As part of achieving this goal, the CPUC is requiring the IOUs during 2009, to develop an integrated marketing, education, and outreach program for all energy efficiency programs, including LIEE. IOUs are also required to target their outreach to LIEE customers who are high energy users, have high energy burden, and/or have high energy insecurity, while also addressing low-income customers with lower energy use. The Energy Commission applauds the CPUC's significant contribution to meeting the state's energy efficiency goals, particularly with regard to the significant impact the CPUC is making in the low-income sector, recently swollen by the downturn in the economy.

Funding for IOU efficiency programs continues to be a high priority for the state. On September 24, 2009, the CPUC approved the 2010–2012 utility energy efficiency portfolios for $3.1 billion dollars of ratepayer-supported energy efficiency programs for 2010–2012 to be administered by the IOUs. The three-year program is estimated to avoid the construction of three 500-megawatt power plants, save almost 7,000 gigawatt hours of electricity and 150 million metric therms of natural gas, and avoid 3 million tons of GHG emissions. The program launches the nation's largest home retrofit program, which targets 20 percent savings for as many as 130,000 homes during 2010–2012. It also provides $175 million to launch California's Big Bold Energy Efficiency Strategies for zero net energy homes and commercial buildings, including design assistance, incentives for above-code construction, and research and demonstration of new technologies and materials.

The portfolios also include phasing down subsidies for basic compact fluorescent lamps while shifting the emphasis to advanced lighting programs, as well as requiring benchmarking for commercial buildings in California that receive energy efficiency funding. In addition, more than $260 million in funding will be provided for 64 cities, counties, and regional agencies for local efforts targeting public sector building retrofits and leading-edge energy efficiency opportunities. Performance metrics will be required to measure the progress of each program toward market transformation and achievement of the short-, medium-, and long-term goals and strategies set forth in the CPUC's *Long-Term Energy Efficiency Strategic Plan*.

Achieving the state's goal of all cost-effective energy efficiency will be challenging and will require continued and accelerated collaborative efforts between state and local agencies along with meaningful input from utilities and industry stakeholders. In particular, state energy agencies must work closely with local and regional governments to provide assistance in meeting the challenges of adopting and implementing energy efficiency programs to reduce GHG emissions. Toward that end, the Energy Commission is updating its 1993 *Energy Aware Planning Guide* with as-

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

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

Center Develops Statewide Demand Response Technologies

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

sistance from the Local Government Commission and other parties, with a target release of early 2010. The guide will provide regional and local governments with a solid reference of energy-conserving/GHG-reducing planning ideas, policy language, program implementation options, environmental and economic effects, examples of programs in operation, and contact information.

The Energy Commission also provides monetary support to local governments through the Energy Conservation Assistance Account Program, a low-interest loan program established in 1979 for public nonprofit schools and hospitals, public care institutions, and local governments. In coordination with the Energy Partnership Program, the program provides a wide range of assistance, from identifying energy saving opportunities in planned facilities to audits and feasibility studies for improvements in existing facilities. The Energy Commission has successfully implemented this revenue bond program and continues to pursue revenue bonds as necessary to continue program operations. Since July 1, 2006, the program has provided technical assistance to 149 projects and awarded 31 low-interest energy efficiency loans. For example, the Sacramento City Unified School District requested technical assistance to evaluate potential efficiency improvements in several of its high schools. Lighting retrofits, controls, and LED exit signs were recommended at each of the schools, leading to reduced energy use and average savings of approximately $53,000 per year. The program is expected to be augmented with American Recovery and Reinvestment Act of 2009 (ARRA) funds.

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

Demand Response

Demand response efforts seek to slow the rising cost of electricity and improve the reliability of the electricity grid by improving the efficiency of the generation, distribution, and consumption of electricity. Demand response measures provide incentives and tools that encourage and enable customers to periodically reduce their consumption in response to system conditions. The demand for electricity varies with the time of day and the season of the year. Most California consumers demand more electricity during the day than at night, and more in summer than winter, due to the increased use of air conditioning and other consumer electronic products during those times. The maximum peak load is projected to grow at a rate of 1.3 percent per year, faster than the overall growth in electricity demand.

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

Not only are peaking units generally less efficient, but because they operate only a few hundred hours per year, operators must pay for the unit's ownership and operating costs over a much shorter period. This results in much higher costs when compared with facilities that can spread their fixed costs over more hours of operation. Peaking units are necessary, however, to ensure that adequate power is available during peak times or to meet unexpectedly high load requirements.

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

The CPUC has recommended policy to move all ratepayers to some form of time-variant pricing along with Advanced Metering Infrastructure – advanced two-way communicating meters – and the Energy Commission has supported this policy. However, Senate Bill 695 (Kehoe, Chapter 337, Statutes of 2009) delays implementation of default time-variant pricing for residential customers until 2013. In its current load management standards proceeding, the Energy Commission proposed adopting a requirement that all utilities in the state adopt some form of time-variant pricing for customers that have advanced meters. To guarantee achieving the potential system cost savings of such a pricing system, the Energy Commission, CPUC, and utilities need to develop plans for default time-variant pricing that can be implemented when the legislated restrictions expire. The interim should be used to upgrade and update billing systems, develop effective and fair revenue-neutral dynamic rate designs, and use interval data as it becomes available to analyze customer impacts and develop customer education efforts to maximize demand response while minimizing and mitigating customer costs.

In the state's *Energy Action Plans*, both the Energy Commission and the CPUC have supported time variant pricing. The CPUC rulemaking (R.07-01-041) to evaluate the utilities' demand response programs sought to establish protocols for estimating load impacts, cost-effectiveness, and modifications to support the California ISO's efforts to incorporate these programs into market designs. A decision (D.08-04-050) regarding load impact estimations was issued in April 2008.[53] The Energy Commission joined in instituting the CPUC rulemaking (R.02-06-001) "to develop demand response as a resource to enhance electricity system reliability, reduce power purchase and individual consumer costs, and protect the environment." The rulemaking focused on developing dynamic rates and demand response programs for large customers and conducting research to evaluate the potential costs and benefits of building an advanced metering infrastructure to serve all IOU customers.

Research by the Demand Response Research Center indicates that with proper application, the new Open Automated Demand Response (OpenADR) standard has the potential to substantially increase the amount of demand response capabilities that exist for grid operators in the future. As California

53 California Public Utilities Commission, available at: [http://docs.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/81972.htm].

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

Renewable Energy

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

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

The 33 percent RPS target is expected to provide 15.2 percent of the total GHG reductions needed to meet the AB 32 goal of achieving 1990 emissions levels by 2020.[54] However, despite efforts to expand renewable generation, recent utility RPS procurement forecasts for 2010 and 2020 indicate that substantial challenges remain. As of November 2009, the CPUC had approved 129 RPS contracts totaling 10,271 MW; of that approved capacity, a little less than 10 percent – 917 MW – has come on-line and is delivering energy to the grid. An additional 30 contracts for 4,605 MW are under review.[55] While the IOUs have made progress adding renewable contracts to their portfolios, they do not expect to meet

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

55 California Public Utilities Commission, *Renewables Portfolio Standard Quarterly Report*, November 2009, available at: [http://www.cpuc.ca.gov/NR/rdonlyres/52BFA25E-0D2E-48C0-950C-9C82BFEEF54C/0/FourthQuarter2009RPSLegislativeReportFINAL.pdf].

the 2010 target and will be significantly below the 33 percent target in 2020 unless they add renewable resources at a much faster pace.

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

The main issues associated with meeting the state's renewable goals include the need for adequate transmission to access renewable resources, challenges to integrating high levels of renewable energy into the existing electricity system, potential difficulties in meeting higher RPS targets given progress to date on reaching the 20 percent by 2010 goal, and environmental concerns associated with building new renewable plants and the transmission to bring the energy from those plants to the state's load centers.

Renewable Energy and the Environment

Renewable energy provides obvious environmental benefits by reducing air and water pollution associated with electricity generation. However, renewables can also face challenges due to environmental concerns with specific technologies or where plants are located. This section discusses some of those issues, including eligibility requirements for the state's RPS and their impact on municipal solid waste plants and deliveries of renewable energy from outside California, environmental impacts of renewable generation and transmission infrastructure, and the potential effects of climate change on that infrastructure.

Expanding Renewables Portfolio Standard Eligibility

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

An example is the use of municipal solid waste (MSW) to produce energy. Although the Energy Commission defines MSW as an RPS-eligible fuel, current law narrowly defines which MSW conversion technologies are allowed. To date, no MSW gasification facility has met these stringent requirements, particularly the requirement that the MSW conversion occur without the use of air or oxygen except ambient air to maintain temperature control.[56] While the Energy Commission is

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

not aware of any gasification technologies that meet the current requirements, staff will continue to evaluate each RPS certification application to determine whether the MSW conversion technology meets the requirements for RPS eligibility. Because the law requires proposed MSW facilities to obtain air permits, it may be difficult for such facilities, even if they meet RPS eligibility requirements, to be built in areas of the state such as the South Coast Air Quality Management District (SCAQMD) that are in nonattainment for federal air quality standards.

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

As the space available for landfills becomes more limited in California, renewable energy developers have expressed interest in MSW gasification and are seeking clarification of rules for RPS eligibility of MSW conversion. In a 2006 report, the California Biomass Collaborative estimates that "biomass in the landfill disposal stream (23.1 million tons plus 2.6 million tons of green ADC [alternative daily cover]) could support about 1,750 MWe of electricity generation with another 900 MWe coming from the plastics and textiles

Agency Plan Recommends Climate Change Adaptation Strategies

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

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

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

components."[57] Given the state's aggressive renewable energy targets and the need for additional renewable energy to meet those targets, the Energy Commission suggests that it work with the California Integrated Waste Management Board to review emerging conversion technologies that use MSW to produce a clean burning fuel that most closely meets the intent of current RPS eligibility requirements as well as environmental considerations and, if appropriate, suggest modifications to applicable state statutes to allow such technologies to be RPS eligible.

Another eligibility issue is the delivery of renewable generation from out-of-state generators. Generation from a renewable power plant located outside California is eligible for the state's RPS if the facility began operation after January 1, 2005, can demonstrate delivery of energy into California, and does not cause or contribute to any violation of a California environmental quality standard or requirement within California.[58] As of September 2009, the Energy Commission has certified only 24 out-of-state renewable facilities as eligible for the RPS, compared to more than 576 eligible in-state facilities.

The delivery requirement for out-of-state renewable facilities is flexible, allowing delivery to occur "regardless of whether the electricity is generated at a different time from consumption by a California end-use customer."[59] This approach can allow out-of-state renewables to be "firmed" or "shaped" to address issues like intermittency, inadequate transmission, or scheduling barriers. Firming and shaping can also provide greater value to the electricity system by converting off-peak renewable generation to on-peak energy delivery. Allowing out-of-state renewables to be firmed and shaped rather than immediately scheduled for delivery may also increase the availability of lower cost renewable resources. Firming and shaping allows renewable electricity counted for California's RPS to be consumed outside California, provided that an equal amount of electricity is delivered to California within the same calendar year. Some parties have argued that counting large amounts of out-of-state renewables for California's RPS could reduce in-state air quality or job creation benefits. On the other hand, as discussed in the *2009 Strategic Transmission Investment Plan*, if California decides to build most of its own renewable energy resources to meet its RPS goals, many miles of land will be needed for new transmission lines to access those resources, which could face challenges associated with public opposition due to land use and environmental concerns.

As shown in Table 2, other states in the WECC area with RPS programs have their own delivery requirements. Arizona has the most restrictive electricity delivery policy, requiring that all electricity generated by the renewable resource being used for compliance with a utility's RPS target be physically delivered to that utility's service territory. Most other WECC states with an RPS program allow some

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

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

59 Public Resources Code § 25741(a).

TABLE 2: RPS DELIVERY AND LOCATION REQUIREMENTS IN OTHER WESTERN STATES

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

Source: KEMA, Inc.

use of unbundled renewable energy credits (RECs)[60] for RPS compliance. However, their use is often constrained by electricity delivery requirements, location requirements, or explicit caps. As a result, some of these states' policies are arguably more restrictive than California's in terms of geographic scope.

Delivery requirements are only one of many RPS design issues that affect how difficult it may be to meet the targets. Simply comparing delivery requirements across states, although important, does not give a complete picture of compliance flexibility.

Limiting access to out-of-state renewable resources could create geographic inequities between California's utilities because there are more in-state renewable resources located in the southern regions of the state, and transmission from south to north is limited. These inequities could be addressed by the use of tradable RECs. The CPUC issued a proposed draft decision authorizing tradable RECs for RPS compliance in December 2008, and issued a revised version in March 2009. If adopted, the revised proposed decision would "allow transfer of RPS credits without regard to constrained transmission pathways."[61]

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

Environmental Impacts of Renewable Infrastructure

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

Initiatives are already underway to facilitate the early identification and resolution of land use and environmental constraints to promote timely development of California's renewable generation resources and associated transmission lines. The Renewable Energy Transmission Initiative (RETI) collaborative process, discussed in more detail in the transmission section later in this chapter, has identified and ranked renewable resource development areas and associated transmission lines to deliver renewable power to load centers. The *RETI Phase 2A Report* is one of the data sources for ranking the transmission projects to interconnect renewables that are in the state's best interests.

To help address potential impacts of new renewable power plants and related transmission lines, the Energy Commission and California Department of Fish and Game are implementing Governor Schwarzenegger's Executive Order S-14-08, which established a process to conserve natural resources while expediting the permitting of renewable energy power plants and transmission lines. The Executive Order's primary objectives are to identify and establish areas for potential renewable energy development and conservation areas in the Colorado and Mojave deserts to reduce the

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

61 California Public Utilities Commission, Draft Proposed Decision Authorizing Use of Renewable Energy Credits for Compliance with the California Renewables Portfolio Standard, ALJ Simon, March 2009, p. 14, available at: [http://docs.cpuc.ca.gov/efile/PD/99016.pdf].

time and uncertainty associated with licensing new renewable projects on both state and federal lands. Federal participation was secured in November 2008, when the two state agencies signed a Memorandum of Understanding with the Bureau of Land Management (BLM) and U.S. Fish and Wildlife Service to create the Renewable Energy Action Team (REAT).

The REAT is developing the Desert Renewable Energy Conservation Plan (DRECP) and a best management practices and developer guidance manual. The REAT meets regularly to discuss renewable energy project permitting issues and to assist developers who are preparing applications to the different agencies. Federal participation was further supported by the Secretary of the Interior's March 2009 Secretarial Order 3285 directing all Department of the Interior agencies and departments (which include the BLM and U.S. Fish and Wildlife Service) to encourage the timely and responsible development of renewable energy, while protecting and enhancing the nation's water, wildlife, and other natural resources.

The DRECP will develop a conservation strategy that will use California's unique Natural Community Conservation Plan process and may develop a federal Habitat Conservation Plan process and/or amend existing resource management plans accordingly. The DRECP will also coordinate with existing desert conservation plans within the Mojave and Colorado deserts (for example, the West Mojave Plan), renewable energy development project plans, the BLM's Solar Programmatic Environmental Impact Statement (Solar PEIS), and Renewable Energy Transmission Initiative (RETI) planning to form an integrated framework for balancing natural resource conservation and renewable energy development within the Mojave and Colorado deserts.

On October 12, 2009, Governor Schwarzenegger and Secretary of the Interior Ken Salazar signed another Memorandum of Understanding (MOU) directing California agencies and U. S. Department of the Interior agencies to take the necessary actions to further the implementation of the Governor's Executive Order S-14-08 and the Secretary's Order 3285 in a cooperative, collaborative, and timely manner. To this end, state and federal agencies have accelerated processing of projects seeking ARRA funds that meet the milestones published pursuant to the MOU so that renewable energy projects that have been permitted[62] can meet the December 2010 start-of-construction date. The state and federal agencies also are coordinating closely to review in a timely manner other renewable energy projects that are not seeking ARRA funds.

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

Another environmental issue associated with renewable infrastructure is potential air quality concerns with new biomass facilities in California. With the Governor's direction in Executive Order S-06-06 to meet 20 percent of the RPS with biopower, it will be important to address these concerns. There is significant potential for renewable electricity generation fueled by biomethane from the state's dairies, but the high cost of emissions controls can interfere with dairies' ability to

62 California Energy Commission, Renewable Energy Action Team, available at: [http://www.energy.ca.gov/33by2020/documents/2009-10-15_Milestones_REAT.PDF].

obtain air permits. California is the largest dairy state in the nation, with more than 1.7 million cows on about 1,800 farms. These cows produce 65 billion pounds of manure per year that could produce biogas that can be burned to produce electricity.

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

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

Climate Change Effects on Renewable Infrastructure

Changes in the environment can also affect renewable energy.[65] Renewable energy depends on natural resources like water, biomass, wind, and the sun, so it can be particularly sensitive to climate variability. The U.S. Climate Change Science Program has identified impacts of climate change on the country's renewable energy resources, including changes in availability of water, biomass, and incoming solar radiation as well as significant changes in established wind patterns and potential effects on geothermal resources.[66] Climate change impacts that affect aspects of conventional energy facilities, such as power plant cooling and water availability, would also apply to certain renewable technologies such as biomass, geothermal, and solar thermal.

In California, only small hydroelectric facilities, those 30 MW or less in size, are eligible for the RPS. Small hydroelectric facili-

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

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

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

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

ties provide about 1.5 percent of California's power but about 13.5 percent of total renewable generation,[67] so potential impacts on precipitation levels and the timing and rate of snowmelt could affect the amount of electricity provided by small hydro facilities and ultimately their contribution to the state's renewable goals.

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

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

California has aggressive policies targeting rooftop photovoltaic systems, which depend both on the amount of incoming solar radiation and changes in temperature. Analysis of systems outside California have shown that a 2 percent decrease in solar radiation resulted in a 6 percent decrease in the electricity output of solar cells.[68]

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

Clearly, more research is needed on the effects of climate change on renewable and low and noncarbon resources, including: effects on biomass supplies and the influence that this would have on the optimal siting of a biomass facility; the California-specific impacts of climate change on photovoltaic technologies; and the location and scale of changes in California's wind patterns, especially in areas targeted for extensive wind energy development. In addition, the *2009 California Climate*

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67 California Energy Commission, 2008 Total System Power, see [http://energyalmanac.ca.gov/electricity/total_system_power.html].

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

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

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

Adaptation Strategy Discussion Draft[71] recommends using the Energy Commission's PIER regional climate modeling and related study efforts to assess the potential impacts of climate change on energy infrastructure from sea-level rise, precipitation, and temperature changes and other impacts.

Renewable Energy and Reliability

There are several ways renewable resources can affect energy reliability. Renewable resources help reduce the state's dependence on natural gas, making the state less vulnerable to natural gas supply disruptions. By reducing the amount of natural gas needed in the electricity sector, renewables could also free up more natural gas for use in industrial processes or residential cooking and heating. In addition, diversifying the state's electricity portfolio reduces customer risk in much the same way that diversifying an investment portfolio reduces financial risk.

However, not all renewables provide the operating characteristics that the system needs to maintain local area reliability, and integrating certain renewable technologies can make it more difficult to operate the system reliably. Necessary operating characteristics include providing baseload power that can meet demand around the clock and throughout the year, peaking power that meets demand during hot summer months, ramping ability in response to changing demand, and voltage support.

Challenges associated with integrating renewables into the system are covered in more detail in Chapter 3. Simply put, California's system operators must constantly balance changing supply and demand to provide reliable electricity and to ensure that the electric grid remains stable. While geothermal and biomass facilities can provide baseload power, intermittent resources like wind, hydro, and solar operate when nature allows and are therefore not always available to meet system needs during peak hours. Intermittent resources can also drop off or pick up suddenly, requiring system operators to compensate quickly for sudden changes. For example, photovoltaic arrays are very sensitive to cloud cover, which can cause generation to drop substantially in less than a minute and jump back to full generation a few minutes later.[72]

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

Another issue with integrating large amounts of renewables into the system is the potential for overgeneration, particularly in the spring when there is a need to spill

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

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

water stored in dams to make room for snow melt. Overgeneration occurs when generation exceeds demand despite the actions by the system operator to reduce generation. Overgeneration can lead to circumstances where market prices for electricity actually become negative as the system operator, in order to maintain system operations, must literally pay adjacent balancing authorities to take the excess energy.

One strategy to improve reliability by addressing the variability of renewable resources and overgeneration concerns is the use of utility scale and distributed energy storage, which is discussed in more detail in Chapter 3. Energy storage provides the ability to make best use of renewable generation facilities by addressing potential mismatches between generation and load while also addressing other issues like ramping rates and power quality. Large utility-scale energy storage technologies like pumped hydroelectric storage, compressed air energy storage, or large multi-megawatt battery storage systems can store renewable energy generated off-peak for later use during peak periods or to provide firming. Pumped hydroelectric storage uses water pumped from a lower elevation reservoir to a higher elevation using low-cost off-peak electric power (including renewable energy) to run the pumps. The water is then allowed to return and generate electricity during times when the renewable generation needs firming or to match the renewable load to the needs of the utility electrical system. Compressed air energy storage uses a compressor to pressurize a storage reservoir using off-peak energy and then releases the air through a turbine during on-peak hours to produce energy. Large compressed air energy storage systems use underground caverns such as depleted natural gas mines to store the air and can provide energy storage for long periods of time. Battery energy storage technology has improved over time to the point where there are several emerging battery technologies that can provide utility-scale energy storage.

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

Renewable Energy and the Economy

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

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

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

The Energy Commission's Renewable Energy Program that was established in 1998 represents an additional $2.1 billion to support the continued operation of existing renewable facilities and the development of new renewable generating facilities and emerging renewable technologies.[73] The consumer education component of the Renewable Energy Program also funded the development of the Western Renewable Electricity Generation Information System, which tracks renewable generation in the Western Electricity Coordinating Council area to ensure that generation is counted only once for purposes of California's RPS.

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

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

Integrating renewable resources into the electricity system has potential economic consequences – primarily, increased potential costs. To the extent that natural gas remains a low-cost fuel, gas-fired generation can help the electricity system absorb the costs of transitioning to a higher level of renewable energy in the electricity system. But determining the actual costs of increased levels of renewables is difficult. Cost studies to date have widely varying assumptions, uncertainties, and approaches. However, study results are influenced by some common factors:

- Estimates of future natural gas prices
- Estimates of the cost of generation for gas-fired and renewable generating technolo-

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

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

gies, including the potential cost of GHG allowances for gas-fired generation, costs for siting and permitting, and the cost of capital to finance new renewable projects

- Availability of tax credits and other incentives for renewable generation

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

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

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

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

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

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

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

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

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

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

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

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

Recognizing that renewables often are more costly than conventional energy sources, the RPS law prior to 2008 set aside a fixed amount of public goods charge funding to

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

offset potentially higher costs to the IOUs of procuring renewable energy. In 2008, legislative action transferred administration of these funds from the Energy Commission to the CPUC, refunded $462 million in unused funds to the IOUs, and eliminated the collection of that portion of the public goods charge. There is now a "cost limitation" for each utility that is equal to the actual amount of funding collected for this purpose from 2002–2007 plus the projected amount that would have been collected from 2008–2011.

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

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

In setting feed-in tariffs, there are two important considerations. First, to keep downward pressure on costs, feed-in tariffs should not be "one-size-fits-all," but instead should be based on the size and type of renewable resource. For example, the cost of generating energy from a 100-MW wind farm is much less than the cost of generating energy from

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

78 Studies include: Summit Blue Consulting and Rocky Mountain Institute, 2007, *An Analysis of Potential Ratepayer Impact of Alternatives for Transitioning the New Jersey Solar Market from Rebates to Market-Based Incentives*, final report, Boulder, CO, Summit Blue Consulting, prepared for the New Jersey Board of Public Utilities, Office of Clean Energy; de Jager, David and Max Rathmann, Ecofys International, BV, *Policy Instrument Design to Reduce Financing Costs in Renewable Energy Technology Projects*, October 2008, PECSNL062979, International Energy Agency Implementing Agreement on Renewable Energy Technology Deployment, available at: [http://www.iea-retd.org/files/RETD_PID0810_Main.pdf]; Ragwitz et al., OPTRES, *Assessment and Optimization of Renewable Energy Support Schemes in the European Electricity Market*, final report, February 2007, European Commission, available at: [http://www.optres.fhg.de/OPTRES_FINAL_REPORT.pdf]; and Cory, Karlynn, Toby Couture, and Claire Kreycik, NREL, *Feed-In Tariff Policy: Design, Implementation, and RPS Policy Interactions*, March 2009, p. 9, available at: [http://www.nrel.gov/docs/fy09osti/45549.pdf].

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

Feed-In Tariffs and Transmission

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

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

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

a 2-MW field of photovoltaic panels. Differentiating feed-in tariffs by type and size can ensure a good mix of new renewable energy projects and avoid paying too much for some technologies and too little for others. Setting a different feed-in tariff for each type of renewable energy technology can also stimulate competition among equipment manufacturers to bring costs down and maximize profit margins for project developers.[80] This approach is being used in Germany, where feed-in tariffs are stimulating development in a broad range of renewable energy types and project sizes.

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

80 Grace, R., W. Rickerson, K. Corfee, K. Porter, and H. Cleijne, KEMA, *California Feed-In Tariff Design and Policy Options*, final consultant report, prepared for the California Energy Commission, CEC-300-2008-009F, pp. 24–25, available at: [http://www.energy.ca.gov/2008publications/CEC-300-2008-009/CEC-300-2008-009-F.PDF].

certainty for manufacturers regarding long-term market growth unless the cap is set as a long-term target.

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

- The level of return on equity and/or debt consistent with the risk profile of the specific technologies.
- The ownership structure, if tariffs will be differentiated by owner type.
- The degree of leverage (debt versus equity).
- How costs are allocated for transmission, distribution, and interconnection.
- How to address the range of costs for each technology to balance costs to ratepayers against stimulating investment.
- How complex the rate-setting model will be and the optimal level of stakeholder involvement.

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

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

Opinions regarding the effects of feed-in tariffs vary. Some parties are concerned that feed-in tariffs would be too costly and would increase electricity rates for utility customers. Others argue that providing clear up-front feed-in tariff guidelines would reduce the time and expense of obtaining a long-term contract by allowing pre-approval of projects that meet those guidelines.[83] Feed-in tariffs could also reduce financing costs by providing increased

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

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

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

certainty for investors.[84] And as with all strategies to reduce the impacts of climate change, determining the cost-effectiveness of feed-in tariffs to incentivize renewable energy must factor in the potential health and environmental costs of not meeting the state's GHG emission reduction goals.

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

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

In California, IOUs have offered a feed-in tariff since 2008 for projects up to 1.5 MW based on the market price referent.[88] As of August 2009, this feed-in tariff has resulted in only 14.5 MW of contracted capacity, suggesting that the market price referent does not provide enough revenue to stimulate development of small-scale renewable projects. The CPUC is considering expanding its feed-in tariffs to renewable projects as large as 10 or 20 MW.[89]

On March 27, 2009, the CPUC administrative law judge (ALJ) in Rulemaking 08-08-009 filed an Energy Division staff proposal for comment. The staff proposal addresses the design and contract terms for an expanded feed-in tariff program with eligibility for projects up to 10 MW in size. It also proposes terms and conditions to include in a standard feed-in tariff contract for projects between 1.5 MW and 10 MW in size. The staff proposal does not consider pricing for an expanded program, but assumes that prices will continue at the current market price referent level.

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

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

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

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

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

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

On August 27, 2009, the ALJ filed an additional staff proposal for comment. The additional proposal addresses a pricing mechanism for system-side distributed generation, which Energy Division staff asserts is consistent with the program goals, guiding principles, and the feed-in tariff proposal filed on March 27, 2009. The staff pricing proposal focuses on system-side renewable distributed generation, defined as small projects (from 1 to 20 MW) that export all of the project's electricity to the utility and connect to the distribution grid. Neither of these proposals takes into account potential legal issues raised by parties in legal briefs filed in June and July 2009 on the question of federal and state jurisdiction in setting the price paid to a wholesale generator by a utility under a feed-in tariff.

California's two largest publicly owned utilities are also developing feed-in tariffs. The LADWP is developing a feed-in tariff for solar on rooftops of public organizations that are not eligible for tax credits, such as the Los Angeles Unified School District, Los Angeles Community College District, the University of California, and California State University.[90] SMUD is also moving forward with a feed-in tariff beginning in January 2010 that is aimed at systems up to 5 MW connected to SMUD's local distribution system, with a systemwide cap of 100 MW.[91] The feed-in tariff applies to both renewable and fossil-fuel generation technologies.

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

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

Distributed Generation and Combined Heat and Power

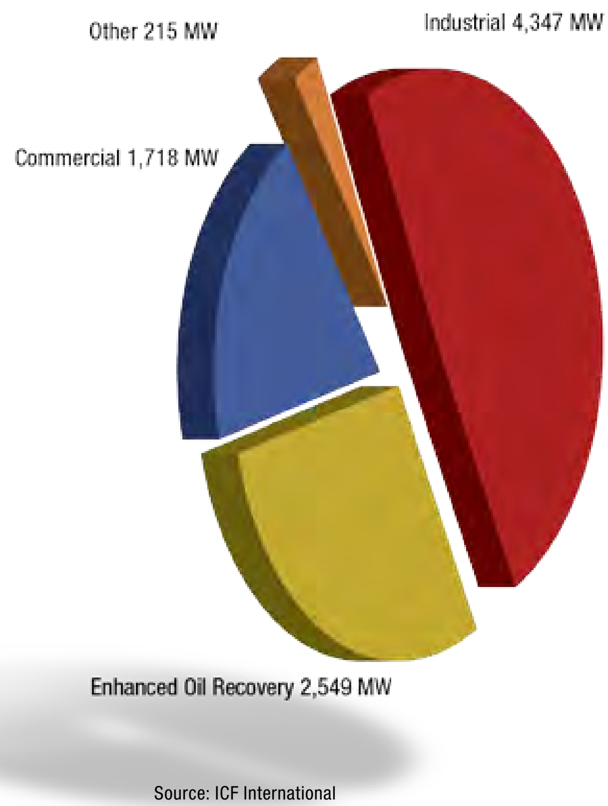
The next element in California's loading order for meeting new electricity needs is distributed generation and CHP. As stated in the *2005 Energy Action Plan*, "After cost-effective efficiency and demand response, we rely on renewable sources of power and distributed generation, such as combined heat and power applications."[92]

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

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

92 California Energy Commission and California Public Utilities Commission, *Energy Action Plan II*, September 21, 2005, [http://www.energy.ca.gov/energy_action_plan/2005-09-21_EAP2_FINAL.PDF].

FIGURE 9: EXISTING COMBINED HEAT AND POWER IN CALIFORNIA



Source: ICF International

tariff for small, new, highly efficient CHP to be implemented under AB 1613 (Blakeslee, Chapter 713, Statutes of 2007). The CPUC opened a rulemaking in June 2008 to implement the requirements of AB 1613, including establishing the policies and procedures for purchasing electricity from new CHP systems, and the Energy Commission is in the process of developing guidelines establishing technical eligibility criteria for programs to be developed by the CPUC and publicly owned utilities. Assembly Bill 1613 requires that the guidelines be adopted by January 1, 2010.

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

Existing Combined Heat and Power in California

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

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

Existing CHP installations in California can also be characterized in terms of facility size, primary fuel, and technology (prime mover). Large installations make up most of the existing capacity, with systems smaller than 5 MW representing only 5.5 percent. Systems larger than 100 MW represent almost 40 percent of the total existing capacity. The market saturation of CHP in large facilities is much higher than for smaller sites; much of the remaining technical market potential for CHP is for smaller systems.

The dominant fuel used for CHP is natural gas, representing 84 percent of the total installed capacity. Renewable fuel makes up 4.5 percent of the total capacity, mostly in the wood products, paper, and food processing industries and in wastewater treatment facilities.

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

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

Combined Heat and Power and the Environment

In December 2008, the ARB adopted its *Climate Change Scoping Plan* with a target of 4,000 MW of CHP to displace 30,000 GWhs of demand and reduce GHG emissions by 6.7 million metric tons of CO_2 by 2020. A CHP facility produces electricity and utilizes the excess heat, thus increasing efficiencies and reducing GHG emissions.

For CHP to meet ARB's goals, a new generation of highly efficient CHP facilities must be encouraged and supported. Critical to achieving these efficiencies and meeting these targets will be the legislatively mandated minimum efficiency standard of 60 percent to guide development and operation of these facilities over time. AB 1613 is intended to encourage the development of new CHP systems in California with a generating capacity of not more than 20 MW. Assembly Bill 1613 directs the Energy Commission to adopt guidelines by January 1, 2010, establishing technical criteria for eligibility of CHP systems for programs to be developed by the CPUC and publicly owned utilities. When these guidelines are adopted, they will set an efficiency standard for CHP facility development and assure that facilities are designed and operated in a way that reduces GHG emissions and will create a new benchmark for CHP efficiencies in California. As CHP technology continues to develop, efficiencies more than 70 percent can be expected to become standard and cost effective.

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

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

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

Combined Heat and Power Technical Potential

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

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

94 California Energy Commission, *Combined Heat & Power Potential at California's Wastewater Treatment Plants*, final staff paper, September 2009, CEC-200-2009-014-SF, available at: [http://www.energy.ca.gov/2009publications/CEC-200-2009-014/CEC-200-2009-014-SF.PDF].

95 *Combined Heat and Power Market Assessment*, draft consultant report, October 2009, CEC-500-2009-094-D, available at: [http://www.energy.ca.gov/2009publications/CEC-500-2009-094/CEC-500-2009-094-D.PDF].

TABLE 3: TOTAL COMBINED HEAT AND POWER TECHNICAL POTENTIAL (MW) IN 2009 BY MARKET SECTOR

	FACILITY SIZE				
MARKET TYPE	50–500 kW	500 kW–1 MW	1–5 MW	> 20 MW	TOTAL
Industrial Onsite	966	501	1,403	245	4,157
Commercial Traditional	297	133	124	0.0	568
Commercial Heating & Cooling	2,862	760	1,668	604	6,802
Export Existing	71	110	261	3,530	4,544
Total	**4,197**	**1,504**	**3,456**	**4,379**	**16,071**

Source: ICF International

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

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

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

Table 3 shows the total technical potential for CHP in existing facilities in California for 2009. There is more potential in commercial facilities than in industrial facilities, which is

TABLE 4: TOTAL COMBINED HEAT AND POWER TECHNICAL POTENTIAL GROWTH (MW) BETWEEN 2009 AND 2029 BY MARKET SECTOR

MARKET TYPE	FACILITY SIZE				
	50–500 kW	500 kW–1 MW	1–5 MW	>20 MW	TOTAL
Industrial Onsite	132	62	154	64	438
Commercial Traditional	47	15	19	4	85
Commercial Heating & Cooling	622	190	416	181	1,526
Export New Facilities	22	16	39	45	294
Total	**823**	**283**	**628**	**294**	**2,346**

Source: ICF International

a switch from the traditional characterization of CHP target markets. There is also a heavy concentration of potential in the small size ranges, indicating that many large facilities already have CHP systems for their on-site needs, leaving the remaining large size system potential in the export market.

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

While the 2009 technical potential estimate is based on the facility data in the potential CHP site list, the 2029 estimate includes economic growth projections for target applications between 2009 and 2029 (Table 4). To estimate the development of new facilities and growth in existing facilities between the present and 2029, economic projections for growth by target market applications in California were used.[96] Due to recent economic factors, the outlook on growth rates for several industries are not as strong as they once were, leading to a lower amount of new technical potential additions in the forecast period.

Clearly, California contains significant technical potential for growth in CHP installations. Considering the market for both existing and new commercial and industrial facilities, there is a total technical market potential that

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

is more than 18,000 MW by 2029. The most significant regions for growth are in PG&E and SCE service territory; however the other utilities in California also have significant room for growth.

Combined Heat and Power Market Potential

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

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

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

Base Case Results

In the 20-year forecast period, the base case market penetration of CHP generating capacity equals 2,731 MW with an additional 267 MW of avoided electric capacity for air conditioning supplied by CHP for a total market impact of 2,998 MW. (With the passage of SB 412 [Kehoe, Chapter 182, Statutes of 2009], an additional 497 MW of combined heat and power was made available for addition to the base case, in accordance with an alternative incentive scenario analyzed for this assessment.)

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

Incentive Cases

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

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

Restore the Self-Generation Incentive Program Eligibility. Senate Bill 412 expands program eligibility to include "distributed energy resources that the [CPUC], in consultation with the State Air Resources Board, determines will achieve reductions of greenhouse gas emissions." This includes CHP facilities that meet specified emissions and efficiency standards. The CPUC will be required to implement the Self-Generation Incentive Program using its own discretion about program details. For this analysis, conducted before SB 412's passage, it was assumed that all payments would be restored as they existed before they were suspended in 2007 and that the current phased expansion of benefits for projects up to 5 MW would be included as well.

Basic Large Export Case. When the AB 1613 feed-in tariffs for new CHP are finalized they will apply only to systems 20 MW or less. In the base case, no mechanism for exporting power from larger facilities (greater than 20 MW) was assumed. In this first of two expanded export scenarios, export of power from large facilities is assumed to be at a contract price reflecting the cost of power generation from a combined cycle power plant using the plant cost and performance assumptions defined in an Energy Commission staff report.[97]

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

Strong Stimulus Large Export Case. A second contract price track for large export CHP projects was also evaluated that included an aggressive contract price.

All Incentives Case. The all-in case represents a combination of restoration of the Self-Generation Incentive Program, addition of CO_2 emissions reduction payments of $50/ton, and encouragement of large export projects with the aggressive contract pricing mechanism and accompanying CO_2 payments. The large export market contributes 2,714 MW to this case.

Incentive Case Results

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

- CO_2 payments increase market penetration by 244 MW.
- The restoration of the Self-Generation Incentive Program for the next 10 years increases market penetration by 497 MW.
- Expanding export contracting to facilities larger than 20 MW with a basic contracting mechanism increases market penetration by 1,441 MW. All of this increase in export market penetration is for facilities larger than 20 MW.
- In the all-in case, which includes all measures plus a more aggressive large export contract price, the market increases by 3,521 MW, with 79 percent of this increase in the export market.

FIGURE 10: BASE CASE CUMULATIVE COMBINED HEAT AND POWER MARKET PENETRATION BY SIZE CATEGORY

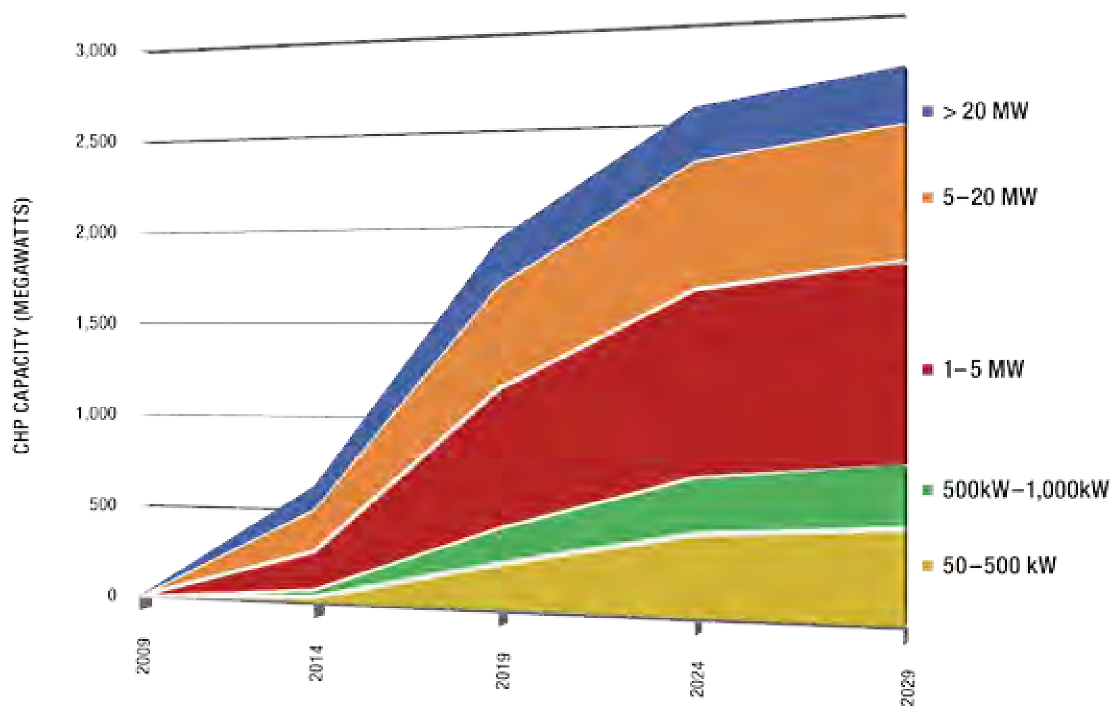
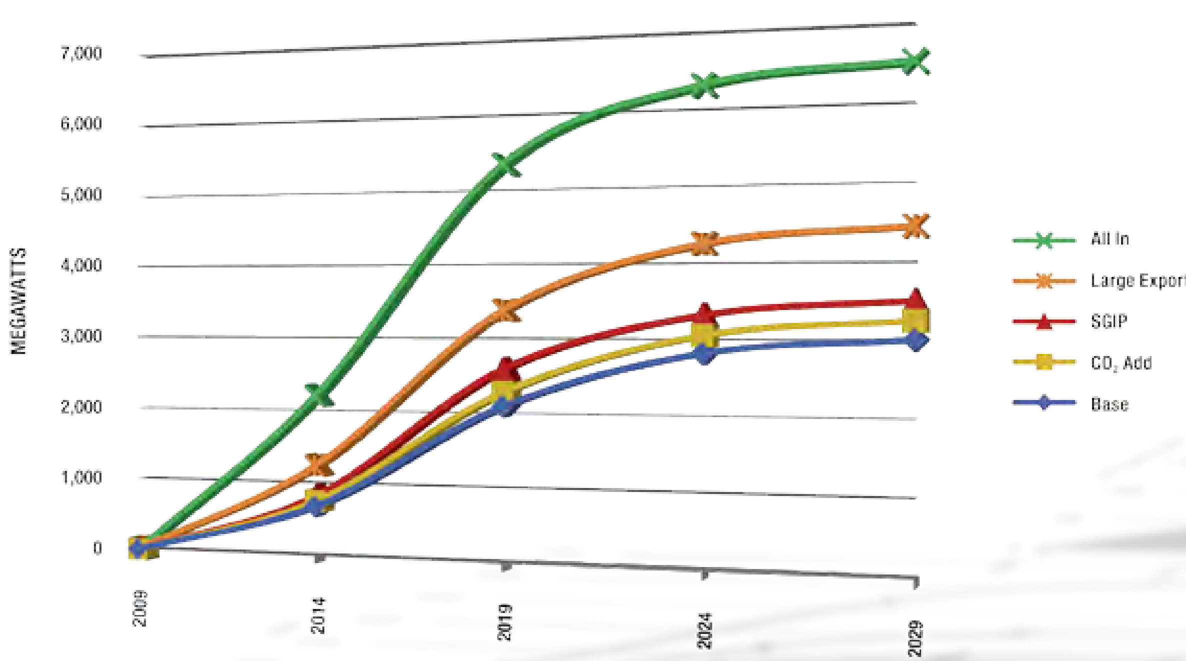
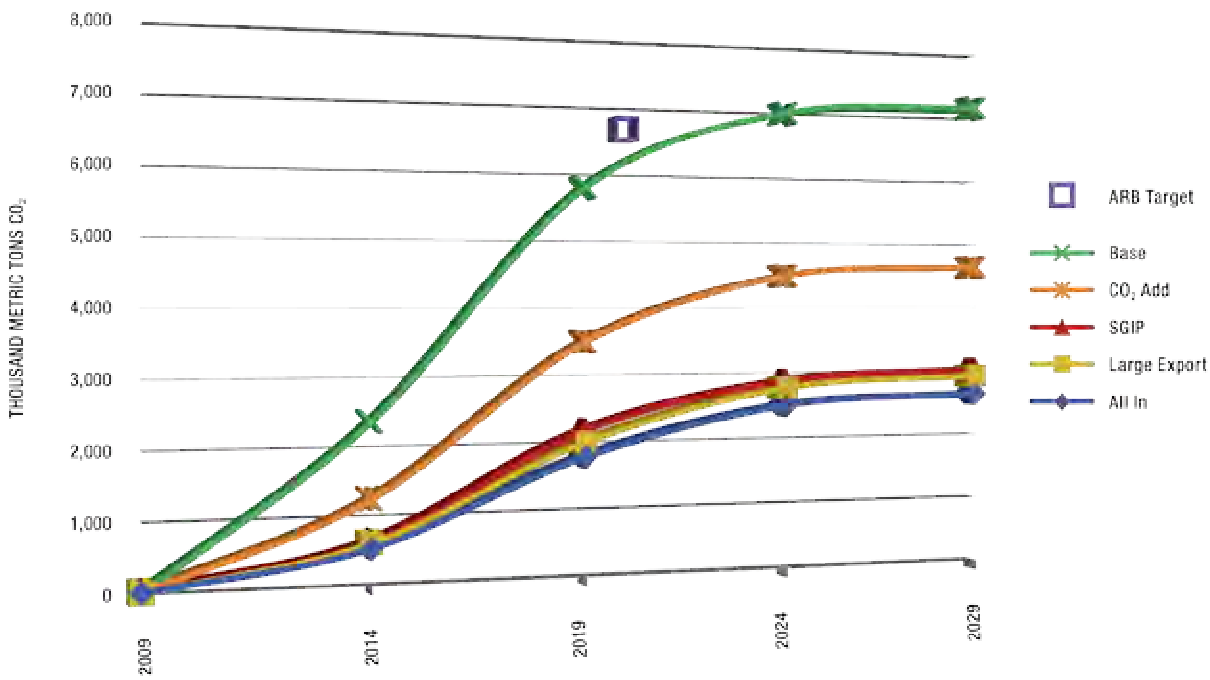


FIGURE 11: INCENTIVE CASES CUMULATIVE MARKET PENETRATION RESULTS



Source for figures: ICF CHP Market Model

FIGURE 12: GREENHOUSE GAS EMISSIONS SAVINGS BY SCENARIO USING AIR RESOURCES BOARD AVOIDED CENTRAL STATION EMISSIONS ESTIMATE



Source: ICF CHP Market Model

TABLE 5: COMPARISON OF STUDY RESULTS GREENHOUSE GAS SAVINGS TO AIR RESOURCES BOARD GOALS

SCENARIO	CAPACITY MW	OUTPUT GWh/YEAR	AVERAGE LOAD FACTOR	AVOIDED CO_2 MMT/YEAR	CO_2 SAVINGS RATE lb/MWh
ARB 2020 Goal	4,000	30,000	85.6%	6.70	492
Base Case 2020	2,240	14,486	73.8%	1.93	294
Base Case 2029	2,998	18,296	69.6%	2.67	322
All In Case 2020	5,532	39,545	81.6%	6.05	337
All In Case 2029	6,549	45,779	80.2%	7.20	347

Source: ARB and ICF International

GHG Emissions Savings

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

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

Because both the ARB estimates and this study are based on the ARB assumption for avoided GHG emissions, the differences to the CO_2 savings rates shown in the table – 492 lb/MWh for ARB and 294–347 lb/MWh for this study – are primarily due to changes in the operating profile and performance assumptions for CHP. The differences are as follows:

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

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

Combined Heat and Power and Reliability

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

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

In addition, if there is a prolonged outage, fuel supplies for diesel generators may also be a problem. After Hurricane Katrina, diesel fuel for backup generators could not be resupplied for many reasons including blocked or destroyed roads and contaminated fuel supplies. Because CHP systems operate continuously (or for extended periods every day) and because they operate (typically) on natural gas, CHP systems eliminate many of these issues. During and after Hurricane Katrina, natural gas lines remained pressurized. As a result, natural gas was the only fuel available for several weeks afterwards.[98]

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

Encouraging and supporting the development of CHP at hospitals and other facilities or institutions that support essential health and safety functions for the state can provide a range of benefits beyond assured reliability. Benefits for hospitals include cost savings, improved patient service, and improved reliability and power quality to ensure expensive and sensitive electronics and equipment are not damaged when voltage fluctuates. From the state's perspective, encouraging the installation of CHP in hospitals and other essential facilities will assure that if electric supplies are interrupted for hours, days, or weeks, as was the case when Hurricane Katrina devastated New Orleans, California citizens will be able to find a "safe haven" at hospitals and other similar institutions in the state that are equipped with CHP systems. A secondary benefit of increased use of CHP at hospitals throughout the state is the retirement of old diesel backup generators and the reduction of emissions associated with their operation.

Combined Heat and Power and the Economy

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

- Uncertainty about the differential between the cost of buying electric power from the grid and the cost of natural gas.

- A required payback period of as little as two years and usually no longer than five years. The new assessment of CHP potential indicates that these facts imply a very high risk perception on the part of potential CHP project developers.

- The ability of a CHP system owner to offset only about 80 percent of the electrical retail rate because of standby and demand charges. Tariffs in other states provide higher offsets.

- Current tariffs not fully accounting for the system and societal benefits that CHP provides.

- Additional technical economic and technical design challenges faced by facilities with fluctuating loads.

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

Natural Gas Power Plants

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

Natural Gas Plants and the Environment

Natural gas has become California's fuel of choice for most new power plants because it is cleaner than other fossil fuels. Yet, emissions from natural gas generation account for (on average) 78 percent of the in-state electric GHG emissions.[99] However, natural gas power plants can also play a key role in meeting the state's climate change goals and RPS targets. The Energy Commission's *Framework for Evaluating Greenhouse Gas Implications of Natural Gas-Fired Power Plants in California* report identifies specific roles and expectations for gas-fired generation to support the integration of renewables under the policy mandates to reduce GHG emissions from the electricity sector. The report found that a natural gas plant providing support to integrate renewable energy under a 33 percent RPS will yield a GHG emission benefit if the addition raises the overall efficiency of the electric system, or if the new plant serves increased demand for electricity more efficiently than the existing power plant fleet. The analysis found that although a single natural gas-fired power plant produces GHG emissions, under certain circumstances the addition of a gas-fired plant may yield a systemwide GHG emission benefit.[100]

Marine impacts from once-through cooling (OTC) power plants are another major environmental concern with the state's natural gas and nuclear power plants. As part of an interagency working group, the Energy Commission, CPUC, and California ISO have been working with the State Water Resources Control Board (SWRCB) to outline a proposal to maintain electric grid reliability while reducing OTC in California's 21 coastal power plants. These plants together pump up to 17 billion gallons of ocean, bay, or estuary water each day.[101] The pumping process impinges on fish, invertebrates, and crustaceans, and destroys billions of fish eggs and larvae, and the heated discharge water also harms marine organisms by increasing the water temperature. The draft has issued a compliance schedule for retiring, refitting, or repowering OTC plants to comply with the federal water policy.

It is crucial that the state develop new generating capacity to replace OTC power plants that may retire in the near future. Plants most likely to retire are located in and around the Southern California area, which has some of the worst air quality in the nation. Replacement power sources will have to meet stringent local air quality requirements; however, emission offsets are in short supply

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

100 Ibid.

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

in the SCAQMD, constraining the Energy Commission's ability to license new power plants in Southern California. Chapter 3 describes the system integration challenges associated with potential retirement of OTC plants as well as difficulties in providing replacement power due to limits on emission reduction credits.

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

As California moves toward reducing GHG emissions associated with electricity generation, it will need innovative strategies to address emissions from fossil power plants that may be required to support system operation or integration of renewable resources. One such strategy is CO_2 capture and storage, also known carbon capture and sequestration (CCS). As part of the *2007 IEPR*, the Energy Commission and the California Department of Conservation developed a report focused on geologic sequestration strategies for the long-term management of carbon dioxide, entitled, *Geologic Carbon Sequestration Strategies for California: Report to the Legislature.*[102]

There have been encouraging technology advancements and investments since publication of the *2007 IEPR*, and technology developers and policy makers examining CCS applications have expanded their view from an initial focus on coal and petroleum coke to natural gas and refinery gas, the predominant fossil fuels used in California power plants and industrial facilities.

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

In the last two years, oxy-combustion CO_2 capture components and systems have been tested at ten times the size of previous pilot units, including California's Clean Energy Systems' rocket engine–derived gas generator. Pre-combustion CO_2 capture systems are now

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

being proposed in commercial power plants based on solid fuel gasification, such as the Hydrogen Energy California project in Kern County (a joint venture of BP and Rio Tinto).

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

Although the cost of applying CCS to natural gas power plants or oil refinery furnaces is relatively high using proven technologies (about $75 per metric ton of CO_2 avoided),[103] the prospect of energy-saving technology improvements and the sale of captured CO_2 to oilfield operators for oil recovery has increased the likelihood that CCS can be economically competitive and, as a consequence, the interest of state agencies working on AB 32 compliance. Positive public comment was also cited as a contributing factor to increased discussion of CCS and support for near-term technology development in the ARB's *Climate Change Scoping Plan*. This momentum appears to be continuing, with an interagency group formed in August 2009 to develop recommendations on CCS-related policy issues.

103 Ibid.

Addressing policy questions in tandem with technology development and demonstration is particularly important for CCS because institutional barriers have been as much of an impediment as high cost. In many cases, the necessary regulatory and statutory frameworks are unclear or do not yet exist.[104] At the federal level, the U.S. Environmental Protection Agency in 2008 proposed new rules for wells used to inject CO_2 for long-term geologic storage.[105] These rules are expected to become final by early 2011, and further federal rules may be forthcoming restricting emissions of CO_2 as an air pollutant. However, many of the legal and regulatory issues needing resolution are within the domain of state rather than federal law.

In particular, legal clarity is needed on ownership of subsurface "pore space" where CO_2 is stored, the ability to independently transfer pore space rights and the dominance of such rights relative to surface and mineral rights, procedures by which access rights to multiple adjoining pore space "parcels" may be secured for CO_2 storage zones spanning multiple estates, and potential long-term liabilities for stored CO_2. More than 30 states are currently wrestling with these issues, with several states having passed laws that suggest approaches for consideration by the California Legislature.

Regulatory issues needing clarity include procedures by which operations permitted for CO_2-enhanced oil recovery become long-term CO_2 storage projects as well; CEQA responsibility and siting jurisdiction for power plant projects with CO_2 capture, pipeline transportation, and off-site geologic CO_2 storage (similar jurisdictional questions may arise for

104 Ibid.

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

other industrial project types); responsibility for monitoring, reporting, and remediation (if necessary) when custody of captured CO_2 is transferred from a regulated industrial source to a subsurface storage site operator; and rules for offshore (sub-seabed) CO_2 storage projects. Most of these issues require legislative solutions, although AB 32 rulemaking may provide some guidance. In the case of oilfield CO_2 injection wells, U.S. Environmental Protection Agency (EPA) has requested public input on treatment of their conversion to geologic sequestration wells, as part of the new "Class VI" rulemaking for dedicated geologic sequestration wells (under the underground injection control [UIC] program for groundwater protection). California must decide whether to seek primacy for administration of the UIC program for Class VI geologic sequestration wells, as it does for UIC Class II oil and natural gas exploration and production wells.

Resolution of legal and regulatory uncertainties will be crucial to helping spur CCS investment and further project development, but economic challenges will remain so long as the value of CO_2 emission allowances remains low. Cap-and-trade proposals with "safety valves" and other measures to limit the rate at which allowance prices rise to their expected long-term value could hamper private investment in CCS without some form of policy incentives. Given the expense and lead-time of the full-scale demonstrations needed to establish CCS technology viability, and the social benefit of associated "learning by doing" cost reductions, California should continue state investment in CCS R&D and demonstrations in tandem with investment by DOE and private industry. Public-private partnerships for CCS demonstration are expected to prove vital to realizing future dividends in terms of more cost-effective commercial application and an overall reduction in the cost of meeting the state's long-term GHG reduction goals.

Natural Gas Plants and Reliability

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

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

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

Replacement of OTC plants is complicated by the current emission credit limitations in the South Coast Air Basin, as discussed earlier in this section. These limitations are causing delay in environmental improvements that accompany investments in new and updated infrastructure. Fortunately, because SWRCB has agreed to delay its original compliance schedule, in part due to these air credit issues, these delays are not jeopardizing the long-term reliability of the region's electricity supplies. These issues related to emissions credits in the South Coast Air Basin are discussed further in Chapter 3.

Nuclear Power Plants

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

Nuclear power plants play a significant role in California's energy mix, providing about 14 percent of the state's total electricity in 2008 from two operating in-state facilities, PG&E's Diablo Canyon Power Plant (Diablo Canyon) and SCE's San Onofre Nuclear Generating Station (SONGS), and from the Palo Verde Nuclear Generating Station in Arizona. As part of the *2008 IEPR Update*, the Energy Commission developed *An Assessment of California's Nuclear Power Plants: AB 1632 Report,*[106] which addressed seismic and plant aging vulnerabilities of California's in-state nuclear plants, including reliability concerns. In addition, the report identified a number of other issues important for the state's nuclear policy and electricity planning. These include:

- Continuing Nuclear Regulatory Commission (NRC) concerns over safety culture, plant performance, and management issues at SONGS.
- The evolving federal policy on long-term waste disposal.
- Costs and benefits of nuclear power compared to other resources.
- Potential conversion from once-through cooling to closed-cycle wet cooling.

An overarching issue with the state's nuclear facilities is plant license renewal. The NRC operating licenses for California's nuclear plants are set to expire in 2022 (SONGS Units 2 and 3) and 2024 and 2025 (Diablo Canyon Units 1 and 2, respectively).[107] It is unknown whether the NRC will approve applications by PG&E and SCE for 20-year license renewals,

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

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

Reactor Vessel Integrity

The NRC recently revised its regulations to provide licensees with a new alternative for assessing the probability of a crack forming through the wall of a reactor pressure vessel. If such a crack occurred, it could damage the reactor core and, in rare cases, release radioactive materials into the environment. The probability of crack formation relates directly to the extent of reactor pressure vessel embrittlement, which determines the ability of metals that make up the reactor pressure vessel to withstand stress without cracking.

The old regulations required licensees to demonstrate that reactor pressure vessel embrittlement would not exceed a screening limit corresponding to a one-in-200,000-year probability of through-wall crack formation. While NRC's recently adopted regulations expand this requirement to a one-in-a-million-year probability, they also allow for the use of a less-conservative method for assessing the probability. With the old methodology, Diablo Canyon Unit 1 and nine other reactors would have exceeded the screening limit during a 20-year license extension and would not be eligible for license renewal unless they could reduce the embrittlement rate or demonstrate that operating the reactor would not pose an undue public risk. In contrast, the new method results in a much lower calculated embrittlement for most reactors, and is no longer expected to limit any U.S. reactor from obtaining a 20-year license renewal (NUREG-1806, p. xxii and Appendix D).

but the NRC has yet to deny a single application and has issued license renewals for 54 of the nation's 104 nuclear power reactors. SCE plans to file a SONGS license renewal application in late 2012. PG&E announced on November 24, 2009 its intention to file the Diablo Canyon application.

The NRC license renewal application process determines whether a plant meets the NRC renewal criteria, not whether it should continue to operate. The NRC states, "Although a licensee must have a renewed license to operate a plant beyond the term of the existing operating license, the possession of that license is just one of a number of conditions that must be met for the licensee to continue plant operation during the term of the renewed license. State regulatory agencies and the owners of the plant would ultimately decide whether the plant will continue to operate based on factors such as need for power or other matters within the State's jurisdiction or the purview of the owners … the NRC has no role in the energy planning decisions of State regulators and utility officials as to whether a particular nuclear power plant should continue to operate."[108]

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

Although the CPUC does not approve or disapprove license applications filed with the NRC, both utilities must obtain CPUC approval to pursue license renewal before receiving California ratepayer funding to cover the costs of the NRC license renewal process.[109] The CPUC proceedings will determine whether it is in the best interest of ratepayers for the nuclear plants to continue operating for an additional 20 years. The proceedings will address issues that are important for electricity planning but are not included in the NRC's license renewal application review.

The purpose of the CPUC license renewal review is to consider matters within the state's jurisdiction, including the economic, reliability, and environmental implications of relicensing.[110] For example, the CPUC will consider the cost-effectiveness of license renewal compared with and replacement power options.

To initiate the CPUC license renewal review, PG&E and SCE are required to submit license renewal feasibility assessments to the CPUC. For example, the CPUC required PG&E to submit an application by June 30, 2011, on whether renewing Diablo Canyon's operating licenses is cost-effective and in the best interest of PG&E's ratepayers.[111] In letters to SCE

108 Nuclear Regulatory Commission, Generic Environmental Impact Statement, NUREG-1437, Vol I, see [http://www.nrc.gov/reading-rm/doc-collections/nuregs/staff/sr1437/v1/part01.html#_1_12].

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

110 The State Water Resources Control Board and the California Coastal Commission would also have the opportunity to review impacts to California from license renewal within the context of their permitting authority and proceedings.

111 Pacific Gas and Electric is required to submit its application by June 30, 2011. Southern California Edison has not been given a deadline. CPUC decision D.07-03-044.

and PG&E in June 2009, the CPUC emphasized that the utilities must address in their feasibility assessments all the issues raised in the *AB 1632 Report*.[112] The CPUC specifically directed the utilities to undertake the following activities:

- Report on the findings from updated seismic and tsunami hazard studies and assess the long-term seismic vulnerability and reliability of the plants.

- Summarize the implications for Diablo Canyon and SONGS of lessons learned from the response of the Kashiwazaki-Kariwa nuclear plant to the 2007 earthquake.

- Reassess whether access roads surrounding the plants are adequate for emergency response and evacuation following a major seismic event.

- Study the local economic impact of shutting down the plants as compared to alternative uses for the plant sites.

- Report on plans and costs for storing and disposing of low-level waste and spent fuel through 20-year license extensions and plant decommissioning.

- Quantify the reliability, economic, and environmental impacts of replacement power options.

- Report on efforts to improve the safety culture at SONGS and on the NRC's evaluation of these efforts and the plant's overall performance (SCE only).

112 Letter from CPUC to Alan Fohrer, CEO of Southern California Edison, June 25, 2009; Letter from CPUC to Peter Darbee, CEO of Pacific Gas and Electric, June 25, 2009.

The comprehensiveness, completeness, and timeliness of these activities will be critical to the CPUC's ability to assess whether or not the utilities should apply to the NRC for license renewals. However, the utilities' reports to date indicate they are not on schedule to complete these activities in time for CPUC consideration. In addition, PG&E has objected to providing the seismic studies to the CPUC as part of a license renewal review.

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

113 Pacific Gas and Electric Company comments on California Energy Commission final Commission report, *An Assessment of California's Nuclear Power Plants: AB 1632 Report*, October 2008, p. 1, available at: [http://www.energy.ca.gov/2008publications/CEC-100-2008-009/CEC-100-2008-009-CMF.PDF].

114 Pacific Gas and Electric Company, October 22, 2008, p. 4.

115 Letter from California Public Utilities Commission to Peter Darbee (Pacific Gas and Electric Company), June 25, 2009.

PG&E continues to object to a CPUC review of Diablo Canyon seismic studies as part of a license renewal review, and its current schedule would in fact not allow time for this review.[116] PG&E is required to submit its license renewal feasibility assessment to the CPUC by June 30, 2011,[117] but does not expect to complete updates to the seismic hazard model and the seismic vulnerability assessment until 2012 and 2013, respectively.[118] Furthermore, PG&E said that it will require ratepayer funding to undertake the 3-D seismic mapping surveys recommended in AB 1632 and that it may use the CPUC license renewal review proceeding as an opportunity to request this funding. If this occurs, the results of these studies will likely not be available for CPUC consideration during this proceeding.

A similar issue arises with SCE. The utility plans to submit an application to the CPUC in late 2010 to pursue an NRC license renewal application and to address issues from the *AB 1632 Report* and the CPUC.[119] However, SCE anticipates also using this application to request funding to complete AB 1632-recommended studies. Furthermore, SCE anticipates filing its CPUC application in the third quarter of 2010, but does not anticipate completing many of its studies until the end of 2010. As a result, SCE acknowledges that the application likely will not include results from all of the AB 1632 studies.[120] However, SCE believes it will be able to provide sufficient information for the CPUC to reach an informed decision, with some studies included in its application and others provided as they are completed.[121]

Nuclear Plants and the Environment

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

Even more so than with natural gas plants, citizens tend to be vocal about potential negative impacts of nuclear facilities operating near

116 Written comments by Pacific Gas and Electric Company on the *2009 Draft IEPR*, October 29, 2009, pp. 16–18, see [http://www.energy.ca.gov/2009_energypolicy/documents/2009-10-14_workshop/comments/PGE_Comments_on_the_2009%20IEPR_Draft%20Committee_Report_2009-10-29_TN-53877.pdf].

117 California Public Utilities Commission decision D.07-03-044.

118 Pacific Gas and Electric data request responses F.01 and F.03.

119 Letter from Alan Fohrer (Southern California Edison) to CPUC, August 4, 2009.

120 Southern California Edison data request response L.01.

121 Written comments by Southern California Edison on the *2009 Draft IEPR*, October 30, 2009, p. 15, [http://www.energy.ca.gov/2009_energypolicy/documents/2009-10-14_workshop/comments/Southern_California_Edison_TN-53916.PDF].

their communities. Concerns include the disposal of radioactive waste, plant safety, and the use of ocean water for power plant cooling.

Nuclear Waste Issues

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

The federal energy and water appropriations bill for fiscal year 2010, signed into law in October 2009, eliminated all funding for development of Yucca Mountain, including further land acquisition, transportation development, and site engineering.[123] This budget cut, initiated by the President's budget proposal, demonstrates the Obama Administration's belief that the Yucca Mountain repository is not a workable solution to the problem of nuclear waste disposal.[124] This represents a major shift in U.S. nuclear waste policy.[125]

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

The federal appropriations bill sets aside $5 million to establish a Blue-Ribbon Commission of experts to investigate such alternative solutions and make recommendations to the Administration. It is not clear how the Commission will be chosen.[126]

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

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

123 Terminations, Reductions, and Savings: Budget of the U.S. Government, Fiscal Year 2010, Office of Management and Budget, available at: [http://www.whitehouse.gov/omb/budget/fy2010/assets/trs.pdf], p.68, and Energy and Water Development and Related Agencies Appropriations Act, 2010, signed as Public Law 111-85 on October 28, 2009.

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

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

126 H.R. 3183 and S. 1436.

plants in-state will remain at these sites for the foreseeable future.[127]

PG&E and SCE have built intermediate-term waste storage facilities at their plants, known as independent spent fuel storage installations (ISFSIs). The ISFSIs at Diablo Canyon and SONGS are currently licensed for 20 years, but they may be eligible for multiple license extensions.[128] The NRC allows spent fuel to be stored at reactor sites in above-ground storage for 100 years and is considering extending that limit by 20 years. PG&E and SCE report enough storage space at their respective nuclear plant sites for all spent fuel generated through the plants' current licenses.

The utilities have not reported plans to pursue the Energy Commission recommendation to modify their spent fuel pools' racking to a less dense orientation.[129] However, the density of the spent fuel pools should decrease as the utilities move assemblies into dry cask storage. Thus far, PG&E has transferred 96 spent fuel assemblies to the Diablo Canyon ISFSI, and SCE has transferred 827 spent fuel assemblies to the SONGS ISFSI.

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

In addition to spent fuel, the nuclear plants generate low-level radioactive waste that must be disposed of at special facilities. In the past, the utilities shipped their low-level waste to several disposal facilities, but there is currently just one facility that will accept low-level waste from California reactors, and it accepts only the least radioactive grade of waste. As a result, PG&E and SCE are also storing more highly radioactive classes of low-level waste at the reactor sites. Each plant generates around 150 cubic feet per year of this waste from regular operations.[130]

Once-Through Cooling

As discussed in the section on natural gas power plants, the SWRCB released a draft policy in June 2009 on the use of coastal waters for power plant cooling.[131] The SWRCB and the California EPA have found that SONGS' cooling system is responsible for about one-third of all OTC-related impingement mortality and entrainment losses along the California coast.[132] The proposed policy calls for coastal power plants to cut water intake by 95 percent to reduce the harmful impacts on marine life. To meet these requirements, the nuclear plants would need retrofitting for closed-

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

128 San Luis Obispo Mothers for Peace is challenging Diablo Canyon's Independent Spent Fuel Storage Installation license before the Ninth Circuit Court of the U.S. Court of Appeals.

129 Pacific Gas and Electric and Southern California Edison data request responses, C.15.

130 Utility responses to California Energy Commission data requests, 2009.

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

132 State Water Resources Control Board and California Environmental Protection Agency, *Water Quality Control Policy on the Use of Coastal and Estuarine Waters for Power Plant Cooling: Draft Substitute Environmental Document,* July 2009, p. 47, available at: [http://www.swrcb.ca.gov/water_issues /programs/npdes/docs/cwa316/draft_sed.pdf].

cycle wet, dry cooling towers, or other cooling means. Previous studies have found that for California's nuclear plants, these options would be very expensive and possibly infeasible from an engineering perspective.[133] The Energy commission expects to review and comment on the studies required in the draft OTC policy regarding compliance implications and compliance alternatives for the two nuclear facilities.

If the SWRCB's policy is approved, the agency will direct PG&E and SCE to commission independent studies to assess the costs of alternative options for SONGS and Diablo Canyon to meet the requirements of the SWRCB's policy. These studies would be completed within three years of the effective date of the policy. The Energy Commission believes that these studies should also be included in the cost-benefit assessment of the plants' license renewal feasibility studies.

Climate Change Impacts

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

133 California Energy Commission, *An Assessment of California's Nuclear Power Plants: AB 1632 Report*, pp. 297–300, available at: [http://www.energy.ca.gov/2008publications/CEC-100-2008-009/CEC-100-2008-009-CMF.PDF].

Nuclear Plants and Reliability

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

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

134 Ibid., pp. 23–24.

Seismic Issues

Diablo Canyon and SONGS are located along California's seismically active coastline. The plants were designed to withstand large earthquakes without release of radiation or major damage; however, scientific understanding of the coastal fault zones has improved over the decades since the plants were designed, with a new fault discovered offshore of Diablo Canyon just last year. Plant components that do not serve a safety function were designed for less stringent seismic standards than the core of the nuclear plants. A large earthquake could cause enough damage to these components to necessitate extended plant shutdowns – five of the seven reactors at the Kashiwazaki-Kariwa plant in Japan remain shut down more than two years after being damaged by an earthquake.[135]

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

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

PG&E has begun to update the Diablo Canyon seismic hazard and vulnerability assessments and expects these assessments to be completed in 2013.[138] PG&E is using a number of advanced techniques to identify and better characterize fault zones near Diablo Canyon, including multi-beam bathymetry, high-resolution marine magnetics, and aeromagnetic surveys, and is purchasing industry seismic data in the vicinity of the plant.[139] PG&E is also sponsoring research on numerical simulations of near fault ground motions to improve ground motion models.[140] In addition, PG&E is planning to request ratepayer funding to undertake the three-dimensional geophysical seismic reflection mapping surveys recommended in the *AB 1632 Report*.[141] PG&E will not include the United

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

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

137 Pacific Gas and Electric data request response F.09; Southern California Edison data request response F.01.

138 Pacific Gas and Electric expects to complete the tsunami assessment by December 2009, the seismic reliability studies on nonsafety related plant components by April 2010, the seismic hazard assessment in early 2011, and the seismic vulnerability assessment in 2013. The data request responses F.03, F.09, F.12, F.13.

139 Pacific Gas and Electric data request response F.07.

140 Pacific Gas and Electric data request response F.02.

141 Pacific Gas and Electric data request response L.02.

States Geological Survey National Hazard Mapping Project models in its studies because the models do not include detailed information pertinent to the Diablo Canyon area. Instead, PG&E believes that information developed in its own studies will inform the USGS databases.[142]

PG&E has already completed initial assessments of two specific seismic hazards in the area of Diablo Canyon, concluding that seismic activity that could be generated by the newly discovered Shoreline Fault is within the design margins of Diablo Canyon. The NRC's preliminary assessment concurs with this conclusion.[143] PG&E is conducting additional geophysical studies and will provide a final report in December 2010.[144] PG&E has similarly concluded that new estimates of the near fault ground motions from large strike-slip earthquakes, including directivity and maximum component effects, reveal a lower hazard than previously thought and therefore do not represent an increased hazard to Diablo Canyon.[145]

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

142 Pacific Gas and Electric data request response F.10.

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

144 Pacific Gas and Electric data request responses F.01, F.06.

145 Pacific Gas and Electric data request response F.02.

As of July 2009, SCE had not begun its updates to the SONGS seismic hazard and vulnerability assessments. Yet, the utility states that it expects to complete these by the end of 2010.[146] The studies are to include seismic source characterization, review of GPS data, probabilistic seismic hazard analysis modeling, review of earthquake recurrence relationships, ground motion updates for current attenuation relationships, review of new tsunami data from the University of Southern California and the National Oceanic and Atmospheric Administration, and an assessment of the reliability implications of the plant's non-safety related components.[147]

It is not clear whether SCE can complete all of these studies in a comprehensive manner by the end of 2010. Indeed, the utility has not committed to using three-dimensional geophysical seismic reflection mapping and other advanced techniques as part of these studies or to installing a permanent GPS array. Instead, SCE committed only to evaluating the costs and benefits of these techniques,[148] an evaluation the Energy Commission has determined should be conducted by state agencies, not the utilities.[149] It remains to be clarified whether SCE plans to collect any new data on the seismic hazards in the SONGS region or whether it is planning simply to review currently available data.SCE established a Seismic Advisory Board to guide and review

146 Southern California Edison data request responses F.01, F.13-F.15.

147 Southern California Edison data request responses F.01, F.12.

148 Southern California Edison data request responses F.07, F.11.

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

the SONGS seismic studies.[150] SCE plans for the board to periodically review the seismic hazard at SONGS and to determine the need for new research and investigations into the plant's seismic setting. As currently structured, the board includes geologists from PG&E and private consultants in geology, seismology, and structural engineering who are familiar with the SONGS plant from previous work for SCE.[151] It includes just one expert not previously employed by SCE or currently employed by PG&E. This is unfortunate since a more independent advisory board would likely contribute to stronger studies.

Nuclear Plant Safety Culture

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

In 2007, the NRC identified a number of concerns about the safety culture at SONGS, particularly with respect to human performance and problem identification and resolution. Since then, SCE's management put a new leadership team in place at SONGS and instituted a series of safety reforms and monitoring programs.[152] For example, SCE implemented safety improvement plans and conducted extensive evaluations to identify the root causes of safety lapses. The utility also instituted weekly monitoring of core performance indicators, established weekly site-wide meetings on human performance and safety issues, set up a system for employees to voice their concerns regarding safety issues, and conducted a safety culture assessment.

The NRC recently concluded that these improvements were not adequate in addressing the overall safety culture at SONGS. The NRC was particularly concerned that it had identified problems in the areas of human performance and problem identification and resolution over the course of four consecutive assessments, including its most recent assessment in September 2009.[153] During the September 2009 assessment, the NRC also identified an additional safety-related issue of "failing to use conservative assumptions" in decision-making.[154]

As a result of these safety culture failures, the NRC intends to maintain the additional oversight that it initially imposed over SONGS in December 2008. At that time, the NRC discovered that a battery used to power a backup generator at the plant had been inoperable since 2004. Although the NRC ranked this as a finding of low to moderate safety significance, the agency noted that the persistence of the problem for four years pointed to inadequate maintenance procedures for the plant overall. The NRC also expressed dissatisfaction that SONGS' self-evaluations had not identified seven other problems at the plant.[155]

In light of these performance lapses, Senator Barbara Boxer and California State Senator Christine Kehoe wrote to the NRC expressing concern about SCE's fall 2009 steam generator replacement project. The NRC responded

150 Southern California Edison data request response F.05, September 18, 2009.

151 Ibid.

152 Southern California Edison data request response, M.09.

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

154 Ibid, p. 2.

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

by expressing confidence in SCE's ability to complete the project safely without any additional restrictions or NRC oversight. This is consistent with the NRC's position that, while SONGS' progress in improving safety culture has been inadequate, the plant continues to be operated in a safe manner.[156]

The Institute for Nuclear Power Operations (INPO), a peer oversight agency, may also be dissatisfied with SONGS' rate of improvement. After a January 2009 inspection, INPO reviewers reportedly concluded that the site had made inadequate progress in all of the areas identified as needing special focus six months earlier, and ranked SONGS in the bottom quartile of U.S. commercial nuclear plants.[157]

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

Improvements to the safety culture and plant performance at SONGS will be reflected in improved ratings by the NRC and INPO and by shorter outages and higher capacity factors. If sufficient improvements are not demonstrated in the coming years, the implications of sustained safety culture lapses and the possible impact on reliability of the plants will need to be considered as part of the state's license renewal assessment for the plant.

Another issue is emergency evacuation planning. The *AB 1632 Report* recommended that the utilities reassess the adequacy of plant roads for allowing access for emergency response teams and for allowing local communities and workers to evacuate. The report recommended that this reassessment be conducted as part of license renewal studies to ensure that plant assets would be protected in an emergency. PG&E has commissioned a study, to be completed in early 2010, on evacuation time estimates for Diablo Canyon.[162] SCE reassesses its evacuation time studies annually.[163]

Nuclear Plants and the Economy

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

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

157 See [http://www.voiceofsandiego.org/articles/2009/02/26/science/963songs022509.txt].

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

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

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

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

162 Pacific Gas and Electric data request response M.06.

163 Written comments by Southern California Edison on the *2009 Draft IEPR*, October 30, 2009, p. 19, [http://www.energy.ca.gov/2009_energypolicy/documents/2009-10-14_workshop/comments/Southern_California_Edison_TN-53916.PDF].

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

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

Until one or more new nuclear plants are constructed in the U.S., these estimates will remain preliminary, making construction of a new nuclear plant a risky endeavor. The risk of capital cost increases is compounded by the long length of time that it takes to get approval for and then construct a new nuclear plant, which raises the risk of cost increases due to regulatory delays, inflation, and increases to financing costs. As a result, Moody's cautioned that they "view new nuclear generation plans as a 'bet the farm' endeavor for most companies" and warned that companies that pursue new nuclear generation may face credit rating downgrades if they do not mitigate this risk.

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

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

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

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

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

168 Pacific Gas and Electric's initial damage claim was for $92.1 million. Pacific Gas and Electric recalculated its claim based on the appellate court's decision.

169 Pacific Gas and Electric data request response D.09.

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

If a federal repository is established, spent fuel will need to be packaged for transport, aging, and disposal. Dry cask storage, an interim storage solution, could prove costly to utilities in the long-term, especially if they need to pay to transfer their fuel from their dry casks into federally approved transport, aging, and disposal casks. The nuclear plants will also need to dispose of a substantial quantity of low-level radioactive waste when they are decommissioned, and the cost to transport and dispose of this waste is expected to be hundreds of millions of dollars or more.

Transmission

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

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

171 Southern California Edison data request response D.09.

the future to facilitate the timely permitting of high-voltage transmission projects.

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

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

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

Transmission and the Environment

In the *2007 Strategic Transmission Investment Plan,* the Energy Commission identified the importance of early consideration of nonwires alternatives in statewide transmission planning processes. Essentially, nonwires alternatives are the preferred resources identified in the state's loading order and include energy efficiency, demand reduction measures (demand response and load management), and the use of small-scale and customer-level distributed generation resources and/or clean fossil-fired central station generation located within the load service area. Cost-effective energy efficiency is the resource of first choice for meeting California's energy needs; at the same time it is imperative that California reach its 33 percent RPS goals and expand distributed generation applications, particularly rooftop solar PV and CHP. Nonwires alternatives are increasingly identified as viable alternatives to new conventional generation and transmission facilities required to connect new generation to demand centers. The CPUC currently performs a project-specific, nonwires alternative analysis as part of its environmental review process for permitting transmission projects, initiated with the filing of a Certificate of Public Convenience and Necessity (CPCN).

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

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

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

Transmission and Reliability

To ensure a reliable network, regulators' challenge is to identify the best mix of transmission projects. Policy decisions like the retirement of aging power plants or OTC plants may require transmission solutions to maintain system reliability in the southern part of the state. Success in meeting RPS and GHG reduction goals depends in large part on the ability to interconnect substantial amounts of new generation from renewable resources. Occasional local opposition to power plants in load centers necessitates remote generation that may prompt the need for increased transmission.

In the *2009 Strategic Transmission Investment Plan*, the IEPR and Siting Committees note that the highest priority is to continue

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

to support the projects identified in previous strategic plans. The Energy Commission found that these projects met the criteria for strategic transmission resources because they provided statewide benefits. As currently planned, these projects would significantly increase the transmission network's ability to reliably connect renewable generation to California load centers. These projects include:

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

The *2009 Strategic Transmission Investment Plan* provides a complete description of these projects and their current status.

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

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

The third priority should be to continue the analysis of the RETI renewable foundation and renewable collector lines that require new corridors and begin the planning work for the priority renewable areas outside Tehachapi, the Imperial Valley, and eastern Riverside County. Public outreach and corridor identification for

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

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

Transmission and the Economy

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

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

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

6) a clear dispute resolution process; 7) regional coordination; 8) study of economic effect of congestion and integration of new resources; and 9) a process for allocating costs of new projects.

The Energy Commission supports the plans of the IOUs, publicly owned utilities, and the California ISO to work together to avoid transmission duplication, optimize use of existing rights-of-way, reduce environmental impacts, lower costs for consumers, and develop a process for cost allocation for joint projects. If CTPG's consolidated utility approach is successful, this collaboration could result in the development of joint transmission projects necessary for implementing a true statewide planning process that reflects broad stakeholder interests.[176]

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

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

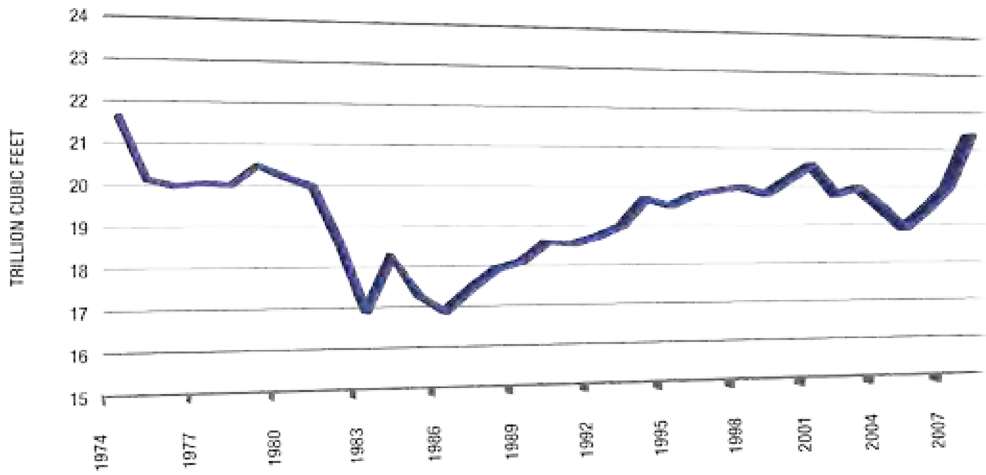
The Western Governors' Association (WGA) has recently asserted western policies that urge Congress to guide centralized regional transmission planning, implemented through actions and policies of federal agencies such as FERC, BLM, and DOE. Its policy letters explicitly urge Congress to require a regional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

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

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

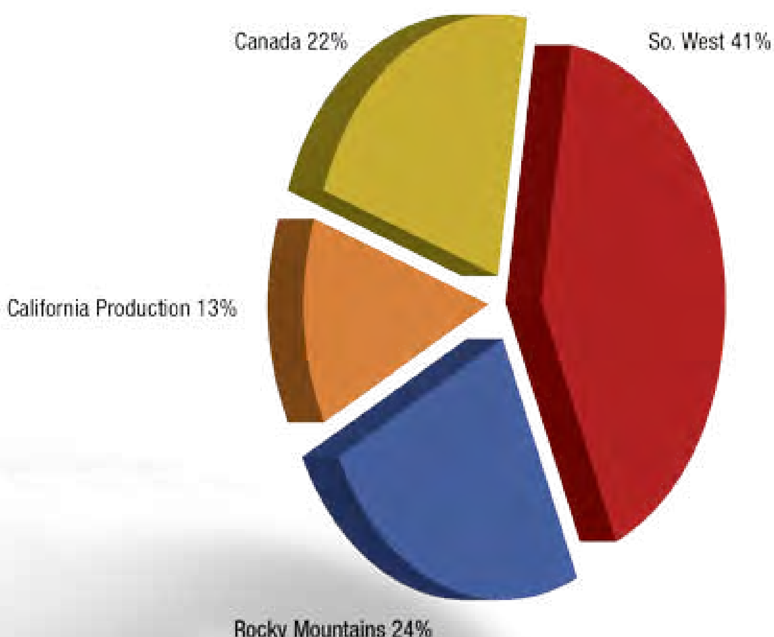
177 Western Governors' Association, Letter to the Honorable Jeff Bingaman, May 1, 2009, available at: [http://www.westgov.org/wga/testim/transmission5-1-09.pdf].

FIGURE 13: U.S. DOMESTIC NATURAL GAS PRODUCTION



Source: Energy Information Administration, *Annual Energy Outlook*

FIGURE 14: 2007 CALIFORNIA NATURAL GAS RECEIPTS BY SOURCE



Source: Pipeline and Utility Filings with the California Energy Commission within an Energy Commission-designated corridor. The Energy Commission believes that FERC should allow an IOU to qualify for cost recovery if the land is set aside for one or more transmission projects that may be constructed 10–15 years in the future and is within an Energy Commission-designated corridor.

Natural Gas

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

Natural Gas Supplies

California's supply of natural gas comes from four areas: in-state production, southwestern United States, the Rocky Mountain region, and Canada, with 87 percent of the state's natural gas coming from out-of-state sources. After nearly a decade of relatively flat or declining U.S. natural gas production, domestic production in the lower 48 states began rising in 2006, and by 2008 returned to levels last seen in 1974 (Figure 13).[178]

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

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

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

Interstate pipelines and California production currently have the capacity to supply California consumers up to 10,230 MMcf/d. However, because of upstream demand and utility multiple receiving points, the state can only rely on receiving 8,315 MMcf/d of supply from pipelines and native production. Simply because an interstate pipeline has a certain delivery capacity does not mean that all of its capacity is available to California. Each pipeline serving California has firm delivery

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

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

FIGURE 15: NATURAL GAS RESOURCE AREAS AND PIPELINES

Source: *2008 California Gas Report*

In Operation

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

Proposed

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

contracts not only for California customers but also for customers upstream from California. Because of these upstream commitments, not all of a pipeline's capacity is available for delivery to the state.

If demand exceeds reliable supply, utilities and noncore customers will still be able to meet demand up to the pipeline delivery capacity, but prices would increase dramatically. To meet their needs, California utilities and noncore customers would then have to purchase natural gas that otherwise would have been delivered to customers outside of California. To attract the supply, they would have to pay elevated prices that would drive California prices above current market levels and cost the state's consumers an unknown amount.

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

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

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

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

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

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

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

Natural Gas Demand

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

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

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

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

Although the method to estimate energy efficiency impacts has been refined, the staff draft forecast uses essentially the same methods as earlier long-term staff demand forecasts. A more detailed discussion of forecast

182 "Lower 48"excludes Alaska and Hawaii.

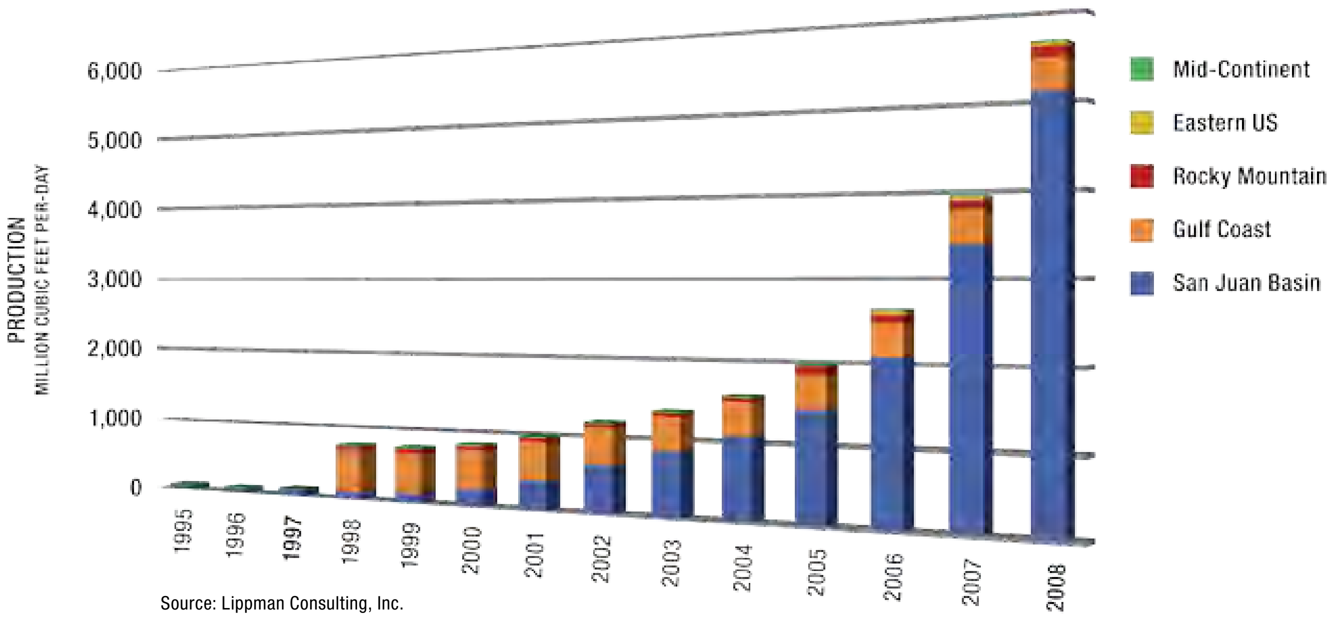
183 Natural Gas Supply Association, News Release, October 8, 2008, "Natural Gas from Shale Could Double in Next Ten Years," available at: [http://www.ngsa.org/newsletter/pdfs/2008%20Press%20Releases/22%20-%20Natural%20Gas%20from%20Shale%20to%20Double%20w%20graphic.pdf].

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

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

186 California Energy Commission, *California Energy Demand 2010–2020 Adopted Forecast*, December 2009, CEC-200-2009-012-CMF, available at: [http://www.energy.ca.gov/2009publications/CEC-200-2009-012/CEC-200-2009-012-CMF.PDF].

FIGURE 16: LOWER 48 SHALE NATURAL GAS PRODUCTION



Source: Lippman Consulting, Inc.

TABLE 6: STATEWIDE END-USER NATURAL GAS CONSUMPTION

	MM THERMS		
	CED 2007	CED 2009 (HIGH-RATE CASE)	PERCENT DIFFERENCE
1990	12,893*	12,893*	0.00%
2000	13,913*	13,913*	0.00%
2007	13,445	12,494*	-0.07%
2010	13,616	12,162	-10.68%
2018	14,058	12,894	-8.28%

* Historic Values

	ANNUAL AVERAGE GROWTH RATES	
1990–2000	0.76%	0.76%
2000–2008	-0.43%	-0.89%
2008–2010	0.63%	-1.34%
2010–2018	0.40%	0.73%

Source: California Energy Commission, 2009 methods and data sources is available in the *Energy Demand Forecast Methods Report*.[187]

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

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

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

Natural Gas and the Environment

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

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

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

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

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

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

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

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

Developing equivalent amounts of natural gas resources, though, requires two to three times more vertical wells than horizontal wells. For example, extracting 20,000 million cubic feet of natural gas may require up to 30 vertical wells but only 10 horizontal wells. The

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190 An indicator of the carbon dioxide equivalent.

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

natural gas industry uses both well types to reach potential natural gas resources located thousands of feet beneath the Earth's surface, but each horizontal well recovers more natural gas on average than a vertical well. As a result, the overall carbon footprint for the entire development of a shale formation may not differ from that of an equivalent-sized formation developed using vertical wells.

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

When development of shale formations occurs near major population centers, environmentalists, with concerns that potential leakage of chemicals used in the hydraulic fracturing process could pose a health and safety risk, are calling for stricter regulation. Some states have developed regulatory requirements for development of shale formations. For example, New York has issued regulations that include guidelines for the use and disposal of water, the protection of groundwater, and the use of chemicals.[192] Pennsylvania has also instituted rules governing the extraction of natural gas from shale formations, noting that, " … developing our energy resources cannot come at the expense of our environmental resources – our water, our land and our ecosystems."[193] In 2008, inspectors from the state's Department of Environmental Protection ordered the partial shutdown of two drilling sites after discovering violations of state regulations.[194]

Investigation into the environmental issues raised by natural gas exploration and production is an ongoing effort that will continue to be addressed by Energy Commission staff. Shale gas is only the latest addition to a portfolio of natural gas extraction technologies that the Energy Commission staff monitors. Staff will continue to monitor and report on developments in all forms of natural gas exploration and production.

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

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

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

194 Environmental News Service, June 16, 2008.

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

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

Reducing the environmental footprint of natural gas use in California should follow the loading order approach used in the state's electricity system. First and foremost is improving residential, commercial, and industrial energy efficiency, as well as the efficient use of natural gas as a transportation fuel, to reduce emissions associated with consumption of natural gas. An example of California's successful energy efficiency efforts are the previously mentioned statistics that the average California home consumed 120 Mcf of natural gas per year 40 years ago, but today consumes less than 50 Mcf per year. The second priority is to accelerate the adoption of clean alternatives to conventional natural gas resources, such as biogas for both the electricity and transportation sectors, as well as improved technologies. Finally, the performance and reliability of the natural gas system and infrastructure must be improved.

Natural Gas and Reliability

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

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

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

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

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

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

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

- The Sunstone Pipeline plans to deliver 1.2 Bcf/d of natural gas from Opal, Wyoming to Stansfield, Oregon. This pipeline is planned to be on-line in 2011 and could displace much natural gas in Oregon, thus freeing up supplies for California.

- The Kern River pipeline expansion project will increase delivery of natural gas from Wyoming to Southern California by 0.2 Bcf/d. The expansion of the existing pipeline is scheduled to be completed in 2010.

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

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

Natural Gas and the Economy

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

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

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

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

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

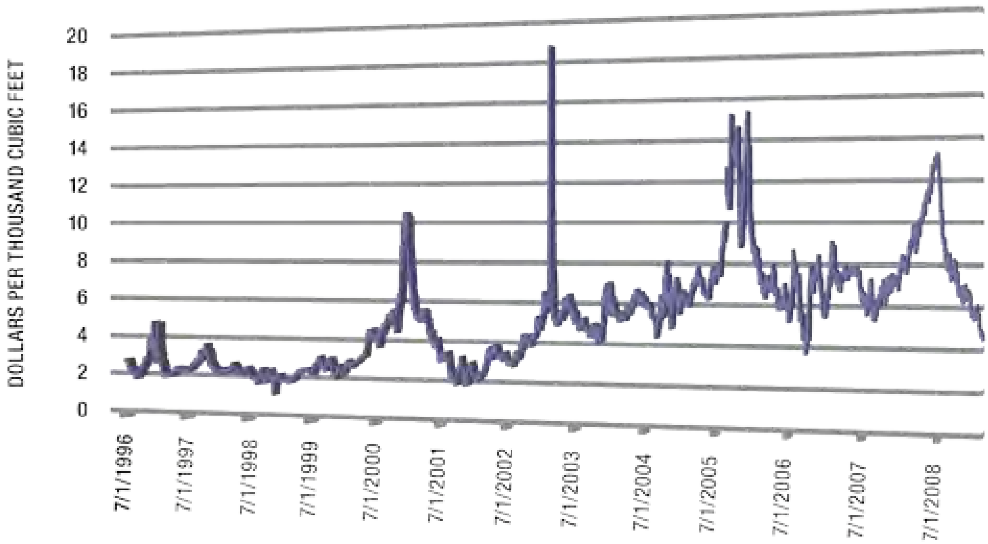
While price volatility can have material consequences for the industrial sector, some large industrial consumers have the ability to take advantage of hedging opportunities to reduce risk. Large users potentially could purchase and store natural gas when prices are low, enter into long-term fixed price contracts, or use financial instruments like options to lower the risk and uncertainty of changing prices.

The electricity generation sector is the largest consumer of natural gas, both nationally and in California,[196] so natural gas price volatility significantly affects this sector and ultimately the price of electricity. Natural gas price volatility leads to increased uncertainty for both regulated utilities and merchant power firms about the ongoing costs of operating natural gas-fired power plants, both existing and new. Increased uncertainty also heightens concern regarding investment in new natural gas-fired plants, which may be seen as more risky when compared to other generation technologies that use coal or renewable fuels.

Natural gas producers are also affected by price volatility, making project evaluation and investment decisions less certain. Price volatility can trigger concerns by lenders and investors and increase the cost of capital as lenders and investors demand greater returns because of increased uncertainty. Price volatility also contributes to recurring boom-bust production cycles and associated operational problems, such as employee turnover and expensive start-up and shutdown costs. The current period of falling natural gas prices provides a good example. Natural gas production is largely a capital intensive venture during well development but has lower marginal production costs once the well is producing gas. During periods of low prices, active wells can remain profitable to operate but, in the longer term, declining prices can lead to reduced production when the number of drilling rigs is reduced in response to sustained lower prices. Since prices peaked in July 2008,

196 Energy Information Administration, Natural Gas Consumption by End Use data, available at: [http://tonto.eia.doe.gov/dnav/ng/ng_cons_sum_dcu_nus_a.htm].

FIGURE 17: HENRY HUB SPOT PRICES 1996–2008



Source: Natural Gas Intelligence data

United States drilling rig numbers dropped each week as prices continued to decline.[197]

Figure 17 shows a period of relatively stable natural gas prices in the late 1990s, followed by several periods of large price spikes after 2000. Henry Hub[198] spot prices traded within a \$2/Mcf to \$3/Mcf band throughout the late 1990s and early 2000s, rose to \$4/Mcf, and surpassed \$6/Mcf by the middle of the decade. One key factor that caused price increases was the growth in domestic demand that exceeded United States domestic production capabilities because North American basins were maturing and producing less gas. The combination of increasing domestic demand and declining domestic production resulted in natural gas prices moving higher.

There have been four major price spikes since 2000 that were caused by many of the physical and financial market factors mentioned earlier in this section. However, each price spike was influenced to different degrees by the various factors. For example, a severe cold winter storm played the significant role in the February 2003 price spike, and back-to-back hurricanes played the significant role in the fall 2005 price spike. The price spikes of winter 2000–2001 and summer 2008 were the result of a number of different factors, including market manipulation and market speculation.

197 Energy Information Administration's April 23, 2009, *Natural Gas Weekly* update reports that the domestic drilling rig count is down over 50 percent from its high in August 2008, reached in response to July 2008 peak prices.

198 Henry Hub is located in Louisiana and is North America's main natural gas trading hub and most widely quoted natural gas pricing point. It interconnects four intrastate and nine interstate pipelines that can transport enough natural gas to satisfy about 3 percent of total United States demand.

The flexibility from having extra infrastructure, coupled with supplies from lower-priced production areas, helps shield the state from the brunt of price volatility. Since California is part of an international natural gas market that includes Canada, the United States, and Mexico, a disruption in one area ripples though the rest of the market. California is not immune to the ripples, but the ripples are much smaller now when they reach the state. Prices of natural gas at California's border are among the lowest in the nation, with current prices considerably less than the Henry Hub price.

Fuels and Transportation

Although the fuels and transportation energy sector is responsible for producing the greatest volume of GHG emissions – nearly 40 percent of California's total – the issues confronting this sector go far beyond climate change. Reducing California's dependence on petroleum in general and foreign crude oil in particular are equally pressing issues. Doing so would not only reduce GHG emissions, but would also mitigate the effects that global demand, geopolitical events, crude oil refining capacity and outages, and petroleum infrastructure challenges have on fuel prices and the average cost of production of goods and services, both of which directly affect the state's economy and gross state product.

Assembly Bill 32 does not directly address GHG emissions reduction in the transportation sector, but legislation at both the state and federal level does. California's AB 1007 (Pavley, Chapter 371, Statutes of 2005), AB 118 (Núñez, Chapter 750, Statutes of 2007), AB 1493 (Pavley, Chapter 200, Statutes of 2002), California's Low Carbon Fuel Standard (LCFS), and the federal Energy Independence and Security Act's revisions to the Renewable Fuel Standard (RFS2) set policies and standards that will ultimately change vehicle and fuel technologies and accelerate the market for low carbon fuels well beyond the current level of demand.

The following section summarizes the Energy Commission's 2009 transportation supply and demand forecast. Providing this data will give decision makers a snapshot of the state's future fuel demand and supply for petroleum, as well as renewable and alternative fuels and vehicles. This data is imperative to understanding future fuel supply and infrastructure needs that could have a major impact on consumer reliability and the environment. In past *IEPR*s, the Energy Commission forecast has only included projections for petroleum transportation fuels. For the *2009 IEPR* cycle, staff expanded the list of transportation fuels to include demand forecasts for E85 (a blend of 15 percent gasoline and 85 percent ethanol), B20 (a blend of 80 percent diesel and 20 percent biodiesel), electricity, compressed natural gas (CNG), and LNG, with more limited analysis of hydrogen and propane.

Transportation Fuels Supply and Demand

In its transportation forecasts, the Energy Commission analyzes trends of transportation demand-related indicators, as well as demographic and economic variables. The transportation demand forecasts encompass four primary transportation sectors:

- Commercial and residential light-duty vehicles (under 10,000 pounds)
- Medium- and heavy-duty transit vehicles, including rail (over 10,000 pounds)

- Medium- and heavy-duty freight vehicles, including rail

- Commercial aviation

Each of these sectors is associated with a distinct forecasting model that estimates the demand for that transportation sector. The California Conventional Alternative Fuel Response Simulator, Freight, Transit, and Aviation models represent each of the corresponding transportation sectors. Staff used a range of fuel price cases, as well as economic and demographic projections from the Department of Finance (DOF) and Moody's Economy.com to cover the forecast period.

Demographics

Demographic growth trends are key indicators of future consumer travel demand. For the next 20 years, DOF forecasts growth in California's population of 25 percent, and Moody's Economy.com forecasts growth in personal income of 76 percent. Between 2009 and 2030, population is projected to increase at an annual compound average rate of 1.15 percent, compared with a growth rate of 2.94 percent in real personal income over the same period. These growth rates indicate that travel demand in California will also likely increase over the forecast period.

To provide historical context, California's gross state product (GSP) increased by 40 percent in real terms from 1998 to 2008. During that same period, employment growth was only 10 percent. The impact of the economic recession is evident in that both GSP and employment decreased between 2008 and 2009. The GSP is projected to return to a positive growth rate by 2010, while total non-farm employment projections do not begin to exhibit positive growth until 2011. Non-farm employment is projected to grow by 20 percent during the forecast period of 2009–2029, in contrast with higher projected growth rates for both population and GSP.

The Energy Commission's draft staff report, *Transportation Energy Forecasts and Analyses for the 2009 Integrated Energy Policy Report* contains more details on these demographic findings.[199]

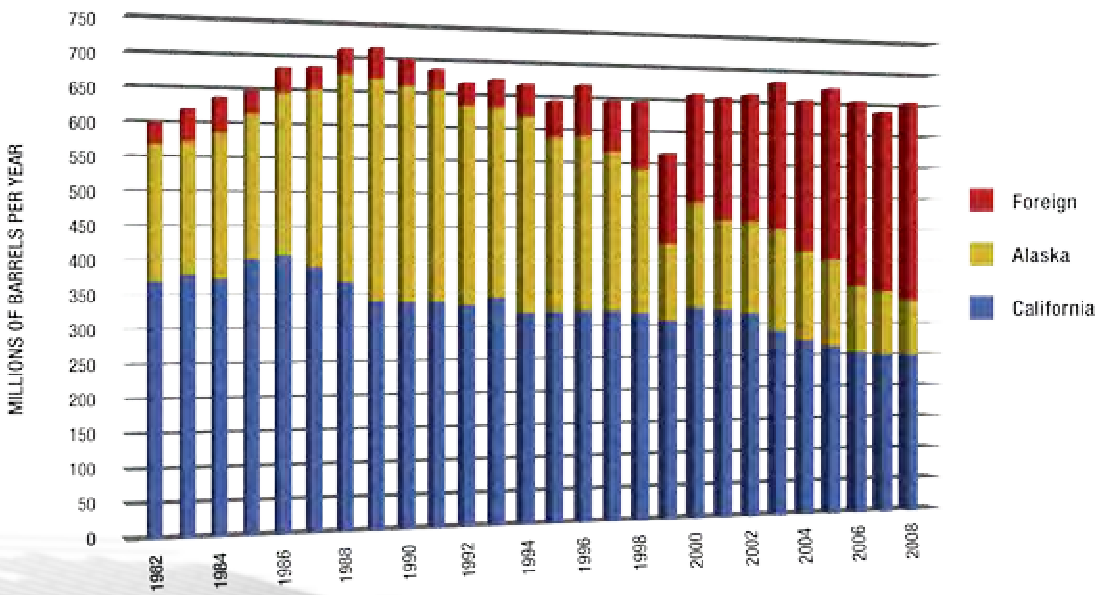
Fuel Supply and Demand

The recession has had a significant impact on the state's transportation sector. Consumer demand for gasoline and diesel fuels continues to decline. Job growth and industrial production – drivers of air travel – are also declining, causing the aviation sector to experience a drop in air traffic. In response to this and higher fuel prices, the aviation sector has reduced the number of planes in service and taken the least efficient aircraft out of service. In addition, the freight sector (rail and trucking) is experiencing a decrease in container movement at the state's three major marine ports – Los Angeles, Long Beach, and the Bay Area.

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

199 California Energy Commission, *Transportation Energy Forecasts and Analyses for the 2009 Integrated Energy Policy Report,* August 2009, CEC-600-2009-012-SD, available at: [http://www.energy.ca.gov/2009publications/CEC-600-2009-012/CEC-600-2009-012-SD.PDF].

FIGURE 18: CRUDE OIL SUPPLY SOURCES FOR CALIFORNIA REFINERIES



Source: Annual crude oil supply data from the California Energy Commission's Petroleum Industry Information Reporting Act database

Petroleum

Although the state's 20 crude oil refineries processed more than 1.8 million barrels a day of crude oil in 2008, California crude oil production continues to decline, despite record crude oil prices and increased drilling activity greater than at any point since 1985. Since 1986, California crude oil production declined by more than 41 percent at an average rate of 3.2 percent per year over the last 10 years and slowed to an annual average of 2.2 percent between 2006 and 2008. Figure 18 indicates the decline in California-sourced oil and the increasing reliance on marine imports, primarily from foreign sources, as Alaska production also declines. The state's refinery capacity is expanding at a slower rate than that of the United States and the rest of the world. Refinery capacity growth, known as refinery creep, is relatively low and expected to increase at an annual average rate between zero and 0.45 percent per year through 2030.

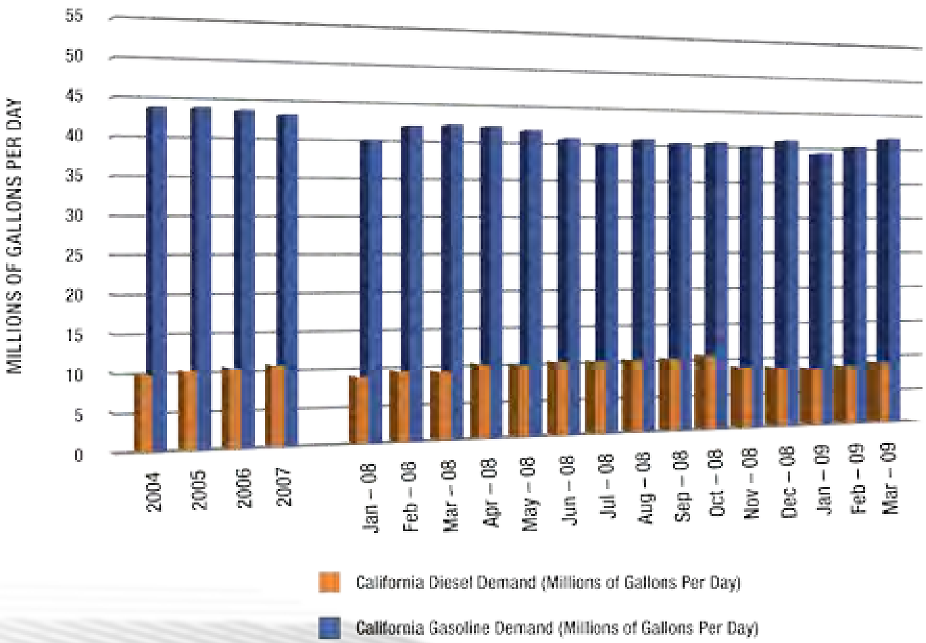
Increased exploration and drilling in state and federal waters could reverse the continuing decline of the state's crude oil production, but any significant production of off-shore oil is at least a decade away. In 2008, the federal government lifted the moratorium on drilling in the Outer Continental Shelf off the coast of California. It is uncertain if off-shore drilling will proceed because of numerous environmental and economic concerns. If expanded off-shore exploration and development is allowed to proceed, however, crude oil production off the coast could increase from 110,000 barrels per day in 2008, to approximately 310,000 barrels per day by 2020, and 480,000 barrels per day by 2030.[200]

200 U.S. Department of Energy/Energy Information Administration *Annual Energy Outlook 2009 and U.S. Energy Security*, Deputy Assistant Secretary, Office of Petroleum Reserves, Washington, D.C., February 2009 presentation, data from slide 6. Pacific Region is assumed to include only California.

Crude oil imports are determined by trends in consumer demand, California refinery output, and exports of petroleum products to neighboring states. In 2008, California refiners imported 406 million barrels of crude oil. Differences in crude oil import forecasts result from contrasting assumptions on the production capabilities of California's refineries and the production of California crude oil.

In the staff's Low Crude Oil Import forecast, refinery production capabilities remained constant over the forecast period, and California crude oil production declined at a rate of 2.2 percent. The High Crude Oil Import forecast assumed refinery production capabilities increased at a rate of .45 percent a year and California crude oil production declined at a rate of 3.2 percent. Under the Low Crude Oil Import forecast, annual crude oil imports increased by 34 million barrels between 2008 and 2015, by 55 million barrels by 2020, and by 91 million barrels by 2030 (a 22.5 percent increase compared to 2008). Under the High Crude Oil Import projection, annual crude oil imports rose by 70 million barrels between 2008 and 2015, by 113 million barrels by 2020, and by 190 million barrels by 2030 (a 47 percent increase compared to 2008). It should be noted that most crude oil imports now come from foreign sources. This means that even under a low-import case, the state's dependence on imported crude oil would grow. During the forecast period, the changes in levels of transportation fuel imports are determined by trends in consumer demand, California refinery output, and exports of petroleum products to neighboring states. The staff forecast shows that California's gasoline imports would decrease significantly over the next 15 years (under the High Petroleum Product Import Case), while imports of diesel and jet fuel would still rise to keep pace with growing demand for those products. Under the Low Petroleum Product Import Case scenario, the growing imbalances between gasoline and

FIGURE 19: HISTORIC CALIFORNIA GASOLINE AND DIESEL DEMAND



Source: California Energy Commission staff-adjusted Board of Equalization sales data

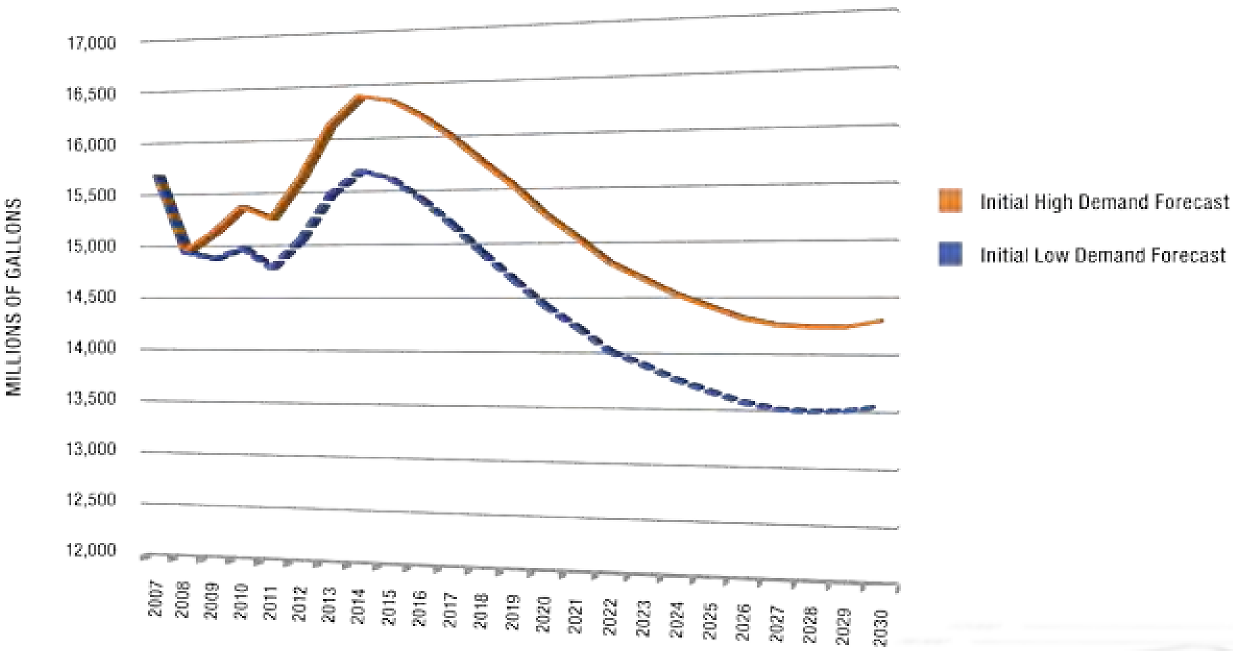
the other transportation fuels are even more extreme, resulting in a total net decline of imports of at least 116,000 barrels per day by 2025, whereby California's gasoline supply balance would switch from a net import of over 51,000 barrels per day in 2008 to a net export of over 218,000 barrels per day in 2025. The latter outcome is unlikely since refiners would adjust operations to decrease the ratio of gasoline components produced from each barrel of crude oil processed.

The Energy Commission staff recently analyzed taxable fuel sales data from the Board of Equalization to determine consumption trends as shown in Figure 19.

Overall, California is experiencing a downward trend in sales for gasoline, diesel, and jet fuel. For example, California's average daily gasoline sales for the first four months of 2009 were 2.1 percent lower than the same period in 2008, continuing a reduction in demand observed since 2004. Daily diesel fuel sales for the first three months of 2009 were 7.7 percent lower than the same period in 2008, continuing a declining trend since 2007. Recent demand trends for jet fuel (8.9 percent decline in 2008) are similar to diesel fuel and reflect the impact of the economic downturn and higher fuel prices.

Staff expects annual gasoline consumption to decrease over the forecast period, largely because of high fuel prices, efficiency gains, competing fuel technologies, and mandated increases of alternative fuel use. The estimate of future gasoline and diesel fuel demand for California was the result of two

FIGURE 20: INITIAL CALIFORNIA GASOLINE DEMAND FORECAST – NO RFS2 ADJUSTMENT

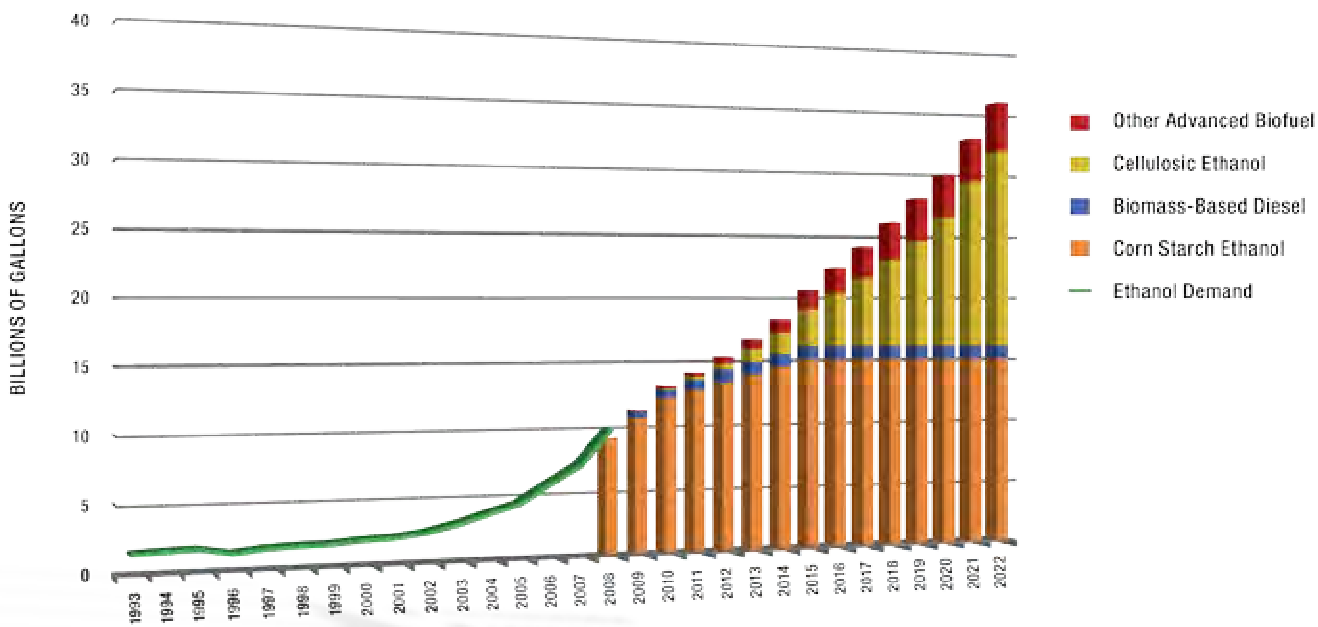


Source: California Energy Commission

distinct stages of analysis. The first step was to quantify demand levels using in-house computer models for both traditional fuels (gasoline and diesel fuel) and specific types of alternative fuels. The second step was to determine the impact of the federal renewable fuel mandates (discussed later in this section) that will likely result in even higher levels of ethanol and biodiesel use beyond the levels initially forecast during the first step of the analysis. Higher levels of renewable fuels calculated in the second step of the analysis would result in slightly lower levels of gasoline and diesel fuel demand for all modeling scenarios.

In the initial results of the forecast's Low Petroleum Price Case (High Demand), the recovering economy and lower relative prices led to a gasoline demand peak in 2014 of 16.40 billion gallons before falling to a 2030 level of 14.32 billion gallons, 4.0 percent below 2008 levels (Figure 20). The initial High Petroleum Price Case (Low Demand) forecast projects a gasoline demand peak of 15.69 billion gallons in 2014 before declining to 13.57 billion gallons by 2030, a decrease of 9.0 percent compared to 2008. Between 2008 and 2030, staff expects total diesel demand in California to increase 49.8 percent in the initial results of the High Petroleum Price Case (Low Demand) to 5.14 billion gallons and 57.4 percent in the Low Petroleum Price Case (High Demand) to 5.40 billion gallons. Between 2008 and 2030 staff expects that jet fuel demand in California will increase by 62.8 percent to 5.12 billion gallons in the High

FIGURE 21: U.S. ETHANOL USE AND RENEWABLE FUEL STANDARD OBLIGATIONS 1993–2022



Sources: Energy Information Administration, U.S. Environmental Protection Agency, and California Energy Commission

Petroleum Price Case (Low Demand) and 82.9 percent to 5.75 billion gallons in the Low Petroleum Price Case (High Demand).

Renewable and Alternative Fuels

Policies mandating increased renewable fuel use are projected to play a significant role in reducing the state's dependence on petroleum. At the federal level, the current Renewable Fuel Standard (RFS1) program, implemented under the Energy Policy Act of 2005, amended the Clean Air Act by establishing the first national renewable fuel standard. The Energy Independence and Security Act of 2007 made changes to the goals of RFS1, mandating increased use of ethanol and biodiesel. These new requirements, known as the RFS2, establish new specific volume standards for cellulosic ethanol, biomass-based diesel, advanced biofuel, and total renewable fuel that must be used in transportation fuel each year. The RFS2 also includes new definitions and criteria for both renewable fuels and the feedstocks used to produce them, including new GHG thresholds for renewable fuels. The U.S. EPA is in the process of a rulemaking, and the target date for changes to take effect is January 1, 2010.[201]

Specifically, the RFS2 will require refiners, importers, and blenders to achieve a minimum level of renewable fuel use each year either through blending or purchasing of Renewable Identification Number credits from other market participants who blend more renewable fuel than needed for their individual obligations. For 2009, the California RFS2 obligation is just over 10 percent and assumes that 11.1

201 United States Environmental Protection Agency, see [http://www.epa.gov/OMS/renewablefuels/420f09023.htm].

billion gallons of renewable fuel will be blended into gasoline and diesel fuel nationally. Figure 21 depicts these renewable fuels obligations.

In recent years, the increased use of ethanol as a transportation fuel has resulted in an expanded domestic production capacity, fluctuating quantities of imports, and inventory build or draws as necessary to balance out demand. As of June 2009, there was an estimated 2.2 billion gallons of surplus ethanol production capacity in the United States. This oversupply of domestic ethanol is primarily responsible for the recent climate of sustained, poor production economics, which brought about the closure of several national and all California ethanol production operations. However, this development will likely be temporary as demand for ethanol is forecast to increase significantly over the next several years because of the RFS2 regulations.

This oversupply of ethanol, along with relatively low ethanol prices in the United States, has reduced ethanol imports to modest levels. Imports of ethanol play a lesser role in California's supply picture, but this could change because of carbon intensity requirements, the state's LCFS, and the fuel obligations of RFS2. Specifically, California is expected to start importing more ethanol from Brazil, as it has lower carbon intensity relative to Midwest ethanol and will meet the LCFS policy requirements.

As for biodiesel, production has increased dramatically in the United States since 2005 in response to federal legislation that included a $1 per gallon blending credit for all biodiesel blended with conventional diesel fuel. As of July 2009, there was more than 2.3 billion gallons of biodiesel production capacity for all operating United States facilities, along with another 595 million gallons per year of idle production capacity and another 289 million gallons per year of capacity under construction. Even though the LCFS will greatly increase the use of biodiesel as a blending component (because of its lower carbon intensities), it appears there will still be sufficient domestic supply from biodiesel production facilities to meet the RFS2 blending requirements for several years.

Increased output of biodiesel, due to the blending credit and attractive wholesale prices, has resulted in increased United States exports to the European Union (EU). In 2008, United States producers exported nearly 70 percent of their supply to the EU. However, in July 2009 the EU officially imposed import duties on United States biodiesel for the next five years. Because of this ruling, United States exports to the EU are likely to decline dramatically.

As already shown, a projected impact of the RFS2 is that it would increase ethanol and biodiesel demand in California. Under the High Petroleum Price Case (Low Demand) for gasoline, staff forecast total ethanol demand in California to rise from 1.2 billion gallons in 2010 to 2.1 billion gallons by 2020. Under the Low Petroleum Price Case (High Demand) for gasoline, staff projects total ethanol demand in California to rise from 1.2 billion gallons in 2010 to 2.6 billion gallons by 2020. Staff also forecast that ethanol demand would exceed an average of 10 percent by volume in all gasoline sales between 2012 and 2013. However, because of various fuel specification and vehicle warranty limitations, it is unlikely that the low-level ethanol blend limit in California would be greater than the current 10 percent by volume (E10), even if the U.S. EPA ultimately grants permission for United States refiners and marketers to blend E15 gasoline.

To meet RFS2 requirements, the availability of E85 at retail sites will need to increase dramatically to ensure that sufficient volumes can be sold. This scenario would require significant increases in both the number of E85 dispensers and flex-fuel vehicles (FFVs). For example, assuming a 10 percent ethanol blending limit, or "blend wall," E85 sales in

California are forecast to rise from 2 million gallons in 2010 to 1.3 billion gallons in 2020 and 1.6 billion gallons by 2030 under the Low Petroleum Price Case (High Gasoline Demand). E85 consumption required to meet the RFS2 is shown in Figure 22; Figure 23 shows the impact of the RFS2 on the final Low Gasoline Demand forecast. However, the pace of this expansion still may not be enough to achieve compliance because of specific infrastructure challenges and lack of incentives (see the Infrastructure Adequacy section below for more details).

As for biodiesel demand, the High Petroleum Price Case (Low Demand) shows biodiesel "fair share," or California's share of mandated biodiesel use proportional to its share of total United States diesel use, would increase from 38 million gallons in 2010 to 57 million gallons by 2030. Under the Low Petroleum Price Case (High Demand), biodiesel fair share ranges from 37 million gallons in 2010 to 58 million gallons by 2030. Based on these projected volumes, California's average biodiesel blending concentration is not expected to be higher than 1.8 percent. However, California's LCFS requirements are anticipated to increase the level of biodiesel use to significantly higher levels that have yet to be fully quantified.

Infrastructure Adequacy

California needs sufficient fuel infrastructure to ensure reliable supplies of transportation fuels for its citizens. Petroleum and alternative and renewable fuels face significant infrastructure issues from the wholesale and distribution level to the end user. The petroleum infrastructure is strained at marine ports and throughout the distribution system. In the case of alternative and renewable fuels, much of the infrastructure that will soon be necessary is not even in place. It is critical that the state expand upon the current petroleum fuel infrastructure to ensure a continued supply of transportation fuel for California and neighboring states and that it build new infrastructure to ensure that California can meet its mandated renewable and alternative fuel goals.

The following two sections describe the most pressing issues and barriers affecting development of the petroleum and renewable and alternative fuels infrastructures in California.

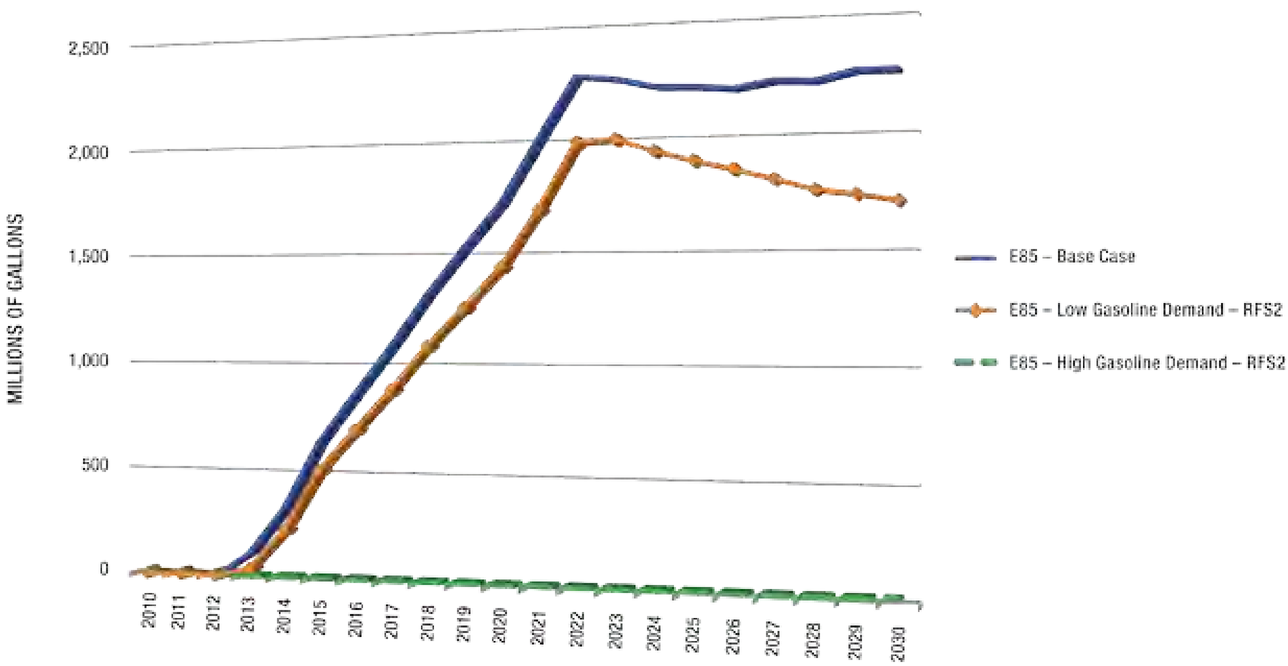
Petroleum Infrastructure

The Energy Commission forecasts that crude oil imports will continue to increase, requiring expansion of the existing crude oil import infrastructure. This infrastructure is critical in ensuring a continued supply of feedstocks to enable refiners to operate their facilities and maintain a reliable supply of fuel for California and neighboring states.

The Energy Commission forecasts that the existing crude oil import infrastructure in Southern California must expand to avoid shortages in supplies for refinery operations. Although progress has been made on developing a facility at Pier 400, Berth 408 in the Port of Los Angeles, the permitting process to start construction has stretched to more than four years. In fact, Plains All-American, the project developer, still does not have all of the requisite approvals to start construction.

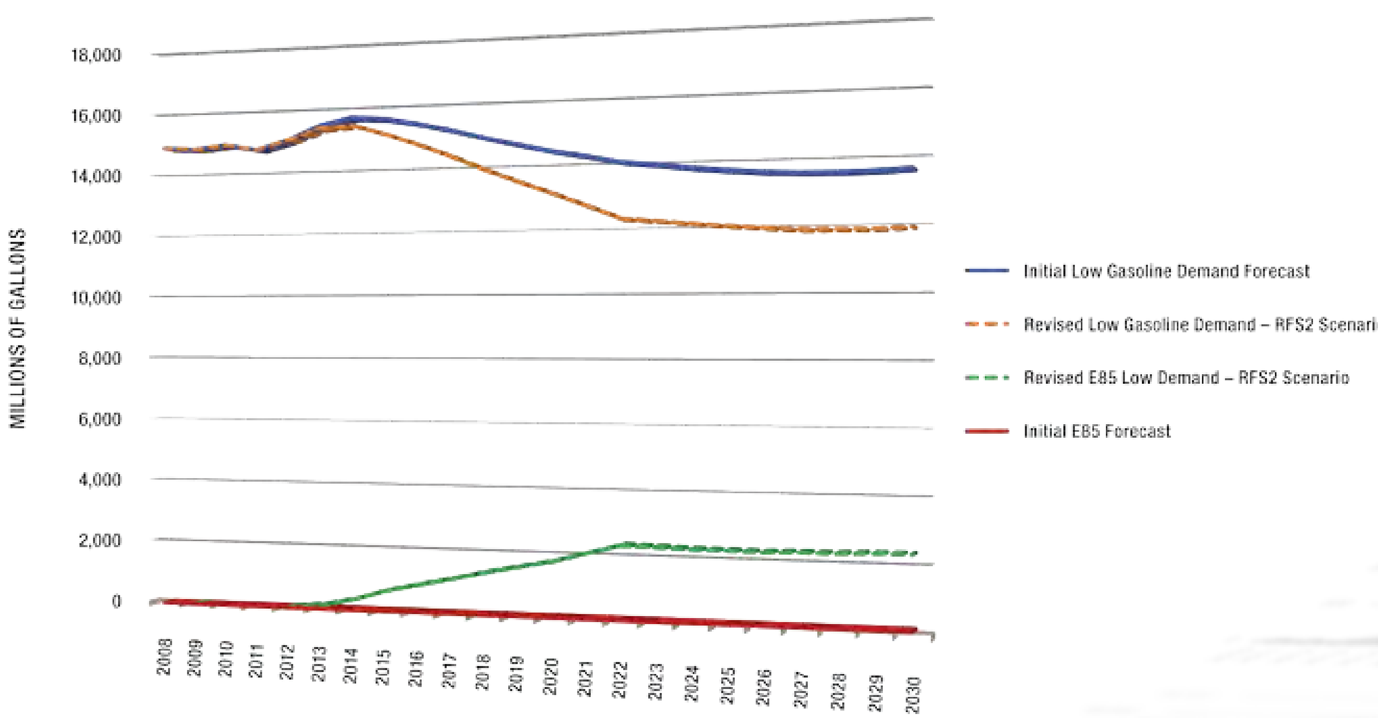
To add further strain, especially in Southern California, staff expects the increased imports of crude oil to result in a greater number of marine vessels arriving in California ports, with 46 to 272 additional arrivals per year by 2030. Additional storage tank capacity beyond that already identified as part of the Berth 408 project must be constructed to handle the incremental imports, and it is unclear where these can be located given the competition for land in and around the ports. Also, the opening of off-shore drilling along California's coast could require additional infrastructure in the way of platforms, interconnecting pipelines, crude oil trunk lines, and pump stations. It is

FIGURE 22: CALIFORNIA E85 DEMAND FORECAST 2010–2030



Source: California Energy Commission, *Transportation Energy Forecasts and Analyses for the 2009 Integrated Energy Policy Report*

FIGURE 23: REVISED LOW DEMAND FORECAST 2010–2030



Source: California Energy Commission

FIGURE 24: KINDER MORGAN INTERSTATE PIPELINE SYSTEM

Source: Kinder Morgan Pipeline Company

recognized that some near-term offshore drilling projects using existing platforms or shore-based operations would mostly be able to use existing crude oil distribution infrastructure.

California exports large amounts of transportation fuels to Nevada and Arizona. Pipelines that originate in California provide nearly 100 percent of the transportation fuels consumed in Nevada and approximately 55 percent of fuels consumed in Arizona. Kinder Morgan's recent East Line pipeline expansion from Texas to Arizona (see Figure 24) caused a drop in Arizona's demand for California fuel exports in 2008, as refiners and marketers shifted to Texas and New Mexico for supply. If Kinder Morgan does not make additional expansions to the pipeline distribution systems, the continued growth of transportation fuel demand in Nevada could exceed pipeline capacity, but not until 2021. Overall, the near- and long-term forecast periods indicate that transportation fuel demand growth in Nevada and Arizona could place additional pressure on California's refineries and petroleum marine import infrastructure.

Renewable and Alternative Fuels and Vehicles Infrastructure

To meet the requirements of RFS2 and the LCFS, several issues must be resolved regarding the adequacy of additional biofuel supplies and the infrastructure needed to receive and distribute increased quantities of ethanol and biodiesel to California consumers. The primary challenges faced by makers of alternative fuel vehicles include a lack of infrastructure in both fuel production and refueling, the need to develop technologies to reduce battery costs, the need for standardized testing, and consumer acceptance of vehicles. Simply stated, the refueling infrastructure has to be in place when the vehicles arrive. Moreover, these refueling sites must meet consumer expectations for access, convenience, and fuel quality assurance.

Flex-fuel vehicles are designed to run with either gasoline or a blend of up to 85 percent ethanol (E85). As shown in Figure 25, the number of FFVs registered in California must increase from 382,000 vehicles in October 2008 to as many as 2.4 million by 2020 to provide demand for enough E85 to be sold to meet the RFS2. However, California's current retail infrastructure is not adequate to handle an increase in E85 sales. The general public only has access to about 25 E85 stations in California today, so a vast majority of FFV owners are fueling with regular gasoline. Retail station owners and operators are not required to make E85 available for sale to the public under RFS2.

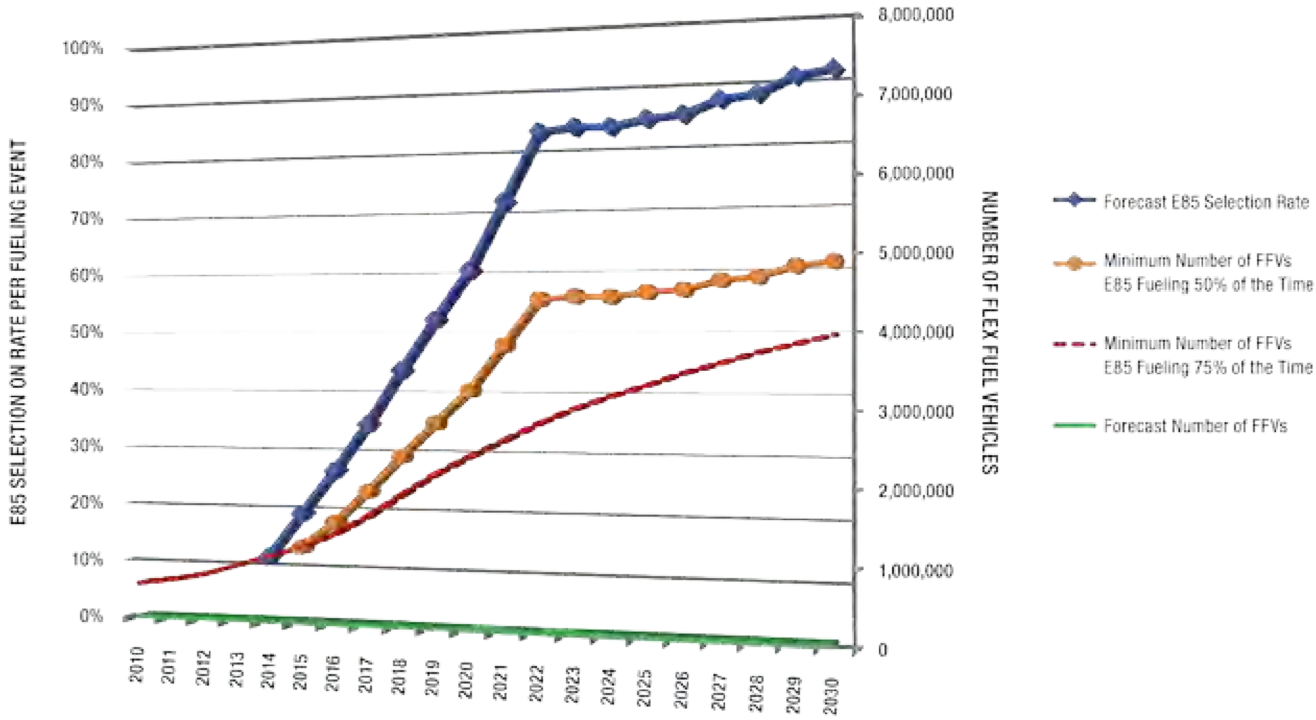
Consumers may continue to buy more FFVs, but that will have little impact on decreasing petroleum consumption or meeting RFS2 standards if E85 is not available at fueling stations. Depending on the average quantity of fuel sold by a typical E85 dispenser, California could require between 3,200 and 23,300 E85 dispensers by 2020 (Figure 26). E85 retail infrastructure is expensive. Costs for installing a new underground storage tank, dispenser, and associated piping range between $50,000 and $200,000. Statewide, the E85 retail infrastructure investment costs could be as low as $192 million, to upward of $4.7 billion between 2009 and 2020. Between 2009 and 2030, the E85 dispenser infrastructure costs could range from $251 million to $6.1 billion. One approach to reduce this anticipated infrastructure cost is for the California Legislature to consider requiring new building code standards that all gasoline-related equipment (underground storage tanks, dispensers, associated piping and so on) be E85 compatible for construction of any new retail stations or replacement of any gasoline-related equipment beginning January 1, 2011. This approach would increase the likelihood of success of renewable fuel penetration policy goals.

The state's current retail infrastructure can handle biodiesel blends at concentrations of 5 percent (B5) or less. On the wholesale and retail receipt and distribution levels, expanded use of biofuels (ethanol and biodiesel) can use the existing network of storage tanks and retail dispensers with little to no modifications for low-level blends (E10 and B5). However, higher concentrations of ethanol (E85) and biodiesel (B20) would require significant infrastructure modifications requiring the installation of thousands of new dispensers and underground storage tanks. In addition, wholesale distribution terminal operators would need to install additional storage tanks to enable the blending of biodiesel at B5 or B20 levels.

The Energy Commission's PIER transportation subject area is pursuing two classes of research initiatives that may allow the use of existing fuel infrastructure to reduce the cost of implementing renewable and alternative fuels. The first class is research into technologies or methodologies such as additives, blending techniques, and thermal thresholds for making renewable and alternative fuels compatible with the existing infrastructure. PIER is initiating a solicitation titled "Research for Biofuels Infrastructure Compatibility." The second is the development of alternative fuels designed for conventional fuel compatibility. PIER is investigating large molecule alternative fuels, such as renewable diesel or "green gasoline," which contain mixtures of complex chemicals and mimic the properties of conventional fuels. Many are fungible with standard petroleum fuels. Therefore, the emerging field of large molecule research and development holds out the potential for biofuels that require little or no new infrastructure or engine modification and are transparent to their end users.

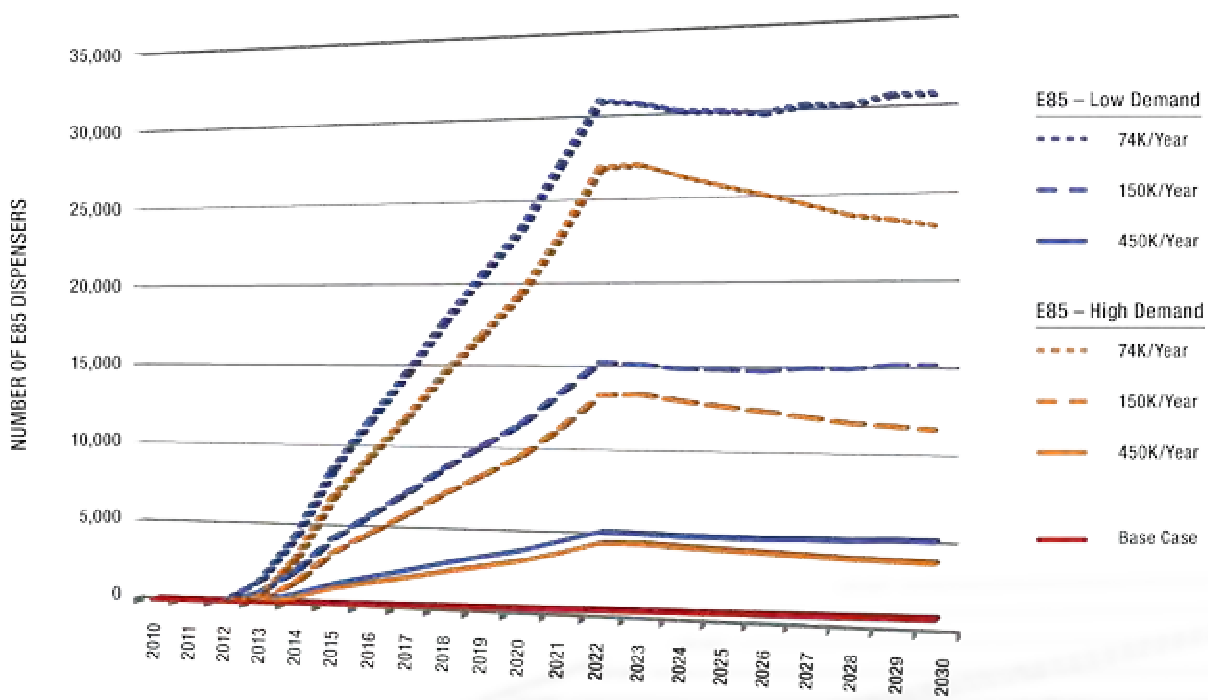
Compressed natural gas or LNG vehicles run on natural gas and have been in use in California for more than 20 years. In 2008, there were 24,810 light-duty CNG vehicles

FIGURE 25: CALIFORNIA FLEX-FUEL VEHICLE LOW DEMAND FORECAST 2010–2030



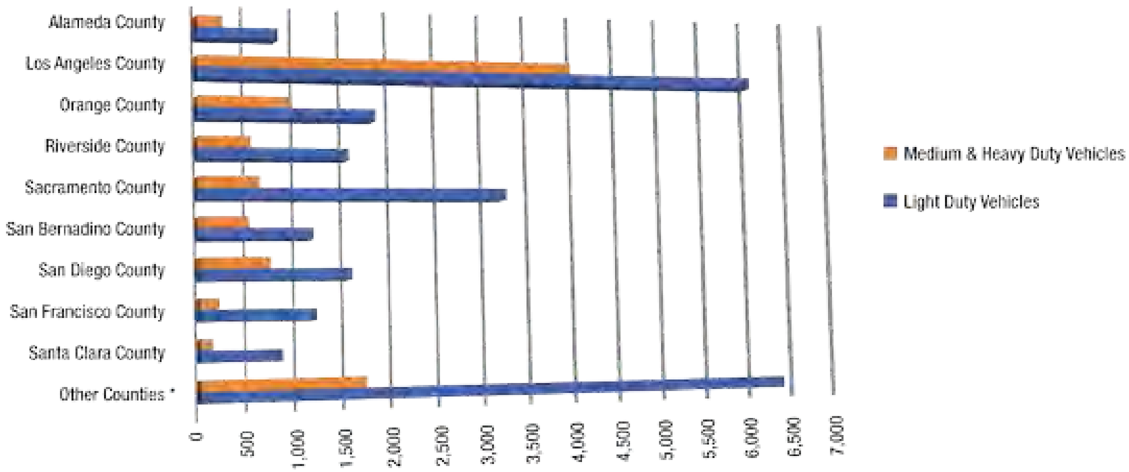
Source: California Energy Commission, *Transportation Energy Forecasts and Analyses for the 2009 Integrated Energy Policy Report*

FIGURE 26: CALIFORNIA E85 DISPENSER FORECAST 2010–2030



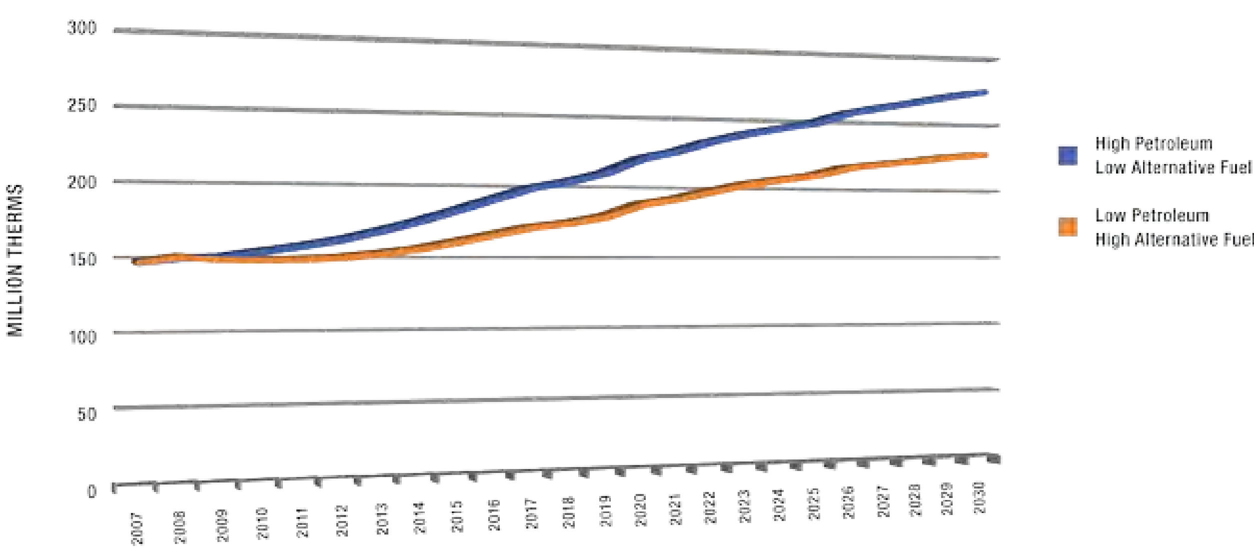
Source: California Energy Commission, *Transportation Energy Forecasts and Analyses for the 2009 Integrated Energy Policy Report*

FIGURE 27: NATURAL GAS VEHICLE COUNTS BY SPECIFIC COUNTIES, OCTOBER 2008



Source: California Energy Commission analysis of DMV Vehicle Registration Database
*The Other Counties category is composed of counties with less than 500 light duty natural gas vehicles

FIGURE 28: CALIFORNIA TRANSPORTATION NATURAL GAS DEMAND FORECAST



Source: California Energy Commission

registered and operating in California; half of these vehicles (10,747) were registered to individual owners.[202] This represents a significant increase over 2000 totals of 3,082; however, the light-duty natural gas vehicle population has been relatively flat since 2001. State and local governments accounted for 31 percent of the ownership of light-duty CNG vehicles with 78 percent of those vehicles existing in government vehicle fleets of 1,000 vehicles or more. In addition, there were 9,674 medium- and heavy-duty natural gas vehicles registered in California in 2008, with 7,144 of those vehicles being CNG-powered buses.

Figure 27 illustrates natural gas vehicle counts for specific California counties.

The state had more than 460 natural gas stations at the beginning of 2009, with more than one-third of those stations offering public access.[203] Compressed natural gas refueling options could be increased through the use of a refueling appliance located at an owner's home.[204] This refueling process takes on average anywhere between five to eight hours to fill 50 miles worth of natural gas and requires the owner to have access to a natural gas line.

California's use of natural gas in the transportation sector is forecast to increase substantially. As measured in therms, the forecast shows demand rising from 150.1 million therms in 2007 to 270.3 million therms by 2030 under the High Petroleum Price Case (High Natural Gas Demand Case) and 222.9 million therms by 2030 under the Low Petroleum Price Case (Low Natural Gas Demand Case, Figure 28).

202 For this discussion, dual fuel compressed natural gas/gasoline vehicles are considered as compressed natural gas vehicles in vehicle counts. All vehicle counts come via the Department of Motor Vehicles' database.

203 See [http://www.cngvc.org/why-ngvs/fueling-options.php].

204 See [http://www.pge.com/myhome/environment/pge/cleanair/naturalgasvehicles/fueling/].

The number of CNG vehicles is expected to grow from approximately 17,569 in 2007 to 112,025 by 2020 and 206,071 by 2030.

In 2008, the Energy Commission's PIER vehicle technologies completed the Natural Gas Vehicles Research Road Map, which identified initiatives and projects that research, develop, demonstrate, and deploy advanced fuel-efficient natural gas-powered transportation technologies and fuel-switching strategies that result in a cost-effective reduction of petroleum fuel use in the short and long term.[205] This PIER subject area is also completing a light-duty vehicle research road map that will advance science and technology to enable alternative-fueled vehicle deployment. Initial road map findings have identified near-term research initiatives to increase vehicle efficiency. For example, PIER vehicle technologies will target research to develop efficiency feedback systems, which will provide drivers with real-time fuel consumption and efficiency information to influence driving behavior and reduce fuel use. This strategy will also help with the deployment of alternative fuel vehicles. While the technology is largely developed, there is an opportunity for research to address system optimization to determine the most effective interface between the driver and feedback system.

There were 14,670 full-electric vehicles (FEVs) operating in California in 2008. Although this is a substantial increase over the 2,905 operating in 2001, it is substantially less than the 23,399 in operation in 2003. Since 2004, this population has remained relatively flat. These FEVs are primarily neighborhood electric vehicles and sub-compacts.

205 See [http://www.energy.ca.gov/2008publications/CEC-500-2008-044/CEC-500-2008-044-D.PDF].

Figure 29 shows FEV counts for specific California counties. According to SCE, the utility is expecting between 400,000 and 1.6 million electric vehicles by 2020.[206] Plug-in hybrid electric vehicles (PHEVs) combine the benefits of electric vehicles (that can be plugged in) and hybrid electric vehicles (that have an engine) and are scheduled for mass production as early as 2011. The Energy Commission forecasts the number of FEVs and PHEVs to reach nearly 3 million by 2030.

Several infrastructure barriers must be overcome to stimulate greater penetration of electric vehicles into the marketplace. Utilities will have to develop procedures, standardized equipment, and rates that meet the needs of vehicle users. Initially, utilities should probably focus on in-home recharging. Most consumers would be comfortable with home charging if time-of-use metering rates and equipment were available, as recharging could easily be accomplished in mostly off-peak hours. Consumers could be further motivated if they were able to receive the carbon credits that accrued with the use of this energy source.[207]

To help overcome infrastructure barriers, the Governor signed Senate Bill 626 (Kehoe, Chapter 355, Statutes of 2009) into law on October 11, 2009. This bill will modify current law to require the CPUC, in consultation with the Energy Commission, the ARB, utilities, and the motor vehicle industry, to evaluate policies that will help develop an infrastructure sufficient to overcome barriers to the widespread use of plug-in hybrid and electric vehicles. The CPUC is required to adopt rules to address this issue by July 1, 2011.

206 Testimony of Robert Graham, Southern California Edison, at the April 14, 2009, IEPR workshop, available at: [http://www.energy.ca.gov/2009_energypolicy/documents/2009-04-14-15_workshop/2009-04-14_Transcript.pdf].

207 Ibid.

As the electric vehicle population grows, the recharging system can expand to the workplace and to public recharging stations. Compatible and consistent standards will need to be developed for recharging connectors and other equipment, including 120/240-volt compatibility and smart chargers. Training of workers to install and service recharging equipment needs to increase, since today's expertise is limited to a few specialized technicians connected with electric vehicle dealers.[208] Additionally, utilities will need to evaluate and update their distribution infrastructure to accommodate the increased electricity demand.

California's use of electricity in the transportation sector is forecast to increase substantially, primarily as a result of the anticipated growth in sales of PHEVs. As measured in GWhs, demand is forecast to rise from 828 GWhs in 2008 to nearly 10,000 GWhs by 2030. As Figure 30 illustrates, the surge in transportation electricity use under the High Petroleum Price Case (High Electricity Demand Case) is mainly from PHEVs and to a lesser extent full-electric vehicles. The number of PHEVs is expected to grow from 32,756 in 2011 to 1,563,632 by 2020 and 2,847,580 by 2030. Electricity use for transit is nearly flat over the forecast period. The transportation portion of statewide electricity demand is expected to rise from 0.29 percent in 2008 to between 1.57 and 1.79 percent in 2020.

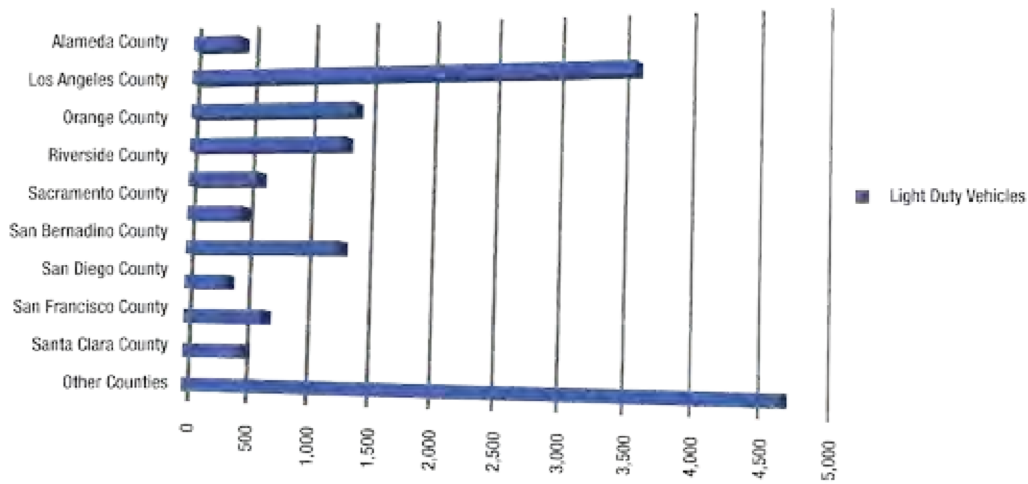
There are 400 to 500 hydrogen-powered vehicles in the United States,[209] with about 190 on the road in California.[210] These vehicles

208 Ibid.

209 Energy Information Administration, see [http://www.eia.doe.gov/oiaf/aeo/otheranalysis/aeo_2009analysispapers/ephev.html].

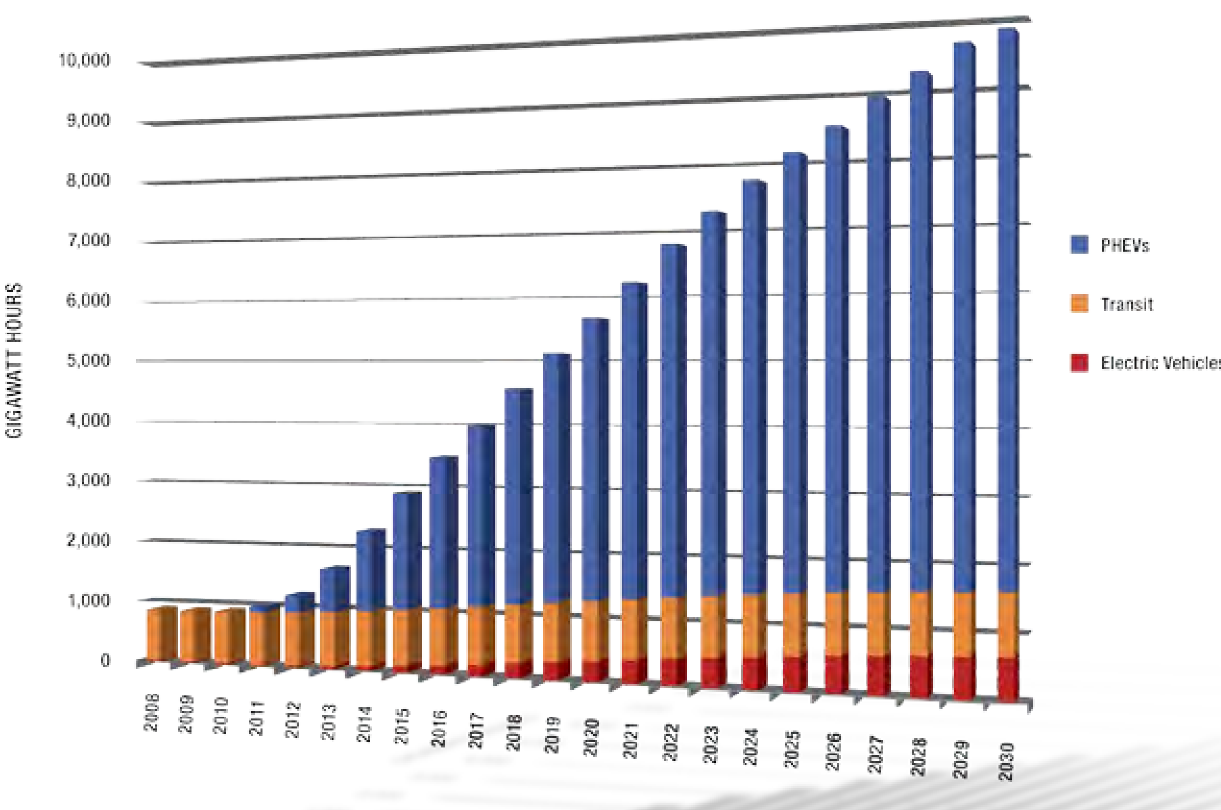
210 See [http://www.cafcp.org/sites/files/Action%20Plan%20FINAL.pdf].

FIGURE 29: FULL ELECTRIC VEHICLE COUNTS BY SPECIFIC COUNTIES, OCTOBER 2008.



Source: California Energy Commission analysis of DMV Vehicle Registration Database
*The Other Counties category is composed of counties with less than 300 electric vehicles

FIGURE 30: CALIFORNIA TRANSPORTATION ELECTRICITY – HIGH DEMAND FORECAST



Source: California Energy Commission

California's Leadership Role in Environmental Sustainability

AB 118 was created to help transform California's transportation market by reducing California's dependence on petroleum and helping California meet climate change goals. While increasing alternative fuels is a key strategy, projects around the world have discovered that producing new fuels can sometimes harm the environment. "A rapid transition to alternative fuels has the potential to encourage environmentally destructive production practices," said Energy Commission Chair Karen Douglas. "We have developed sustainability goals and criteria for AB 118, and will consider sustainability in every funding decision we make."

California is one of the first states in the nation to use sustainability as a basis to fund energy projects. The Energy Commission is taking a leadership role in working closely with state partners and global organizations in advancing the state-of-science in this emerging field. To receive AB 118 funding, proposed projects must meet the sustainability goals and evaluation criteria outlined in the Alternative and Renewable Fuel and Vehicle Technology Program regulations. The first goal is to substantially reduce GHG emissions, and the second is to protect the environment while striving to achieve superior environmental performance. The third requirement is to achieve project goals in accordance with certified sustainable production practices.

Preference is given to projects that use certified sustainable feedstocks and create alternative fuels that will be in accordance with sustainability certification standards.

By integrating sustainability in all aspects of fuel production, the Energy Commission is encouraging the next generation of alternative and renewable fuel makers as the state transitions away from fossil fuels.

use stored hydrogen, which is combined with oxygen (from the atmosphere) through an electrochemical reaction in a fuel cell to produce electricity that powers an electric motor. This technology is still relatively expensive because of high production costs of both fuel cells and the hydrogen, yet it is seen as an attractive technology because of its clean emissions capabilities.

While hydrogen has air quality benefits, it currently has no fuel quality or measurement standards for consumption and sale.[211] National and in-state standards need to be developed that address fuel quality, testing and certification methods, and sampling techniques, as well as the method of retail sale, dispensing facilities, and even the unit used to measure a sale. Fire regulations address most of the safety standards in the permitting process.

Existing hydrogen stations in the state cannot sell hydrogen at their pumps because of the lack of metering systems and dispensing rules approved by California Department of Food and Agriculture's Department of Weights and Measures.

Transportation and the Environment

Currently, high fuel prices and the recession have reduced consumer demand for gasoline, thereby benefitting the environment. These economic factors are also causing more citizens to choose transit over vehicle travel. However, to significantly reduce petroleum consumption in the longer term and achieve the state's climate change targets, California must make large strides in making renewable and alternative fuels available for consumers.

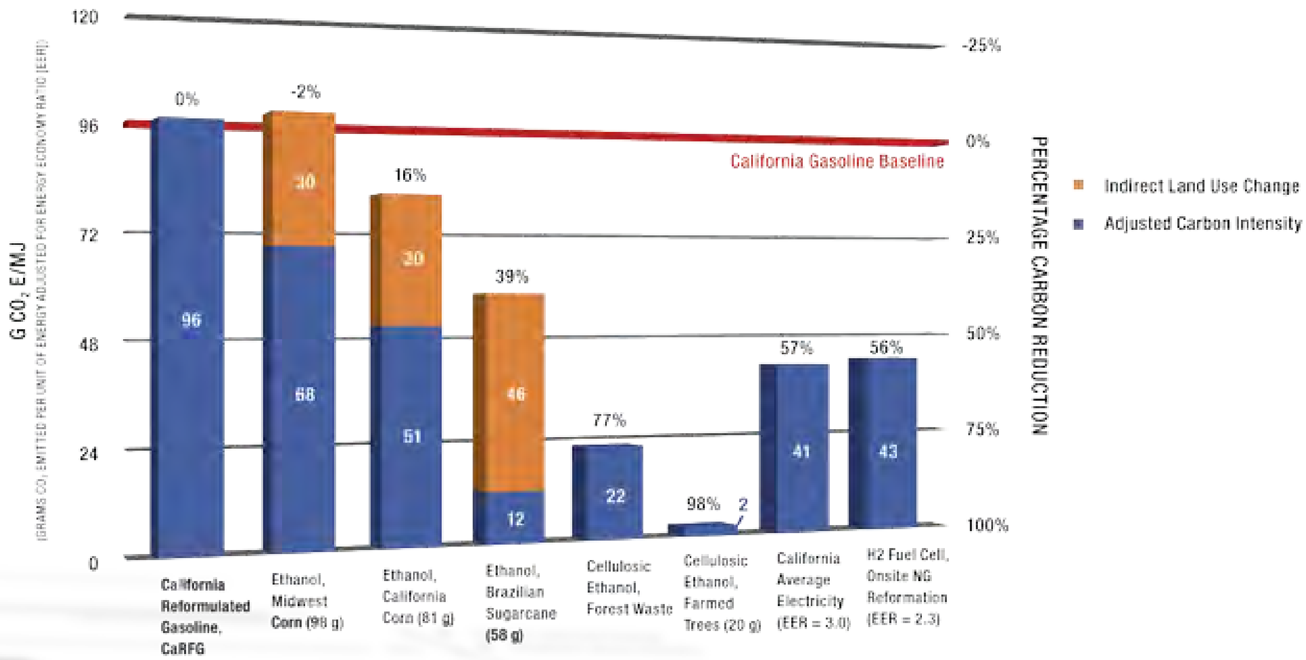
The *State Alternative Fuels Plan* set targets for the use of alternative and renewable fuels in the California market, and the *Bioenergy Action Plan* set aggressive goals to accelerate in-state biofuels production. These goals help to frame California's strong support for alternative fuels and a concerted and meaningful transition away from petroleum fuels and toward alternative fuels' attendant economic and environmental benefits.

Meeting the 2022 target in the *State Alternative Fuels Plan* would increase annual demand for alternative and renewable fuels to approximately 4 billion gallons. Reaching this goal would require the addition of more than 1 million gallons of new alternative and renewable fuels per day into the California market for the next 13 years. The Energy Commission recognizes that introducing these large volumes of alternative and renewable fuels carries the risk of encouraging or promoting environmentally and socially destructive production practices in California, North America, and throughout the world.

To gauge the environmental impacts of various transportation fuels, the Energy Commission employs a technique known as a "full fuel cycle assessment" or FFCA. Since 1989, the Energy Commission has relied on FFCA to develop policies supporting the use of alternative transportation fuels. The FFCA is used to evaluate and compare the full energy, environmental, and health impacts of each step in the life cycle of a fuel including, but not limited to, feedstock extraction, transport, and storage; fuel production, distribution, transport, and storage; and vehicle operation, refueling, combustion, conversion, and evaporation. The Energy Commission and ARB have developed a common FFCA methodology that is used as a basis for investment decisions in the Alternative and Renewable Fuels and Vehicle Technol-

211 Testimony of John Mough, California Department of Food and Agriculture, Division of Weights and Measures, at the April 14, 2009, IEPR workshop.

FIGURE 31: LIFE-CYCLE ANALYSIS CARBON INTENSITY VALUES FOR GASOLINE AND SUBSTITUTES



Source: Air Resources Board Low Carbon Fuel Standard

ogy Program and the LCFS.[212] The focus of this FFCA work has been in comparing GHG emissions of alternative and renewable fuel options with those of gasoline and diesel fuels.

The value of FFCA is determined by the underlying data, models, methodologies, and treatment of uncertainties in the development, presentation, and use of results. These areas are proving to require additional work. A key area of interest to researchers is the treatment of indirect emissions in general and land use change emissions in particular. The inclusion of indirect GHG emissions in any FFCA can significantly alter the outcome and potential public policy support for various fuel options. This effect is illustrated in Figure 31.

The nascent nature of this work creates uncertainty as to the best approach for treating indirect emissions in a policy, programmatic, regulatory, or market framework. In adopting its initial LCFS regulation in 2008, the ARB included indirect land use change emissions in determining carbon intensity values, but only for biofuel. However, all fuels must be evaluated equally. The ARB will reassess this aspect of the LCFS in 2010, and the Energy Commission and the ARB are continuing joint research into this topic.

As shown in Figure 31, not all biofuels are created equal. Depending on the origin of the fuel, the feedstock, and the type of energy

212 See [http://www.energy.ca.gov/2007publications/CEC-600-2007-004/CEC-600-2007-004-REV.PDF].

used in its production, the GHG implications of a given biofuel on an FFCA basis can vary dramatically. Ethanol is currently the dominant biofuel of choice today and will be needed to achieve federal energy and environmental policy mandates and goals. However, traditional corn-based ethanol originating from facilities in the Midwest is estimated by ARB to have full-fuel-cycle assessment GHG emissions roughly equivalent to gasoline produced at California refineries.

To help achieve compliance with the LCFS, obligated parties will need to lower carbon ethanol. Producing corn-based ethanol in California provides roughly a 16 percent reduction in GHG emissions compared to gasoline. However, sugarcane-based ethanol (for example, produced in Brazil and imported to California) or "second generation" cellulosic ethanol (for example, using biomass such as nonfood parts of crops and municipal, agricultural, and forest waste material as a feedstock) will reduce GHG emissions by 79 percent over gasoline.

Similarly, biomass-based diesel fuels (including biodiesel and renewable diesel, as well as specific feedstock- and process-based diesels such as algae-based diesel, biomass-to-diesel, and diesel from thermal depolymerization of industrial and processing waste) could be significant contributors to reducing GHG emissions in California. Of these fuels, only biodiesel is commercially available in California and the United States today.

Biodiesel produced today in California reduces GHG emissions by 10 to 50 percent compared to diesel that meets ARB's diesel fuel regulations. These facilities use recycled cooking oil (yellow grease) as their lowest-cost feedstock option, but also use more expensive and abundant soybean, palm, and a variety of plant and animal oils. Moving beyond these oils and into facilities using cellulose, waste, and algae are necessary to achieve deeper GHG emission reductions. Depending on the feedstock, fuel production process, blend concentration, and vehicle type, these biodiesel and renewable diesel fuels could reduce GHG emissions by 61 to 94 percent compared to conventional diesel fuel meeting ARB's regulations.

Full-electric vehicles and PHEVs have numerous benefits that make them attractive in addressing carbon reduction and petroleum dependence. Based on the California average electricity mix, FEVs have the potential to reduce GHG emissions by 57 percent; the reductions from PHEVs will be less due to the partial reliance on an internal combustion engine. However, several utilities in California rely on electricity imports from out-of-state coal-fired plants. This will affect the GHG reduction potential and needs careful consideration in formulating broad public policies supporting FEVs and PHEVs. Use of substantial numbers of these vehicles would also provide localized air quality benefits by reducing criteria pollutant emissions compared to conventional vehicles.

Natural gas vehicles emit 30 to 40 percent less GHG emissions than gasoline- and diesel-powered engines. The environmental profile of natural gas can be further improved through advancements in biomethane or biogas, which are renewable sources for the production of natural gas. Biomethane can be produced by capturing methane from landfills, dairy farms, and wastewater treatment plants and by anaerobic digestion of organic matter such as municipal solid waste. The use of biomethane in state-of-the-art natural gas vehicles has a much greater GHG benefit, reducing emissions by as much as 97 percent. California biomethane resource potential is estimated to provide transportation fuels for up to 250,000 vehicles per year from dairy operations, representing roughly 1 percent of the existing population of light-duty vehicles in the state as of October 2008.[213]

Natural gas is currently the primary feedstock needed for manufacturing hydrogen and results in a reduction of GHG emissions by about 56 percent compared to gasoline. The use of electrolysis to produce hydrogen (a process where hydrogen is separated from water) has the potential of reducing GHG emissions even further. However, this technique depends on the source of the electricity used for the process. Renewable power has the greatest potential to reduce the emissions to near zero. Hydrogen can also be created from biomethane to further improve its environmental profile.

Propane is produced as a by-product of refinery operations and is a coproduct in the extraction of oil and natural gas. Propane reduces GHG emissions up to 19 percent compared to gasoline. While not yet available commercially, studies are being conducted at Mississippi State University and Massachusetts Institute of Technology on the generation of renewable propane. Renewable propane can be derived from algae, row crops, and wood. While the GHG profile of renewable propane is not known at this time, production requires little additional energy and results in a product that contains the same energy content as propane derived from petroleum.

While considerable work is focused on understanding the carbon implications of various fuel options, FFCA methodologies do not typically reflect the notion of "embedded carbon." Regulatory and market incentive policies encourage the introduction of new vehicles to achieve GHG emission targets. The importance of this strategy is clear. However, the energy and raw material inputs involved in manufacturing new vehicles cause GHG emissions. A new more fuel-efficient vehicle may have to travel tens of thousands of miles to compensate for the emissions resulting from the manufacturing process. Embedded carbon also raises the question of the tens of millions of existing gasoline and diesel vehicles that will continue to emit carbon as new advanced vehicles are being introduced into the marketplace. A strategy that would provide incentives to retrofit segments of the existing fleet with low-carbon technologies should be examined from a public policy perspective.

It is clear that California will remain heavily dependent on petroleum, at least in the near term, as its primary transportation fuel. There will be a need for strategies to address the carbon emissions associated with petroleum refining. California has been conducting extensive research on carbon capture and sequestration as a GHG mitigation strategy for industrial sources, including oil refineries. On October 2, 2009, the DOE awarded $3 million in ARRA funding to C6 Resources, an affiliate of Shell Oil Company, to conduct a seven-month scoping study on a project that will sequester approximately 1 million tons per year of CO_2 streams from a Martinez, California, refinery and inject it into a saline formation more than two miles underground. At the end of the study, C6 Resources will submit a proposal for the actual project.

Transportation and Reliability

As production from California's crude oil fields continues to decline, and as California's oil refineries continue to expand their production capacity, refiners will turn to importing additional volumes from sources outside the state. Since Alaska crude oil production has declined at a greater rate than California production, refiners must seek substitute crude oil from foreign sources. There is concern about the political stability of oil-producing nations such as Iraq and Nigeria and its potential impact

213 Biomethane Resource Potential, CALSTART, Steven Sokolsky, IEPR Workshop, April 15, 2009, slide 6.

on crude oil availability. Offshore drilling could increase the domestic supply and help ensure reliability. However, environmental concerns with drilling activity in sensitive marine habitat could prevent or delay new production. These factors, along with an inadequate marine import infrastructure, could significantly impact fuel security and reliability for California and neighboring states.

Uncertainty regarding future supplies of crude oil represents an opportunity for the state to move more aggressively in expanding the use of alternative and renewable fuels. However, these fuels are not without their own challenges. Unless the state takes concerted steps to grow the alternative and renewable fuel industry domestically, policy makers may be faced with similar potential supply interruptions from an over-reliance on foreign sources of fuel and feedstock. To compound the issue, the LCFS could push the industry to import commercial quantities of lower carbon-intensity fuels, further stressing California's marine infrastructure. Increasing reliance on foreign sources of renewable fuels also creates uncertainty as to the true carbon intensity of the fuel and therefore brings into question the suitability of the fuel for the California market.

Increasing imports of renewable and alternative fuels will require additional infrastructure including new off-take terminals, storage and distribution, and retail sites. Also, buyers of alternative and renewable fuel vehicles must be assured that fuel or recharging stations are available and that they have access to vehicle parts, maintenance, and manufacturer warranties.

As California transitions from conventional biofuels to more advanced second generation biofuels, a great emphasis will be placed on identifying sustainable feedstocks. California's municipal, agricultural, and forest biomass waste stream is a massive unused resource that could be used as a feedstock for biofuels. California currently produces a total of 83 million gross bone dry tons per year (BDT/y) of combined biomass waste; this is projected to increase to 99 million BDT/y by 2020. However, only about 32 million BDT may be accessible as an energy feedstock because of economic and environmental limitations. At the current rate of use of just 5 million BDT/y, this is an under-used resource. Still, biofuel producers will be competing with operators of biomass-fired power plants and users of nonenergy bioproducts. It is imperative to determine if there will be sufficient biomass waste to meet these growing and competing demands. Preliminary data suggest that there may be sufficient biomass waste in the near term for competing energy uses, but more thorough and in-depth analysis is needed for both the biofuels and electricity industries.

Alternatively, purpose-grown crops may be an important complement to biomass waste as an energy feedstock. Biodiesel can be derived from oil crops, cellulosic sources, and algae. The ethanol industry has been looking at sugarcane, sugar beets, sweet sorghum, grain sorghum, and cull fruits. These crops also may represent new sources of income in economically depressed communities. If energy crops are used as a biomass source, additional analysis will be needed to determine life cycle carbon implications, including both direct and indirect land use changes, and to ensure that crops are being grown in a certifiably sustainable manner using best management practices.

Transportation and the Economy

The economic recession has impacted the transportation industry at almost every level. At the consumer level, behavior changes are evident. Consumers are reducing vehicle trips and cutting back on personal spending in response to higher gasoline prices and the recession. In addition, consumers are showing a purchasing trend of smaller cars, along with more FFVs and hybrids (Table 7). This has resulted in an overall shift in production to more fuel efficient vehicles. In difficult economic times, price and fuel cost are significant factors in vehicle choice, suggesting that California consumers are aware of the tradeoff between these cost factors.

Consumers are particularly affected by fuel price volatility. Last year, crude oil prices rose to over $140 per barrel in July 2008, declined sharply to a level below $30 in December, and then steadily climbed again to about $70 in September 2009. These events led to volatile gasoline prices, impacting consumers directly at the pump. At its highest peak, in June 2008, the U.S. Energy Information Administration reported the average price of California regular-grade motor gasoline was $4.48 per gallon. By December 2008, the price fell to $1.82, before rising again to $3.10 in September 2009. Consumers responded to this price volatility and overall economic conditions by reducing gasoline consumption; according to Board of Equalization data, California sales of gasoline fell by 6.2 percent from 2004 to 2008.

For the *2009 IEPR* transportation fuel forecast, staff developed high and low crude oil price forecasts for California transportation fuels and used these as the basis for California-specific high and low case regular-grade gasoline and diesel price forecasts. The Energy Commission's High Petroleum Price Case starts at $2.90 per gallon for gasoline and $3.09 for diesel in 2009, jumps to $4.36 and $4.43, respectively, in 2015, and then continues to rise to $4.80 and $4.87 by 2030 (all prices are in 2008 dollars to adjust for inflation). The Energy Commission Low Petroleum Price Case price forecasts start at $2.34 for gasoline and $2.42 for diesel per gallon in 2009, climb to $3.17 and $3.19, respectively, in 2015, and then hold constant until 2030. If the High Petroleum Price Case forecast holds true, the state could see more consistent and sustained behavior changes in citizens related to driving patterns, gasoline demand, and vehicle purchasing decisions.

Cheaper fuel sources would be a major motivating factor for consumers to choose alternative fuel vehicles. The alternative fuel price forecasts show most of these fuels costing about the same (or sometimes more) than gasoline or diesel, but there are considerable uncertainties in these projections. Moreover, other factors, such as the efficiency with which the vehicle technology uses the energy in its fuel as well as insurance and maintenance costs, will also affect total operating costs. Finally, the purchase price of many alternative fuel vehicle types exceeds that of conventional gasoline vehicles.

The downturn of the economy has greatly affected the biofuels industry. All seven of the ethanol production plants in California are currently sitting idle. California ethanol producers cite the primary reason for ceasing production as poor market conditions and the economics of producing ethanol. On May 17, Pacific Ethanol, one of the larger California ethanol producers, filed for Chapter 11 bankruptcy protection. Ethanol producers in other parts of the country, particularly the Midwest, are feeling strain from the economy, but the effects are not as detrimental as those felt in California. Midwest states support agriculture, corn production, and ethanol plants simultaneously, and California may need to take a similar role for its ethanol industry to survive. Also, companies have ceased construction on a number of biofuel projects because of their inability to secure financing. Financial institutions are not funding unique biofuel infrastructure projects, which all pose risks.

The California biodiesel plants are also struggling. The SWRCB prohibition of biodiesel in underground storage tanks (which was rescinded in May 2009) and the recession created detrimental economic hurdles. California has nine biodiesel plants with a

TABLE 7: SUMMARY OF CALIFORNIA ON-ROAD LIGHT-DUTY VEHICLES

	LIGHT DUTY VEHICLE COUNTS					
	GASOLINE	DIESEL	HYBRID	FLEX FUEL	ELECTRIC	NATURAL GAS
2001	22,779,246	316,872	6,609	97,611	2,905	3,082
2002	23,384,639	334,313	15,159	129,734	11,963	25,682
2003	24,516,071	364,411	24,182	183,546	23,399	17,228
2004	24,785,578	391,950	45,263	195,752	14,425	21,269
2005	25,440,904	424,137	91,438	269,857	13,947	24,471
2006	25,741,051	449,305	154,165	300,806	14,071	24,919
2007	25,815,758	465,654	243,729	340,910	13,956	25,196
2008	25,654,102	463,631	333,020	381,584	14,670	24,810
Compound Average Growth Rate	**1.71%**	**5.59%**	**75.06%**	**21.50%**	**26.03%**	**34.71%**

Source: California Energy Commission analysis of California DMV data

State and Federal Funding Efforts Stimulate Electric Vehicle Market

California is home to start-up companies like Tesla Motors, Aptera Motors, and Fisker Automotive that are promising to bring upscale all-electric vehicles to market soon. Today, major manufacturers including Ford, Chrysler, BMW, Toyota, Mitsubishi, Subaru, and General Motors are actively exploring electric technology with the help of federal funding.

California is providing state funding support as well. Through AB 118, the Energy Commission is offering $9 million to manufacturers of electric vehicles and electric vehicle components willing to locate in California. The incentives will create several thousand green California jobs and help to boost local economies. Overall, AB 118 offers a total of $46 million in state funds to support electric transportation.

As automobile manufacturers in Asia, Europe, and the U.S. rush to capture a growing worldwide market for more efficient, environmentally friendly vehicles, California and the federal government are helping American companies compete in the race to develop vehicles for the 21st century.

combined 2009 theoretical capacity of 63 million gallons; these plants will likely produce less than 25 million gallons. Today, six biodiesel plants are idle.[214] The biodiesel industry has to work doubly hard to re-establish itself from the rescinded prohibition to store biodiesel in underground storage tanks during the recession. The added uncertainty from ARB's LCFS treatment of indirect emissions further exacerbates the lack of economic support for biofuels.

To move high levels of biofuels into California's predominantly gasoline market, incentives may be needed to stimulate in-state production as well as infrastructure investments. It is important that California efficiently maximize the benefits from federal grants as well as assistance with state funding and assistance resources. This will be a key aspect of leveraging AB 118 monies with federal stimulus funding.

Economic barriers to wider-spread purchase of FEVs and PHEVs include the lack of commercially available models and delays in delivery, their higher price, and concerns about their size and range.[215] These perceptions of FEVs by potential vehicle purchasers may be intensified by a lack of familiarity with the technology and uncertainties over how the vehicles would be recharged or the expense of replacing batteries. Battery cost could be reduced through mass production of batteries, but there is still a great deal of research,

214 Docket Comments by the California Biodiesel Alliance, February 16, 2009.

215 A recent study completed by the Government Accountability Office describes the various challenges facing increased use of plug-in hybrid electric vehicles (PHEVs), as well as elaborating on specific developments that would be necessary for PHEVs to be competitive. Government Accountability Office, *Plug-in Vehicles Offer Potential Benefits, but High Costs and Limited Information Could Hinder Integration into the Federal Fleet*, June 2009, GAO-09-493, available at: [http://www.gao.gov/new.items/d09493.pdf].

development, and demonstration taking place to improve vehicle range. Improving performance is important because as the technology currently stands, it is not possible to exceed vehicle range without a lengthy pause to recharge the battery. Overall, the initial costs of electric vehicles (EVs) are higher than for gasoline vehicles because of the additional cost of the battery and home recharging installation.

Several different vehicle manufacturers have produced light-duty CNG vehicles, but currently only the Honda GX CNG is offered for sale in the United States. A lack of vehicle offerings was identified by the *State Alternative Fuels Plan* as one of the primary hurdles to natural gas becoming a major publicly used transportation fuel in California.[216] Another barrier is that light-duty CNG vehicles often require more frequent refueling due to having approximately 25 percent less range than gasoline or diesel vehicles per one tank of fuel. And like electric vehicles, natural gas vehicles are so unfamiliar to the majority of consumers that they are unable to generate favorable impressions among many potential car buyers.

The price of natural gas fuel can be attractive to high-volume purchasers, but vehicle cost can be a barrier to more light-, medium-, and heavy-duty vehicle purchases unless alleviated by declining production costs driven by on-board fuel storage needs or consumer incentives. The Energy Commission's *State Alternative Fuels Plan – AB 1007 Report* also identified several actions that would encourage the development of the industry: develop new utility rate structures for home refueling appliances; stimulate the development of biomethane/biogas for use in natural gas vehicles and as a feedstock for hydrogen; improve on-board storage technology to improve the range and costs of natural gas vehicles; develop natural gas hybrid electric technology; and use the GHG emission benefit credits in investment and business operation plans.

The ARRA includes multiple elements to advance alternative fuel and vehicle technologies. For example, Ford received $5.9 billion in loans from the U.S. DOE to help it retool its plants to produce 13 fuel-efficient models, including as many as 10,000 EVs a year beginning in 2011. Nissan received $1.6 billion in loans to retool its Tennessee plant to make EVs. In August 2009, Ford, GM, Chrysler, and others received $2.4 billion in federal grants to encourage the development of HEVs and EVs. The grants include $1.5 billion for battery makers, $500 million for companies developing electric motors and drive components, and $400 million to test a recharging system for electric cars. The grants are part of the federal government's $787 billion economic stimulus program.

As its population continues to grow, California must plan to ensure it has enough fuel to keep its economic engine running, while protecting the state's public health and natural resources. Regulations already in place demand that the state's energy supply become increasingly sustainable as Californians work to cut GHG emissions. Sustainability is becoming ever more important as the United States tries to wean itself from constrained resources like foreign oil. The state must avoid, however, trading one vulnerability for another, such as becoming dependent on electric automobile batteries that require rare lithium from other, perhaps less-than-friendly countries. The recession makes it increasingly important that California develop United States resources and provide United States jobs in a sustainable way.

216 *State Alternative Fuels Plan – AB 1007 Report* - Docket # 06-AFP-1, see [http://www.energy.ca.gov/ab1007/index.html].

CHAPTER 3

THE FUTURE OF CALIFORNIA'S ELECTRICAL SYSTEM

California's numerous energy policy goals must balance the need to minimize environmental impacts while maintaining reliability and affordability of electric power. Those goals include increasing the use of preferred resources (energy efficiency, demand response, renewable energy, combined heat and power, rooftop photovoltaic, and other distributed renewables), decreasing the use of once-through cooling technologies in power plants, retiring aging power plants, and modernizing the state's system of power lines. Overlaying these goals is the state mandate to reduce greenhouse gas (GHG) emissions. Because electricity generation is the second largest source of California's GHG emissions after transportation, making changes in the electricity sector is critical.

Thus far, these goals have been only weakly integrated. To coordinate planning, procurement, and permitting of power plants into an integrated system, decision makers must reconcile priorities, identify tradeoffs, and transform broadly framed objectives into concrete measures. Forming a unified vision and translating that vision into a blueprint of specific goals and objectives will provide a foundation for in-depth planning for specific generation and transmission projects. Clearly identifying which generation projects are needed (and which are not) will ease concerns from environmental advocates that the state has not fully embraced a future driven by GHG emission reductions. More efficient and coordinated transmission planning will avoid contentious, lengthy, and ineffective processes that can delay the transmission needed to meet the state's environmental goals. Further, an integrated process will minimize duplication among the state's energy agencies and provide complementary and reinforcing forums for integrating the various analyses and other efforts underway at those agencies. "Integration" in this context refers not only to the state's actual generation and distribution resources, but also to the substantial number of policies, laws, and regulations that govern the system, as well as the multiple agencies involved in establishing and executing those mandates.

This chapter is organized in three parts. The first identifies the major challenges resulting from the effects of the State Water Resources Control Board's once-through cooling mitigation policies on coastal power plants, the extreme scarcity of air credits in the South Coast Air Basin that is inhibiting development of replacement power plants, and impacts of these issues on Energy Commission power plant licensing. The second section discusses implementation issues associated with the preferred resource additions that are a key element of the vision for a new electricity system of the future. The final part addresses the institutional coordination challenges of getting all of the affected parties to efficiently study, plan, and act to steer infrastructure development toward a common future vision.

Issues Affecting Power Plants

In its *2005 Integrated Energy Policy Report (2005 IEPR)*, the Energy Commission called for the retirement, replacement, and/or repowering of aging power plants in the state. These plants operate at high heat rates when compared with new generation technologies and result in less efficient use of natural gas and higher levels of air pollutants, including GHG emissions. The Energy Commission also recommended that the California Public Utilities Commission (CPUC) ensure that long-term resource procurement explicitly take into account the retirement, replacement, and/or repowering of aging power plants – including those in the Los Angeles Basin – with cleaner, combustion-based technologies that operate at higher efficiencies. In its 2006 Long-Term Procurement Plan (LTPP) decision, D.07-12-052, the CPUC included substantial retirements in determining future investor-owned utility (IOU) needs.

In addition to this policy goal, the following four external forces continue to exert major influence over the electricity industry:

- Policies to reduce or eliminate the use of once-through cooling in power plants.
- The scarcity and high cost of emissions credits needed for new power plants.
- The need to shift the mix of resources toward demand-side resources and renewables and away from fossil power plants in response to global climate change initiatives.
- Multiple jurisdictions responsible for permitting power plants.

Effects of Once-Through Cooling Mitigation Policies

At the end of 2008, 19 power plants (20,400 MW) in California used once-through cooling (OTC) technologies. In June 2009, the State Water Resources Control Board (SWRCB) published a draft policy that establishes closed-cycle wet cooling towers as the benchmark for compliance with OTC mitigation requirements.

The draft policy also proposes a compliance schedule based on the suggestion by the Energy Commission, the CPUC, and the California Independent System Operator (California ISO) on how to address reliability concerns given the proposed timeline for OTC mitigation compliance.[217] The three energy agencies agreed that a fixed-year outer bound on OTC mitigation compliance can be established, provided it allows for the orderly development of necessary replacement infrastructure and can be amended if conditions such as permitting and construction delays indicate such change is needed to ensure reliability.

The proposed compliance schedule for each OTC plant is based on the time required to create replacement infrastructure. A wide range of circumstances exists within the OTC fleet. As new facilities become operational, some OTC power plants are losing their importance for local reliability. For others, the proposed schedule incorporates the construction timeline for replacement infrastructure when that is already underway. For many power plants, substantial analysis of the options, decisions among the energy agencies, and then procurement, permitting, and construction create long lead times before replacement infrastructure can be operational. The complexities of these analyses differ from one region to another, with the Los Angeles Basin being the most problematic given severe limitations on the air credits needed for new generation development. For this reason, the schedule of dates for replacement infrastructure may occur further into the future for the existing OTC plants located in the Los Angeles Basin.

217 California Energy Commission, California Public Utilities Commission, and California Independent System Operator, *Implementation of Once-Through Cooling Mitigation through Energy Infrastructure Planning and Procurement*, July 2009, CEC-200-2009-013-SD, available at: [http://www.energy.ca.gov/2009publications/CEC-200-2009-013/CEC-200-2009-013-SD.PDF].

It is critical to integrate the perspective of environmental regulators into reliability concerns. The SWRCB must establish a policy with a fixed deadline to force action by the plant operators and to allow regional boards to issue permits to existing plants with knowledge that OTC mitigation will occur on a fixed schedule. At the same time, the energy agencies strongly believe that implementation of an OTC mitigation policy for existing generators has to be integrated with planning and development of the replacement infrastructure necessary to support system reliability.

In the joint energy agency proposal to the SWRCB, the energy agencies provided estimated operation dates for new infrastructure. The energy agencies must review and update these dates periodically, which are then reviewed by the SWRCB. Where significant changes have been made, the SWRCB must use them as the basis for changing the permits for existing OTC plants. The energy agencies are committed to working together and with the SWRCB to achieve this objective, and SWRCB staff's draft proposed policy incorporates the joint agency proposal.

Factors Affecting Once-Through Cooling Replacement Infrastructure

Within the broad umbrella of linking OTC mitigation to the development of replacement infrastructure, the state could propose many alternative plans. State agency policies emphasize preferred resource types, including energy efficiency and demand response, renewables, and distributed generation. Including these resources in the analysis will likely result in a set of proposed replacement plants that do not rely strictly on conventional fossil power.

The energy industry's compliance with the California Air Resources Board's (ARB) *Climate Change Scoping Plan* regulations will presumably lead to a lower electricity demand forecast because additional energy efficiency measures will reduce demand, and rooftop photovoltaic (PV) and other distributed generation resources will displace sales of electricity from the bulk power system to end users. A lower demand forecast would require fewer central station generating facilities within load pockets to satisfy reliability criteria. Compliance with climate change regulations presumably also strengthens the role of renewable power generation, which encourages more transmission development to interconnect remote renewable resources, lessening the need for energy from traditional fossil generation but simultaneously increasing the need for dispatchable facilities (those that have the ability to control their output) to provide reliability services. Recognizing these likely consequences could lead to changes in both the mix and capabilities of fossil generation needed in load pockets, whether from repowered OTC plants or from new facilities that are electrically equivalent.

In addition, air permitting issues in the South Coast Air Quality Management District (SCAQMD), discussed in more detail in the next section, will affect the type of replacement power that could be built. The Superior Court decision voiding the SCAQMD's Priority Reserve Rule will result in serious limitations on power plant development in the South Coast Air Basin and nearby areas for some time.[218] SCAQMD's air quality permitting processes affect 7,500 megawatts (MW) of existing fossil capacity in the Los Angeles local capacity area of the California ISO and the Los Angeles Department of Water and Power (LADWP). New facilities totaling 1,750 MW in capacity have power purchase agreements with

218 Natural Resources Defense Council, Inc., et al. vs. South Coast Air Quality Management District, Superior Court of the State of California, County of Los Angeles, Case No. BS 110792.

Southern California Edison (SCE) but cannot be licensed because they do not have access to the Priority Reserve. If this issue remains unresolved, these facilities will not be available to reduce the reliability threat from the proposed limitation on the use of OTC. This would significantly increase the challenge of siting new power plants needed to implement the OTC policy and require solutions that rely on transmission system upgrades to access remotely located generation.

The state must also consider local capacity requirements when discussing replacement power. The Energy Commission, CPUC, and California ISO are developing enhanced local capacity requirements analyses for each local capacity area, or load pocket, within the California ISO balancing authority area. Some areas lack excess capacity and must develop replacement capacity to meet increases in peak load or power plant retirements. Others have surpluses and could therefore tolerate some retirements. Based on load and resource assumptions, the local capacity requirement analyses will extend current requirements to 10 years and identify the amount and various operating characteristics needed to plan for OTC retirement in some load pockets.

The results will be used as key inputs for an OTC power plant infrastructure replacement plan that would produce specific reliability designations, or retirement dates for specific power plants, as determined by the physical requirements in the load pocket and expected timing of replacement infrastructure development. The plan would identify, for each region, the required actions for eliminating reliance upon a power plant or unit using OTC. Most importantly, this plan would identify the complete set of infrastructure additions that, once operational, would allow OTC to be eliminated.

Recognizing these problems, the Legislature proposed multiple bills in its 2009 session to address OTC mitigation and restoration of a functioning air quality credit mechanism for new power plants in the South Coast Air Basin. Of these, only AB 1318 (V. Manuel Perez, Chapter 285, Statutes of 2009) and SB 827 (Wright, Chapter 206, Statutes of 2009) passed through the Legislature and were signed by the Governor. Assembly Bill 1318 will require the ARB, in consultation with the CPUC, the Energy Commission, the California ISO, and the SWRCB, to submit a report to the Legislature and Governor evaluating the electric system reliability needs of the South Coast Air Basin and recommend strategies to meet those needs while ensuring compliance with AB 32, OTC mitigation requirements, state and federal air pollution laws and regulations, resource adequacy requirements, and renewable and energy efficiency requirements. Assembly Bill 1318 would also authorize issuance of air credits to specific plants satisfying eligibility criteria. Similarly, SB 827 would authorize SCAQMD to issue needed air credits for a limited number of specific plants meeting eligibility criteria, but those criteria are different than those in AB 1318. These bills were signed into law by the Governor on October 11, 2009, but do not provide a comprehensive solution to the lack of air credits for power plants in the South Coast Air Basin.

Planning for Once-Through Cooling Replacement Infrastructure

The state will have to make significant decisions regarding the planning, procurement authorization, and permitting of specific energy infrastructure projects to accomplish the retrofit, repowering, or retirement of what amounts to more than 30 percent of the state's power generating capacity that OTC plants represent.[219] All of the 19 generation plants with OTC units are located in the California ISO and the LADWP control areas. Of the 16 OTC plants in the California ISO control area, 13 are located in transmission-constrained regions. Transmission constraints also influence the need for and options among refitting, repowering, and replacing the three OTC plants within the LADWP balancing authority. Thus, the CPUC, the California ISO, and the Energy Commission have recommended, rather than follow a fixed compliance schedule, that regions with less need for complex analyses and more advanced possible solutions reduce OTC harm more quickly than regions with more extensive constraints on implementing solutions.

The proposal submitted to the SWRCB encompasses three broad efforts. First, the agencies would conduct a series of studies examining the consequences of retiring individual or clusters of existing OTC power plants under a range of alternative futures and transmission system configurations to identify generation and transmission options for replacing each OTC facility. These futures would encompass increased efforts to reduce load through demand-side policy initiatives and alternative ways in which high renewable generation could be developed through time. The Energy Commission would facilitate a review of the LADWP power plants, which are outside the jurisdiction of both the CPUC and the California ISO.

Second, the agencies would review key analytic results to determine a strategy that is compatible with broad energy policy preferences. The ARB's AB 32 *Climate Change Scoping Plan* incorporates a number of the broad energy policy initiatives being pursued by the energy agencies as far back as the *2003 Energy Action Plan*. Assessment of alternative futures that are compatible with these elements of the *Climate Change Scoping Plan* and system/local reliability requirements can identify options for reducing reliance upon fossil generation (either new green field plants or repowered existing plants) through these preferred resources or transmission system upgrades. When results are available, they would be entered into the 2010 or 2012 CPUC LTPP proceeding for further analysis by the IOUs and consideration by the CPUC, with the objective of issuing procurement guidance to IOUs to acquire resources, and to the California ISO annual transmission planning process to identify specific transmission projects.

Finally, the CPUC would approve necessary power plant additions and transmission projects. The Energy Commission would license the power plant projects. Staff of the energy agencies would monitor progress, periodically report to the SWRCB, and as appropriate, recommend changes.

Some power plant operators suggested they may retrofit their power plant to satisfy SWRCB's proposed draft policy. For particular units, this might make sense, especially if the investments are lower than for repowering and the expected life of the unit makes such investments cost-effective to ratepayers. Since AB 32 encourages deployment of renewables to the extent feasible, retirements are being delayed, compared to earlier *IEPR* recommendations, to synchronize with renewable development schedules. The Energy Commission first articulated its policy in favor of retiring aging power plants in the *2005 IEPR* and then modified it to explicitly encompass repowering in the *2007 IEPR*. Therefore, it is appropriate that the Energy Commission modify the policy here to support limited retrofitting of units to

219 Retrofitting or refitting refers to the installation of a cooling system that complies with the proposed SWRCB policy. Repowering entails replacement of the existing boiler with advanced generation technology – improving thermal efficiency – and installing a compliant cooling technology. Retirement may, and often does, require replacement of the foregone capacity with generation at another location.

those most efficient and useful to integration of renewables and other system support functions. For the 2020 time horizon and beyond, the state should still pursue the goal of retiring or repowering these aging facilities.

Emission Credits for Power Plants

The second major issue affecting the electricity sector is the scarcity of emissions credits for new power plants. New generating capacity development to replace aging or OTC power plants is critical to achieving reduced GHG emissions from more efficient use of natural gas. However, recent court rulings limiting the supply of air emissions credits in the SCAQMD present new challenges for California to achieve its environmental goals while ensuring sufficient generating supplies for system resource needs and local area reliability.

Southern California air basins have some of the worst air quality in the nation, resulting in stringent local air quality requirements, including offsetting new sources of emissions with reductions in emissions from existing sources. These offsets, or emission credits, are in short supply in the SCAQMD, making it difficult to license new power plants or repower existing aging plants in Southern California. In 1990, the SCAQMD established a Priority Reserve of emission credits set aside for use by entities serving a public interest, but did not explicitly include power generation as an eligible industry.

In August 2007, the SCAQMD amended its Priority Reserve Rules to allow offsets to be purchased for new power plants licensed by the Energy Commission. The SCAQMD, under Rule 1309.1, limited these power plant credits, requiring developers to have a one-year power sales contract and a license from the Energy Commission to construct their facility before the SCAQMD board would release any credits. Plants being proposed by municipal utilities were allowed only enough credits to build projects to serve their native load. The SCAQMD also limited the total amount of new electricity generating capacity that could access Priority Reserve credits to no more than 2,700 MW.

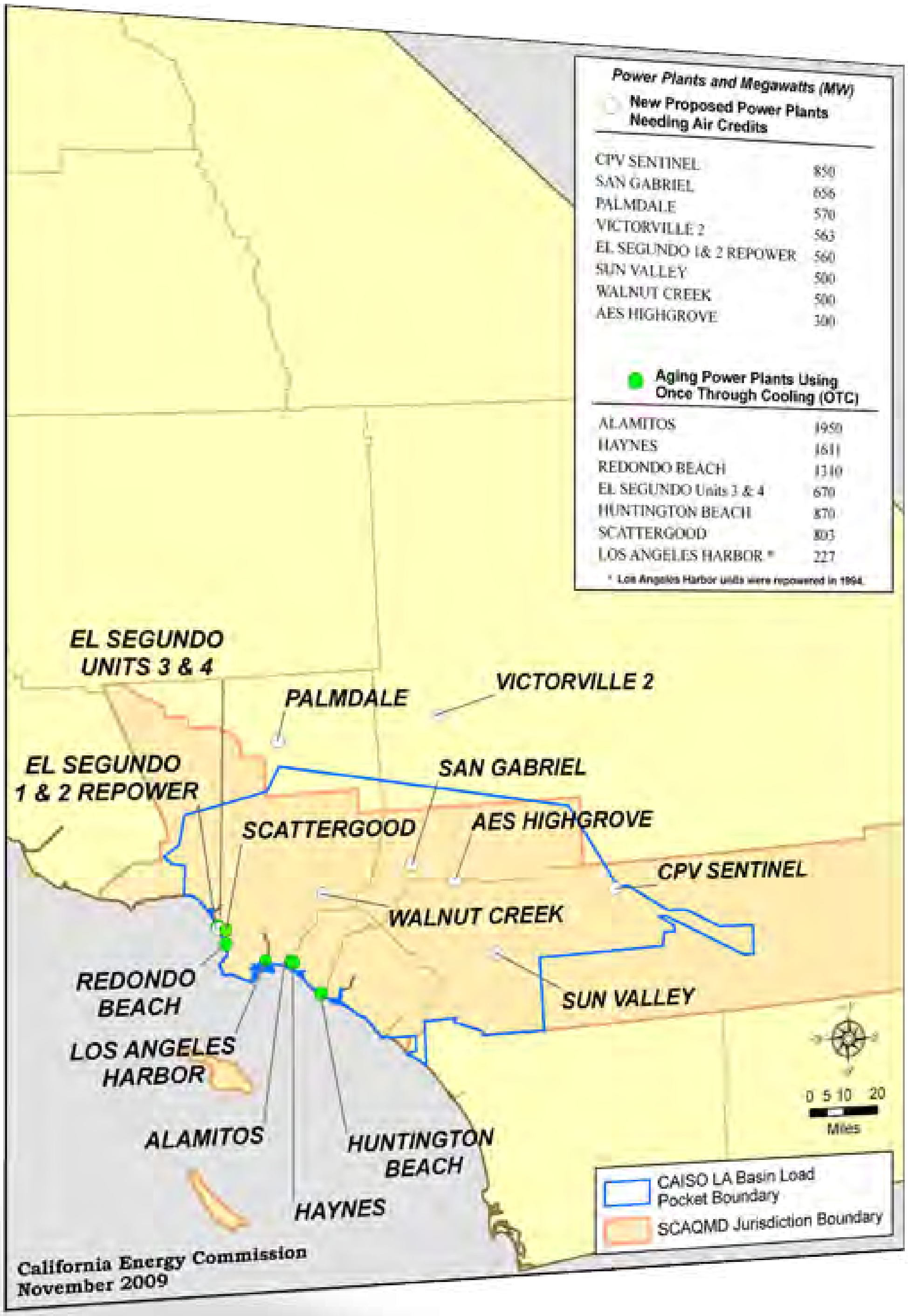
The SCAQMD Priority Reserve Rule was challenged in Los Angeles County Superior Court and in July 2008, the court decision found the air district's California Environmental Quality Act (CEQA) analysis inadequate and indicated that a sufficient environmental document would require significant new analysis that the SCAQMD believes it cannot reasonably provide. As a consequence, the SCAQMD is unable to issue any offsets for power plants or for any facilities requiring a permit for emissions. The SCAQMD is now working to modify its regulations to allow permits for nonpower plant facilities, but has no specific plans to develop new rules specific to power plants. Instead, power plant proponents and SCAQMD sponsored legislation in the 2009 session that would overturn the state court ruling. Staff is conducting analyses to identify the need for resource additions in the Los Angeles Basin under various sets of future conditions that will allow a more analytically based debate about means to find the corresponding air credits needed. Initial results of this effort were discussed at a September 24 workshop.[220]

Figure 32 shows the geographic location of the existing OTC power plants impacted and those currently in the Energy Commission licensing process affected by SCAQMD's problems issuing air credits to new power plants.

If new gas-fired power plants cannot be licensed in the Los Angeles Basin because

220 Energy Commission staff presentation, available at: [http://www.energy.ca.gov/2009_energypolicy/documents/index.html#092409].

FIGURE 32: POWER PLANTS AFFECTED BY AIR CREDIT LIMITATIONS IN SOUTH COAST AIR BASIN



Source: California Energy Commission

air emission credits from the SCAQMD Priority Reserve are unavailable and other rules favorable to power plant development are disallowed, system reliability will require continued and ongoing operation of aging, less efficient, higher emission power plants to maintain planning reserve margins between 15 and 17 percent. Most of these are also OTC plants, so the SWRCB's draft policy encouraging replacement by new infrastructure would likely be delayed. Eventually, the shortage of emission credits could have a negative impact on Southern California's ability to meet the California ISO summer peak and local capacity requirements if no new fossil plants can be built and if demand-side preferred resources cannot overcome load growth year after year. Local capacity requirements are designed by the California ISO to ensure that there is sufficient generation to provide uninterrupted service during all hours even if a major power plant or transmission line fails. In 2008, the Los Angeles Basin is meeting nearly half of its electrical load with local generating capacity, including aging power plants.

Impacts on Power Plants Licensed by the Energy Commission

The Energy Commission has permitting jurisdiction for all thermal power plants with capacity of 50 MW or greater. The Energy Commission's permitting process does not substitute for the requirements of other entities, so the difficulties in acquiring air credits in the South Coast Air Basin mean that projects that would normally get a permit from the Energy Commission have been delayed. Three power plants licensed by the Energy Commission are located in the Los Angeles Basin load pocket and could, if developed, allow retirement of some of the existing aging power plants.

- Sentinel Units 1 and 2 totaling 800 MW nameplate[221] completed its Energy Commission review, but depended on Priority Reserve credits and had to await resolution of this issue. With the passage of AB 1318, Sentinel is likely to acquire air credits and complete the Energy Commission process.

- The owner of the existing El Segundo power plant, NRG Energy, secured a license for repowering of Units 1 and 2 from the Energy Commission in 2005 (nameplate capacity of existing units is 350 MW; license was granted for a repowered facility with nameplate capacity of 630 MW). In June 2007, NRG petitioned to amend its license so it could shift from an OTC technology and build a 560-MW air-cooled facility. With the change in facility size, NRG did not have sufficient emission reduction credits to move forward with construction of its El Segundo repower project with a nameplate capacity of 560 MW. Passage of SB 827 may allow the owners of El Segundo to make use of SCAQMD's Rule 1304 to avoid purchasing air credits if they decide to retire another of the older units at the facility.

- Walnut Creek Energy Center (nameplate capacity 500 MW) received a permit from the Energy Commission in summer 2008 using the SCAQMD Priority Reserve credits. The facility is currently on hold with construction to start in late 2009, pending resolution of the air credit issues. Walnut Creek is not helped by either AB 1318 or SB 827, and a comparable bill, SB 388 (Calderon), created to authorize air credits for it, did not pass the Legislature in 2009.

221 "Nameplate" refers to the manufacturer's rating for output of power plant equipment.

TABLE 8: SOUTHERN CALIFORNIA EDISON CAPACITY IMPACTED BY SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT RULE

YEAR	FACILITY	CAPACITY (MW)	CUMULATIVE (MW)
2010	Sentinel I	455	
2011	El Segundo Repower – Units 1&2	550	1005
2012	Sentinel II	273	1278
2013	Walnut Creek	479	1757

Source: California Energy Commission

TABLE 9: STAFF PLANNING ASSUMPTIONS AND RESERVE MARGIN RESULTS FOR SOUTHERN CALIFORNIA USING HIGH RETIREMENTS (MEGAWATTS)

Supply/Demand Forecast	2010	2011	2012	2013	2014
Peak Demand	27,995	28,363	28,800	29,256	29,620
Existing Generation	22,927	22,927	22,927	22,927	22,927
Net Imports	10,100	10,100	10,100	10,100	10,100
DR & Interruptable	1,491	1,512	1,534	1,547	1,551
New Thermal	995	1,707	1,992	1,992	1,992
New Renewable	162	251	533	965	1,157
Retirement	(354)	(354)	(354)	(354)	(708)
Total Generation	35,321	36,142	36,731	37,177	37,020
Reserve Margin w/o OTC Requirements	26%	27%	28%	27%	25%
Surplus over 15%	3,127	3,525	3,611	3.532	2,957
Add'l Retirements (CPUC Decision)	(1850)	(3,050)	(4,500)	(5350)	(5,350)
Reserve Margin w OTC Retirements	20%	17%	12%	9%	7%
Surplus over 15%	**1,277**	**475**	**(889)**	**(1,818)**	**(2,393)**

Source: California Energy Commission

Other power plants currently in the licensing process at the Energy Commission could, if permitted and brought on-line, allow even more aging power plant retirement. However, at this time there is no clear path forward for these units.

SB 827, by allowing use of SCAQMD's Rule 1304 exemption for repowering projects, creates an incentive for repowering in place that cannot be matched by new greenfield power plants. It is unclear whether such repowering will take place. The plaintiffs in a second lawsuit against SCAQMD's permitting practices continue to express concerns about whether the air credits in SCAQMD's internal accounts are valid (accumulated through shutdowns and other orphan uses never converted into marketable renewable energy credits). SCAQMD asserts that U.S. EPA's review of its Rule 1315 establishes federal satisfaction over its internal account. Others may be ready to test this belief in federal court. Repowering projects that satisfy Rule 1304's exemption requirements would not increase capacity, so they may not be under the Energy Commission's licensing jurisdiction. Such plants would be licensed by local authorities, and some plants have well organized opposition groups that seek conversion of these sites into other uses. In sum, whether SB 827's reopening of SCAQMD's Rule 1304 for repowering exemptions creates a pathway to assure sufficient capacity of the right kind and right location of power plants is still very much in doubt.

Impacts on Specific Utilities

Any substantial delays in the construction of new fossil fuel facilities proposed in the Los Angeles Basin will impact the electricity supplies available to meet summer peak loads. SCE is the major utility in the Los Angeles Basin; however, many municipal utilities are also located there including: LADWP, Burbank Water and Power, Glendale Water and Power (all in the LADWP control area) and Anaheim, Riverside, Pasadena, and other smaller municipals in the California ISO control area. SCE likely will be the most affected by the SCAQMD ruling. The SCAQMD ruling threatens 1,757 MW of the capacity that had been expected to come on-line from 2010 to 2013 (Table 8).

Energy Commission staff evaluated the supply-demand balance in the South of Path 26 region (SP26).[222] The resulting staff paper used Southern California Edison and other utility assumptions since the *2009 IEPR* had not yet been compiled. The paper computed two alternative retirement scenarios juxtaposed against the limited amount of new additions that could be permitted given the SCAQMD air credit limitations. An updated analysis using staff's planning assumptions and planning reserve margin calculations for the Southern California region over the next five years was presented at the September 24 workshop on SCAQMD air credit issues.[223] The results using the CPUC procurement authorization assumptions are shown in Table 9. The Southern California portion of the California ISO control area has more capacity than necessary to sustain a 15 percent reserve margin through 2011, but falls below that level in 2012 and gets progressively worse. This increases vulnerability to situations like unexpected outages, which the full 15 percent planning reserve margin is designed to address. Fortunately, this assessment is no longer realistic since the SWRCB,

222 California Energy Commission, *Potential Impacts of the South Coast Air Quality Management District Air Credit Limitations and Once-Through Cooling Mitigation on Southern California's Electricity System*, February 2009, CEC-200-2009-002-SD, available at: [http://www.energy.ca.gov/2009publications/CEC-200-2009-002/CEC-200-2009-002-SD.PDF].

223 A further update using the final demand forecasts adopted by the Energy Commission in this IEPR proceeding has been made to the results provided in this chapter, but the demand forecast changes are sufficiently small that there is no material change in the conclusions reached.

in consultation with the energy agencies, has delayed the compliance dates for OTC power plants in the Los Angeles Basin to allow time for replacement infrastructure to be developed and brought on-line.

By revising the OTC retirement assumptions to match the schedule proposed by the energy agencies and accepted by SWRCB staff in its draft OTC policy, the deficits relative to the designed planning margin are eliminated, and there are comfortable surpluses throughout the five-year period. Table 10 shows these results. The negative impacts of a fast retirement schedule, in light of air credit limitations on new power plant development, which the energy agencies were able to get SWRCB to accommodate, allows time for the air credit issues to be resolved. However, once the full OTC retirements occur in later years, the 15 percent planning reserve margin cannot be satisfied unless additional resources are brought on-line.

The SCAQMD court ruling has had similar impacts on publicly owned utilities in the Southern California portion of the California ISO control area. LADWP has three power plants totaling over 2,000 MW of capacity that use OTC and apparently intends to repower most of the units in these plants in order to comply with SWRCB draft OTC policy. In securing air quality permits, LADWP has faced the same challenges as other entities within the SCAQMD's jurisdiction, since its ability to use SCAQMD's Rule 1304 exemption from providing air credits for its repowers has been blocked by the court ruling. SB 827 would apparently restore repowering exemptions via Rule 1304, so LADWP's strategy of OTC compliance through repowering may no longer be blocked by air credit limitations. This analysis shows the strong interdependencies of the likely consequences of the SWRCB's OTC mitigation policies with air credit availability to support new power plant development. In the Los Angeles Basin there is a clear conflict. This conflict has been shifted out beyond 2014 – the near-term period requiring immediate action – toward the end of the 2010 decade.

The 2009 legislative "solutions" have not addressed the full issue, but have sanctioned use of air credits at a limited number of specific power plants already well into the licensing process. The workshop conducted September 24 revealed strong interest in a comprehensive solution to this issue, rather than a series of piecemeal attempts to license specific power plants. Staff's analytic project is on the right track and should be continued in conjunction with inputs from other stakeholders. The reliability study required by AB 1318 can build upon staff's initial work and perhaps become the basis for broader recognition of the scale of the problem.[224] Eventually legislation is probably required, but it should provide for a systematic, even-handed method for determining which power plants are able to obtain scarce air credits,[225] while the environment is protected from excessive criteria pollutant emissions. That other sources in the Los Angeles air shed have to be regulated more tightly to allow for needed power plant capacity may be the price this region needs to pay to secure reliable electricity services.

224 AB 1318 (V. Manuel Perez, Chapter 285, Statutes of 2009), requires the Air Resources Board, in consultation with the Energy Commission, CPUC, California Independent System Operator, and State Water Resources Control Board, to complete a reliability study of the South Coast Air Basin by July 2010.

225 When air credits are procured from market sources, or a special program open to all categories of power plant, then all power plants pay for them on the basis of the prospective missions from the facility. Exemptions for repowering and legislative gifts of credits to specific power plants tilt away from a level playing field, with the potential for unintended consequences and suboptimal outcomes.

TABLE 10: STAFF PLANNING ASSUMPTIONS AND RESERVE MARGIN RESULTS FOR SOUTHERN CALIFORNIA USING STATE WATER RESOURCES CONTROL BOARD ONCE THROUGH COOLING RETIREMENTS (MEGAWATTS)

Supply/Demand Element	2010	2011	2012	2013	2014
Peak Demand	27,995	28,363	28,800	29,256	29,620
Existing Generation	22,927	22,927	22,927	22,927	22,927
Net Imports	10,100	10,100	10,100	10,100	10,100
DR & Interruptable	1,491	1,512	1,534	1,547	1,551
New Thermal	995	1,707	1,992	1,992	1,992
New Renewable	162	251	533	965	1,157
Retirement	(354)	(354)	(354)	(354)	(708)
Total Generation	35,321	36,142	36,731	37,177	37,020
Reserve Margin w/o OTC Requirements	26%	27%	28%	27%	25%
Surplus over 15%	3,127	3,525	3,611	3.532	2,957
Add'l Retirements (SWRCB OTC)	0	0	0	0	0
Reserve Margin w OTC Retirements	26%	27%	28%	27%	25%
Surplus over 15%	**3127**	**3525**	**3611**	**3532**	**2957**

Source: California Energy Commission

Preferred Resource Additions

California has long pursued a path to use more environmentally sensitive technologies to satisfy consumer energy needs. Even during the enthusiasm for markets in the mid- and late-1990s, public goods charges were established to ensure that funding for energy efficiency and renewables would continue to achieve goals for these preferred resources. The Energy Action Plan process signaled inter-agency support for these technologies. The more recent motivation to mitigate climate change accentuates these past efforts.

Because the electricity sector represents a significant source of GHG emissions, it is viewed as a source for major emission reductions to satisfy the state's GHG emission reduction goals. California's continuing emphasis on energy efficiency and shifting the mix of generating resources from fossil plants to renewable resources will provide the bulk of the reductions from the electricity sector. Additional reductions will come from moving to more efficient fossil sources like combined heat and power (CHP) and state-of-the-art natural gas plants.

Uncommitted Energy Efficiency Goals

Since the original *Energy Action Plan*, energy efficiency has been assigned the highest priority among all preferred resources. Prior *IEPRs* and now the ARB *Climate Change Scoping Plan* hold out high aspirations for additional energy efficiency impacts beyond those included in the baseline demand forecast. The *2007 IEPR* called for "achieving all cost effective energy efficiency." In late 2008, the ARB adopted high goals for additional energy efficiency as part of its *Climate Change Scoping Plan*.[226]

The *2008 IEPR Update* described the review of the approach of segregating between committed and uncommitted energy efficiency and only including what the Energy Commission calls "committed" impacts in the baseline demand forecast. The Energy Commission did this to call attention to the need for numerous actions before broad, uncommitted goals can be achieved – for example, programs have to be designed and funded, utilities and other program administrators have to successfully implement programs, end users have to participate either voluntarily through utility programs or involuntarily through mandated standards, technologies must meet or exceed the technological development rates assumed in broad projections, and the general scope and pace of economic development has to continue as assumed when making estimates of program potential and participation. Many things can and do deviate from the expected when hundreds of thousands, or millions, of end-use customers have to participate in order to generate the savings estimated in potential studies and savings goal decisions.

As noted later in this chapter, the degree to which the high goals established for uncommitted energy efficiency are achieved interacts strongly with the goals for renewables. Simply said, the amount of renewable energy required under a 33 percent by 2020 Renewables Portfolio Standard (RPS) formula is nearly 50 percent higher without the impacts of additional efficiency. Assuming renewables are pursued in a reasonably logical manner of easiest, cheapest first, the success of energy efficiency aspirations determines whether the

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

state has to construct the difficult and more expensive subset of renewable potential. Thus, the success of achieving the 33 percent renewables goal by 2020 may depend on whether energy efficiency goals are achieved.

Chapter 2 described the efforts that Energy Commission staff is pursuing to develop estimates of the incremental impacts of three scenarios of uncommitted energy efficiency program initiatives derived from CPUC D.08-07-047. The CPUC wishes to use these estimates in its forthcoming LTPP proceeding as adjustments to the baseline demand forecast. The CPUC intends to require the IOUs to evaluate the alternative futures implied by these three "managed" demand forecasts (baseline less incremental, uncommitted impacts) when conducting its portfolio analyses. Examining three alternative futures is highly commendable, but these three do not reflect the full range of uncertainty about the incremental impacts of uncommitted energy efficiency. The three scenarios established by the CPUC reflect differences in the breadth of programs that are imagined to unfold through time via funding for utility programs, number and strength of ratchets in building standards, federal appliance mandates, and pursuit of net zero building designs. There are numerous other sources of uncertainty about incremental impacts that the staff's analytic effort is not examining. Among these are:

- Willingness of customers to participate in voluntary programs.
- The extent to which high efficiency buildings, appliances, and production processes encourage high levels of use thus "taking back" some portion of engineering estimates of savings.
- Measures of technological performance through time.

As the Energy Commission staff develops a capability to project incremental impacts of a less highly structured set of energy efficiency proposals, these other elements of uncertainty should be addressed in the method and assumptions used in making the projections.

On September 24, 2009, the CPUC unanimously adopted a $3.1 billion, three-year Strategic Plan for Energy Efficiency, to be administered by the state's IOUs. Implementing the plan will avoid the need for three additional 500-MW power plants. It will also create between 15,000 and 18,000 new jobs, launch the nation's largest home retrofit program, and provide $175 million to launch California's Big Bold Energy Efficiency Strategies for zero net energy homes and commercial buildings. The plan was dedicated to Energy Commissioner Arthur Rosenfeld in recognition of his contributions to the field of energy efficiency. During 2010, the triennial AB 2021 (Levine, Chapter 734, Statutes of 2006) process of establishing long-term energy efficiency goals for each utility will be revisited. This effort provides another opportunity for the Energy Commission and CPUC to work collaboratively in setting goals that can reduce forecast loads in ways that are achievable and cost effective.

The Energy Commission collaborates with California's publicly owned utilities to promote cost-effective energy efficiency activities. As required by AB 2021, each year the publicly owned utilities report their efficiency expenditures and energy savings to the Energy Commission, which evaluates progress. In addition, every three years, publicly owned utilities identify all potentially achievable cost-effective electricity energy savings and establish annual targets for energy efficiency savings and demand reduction for the next 10-year period. Coordinating with the CPUC for the IOUs and the publicly owned utilities, the Energy Commission develops statewide energy efficiency potential estimates and adopts targets for California's IOUs and publicly owned utilities.

Renewables Portfolio Standard Goals

A major issue in implementing climate change policy is how to meet the RPS goal of 33 percent renewable energy by 2020, given the challenges of integrating such large amounts of renewable energy into the system.[227] While some renewable resources like geothermal and biomass can operate much like conventional baseload power plants, intermittent and remotely located renewable generation presents new challenges for matching the power produced with consumer demands. Intermittency of production means that capacity is derated from nameplate values as part of the resource adequacy process, and it also means that dispatchable resources are required to ramp up or down to match the characteristic daily patterns and sudden changes in electricity production from wind and solar resources. Integrating higher levels of renewables into the electricity system must also be integrated with other state policies to reduce the negative impacts of OTC, reduce waste through energy efficiency and combined heat and power, modernize the transmission and distribution grids, and use electricity as an alternative transportation fuel.

A primary question is the amount of added renewable energy needed to meet the RPS goal, referred to as the renewable "net short." This is an issue because the existing RPS law focuses on renewables as a percentage of retail sales. Anything that reduces retail sales – energy efficiency program savings, rooftop solar PV, and other customer-side-of-the-meter distributed generation – reduces the renewable requirement. As shown in Figure 33, assumptions about the resource mix of future renewable additions varies widely, and no studies have examined a scenario that would maximize the use of baseload biomass and geothermal resources rather than variable wind and solar technologies.[228]

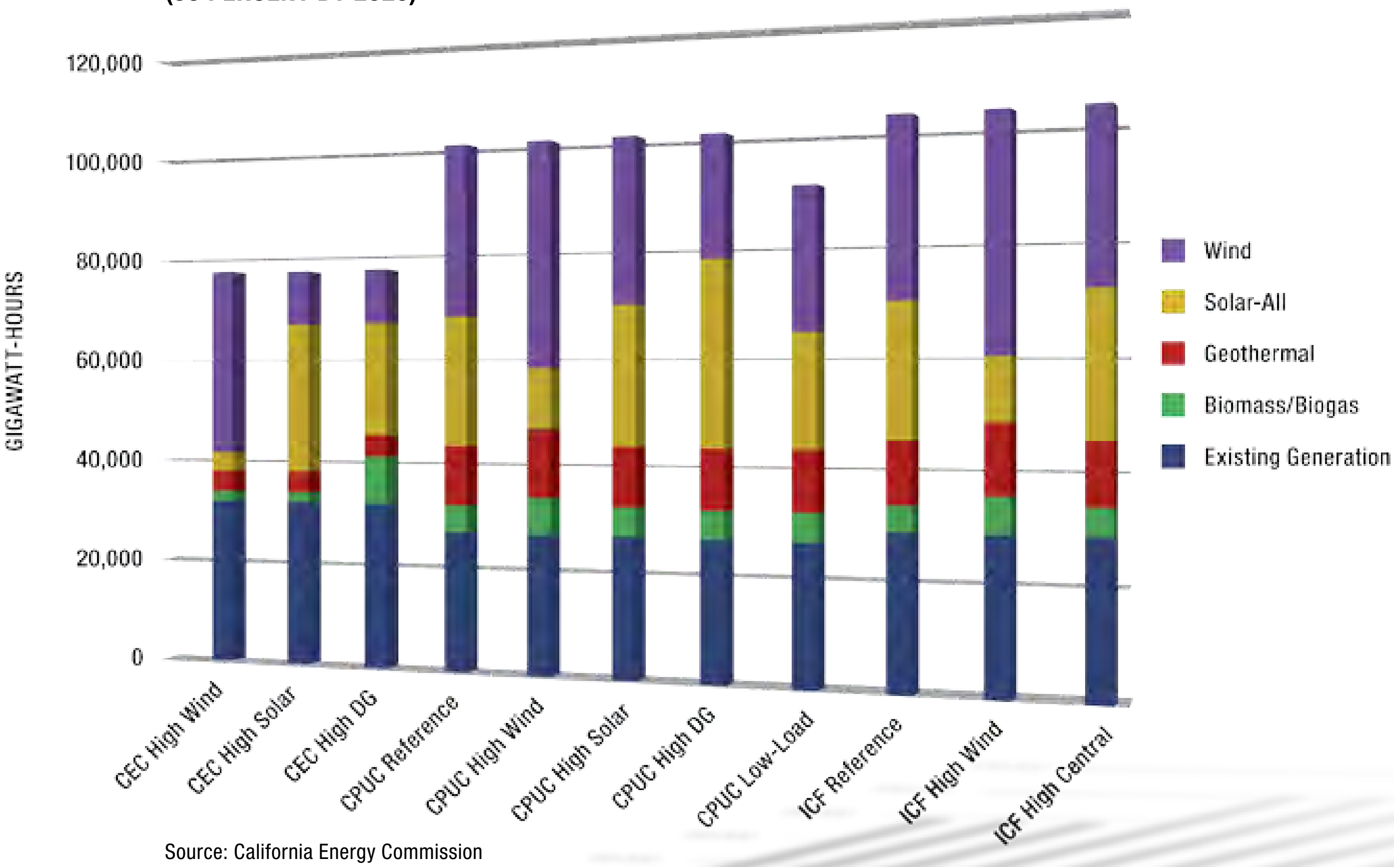
Recent estimates of the 2020 renewable energy net short vary from 45,000 gigawatt hours (GWhs) to almost 75,000 GWhs, depending on forecasted electricity demand along with the amount of expected energy efficiency, CHP, rooftop solar, and existing renewables included in the analysis. Since the RPS target is based on retail sales of electricity, estimates of the renewable net short will change over time as forecasts of electricity demand change. Similarly, meeting the state's targets for energy efficiency, CHP, and rooftop solar will affect the amount of renewable energy ultimately needed.

Needed additions will also depend on how much renewable power is already flowing into the system. Estimates of existing renewable generation vary from 27,000 to 37,000 GWhs, depending on the vintage of the estimate, the amount of out-of-state renewable generation attributed to publicly owned utilities, and the amount of unclaimed renewables (renewable generation not claimed as eligible for the RPS)

227 The challenges of accomplishing this integration are very similar whether the details of the program are defined by statute or by regulation.

228 The Energy Commission study and presentations of the ICF International study are available at: [http://www.energy.ca.gov/2009_energypolicy/documents/index.html#062909]; the California Public Utilities Commission study, underlying calculator, and supporting white papers are available at: [http://www.cpuc.ca.gov/PUC/energy/Renewables/hot/33implementation.htm].

FIGURE 33: COMPARISON OF RECENT SCENARIOS FOR INCREMENTAL AND EXISTING RENEWABLE ENERGY
(33 PERCENT BY 2020)



Source: California Energy Commission

that is included in the estimate.[229] The wide variation between estimates illustrates the need for common assumptions and counting conventions so that the public can be confident in both the targets and reported progress.

Implementing the OTC mitigation policies discussed earlier in the chapter will affect the integration of renewables because it is unclear what characteristics replacement power will have and therefore how it could support renewable integration. OTC units may need to be replaced within the same local capacity area, elsewhere on the grid, or not at all. Replacement plants could be combustion turbines with relatively few hours of operation or new, efficient combined cycle plants that would operate more hours per year than the plants they replace. In addition, the strict regulation of criteria air pollutants in the South Coast Air Basin will restrict the amount of in-basin replacement power, increasing the amount of generation needed from outside the area. The amount of energy imported to meet load in the South Coast Air Basin could be reduced with increased amounts of wholesale distribution-level renewables, although some amount of gas-fired generation or other types of "spinning reserves" may still be needed to

229 The studies discussed at the June 29, 2009, IEPR workshop used the *2007 Net System Power Report* as the basis for their estimates of existing renewables, but varied in the way the data from the report was used. The California Public Utilities Commission had the lowest estimate of existing Renewables Portfolio Standard renewable; the *Renewable Energy Transmission Initiative Phase 1B Report* had the highest estimate.

allow transmission lines to continue to bring in electricity from outside the area.

Expiring coal contracts will also affect California's system mix and the operational attributes replacement plants will need. Coal contributed about 56,000 GWhs of energy in 2008, with more than 11,000 GWhs of coal-fired generation provided through contracts that will expire by 2020.[230]

Reserve margins are also an issue. To ensure system reliability, utilities are required to have a minimum planning reserve margin of 15 to 17 percent. Reserve margins cover uncertainties in load forecasting, forced and planned outages, largest single contingencies and other operational problems. Planners want enough reserves on hand to handle contingencies, but do not want so much extra capacity that ratepayers end up paying for unused generating units or transmission lines. Because resources like wind and solar may produce a large amount of energy at times other than system peak, conventional resources, technology improvement in power plants, or storage may be needed to provide the necessary reserves.

Natural Gas Plants

In designing a future low carbon electricity system, questions have been raised regarding why new natural gas units are needed, if they are needed in specific locales, if they are a help or a hindrance to the development of other preferred resources, and generally what role natural gas will play in the transformed electricity resource mix. The Energy Commission chose to investigate the role of natural gas, both in its function as the siting agency for thermal units over 50 MWs and as part of its integrated resource planning infrastructure for generation, transmission, storage, and pipelines. Natural gas generation has many features that complement rather than compete with variable resources such as wind and solar and is therefore part of the suite of options to help create a low carbon system.

What type of natural gas facilities might be added and when they are needed is complicated. If high levels of energy efficiency are achieved, less overall energy will be needed, though capacity requirements may still be hefty. If combined heat and power units are built instead of central station gas generation, different system attributes will be affected. Finally, policies other than supporting incremental renewables are affecting the type and timing of new natural gas-fired units. These include reducing use of OTC at existing plants, meeting local area capacity requirements, and abiding by the criteria pollutant limits in the SCAQMD.

As part of the multi-agency efforts to understand the impacts of integrating higher levels of renewables into the grid, Energy Commission staff analyzed the potential impacts on natural gas use and generation.[231] The study used a reference case that did not include the ARB *Climate Change Scoping Plan* policies and only assumed that the 20 percent RPS goal was met by 2012 statewide. Staff developed two "bookend" cases that included the *Climate Change Scoping Plan* policies and meeting the 33 percent RPS target by 2020. The two bookend cases included a high solar and a high wind case. Including the demand-

230 Total utility out-of-state coal generation comes from the 2007 self-reported claims from the utilities for the Power Source Disclosure Program. Los Angeles Department of Water and Power claimed around 10,000 GWhs of imported coal generation from the Navajo plant, and California Department of Water Resources contracts around 1,300 GWhs of coal generation from Reid Gardner.

231 California Energy Commission, *Impact of Assembly Bill 32 Scoping Plan Electricity Resource Goals on New Natural Gas-Fired Generation*, June 2009, CEC-200-2009-011, available at: [http://www.energy.ca.gov/2009publications/CEC-200-2009-011/CEC-200-2009-011.PDF].

reducing policies from the *Climate Change Scoping Plan* and reducing the amount of incremental renewables required to reach 33 percent of retail sales added only 45,000 GWhs of incremental renewables compared to the 75,000 GWhs added in studies that did not include the *Climate Change Scoping Plan* measures.

The study found that the potential impacts of adding large amounts of intermittent renewables on natural gas-fired generation were affected by two programs that had significant direct impacts on natural gas use and the type of plants to be built. The *Climate Change Scoping Plan*'s energy savings targets translated into an incremental 4,700 MW of CHP in the staff's model. By 2020, CHP consumed 20 percent of all California's natural gas used for power generation. This amount of CHP reduced electricity sales to end-use customers but did not create a proportional reduction in natural gas use. It also added a large amount of baseload generation to Southern California, where 60 percent of potential host sites for large CHP are located.

OTC policies also affected the potential impacts of intermittent renewables in the model because much of the generation needing retrofit or replacement serves local functions that continue to be supported by generation located in local reliability areas. Of the 15,069 MW of existing OTC units, 964 MW were retained, 1,450 MW have recently been repowered, and 7,758 MW were replaced with new, efficient units. By 2020, depending on the case, between 11 and 23 percent of natural gas-fired generation in California is from power plants associated with the OTC issue. Once CHP targets and OTC replacements were made, only a few new natural gas plants had to be added to meet local capacity and energy needs. Those were in the Sacramento Municipal Utility District, Turlock Irrigation District, and Imperial Valley control areas, which have no OTC and limited numbers of large host industrial or commercial facilities for new CHP. The amount of natural gas units added did not change between the base case and the two bookend cases. This suggests that the CHP additions and those used for OTC policies provided enough gas flexibility so that more units were not needed even in the more intermittent wind cases. But the capacity factors for generic additions and OTC replacement combined cycles, which start out at normal baseload levels, drop much lower by 2020 in the two bookend cases, making the long-run cost-effectiveness of these combined cycles questionable. This suggests that the sample compliance path used in this study was not optimal if the large amount of CHP baseload is added. Baseload energy from "must take" CHP resources reduces the need for energy from combined cycle merchant plants, thus shifting them into a load following pattern of operations, which may not justify the incremental cost of combined cycle versus simple cycle combustion turbines. Thus, a key finding of the study is that none of these policies should be assessed in isolation. To test these conclusions, additional model runs could be done that lower the amount of must-take CHP and switch some of the OTC combined cycles to combustion turbines.[232]

For electricity generation, the Western Electricity Coordinating Council (WECC) systemwide amount of natural gas did decrease by 15 percent in both of the bookend cases. However, the reductions were not distributed evenly, with at least 70 percent of the gas reductions occurring out of state. In-state gas-fired generation decreased by 10 percent in the high wind case and 13 percent in the

232 Subsequent to the June 29, 2009, IEPR workshop, technical staff of the agencies participating in the California Independent System Operator 33 percent renewable integration study developed and agreed to assess a combination of renewable development and demand-side policy initiatives to better understand the interactions between these policies.

TABLE 11: CALIFORNIA USE OF NATURAL GAS IN POWER PLANTS IN BILLION CUBIC FEET PER DAY (BCF/D)

	2012	2016	2020 CHANGE FROM CASE 1
Case 1 Reference Case RPS	2.36	2.57	
Case 2 High Solar	2.34	2.45	-12%
Case 3 High Wind	2.34	2.48	-10%

Source: Energy Commission, Electricity Analysis Office

high solar case. In contrast, out-of-state gas-fired generation dropped 21 and 20 percent, respectively. This suggests that out-of-state natural gas is the marginal resource and that in-state gas is used for local reliability or ancillary services.

The study also found that a resource mix with a high proportion of wind required more in-state natural gas generation than the high solar case. In addition, more impacts were seen in Southern California than in Northern California. While wind is distributed across the state, solar resources are almost completely concentrated in Southern California. OTC units and potential CHP sites are also concentrated in the southern part of the state. This indicates that there may be more system impacts and potential system stressors in the southern transmission grid.

While gas used for serving retail load dropped, total gas use increased. As Table 11 shows, between 2012 and 2020, total natural gas consumption rose slightly in all cases. The increases in the high wind and high solar cases were more modest, but still increased as large amounts of CHP fueled by natural gas were added to the system. Those increases were less in the high solar case than in the high wind case when compared to the reference case.

In contrast to the Energy Commission staff study, a recent study by ICF suggested that 33 percent renewables could lead to an increase of 3,000 MW of gas-fired capacity between 2009 and 2020, but a net decrease of 11,000 GWhs of in-state gas-fired generation. The different result in the two studies was the result of different modeling assumptions; for example, the Energy Commission study included local reserve and area reliability requirements, including publicly owned utility reserve requirements for new gas-fired capacity needed to modernize the OTC fleet. In addition, the

Energy Commission study included 32,000 GWhs of gas-fired CHP, consistent with the target in the ARB's *Climate Change Scoping Plan*, while the ICF study did not add any CHP. Finally, ICF assumed that total natural gas use in the WECC would rise over the forecast period and that California would import more power generated using natural gas, but that the increase in total in-state use would exceed any increase in imports.

The Energy Commission's study results indicate that at least three areas deserve further research because of the affect of study assumptions on the type of proxy generation needed to firm and back up intermittent renewables. First, alternative levels of CHP should be tested, since the addition of base-load power in-state and in Southern California may be difficult to achieve with existing emission credit problems and the lack of a mechanism to make it happen. Second, alternative assumptions about compliance with OTC mitigation requirements should be tested because the interactions of all the *Climate Change Scoping Plan* programs lead to unrealistic capacity factors in the replacement of OTC combined cycles by 2020.

Finally, the possibility of overgeneration, a condition when more generation is provided than there is available load, will require additional analysis. In the June 29, 2009, IEPR Committee workshop on renewable integrating issues, SCE reported that a Nexant study suggests a possible overgeneration problem in April and May as the state moves to 2020 if there is high solar incidence in the desert, high generation of wind, and the need to spill water stored in dams to make room for snow melt. In addition, parties at the July 23, 2009 IEPR workshop on CHP issues noted the risk of overgeneration when large amounts of both renewables and CHP are added to the system mix.

Energy Storage

To the extent that natural gas remains a low-cost fuel, gas-fired generation can help the electricity system absorb the costs of transitioning to higher levels of renewable energy. However, looking forward, some of the firming services provided by gas-fired generation will need to come from existing and emerging energy storage technologies that allow generators and transmission operators to fill the gap between the time of generation (off-peak) and the time of need (on-peak) for intermittent renewable energy. Energy storage systems can respond quickly – in less than a second – to the needs of the electric grid system when compared to conventional gas-fired generation, which takes minutes to tens of minutes, and potentially reduce the overall amount of energy needed to balance the system needs. The fast response of energy storage also suits the variability of renewable energy systems such as wind, and this combination can allow grid operators to use increased levels of renewable energy and still maintain desired levels of reliability and control.

Examples of energy storage technologies commercially available and under development include advanced technology batteries, flywheels, compressed air energy storage, pumped hydroelectric energy storage, capacitors, and others. These technologies can provide value at each level in California's electric grid – generation, transmission and distribution, and end use – with storage technologies varying in type and size depending on the level of service needed. Generation-level energy storage focuses on the ancillary services market[233] and renewable integration, with grid frequency regulation becoming an area of

233 Ancillary services support the transmission of electricity from its generation site to the customer. Services could include load regulation, spinning reserve, nonspinning reserve, replacement reserve and voltage support.

interest of substantial technological advancements over the last few years. Storage at the transmission and distribution level focuses on load shifting, transmission congestion relief, reliability, and capital deferral. For end users, storage at commercial and industrial facilities can provide peak shaving, electricity backup, and increased reliability.

Energy storage continues to be one of the more promising application areas to make renewable generation available when needed. Energy storage technologies will allow better matching of renewable generation with electricity needs as well as address the severe ramping rates observed with wind and PV. The use of energy storage technologies can also reduce the number and amount of natural gas-fired power plants that would otherwise be needed to provide the firming characteristics the system needs to operate reliably. Energy storage systems can respond rapidly to the needs of the electric grid, and Energy Commission research indicates that smaller amounts of energy storage can smoothly and effectively integrate renewable energy when compared to the amount of natural gas-fired power plants required to meet the same response times. California should seize this opportunity and encourage developers to install energy storage to support commercial scale solar and wind farms and reduce the need for new natural gas-fired plants as an energy-firming source.

California can use storage to support renewables in several applications. Storage can provide the ancillary services needed for integrating large amounts of renewables into the system that would otherwise be provided by conventional generating resources. Also, the state can use grid-connected utility-scale energy storage to avoid cutting back on remote wind farm production in response to transmission limits. Another application is to use large-scale energy storage to shift renewable production to times of higher value and demand, which can help address overgeneration by storing excess renewable energy and sending it back to the grid when needed. Finally, fast-response storage can improve electricity system stability and reduce stability and frequency response issues that may occur with high penetrations of renewables.

Research completed by the Energy Commission indicates these utility-scale energy storage systems can provide the grid system a variety of benefits. The energy storage systems can respond rapidly to grid system reliability issues and improve the overall operation of the grid. They can also improve the dispatchability and availability of renewable generation systems by responding to the intermittent nature of wind and solar renewable systems. Additionally, energy storage systems can provide the grid operators ancillary services such as frequency response and spinning reserve. Grid operators need a mixture of many types of generation, demand management, and energy storage capabilities to effectively manage the utility grid. When properly integrated, energy storage and automated demand response can offer critical capabilities currently provided by conventional natural gas generation.

Energy storage is typically measured as a combination of time increments and capacity (in kW or MW) and can range from a few minutes up to many hours. Batteries and flywheel systems are examples of short-duration storage that can compensate when passing clouds block the sun and cause generation to drop substantially in less than a minute and jump back to full generation a few minutes later.[234]

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

The Electric Power Research Institute reports that sodium sulfur batteries and lithium ion batteries can provide frequency regulation to mitigate these kinds of fluctuations in PV generation.[235] In addition, the Energy Commission's Public Interest Energy Research (PIER) program has demonstrated that short-term energy storage systems such as flywheel technology can provide this capability.

The U.S. Department of Energy (DOE) recently provided American Recovery and Reinvestment Act (ARRA) loan guarantees to a PIER frequency demonstration project company, permitting it to construct a 20-MW facility. Other energy storage projects have been proposed to DOE that, if awarded ARRA funding, could result in the construction of several major utility-scale energy storage projects in California over the next few years.

For longer duration storage needs, pumped hydropower uses low-cost off-peak energy to pump water from lower to higher elevation reservoirs, and the water is then released during higher-cost peak times to generate electricity. However, most of the existing water infrastructure that could be used for this purpose must compete with irrigation, flood control, in-stream flow requirements, and other demands placed on the state's water systems. Developing dedicated reservoirs for pumped storage is extremely difficult.[236] Also, under current tariff structures for energy services, there is inadequate support for pumped hydropower systems to cover costs, resulting in only a limited number of operational systems in California. In addition, pumped hydropower has its own set of environmental challenges, which may limit its use going forward.

In IEPR workshops on energy storage and smart grid, stakeholders indicated that paying for these technologies is a significant barrier to increasing the amount of utility-scale energy storage in California. In many cases, energy storage systems provide utility grid services that cannot be recovered within existing rates and tariffs. Stakeholders recommended that the Energy Commission, California ISO, and the CPUC consider new rates and tariff options to permit adequate reimbursement to the energy storage system for all the services it provides to the grid. System cost-effectiveness models can be developed to more accurately reflect the true value energy storage systems provide to the utility grid for renewable integration, system reliability improvements, and ancillary services markets.

To help in this effort, the PIER program is developing system performance models for several energy storage technologies to help identify more revenue sources for energy storage systems. Because energy storage is not considered generation, transmission, or load, new information is needed to properly integrate these technologies into the utility grid system. Once developed and demonstrated, these system performance models can be used to assist the California ISO in integrating them into the ancillary service and other potential markets operated under the new Market Redesign Technology Upgrade grid management system. In addition, the PIER program is developing similar models for the load reduction capabilities provided by automated demand response systems.

California ISO recognizes the important role of energy storage in integrating renewables into the electricity system, and in September 2009, it released an issue paper about nongenerator resources, including energy storage resources, participating in ancillary

235 Transcript of the April 2, 2009, IEPR workshop, EPRI presentation, pp. 27–32, available at: [http://www.energy.ca.gov/2009_energypolicy/documents/2009-04-02_workshop/2009-04-02_TRANSCRIPT.PDF].

236 Examples of trying to create dedicated pumped-storage reservoirs include Lake Elsinor Pumped Storage and the Eagle Crest facilities, both in Southern California.

services markets.[237] The California ISO is also developing an energy storage pilot program to analyze the performance of storage devices and identify and eliminate barriers to increased deployment.[238] This work should be further expanded in time to encourage installation of storage in the 2015 to 2020 time frame as the state ramps up to the 33 percent level of renewable energy.

Other Renewable Technologies

Baseload renewable technologies such as biomass, biogas, and geothermal also will play an important role in reducing the potential need for gas-fired generation to firm up renewable energy.[239] Geothermal facilities currently provide 42 percent of California's renewable energy and generally operate as baseload; however, in combination with storage, geothermal facilities can offer load following or peaking services as well.

Biomass and biogas provide about 20 percent of California's renewable energy, with solid-fuel biomass providing the largest share. Executive Order S-06-06 requires meeting 20 percent of the state's RPS with bioenergy resources. Depending on the availability of fuel, biomass and biogas can provide baseload, load following, or peaking energy products.[240] Biopower could help displace the amount of new gas-fired generation needed to integrate higher levels of renewable energy, but because many of the existing biomass generators are operating at a financial loss under their current contracts, it is unclear whether providing load following or peaking support will be cost-effective for these facilities.

Improved Production Forecasting for Renewables

Another tool used by system operators to help integrate renewables into the system is production forecasting. Much as load forecasters use data analysis techniques to develop short-term load forecasts, system operators use production forecasting tools to anticipate the amount of renewable energy that will be delivered from various resources. Errors in load forecasting reduce the ability of system operators to anticipate the amount of energy needed to meet demand. If the amount of delivered renewable generation is different than the amount forecasted, system operators will need to increase or decrease generation from other sources of energy to make up the difference, which decreases the value of renewables to the system and increases costs.[241]

237 California Independent System Operator, *Issue Paper for Participation of Non-Generator Resources in California Independent System Operator Ancillary Services Markets*, September 1, 2009, available at: [http://www.caiso.com/241c/241cd4af47ca0.pdf].

238 California Independent System Operator, see [http://www.caiso.com/2337/2337f16064bc0.pdf].

239 For example, see comments by ICF, IEPA, and Covanta Energy from the June 29, 2009, IEPR workshop, transcript, pp. 146, 172, and 190.

240 "For solid-fuel biomass facilities, which are unique among renewables in having a significant fraction of their total cost of electricity production in the category of variable operating cost (mostly fuel cost), it might be possible to develop feed-in tariff contracts that have elements of load following that would increase their value to the utility at little or no cost to the biomass generator." Written comments by Green Power Institute, May 28, 2009, IEPR workshop, pp. 9–10, available at: [http://www.energy.ca.gov/2009_energypolicy/documents/2009-05-28_workshop/comments/Green_Power_Institute_TN-51936.PDF].

241 California Energy Commission, *2008 IEPR Update*, p. 21, available at: [http://www.energy.ca.gov/2008publications/CEC-100-2008-008/CEC-100-2008-008-CMF.PDF].

Work at the Energy Commission and the National Renewable Energy Laboratory has led to improvements in the characterization of wind areas for planning purposes. In addition, forecasting day-ahead and hour-ahead generation from wind facilities has improved, due in part to the California ISO's Participating Intermittent Resource Program. A recent study by the North American Electric Reliability Corporation suggested that system operators expand their use of wind forecasting and conduct plant scheduling on intervals shorter than hourly to increase the ability of the electricity system to respond to changes in generation from wind energy resources.[242] Building on this progress, further work is needed to improve the accuracy of five-minute, hourly, and day-ahead forecasts for electricity demand and solar energy.

Less progress has been made in the development of forecasting models for PV and solar thermal electric generation, which still result in large errors. Cloud cover can cause generation from PV systems to drop by 50 percent in a minute or less.[243] More data is needed to improve forecasting of solar energy generation, especially data on variation on the scale of five-minute intervals and minute-to-minute generation from large-scale PV fields. The need for advances in this area is becoming more urgent because of the increasing number of utility-scale PV fields under development and the growing interest in wholesale distributed PV systems. The California ISO plans to add solar to its Participating Intermittent Resource Program later this year.[244]

Beyond the needs of transmission system operators addressed above, real-time web-based wind speed and solar radiation data and forecasts will be needed much more broadly throughout the state's future smart grid as community- and building-based systems are operated to respond to pricing signals and local and building demand. It is unlikely that current deployment of anemometry and radiation sensors will be enough to adequately support the need for accurate real-time local forecasts. PIER has identified and is developing plans to address this long-term need.

Distributed Resources

Although improvements are underway to streamline siting and permitting for transmission and renewable energy facilities, there is a risk that a resource mix depending heavily on utility-scale solar electric projects in remote areas may be delayed beyond 2020. Shifting to a resource mix including both large-scale central station projects and distributed generation (DG) would help the state meet its goal of 33 percent of retail sales from renewable energy by 2020 and lay the foundation for achieving the Governor's Executive Order goal of 80 percent reduction in greenhouse gas emissions from 1990 levels by 2050.

Distributed renewable resources include ground-mounted solar projects up to 20 MW in size; distributed biogas capacity from wastewater processing, landfill gas, animal

242 Center for Energy Efficiency and Renewable Technologies, June 29, 2009, IEPR workshop, transcript pp. 165–166. For further information, see North American Electric Reliability Corporation, *Special Report: Accommodating High Levels of Variable Generation*, April 2009, available at: [http://www.nerc.com/files/IVGTF_Report_041609.pdf].

243 This point was raised by Southern California Edison at the June 29, 2009, IEPR workshop, transcript p. 54. Clean Power Research, *Quantifying PV Power Output Variability*, Thomas E. Hoff and Richard Perez, May 2, 2009, available at: [http://www.cleanpower.com/research/capacityvaluation/QuantifyingPVPowerOutputVariability.pdf].

244 For more information, see the California Independent System Operator Participating Intermittent Resource Program website at: [http://www.caiso.com/docs/2003/01/29/2003012914230517586.html], including California Independent System Operator Participating Intermittent Resource Program Solar Telemetry Requirements, Draft Version 1.2, August 2009, available at: [http://www.caiso.com/2403/2403c293428c0.pdf].

manure digester gas, and food processing; distribution-scale solid fuel biomass; other clean stand-alone technologies; and distribution-level CHP that reduces GHG emissions through the joint production of electricity and energy needed to meet industrial and commercial thermal loads. Renewable projects that interconnect to the grid at the distribution level can come on-line faster than large projects (greater than 20 MW) that interconnect to the transmission system directly. Typically they do not require new transmission investment, extensive environmental reviews, or a lengthy permitting process.

Recent studies indicate substantial technical potential for distribution-level generation resources located at or near load. A 2007 estimate from the Energy Commission suggests that there is roof space for over 60,000 MW of PV capacity, although the study did not factor in roof space that is shaded or being used for another purpose.[245] The California *Renewable Energy Transmission Initiative Phase 1B Final Report* (*RETI Phase 1B Report*) included a preliminary estimate suggesting that as much as 27,500 MW of 20-MW ground-mount PV projects could be located at substations in California.[246] The California Biomass Collaborative estimates that there is technical potential for about 1,700 MW of distributed biogas capacity in California from wastewater processing, landfill gas, animal manure digester gas, and food processing.[247]

Studies by the CPUC and the Energy Commission have included scenarios of high penetration of distributed resources. The CPUC Energy Division Preliminary 33 Percent Implementation Analysis included a scenario with about 14 gigawatt (GW) of PV systems under 20 MW and also included about 250 MW of distributed biogas capacity.[248] Energy Commission staff analysis included a scenario that met one-fifth of the 33 percent goal with biopower, consistent with the Governor's Executive Order S-06-06. This scenario included about 8 GW of distributed solar and about 190 MW of distributed biopower, although this excludes biomass projects identified by the *RETI Phase 1B* report as having fuel to support more than 20 MW of solid-fuel biomass capacity.

Simulations and system analysis have shown that a significant amount of wholesale distributed renewable energy could be integrated into the California distribution grid. A recent analysis by E3 for the CPUC Energy Division found that approximately 69 percent of the California IOU substations can interconnect projects of 10 MW or smaller. Another study by General Electric on the effect of distributed renewable energy on feeder lines found that limits could range from 15 percent to 50 percent of feeder capacity depending on location and distribution. In addition, preliminary staff analysis suggests that about 10 GW to 11 GW

245 California Energy Commission, *California Rooftop Photovoltaic (PV) Resource Assessment and Growth Potential by County*, September 2007, CEC-500-2007-048, available at: [http://www.energy.ca.gov/2007publications/CEC-500-2007-048/CEC-500-2007-048.PDF].

246 RETI Coordinating Committee, *Renewable Energy Transmission Initiative Phase 1B Final Report*, pp. 1–10, 6–23 through 6–25, January 2009, RETI-1000-2008-003-F, available at: [http://www.energy.ca.gov/2008publications/RETI-1000-2008-003/RETI-1000-2008-003-F.PDF].

247 California Biomass Collaborative, *An Assessment of Biomass Resources in California, 2007*, March 2008, available at: [http://biomass.ucdavis.edu/materials/reports%20and%20publications/2008/CBC_Biomass_Resources_2007.pdf].

248 California Public Utilities Commission, *33 Percent Renewables Portfolio Standard, Implementation Analysis, Preliminary Results*, June 2009, available at: [http://www.cpuc.ca.gov/NR/rdonlyres/1865C207-FEB5-43CF-99EB-A212B78467F6/0/33PercentRPSImplementationAnalysisInterimReport.pdf].

of wholesale distributed renewable energy could be connected at the distribution level, at substations, or on distribution feeders.

So far, the potential for distributed resources to contribute to the RPS goals remains largely untapped. As of July 2009, there are more than 560 MW of PV and more than 300 MW of biopower installed in California at the distribution level (20 MW or less per project). While most of the currently installed PV is not eligible for the RPS, much of the biopower is. IOUs have active RPS contracts for more than 180 MW of projects 20 MW and smaller; this is less than 2 percent of IOU RPS contracts. Publicly owned utilities have active RPS contracts for almost 150 MW of projects 20 MW and smaller; this is about 14 percent of publicly owned utility RPS contracts.

Although there is clearly potential for adding large amounts of distributed renewable generation on distribution systems throughout the state, doing so presents significant challenges. Currently, the state's electric distribution systems are not designed to easily accommodate large quantities of randomly installed distributed generation resources at customer sites. Accomplishing this objective efficiently and cost-effectively will require the development of a new transparent distribution planning framework that allows for the active participation of all stakeholders.

Transportation Electrification

Parties have raised the issue of the effect increased electrification of the transportation system may have on electricity demand and therefore the amount of renewable energy needed to meet statewide targets. Even though the demand forecasts adopted in this *2009 IEPR* include some limited amounts of plug-in hybrid electric vehicles and electric vehicle electricity loads, at this time the extent and pace of transportation and industrial electrification is highly speculative. Generally the impacts of a substantial shift in transportation energy usage toward electricity are viewed as beyond the 10-year time horizon that the electricity industry is accustomed to. Stretching planning and analysis efforts out to 20 years and beyond seems necessary, and initial efforts to do so have begun; however, it is less clear how to make decisions about time periods 10 to 20 years into the future.

Issues Affecting Transmission and Distribution

As the population grows and electricity supply portfolios change, new transmission facilities will be needed to maintain system reliability and deliver electricity – including increasing amounts of renewable energy – to consumers. Conceptual planning identifies such potential transmission facilities for detailed study. Power flow modeling and production cost simulations performed by the California ISO and electric utilities then determine which projects are necessary for reliability and make economic sense and how they must be configured electrically. An implementation plan is developed only after such detailed study and only after land use and environmental implications have been fully considered for specific transmission routes.

The *2009 Draft Strategic Transmission Investment Plan* released in September 2009 provides a detailed discussion of initiatives, trends, and drivers affecting California's transmission system and planning efforts, which are briefly summarized here. First among these is RETI. In August 2009, RETI released its Phase 2A conceptual transmission plan. Phase 3 of the project will focus on developing detailed plans of service for high-priority components of the statewide transmission plan.

The RETI conceptual transmission plan identifies additional transmission capacity necessary to access and deliver renewable energy to meet the state renewable energy goals in 2020, and evaluates the relative usefulness of potential lines for accessing renewable energy. The plan identifies potential transmission network lines for further detailed study by the California ISO and electric utilities. Finally, the plan builds in environmental considerations and high level screening of conceptual transmission lines and incorporates a wide range of stakeholder perspectives.

The second issue affecting transmission planning is Governor Schwarzenegger's Executive Order S-14-08, which established an RPS target for California that directs all retail sellers of electricity to serve 33 percent of their load with renewable energy by 2020.[249] The order directs state government agencies "to take all appropriate actions to implement this target in all regulatory proceedings, including siting, permitting, and procurement for renewable energy power plants and transmission lines." Activities to implement the provisions of the Executive Order are being closely coordinated with RETI and with the Bureau of Land Management's Department of Energy Solar Programmatic Environmental Impact Statement (Solar PEIS).

The Solar PEIS is the result of requirements in the Energy Policy Act of 2005 for the Secretary of the Interior to plan for installing at least 10,000 MW of renewable generation capacity on public lands in six western states. In 2008, the BLM and the U.S. Department of Energy announced they were preparing a Solar PEIS to cover development of large-scale, grid-connected solar electric facilities in Arizona, California, Colorado, Nevada, New Mexico, and Utah. The Energy Commission is a cooperating agency for the Solar PEIS. The purpose of the Solar PEIS is not to eliminate the need for site-specific environmental review, but instead to identify best management practices and environmental mitigation strategies that proposed projects should follow. The Solar PEIS will also consider whether new transmission corridors are needed on land managed by the Bureau of Land Management to interconnect solar electric facilities to the grid.

Another effort that will affect transmission is the CPUC's proceeding to consider issues related to the development of transmission infrastructure to provide access to renewable energy resources for California.[250] In February 2009, the CPUC held a prehearing conference and staff workshop to consider whether the output of the statewide RETI could be used to support cost recovery for transmission planning and the CPUC's standards for determining need within the transmission permitting process. In its comments, the California ISO noted that competitive renewable energy zones (CREZs) have been identified by RETI and may provide a basis for certification. The California ISO and other parties also addressed 1) the use of RETI results in the California ISO long-term transmission planning process; 2) whether a rebuttable presumption of need should be afforded to renewable transmission projects studied and approved by the California ISO; and 3) how project development costs

249 Office of the Governor, Executive Order S-14-08, November 17, 2008, available at: [http://gov.ca.gov/executive-order/11072/].

250 California Public Utilities Commission, Order Instituting Rulemaking on the Commission's Own Motion to actively promote the development of transmission infrastructure to provide access to renewable energy resources for California, March 2008, available at: [http://docs.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/80268.htm].

can be recovered by project proponents. The CPUC has not yet issued a proposed decision or subsequent notice.

The California Transmission Planning Group (CTPG), composed of electric utilities and the California ISO,[251] is working toward finding transmission solutions for meeting California's environmental, reliability, economic, and other policy objectives. The group plans to produce its draft 2009 Study Plan in December 2009, with a final report expected in January 2010.

California's transmission infrastructure is an intrinsic component of the high-voltage Western Interconnection, making the state both an essential participant and a partner in several regional and federal planning and permitting initiatives that will alter the way transmission planning and permitting take place in the future.

Expected provision of new federal funding in 2010 for regional transmission planning will result in interconnection-wide 10-year and 20-year transmission plans for the WECC. These plans may identify projects and/or corridors that are needed, and these will become candidates for Federal Energy Regulatory Commission (FERC) ratemaking and possibly other federal incentives. It is critical that California engage in defining what these plans are and ensuring that they reflect California's policies and assumptions accurately. Concerns include:

- If advocates of federal legislation that would establish new FERC authority for siting and cost allocation succeed in passing a bill in 2009–2010, the pressure to site a new interstate line or lines will increase, with associated controversy over siting processes and impacts on environmental resources, both in and out of state. If FERC mandates a cost allocation method, California could be required to pay for projects not consistent with RETI, RPS goals, and carbon reduction policies.

- In addition, transmission system upgrades and additions anywhere in the Western Interconnection will affect the operation of existing lines, including those owned by California utilities and private companies. Proactively participating in WECC analyses of new lines and path ratings is critical to ensure continued high performance levels of key paths such as the California-Oregon Intertie.

- With federal funding, western sub-regional transmission planning groups are taking on enhanced planning roles, including preparation of an integrated 10-year subregional transmission plan. Successful development and engagement of the CTPG and participation of the California ISO are essential to find consensus on projects and analyses reflective of California interests.

- Greatly increased federal funding for the Western Governors' Association Western Renewable Energy Zone Phase 3 and 4 projects (described below) will continue to promote geographically constrained low-carbon resources and large-scale transmission to move remote resources to distant loads. If California policy prefers to procure more resources locally, as reflected in RETI, conflict among states seeking to export and in-state development interests will emerge.

251 The California Independent System Operator, California Municipal Utilities Association, Imperial Irrigation District, City of Los Angeles Department of Water and Power, Pacific Gas and Electric Company, Southern California Edison Company, San Diego Gas & Electric Company, and the Transmission Agency of Northern California.

- Major project developers continue the trend of pursuing large transmission projects to deliver power to coastal and desert load centers. Significant resources are being spent to evaluate feasibility and siting for these projects. California needs to be involved in these efforts to provide feedback to project developers on whether these projects are needed or desirable for the state.

Role of the California Smart Grid

The Energy Commission's PIER program is completing research, development, and demonstration (RD&D) efforts to help bring to market new and innovative solutions to the issues facing the California transmission system and the challenges caused by the integration of more renewables into the utility grid system. In addition to research on energy storage, automated demand response, distributed generation, CHP, and improved renewable technologies, the PIER program is leading a very aggressive effort to encourage the implementation of the California smart grid of the future, which will be driven by existing and future energy policies being implemented in California. Some of the current key policies are:

- A 33 percent Renewables Portfolio Standard by 2020.

- Implementing advanced metering infrastructure by the IOUs for residential customers. Current plans by the CPUC include the installation by the of more than 12 million "smart meters" in the next two to five years.

- Implementation of 100 percent of the cost effective energy efficiency by 2016.

- Demand response implementation goals.
- AB 32 GHG emission reductions goals.

In addition to these specific state policies, other technology improvements are rapidly progressing in California, the nation, and the world. Some of these are:

- Substantial increase in the number of electric vehicles and plug-in-hybrid electric vehicles projected over the next decade.
- Commercial growth of home area network technologies in California residences.
- Field implementation of a wide range of two-way communications technologies.
- Automation of demand response (ADR) and implementation of a common OpenADR standard in California.
- Field implementation of high speed synchrophasor data collection and reporting systems.
- Advancements in the automated management of the utility distribution system.
- Increased emphasis on the need for new cyber security capabilities.

The California smart grid will take advantage of these and many more technologies and capabilities as the smart grid system is fully implemented over the next decade. The national smart grid effort is being driven by the requirements in the Energy Independence and Security Act of 2007 and the efforts of DOE to implement a national smart grid. One key driver for the rapid expansion of these technologies is the amount of ARRA funding for smart grid. The DOE is expected to fund more than $4 billion in smart grid projects nationally over the next 12 to 14 months, representing more than 10 times the normal rate of investments this area has seen in the past. California could easily receive $400 to $600 million in smart grid funding from DOE. Because projects require 50 percent match funding by the utilities and commercial companies requesting these funds, California could have more than $1 billion in smart grid projects over the next few years. This level of funding in California and the high level of national smart grid project funding will result in the very rapid growth of smart grid technologies and capabilities.

The implementation of the smart grid in California is expected to provide new opportunities to meet current and future energy policy goals such as:

- Utility system data reporting capabilities based on synchrophasor technology, advanced metering infrastructure, distribution automation, and new home area network technologies. These systems are expected to allow the utilities and California ISO to more rapidly recognize and analyze system problems, develop possible solutions, and repair or recover grid problem areas more quickly than with the current grid system. Consumers can expect the smart grid of the future to have fewer failures and faults, more rapid recoveries when problems do occur, and more efficient and cost-effective operation.
- The smart grid will provide new methods and technologies to implement energy efficiency and demand response capabilities in the future. The new data collection capabilities, increased two-way communication, smarter consumers, and wide range of energy savings tools and products will allow consumers to make much smarter individual energy management decisions.

- The smart grid will provide expanded abilities to integrate higher penetrations of renewable technologies. The management of energy storage, distributed generation, automated demand response, distribution level renewables and other capabilities will allow the grid to accept much higher amounts of renewables while maintaining high levels of reliability and controllability.

- The smart grid will allow high numbers of electric vehicles and plug-in hybrid electric vehicles on the roads and, with smart charging systems, permit these vehicles to operate effectively without causing major disruptions on the utility grid. Some electric or plug-in hybrid vehicles could actually be used as grid assets and provide ancillary services for grid operators when parked in facilities where commercial energy service providers can aggregate their loads into one single energy response system.

- The smart grid will provide better tracking of GHG emissions and will help California meet future emission goals by increasing the use of renewables, energy efficiency, and electric vehicles and by reducing the number of power plants needed to support the grid by using demand response and energy storage as alternative sources of energy for the grid management.

The *2007 IEPR* dedicated a chapter to California's electric distribution system. The information covered and recommendations provided are still relevant and are not repeated in the *2009 IEPR*. The smart grid is expected to provide new opportunities to address the issues facing the distribution system and can help with areas such as upgrading distribution system reliability, integrating higher levels of distributed generation, and allowing a higher penetration of distribution level renewables on the California grid system.

Senate Bill 17 (Padilla, Chapter 327, Statutes of 2009) requires the IOUs to develop and submit a smart grid deployment plan to the CPUC for approval by July 1, 2011. The Energy Commission will work actively with the CPUC and the California ISO to help develop these smart grid deployment requirements and ensure that the issues and concerns of state utilities, both publicly and investor-owned, are considered when developing the statewide requirements.

Role of Research and Development

One expected challenge for the smart grid is to address the interaction of rapid deployment of new technologies while ensuring the California smart grid is interoperable both within the state and with other national systems. The PIER program is actively working with other state agencies, industry, and the academic community to identify key standards, protocols, and reference designs that will help ensure that the smart grid operates smoothly. The smart grid standards being implemented nationally will provide significant guidance in this area, but it is expected that California may lead the nation in the implementation of a smart grid and therefore will need to make some initial decisions to ensure the state has the interoperability and commonality needed in the future.

Another area where additional RD&D efforts are needed is renewable energy secure communities. Community-based energy systems are attracting investment, policy attention, and public support nationally and around the world, as community leaders respond to public interest in climate change, sustainable growth, job creation, reducing energy imports, and managing the economic impacts of fossil fuel price escalation and volatility. California is providing leadership in RD&D to identify technical solutions communities can use to optimize their energy supply and integrate building and community-scale energy sources with energy efficiency solutions and programs and smart grid capabilities. The Energy Commission held a solicitation for renewable energy secure community technical integration projects resulting in 50 proposals. The DOE has followed suit with its own solicitation on this topic, and other states and countries are exploring policy mechanisms that allow communities to actively participate in the development of the best energy investment strategy for their individual community.

For utility-scale renewables, additional RD&D is needed on integration challenges with solar energy, since it now appears that solar will play a larger role than originally assumed when the Energy Commission completed its Intermittency Analysis Project. The Energy Commission's PIER program should define and complete a study that builds on previous utility-scale renewable energy integration studies.

PIER has adjusted the emphasis of its renewable energy RD&D investments to better address technical integration issues and solutions related to RPS implementation as well as the need for technical solutions enabling community- and building-scale renewable energy deployment. In addition, the Energy Commission is providing seed funding to the California Renewable Energy Collaboration for development of an integrated renewable energy systems program. When fully funded, the program will conduct and coordinate cutting-edge studies addressing the major technical, economic, and policy questions facing the state as it deploys additional renewable energy supply throughout its electricity and energy end-use infrastructure.

Further research is also needed to understand what parts of the distribution system can best tolerate renewable generation and what role wholesale renewable distributed energy can play in providing local reliability. Research should also focus on the interaction of energy policies affecting the distribution grid, including on-site renewable generation, distributed energy storage, electrification of vehicles, energy efficiency, demand response, and zero net energy homes and buildings. For example, distribution lines may need to be reinforced with technology that can meet demand when on-site distributed renewable energy is not generating electricity. At the same time, upgrades, storage, or other resources may be needed to accommodate two-way flows from intermittent renewable power that is not dispatchable and is placed where it is convenient to the customer, but not to the grid.

Research should also focus on the technical feasibility of adding large amounts of wholesale distributed renewable energy to help the state meet 33 percent of retail sales with renewable energy by 2020, including review of the logistics of upgrading distribution grid infrastructure to meet this timeline. Better understanding of the amount of wholesale distributed renewable energy that is technically feasible by 2020 can help guide studies of market designs supporting smart grid communities, such as feed-in tariffs for CHP and renewable energy.

In addition, integrating increased quantities of distributed generation will require California's energy agencies to work together to develop a comprehensive understanding of the importance of distribution system upgrades not just to assure reliability but also to support the cost-effective integration and interoperability of large amounts of distributed energy for both on-site use and wholesale export. Utilities will need to assess where on their systems distributed generation, both for on-site use and for export to the grid, would be of the greatest value and provide that information to the energy agencies. These studies should identify which operational characteristics have the highest value; what tools, data, and criteria are used to select these locations; and what obstacles exist to deploying specific types of distributed generation.

Infrastructure Investment

The hybrid electricity market established through AB 1890 (Brulte *et al.*, Chapter 854, Statutes of 1996) created multiple entities that invest in and operate specific facilities that are part of the overall electricity infrastructure in California. Merchant generation has a strong position in California. IOUs and various forms of publicly owned utilities continue to dominate the distribution and transmission elements of the electric grid, but even here niche participants have appeared. The Trans Bay Cable from Pittsburg to San Francisco is a good example of a transmission investment made by a public-private partnership. The large and growing number of distributed generation facilities satisfying end-user load, but exporting some of their production to the grid, represents an alternative type of investor. Each of these categories of investor makes decisions about securing capital and constructing facilities using different financial perspectives, accounting rules, tax liabilities, and risk mitigation preferences. Explicit legislation and regulatory agency decisions must guide these investors to make decisions compatible with the vision that the state has for the electricity grid.

Forward Energy or Capacity Markets

In the California ISO balancing authority area, the California ISO and the CPUC have established a one-year ahead forward capacity requirement for all load-serving entities under their various jurisdictions. By establishing a capacity requirement to satisfy reliability needs, a distinct value for capacity will emerge that covers a substantial portion of the investment in a power plant, and the needs for energy will be satisfied through less regulated market decisions. For several years the CPUC has been investigating whether this structure is adequate to provide signals to a competitive industry that additional generation is needed. Advocates of both a central capacity market and a bilateral forward market have put forward the merits of their proposals. At the July 28, 2009, IEPR workshop on OTC issues and in comments following, several generators urged consideration of their forward capacity market construct submitted to the CPUC. They asserted that this would be the best mechanism to surface replacement generation proposals.

On November 3, 2009, the CPUC issued a proposed decision in R.05-12-013 that endorses a multi-year forward extension of the current bilateral contract form of capacity obligation. By this means, the CPUC hopes to both identify future electricity system requirements and induce load-serving entities to contract with existing and new generation to satisfy such obligations. In addition, the proposed decision highlights the need for a standardized capacity product and an electronic bulletin board that would facilitate trading of capacity resources as load migration among load-serving entities shifts responsibility for future obligations.

The proposed decision notes that the existing one-year ahead resource adequacy process makes use of the capabilities of the Energy Commission and California ISO in developing the planning assumptions and suggests that continuation of such a coordinated planning process would utilize the expertise of the energy agencies. The Energy Commission supports this approach regardless of the final decision and will work with other agencies to support a forward capacity mechanism.

Forward Generation Investment by Publicly Owned Utilities

The Energy Commission is required by AB 380 (Nuñez, Chapter 367, Statutes of 2005) to oversee the resource adequacy efforts of all publicly owned utilities in California. The legislature has authorized a limited "review and report" form of oversight, which allows the Energy Commission to collect information from these utilities and biennially report results of its review as an adjunct to the *IEPR*. Energy Commission staff collected such information during 2009 and presented its results at a workshop on August 6, 2009.[252]

Collectively, and almost without exception, publicly owned utilities are resource adequate several years into the future. As integrated utilities responsible to oversight boards, the various publicly owned utilities have incentives to acquire resources to cover expected loads. As discussed elsewhere in this report concerning the various elements of demand-side or supply-side resource choice, publicly owned utilities have traditionally emphasized low cost options. As a consequence, their collective exposure to out-of-state coal, either through fractional ownership shares or wholly owned facilities, is now at odds with state policy to reduce GHG emissions. As state policy emphasizing preferred resource additions becomes more directly applicable to publicly owned utilities, a shift in resource mix is expected requiring publicly owned utilities to commit to long-term contracts or invest directly in such resources. This will increase total investment or credit requirements.

Investment in Transmission and Distribution

Utilities are expected to make sizeable investments in additional transmission infrastructure, both to facilitate use of remote renewables in satisfying load concentrated in urban centers and to upgrade transmission facilities within these urban centers to reduce local capacity requirements. At the July 28, 2009, IEPR workshop on OTC, SCE strongly cautioned that long lead-time transmission investments could be rendered not useful and thus not recoverable if short lead-time generation investments substituted for transmission at the last moment.[253] It appears that SCE wanted to communicate the message that the OTC replacement infrastructure proposal made jointly by the energy agencies to SWRCB should be followed through fully all the way to the final ratemaking actions by the CPUC.

The *2009 Strategic Transmission Investment Plan* provides an in-depth review of near-term and longer term issues associated with transmission needed to achieve renewable development. However, as noted in this chapter, there are still many uncertainties affecting the

252 The transcript and presentations from the August 6, 2009, IEPR workshop are available at: [http://www.energy.ca.gov/2009_energypolicy/documents/index.html#080609].

253 Comment by Pat Arons, Southern California Edison, at the July 28, 2009, IEPR workshop.

transmission needed to support this renewable development. Among these are:

- The amount of renewable development that will be required to satisfy an RPS formula of 33 percent of retail sales by 2020 given various demand-side policy preferences.

- Whether, and to what extent, out-of-state renewables will be eligible to contribute toward RPS goals.

- What mix of renewable resource types, especially wind versus solar, is likely to emerge since the transmission lines and routing are largely different among various development scenarios.

Fortunately, the transmission revenue requirement issues associated with FERC treatment of transmission to support state energy policy goals seems to have been resolved. On January 25, 2007, the California ISO filed a petition with FERC for a declaratory order seeking conceptual approval of a new financing mechanism to aid the construction of interconnection facilities for location-constrained resources (primarily remotely located renewables). On April 19, 2007, FERC granted the California ISO's petition and accepted the design concepts proposed therein, thus paving the way for the California ISO to file tariff language implementing this initiative. The California ISO filed a tariff amendment for the Location Constrained Resource Interconnection on October 31, 2007. FERC approved the amendment on December 21, 2007.

The rollout of smart meters by IOUs and some publicly owned utilities and related smart grid technologies will also require substantial investments.[254] While the infrastructure itself will be deployed by utilities (or commercial entities under long-run contract to utilities), once the system is in place end-use customers will need to make investment themselves to make full use of some of the new capabilities.

End-Use Customer Investments

Pursuing energy efficiency, customer-side-of-the-meter distributed generation, and demand response as preferred resources substituting for conventional generating facilities places substantial investment requirements on end-use customers. Customers are asked to make investments that will reduce expected energy purchase costs, hopefully saving money in the long run. The turmoil in credit markets stemming from the housing crisis of 2008–2009 and its spillover into the stock market and tightening of all forms of lending bodes ill for expectations that end users can easily provide the investment capital required. Early monitoring data from 2009 IOU energy efficiency programs suggest that IOUs are not making the energy savings goals established for them by the CPUC and that customers are simply not as willing to make the required investment despite the incentives provided through IOU programs authorized by the CPUC.[255]

The energy agencies need to carefully review policies that depend upon consumer investments and determine whether new forms of assistance are required, how this might be provided, and what coordination among other

254 On October 27, 2009, the U.S. Department of Energy announced that the Sacramento Municipal Utility District will be awarded about $135 million to install a smart metering system for all end-use customers.

255 IOUs provide monthly and quarterly reports to the CPUC providing data on customer installations. In the reports through June 2009, Pacific Gas and Electric was installing only one-half the measures achieved in the comparable period of 2008, while Southern California Edison and San Diego Gas & Electric were matching the prior year's successes. See *California Energy Demand 2010–2020 Adopted Forecast*, CEC-200-2009-012-CMF, available at: [http://www.energy.ca.gov/2009publications/CEC-200-2009-012/CEC-200-2009-012-CMF.PDF].

state and local institutions is appropriate. If end-use customers cannot uphold expectations implicit in current demand-side program goals, then either programs need to be redesigned to increase incentives or program goals need to be scaled back in the near term or long term.

Integrating Policy and Planning

This chapter has outlined the numerous challenges that California faces in integrating the many overlapping and often conflicting energy policy goals related to the electricity sector. First there is the overarching goal of reducing GHG emissions from the electricity sector, through strategies such as achieving all cost-effective energy efficiency and demand response measures, meeting the state's RPS goals of 33 percent by 2020, adding 3,000 MW of solar through the California Solar Initiative by the end of 2016, and increasing CHP by 4,000 MW. Next are other environmental goals like retiring or repowering plants that use OTC to reduce the impacts of electricity generation on marine life, reducing the impacts of siting solar plants in the California desert, and improving air quality in nonattainment areas of the state such as Southern California. OTC mitigation is likely to reduce the amount of flexible fossil resources available to integrate renewables, so newly constructed power plants will be needed to support such integration. But air quality regulations strongly penalize new power plants compared to the continued operation of existing power plants, so licensing the amounts of new fossil generation needed for renewable integration will be extremely difficult in some regions of the state. Another potential area of conflict is the need for new transmission lines to access remote renewable resources that may have land use, environmental, visual, or cost impacts. Finally, there is the long-standing policy to reduce the state's dependence on natural gas and natural gas imports, as well as the Energy Commission's mandate to develop energy policies that ensure electricity reliability, sufficiency, affordability, and public health and safety.

In the California ISO balancing authority area, formal resource adequacy requirements established by both the CPUC and California ISO provide a framework for evaluating reliability. However, the need for dispatchable power plants in specific locations to support the California ISO's local reliability needs remains analytically opaque and there is, as yet, no mechanism to ensure that the needed resources will be built. As the recent joint energy agency proposal to SWRCB concerning development of OTC replacement infrastructure makes clear, all these entities support reliability goals, but converting that common policy sentiment into concrete action steps resulting in operational power plants and transmission lines remains a challenge.

These GHG reduction, environmental protection, and reliability goals must be integrated so that the state can set priorities and better understand tradeoffs when goals are in direct conflict. Policy makers need to understand the interactions between goals and make decisions that reconcile or prioritize these goals. Planning processes must consider how realistic policy goals and their target dates are and whether they will be achieved in full and on schedule and if not, plan accordingly. This could lead to more resources than are actually needed, which could be preferable to supply shortages that reduce system reliability or to resorting to expensive emergency actions in an attempt to "catch up."

At the same time, energy agency planning, procurement, and permitting decisions must consider technological, financial, and environmental constraints. On the engineering side, dispatchable power plants are needed to meet hourly, daily, and seasonal fluctuations in electricity demand and supply that can result from changes in weather, hydroelectric or natural gas supplies, variable renewable generation, planned outages for maintenance, or equipment failure. System operators also have to account for adequate electricity resources in specific areas of the state, known as load pockets, so that transmission limitations into and out of those areas do not lead to operational problems or even outages. Also, transmission and generation are sometimes complementary, such as when transmission additions are needed to allow the development of remote renewable resources, and sometimes substitutes, as when transmission upgrades allow the retirement of certain power plants that provide local reliability functions in load pockets.

On the financial side, both electric utilities and private developers make decisions based on reasonable expectations of profits, which will affect how much investment in new infrastructure will be made at any one time. It is also a reality that all of California's preferred resources (energy efficiency, demand response, renewables, and distributed generation) have costs as well as benefits, and those costs must be taken into account when making decisions about policy tradeoffs. Further, since the state's overall industry structure is dependent upon private entities responding to state energy plans to motivate their investments, the state energy agencies need to provide clear and convincing messages about the type and timing of investments.

Planning in the Electricity Sector

There are numerous agencies within California involved in electricity planning. The Energy Commission, CPUC, and California ISO each conduct electricity planning processes that provide general guidance on policies and specific guidance on a limited range of electricity topics unique to the responsibilities of each agency. Some degree of coordination already exists, but more will be necessary going forward. For example, the Energy Commission forecasts statewide electricity demand in its biennial *IEPR*, while the CPUC oversees investor-owned utility procurement of the resources needed to meet that demand. The California ISO analyzes and approves plans for the transmission needed to reliably bring those resources to customers and uses the Energy Commission demand forecasts in such analyses. However, while portions of the California ISO's analyses rely upon Energy Commission studies, other parts are less well-coordinated with state energy policy goals. In addition, publicly owned utilities conduct their own planning and procurement processes to meet resource needs in their service territories. Overlaying these planning processes, the ARB identifies strategies for achieving emission reductions in the electricity sector needed to help the state meet its GHG emission reduction goals.

State and regional environmental agency processes can also have a major effect on the electricity sector. For example, the SWRCB implements federal Clean Water Act provisions related to the use of ocean water in power plants, with the authority to approve and set conditions for permits without which those plants cannot operate. Withdrawing such permits can shut down an existing power plant, something that none of the energy agencies has authority to do. Another example is the

SCAQMD, which determines which power plants get air credits. As noted earlier, current legal issues surrounding those credits have created a temporary moratorium on power plant licensing in the Los Angeles Basin.

On the transmission side, IOUs and publicly owned utilities plan for their own service territories. IOUs submit their planning considerations to the California ISO annual transmission planning process, while publicly owned utilities submit their future transmission priorities to the Energy Commission as part of the development of the *Strategic Transmission Investment Plan*.

The California ISO's annual plan addresses only the California ISO-controlled grid and is limited to electrical system planning requirements, so land use and environmental considerations are not included. The annual plan captures a 10-year time horizon and does not assess needs well into the future for a longer term view. The plan establishes the need for new transmission infrastructure proposals for IOUs who in turn seek permits for those facilities at the CPUC.

The Energy Commission is involved in transmission through the development and adoption of the *Strategic Transmission Investment Plan* as part of the requirements of the biennial *IEPR* to assess all aspects of energy supply, which includes transmission. The plan identifies and recommends actions needed to implement transmission investments needed for reliability, congestion relief, and future load growth. The plan also describes transmission challenges and provides recommendations to address those challenges and also identifies high priority transmission projects that are then integrated into the California ISO's annual transmission plans.

Lastly, the informal RETI process is influencing formal transmission planning. The RETI effort undertaken by stakeholders obviously brings together renewable generation development with the transmission lines needed to gather such power and move it to load centers. The electric utilities, the California ISO, and the Energy Commission have all committed to consider RETI results in their transmission planning processes. Because the RETI process only addresses the interconnection of renewable energy, it will not result in a complete and detailed California transmission plan of service. However, it is a first step toward a detailed statewide transmission plan because it articulates the requirements associated with connecting renewable resources to the transmission system, which is the most important and difficult requirement for future transmission infrastructure in California. More importantly, it balances electric considerations with land use and environmental considerations in a stakeholder process to create broad support for new infrastructure needs.

All of these complementary and often overlapping electricity and transmission planning processes are only loosely coordinated among the many agencies involved. The CPUC's biennial LTPP proceeding uses information developed in the Energy Commission's *IEPR* to provide procurement guidance to the IOUs, and the CPUC's Energy Division staff has proposed expanding the scope of the LTPP to address "system requirements" rather than just IOU-bundled customer needs. If accepted as proposed, this "straw proposal" would be implemented during 2010–2011. The California ISO conducts an annual transmission planning process to evaluate both conceptual transmission developments and specific project proposals, and its study of local reliability is used to determine local capacity requirements for both CPUC-jurisdictional load-serving entities and those publicly owned utilities governed by the California ISO's resource adequacy tariff. These key elements guide requirements for transmission owners and load-serving entities today.

Publicly owned utilities have their own processes that are even more loosely connected.

Despite periodic efforts to coordinate these processes, the dynamics of independent institutions mean that only partial coordination has been sustained through time.

There have been some efforts to integrate the various statewide electricity planning processes. Senate Bill 1389 (Bowen and Sher, Chapter 568, Statutes of 2002) completely revised the electricity and natural gas planning responsibilities of the Energy Commission. It established the biennial *IEPR* and directed the Energy Commission to consider the input of nine named state agencies in developing its assessments. It also requires these nine agencies to use *IEPR* information and analyses in carrying out their own energy-related activities. The CPUC then established a biennial LTPP process conducted in even-numbered years to follow immediately upon the Energy Commission's *IEPR*. In a process known as integrated planning and procurement mechanism, the Energy Commission, CPUC, and California ISO negotiated how their respective planning and procurement activities would dovetail. By fall 2004, detailed flowcharts and narrative descriptions of process integration had achieved some degree of success. However, this process terminated by spring 2005 without reaching a formal agreement.

In decisions in 2004 and 2005, the CPUC directed that the *2005 IEPR* demand forecast be used as the basis for the 2006 LTPP proceeding and that the *2005 IEPR* policy recommendations be considered in the forthcoming CPUC LTPP rulemaking. The Energy Commission provided the CPUC with a special transmittal report containing the electricity demand forecast, net short results, and policy recommendations from the *2005 IEPR*. Despite opposition from IOUs and delays that deferred conclusion beyond the expected time frame, the CPUC issued a decision in the 2006 LTPP rulemaking to use the *2005 IEPR* demand forecast and accept the spirit of the aging power plant retirement policy established in the *2005 IEPR*. This process was not repeated for the *2007 IEPR* and the 2008 LTPP proceeding because the CPUC decided to devote the 2008 LTPP proceeding to reviewing and upgrading the methods used in LTPP portfolio analyses and other elements of the planning process that would then be used in the 2010 LTPP proceeding.

The next opportunity for coordination between the Energy Commission's *IEPR* and the CPUCs LTPP proceeding is the *2009 IEPR* and the 2010 LTPP. The CPUC has clearly stated its intention to use the demand forecast adopted in the *2009 IEPR*. Further, the CPUC has determined that it will use the Energy Commission's analysis of the incremental impacts of uncommitted energy efficiency projections as the source of modifications to the Energy Commission's baseline load forecast. These adjustments result from calculating the additional energy efficiency previously established within the CPUC energy efficiency goal setting process that should be used to adjust the baseline forecast. The 2009 IEPR proceeding has agreed to provide such a product to the CPUC consistent with the CPUC's required schedule.

Although the discussions regarding coordination between the three energy agencies broke down in spring 2005, continuing discussions with the California ISO regarding coordinated planning resulted in proposals that the California ISO use the Energy Commission's long-term demand forecast as the basis for transmission planning. Since that time, the California ISO has used the *IEPR* demand forecast as the basis for its transmission planning studies and requires participating transmission owners to do the same. However, Energy Commission staff is unaware whether the California ISO modifies the baseline demand forecasts to reflect potential decreases in electricity demand as a result of the goals in the ARB's *Climate Change Scoping Plan* for increased energy efficiency and use of distributed generation resources. The California ISO also uses Energy Commission short-term demand forecasts in developing one-year-ahead local resource adequacy requirements, which the CPUC reviews and adopts each year as part of its resource adequacy requirements.

Statewide collaboration with regard to formal transmission planning does not exist and remains elusive. In the final analysis, transmission plans developed by formal transmission planning organizations in California are disjointed and uncoordinated and do not adequately address future transmission infrastructure requirements on a statewide basis. There is no single transmission planning process that addresses the state's complete transmission system or grid, even though all elements are part of the overall Western Interconnection. None of the existing transmission planning processes adequately considers transmission line routing and related land use and environmental implications, and existing planning processes do not adequately consider long-term needs well beyond the 10-year time horizon.

Given the challenges facing California's electricity system in the next decade, the state requires tighter coordination among energy agencies to address these challenges and avoid unnecessary duplication of effort for both the agencies and the stakeholders they serve. Lack of this coordination, let alone full integration, means that some efforts are duplicated while others are inconsistent or not receiving the attention they deserve. For example, numerous efforts examining various implications of 33 percent by 2020 were presented at an Energy Commission IEPR workshop on June 29, 2009. However, the most fundamental work to understand the amounts of flexible, dispatchable resources to complement the intermittency of some renewables is still needed.

Another example is the use of alternative planning assumptions in various forums, including licensing proceedings, to evaluate specific generation or transmission projects. There are known discrepancies in these assumptions compared to state policy goals. Although the California ISO considers the Energy Commission adopted demand forecast in its annual transmission planning process, it does not modify the load forecast to account for the impacts of the demand-side resource goals adopted by the state for incremental energy efficiency, demand response reductions at peak, or distributed generation. Omitting these impacts leads to conclusions that electricity demand will be higher, thus making more projects cost effective. This conservative approach may make sense from a "reliability first" perspective, but if it extends from just analysis to actual project proposals, such practices may increase the number of interventions in transmission licensing proceedings because some parties may feel proposed transmission lines would not be needed if the preferred demand-side policies were taken into account in the analyses.

Finally, no energy agency is systematically examining the long-term future. Electricity demand patterns may be very different 15 to 25 years into the future, and power plants that will be licensed and built in the ensuing years will still be viable and not yet fully depreciated. Transmission planning beyond the normal 10-year horizon is needed to prevent short-term infrastructure decisions from interfering with longer term needs or creating additional land use and environmental conflicts. Achieving the GHG emission reductions called for in Executive Order S-20-06 for 2050 will involve much more complex tradeoffs between fuels and electricity. Electricity demand may increase as a result of higher penetration of electric vehicles or increased electrification of industrial processes to help those sectors meet their GHG emission reduction goals. While it is too early to make firm commitments to power plants on the basis of this speculative electrification, it is not too early to begin identifying how larger electricity demand might be met by expanding the transmission system to access more sources, establishing transmission corridors to assure that transmission can be expanded in the future, and evaluating whether "energy parks" ought to be planned in advance to support electrification to the extent it is needed. Further, differences in demand patterns may alter the current mix of resources, relying either more or less than today on "peaking" resources that might be satisfied by storage technologies. A future which relies to a greater extent on electricity as the energy "source" for end-user equipment (homes, businesses, factories, and transportation) should motivate all energy agencies to evaluate whether reliability requirements for electricity generation, transmission, and distribution must evolve as well.

Need for Statewide Planning

Finding ways to coordinate and streamline the collective responsibilities of the energy agencies will be essential in meeting the state's important policies and policy goals.[256] Public Resources Code 25302(e) suggests that the Energy Commission seek input from the CPUC and the California ISO, as well as stakeholders and other agencies, in the Energy Commission's IEPR proceedings on future electricity infrastructure needs and requirements and by consolidating recommendations on future needs.

Senate Bill 1389 establishes the Energy Commission's *IEPR* as the forum for establishing energy policy. It is expected that the Energy Commission's forecasts and assessments are to be relied on by other agencies, including the CPUC, in carrying out their energy-related functions. There have been efforts to better link and coordinate the *IEPR* with the CPUC's LTTP. However, in recent years, the scope of the LTTP has grown in response to direct legislative mandates and under the CPUC's general interpretation that minimizing ratepayer costs requires it to make choices that balance resource preference goals with just and reasonable rates.[257]

Recently, the Legislature also gave the Energy Commission greater authority over publicly owned utilities to ensure they also follow the broad resource policy preferences established by the Energy Commission and CPUC or required by the Legislature. Similarly, the Energy Commission has been granted authority to designate transmission corridors to smooth the way toward specific transmission line projects in the future, which would presumably be evaluated, approved, and, once constructed, operated by the California ISO.

The recent proposed decision in CPUC R.05-12-013 signals a possible close to the long-standing issue of whether load-serving entity-specific forward capacity requirements to satisfy a multi-year forward resource adequacy requirement will be set as they are today in a bilateral contract manner or through a centralized capacity market auction. Importantly for coordinated planning, the proposed decision suggests that the planning analyses that will determine new capacity require-

256 The California Energy Commission staff prepared an integrated planning paper and distributed it among various agencies during August 2009. Feedback from these agencies has been mixed.

257 A California Public Utilities Commission Energy Division straw proposal for the 2010 LTPP cycle, released July 1, 2009, proposes to add a "system plan" element alongside direct IOU-bundled customer procurement to identify needed resource additions. The straw proposal explains that undertaking this new scope would add to the length and complexity of the LTPP proceeding.

ments should continue to be established in a coordinated manner using the capabilities and expertise of the Energy Commission and the California ISO as is the case today for the year-ahead requirements. The Energy Commission supports the development of common planning assumptions and results and hopes the final decision will include these provisions.

The Energy Commission has long required all load-serving entities with peak loads above 200 MW to submit their demand forecast and resource plans to the Energy Commission for review. This includes IOUs, publicly owned utilities, and CPUC-jurisdictional load-serving entities. The CPUC has similar requirements for the IOUs. While the CPUC's focus on IOUs is important, it does not cover efforts by its own regulated electric service providers or publicly owned utilities located in the transmission areas served by SCE or PG&E.[258] Similarly, while the California ISO is the largest system operator and transmission planning organization in the state, there are four other balancing authorities in California that play similar roles. Among these, LADWP is the most important of those with autonomy from the CPUC as a publicly owned utility and from the California ISO as an independent operator of a balancing authority area. This issue cannot be solved by the CPUC and California ISO alone. LADWP is an important player in developing its own plans to use scarce air quality credits that new or repowered generators will need in the overall Los Angeles Basin as the power generating fleet complies with the SWRCB's once-through cooling mitigation policy.

Now that the joint agency proposal has been accepted by SWRCB staff and incorporated into the draft OTC mitigation policy issued for formal public comment,[259] the energy agencies need to confront the details of how the proposed analyses will be accomplished in a timely manner and how existing decision-making processes will be modified to make tough choices. While the proposal emphasized the broad steps leading to the product the SWRCB needs – a schedule for OTC power plant replacement – it did not lay out changes needed in planning process or decision-making practices to achieve the collaborative analyses and broad decisions about preferred options. Recent modifications made by SWRCB to its proposed OTC mitigation policy clarify the ongoing need of the energy agencies to review the preliminary schedule provided to SWRCB and to update it periodically.[260] The energy agencies must align their processes in order to make the best and most expeditious decisions to determine which OTC power plants will be repowered, retired, or retired with the capacity replaced remotely and/or with transmission system upgrades.

258 Senate Bill 695 (Kehoe, Chapter 337, Statutes of 2009) authorizes an expansion of retail choice and thus may once again create splits between the interests of IOU-bundled service customers and those of customers provided energy services through an electric service provider.

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

260 The State Water Resources Control Board staff issued a revised once-through cooling mitigation policy proposal on November 23, 2009. Many of the changes formalized in the once-through cooling policy itself the implicit understandings that the energy agencies had received from SWRCB staff about the implementation of the policy through time. The State Water Resources Control Board conducted a public workshop on these changes on December 1, 2009.

The New Electricity System

Numerous discussions have been taking place among the affected energy and environmental agencies to develop plans to achieve the “new electricity system.” The ARB AB 32 Climate Change Scoping Plan implementation, SWRCB once-through cooling policy implementation, SCAQMD air credit allocations among scarce facilities, and Desert Renewable Energy Conservation Plan are examples. Each stems from some vision of a future electricity system that is substantially different from the one that exists today. Unifying these disparate visions and then translating them into the level of detail necessary to create and sustain multi-year implementation plans is a daunting task.

Discussions among agencies and stakeholders about developing blueprints for future resources that identify desired quantities of specific resource types and determining whether a specific project matches those needs requires common terminology to allow effective communication. Potential definitions are offered below:

Vision: A view of the future electricity system incorporating the preferred policy elements (renewable generation, demand-side initiatives) and supporting infrastructure (transmission, smart grid, distribution components) that both achieve GHG emission reduction goals and assure reliability standards.

Blueprint: A semi-quantitative plan, guide, or framework that translates the vision by juxtaposing the resource policy preferences against reliability standards, thereby resolving conflicts, reflecting priorities among policy preferences where they interact or conflict, indicating which entities are guided by the plan, and establishing how agencies coordinate with one another. A blueprint provides the basis for developing detailed plans. Borrowing from architecture, the Energy Commission refers to this specific translation of the general vision as a “blueprint,” the blueprint being the detailed specifications a contractor would need to execute a more general architectural rendering or “vision.”

Infrastructure assessment: A process of quantitatively evaluating the state’s blueprint using current and expected electricity demand, new supply additions, possible retirements of existing power plants, operating requirements, and necessary transmission to guide decisions about the future energy system mix to determine the necessary attributes and locations of necessary power plants, and in what time frame.

Developing a Blueprint for the Future

Numerous elements describing the future electricity system were identified as far back as the original *Energy Action Plan*. Most of these original policy preferences have been ratified, along with new elements, in the ARB *Climate Change Scoping Plan*. What remain to be added to these are the reliability and system efficiency objectives that are called out in state law, decisions of the agencies, and federal requirements. While it is reasonably straightforward to enumerate a long list of elements describing a vision for this future electricity system, specifying which objectives are preferred and determining the numerous tangible actions needed to accomplish them are much less clear.

The Energy Commission refers to this specific translation of the general vision as a “blueprint.” Increasing the specificity from that appropriate for a vision to that necessary for a blueprint requires that policy interactions be recognized and resolved. Ambiguities unimportant in stating a general goal may have to be resolved to actually achieve the goal, and there may be preferences of one path over another once the consequences of alternative interpretations are recognized.

An example of interactions that must be resolved is the specification of a renewable development path and the amount of incremental energy efficiency that will be achieved by a specific year while pursing an ultimate goal of all cost-effective potential. First, any incremental energy efficiency impacts that are achieved diminish the aggregate amount of renewables that must be developed to achieve a 33 percent RPS goal. Figure 33 showed the implications of alternative assumptions about incremental energy efficiency and the amount of net short renewables needed in 2020. The range is actually wider than Figure 33 reveals when the full set of demand-side policy initiatives are considered (additional energy efficiency programs, CHP, and distributed generation).

Second, the development pattern of renewables is crucial for identifying the amount and type of supplemental generating facilities and transmission development. Determining whether renewables will be concentrated in preferred zones or widely dispersed will impact infrastructure needs. Additionally, a development path that emphasizes in-state renewables means more in-state transmission and more firming generation to be located in California than does a development path that has higher amounts of renewables imported from the rest of WECC, where the local balancing authority provides firming resources.

Numerous scientific and analytic studies are necessary to develop a blueprint level of specificity, some of which are already underway. Examples include:

- The California ISO study of the generation requirements to achieve 33 percent renewables by 2020.
- The inter-agency OTC study to ascertain the amount and type of both flexible generation and transmission system upgrades needed to replace existing capacity in a manner that assures local and system reliability, while maximizing use of the resources already committed toward achieving AB 32 goals.
- The Energy Commission/CPUC study of the incremental impacts of energy efficiency initiatives developed for the CPUC in the *2008 Goals Update Report* as the foundation for IOU goals in D.08-07-047.
- The Energy Commission, Department of Fish and Game, Bureau of Land Management, and U.S. Fish and Wildlife Service Desert Renewable Energy Conservation Plan, currently in development, a science based conservation strategy to identify and establish areas for potential renewable energy development and conservation in the Colorado and Mojave deserts. The plan's goal is to reduce the time and uncertainty associated with licensing new renewable projects on both state and federal lands.

While each of these efforts is being pursued on its own timeline and with a specialized team, all of the efforts must be coordinated and reasonably consistent for them to be integrated into the blueprint later. In addition, since there is much uncertainty about the future, the emphasis should be on conducting analyses of multiple, plausible futures (including futures in which 33 percent RPS or other policy goals are not reached "on a straight line"), estimating the magnitude of the resources likely to be needed in the next 10 years, and defining what could be built without regret over five to eight years.[261] Assumptions about the development of other system components, as well as habitat and land use constraints, will be essential to these analyses. Such analyses would translate into statewide planning guidance disaggregated and quantified to some set of defined areas, including perhaps the ISO control area, utility service areas, planning areas, and/or local reliability areas.

Infrastructure Assessment

Assuming one has a clear translation of the vision into a blueprint, one can determine specific elements to achieve this blueprint. Again, the consequences of interacting elements have to be closely integrated. It is well understood that the California ISO's 33 percent renewable study will determine the amount of flexible capacity that provide incrementing, decrementing, ramping, and spin and nonspin reserve services. It is also understood that the consequences of the SWRCB's once-through cooling mitigation policy will lead to the loss of some of the resources that provide these services, such as aging OTC power plants. Thus, the combined effect of the 33 percent renewables goal and an OTC mitigation requirement that leads to retirements is the need for a large amount of flexible resource development, both to replace that lost through OTC power plant retirement and the additional amount needed to accommodate renewable development. Finally, to the extent that incremental energy efficiency policy initiatives can be relied upon to produce firm savings, fewer flexible fossil resources will be needed.

The resulting infrastructure assessment for flexible, dispatchable generation would be spelled out in amounts, location, and specific services required. Similarly, there are considerable differences in transmission development to achieve different ways of satisfying local capacity requirements. Developing transmission system elements within some urban load centers would diminish the need for local capacity and increase the locational options for needed generation development. This would likely be beneficial from both a market power and a power plant permitting perspective. As a result, there is interaction between generation and transmission system infrastructure not just because of alternative paths of renewable development, but between generation versus transmission. Resolution of these uncertainties in the development of a blueprint allows the next stage to focus on the specific facilities or sets of facilities that are needed. This level of detail can then become the basis for tracking whether resource additions are progressing as necessary, or whether corrective action of some sort must be taken to return to the resource additions called out in the infrastructure assessment.

The infrastructure assessment should be broad in scope, yet detailed enough to be relevant for all jurisdictions in specifying the types and sizes of power plants. For example, a local air pollution control district evaluating a 49-MW geothermal plant – below the 50-MW size threshold of the Energy Commission's licensing jurisdiction – must recognize that the generation from such a plant would displace emissions from natural gas and coal power plants that have much greater GHG emissions per unit of production. Similarly, while major central station solar power plant proposals that use PV technologies are outside the Energy Commission's jurisdiction, many of the permitting issues the local agency must consider are the same as those considered by the Energy Commission for a solar thermal power plant. The statewide infrastructure assessment should be used to guide each agency's infrastructure approval and licensing respon-

261 "Without regret" means the amount of power plant development foreseen to be necessary under all reasonably likely sets of future conditions.

sibilities and thus maximize coordinated action to achieve state energy policy goals.

Generation Infrastructure Assessment

The Energy Commission is the permitting agency for thermal power plants greater than 50 MW in size. Although some renewable generating technologies are permitted by local agencies, the majority of power plant capacity additions are permitted by the Energy Commission. Intervenors in recent cases have explicitly raised need issues even though the legal construct of the licensing process does not call out infrastructure assessment. The Energy Commission is exploring generation infrastructure assessment issues through an Order Instituting Investigation concerning how to treat GHG emissions as part of the CEQA process for its power plant licensing process. The report issued by the Energy Commission's Siting Committee called for several follow-up studies, as well as a further review in the 2009 IEPR proceeding.[262] This makes the Energy Commission's permitting process one of the principal clients of a generation infrastructure assessment product. From the narrow perspective of providing a foundation for possible Energy Commission generation infrastructure determinations for larger fossil power plants, the critical component of the infrastructure assessment is analysis that indicates what fossil or other resources would be needed under different futures.

A comprehensive compilation of resource policy preferences was accomplished through

262 California Energy Commission, *Committee Guidance on Fulfilling California Environmental Quality Act Responsibilities for Greenhouse Gas Impacts in Power Plant Siting Application*, March 2009, CEC-700-2009-004, available at: [http://www.valleyair.org/programs/CCAP/documents/CEC-700-2009-004.pdf].

a contractor report,[263] which suggested that a dispatchable gas plant could serve one or more of five roles. Some roles required that a power plant be located in specific geographic areas, such as the local capacity areas identified by the California ISO through its local capacity requirements studies. Other roles required power plants that could provide the sorts of services now being studied by the California ISO in its 33 percent renewables integration study, such as incrementing, decrementing, ramping, fast start, and related services. Plants possessing such capabilities are perceived to be more useful and necessary to the future electricity system than plants without these characteristics.

In several IEPR workshops, it became clear that siting fossil power plants will be increasingly difficult in California, suggesting that plants that are successfully permitted should be the ones with the characteristics that are most needed. However, parties to these workshops raised two fundamental questions:

- To what extent should the Energy Commission licensing process help to skew the limited number of additional fossil power plants that can be constructed toward those that are really needed?

- What is the appropriate sequence between achieving an Energy Commission permit and a long-term contract via a procurement process of a load-serving entity (or decision to construct by a load-serving entity itself)?

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

These questions could not be resolved in the 2009 IEPR proceeding, but are at the core of deciding how formally the Energy Commission's licensing process will incorporate a need conformance element in the future. Further effort is needed to make a decision and to craft a legislative proposal for the next session of the Legislature.

Transmission Infrastructure Assessment

Addressing the need for transmission infrastructure takes place in transmission development, mostly between the California ISO and the CPUC but also under ad hoc arrangements frequently created for specific projects. Even though the California ISO reviews specific transmission projects proposed by transmission owners and other entities and determines whether they are needed, larger transmission projects requiring a CEQA determination from the CPUC often encounter strong opposition in the permitting process, and need conformance is frequently a fundamental issue. As an example, opponents of the Sunrise Powerlink in San Diego asserted that urban rooftop PV could substitute for the transmission line and the power it would import. In their perspective, the proposed transmission line was not needed. Another example occurred when publicly owned utilities proposing a transmission line from Northern California renewable developments to Central California encountered resistance from land owners along the route, who contested that their land should not be used for a transmission line clearly intended to serve others that also did not provide the landowner with any policy or monetary benefit. From the opponents' perspective, the need for the line was not justified.

The *2009 Strategic Transmission Investment Plan* proposes a consolidated statewide transmission plan that could help resolve some of these concerns. First, planning would be divided into two time frames: a short-term, 10-year planning horizon and a second time frame that looks at the 10- to 30-year horizon. In the short-term planning process, each IOU would submit its planning perspective to the California ISO, and publicly owned utility balancing authorities would submit planned projects of statewide significance to the CTPG. Projects without statewide significance would go directly to permitting because they would not affect statewide planning. Next, the California ISO would develop its Annual Plan, which addresses the California ISO-controlled grid.

The CTPG could then work to develop a single statewide transmission plan, with the IOUs and the publicly owned utility balancing authorities acting in a fully coordinated manner. To adequately reflect stakeholder interests, the plan must have broad stakeholder support through all phases of plan development, particularly with regard to RETI. While consensus is not realistic on a statewide basis, the goal should be to achieve broad enough stakeholder support that transmission permitting will be less contentious and have a greater likelihood of success.

The CTPG statewide plan could then be submitted for evaluation to the Energy Commission's Strategic Transmission Investment Plan proceeding. The objective is to ensure that state interests regarding state policy goals and objectives are evaluated in a public forum. Projects conforming to state policy goals and objectives would be given greater weight in the permitting process. The *Strategic Transmission Investment Plan* also targets transmission projects for the Energy Commission's corridor designation process, and this step envisions recommending multiple projects identified in the CTPG statewide plan for simultaneous designation, rather than a piecemeal approach of one corridor designation proceeding at a time.

The final step is permitting, which is the most controversial stage of transmission development because it has the highest level of analysis and scrutiny. The CPUC has jurisdiction over IOU transmission line projects, and the publicly owned utility balancing authorities have jurisdiction over transmission line projects proposed for their service territories. As pointed out, an inadequate transmission planning process compromises the permitting process because transmission line owners seeking permit approvals for their projects will likely fail for lack of support and because of active stakeholder resistance. This step assumes that need for new transmission is ultimately determined during the permitting process. However, this process envisions that analyses in support of need determination are being carried out during each of the preceding steps.

Assuming the CTPG statewide plan secures broad stakeholder support, this permitting step envisions stakeholders' support for transmission project permit applications that are consistent with the CTPG plan. For projects largely facilitating renewable development, the RETI stakeholders understand the benefits of such a project and can presumably be relied upon to express support for such projects. For others, however, such as upgraded transmission lines facilitating reduced reliance upon OTC power plants, support from stakeholders is less obvious and will have to be marshaled.

For longer term planning, it is impossible to produce a 30-year plan with the same level of detail as the 10-year California ISO Annual Transmission Plan. Instead, the long-term plan would build on the 10-year California ISO plan and CTPG statewide plan and would consider the RETI conceptual plan and Western Renewable Energy Zone initiative planning output. The Energy Commission would prepare and vet the long-term plan in the Strategic Transmission Investment Plan proceeding, with the cooperation of electric utilities and interested stakeholders. The long-term plan would feed back into subsequent RETI conceptual transmission planning cycles, which this planning approach assumes would be undertaken every two years. The objective of subsequent RETI cycles would be to update the conceptual transmission plan completed two years previously. In addition, like the 10-year transmission planning proposal, the long-term plan would signal transmission corridor needs for the Energy Commission's corridor designation program.

This type of far-reaching planning horizon would not seek precision, but it would offer a vision of possible future transmission needs for California significantly into the future. In addition, it would help ensure that shorter term planning by the California ISO, electric utilities, and the RETI collaborative stakeholder process do not preclude or conflict with longer term transmission options for California beyond the customary 10-year planning horizon.

Integrated Generation/ Transmission Planning

For too long, the generation and transmission planning processes have operated as parallel, not integrated, mechanisms. Assessing the options for retirement of existing OTC generation is another area in which tradeoffs and complementary roles for generation and transmission have to be assessed. Part of the joint proposal of the Energy Commission, the CPUC, and the California ISO to the SWRCB is an agreement to conduct analyses that identify the options for retiring each OTC power plant and specifying the necessary replacement infrastructure. Both the renewable generation and the OTC replacement topics illustrate the need for and the beginning of efforts to bring generation and transmission analyses together. This is a good first step, but what is needed now is a more explicit electricity infrastructure planning process where decisions make use of such analyses.

The complexity of the issues involved in deciding what infrastructure is needed, coupled with the number of moving parts within the electricity sector including demand- and supply-side options and goals, calls for a new, more integrated planning process in California. The stakes of making isolated choices that may preclude other more electrically and economically advantageous choices are high. Generation, transmission, smart grid, and storage technology are rapidly evolving. The best strategies for meeting environmental goals – including achieving GHG reductions and reducing OTC impacts and air pollution emissions, as well as protecting biological and cultural resources – are still developing. In addition, the tradeoffs involved in choices about the power plants, transmission lines, and other approaches necessary to improve California's electricity infrastructure to meet our environmental challenges are only now becoming more clear. California must develop a more streamlined and integrated process for examining options and making decisions on electricity infrastructure needed to meet the state's future policy goals. The Energy Commission plans to work with the CPUC, California ISO, ARB, SWRCB, and a broad set of stakeholders to develop such a process.

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CHAPTER 4
RECOMMENDATIONS

California's energy systems must constantly respond to changes in energy supply and demand, new policy priorities, and technological advances. Although the current economic downturn has reduced projected energy demand in the short term, demand is expected to increase over time as the population continues to grow and the economy recovers. Energy system planning must be flexible enough to respond to changes in energy markets, new technologies, evolving policy direction, and economic fluctuations.

At the same time, California needs to maintain reliable and cost-effective energy supplies while also incorporating new environmental policies and regulations. Policy makers consider the costs of providing clean and reliable energy to both energy providers and consumers while they balance the short-term costs of doing so against the long-term costs and impacts of catastrophic climate change.

The primary policy driver for energy in both the short and long term is the state's goal of reducing greenhouse gas (GHG) emissions. The state has identified near-term strategies for its 2020 goals, but more aggressive policies and actions will be needed to meet the longer term goal of reducing GHG emissions to 80 percent below 1990 levels by 2050. To achieve this target will require fundamental changes in the way energy is produced and used as well as extensive efforts to develop new technologies to meet the challenges that lie ahead.

As California moves toward less carbon-intensive energy sources to meet its climate change goals, the state needs to identify emerging technologies that can help address the challenges facing the various energy sectors. Because of the long lead times associated with research and development efforts, the state must begin now to identify the most promising areas of research and development on which to focus its efforts and ensure that research and development activities are used to further the state's energy policy goals. In addition, the state needs to continue its research on how climate change will affect the state's energy infrastructure and its ability to serve the citizens of California.

Chapters 2 and 3 discussed some of the major issues facing California's transportation, electricity, and natural gas sectors. This chapter identifies recommendations that the California Energy Commission believes should be implemented immediately to ensure that the state's energy systems continue to meet the needs of California's citizens.

Recommendations for Electricity

Energy Efficiency and Demand Response

California needs to increase its efforts to achieve all cost-effective energy efficiency in the state to meet the GHG emission reduction requirements in California law and the recommended actions in the California Air Resources Board's (ARB's) *Climate Change Scoping Plan*. Strategies to achieve these GHG reductions include zero net energy new buildings, increased building and appliance standards along with better enforcement of those standards, and increased efficiency of the state's existing building stock. With the prospect of expanding population growth in drier, hotter inland areas and the resulting increase in air conditioning loads, California must continue its efforts to reduce peak electricity demand to reduce the need for expensive and higher-emission peaking power plants. In addition, the Energy Commission needs to continue its efforts to accurately reflect energy efficiency impacts in its electricity demand forecast.

Zero Net Energy Buildings

To achieve the goal that all new residential construction in California be zero net energy by 2020 and all new nonresidential construction be zero net energy by 2030, the Energy Commission recommends that by December 2010, it establish a statewide task force that includes state agencies, local governments, utilities, industry, enforcement bodies, and technical experts to address and develop recommendations on issues such as:

- The definition of zero energy – for example, zero net energy, zero peak energy, and zero net carbon.

- Whether progress toward the goal should be measured by individual home or nonresidential building, by neighborhood, by community, or by climate zone.

- The optimal level of energy efficiency needed before installing on-site renewable resources and how to incorporate that into building codes.

- The most important aspects of residential and nonresidential design and construction techniques that need attention in enforcement efforts and code upgrades to stay on the zero net path.

- Lessons learned from national efficiency code programs and appliance standards.

- The role of land use planning and neighborhood design and the need for continuing dialogue with local governments.

- The role of reach standards, green building codes, and other voluntary programs.

- Ways to better integrate and compensate distributed generation through zero net energy buildings, neighborhoods, and other developments.

- Potential pilot program design and implementation.

Because the goal of zero net energy buildings will involve not just efficiency but also building-based energy supply, the Energy Commission's standards for building energy efficiency should be expanded to address building-scale renewable energy solutions.

Building and Appliance Standards

To improve the contribution of the state's building and appliance standards to statewide energy efficiency goals, the Energy Commission will:

- Adopt and enforce building and appliance standards that put California on the path to zero net energy residential buildings by 2020 and zero net energy commercial buildings by 2030.

- Increase the energy efficiency achievements of the building standards by an average of 15 percent in each cycle of the standards in order to achieve zero net energy by 2020 for residential and 2030 for nonresidential construction.

- Expand the scope of building standards to include process loads, laboratories, refrigeration systems, and high energy-using commercial building types.

- Continue to adopt appliance standards for consumer electronics, general lighting, irrigation controls, and refrigeration systems.

- Work toward meeting the Governor's commitment to achieve 90 percent compliance with the building and appliance standards by 2017, by improving enforcement and compliance with building standards. The Energy Commission will work with building departments and provide them with the education and tools needed to increase their compliance rates and will expand work on appliance standards through partnering with the state's attorney general and municipal offices of the district attorney.

- Expand collaboration with the Contractors State Licensing Board to take action to investigate and discipline unlawful activity by licensed and unlicensed contractors that results in noncompliance with the building energy efficiency standards.

Efficiency in Existing Buildings

To take advantage of the significant potential for energy efficiency savings from California's existing residential and commercial buildings, the Energy Commission recommends the following:

- The state should require home energy ratings and energy efficiency retrofits at point of sale, remodel, or refinancing as one approach in a package of strategies to significantly improve energy efficiency in the existing building stock. Energy Commission staff will develop the necessary infrastructure to ensure that such an approach is successful, with the goal of developing incentives by 2013 that include funding for home energy ratings and maximum levels of required expenditures for retrofits to avoid dissuading homeowners from selling or making improvements to their homes. Additional strategies will also be explored and closely coordinated with the current utility programs, stimulus fund programs, and the upcoming proceeding directed by AB 758 (Skinner, Chapter 470, Statutes of 2009) to ensure a comprehensive and coordinated approach that captures all cost-effective energy efficiency in existing buildings.

- Legislation, utility incentives, and local ordinances should require quality installation and maintenance of heating, ventilation, and air conditioning equipment, employing qualified technicians and third-party verification, and providing public information regarding the benefits achieved through quality installation and how to engage contractors who provide quality installations.

■ The Energy Commission and the California Public Utilities Commission (CPUC) will work together to develop and implement audit, labeling, and retrofit programs for existing buildings that achieve all cost-effective energy efficiency measures, maximize the benefit of existing utility programs, and expand the use of municipal and utility on-bill financing opportunities.

■ For rating nonresidential buildings as part of AB 1103 (Saldaña, Chapter 533, Statutes of 2007) performance disclosure requirements, the Energy Commission will develop a California Energy Performance Tool to provide a performance rating for energy usage by building size and type; an asset rating for the building shell, heating/ventilation/air conditioning, boilers, and other equipment; and a carbon rating for renewable energy generation on-site that offsets electricity or natural gas use by 2012. The European Union's Energy Performance of Buildings Directive will be considered as a model.

■ Because the energy performance disclosure requirements under AB 1103 apply only to entire buildings, the Energy Commission will develop regulations by 2012 to address how to obtain meaningful building performance data for tenant-leased spaces.

■ To capture all cost-effective energy savings in existing buildings, the CPUC will encourage the energy and water utilities to transform the market from near-term savings to sustained long-term strategies and activities through performance-based incentives, comprehensive packages of energy-saving strategies, and decoupling of earnings from energy and water sales.

■ The Energy Commission's Public Interest Energy Research program will target and support research efforts in new and emerging energy efficiency technologies and techniques as well as building maintenance and commissioning.

Publicly Owned Utility Energy Efficiency Programs and Reporting

To ensure that publicly owned utilities are making progress toward achieving the statewide goal of 100 percent cost-effective energy efficiency savings, the Energy Commission recommends the following:

■ Publicly owned utilities should apply integrated resource planning to compare demand-side resources with supply-side resources using cost-effectiveness metrics. This approach should result in increased funding for energy efficiency from utility sources beyond the public goods charge (that is, procurement) and should increase future energy savings enough to reach adopted targets.

■ To demonstrate this commitment, the publicly owned utilities should provide additional information in their March 15, 2010 annual report to the Energy Commission on the role of energy efficiency in their integrated resource planning and the details of how increased funding will help to meet adopted energy efficiency targets.

■ Each publicly owned utility should continue to complete evaluation, measurement, and verification studies to show that energy savings have been realized; should fund these studies consistent with their importance as a significant resource; and should report on evaluation, measurement and verification plans, studies, and results in their next annual AB 2021 (Levine, Chapter 734, Statutes of 2006) submittal to the Energy Commission due March 15, 2010.

- To provide confidence that publicly owned utilities are achieving their energy efficiency targets with bona fide program savings, publicly owned utilities should increase the transparency of information on energy efficiency activities, expenditures, savings estimations, and cost-effectiveness calculations. In addition, they should provide to the Energy Commission staff the data used to create their annual status reports. The Energy Commission will work toward developing protocols for the publicly owned utilities to provide information that explains 1) year-to-year differences in budget and savings accomplishments and 2) methodologies and assumptions for estimating and verifying annual savings, as well as for determining feasible AB 2021 potential and targets. Energy Commission staff will develop a draft outline of specific data requirements for comment by publicly owned utilities and other parties by late January 2010.

- Energy Commission staff will establish a working group that incorporates appropriate parties to discuss successful energy efficiency portfolio and resource planning approaches and to provide a collaborative forum that identifies not only existing barriers, but also solutions for overcoming the most significant barriers that publicly owned utilities face when attempting to capture all cost-effective energy efficiency.

Demand Response

To help the state meet its goal of reducing peak demand by 5 percent through demand response measures, the Energy Commission recommends the following:

- All utilities, including publicly owned utilities, should install meters capable of recording hourly consumption and should publish their time-varying electric rates in an actionable and open source format. Status reports on the progress of meter installation should be included in the *2011 Integrated Energy Policy Report (IEPR)*.

- All customers with advanced meters should have no-cost access to near real-time information about their energy use in a format that is both meaningful and easy to understand.

- All utility price signals should use open source, nonproprietary formats.

- The Energy Commission will continue efforts to adopt a statewide load management standard requiring all utilities in the state to adopt default but optional time-varying pricing for customers that have advanced meters. In developing load management standards, the Energy Commission will continue collaboration with the CPUC, the California Independent System Operator (ISO), and publicly owned utilities.

- The Energy Commission's Public Interest Energy Research program will continue to pursue research and development that supports load management standards.

Incorporating Efficiency in the Demand Forecast

To integrate efficiency into future demand forecasts, the Energy Commission recommends the following:

- Energy Commission staff will actively participate in CPUC's evaluation, monitoring, and verification activities for the investor-owned utilities, as well as similar activities for the publicly owned utilities, to get insight into determinations of program savings and potential for future savings, which are closely related to Energy Commission demand forecast responsibilities.

- The Energy Commission will use the 2009 adopted forecast as a starting point to estimate the incremental impacts from future efficiency programs and standards that are reasonably expected to occur, but for which program designs and funding are not yet committed. Staff is planning to use and possibly modify Itron's forecasting model, SESAT, for this new purpose, with Itron to provide training for the model in early 2010. The Energy Commission, in cooperation with the CPUC, the investor-owned utilities, and the publicly owned utilities, will devote sufficient resources to develop in-house capability to differentiate these future energy efficiency savings from energy efficiency savings that are already accounted for in the demand forecast.

- Energy Commission staff will work closely with CPUC staff in establishing feasible statewide energy efficiency goals as part of the periodic AB 2021 requirements, as well as other forums.

Renewable Resources

Producing electricity from renewable resources provides a number of significant benefits to California's environment and economy, including improved local air quality and public health, reduced global warming emissions, a diversified state energy supply, improved energy security, enhanced economic development, and creation of green jobs. California has and can access some of the best renewable resource areas in the world. State policy makers should continue to lead the nation and the world in creating policies that maximize the cost-effective development of renewable energy generation.

Increasing the portion of California's electricity that comes from renewable power will be essential to achieving statewide GHG emission reductions from the electricity sector. However, the state has encountered significant roadblocks in its effort to meet the 20 percent by 2020 Renewables Portfolio Standard (RPS) goal that continues to present challenges to achieving 33 percent renewables. Major issues associated with meeting the larger target include difficulty in securing financing, delays and duplication in siting processes, time and expense of new transmission development, the cost of renewable energy in a highly fluctuating energy market, integration of large amounts of renewable resources into the electricity grid, and challenges in maintaining the state's existing renewable facilities.

In September 2009, after unsuccessful negotiations on legislation that would have codified the 33 percent renewable target, Governor Schwarzenegger issued Executive Order S-21-09, which directs the ARB to act as lead agency under the authority of AB 32 (Núñez, Chapter 488, Statutes of 2006) in implementing a policy consistent with the achievement of a 33 percent Renewable Energy Standard. The ARB is directed to adopt the policy by July 2010, and will work closely with the CPUC and the Energy Commission to draft the regulations.

Renewables Portfolio Standard Targets

To support efforts to achieve RPS goals, the Energy Commission recommends the following:

- The state should pursue codification of the 33 percent renewable target, drawing upon efforts that are underway to implement Executive Order S-21-09 and to accelerate the permitting of renewable energy infrastructure and facilities in California.

- The Energy Commission, the ARB, the CPUC, and the California ISO must continue to work together to implement a 33 percent renewable electricity policy that applies to all load-serving entities and retail providers. The Energy Commission encourages the ARB to keep the market for renewable energy in California stable by ensuring that the 33 percent policy is similar in rules and structure to the 20 percent RPS. In addition, the ARB effort should use the analyses and findings from the *2009 IEPR* as the starting point in developing regulations.

■ Because of the importance of achieving the state's 33 percent RPS goals, the Energy Commission recommends, as it has in past *IEPR*s, that the CPUC ensure that investor-owned utilities meet RPS targets and that it consider the imposition of strong penalties for noncompliance.

Renewable Integration

To facilitate integrating renewable energy into California's electricity system while maintaining reliability, the Energy Commission recommends that the following actions be completed by the end of 2011:

■ To avoid overbuilding new gas-fired power plants in the near term that will not be needed in the longer term, the Energy Commission will work with the CPUC, the California ISO, the ARB, utilities, and other stakeholders to coordinate implementation of energy efficiency, combined heat and power, renewable energy, and once-through cooling requirements.

■ The Energy Commission will conduct further analysis to identify solutions to integrate increasing levels of energy efficiency, smart grid infrastructure, and renewable energy while avoiding infrequent conditions of surplus or overgeneration in which more electricity is being generated than there is load to consume it. Potential solutions include better coordination of the timing of resource additions and the mix of resources added to efficiently meet customer needs and maintain system reliability. In addition, there will be efforts to determine what new, more flexible, and efficient natural gas technologies best fit into an electricity grid in transition. The Energy Commission will complete an initial study of the surplus generation issue to identify specific resource and data needs as part of the *2010 IEPR Update*, with the in-depth analysis as part of the *2011 IEPR*.

■ Achieving 33 percent renewable energy will change the resources needed to maintain electricity system reliability, including local ramp rates, inertia, and other transmission-related ancillary service functions. To prepare for these changes, the Energy Commission will continue to share input assumptions and analysis from previous Energy Commission studies with the California ISO to inform its ongoing work to understand operational impacts of large amounts of intermittent renewable resources.

■ The Energy Commission's Public Interest Energy Research program will develop tools to forecast operational performance of solar energy generation facilities. The tools will be designed to examine whether forecasting errors in load magnify errors in forecasting wind and solar energy production, as well as the benefits that power plant-based storage can provide to reduce errors in forecasting solar energy production. As part of this effort, the program will develop a publicly available dataset that project developers can use to estimate electricity that can be produced in California from roof-top, community-scale, and utility-scale photovoltaic systems and solar thermal electric systems with and without storage.

■ Energy storage is a key strategy for accommodating the intermittent nature of some renewables. However, a separate tariff or incentive is needed to create market incentives to encourage the development of large energy storage projects. The Energy Commission will coordinate with the California ISO and with Federal Energy Regulatory Commission, as well as utilities and other interested parties, to determine how best to incentivize storage, including determining whether storage can be allowed to participate in the ancillary services market.

■ The Energy Commission will continue to research storage technologies to reduce cost and determine the best placement and sizing of new facilities to maximize electric system value.

Smart Grid

To support the integration of renewables, California needs to implement a smart grid. To do so, standards must be adopted to ensure that the smart grid provides an open architecture that allows access to a wide variety of technologies. The Energy Commission recommends the following:

■ The Energy Commission will work with the CPUC to develop a regulatory framework for adopting National Institute of Standards and Technology (NIST) Smart Grid interoperability and cyber security standards consistent with Federal Energy Regulatory Commission rulings to ensure national and international compatibility.

■ The Energy Commission, the CPUC, and the California ISO should participate in the NIST Smart Grid Interoperability Panel to ensure that California smart grid activities are shared nationally and that California can learn from smart grid activities in other states. In addition, there should be continued coordination with NIST on smart grid standards such as Open Automated Demand Response.

■ The Energy Commission will continue to coordinate with the CPUC, the California ISO, utilities, and stakeholders to develop smart grid plans, consistent with the requirements in SB 17 (Padilla, Chapter 327, Statutes of 2009), as described in Chapter 1.

■ The Energy Commission will continue Public Interest Energy Research program research on technologies that mitigate or resolve intermittency of renewable resources, as well as research on bidirectional power flows and power quality issues resulting from increased use of renewable resources.

Maintaining Existing Renewable Facilities

To help maintain California's baseline of existing renewable facilities, the Energy Commission recommends the following:

■ The Governor's Bioenergy Action Plan should be updated to address continuing barriers to the development and deployment of bioenergy. These barriers include air quality permitting, expiring incentive programs, and lack of private project financing. The Bioenergy Action Plan should also be expanded to identify issues and potential solutions related to biogas injection and gas cleanup.

■ The Energy Commission will explore options to ensure that existing biomass facilities continue to operate, including continuation of the Existing Renewable Facilities Program, subsidizing biomass feedstocks, or developing a feed-in tariff for existing biomass facilities.

Supporting New Renewable Facilities and Transmission

To facilitate permitting of new renewable facilities and securing the necessary transmission corridors and lines to access those facilities, the Energy Commission recommends the following:

■ The Energy Commission will work with the CPUC, the California ISO, the Bureau of Land Management, the Department of Fish and Game, and other agencies to implement specific measures to accelerate permitting of new renewable generation and the transmission facilities needed to serve that generation, including measures to eliminate duplication, shorten permitting timelines, and complete planning processes to balance clean energy development and conservation such as the Renewable Energy Transmission Initiative and the Desert Renewable Energy Conservation Plan.

■ Energy Commission staff will actively participate in the CPUC Investigation and Rulemaking on Transmission for Renewable Resources and collaborate with the CPUC and other agencies to eliminate duplicative transmission needs determination and permitting processes.

■ Energy Commission staff will continue to participate in the Renewable Energy Action Team's efforts to streamline and expedite the permitting processes for renewable energy projects, while conserving endangered species and natural communities at the ecosystem scale in the Mojave and Colorado Desert regions through the Desert Renewable Energy Conservation Plan. The Energy Commission staff will ensure that the generation findings in the Desert Renewable Energy Conservation Plan are considered in California ISO and CPUC transmission processes.

■ The Energy Commission, California ISO, and the California Transmission Planning Group will prioritize transmission planning and permitting efforts for renewable generation and work to overcome barriers and find solutions that would aid their development.

■ To meet the Governor's target of 20 percent of the state's renewable energy goals from biomass resources, the Energy Commission will facilitate and coordinate programs with other state and local agencies to address barriers to expanding biopower, including regulatory hurdles and project financing. The Energy Commission will also encourage additional research and development to reduce costs for biomass conversion, biopower technologies, and environmental controls.

■ To leverage funding mechanisms for projects that simultaneously use biopower and biofuels, the Energy Commission's Public Interest Energy Research Renewable-Based Energy Secure Communities program will provide grants focusing on projects that capitalize on the synergies of co-locating electricity generation from biomass with the production of biofuel for use in the transportation sector.

■ Local air pollution districts should be encouraged to become involved in the Interagency Biomass Working Group since they have key regulatory authority over biomass projects. Furthering the dialogue between air districts, the state's energy agencies, the Governor, and the Legislature can result in innovative solutions to mitigate air pollution while enabling California to meet its biomass/biogas energy goals.

■ Energy Commission staff will conduct early outreach to local governments and other land use agencies to inform them of the planning initiatives that are under way to facilitate the development of renewable generation and to encourage their timely participation in planning for and designating transmission corridors to help meet the state's energy policy objectives.

Expanding Feed-In Tariffs

To facilitate lower-cost development of renewable resources, the Energy Commission recommends the following actions to expand the use of feed-in tariffs in California:

- To help meet the goal of the RPS and expand the amount of renewable energy located near load, the CPUC should require the investor-owned utilities to offer simplified and standardized contracts set at reasonable prices for renewable energy projects 20 megawatts or less in size. The contracts should be designed to help small businesses participate in the RPS, reduce the transaction costs of the RPS contracting processes, and provide gradually declining, publicly available, technology-specific (or product-specific) price signals to stimulate competition among manufacturers to lower the cost of renewable energy.

- To help reduce the environmental impacts of achieving 33 percent renewable electricity by 2020, the Legislature should consider requiring utilities or the California ISO to offer technology-specific (or product-specific) feed-in tariffs designed to effectively spur development and integration of renewable energy projects 20 MW and smaller in low-impact competitive renewable energy zones and along renewable-rich transmission corridors. These geographically specific feed-in tariffs should be offered for limited time periods to best coordinate the development of renewable energy with the timing of new transmission development.

- California should support clarification of federal law to ensure that states can implement cost-based feed-in tariffs for resources that help reduce health and environmental impacts of electricity generation, including GHG emissions.

Distributed Generation

The *2007 IEPR* identified the need to expand and upgrade California's distribution system to prepare for the resource mix needed to reach GHG emission reduction goals. With state policies that rely increasingly on preferred resources, the distribution system must be able to integrate and efficiently use distributed resources. With potentially billions of dollars being spent on distribution system upgrades, the state needs to ensure that those upgrades will facilitate meeting the goals for increased renewable resources.

To support the goal of integrating increased quantities of both renewable and nonrenewable distributed generation into the grid, the Energy Commission recommends:

- The Energy Commission and the CPUC should open a joint proceeding to develop a comprehensive understanding of the importance of distribution system upgrades, not only to assure reliability, but also to support the cost-effective integration and interoperability of large amounts of distributed energy for both on-site use and wholesale export. The proceeding should focus on the following:

  - Requiring utilities to provide an assessment of the areas or locations on their systems in which distributed generation for both on-site use and/or export would be of greatest value. The studies should report on operational characteristics that would have greatest value; tools, data and criteria used to select these locations; and obstacles to deploying specific types of distributed generation in these areas (for example, high density residential areas).

- ☐ Reviewing and requiring the use of distribution system operational models and economic/capital investment models in utility rate cases.

- ☐ Requiring utilities to use these tools to demonstrate that investments in advanced grid technologies will support grid modernization goals, including from a standpoint of cost-effectiveness.

- ☐ Implementing and validating open International Electrotechnical Commission (IEC) communication standards for distributed energy resources before proprietary solutions become established. Although these standards are not required in the United States, they are being implemented in Europe where most countries are mandated to use IEC standards. California can leverage European efforts to develop and implement these standards and ensure that the state benefits from the widespread use of communication standards. Once implemented for photovoltaic, the same communication standards can be used for other renewable systems, such as wind, fuel cells, and biomass, as well as for distribution automation equipment.

■ Because net metering is an essential tool for making renewable distributed generation a cost-effective choice for customers and for maximizing the development of in-state renewable generation that requires no transmission upgrades, the Legislature should require utilities to increase their net energy metering cap to 5 percent to allow reasonable growth and support for the deployment of renewable generation in California. The CPUC is required to report to the Legislature and the Governor by January 1, 2010, on the costs and benefits of net energy metering. Once that report has been completed and reviewed, increasing the cap beyond 5 percent can be evaluated.

Combined Heat and Power

Combined heat and power (CHP) provides benefits to the system through more efficient use of natural gas fuel, which also results in decreased GHG emissions. The barriers to increased penetration of CHP technologies have been identified repeatedly in past *IEPR*s, but little progress has been made.

Meeting Scoping Plan Targets for Combined Heat and Power

Based on a 2005 CHP market forecast, the ARB in its *Climate Change Scoping Plan* set a target of 6.7 million metric tons of carbon dioxide (CO_2) emissions reduction from CHP by 2020. This was translated into 30,000 gigawatt hours and 4,000 MW of new CHP. The new market forecast done for the *2009 IEPR* found that 5,500 MW of new CHP could be installed by 2020 with a combination of incentives, including export sales for CHP systems larger than 20 MW. This capacity represents 6.0 million metric tons of CO_2 emission reductions, about 90 percent of the targeted reduction. In addition, the future of existing qualifying facility contracts for CHP (representing about 6,000 MW of existing CHP) is in question. Also, recession has altered the economic landscape – natural gas prices are low, and economic growth estimates are reduced. Consequently the prospect for attaining system efficiencies, grid stability, and GHG reduction seems to be in jeopardy unless a combination of remedial policies and programs are implemented with urgent priority.

The development of new CHP can lead to a reduction in CO_2 equivalent emissions of 4 million metric tons per year by 2020. To realize these reductions, the Energy Commission recommends the following:

- The Energy Commission will work with the ARB and the CPUC in the development of CHP to meet the state goals for emission reductions from these technologies. Actions include mandates to remove market barriers to the development of CHP facilities and provision of analytical support on efficiency requirements and other technical specifications so that CHP is more widely viewed and adopted as an energy efficiency measure.

- The Energy Commission will work with the CPUC and the ARB to establish minimum efficiency standards, GHG emission criteria, and monitoring and reporting mechanisms.

- Electric utilities should develop programs and solicit projects to promote CHP as a strategy to replace boilers, increase energy efficiency, and reduce emissions. Programs should include a mix of mechanisms such as energy audits, an electricity export sales tariff, and a pay-as-you-save pilot program for nonprofit organizations. Utility ownership is acceptable where it does not crowd out private investment.

- Eligibility for CHP systems with a generating capacity of 5 MW or less that meet minimum performance, monitoring, and reporting standards should be re-instituted in the Self-Generation Incentive Program. The amount of the incentive should be based on efficiency and GHG reduction metrics rather than technology and fuel types.

- California hospitals, correctional facilities, and military bases that support essential health, safety, and security functions should be targeted for CHP development. The Energy Commission and CPUC should establish information and incentive programs to support and encourage these critical facilities to install CHP as a way to ensure that their essential services continue to operate reliably, even if a major disruption of local or regional power occurs.

Renewable Combined Heat and Power

CHP systems installed at wastewater treatment facilities use biogas from sludge and provide multiple benefits. Besides reducing on-site energy needs, they reduce methane generated by the facility. Such CHP systems also help to meet RPS goals. Yet the near-term potential of these CHP systems remains unfulfilled due to conflicting regulatory requirements for air emissions.

Co-digestion of organic material at wastewater treatment plants can help to mitigate the GHG emissions emanating from California's multiple organic waste streams. In addition, co-digesting multiple biodegradable waste streams such as municipal waste sludge, food processor waste, restaurant leftovers, and dairy manure can add as much as 450 MW to the CHP potential in California.

The Energy Commission recommends that:

- Energy and environmental regulatory agencies should collaborate to resolve conflicting regulations that result in the flaring of biogases that could be used productively for distributed generation and CHP operations. New approaches to balance criteria pollutant emission reductions against energy efficiency improvements and gas reductions from electricity generation should be developed.

- The Energy Commission, the CPUC, and utilities should develop financing programs to fund the near-term potential of CHP systems that use biogas at wastewater facilities. Financing options should include, but not be limited to, grants, loans, or incentives for developing and expanding biowaste digester infrastructure, generation, and emission control equipment.

- The Energy Commission will commit research dollars to develop a web-based database to provide location, volume, quality, and seasonality of biodegradable waste suitable for co-digestion at wastewater treatment plants. This could be done in collaboration with industry associations. The database will include waste from California's agriculture, food processing, and dairy industries.

■ The Energy Commission will assess the economic and environmental benefits of GHG reduction and grid stability from co-digesting California's biodegradable waste from the dairy, agriculture, and restaurant industries at wastewater treatment plants. This assessment will include the benefits both to the state and to the individual industry contributing to the waste.

■ The Energy Commission, the ARB, and the California Carbon Reduction Reserve (formerly Carbon Reduction Registry) must develop methodologies both for attaining and monitoring GHG reductions and low-cost protocols for verification of such reductions for biodegradable materials whose eligibility for GHG reduction credits is not yet established.

Nuclear Plants

In light of current policy and considerations regarding nuclear plants, the Energy Commission recommends the following:

■ To help ensure plant reliability and minimize costs, Pacific Gas and Electric Company (PG&E) and Southern California Edison (SCE) should complete and report in a timely manner on all of the studies recommended in the *AB 1632 Report*, including those that the CPUC identified for completion as part of license renewal review. The utilities should make their findings available for consideration by the Energy Commission and to the CPUC and the U.S. Nuclear Regulatory Commission (NRC) during their reviews of the utilities' license renewal applications. The utilities should not file license renewal applications with the NRC without prior approval from the CPUC. These studies should include:

- ☐ Reporting on the findings from updated seismic and tsunami hazard studies, including results of 3D seismic imaging studies, and assessing the long-term seismic vulnerability and reliability of the plants.

- ☐ Summarizing the implications for Diablo Canyon Power Plant and San Onofre Nuclear Generating Station (SONGS) of lessons learned from the response of the Kashiwazaki-Kariwa nuclear plant to the 2007 earthquake.

- ☐ Reassessing whether plans and access roads surrounding the plants, following a major seismic event and/or plant emergency, are adequate for emergency response to protect the public, workers, and plant assets and for timely evacuation following such an event.

- ☐ Studying the local economic impact of shutting down the plants as compared to alternative uses for the plant sites.

- ☐ Reporting on plans and costs for storing and disposing of low-level waste and spent fuel through 20-year license extensions and plant decommissioning using current and projected market prices.

- ☐ Quantifying the reliability, economic, and environmental impacts of replacement power options.

- ☐ Assessing the options and costs for complying with the proposed State Water Resources Control Board once-through cooling policy. These studies should be included in the cost-benefit assessment of the plants' license renewal feasibility studies.

- ☐ Reporting on efforts to improve the safety culture at SONGS and on the NRC's evaluation of these efforts and the plant's overall performance (SCE only).

Requiring the utilities to complete these studies is consistent with the CPUC's General Rate Case Decision 07-03-044 regarding the state's important role in deciding whether to pursue license renewal. The General Rate Case decision required PG&E to incorporate the findings and recommendations of the Energy Commission's *AB 1632 Report* assessment in PG&E's license renewal feasibility study and to submit the study to the CPUC no later than June 30, 2011, along with an application on whether to pursue license renewal for Diablo Canyon. Letters on June 25, 2009, from the president of the CPUC to PG&E and SCE reiterated the requirements that each utility complete the *AB 1632 Report's* recommended studies, including the seismic/tsunami hazard and vulnerability studies, and report on the findings and the implications of the studies for the long-term seismic vulnerability and reliability of the plants. These studies are necessary to allow the CPUC to properly undertake its obligations to ensure plant and grid reliability in the event that either Diablo Canyon or SONGS has a prolonged or permanent outage and for the CPUC to reach a decision on whether to pursue license renewal.

■ The CPUC should assess the need to establish a SONGS Independent Safety Committee patterned after the Diablo Canyon Independent Safety Committee.

■ The Energy Commission will continue to monitor the NRC and the Institute of Nuclear Power Operations reviews of Diablo Canyon and SONGS, and in particular monitor plant performance and safety culture at SONGS.

■ The Energy Commission will continue to monitor the federal nuclear waste management program and represent California in the Yucca Mountain licensing proceeding to ensure that California's interests are protected regarding potential groundwater and spent fuel transportation impacts in California.

■ The Energy Commission will continue to participate in U.S. Department of Energy and regional planning activities for nuclear waste transportation.

■ The Energy Commission, CPUC, and the California ISO should assess the reliability implications and impacts from implementing California's proposed once-through cooling policy and regulations for California's operating nuclear plants.

■ To support the state's long-term energy planning, SCE and PG&E should report, as part of the *2010 IEPR Update*, what new generation and/or transmission facilities would be needed to maintain voltage support and system and local reliability in the event of a long-term outage at Diablo Canyon, SONGS, or Palo Verde Nuclear Generating Station. The utilities should develop contingency plans to maintain reliability and grid stability in the event of an extended shutdown at SONGS, Diablo Canyon, or Palo Verde.

■ The Energy Commission will continue to update information on the comprehensive economic and environmental impacts of nuclear energy generation compared with alternatives. These economic and environmental assessments will consider "cradle to grave," or life cycle impacts, including impacts from uranium mining; reactor construction; fuel fabrication; reactor operation, maintenance and repair; reactor component replacement; spent fuel storage, transport and disposal; and decommissioning.

■ The SONGS' Seismic Advisory Board should include greater representation from independent seismic experts, such as university or government scientists and/or engineers with no current or prior employment with the plant owners or their consultants.

■ The Diablo Canyon Independent Safety Committee should evaluate reactor pressure vessel integrity at Diablo Canyon over a 20-year license extension and recommend mitigation plans, if needed. This review should consider the reactor vessel surveillance reports for Diablo Canyon in the context of any changes to the predicted seismic hazard at the site.

Transmission

The *2009 Strategic Transmission Investment Plan* describes the immediate actions that California must take to plan, permit, construct, operate, and maintain a cost-effective, reliable electric transmission system that is capable of responding to important policy challenges such as achieving significant GHG reduction and RPS goals. The plan makes a number of recommendations intended to ensure that the critical link between transmission planning and transmission permitting is made so that needed projects are planned for, have corridors set aside as necessary, and are permitted in a timely and effective manner that maximizes existing infrastructure and rights-of-way, minimizes land use and environmental impacts, and considers technological advances.

The Energy Commission supports the many recommendations adopted in the *2009 Strategic Transmission Investment Plan* and highlights the following recommendations:

■ The Energy Commission staff will work with the California ISO and the recently formed California Transmission Planning Group in a concerted effort to establish a 10-year statewide transmission planning process that uses the Energy Commission's Strategic Plan proceeding to vet the California Transmission Planning Group plan described in Chapter 4 of the *2009 Strategic Transmission Investment Plan*, with emphasis on broad stakeholder participation.

■ The Energy Commission staff will work with the California ISO, the CPUC, investor-owned utilities, and publicly owned utilities to develop a coordinated statewide transmission plan using consistent statewide policy and planning assumptions.

■ The Energy Commission, California ISO, and the California Transmission Planning Group will prioritize transmission planning and permitting efforts for renewable generation, as outlined in Chapter 6 of the *2009 Strategic Transmission Investment Plan*, and work on overcoming barriers and finding solutions that would aid their development.

■ The Energy Commission will continue support for ongoing activities related to the Renewable Energy Transmission Initiative (RETI), including the Coordinating Committee, Stakeholder Steering Committee, and working groups, by providing appropriate personnel and contract resources.

■ The Energy Commission staff will continue to coordinate with the RETI stakeholders group to incorporate RETI's new information in applying the method described in Chapter

6 of the *2009 Strategic Transmission Investment Plan* to reach consensus on the appropriate transmission line segments that should be considered for corridor designation to promote renewable energy development.

■ The Energy Commission will continue to participate in the Western Renewable Energy Zone process to ensure consistency with RETI results for both preferred renewable development areas and environmentally sensitive areas that should be avoided.

Coordinated Electricity System Planning

California faces challenges in implementing state policy goals to decrease the use of once-through cooling in power plants and retire aging power plants, given the need to maintain system reliability and the limitations on emissions credits for replacement plants in the southern part of the state. At the same time, the state needs to better coordinate its electricity policy, planning, and procurement efforts to eliminate duplication and to ensure that planners and policy makers understand the interactions and conflicts that may exist among state energy policy goals.

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

■ The Energy Commission will work with the CPUC and California ISO, along with other agencies and interested stakeholders, to develop a common vision for the electricity system to guide infrastructure planning and development. Such coordinated plans can be used to guide each agency's own infrastructure approval and licensing responsibilities and thus maximize coordinated action to achieve state energy policy goals.

■ The Energy Commission will continue its ongoing efforts to improve the quality and transparency of its demand forecasts, which are now used at the CPUC and California ISO for electricity system planning. The Energy Commission's Demand Analysis Office is engaged in an intensive review and evaluation of current modeling methods. This process places high priority on assessing whether current modeling tools are effectively matched to the purposes they are intended to serve. Once the existing model review stage to identify process improvements has been completed, active steps to incorporate model modifications or model replacements will be initiated in the 2011 IEPR cycle after these changes are fully tested and reviewed.

■ The Energy Commission will continue to work with the CPUC, the California ISO, and the State Water Resources Control Board to implement the joint energy agency proposal that establishes a schedule for complying with once-through cooling mitigation while addressing electric system reliability concerns.

■ The Energy Commission will conduct analysis to determine the amount of air credits needed in the South Coast air shed and work cooperatively with the South Coast Air Quality Management District, the ARB, and other appropriate agencies to design new methods to allocate scarce air credits to proposed power plants that best meet system and local needs.

- Through a public process with interested stakeholders, the Energy Commission will define a course of action that incorporates integrated planning results into the decision-making process for the power plants it licenses.

- The Energy Commission will focus its forecasting, planning, IEPR, and Strategic Transmission Investment Plan processes on conducting the statewide integrated planning that is clearly now required. Efforts will be coordinated with those of the CPUC and California ISO to reduce duplication.

- The Energy Commission's Cost of Generation model will be used where applicable as a transparent tool for upcoming integrated resource planning studies. A reasonable range of inputs will be used to generate a range of potential levelized cost estimates for the *2011 IEPR*.

Recommendations for Natural Gas

New technologies and resource finds, such as shale gas, have increased the availability of natural gas in North America. Natural gas is the cleanest of the fossil fuels and will continue to play a role in GHG reductions in the electricity sector. However, there are potential environmental impacts associated with exploration and development of shale gas as an additional source of natural gas supplies. Plentiful supplies of natural gas will moderate prices and make natural gas an attractive option throughout the West as the electricity industry starts to build a less carbon-intensive infrastructure. Because California is at the end of the gas supply pipelines, demand for natural gas "upstream" of California could increase competition and prices and reduce available supplies for California.

The Energy Commission recommends:

- The Energy Commission will continue to monitor the potential environmental impacts associated with shale gas extraction, including carbon footprint, volume of water use and risk of groundwater contamination, and potential chemical leakage. Specifically, the Energy Commission staff will coordinate and exchange information with energy agencies in states with shale gas development, such as New York, Texas, and other midcontinent states, and will report new findings in the *Integrated Energy Policy Report* and other Energy Commission forums.
- California should work closely with western states to ensure development of a natural gas transmission and storage system that has sufficient capacity and alternative supply routes to overcome any disruption in the system, such as weather-related line freezes, pipeline breaks, and so on. The state should support construction of sufficient pipeline capacity to California to ensure adequate supply at a reasonable price.

Recommendations for Fuels and Transportation

State and federal policies encourage the development and use of renewable and alternative fuels to reduce California's dependence on petroleum imports, promote sustainability, and reduce GHG emissions. The Governor's Executive Order S-06-06 established clear targets for increased use and in-state production of biofuels. California and the federal government also have policies to improve vehicle efficiencies and to reduce vehicle miles traveled in efforts to achieve the 2050 GHG reduction targets. Until new vehicle technologies and fuels are commercialized, however, petroleum will continue to be the primary fuel source for California's vehicles. The state will need to enhance and expand its existing petroleum infrastructure, particularly at in-state marine ports, as well as its alternative fuel infrastructure.

Since the Energy Commission published the *2007 IEPR*, additional actions have been taken to encourage alternative and renewable fuels. The Low Carbon Fuel Standard has been put in place to lower the carbon content of transportation fuels over the next 10 years. The federal government has granted a waiver allowing California to set emissions levels under the state's Passenger Motor Vehicle Greenhouse Gas Emission Standards and is setting considerably higher national fuel economy standards based on California's regulations. The state has created the Alternative and Renewable Fuel and Vehicle Technology Program, a comprehensive funding program to stimulate the development and deployment of innovative, low-carbon fuels and advanced vehicle technologies.

With these and other directives, the Energy Commission believes that California is well positioned to develop a system of sustainable, clean, and alternative transportation fuels. The state should continue on its present course of action by providing responsible agencies with the time and funding to implement these programs. Enactment of complementary federal transportation fuel and vehicle technology programs and financial incentives would accelerate innovations in low-carbon fuels and advanced vehicle technologies.

In addition, the Energy Commission recommends:

- To maintain energy security, state and local agencies need to ensure that there is adequate infrastructure for the delivery of transportation fuels. The state should modernize and upgrade the existing infrastructure to accommodate alternative and renewable fuels and vehicle technologies as they are developed and to address petroleum infrastructure needs to preserve past investments and to expand throughput capacity in the state.

- The Energy Commission will collaborate with partner agencies and stakeholders to develop policy changes to address regulatory hurdles and price uncertainty for alternative fuels, particularly biofuels, in California.

- California should support the development of alternative and renewable fuels that can provide immediate GHG emission reduction benefits and a bridge to the introduction of fuels that will result in deeper GHG emission reductions in the future.

- Transportation energy efficiency should be pursued through increased federal vehicle fuel economy standards and more sustainable land use practices, in conjunction with local governments.

- The state's Bioenergy Interagency Working Group should continue to coordinate the efforts of state government in order to maximize the use of California's abundant waste stream, including agricultural waste, municipal solid waste, and forest waste, to produce energy for transportation uses in a sustainable manner. The working group should examine appropriate forest thinning and fire risk-reduction strategies that have the potential to create large volumes of woody biomass waste materials that can be used as a feedstock for transportation fuels, but that also ensure the sustainability of California's private and public lands forests.

- The Bioenergy Interagency Working Group should investigate and develop economic methods for the sustainable harvest and transport of woody biomass materials.

- The Bioenergy Interagency Working Group should examine local permit and enforcement activities to help ensure that biofuel infrastructure is installed in a manner to meet growing demand for renewable fuels. The Working Group should examine the feasibility of requiring that new building code standards for all gasoline- and diesel-related equipment (underground storage tanks, dispensers, associated piping, and so on) be ethanol (E85) and biodiesel (B20) compatible for construction of any new retail stations or replacement of any gasoline- and diesel-related equipment beginning January 1, 2011.

Recommendations for Land Use and Planning

Land use planning and investment decisions are made at the local government level. Community design decisions impact transportation choices, energy consumption, and GHG emissions. The *2006 IEPR Update* stated that the single largest opportunity to help California meet its statewide energy and climate change goals resides with smart growth. The *2007 IEPR* further noted that to reduce GHG emissions, California must begin reversing the current 2 percent annual growth rate of vehicle miles traveled.

The Energy Commission is one of many state agencies working proactively with local and regional governments to foster sustainable land use planning and investment decisions. Caltrans coordinates regional and state planning through its Regional Blueprint Planning Program. Senate Bill 375 (Steinberg, Chapter 728, Statutes of 2008) requires the ARB to set regional emissions goals by working with metropolitan planning organizations. Senate Bill 732 (Steinberg, Chapter 729, Statutes of 2008) recognized the need for state agencies to work more closely together on land use issues when it created the Strategic Growth Council, a cabinet-level decision-making body composed of agency secretaries from Business, Transportation and Housing; California Health and Human Services; the California Environmental Protection Agency; and the California Natural Resources Agency, along with the director of the Governor's Office of Planning and Research.

In addition, SB 732 authorized the Strategic Growth Council to provide $90 million in Proposition 84 funds to local and regional governments for planning grants and planning incentives to encourage the development of regional and local land use plans that are designed to promote water conservation, reduce automobile use and fuel consumption, encourage greater infill and compact development, protect natural resources and agricultural lands, and revitalize urban and community centers.

These state policies require state agencies to coordinate more closely and to provide bond funding to help local governments achieve the benefits of coordinated land use planning and sustainable economic development. State government must actively engage with local governments to better understand the problems they face before adopting new state policies. This includes taking into account and addressing the fiscal constraints local governments face in these challenging economic times.

The Energy Commission makes the following recommendations related to land use planning and decisions:

- To reduce energy use and support the transportation GHG reduction goals, state agencies in collaboration with the Strategic Growth Council and local and regional governments will continue to conduct research, develop analytical tools, assemble easy-to-use data and provide assistance to local and regional government officials to help them make informed decisions about energy opportunities and undertake sustainable land use practices, while recognizing the different needs of rural and urban regions. The Strategic Growth Council is uniquely positioned to coordinate the many issues, programs, and activities of its members and those of other state agencies such as the Energy

Commission, California Department of Transportation, and the ARB. These issues include energy efficiency, renewable energy development, and energy supply.

■ Local land use planners should have access to easy-to-use tools to help them make informed decisions about energy concerns and GHG reductions. To that end, the Energy Commission will revise and market editions of its *Energy Aware Planning Guide I* and its *Energy Aware Planning Guide II: Energy Facilities*, documents that detail the importance of energy in local planning processes and explain energy infrastructure licensing processes. The Energy Commission will also help market and distribute energy tools created in partnership with the San Diego Association of Governments. These include the *Sustainable Region Program Action Plan and Toolkit*, a guide to developing energy management plans and implementing cost-saving energy measures; the *Regional Alternative Fuels, Vehicles, and Infrastructure Report*, a report showing local governments and regional stakeholders how the San Diego region plans to increase penetration of alternative fuel vehicles and infrastructure; the *Final Regional Energy Strategy Update*, which includes a how-to guide for creating a model regional energy plan; and the Regional Climate Action Plan, a how-to guide for a model regional climate plan.

■ The state should recognize that rural and urban regions differ and ensure that new sustainability, GHG, and energy requirements reflect these differences.

■ The Strategic Growth Council should research and recommend a comprehensive and stable funding source to support further efforts by local and regional governments to prepare and implement land use policies and investments consistent with the requirements of AB 32 that contribute significantly to achieving the state's 2050 GHG reduction target.

Recommendations for Carbon Capture and Sequestration

California will need innovative strategies to address GHG emissions associated with energy production and use. One such strategy is carbon capture and storage, also known as carbon capture and sequestration. The *2007 IEPR* focused on geologic sequestration strategies for the long-term management of carbon dioxide, but there have been encouraging technology advancements and investments since then. Technology developers and policy makers who are examining carbon capture and sequestration applications have expanded from an initial focus on coal and petroleum coke to natural gas and refinery gas, the predominant fossil fuels used in California power plants and industrial facilities.

The expectation that more new western power plants may rely on natural gas has expanded the emphasis on CO_2 capture and storage research, development, and demonstrations to include natural gas combined cycle plants. Similarly, California's Low Carbon Fuel Standard could lead to application of CO_2 capture and storage in conjunction with natural or refinery gas-fired furnaces/heaters, boilers, and steam/power cogeneration units. Timely resolution of issues surrounding carbon capture and sequestration projects is important because several California project proposals have been awarded support funding from the U.S. Department of Energy, with funding and associated jobs creation dependent on projects being able to proceed expeditiously.

The Energy Commission recommends:

- As a mechanism for achieving state energy and environmental objectives, the Energy Commission will continue to support and conduct carbon capture and sequestration research to demonstrate technology performance and facilitate interagency coordination to develop the technical data and analytical capabilities necessary for establishing a legal and regulatory framework for this technology in California.

- The Legislature should establish the necessary legal structure to enable efficient means of site access for carbon capture sequestration projects similar to legislation in other states that has been established to clarify or define ownership rights for the pore space within geologic formations that could store CO_2 on a long-term basis as a GHG mitigation measure. The Legislature should also adopt limited-term measures to address legal ambiguities or barriers that could hinder early carbon capture and sequestration projects.

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ACRONYMS

AB	–	Assembly Bill
ARB	–	California Air Resources Board
ARRA	–	American Recovery and Reinvestment Act of 2009
Bcf/d	–	billion cubic feet per day
BDT/y	–	bone dry tons per year
BLM	–	Bureau of Land Management
Cal/EPA	–	California Environmental Protection Agency
California ISO	–	California Independent System Operator
Caltrans	–	California Department of Transportation
CCS	–	carbon capture and sequestration
CED	–	California Energy Demand
CEQA	–	California Environmental Quality Act
CHP	–	combined heat and power
CNG	–	compressed natural gas
CO	–	carbon monoxide
CO_2	–	carbon dioxide
CPCN	–	Certificate of Public Convenience and Necessity
CPUC	–	California Public Utilities Commission
CREZ	–	Competitive Renewable Energy Zone
CTPG	–	California Transmission Planning Group
DOE	–	(United States) Department of Energy
DOF	–	Department of Finance
DRECP	–	Desert Renewable Energy Conservation Plan
EISA	–	Energy Independence and Security Act of 2007
EPBD	–	Energy Performance of Buildings Directive
EU	–	European Union
EV	–	electric vehicle
FERC	–	Federal Energy Regulatory Commission
FEV	–	full electric vehicle
FFV	–	flex fuel vehicle
GHG	–	greenhouse gas
GSP	–	gross state product
GW	–	gigawatt
GWh	–	gigawatt hour
HVAC	–	heating, ventilation, and air conditioning
HERS	–	Home Energy Rating System
IEC	–	International Electrotechnical Commission
IEPR	–	Integrated Energy Policy Report
INPO	–	Institute for Nuclear Power Operations

IOUs	–	investor-owned utilities
ISFSI	–	independent spent fuel storage installations
kWh	–	kilowatt hour
LADWP	–	Los Angeles Department of Water and Power
LCFS	–	Low Carbon Fuel Standard
LIEE	–	low-income energy efficiency
LNG	–	liquefied natural gas
LTTP	–	Long-Term Procurement Plan
Mcf	–	thousand cubic feet
MMcf/d	–	million cubic feet per day
MSW	–	municipal solid waste
MW	–	megawatt
NOx	–	nitrogen oxide
NRC	–	Nuclear Regulatory Commission
OpenADR	–	Open Automated Demand Response
OTC	–	once-through cooling
PG&E	–	Pacific Gas and Electric Company
PHEV	–	plug-in hybrid electric vehicle
PIER	–	Public Interest Energy Research
PM	–	particulate matter
PURPA	–	Public Utility Regulatory Policies Act of 1978
PV	–	photovoltaic
RD&D	–	research, development, and demonstration
REAT	–	Renewable Energy Action Team
REC	–	renewable energy credit
RETI	–	Renewable Energy Transmission Initiative
RFS	–	Renewable Fuel Standard
RPS	–	Renewables Portfolio Standard
SB	–	Senate Bill
SCAQMD	–	South Coast Air Quality Management District
SCE	–	Southern California Edison Company
SDG&E	–	San Diego Gas & Electric Company
SMUD	–	Sacramento Municipal Utility District
SoCal Gas	–	Southern California Gas Company
Solar PEIS	–	Solar Programmatic Environmental Impact Statement
SONGS	–	San Onofre Nuclear Generating Station
SWRCB	–	State Water Resources Control Board
U.S. EPA	–	United States Environmental Protection Agency
WECC	–	Western Electricity Coordinating Council
WGA	–	Western Governors' Association

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Witness:

California Energy Commission

Committee Report

Incremental Impacts of Energy Efficiency Policy Initiatives Relative to the 2009 Integrated Energy Policy Report Adopted Demand Forecast

CALIFORNIA ENERGY COMMISSION

INCREMENTAL IMPACTS OF ENERGY EFFICIENCY POLICY INITIATIVES RELATIVE TO THE *2009 INTEGRATED ENERGY POLICY REPORT* ADOPTED DEMAND FORECAST

COMMITTEE REPORT

May 2010
CEC-200-2010-001-CTF

Arnold Schwarzenegger, *Governor*

CALIFORNIA ENERGY COMMISSION

ELECTRICITY AND NATURAL GAS COMMITTEE

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DISCLAIMER

This report was prepared by the California Energy Commission's Electricity and Natural Gas Committee as part of the *2009 Integrated Energy Policy Report* process. The report may be considered for adoption by the full Energy Commission at a future Business Meeting. The views and recommendations contained in this document are not official policy of the Energy Commission until the report is adopted.

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Abstract

This report provides estimates of the impact on energy and peak demand of a set of electricity energy efficiency policy initiatives that the California Public Utilities Commission adopted in 2008. These estimates are designed to be incremental to savings already included in the adopted *2009 Integrated Energy Policy Report* demand forecast. Estimates are provided for three scenarios — low, medium, and high — that vary by policy requirements and therefore impact. An additional estimate represents directives issued by the California Public Utilities Commission for investor-owned utilities to replace 50 percent of program savings that decay as efficiency measures wear out, starting in 2006. Staff did not incorporate this decay in the previously adopted demand forecast.

For the three major investor-owned utilities combined, estimated incremental energy savings in 2020 total between 10,700 gigawatt hours and 14,400 gigawatt hours; 2020 peak savings total between 4,000 megawatts and 5,400 megawatts. These savings would reduce projected energy growth from 2008-2020 by between 57 and 77 percent and projected peak demand growth by between 56 and 91 percent. These scenario results, the additional estimates of 1,860 gigawatt hours and 382 megawatts in replaced savings decay, and the adopted 2009 demand forecast will be used in the California Public Utility Commission's forthcoming 2010 procurement rulemaking as key inputs into assessments of needed generation and other energy supply resources and will ultimately affect the procurement authority granted to investor-owned utilities.

Keywords: Efficiency, committed savings, uncommitted savings, incremental uncommitted savings, Total Market Gross, Big Bold initiatives, managed forecast, decay

Executive Summary

Energy efficiency is the top priority for addressing California's electricity system issues. Quantitative goals reflective of this commitment are established in state law, decisions by various agencies and planning analyses. Although California has pursued energy efficiency since the 1970s through building, and appliance standards, utility and public agency programs, local ordinances, and loan/grant programs, it can be hard to determine the incremental effect of undefined future efforts. Resource planners, who must identify the amount and type of additional grid-connected power plants and local capacity to support reliability, need accurate projections of incremental savings from energy efficiency beyond the funded programs included in the baseline demand forecasts. This report documents efforts to develop sufficiently rigorous analyses of a future set of policy initiatives to use in resource planning and reliability studies.

Incremental Impacts of Energy Policy Initiatives Relative to the 2009 Integrated Energy Policy Report Adopted Demand Forecast estimates the effect on energy and peak demand by a set of electricity energy efficiency policy initiatives[1] that the California Public Utilities Commission (CPUC) adopted in D.08-07-047. With few exceptions, the policy initiatives evaluated are the same set of hypothetical delivery mechanisms originally evaluated by Itron and adopted by the CPUC in the *2008 Energy Efficiency Goals Update Report*[2] *(2008 Goals Study)*. The Energy Commission does not consider this set of delivery mechanisms to be *committed*, or firm, and so their impacts were not included in the *2009 Integrated Energy Policy Report*[3] *(IEPR)* demand forecast.[4] At the CPUC's request, this report documents the results of an analysis designed to estimate the *incremental* impacts of three levels of policy stringency for these initiatives. In this context, *incremental* refers to savings from the CPUC efficiency policy initiatives that are separate from any overlap with savings already included in the demand forecast. CPUC staff intends to use these projected load impacts as part of the portfolio assessment analyses used to define the need for electricity resources in the forthcoming 2010 Long-Term Procurement Plan rulemaking.

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1. In this report, "initiatives" refer to all types of policy-related efficiency delivery mechanisms, including utility and public agency programs, codes and standards, and efficiency-related legislation.

2. http://www.cpuc.ca.gov/NR/rdonlyres/8944D910-ECA2-4E19-B1F3-96956FB6E643/0/Itron2008CAEnergyEfficiencyStudy.pdf.

3. California Energy Commission, *2009 Integrated Energy Policy Report, Commission Final Report*, December 2009, CEC-100-2009-003-CMF. http://www.energy.ca.gov/2009publications/CEC-100-2009-003/CEC-100-2009-003-CMF.PDF.

4. California Energy Commission, *California Energy Demand 2010-2020, Commission Adopted Forecast*, December 2009, CEC-200-2009-012-CMF. http://www.energy.ca.gov/2009publications/CEC-200-2009-012/index.html.

Table 1 provides a summary of the 2020 energy and peak savings that are considered incremental to savings included in the *2009 IEPR* demand forecast for each of the three major investor-owned utility service areas and for each of the three scenarios that were investigated. The peak and energy impacts of the three scenarios can be subtracted directly from the *2009 IEPR* demand forecast in the CPUC's effort to develop a *managed demand forecast*[5] that investor-owned utilities would use in the 2010 Long-Term Procurement Plan's portfolio assessments.

Table 1: 2020 Incremental Impacts of *2008 Energy Efficiency Goals Update Report* Policy Initiatives Beyond Those Included in the *2009 IEPR* Demand Forecast

Utility	Savings	Scenario		
		Low	Mid	High
PG&E	Energy (GWh)	4,634	5,130	6,087
	Peak (MW)	1,731	2,245	2,722
SCE	Energy (GWh)	4,971	5,874	6,848
	Peak (MW)	1,941	2,593	3,160
SDG&E	Energy (GWh)	1,091	1,222	1,440
	Peak (MW)	363	514	602
Total IOUs	Energy (GWh)	10,658	12,225	14,374
	Peak (MW)	4,034	5,352	6,484

Source: Itron and California Energy Commission, 2009.

Table 2 shows the percentage of projected demand forecast load growth represented by the incremental energy and peak savings in 2020. For example, in the low savings scenario for Pacific Gas and Electric, 56 percent of energy growth from 2008-2020 projected in the *2009 IEPR* demand forecast would be eliminated by the estimated incremental uncommitted savings.

5. *Managed demand forecast* means a forecast that is different from "business as usual" through the explicit use of program activities to adjust demand downward. Such adjustments could include any demand-side policy initiatives: energy efficiency, distributed generation, and other types of response considered demand adjustments rather than supply-side resources.

Table 2: 2020 Incremental Impacts of 2008 Energy Efficiency Goals Update Report Policy Initiatives as a Percentage of Projected Load Growth

Utility	Savings	Scenario		
		Low	Mid	High
PG&E	Energy	56%	62%	74%
	Peak	70%	91%	110%
SCE	Energy	62%	74%	86%
	Peak	50%	67%	81%
SDG&E	Energy	44%	49%	58%
	Peak	46%	65%	77%
Total IOUs	Energy	57%	65%	77%
	Peak	56%	75%	91%

Source: Itron and California Energy Commission, 2009.

This analysis was prepared by Energy Commission staff and the consulting firm Itron. Most of Itron's efforts were funded by the CPUC. With some exceptions, the definitions of initiatives established in the *2008 Goals Study,* used to establish the investor-owned utility interim 2012–2020 energy efficiency goals, remained the same. A few were modified because not all initiatives had started by January 2009 as assumed in that study. Also, the values for fundamental inputs used in this analysis have been updated from those used in the *2008 Goals Study* to conform to those used in the *2009 IEPR* demand forecast. Finally, some energy efficiency programs considered prospective in previous forecasts now satisfy the Energy Commission's definition of committed. Those program impacts are embedded in the *2009 IEPR* demand forecast, so are not included in this analysis. Consequently, this project reassesses the impacts of the original policy initiatives first quantified in the *2008 Goals Study*, adjusting the analyses to reflect changes that arose in the intervening period and to ensure consistency with the *2009 IEPR* demand forecast. The impacts resulting from this approach are incremental to, and consistent with, the analyses in the base *2009 IEPR* demand forecast itself.

The results shown in **Table 1** document estimated energy and peak impacts for a specific set of hypothetical energy efficiency initiatives identified in the CPUC's 2008 goal-setting effort. Four broad categories of policy initiatives were included:

- Expanded investor-owned utility programs
- State and federal codes and standards
- The Big Bold energy efficiency initiatives, part of the CPUC's Long Term Energy Efficiency Strategic Plan designed specifically for heating, ventilation, and air conditioning, "zero-energy" homes and businesses, and low-income homes.
- Lighting efficiency measures in satisfaction of Assembly Bill 1109 (Huffman, Chapter 534, Statutes of 2007)

The *2008 Goals Study* defined three scenarios involving various programmatic stringencies and degrees of effort across these four categories. The CPUC chose to adopt the mid scenario results as the basis for interim energy efficiency savings goals for 2012–2020. For this report, the scenario definitions have been retained, and the effects resulting from each of the three are projected through 2020.

The three scenarios reflect specific sets of delivery mechanisms, defined in terms that allow broad quantification of their energy impacts. The scenarios are alternative interpretations of how the Energy Commission, CPUC, and other agencies might pursue a high energy efficiency future for California. These results can be viewed as a step in the direction of quantifying the Energy Commission's *2007 IEPR* policy recommendation to pursue all cost-effective energy efficiency potential. By identifying hypothetical designs for a set of energy efficiency mechanisms, one can make initial estimates of impacts and costs. These hypothetical designs can also be viewed as specifying a set of policy initiatives, which, if pursued through actual program design and implementation, would begin to achieve the high energy efficiency goals established in the California Air Resources Board (ARB) *AB 32 Scoping Plan*.[6]

The estimates of incremental uncommitted savings in this analysis are not directly comparable to the AB 32 *Scoping Plan* targets. Instead, those targets are statewide goals specified relative to a "business as usual" future developed using the *2007 IEPR* demand forecast. However, an approximate contribution that the estimated incremental savings may make toward meeting the 2020 AB 32 target can be calculated. This is done by adjusting the 2020 target by the increase in efficiency impacts in the *2009 IEPR* demand forecast relative to the 2007 forecast (extrapolated to 2020 by Energy Commission staff). The AB 32 *Scoping Plan* specifies a statewide electricity reduction target of 32,000 gigawatt hours (GWh) in 2020 (Appendix C, p. C-99) relative to the 2007 forecast. Subtracting the *2009 IEPR* demand forecast increase in efficiency impacts statewide projected for 2020 (around 10,000 GWh) leaves 22,000 GWh. In the low, mid, and high scenarios for this report, combined IOU incremental uncommitted savings in 2020 are estimated at 10,700 GWh, 12,200 GWh, and 14,400 GWh, respectively. These estimates are for just the three large IOUs, which are roughly 75 percent of statewide electricity consumption. If, for sake of argument, the POUs pursue uncommitted efforts in a manner comparable to the IOU efforts assessed in this report, then the policy initiatives included in this analysis cover 65 - 90 percent of the *Scoping Plan* goal on a statewide basis, depending on the scenario.

In addition, directives issued by the CPUC to IOUs that 50 percent of historical program savings decay since 2006 be replaced through additional programmatic efforts were not reflected in the adopted demand forecast. Staff estimates that 1,860 GWh and 382 megawatts (MW) of additional 2006–2012 impacts (further savings) would have been reflected in the adopted demand forecast by 2020 if such policy directives had been followed in preparing the demand forecast. This suggests that an additional 1,860 GWh and 382 MW be subtracted from the adopted forecast when using the adopted demand forecast in a CPUC resource planning and

6. http://www.arb.ca.gov/cc/scopingplan/scopingplan.htm.

procurement proceeding. This decay replacement is additional to whatever scenario policy initiatives the CPUC directs IOUs to pursue in their portfolio assessments.

Considerable uncertainty exists about the results of a pursuing a high energy efficiency future through this or any other sets of hypothetical delivery mechanisms. The CPUC confronted policy uncertainty in the *2008 Goals Study* by positing three scenarios of alternative assumptions that varied the stringency of standards, the levels of incentive funding for voluntary programs, and assumptions about the proportion of future homes and businesses constructed to reduce energy usage.

The three amounts of incremental annual energy and peak demand impacts presented in this report reveal the spread resulting from the different delivery mechanism specifications. In addition, numerous dimensions of technical uncertainty should also be recognized, even though they have not been quantified. For example, the level of economic and demographic growth through 2020 directly affects the new construction savings possible through mandatory Title 24 building standards. Further, whether end-use customers will voluntarily agree to participate in utility programs to the degree assumed here depends on their general willingness to participate, the incentive levels for high efficiency measures, and the amount of disposable income available to invest in more efficient equipment. Finally, whatever the quantity of more efficient equipment installed, real-world savings could be higher or lower than assumed in this study. These factors, and numerous others, place a considerable uncertainty band around the savings estimates associated with each of these three scenarios. The uncertainties identified in this report will be addressed further in the CPUC's procurement and energy efficiency implementation process.

Although the precise details of how these energy efficiency scenario results will be used in the 2010 procurement proceedings remain to be determined, **Attachment C** of this report provides a sketch of the how CPUC Energy Division staff anticipates using these results to prepare managed demand forecasts for use in supply-side portfolio assessments.

Three more general points need to be made regarding the results in this analysis. First, a more holistic approach toward energy efficiency adjustments and their likelihood of occurrence should guide planning assumptions about supply resources needed to meet future energy demand. Historically, economic and demographic variables have been the main drivers of energy growth trends, but the results of this analysis imply that policy drivers are also a large factor. Economic and demographic growth is always uncertain, but future ranges can generally be bounded. Policy drivers are more difficult to predict. Second, decision makers must consider the implications of efficiency-induced projections for very low or even negative energy and peak demand growth through 2020. While the *Energy Action Plan* loading order emphasizes cost-effective energy efficiency as California's first choice to meet demand growth, relying solely on these resources for long-term resource adequacy is uncharted territory. Third, if decision makers postpone decisions to invest in new generation and energy efficiency fails to deliver as forecasted, serious reliability (and cost) consequences could result, unless such shortfalls are recognized and contingency actions identified.

The Energy Commission's IEPR Committee endorses the following recommendations, most of which were suggested by staff in the draft of this report:

- In further goal-setting proceedings, goals should be described with reference to a baseline projection or set of assumptions. This will make clearer the incremental impacts of such goals beyond similar impacts already included in the baseline.
- The CPUC should use the projections of incremental uncommitted initiative impacts developed in this report as one of several adjustments to the adopted *2009 IEPR* demand forecast to develop three separate managed demand forecasts to use as the basis for portfolio analyses in the forthcoming 2010 Long-Term Procurement Plan proceeding.
- The CPUC should further adjust the managed forecast downward to conform to its directives for IOUs to replace 50 percent of utility programmatic savings decay beginning in 2006. These estimates are provided for both peak and energy savings in **Table 12**, Chapter 5.
- To the extent that separate models (such as the Energy Commission's demand forecasting models and Itron's SESAT) are used in subsequent analyses to determine the incremental impact of hypothetical policy initiatives, better coordination of primary input assumptions should be made, such as rerunning all models with a common set of price projection assumptions.
- The Energy Commission staff should continue to develop a capability for making incremental uncommitted energy efficiency projections for use in the 2011 IEPR proceeding, CPUC 2012 procurement proceedings, ARB efforts to assess options for satisfying the GHG emission reduction requirements of Assembly Bill 32 (AB 32) (Núñez, Chapter 488, Statutes of 2006), and related inquiries. This capability will require further coordination of modeling methods and assumptions between those used to prepare baseline demand forecasts and those used to estimate the incremental impacts of uncommitted policy initiatives. In turn, such efforts depend upon appropriate staffing and data collection activities.

CHAPTER 1: Introduction

This report, along with a detailed appendix prepared by Itron, provides an assessment of the *incremental* impacts of a set of California Public Utilities Commission (CPUC) energy efficiency policy initiatives[7] not incorporated in the demand forecast adopted by the California Energy Commission[8] in the *2009 Integrated Energy Policy Report*[9] (*2009 IEPR*) proceeding. In this context, incremental refers to electricity savings from the CPUC efficiency initiatives that are net of any overlap with savings already included in the adopted *2009 IEPR* demand forecast. These initiatives were not incorporated in the *2009 IEPR* demand forecast because they were not considered *committed,* or firm. This analysis uses the *2009 IEPR* demand forecast as the reference point, since this forecast will be used in procurement assessments at the CPUC.

The Energy Commission and other energy agencies are dedicated to pursuing energy efficiency at a level exceeding that incorporated in the *2009 IEPR* demand forecast. In some cases, this pursuit is described in non-quantitative terms, such as all cost-effective energy efficiency potential. In other cases, it is put in terms of quantitative goals for a specific year, such as 33,000 GWh of electricity savings by 2020. In its most recent cycle of strategic planning and energy efficiency goal setting, the CPUC identified a specific set of initiatives to reflect its aggressive treatment of energy efficiency. Through various decisions, the CPUC requires that such aggressive treatment be incorporated in long-term procurement planning for the investor-owned utilities (IOUs) it regulates. During the 2008 IEPR Update proceeding, the CPUC requested that the Energy Commission develop corresponding incremental energy efficiency estimates that could be subtracted from the Energy Commission's adopted demand forecast. These energy efficiency adjustments contribute to a *managed demand forecast*[10] that IOUs would use in the resource planning assessments for the 2010 Long-Term Procurement Plan (LTPP) proceeding. The Energy Commission agreed to undertake such an effort, and this report includes low, medium, and high estimates of incremental load impacts from these initiatives.

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7. In this report, "initiatives" refer to all types of policy-related efficiency delivery mechanisms, including utility and public agency programs, codes and standards, and other efficiency-related legislation.

8. California Energy Commission, *California Energy Demand 2010-2020, Commission Adopted Forecast*, December 2009, CEC-200-2009-012-CMF. http://www.energy.ca.gov/2009publications/CEC-200-2009-012/index.html. Referred to in this report as the *2009 IEPR* demand forecast.

9. California Energy Commission, *2009 Integrated Energy Policy Report, Commission Final Report*, December 2009, CEC-100-2009-003-CMF. http://www.energy.ca.gov/2009publications/CEC-100-2009-003/CEC-100-2009-003-CMF.PDF.

10. *Managed demand forecast* is meant to convey a forecast that is different from "business as usual" through the explicit use of program activities to adjust demand downward. Such adjustments could include any demand-side policy initiatives: energy efficiency, distributed generation, and other types of response considered demand adjustments rather than supply-side resources.

Energy Commission Demand Forecast

The Energy Commission prepares an *IEPR* on a biennial cycle, with the report typically adopted in November of odd-numbered years (an update to the currently adopted IEPR is prepared in even-numbered years). The electricity demand forecast covers 10 future years, so the forecast extends to 2020 for the *2009 IEPR*. The Energy Commission forecasts demand for eight "planning areas" encompassing all of the load and resources for the five balancing authorities contained within California. (Minor portions of upper Northern California and the Lake Tahoe area are served by utilities centered in Oregon and Nevada, respectively.) The analysis discussed in this report requires demand forecasts for the actual IOU service areas, which differ from the planning areas in the case of Pacific Gas and Electric (PG&E) and Southern California Edison (SCE). The *2009 IEPR* demand forecast provides these service area forecasts by subtracting out demand forecasts for all of the publicly owned utilities included within the broader PG&E and SCE planning areas. No such adjustments are needed for San Diego Gas & Electric (SDG&E) since there are no publicly owned utilities embedded within the SDG&E planning area.

In preparing its long-run demand forecasts, the Energy Commission follows a practice of distinguishing between demand-side impacts that it considers *committed* and others that are *uncommitted.* Committed initiatives include utility and public agency programs, codes and standards, and legislation and ordinances that have final authorization, firm funding, and a design that can be readily translated into characteristics that can be evaluated and used to estimate future impacts (for example, a package of IOU incentive programs that has been funded by CPUC order). In addition, committed impacts include *naturally occurring* savings, which consist of price effects and other savings not directly related to a specific initiative.[11] Committed impacts are evaluated and embedded within the demand forecast. The impacts of initiatives that do not meet the committed criteria, uncommitted impacts, are typically more uncertain and cannot be projected with the accuracy expected of baseline demand forecasts used for resource planning and investment decision-making. Additional discussion of committed versus uncommitted impacts is provided in **Chapter 2**.

An illustration of this rationale involves CPUC-funded energy efficiency programs administered by the IOUs. Funding cycles for these energy efficiency programs are approved typically in three-year cycles. As a result of CPUC Decision D.09-09-047, programs are committed through the end of 2012.[12] The *2009 IEPR* demand forecast, however, extends through 2020. On the one hand, the Energy Commission aims to include only committed initiatives in its demand forecast. On the other hand, there is a high probability that the CPUC will fund additional energy efficiency programs of some type during the time frame covered by

11. The naturally occurring category also includes savings resulting from social phenomena that induce shifts toward lower energy consumption and technological innovation bringing more efficient products to market.

12. CPUC energy efficiency decisions referenced in this report are documented in **Attachment B**.

the *2009 IEPR* demand forecast. Therefore, this analysis serves as a supplement to the *2009 IEPR* demand forecast by providing estimates of incremental impacts of prospective CPUC-funded energy efficiency programs in the years following 2012. This analysis also includes estimated energy efficiency savings from other sources that, like the CPUC-funded energy efficiency programs, are expected to occur during the forecast period but are appropriately designated as uncommitted. Through its goal setting process, the CPUC is making commitments to further energy efficiency policy initiatives, even though the characterization or content of the delivery mechanisms is highly likely to change over time. Because of this greater uncertainty, three alternative policy initiative scenarios were assessed by varying the stringency and timing of the activities pursued. The analysis, therefore, reflects policy uncertainty about the actual design and stringency of the programs.

The repeal of large sections of the Public Resources Code through Senate Bill 1389 (Bowen, Chapter 568, Statutes of 2002) and their replacement with the current language of Public Resources Code Sections 25300 – 25322 removed from law the efficiency-related concept described as "reasonably expected to occur." This term served as guidance for the level of energy efficiency the Energy Commission should consider in its electricity planning efforts, functioning as a constraint in Energy Commission demand forecasts. Although the current approach should not necessarily be construed as being consistent with the former statutory test, those portions of energy efficiency impacts considered committed, and therefore already included in the *2009 IEPR* demand forecast, might be readily agreed to satisfy the former "reasonably expected to occur" standard.

This standard could also serve as a constraint for the analysis of uncommitted initiatives, in terms of which ought to actually be recognized in electricity planning efforts. However, this report has not been designed to endorse a position regarding whether or to what degree the energy efficiency initiatives and associated levels of commitment included in this analysis are "reasonably expected to occur" or whether some other level, higher or lower, might be expected. **Attachment D** to this report provides a discussion of application of the concept of "reasonably expected to occur" as the CPUC/Energy Division (ED) staff proposes it be applied in the forthcoming 2010 Long-Term Procurement Process (LTPP) proceeding.

CPUC Specification of Alternative Sets of Hypothetical Policy Initiatives

There are undoubtedly many descriptions of uncommitted energy efficiency initiatives that could potentially occur during the forecast period. However, this analysis is not designed to quantify the potential universe of all energy efficiency investments that might be considered economic. Rather, this report seeks to quantify the projected effects from a specific set of activities outlined in the CPUC-sponsored *2008 Energy Efficiency Goals Update Report*[13] (*2008 Goals Study*). The *2008 Goals Study* focused on energy efficiency that could be captured as a result of key initiatives likely to affect efficiency in the IOU service territories through 2020, based on information that was available when the report was prepared in 2008. The CPUC intends to update the *2008 Goals Study*, as well as CPUC-adopted energy efficiency goals, every few years to include new analyses and information as appropriate.

The CPUC is interested in obtaining the incremental impacts relative to Energy Commission IEPR demand forecasts from a set of prospective energy efficiency impacts defined as part of the *2008 Goals Study* and D.08-07-047. In this case, incremental impacts will be used to modify the *2009 IEPR* demand forecast in the 2010 LTPP proceeding. The CPUC/ED staff proposes that managed demand forecasts incorporating these and other adjustments will be the basis for resource portfolio assessments that will set the stage for procurement authority issued by the CPUC for each IOU.[14]

The CPUC has indicated that, in the 2010 cycle, the LTPP will be split into two proceedings: one addressing electricity system reliability and need assessments and a second addressing "bundled" IOU procurement plans.[15] Thus, there are two potentially distinct applications for this analysis. First, the entire amount of any of the three scenario impacts through time may properly be used to develop a managed demand forecast for an IOU service area, or the collection of all three IOU service areas, as a basis for determination of need for new system resources. Second, a smaller amount, scaled down to reflect the portions of the results that apply strictly to bundled service customers, may be the appropriate amount to use in devising procurement authority for IOU bundled service customers. The second application is likely to become more important over time with the recent passage of Senate Bill 695 (SB 695) (Kehoe, Chapter 337, Statutes of 2009), allowing the expansion of direct access service to individual retail non-residential end-use customers. CPUC D.10-03-022 implements SB 695 by providing a schedule for the gradual increase in the proportion of load that can shift to direct access through time.

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13. http://www.cpuc.ca.gov/NR/rdonlyres/8944D910-ECA2-4E19-B1F3-96956FB6E643/0/Itron2008CAEnergyEfficiencyStudy.pdf.

14. See Attachment 2 to the July 1, 2009, Assigned Commissioner's Ruling in the 2008 LTPP Rulemaking (R.) 08-02-007: *Energy Division Straw Proposal on LTPP Planning Standards*, July 2009. http://docs.cpuc.ca.gov/word_pdf/RULINGS/103212.pdf

15. See December 3, 2009, *Assigned Commissioner's Ruling Addressing Future Commission Activities Related to Procurement Planning*. http://www.cpuc.ca.gov/EFILE/RULINGS/110674.pdf. Bundled service refers to customers who receive electric generation, transmission, distribution, and related customer service and support functions as a combined service.

Focus for Energy Commission Demand Forecasting Efforts in the *2009 IEPR* Cycle

The Energy Commission's demand forecasting efforts require most of a two-year IEPR cycle to prepare for and complete. Given the issues of the day, sometimes the emphasis within a specific biennial cycle may be targeted to a specific topic needing more attention. As a result of controversy in past CPUC procurement proceedings about the level of efficiency savings actually embedded in the Energy Commission demand forecast, the emphasis in the *2009 IEPR* cycle was on better quantifying energy efficiency. Within this broad topic, two principal efforts focused on:

- Updating and improving the analysis of energy efficiency savings considered committed for the *2009 IEPR* demand forecast.
- Creating a new capability to assess the incremental impacts of what the Energy Commission considers uncommitted energy efficiency savings.[16]

The analysis of the incremental impacts of uncommitted initiatives builds from the *2009 IEPR* electricity demand forecast in two ways. First, it reduces the original programmatic scope of the scenarios from the *2008 Goals Study* by eliminating programs now considered committed by the Energy Commission and whose impacts are included within the adopted *2009 IEPR* demand forecast. This is an accounting treatment that recognizes that the passage of time between adoption of the *2008 Goals Study* and the preparation of the *2009 IEPR* demand forecast. The obvious example of this is the 2009-2011 energy efficiency program proposals that were adopted by the CPUC in September 2009 as 2010-2012 programs by D.09-09-047.

Second, it conforms the analysis of uncommitted initiative designs and their impacts in the *2008 Goals Study* to the economic driver assumptions (for example, household and commercial floor space growth) used in the *2009 IEPR* demand forecast. This reflects the fact that, while the energy efficiency goals articulated in D.08-07-047 are commonly thought of in terms of absolute energy and peak demand reductions that utilities are required to achieve, the goals are actually conditional upon economic and demographic growth and other descriptors of underlying energy usage behavior. The analysis in the *2008 Goals Study* was developed in large part using economic, demographic, and other assumptions used in the *2007 IEPR* demand forecast. In the real world, neither economic and demographic activity nor energy usage behavior conforms neatly to planning assumptions. Therefore, the newer assumptions used in the *2009 IEPR* demand forecast were used to recalculate the savings impacts of the portion of the *2008 Goals Study* scenarios that are still considered to be uncommitted.

A draft version of this report was prepared in advance of two workshops held in February 2010. A staff workshop on February 3, 2010, was dedicated to technical issues related to the analysis

16. The CPUC funded Itron to assist the Energy Commission staff in both elements of this effort.

and a workshop under the authority of the IEPR and Electricity and Natural Gas Committees was held on February 17, 2010, to examine policy-related questions. Discussion at these workshops, comments received, and direction of the committees guided preparation of this final report. Some discussion and comments raised issues that cannot be resolved in the context of this project but are useful to consider in future iterations of this analysis. The principal ways in which this final report differs from the draft are: (1) incorporation of CPUC directives to IOUs concerning replacement of savings decay from IOU program efforts; and (2) alternative peak demand results that are significantly linked to peak weather assumptions. This linkage is highly visible for particular programs emphasizing air conditioning measures. The final report and appropriate communications from the Energy Commission will be provided to the CPUC as an input in the 2010 LTPP rulemaking, which is expected to begin in May 2010.

Organization of This Report

Chapter 1 provides the basic background needed to understand the context of this report. **Chapter 2** summarizes the specific policy context for incremental uncommitted energy efficiency savings, as first debated in R.06-02-013. **Chapter 3** discusses the conceptual issues related to determining the portion of uncommitted energy efficiency impacts incremental to the *2009 IEPR* demand forecast. **Chapter 4** discusses the method used to estimate incremental uncommitted savings. **Chapter 5** summarizes the results for each of the three scenarios that were investigated. **Chapter 6** provides conclusions, caveats, and recommendations.

Attachment A, prepared by Itron, gives a full description of the incremental uncommitted analysis and provides detailed results. **Attachment B** provides an explanation by CPUC/ED staff of the series of adjustments to IOU energy efficiency goals and the CPUC efficiency goal-setting history since 2004. **Attachment C** gives a brief explanation by CPUC/ED staff concerning the concept of a managed demand forecast and how such a demand forecast could be used in supply-side portfolio assessments. **Attachment D** is a technical glossary.

CHAPTER 2: Policy Context

The Energy Commission and CPUC both conduct electricity planning processes under various statutory directives and agency prerogatives. Some coordination between these processes has been accomplished, while further coordination discussions between the two Commissions and with the California Independent System Operator (California ISO) are underway.

In the context of long-run demand forecasts and assessing the impacts of energy efficiency on annual energy and peak demand, the Energy Commission conducts planning assessments for all of California, while the CPUC conducts assessments for the service areas where its regulated utilities provide energy and distribution services. Further reflecting slightly different legislative mandates, the Energy Commission's assessments find use in many applications, while the CPUC is especially concerned with authorizing energy efficiency programs and procuring generation services for utility-bundled service customers and assessing the financial consequences of these actions on IOU customer rates. The CPUC also authorizes IOU procurement of new resources for system reliability through the resource adequacy program, under Public Utilities Code Section 380.

Problems arose in the 2006 LTPP proceeding when the CPUC attempted to combine an Energy Commission baseline demand forecast with independently prepared estimates of energy efficiency program impacts analyzed using different models and input assumptions. Lacking sufficient time and resources to resolve this problem when it was encountered, the CPUC and Energy Commission decided to improve coordination to avoid the problem in subsequent IEPR/LTPP planning cycles.

Context of 2006 LTPP Proceeding and D.07-12-052

Following passage of SB 1389, directing the Energy Commission to undertake a biennial planning and policy report cycle culminating in the *IEPR*, and Assembly Bill 57 (AB 57) (Wright, Chapter 835, Statutes of 2001), establishing a legal foundation for IOU electricity resource procurement under ground rules set by the CPUC, D.04-01-050[17] created a biennial LTPP rulemaking process. The LTPP cycle was designed to follow completion of a biennial *IEPR* so that the *IEPR's* information and analyses could be used in the LTPP analyses.

As a part of planning process coordination discussions between the Energy Commission and the CPUC, CPUC President Michael Peevey issued two Assigned Commissioner Rulings in the 2006 LTPP rulemaking that directed use of the demand forecast and consideration of other information and analyses contained within the Energy Commission's *2005 Integrated Energy*

17. California Public Utilities Commission, Decision 04-01-050, *Interim Opinion*, January 22, 2004, available at http://docs.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/33625.htm.

Policy Report (*2005 IEPR*).[18] This information was communicated to the CPUC in a November 2005 "transmittal report" developed to provide the results contained within the *2005 IEPR* and references to the key aspects of the Energy Commission's IEPR proceeding. Utilities raised various issues about the *2005 IEPR* demand forecasts in the CPUC rulemaking, making unclear for a time whether the Energy Commission's forecasts would actually be used.

A key issue during the 2006 LTPP rulemaking was the extent to which projections of future utility "net short" positions[19] would take into account estimates of modifications to base energy forecasts for demand-side policy impacts such as energy efficiency, demand response, and other preferred resource types. The more the base demand forecast was adjusted downward for impacts of policies not already embedded in the base demand forecast, the lower the "net short" results would be.

Late in the 2006 LTPP rulemaking, when the proposed decision relied on the *2007 IEPR* demand forecast[20] (to be adjusted by subtracting out utility estimates of preferred demand-side resource additions), utilities questioned the extent to which the impacts of such policy initiatives might already be embedded in the Energy Commission forecast. At this point in the proceeding, there was neither time nor detailed documentation from the Energy Commission about its 2007 demand forecast to settle this question. This gave rise to the initial supposition within the proposed decision that 50 percent of initiative impacts were already embedded in the demand forecast, leaving 50 percent to be "subtracted off" as a further adjustment to the forecast before computing "net short" positions. Utilities protested this solution, and eventually D.07-12-052 adopted 80 percent as overlap factors for PG&E and SCE (20 percent of impacts subtracted off the forecast), and a 100 percent overlap factor for SDG&E. These values meant that relatively few impacts of the proposed policy initiatives were considered incremental to the baseline demand forecast, resulting in a larger "net short" position for the IOUs. Thus, the three IOUs were authorized to procure more resources than would have been the case had a smaller proportion of the estimated program savings been considered overlapping with efficiency impacts incorporated in the *2007 IEPR* demand forecast.

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18. ACRs issued September 2004 and March 2005 in CPUC R.04-04-003.

19. *Net short* is the difference between projected utility sales and forward purchase contracts, after adjusting for loading order resources such as energy efficiency.

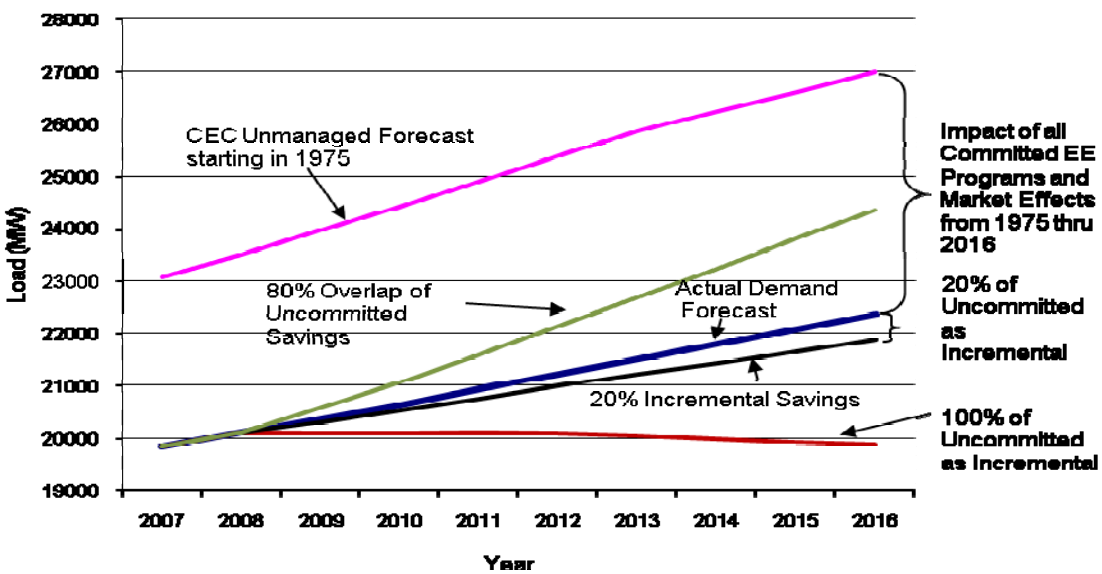
20. Due to the passage of time, the Energy Commission had already completed another biennial cycle for its *Integrated Energy Policy Report*. CPUC staff proposed to substitute the *2007 IEPR* demand forecast for the *2005 IEPR* demand forecast. The detailed documentation for this demand forecast, including description of the energy efficiency program impacts embedded within it, was not released until November 2007, only weeks before the final decision in the 2006 LTPP rulemaking was adopted. California Public Utilities Commission, Decision 07-12-052, *Opinion Adopting Pacific Gas and Electric Company's Long-Term Procurement Plans*, December 20, 2007, available at: http//docs.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/769079.htm.

Figure 1 illustrates how one might think of the issue of overlap between committed and uncommitted savings, using the *2007 IEPR* demand forecast and PG&E for this example.[21] The topmost curve shows what the demand forecast for PG&E would look like on a completely unmanaged basis, that is, without any impacts from committed energy efficiency savings from 1975 onward. The distance between this curve and the one showing the actual demand forecast represents the total amount of committed savings incorporated in the forecast. Two additional lines show the implied impacts of an overlap factor for uncommitted savings of 80 percent: The distance between the curve labeled "80% Overlap of Uncommitted Savings" and the actual demand forecast curve adopted in the *2007 IEPR* represents the amount of uncommitted savings impacts that would already be embedded in the forecast under the 80 percent assumption. The corresponding curve labeled "20% Incremental Savings" shows the managed forecast[22] under this assumption. On the other hand, assuming no overlap between committed and uncommitted savings, meaning all uncommitted savings would be subtracted, results in a declining managed forecast (bottom curve labeled "100% Incremental Savings"). Clearly there is a major distinction between these two results in terms of the amount of generating resources required to provide the energy end users are expected to consume and/or satisfy reliability standards.

21. Figure 1 uses peak demand data for PG&E from D.07-12-052 to illustrate the issue. Similar graphs could be developed for SCE and SDG&E from the same source. An earlier version of this figure was included in the Energy Commission's *2008 IEPR Update*.

22. For this example, adjustment from the demand forecast to the managed forecast is assumed to include only additional efficiency impacts.

Figure 1: Illustration of CPUC D.07-12-052 Adjustments to Energy Commission Demand Forecast for Incremental EE Impacts (PG&E Service Area Values)



Source: California Energy Commission, 2009

2008 Goals Update Report and D.08-07-047

Beginning in 2007, CPUC/ED staff initiated an effort with Itron as principal contractor to develop what became the *2008 Goals Study*. Augmenting previous energy efficiency potential studies, including a utility-funded *2008 Energy Efficiency Potential Study,*[23] this effort considered the long-range impact of a wide range of initiatives, not just utility-based efficiency programs. Through the CPUC's *California Long-Term Energy Efficiency Strategic Plan*[24] and as part of energy agency contributions to the development of the California Air Resources Board (ARB) AB 32 *Climate Change Proposed Scoping Plan*[25] for greenhouse gas reductions, the CPUC thought expansively about how to realize large amounts of remaining untapped energy efficiency potential from all customer sectors. It recognized that IOU programs were not the only delivery mechanisms operating in the real world, nor should they be the only source of prospective savings to consider when determining goals to achieve.

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23. http://www.calmac.org/startDownload.asp?Name=PGE0264_Final_Report.pdf&Size=5406KB.

24. California Public Utilities Commission, *California Long Term Energy Efficiency Strategic Plan*, September 2008. http://www.cpuc.ca.gov/NR/rdonlyres/D4321448-208C-48F9-9F62-1BBB14A8D717/0/EEStrategicPlan.pdf.

25. http://www.arb.ca.gov/cc/scopingplan/document/psp.pdf

Itron was charged with developing a study that identified impacts from energy efficiency initiatives pursued through a broad range of delivery mechanisms. These initiatives included:

- Expanded utility programs
- Periodically updated state Title 20 and 24 standards along with updated federal appliance standards
- CPUC's Big Bold energy efficiency initiatives
- Lighting efficiency measures in satisfaction of Assembly Bill 1109 (Huffman, Chapter 534, Statutes of 2007)

Energy efficiency savings that could potentially be achieved from these sources taken together were referred to as *total market gross* savings. The CPUC adopted this concept in D.08-07-047. This was a policy shift in two respects. First, "total market" refers to policy initiatives beyond those historically pursued through utility programs. For example, the goals adopted in D.08-07-047 explicitly include codes and standards, which the utilities could not implement themselves, although they have pursued programs intended to increase compliance. Second, "gross" means that ancillary consequences of programs, such as free-ridership and spillover, would be counted toward the goal. This policy shift therefore means that a variety of savings sources now count toward goal achievement. Itron assessed the likely total market gross savings impacts from three different scenarios (high, mid, and low). **Chapter 3** provides details on each of these scenarios.

Itron developed its report, the CPUC/ED prepared a white paper proposing how the results should be used, parties provided responses, a proposed decision was issued, and the CPUC ultimately adopted energy efficiency total market gross goals described in D.08-07-047. In addition to its role in providing an estimate of energy efficiency savings that ARB could rely upon for its *Climate Change Proposed Scoping Plan*, the decision also directed that the total market gross goals be used in subsequent LTPP rulemakings to guide IOU generation procurement actions. Of importance to this analysis, the CPUC elaborated upon the direction it had provided to the IOUs in a previous decision[26] to incorporate 100 percent of the adopted savings goals in subsequent LTPP proceedings.[27] The adopted values came from the mid savings scenario results provided in the *2008 Goals Study* prepared by Itron.

The switch to total market gross goals has numerous implications for how energy efficiency programs are implemented, incorporated into Energy Commission *IEPR* demand forecasts, and used for procurement planning purposes. This analysis begins the process of examining these implications, but further work is needed to transition demand forecasting and resource planning to this new paradigm.

26. D.04-09-060, OP 6.

27. D.08-07-047, p. 26 and OP 3.

Energy Commission Use of Committed/Uncommitted Paradigm

In response to positions advocated by various parties (IOUs in particular), the Energy Commission considered in the *2008 IEPR Update* proceeding whether it should revise its traditional use of the committed/uncommitted paradigm. IOUs urged the Commission to abandon its traditional approach and instead shift to a managed demand forecast that would broaden the energy efficiency activities and other demand-side policy initiatives and other embedded in the demand forecast to include the goals established by the CPUC. The Energy Commission rejected this approach and decided to continue using the committed/uncommitted distinction for the *IEPR* demand forecast, but also to develop a separate capability to assess the incremental effects of additional uncommitted initiatives. This decision was made in the context of a CPUC request to the Energy Commission in the text of the 2008 LTPP Order Instituting Rulemaking (OIR) as well as CPUC/ED comments filed as part of the *2008 IEPR Update* proceeding.

The incremental energy efficiency provided in this report is expected to be used in the 2010 LTPP, along with other adjustments (distributed generation and demand response, for example) to produce a managed forecast. The distinction is that the *2009 IEPR* forecast incorporates only committed energy efficiency, while the estimates of incremental effects from uncommitted initiatives are produced separately.

2008 LTPP Assignment to *2009 IEPR* and *IEPR* Activities

In the OIR for the 2008 LTPP proceeding, the CPUC, in consultation with the Energy Commission, directed utilities and other parties to pursue the issue of overlap between the energy efficiency impacts embedded in Energy Commission demand forecasts and the uncommitted savings corresponding to CPUC energy efficiency goals in the *2009 IEPR* proceeding. Energy Commission staff proposed an overall project design with two subprojects: (1) improvements in the characterization of committed efficiency program impacts in the staff's *2009 IEPR* demand forecasts, and (2) estimation of incremental uncommitted savings from policy initiatives using the *2008 Goals Study* program delivery mechanisms.

To facilitate communication by more informal means than the usual IEPR workshop process, Energy Commission staff formed a Demand Forecast Energy Efficiency Quantification Project (DFEEQP) working group. Along with Energy Commission staff, membership includes CPUC/ED, IOUs, publicly owned utilities, ARB, and other stakeholders interested in this effort. Beginning in December 2008, the DFEEQP working group has met roughly every six weeks to obtain briefings on the status of this project, discuss sources of information that can be used to improve assessments of energy efficiency programs in a demand forecasting context, compare and contrast forecasting and efficiency measurement approaches used by the utilities with those used by Energy Commission staff, and attempt to devise a more standardized set of terminology between the demand forecasting and energy efficiency measurement and evaluation communities.

To date, the DFEEQP Working Group has conducted 13 meetings or webinars. These meetings have been the principal working mechanism for the Energy Commission and CPUC staff to communicate about this overall effort to stakeholders, both to inform them of plans and results once available and to seek data and solutions to analytic problems. A working group meeting was held in December 2009 to discuss the preliminary results of this analysis and to present an initial draft of Itron's technical appendix (**Attachment A**) to obtain feedback from working group members that could be incorporated into the final results and documentation.[28]

The Energy Commission's *2009 IEPR* Committee conducted five public workshops devoted entirely or partly to the question of energy efficiency embedded in the demand forecast and the plan to develop a complementary assessment of the incremental impacts of uncommitted policy initiatives, as follows:

- March 11, 2008, focused on a review of the energy efficiency embedded in the *2007 IEPR* demand forecast and staff's plans for the effort requested by the CPUC.
- August 12, 2008, focused on the multistage plan proposed by Energy Commission staff and initial efforts by Itron as part of its contractual efforts underwritten by the CPUC.
- May 21, 2009, focused on the energy efficiency program assessment efforts completed in time for the draft staff demand forecast for the *2009 IEPR.*
- June 26, 2009, focused on the draft staff demand forecast, including the extent to which this demand forecast was reduced through the incorporation of improved assessment of committed energy efficiency programs.
- September 21, 2009, focused on a revised demand forecast and remaining issues, including the then-pending proposed decision to convert utility 2009–2011 energy efficiency programs to cover 2010–2012.

In addition, two Energy Commission workshops were conducted on the results of the incremental uncommitted analysis: (1) a staff workshop held on February 3, 2010, focused on technical issues; and (2) an Energy Commission workshop held on February 17, 2010, focused on policy issues.

In addition to these public events, Energy Commission staff, CPUC/ED, and Itron have met informally numerous times to refine project plans, exchange data, discuss reviews of methods

28. A key issue discussed at this meeting was Itron's use of 2006 peak demand assumptions (hotter than normal weather conditions) for the incremental peak savings. As a result, staff/Itron decided to shift to "average weather" for the final results, using Energy Commission staff peak-to-energy factors representing an average weather year.

and assumptions, and make other necessary efforts to coordinate activity among the three entities.

CHAPTER 3: Conceptual Approach for Determining Incremental Impacts Above Historical/Committed Impact Projections

This chapter describes the conceptual approach used to measure the incremental impacts of the uncommitted initiatives described in **Table 3**, an approach that involves minimizing overlap of these initiatives' impacts with historical/committed savings embedded in Energy Commission demand forecast.

Background

Meaningful estimates of the impacts of additional uncommitted initiatives are impossible without considering the impacts of committed programs already included within the adopted demand forecast, and the methods for developing the demand forecast itself. As noted, this approach requires consideration of two elements: (1) the inclusion of specific programs and other delivery mechanisms within the committed and uncommitted categories, and (2) methods of analysis for committed and uncommitted impacts.

Questions about committed/uncommitted overlap could not be answered during the 2006 LTPP and *2007 IEPR* proceedings because neither the demand forecast nor the estimates of additional energy efficiency savings were prepared or documented in a manner that could allow technical answers. Therefore, simple assumptions were made, as described in **Chapter 2**. The analyses documented in this report seek to eliminate any concern about overlap by preparing savings estimates that are explicitly incremental to the *2009 IEPR* demand forecast.

This chapter will address the overlap problem conceptually in the context of the forthcoming CPUC 2010 LTPP rulemaking: how to estimate incremental impacts of the three future energy efficiency scenarios described in the *2008 Goals Study* relative to the Energy Commission's *2009 IEPR* demand forecast. Although a literal reading of the text of the final decision of the 2006 LTPP rulemaking (D.07-12-052) implies that the *2007 IEPR* demand forecast should be the reference point, the timeline required to develop analytically defensible solutions to the problem allowed the use of an updated 2009 forecast.

During the March 11, 2008, workshop, Energy Commission staff proposed to upgrade the level of energy efficiency program assessment for programs considered committed as well as to develop a new capability to estimate the incremental impacts of uncommitted energy efficiency initiatives. During the August 12, 2009, workshop, Energy Commission staff presented a conceptual project plan[29] that encompassed three steps:

- Improve characterization of energy efficiency within the base demand forecast for the *2009 IEPR.*
- Create/adapt a capability to assess incremental impacts of uncommitted initiatives.
- Create/adapt a capability to assess the incremental impacts of further energy efficiency initiatives.

A multi-step process to achieve these goals was later ratified by the Energy Commission in the *2008 IEPR Update*,[30] **Chapter 2**.

This analysis draws upon Step 1 efforts, which are documented in the *2009 IEPR* demand forecast report.[31] Although Energy Commission staff has made and will continue to make progress in the direction of developing an independent uncommitted projection capability (Step 2) this analysis still depends upon the technical expertise of Itron. In Step 3, Energy Commission staff will also develop a capability to project energy efficiency potential and its various categories of interest (technical potential, economic potential, achievable economic potential, and so on).

End-Use/Measure Penetration Assumptions and CPUC Goals

Extending back as far as 2004, the CPUC has adopted electricity energy and peak and natural gas energy goals for IOU energy efficiency efforts. Such goals have encompassed various portions of the total cost-effective energy efficiency potential identified in technical and economic studies. The goals are periodically revised as new information becomes available. **Attachment B**, prepared by CPUC/ED staff, summarizes the changes in electricity goals through time, including the latest adjustment to the goals for each IOU given in D.09-09-047.

The literal language of CPUC decisions directs IOUs to achieve the stated values, making up shortfalls in any one program year's efforts in subsequent years. While CPUC decisions consider the goals as a "hard constraint," a series of CPUC decisions continue to clarify what this means in practice.

29. California Energy Commission, *Conceptual Project Plan: Demand Forecast and Energy Efficiency Impact Assessment*, August 2008 IEPR Workshop. http://www.energy.ca.gov/2008_energypolicy/documents/2008-08-12_workshop/2008-08-08_CONCEPTUAL_PROJECT_PLAN.PDF

30. California Energy Commission, *2008 Integrated Energy Policy Report*, November 2008, CEC-100-2008-008-CMF. http://www.energy.ca.gov/2008publications/CEC-100-2008-008/CEC-100-2008-008-CMF.PDF.

31. *California Energy Demand 2010-2020, Commission Adopted Forecast*, Chapter 8.

This analysis, focused on quantifying the incremental impact of uncommitted initiatives beyond those included in the 2*009 IEPR* demand forecast, requires attention to the specification of the various delivery mechanisms that collectively define the end-use/measure penetration assumptions used in the *2008 Goals Study*, rather than the numeric long-term goals specified in CPUC decisions. It is impossible to assess the incremental portion of an aggregate quantity goal without understanding the precise specification of its end-use/measure effects relative to the underlying adopted demand forecast. Therefore, this report and its attachments focus on the policy initiatives specified in the *2008 Goals Study* process and provide estimates of the incremental impact of these collections of policy initiatives at the end-use level relative to the results in the *2009 IEPR* demand forecast.

2009 IEPR Assessments of Committed Efficiency Impacts

With the DFEEQP working group as a sounding board, the Energy Commission staff proposed to improve utility program savings assessment in the *2009 IEPR*. In part, this was accomplished by tying the forecast much more directly than in the past to reported program savings estimates by measure and end use, and other disaggregated descriptors of program activity quantified through the evaluation, measurement, and verification (EM&V) processes. Although participants agreed that this made conceptual sense, the mechanics of gaining access to a comprehensive body of utility program activity results proved to be much more difficult than Energy Commission staff had anticipated. For projections of the impacts of codes and standards, Energy Commission staff proposed no substantive changes to methods used in prior forecast cycles. During this project, the creation of various federal stimulus programs centered on energy efficiency programs increased interest in assessing the impacts of these non-IOU policy initiatives, but this proved to be impossible for the *2009 IEPR*.

Tasks undertaken to improve measurement of utility program impacts culminated in a major upgrade for the *2009 IEPR* cycle. These included:

- Compiling first-year savings by end use and measure for program year activities extending back to 1998.
- Developing a new system to track the savings from program-induced energy efficiency that incorporates measure decay[32] and *ex post* (relative to initial reported or projected savings) adjustments that may occur as a result of EM&V processes.
- Segregating between measures/end uses whose impacts would be explicitly included in the Energy Commission staff demand forecasting models and those that would not.
- Upgrading Energy Commission staff demand forecasting models to create a residential lighting end use along with acquiring data to rationalize historical growth in fixture/socket

32. Measure decay arises when an energy efficiency measure is installed, reaches an end to its useful life, and is replaced, but with a less efficient measure. Some or all of the original savings are lost.

potential and shifts in the shares among bulb types (incandescent, compact fluorescent, LED, and so on) through time.

- Modifying preparation of the final forecast to adjust the raw model output for the impacts of programs not incorporated directly into the models.

This set of activities was accomplished for the draft demand forecast released by Energy Commission staff in June 2009. The approach and methods were discussed in workshops held on May 21, 2009, and June 26, 2009. Some refinements and adjustments to assumptions were made as part of a September 2009 revised forecast, and one key final adjustment (shift of IOU programs from 2009–2011 to 2010–2012) was made as part of a second revised demand forecast at the request of the 2009 IEPR Committee.[33] The Energy Commission adopted the second revised forecast at its regular business meeting on December 2, 2009.

The improvement in treatment of IOU program impacts is documented in the demand forecast report,[34] which provides a basis for understanding the level of energy efficiency embedded within the final demand forecast adopted as part of the *2009 IEPR*. This documentation should allow the effort to identify incremental savings impacts beyond those in the forecast to be more transparent.

IOU Program Impacts

Energy Commission staff found that acquiring estimates of energy efficiency savings by measure across programs and applying the various appropriate *ex post* EM&V adjustments was much more difficult than anticipated. No single database across utilities, or even a single database for each utility, existed with the needed information. Thus, finding a common format and acquiring consistent data to fit into a database was an unforeseen first step. Working with Itron, Energy Commission staff created a format for aggregated savings resembling IOU net first year savings reports to the CPUC. Some measures were carried separately while others were grouped into end uses. Itron provided savings in this format for program years 2004 and 2005 and Energy Commission staff developed values for 2006-2008 first-year savings based on detailed program filings to the CPUC. Earlier years were added at a later stage, but some approximations were needed since the primary sources of reported measure installations were less readily accessible and pre-2004 measure data were named and classified in a different style. The numerous data sources and judgments required to adjust these data to prepare a consistent time series are described in the *2009 IEPR* demand forecast report.[35]

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33. The CPUC adopted a set of IOU program designs and funded these for years 2010-2012 on September 24, 2009. The year 2009 was treated largely as a continuation of 2006-2008 program activities.

34. *California Energy Demand 2010-2020, Commission Adopted Forecast*, Chapter 8.

35. *California Energy Demand 2010-2020, Commission Adopted Forecast*, Chapter 8.

To characterize the program accomplishments in life cycle savings terms, Energy Commission staff developed spreadsheet methods to track measure savings across time using first-year measure installation data, estimates for expected useful life available in the CPUC's Database for Energy-Efficient Resources[36] (DEER), and assumed decay functions. Discounts to reported first year savings estimates based on initial findings from 2006-2008 CPUC energy efficiency verification reports were also merged into the data.[37] Finally, assumptions about IOU energy efficiency program activity for 2009 through 2012 were made based on the latest set of IOU program plans submitted to the CPUC. The analysis of the impacts of 2009–2011 programs based on these plans was pushed forward to become the assumed impacts for 2010–2012, with 2009 treated as a continuation of 2008 activities.[38] Since program activity beginning in 2013 is considered uncommitted from the Energy Commission's perspective, no new IOU program savings for this or subsequent years were included in the demand forecast. The accumulated savings achieved by earlier first-year accomplishments gradually diminish beyond 2012 as the measures decay according to the expected useful life formulas. (Further consideration of savings decay from committed programs will be discussed later in this chapter.)

The level of disaggregation carried by the end-use/measure format was designed to accommodate the fact that some measures are addressed directly within Energy Commission staff demand forecast models while others are not evaluated in any measure-specific manner, but only at the more aggregate end-use level. The database and spreadsheet method described above is needed to account for all first-year savings from utility programs, with impacts for some end uses incorporated directly in the forecast models and savings for the rest subtracted from the "raw" model results.

Industrial program savings collected through this process were not used in the *2009 IEPR* demand forecast. That is, no *net* program savings were assumed in the industrial sector. Evidence suggests a potentially much higher level of free-ridership[39] in the industrial sector compared to other sectors. For the 2009 forecast, staff did not have the time to do an in-depth analysis and assumed that all reported program savings would have occurred whether or not the programs existed. This assumption will be revisited for the *2011 IEPR*.

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36. http://www.deeresources.com/.

37. The late 2009/early 2010 round of *ex post* studies generally found even lower long-term savings than the initial estimates included in staff's revised demand forecast and this incremental analysis.

38. Energy Commission staff monitored 2009 monthly IOU reports to the CPUC concerning measure adoption, and concluded that the first half of 2009 was similar to 2008 for SCE and SDG&E, but that PG&E was achieving only around one-half of 2008 accomplishments. Therefore, SCE and SDG&E were assigned 2008 efficiency program savings in 2009, while PG&E was assigned one-half of their 2008 total.

39. That is, industrial firms tend to adopt more energy-efficient methods for competitive reasons whether utility program incentives are available.

Other Changes in Methods and Assumptions

The largest single change in methods used to incorporate efficiency measures results from creating a lighting end use in the residential sector. The staff residential forecasting model as it existed through the *2007 IEPR* included lighting along with other miscellaneous plug loads as a single end use. However, the growth in lighting use as a result of higher average intensities[40] and the interest in more lighting efficiency as typified by high funding levels for IOU retrofit programs and the AB 1109 legislation motivated a change. Staff separated lighting from the miscellaneous end use, maintaining the aggregate residential consumption backcast[41] by the model in the recent historical period by subtracting from miscellaneous use the same energy consumed in the new lighting end use. The residential forecasting model can now incorporate lighting measure savings and changing lighting patterns in the residential sector directly, including shifts in bulb type from incandescent to compact fluorescent lamps.

The analytical methods for building and appliance standards were unchanged in the 2009 forecast cycle. Impacts from the 2002 refrigerator standards were introduced in the residential model. The only other differences in aggregate impacts of standards result from different patterns of new construction exposed to these requirements, or small changes resulting from slightly different appliance turnover patterns, which are caused by different assumptions about growth in economic inputs, including housing and commercial floor space.

Although staff's demand forecasting models have always included some degree of response to electricity price, conservative assumptions about price increases included in previous forecast cycles made these effects small. The *2009 IEPR* demand forecast includes a 15 percent increase in real electricity prices over the 10-year forecast horizon—a much higher increase than had been projected in previous IEPR forecasts. This price increase induces some degree of consumption reduction and efficiency improvement.[42]

Price response is grouped into the category of naturally occurring savings. For the *2009 IEPR* demand forecast, this category also includes additional, non-incentivized residential lighting savings assumed to occur after 2012. Energy Commission staff assumed average lighting per household would remain at 2012 levels in the IOU planning areas and at 2009 levels for the publicly owned utilities without incentives through the rest of the forecast period. The difference between the 2009 or 2012 average and an increasing average that would have occurred as utility impacts decayed was assigned to naturally occurring savings. Staff felt that it was unrealistic to assume no continued lighting savings beyond utility programs given the

40. An increasing number of lighting sockets and lamps are being installed in new homes.

41. A *backcast* refers to model estimates for a historical period before any adjustment is made based on actual historical data.

42. Price elasticity of electricity demand, defined as the percentage change in consumption induced by a 1 percent change in price, averages around 6 percent in the Energy Commission forecasting models. Price responsiveness is assumed highest in the commercial sector, with a price elasticity of about 15 percent.

legislative focus on lighting programs (particularly AB 1109). These savings were meant to be a placeholder for further refinement in this analysis.

Committed Savings Embedded in *2009 IEPR* Demand Forecast

Table 3 provides a summary of estimated historical and projected committed energy savings embedded in the *2009 IEPR* demand forecast for the three IOU planning areas beginning in 2006, the base year for the incremental uncommitted analysis. Energy Commission staff demand forecast models are benchmarked to 1975, a year roughly matching the commencement of major energy efficiency programs.[43] By 2006, substantial savings have already reduced demand from what it would otherwise have been. Overall, projected committed savings in 2020 are almost 75 percent higher than the 2006 level. Savings from building and appliance standards continue to rise after 2006 as greater portions of the stock of buildings and appliances are covered by such standards, even though no increase in stringency is included through the forecast period. Naturally occurring savings rise as a result of the 15 percent increase in real electricity rates and the additional residential lighting savings. Utility program savings rise through 2012 and then gradually decrease as measures reach their useful life, decay, and are not replaced. Numerous small state and municipal programs make up the Public Agency category. No net savings were included from American Reinvestment and Recovery Act stimulus funding, given the uncertainty of energy efficiency components at the time this analysis was conducted. Finally, although the savings identified here provide a basis for comparing the impacts of a wide range of energy efficiency activities to the counterfactual case absent these activities, uncertainty about both the aggregate amount and attribution among these broad categories remains.

43. The year 1975 is a starting point for the residential sector model corresponding to the 1975 building standard promulgated by the California Housing and Community Development Department.

Table 3: Aggregate Energy Savings by Program Delivery Mechanism Embedded in *2009 IEPR* Demand Forecasts for the IOU Planning Areas (GWh)

Year	Building Standards	Appliance Standards	Utility Programs	Public Agency Programs	Naturally Occurring Savings	Total Savings
2006	8,814	13,016	5,059	11	13,277	40,178
2007	9,333	13,821	6,569	7	12,898	42,628
2008	9,853	14,574	8,661	3	11,526	44,617
2009	10,170	15,226	9,898	1	13,332	48,627
2010	10,612	15,969	10,731	1	13,671	50,984
2011	11,079	16,730	11,500	0	14,084	53,393
2012	11,580	17,501	12,227	0	14,537	55,846
2013	12,119	18,259	11,542	0	15,238	57,158
2014	12,677	19,003	10,808	0	16,030	58,518
2015	13,260	19,742	10,008	0	16,961	59,972
2016	13,829	20,466	9,132	0	18,241	61,668
2017	14,378	21,169	8,174	0	19,633	63,353
2018	14,904	21,843	7,152	0	21,068	64,967
2019	15,430	22,499	6,105	0	22,536	66,570
2020	15,903	23,125	5,081	0	23,986	68,095

Source: California Energy Commission, *2009 IEPR* Demand Forecast

Approach to Potential Overlap With Impacts From Program Designs Embodied in CPUC Goals Study Scenarios

As discussed, the basis for assessing further energy efficiency policy initiatives in this analysis is the *2008 Goals Study*. In this study, Itron developed prospective impacts for a series of program delivery mechanisms, including:

- Expanded utility programs
- Periodically updated state Title 20 and 24 standards along with updated federal appliance standards
- CPUC's Big Bold energy efficiency initiatives
- Lighting efficiency measures in satisfaction of AB 1109

Each of these categories was evaluated starting in 2006 for multiple levels of stringency/number of assumed updates extending through 2020. Three scenarios were simulated that could be characterized as resulting from pursuing the same four strategies, but with levels of effort resulting in low, mid, and high savings. The definitions of these scenarios were not changed, except for specific reasons explained below, but their impacts are reassessed for this analysis to eliminate overlap with the adopted demand forecast. **Table 4** details these scenarios by initiative type. The policy assumptions used to define these initiatives and scenarios are described in **Attachment A**.

Given the definition of committed programs used by Energy Commission staff, there are various degrees of expected overlap between the assumptions about each of these specific categories of program. The discussion that follows is a high-level assessment of the overlap or duplication that one might expect simply on the basis of a qualitative understanding of the Energy Commission's demand forecast methods and assumptions versus the analysis conducted by Itron for the *2008 Goals Study*. A more detailed discussion of the methods to adjust for overlap can be found in **Attachment A** of this report.

Utility Programs

The category of utility programs clearly presents opportunities for overlap with energy efficiency savings included in the *2009 IEPR* demand forecast. Energy Commission staff extensively modified its methods for computing savings from utility programs in the *2009 IEPR* cycle of analysis and extended the period considered committed out through 2012, consistent with D.09-09-047 adopted by the CPUC on September 24, 2009. The *2008 Goals Study* included savings from IOU programs beginning in 2006; so it would be reasonable to expect that some of the savings in the *2008 Goals Study* are now included within the Energy Commission *2009 IEPR* demand forecast, and that such savings are no longer appropriate to include in the analysis of incremental uncommitted programs.

To separate net and gross impacts, utility program savings estimates in the *2008 Goals Study* incorporate naturally occurring savings through estimates of the extent to which customers would have adopted the same measures included within programs irrespective of the incentives and information distributed as a result of their operation. Price effects in the *2009 IEPR* demand forecast could overlap with these estimates of naturally occurring savings. Especially in the commercial building sector model, where price effects are pervasive in the design of the model, the Energy Commission's assumption that rates will increase 15 percent in real terms by 2020 leads to price-induced energy efficiency. The question is to what extent this price effect duplicates some portion of the naturally occurring savings estimated in the *2008 Goals Study*. This question is addressed in **Attachment A** and is summarized in **Chapter 5**.

Codes and Standards

The *2008 Goals Study* scenarios assumed periodic updates every three to six years to state Title 20 and 24 standards. The differences in overall savings across the three scenarios are based on the number of revisions through 2020 and the increase in severity of the standards in each revision. The first revision cycle was assumed to occur in 2008 and then in three- to six-year periods thereafter. The *2009 IEPR* demand forecast does not include the impacts of updated state standards beyond 2005, so there is no reason to believe that the impacts calculated as part of the *2008 Goals Study* are already counted within the Energy Commission's *2009 IEPR* demand forecast.

Future federal appliance standards for various residential and commercial building end uses were assumed in the *2008 Goals Study* scenarios, but not in the *2009 IEPR* demand forecast. Thus, there is no substantial reason to believe that energy efficiency savings from this source of impacts is duplicative.

Table 4: Overview of Energy Efficiency Initiative Scenarios Defined in the *2008 Goals Study*

Category of Initiative	Description	Scenario		
		Low	Mid	High
IOU Programs	Continuation of 2006-2008 program mix through 2020	Partial incentives	Partial incentives	Full incentives
Codes and Standards	Title 24 Building Standards ratcheted multiple times	Residential: 10% ratchet in 2014 only Commercial: 5% ratchet in 2014 only	Residential: 10% ratchet in 2011 and 2014 Commercial: 5% ratchet in 2011 and 2014	Residential: 10% ratchet in 2011, 2014, 2017 Commercial: 5% ratchet in 2011, 2014, 2017
	Federal appliance standards updated according to DOE schedule issued in 2006	Updates to standards for residential clothes washers, dishwashers, central AC and room AC; updates to standards for commercial packaged AC units	Same as Low	Same as Low
Big Bold Initiatives	Zero Net Energy level achieved by 2020 in residential and by 2030 in commercial new construction	Residential 60% Tier 2 25% Tier 3 Commercial 40% Tier 2	Residential 80% Tier 2 60% Tier 3 Commercial 55% Tier 2	Residential 100% Tier 2 90% Tier 3 Commercial 70% Tier 2
	HVAC standards modified to match "hot, dry" conditions	Accelerated penetration of SEER 15 AC units	Accelerated penetration of SEER 15 AC units	Accelerated penetration of SEER 15 AC units
Huffman (AB 1109)	Lighting measure efficiency increased according to adopted Title 20 standard	Low compliance	Mid compliance	Mid compliance

Source: *2008 Goals Study*

Big Bold Initiatives

The Big Bold category consists of three individual initiatives—two of which involve new construction in the residential and non-residential sectors and one encompassing heating, ventilation, and air-conditioning (HVAC) systems "tuned" to hot, dry climates. The new construction programs tighten efficiency standards for new construction in conjunction with on-site power generation (for example, photovoltaic systems) to achieve zero net energy use for individual sites. The three scenarios vary the proportion of new construction that is assumed to achieve this combination of lower energy usage and onsite generation. The *2009 IEPR* demand forecast includes a major penetration of rooftop photovoltaic, which is an ingredient of the Big Bold initiatives, but does not include the energy efficiency improvements that correspond to the Big Bold assumptions. Thus the *2009 IEPR* demand forecast cannot be assumed to incorporate the energy efficiency reductions that are part of the Big Bold strategies.

Lighting Reductions Required by AB 1109

Lighting is affected by state legislation adopted as AB 1109, calling for major reductions in residential and commercial lighting relative to consumption in 2007. Lighting is also affected by federal appliance standards that call for elimination of less efficient incandescent lighting in most applications by 2012. As discussed above, the *2009 IEPR* demand forecast now includes significant reductions in residential lighting that reflect AB 1109 and federal legislation. Thus, the assumptions made in the *2008 Goals Study* for lighting are likely to be at least partially duplicative of lighting impacts already included within the *2009 IEPR* demand forecast. As a result, considerable care was devoted to understanding what Energy Commission staff assumed in the forecast, what Itron had assumed in the *2008 Goals Study*, what has happened since the AB 1109 legislation was enacted, and how to reconcile these considerations.

Overview of Qualitative Assessment Results

Table 5 provides an overview of the relative size of electricity energy savings in 2020 for all three electric IOUs that D.08-07-047 attributes to the mid-level scenario from the *2008 Goals Study*, and a qualitative assessment of the degree to which such impacts might already be considered committed in the *2009 IEPR* demand forecast. As the table reports, overlap could be expected in two of the four categories (shaded), which are also the two largest. **Chapter 5** and **Attachment A** provide the results of the in-depth assessment of this overlap, focusing on IOU programs and AB 1109 lighting measures.

Treatment of Savings Decay From Committed IOU Programs

Besides overlap, an additional category of adjustment—committed program savings decay in the *2009 IEPR* demand forecast—must be considered in developing incremental impacts to assess IOU procurement requirements. The concept of savings decay arises when an energy efficiency measure is installed, reaches an end to its useful life, and is replaced, but with a less efficient measure. This additional category of adjustment highlights modeling differences between Itron's ASSET model[44] and the Energy Commission staff's demand forecast models.

As described earlier in this chapter, for the *2009 IEPR* demand forecast, staff obtained first-year savings data from programs back to 1998 and decayed the savings from these measures using standard decay formulas and measure lifetime assumptions from DEER. It is also possible that the replacement is equally or more efficient, in which case there is no decay. The situation is further complicated by new building codes that may phase in over time. Forecasters must develop frameworks for simulating these situations. In the Energy Commission models, if a utility program is operating in the year in which decay takes place, the installed program measures are assumed to be going to new first savings, not decay replacement. In effect, the energy efficiency savings are assumed to be lost as the measures inducing the savings decay. The aggregate consequence of this approach to modeling decay was shown in **Table 3**, where IOU program savings drop from a high value of 12,227 GWh in 2012 to 5,081 GWh in 2020.

In contrast, Itron's analysis for the *2008 Goals Study* assessed prospective IOU programs and associated decay using Itron's ASSET model. To track decay in ASSET, two phenomena are considered. First, in ASSET some measures are not allowed to revert back to pre-installation efficiency levels if the associated equipment investment does not make economic sense. For example, if a lighting measure funded in part by IOU subsidies converted incandescent sockets and bulbs to linear fluorescent tubes, the customer is not likely to remove the fluorescent fixture upon tube burnout, but simply replace the tubes. Second, even if this "hardwiring" of choices is not applicable, ASSET's choice algorithm allows a portion of the customers for which the measure is cost effective without a utility program subsidy to make the choice to re-install the existing measure when it decays. Remaining customers are assumed to revert to a pre-program level of efficiency at program end, so some savings are lost to decay, but not to the degree as in the Energy Commission forecast.

In addition, the Itron *2008 Goals Study* examined only the impacts of new program funding beginning in 2006; so it did not include savings decay from the entire historical period of utility program activity as in the *2009 IEPR* forecast. Most measures have lifetimes that would not expose the majority of programmatic activity beginning in 2006 to measure decay before 2020. Therefore, replacement of decayed savings from committed programs was not a major issue in the *2008 Goals Study*. Rapidly expanding programs and short-lived measures, as is the case with CFL retrofit programs, is the combination of circumstances that leads to major concern about measure decay and replacement treatment in both the real world and models.

44. Itron's ASSET model uses a behavioral framework to predict customer adoptions of efficiency measures from utility programs, based on cost, benefits, and awareness of measure availability. ASSET provides predictions of measure adoptions as input for the SESAT model, discussed in Chapter 4.

Table 5: Potential Duplication Between 2008 *Goals Study* Program Categories and Energy Efficiency Impacts Included Within *2009 IEPR* Demand Forecasts

Category of Initiative	Cumulative 2012–2020 Impacts (GWh)	Overlap with *2009 IEPR* Demand Forecast?
IOU Programs (and Naturally Occurring Savings)	8,508	*IEPR* demand forecast includes IOU program activities through 2012 and then the continued effects of the savings from such programs not decayed away in a future year. IEPR includes price effects resulting from 15% increase in rates. *2008 Goals Study* includes naturally occurring stemming from ASSET analyses.
Codes and Standards	2,880	*IEPR* demand forecast includes no state or federal standards beyond the T24 update in 2005
Big Bold Initiatives	1,252	*IEPR* demand forecast does not contain these new program initiatives
Huffman (AB 1109)	3,658	*IEPR* demand forecast includes savings that partially implement Huffman lighting reduction requirements
Total Market Gross	16,298	*IEPR* demand forecast includes at least some savings from the two AB 1109 and IOU Program categories of the *2008 Goals Study*

Source for 2020 Goal Savings: D.08-07-047 (Itron *2008 Goal Study* Mid Case)

The mandate in D.08-07-047 that IOUs achieve *cumulative* measure saving goals means that the utilities must make up at least some portion of decay. The current CPUC direction, given in D.09-09-047, requires that 50 percent of decayed savings be replaced, beginning with 2006 programs.[45] This requirement was not incorporated into the programmatic assessments included in the Energy Commission's adopted demand forecast; therefore, an adjustment to cover savings loss in the *2009 IEPR* demand forecast from measure decay of committed program impacts accumulating from 2006 through 2012 must be considered. This issue is discussed further in Chapter 5.

45. D.09-05-037 removed the savings for the 2004-2005 period as part of the cumulative goals in the 2009-2011 program period, subsequently removing the obligation of the utilities to make up any shortfall in savings in future cycles.

CHAPTER 4: Technical Approach

This chapter describes the approach used by Itron and Energy Commission staff to develop estimated incremental impacts of energy efficiency policy initiatives to be used to adjust the *2009 IEPR* demand forecast for use in forthcoming 2010 LTPP portfolio analyses. The specific methods used by Itron to recompute the *2008 Goals Study* scenarios are described in detail in **Attachment A**.

Overview of Approach

This analysis focuses on the technical specification of the program delivery mechanisms included in the *2008 Goals Study* and re-computes savings resulting from these policy initiatives, after adjusting for committed energy efficiency embedded in the *2009 IEPR* demand forecast. That is, because of likely overlap, the analysis does not rely simply upon subtracting the mid-level savings results adopted in D.08-07-047 from the demand forecast. Therefore, accounting for the impact of committed programs included in the *2009 IEPR* demand forecast is a foundational step.

Itron used the Scenario-based Energy Savings Analysis Tool (SESAT) for this analysis. SESAT is a spreadsheet-based model designed specifically for the analysis of wide-ranging efficiency scenarios embodied in the total market gross approach. SESAT was also used in the *2008 Goals Study*. The results of this analysis are based on matching Energy Commission demand forecast input assumptions and results with Itron's SESAT modeling assumptions and then preparing results for each of the three scenarios of the *2008 Goals Study*.

A fundamental issue Energy Commission staff confronted in this study is the extent to which a demand-side goal can be stated in absolute energy or peak terms when most demand-side opportunities are conditional on economic and demographic growth, the saturation of appliances and energy-consuming equipment, and a wide range of behavioral influences on equipment operation. Assumptions for these factors must be updated periodically, and it is therefore necessary to update the assumptions used to produce energy efficiency goals. Furthermore, as discussed earlier, initiatives that were considered uncommitted in prior forecasts often become committed over time as plans are approved and funded. Some initiatives evolve over time—they may be modified or implemented in time frames that differ from the assumptions used to construct the goals. This means that estimates of measure savings, penetration, and many other types of input assumptions used to create initial energy efficiency goal estimates will need revision. Moreover, the further forward in time goals are focused, the greater the problem because of increasing uncertainty about underlying end-user characteristics affecting both baseline demand and the impacts of policy initiatives. The short-term forecasts implicitly underlying the three-year IOU energy efficiency program authorization cycle have not had to confront this issue because, typically, there is a relatively small range of uncertainty in economic and demographic activity projections three years forward. In addition, IOU programs have been dominated by retrofit of existing customer premises with modest reliance upon savings that depend on economic growth, such as those from new construction programs.

However, the long-term goals established in D.04-09-040 and D.08-07-047 confront 10-year or longer time horizons, as do the assessments that are required of the IOUs in the LTPP rulemaking to provide procurement guidance. Over this time horizon, energy service demand in some market segments addressed by specific program designs in the *2008 Goals Study* could change appreciably. For example, the Energy Commission's commercial floor space projections in the *2009 IEPR* forecast are lower in every year compared to the values assumed in the *2007 IEPR* demand forecast and used in the *2008 Goals Study* (for example, 12 percent lower in 2012 and 6 percent lower in 2018). Clearly, projected service demand and, therefore, savings related to commercial new construction should be smaller for those programs focused in this area compared to what was adopted in D.08-07-047.

Consequently, this analysis has been designed to reassess the impacts of the original program designs first quantified in the *2008 Goals Study*, adjusting not only for the penetration of committed efficiency measures encompassed within the *2009 IEPR* demand forecast, but also for changes in the key economic and demographic assumptions behind the forecast. The impacts resulting from this approach will be truly incremental to, and consistent with, the analyses in the base *2009 IEPR* demand forecast itself.

Methods

Background

For this analysis, the CPUC augmented a pre-existing contract with Itron to assist the Energy Commission in preparing both energy efficiency program savings for its baseline demand forecast and estimates of the incremental impacts of uncommitted energy efficiency initiatives, and Energy Commission staff wishes to acknowledge this assistance. The quantitative work to identify potential overlap began in the spring of 2009 using the first of three iterations of the staff demand forecast. The *2009 IEPR* demand forecast was finalized in three stages: (1) a draft demand forecast released in June 2009, (2) a revised demand forecast prepared in September 2009, and (3) a second, final revised demand forecast adopted by the Energy Commission as part of the *2009 IEPR*. Each of these iterations incorporates some degree of improvement in energy efficiency program impact assessment. Itron received data from all three demand forecast iterations; the draft and initial revised demand forecast results identified characteristics of the demand forecast that could be aligned to features of the SESAT model for comparing assumptions and results.

Upgrading and fully documenting the committed savings effort took longer than expected. In addition, the economic downturn and related uncertainties prompted Energy Commission staff, at the direction of the IEPR Committee, to spend a significant amount of time developing alternative economic scenarios for the *2009 IEPR* demand forecast. Thus, this incremental impacts assessment is coming later in time than originally expected, although still in time for use within the 2010 LTPP rulemaking, which itself has suffered schedule slips.

Use of SESAT to Estimate Future Load Impacts

For the *2008 Goals Study*, Itron obtained various input data from the Energy Commission's *2007 IEPR* demand forecast and combined this with output data from runs of its ASSET model for IOU programs along with other assumptions to create SESAT. SESAT is a relatively simple model that develops estimates of savings from prospective energy efficiency initiatives quantified through reductions in projected end-use consumption. Although SESAT is relatively simple, careful preparation of the input assumptions can yield not only estimates of impacts of single programs but also of the combined effects of multiple initiatives influencing the same market sector/end use.

While not a demand forecasting model *per se*, SESAT bears some resemblance to an end-use forecasting model. Aggregate energy consumption in SESAT is the sum across all market sectors of each end use's energy consumption, which is calculated by multiplying estimated base year unit energy consumption by a saturation index for the future year relative to the base year and an intensity-of-use index for the future year relative to the base year, and multiplying this product by units of consumption (for example, number of households). Savings are determined by comparing alternative sets of projections across the range of affected end uses.

Table 6 extracts key equations used in SESAT to provide a better sense of its level of computations. A significant part of the effort for this analysis focused on updating the unit energy consumption (UEC) and energy use intensity (EUI) reduction assumptions in SESAT associated with the definitions of the various *2008 Goals Study* delivery mechanisms, given the committed savings impacts incorporated in the *2009 IEPR* demand forecast.

This analysis required that Itron update the basic drivers of service demand in SESAT—the projected number of residential households and amount of commercial building floor space—to match those developed by the Energy Commission staff for the *2009 IEPR* demand forecast. Itron also updated its end-use UEC and EUI assumptions to reflect changes the Energy Commission staff had made since the *2007 IEPR* cycle, including the effect of adding additional years of utility energy efficiency programs within the demand forecast definition of committed impacts, since IOU programs funded in 2009 and for 2010–2012 now meet the Energy Commission's criteria for being committed.

Table 6: Key Equations Defining the Computations in SESAT

Three identities define how SESAT computes total electricity energy requirements, one each for the three broad customer sectors.

Total residential energy use = $\Sigma_{ij} UEC_{ij} * SAT_{ij} * HH_j$

Total commercial energy use = $\Sigma_{ik} EUI_{ik} * SAT_{ik} * FloorArea_k$

Total industrial energy use = $\Sigma_{il} kWh_{il}$

where: i = end use

j = residential building type

k = commercial building type

l = industrial subsector

UEC = unit energy consumption by end use i in building type j (kWh/household)

SAT = end-use saturation (%)

HH = total number of building type j

EUI = unit energy intensity by end use i in building type k (kWh/ft^2)

$FloorArea$ = floor area of building type k (ft^2)

kWh = annual consumption by end use i in subsector l (kWh)

The impacts of specific energy efficiency measures affect individual end uses in the residential sector as defined in the following equation. Commercial EUIs are affected in a similar manner.

$UEC_{ijy} = UEC_{ijbase} * EffAdj_{ijy} * UseAdj_{ijy}$

where: UEC_{ijy} = unit energy consumption for end-use i in building type j in year y

UEC_{ijbase} = unit energy consumption for end-use i in building type j in the base year

$EffAdj_{ijy}$ = technical efficiency for end-use i in year y relative to technical efficiency

Data Provided to Itron

Energy Commission staff provided three kinds of data and input assumptions from the *2009 IEPR* demand forecast to reduce inconsistencies between the inputs and assumptions used in SESAT for the *2008 Goals Study* and those used to prepare the adopted forecast:

- The residential and commercial sector economic/demographic projections used to prepare the final *2009 IEPR* demand forecast. Itron used these new projections to replace those included in SESAT as originally configured to prepare the *2008 Goals Study*.
- Energy efficiency savings estimates incorporated in the *2009 IEPR* demand forecast.
- Information resulting from special runs of the Energy Commission forecasting models to determine energy efficiency initiative and naturally occurring impacts subsequent to 2006 to match the *2008 Goals Study* benchmark.
- Data reflecting end-use peak-to-energy factors from the *2009 IEPR* demand forecast.

Preparing Peak Demand Impacts

The majority of the analysis within SESAT is conducted using annual energy values. Once energy results have been obtained, their impacts on peak demand are computed using peak-to-energy ratios by end use. The data for this purpose were taken from the *2008 Goals Study* and from the *2009 IEPR* demand forecast. For ratios taken from the demand forecast, the first projected year (2009) was used as opposed to a specific historical year to avoid excessively high or low peak impact values that could result from actual weather conditions. A list of the peak-to-energy ratios used in this analysis is included in **Attachment A**.

Model Reconciliation

The modeling tools and input assumptions used in the *2009 IEPR* demand forecast and the *2008 Goals Study* are quite different in some respects, even though both approaches ultimately make use of highly detailed end-use/measure computations. Reconciling two such highly detailed sets of models was a formidable task. Since many of the model inputs for each approach by necessity come from estimates rather than actual recorded data, the decision on which of the alternative characterizations is most correct is somewhat arbitrary. Itron computed "calibration" results at the sector level, which satisfied the project team that the SESAT and Energy Commission models were in rough agreement.

Itron's ASSET model plays a key input role for SESAT, defining the results of hypothetical utility programs driven by alternative incentive levels, which is the category with the largest expected savings of the four categories in the *2008 Goals Study* shown in **Table 5**. In the review of historical IOU program first-year accomplishments and *ex post* measurement indicators that led to Energy Commission staff's assumptions for utility program savings through 2012, considerable differences with the ASSET projections were discovered. That is, there were differences in the pre-2013 period that could not be fully reconciled. In addition, SESAT includes a very small amount of savings not included in the *2009 IEPR* demand forecast from the other three initiative categories prior to 2013. Therefore, the project team decided that incremental results would be computed as starting in 2013 and assumed no incremental impacts for the savings computed by SESAT in 2012. This "zero-basing" avoided the need to reconcile each of the hundreds of market segment/measure combinations included within ASSET, SESAT, and the Energy Commission models prior to 2013. Charts in **Attachment A** show the size of this "gap" between ASSET/SESAT and *2009 IEPR* demand forecast savings from 2008–2012. This is a conservative approach that is intended to assure that savings attributable to the policy initiatives are not already included in the baseline demand forecast.

SESAT also incorporates naturally occurring savings estimates from ASSET. The modeling assumptions used in ASSET included constant electricity prices, while Energy Commission staff assumed 15 percent real price growth by 2020 in the *2009 IEPR* demand forecast. The resources required to rerun ASSET with a comparable price projection were beyond the scope of the budget for this project, so naturally occurring savings estimates from the *2009 IEPR* demand forecast were incorporated in the analysis.[46]

Itron generally resolved questions of "calibrating" SESAT to the *2009 IEPR* demand forecast by comparing its end-use reductions to those included in the Energy Commission demand forecast. By focusing on percentage reductions in end-use usage values through time, Itron minimized the impact of differences in their absolute UECs and EUIs with those in the underlying *2009 IEPR* demand forecast.

Despite these attempts to reconcile the two models, there are differences that could not be resolved in the time frame for this analysis. Some limitations to the results reported in the next chapter are based on differences in the basic structure between Itron and Energy Commission models, not just in the input assumptions. As explained in more detail in **Attachment A**, the computation of incremental savings takes a conservative approach intended to assure savings attributable to the policy initiatives are truly incremental to the demand forecast.

Annual Impacts

SESAT and Energy Commission forecasting models have quite different architecture with respect to individual years within the analysis:

46. Note that the concept of naturally occurring savings differs slightly between ASSET and the Energy Commission demand forecasting models. ASSET estimates naturally occurring savings by simulating the level of measure adoption that customers would have made with no incentive programs. Such customer adoptions are assumed to take place according to the behavioral parameters to which the model is benchmarked along with the technical range of measure efficiencies that are input to the model. No comparable measure-specific determination of naturally occurring savings is possible within the Energy Commission demand forecast models. In addition, the Energy Commission models incorporate two types of price response: increased efficiency investment and reduced usage. ASSET incorporates only increased efficiency.

- SESAT devotes the majority of its assessment to the 2020 (or other target years), and only in a secondary assessment converts the 2020 impacts into a time series of impacts. In contrast, the Energy Commission models compute each year individually, providing results for every year through the forecast time horizon. Adapting SESAT to operate annually was beyond the scope of this project.
- The implication of this limitation in SESAT is that there is an additional element of uncertainty about the precise pattern of annual savings between 2012 and 2020.

Building and Appliance Vintaging

Although the market segments of SESAT and the Energy Commission demand forecasting models align reasonably well, SESAT uses a much simpler vintaging (age) structure than does the Energy Commission. Some specific differences were not fully resolved:

- Energy Commission models use annual vintages from 1975 through 2020 while SESAT has a two-vintage structure—existing and new, starting in 2006.
- Energy Commission models carefully track the survival of commercial floor space or housing stock in years beyond 2006 and take into account the age structure of these inputs. SESAT cannot track age structure within the "existing" vintage.
- Energy Commission models simulate appliance and equipment survival using decay functions nested within housing and commercial building age while SESAT does not. This is especially important for HVAC end uses where there are strong interactions between appliance efficiency and building shell characteristics that affect actual end-use energy consumption.
- The implication of this difference in model structure is that the exposure to mandatory standards over time is approximated in the SESAT analysis, compared to a more precise savings computation in the Energy Commission models.

Decayed Measure Savings Induced by IOU Incentive Programs

The Energy Commission and Itron modeling approaches have a quite different treatment of measuring "replacement on burnout," as discussed in **Chapter 3**. Itron's analyses using SESAT takes no account of measure decay at all unless the inputs from other sources address this phenomenon. Itron's utility program assessments using ASSET do incorporate measure decay and replacement, but it was not possible to understand in the aggregate how ASSET results compare to the 50 percent replacement requirement that the CPUC has issued. Energy Commission staff forecasting models and supplemental analyses to prepare the *2009 IEPR* demand forecast include measure decay but did not reflect the 50 percent replacement requirement issued by the CPUC in September 2009. Thus, the individual parts of this analysis dealt with measure decay and replacement in different ways and have not been reconciled. For this final report, staff has prepared an estimate of the impact of 50 percent decay replacement starting in 2006 on committed efficiency savings in the *2009 IEPR* demand forecast that the

CPUC should consider in developing its managed demand forecasts for portfolio planning purposes.

Summary

Analyses documented in this report and its attachments sought to eliminate the issue of overlap by preparing savings estimates that are explicitly incremental to the baseline demand forecast. The consequence of the modeling differences described above means that there are a few remaining uncertainties about the degree of overlap between the energy efficiency impacts within the *2009 IEPR* demand forecast and the uncommitted impacts estimated with SESAT. It is not possible at this point to describe the overall impact of the differences described above. However, the majority of analytic issues related to overlap, including timing of program initiatives and consistency between the underlying forecast assumptions in the *2009 IEPR* and the incremental efficiency analysis, were resolved.

Computing Incremental Impacts From SESAT Scenario Results

SESAT produces a series of scenario outputs in which the input characteristics of the scenario, which affect estimated UECs and EUIs, produce a different set of end-use results. These reductions are net of UEC and EUI impacts related to savings embedded in the *2009 IEPR* demand forecast, so there is no overlap with committed savings. For example, the residential refrigerator end-use savings from proposed federal appliance standards is computed as percentage change in refrigerator UECs above those already assumed in the *2009 IEPR* demand forecast. The results for each such scenario are then incremental to savings incorporated in the demand forecast.

As discussed above, the incremental results were computed as starting in 2013, zero-based to the impacts computed by SESAT in 2012. This reduces the incremental impacts compared to what they would have been had the raw SESAT results been used but also avoids the need to reconcile the two models and their respective sets of input assumptions.

This adjustment has little impact on two of the four categories—Title 24 and federal standards and Big Bold initiatives – but diminishes the incremental savings from AB 1109 and from IOU programs. Of these two categories, the IOU programs are affected the most. However this is the category with the greatest propensity for misalignment between the two models and their vintages of input assumptions.

In eliminating some of the raw SESAT results for IOU programs, the project team acknowledges unresolved differences in computing incremental savings. Efforts to prepare incremental impacts of uncommitted policy initiatives in future IEPR and LTPP cycles should benefit from lessons learned from this analysis and result in closer coordination and less need to impose methods like zero-basing to a future year to reduce concerns about inconsistency.

CHAPTER 5: Results of Incremental Energy and Peak Savings Projections

This chapter summarizes the incremental savings impacts estimated for each of the three scenarios of hypothetical initiatives defined within the *2008 Goals Study*. More detailed results are included in the Itron technical report attached as **Attachment A** of this report. The peak and energy impacts of the three scenarios can be subtracted directly from the *2009 IEPR* demand forecast as part of the effort[47] to develop three managed demand forecasts for use in the 2010 LTPP proceeding.

Results by Savings Scenario

Table 7, Table 8, and Table 9 show estimated incremental uncommitted savings for the low, mid, high scenarios, respectively, for the IOUs combined. Individual utility results by year are given in **Attachment A**. **Figure 2** and **Figure 3** show mid-case incremental energy and peak savings, respectively, in graphical form. Characteristics of the different cases were given in **Table 4**; more details are provided in **Appendix A**.

In 2020, IOU utility programs produce the highest levels of incremental energy savings in each scenario, followed by AB 1109 in the low case and the Big Bold initiatives in the mid and high cases. More aggressive utility program efforts in the mid and high scenarios reduce the impact from AB 1109 compared to the low scenario—a significant portion of savings in the low case from AB 1109 are credited to utility programs in the mid and high cases. Big Bold initiatives claim the highest peak savings in the low and high cases and yield virtually the same savings as utility programs in the mid case. These initiatives gain in relative importance for peak because of their HVAC impacts, while the share of savings from AB 1109 decreases compared to energy results.

47. Energy Commission staff understands the CPUC/ED July 1, 2009, straw proposal in the 2008 LTPP rulemaking to assume that several categories of "incremental" impacts will be used to adjust the baseline demand forecast of the *2009 IEPR* to produce one or more managed demand forecasts. Other categories of adjustment include: demand-response programs, combined heat and power program impacts, and other distributed generation impacts. Thus, energy efficiency is just one of several programmatic adjustments to produce a managed demand forecast that becomes the basis for supply-side portfolio assessments.

Table 7: Electricity Energy and Peak Demand Impacts Incremental to *2009 IEPR* Demand Forecast for Combined IOUs: Low Savings Scenario

Low Goals Case	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
Energy Impacts (GWh)								
IOU programs	642	1,258	1,853	2,376	2,920	3,431	3,940	4,448
Huffman Bill (AB 1109)	740	785	645	1,220	2,213	3,224	3,653	3,602
Title 24 & Fed Standards	28	75	143	261	380	516	656	798
Big Bold Initiatives	163	333	549	776	1,013	1,267	1,533	1,809
Total GWh	**1,573**	**2,452**	**3,191**	**4,632**	**6,526**	**8,439**	**9,782**	**10,658**
Peak Impacts (MW)								
IOU programs	189	373	554	723	895	1,063	1,230	1,396
Huffman Bill (AB 1109)	102	110	93	172	307	445	504	498
Title 24 & Fed Standards	16	35	66	162	260	368	477	588
Big Bold Initiatives	132	271	455	647	849	1,073	1,308	1,552
Total MW	**439**	**788**	**1,168**	**1,705**	**2,312**	**2,949**	**3,518**	**4,034**

Source: Itron and California Energy Commission, 2009

Table 8: Electricity Energy and Peak Demand Impacts Incremental to *2009 IEPR* Demand Forecast for Combined IOUs, Mid Savings Scenario

Mid Goals Case	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
Energy Impacts (GWh)								
IOU programs	1,050	2,055	3,017	3,847	4,716	5,521	6,325	7,126
Huffman Bill (AB 1109)	345	302	163	430	941	1,469	1,678	1,628
Title 24 & Fed Standards	55	133	254	437	624	844	1,071	1,304
Big Bold Initiatives	194	397	655	926	1,209	1,516	1,835	2,167
Total GWh	**1,644**	**2,888**	**4,089**	**5,640**	**7,490**	**9,350**	**10,909**	**12,225**
Peak Impacts (MW)								
IOU programs	284	560	830	1,081	1,336	1,583	1,830	2,075
Huffman Bill (AB 1109)	49	46	29	67	137	210	240	234
Title 24 & Fed Standards	36	76	143	294	448	623	803	987
Big Bold Initiatives	175	358	602	857	1,123	1,421	1,732	2,056
Total MW	**544**	**1,039**	**1,604**	**2,298**	**3,045**	**3,839**	**4,605**	**5,352**

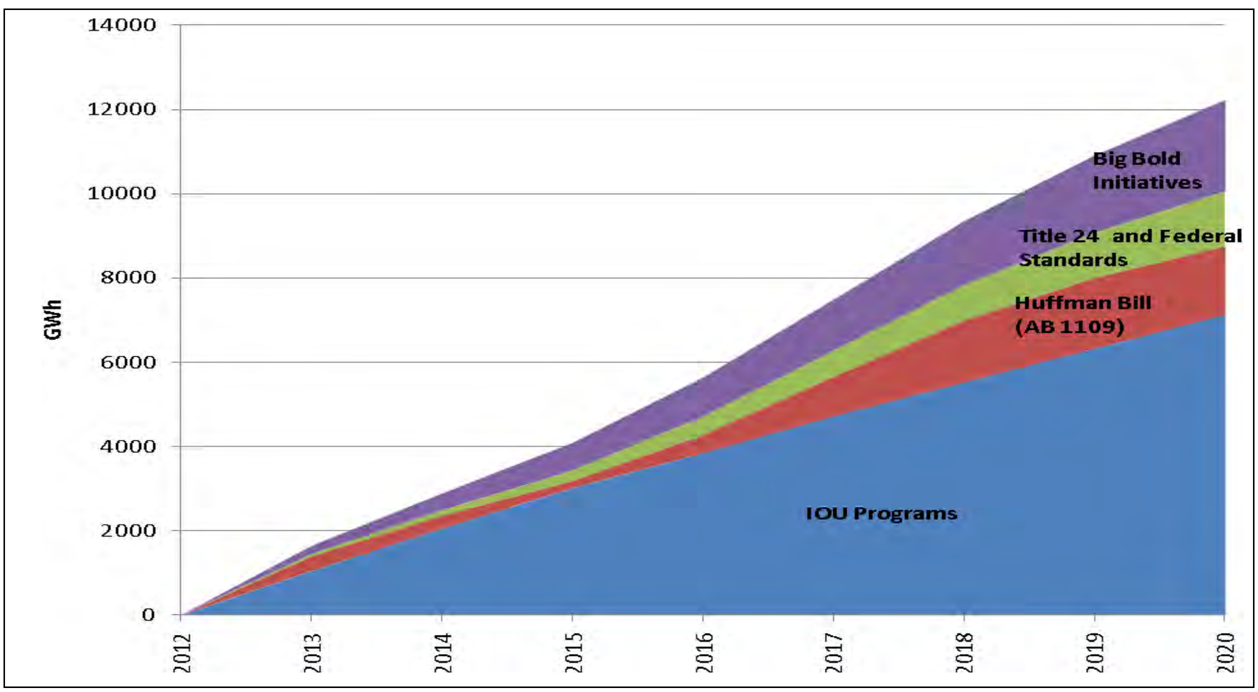
Source: Itron and California Energy Commission, 2009

Table 9: Electricity Energy and Peak Demand Impacts Incremental to *2009 IEPR* Demand Forecast for Combined IOUs, High Savings Scenario

High Goals Case	2013	2014	2015	2016	2017	2018	2019	2020
Energy Impacts (GWh)								
IOU programs	1,050	2,055	3,017	3,847	4,716	5,521	6,325	7,126
Huffman Bill (AB 1109)	514	509	369	768	1,486	2,220	2,524	2,473
Title 24 & Fed Standards	79	187	356	606	864	1,168	1,482	1,805
Big Bold Initiatives	266	544	899	1,271	1,659	2,078	2,515	2,970
Total GWh	**1,910**	**3,296**	**4,642**	**6,492**	**8,724**	**10,988**	**12,845**	**14,374**
Peak Impacts (MW)								
IOU programs	284	560	830	1,081	1,336	1,583	1,830	2,075
Huffman Bill (AB 1109)	72	74	57	112	211	312	355	349
Title 24 & Fed Standards	43	92	173	365	560	782	1,009	1,241
Big Bold Initiatives	241	492	827	1,177	1,543	1,951	2,377	2,820
Total MW	**640**	**1,217**	**1,887**	**2,735**	**3,651**	**4,629**	**5,570**	**6,484**

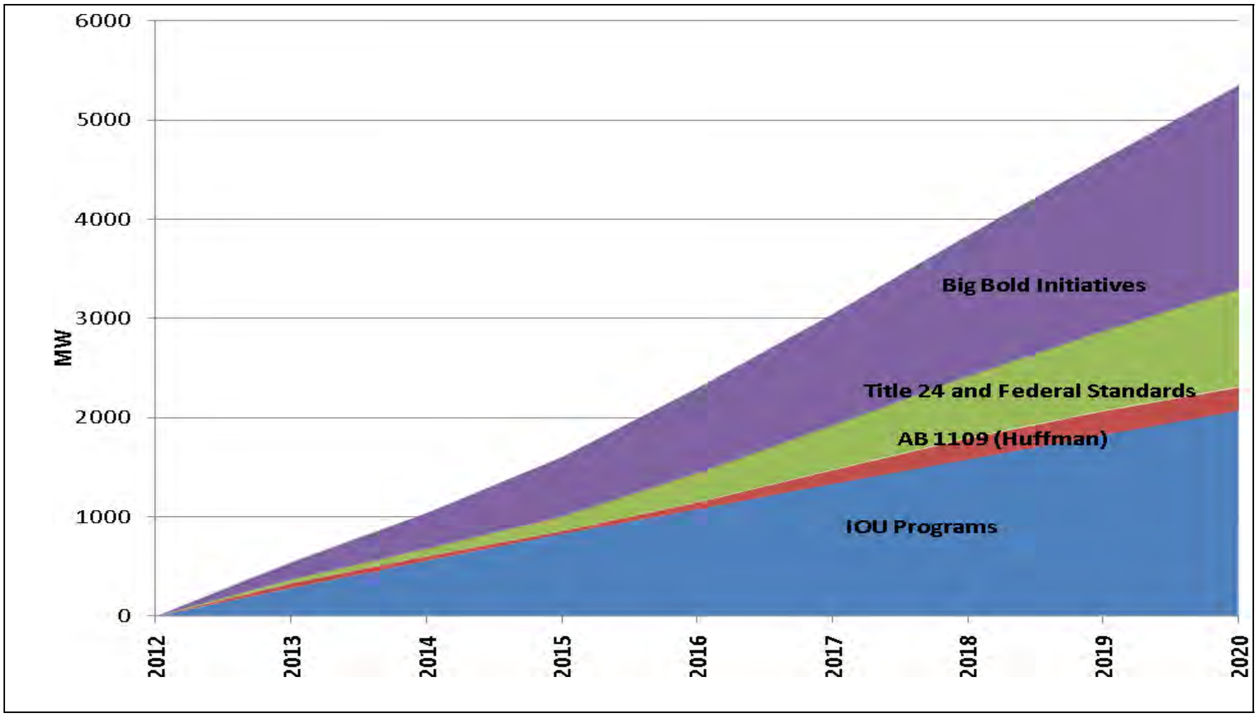
Source: Itron and California Energy Commission, 2009

Figure 2: Uncommitted Energy Impacts Incremental to *2009 IEPR* Demand Forecast for Combined IOUs, Mid Savings Scenario



Source: Itron and California Energy Commission, 2009

Figure 3: Uncommitted Peak Impacts Incremental to *2009 IEPR* Demand Forecast for Combined IOUs, Mid Savings Scenario



Source: Itron and California Energy Commission, 2009

Table 10 compares IOU-specific and total results in 2020 with the service area energy and peak forecasts from the *2009 IEPR* demand forecast and shows the percentage of projected demand forecast load growth represented by the total incremental energy and peak savings. For example, in the low savings scenario for PG&E, 56 percent of projected energy growth from 2008-2020 would be avoided by estimated incremental uncommitted savings.

Table 10: Incremental Uncommitted Savings in 2020 and Impact Relative to Energy Commission *2009 IEPR* Forecast by Service Area

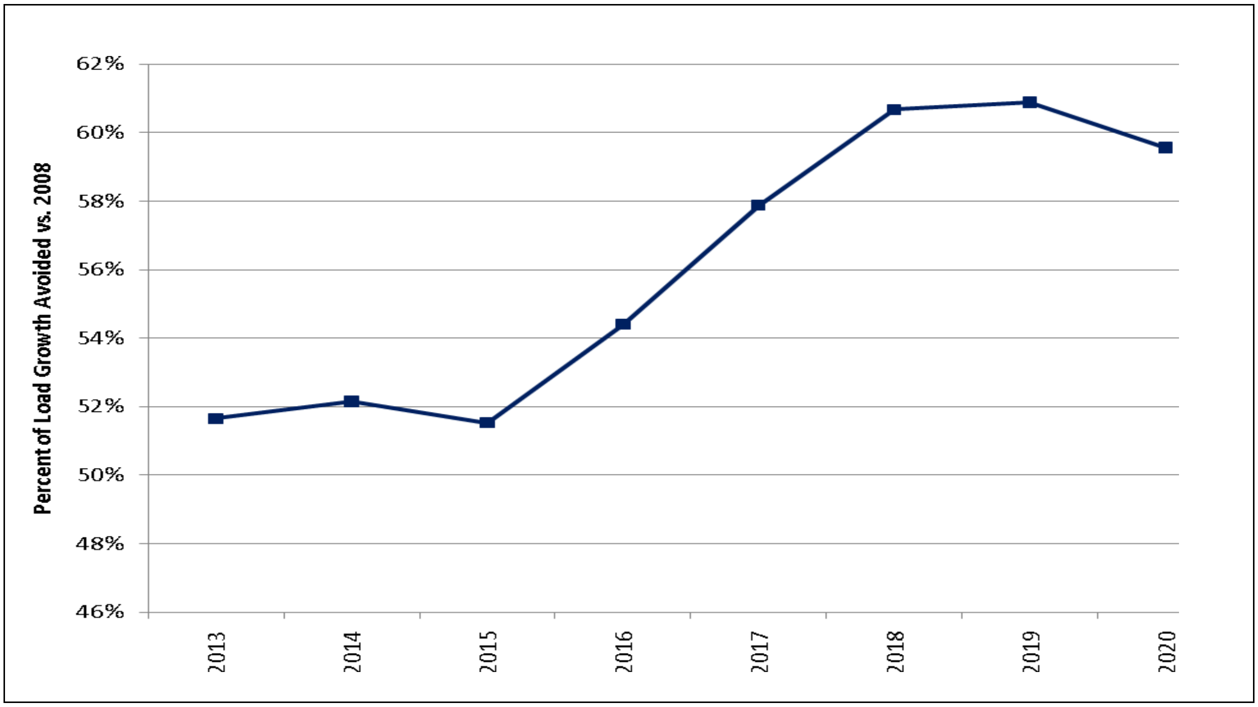
		2009 IEPR Forecast		2020 Incremental Uncommitted Impacts			Percent Load Growth Avoided		
Utility	Units	2008	2020	Low	Mid	High	Low	Mid	High
PG&E	Energy (GWh)	88,359	96,612	4,634	5,130	6,087	56%	62%	74%
	Peak (MW)	20,204	22,683	1,731	2,245	2,722	70%	91%	110%
SCE	Energy (GWh)	90,009	97,995	4,971	5,874	6,848	62%	74%	86%
	Peak (MW)	20,262	24,146	1,941	2,593	3,160	50%	67%	81%
SDG&E	Energy (GWh)	20,623	23,102	1,091	1,222	1,440	44%	49%	58%
	Peak (MW)	4,371	5,157	363	514	602	46%	65%	77%
Total IOUs	Energy (GWh)	198,991	217,709	10,658	12,225	14,374	57%	65%	77%
	Peak (MW)	44,837	51,986	4,034	5,352	6,484	56%	75%	91%

Source: Itron and California Energy Commission, 2009

For SCE and PG&E, incremental uncommitted savings reduce load growth by at least one-half in all three scenarios and by over 70 percent in the high case. Peak demand in the PG&E service territory is reduced by a greater percentage than in the SCE territory as a result of a different mix of utility programs combined with lower projected peak growth. Percentage reductions in load growth are lowest for SDG&E, a function of lower relative impacts from the Big Bold initiatives (See **Attachment A** for details.) and higher projected energy and peak demand growth.

Note that, as reflected in **Table 7, Table 8,** and **Table 9**, the pattern of expected impact is weighted toward the end of the forecast period, so that there is a lower percentage impact on load growth earlier in the forecast period compared to later years. **Figure 4** shows the percentage of projected energy growth relative to 2012 avoided for the three IOUs combined from the incremental uncommitted savings for the mid scenario. The percentage rises sharply between 2015 and 2018, largely a result of growing impacts from Title 24 and federal standards and the Big Bold initiatives.

Figure 4: Percentage of Energy Load Growth Avoided Relative to 2012, Mid Savings Scenario, Three IOUs Combined



Source: Itron and California Energy Commission, 2009

Impacts of Historical Measure Decay on IOU Program Savings

As noted at the end of Chapter 3, Energy Commission staff's method of including IOU committed energy efficiency program impacts in the *2009 IEPR* demand forecast results in a loss of efficiency savings through measure decay that is not replaced. However, CPUC efficiency goal-setting decisions outlined in **Attachment B** now require that IOUs replace 50 percent of decayed savings accumulating since the beginning of the 2006-2008 program cycle. This section provides estimates of additional committed savings that would be realized if 50 percent of decay from 2006 and later assumed in the *2009 IEPR* demand forecast were replaced. As discussed in Chapter 6, Energy Commission staff recommends that these estimates be incorporated into the CPUC managed forecast by subtracting additional efficiency savings from the adopted *2009 IEPR* demand forecast.

Table 11 provides the annual (noncumulative) efficiency program energy and peak savings decay, starting with 2006 programs, applied in the *2009 IEPR* demand forecast for each IOU. Total decay in a given year is equal to the annual estimate plus decay from all previous years back to 2006.[48] Following the CPUC directives, additional annual savings from decay replacement would equal 50 percent of the values in **Table 11**. Acumulating these additional savings starting in 2006 gives the cumulative additional savings corresponding to 50 percent replacement of measure decay, as shown in **Table 12**. For the three IOUs, these savings total 1,860 GWh and 382 MW in 2020.

Table 11: Estimated Annual IOU Program Savings Decay Beginning With 2006 Programs

	PG&E		SCE		SDG&E	
Forecast Year	Energy (GWh)	Peak (MW)	Energy (GWh)	Peak (MW)	Energy (GWh)	Peak (MW)
2006	30	6	6	1	1	0
2007	73	13	12	3	2	1
2008	159	28	52	11	3	1
2009	196	35	87	19	5	1
2010	244	44	101	22	7	2
2011	277	51	122	27	10	2
2012	297	56	131	30	14	3
2013	252	48	96	21	12	2
2014	230	45	80	18	12	2
2015	197	41	66	15	11	2
2016	158	34	58	14	10	2
2017	122	27	56	14	10	2
2018	98	21	61	16	11	2
2019	87	19	70	19	14	3
2020	87	18	78	21	18	4

Source: California Energy Commission, 2009

48. For example, the total estimated amount of PG&E energy savings lost to decay by the end of 2008 equals 30+73+159=262 GWH. The CPUC requires 50 percent of this loss to be replaced beginning in 2006.

Table 12: Cumulative Additional IOU Program Committed Savings From 50 Percent Decay Replacement Starting in 2006

	PG&E		SCE		SDG&E	
Forecast Year	Energy (GWh)	Peak (MW)	Energy (GWh)	Peak (MW)	Energy (GWh)	Peak (MW)
2006	15	3	3	1	0	0
2007	51	9	9	2	1	0
2008	131	23	35	7	3	1
2009	229	41	79	17	5	1
2010	350	63	129	28	9	2
2011	489	89	190	41	14	3
2012	637	117	255	56	21	4
2013	763	141	303	67	27	6
2014	878	164	343	76	33	7
2015	977	184	376	83	38	8
2016	1,056	201	405	90	43	9
2017	1,117	214	433	97	48	10
2018	1,166	225	464	105	54	11
2019	1,209	234	499	115	61	12
2020	1,253	243	538	125	70	14

Source: California Energy Commission, 2009

Alternative Peak Case

The end-use peak-to-energy ratios used to convert energy savings to peak are very sensitive to weather assumptions, particularly in the residential sector. The peak savings results presented in the previous section and corresponding ratios developed by Energy Commission staff assume an "average" weather year. In the *2008 Goals Study*, which formed the basis for the current IOU efficiency goals, Itron employed peak-to-energy ratios estimated for 2004 from load shapes used in the ASSET model.[49] In part because 2004 was a relatively cool year statewide, the ratios are significantly lower than in the "average" case. **Table 13** shows the effect in 2020 of replacing the Energy Commission average ratios with the 2004 values used by Itron for the combined IOUs during the uncommitted period, and **Table 14** provides the same comparison for the individual IOUs.

49. For a description of the sources of these load shapes, see pages 3-33 and 3-34 in the *2008 California Energy Efficiency Potential Study*: http://www.calmac.org/startDownload.asp?Name=PGE0264_Final_Report.pdf&Size=5406KB.

Table 13: Comparison of Peak Incremental Uncommitted Savings (MW) Using Average Weather and Itron 2004 Peak-to-Energy Ratios, Three IOUs Combined

	Average Weather Peak-to Energy Ratios			Itron 2004 Peak-to-Energy Ratios		
	Low Scenario	Mid Scenario	High Scenario	Low Scenario	Mid Scenario	High Scenario
2013	439	544	640	346	410	475
2014	788	1,039	1,217	603	771	888
2015	1,168	1,604	1,887	866	1,164	1,344
2016	1,705	2,298	2,735	1,249	1,639	1,914
2017	2,312	3,045	3,651	1,696	2,160	2,544
2018	2,949	3,839	4,629	2,159	2,704	3,206
2019	3,518	4,605	5,570	2,551	3,214	3,823
2020	4,034	5,352	6,484	2,885	3,699	4,405

Source: Itron and California Energy Commission, 2009

Table 14: Comparison of Peak Incremental Uncommitted Savings (MW) in 2020 Using Average Weather and Itron 2004 Peak-to-Energy Ratios, By IOU

	Average Weather Peak-to Energy Ratios			Itron 2004 Peak-to-Energy Ratios		
	Low Scenario	Mid Scenario	High Scenario	Low Scenario	Mid Scenario	High Scenario
PG&E	1,731	2,245	2,722	1,308	1,666	2,007
SCE	1,941	2,593	3,160	1,314	1,697	2,007
SDG&E	363	514	602	265	337	390
Total	4,034	5,352	6,484	2,885	3,699	4,405

Source: Itron and California Energy Commission, 2009

The percentage differences in savings between the two peak cases increase over time as program impacts grow because the Big Bold policies emphasize air conditioning-related measures more than do other policy initiatives. For the three IOUs combined, the differences in peak savings across the two cases range from 21 percent to 26 percent (low scenario to high scenario) in 2013, increasing to between 28 percent and 32 percent by 2020. Among the IOUs, SCE yields the largest peak savings reduction range in 2020, 32 percent to 36 percent (low scenario to high), and PG&E the smallest, 24 percent to 26 percent.

It is important to note that the Itron peak-to-energy ratios are not necessarily consistent with those used in the *2009 IEPR* demand forecast.[50] There are some significant end-use ratio differences between the Energy Commission and Itron ratios meant to represent 2004, particularly in residential cooling. Therefore, to be consistent with the baseline peak results, staff plans to develop a peak savings range for cool and hot years using Energy Commission peak-to-energy ratios. Staff was not able to complete this work in time for this final report but will submit the peak range results as a supplemental analysis later in the LTPP process.

50. Itron historical peak-to-energy ratios are derived from load shapes used in the Asset Model that are based on "simulated average" weather that does not vary by year. The ratios are then effectively calibrated in SESAT when estimated peak is matched to historical peak by sector in a given year. In the Energy Commission forecast, peak-to-energy ratios for a historic year, such as 2004, are based on actual weather in that year.

CHAPTER 6: Conclusions, Caveats, and Recommendations

Conclusions

This analysis is meant to provide a directly useful product to the CPUC for use in the 2010 LTPP rulemaking, as requested by the CPUC in earlier decisions and rulemaking scoping memos. The results of the analysis give incremental impacts of specified efficiency initiatives taken directly from the *2008 Goals Study*, which was the basis for the adopted energy savings goals included in D.08-07-047 and modified subsequently as described in **Attachment B**. Adjustments to the *2008 Goals Study* have been made to account for the updated economic and demographic projections used in the *2009 IEPR* demand forecast and for the increased amount of energy efficiency impacts now embedded within the demand forecast, due both to inclusion of now-committed IOU programs through 2012 as well as from improved estimates of savings from IOU programs through 2008.

For the three IOUs combined, estimated incremental uncommitted energy savings in 2020 total between 10,700 GWh and 14,400 GWh; 2020 peak savings total between 4,000 MW and 5,400 MW. These savings would reduce projected energy growth from 2008-2020 by between 57 and 77 percent and projected peak demand growth by between 56 and 91 percent. Savings impacts are weighted toward the last years in the forecast period. To satisfy directives to IOUs about pursuit of cumulative savings goals, the CPUC may also choose to adjust the *2009 IEPR* demand forecast downward based on the discussion of committed savings decay given in **Chapter 3** and **Chapter 5**.

The three sets of scenario impacts correspond to different groupings of proposed program initiatives, which can be thought of as reflecting policy uncertainty. Other uncertainties, of a technical nature, have not been quantified, although they have been acknowledged in **Chapter 4**. Except possibly for the treatment of loss of savings through measure decay, this analysis requires no further adjustments to be used, along with other demand side policy adjustments, to produce a managed demand forecast as proposed by the CPUC/ED staff.

Caveats

Three alternative scenarios are presented, with the decision about which case to use in the LTPP process left to the CPUC. However, there is no assurance that efficiency savings from any of the three scenarios will be realized. Even the low case requires that various state and federal entities continue to pursue energy efficiency activities under their jurisdiction in what historically is considered an aggressive approach.

On the one hand, the effort to continue increasing efficiency may grow more difficult through time as future initiatives exhaust the "low-hanging fruit." On the other hand, even though they have not been quantified, there are additional energy efficiency savings that may be accomplished through time across the entire range of delivery mechanisms that have not been addressed in this analysis. For example, the Energy Commission adopted television standards in late 2009, and the savings from such standards are not included within the scope of the state or federal standards evaluated in this project.

The use of scenarios defined through alternative policy initiative assumptions is a key element in incorporating uncertainty about future uncommitted program impacts. This uncertainty reflects in part the question of whether future policy makers will enact the standards and other programs required to achieve ever higher levels of cumulative savings. Commissions and boards typically resist making commitments binding on future commissioners and board members, yet the uncommitted program initiatives that are the basis for the *2008 Goals Study* presume that IOU programs will be continue to be funded at current or higher levels continuously through 2020, that the Energy Commission will continually ratchet building standards tighter with each three-year update cycle, and that the Big Bold concepts will actually be enacted on schedule and to an extent comparable to that quantified in the *2008 Goals Study*.

There are other dimensions of uncertainty that have not been fully explored in this analysis. Decision makers should be aware of the following:

- IOU program impacts constitute a large percentage of total future efficiency savings, and they rely upon voluntary decisions by end users to participate. Unprecedented levels of participation are projected, levels which depend on many factors, including the state of the economy.
- The Energy Commission's *2009 IEPR* demand forecast assumes a 15 percent increase in retail prices by 2020, and some impact via price elasticity is included in the base demand forecast. However, it is easily conceivable that retail prices could rise by a significantly different rate, which could result in modifications to presumed utility program activity.
- This analysis and the *2009 IEPR* demand forecast rely on a single set of economic/demographic projections. Thus, additional uncertainty in both committed and incremental uncommitted savings estimates is introduced to the extent that the level of economic growth affects customer efficiency adoption decisions. [51]

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51. Economic/demographic uncertainty is also relevant to the CPUC managed forecast through impacts on load growth unrelated to efficiency. In comments received after the two February workshops, some stakeholders suggested that the CPUC incorporate into the LTPP the alternative economic/demographic scenarios included in the *2009 IEPR* demand forecast. The Energy Commission makes no recommendation on this matter, but if the CPUC wishes to incorporate economic uncertainty in the managed forecast, Energy Commission staff can easily adjust the scenario results, done at the planning area level, to reflect IOU service territories.

Section 4.5 in **Attachment A** provides further technical discussion on caveats and uncertainties related to this analysis. In general, decision makers must consider the implications of efficiency-induced projections of very low or even negative energy and peak demand growth through 2020. While the *Energy Action Plan* loading order emphasizes cost-effective energy efficiency as California's first choice to meet demand growth, relying solely on these resources for long-term resource adequacy is uncharted territory. If decision makers postpone decisions to invest in supply-side resources and energy efficiency fails to deliver as forecasted, then serious reliability (and cost) consequences could result, unless such shortfalls have been anticipated and contingency actions identified.

Recommendations

The Energy Commission's IEPR Committee endorses the following recommendations, most of which were suggested by staff in the draft of this report:

- In further goal-setting proceedings, goals should be described with reference to a baseline projection or set of assumptions. This will make clearer the incremental impacts of such goals above similar impacts already included in the baseline.
- The CPUC should use the projections of incremental uncommitted initiative impacts developed in this report as one of several adjustments to the adopted *2009 IEPR* demand forecast to develop three separate managed demand forecasts as the basis for portfolio analyses in the forthcoming 2010 LTPP proceeding.
- The CPUC should further adjust the managed forecast downward to conform to its directives for IOUs to replace 50 percent of utility programmatic savings decay beginning in 2006. These estimates are provided for both peak and energy savings in **Table 12**, Chapter 5.
- To the extent that separate models (such as the Energy Commission's demand forecasting models and Itron's SESAT) are used in subsequent analyses to determine the incremental impact of hypothetical policy initiatives, better coordination of primary input assumptions should be made, such as rerunning all models with a common set of price projection assumptions.
- The Energy Commission staff should continue to develop a capability for making incremental uncommitted energy efficiency projections for use in the *2011 IEPR* proceeding, CPUC 2012 LTPP proceedings, ARB efforts to assess options for satisfying the GHG emission reduction requirements of AB 32, and related inquiries. This capability will require further coordination of modeling methods and assumptions between those used to prepare baseline demand forecasts and those used to estimate the incremental impacts of uncommitted policy initiatives. In turn, such efforts depend upon appropriate staffing and data collection activities.

APPENDIX A: Glossary of Terms

Introduction

This glossary of terms briefly defines key general concepts and terms arising in the *Incremental Effects of Energy Efficiency Policy Initiatives* report. The purpose of these general definitions is to help policy makers and others in interpreting information provided in this report that employs technical language. It is the initial product of a much more involved consideration of taxonomic issues related to reconciling models and more generally adopting common language between forecasting and energy efficiency.

To adequately interpret the information in this report, policy makers and others must also appreciate that these brief general definitions are not the same as the much more detailed technical definitions that are used to operationalize models in conjunction with available data in order to derive quantitative estimates of the naturally occurring and incremental energy efficiency saving impacts. A concentrated effort was made to present and compare technical operational definitions for the models described in this report, but the barriers cited below were not overcome, and consequently developing meaningful conceptual definitions became the focus of this effort. Future modeling exercises or modifications should strive to have common operational and conceptual definitions from initiation of the analyses through completion.

The distinction between general conceptual and more detailed operational definitions is important because the quantitative estimates in this report are derived from more than one model, each of which has different operational definitions. For example the CED and Asset models each have different operational definitions for a number of the basic terms such as, base year, naturally occurring savings, free ridership, and energy efficiency, that are defined conceptually below.

These different operational definitions come about because the model builders had to adapt to the differences that they confronted at the time of their model construction with respect to the practical limits of available data and the different purposes their models were originally intended to serve.

The reader should be forewarned that such differences in the detailed definitions are conducive to the creation of problems such as the possible overlap and other possible inconsistencies between incremental savings from one model and embedded savings in the other.

This report represents an attempt to cope with these potential problems of inconsistency between models and coordination of the Energy Commission and Itron modelers involved. It should nevertheless be noted that the differences in operational definitions preclude the resolution of such lurking inconsistencies by means of explicit formal modeling approaches. Instead, the information provided in this report results on reliance on an inherently less transparent use of collaborative professional judgment on the part of the Energy Commission and Itron modelers.

In addition to reconciling these two specific models it was also revealed, through review of several leading resource documents, that the terms that are so commonly used in describing energy efficiency are not consistent or defined in a meaningful way. If energy efficiency is to be an essential resource, the terminology used needs to be tight enough to accurately describe the resource and should continue to be refined.

Terms

Attribution

The process of identifying the fraction of energy savings in a given market or end use that is estimated to be solely caused by (or *attributed to*) a specific policy or program.

Base Year

A reference year used in forecasting models that can be used for calibrating to existing historical data or calibrating to another model, or to characterize changes over time (that is, changes are expressed relative to values in the base year), or some combination of those purposes.

Committed Savings (or Committed Load Impacts)

The energy and demand savings from energy efficiency policies or programs that have been implemented or for which funding has been approved and some form of program and/or implementation plan developed. *Committed savings* includes all explicit energy efficiency impacts in the base demand forecast, including utility programs, implemented building and appliance standards, public agency programs, and naturally occurring savings.

Cumulative Load Impacts

The accumulation or sum of the annual load impacts from energy efficiency programs or policies over the lifecycle of energy efficiency measures for a specific period. Cumulative impacts include the first year impacts of new programs or policies plus the residual impacts from measures installed in prior years minus any decay using estimates of annual measure savings and effective useful life.

Delivery Mechanism

A method by which demand-side measures can be promoted or introduced to the end user either voluntarily through programs or through mandates. This includes but is not limited to utility programs, building codes, and appliance standards.

Energy Efficiency Initiative

Any policy-related effort to increase energy efficiency. Includes utility programs, building codes, appliance standards, and other efficiency-related legislation and ordinances.

End Use

An activity or process for which energy is used to accomplish a specific purpose. For example, end uses include cooking, lighting, space conditioning and clothes washing/drying.

End Use Intensity

The average energy use for an end use. The intensity measurement may differ depending on the sector in question (for example, per square foot of floorspace for commercial lighting or refrigeration; or per unit of production for agricultural pumping or industrial process).

Energy Efficiency

Using less energy to perform the same function or provide the same or an improved level of service to the energy consumer.

Energy Savings

The load impacts (energy and demand) resulting from naturally occurring savings, building codes and appliance standards, and energy efficiency programs or policies.

Energy Service

The desired level of benefit obtained from using energy for purposes such as such as heating, cooling, refrigeration, or operating appliances.

Free-Ridership Rate

An estimate of the fraction of energy efficiency savings arising from program participants who would have implemented the program measure or practice even in the absence of the program.

Incremental Savings

The energy and demand savings from energy efficiency policies or programs that were identified in the CPUC's *2008 Energy Efficiency Goals Update* report but for which funding has neither been approved nor an implementation plan developed, net of any overlap with committed savings included in the *2009 IEPR forecast*. *Incremental savings* are associated with uncommitted programs or policies, and are not included in the Energy Commission's base demand forecast. They are therefore considered incremental to that forecast.

Incremental Savings Projection

The analytic characterization of energy and demand impacts resulting from uncommitted energy efficiency delivery mechanisms defined as part of the *2008 CPUC Energy Efficiency Goals Update Report* and D.08-07-047, net of any overlap with committed savings included in the base demand forecast. Three sets of projected incremental impacts on electricity demand (low, medium and high assumptions for energy efficiency, corresponding to three scenarios developed as part of the CPUC's *Energy Efficiency Goals Update Report*) will be used to modify base demand forecasts obtained from the *2009 IEPR*. The projection is being developed for the CPUC's 2010 Long Term Procurement Plan (2010 LTPP).

Managed Demand Forecast

A *managed demand forecast* describes the peak and energy demand that results from decrementing the results of an external analysis such as the incremental-uncommitted energy efficiency projection from the baseline demand forecasts published in the Energy Commission's *IEPR*. Conversely, an "unmanaged" demand forecast refers to a base forecast. Note that there could be multiple types of managed forecasts, wherein one or more sets of activities (for example, preferred resources such as energy efficiency, self-generation, demand response, and so forth) are added to, or more commonly, subtracted from a base forecast.

Naturally Occurring Savings

Naturally occurring savings are energy savings that are independent of specific programs or standards effects, caused instead by the combination of customer energy conservation choices and supplier product mix and development choices that result from interacting forces of market supply and demand, which, in turn, respond to changes in societal norms, prices, and other energy product information.

Overlap

A phenomenon wherein projections of uncommitted energy efficiency savings may coincide with or *overlap* committed savings already included in the base forecast. Overlap is especially likely to happen when one model and set of assumptions are used to prepare a base forecast, and another model and set of assumptions is used to develop uncommitted savings, with little or no coordination between the two efforts.

Program Net Savings

Program net savings in the context of this report refers to load impacts or savings from energy efficiency programs sponsored by the CPUC and implemented by the investor-owned utilities and their contractors, adjusted for estimates of free-ridership.

Total Market Gross Savings

A term coined in the CPUC's *2008 Energy Efficiency Goals Update* report to describe total savings impacts from key programs, policies and market forces relative to a base year. "Total market" refers to policy initiatives beyond those historically pursued through CPUC-sponsored utility programs. "Gross" means that ancillary consequences of programs, such as free-ridership and spillover, would be counted as savings.

Uncommitted Savings

The estimated future energy and demand savings from energy efficiency policies or programs for which funding has not yet been approved and/or an implementation plan developed. *Uncommitted savings* are associated with uncommitted programs or policies, and therefore are not included in the Energy Commission's base demand forecast. In this report, the uncommitted savings measured are those from initiatives that were identified in the *CPUC's 2008 Energy Efficiency Goals Update* report.

Unit Energy Consumption (UEC)

The average energy use for an end use, per unit of measurement (usually a residential dwelling) in a given year, for use in forecasting models. *Unit energy consumption* tends to be used as an analytic term when modeling impacts from appliances and equipment in the residential sector (for example, residential refrigerators), and describes the average consumption per unit (for example, dwelling unit) for a particular end use within the forecast area in a given year.

ATTACHMENT A: Technical Report Incremental Impacts of Energy Efficiency Policy Initiatives Relative to the *2009 Integrated Energy Policy Report* Adopted Demand Forecast

This consultant report is available as a separate volume. Please download that report at:

www.energy.ca.gov/2010publications/CEC-200-2010-001/index.html

ATTACHMENT B: History of California Public Utility Commission Goals for Energy Efficiency[52]

California Public Utilities Commission

Energy Division

Energy Efficiency

Prepared by: Carmen L. Best, CPUC Energy Division, Energy Efficiency

Original Goals Decision: D. 04-09-060; September 23, 2004

http://docs.cpuc.ca.gov/word_pdf/FINAL_DECISION/40212.pdf

The original goals decision established goals for 2004-2013 based on the Secret Surplus potential study[53]. In addition a Statewide Goals Study prepared by CEC staff was used identify achievable potential and establish the adopted goals.[54]

> *". . . today's adopted savings goals reflect the expectation that energy efficiency efforts in their combined service territories should be able to capture on the order of 70% of the economic potential and 90% of the maximum achievable potential for electric energy savings over the 10-year period based on the most up to date study of that potential. These efforts are projected to meet 55% to 59% of the IOUs' incremental electric energy needs between 2004 and 2013. .. . For natural gas, our adopted savings goals are designed at this time to capture approximately 40% of the maximum achievable potential identified in the most recent studies of that potential." p. 2-3*

In the decision the goals are identified as stretch goals, but consistent with the findings of the most currently available potential study. It also established the definition of cumulative savings goals.

> *"The cumulative numbers represent the annual savings from energy efficiency program efforts up to and including that program year."p.10*

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52. This appendix was prepared for the Energy Commission's Demand Forecast Energy Efficiency Quantification Project Working Group by CPUC/ED staff, January 12, 2010.

53. Mike Rufo and Fred Coito, Xenergy Inc., 2002. *California's Secret Energy Surplus: The Potential for Energy Efficiency*, prepared by Xenergy Inc. for the Energy Foundation and Hewlett Foundations, October, 2002.

54. Mike Messenger, California Energy Commission Staff Report. *Proposed Energy Savings Goals for Energy Efficiency Programs in California.* October 27, 2003

The application of the goals for long term planning is also called out in this decision in Ordering Paragraph 6.

> *"The energy savings goals adopted in this proceeding shall be reflected in the IOUs' resource acquisition and procurement plans so that ratepayers do not procure redundant supply-side resources over the short- or long-term. . . . subsequent procurement plan cycles . . . shall incorporate the most recently-adopted energy savings goals into those filings."p.52-53*

Incentive Mechanism: D. 07-09-043; September 20, 2007

http://docs.cpuc.ca.gov/WORD_PDF/FINAL_DECISION/73172.PDF

The Shareholder Risk/Reward Incentive Mechanism for Energy Efficiency Programs was adopted in D. 07-09-043 and was superimposed upon the administrative structure adopted for the 2006-2008 energy efficiency program cycle. In this decision the "Minimum Performance Standard" (MPS) for utilities to make an earnings claim was based on partial achievement of the goals.

> *"The MPS is the minimum level of savings that utilities must achieve relative to their savings goal before accruing any earnings, and is expressed as a percentage of that savings goal." p.22*

That minimum threshold is 85% of the goals averaged across GWH, MW and Therms AND 80% of any given savings metric. This decision put added emphasis on the numeric goals adopted by the Commission by linking them to earnings.

Interim Opinion on Issues Relating to Future Savings Goals: D.07-10-032, October 18, 2007

http://docs.cpuc.ca.gov/WORD_PDF/FINAL_DECISION/74107.PDF

This Decision (in section 6.3.1 Cumulative Savings) clarified the definition of cumulative savings and recognized three ways the utilities could maintain the equivalent level of additive first year savings.

> *"A utility's 2009-2011 portfolio then can reflect one or more options as to how to "maintain" this level of equivalent savings, such as by repeating the equivalent measure delivery and incentive again, promoting measures with much longer expected lives that will endure over many years ahead and not have to be replaced so soon, and/or achieving market transformation strategies that ensure only like-kind efficiency lamps can be purchased in 2009."pg 80*

The utilities were directed to report in their applications for the 2009-2011 portfolio approvals the expected cumulative savings over the long term. Likewise, progress toward cumulative goals is to be included in the required EM&V reports from Energy Division staff.

"We direct the utilities to report in their applications for 2009-2011 energy efficiency portfolio approvals the expected cumulative savings (as described above) of their portfolio plans over the long-term (i.e., at least 20 years). Using 2004 as the base year, we also expect to see the cumulative effect of these savings across program cycles in their annual reporting, commencing with the 2004-2005 portfolio when we established the cumulative goals. Utilities shall include this information in the Strategic Plan and 2009-2011 portfolio plan applications. Cumulative savings as clarified herein also should be included in Commission staff's Verification and Performance Earnings Basis reports that are required under our EM&V protocols" pg. 81-82

2008 Goals Decision: D. 08-07-047; July 31, 2008

http://docs.cpuc.ca.gov/WORD_PDF/FINAL_DECISION/85995.PDF

D. 08-07-047, the "Decision Adopting Interim Energy Efficiency Savings Goals For 2012 Through 2020, and Defining Energy Efficiency Savings Goals for 2009 Through 2011" utilized an updated potentials study, and goals study (by Itron) to develop total market gross goals for 2012-2020.

"In a hybrid goal structure, goals are established for all energy efficiency actions taken across the market within a utility service territory, referred to as Total Market Gross (TMG), and for the savings associated specifically with each utility energy efficiency portfolio (utility program-specific)."Appendix p 1. D. 08-07-047

The rationale for this goals paradigm was stated in that decision.

"Energy Division believes a hybrid goal structure (which incorporates both a total market gross goals and a utility program–specific goal) which measures all savings achievements within IOU service territories begins to solve the crucial interagency need for a metric appropriate to load forecasts, associated emission reduction baselines, and economically efficient procurement plans." p. 13

The need for more evaluation and measurement frameworks to measure these savings was also recognized in this decision.

"Such a definition must be accompanied by a Commission commitment to develop any significant missing evaluation, measurement & verification (EM&V) protocols for attributing savings to utility programs." p. 13

"Energy Division believes a hybrid goal structure employing "expansive net" as the metric for which IOU program efficacy is measured also encourages utilities to innovate their program delivery through non-traditional channels. The EM&V profession refers to these additional EE effects variously as "participant spillover," "market effects," "naturally occurring" savings." p. 14

More details regarding this proposal were presented in a Staff White Paper (May 12, 2008.) entitled *"2012-2020 Energy Efficiency Goal Setting: Technical and Policy Issues."*

Goals for 2008-2020 were proposed, and cited in D. 08-07-047, but were adopted on an interim basis (OP1). They were adopted for use by the California Air Resources Board in its Assembly Bill 32 planning process and again cited to be used in the Commission's long-term procurement planning process (OP3).

> *"3. Energy utilities shall use one hundred percent of the interim Total Market Gross energy savings goals for 2012 through 2020 in future Long-Term Procurement Planning proceedings, until superseded by permanent goals."*

This decision also characterized the existing goals for the 2009-2011 energy efficiency program cycle as 'gross' to better align them with the 2002 Secret Surplus study. However, the numeric values of the goals did not change. (OP4)

A preliminary target for updating the goals was also ordered in this decision.

> *"5. The 2012 through 2020 interim goals shall be updated and utility portfolio goals shall be established after the 2006 -2008 Impact Evaluation studies are completed (expected to be March 2010) and the inquiry shall be completed by October of 2010. The assigned Commissioner and/or Administrative Law Judge may adjust the schedule for updating and establishing new energy savings goals for 2012 through 2020."*

May 2009 decision: D.09-05-037; May 21, 2009

http://docs.cpuc.ca.gov/WORD_PDF/FINAL_DECISION/101543.PDF

This decision redefined cumulative savings for the 2009-2011 program cycle to begin in 2006 rather than 2004. It removed the savings for the 2004-2005 period as part of the cumulative goals in the 2009-2011 program period, subsequently removing the obligation of the utilities to make up any shortfall in savings in future cycles. The reasoning for removing 2004-2005 was because the evaluations in this period were not guided by the CPUC and the standard protocols were not in effect.

This decision granted SDG&E and PG&E (dual fuel utilities) reductions in their therm goals of 22% and 26% respectively. This was done to align expectations with the DEER 2008 application of interactive effects primarily for prescriptive lighting measures.

Energy Division was directed to do further study on measure decay in preparation for the next program cycle (2012-2015). (OP 2)

> *"Energy Division shall study specific assumptions around decay in advance of the 2012-2015 energy efficiency portfolio applications, with opportunities for interested parties and persons to provide input on and comment on the Energy Division recommendations."*

September 2009 Decision: D. 09-09-047; September 24, 2009

http://docs.cpuc.ca.gov/PUBLISHED/GRAPHICS/107829.PDF

D. 09-09-047 granted SDG&E, PG&E and SCE all 5% and 1% decrement to their annual goals for kWh and kW respectively. The purpose was to align expectations for meeting the goals with the requirement to apply the DEER 2008 ex-ante assumptions to 2006-2008 and 2009-2012 claims.

SDG&E also had a long standing anomaly in their goals compared to the other utilities; they had been required to achieve a larger portion of electric potential than the other utilities. The correction in the decision resulted in a 25% reduction on their kWh and kW annual goals. This was applied before the 5% and 1% corrections were made. This correction was also applied retroactively to the 2006-2008 period to correct for cumulative savings shortfall.

This decision also adopted the D. 04-09-060 goal for 2012 (with the subsequent adjustments); not the D. 08-07-047 goal for 2012.

This decision required that the utilities should make up 50% of the savings decay as measures expire, but also for further study.

> *". . . until EM&V results inform better metrics, utilities may apply a conservative deemed assumption that 50% of savings persist following the expiration of a given measure's life. This reflects our expectation that our energy efficiency program efforts are in fact resulting in market transformation, changing consumption habits and preferences, while acknowledging that measure uptake in the absence of program support may not be universal.*
>
> *Given the exclusion of 2004-2005 from cumulative savings calculations in D.09-05-037, measure life drop off is expected to have a relatively minor effect on utility goal achievement for the current cycle, hence the appropriateness of a deemed assumption. However, we understand that the scope of this issue will grow over time as cumulative savings obligations increase and a larger swath of measure lives expire. Therefore, this is an important analytical issue critical to our understanding of savings persistence over time, and demands greater attention in our EM&V work. D.09-05-037 directed Energy Division to study specific assumptions around efficiency measure savings "decay" in advance of the 2012-2014 (now 2013-2015) portfolio applications. We intend to take this up for further examination in R.06-04-010, or its successor rulemaking." p 38-39*

Current Status of Goals

The following graphics illustrate the affect on the CPUC adopted goals as a result of decisions since D.04-09-060. Actual values are provided in the Decisions.

Figure 1. Changes to GWH Savings Goals [Projection] per decision

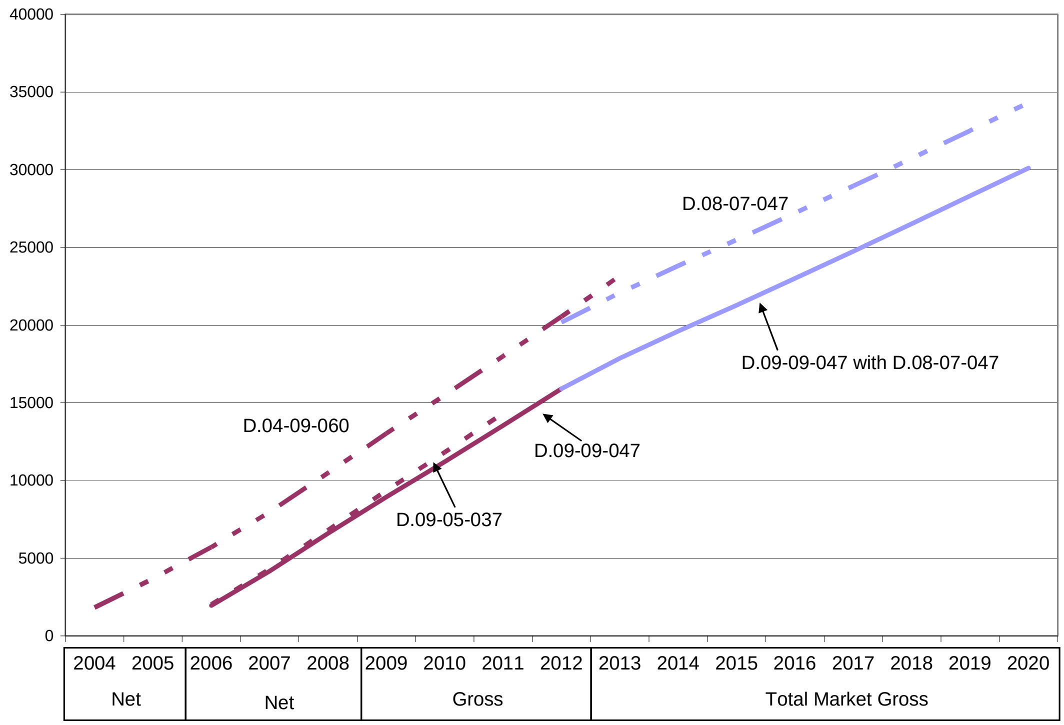


Figure 2. GWH Savings Goals [Projection]

Comparison of Original D. 04-09-060 to Current D. 09-09-047 [aggregate effects]

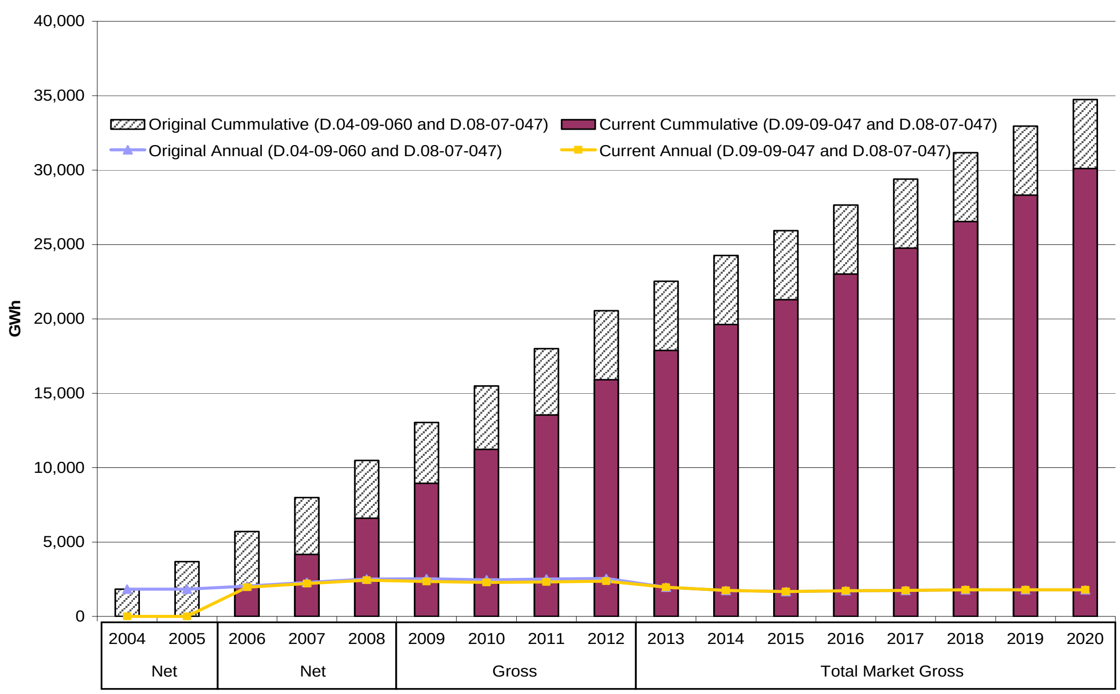


Figure 3. MW Savings Goals [Projection]

Comparison of Original D. 04-09-060 to Current D. 09-09-047 [aggregate effects]

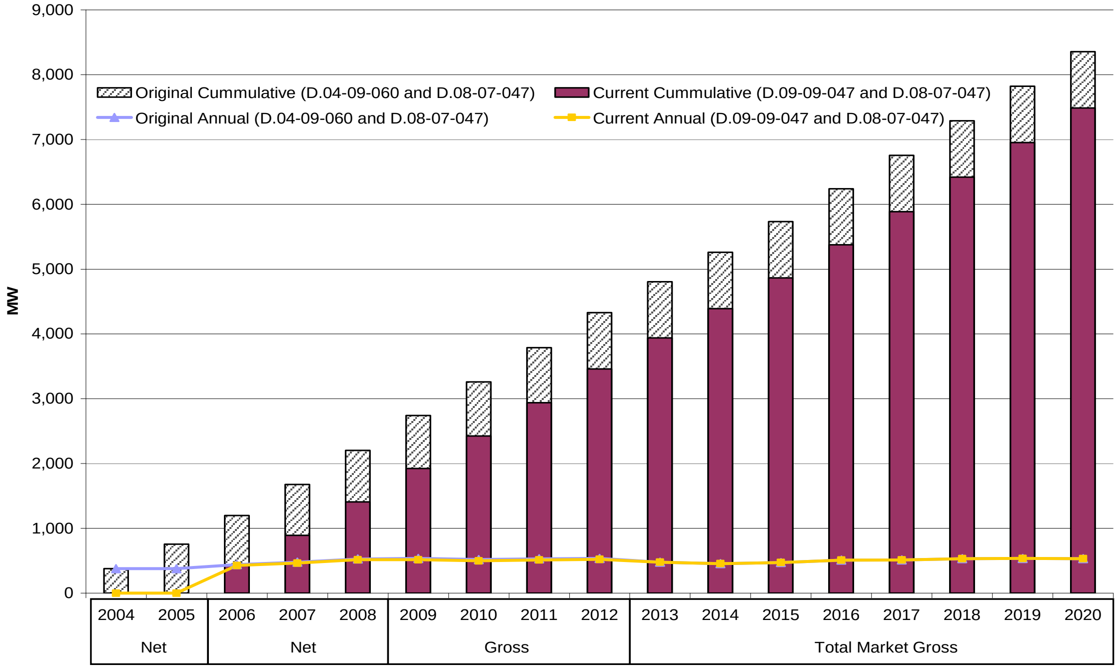
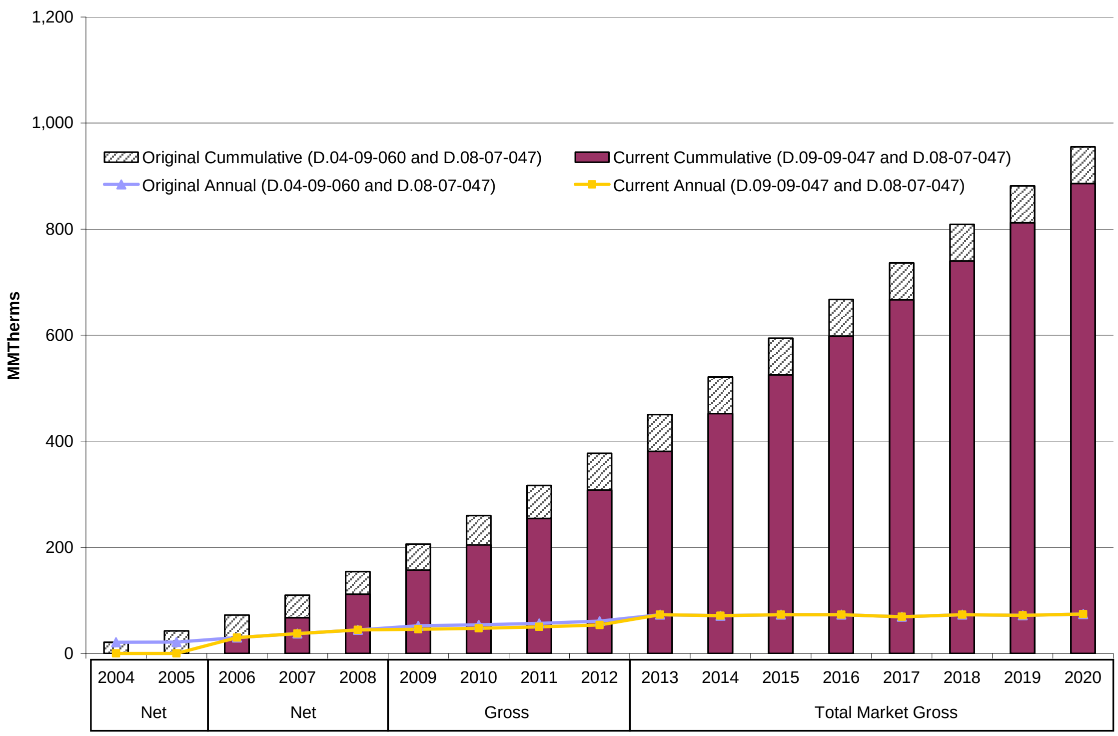


Figure 4. Therm Savings Goals [Projection]

Comparison of Original D. 04-09-060 to Current D. 09-09-047



Lifecycle Logged Savings by Utility by Fuel Type

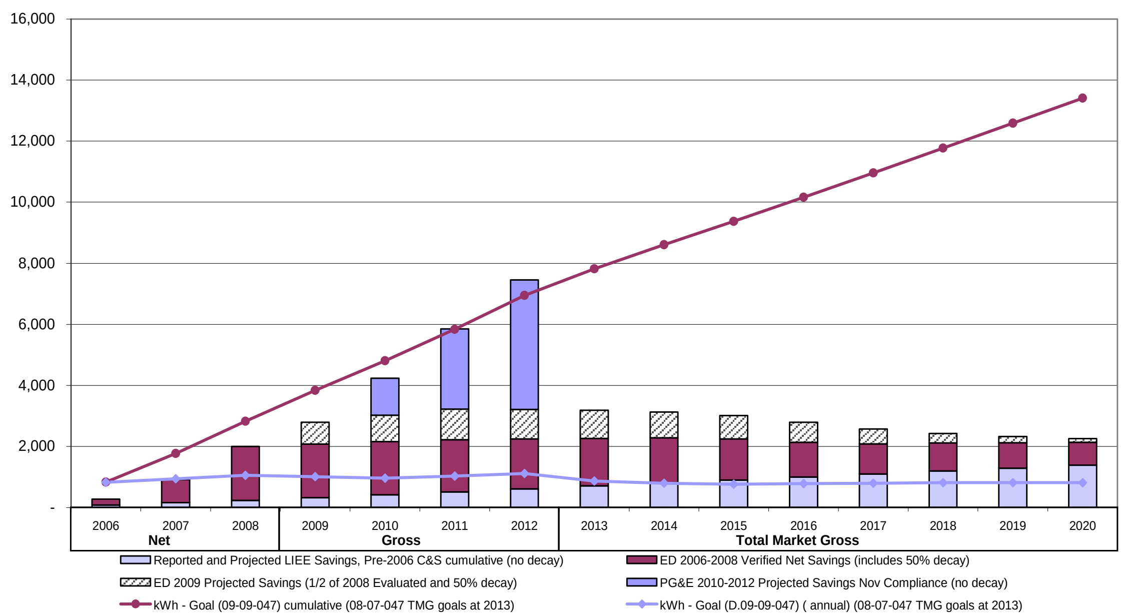
The following figures illustrate the *2006-2008 evaluated net* savings the Commission has reported for the 2006-2008 program period including 50 percent of the decay projected for these measures expiring over time. The savings in the 2010-2012 period are *projected* based on their July 2nd 2009 filings. The 2006-2008 evaluated energy savings can be found at the following link:

http://www.cpuc.ca.gov/PUC/energy/Energy+Efficiency/EM+and+V/2006-2008+Energy+Efficiency+Evaluation+Report.htm

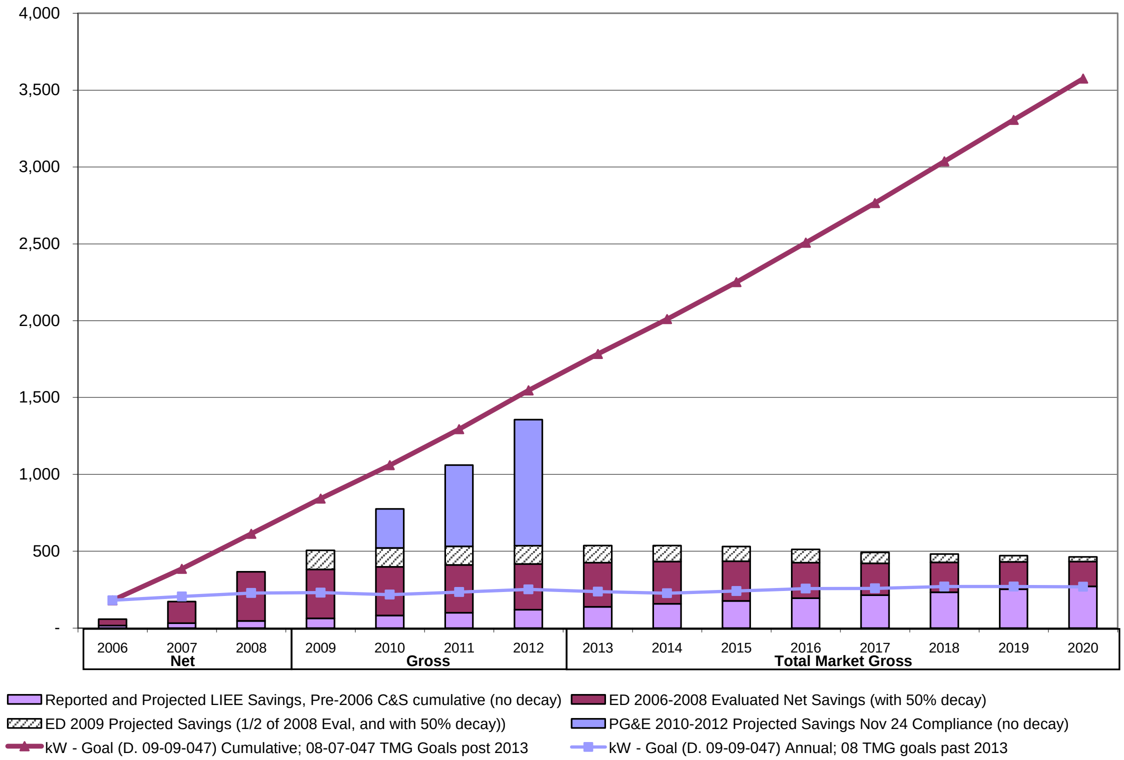
The projected savings for 2009 are assumed to be equal to the gross savings achieved in 2008 based on reported savings from the 4th quarter of 2009. The exception is for PG&E which saved about half of 2008 savings.

No assumptions about the decay or lifecycle savings for the 2010-2012 proposed programs are included in these figures; and pre-2005 C&S and Low Income projections past 2009 assume continued savings at the same pace with no decay.

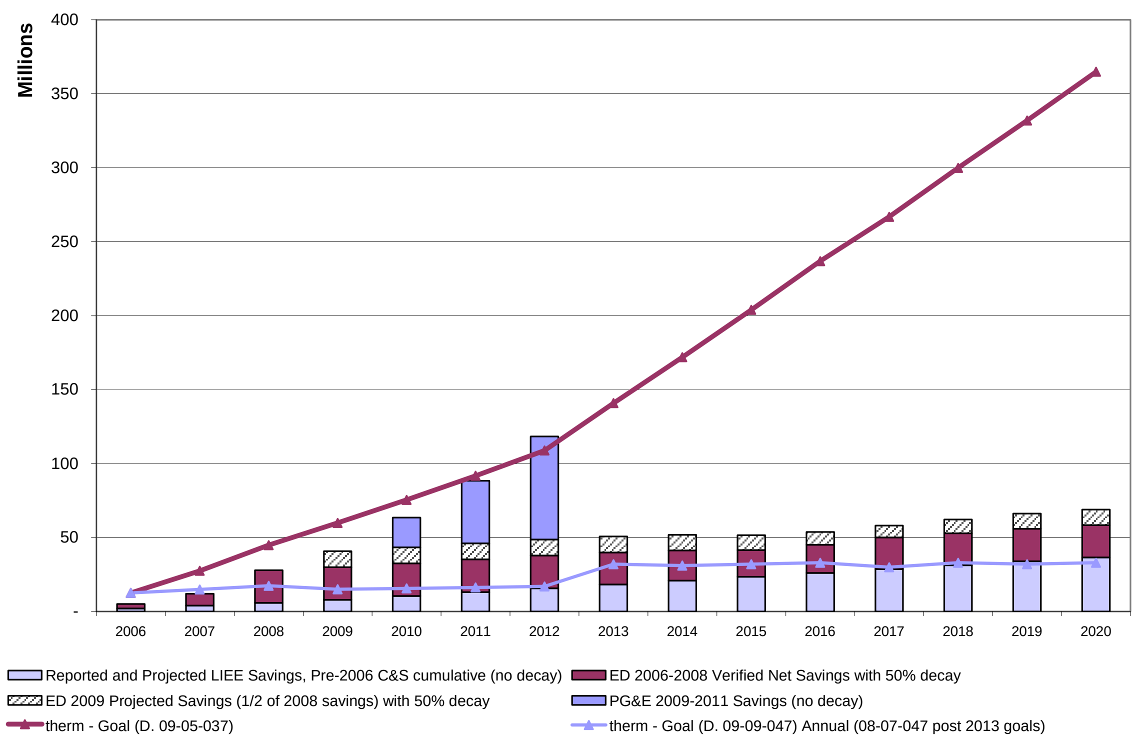
PG&E Recorded and Projected Savings v. Commission Adopted Goals GWh



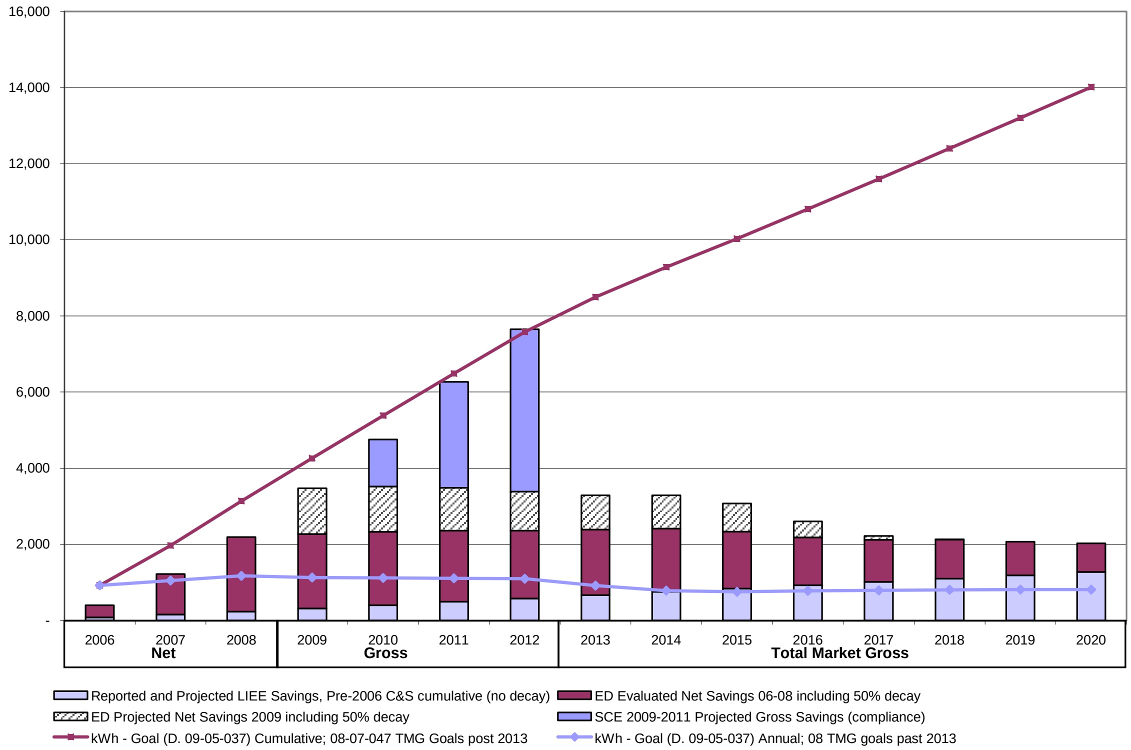
PG&E Recorded and Projected Savings v. Commission Adopted Goals MW



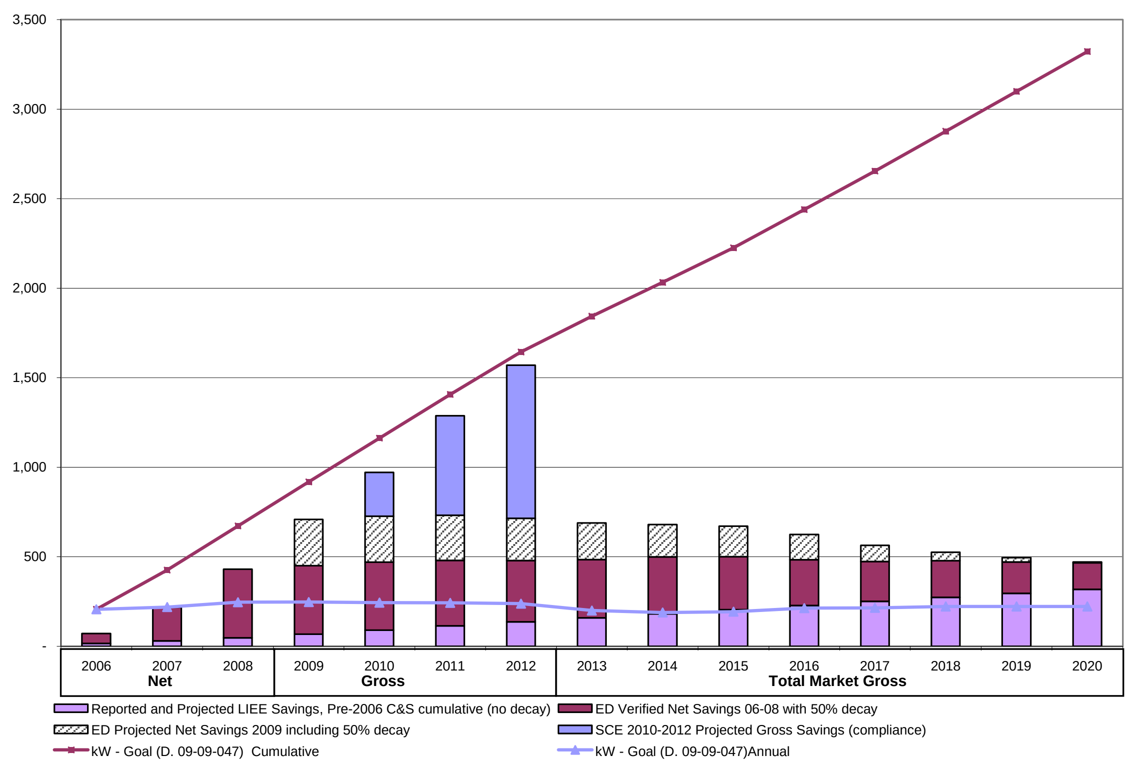
PG&E Recorded and Projected Savings v. Commission Adopted Goals MMTherms



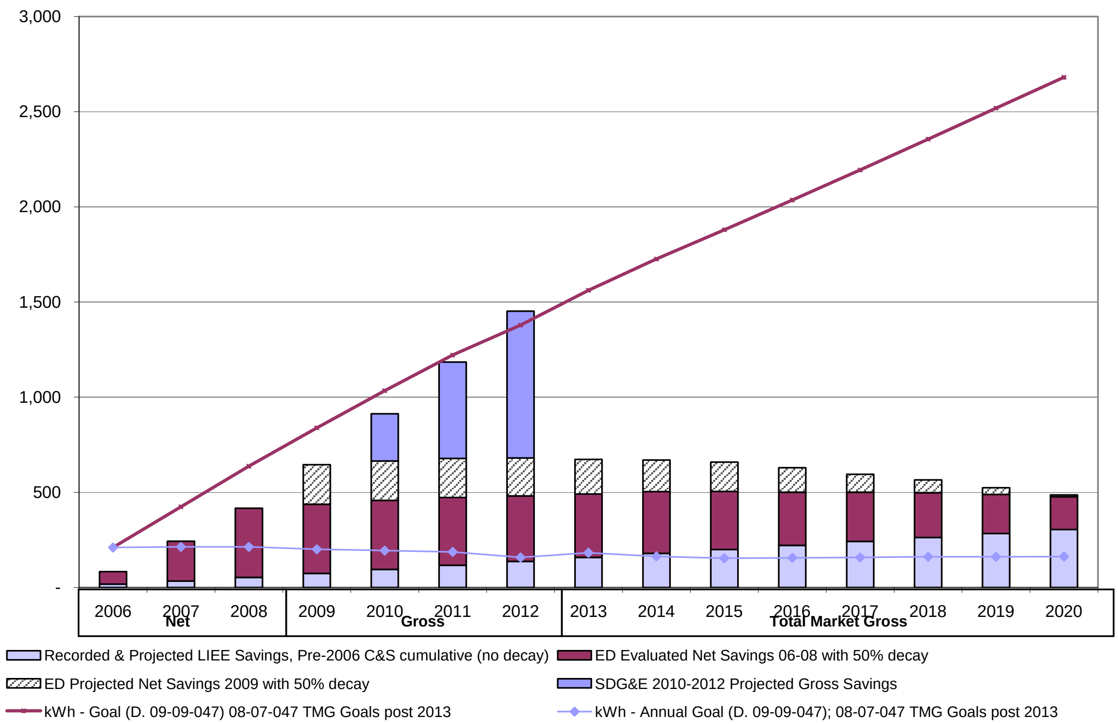
SCE Recorded and Projected Savings v. Commission Adopted Goals GWH



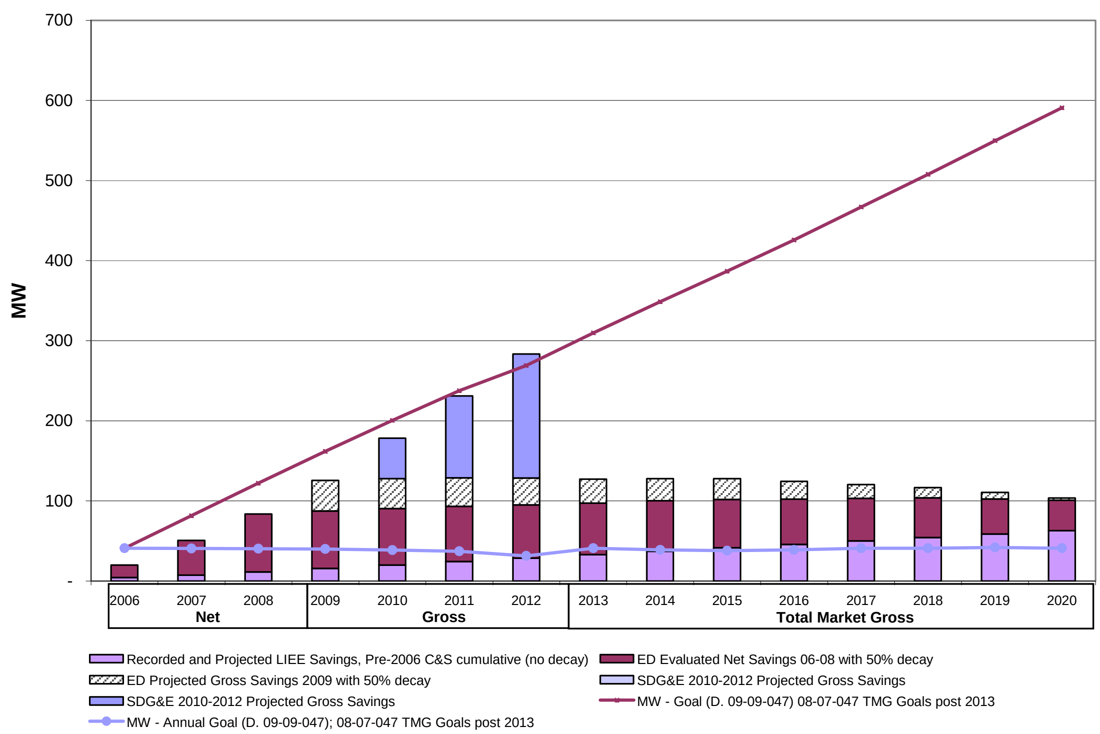
SCE Recorded and Projected Savings v. Commission Adopted Goals MW



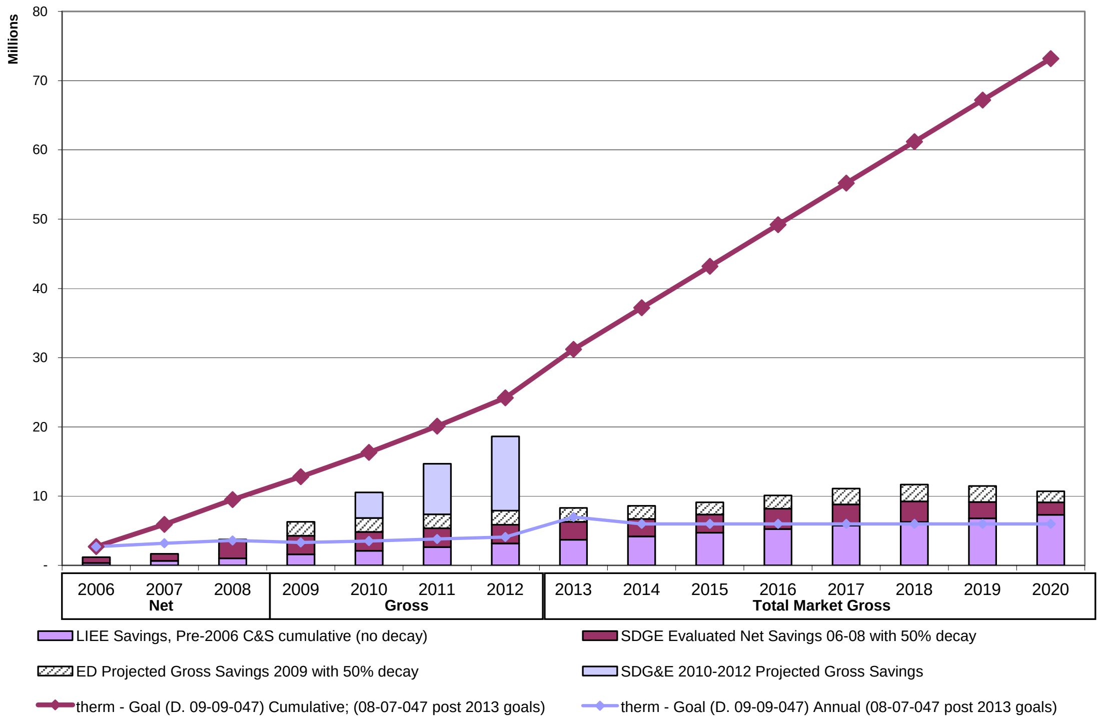
SDG&E Recorded and Projected Savings v. Commission Adopted Goals GWH



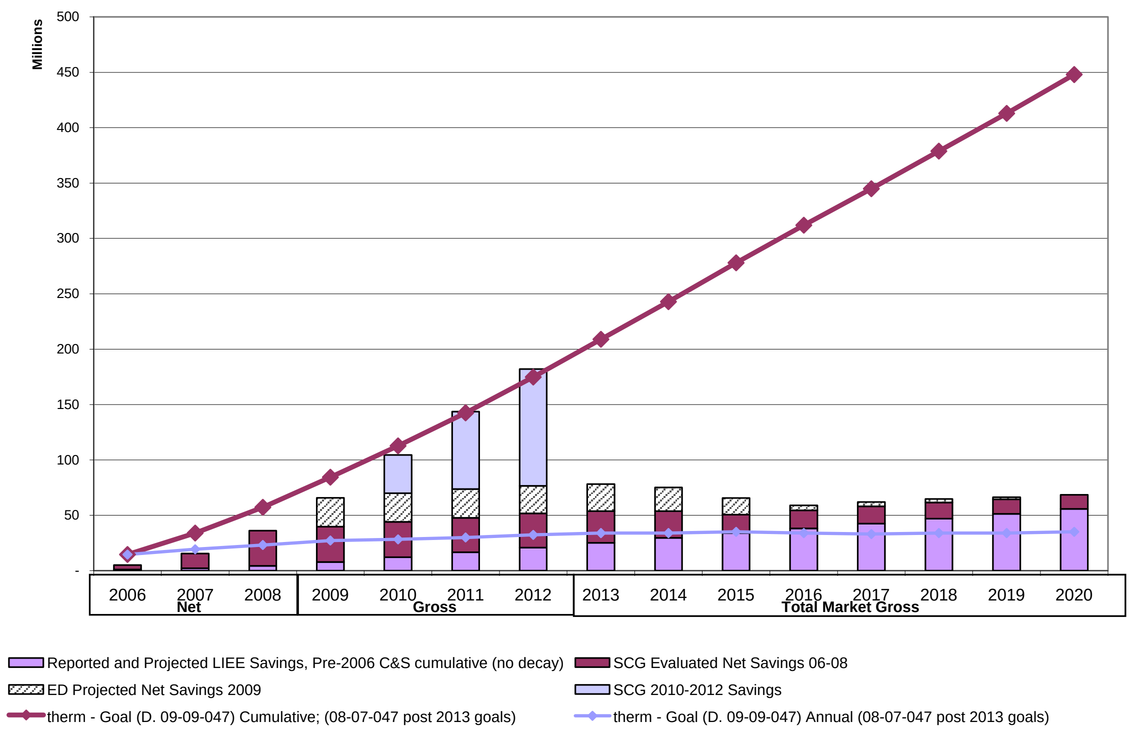
SDG&E Recorded and Projected Savings v. Commission Adopted Goals MW



SDG&E Recorded and Projected Savings v. Commission Adopted Goals MMTherms



SCG Recorded and Projected Savings v. Commission Adopted Goals MMTherms



ATTACHMENT C: Long-Term Procurement Planning Issues

California Public Utilities Commission

Energy Division

Procurement &Resource Adequacy

Developing a Managed Demand Forecast for Long-Term Procurement Planning

Prepared by: Simon Eilif Baker, CPUC Energy Division, Procurement

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Energy Efficiency in the Procurement Process

Energy efficiency is California's first-choice to serve demand for electricity. Public Utility Code § 454.5, which codifies the CPUC's Long-term Procurement Plan (LTPP) process, states that an investor-owned utility's (IOU) procurement plan must show that it "will first meet its unmet resource needs through all available energy efficiency [EE] resources and demand reduction measures that are *cost effective, reliable and feasible*."[55] In 2003, the state reinforced this policy by placing EE first in the Energy Action Plan (EAP) loading order.[56]

In practice, this means the IOUs should plan to a "managed forecast," which, in resource planning parlance, is a base demand forecast (including some embedded EE), plus adjustments to represent incremental impacts of all "cost effective, reliable and feasible" demand-side resources.[57] In interpreting the statute, the challenge for demand forecasters, IOU resource planners, and the CPUC, is to estimate "cost-effective, reliable and feasible" levels of EE and determine what is "reasonably expected to occur." [58]

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55. Pub. Util. Code § 454.5 at Subsection (b)(9)(C). Added by AB 57 (Wright, Chapter 850, Statutes of 2002). (Emphasis added.)

56. CEC, CPUC, and CPCFA. (2003). *Energy Action Plan*, at p. 4; and CEC and CPUC. (2005) *Energy Action Plan II*, at p. 2.

57. Examples of additional demand-side resources include combined heat and power facilities, and rooftop solar photovoltaic installations.

58. Here, CPUC staff borrows from the "reasonably expected to occur" (RETO) concept that previously guided the Energy Commission's electricity planning efforts under SB 1389 (Bowen,

While P.U.C. § 454.5 originally focused on the procurement needs of the IOUs' bundled customers,[59] CPUC Decision (D.) 06-07-029 expanded the scope of the LTPP proceeding, on an interim basis, to identify system-wide[60] resource needs and provide a backstop procurement mechanism to ensure long-term resource adequacy, pursuant to P.U.C. § 380.[61] It is expected that the LTPP will continue to play this role in the forthcoming 2010 LTPP proceeding. Thus, a key role of the CPUC's oversight in the LTPP proceeding is to ensure system reliability, while verifying adherence to the EAP loading order.

In the CPUC's need determination, a unique challenge presents itself because procurement authorizations must consider longer timescales (about 5-7 years forward) than either utility or non-utility EE initiatives, which typically operate on three-year cycles (of program design, implementation/delivery, and evaluation). For the 2010 LTPP cycle, the CPUC will review procurement plans spanning the period 2010-2020 and most likely decide whether to construct new resources in the 2017-2018 timeframe. Compared to the currently approved 2010-2012 utility EE portfolios, procurement planning has a markedly different frame of reference. In effect, this means the CPUC's procurement decision must judge the expected impacts of EE policy initiatives which have yet to be concretely defined and for which measured impacts are difficult to predict.

The CPUC and Energy Commission, respectively, adopt specific new utility programs and standards every three years at a level of implementation detail. But, *both* processes are guided by longer-term policies (e.g. to strengthen standards by 15% each cycle), goals (e.g. out to 2020), and/or targets (e.g. 50% reduction in energy use by existing commercial buildings, as set forth in the CPUC's Energy Efficiency Strategic Plan). A similar situation occurs in procurement, where procurement authorizations are made 5-7 years forward, but specific resource additions get firmed up in later years. Thus, the CPUC's procurement decision must equally consider the likely composition of both supply- and demand-side resource acquisitions.

Chapter 568, Statutes of 2002). While the RETO concept was repealed from law under the current statute (P.R.C. §§25300 – 2532), it remains a familiar and useful criteria for resource planning because it entails a judgment by decision-makers regarding an acceptable level of uncertainty that specific amounts of EE will be available to serve load.

59. Bundled customers take retail electric service from the IOUs as load-serving entities (LSEs).

60. The CPUC has defined "system" as an IOU's service area including load from bundled, direct access (and community choice aggregator) customers; and excluding load from embedded publicly-owned utilities (D.07-12-052; see, e.g., Table PGE-1, footnote 2, p. 121 (116)). System also corresponds to the IOUs' distribution service territory.

61. Added by AB 380 (Nunez, Chapter 367, Statutes of 2005).

The remainder of this appendix provides a staff-level synthesis of issues the CPUC faces when developing a managed demand forecast for procurement planning. It also traces the historical trajectory of the CPUC's examination of these EE uncertainties, beginning with the most recent LTPP decision.

Energy Efficiency Uncertainty in Procurement Planning

In making procurement decisions, the CPUC faces three types of uncertainty with regard to need determination and the projected impact of EE:

- **Methodological uncertainty** – This category addresses data and modeling assumptions underlying the Energy Commission's IEPR demand forecast and the CPUC's EE goals analyses. Uncertainty stems from two main sub-categories: (1) the forecast error *within* each agency's modeling effort (i.e., intra-agency issues); and (2) forecast errors that arise *between* modeling efforts and from the need to reconcile assumptions, when attempting to quantify incremental impacts of the CPUC's EE goals relative to impacts already embedded in the Energy Commission's demand forecast (i.e., inter-agency issues).

  As to intra-agency issues, a principal driver is the set of assumptions used to produce *ex-ante* forecasts of savings in the CPUC's goals-setting process. These uncertainties were evaluated in the *2008 Energy Efficiency Goals Update Report* (2008 Goals Study),[62] which looked at scenarios of expected savings expected from Huffman Bill,[63] codes and standards, and Big Bold Energy Efficiency Strategies (BBEES) [64] by varying implementation assumptions. The CPUC goals Decision (D.) 08-07-047, weighing the goals scenarios and evidence presented at the time, found that the TMG goal was realistic and achievable, and required that 100% of TMG be used in future LTPP proceedings.[65]

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62. Itron Inc. (2008). *Assistance in Updating the Energy Efficiency Savings Goals for 2012 and Beyond: Prepared for the California Public Utilities Commission, Vols. 1 & 2.* Attachment to March 25, 2008 Assigned Commissioner's Ruling in R.06-04-010. Available at www.cpuc.ca.gov/NR/rdonlyres/D72B6523-FC10-4964-AFE3-A4B83009E8AB/0/GoalsUpdateReport.pdf.

63. Assembly Bill 1109 (Huffman, Chapter 534, Statutes of 2007)

64. Big Bold Energy Efficiency Strategies (BBEES) are strategies "to promote maximum energy savings through coordinated actions of utility programs, market transformation, and codes and standards." (D.07-10-032, at p. 35). In D.07-10-032, the CPUC adopted three BBEES: (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; and (3) The HVAC industry will be reshaped to assure optimal performance of HVAC equipment.

65. See D.08-07-047, at pp. 24-26.

As to inter-agency issues, the modeling study in this uncommitted EE report addressed many of these uncertainties. But, the study also identified new ones which have yet to be resolved. These include the importance of a consistent calibration year when matching up peak-to-energy ratios in CPUC goals and Energy Commission estimates of committed/uncommitted EE; and the need for consistent approaches to modeling measure decay.

- **Policy uncertainty** – This category addresses what specific policies are adopted at the CPUC, Energy Commission, and other agencies; how they are structured over the forecast period; and the measurement of what is achieved. Some of these were evaluated in the 2008 Goals Study, such as the assumed level of IOU program funding. Others were not explicitly considered at that time, including effectiveness of mechanisms to enforce cumulative goals, changes in definitions or thresholds of cost-effectiveness, and accounting or attribution of utility savings in the Total Market Gross (TMG)[66] paradigm.

- **Implementation uncertainty** – This category addresses the likely level of savings that will be achieved in the implementation of EE policies at the CPUC (and other agencies). Here, the emphasis is on *ex-poste* assessments of savings actually achieved. *Implementation uncertainty* captures "yield" variations of EE initiatives versus what was expected (*ex-ante*) in CPUC goals studies. Yield variations arise from the way EE measures are deployed and function in the marketplace. The CPUC's Evaluation, Measurement, and Verification (E,M&V) studies inform these yield variations.

  For "committed" [67] utility programs, the Energy Commission captures *implementation uncertainty* by assuming certain "realization rates" of utility program savings, based on net-to-gross ratios from CPUC E,M&V studies. However, for the "uncommitted" period, other yield assessments (based on methodologies yet to be developed) may be required to fully characterize *implementation uncertainty* in the TMG paradigm.[68]

66. Total Market Gross is "all energy efficiency actions taken across the market within a utility service territory." (D.08-07-047, Appendix 1, at p. 1). See also Appendix B to this report, at p. B-2.

67. The Energy Commission defines *committed* programs as "programs that have already been implemented or for which funding has been approved." "*Uncommitted* effects are the incremental impacts of the level of future programs…impacts of new programs, and impacts from expansions of current programs." (*California Energy Demand 2008-2018 Staff Revised Forecast*, at p. 25.)

68. For example, net-to-gross ratios will likely become less relevant for procurement purposes under the TMG paradigm, because what matters is the total managed forecast, regardless of whether energy savings come from utility or non-utility actions.

In sum, uncertainty still surrounds the level of EE that is reasonable to assume for procurement planning purposes: some have yet to be addressed; and others are newly identified.

2006 Long-Term Procurement Plan Decision (D.) 07-12-052

In D.07-12-052 adopting the IOUs' 2006 LTPPs, the CPUC deferred to the Energy Commission's IEPR process to quantify impacts of the CPUC's EE goals embedded in the demand forecast. The CPUC also acknowledged uncertainty in attempting to quantify the incremental impacts, relative to the 2007 IEPR forecast, of "uncommitted" EE that is treated as a resource in procurement planning. The CPUC ultimately assumed that 20% of the CPUC's EE goals for PG&E and SCE and 0% of the goals for SDG&E,[69] as defined by D.04-09-060,[70] were incremental to the forecast.

Decision 07-12-052 also clarified the CPUC's definition of "uncommitted" EE "as the projected savings attributable to future EE program cycles (2009-2011 and beyond) that meet or exceed the Commission-adopted EE goals."[71] Because the CPUC goals at the time (D.06-09-060) were focused exclusively on net savings from *utility programs*, this use of the term differed slightly from the Energy Commission's more expansive concept of "uncommitted effects" which includes non-utility programs such as codes and standards, as well as conservation due to price or market effects. As it happens, the CPUC's goals update decision, D.08-07-047 (see below), later aligned with the Energy Commission's more expansive definition of uncommitted effects, which should help to reduce confusion and align future modeling efforts. However, *methodological uncertainty* remains in the quantification and attribution of savings from utility programs, non-utility programs, and market or price effects in the various models used to forecast these impacts.

Finally, D.07-12-052 recognized a need for a "robust methodology to quantify the portion of future EE program measures that are embedded in the CEC forecast."[72] Pursuant to this direction, CPUC staff devoted considerable time and resources to the 2009 IEPR effort to develop such a methodology.

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69. Energy efficiency associated with SDG&E's goals was assumed to be 100% embedded (or conversely, 0% incremental).

70. Because D.04-09-040 goals only extended to 2013, it was necessary to extrapolate those goals through 2016, the end of the 2006 LTPP planning period.

71. D.07-12-052, at p. 42.

72. D.07-12-052, at p. 45.

2008 Long-term Procurement Plan Rulemaking (R.) 08-02-007

A central focus of the Order Instituting Rulemaking (OIR) for the 2008 LTPP proceeding (R.08-02-007) was to "develop standardized resource planning practices, assumptions and techniques, based on an integrated resource planning framework."[73] The CPUC's consideration of this issue was partly informed by 2007 IEPR recommendations calling for a "common portfolio analytic method"[74] to the IOUs' resource plans.

In addition, the OIR scoped the CPUC's consideration of EE uncertainty in two main areas:

(1) Quantification of EE in the Energy Commission demand forecast; and

(2) Long-term firm capacity projections for demand-side resources

The first issue is being addressed through the Energy Commission's Demand Forecasting and Energy Efficiency Quantification Project (DFEEQP) in the 2009 IEPR. CPUC staff notes that the DFEEQP was originally conceived to address *methodological uncertainty* – and a great deal has been accomplished towards that end – but it was *not* designed to address *policy uncertainty* or *implementation uncertainty*.

The second issue deals primarily with *implementation uncertainty*, but also relates to *methodological uncertainty* in the CPUC's EE goals analyses. It was partly considered in the CPUC's EE goals update process, which culminated in D.08-07-047.

2008 Energy Efficiency Goals Decision (D.) 08-07-047

In the 2008 goals update proceeding (R.06-04-040) the CPUC evaluated scenarios for possible EE goals based on the 2008 Goals Study. The study scenarios put forth a new methodology to develop savings from utility and non-utility efforts. As discussed above and in Appendix A, Itron's scenarios assessed various levels of achievement of savings from utility and non-utility programs. In D.08-07-047, the CPUC adopted TMG goals based on the mid-range goals scenario.[75] Pursuant to the decision, TMG goals,

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73. R.08-02-007 OIR, at p. 10 and pp. A-1 – A-10.

74. CEC. *2007 IEPR*, at p. 67.

75. The mid-range goals scenario assumed a high level of IOU program funding, with IOU programs offering aggressive rebates at or near 100% of incremental measure costs. It also assumed that revisions to Title 24 building codes and federal appliance standards would be more substantial than the low case and that new code compliance programs would capture additional savings. A mid range of savings from BBEES was assumed. Importantly, a more tempered outlook was assumed for savings from the Huffman Bill, reflecting potential challenges in complying with the standard and achieving significant savings from lighting applications. (See also Appendix A to this uncommitted EE report, at p. 9)

combining projected savings from utility <u>and</u> non-utility actions, were adopted for the period 2012-2020. The decision also ordered the utilities to use 100% of the TMG goal in the LTPP proceeding.

CPUC staff believes the 2008 Goals Study made considerable strides towards assessing both *methodological uncertainty* and *policy uncertainty*.

On August 28, 2008, the Scoping Memo for Phase 1 of the 2008 LTPP proceeding noted the EE goals decision (D.08-07-047) had considered "long-term firm capacity projections" for EE, pursuant to the LTPP OIR, and required 100% of TMG goals to be used in the LTPP proceeding.

2008 LTPP Staff Proposal

On July 1, 2009, an Amended Scoping Memo released an *Energy Division Staff Proposal on LTPP Planning Standards* (Staff Proposal), which proposed specific guidelines for how EE should be quantified and assessed in the IOUs' portfolio analysis. The Staff Proposal acknowledged the current effort to produce an uncommitted EE forecast, which, when combined with the Energy Commission's base forecast and other demand-side policy initiatives, would produce a managed forecast for procurement planning. CPUC staff recommended that the original CPUC goals scenarios be carried through the Energy Commission's quantification of uncommitted EE, so that the results of the analysis could be used in sensitivity analysis to quantify a range of for new resources in the LTPP.

The Staff Proposal also put forth a "Deliverability Risk Assessment" concept, analogous to the *implementation uncertainty* discussed herein and also analogous to the Energy Commission's "reasonably expected to occur" principle used in demand forecasting. Because the Energy Commission is not expected to rule on "reasonably expected to occur" projections of uncommitted EE, that determination would presumably be left to the CPUC. Indeed, the 100% of TMG requirement set forth in D.08-07-047 appears to be the CPUC's current position on "reasonably expected to occur" for procurement planning.[76] Anticipating that, with the passage of time and availability of new information, the CPUC may revisit the 100% of TMG requirement, the Staff Proposal recommended that the IOUs also be required to estimate the "probability of occurrence" of need sensitivities based, in part, on forecasts of uncommitted EE. Such information

76. This assumes that *methodological uncertainty* is resolved through satisfactory reconciliation of data and models used in the Energy Commission demand forecast and the CPUC's EE goals analyses.

would provide additional evidence for the CPUC to consider in future determinations of "reasonably expected to occur" levels of EE for procurement purposes.

The Staff Proposal recognized, however, that interpreting the numerical impact of TMG goals relative to the IEPR forecast was a task best left to the Energy Commission. This is because estimates of committed and uncommitted EE must be rooted in the same underlying data and methodologies to avoid over- or under-counting savings.

The Energy Commission's 2009 IEPR forecast and uncommitted EE forecast are based on the most current datasets for economic and demographic drivers of EE (e.g., new housing starts, new commercial floor space). Because the 2008 Goals Study used older datasets, as well as other model inputs, a mismatch between the CPUC's numerical TMG goals and the Energy Commission's calculations of committed and uncommitted EE is almost inevitable. In fact, the results of the uncommitted EE report bear this out.

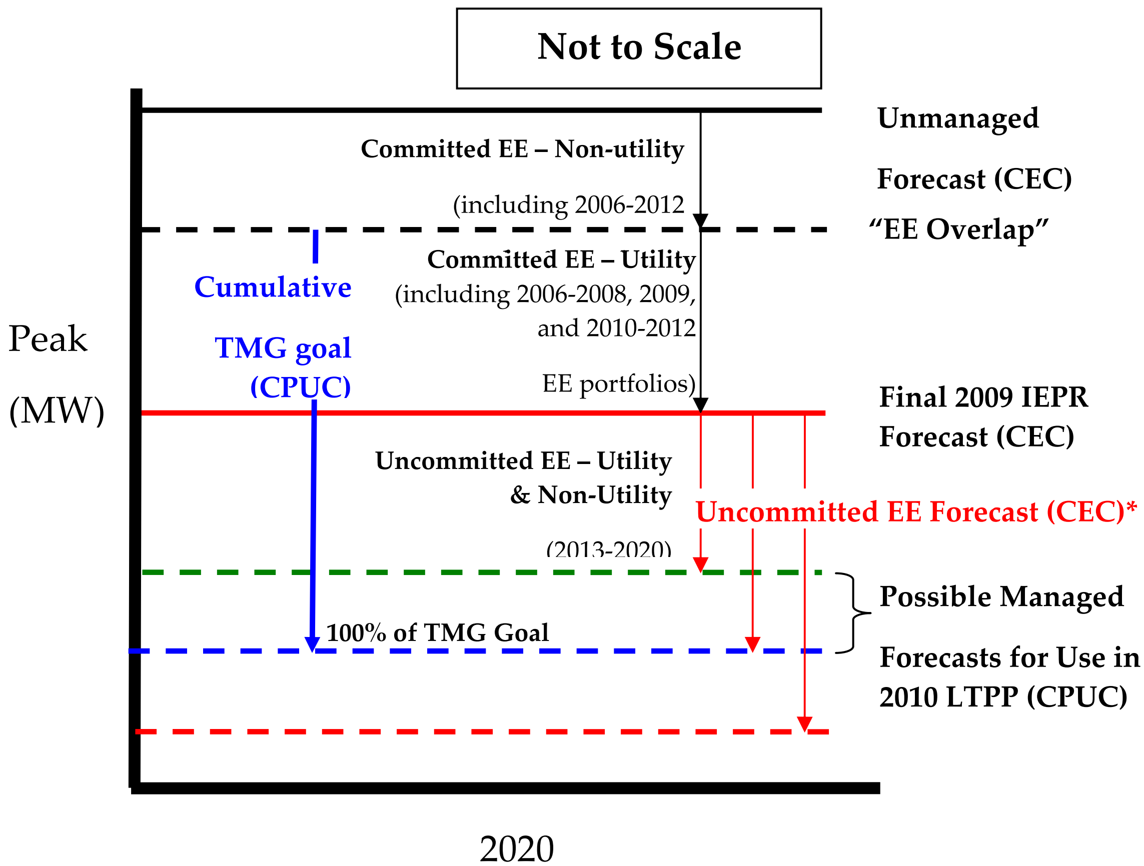
In the event of a mismatch, the Staff Proposal recommended using the lower of the two quantities for purposes of procurement planning. The rationale for using the lower of the two was "at worst, a conservative choice from among the two uncertain quantities would result in earlier procurement of resources than would otherwise be the case (even if this insurance comes at a cost)."[77]

Figure C-1 below provides a graphical illustration of how the Staff Proposal would be implemented in the 2010 LTPP. The solid black line represents the CEC's "unmanaged forecast" which subtracts out committed energy savings in the pre-2013 period. The CEC's Final 2009 IEPR Forecast, represented by the solid red line, includes these committed effects, some of which are attributed to utility programs, and others are not. The proportion of CPUC goals assumed to be embedded in the Energy Commission forecast has been called "EE overlap," which is shown in the black dashed line. The CPUC's TMG goal, represented by the solid blue arrow, includes cumulative impacts of utility programs implemented during the committed period (pre-2013), as well as impacts of new utility and non-utility initiatives in the uncommitted period (2013 and beyond). The Energy Commission's uncommitted EE forecast, represented by the red arrows, may or may not match up to the CPUC's numerical TMG goals for reasons described above (thus, the three red arrows illustrating three possible outcomes). Note these three possible outcomes represent a hypothetical range of results for the mid-range scenario; they do *not* correspond to the three original CPUC goals scenarios.

77. Attachment 2 to July 1, 2009 ACR in R.08-02-007: *Energy Division Staff Proposal on LTPP Planning Standards*, at p. 92.

According to the Staff Proposal, if the Energy Commission's uncommitted EE forecast were to fall at the green dashed line, then the CPUC would use that value for the managed forecast instead of the blue dashed line. Conversely, if the Energy Commission's uncommitted EE forecast were to fall at the red dashed line, then the managed forecast for procurement purposes would use the blue dashed line.

Figure C-1. Conceptual illustration of 2020 peak demand and EE quantities used for procurement planning, as proposed in the July 1, 2009 CPUC Staff Proposal



*The three arrows represent a range of hypothetical results for the mid-range CPUC goals scenario

The CPUC received comments on the Staff Proposal, as well as party alternative proposals, during the fall of 2009.

Preliminary Direction for the 2010 LTPP Proceeding

On December 3, 2009, the Assigned Commissioner issued a ruling signaling a new direction for the LTPP proceeding. [78] First, the ruling suspended the previously determined schedule of activities, including the timeframe for a proposed decision. Second, the ruling indicated that, beginning in the 2010 cycle, the LTPP will be split into two separate proceedings: one addressing "system" reliability and need assessments; and another addressing "bundled" IOU procurement plans. CPUC staff expects the uncommitted EE scenarios would primarily inform need assessments for new resources in the system proceeding, but may also inform IOU contracting positions assessed in the bundled proceeding.

78. December 3, 2009 *Assigned Commissioner's Ruling Addressing Future Commission Activities Related to Procurement Planning*, R.08-02-007.

Rulemaking: 12-03-014
Exhibit No.: ISO-12
Witness:

2011 Integrated Energy Policy Report

2011 IEPR

INTEGRATED ENERGY POLICY REPORT

CALIFORNIA ENERGY COMMISSION
EDMUND G. BROWN JR., GOVERNOR

CEC-100-2011-001-CMF

The *2011 Integrated Energy Policy Report* is dedicated to

JAMES D. BOYD

Energy Commissioner
February 2002 – January 2012

With gratitude for his 50 years of dedicated public service and his unceasing efforts to develop and implement state policies contributing to California's achievements as a global energy leader.

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Preface

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

Abstract

The 2011 Integrated Energy Policy Report provides a summary of priority energy issues currently facing California. The report provides strategies and recommendations to further the state's goal of ensuring reliable, affordable, and environmentally responsible energy sources. Energy topics covered in the report include progress toward statewide renewable energy targets and issues facing future renewable development; efforts to increase energy efficiency in existing and new buildings; progress by utilities in achieving energy efficiency targets and potential; improving coordination among the state's energy agencies; streamlining power plant licensing processes; results of preliminary forecasts of electricity, natural gas, and transportation fuel supply and demand; future energy infrastructure needs; the need for research and development efforts to support statewide energy policies; and issues facing California's nuclear power plants.

KEYWORDS

Air Resources Board, biodiesel, bioenergy, biofuels, building and appliance efficiency standards, California Energy Commission, California Independent System Operator, California Public Utilities Commission, California's Clean Energy Future, clean energy economy, coal-fired generation, combined heat and power, crude oil imports, demand response, diesel, distributed generation, economic development, electric vehicles, electricity, electricity demand, energy efficiency, ethanol, gas-fired generation, gasoline, Governor Brown's Clean Energy Jobs Plan, greenhouse gas, jet fuel, job creation, Low Carbon Fuel Standard, natural gas demand, natural gas pipelines, nuclear power plants, once-through cooling, petroleum reduction, power plant licensing, Public Interest Energy Research Program, renewable, Renewables Portfolio Standard, resource adequacy, transmission, transportation fuel demand, zero net energy

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EXECUTIVE SUMMARY

Every two years, the California Energy Commission prepares an Integrated Energy Policy Report as directed by Senate

Bill 1389 (Bowen, Chapter 568, Statutes of 2002). The report examines various aspects of energy supply, demand, distribution, and price and, based on these assessments, provides policy recommendations to ensure system reliability and safety, conserve resources, protect the environment, and contribute to a healthy economy.

This *2011 Integrated Energy Policy Report* provides an overview of policies that guide California's energy system and summarizes progress in implementing these policies. The report is built on a series of in-depth analyses of key aspects of the state's energy system and highlights issues that California must consider as it moves forward in meeting its energy goals. These issues fall into three general categories:

- Ensuring that the state has sufficient, reliable, and safe energy infrastructure to meet current and future energy demand as well as the state's clean energy goals. This will involve improved forecasting of demand for electricity, natural gas, and transportation fuels; promoting energy efficiency, demand response, distributed generation, and combined heat and power to reduce the need for additional central-station generation and transmission infrastructure; modernizing the electricity transmission and distribution system; evaluating the need for and developing new electricity, natural gas, and transportation fuel infrastructure to maintain energy reliability and support clean energy policies; streamlining and improving power plant licensing processes; and addressing safety and reliability issues associated with natural gas pipelines and nuclear power plants.

- Addressing challenges to achieving policy goals for energy efficiency, renewable energy, distributed generation, combined heat and power, alternative transportation fuel, and reduced greenhouse gas emissions. Goals include achieving all cost-effective energy efficiency; reducing energy use in existing buildings; promoting zero net energy buildings; increasing renewable electricity generation to 33 percent of retail sales by 2020; increasing the production and use of bioenergy resources; achieving Governor Edmund G. Brown Jr.'s Clean Energy Jobs Plan targets of 12,000 megawatts (MW) of renewable distributed generation by 2020 and 6,500 MW of combined heat and power by 2030; increasing the use of alternative and renewable transportation fuels to 26 percent of fuel consumption by 2022; and decreasing the carbon intensity of transportation fuels by at least 10 percent by 2020.

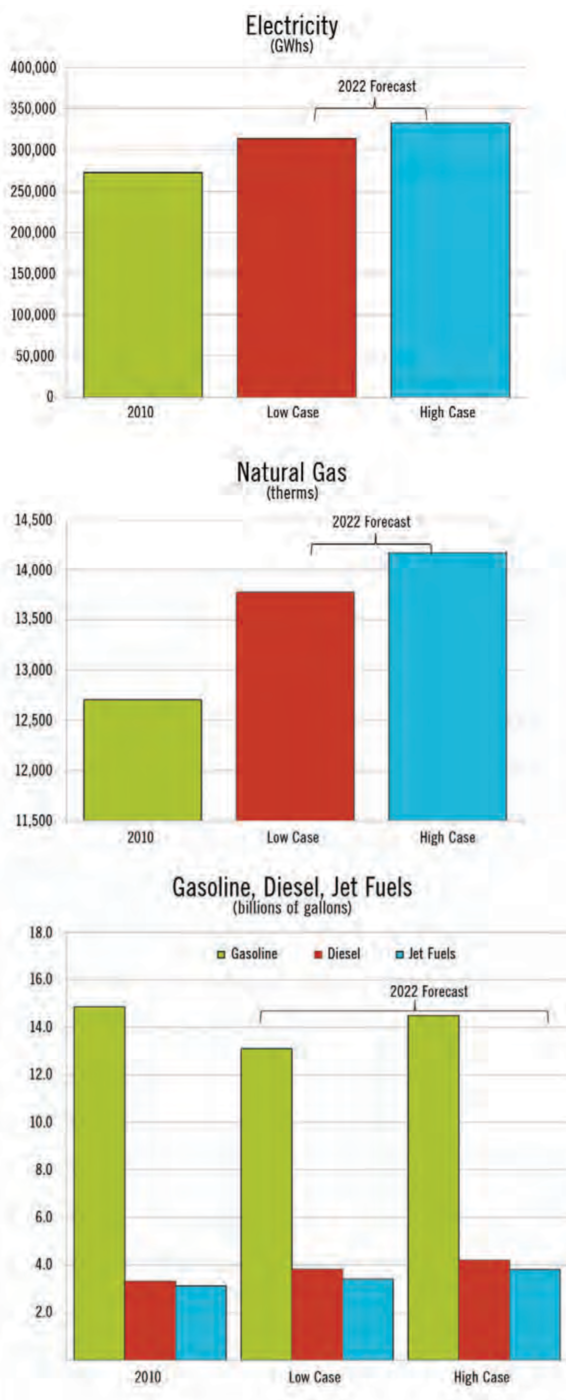
- Securing the economic development benefits of the clean energy economy by strategically targeting state funding investments for energy efficiency, renewable energy, the smart grid, alternative and renewable transportation fuels, and research and development to create jobs and leverage additional private investment. As Governor Brown noted in his 2012 State of the State speech: "California is leading the nation in creating jobs in renewable energy and the design and construction of more efficient buildings and new technologies … and California is positioned perfectly to reap the economic benefits that will inevitably flow."

California's Current and Future Energy Needs

Even in this economic downturn, California's demand for energy continues to grow. In 2010, Californians consumed about 272,300 gigawatt hours (GWh) of electricity; natural gas consumption (excluding fuel for electricity generation) represented almost 12,700 million therms. Energy Commission staff estimates that by 2022, California's electricity consumption will reach between 313,493 GWh and 332,514 GWh, an annual average growth rate of between 1.18 percent and 1.68 percent. Natural gas consumption is expected to reach between 13,773 million and 14,175 million therms by 2022, an average annual growth rate of between 0.7 percent and 0.94 percent.

On the transportation side, in 2010 Californians consumed 21.5 billion gallons of gasoline, diesel, and jet fuel, which represents a 7.2 percent decline from 2006 levels. Data for the first seven months of 2011 indicate that gasoline and diesel consumption was down about 2 percent from 2010 levels. This decline is due to a combination of sustained high fuel costs, low economic growth, declines in the value of real estate and equities, and continued high unemployment. Energy Commission staff forecasts of future gasoline consumption range from a decline of 15.6 percent from 2009 levels to an increase of 3.6 percent by 2030. The lower range is based on a low petroleum fuel demand scenario that assumes increased efficiency, more fleets using hybrids and diesel, and the introduction of alternative fuels. The higher range is based on a high petroleum demand scenario with

Figure E-1: California's Changing Energy Needs



Source: California Energy Commission

a recovering economy and lower fuel prices. Diesel consumption is forecasted to increase by between 22.3 percent and 50.4 percent compared to 2009 levels because of assumptions about steady economic growth along with the historical relationship between diesel demand and the movement of consumer goods by truck and rail.

Consumption of alternative transportation fuels is also expected to rise. Staff estimates that cumulative electric vehicle sales could increase to 440,000 vehicles in 2020 and as many as 1.4 million in 2025, although additional analysis is needed to estimate the number of battery electric and plug-in electric vehicles and total electricity consumption. Consumption of natural gas as a transportation fuel is also expected to increase at a compound annual rate of more than 3 percent, with natural gas consumption by 2030 representing 87 to 96 percent above 2009 levels. Staff also expects increased consumption of ethanol or advanced biofuels of between 2.2 billion and 3.2 billion gallons by 2030.

California's Energy Infrastructure Needs

Electricity Sector

By 2020, California could see retirement, replacement, or divestiture of more than 15,000 MW of fossil generation, which includes 13,000 MW of gas-fired generation and 2,000 MW of coal-fired generation. The state's policy to reduce once-through cooling in power plants – water that is pumped from the ocean, estuaries, rivers, or lakes through a steam turbine condenser and then returned to its source – may require more than 13,000 MW of existing gas-fired generation to comply with that policy by 2020. Most owners of California's plants that use once-through cooling would prefer to repower them, according to implementation plans submitted in April 2011, but no owners indicated willingness to make the necessary investment without a long-term power purchase agreement. Similarly, plant owners say they would need long-term power purchase agreements to finance refitting their existing plants with alternative cooling technologies. Retirement of these plants will increase the need for new generating capacity to satisfy peak electricity demands and maintain appropriate reserves.

The Energy Commission also expects more than 2,000 MW of coal-fired generating capacity to be divested between now and 2019 as a result of Senate Bill 1368 (Perata, Chapter 598, Statutes of 2006), which limits long-term utility investments in baseload generation to power plants that meet an emissions performance standard. This divestiture will reduce the share of California's electricity needs met by coal-fired generation from roughly 10 percent to less than 4 percent.

At the same time, air quality constraints are restricting the development of new fossil fuel power plants that could replace retiring or divested generating capacity, particularly in the southern part of the state. That region will likely need to replace some older generating capacity with dispatchable, flexible fossil fueled power plants when existing once-through cooling plants retire to satisfy local capacity requirements and help integrate variable renewable generation resources developed as a result of the state's Renewables Portfolio Standard. To better understand the potential conflicts between the need for new capacity and the scarcity of emission offsets to develop that capacity, Assembly Bill 1318 (V. Manuel Pérez, Chapter 285, Statutes of 2009) requires the California Air Resources Board to develop a report, in consultation with various agencies including the Energy Commission, to assess the need for new power plant capacity in the South Coast Air Basin and evaluate the need for emission offsets compared to available amounts. The report will also examine whether rule changes and other permitting mechanisms are needed to allow power plants to be developed while safeguarding air quality. The project has been underway since spring 2010, and the Air Resources Board anticipates providing a final report to the Legislature in the summer of 2012.

In addition to participating in the Assembly Bill 1318 study, the Energy Commission is assessing the electricity infrastructure needed to support California's transition to a low-carbon future while maintaining resource adequacy and reliability. This assessment, begun in the *2011 Integrated Energy Policy Report* proceeding and continuing as part of the *2012 Integrated Energy Policy Report Update* proceeding, is evaluating key factors that will affect the need for new generating and transmission infrastructure, including electricity demand growth; potential retirement of large amounts of generating capacity due to age or state water policies; limited availability of emission offsets for replacement generating facilities; retirement, replacement, or divestiture of coal-fired generation serving California; and achievement of state policy goals for increased use of energy efficiency, renewable resources, distributed generation, combined heat and power, and energy storage.

There are also infrastructure challenges associated with the state's licensing process for large-scale natural gas, solar, and other thermal power plants. Since 1996, the Energy Commission has licensed more than 16,000 MW of electricity generating capacity that is currently operating and delivering energy to California customers. In December 2010, after licensing more than 4,000 MW of solar thermal projects and 3,000 MW of natural gas plants, the Energy Commission began analyzing its permitting process to identify strategies to streamline and speed up the process without compromising transparency, effective participation, or environmental outcomes. During 2012, the Energy Commission's "lessons learned" proceeding will provide white papers and public workshops on a variety of issues that will be used to develop recommendations. Depending on the nature of those recommendations, the Energy

Commission may pursue changes to the regulations that guide and define the Energy Commission's power plant licensing process.

The Energy Commission is also working closely with federal, state, and regional agencies to improve power plant and transmission line permitting processes through the Desert Renewable Energy Conservation Plan and the U.S. Bureau of Land Management's Draft Solar Programmatic Environmental Impact Statement. The Desert Renewable Energy Conservation Plan planning effort brings together a large and diverse stakeholder group to develop conservation strategies that identify and map areas for renewable energy generation and transmission development and for long-term natural resource conservation. The Draft Solar Programmatic Environmental Impact Statement is intended to establish a solid foundation for long-term planning for solar energy development on public lands in California and five other western states and will promote better, smarter licensing of utility-scale solar projects while avoiding or minimizing conflicts with wildlife, and cultural and historical resources.

California's clean energy goals for energy efficiency, renewable resources, distributed generation, combined heat and power, and energy storage will also affect the need for upgraded and new energy infrastructure. Using energy more efficiently reduces electricity demand and therefore the need for new generation and transmission infrastructure. Increased amounts of distributed generation located near electric loads can also reduce the need for new large-scale power plants and transmission lines but will require upgrades to the existing distribution infrastructure. Meeting the state's Renewables Portfolio Standard target of 33 percent renewable electricity by 2020 will require new renewable power plants, transmission lines to bring power from those plants to the state's load centers, and other infrastructure like natural gas-fired power plants, energy storage, and demand response to support integrating high levels of variable renewables into the electricity system while maintaining system operations and reliability. Specific issues with California's clean energy policies are discussed later in this summary.

A final infrastructure issue in the electricity sector is the safety and reliability of the state's nuclear power plants. In 2010, nuclear power from the Diablo Canyon Power Plant and the San Onofre Generating Station provided 15.7 percent of California's in-state electricity generation. These plants are located near major earthquake faults and have significant inventories of spent nuclear fuel stored on-site. Concerns about nuclear plant safety and reliability have increased because of recent large earthquakes in Japan, particularly the 9.0 magnitude quake in March 2011 and the resulting 40-foot tsunami that affected the Fukushima Daiichi plant. In July 2011, the Energy Commission and the California Public Utilities Commission conducted a joint public workshop on the implications of the Fukushima Daiichi accident for California's nuclear power plants and the utilities' progress in carrying out the recommendations made in a 2008 Energy Commission assessment of seismic hazard and nuclear plant vulnerabilities, which was required by Assembly Bill 1632 (Blakeslee, Chapter 722, Statutes of 2006). After that workshop, the Energy Commission, in consultation with the California Public Utilities Commission, developed a set of specific recommendations in the *2011 Integrated Energy Policy Report* to address issues with California's nuclear power plants, including completion of seismic studies; improvements in spent fuel storage; lessons learned from the station blackout at Fukushima; new generation or transmission facilities needed to maintain reliability in the event of a long-term outage; and adequacy of emergency response planning.

Natural Gas Sector

The primary infrastructure issue in the *2011 Integrated Energy Policy Report* related to the natural gas sector is the safe and reliable operation of the state's network of natural gas pipelines. On September 9, 2010, a high-pressure natural gas transmission pipeline owned by Pacific Gas and Electric Company exploded under a neighborhood street in San Bruno, California, killing eight people and destroying 37 homes. In response, the California Public Utilities Commission and the National Transportation Safety Board both launched investigations into the explosion, and the Energy Commission provided Public Interest Energy Research Program funds for natural gas safety research.

The California Public Utilities Commission initially ordered pressure reductions and subsequently ordered Pacific Gas and Electric Company to reduce operating pressures on lines of similar vintage and characteristics as the failed segment. In June 2011, the California Public Utilities Commission directed Pacific Gas and Electric Company, Southern California Gas, San Diego Gas & Electric, and Southwest Gas to pressure test or replace all pipelines, which is expected to take several years. Until this is complete, pressure levels may be reduced below maximum allowable operating pressure or the utilities may implement other measures intended to assure safe operations. A formal report on hydrotesting efforts and preliminary results was the subject of an evidentiary hearing at the California Public Utilities Commission on November 22, and on December 15 the California Public Utilities Commission granted Pacific Gas and Electric Company's request to restore pipeline pressures on several key Bay Area lines after hydrotesting was complete. Since that time, the California Public Utilities Commission has issued a comprehensive staff report detailing its findings and making recommendations for changes at Pacific Gas and Electric Company.

The Energy Commission has closely monitored the testing schedule and operating pressures for any impacts on service to natural gas consumers, including the natural gas-fired power plants that California relies on for about 42 percent of its electricity. Pacific Gas and Electric Company has reported no curtailments to customers as a result of reducing the operating pressure. Two pipeline segments have failed hydrostatic testing, but in each case, as long as testing occurs outside high-demand periods, Pacific Gas and Electric Company should have the ability to reroute natural gas to continue service to customers, including gas-fired generating plants.

Energy Commission staff also analyzed the effect of flow reductions due to lower operating pressures on Pacific Gas and Electric Company's intrastate or "backbone" natural gas transmission pipeline systems. The key conclusion is that even if less gas is able to flow over backbone capacity, curtailments should be able to be avoided by relying more on gas from underground storage. This underscores the importance of filling not only Pacific Gas and Electric Company storage, but independent storage as well to make up for the constrained backbone capacity on days when colder than average conditions occur.

Transportation Sector

California must also ensure sufficient infrastructure to meet the state's conventional and alternative transportation fuel needs. Industries, commercial businesses, households, transit agencies, and government all rely on transportation fuels for movement of goods and people over highways, rail, waterways, and air. Transportation fuels also provide energy for off-road, industrial, agricultural, commercial, military, and recreational uses.

California oil production has fallen 47.2 percent since 1985, and Energy Commission staff estimates future declines ranging from 2.2 to 3.1 percent per year. The state's 20 oil refineries, which processed more than 1.7 million barrels of crude oil per day in 2010, continue to rely on crude oil imports by marine vessel from Alaska and a variety of foreign sources. Staff expects crude oil imports to rise by between 22 million and 104 million barrels per year by 2030 compared to 2010 levels.

Energy Commission staff believes there is sufficient existing spare import capability to meet the low estimate for crude oil imports and satisfy the state's need for conventional transportation fuels. There are two crude oil import infrastructure projects proposed in Southern California that are at early stages of development, Berth 408 at Pier 400 in the Port of Los Angeles, and Berth T126 at Pier Echo in the Port of Long Beach. Based on Energy Commission analysis, the Southern California market should require construction of only one of these crude oil import facilities over the forecast period. However, oil imports at the high end of the range will require expanded capability to receive crude oil imports within the next four to five years to ensure sufficient supplies of conventional transportation fuels.

For alternative transportation fuels, demand for biofuels is expected to grow as a result of the federal Renewable Fuels Standard 2 mandates and the state's Low Carbon Fuel Standard. Certain biofuels (ethanol in low-level blends, biodiesel, renewable diesel, and renewable gasoline) will require only modest fueling infrastructure investment and little to no modifications to motor vehicles to enable greater use. California's infrastructure to receive, distribute, and blend ethanol is robust and adequate to accommodate a continued growth of ethanol use over the next several years. Although California's biodiesel infrastructure is currently inadequate to accommodate widespread blending of biodiesel, with sufficient lead time (12 to 24 months) modifications could be completed that would enable expansion of biodiesel use. An initial $100 million investment from the Energy Commission and private sources should accelerate the development of several biofuel production projects in California by 2017.

Other alternative transportation fuels like electricity, natural gas, and hydrogen will require considerable investment over the next several years in fueling infrastructure and vehicles that run on these fuels. Significant public and private investments are being made in California's electric charging infrastructure, and federal economic stimulus funds matched with Energy Commission program funds and other private and public funds are providing the charging infrastructure to support the deployment of plug-in electric vehicles in California. The Energy Commission has also allocated funds to upgrade and install fueling infrastructure for 20 natural gas stations, 11 hydrogen stations, and 50 E85 (85 percent ethanol) dispenser stations.

California's Clean Energy Goals

In his 2012 State of the State address, Governor Brown stated that "California is leading the nation in creating jobs in renewable energy and the design and construction of more efficient buildings and new technologies." This commitment to clean energy was echoed by President Obama in his 2012 State of the Union remarks calling for Congress to set "a clean energy standard that creates a market for innovation."

California's ambitious energy and environmental policy goals are important strategies to promote energy independence, increase energy reliability and safety, reduce statewide greenhouse gas emissions, and help create clean energy jobs. The *2011 Integrated Energy Policy Report* discusses issues associated with the state's clean energy goals to increase energy efficiency, renewable electricity, distributed generation, combined heat and power, and alternative and renewable transportation fuels. In addition, the report discusses the important roles that interagency coordination, and research and development will play in achieving these goals.

Energy Efficiency

Energy efficiency remains California's top priority for meeting new electricity needs and is a key strategy for increasing jobs and reducing greenhouse gas emissions from the electricity sector. Past and current government energy policies and programs have made California a national leader in energy efficiency; in the last three decades, California's policies, programs, and efficiency standards for buildings and appliances have contributed to keeping California's per capita electricity consumption relatively constant while use in the rest of the United States has increased 40 percent. The Energy Commission staff estimates that standards have also saved customers $66 billion in electricity and natural gas costs (in 2010 dollars) since 1975. President Obama, noting in his 2012 State of the Union address that more efficient use of energy saves money, asked Congress to send him a bill to: "Help manufacturers eliminate energy waste in their factories and give businesses incentives to upgrade their buildings. Their energy bills will be $100 billion lower over the next decade, and Americans will have less pollution, more manufacturing, and more jobs for construction workers who need them."

California's energy efficiency policies include achieving all cost-effective energy efficiency; reducing energy use in existing buildings built before the advent of building and appliance efficiency standards; and making all new residential construction in California "zero net energy" (a combination of greater energy efficiency and on-site clean energy production to reduce building energy use to "net zero") by 2020, and all new commercial construction zero net energy by 2030.

Achieving All Cost-Effective Energy Efficiency

To further California's goal of achieving all cost-effective energy efficiency, Assembly Bill 2021 (Levine, Chapter 734, Statutes of 2006) requires the Energy Commission, in consultation with the California Public Utilities Commission, to develop statewide energy efficiency potential estimates and targets for California's investor-owned and publicly owned utilities and report on their progress toward these targets in the *Integrated Energy Policy Report*. In December 2011, the Energy Commission staff released the *Achieving Cost-Effective Energy Efficiency for California 2011–2020* final report, which summarizes utility progress and recommends improvements for publicly owned utility efficiency efforts. Investor-owned utilities reported 4,607 GWh of annual energy savings and 837 MW of peak savings for 2010, which exceeded the California Public Utilities Commission 2010 savings goals of 2,276 GWh and 502 MW. Reported natural gas savings were 46 million therms, just short of the California Public Utilities Commission's natural gas savings goal for 2010 of 48 million therms. Publicly owned utilities achieved 74 percent of the 2010 energy savings target and provided 523 GWh of electric energy savings, a decrease of 19 percent from 2009, and 94 MW of peak savings, 20 percent less than in 2009.

For future savings potential, the *Achieving Cost-Effective Energy Efficiency for California 2011–2020* report estimates 9,525 GWh of cost-effective savings potential for the publicly owned utilities for 2011–2020. This target, however, only represents about 42 percent of net annual savings from all publicly owned utilities. The two largest publicly owned utilities will be updating their savings potential and targets at a later date.

Forecasted savings from several individual utilities meet the AB 2021 goal of 10 percent savings over 10 years, but the combined publicly owned utility targets achieve only 6.8 percent savings from forecasted 2020 base energy use. For most utilities, market savings potential was calculated using a 50 percent customer measure incentive level. Energy Commission staff analysis indicates that when a 75 percent incentive level is used, nearly all utilities would meet the 10 percent consumption reduction goal contained in AB 2021. This suggests that the publicly owned utilities can meet the consumption reduction goal but may require a higher level of program effort and budget than was factored into their targets. However, the issue of cost-effectiveness is a key factor in setting incentive levels and determining which efficiency measures to include in programs. Increasing incentive levels to 75 percent may not be cost-effective for all utilities.

Reducing Energy Use in Existing Buildings

Existing buildings also provide a tremendous opportunity for low-cost energy savings, reduced greenhouse gas emissions, and job creation. More than half of California's 13 million residential units and more than 40 percent of commercial buildings were built before implementation of the state's building standards. Assembly Bill 758 (Skinner, Chapter 470, Statutes of 2009) directed the Energy Commission to develop, adopt, and implement a comprehensive statewide program to reduce energy consumption in existing buildings and report on that effort in the *Integrated Energy Policy Report*.

Efforts by the Energy Commission, the California Public Utilities Commission, local governments, and utilities to coordinate residential and commercial building retrofit programs under the Energy Upgrade California™ brand are providing the foundation for the AB 758 program. Next steps are to complete needs assessments for both residential and non-residential buildings, identify what must be done in program component areas (including lessons learned from pilot programs), and develop action plans for moving forward with AB 758 program development.

The Energy Commission will also work with the California Public Utilities Commission to emphasize joint efforts to achieve improved compliance with building and appliance standards to ensure that energy efficiency measures and equipment are properly installed and delivering savings. The Energy Commission will also develop regulations to improve compliance with appliance efficiency standards using its authority under Senate Bill 454 (Pavley, Chapter 591, Statutes of 2011), which allows the Energy Commission to adopt an enforcement process for violations of appliance efficiency regulations and impose civil penalties of up to $2,500 for each violation.

Achieving Zero Net Energy Homes and Buildings

The Energy Commission, the California Public Utilities Commission, and the Air Resources Board have adopted a goal of achieving zero net energy building standards by 2020 for residential buildings and 2030 for commercial buildings. According to the California Public Utilities Commission, California has more zero net energy buildings than any other state. To support the state's zero net energy goals, in September 2011 the California Public Utilities Commission released its *2010–2012 Zero Net Energy Action Plan* for the commercial building sector.

The Energy Commission is contributing to zero net energy goals by regularly updating its building efficiency standards to reflect new technologies and strategies with the goal of achieving 20 to 30 percent energy savings in each triennial update, and by updating appliance standards to include electronics and other devices plugged into electrical outlets that represent an increasing portion of California's energy use. In 2010, appliance efficiency standards alone saved an estimated 18,761 gigawatt hours of electricity, representing nearly 7 percent of California's electric load, and saved consumers about $2.6 billion in energy costs.

Governor Brown noted in his 2012 State of the State address: "Our state keeps demanding more efficient cars, machines, and electric devices. We do that because we understand that fossil fuels, particularly foreign oil, create ever rising costs to our economy and our health." To meet the demand for more efficient electric devices, the Energy Commission in early 2012 adopted standards for the estimated 58 million battery chargers sold each year in California that, when implemented, will save state ratepayers an estimated $306 million each year, provide annual electricity savings of more than 2,000 GWh, and eliminate 1 million metric tons of carbon emissions.

Renewable Energy

California has more than 10,000 MW of renewable generating capacity on-line, with estimated technical potential (which does not reflect economic, environmental, or market constraints) of 18 million MW of additional resources. The state is the leading producer of renewable energy in the United States with nearly 16 percent of electricity supplies coming from renewable resources like wind, solar, geothermal, biomass, and small hydroelectric in 2010. California's leadership is due in part to strong state government policies and programs that have encouraged renewable development and helped reduce the costs of renewable technologies. For example, according to the National Renewable Energy Laboratory the per-watt price for solar modules has dropped from $22 in 1980 to under $3 today.

Renewables Portfolio Standard

California's Renewables Portfolio Standard requires utilities to procure 33 percent of their retail sales of electricity from renewable resources by 2020. In 2010, renewable generation represented about 16 percent of retail sales of electricity. Energy Commission staff estimates that generation from existing facilities combined with generation from utility contracts signed and pending could deliver enough renewable energy to meet the 33 percent target by 2020. However, it is uncertain whether existing renewable facilities will remain operational through 2020 and whether all contracts for new facilities will come to fruition given utility assumptions of a 40 percent contract failure rate.

To support the Renewables Portfolio Standard target, Governor Brown's Clean Energy Jobs Plan called for adding 20,000 MW of new renewable capacity by 2020, including 8,000 MW of large-scale wind, solar, and geothermal resources as well as 12,000 MW of localized renewable generation close to consumer loads and transmission and distribution lines. Governor Brown's Clean Energy Jobs Plan directed the Energy Commission to prepare a plan to "expedite permitting of the highest priority [renewable] generation and transmission projects" to support investments in renewable energy that will create new jobs and businesses, increase energy independence, and protect public health. In December 2011, the Energy Commission released the *Renewable Power in California: Status and Issues* report, which describes the status of renewable development in California and identifies challenges to meeting renewable goals.

Many of the challenges to renewable development relate to energy infrastructure needs, including addressing land use issues, and fragmented and overlapping permitting processes associated with building new renewable utility-scale and distributed generation facilities; building sufficient transmission needed to interconnect and deliver renewable generation, and upgrading the distribution system to reliably and safely support high levels of renewable distributed generation; developing supporting infrastructure like natural gas-fired plants, energy storage, and demand response measures to help integrate variable renewable resources; securing the necessary investment and financing to build new renewable facilities; and conducting research and development to develop new technologies and strategies to support renewable electricity infrastructure needs.

To address these challenges, the Energy Commission will work closely with other agencies and stakeholders to develop a renewable strategic plan in 2012 as part of the *2012 Integrated Energy Policy Report Update*. High-level strategies that will form the basis for the renewable strategic plan include: (1) prioritize geographic areas for development; (2) evaluate costs and benefits of renewable projects; (3) minimize interconnection costs and time; (4) promote incentives for projects that create in-state benefits; and (5) promote and coordinate existing financing and incentive programs for critical stages in the renewable development continuum.

Bioenergy Development

In addition to broad policy goals for increasing renewable electricity use, California also supports development of bioenergy to help achieve the state's clean energy goals. Biopower and biogas will contribute toward the goal of 12,000 MW of local distributed energy generation, and biofuels and biogas will play important roles in reducing carbon emissions in the transportation sector. However, development of these resources has been slow. In March 2011, the Energy Commission adopted the *2011 Bioenergy Action Plan*, which noted that the biopower share of renewable electricity generation decreased from 20 percent in 2008 to 17 percent in 2010, and in-state biofuel production in 2010 represented only 5.6 percent of California's biofuel demand.

The *2011 Bioenergy Action Plan* identifies a number of strategies to support bioenergy, including: reauthorization of the Public Goods Charge to provide incentives to existing and emerging bioenergy technologies; developing biogas and biomethane for pipeline injection and on-site use in-state; streamlined and expedited permitting; revising regulations that increase access to the electricity transmission and distribution grid and natural gas pipelines; providing incentives such as expanded feed-in tariffs, more favorable power purchase agreements, and research and development grants; and developing a plan and program to reduce costs associated with collection and transport of biomass residues.

The *2011 Bioenergy Action Plan* was intended to be updated and refreshed as needed to adapt to changing conditions. Parties are continuing to work on completing and updating measures, and the Energy Commission will report on updates and processes in future *IEPRs.*

Distributed Generation and Combined Heat and Power

In the right circumstances, distributed generation – small-scale power generation located close to electricity loads – can reduce or eliminate the need for new generation, transmission, and distribution infrastructure. Distributed generation can improve the efficiency of the electric system by avoiding transmission and distribution losses that occur when electricity travels over power lines. These systems can also improve reliability by providing electricity to a site regardless of what might occur on the power grid. Distributed generation that delivers during peak demand periods can free up other generating capacity and ease transmission bottlenecks and line congestion.

In a recent joint report by the Brookings Institution and the Hoover Institution, *Assessing the Role of Distributed Power Systems in the U.S. Power Sector*, George Shultz of the Hoover Institution noted that, "Many energy analysts have noted the potential for [distributed generation] to become a major part of our electricity infrastructure…. But in this rapidly developing field, the great progress on the technological front has yet to be fully matched by progress in policy making. And major questions of affordability, integration, and security remain to be answered before we can determine what role distributed energy sources should play in our future energy system."

For the purposes of the 12,000 MW of renewable distributed generation by 2020 goal, distributed generation is defined as (1) fuels and technologies accepted as renewable for purposes of the Renewables Portfolio Standard; (2) sized up to 20 MW; and (3) located within the low-voltage distribution grid or supplying power directly to a consumer. California has about 3,000 MW of renewable distributed generation installed, with another 6,200 MW that is pending or authorized under existing state programs to support distributed generation. Meeting the Governor's target will require improvements in the permitting and interconnection processes affecting distributed generation facilities. It will also require upgrades to the state's aging distribution system to address physical challenges and maintain safety and reliability when interconnecting large amounts of distributed generation. These issues will be considered during the development of the Energy Commission's renewable strategic plan during 2012.

In addition to California's distributed generation goals, the Air Resources Board's *Climate Change Scoping Plan* originally called for development of

4,000 MW of new combined heat and power by 2020 to reduce greenhouse gas emissions, and the Governor's Clean Energy Jobs Plan includes a target of 6,500 MW by 2030. Combined heat and power, which is often a distributed generation resource, is an important part of California's energy mix. Combined heat and power facilities can reduce energy use by capturing waste heat associated with electricity production and using it to power industrial facilities, universities, hospitals, and other facilities. There is currently more than 8,500 MW of combined heat and power installed in California, making the state's fleet of combined heat and power facilities the second largest in the United States. These facilities improve the efficiency of the electric system by using less fuel to produce energy and can reduce air pollution and greenhouse gas emissions since less fuel is burned to produce each unit of energy output.

California's Qualifying Facility and Combined Heat and Power Program settlement, approved by the Federal Energy Regulatory Commission in June 2011, established a combined heat and power framework for the state's investor-owned utilities. The settlement resolved years of utility-generator litigation; established capacity targets; incorporated the investor-owned utility portion of the Air Resources Board's greenhouse gas reduction goal; revised the pricing calculation; initiated a competitive solicitation process to sign new power purchase agreements; and created an avenue for procuring combined heat and power in the future.

The Governor's policy goals for distributed generation and combined heat and power, along with the recent qualifying facility settlement, will have a major effect on future electricity demand and infrastructure needs. As part of the *2012 Integrated Energy Policy Report Update* and the *2013 Integrated Energy Policy Report* proceedings, the Energy Commission intends to update past assessments of the status and potential of combined heat and power in California and develop forecasting methods and scenarios that more accurately take into account the potential contribution of distributed generation and combined heat and power to the state's energy mix.

Transportation Fuels

California's transportation policies include increasing the efficiency of its transportation fleet, increasing energy security through the development of alternative transportation fuels and vehicles to reduce dependence on petroleum, and reducing greenhouse gas emissions in the transportation sector, which accounts for nearly 40 percent of the state's greenhouse gas emissions. In 2007, the Energy Commission and the Air Resources Board approved the *State Alternative Fuels Plan,* which recommended adopting alternative and renewable fuel use goals of 9 percent by 2012, 11 percent by 2017, and 26 percent by 2022. The state also has a goal of producing a steadily increasing share of its biomass-based transportation fuels from in-state sources between now and 2050. Other important transportation-related policies include California's Low Carbon Fuel Standard regulation to reduce the carbon intensity of transportation fuels used in the state by at least 10 percent by 2020, and the Air Resources Board's Zero Emission Vehicle regulations, which require manufacturers to produce increasing numbers of zero emission vehicles and plug-in hybrid electric vehicles in the 2018–2025 model years. Federal policies like the revised Renewable Fuel Standards also encourage the development and use of renewable and alternative fuels by mandating the volumes and types of renewable fuels that must be used nationally, with individual states required to meet proportional-share volumes.

California is making progress toward achieving its clean energy goals. The efficiency of the state's light-duty vehicle fleet is improving, with fuel economy increasing by 3 percent between 2004 and 2009, from 19.94 miles per gallon to 20.56 miles per gallon. Petroleum dependence in 2010 declined an estimated 9.8 percent from 2006 levels due to the increased use of ethanol in gasoline. The use of alternative vehicles is increasing, with the number of registered hybrid vehicles growing from 0.03 percent of California's light-duty vehicle fleet in 2001 to 1.45 percent in 2009. During the same period, flex fuel vehicles – vehicles that can use gasoline containing any concentration of ethanol up to 85 percent – increased from 0.42 percent to 1.54 percent, and the number of natural gas-powered buses rose from just under 1,400 to more than 11,000.

According to Energy Commission staff projections, consumption of alternative transportation fuels is expected to increase between now and 2030. Staff forecasts indicate that annual transportation electricity consumption will increase at a compound annual rate of nearly 14.5 percent, largely as the result of substantial market penetration of plug-in hybrid electric vehicles. Similarly, consumption of natural gas for transportation is expected to increase at a compound annual rate of more than 2.8 percent, and consumption of E85 could be as high as 3.2 billion gallons by 2030. Additional analysis is needed to confirm consumption rates and the geographic location of market growth.

There are two programs in place that will support the development of alternative and renewable fuels and vehicles to meet future demand and help attain California's greenhouse gas emission reduction goals, both created by Assembly Bill 118 (Núñez, Chapter 750, Statutes of 2007). The Air Resources Board's Air Quality Improvement Program, with an annual budget of $30 million to $40 million, supports development and deployment of zero-emission and reduced-emission light-duty vehicles and trucks. The Energy Commission's Alternative and Renewable Fuel and Vehicle Technology Program, with a budget of about $100 million annually through 2015, supports development and deployment of alternative and renewable fuels and advanced transportation technologies. This program invests in a wide variety of alternative and renewable fuels, including electric drive, biomethane, diesel substitutes, ethanol, natural gas, propane, and hydrogen, and funds workforce training. To date the Energy Commission has funded 86 projects totaling $204 million and approved plans for an additional $152 million allocation.

Under Assembly Bill 109 (Núñez, Chapter 313, Statutes of 2008), the Energy Commission is directed to evaluate the benefits of the Alternative and Renewable Fuel and Vehicle Technology Program and report on progress as part of the *Integrated Energy Policy Report*. The results of the first such evaluation are reported in this *2011 Integrated Energy Policy Report*.

As a result of the Alternative and Renewable Fuel and Vehicle Technology Program, California now has the largest network of electric vehicle charging systems and hydrogen fueling stations in the country. In addition, compared to 2009–2010 levels, the program has more than doubled the number of E85 fueling stations in the state and has added 20 natural gas stations. Program investments will also add more than 1,400 alternative vehicles to the California fleet. The program has also helped bring additional investment to California, with $384 million leveraged from private financing and other public funding sources.

Other program benefits include significant estimated reductions in California's use of petroleum fuels. Program investments in electric drive technologies, production of biofuels, diesel substitutes, natural gas medium- and heavy-duty vehicles, and hydrogen fueling stations will contribute toward estimated petroleum reductions of 380.4 million to 1.4 billion gallons per year in 2020. Expected reductions in greenhouse gas emissions and criteria pollutants are also significant. In 2008, total on-road greenhouse gas emissions were estimated at 163.3 million tonnes of CO_2e (carbon dioxide equivalent). Program investments are estimated to reduce greenhouse gas emissions by 2.7 million tonnes of CO_2e to 9.7 million tonnes of CO_2e in 2020, and reduce emissions of criteria pollutants such as volatile organic compounds, carbon monoxide, nitrogen oxides, and particulate matter.

These benefits will have a positive impact in fulfilling California's transportation energy policy goals. Development and commercialization of the 86 projects funded to date have the potential to displace up to

6 percent of the estimated petroleum fuel demand in 2020 and reduce up to 4 percent of the estimated business-as-usual greenhouse gas emissions from transportation in that same year. In addition, commercialization of biofuel projects funded by the program will contribute toward achievement of the state goal to produce an increasing share of California's biofuel consumption from in-state sources by 2020.

Supporting California's Clean Energy Goals: Agency Coordination and Research and Development

Energy Agency Coordination

To achieve California's clean energy goals, state energy agencies must coordinate closely to maintain a broad perspective on energy policies and to identify policy overlaps, conflicts, potential consequences, and areas of concern that must be addressed. Recognizing the growing interdependencies among the state's energy and environmental agencies, in 2010 the Energy Commission, the Air Resources Board, the California Environmental Protection Agency, the California Public Utilities Commission, and the California Independent System Operator developed a vision, implementation plan, and roadmap to achieve a clean energy future for California. The *California's Clean Energy Future: Overview,* released in September 2010, focuses on 2020 but also considers the state's goal to reduce greenhouse gas emissions to 20 percent of 1990 levels by 2050.

The *Overview* focuses on four elements for achieving the state's 2020 electricity and natural gas goals: reducing peak energy demand through efficiency, demand response, and installation of distributed generation; increasing the amount of renewable energy in the state's portfolio by achieving the 33 percent by 2020 Renewables Portfolio Standard; ensuring that sufficient transmission and distribution infrastructure will be available to meet renewable goals and greenhouse gas emission reduction targets; and using supporting processes, including cap and trade, to provide opportunities for lower-cost greenhouse gas emission reductions and advancements in emerging technologies.

As part of the California's Clean Energy Future process, agencies jointly prepared publicly available "metrics" to show progress toward meeting the policies identified in the *Overview*. Metrics are posted on the California Clean Energy Future website and will be updated periodically to reflect new information. The agencies also plan to update the *Overview* to reflect significant developments since its release, including the passage of legislation to enact the 33 percent Renewables Portfolio Standard and Governor Brown's leadership in energy policy, and have committed in the *Overview* to review and revise strategies and targets biennially following each demand forecast update provided by the Energy Commission in the *Integrated Energy Policy Report*.

Research and Development

The invention and application of new technologies are essential to support California's clean energy and economic development goals. Private sector firms understandably tend to focus their research and development activities on projects that benefit their individual firms and bottom lines. In contrast, government research activities are targeted toward benefitting entire industries as well as society as a whole. President Obama, in his 2012 State of the Union comments on natural gas development, noted that "it was public research dollars, over the course of 30 years, that helped develop the technologies to extract all this natural gas out of shale rock – reminding us that government support is critical in helping businesses get new energy ideas off the ground. What's true for natural gas is true for clean energy."

Over the last 14 years, the Energy Commission's Public Interest Energy Research Program has funded energy-related research that responds to market needs and supports the state's energy policy goals. The program funds research across a broad spectrum of energy areas, including energy efficiency, renewable energy, advanced electricity technologies, energy-related environmental protection, transmission and distribution, and transportation technologies.

To further the state's goal of achieving all cost-effective energy efficiency savings, Energy Commission-funded research has supported technologies and strategies now included in the 2008 Building Efficiency Standards such as residential cool roofs (materials that effectively reflect the sun's energy from the roof surface) to reduce air-conditioning use, requirements to improve energy performance of air handlers and duct systems, and more efficient kitchen and underground pipe insulation. In addition, requirements in the 2007 and 2010 Appliance Efficiency Standards for external power supplies and flat-screen televisions resulted directly from Energy Commission-funded research. Overall, these measures will produce estimated annual energy savings of more than $1 billion for California electric and natural gas ratepayers when fully implemented.

The Public Interest Energy Research Program also funds research to bring products to the marketplace. Support for Adura® Technologies contributed to the development of a breakthrough wireless lighting control network that creates energy savings of up to 70 percent. Another example is demonstration of an innovative cooling system developed by Federspiel Controls (now Vigilent Systems) in eight data centers throughout California that reduced energy use for cooling by 19 to 78 percent and reduced annual energy costs by $240,000.

Research and development are also essential to support California's renewable energy goals. Energy Commission-funded projects have helped renewable technologies reach maturity and achieve faster market penetration, ultimately leading to more renewable energy in the state's electricity portfolio. One example is a new concentrating photovoltaic system developed by GreenVolts, Inc., originally funded by the Public Interest Energy Research Program, which is now in full production. There are six installations in California and Arizona and several additional sites under development including a 2.5 MW facility under construction in Byron, California.

Energy Commission research funding also supports technologies to improve management and operation of the electric grid. For example, synchrophasor measurement systems – which provide information to grid operators up to 30 times per second – are being used by the California Independent System Operator to help foresee and prevent power outages. In January 2008, one such system alerted grid operators about unusual grid oscillations that were causing grid instability, allowing the shutdown of a power line in time to avoid a major blackout. Prior to installation of this system, the California Independent System Operator probably would not have detected the irregularity. In the future, synchrophasor technologies are expected to save electricity consumers $210 million to $370 million per year by avoiding expensive power outages along with $90 million per year in reduced electricity costs.

A major challenge facing the Public Interest Energy Research Program is the expiration on January 1, 2012, of the state's Public Goods Charge to support energy-related research and development. There is support from the Governor and key legislative leaders to continue the Public Goods Charge, and in October 2011 the California Public Utilities Commission opened a rulemaking to evaluate potential continuation of public benefits funding. On December 15, 2011, the California Public Utilities Commission approved a decision to collect funds on an interim basis for renewables and research, development, and demonstration programs. Funds will be placed in balancing accounts and not disbursed until authorized by a final decision at the conclusion of Phase 2 of the proceeding, which will address more detailed program design, oversight, and administrative questions.

Economic Development and Job Creation

Governor Brown's Clean Energy Jobs Plan emphasizes that investing in energy efficiency and clean energy is a central element of rebuilding California's economy. California's energy policies continue to be instrumental in encouraging venture capital investments, attracting new companies, and growing new industries and jobs by creating market demand for clean energy technologies, products, and services. Governor Brown also noted in his 2012 State of the State address: "In the beginning of the computer industry, jobs were numbered in the thousands. Now they are in the millions. The same thing will happen with green jobs."

Energy efficiency standards promote investments in technology innovation to develop new products as well as job creation for the workforce needed to provide energy audits, home energy ratings, and building commissioning to identify efficiency improvements and products and support installation and testing of products and technologies. A 2008 report by Next 10 noted that California's efficiency policies have contributed to creating more than 1.5 million full-time equivalent jobs, including direct jobs created by services and products to support energy efficiency programs and indirect jobs created when customers redirect dollars savings from energy bills to other goods and services in the economy.

Clean energy policies to support renewable energy support clean technology investment in California, which leads to jobs both in clean tech industries and support industries like construction. According to a recent Ernst & Young, LLP, analysis, in the first quarter of 2011 alone, California received $637 million in venture capital investment for clean tech companies, representing 56 percent of national investments in the clean tech industry. A 2011 Brookings Institution report concluded that, nationally, the clean economy employs more people than the fossil fuels and biotech industries, with four of the five fastest growing clean tech segments between 2003 and 2010 in renewable energy, which added about 50,000 jobs in the solar thermal, solar photovoltaic, wind power, biofuels, fuel cell production, and smart grid industries. In California, a 2010 survey by the Center for Energy Efficiency and Renewable Technologies found that thousands of workers will be needed between now and 2015 to build renewable power plants being proposed in Southern California, with hundreds of operations and maintenance jobs needed for the next 20–30 years. In addition, it estimated that construction jobs to build 2,000 photovoltaic projects totaling 6,000 MW over a 10-year period would create a monthly average of 10,400 jobs.

California's investments in alternative and renewable transportation fuel projects are also contributing to job creation. While awards through the Alternative and Renewable Fuel and Vehicle Technology Program are still in the early stages, awardees expect to create more than 5,000 jobs throughout the market spectrum, including manufacturing, construction, engineering, and operations and maintenance. Using economic benefit multipliers, program investments in 1,000 manufacturing jobs alone could create from 3,000 to 5,000 indirect jobs in finance, transportation, supply chains, installation, and related businesses. Awardees also estimate that more than 800 California businesses will participate in their projects, more than half of which are small businesses. The program also leverages state investments with private financing and other public funding sources, with estimates of leveraged funds as high as $384 million.

Research and development activities to support the state's clean energy goals are also instrumental in bringing additional venture capital investments to California and creating clean energy jobs. Energy Commission staff estimates that research funded by the Public Interest Energy Research Program created more than 2,100 direct jobs, 1,250 indirect jobs (resulting from entities doing the work purchasing goods and services), and 2,180 induced jobs (where business owners and employees purchase goods and services). Funding from the Public Interest Energy Research Program also leverages additional investments. For example, the Energy Innovations Small Grant Program has provided $30 million to awardees who went on to secure more than $1.4 billion in subsequent investment. Products developed through these grants are worth $1.3 billion to the private sector – more than 40 times the initial investment of program funds – and create jobs and other economic benefits for the state. In addition, in 2010 the Public Interest Energy Research Program successfully leveraged more than $500 million in federal stimulus funding under the American Recovery and Reinvestment Act of 2009 and $900 million in private investment using only $20 million of program funding.

Conclusion

This *2011 Integrated Energy Policy Report* identifies the wide variety of issues that California must address to ensure safe and reliable energy infrastructure to meet increasing energy needs, achieve the state's clean energy goals, and promote economic development and job creation through a clean energy economy.

Significant infrastructure investments are needed to support the integration of renewable electricity, increase the use of alternative and renewable transportation fuels, and provide reliable and safe supplies of energy as demand increases. Investments in electricity transmission projects are needed to enable the flow of electricity from new renewable projects to meet the state's 33 percent Renewables Portfolio Standard goal. Additional investment is needed to upgrade the state's aging electricity distribution system to accommodate increasing numbers of distributed generation facilities. Continued investment is needed in energy efficiency, demand response, natural gas plants, and energy storage to help smooth the integration of variable renewable resources. Increased demand for alternative and renewable transportation fuels, as well as the continuing need for petroleum, will require investments in alternative vehicle fueling and charging infrastructure and facilities to accommodate imports of petroleum and ethanol fuels. California must also monitor the safety and reliability of energy infrastructure like natural gas pipelines and the state's nuclear plants and work closely with utilities as they address safety issues.

California must also address issues associated with meeting its clean energy goals. The state must continue its efforts to achieve energy efficiency savings in existing and new buildings, promote the development of zero net energy buildings, and ensure compliance with existing and new standards. California also needs to address challenges to achieve the Renewables Portfolio Standard target and other renewable electricity goals, as well as challenges to achieve the state's clean transportation fuel, bioenergy, and combined heat and power goals.

Finally, California must continue its commitment to securing the economic development and job creation benefits of the clean energy economy through targeted investments in energy efficiency, renewable energy, alternative and renewable transportation fuels, and research and development activities that support the state's clean energy goals.

CHAPTER 1

Introduction

As the United States recovers from the recent economic recession, it is more important than ever that California

continue to pursue clean energy policies and development. Not only does clean energy provide environmental benefits, it increases energy security and stimulates economic growth. Because clean energy tends to rely more on domestic energy resources, it is more environmentally sustainable and less vulnerable to the highs and lows of global economic activity. Clean energy projects also generate job growth in local communities, often in those hit hardest by the recession. According to a 2011 report by Next 10, from 1995 to 2009 the energy generation sector created the most jobs in California's green economy, adding nearly 20,000 jobs.[1] Nationally, a 2011 Brookings Institution report concluded that the clean economy

1 Next 10, *Many Shades of Green: Diversity and Distribution of California's Green Jobs,* January 2011, www.next10.org/next10/publications/green_jobs/2011.html.

employs more workers than the fossil fuels and biotech industries.[2]

The California Energy Commission continues to support policies and programs that encourage investments in expanded and updated energy infrastructure and innovative energy technologies that will create jobs, build 21st century businesses, increase energy independence, and protect public health.[3] Many of the state's energy policies, including aggressive 2020 greenhouse gas (GHG) emission reduction targets, increased energy efficiency standards for buildings and appliances, the 33 percent by 2020 Renewables Portfolio Standard (RPS), zero net energy buildings, and the Low Carbon Fuel Standard support a transition away from fossil fuel dependency and toward clean energy development. In addition, Governor Jerry Brown's Clean Energy Jobs Plan notes the need to increase investments in clean energy and energy efficiency to help rebuild California's economy.

The *2011 Integrated Energy Policy Report (2011 IEPR)* discusses a range of issues facing California's electricity, natural gas, and transportation fuel sectors. The report provides an overview of issues in the following areas: renewable energy; energy efficiency; increased agency coordination and improved planning processes; forecasted electricity and natural gas supply and demand; electricity infrastructure needs; transportation demand and alternative fuel and vehicle development; energy-related research and development; bioenergy goals; and California nuclear power plant issues.

2 Muro, Mark, Jonathan Rothwell, Devashree Saha, The Brookings Institution Metropolitan Policy Program, *Sizing the Clean Economy: A National and Regional Green Jobs Assessment*, July 2011, www.brookings.edu/~/media/Files/Programs/Metro/clean_economy/0713_clean_economy.pdf.

3 www.jerrybrown.org/Clean_Energy.

Renewable Energy

California's RPS target, originally established in 2002, was expanded in 2011 to 33 percent by 2020. To support that target, Governor Brown's Clean Energy Jobs Plan set a goal of adding 20,000 megawatts (MW) of renewable generating capacity by 2020, including 12,000 MW of localized electricity generation – small, on-site residential and business systems and intermediate-sized energy systems close to existing consumer loads and transmission lines – as well as 8,000 MW of large-scale wind, solar, and geothermal energy systems. In addition, renewable energy is also a key strategy in achieving GHG emission reductions. In October 2011, the California Air Resources Board adopted final cap-and-trade regulations as part of the state's Assembly Bill 32 *Climate Change Scoping Plan*.[4]

Under Governor Brown's direction, the Energy Commission is preparing a renewable plan to "expedite permitting of the highest priority generation and transmission projects." In December 2011, the Energy Commission released the *Renewable Power in California: Status and Issues* report, which identifies high level strategies to support renewable development. These strategies will be the basis for a comprehensive renewable strategic plan that will be developed as part of the *2012 Integrated Energy Policy Report Update.* The *2011 IEPR* includes a summary of the *Renewable Power in California: Status and Issues* report, including issues that must be addressed to ensure that California meets its renewable energy goals. Issues include environmental sensitivities, planning, and permitting; transmission; renewable integration at both the grid and distribution levels;

4 The regulation sets a statewide limit on sources responsible for 85 percent of California's greenhouse gas emissions and establishes a price signal needed to drive long-term investment in cleaner fuels and more efficient use of energy.

investment and financing; cost; research and development; environmental justice; coordination with local governments; and workforce development.

An additional challenge is the expiration of the Public Goods Charge (PGC) to support renewable energy on January 1, 2012.[5] If the PGC is not reauthorized or continued in some fashion, state incentive programs such as the New Solar Homes Program, the Emerging Renewables Program, and the Existing Renewables Program will be unfunded, and alternative funding will be needed for Energy Commission staff and activities related to the RPS implementation, RPS eligibility certification, and the regional renewable energy certificate tracking and registry system.

There is support from the Governor and key legislative leaders to continue the PGC for renewable energy programs; in a September 26, 2011, letter to California Public Utilities Commission (CPUC) President Michael Peevey, Governor Brown requested the CPUC to take action to "ensure that programs like those supported by the Public Goods Charge are instituted – and hopefully at their current levels."[6] The letter also noted that, "we cannot afford to let any of these job-creating programs lapse." In response, the CPUC established a rulemaking in October 2011 to address funding and program issues related to the renewable energy and research, development, and demonstration portions of the expiring PGC funding.[7]

The first phase of the proceeding is addressing appropriate funding levels for renewable and research programs and how funds should continue to be collected. On December 15, 2011, the CPUC approved its Phase 1 decision instituting the Electric Program Investment Charge (EPIC) to collect funds on an interim basis for renewables and research, development, and demonstration programs.[8] Rates and allocations for the EPIC will be at the same levels as the current PGC. Funds will be placed in balancing accounts and not disbursed until authorized by the CPUC's final decision at the conclusion of Phase 2 of the proceeding, which will address more detailed program design, oversight, and administrative questions.

Energy Efficiency

California's energy resource "loading order" guides the state's energy decisions and requires meeting new electricity demand first with energy efficiency. As part of this commitment, Assembly Bill 2021 (Levine, Chapter 734, Statutes of 2006) established several important energy efficiency policies, including a statewide commitment to cost-effective and feasible energy efficiency. AB 2021 requires the CPUC and the Energy Commission to identify potentially achievable cost-effective electric and natural gas energy efficiency savings and set goals for investor-owned utilities (IOUs) and publicly owned utilities to achieve this potential.[9] As required by AB 2021, the *2011 IEPR* provides an overview of results from the Energy Commission's evaluation of publicly owned utilities' progress toward meeting targets and 2010 revised energy efficiency potential estimates and targets.[10]

5 The Public Goods Charge is a surcharge imposed on all retail sales of electricity to fund energy efficiency, renewable energy, public goods research, development and demonstration, and to support low income assistance programs. The PGC on electricity consumption is about 0.48 cents per kilowatt hour, www.aceee.org/sector/state-policy/california.

6 gov.ca.gov/news.php?id=17237.

7 California Public Utilities Commission, Order Instituting Rulemaking 11-10-003, October 6, 2011, docs.cpuc.ca.gov/published/Final_decision/145392.htm#P60_1205.

8 docs.cpuc.ca.gov/PUBLISHED/NEWS_RELEASE/155619.htm.

9 The terms for energy efficiency "targets" and "goals" are used interchangeably. There is an established convention (at least since 2004) that the CPUC and IOUs use the term "goals." Publicly owned utilities have adopted the term "targets" since that is the term used in AB 2021.

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

Another statewide commitment to reduce electricity demand is to increase energy efficiency in California's new and existing buildings. The Energy Commission recognizes that more efficient residential and commercial buildings will contribute significantly to achieving California's clean energy and GHG emission reduction goals. State policies like Assembly Bill 32 (Núñez, Chapter 488, Statutes of 2006) and California's Clean Energy Future initiative support the state's efforts to achieve all cost-effective energy efficiency in buildings. In addition, Assembly Bill 758 (Skinner, Chapter 470, Statutes of 2009) directed the Energy Commission to develop, adopt, and implement a comprehensive program to reduce energy consumption in existing buildings, including regulations for energy ratings and improvements in existing buildings. The *2011 IEPR* discusses the role of building and appliance standards in increasing efficiency in new and existing buildings as well as progress toward implementing the AB 758 program.

Improved Coordination and Planning Processes

Addressing challenges to future clean energy development will require close collaboration among the state's energy agencies. This collaboration is already occurring through an interagency effort known as California's Clean Energy Future (CCEF), which includes the Energy Commission, the CPUC, the California Independent System Operator (California ISO), the California Air Resources Board, and the California Environmental Protection Agency. In September 2010, the agencies released the *California's Clean Energy Future Overview*, which describes the elements needed to meet the state's ambitious clean energy goals and points the way toward new investments in energy efficiency, increased use of renewable resources, transmission, and smart grid applications. The overall goal of CCEF is to ensure the agencies work together to identify their policy interdependencies, prevent duplication, and increase communication and coordination to overcome challenges, thereby accelerating progress on the state's clean energy policies. This effort committed the agencies to review and revise recommended strategies and specified targets biennially. This *2011 IEPR* provides an interim status report on CCEF activities.

To improve the Energy Commission's power plant licensing process, in December 2010 the Energy Commission initiated an Order Instituting Informational (OII) Proceeding regarding "lessons learned" during the licensing of solar thermal and natural gas-fired power plants during 2009 and 2010. The OII Proceeding began with a scoping workshop in December 2010, at which stakeholders provided focused comments on addressing challenges with power plant licensing. The staff used this feedback in analyses that constitute the core of a "lessons learned" self-assessment for improving and streamlining the Energy Commission's siting process. The *2011 IEPR* provides an overview of the initial findings from that assessment. Staff will continue to examine critical issues and will hold workshops through 2012, with a final staff report and findings to follow.

The Energy Commission is improving and streamlining other planning processes as well. In terms of electricity resource planning, the Energy Commission is moving the release dates of its biennial *Natural Gas Assessment* and *California Energy Demand* forecast to improve coordination and timing with the CPUC Long-Term Procurement Plan (LTPP) and the California ISO's Transmission Plan. Traditionally, the Energy Commission has conducted assessments and forecasts during odd-numbered years to develop policies for the *IEPR*.[11] Releasing the results in even-numbered years will still allow the Energy Commission to present policy findings in the *IEPR Updates* and may provide a better fit with other agencies' processes. Consequently, the *2011 IEPR* summarizes the status of the Energy Commission's natural gas assessment and the electricity and natural gas demand forecasts, with comprehensive forecast results to be included in the *2012 IEPR Update*.

Energy Assessments and Forecasts

Natural gas continues to play an essential role in meeting the state's energy demand and for various end uses in the residential, commercial, and industrial sectors. Natural gas power plants, with some modifications, will also be important to help integrate intermittent renewable energy resources into the electricity system. The Energy Commission staff draft *2011 Natural Gas Market Assessment: Outlook* reflects comprehensive analyses of natural gas issues that will affect California's infrastructure and energy supply needs, and includes discussions of natural gas uncertainties, potential price vulnerability, managing risks, and an update on potential impacts of the September 2011 San Bruno pipeline incident.[12]

The Energy Commission staff draft *Preliminary California Energy Demand Forecast 2012–2022,* released in August 2011, describes preliminary forecasts for electricity consumption, peak, and natural gas demand for California as a whole and for each major utility planning area within the state.[13] The analysis characterizes the effects of economic and demographic trends, human behavior, emerging technologies, state and federal policies, and California's diverse climatic and geographic landscape on current and future energy needs. Staff used three preliminary demand scenarios (high, mid, low). For natural gas, all three scenarios predict greater consumption in 2020 than previously expected, and this is also true for the mid and high cases for electricity. The *2011 IEPR* presents an overview of these preliminary findings and discusses the effects on future energy demand from economic conditions, self-generation, and energy efficiency.

To support energy planning processes, the Energy Commission provides objective analysis on the state's electricity and natural gas infrastructure needs and related environmental issues. The *2011 IEPR* outlines the status of assessments being conducted by the Energy Commission and an interagency team related to the need to reduce impacts on marine and estuarine environments of the use of once-through cooling (OTC) technologies in older power plants and the difficulty in licensing new replacement generating capacity given the scarcity of emission offsets for new fossil power plants.

The *2011 IEPR* also discusses major uncertainties affecting estimates of the natural gas-fired generation needed to support integration of variable energy resources and maintain system and local reliability. Uncertainties include demand growth (including future electric vehicle penetration), potential retirement of generation units using OTC, renewable energy development (especially renewable distributed generation), the need for generation to provide ancillary

11 As required by Senate Bill 1389 (Bowen and Sher, Chapter 568, Statutes of 2002), see: www.energy.ca.gov/energypolicy/documents/sb_1389_bill_20020915_chaptered.pdf.

12 California Energy Commission, *2011 Natural Gas Market Assessment: Outlook*, draft staff report, September 2011, www.energy.ca.gov/2011publications/CEC-200-2011-012/CEC-200-2011-012-SD.pdf.

13 Kavalec, Chris, Tom Gorin, Mark Ciminelli, Nicholas Fugate, Asish Gautum, and Glen Sharp, *Preliminary California Energy Demand Forecast, 2012–2022*, California Energy Commission, CEC-200-2011-011SD, available at: www.energy.ca.gov/2011publications/CEC-200-2011-011/CEC-200-2011-011-SD.pdf.

services in support of renewable resource integration, the composition of new gas-fired generation, and development of combined heat and power. The *2011 IEPR* discusses how these uncertainties affect electricity planning by the state's energy agencies and how to account for these in planning assumptions during the current planning cycle.

For the transportation sector, the Energy Commission has developed preliminary long-term projections of California transportation energy demand to support its analysis of petroleum reduction and efficiency measures, introduction and commercialization of alternative fuels, integration of energy use and land-use planning, and transportation fuel infrastructure requirements. Projections describe what must be added to the state's existing infrastructure to support increased petroleum imports and what must be built to support future renewable and alternative fuel demand. A key part of this analysis focuses on California's progress and challenges in meeting state and federal mandates for reducing petroleum dependency and addressing climate change – specifically, the state's Low Carbon Fuel Standard (LCFS) and the federal Renewable Fuel Standard (RFS). The *2011 IEPR* provides an overview of key findings on issues the state must address if it is to meet mandated clean transportation energy goals.

Alternative Fuel and Vehicle Development

The development of innovative technologies is crucial for meeting California's bioenergy and other clean energy goals. The Energy Commission's Alternative and Renewable Fuel and Vehicle Technology Program, created by the Legislature in 2007, provides funding to develop and deploy alternative and renewable fuels and advanced transportation technologies to help attain the state's climate change, petroleum reduction, and energy security policies. The *2011 IEPR* provides a high-level status report on funded projects and expected benefits, with the full evaluation (*Benefits Report for the Alternative and Renewable Fuel and Vehicle Technology Program*) to be released in 2012. Early findings show that program funding has led to more alternative fuel vehicles on the road, an expanded fueling infrastructure, and job creation. Early estimates also find that these projects will lead to reduced petroleum consumption and decreased GHG emissions by 2020.

Energy-Related Research and Development

The Energy Commission's Public Interest Energy Research (PIER) Program has been supporting research on and development of clean energy technologies since 1996.[14] Through the PIER Program, the Energy Commission has developed and helped bring to market energy technologies that provide environmental benefits, greater system reliability, and lower system costs. The *2011 IEPR* provides an overview of the program's vital role in advancing electricity and natural gas technologies to market acceptance, and in funding projects that create jobs and attract investments to California. It also provides examples of PIER-funded products and technologies that have greatly advanced California's clean energy policy and economic goals. A major issue facing the PIER Program is the expiration of authority to collect funding for public interest energy research on January 1, 2012. As discussed earlier, the CPUC has opened a proceeding to evaluate continuation of the PGC to fund research, development, and demonstration

14 Public Resources Code Section 25620.1.

efforts and in December 2011 approved the collection of funds on an interim basis for renewables and research, development, and demonstration programs. [15]

Progress on Bioenergy Goals

The Energy Commission published California's first *Bioenergy Action Plan* in 2006 to promote and expand the development of biopower, biogas, and biofuels to help achieve the state's clean energy goals. Following publication of the *2006 Bioenergy Action Plan*, some new bioenergy facilities were proposed or constructed and some idle facilities were restarted. However, by 2011, most of these gains were lost due to adverse market conditions, high transportation fuel costs, and in some cases, competition with fossil fuels. In March 2011, the Energy Commission adopted the updated *2011 Bioenergy Action Plan*, which provides objectives for accelerating progress and and recommendations to overcome challenges to bioenergy.[16] The *2011 IEPR* provides an overview of the *2011 Bioenergy Action Plan*.

California's Nuclear Power Plants

In 2010, nuclear power provided about 16 percent of California's in-state electricity generation and 13.9 percent of the entire California power mix. While California's two nuclear plants are an important factor in maintaining California's electricity reliability and meeting climate change goals, the state has significant concerns regarding nuclear waste transport, storage, and public safety issues relating to emergency situations. The *2011 IEPR* describes new seismic and tsunami concerns in the wake of the March 2011 earthquake and tsunami in Japan that disabled the Fukushima Daiichi Nuclear Plant. It also provides the status of the utilities' progress on safety recommendations outlined in the Energy Commission's *AB 1632 Report*.[17]

15 docs.cpuc.ca.gov/PUBLISHED/NEWS_RELEASE/155619.htm.

16 *2011 Bioenergy Action Plan*, California Energy Commission, prepared for the Bioenergy Working Group, available at: www.energy.ca.gov/2011publications/CEC-300-2011-001/CEC-300-2011-001-CTF.PDF.

17 California Energy Commission and MRW & Associates, Inc., *An Assessment of California's Nuclear Power Plants: AB 1632 Report*, November 2008, www.energy.ca.gov/2008publications/CEC-100-2008-009/CEC-100-2008-009-CMF.PDF.

CHAPTER 2

Renewable Electricity Status and Issues

California has used renewable energy — energy from natural resources like sunlight, wind, rain, and the Earth's heat —

to help meet its electricity needs for more than a century. Renewable electricity provides many economic and environmental benefits including local jobs in clean technology and construction industries; revenues from property and sales taxes; energy independence from using local energy sources and fuels rather than imported natural gas; reduced fossil-fuel generation that has negative impacts on air and water quality; and reduced greenhouse gas emissions from the electricity sector to help meet state climate change goals. California has been a leader in expanding its consumption of renewable energy since the late 1970s when, under Governor Jerry Brown's first administration, the California Public Utilities Commission ordered utilities to establish standard offers for buying electricity from alternative suppliers ("qualifying facilities") at cost-based rates, with the price equal to the buyer's full avoided cost. By 1991, these standard contracts resulted in more than 11,000 megawatts (MW) of qualifying facilities on-line in California, about half of which used renewable resources.

Now, Governor Brown is putting forth new and expanded targets. In his Clean Energy Jobs Plan, the Governor is emphasizing the importance of investing in renewable energy as a central element of rebuilding California's economy. The Governor directed the Energy Commission to prepare a plan to "expedite permitting of the highest priority [renewable] generation and transmission projects" to support investments in renewable energy that will create new jobs and businesses, increase energy independence, and protect public health. In December 2011, the Energy Commission released the *Renewable Power in California: Status and Issues* report, which describes the current status of renewable development in California and identifies challenges to meeting the state's renewable goals. This chapter summarizes that report and outlines high-level strategies to be included in a comprehensive strategic plan for renewable energy in California that will be developed as part of the *2012 Integrated Energy Policy Report Update*.

California's Renewable Electricity Targets and Status

In 2002, the California Legislature established the Renewables Portfolio Standard (RPS) to diversify the electricity system and reduce growing dependence on natural gas. At that time, the target was to increase the amount of renewable electricity in the state's power mix to 20 percent by 2017, which was subsequently accelerated to 2010 by legislation passed in 2006. In 2011, the RPS was further revised and expanded to require that renewable electricity should equal an average of 20 percent of the total electricity sold to retail customers in California during the compliance period ending December 31, 2013, 25 percent by December 31, 2016, and 33 percent by December 31, 2020.[18] To support these RPS targets, Governor Brown's Clean Energy Jobs Plan calls for adding 20,000 MW of new renewable capacity by 2020, including 8,000 MW of large-scale wind, solar, and geothermal as well as 12,000 MW of localized generation close to consumer loads. According to a recent presentation by Michael Picker, Senior Advisor to the Governor for Renewable Facilities, resources included in the 12,000 MW goal are defined as: (1) fuels and technologies accepted as renewable for purposes of the Renewables Portfolio Standard; (2) sized up to 20 MW; and (3) located within the low-voltage distribution grid or supplying power directly to a consumer.[19] Some parties have suggested that this definition be expanded to include other low GHG-emitting resources, such as fuel cells and high-efficiency combined heat and power facilities. The Energy Commission will hold workshops during the *2012 IEPR Update* and *2013 IEPR* proceedings to discuss combined heat and power issues, and welcomes suggestions from parties on how to best ensure that the state's distributed generation and combined heat and power goals are complementary.

California appears to be on track to achieve the 20 percent average by 2013 RPS compliance period, with nearly 16 percent of statewide retail sales coming from

18 The California Public Utilities Commission recently established procurement quantity requirements for interim years of 21.7 percent (2014); 23.3 percent (2015); 27 percent (2017); 29 percent (2018); and 31 percent (2019). Decision 11-12-020, *Decision Setting Procurement Quantity Requirements for Retail Sellers for the Renewables Portfolio Standard Program*, December 1, 2011, docs.cpuc.ca.gov/WORD_PDF/FINAL_DECISION/154695.PDF.

19 Michael Picker, presentation at the December 8, 2011, California Foundation on the Environment and the Economy Energy Roundtable Summit on Distributed Generation, www.cfee.net/_documents/Picker.pdf.

Table 1: In-State Renewable Capacity and Generation (2010)

Renewable Resource	Utility-Scale Capacity (MW)	Wholesale Distributed Generation Capacity (MW)	Distributed Generation Capacity (MW)	Total Capacity (MW)	Total Generation (GWh)
Biomass	1,070	632	25	1,727	5,745
Geothermal	2,521	46	0	2,567	12,740
Small Hydro	315	1,080	0	1,395	4,441
Solar	408	149	1,070[B]	1,627	908
Wind	No data	No data	8[C]	3,027[D]	6,172
Total	**4,314**	**1,907[A]**	**1,103[E]**	**10,343**	**30,005**

Source: California Energy Commission

A. Sources of the data include the Energy Commission's Quarterly Fuels and Energy Report Database and POU RPS database; CPUC's IOU database (www.cpuc.ca.gov/PUC/energy/Renewables/), and CPUC staff update on installed capacity under SB 32.

B. Solar PV systems under SB1 (CPUC staff calculation for CSI, Energy Commission staff calculation for NSHP, and Energy Commission staff calculation as reported by the POUs for their portion), the Self-Generation Incentive Program (energycenter.org/index.php/incentive-programs/self-generation-incentive-program/sgip-documents/sgip-documents), and the Emerging Renewables Program (www.energy.ca.gov/renewables/emerging_renewables/).

C. Wind turbine systems in the Self-Generation Incentive Program (energycenter.org/index.php/incentive-programs/self-generation-incentive-program/sgip-documents/sgip-documents) and the Emerging Renewables Program (www.energy.ca.gov/renewables/emerging_renewables/)

D. Includes 3019 MW of utility scale and wholesale distributed generation wind capacity. California ISO data on wind projects located in the California ISO and the Energy Commission's QFER Database, energyalmanac.ca.gov/electricity/web_qfer/ for wind projects located outside the California ISO.

E. Total updated in 2011.

renewable generation in 2010.[20] In-state renewable generation represented about 75 percent of total renewable generation from more than 10,000 MW of renewable generating capacity (Table 1).[21]

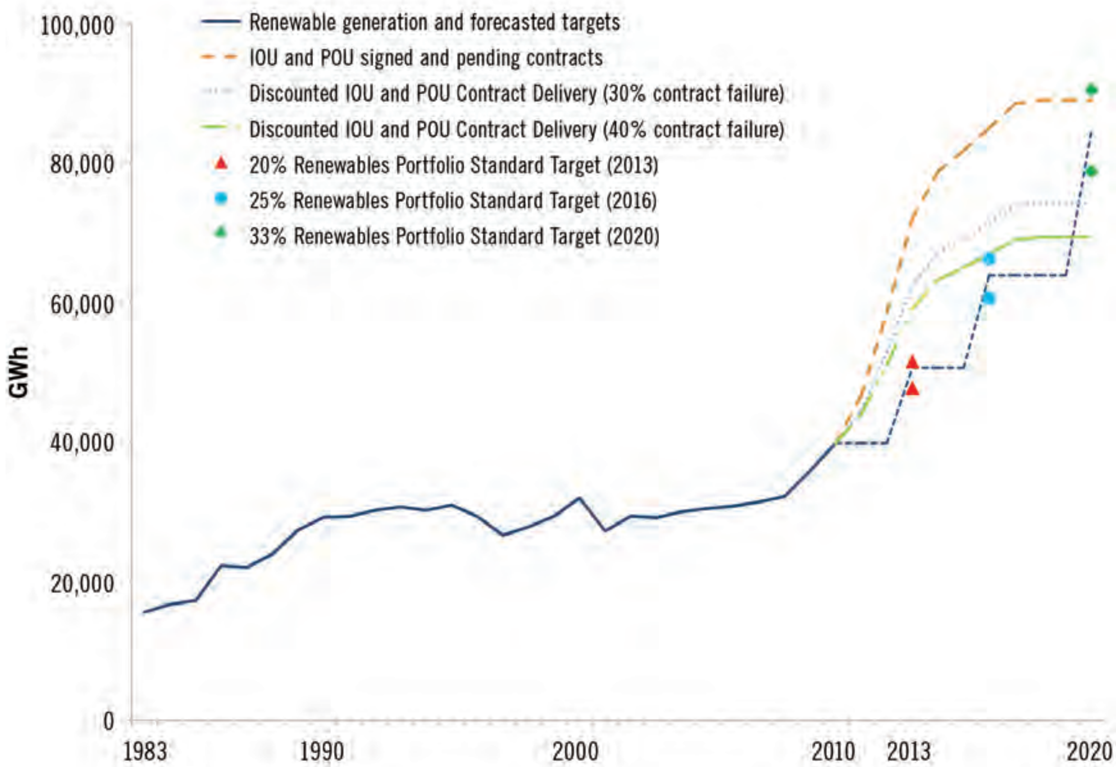
For the 33 percent by 2020 target, Energy Commission staff estimates that the state will need renewable generation in the range of 35,000 gigawatt hours (GWh) to 47,000 GWh in addition to generation expected from existing facilities. Utility contracts signed and pending to date are expected to deliver enough energy to reach the upper bound of this range if most or all of the contracted renewables are built and generating by 2020 (Figure 1).

This estimate includes a number of short-term contracts that may not be renewed, as well as existing facilities that may retire due to age or contract expiration, which could reduce the contribu-

20 Depending on the data source, total renewable generation varies between 15 and 16.5 percent of statewide retail sales from renewable generation in 2010. Procurement and generation sources include: The Power Source Disclosure Program, CPUC RPS Compliance Filings, Energy Commission RPS Tracking, and the Energy Commission's Total System Power.

21 The wholesale DG total in Table 1 was based on project size (20 MW or less) and excluded wind capacity due to lack of reliable data; the total will therefore need further refinement, given the revised definition of what meets the Governor's 12,000 MW goal, to screen out projects connected at the transmission level and include wholesale DG wind capacity.

Figure 1: Renewable Generation for California and Renewables Portfolio Standard Goals



Source: California Energy Commission, *Renewable Power in California: Status and Issues*, December 2011.

Dashed orange line showing expected renewable generation does not include potential generation from electric service providers, community choice aggregators, or small multi-jurisdictional utilities which are also subject to the RPS. In 2010, renewable generation from these entities represented only about 5 percent of statewide renewable generation.

tion from existing facilities.[22] There is also risk of contract failure; data from the Energy Commission's IOU contract database indicates that since the start of the RPS program, about 30 percent of long-term RPS contracts (10 years or more) approved by the California Public Utilities Commission (CPUC) have been cancelled.

The contract failure rate increases to about 40 percent when also considering contracts that have been delayed, and, at the September 14, 2011, workshop on the draft *Renewable Power in California: Status and Issues* report, two utilities indicated that they currently assume a contract failure rate of 40 percent.[23] This suggests it would be prudent for utilities to contract for renewable generation in the range of 55,000 GWh (contract failure rate of 30 percent) to 85,000 GWh (contract failure rate of 40 percent).[24]

22 According to metrics on the California Clean Energy Future website, contracts for roughly 12,000 GWh of renewable generation will expire before 2020, www.cacleanenergyfuture.org/documents/RenewableEnergy.pdf.

23 Transcript of the September 14, 2011, Integrated Energy Policy Report workshop on the *Draft Renewable Power in California: Status and Issues* report, comments by Valerie Winn, Pacific Gas and Electric Company, (page 72) and Gary Stern, Southern California Edison (page 73), www.energy.ca.gov/2011_energypolicy/documents/2011-09-14_workshop/2011-09-14_transcript.pdf.

24 The Energy Commission acknowledges that historical contract failure rates are not predictive of future rates, which could be lower or higher.

Table 2: Preliminary Regional Targets for 8,000 Megawatts of New Renewable Capacity by 2020

Identified Transmission Line(s)	CREZ Served	Cumulative Renewable Deliverability Potential with New/Upgraded Lines (MW)	2010 Permitted Generating Capacity Associated with New/Upgrades (MW)	Additional Transmission Project Capacity (MW)
Sunrise Powerlink	Imperial North and South, San Diego South	1,700	760	940
Tehachapi and Barren Ridge Renewable Transmission Projects	Tehachapi, Fairmont	5,500	2,810	2,690
Colorado River, West of Devers, and Path 42 Upgrade	Riverside East, Palm Springs, Imperial Valley	4,700	1,825	2,875
Eldorado-Ivanpah, Pisgah-Lugo, and Coolwater-Jasper-Lugo	Mountain Pass, Pisgah, Kramer	2,450	1,470	980
Borden-Gregg	Westlands	800	145	655
South of Contra Costa	Solano	535	155	380
Carrizo-Midway	Carrizo South, Santa Barbara	900	800	100
			TOTAL	**8,620**

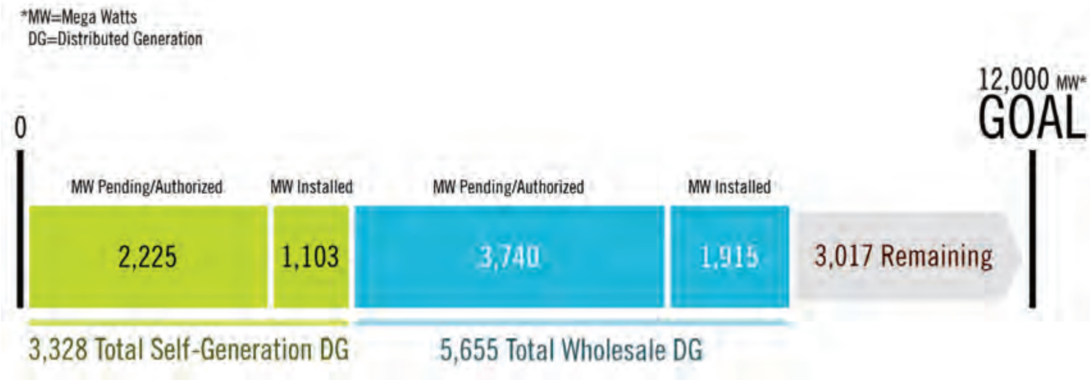
Source: California Energy Commission, *Renewable Power in California: Status and Issues*, December 2011.

As a starting point for measuring progress toward meeting the Governor's 20,000 MW goal, the *Renewable Power in California: Status and Issues* report included preliminary regional targets for both utility-scale and localized renewable generation facilities. For the target of 8,000 MW of utility-scale renewables by 2020, Energy Commission staff identified rough regional targets based on new transmission lines and upgrades that have been identified by the California Independent System Operator (California ISO) for all of California's balancing authorities and potential renewable capacity in Competitive Renewable Energy Zones (CREZ) identified through the 2007–2010 Renewable Energy Transmission Initiative (RETI) that would be served by those lines and upgrades (Table 2).[25]

If these new lines and upgrades are permitted, built, and operating before 2020, they could allow generation from more than 16,000 MW of cumula-

25 RETI was initiated in 2007 as a joint effort among the CPUC, the Energy Commission, the California ISO, utilities, and other stakeholders. Primary goals were to identify transmission projects needed to accommodate California's renewable energy goals; promote designation of corridors for future transmission line development; and make transmission and generation siting and permitting easier. *Renewable Energy Transmission Initiative Phase 2B Final Report*, RETI-1000-2010-002-F, May 2010, www.energy.ca.gov/reti/documents/index.html.

Figure 2: Renewable Distributed Generation Capacity Counted Toward 12,000 MW Goal



Source: California Energy Commission.

"Pending" capacity refers to projects approved under existing programs and in development but not yet completely installed. "Authorized" capacity refers to capacity allocated under existing programs that is not yet approved or installed. Existing programs include the Senate Bill 32 feed-in tariff, the Renewable Auction Mechanism, the Utility Solar Photovoltaic Program, and the California Solar Initiative. The Energy Commission acknowledges that the totals presented in this figure will need further refinement; for example, not all projects developed under the Renewable Auction Mechanism may qualify as wholesale DG under the definition of DG presented in this report.

tive renewable capacity to flow across those lines.[26] In 2010, state and local entities issued permits for roughly 9,000 MW of new renewable capacity, about 8,000 MW of which is associated with the new lines and upgrades. This indicates that another 8,000 MW of renewable capacity could be sited in the CREZ associated with these lines in the future.

For the 12,000 MW distributed generation (DG) target, Energy Commission staff developed preliminary regional targets for localized generation (Table 3), defined for purposes of the analysis at that time as renewable DG projects 20 MW and smaller interconnected to the distribution or transmission grid. The analysis was technology neutral and included solar, biomass, geothermal, wind, fuel cells using renewable fuel, and small hydropower. The analysis also assumed that renewable DG capacity installed would count toward meeting the 12,000 MW goal. California has roughly 3,000 MW of renewable DG capacity installed and, if existing state programs to support renewable DG are fully successful, the state could add about 6,200 MW of capacity in the next five to eight years (Figure 2). More information is needed to assess the legitimacy of the targets and the targets should be periodically updated. Given the trend of declining costs for solar photovoltaic (PV) technologies, the Energy Commission believes the focus should be on developing the "low-hanging fruit" in the next few years. Meanwhile, the state should focus on reforming permitting and interconnection processes so that subsequent development of renewable DG installations can take advantage of cost reductions and improved regulatory structures in later years.

26 Written comments by Kern County and Critical Path Transmission on the draft 2011 IEPR suggested a transmission line which, if built, could potentially open up the West Mojave Desert to renewable energy development. The West Mojave Desert has been identified as an area of high solar insolation and the Energy Commission and other members of California's Renewable Energy Action Team have encouraged development there. That area also has lands with high conservation value, particularly for the Mohave ground squirrel and desert tortoise, and the Desert Renewable Energy Conservation Plan provides a forum for balancing energy and conservation needs in the area. Toward this end, the Energy Commission supports efforts by independent transmission advocates to improve access to the West Mojave and will work with agencies and stakeholders involved in the Desert Renewable Energy Conservation Plan to address development and resource conservation options.

Table 3: Proposed Preliminary Regional DG Targets by 2020

Region	Behind the Meter (all technologies) (MW)	Wholesale (MW)	Undefined (mix of behind the meter and wholesale) (MW)	Total (MW)
Central Coast	280	90	0	370
Central Valley	830	1590	0	2,420
East Bay	420	30	0	450
Imperial	50	90	0	140
Inland Empire	480	430	0	910
Los Angeles (city and county)	970	860	2170	4,000
North Bay	220	0	0	220
North Valley	120	50	0	170
Sacramento Region	410	170	220	800
San Diego	500	50	630	1,180
SF Peninsula	480	10	310	800
Sierras	30	40	0	70
Orange	420	10	40	470
Total	**5,210**	**3,420**	**3,370**	**12,000**

Source: California Energy Commission, *Renewable Power in California: Status and Issues*, December 2011.

Post-2020, additional investments in renewable generation may be needed to replace generation expected to decline over the course of the next decade, such as generation from expiring coal contracts. Generation from a number of these contracts, which currently represents about 10 percent of total generation serving California, is expected to decline by 61 percent between 2010 and 2020 due to constraints imposed by the Emission Performance Standard.[27] Remaining coal contracts are expected to expire between 2027 and 2030, which will require replacement power from a mix of renewable and thermal generation with storage to satisfy electricity needs while still meeting greenhouse gas emission reduction goals.

When signing the 2011 RPS legislation, Governor Brown indicated that the 33 percent by 2020 RPS target should be considered a floor rather than a ceiling. This is consistent with the need for additional renewable generation and other zero-carbon electricity resources to meet the state's long-term (2050) GHG emission reduction goals. Back-of-the-envelope estimates by Energy Commission staff indicate that if new renewables alone provided the zero-emission generation needed to meet electricity needs in 2050,

27 The Emission Performance Standard prohibits California utilities from renegotiating or signing new contracts for baseload generation that exceeds 1,100 lbs of carbon dioxide equivalent (CO2e) emission per MWh. A number of contracts with coal generation facilities that exceed the Emission Performance Standard will expire within the decade and cannot be renewed with another long-term contract.

Table 4: California's Renewable Energy Potential

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

Source: California Energy Commission, *Renewable Power in California: Status and Issues*, December 2011.

renewable generation could represent from 67 to 79 percent of total electricity sales in 2050.[28]

California's estimated renewable technical potential is 18 million MW (Table 4).[29] Although this figure does not reflect economic or environmental constraints, development of even one-tenth of 1 percent of this potential would nearly meet the Governor's 20,000 MW renewable goal. Achieving this potential will depend on the ability of project developers to secure financing, permits, transmission, interconnection, local community acceptance, and power purchase agreements.

Despite these challenges, recent trends indicate increasing market interest in renewable development. The 2009 RPS solicitation by the investor-owned utilities (IOUs) drew bids from developers offering to supply enough renewable generation to meet half of the IOUs' total electrical load in 2020, and IOUs currently have signed contracts for roughly 14,000 MW of new renewable capacity. In 2010, state and local entities issued permits for 9,435 MW of renewable capacity, and another 28,000 MW is being tracked in various

28 The 67 percent estimate assumes that electricity demand, the number of self-generation projects, and energy efficiency programs continue to grow at current rates; increased penetration of electric vehicles; and continued operation of existing renewables, nuclear, and hydroelectric generation at the same levels in 2050 as today. The 79 percent estimate uses the same assumptions with the exception of nuclear and assumes that existing nuclear plants are not relicensed. These estimates do not consider the additional need for integration of intermittent renewables, which may require additional flexible capacity toward which fossil fuels, energy storage, and demand response could play a part. Estimates are presented for illustration only and not intended to be used for planning purposes.

29 *Technical potential* refers to the amount of generating capacity theoretically possible given resource availability, geographical restrictions, and technical limitations like energy conversion efficiencies and does not reflect economic potential (how much could be developed at cost levels considered competitive) or market potential (how much could be implemented in the market after accounting for energy demand, competing technologies, costs and subsidies, and barriers).

permitting processes.[30] The California ISO's Interconnection Queue includes about 57,000 MW of renewable capacity, and there are 450 active interconnection requests for DG systems in the Wholesale Distribution Access Tariff queue totaling about 5,200 MW.

Issues Affecting Future Renewable Development in California

The *Renewable Power in California: Status and Issues* report identified a variety of issues that will affect the amount of renewable capacity ultimately developed, including environmental, planning, and permitting; transmission; grid- and distribution-level integration; investment and financing; cost; research and development (R&D); environmental justice; local government coordination; and workforce development. The report also discussed past and current efforts to address these challenges, which must be overcome to achieve California's renewable energy targets and goals.

Planning and Permitting Issues

For utility-scale renewable plants, the primary planning and permitting challenges are environmental/land use issues and fragmented and overlapping permitting processes. Renewable facilities can have a variety of environmental and land-use impacts depending on location and technology. Because the majority of new renewable development is proposed in the California desert, the *Renewable Power in California: Status and Issues* report focused on desert environmental impacts. These include impacts on sensitive plant and animal species, water supplies and waterways, and cultural resources like areas of historical or ethnographic importance. There are also land-use concerns because the majority of desert lands in California are owned by the federal government and managed for multiple uses, including recreation, wildlife habitat, livestock grazing, and open space.

In terms of the permitting process, a variety of federal, state, and local agencies have licensing authority for different types of utility-scale renewable projects. This can lead to inconsistent environmental reviews and standards and variation in the extent of environmental evaluation, interpretation of results, and mitigation requirements. The result is that developers may have to satisfy more than one set of conditions, submit duplicate information, or face delays while agencies resolve their differences.

For renewable DG facilities, widely varying codes, standards, and fees among local governments with jurisdiction over these projects are a challenge for developers trying to meet permitting requirements. In addition, developers must get permit approvals from multiple local entities like fire departments, building and electric code officials, and local air districts, which can lead to duplication and inefficiency in the permitting process. Also, many local jurisdictions do not have energy elements in their general plan or zoning ordinances to guide renewable development and may have environmental screening and review processes in place only for large-scale renewables, not DG projects.

The state's Renewable Energy Action Team (REAT) is developing the Desert Renewable Energy Conservation Plan (DRECP) to help minimize environmental impacts of renewable generation and transmission

30 California Energy Commission, see: www.energy.ca.gov/33by2020/documents/renewable_projects/REAT_Generation_Tracking_Projects_Report.pdf.

projects in the desert.[31] The DRECP's role is to identify areas in the Mojave and Colorado Desert regions suitable for renewable generation and transmission project development and areas that will contribute to the conservation of sensitive species and natural communities. The DRECP encompasses roughly 22 million acres in Kern, Inyo, Los Angeles, San Bernardino, Riverside, San Diego, and Imperial counties (Figure 3). It will promote development of solar thermal, utility-scale solar PV, wind, and other forms of renewable energy as well as associated infrastructure such as transmission lines.

Other efforts to improve permitting for utility-scale and DG renewable projects include:

- The REAT published the multidisciplinary *Best Management Practices and Guidance Manual: Desert Renewable Energy Projects* in December 2010, which helps project developers design projects that minimize environmental impacts. [32]

- The Energy Commission's Public Interest Energy Research (PIER) Program is funding research to help reduce the environmental impacts of renewable energy facilities, including strategies to diminish the effects of desert solar and wind projects on sensitive species. For more information about the role of the PIER Program, please see Chapter 12.

- The Energy Commission initiated an Order Instituting Informational Proceeding in December 2010 to evaluate lessons learned during the licensing of large-scale renewable facilities in 2010 with the goal of identifying innovative approaches to future planning and permitting (see Chapter 6).

- The U.S. Department of Energy's (U.S. DOE) Solar America Cities Program provided funding for cities that promote solar power and streamline interaction between local government and residents.

- The U.S. DOE's SunShot Initiative provides funding to encourage cities and counties to streamline and digitize permitting processes and to develop innovative information technology systems, local zoning and building codes, and regulations.

- California's Assembly Bill X1 13 (V. Manuel Pérez, Bradford, and Skinner, Chapter 10, Statutes of 2011), passed in 2011, requires the Energy Commission to, upon appropriation, provide $7 million in grants to qualified counties for developing or revising rules and policies (including general plan elements, zoning ordinances, and a natural community conservation plan) to promote the development of eligible renewable energy resources.

- Many jurisdictions are supporting renewable DG by identifying permitting barriers, developing expedited permitting processes, offering online permits for solar PV systems, and offering permit fee waivers for solar and wind projects. The California County Planning Directors Association is also coordinating a multi-stakeholder effort to draft a model ordinance for solar electric facilities for cities and counties across the state.

- The Ocean Protection Council recently passed a resolution recommending that "the Energy Commission should adopt an ocean renewable energy policy that guides the state's goals for the development of

31 Executive Order S-14-08, November 2008, directs state agencies to create comprehensive plans to prioritize regional renewable projects based on renewable resource potential and protection of plant and animal habitat. The Energy Commission and the California Department of Fish and Game signed a memorandum of understanding formalizing a Renewable Energy Action Team to implement and track progress of this effort. See Desert Renewable Energy Conservation Plan website at www.drecp.org.

32 Renewable Energy Action Team, *Best Management Practices and Guidance Manual: Desert Renewable Energy Projects*, December 2010, www.drecp.org/documents/index.html.

Figure 3: Desert Renewable Energy Conservation Plan Area

Source: California Energy Commission, *Renewable Power in California: Status and Issues*, December 2011.

these renewable energy technologies while balancing this development with the protection and conservation of ocean resources for broad public benefit" and to "consider adopting an ocean renewable energy policy for inclusion in the *2012 IEPR Update*."[33]

Transmission Issues

The primary transmission issues identified in the *Renewable Power in California: Status and Issues* report are the need to ensure interconnection of renewable generation projects, particularly those receiving federal stimulus funding; the need for coordinated land use and transmission system planning; and better use of the existing grid.

There are 13 major transmission projects that are critical for interconnecting and delivering the renewable generation needed to meet California's 33 percent by 2020 renewable mandate.[34] Six projects are licensed or under construction, while the remaining seven do not yet have active licensing applications. Many of these projects are needed to interconnect renewable generation projects that received funding through the American Recovery and Reinvestment Act (ARRA), which are essential to achieving the state's renewable goals. In addition, the state needs to strengthen the north-south 500 kilovolt (kV) "backbone" system to address bottlenecks arising from Southern California desert renewable energy resource areas and Central and Northern California load centers.

The second transmission issue is the need to streamline and coordinate transmission planning processes to build the most appropriate transmission projects to connect renewable resources while ensuring proper land use and environmental considerations. Currently, identification of transmission routing issues and constraints does not begin until after the "wires" planning process is complete. This lengthens the transmission development process and increases the risk that approved projects will not be developed because of environmental issues. Stakeholders also identified the lack of transparent and consistent assumptions and processes used by transmission planning organizations as an issue that makes it difficult to participate effectively in planning processes.

The third transmission issue is how to make better use of the existing transmission grid. Currently, proposed renewable generation projects are evaluated in queue clusters and selected based on existing energy load needs. Allowing projects to be upsized beyond what is needed could provide unused capacity for future use, maximizing the value of land associated with already necessary transmission investment and avoiding future costlier upgrades to accommodate additional renewable development. There is also need for additional research to identify technologies that can improve the performance of the existing transmission system.

RETI was a statewide land use planning process intended to improve transmission planning by identifying transmission projects needed to meet the state's renewable energy goals.[35] RETI identified 30 CREZs throughout the state most likely for cost-effective and environmentally responsible generation development with corresponding transmission interconnections and lines. This process led directly to the collaborative land-use planning occurring in the DRECP, and energy agencies are working together to ensure integration of land-use planning from the DRECP into the California ISO's annual transmission planning process.

Other efforts to improve transmission planning include:

33 www.opc.ca.gov/webmaster/ftp/pdf/agenda_items/20111216/7._OceanRenewables/2011.12.16_ OceanRenewables_Memo.pdf.

34 For a list of projects and detailed description of project status, see California Energy Commission, *Renewable Power in California: Status and Issues*, December 2011, www.energy.ca.gov/2011_energypolicy/documents/index.html.

35 For more information about the 2007–2010 RETI, see: www.energy.ca.gov/reti/.

- The California Transmission Planning Group, formed in 2009, is working to address California's transmission needs in a coordinated manner by developing a conceptual statewide transmission plan that identifies the necessary transmission infrastructure to meet the state's 33 percent by 2020 RPS goal.

- The California ISO has revised its transmission planning process to include transmission upgrades needed to meet California's policy mandates, with the *2010–2011 Transmission Plan* focusing on the RPS mandate in identifying policy-driven transmission projects.

- The California ISO received a one-time waiver from the Federal Energy Regulatory Commission to exempt upgrades associated with renewable projects receiving federal stimulus funding from further study in the 2010–2011 transmission planning process to allow generators to meet the construction start date of December 31, 2010.

Efforts to promote better use of the existing transmission grid include:

- The DRECP has a goal to support consolidation of renewable development, including transmission infrastructure, rather than scattered "leapfrog" development.

- The PIER Program has funded a wide variety of projects related to improving the performance of the existing transmission system. These include research to increase the carrying capacity of existing lines, reduce instabilities that are causing some transmission connections to be operated thousands of MW below maximum capacity, and develop transmission cables that can be operated at higher temperatures and allow more power to be transferred over existing transmission rights-of-way.

Integration Issues

Grid-Level Integration

Maintaining reliable operation of the electric system with high levels of intermittent resources will require a variety of strategies including, but not limited to, regulation to follow real-time ups and downs in generation output, voltage, or frequency caused by changes in generation or load; ramping generation from other units to follow potential up or down swings in wind or solar generation; spinning reserves[36] to provide standby power as needed; and replacement power for outages. System operators will also need strategies to address potential overgeneration issues that occur when there is more generation than there is load to use it and to improve forecasting of wind and solar technologies so they know how much variability to plan for.

Complementary technologies like natural gas-fired power plants, energy storage, and demand response provide various choices for flexible and rapid response for renewable integration. Natural gas units can provide quick startup, rapid ramping, regulation, spinning reserves, and energy when intermittent resources are not available. However, a challenge is the need to modify revenue streams to cover the incremental costs of shifting the use of these units from providing maximum energy production to providing flexible products, as well as potential environmental impacts and loss of machine life from cycling these units more frequently.

Energy storage can provide a variety of integration services, but additional evaluation is needed about cost-effectiveness, appropriate targets, and specific technologies to determine which can provide the rapid response and operational flexibility needed

36 Spinning reserve is the on-line reserve capacity that is synchronized to the grid system and ready to meet electric demand within 10 minutes of a dispatch instruction by the California ISO, see: www.caiso.com/docs/2003/09/08/2003090815135425649.pdf.

to provide regulation and load following.[37] Demand response – having electricity customers reduce their consumption at critical times or in response to market prices – can also play an important role by providing short-term load reductions and combining smaller loads to provide regulation or ramping through automatic controls that turn individual loads up or down as needed. Here, too, there is need for additional evaluation to determine how existing utility demand response programs might be used to provide renewable integration services.

Efforts to address grid-level integration issues include:

- The California ISO is working to improve its forecasting techniques to reduce uncertainty and the amount of standby capacity that will be needed to compensate for variations between generation and load.

- Formal planning for adding cost-effective energy storage to the electric system began with the passage of Assembly Bill 2514 (Skinner, Chapter 469, Statutes of 2010), which directed the CPUC and publicly owned utilities to evaluate the need for and benefits of cost-effective and viable energy storage systems, and determine appropriate targets by October 2013.

- Demand response is being used throughout the United States for ancillary services, and the California ISO offers two demand response products that are laying the foundation for the role of demand response in renewable integration efforts. The California ISO is also scheduled to implement a regulation energy market in spring 2012 that will allow demand response and energy storage to submit bids to provide ancillary services.

- The CPUC is evaluating integration costs as part of its Long-Term Procurement Plan proceeding for various scenarios.

- The Energy Commission's PIER Program is funding a wide array of projects intended to develop better forecasting tools for wind and solar generation, develop and demonstrate energy storage technologies, identify ways that demand response can support renewable integration, and develop the smart grid of the future.

Distribution-Level Integration

There are also issues with integrating large amounts of renewable DG into the distribution system, which brings power from substations to consumers. Much of today's distribution system still uses designs, technologies, and strategies that were developed to meet the needs of mid-20th century customers and move electricity in only one direction. The distribution system needs to be modernized and use technologies that easily allow for two-way flow of electricity as well as improved communication technologies, better protection systems, uniform standards, cyber security measures, and inverter standards. Better models and simulation tools are also needed to evaluate protection, control, and operational requirements of the grid with a high penetration of distributed generation resources. There are also process challenges associated with the increasing number of requests for interconnection and the need to reduce the complexity, expense, and length of time associated with that process.

Efforts to improve distribution-level integration include:

- In September 2011, the CPUC opened a proceeding on interconnection-related issues to review rules

37 Load following is a utility's practice of adding additional generation to available energy supplies to meet moment-to-moment demand in the distribution system served by the utility or keeping generating facilities informed of load requirements to insure that generators are producing neither too little nor too much energy to supply the utility's customers, see: www.energyvortex.com/energydictionary/load_following.html.

and regulations governing interconnecting generation and storage resources to IOU distribution systems.[38]

- California utilities are already modernizing their distribution systems by replacing equipment at the end of its useful life with new equipment that often has more advanced communication and functional capabilities. This modernization is likely to increase as a result of Senate Bill 17 (Padilla, Chapter 327, Statutes of 2009), which requires utilities to develop smart grid deployment plans.

- The CPUC has established the Renewable Distributed Energy Collaborative working group to help address interconnection issues.

- Fast-track processes are available within each of the state's interconnection processes to streamline interconnection of smaller projects, and utilities are providing information on their websites to help developers identify locations on the distribution grid where projects can be interconnected more quickly and at lower cost.

- The Energy Commission and the California ISO funded a study on renewable DG integration in Germany and Spain to identify strategies that can be applied to California's system.[39]

- Research funded through the PIER Program is focused on predicting the impacts of DG on distribution circuits, and developing smart grid and battery storage technologies that can support integration at the distribution level.

38 California Public Utilities Commission, see: docs.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/144161.htm#P60_1197.

39 Corfee, Karin, D. Korinek, C. Hewicker, M. Pereira Morgado, H. Ziegler, J. Zillmer and D. Hawkins, KEMA, *European Renewable Distributed Generation Infrastructure Study – Lessons Learned From Electricity Markets in Germany and Spain*, December 2011, California Energy Commission, Renewable Energy Office, available at: www.energy.ca.gov/publications/displayOneReport.php?pubNum=CEC-400-2011-011.

Investment and Financing Issues

The primary financing challenge identified in the *Renewable Power in California: Status and Issues* report was the need to ensure adequate financing at critical stages of renewable project development. In particular, there are funding gaps at the R&D and early commercial stages. Private companies are often reluctant to invest in R&D to accelerate clean energy innovation due to the higher price of clean energy technologies, knowledge spillover risks, technology and policy uncertainty, the scale and long time horizon of many clean energy projects, and lack of widespread enabling clean energy infrastructure. Although overall R&D investment in the United States has grown annually by 6 percent, investment in energy-related research is about $1 billion less than a decade ago, with the private sector's share of energy R&D investment declining from nearly half in the 1980s and 1990s to about 25 percent today. At the early commercial stage, firms have traditionally used private equity, debt, and tax equity markets to provide financing, but since the financial crisis these options are either impractical given economic conditions, depend on government incentives to function well, or do not provide sufficient returns for investors.

Efforts to address financing issues include:

- National government laboratories are performing cutting-edge research on a variety of clean energy technologies, and the federal Advanced Research Projects Agency – Energy funds high-risk, high-reward technologies to bridge the gap between basic energy research and industrial application.

- Other federal government support mechanisms include tax incentives such as the business energy investment tax credit and the renewable production tax credit, as well as accelerated depreciation of renewable energy assets and loan and bond financing programs.

- State incentives include programs to support renewable DG, including the California Solar Initiative (CSI), the Emerging Renewables Program (ERP), the New Solar Homes Partnership (NSHP), the Self-Generation Incentive Program, and net energy metering, as well as sales and use tax exclusions under California's Advanced Transportation and Alternative Sources Manufacturing Sales and Use Tax Exclusion Program.[40]

- The PIER Program provided roughly $179 million for renewable energy research between 1997 and 2010, including seed funding for technology incubators that accelerate the growth and development of clean technologies.

- California's Innovation Hub initiative leverages research parks, technology incubators, universities, and federal laboratories to provide an innovation platform for startup companies, economic development organizations, business groups, and venture capitalists.

- The CPUC's Renewable Auction Mechanism streamlines the procurement process for developers, utilities, and regulators by allowing bidders to set their own price, providing a standard contract for each utility, and allowing projects to be submitted to the CPUC through an expedited regulatory review process.[41]

- Tools like feed-in tariffs provide a relatively guaranteed revenue stream, reduce transaction costs, and help support low-cost private financing. In February 2008, the CPUC made feed-in tariffs available for the purchase of up to 480 MW of renewable generating capacity from small facilities (1.5 MW or less). Senate Bill 32 (Negrete McLeod, Chapter 328, Statutes of 2009) increased eligible project size to 3 MW, and Senate Bill X1 2 (Simitian, Kehoe, and Steinberg, Chapter 1, Statutes of 2011) made additional amendments including how the feed-in tariff price would be determined. CPUC Rulemaking 11-05-005 is implementing these changes, with a ruling issued in January 2012 directing utilities to work together to create one standard contract for the revised feed-in tariff program and to file the contract with the CPUC by February 15, 2012.[42]

Funding for programs like the NSHP, the ERP, and the PIER Program, which help overcome financing challenges, expired at the end of 2011 and will be unfunded if the Public Goods Charge or alternate source of funding is not reauthorized. On December 15, 2011, the CPUC approved its Phase 1 decision instituting the Electric Program Investment Charge (EPIC) to collect funds on an interim basis for renewables and research, development, and demonstration programs.[43] Funds will be placed in balancing accounts and not disbursed until authorized by the CPUC's final decision at the conclusion of Phase 2 of the proceeding.

Cost Issues

Renewable technologies have a wide range of costs depending on the technology. Historically, technologies like solar thermal electric and solar PV were thought to have levelized costs greater than those of conventional generation. However, recent contract bids show that this is changing. According to the

40 See: www.gosolarcalifornia.ca.gov/, www.energy.ca.gov/renewables/emerging_renewables/index.html, www.cpuc.ca.gov/PUC/energy/DistGen/netmetering.htm, and www.treasurer.ca.gov/caeatfa/sb71/index.asp.

41 See: www.cpuc.ca.gov/PUC/energy/Renewables/hot/Renewable+Auction+Mechanism.htm.

42 California Public Utilities Commission, *Joint Assigned Commissioner's and Administrative Law Judge's Ruling Setting Workshop on a Utility Standard Form Contract for the Section 399.20 Feed-In Tariff Program,* January 10, 2012, docs.cpuc.ca.gov/efile/RULINGS/157031.pdf.

43 California Public Utilities Commission, News Release, December 15, 2011, see: docs.cpuc.ca.gov/PUBLISHED/NEWS_RELEASE/155619.htm.

Energy Commission's IOU contract database, the majority of solar thermal power tower technology contracts signed and pending are below the 2008 Market Price Referent (MPR), a proxy for the levelized cost of a new 500-megawatt natural gas combined cycle.[44] For utility-scale renewable projects, the Energy Commission, California ISO, and CPUC are continuing to work together to evaluate transmission and renewable integration costs. While costs of both appear significant, they are certainly not insurmountable.

Renewable DG projects were once considered more costly due to higher transaction costs and lack of economies of scale. Now, standardization of contract terms and the way PV is manufactured and sold are reducing bids for DG systems, as shown by advice letters filed by Southern California Edison (SCE) with the CPUC stating that all contracts signed under their 2010 Renewable Standard Contract are below the 2009 MPR.[45] It is likely that there will be significant changes in the market in the next five to ten years as DG systems become more cost-competitive. While distribution system upgrades and modernization could be significant depending on the location of DG projects and the pace at which they are deployed, there are a variety of efforts underway to identify optimal locations for such projects and develop the smart grid technologies needed to ease integration into the distribution system.

In any discussion of the costs of renewable technologies, it is important to recognize that renewables provide important benefits that have not been adequately quantified, such as the value of having a diverse portfolio of generating resources that reduces costs and risk to ratepayers, provides business and economic development benefits, reduces dependence on natural gas and vulnerability to natural gas supply shortages or price spikes, and reduces GHG emissions.

44 www.energy.ca.gov/portfolio/contracts_database.html.

45 www.sce.com/NR/sc3/tm2/pdf/2547-E.pdf.

Research and Development Issues

Continued public sector investment in energy-related R&D is an important tool to help address many of the challenges facing California's renewable industry. The Energy Commission's PIER Program has funded a wide variety of research to identify ways to address the environmental impacts of renewable energy facilities; develop technologies to improve the performance of the state's transmission and distribution systems; promote integration of renewable generating technologies at both the transmission and distribution level through the development of smart grid, energy storage, and demand response technologies; and reduce renewable technology costs while improving efficiency. With increasing levels of renewable resources in California's electricity mix, continued research will be required in each of these areas to provide the technological advancements needed to support the state's clean energy policy goals. Statutory collection of funding to support the PIER Program ended at the end of 2011 but funds are being collected on an interim basis pending a final decision by the CPUC.[46]

Environmental Justice Issues

Environmental justice (EJ) is defined in California law as "the fair treatment of people of all races, cultures, and incomes with respect to the development, adoption, implementation, and enforcement of environmental laws, regulations, and policies." The Energy Commission has considered EJ issues in its power plant licensing process since 1995, including reaching out to community members, identifying areas potentially affected by emissions or other environmental impacts, determining where there are significant populations of minority or low-income residents in an area potentially affected by proposed

46 docs.cpuc.ca.gov/PUBLISHED/NEWS_RELEASE/155619.htm.

projects, and determining whether there may be a disproportionate effect on minority or low-income populations. However, EJ organizations have concerns about the types of power plants that will be built to meet increased electricity demand and replace aging power plants and plants that may retire as a result of the State Water Resources Control Board's policy on the use of once-through cooling in power plants, particularly in the southern part of the state, which has some of the worst air quality in the nation. There are also concerns about the types of fossil generation that may be built to support renewable integration, including flexible natural gas turbines ("peakers") that are less efficient than baseload resources and have increased emissions that may affect the communities in which they will be located.

EJ communities do see the value of renewable generating resources, particularly renewable DG such as rooftop PV, in their communities. Rooftop PV in urban environments can provide value to these communities by reducing the health and environmental impacts of fossil-fueled power and increasing economic revitalization and creation of local green jobs. However, rooftop solar is not always accessible to these communities due to the high upfront cost of these systems. In addition, many residents of EJ communities live in multiunit residential rental properties whose landlords may not see any benefits for allowing solar system construction, especially in situations where they are paying for the systems and additional wiring while tenants are receiving the benefits of reduced energy costs.

Efforts to help offset the costs of installing rooftop PV on affordable and low-income housing include:

- The Energy Commission's NSHP offers affordable housing projects higher incentives than standard market-rate housing projects. Of the overall 400 MW goal for the entire NSHP program, 36 MW will be made available for new affordable housing during the 10-year program.[47] As noted, this program relies on funding from the state's Public Goods Charge.

- Under the California Solar Initiative, the CPUC has two programs, the Single-Family Affordable Solar Homes Program and the Multifamily Affordable Solar Housing Program. The goals of these programs include improving energy use and the quality of affordable housing through use of solar and energy efficiency technologies and decreasing electricity use and costs without increasing monthly household expenses for residents. Programs provide solar incentives for qualifying affordable housing in the service territories of PG&E, SCE, and San Diego Gas & Electric.[48]

- The nonprofit Grid Alternatives Solar Affordable Housing Program provides training to install solar electric systems for low-income homeowners.[49] This program began in 2004 and as of January 2012 has installed 1,571 solar electric systems in partnership with low-income families throughout California. These systems represent nearly 4.2 MW of generating capacity and are reducing each family's electric bills by about 75 percent. Grid Alternatives has also trained more than 8,000 community volunteers and job trainees on the theory and practice of solar electric installation.

- The "Solar for All California" program, implemented by the California Department of Community Services and Development using funding from the

47 Go Solar California website, www.gosolarcalifornia.ca.gov/affordable/nshp.php.

48 California Public Utilities Commission, CSI Single-Family Affordable Solar Homes Program website, see www.cpuc.ca.gov/PUC/energy/Solar/sash.htm, and CSI Multifamily Affordable Solar Housing Program website, see: www.cpuc.ca.gov/puc/energy/solar/mash.htm.

49 Grid Alternatives website, see: www.gridalternatives.org/impact-numbers.

Low Income Home Energy Assistance Program,[50] has a goal of installing 1,000 new PV systems on single- and multifamily low-income homes throughout California by October 2011. As of November 2011, the program has installed 422 single-family systems and has approved an additional 491 single-family systems and nine projects that will benefit 666 multifamily units.

- The Los Angeles Department of Water and Power (LADWP) recently relaunched its Solar Incentive Program with applications accepted beginning September 1, 2011. As part of the program, LADWP staff has been asked to investigate more options for making solar affordable to low-income customers with the goal of developing leasing options and other proposals for lower income households.[51]

Local Government Coordination Issues

Renewable development at the local level will be an essential component of the state's efforts to meet the goal of adding 12,000 MW of DG by 2020, which will be permitted at the local level. Local governments are closely involved in land use decisions, environmental review, and permitting for a wide range of renewable projects. Many local governments face constraints due to decreased staffing as a result of the economic downturn, limited expertise about renewable technologies, and lack of energy elements in their general plans and ordinances that could delay the processing of permits for renewable facilities, but many local jurisdictions are also showing strong leadership and innovation in promoting renewable energy development. The state needs to work closely with local governments to understand their needs and provide assistance where possible to help expedite the permitting and installation of renewable DG projects as well as renewable utility-scale projects that are under local jurisdiction.

There are several initiatives underway to streamline and standardize permitting processes for renewable DG projects:

- Through its Solar America Communities program, the U.S Department of Energy (DOE) in 2007 and 2008 selected 25 U.S. cities, six of which are in California, as "Solar America Cities."[52] This unique federal-local partnership initiative aims to identify barriers to greater adoption of solar technologies and develop solutions to those barriers.

- As part of the overall strategy to reduce barriers to the adoption of solar technologies and to stimulate market growth, DOE has funded the Solar America Board for Codes and Standards to improve building codes, utility interconnection procedures, and product standards, reliability, and safety.[53]

- The DOE's $12.5 million "SunShot Initiative: Rooftop Solar Challenge" aims to reduce the administrative costs for PV systems.[54] This is a national competition for local and regional teams of government, utilities, installers, and others to "compete for funds to implement their plan to reduce administrative barriers to residential and small commercial solar

50 California Department of Community Services and Development, Solar For All California website, see: www.csd.ca.gov/AboutUs/Solar%20For%20All%20California.aspx.

51 Los Angeles Department of Water and Power, "LADWP to Relaunch Solar Incentive Program with Revised Incentive Levels and Streamlined Customer Service," press release, August 2, 2011, see: www.ladwpnews.com/go/doc/1475/1153343/.

52 For a list of the 25 Solar America Cities, see: solaramerica-communities.energy.gov/.

53 Solar America Board for Codes and Standards, see: www.solarabcs.org.

54 www.eere.energy.gov/solarchallenge/.

PV installations by streamlining, standardizing, and digitizing administrative processes."[55]

- The Energy Commission's *Energy Aware Planning Guide* provides information for local governments to use in encouraging DG in their jurisdictions and suggests a wide variety of implementation strategies to promote DG projects.[56]

Workforce Development Issues

As investment in the clean energy economy expands, there is increased need for a coordinated approach to workforce training that is closely aligned with labor demand. While growth in clean tech segments of the economy like wind, solar photovoltaics, and smart grid is creating demand for workers and there are a number of workforce training programs in place, the fragile economy has made employers hesitant about taking on more employees. This has resulted in low placement rates for some of these programs. In addition, expiration of federal stimulus funding for workforce development may make it difficult for community colleges, trade associations, and other training providers to continue their clean energy training curricula in the future.

Efforts to address workforce development challenges include:

- In 2010, a survey by the Center for Energy Efficiency and Renewable Technologies (CEERT) indicated that thousands of workers will be needed between 2010–2015 to build power plants being proposed in Southern California, with hundreds of operations and maintenance jobs needed for the next 20–30 years. CEERT also estimates that construction jobs to build 2,000 PV projects totaling 6,000 MW over a 10-year period would create a monthly average of 10,400 jobs.[57]

- The Clean Energy Workforce Training Program, the largest state-sponsored green jobs training program in the nation, is training workers needed to operate large-scale renewable power plants and install PV systems. The program also provides grants that will establish community college and other training programs as part of established curricula, which will provide the basis for long-lasting and sustainable changes in clean energy workforce training in California.[58]

- The Clean Energy Workforce Training Program also has an interagency agreement with the Employment Training Panel which provided $4.5 million in grants for career advancement training. Grantees train incumbent workers in clean energy skills while also meeting a 90-day employment retention period after the training is completed. The program is set to train nearly 3,000 incumbent workers.

- The Green Innovation Challenge Grant program is helping community college students in the San Francisco Bay Area learn the skills to perform after-market repairs and maintenance to electric and alternative fuel vehicles; helping the San Diego region to develop college-level curriculum and certificates for workers in the biofuel industry; and helping to train PV solar installers, system designers, and marketing professionals.

- SBX1 1 (Steinberg, Chapter 2, Statutes of 2011) will provide up to $8 million in funding annually to the

55 www1.eere.energy.gov/solar/pdfs/rooftop_solar_challenge.pdf.

56 California Energy Commission, *Energy Aware Planning Guide*, February 2011, www.energy.ca.gov/2009publications/CEC-600-2009-013/CEC-600-2009-013.PDF, Section C.2.2.

57 Center for Energy Efficiency and Renewable Technologies, presentation to Inter-Solar North America, July 12, 2011, www.ceert.org/PDFs/reports/110712_DG-Jobs_CEERT_InterSolar-NA.pdf.

58 For more information on the Clean Energy Workforce Training Program, see: www.energy.ca.gov/cleanenergyjobs/.

Superintendent of Public Instruction to implement and administer a grant program to fund clean energy partnership academies in public schools for grades 9–12. The partnership academies, which serve primarily at-risk students, will focus on preparing students for careers in energy and water conservation, renewable energy, pollution reduction, and similar technologies.

- The PIER Program invested $12 million in the California Partnership Academies' Green/Clean Initiative to build clean energy career pathways for students in grades 10–12.[59] This effort funded about 60 programs through the California Department of Education that integrated academic and career technical education, business partnerships, mentoring, and internships with a focus on green careers such as green buildings, sustainable design, and green engineering.

- The PIER Program provided cost-share funding that helped leverage ARRA funding for the California State University, Sacramento, to develop a clean energy workforce curriculum for the electric power sector, specifically targeted toward training needed for jobs being created in smart grid applications. The PIER Program also sponsored research on the need for a National Center for the Clean Energy Workforce to provide a clearinghouse for information on best practices and technical assistance to translate this information into practical changes in workforce development strategies.

Public Leadership Issues

California has the potential to develop renewable energy systems on state-owned buildings, properties, and rights-of-way to help meet the state's renewable energy goals, create green jobs, and reduce greenhouse gas emissions and other harmful air pollutants. These investments will also reduce energy costs in state buildings and create new revenue for state government through the lease of vacant or unused land. State leadership will also demonstrate the benefits of renewable DG and help encourage larger-scale deployment throughout the state and across the country.

A number of state agencies entered into a memorandum of understanding in December 2010 to promote the development of renewable energy projects on state properties. As part of that effort, the Energy Commission staff released a draft report in April 2011 that identified current development of renewable on state properties, barriers and solutions to future deployment, opportunities for further development, and recommended next steps. The Energy Commission adopted the final report in early 2012.[60] Based on its inventory of state properties to identify opportunities for deployment of renewable DG systems, Energy Commission staff recommended a target of 2,500 MW of new renewable generating capacity on state properties by 2020.

Efforts underway by various state agencies that will contribute toward meeting these targets include:

- The Department of General Services (DGS) tracks energy use at state buildings to measure progress toward reducing energy consumption 20 percent by 2020 as called for by Executive Order S-20-04. DGS also released three requests for proposals to develop solar PV at state facilities and university campuses. The first solicitation resulted in the installation of 4.25 MW, the second awarded power purchase agreements for 21 MW, and the third solicitation is expected to result in about 30 MW, for a total of about 55 MW.[61]

59 Funding for this effort was appropriated by Assembly Bill 519 (Budget Committee, Chapter 757, Statutes of 2008).

60 California Energy Commission, *Developing Renewable Generation on State Property*, November 2011, www.energy.ca.gov/2011publications/CEC-150-2011-001/CEC-150-2011-001-LCF.pdf.

61 The majority of these DGS contracts are for CDCR facilities identified in a subsequent bullet and should not be double counted.

- California Department of Transportation (Caltrans) is pursuing the installation of PV along the California highway system consistent with Governor Brown's support of the California Solar Highway. One project in Santa Clara County is in development. Caltrans has also identified 70 state-owned structures for installation of PV panels; 55 of those facilities are generating energy with the remainder expected to be producing energy by the end of fiscal year 2011–2012.

- The Department of Water Resources (DWR) is evaluating several renewable energy projects, including developing small hydroelectric generation in the State Water Project and assessing feasibility for a test project for in-aqueduct hydrokinetic generation. DWR is also negotiating with the University of California on a solar PV demonstration project along the California Aqueduct and next to one of its pumping plants, and is negotiating a power purchase agreement for wind energy with an annual output of almost 144 GWh.

- California's fairgrounds have installed solar PV at 26 of the 74 state fairgrounds ranging in size from 41 kilowatts to 1 MW, with a total installed capacity of 6.5 MW.

- The Department of Forestry and Fire Protection will continue to explore the feasibility of biomass facilities at conservation camps.

- The California Department of Corrections and Rehabilitation (CDCR) has two operational 1 MW PV ground-mounted solar arrays at state prisons with contracts to expand to nearly 9 MW. CDCR also has power purchase agreements for three additional sites, for a total of 21.5 MW at five sites, and is reviewing proposals for an additional 14 locations. CDCR's next solar effort will include sites that can be considered for wholesale generation, combined with providing on-site power to the prisons for systems ranging from 1 to 20 MW. CDCR is also implementing roof-mounted PV for several new building construction projects as well as a request for information for wind resource opportunities.

- The State Lands Commission manages thousands of acres of "school lands" as a revenue source for the State Teachers' Retirement System. Unlike the other agencies, the State Lands Commission is focusing on utility-scale development rather than DG. It has approved leases for renewable energy projects on these lands and is considering applications for new projects.

- As part of its effort to reduce greenhouse gas emission levels to year 2000 levels by 2014 and 1990 levels by 2020, the University of California has set aggressive energy efficiency targets, and has made substantial investments in combined heat and power plants. As of September 2011, the University of California had 8.4 MW of onsite PV installed or under construction and an additional 6.2 MW of biogas-powered generation.

Recommendations

Building on the Energy Commission's study, numerous public workshops, and the input of stakeholders from various communities and industries throughout California, the Energy Commission proposes five overarching strategies to guide the state as it works toward achieving the 33 percent RPS mandate, the 12,000 MW DG goal, and promoting economic recovery and job creation through investments in the clean energy sector:

1. Identify and prioritize geographic areas in the state for both renewable utility-scale and distributed generation development. Priority areas should have high levels of renewable resources, be located where development will have the least environmental impact,

and be close to planned, existing, or approved transmission or distribution infrastructure. Prioritization should also include increasing efforts between state and local agencies to coordinate local land-use planning and zoning decisions that promote the siting and permitting of renewable energy-related infrastructure.

2. Evaluate the cost of renewable energy projects beyond technology costs – including costs associated with integration, permitting, and interconnection – and their effect on retail electricity rates. This evaluation shall be coupled with a value assessment that could potentially lead to monetizing the various system and non-energy benefits attributable to renewable resources and technologies, particularly those benefits that enhance grid stability and reduce environmental and public health costs.

3. Develop a strategy that minimizes interconnection costs and time and minimizes integration costs and requirements at the distribution level (such as use of remote telemetry and other smart grid technologies) and the transmission level (such as improved forecasting, the development of an energy imbalance market, and procurement of dispatchable renewable generation), and that strives for cost reductions and improvements to integration technologies, including storage, demand response, and the best use of the state's existing natural gas-fired power plant fleet.

4. Promote incentives for renewable technologies and development projects that create in-state jobs and support in-state industries, including manufacturing and construction. In implementing this strategy, the state should evaluate how current renewable energy policies and programs are affecting in-state job growth and economic activity, how to optimize their effectiveness and transparency, and identify which renewable technologies rely on supply chains that provide the best opportunities for California businesses.

5. Promote and coordinate existing state and federal financing and incentive programs for critical stages including research, development, and demonstration; precommercialization; and deployment. In particular, the state should maximize the use of federal cash grants and loan guarantee programs by prioritizing the permitting and interconnection of California-based renewable energy projects (and their associated transmission or distribution infrastructure) vying for federal stimulus funds.

Detailed implementation strategies and action items will be developed in the upcoming *2012 Integrated Energy Policy Report Update* proceeding to provide further guidance on specific activities in which various state and local entities can engage to successfully carry out these high-level strategies in the near, medium, and long term.

CHAPTER 3

Achieving Cost-Effective Energy Efficiency for California

Assembly Bill 2021 Progress Report

This chapter summarizes the Energy Commission final staff report Achieving Cost-Effective Energy Efficiency for California

2011–2020, including key points from the report, progress on utilities' energy efficiency savings and measurement and verification efforts, and policy recommendations.[62]

California has demonstrated a strong commitment to cost-effective energy efficiency for the last 30 years with the adoption of progressive policies, programs, and activities. In 2003, the state's first *Energy Action Plan* established the state's loading order, calling for electricity needs to be met first with increased energy efficiency and demand response. Assembly Bill 32 made customer-side energy efficiency a key strategy for reducing greenhouse gas emissions to 1990 levels by 2020.

62 California Energy Commission, *2011 AB 2021 Progress Report: Achieving Cost-Effective Energy Efficiency for California,* December 2011, www.energy.ca.gov/2011publications/CEC-200-2011-007/CEC-200-2011-007-SF.pdf.

In 2005, Senate Bill 1037 (Kehoe, Chapter 366, Statutes of 2005) made energy efficiency a priority strategy for electric utilities to meet their resource needs. SB 1037 requires the California Public Utilities Commission (CPUC) and the Energy Commission to identify potentially achievable cost-effective electric and natural gas energy efficiency savings and set goals for investor-owned utilities (IOUs) to achieve this potential.[63] Both agencies must review the procurement plans to ensure the consideration of energy efficiency and other cost-effective supply options. In addition, SB 1037 requires all publicly owned utilities, regardless of size, to report annually to their customers and to the Energy Commission on investments in energy efficiency programs.

Assembly Bill 2021 (Levine, Chapter 734, Statutes of 2006) added more specific legal directions for increasing California's energy efficiency programs. AB 2021 requires each publicly owned utility to:

- Beginning in 2007 and every three years thereafter, identify all potentially achievable cost-effective electricity energy savings. Using the efficiency potential estimates, establish annual targets for energy efficiency savings for the next 10-year period.

- Report on program cost-effectiveness and third-party energy evaluation, measurement, and verification (EM&V) of program savings.

AB 2021 directs the Energy Commission to:

- Include a summary of the publicly owned utilities' savings and evaluation, measurement, and verification (EM&V) studies in the *Integrated Energy Policy Report (IEPR)*.

- In consultation with the CPUC as the regulator of IOUs' energy efficiency programs, provide a triennial statewide estimate of energy efficiency potential and targets for a 10-year period.

- Provide recommendations to publicly owned utilities, Legislature, and the Governor of possible improvements by the publicly owned utilities.

In response to AB 2021, the Energy Commission released the fifth annual final staff report *Achieving Cost-Effective Energy Efficiency for California 2011–2020 (2011 AB 2021 Progress Report)* on December 21, 2011. The following section provides an overall summary of the utilities' progress on energy efficiency program savings, EM&V reporting, and a more detailed description of setting energy efficiency targets, followed by recommendations for improvement of these efforts.

Staff Assessment of Utilities' Progress

Investor-Owned Utilities' Progress

The IOUs administer efficiency programs under the CPUC's Decision 09-09-047, which approved the IOUs' efficiency program portfolios for 2010–2012 with a total budget of $3.1 billion. The combined IOUs reported 4,607 gigawatt hours (GWh) of annual energy savings, 837 megawatts (MW) of peak savings, and 46 million therms of natural gas savings in 2010, which exceeded their 2010 CPUC-mandated goals. The 2010 natural gas savings fell just a bit short of the CPUC's natural gas goals for 2010.

The 2010 IOU savings numbers are still *ex ante* savings, that is, self-reported savings that have not

63 The terms for energy efficiency "targets" and "goals" are used interchangeably. There is an established convention (at least since 2004) that the CPUC and IOUs use the term "goals." Publicly owned utilities have adopted the term "targets" since that is the term used in AB 2021.

Table 5: IOUs' and Publicly Owned Utilities' 2009 and 2010 Savings and Expenditures

	Investor-Owned Utilities		Publicly Owned Utilities	
	2009	2010	2009	2010
Gigawatt hours	3,770	4,610	644	523
Megawatt hours	700	839	117	94
Therms	54	46	-	-
Expenditures ($ Millions)	$722	$755	$146	$123

All savings data for both IOUs and publicly owned utilities are self-reported and have not been verified by third-party evaluators.

Source: Data obtained from the IOUs' Annual Reports for 2009 and 2010 (eega.cpuc.ca.gov), and CMUA, *Energy Efficiency in California's Public Power Sector: A Status Report*, March 2010 and March 2011 (cmua.org).

been verified by third-party evaluators. Beginning with the 2006–2008 program implementation cycle, the CPUC instituted a more comprehensive process for capturing, retaining, and reporting *ex post* evaluation results. The CPUC's 2006–2008 EM&V results show a significant difference between reported and evaluated savings for that period. While the IOUs reported surpassing their energy savings goals, the evaluation report indicated that the utilities achieved between 37 percent and 71 percent of their goals for that period. However, the CPUC's *2009 Energy Efficiency Evaluation Report for the 2009 Bridge Funding Period* verified that the IOUs achieved 141 percent of the GWh goal and 104 percent of the MW goal.[64]

A new CPUC *Potential and Goals Study* for efficiency is underway and expected to be completed in late summer 2012. The results of this study will be incorporated into the next AB 2021 report to be released in 2014.

64 California Public Utilities Commission, *Energy Efficiency Evaluation Report for the 2009 Bridge Funding Period*, January 2011, www.cpuc.ca.gov/NR/rdonlyres/D66CCF63-5786-49C7-B250-00675D91953C/0/EEEvaluationReportforthe2009BFPeriod.pdf, p. 23.

Publicly Owned Utilities' Progress

In 2010, all publicly owned utilities combined spent a total of $123 million on energy efficiency programs, a 15 percent decrease from 2009 and the first drop in energy efficiency program spending since 2006 (Table 5). Likewise, both energy and peak savings declined for the publicly owned utilities for the first time since 2006. In 2010, the 39 reporting publicly owned utilities provided 523 GWh of electric energy savings, a decrease of 19 percent from 2009. The publicly owned utilities achieved 74 percent of their 2010 energy savings target set in 2007. The decline in the 2010 numbers, however, is largely due to the completion of a large contracted lighting program at Los Angeles Department of Water and Power (LADWP).[65] Despite 2010's lackluster economic conditions, mid-sized

65 In its December 23, 2011, written comments on the draft *2011 IEPR*, LADWP noted that it is "evaluating an updated version of the lighting program, which will be targeted to capture additional energy savings from the small business market that are historically difficult to reach with efficiency programs." (www.energy.ca.gov/2011_energypolicy/documents/comments_draft_iepr/index.php).

and small utilities performed reasonably well in both efficiency spending and savings.

This report contains metrics that measure the progress made by the publicly owned utilities in their energy efficiency programs: trends in reported energy efficiency expenditures, energy efficiency spending as a percentage of revenue, energy savings relative to adopted targets, energy savings as a percentage of total utility sales, and the cost-effectiveness of efficiency programs.

Energy Commission staff has requested information from the publicly owned utilities that would help to interpret data on efficiency progress. Their response to information requests has improved since 2008, but the Energy Commission is still not receiving some significant material. As staff learns their specific objections to data sharing, the Energy Commission and the publicly owned utilities can develop resolutions.

Evaluation and Verification of Publicly Owned Utilities' Efficiency Savings

The publicly owned utilities' savings reported in this document have not been modified as a result of independent verification studies. Unlike the IOUs, for which the CPUC can report evaluated savings, most publicly owned utilities do not yet have consistent evaluation methods. Since the passage of AB 2021 in 2006, nearly half of the publicly owned utilities have filed at least one EM&V impact study for program years 2007–2009. The Energy Commission developed EM&V guidelines in 2010 but learned in 2011 workshops that, for many publicly owned utilities, EM&V can impose costs without equal benefits. Not all publicly owned utilities provide earmarked funding for EM&V in their budgets so there can be tradeoffs between paying for third-party evaluation and providing program services. Other publicly owned utilities had difficulty meeting the Energy Commission's draft guidelines because diversity in size, resources, customer types, and program delivery approaches makes it difficult to meet "one-size-fits-all" prescriptive guidelines for EM&V activities. Some utilities, however, did indicate benefits received from EM&V studies, including using study recommendations to improve data tracking systems and program delivery.

Status of Statewide Estimate of Energy Efficiency Potential and Targets for 2011–2020

AB 2021 requires publicly owned utilities to develop estimates of energy efficiency potential and targets on a triennial basis. Due to the unavailability of certain data, the Energy Commission could not set the statewide efficiency estimates for all utilities with the method directed in AB 2021. After the passage of AB 2021, the Energy Commission coordinated 10-year savings targets in December 2007 for both the IOUs and publicly owned utilities. In 2007, all the utilities had a recent potential study and set of approved targets and goals from which to develop the statewide savings potential estimate. In 2010–2011, however, the IOUs did not have revised potential estimates and goals available, Sacramento Municipal Utility District

Table 6: Estimated Potentials for Publicly Owned Utilities (Excluding SMUD and LADWP)

	Energy Potential – GWh			Demand Potential – MW		
	Technical	Economic	Market	Technical	Economic	Market
Current Analysis (2010), 2011–2020	10,693	9,525	2,143	2,861	2,283	526
Previous Analysis (2007), 2007–2016	5,460	4,038	2,109	732	507	302

Note: Excludes LADWP and SMUD.

Source: KEMA, Inc., *POUs' Revised Energy Efficiency Potential and Targets*, July 2010, CEC-200-2008-007-SF, May 2011.

(SMUD) did not have a revised potential study,[66] and LADWP did not have revised savings potential or targets.[67] As a result, the 2011–2020 efficiency target includes 42 percent of all publicly owned utilities' savings and 6 percent of all California's utility savings.[68] While this estimate includes the substantial majority of the publicly owned utilities, it does not represent the largest contributors to California's utility energy savings.[69]

The California Municipal Utilities Association (CMUA) coordinated 36 medium-sized and small utilities that used the California Energy Efficiency Resource Assessment Model to develop technical, economic, and market-level savings potentials. Taken together, SB 1037 and AB 2021 require targets to be cost-effective, feasible, and reliable. Target criteria were developed for these attributes and used in this evaluation. Methodological criteria were developed and used in evaluating the models and inputs.

Technical efficiency potential represents the complete penetration of efficiency measures where they are technically feasible. The estimate of technical energy savings potential is 10,693 GWh from 2011–2020. This estimate represents 33 percent of base energy consumption in 2020 and is 96 percent higher than the 2007 estimate of technical potential estimated for the decade 2007–2016 (Table 6). Economic efficiency potential is that percentage of technical potential that is cost-effective. The economic savings potential estimated for the publicly owned utilities in the 2010 study is 9,525 GWh for 2011–2020, or 29 percent of base energy consumption. This estimate of economic potential is 136 percent higher than the 2007 estimate of economic potential for the decade 2007–2016.

The most significant level of efficiency potential

66 SMUD indicated in December 23, 2011, written comments on the draft *2011 IEPR* that they are in the process of securing a contractor to do a revised potential study.

67 Energy Commission staff met with LADWP representatives in August 2011 and LADWP is in the process of providing targets and an updated potential study. LADWP also indicated in its December 23, 2011, written comments on the draft *2011 IEPR* that they approved new energy savings targets in December 2011.

68 This is based on 2009 data from *Achieving All Cost-Effective Energy Efficiency for California: An AB 2021 Progress Report*, December 2010, CEC-200-2010-006, available at: www.energy.ca.gov/2010publications/CEC-200-2010-006/CEC-200-2010-006.PDF.

69 LADWP is working on a potential and target study with Global Energy Partners; its original due date was during fall 2010. SMUD does not have current plans to revise its efficiency potential estimate.

is market savings potential, which is the percentage of economic potential that results when program designs, customer preferences, and market conditions are assessed. With a few exceptions, the publicly owned utilities used the market potential as their revised targets for 2011–2020. For the 36 utilities, the market potential was 23 percent of their economic potential. In the initial target setting in 2007, these same utilities derived targets (that is, market potential) that were roughly 50 percent of their economic potential. In general, while the 2010 estimate of technical and economic potential differed greatly from the levels developed in 2007, the targets derived by the utilities, and approved by their governing boards, were very similar.

While the forecasts of some individual utilities achieve 10 percent savings over 10 years, the combined publicly owned utilities' targets do not meet the AB 2021 consumption reduction goal, reaching 6.8 percent savings from forecasted 2020 base energy use. Only 3 of the 36 publicly owned utilities individually meet the 10-year goal, with 2 others falling only slightly short.

For most utilities, market savings potentials were calculated using a 50 percent customer measure incentive level.[70] Additional modeling indicated that when a 75 percent incentive level is used, nearly all utilities meet the 10 percent consumption reduction goal. This indicates that the publicly owned utilities can meet the consumption reduction goal of AB 2021 but may require a higher level of program effort and budget than most of them factored into their targets. However, the issue of cost-effectiveness is a key factor in setting incentive levels and determining which efficiency measures to include in programs. Increasing incentive levels to 75 percent may not be cost-effective for all utilities.

70 "Fifty percent customer measure incentive level" means that the utility pays for 50 percent of the cost of the energy efficiency measure, such as through a rebate.

Recommendations

Information Requested to Interpret Efficiency Progress

- The most important data needed by staff to evaluate annual savings is the E3 Reporting Tool, which calculates savings potential for each publicly owned utility based on specific assumptions. In 2011, the publicly owned utilities stated that the reason for withholding the data tool was to protect customer identities. The Energy Commission is not interested in individual customers and is willing to accommodate an aggregation or redaction adjustment of the E3 Tool.

- The Energy Commission requests data by March 2012 on utility energy efficiency expenditures with other uses of Public Goods Charge (PGC) funding: low-income, research and development, and renewable energy projects.

- Staff requests that publicly owned utilities provide information by March 2012 on the role of energy efficiency in integrated resource planning in 2009. CMUA's *2009 and 2010 Status Reports* identified utilities that were allocating funds to efficiency programs beyond their PGC funding, but there is no indication that this allocation results from an integrated resource assessment. While some publicly owned utilities have performed recent integrated resource assessments, they usually treat efficiency as a load adjustment, not an equally comparable supply resource.[71]

71 See public utility websites for their integrated resource plans; for example, LADWP's is at: www.ladwp.com/ladwp/cms/ladwp014239.pdf.

Publicly Owned Utility Efficiency Evaluation, Measurement, and Verification

- The publicly owned utilities should continue with their current plans for 2011 EM&V studies, especially the Southern California utilities that are working on their first EM&V studies since 2007. The Energy Commission is especially interested in working through the impact study process with LADWP staff because of the magnitude of their savings.

- The Energy Commission will engage with publicly owned utilities to develop versions of revised EM&V guidance documents, tools, and services appropriate for the three groups. These groups are stratified by these criteria: magnitude of savings, capacity to perform and manage EM&V studies, and program need for specific evaluation information. The Energy Commission will sponsor two EM&V workshops each year to increase agency and publicly owned utilities' understanding of practical EM&V; the next workshops will occur in late 2012.

Publicly Owned Utility Potential Estimates and Target Process in 2010–2011

- IOU goals will not be revised or approved until 2012.[72] The Energy Commission is coordinating with the CPUC post-2013 potential and goals process. The goal of both agencies is to better align the efficiency planning process of the IOUs and publicly owned utilities. The Energy Commission should identify these AB 2021 schedule issues, discuss them with the utilities and CPUC, and, if necessary, recommend an adjustment to the triennial deadline for statewide potential estimates and targets.

- While AB 2021 required all publicly owned utilities to submit efficiency potential estimates and targets by June 1, 2010, neither SMUD nor LADWP was in full compliance by that date.[73] In the future, revisions of potential and targets should anticipate AB 2021 deadlines.

- Estimates of technical savings potential for the publicly owned utilities in 2010 were substantially greater than those of 2007. The model used by the publicly owned utilities' consultant (Navigant) for estimating potential in 2010 was different from the model used by their 2007 consultant (Rocky Mountain Institute). There must be some continuity in method from one revision to the next to make sense of changes in potential estimates. If publicly owned utilities do not use the California Energy Efficiency Resource Assessment Model in the next potential study cycle, they should provide an accounting of method and data changes from one triennial revision to the next to maintain transparency in the process.

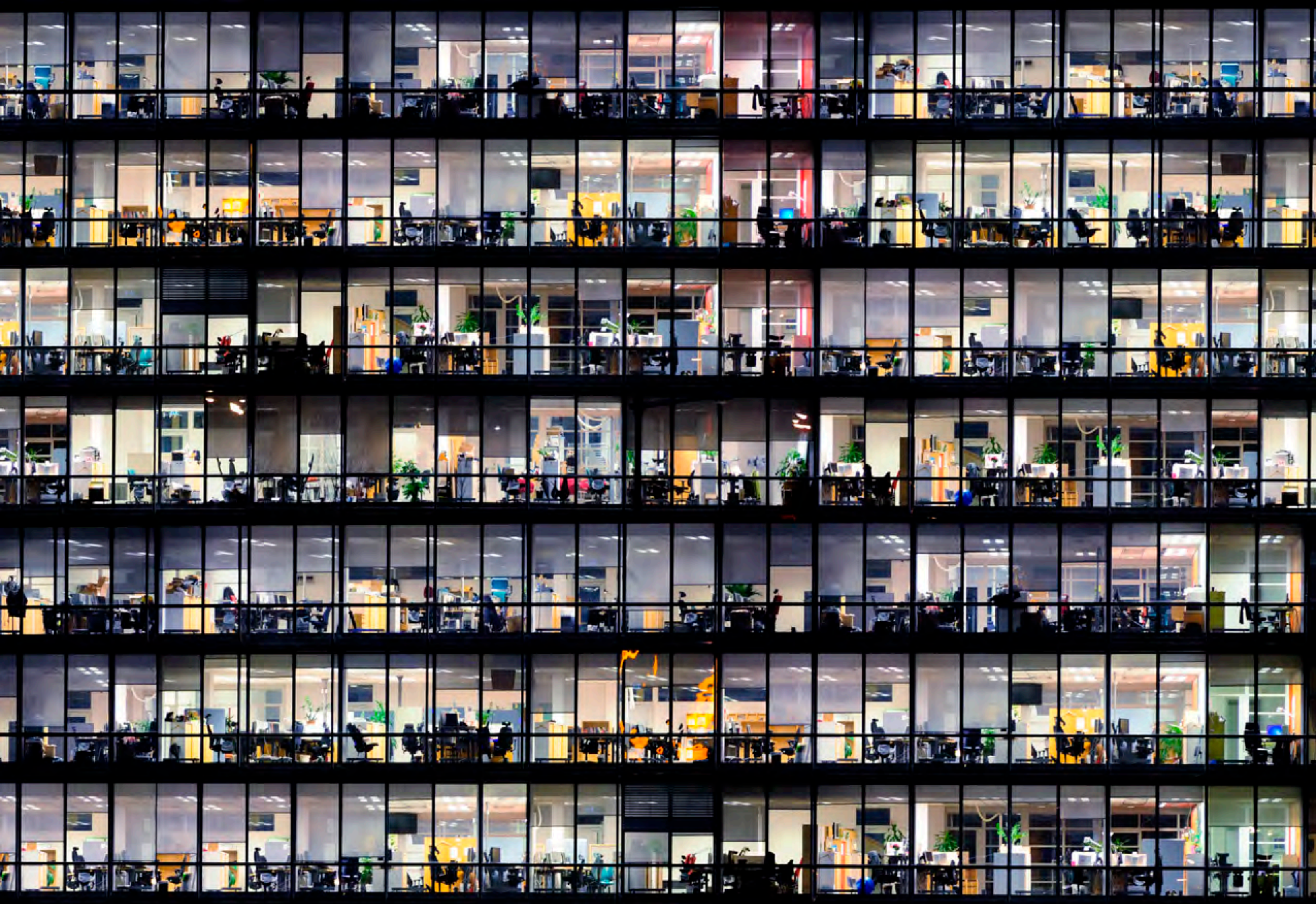
- The Energy Commission requires more documentation from the publicly owned utilities to understand the assumptions behind the potential estimates and energy efficiency targets adopted. Utilities should provide the Energy Commission with the version of the model that they used to calculate targets. The

72 Scope and schedule for the revised IOUs' post-2013 efficiency potential study and goals is available at: www.iepec.org/CPUC%20RPF%20021511.pdf.

73 AB 2021 states that "on or before June 1, 2007, and by June 1 of every third year thereafter, each local publicly owned electric utility shall identify all potentially achievable cost-effective electricity efficiency savings and shall establish annual targets for energy efficiency savings and demand reduction for the next 10-year period." In its December 23, 2011, written comments submitted on the draft *2011 IEPR,* SMUD indicated that it has established targets aimed at reducing energy use by 15 percent, 50 percent more aggressive than the 10 percent called for in AB 2021.

publicly owned utilities should document the ways in which they customized the model and the reasons for the customization.

➨ The analysis of energy efficiency potential and adopted targets clearly showed that some publicly owned utilities were more aggressive in pursuing energy efficiency than others to meet their load. The efficiency potential analysis showed that, for most utilities, providing higher customer incentives (of at least 75 percent) would achieve an important goal of AB 2021 by increasing savings sufficiently to reduce energy consumption by 10 percent in 2020.



CHAPTER 4

Achieving Energy Savings in California Buildings

This chapter summarizes the Energy Commission staff report Achieving Energy Savings in California Buildings: Saving

Energy in Existing Buildings and Achieving a Zero-Net-Energy Future.[74] The overview contains key points from the report, including background, strategies, and challenges in achieving the state's energy efficiency and climate change goals, and recommendations to help accelerate progress.

California has a long history of leadership in delivering the economic, environmental, and energy system reliability benefits that derive from its energy efficiency standards and programs. Expansion and acceleration of energy efficiency initiatives are at the forefront of the state's energy policy goals and mandates. The state's ongoing efforts to achieve all cost-effective energy efficiency in buildings are

74 California Energy Commission, *Achieving Energy Savings in California Buildings: Saving Energy in Existing Buildings and Achieving a Zero-Net-Energy Future*, July 2011, CEC-400-2011-007-SD, available at: www.energy.ca.gov/2011publications/CEC-400-2011-007/CEC-400-2011-007-SD.pdf.

pivotal for achieving the state's goals for job creation, economic development, and environmental protection, including the following:

- The Energy Action Plan has guided California energy policy since the California energy crisis of 2000–2001 and is designed to improve energy system reliability and manage costs. The plan established the principle of following the "loading order" for new generation resources, directing that growth in energy needs must be met first by cost-effective energy efficiency improvements.

- The Global Warming Solutions Act (Assembly Bill 32 [Núñez, Chapter 488, Statutes of 2006]) has been the foundation of California's efforts over the past five years to address climate change by reducing greenhouse gas (GHG) emissions to the state's 1990 level by 2020. The adopted *AB 32 Scoping Plan* recommended expanding and strengthening building and appliance standards and energy efficiency programs aimed at existing buildings.[75] The Energy Commission's *2007 Integrated Energy Policy Report* concluded that climate change is the most important environmental and economic challenge of the century; GHG emissions are the largest contributors to global warming; and California's ability to slow the rate of GHG emissions depends first on energy efficiency.

- California's Clean Energy Future (CCEF) Initiative is a collaborative effort of the state's energy and environmental agencies and the California ISO to advance carbon-cutting innovation and green job creation. It articulates the importance of new investments in energy efficiency, as well as in electricity transmission, smart grid applications, and increased use of renewable resources.[76]

- Governor Brown's Clean Energy Jobs Plan (2010)[77] advocates focusing on renewable energy and energy efficiency technologies to achieve California's economic recovery and growth goals, creating more than half a million green jobs. In the area of building efficiency, the plan calls for:

    - Adopting stronger appliance standards for lighting, consumer electronics, and other products.

    - Creating new efficiency standards for new buildings.

    - Adopting a plan and timeline for achieving "zero net energy" homes and businesses through the building standards by integrating high levels of energy efficiency with onsite renewable electricity generation.

    - Increasing public education and enforcement efforts so that the gains promised by California's efficiency standards are realized.

    - Making existing buildings more efficient, especially the half of California homes that were built before the advent of modern building standards.

75 California Air Resources Board, *Climate Change Scoping Plan: A Framework for Change,* December 2008, page 16, arb.ca.gov/cc/scopingplan/document/scopingplandocument.htm.

76 The California Air Resources Board, California Public Utilities Commission, the Energy Commission, and California Environmental Protection Agency are partnering with the California ISO to ensure California's continued leadership in clean technology over the coming decade. See *California's Clean Energy Future: An Overview on Meeting California's Energy and Environmental Goals in the Electric Power Sector in 2020 and Beyond*, available at www.cacleanenergyfuture.org/.

77 Governor Jerry Brown, see: www.jerrybrown.org/Clean_Energy.

- Providing energy performance information to commercial investors and homebuyers by requiring disclosure prior to the purchase of the building or home.

To respond to these policy expectations, the Energy Commission and other agencies are collaborating on strategies to achieve extensive energy savings in newly constructed and existing buildings, benefiting all Californians by reducing energy costs and the environmental and climate impacts of buildings.

Goals and Strategies for Newly Constructed Buildings

Zero Net Energy Buildings

The Energy Commission, California Air Resources Board (ARB), and the California Public Utilities Commission (CPUC) have adopted the policy goal, consistent with existing statutory authority, to achieve zero net energy (ZNE) building standards by 2020 for residential buildings and 2030 for commercial buildings through the *2008 Energy Action Plan*, *2007 IEPR*, and the *2008 California Long-Term Energy Efficiency Strategic Plan*. The CCEF initiative and Governor Brown's Clean Energy Jobs Plan also identify ZNE as a priority goal.

A ZNE building has zero net energy consumption. Consistent with the loading order, the goal is to minimize energy use as much as technologically possible through cost-effective efficiency measures, and then generate the balance of the building's energy needs with onsite renewable electricity generation such as solar photovoltaic systems or wind-driven electricity generators. The substantial energy efficiency improvements built into ZNE buildings contribute also to maintaining and improving the building's comfort and functionality.

While the ZNE idea is straightforward, translating the policy into standards, guidelines, and incentive structures requires collaboration between agencies and stakeholders. To maximize the alignment of ZNE with California energy system reliability and policy goals, the Energy Commission recommends the use of metrics that account for the societal value of energy, including the critical impact of avoiding peak demand and the value of avoided carbon emissions, and other energy system costs. These components are well-addressed in the time-dependent valuation of energy concept used by the Energy Commission for its efficiency standards and the CPUC for its valuation of efficiency program savings.[78]

Building Energy Efficiency Compliance and Reach Standards

California's mandatory Building Energy Efficiency Standards (Building Standards) are fundamentally performance standards that establish an "energy budget" for the entire building as an alternative to prescriptive requirements for individual components. This affords California builders, designers, and contractors the flexibility to achieve energy efficiency in buildings using a wide array of measures that fit their construction goals and meet the standards at the lowest cost.

The Building Standards are an important strategy for meeting the ZNE goal, as each subsequent standards update (done on a three-year cycle) will progressively raise the bar by requiring increased energy-saving features in building designs and

78 Under the time-dependent valuation of energy, the value of electricity differs depending on time of use (hourly, daily, seasonally) and the value of natural gas differs depending on season. Time-dependent valuation is based on the cost for utilities to provide energy at different times.

equipment. Using cost effective efficiency requirements, the Energy Commission's goal is to achieve a 20 to 30 percent energy savings for each triennial Building Standards update. As an initial step, the 2013 Building Standards will address high-efficacy building envelopes, lighting, and heating, cooling and water heating systems, and energy demand response management technologies.

No matter how much demand is reduced, however, some amount of onsite generation will be required. As part of its policy setting responsibility under Senate Bill 1 (Murray, Chapter 132, Statutes of 2006) and its management responsibility for the New Solar Homes Partnership, the Energy Commission developed standards and tools for achieving high-performance rooftop photovoltaic (PV) systems. These standards and tools are designed to promote high-efficiency solar energy system components, effective installation practices, and calculation and demonstration of expected system performance. They will serve as the foundation for considering upcoming building standards for rooftop PV systems.

The joint agency strategy for achieving the ZNE goals calls for establishing not only mandatory standards in each triennial update of the Building Standards, but voluntary "reach standards." The reach standards further a "market pull strategy" by establishing higher standards than required, which can be used when developing minimum standards in subsequent cycles. These reach standards are often met by a substantial portion of newly constructed buildings, demonstrating their feasibility, cost-effectiveness, and value in the market. In developing these standards, the Energy Commission collaborates with the CPUC and the utilities' new construction programs to incentivize builders to meet the reach standards. In addition, they are included as voluntary measures in the California Green Building Standards Code (Title 24, Cal. Code Regulations, Part 11).

Other governmental agencies incorporate the reach standards as locally mandated requirements in their regulations and programs. For example, local governments are including them in local green building and energy ordinances, and the California Tax Credit Allocation Committee has incorporated these standards in its regulations governing qualification for federal and state tax credits for affordable housing projects. Several benefits accrue when a substantial portion of the marketplace constructs buildings that meet the reach standards. Industry gains expertise in delivering greater building efficiency. Also, costs tend to decline for the more efficient features as they become mainstream rather than premium and as suppliers and installers compete to provide them.

Strategies for Existing Buildings

More than half of California's 13 million residential units and more than 40 percent of the commercial buildings were built before 1978, when the state first implemented Building Energy Efficiency Standards. These existing buildings, and the rest built under previous vintages of the Building Code, provide a huge opportunity for low-cost energy savings. The *AB 32 Scoping Plan* concluded that improving the energy efficiency of existing residential and commercial buildings is the most important way to reduce GHG emissions in the electricity and natural gas sectors. The CPUC's Long-Term Energy Efficiency Strategic Plan set major goals for achieving deep, whole building energy savings in existing residential and commercial buildings. Efficiency improvements in existing buildings are also a priority goal of both the CCEF initiative and Governor Brown's Clean Energy Jobs Plan.

The Legislature at several points in time has directed the Energy Commission to develop policies and programs to pursue improved efficiency in existing buildings, including to develop a statewide Home Energy Rating System Program (Senate Bill 1922 [Lewis, Chapter 553, Statutes of 1994]), develop and report to the Legislature recommendations for improving the energy efficiency of existing buildings in California (Assembly Bill 549 [Longville, Chapter 905, Statutes of 2001]), investigate options and develop a plan to decrease peak electricity demand for air conditioners across the state (Assembly Bill 2021 [Levine, Chapter 734, Statutes of 2006]), and establish a program requiring nonresidential building owners to benchmark the energy use of their buildings in comparison to other similar buildings and disclose the benchmarking data and ratings to prospective buyers, lessees, and lenders (Assembly Bill 1103 [Saldaña, Chapter 533, Statutes of 2007] and Assembly Bill 531 [Saldaña, Chapter 323 , Statutes of 2009]). Building on this prior legislation, Assembly Bill 758 (Skinner, Chapter 470, Statutes of 2009) directed the Energy Commission to develop, adopt, and implement an ongoing, comprehensive, statewide program to reduce energy consumption in existing buildings, including the adoption of regulations for energy ratings and improvements in existing buildings.

This comprehensive portfolio of programs is required to implement a variety of complementary techniques, applications, and practices to achieve greater energy efficiency in homes and businesses. AB 758, for example, authorizes (among other things) the program to provide:

- Energy assessments to identify and recommend opportunities for saving energy use in individual buildings.

- Energy efficiency financing options and other financial incentives.

- Information and education to property owners to help them implement energy efficiency improvements.

- Systematic workforce training to ensure that workers employed to provide the services needed under the program will be well trained and supported to deliver high-quality work.

The Energy Commission is required to evaluate the most effective ways to report the energy assessment results and efficiency improvement recommendations to the property owners, including prioritizing the energy efficiency improvements and determining how different types of financial incentives and financing can be used to accomplish the improvements. The bill also directs the Energy Commission to evaluate the appropriate methods to inform and educate the public about the need for and benefits of making energy efficiency improvements.

AB 758 calls for the Energy Commission to develop and implement the program in collaboration with the CPUC and industry stakeholders. The CPUC is directed to investigate the ability of investor-owned utilities to provide financing to their customers for energy-efficiency improvements and to report to the Legislature the progress of the utilities in implementing the program.

Contemporaneously with the passage of AB 758, the federal government passed the American Recovery and Reinvestment Act (ARRA). ARRA funding provided California additional resources to develop and conduct programs aimed at saving energy, creating jobs, and contributing to California's economic recovery through energy efficiency upgrade projects in existing buildings. The Energy Commission designed the ARRA-funded programs to incorporate the same approaches that were called for by AB 758 as a way to pilot those approaches. The ARRA programs emphasized collaborations of local governments and industry to deliver energy assessments, ratings, efficiency improvements, and quality assurance. ARRA also funded the nation's largest workforce development effort, meshing the well-established state and local workforce development infrastructure with statewide efforts to implement energy efficiency upgrades in existing buildings.

In an unprecedented collaboration, the Energy Commission, CPUC, local governments, and utilities came together to closely coordinate residential and commercial building upgrade programs under the Energy Upgrade California™ brand. The collaborative pilot programs provided a number of components authorized by AB 758, including:

- Public Awareness and Outreach
- Workforce Development
- Financing Options and Financial Incentives (Rebates)
- Energy Performance Ratings and Disclosure
- Efficiency Recommendations and Improvements (including Quality Assurance)

Major efforts have occurred all over California to implement and pilot each of these AB 758 program components. These efforts leveraged the ARRA funding to collaborate on the details of delivering energy efficiency upgrades in existing buildings. In the area of clean energy financing options, for example, the ARRA-funded programs have allowed California to establish revolving loan programs that will remain in operation after the ARRA funding ceases, provide loan loss reserves to encourage lenders to provide financing for energy efficiency upgrades, and pilot Property Assessed Clean Energy (PACE) financing in concert with local property assessments. On August 2, 2011, Governor Brown signed Assembly Bill X1 14 (Skinner, Chapter 9, Statutes of 2011), authorizing the State Treasurer to administer a new $50 million program to provide loan loss reserves for energy upgrades consistent with Energy Commission guidelines. This new program represents a major opportunity for the Energy Commission, State Treasurer's Office, CPUC, and other partners to create financing solutions for building owners wanting to implement energy upgrade projects. In addition, on January 10, 2012, the CPUC issued an Administrative Law Judge's ruling on energy efficiency financing requesting comments on a CPUC Energy Division staff proposal on energy efficiency financing activity in 2013–2014, a report prepared for the CPUC on energy efficiency financing needs and gaps, and a proposal by the Environmental Defense Fund on on-bill repayment.[79]

The Energy Commission's next steps are to complete needs assessments for both residential and nonresidential buildings, identify what must be done in each of AB 758's program component areas (taking advantage of the lessons learned from the ARRA piloting), and develop action plans for moving forward with AB 758 program development. The AB 758 program will be developed in three phases. Phase 1 (2010–2012) will include developing infrastructure and implementation plans; Phase 2 (2012–2014) will support market development and partnerships; and Phase 3 (2014 and beyond) will include development of statewide ratings and upgrades requirements.[80] The implementation plans developed under Phase 1 will include detailed schedules of activities, and each Phase will include ample opportunity for public input. Key areas of focus include recommending improvements to the Home Energy Rating System program, developing the Commercial Building Energy Asset Rating System (BEARS), and building strategies for effective rating, labeling, and disclosure of energy-efficiency information. Attention will also focus on improving compliance with and enforcement of California's Building Energy Efficiency Standards requirements for alterations of existing buildings. As a condition for accepting ARRA State Energy Program funding, each state's governor

79 California Public Utilities Commission, *Administrative Law Judge's Ruling Regarding Energy Efficiency Financing,* January 10, 2012, docs.cpuc.ca.gov/efile/RULINGS/157047.pdf.

80 For more information on the program, see: www.energy.ca.gov/ab758/.

committed to putting advanced state energy codes into effect (such as the Energy Commission's 2008 and subsequent Building Energy Efficiency Standards) and developing approaches to achieve high levels of compliance with those standards.

AB 758 directed the Energy Commission and the CPUC to collaborate on how to best deliver financing and design utility programs for upcoming funding cycles to advance the comprehensive AB 758 program.

Efficiency Improvements in Appliances

The Appliance Efficiency Standards (Appliance Standards) are another strategy for reducing energy use in newly constructed and existing buildings. While permanently installed equipment and appliances are a substantial part of the building's energy use,[81] electronics and other devices plugged into outlets make up a growing portion of California's energy use. Unfortunately, the energy use (and thus the true cost) of appliances and electronic devices is often invisible to the consumer, and manufacturers lack the direct incentive (of having to pay for the energy their products consume) to design products that use energy efficiently.

The Energy Commission's Appliance Standards can address this issue by setting cost-effective minimum efficiency requirements for appliances, electronics, and other devices. These efficiency standards set the bar at a level that affects only the least efficient products. Since 1976, the Energy Commission has adopted standards covering a wide range of appliances, including all major household appliances, air conditioners, furnaces, and water heaters. In many instances, California standards have subsequently been adopted as national standards by the United States Department of Energy (U.S. DOE).

Historically, California's energy efficiency standards have resulted in significant reductions in energy consumption. The Energy Commission estimates that appliance efficiency standards adopted between 1976 through 2005 saved 18,761 gigawatt hours (GWh) in 2010.[82] This represents 6.7 percent of California's electric load and is roughly the amount of energy produced by California's two largest power plants. At an average rate of 14 cents per kilowatt hour, appliance efficiency regulations saved California consumers about $2.68 billion in 2010.

Despite the success of appliance efficiency standards, the amount of energy consumed by devices plugged in by building occupants ("plug load") has been climbing rapidly.[83,84] To address these growing plug loads, the Energy Commission has initiated and completed several rulemakings covering products

81 The breakdown of 2009 annual household electricity consumption by end use is: lighting, 22 percent; refrigerators and freezers, 20 percent; television, computer, and office equipment, 20 percent; air conditioning, 7 percent; pools and spas, 7 percent; dishwasher and cooking, 4 percent; laundry, 4 percent; space heating, 2 percent; water heating, 3 percent; and miscellaneous, 11 percent. California Energy Commission, *2009 California Residential Appliance Saturation Study,* October 2010, page 3, www.energy.ca.gov/2010publications/CEC-200-2010-004/CEC-200-2010-004-ES.PDF.

82 Savings from California's appliance efficiency standards are forecasted to grow to 27,116 GWh a year by 2020. This would represent 8.6 percent of projected load in 2020. At the current rate of 14¢ per kilowatt hour, this would save the state about $3.8 billion for 2020, see: www.energy.ca.gov/2009_energypolicy/index.html.

83 C.D. Barley, C. Haley, R. Anderson, and L. Pratsch, November 2008, *Building America System Research Plan for Reduction of Miscellaneous Electrical Loads in Zero Energy Homes*, National Renewable Energy Laboratory and U.S. Department of Energy, NREL/TP-550-43718, page 5, www.nrel.gov/docs/fy09osti/43718.pdf.

84 U.S. Energy Information Administration, March 28, 2011, *Share of Energy Used by Appliances and Consumer Electronics Increases in U.S. Homes*, available at: www.eia.gov/consumption/residential/reports/electronics.cfm.

such as televisions, external power supplies (EPS), DVD players, and compact audio devices. These regulations provide minimum efficiency or maximum power use requirements for more than 26 million unit sales per year (TV: 4 million 2010, EPS: 20.6 million 2005, DVD: 1.5 million, compact audio: 1.1 million). The Energy Commission is also developing standards for the estimated 58 million battery chargers sold (2009) in California per year. The estimated energy savings for battery charger standards is 2,000 GWh per year,[85] of which 1,600 GWh will be attributable to reduced residential plug load energy demand and 400 GWh toward reduced commercial plug load energy demand. The battery charger standards will improve the efficiency of a wide range of plug loads, such as laptop computers, power tools, electric toothbrushes, cell phones, mp3 players, and golf carts.

The Energy Commission is developing a new scoping order to identify the appliance types that should be included in new standards and to upgrade levels of existing standards. Stakeholder proposals have identified up to 8,000 GWh in potential savings from new standards. Proposals include computers and computer servers, set top boxes, linear fluorescent fixtures, and outdoor lighting as key opportunities for new Appliance Standards.

Improvements to Lighting Efficiency

Lighting is the largest electrical load in both homes and businesses, accounting for 35 percent of commercial annual electricity use and 22 percent of residential annual use. Assembly Bill 1109 (Huffman, Chapter 534, Statutes of 2007) requires an 11 percent reduction in electricity consumption from residential lighting and an 8.6 percent reduction from commercial lighting. Achieving these goals would reduce California's total electricity use by more than 6 percent.

Since the passage of AB 1109, the U.S. DOE has adopted new federal standards for general service fluorescent lamps and incandescent reflector lamps. California has exercised its discretion to implement the federal standards one year ahead of the federal schedule. The Energy Commission has also gone beyond the scope of the federal standards by adopting new standards for metal halide and portable luminaires, updated lighting efficiency, and design and use standards in the 2008 Building Energy Efficiency Standards, and will further address lighting efficiency in upcoming triennial updates. The above initiatives will advance the state's progress in meeting the AB 1109 residential lighting mandates. However, the challenge of meeting commercial lighting and outdoor lighting mandates must be addressed through additional standards and voluntary programs developed in collaboration with the lighting industry, consumers, the CPUC, and the state's utilities.

Light-emitting diode (LED) lamps are a promising example for advancing beyond current mandatory lighting standards. LEDs have enormous energy savings potential given their inherent efficiency at converting electricity to light. However, a number of challenges regarding cost, quality, and efficacy must be addressed. Rapid advancements in LED technology have led to a proliferation of products in a growing range of applications at lower prices. Research at the California Lighting Technology Center (CLTC) has revealed large variations in quality across a number of performance parameters, including light quality and longevity, which could reduce consumer acceptance of the technology. As with early efforts to bring compact fluorescent lamps to market, when similar performance quality issues severely dampened

85 Future savings estimated to be achieved in one year after the entire stock of appliances that are covered by the standards meet the requirements of the standards. This would happen in a future year after all such appliances that were manufactured prior to the effective date of the standards are no longer in use because they have reached the end of their useful lives.

consumer demand, there is a risk that barriers to wide acceptance of LEDs could result if California consumers have negative experiences with low-performing products. To address this risk, the Energy Commission is working with CLTC engineers, industry, the state's utilities, and the CPUC to develop product quality specifications for LEDs that could serve as a basis for future utility incentive programs.

Achieving Better Compliance With Standards

Compliance with Building Standards is much better for new construction than for alterations to existing buildings, primarily because alterations are frequently made without the required permits. Without the oversight of local building officials, energy efficiency codes are rarely followed. For example, less than 10 percent of contractors pull building permits and abide by legal requirements for change outs of furnaces and air conditioners. In general, local building departments have limited resources for enforcing building codes, especially those beyond minimum health and safety requirements. The lack of compliance with standards can result in defective construction and installation, including improper installation of wall and duct insulation, HVAC systems, and other efficiency measures, all of which can drive up energy costs for home and building owners.

Widespread noncompliance with appliance regulations also has been brought to light through complaint filings by competing manufacturers and retailers as well as energy efficiency advocates and others. Recent market surveys reveal high rates of noncompliance with the Appliance Standards, finding large numbers of ineligible products being offered for sale in stores, through catalogs, and over the Internet. Addressing the issue of noncompliance has been extremely difficult because the Energy Commission has had limited authority to take enforcement actions against noncompliant manufacturers, distributors, and retailers. If an appliance was found to be noncompliant with a standard, the Energy Commission could conduct an administrative hearing to remove it from the database (if it were improperly certified). However, the Energy Commission was required to petition the Attorney General to seek injunctive or other relief from a court to forbid the sale of an appliance. This administrative process could take up to 190 days, and court actions can take many months or years.

On October 8, 2011, Governor Brown signed Senate Bill 454 (Pavley, Chapter 591, Statutes of 2011) into law, which will help address the challenge with widespread noncompliance by manufacturers and retailers. The legislation allows the Energy Commission to adopt an enforcement process for violations of appliance efficiency regulations and impose civil penalties of up to $2,500 for each violation. The bill establishes the Appliance Efficiency Enforcement Subaccount within the Energy Resources Program Account, where civil penalty funds will be deposited that can then be spent upon appropriation by the Legislature for public education and enforcement of the appliance efficiency standards.

The Energy Commission will use the following criteria in assessing a civil penalty:

- The nature and seriousness of the violation
- The number of violations
- The persistence of the violation
- The length of time over which the violation occurred
- The willfulness of the violation
- The violator's assets, liabilities, and net worth

- The harm to consumers and to the state from the amount of energy wasted because of the violation

Following these criteria will ensure that the Energy Commission imposes only appropriate penalties against violators based on specific circumstances. By providing this authority to the Energy Commission, the Legislature has helped ensure a level playing field for all regulated manufacturers.

Recommendations

Newly Constructed Buildings

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

- The Energy Commission should adopt triennial building standards updates that increase the energy efficiency of newly constructed buildings by 20–30 percent in every triennial update to achieve ZNE standards for newly constructed homes by 2020.

- The Energy Commission should adopt reach standards for newly constructed buildings that provide best practices energy efficiency levels for the marketplace to strive for and serve as a means to pull the industry rapidly to the level needed to achieve ZNE goals.

- The Energy Commission, CPUC, local governments, the state's utilities, and builders should collaborate to encourage the building industry to reach these advanced energy efficiency levels in a substantial segment of the market through industry-specific training and financial incentives.

- The Energy Commission and CPUC should coordinate future investor-owned utility "new construction-related" programs with the Energy Commission's efforts to meet the ZNE goals through triennial updates of mandatory and reach standards. By offering incentives for achieving reach standards, providing technology demonstration and development, and conducting pilot programs for demonstrating ZNE solutions, new technologies and building practices will be integrated into upcoming triennial updates of the Building Standards quicker and with more success.

- The Energy Commission, CPUC, builders, and other stakeholders should collaborate to accomplish workforce development programs to impart the skills necessary to change building practices to accomplish ZNE in newly constructed buildings.

Existing Buildings

- The Energy Commission and CPUC should coordinate future investor-owned utility energy efficiency portfolios with the programs and rules developed in the Energy Commission's AB 758 proceeding. The Energy Commission, in collaboration with stakeholders, should develop an asset rating system for nonresidential buildings that can be used to rate the energy efficiency of commercial properties and provide owners and potential buyers with information about the energy efficiency of the buildings they own or are considering for lease or purchase. This will help drive market demand for efficiency. The Energy Commission also should consider how the cost-effectiveness of options to achieve greater energy efficiency in those buildings can be addressed in conjunction with building asset ratings. The Energy Commission, utilities, the CPUC, and other stakeholders should collaborate to pilot the implementation of the rating system through education and financial incentives.

- The Energy Commission should review ARRA pilot programs to identify lessons learned and opportunities for improvements in rating systems, financial products, workforce development, consumer education, and program coordination.

- The CPUC, the Energy Commission, the State Treasurer, and other agencies should collaborate with local governments, the financial industry, and other stakeholders to promote the availability of financing products for the upgrade of all building sub-sectors.

- The Energy Commission should focus significant resources during the next Building Standards update on efficiency improvements in building additions and alterations.

Appliance Efficiency Standards

- The Energy Commission should adopt appliance standards that focus on reducing plug loads to enable California's ZNE goals to be achieved.

- The Energy Commission should continue to adopt standards for appliances that represent the most significant statewide energy savings potential.

- The Energy Commission and CPUC should collaborate on research to identify the most cost-effective opportunities for new appliance standards and to reevaluate existing standards to identify the most cost-effective opportunities for updates to achieve greater energy savings.

- The Energy Commission and CPUC, in collaboration with utilities and other stakeholders, should jointly develop a roadmap to meet the lighting energy savings mandated by AB 1109, including new appliance and building efficiency standards and market transformation programs to achieve higher levels of energy efficiency than required by standards.

- The Energy Commission should collaborate with industry to develop reach standards for appliances that set higher expectations in California for the quality and performance of key appliances.

- The Energy Commission and CPUC should collaborate to develop voluntary LED quality performance standards.

- The Energy Commission should engage in DOE proceedings that are developing federal test methods and appliance standards.

Compliance With Standards

- The Energy Commission should immediately begin developing regulations to implement the enforcement authorities provided by SB 454 to increase compliance with the Appliance Standards.

- The Energy Commission and CPUC should emphasize joint efforts to achieve improved compliance with the Building Energy Efficiency and Appliance Standards.

CHAPTER 5

California's Clean Energy Future

This chapter reports on the status of the California's Clean Energy Future (CCEF) joint agency collaborative effort.

Recognizing the growing interdependencies among the state's energy and environmental agencies, the California Air Resources Board (ARB), California Environmental Protection Agency (Cal/EPA), California Energy Commission, California Public Utilities Commission (CPUC), and California Independent System Operator (California ISO) developed a vision, implementation plan, and roadmap to achieve a clean energy future for California.[86] Launched in 2010, the planning effort focuses on 2020, with consideration of the goal to reduce greenhouse gas (GHG) emissions to 80 percent below 1990 levels by 2050.[87]

86 These documents are available at: www.cacleanenergyfuture.org.

87 Executive Order S-03-05, gov.ca.gov/news.php?id=1861.

The purpose of the CCEF effort is to:

- Compile existing policy goals to support inter-agency planning and management.
- Identify policy interdependencies, key milestones, and delivery risks to improve communications and cooperation.
- Use adaptive management practices "to identify policy overlaps, conflicts, unanticipated or unintended consequences, and to make necessary trade-offs and course corrections."[88]

The *California's Clean Energy Future: Overview (Overview)* outlines the agencies' vision for 2020. The agencies released the planning document in September 2010, but it has not yet been updated to reflect the goals of the Brown Administration. The agencies plan to refresh their planning efforts to reflect significant developments since its release, such as the passage of legislation to enact the 33 percent Renewables Portfolio Standard (RPS). Future planning efforts will also reflect findings coming from the Governor's July 2011 Conference on Local Renewable Energy Resources, the Energy Commission's report on *Renewable Power in California: Status and Issues*, and the Energy Commission's *IEPR* and *Renewable Strategic Plan* that will be developed in 2012.

The *Overview* focuses on four elements for achieving the state's 2020 electricity and natural gas goals, with the first being energy demand. As currently drafted, the agencies target reductions of 5,000 to 8,100 MW on peak by 2020 with advancements in efficiency and demand response. This is in addition to the 2,300 MW (on-peak) committed energy efficiency savings already included in the 2009 demand forecast. The current version also calls for installing 5,000 MW of distributed generation (DG) by 2020, although the agencies recognize Governor Brown calls for 12,000 MW of localized renewable generation by 2020.

The second element is energy supply. The *Overview* envisions achieving a 33 percent RPS while maintaining reliability needs and meeting environmental goals, such as phasing out once-though cooling in power plants. The agencies put forward a goal of developing at least one utility-scale carbon capture and storage facility in California by 2020.

The third element is transmission, distribution, and operations. The agencies envision a coordinated effort for planning and permitting to ensure that sufficient transmission and distribution-level infrastructure will be available to meet renewable goals and GHG reduction targets. Investments in advanced metering and smart grid will empower customers to use energy more efficiently. Through agency-supported pilot studies, the agencies are targeting 1,000 MW of additional storage capacity by 2020 to promote renewable integration.

The fourth element is additional supporting processes, including cap and trade, to provide opportunities for lower-cost GHG reductions and advancements in emerging technologies. The *Overview* also recognizes that alternative fuel vehicles, and electrification of the transportation sector in particular, will be a central component to energy security and reduced GHG emissions. The *Overview* calls for California to "develop the infrastructure and operational capabilities necessary to absorb a targeted 1,000,000 fully electric and plug-in hybrid-electric vehicles (PHEV) by 2020." In addition to efforts to reduce GHG emissions, California will need to plan for and adapt to actual changes in climate, such as temperature and precipitation changes and other impacts affecting energy supply and demand. Finally, the plan calls for engaging California's institutions and residents as partners in achieving these goals.

88 *California's Clean Energy Future, 2010, Overview*, page 2, see: www.cacleanenergyfuture.org/2821/282190a82f940.pdf.

CCEF Updates and Metrics

On July 6, 2011, the Energy Commission held an IEPR workshop jointly with the ARB, Cal/EPA, California ISO, and CPUC to discuss updates to the *California's Clean Energy Future* planning document. Updates provide an opportunity for incorporating new policy developments and identifying any areas that need course correction. The agencies anticipate the planning updates to include:

- 33 percent Renewables Portfolio Standard (RPS) legislation Senate Bill (SB) x1 2 (Simitian, Chapter 1, Statutes of 2011–12 First Extraordinary Session).
- The goals in the Governor's Clean Energy Jobs Plan, including:
  - 12,000 MW of localized energy by 2020.
  - 8,000 MW of large-scale renewable and associated transmission lines.
  - Develop 6,500 MW of combined heat and power (CHP) over the next 20 years.
- Metrics and data references to indicate progress toward achieving California's clean energy goals and indicate opportunities for the CCEF agencies to propose course corrections.

At the workshop, the IEPR Committee requested comments from stakeholders and the public on draft metrics and received 21 sets of comments. While the agencies could not reflect all the comments, the discussion below highlights the changes made to the metrics in response to stakeholder input. Below is a discussion of the metrics and how they were updated from the workshop.[89]

The agencies publicly posted the revised metrics on the CCEF website[90] on December 22, 2011. The agencies will be updating the metrics periodically to reflect new information.

GHG Emissions

The metric presented at the workshop shows historical and forecasted GHG emissions from 2000 to 2020. Emission forecasts provide a reference for assessing the effect of GHG reduction measures. In response to stakeholder comments, staff revised this metric to include information on GHG intensity, such as GHG emissions per capita and per gross state product, as suggested by Sempra. Other revisions include: adding a business-as-usual projection (per Environmental Defense Fund) and providing a graphic showing progress of GHG emission reductions for all sectors included in Assembly Bill 32 (Núñez, Chapter 488, Statutes of 2006) (per Natural Resources Defense Council [NRDC] and Southern California Edison [SCE]).

Energy Efficiency

The metric presented at the workshop shows California investor-owned utilities' (IOUs) and publicly owned utilities' energy savings from 2006 to 2010. The metric also shows the IOUs' annual energy savings, peak savings, and natural gas savings in comparison with the goals set by the CPUC. For the publicly owned utilities, the metric shows net annual energy savings

89 At the workshop, staff presented seven metrics and four "data references" that were intended to provide supporting information to the metrics. The CCEF agencies ultimately chose to abandon the distinction between data references and metrics, and refer instead to all as "metrics."

90 See: www.cacleanenergyfuture.org.

and net peak savings as reported by the utilities in comparison with efficiency goals set by the Energy Commission. Stakeholder comments on this metric included NRDC's suggestion to show indicators of net benefits of energy efficiency programs and energy efficiency codes and standards. Sempra suggested adding an indication of the energy intensity of existing and new buildings. Bevilacqua-Knight Inc. supports adding the savings expected from zero net energy strategies included in the *California Energy Efficiency Strategic Plan*.[91] Staff revised the metric to provide indicators of cost effectiveness for utility energy efficiency portfolios, the energy intensity standards for California homes constructed after 2001, progress toward zero net energy homes, and energy savings from building codes and standards.

Demand Response

Demand response generally refers to a reduction in customers' electricity consumption over a given time interval in response to a price signal, other financial incentives, or a reliability signal. The demand response metric provides a historical view of the estimated levels of demand response for the IOUs from 2009 through 2011, and a projection to 2020, which assumes broad deployment of advanced metering infrastructure. Staff plans to modify this metric as more information becomes available through the CPUC's Smart Grid Rulemaking.

Renewable Energy

The metric presented at the workshop shows the amount of renewable generation for California, excluding large hydro, from 1983–2009 and estimates of the amount of renewable generation needed to meet the 2013, 2016, and 2020 RPS targets. Data are also provided showing historical generation by fuel type. Since the RPS calls for a specified percentage of retail sales served with renewable energy, the metric shows a range for the amount of renewable energy needed to meet the RPS target based on factors that can affect retail sales, including energy efficiency, self-generation, CHP, and economic and population growth.

Comments from stakeholders included a suggestion by the Sierra Club to add information on project failure by procurement program (SB 32, California Solar Initiative, Renewable Auction Mechanism, feed-in tariff). Pacific Gas and Electric (PG&E) suggested adding indicators related to the CCEF goal that "a significant fraction of renewables will be dispatchable." SCE asked staff to clarify the impact of recontracting on progress toward RPS goals. In response to comments, staff added information on progress for each procurement mechanism and information to track dispatchable renewable resources. Also, staff revised the information on approved and pending RPS contracts to show only contracts for new resources. Finally, a graphic showing the development progress of new renewable projects under contract with the IOUs was revised to show estimated project feasibility based on the CPUC's analysis.[92]

Installed Capacity

This metric presented at the workshop shows on-line, nameplate capacity for all electricity generation resources in California by technology from 2001 to 2010.[93] If all contracts for new large-scale renewable energy facilities in California succeed, they will add more than 8,000 MW. In response to Independent Energy Producers' (IEP) suggestion to show growth rates,

91 California Energy Commission, July 6, 2011, workshop, comments available at: www.energy.ca.gov/2011_energypolicy/documents/2011-07-06_workshop/comments/.

92 www.cpuc.ca.gov/NR/rdonlyres/2A2D457A-CD21-46B3-A2D7-757A36CA20B3/0/Q3RPSReporttotheLegislatureFINAL.pdf.

93 Nameplate capacity is the maximum possible output from a generation facility under specific conditions as designated by the manufacturer.

staff revised the metric to show that contracts for large renewable resources in California are scheduled to come on-line at an average annual growth rate of 18 percent per year from 2010–2016.

The CCEF includes a goal to add 1,000 MW of energy storage by 2020. In response to comments calling for more information about storage, staff shows that about 2,800 MW of pumped hydropower were on-line in 2010 in California. Nine additional projects in California with a combined capacity of 4,900 MW have received licenses from the Federal Energy Regulatory Commission. The goal to add 1,000 MW of new storage would be met if about 20 percent of the licensed capacity completes environmental permitting and comes on-line by 2020. Several hundred megawatts of distributed electricity storage facilities may come on-line by 2020 as well, depending on various factors. For example, one factor is the outcome of the CPUC's Assembly Bill 2514 proceeding (OIR R.10-12-007), which will determine whether and how the CPUC should further encourage storage. Other examples include the eligibility of storage for incentives, the results of utility storage demonstration projects, the cost of storage, and rate structure developments that could make storage more attractive.

Staff revised the metric to show estimates of CHP potential and a goal of adding about 6,500 MW of CHP by 2032. To achieve the goal, staff estimates that CHP would need to grow about 4.7 percent per year from 2012–2022.

Sempra stated that even if the energy efficiency goals are met, the goals for new electricity facilities cannot be met because supply would exceed demand for electricity.[94] In response to this comment, staff expanded the discussion of the interaction of goals for high levels of energy efficiency and the Governor's goals for renewable energy and CHP.[95]

Transmission Expansion

Twelve transmission projects are underway in the California ISO's footprint that will provide sufficient capacity for the state to achieve

95 If existing renewable energy facilities 20 MW and smaller (about 3,000 MW of wholesale and customer-side DG) are counted toward the 12,000 MW goal for localized renewable energy resources, the Governor's goals would add about 17,300 MW of new renewable energy facilities by 2020 and 1,000 MW of new energy storage. Using CPUC input assumptions, the California ISO study on 33 percent RPS modeled "base load case" scenarios, adding about 17,500 MW to 20,800 MW of new renewable facilities by 2020. The scenarios assumed a large amount of energy efficiency (more than 18,000 GWh) was achieved by 2020 beyond the levels included in the 2009 energy demand forecast. (https://www.pge.com/regulation/LongTermProcure2010-OIR/Testimony/CAISO/2011/LongTermProcure2010-OIR_Test_CAISO_20110701_212930.pdf, Exhibit 3, Table 6.) The CHP goal extends to 2032; depending on the renewable resource mix, the amount of energy efficiency achieved, and replacement of gas-fired power plants in California that use OTC, achievement of the CHP goal may not begin in earnest until after 2020. "Post 2020, additional investments in renewable generation may be needed to replace generation expected to decline over the course of the next decade, such as generation from expiring coal contracts. Generation from a number of these contracts, which currently represents about 10 percent of total generation serving California, is expected to decline by 61 percent between 2010 and 2020 due to constraints imposed by the Emission Performance Standard. Remaining coal contracts are expected to expire between 2027 and 2030, which will require replacement with a mix of renewable and thermal generation with storage to satisfy electricity needs while still meeting greenhouse gas emission reduction goals." www.energy.ca.gov/2011publications/CEC-150-2011-002/CEC-150-2011-002-LCF-REV1.pdf.

94 www.energy.ca.gov/2011_energypolicy/documents/2011-07-06_workshop/comments/Sempra_Energy_Utilities_Companies_Comments_on_Joint_A_2011-07-20_TN-61463.pdf.

the 33 percent RPS.[96] The metric tracks the approval status, capacity, and expected on-line date of these projects.

Electric Vehicle (EV)

The metric presented at the workshop shows actual sales-to-date of EVs in California, a scenario of anticipated sales under the Zero Emission Vehicle program, and the potential sale of 1 million EVs consistent with the CCEF goal. For the Zero Emission Vehicle program, the metric reflects anticipated cumulative sales for both battery EVs and PHEVs. In response to stakeholder comments, staff plans to add information on efforts underway to advance deployment of infrastructure needed for the expanded use of plug in electric vehicles in California.

Energy Demand

The metric on energy demand shows statewide electricity and natural gas consumption from 1990 to 2008 by end-use sector and shows electricity consumption by county. Staff also provided data on noncoincident statewide net peak[97] demand for 1990 to 2009, reflecting a combination of peaks that often occur at different times in different planning areas. In addition, staff provided data on coincident statewide peak demand, which is the peak demand for California at the same point in time.

96 The number of transmission projects (12) differs from the 13 projects identified in Chapter 2 because this metric includes only projects within the California ISO balancing authority area.

97 Net peak is total electricity demand at peak on the customer side, plus utility transmission and distribution losses, minus peak demand met by self-generation.

Reserve Margin

A reserve margin is a measure of the amount of electricity imports and in-state generation capacity available over average peak demand conditions. The metric shows available reserve margins in comparison to California's 15 to 17 percent planning reserve target. The planning reserve margin target is intended to assure sufficient electricity supplies can meet real-time operating reserve requirements and ensure that outages occur no more frequently than one-day-in-ten-years.

System Average Rate

The system average rate is calculated by dividing the annual revenue requirement of the IOUs by their annual retail sales. This metric provides a normalized basis for assessing trends in utility costs over time, but it does not necessarily reflect actual rates or trends in those rates experienced by different customer classes.

Once-Through Cooling Phase Out

This metric provides information to track compliance with regulations to phase out once-through cooling (OTC) at 19 power plants in California. Of these, 16 plants totaling roughly 17,500 MW are in the California ISO Balancing Area Authority, and 3 are in the Los Angeles Department of Water and Power Balancing Area Authority. Compliance dates for the power plants range from 2010 to 2024. Staff added a description of the technologies and strategies that were part of the submitted OTC implementation plans in response to comments from NRDC.

Additional Metrics

Based on input from the workshop and written comments, the CCEF agencies added the following five metrics:

Expected Jobs

This metric provides a preliminary measure of job creation as result of CCEF renewable and efficiency initiatives. This approach takes into account comments from stakeholders that support tracking clean energy jobs in California and those cautioning that it is difficult to provide a precise measurement of the effect of energy policies on jobs.[98]

The analysis estimates gross job creation and does not attempt to estimate job losses or jobs avoided. This analysis is in terms of a "job-year," which is a full-time job that lasts one full calendar year and includes estimates of direct, indirect,[99] and induced[100] jobs.

Private Investment

This provides a rough indication of the level of private investment from new transmission and renewable projects despite the economic downturn. For transmission, the total anticipated investment is on the order of $7.5 billion. The cost estimates are collected from interconnection studies and public filings.

Estimated private investment in central station renewable facilities is based on instant cost, generally referred to as "overnight cost" or "initial capital expenditures," for building a new power plant. Instant cost includes component, land, development, and permitting costs. It also includes connection equipment costs such as for transmission and environmental control. The instant cost is the most significant driver for the levelized cost of electricity, but it does not include the costs associated with the time it takes to build a power plant, such as the effort in securing construction loans.

Staff estimated investment in renewable distributed generation by applying the cost basis used by the United States Treasury for the federal program offering cash grants in place of the 30 percent investment tax credit. The estimate is reduced by 15 percent in 2011 and 2012 to reflect the continued downward trends in installed costs for photovoltaic systems.

Energy From Coal

This tracks reliance on coal to meet California's electricity demand. California Municipal Utilities Association (CMUA), Center for Energy Efficiency and Renewable Technologies, American Lung Association, NRDC, and Sierra Club supported tracking the reduction of coal and natural gas to generate electricity used in California.[101] The metric shows that the electricity generated from coal and petroleum coke plants is expected to decline by 60 percent (17,800 GWh), and the associated greenhouse gas emissions are expected to drop from about 30 million tons of carbon dioxide

98 Sempra warned, "The variable baseline of what jobs would have been created if California's energy dollars had been spent on less expensive conventional energy plus general consumer spending from that savings on energy is highly debatable and speculative." www.energy.ca.gov/2011_energypolicy/documents/2011-07-06_workshop/comments/.

99 Indirect jobs from efficiency projects, for example, occur within the firms that supply construction materials.

100 The increased spending in the general economy from wages and profits of direct and indirect jobs and reduced energy expenses of households and businesses leads to increases in general employment levels and induced jobs.

101 Energy Commission, July 6, 2011, IEPR workshop, transcript, www.energy.ca.gov/2011_energypolicy/documents/2011-07-06_workshop/2011-07-06_transcript.pdf, pages 44, 63–64, 75, 108, 157.

equivalent (CO_2e) to 12 million tons between 2010 and 2020. The decline in coal contract deliveries is due to the constraints imposed by the Emission Performance Standard (Senate Bill 1368, Perata, Chapter 598, Statutes of 2006). The Emission Performance Standard prohibits California utilities from renegotiating or signing new contracts for baseload generation that exceeds 1,100 lbs of CO_2e emission per MWh. Several contracts with coal generation facilities that exceed the Emission Performance Standard will expire within the decade and cannot be renewed with another long-term contract. Some qualifying facility contracts for small power plants located in California that use coal and petroleum coke are slated to expire through the decade, but some owners are renegotiating contracts for an early termination or considering repowering to burn natural gas or biomass fuels.

Resource Flexibility

The agencies added a metric on resource flexibility for reliability in response to comments from the CMUA, IEP, and SCE supporting an indicator of the flexibility of system operations. The metric shows that the resource flexibility needs increase with declining availability of nongeneric[102] resource capacity due to the once-through cooling retirements and the increasing amounts of variable renewable energy resources coming on-line. This metric shows the forecast for additional nongeneric resource capacity requirements to manage the changes based on 2020 renewable portfolio scenarios.[103] The metric shows both upward and downward flexibility requirements. Upward flexibility is provided by resources that are capable of responding to centralized automatic generation controls to increase output as needed to address balancing and load-following requirements. Conversely, downward flexibility involves resources capable of decreasing output.

Distributed Generation

As presented at the July 6 workshop, the installed capacity metric included information about renewable DG 20 MW and smaller (customer self-generation and wholesale), but the CCEF agencies made DG a separate metric to reflect more clearly the Governor's 12,000 MW goal for localized renewable generation.

102 Generic capacity would be that required to support energy requirements, as well as spinning and non-spinning operating reserves. Nongeneric capacity includes resources used for ramping, regulation reserve, and load following, as well as for voltage or inertia support when specifically needed in excess of energy requirements.

103 Track I Direct Testimony of Mark Rothleder on behalf of the California Independent System Operator in CPUC Rulemaking proceeding R.10-05-006, https://www.pge.com/regulation/LongTermProcure2010-OIR/Testimony/CAISO/2011/LongTermProcure2010-OIR_Test_CAISO_20110701_212930.pdf. See also *Integration of Renewable Resources-Operational Requirements and Generation Fleet Capability at 20% RPS* at: www.caiso.com/2804/2804d036401f0.pdf and *Draft Technical Appendices for Renewable Integration Studies - Operational Requirements and Generation Fleet Capability* at: www.caiso.com/282d/282d85c9391b0.pdf.

CHAPTER 6

Power Plant Licensing Lessons Learned

The Energy Commission's power plant licensing process was established in 1974 to provide a comprehensive

"one-stop" process for permitting thermal power plants 50 MW or larger. Currently the process takes about 12 to 18 months and includes an independent environmental and engineering assessment called a staff assessment (SA). The Energy Commission staff publishes the SA, working collaboratively with federal, state, and local agencies as well as Tribal governments. The assessment is the functional equivalent of a draft environmental impact report and includes all proposed mitigation that would be required by other state and local permits except for the Energy Commission's jurisdiction. In addition to developing the SA, the 12- to 18-month review period includes public workshops, exchange of data through a formal discovery period, evidentiary hearings, publication of the proposed and final decisions, and a final approval hearing.

In December 2010, the Energy Commission's Siting Committee initiated an Order Instituting Informational (OII) Proceeding on "lessons learned" during the licensing of American Recovery and Reinvestment Act (ARRA) solar projects and natural gas-fired power plants reviewed during 2009 and 2010. The OII Proceeding commenced with a scoping workshop attended by various stakeholders, including project proponents, project intervenors, environmental organizations, local government officials, advocacy organizations, elected officials, and the public. Stakeholders provided oral and written comments relevant to the licensing process that were primarily focused on the following topics:

- Timing/coordination with federal permits for large solar projects located on federal lands managed by the U.S. Bureau of Land Management (BLM)

- Staff's information requirements to develop the SA, such as:

    - The length of the SA and the complexity of the mitigation

    - The confusing intervention process and the cumbersome document filing procedures

    - Restrictions on communication between Energy Commission staff and the applicant on substantive issues

    - Local agency and public participation in the planning and permitting of large solar projects

- Siting process consistency between different solar project proceedings, including cumulative analyses determinations and definitions that affect significant impact determinations and associated mitigation

- California Environmental Quality Act (CEQA)/National Environmental Protection Act joint review and alternatives analyses coordination

In the months following the initial scoping workshop, Energy Commission staff began and will continue a process to assess challenges to effective environmental review and facility licensing. Staff also will develop proposed changes to eliminate these challenges, which will help streamline the process without compromising transparency and effective participation. As described below, staff is reviewing three subareas: development/drafting of the SA, evidence and hearings, and the public process.

In addition, staff involved in the OII is closely following the separate but related Desert Renewable Energy Conservation Plan and Programmatic Environmental Impact Statement processes to ensure that the OII lessons learned effort builds on other renewable energy and land use assessments.

Development and Drafting the Staff Assessment

The Energy Commission faces a challenge with the increased length and complexity of SAs and conditions of certification. This was especially true during 2010, when the Energy Commission reviewed several large solar projects – often jointly with the BLM – as part of the ARRA initiative. To help address this issue, staff is evaluating whether the SA can be "pared down" or better formatted in future proceedings, while still meeting the requirements of CEQA and Energy Commission regulations. Staff is comparing Energy Commission environmental documents to those of other state and local jurisdictions to identify effective strategies in drafting environmental analyses. This comparative analysis will help determine if staff documents are within the scope and depth of other agencies' environmental documents, or if Energy Commission documents are outliers. The Energy Commission is under different mandates and requirements than local authorities, including its all-encompassing license, which folds other jurisdictional determinations into its own "one-stop shop process" and ultimately affects the content of SAs and Energy Commission decisions.

Besides reviewing other jurisdictions' environmental documents, another prominent strategy that has transpired as part of the OII Lessons Learned Proceeding is staff training, which is already improving the overall quality of the SA and oral testimony at evidentiary hearings. The training is increasing the consistency between technical sections in the SA and clarifying staff member roles in the project review and document drafting.

Another siting process challenge is the amount of data required upfront in a project application versus what information could be provided during the discovery phase. Ideally, the project proponent (applicant) should file a well-developed project application for certification (AFC) and provide near complete data sets at the time of the AFC's filing, so that staff can efficiently determine the project impacts and develop appropriate mitigation measures to offset these impacts to less-than-significant levels. For various reasons, however, applicants are often unable to submit key components of their proposed project at the time of the AFC filing and have trouble providing the necessary information early, not only for data adequacy purposes, but during the discovery phase of the 12-month process. Staff is reviewing the information and data gathering process to ensure that any changes will balance the need for information with the ability to draft the SA in a timely manner.

A major cause of past project-licensing delays is from the proponent making significant changes to the project during staff's review and preparation of the SA. While changes often result in reducing the project's environmental impacts, changes that occur well into the process require reassessment for each technical analysis, causing delay. It is not uncommon to see major project changes in such critical areas as cooling technology, water sources, gas line routes, transmission line routes, or facility layouts late in the process, all of which cause delays. Projects that come in as complete as possible following the best practices guidelines should be able to complete the licensing process faster and with fewer mitigation costs, thereby assuring project proponents, investors, regulators, and the public of a project's viability and certainty in terms of its integration into the larger electrical system.

In addition, efforts are underway to improve the docketing process and to implement an e-filing process, which should increase the ease of submitting documents and reduce transaction costs for applicants.

Evidence and Hearings

The Energy Commission is making a concerted effort to review the evidentiary hearing process and development of the hearing record. Staff is in the process of answering the following questions:

- Are evidentiary hearings always needed?
- When a hearing is required, can the proceeding be more focused?
- What evidence is admissible versus what can be relied on for a decision?
- Does the public find the process user-friendly?

The goal is to create a process that is flexible enough to allow uncontested projects a more informal process while maintaining a formal hearing structure for projects with significant environmental issues or controversy.

Public Process

The Energy Commission's siting regulations require that "all hearings, presentations, conferences, *meetings*, workshops and site visits shall be open to the public" [emphasis added] (Cal. Code Regs., tit. 20, § 1710) and that "all meetings shall be noticed…" no less than ten days in advance (Cal. Code Regs., tit. 20, § 1718). However, section 1710 (h) allows an applicant to "... formally exchange information or discuss *procedural issues* with Energy Commission staff without a publicly noticed workshop." This means that the Energy Commission has to notice any discussions related to substance (for example, mitigation) and hold a workshop.

The Energy Commission and other stakeholders question these particular meeting restrictions, since staff does not make the decisions, and these restrictions are typically greater than those on staff at other agencies (such as the CPUC). As expected, most intervenors have traditionally opposed relaxing the existing noticing requirements, as they take the position that staff is already working too closely with the applicant. Staff expects this issue to be a discussion topic at future workshops.

The relevant Energy Commission departments, including the Public Adviser's Office, are discussing potential regulations or changes in Energy Commission practice to balance transparency, public participation, and appropriate environmental analysis with efficiency and the desire to streamline the siting process. These topics and others will be discussed at future workshops.

Next Steps

The OII Proceeding will continue drafting various white papers and scheduling public workshops, leading to a process of publishing draft recommendations for the Committee and Energy Commission's consideration on the topics discussed above. The Energy Commission will also continue to evaluate policy issues associated with the power plant licensing process. Depending on the nature of resulting recommendations, there is the possibility that the Energy Commission may adopt an Order Instituting Rulemaking Proceeding for updating and augmenting the rules and regulations that guide and define the Energy Commission's Siting, Transmission, and Environmental Protection Division and its work.

CHAPTER 7

Natural Gas Assessment

This chapter summarizes the Energy Commission's staff 2011 Natural Gas Market Assessment: Outlook that was prepared in support of the *2011 IEPR*.[104] The Energy Commission, California Environmental Protection Agency, California Air Resources Board (ARB), California Public Utilities Commission (CPUC), and the California Independent System Operator (California ISO) recognize that natural gas plays a significant and ongoing role in California's energy supply, especially for electricity generation and for meeting the state's clean energy and environmental goals. Natural gas resources will continue to be essential in meeting California's energy demand, and procurement and resource adequacy programs will deliver resources needed for system and local reliability requirements and system operational needs.

104 California Energy Commission, *2011 Natural Gas Market Assessment: Outlook*, draft staff report, September 2011, www.energy.ca.gov/2011publications/CEC-200-2011-012/CEC-200-2011-012-SD.pdf. Final report expected March 2011.

As regulators and the market grapple with ways to integrate and back-up renewable technologies, natural gas will play a role in supporting renewable integration, and therefore the existing thermal power plant fleet will have to be modified to provide increased operational flexibility, ramping capability and regulation services, lower operating limits, and more frequent start/stop operation. This modification will allow the state to integrate substantial amounts of intermittent renewable generation while generating the least amount of greenhouse gas (GHG) emissions. State agencies and the California ISO will develop the appropriate procurement and market rules to provide the revenues for implementing these changes and for covering additional operating and maintenance costs.

Natural gas production from shale formations in the United States is transforming the natural gas market. In the last five years, natural gas supply from shale plays has increased from 2.5 billion to 22.5 billion cubic feet per day (bcf/d). Shale gas now comprises roughly 34 percent of the total gas production in the United States. Experts in the governmental sector and the environmental community have raised numerous environmental concerns with the technology used to produce shale gas. These concerns range from the chemicals involved in the hydraulic fracturing technique to crack the shale formations where the gas is stored to the amount of water used in the process. Energy Commission staff is monitoring and will continue to monitor the potential impacts of hydraulic fracturing and possible new environmental protection requirements. At the state level, the Energy Commission will work collaboratively with the California Air Resources Board, the Department of Conservation's Division of Oil, Gas, & Geothermal Resources, and the California Environmental Protection Agency to address the above issues.

Future Role of Natural Gas in California's Economy and Energy Supply

California may have to retire, repower, replace, and/or mitigate more than 13,000 MW of natural gas-fired generation to comply with the State Water Resources Control Board's once-through cooling (OTC) policy by 2020. A major challenge with this transition is that these older power plants are typically located in transmission-constrained areas that require local generation. Remotely located renewable resources can provide some of the needed replacement capacity but a portion of these will require new or upgraded transmission lines to deliver electricity to the load centers. The advantage is that the new (or repowered) facilities (for example, solar thermal power plants) are more efficient than those they replace, which will help reduce GHG emissions.[105]

Over the long term, new natural gas-fired power plants (including combined heat and power plants), combined with energy efficiency, demand response, and central station and distributed renewable generation, will replace baseload generation from retiring out-of-state, coal-fired, and possibly nuclear power plants. Complex economic, environmental, and public safety issues make the magnitude and timing of these power plant retirements uncertain. Therefore, natural gas-fired power plants could be a viable option to address such contingencies.

105 California Energy Commission, *California's Clean Energy Future, An Overview on Meeting California's Energy and Environmental Goals in the Electric Power Sector in 2020 and Beyond*, CEC-100-2010-002, page 5, www.cpuc.ca.gov/NR/rdonlyres/ED820DFE-46A3-40A8-8E84-F728BC94DCA5/0/CleanEnergyFuture092110.pdf.

The use of natural gas as a transportation fuel in compressed natural gas vehicles, and as a feedstock to make methanol additives for cleaner-burning gasoline, may give natural gas a "bridging" role in attaining California Clean Energy Future (CCEF) goals. However, the penetration of natural gas in the transportation sector is also uncertain. Due to its thermal efficiency, wide-scale delivery infrastructure, end-user familiarity and relatively clean combustion, natural gas will continue as a significant energy supply source for residential, commercial, and industrial end uses such as cooking, space heating, and to fuel boilers and process heaters. In the longer term, the role of natural gas in these sectors may diminish as energy efficiency and conservation, renewable substitutes such as solar thermal or biogas applications, and electrification become more cost-effective or play a larger role in meeting the state's climate change goals. While natural gas serves as a feedstock to manufacture plastics, fertilizers, antifreeze, pharmaceuticals, and fabrics, additional factors besides energy and environmental policies will determine future demand for these end uses.

Natural Gas Uncertainties

Whether by choice or necessity, natural gas will play a significant role in California's energy future. This conclusion prompts the following basic questions:

- To what extent will California's future energy supply include natural gas – what might be the demand for natural gas?
- What will be the cost to California of this demand for natural gas – at what price might it be available?
- What can be done to understand and to manage the risks associated with this role of natural gas in California's energy supply?

Most experts agree that it is not feasible to make single-point forecasts of future gas prices and other market activities, and that it may not be particularly useful. This is a necessary consequence of the gas market's complexity, large menu of competing options for actions, and deep uncertainties about future underlying conditions that are beyond anyone's control.

The Energy Commission has concluded that single-point forecasts of future natural gas prices are not only inaccurate, but not useful in focusing proper attention on the gas market's complexity and range of potential outcomes. Instead, the Energy Commission has, in this *IEPR*, focused on a range of plausible underlying conditions to develop conditional estimates of prices that could occur. This approach can decrease the chance of being unpleasantly surprised by a future not considered and the negative consequences resulting from actions taken under conditions that did not materialize.

Despite the inability of anyone to accurately predict future gas market outcomes, many people – including California's public policy makers – need to make decisions based on an expectation of what those outcomes might be. For example, the California policy to "implement all cost-effective energy efficiency" requires a cost-effectiveness analysis of potential energy efficiency measures and programs. So, having *some expectation* of future gas prices (and other effects of gas extraction, transportation, and use) is a requirement of this analysis and decision-making.

Staff is improving the analytical process on an ongoing basis and has committed to using its models to develop insights rather than simply quantitative results; comparing results of staff model runs to other relevant studies; evaluating alternative scenarios or futures using different sets of assumptions; explaining both what is known and unknown; and making every attempt to present the results fully and clearly.

Exploring California's Potential Gas Price Vulnerability

Natural gas is a heavily traded commodity in a market characterized by price volatility. Over the last decade, daily spot market prices for natural gas traded at Louisiana's benchmark Henry Hub have spiked several times. Figure 4 shows the prices over the past decade, in current year or nominal dollars. The winter periods of 2000–2001 and 2003–2004 saw prices spike to $10.00 per million British thermal units (MMBTU) and $18.00/MMBTU, respectively. Cold weather, which increased demand and put upward pressure on prices, triggered these increases. In September 2005, hurricanes Katrina and Rita caused natural gas production wells in the Gulf Coast to be shut in, which lowered available supply and caused prices to spike to over $15.00/MMBTU.

Since late 2008, daily spot market prices have trended lower (in the $4.50 to $5.00 range) and only once did prices increase above $6.00 (in 2009). The lower prices following the 2008 price spike can be explained by two factors. The late-2008 economic recession reduced overall demand for natural gas, especially in the industrial and power generation sectors. This lower natural gas demand had a negative effect on prices. Secondly, large amounts of shale gas are now becoming technically and economically recoverable at relatively low costs. This injection of shale gas into the market increased the supply of gas available to consumers and thus helped to lower the price. Over the last year (April 2010-April 2011), Henry Hub daily spot prices have averaged $4.15/MMBTU.

The Energy Commission's *2011 Natural Gas Market Assessment: Outlook* explored how a plausible range of assumptions about underlying United States natural gas supply and demand conditions might affect the long-term annual average market price of natural gas.[106] Staff's analysis is based on the well-recognized global gas market expertise of consultant Dr. Kenneth Medlock III.[107] Dr. Medlock used the MarketBuilder platform to construct the Rice World Gas Trade Model (RWGTM). For this analysis, Dr. Medlock and staff worked closely together to modify the RWGTM for use in the *2011 IEPR* proceeding. Staff's analysis contains the following four cases that focus on potential future national natural gas market prices:

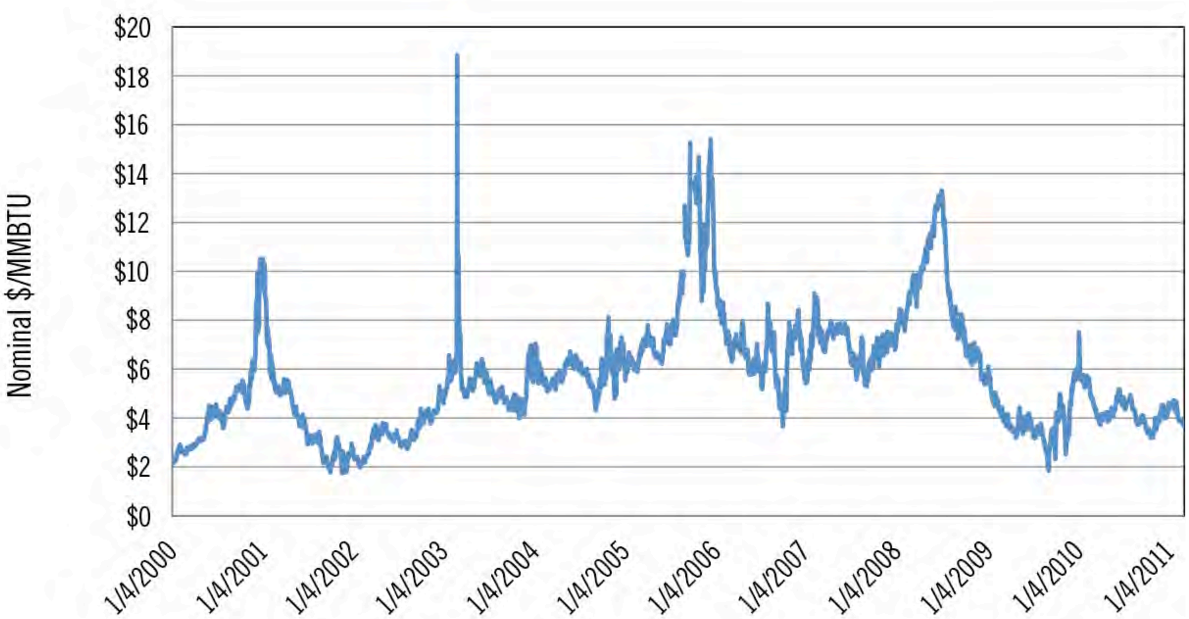
- **Reference Case:** assumes a "business as usual" starting point case
- **High Gas Price Case:** assumes higher gas demand and more constrained, higher cost gas resources
- **Low Gas Price Case:** assumes lower gas demand and less constrained, lower cost gas resources
- **Constrained Shale Gas Case:** assumes higher gas operations and maintenance costs to ensure that development is environmentally acceptable

In addition to the four cases outlined above, two additional cases were added to the analysis in response to stakeholder input suggesting that the estimated natural gas price range was too narrow as a result of keeping the cost of discovery constant across all cases. The two additional cases are:

106 Brathwaite, Leon D., Paul Deaver, Robert Kennedy, Ross Miller, Peter Puglia, William Wood, *2011 Natural Gas Market Assessment: Outlook*, California Energy Commission, Electricity Supply Analysis Division, Publication Number: CEC-200-2011-012-SD. Final report expected March 2011.

107 Dr. Medlock is the James A. Baker III and Susan G. Baker, Fellow in Energy and Resource Economics and Deputy Director of the Energy Forum of James A. Baker III Institute for Public Policy at Rice University in Houston, Texas.

Figure 4: Henry Hub Daily Spot Market Natural Gas Prices



Source: intelligencepress.com.

- **High Finding and Development Cost Case:** assumes that only a small amount of gas beyond what is currently proved will be added to the current stock due to high costs of finding and development, driving market prices higher. This case uses the High Gas Price Case as a starting point and changes only the discovery costs.

- **Low Finding and Development Cost Case:** assumes that a larger than average amount of gas beyond what is currently proved will be added to the current stock due to low costs of finding and development, driving market prices lower. This case uses the Low Gas Price Case as a starting point and changes only the discovery costs.

Key input assumptions for the Reference Case, highlighting those assumptions that change in at least one of the changed cases, include the following:

- Average annual growth rate in U.S. gross domestic product is 2.6 percent.

- The marginal cost curve for gas supplies reflects year 2011 vintage state of knowledge about the underlying gas resource base and production technologies.

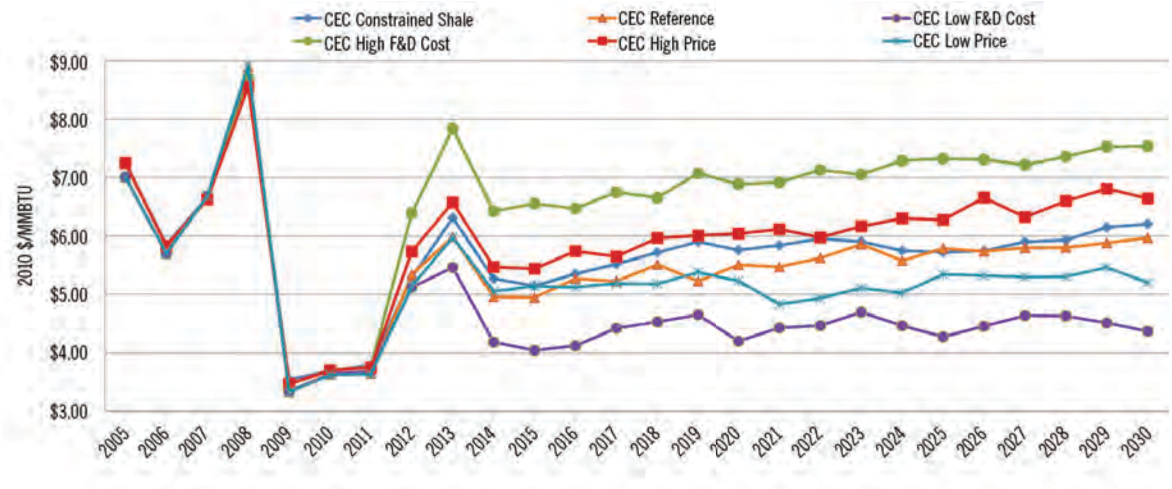
- Average annual rate of "learning" improvement in gas technology is 1 percent.[108]

- Shale gas development in New York is constrained per current moratorium.

- Iran, Iraq, and Venezuela do not enter the market until 2020.

108 "Learning improvement" means increased productivity achieved through practice, self-perfection, and minor innovations.

Figure 5: Henry Hub Annual Average Natural Gas Spot Market Prices



Source: Energy Commission Staff Final Analysis

- Liquefied natural gas exports are allowed to occur.[109]
- Pipeline capacity additions are allowed to occur.
- The future power generation mix for U.S. states follows current trends based on U.S. Energy Information Administration (EIA) state level historical data except renewable generation:
  - California meets its existing RPS target in 2020.
  - Other states with an RPS meet targets five years late.
  - Growth of renewable generation in states without RPS targets follows past trends.

109 The phrase "allowed to occur" here means that their occurrence is not prohibited and that the feature may appear in a result in any case, dependent on the model's evaluation of the feature's commercial viability given the endogenous outlook for gas prices (past, present, and future) in that case.

The High Gas Price Case made plausible assumptions that would move natural gas market prices higher than in the Reference Case. On the demand side, the economy is growing strongly (at 3.5 percent annually), while 50 GW of retiring coal-fired power plants and a slowing of renewable generation programs in other states by 15 years are leading to increased natural gas demand for electric generation. On the supply side, some jurisdictions in the United States are restricting the development of natural gas resources, particularly shale formations. Also, in places where production continues, safety concerns over hydraulic fracturing, water use and disposal, and other potential impacts are causing environmental compliance costs to rise for conventional and unconventional gas production activities.

Technology development dominates the Low Gas Price Case. In this case, the technology learning improvement is held constant at one percent annually. On the demand side, the economy is weak, with annual Gross Domestic Product growth capped at 2.1 percent. All states with RPS programs are complying on time, thereby reducing the need for gas-fired generation. On the supply side, environmental concerns are decreasing as technological developments allow deployment of adequate environmental mitigation without significant overall cost increases. Jurisdictions that restricted natural gas development are starting to ease regulations.

The Constrained Shale Gas Case is a sensitivity case to the Reference Case that assumes environmental concerns, particularly about the treatment and disposal of water used in the hydraulic fracturing process. These concerns prompt many jurisdictions to implement additional regulatory requirements on development of natural gas from shale formations. Regulatory compliance after 2013 adds another $0.40 per 1000 cubic feet (MCF) of natural gas to the cost of production of shale natural gas and $0.20/MCF on conventional production (2005 dollars). Figure 5 plots the annual average equilibrium price for spot gas purchases at Henry Hub for 2005 through 2030 for the six cases, in real 2010 dollars.[110]

Beginning in approximately 2012, the Reference Case price jumps from about $4.00 to $6.00/MMBTU, assuming the economy recovers and demand increases, thereby reestablishing a balance between supply and demand. A rush in investments occurs in the market, and the most economical shale plays are being developed first.[111] As these shale areas mature, they produce less gas, and the relatively more expensive shale plays start bringing supply to market. Beyond 2015, the price remains fairly flat, growing from about $5.00/MMBTU to just under the $6.00/MMBTU by 2030 (in 2010 dollars).

110 The WGTM performs all of its calculations in real 2005 dollars. Its input assumptions are expressed in 2005 dollars as well. Staff converts its output to real 2010 dollars using the Demand Analysis Office's *2011 IEPR* deflator series. This estimate of future inflation expectations may also be used to convert WGTM results to current year or nominal dollars.

111 A shale play is geographic area containing an organic-rich, fine-grained sedimentary rock displaying the following characteristics: Particles are the size of clay or silt, contains high percentage of silica (and sometimes carbonates), is thermally mature, has hydrocarbon-filled porosity and low permeability, is distributed over a large area, and economic production requires fracture stimulation.

The Henry Hub annual average spot price in the High Gas Price Case reaches $6.00/MMBTU by 2018 (12 years before the Reference Case hits that mark) and somewhat levels off below $6.80/MMBTU (in 2010 dollars) by 2030. The case projects that shale gas will be the marginal source of natural gas for the next 10 years and beyond. The higher environmental compliance costs assumed in the Constrained Shale Gas Case puts the resulting prices in between the Reference and High Gas Cost cases, as expected. The Low Gas Price Case Henry Hub prices hover around $5.00/MMBTU thru 2024, increasing to about $5.30/MMBTU afterward (in 2010 dollars).

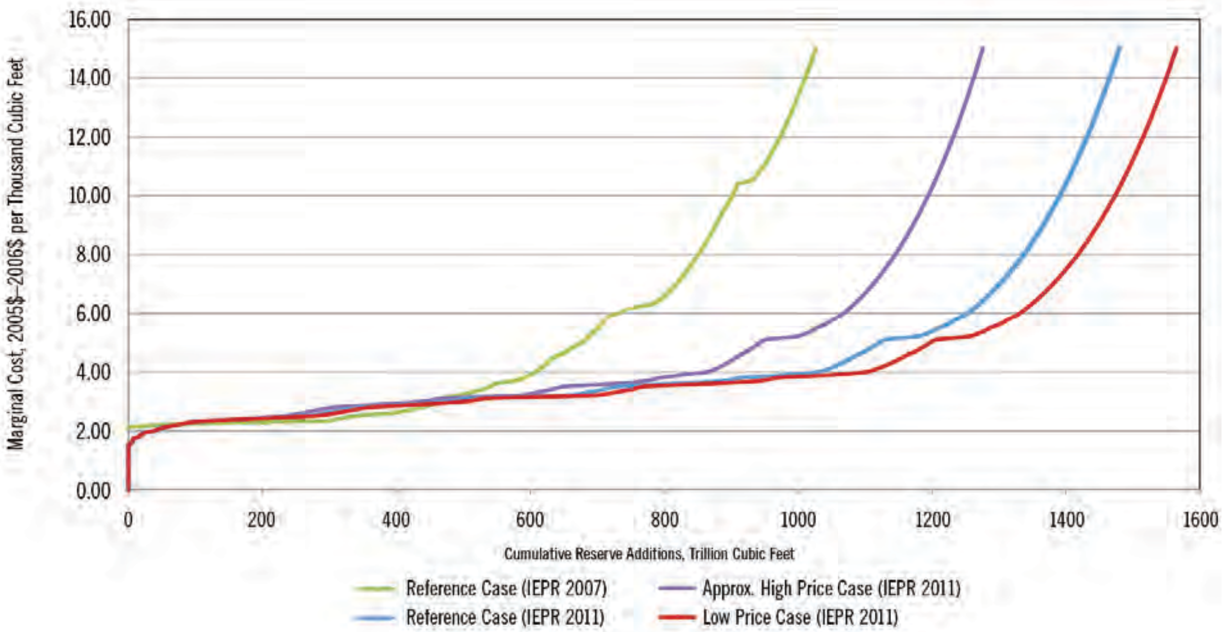
Participants in the *2011 IEPR* proceeding cautioned that staff's range of future annual average Henry Hub spot market prices might be too narrow – that future prices could possibly be higher or lower. El Paso offered a case that is lower than staff's Reference Case until 2017 but higher afterward. Staff and other parties generally agree that a significant contributing factor to staff's narrow price range is the underlying assumption that the gas resource marginal supply curves are all relatively flat and remain so, even across the cases that modify them significantly.

Figure 6 illustrates how staff's assumptions about marginal gas supply curves differ between *2007 IEPR* and *2011 IEPR* Reference Cases.

The curves represent the summation of all of the different supply curves for each natural gas play. The significant increase in gas supply reflects the industry's view about North American shale gas resources – that much more natural gas is available (and accessible at lower cost) than previously thought.

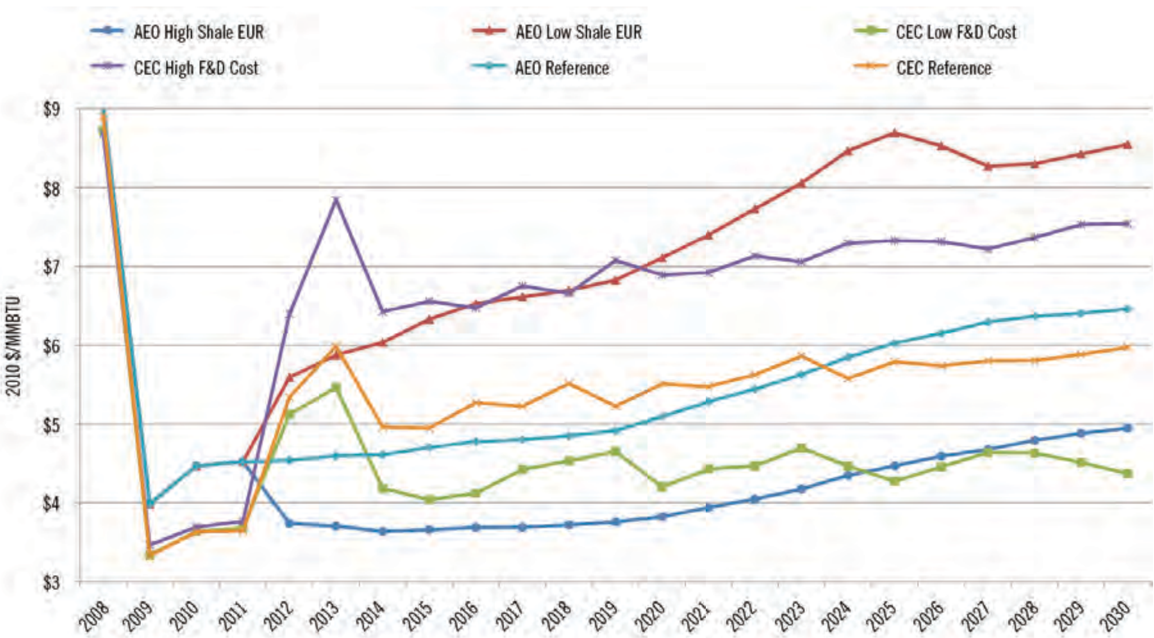
The 2007 and 2011 Reference Case curves make use of an "expected value" assessment of the quantities of recoverable gas resources (proved reserves plus a "P50"assessment of growth in known reserves and undiscovered resources). By industry convention, the P50 assessments mean there is a 50 percent probability that at least this much gas is recoverable from that play using current technology. To increase the spread of resulting gas prices, additional cases were run assuming higher probability but lower

Figure 6: Marginal Gas Supply Curves for National Cases



Source: California Energy Commission Staff Draft Analysis

Figure 7: EIA Annual Energy Outlook 2011, Annual Average Henry Hub Spot Market Prices



Sources: U.S. Energy Information Administration and California Energy Commission analysis.

resource amounts (a P90 case) and lower probability but higher resource amounts (a P10 case). Interpreting the result of these cases should be done carefully, however, as this method effectively introduces a one-sided bias into the resource assessment.[112]

Staff's marginal costs in the supply curves represent an overall finding and development cost environment that changes over time. Figure 6 also shows the cumulative effect on the Reference Case's marginal gas supply curve from changes in assumptions in the High and Low Gas Price cases (moving the supply curves to the left and right, respectively). The Constrained Shale Gas case uses the same marginal supply curve as the Reference Case. Its higher environmental mitigation costs are added to variable operating costs, which are not included in the supply curves. Assuming a wider range of environmental mitigation costs, or other variable operating costs, would be another way to increase the spread of resulting model prices.

Comparing the Energy Commission natural gas forecast to those produced elsewhere is a reasonable check for consistency. Ideally, the assumptions and methods used in the comparison cases are transparent enough for staff to assess their plausibility and compare them to the Energy Commission cases, and, as a result draw useful insights. The U.S. Energy Information Administration's *Annual Energy Outlook 2011 (AEO 2011)* is a source of such useful comparisons.

Figure 7 compares annual average Henry Hub spot market prices for staff's Reference Case and High and Low Finding and Development Cost cases to the *AEO 2011* Reference Case and two other cases specifically designed to examine the effect on natural gas prices from uncertainties in factors related to underlying estimates of the technically recoverable shale gas resource base.

112 Some plays will be discovered to have more resources than the expected value and some fewer. The preferred method of simulating this would be to run the model stochastically, randomly drawing from the probability distribution of each resource curve, cumulating the results within the model.

The high shale resource case assumes the estimated unproved technically recoverable resource base (excluding inferred resources) is 50 percent higher than in the *AEO 2011* Reference Case: 1,230 trillion cubic feet (Tcf) instead of 827 Tcf. The low shale resource case assumes that the resource base is 50 percent lower than in the *AEO 2011* Reference Case: 423 Tcf instead of 827 Tcf.

- The High Shale EUR Case assumes the estimated ultimate recovery (EUR) per shale gas well is 50 percent higher than in the *AEO 2011* Reference Case due to better development and production techniques. The case's assumed lower cost per unit of production result in the lowest gas prices.

- The Low Shale EUR Case assumes the EUR per shale gas well is 50 percent lower than in the *AEO 2011* Reference Case, from faster than expected rates of decline in gas production. The case's assumed higher cost per unit of production results in the highest gas prices.

The range of Henry Hub prices from the *AEO 2011* modified resource base cases track very closely with the range of prices in staff's cases. The explanations for all of these cases are fairly consistent. The more extreme *AEO 2011* cases illustrate the effects on prices from changing assumptions related to gas resource supply curves. Stakeholders suggested staff's analysis did not stress this enough. While Figure 7 may provide a more useful picture of the potential range for annual average prices (between $4.50 and $8.50 in 2010 dollars), the process for developing these cases affects how they are interpreted and compared to others. The two outlying *AEO 2011* cases, along with the two outlying Energy Commission cases, are less likely to be observed than the other cases, simply because they were constructed by moving away from the currently "expected" value for those assumptions.

Managing Potential Natural Gas Risks

Given the significant role of natural gas in California, any decision involving an expectation of future energy prices or avoided energy costs will require an assumption about future natural gas prices.[113] Model-based natural gas market assessments can provide conditional estimates of these prices, but their utility depends on a transparent description of assumptions, an understanding of their inherent limitations, a useful design for alternative cases, and a reflective interpretation and use of results.

Considering the possibility and consequences of both high and low price outcomes helps guard against one-sided biases. Generally, when using a conditional estimate, it is prudent to examine the potential consequences of using one estimate for a specific purpose should the future estimate turn out to be different. This is especially true when the experts have no defensible argument for one estimate being more likely to occur than another (although outcomes not deemed "most likely" will still occur). For example, decisions based on assumptions that future gas prices will be low could have significant negative consequences if gas prices turn out to be high, and vice versa. The consequences depend on the specific use of the conditional estimates, whether it is an individual using the estimate to purchase a more energy-efficient furnace, or a utility assessing the cost-effectiveness of a proposed energy efficiency program.

113 For example, natural gas price assumptions can be key to understanding how to measure cost-effective energy efficiency measures and programs (and what consumers may choose to do); what it costs to add renewable central station or distributed generation to the energy portfolio; the value of carbon allowances; the value of Renewable Energy Credits; the cost of using more natural gas in vehicle fuel compliance with the LCFS; the cost of electricity if gas is on the margin during hours when EVs are being recharged; and how consumers will perceive the cost of gas pipeline system retrofits/upgrades.

The users' own assessments of potential regret associated with their use of available alternative estimates may help them choose, based on their level of risk tolerance, the most prudent gas price estimate. What results is a decision that has a better chance of performing acceptably over a wide range of possible futures. Gas market analysts can advise these purpose-specific decision analyses but cannot conduct them, as they require knowledge and details about the specific uses of the estimates and how consequences play out.[114,115]

Potential Effects of the Gas Pipeline Explosion in San Bruno

On September 9, 2010, a 30-inch-diameter, high-pressure natural gas transmission pipeline exploded under a neighborhood street in San Bruno, California. The explosion of Line 132, owned by Pacific Gas and Electric (PG&E), killed 8 people and destroyed 37 homes. In addition to the tragic loss of lives and destruction of a neighborhood, the explosion resulted in a temporary evacuation, longer-term community disruption, and widespread concerns regarding public safety. The CPUC and the National Transportation

114 For example, the question of which energy efficiency measure is cost-effective is about the conditional estimates of the proposed measure's cost and performance as much as it is about the cost of the fuel their success may avoid.

115 For a discussion of how a regret analysis can help users of forecasts manage their risks of using forecasts that turn out to be inaccurate, see *Looking Before Leaping: Are Your Utility's Gas Price Forecasts Accurate? Ken Costello, National Regulatory Research Institute, May 2010. www.nrri.org/pubs/gas/NRRI_gas_price_forecasting_may10-08.pdf.*

Safety Board (NTSB) both launched investigations into the explosion. The Energy Commission responded by transferring Public Interest Energy Research Program funds to the CPUC, making them available for safety research, and by offering assistance to the CPUC, California ISO, and PG&E. As discussed below, the Energy Commission is closely monitoring for potential impacts to natural gas service or markets that might result from pressure reductions or lines being taken out of service for testing as the CPUC and the gas utilities work to assure the safety of California's pipeline system.

The CPUC initially ordered pressure reductions as an immediate response to the explosion. Then, in January 2011, the NTSB announced that the failed segment of Line 132 has been longitudinally seamed, contrary to PG&E's records showing the segment was seamless. As a result, the NTSB encouraged – and the CPUC ordered – PG&E to begin searching for "traceable, verifiable, and complete" records to confirm the features and maximum allowable operating pressure (MAOP) of its pipelines in "High Consequence Areas" (HCAs). The NTSB released the Pipeline Accident Report on August 10, 2011 (adopted August 30, 2011).[116] In the report, the NTSB identified a substandard and poorly welded pipe section that eventually led to the rupture of the pipeline. The CPUC also ordered PG&E to reduce operating pressures on lines of similar vintage and characteristics to Line 132 located in HCAs by 20 percent below the MAOP.

The CPUC expanded this order in June 2011 when it issued an order as part of Order Instituting Rulemaking 11-02-019 into new pipeline safety rules, directing PG&E, Southern California Gas, San Diego Gas & Electric, and Southwest Gas to pressure test or replace all pipelines, not just those in HCAs, for which the operators do not have "traceable, verifiable, and complete" records of MAOP. This testing is expected to take several years. Until this is complete, the utilities will adopt appropriate interim safety measures that include enhanced patrolling and leak surveys. As utilities pursue the extensive examination of pipeline system records, conduct hydrostatic testing, and replace pipelines, customers may experience reduced system pressures and capacity as well as occasional outages. The CPUC directed the noted utilities to prepare pipeline safety enhancement plans for their respective systems to describe how the pipeline testing would be carried out along with other safety enhancement measures.

PG&E then lowered operating pressures on several additional pipeline segments based on its June 30 "Class Location Study." The Class Location Study found that several of PG&E's pipelines were misclassified, leading to those pipeline segments operating at too high a pressure given the pipeline segment's proximity to homes and businesses.

On August 26, 2011, PG&E filed its Pipeline Safety Enhancement Plan as required by the CPUC. The first phase of the plan will run from 2011 to 2014 and calls for pipeline modernization, valve automation, records integration, and interim safety measures. The cost of the plan is estimated to be $2.2 billion over the next four years, and it remains to be seen how costs will be recovered pending CPUC approval of the plan. PG&E has already started work on the plan (pipeline testing and replacement), and costs incurred in 2011 will be borne by shareholders. All stakeholders will be given a chance to comment on PG&E's plan as part of the rulemaking procedure. A final decision on the plan from the CPUC is expected by June 2012.

SoCalGas and SDG&E also submitted its Pipeline Safety Enhancement Plan on August 26, 2011. The plan consists of several component phases with Phase 1A expected to extend from 2012 to 2015. Phase 1A calls for pipeline modernization, valve automation, enhanced incident detection and damage avoidance, and the development of a "blueprint" of a comprehensive asset management system. The direct cost of the plan for both SocalGas and SDG&E is estimated to be about $1.6 billion (Phase 1A). Phase 1B will continue work started in Phase 1A and will span from 2015 to 2021

116 www.ntsb.gov/investigations/summary/PAR1101.html.

costing about $1.4 billion. The plan is still waiting for CPUC final approval as part of the rulemaking process.

The Energy Commission has closely monitored the testing schedule and operating pressures for any impacts on service to natural gas consumers, including the natural gas-fired power plants that California relies on for about 41.9 percent of its electricity. Such impacts could occur based on three key factors. First, reducing operating pressure in a pipeline effectively reduces the amount of natural gas that can be delivered through that pipeline in a given period. Such reductions in a high demand period could lead to curtailments in gas service and are analyzed further below. To date, PG&E has reported no curtailments to customers as a result of reducing the MAOP to pressures consistent with the location class study.

Second, lower pressures reduce PG&E's daily operating flexibility. This flexibility is embodied in what PG&E calls "pipeline system inventory." The inventory describes a minimum and maximum amount of natural gas that PG&E needs in the pipeline system to meet demand. Normally the range between the minimum and maximum is 600 million cubic feet (MMcf). With the additional pressure reductions necessitated by the findings of the Class Location Study, PG&E's 600 MMcf per day permissible inventory swing became 200 MMcf per day. PG&E was, as of July 1, 2011, issuing high and low inventory Operational Flow Orders (OFOs) simultaneously, which required customers to match their deliveries of gas into the PG&E system more closely with their daily usage than they do under normal conditions or incur imbalance penalties. While generators have asked the California ISO if they will be reimbursed for penalties or costs incurred as a result of the tighter balancing tolerances, and some third-party balancing service agreements may have been modified, staff has detected no impact on citygate or border prices paid by Californians as a result of the tighter balancing. Staff also notes that as of December 1, 2011, PG&E had returned the inventory swing to 450 MMcf, eliminating the need for the simultaneous high and low OFOs.

Third, hydrostatic testing means taking pipeline segments out of service for several days. If the test causes the pipeline to fail, then it must be replaced, during which time the segment remains out of service. To date, PG&E has had two segments fail hydrostatic testing: one near Bakersfield on Line 300A and one near Woodside on Line 132. (PG&E also discovered via testing a leak on Line 132 in Palo Alto). In each of these cases, and as long as the testing continues to occur outside of high demand periods, PG&E should have the ability to reroute natural gas to continue service to nearby customers, including gas-fired electricity generating plants. The Energy Commission is working with its sister agencies to provide information and contingency planning support to address any potential outages during the testing.

By mid-summer, the aggregate effect of the lower operating pressure reduced capacity on the "backbone" portion of PG&E's transmission system by about 500 MMcf/d. With the possibility of such reductions lasting into December, staff analyzed whether the reductions could have an effect on service to customers and under what conditions those impacts might occur.[117] Staff first looked at whether the reduced flows would affect PG&E's ability to fill underground gas storage during summer months. Analysis showed that PG&E should be able to inject into storage most, if not all, of the gas it needs to protect service to core customers even with the reduced operating pressures and lower gas flows. As discussed at the September 27, 2011, IEPR Committee Workshop on natural gas, noncore customers would be prudent to use available backbone capacity to inject as much gas as possible into storage.

Staff then looked at whether the reduction in lower backbone transmission availability could affect the state's ability to meet monthly projected natural

117 This analysis is fully described in Chapter 4 of *2011 Natural Gas Market Assessment: Outlook*, Leon Brathwaite, 200-2011-012SD, see: www.energy.ca.gov/2011publications/CEC-200-2011-012/CEC-200-2011-012-SD.pdf.

Table 7: PG&E High Demand Day Gas Requirements and Sources

MMcf/d	Dec 8, 2009 Recorded	Dec 9, 2009 Recorded	Winter Peak Day Forecast from 2010 California Gas ReportA
Demand			
Core	2,840	2,926	2850
Industrial	677	692	420
Electric Generation	551	528	1000
Off-System	27	68	0
Total	**4,095**	**4,214**	**4,270**
Capacity & Supply			
Redwood	901	809	1,800B
Baja	1,031	1,051	733
Silverado (CA Production)	120	120	130
PG&E Storage	1,344	1,228	1,100
Independent Storage	699	1,006	507
Total	**4,095**	**4,214**	**4,270**

Source: Compilation of data reported on PG&E Pipe Ranger, California Gas Report, and staff analysis.

A The capacity and supply data shown are Energy Commission staff projections, updated for PG&E notices of expected capacity availability on its Pipe Ranger website. See: www.pge.com/pipeline/operations/pipeline_maintenance/foghorn.shtml.

B Ruby Pipeline feeds into the Redwood path. PG&E has noted in previous California Gas Reports that under very cold conditions it often sees a diminution in supply delivered to the California border. Achieving deliveries of 1,800 MMcf/d on a cold day seems reasonable given the new supply offered from Ruby.

gas demand. The analysis suggests that PG&E's natural gas capacity reserve margin could be pushed to very close to zero in December and January, even under normal weather conditions, without using higher-than-average storage withdrawals. As of December 1, 2011, PG&E has returned the inventory swing to 450 MMcf.

Finally, staff looked at what would happen under "Winter Peak Day" (WPD) conditions. The capability to serve WPD demand and a comparison to two cold days with demand close to WPD from December 2009 are shown in Table 7. The key conclusion is that curtailments should be avoided even if less gas is able to flow over backbone capacity with more reliance on gas from underground storage. This underscores the importance of filling not only PG&E storage, but independent storage to make up for the constrained backbone capacity on days colder-than-average conditions occur.

This analysis does not look at potential local area curtailments. PG&E completed hydrotesting on several key Bay Area lines and requested expedited review to restore pipeline pressures on those lines. The CPUC granted PG&E's request on December 15, 2011.

Since then, the CPUC has issued and held a workshop on a straw proposal to consider how safety regulations should be changed. The CPUC has also issued a comprehensive staff report detailing its findings and making numerous recommendations for changes at PG&E;[118] the Energy Commission continues to offer its assistance as needed.

PG&E has been steadily restoring pipeline capacity and available inventory as pipe segments have been cleared through testing. As of November 28, 2011, system capacity along the Redwood Path was at 2130 MMcf/d – which is 98 percent of maximum capacity. System capacity along the Baja Path was operating at 72 percent of maximum capacity (822 MMcf/d). PG&E reports that as of December 5, 2011, available system inventory stands at 4361 MMcf – an increase from 2000 MMcf due to pipeline testing. The increase in inventory is expected to eliminate the need to call high/low inventory Operational Flow Orders (OFOs.) However, it is expected that that calls for one-sided OFOs will continue on an ongoing basis as necessary. On November 4, 2011, PG&E reported that Northern California's storage inventory levels were higher than they have been in the last three years for this point in time of the storage season. Therefore, PG&E expects no limitations in regular withdrawal capabilities for the storage facilities located in PG&E's system this winter.

118 California Public Utilities Commission Consumer Protection & Safety Division, *Incident Investigation Report, September 9, 2010 PG&E Pipeline Rupture in San Bruno, California*, January 12, 2012, www.cpuc.ca.gov/NR/rdonlyres/28720A78-1DC7-4474-B51F-00C5E8BB5069/0/AgendaStaffReportreOIIPGE-SanBrunoExplosion.pdf.

CHAPTER 8

Electricity and Natural Gas Demand Forecast

Measuring California's energy use is the essence of a much broader analysis conducted every two years as part of the

Integrated Energy Policy Report (IEPR). This chapter summarizes the Energy Commission staff's *Preliminary California Energy Demand Forecast 2012–2022* (*CED 2011 Preliminary*).[119] The report's analysis characterizes the effects of economic and demographic trends, human behavior, emerging technologies, state and federal policies, and California's diverse climatic and geographic landscape on current and future energy needs. The chief product of this work is the California Energy Demand (CED) forecast of electricity and natural gas consumption over the next 10 years. Staff will release a revised forecast in mid-February and expects to adopt a final version in early spring 2012.

119 Kavalec, Chris, Tom Gorin, Mark Ciminelli, Nicholas Fugate, Asish Gautum, and Glen Sharp, *Preliminary California Energy Demand Forecast, 2012–2022*, 2011, CEC-200-2011-011SD, available at: www.energy.ca.gov/2011publications/CEC-200-2011-011/CEC-200-2011-011-SD.pdf.

Californians consumed around 272,300 gigawatt hours (GWh) of electricity in 2010. Natural gas consumption, excluding fuel for electricity generation, reached almost 12,700 million therms that same year. Forecasts of expected growth in energy demand underlie California's efforts to develop effective policy, conserve natural resources, protect the environment, and promote public health and safety while ensuring adequate energy supplies and economic growth. To that end, the Energy Commission's long-term forecast appears in many venues: as the foundation for policy recommendations to the Governor and Legislature through the *IEPR*; as a yardstick by which to measure the utilities' need for new generation resources in the California Public Utilities Commission's (CPUC) Long-Term Procurement Planning proceeding; as a reference point in the Air Resources Board's *AB 32 Scoping Plan*; as a benchmark for assessing the state's progress toward meeting its Renewables Portfolio Standard (RPS); as a baseline for estimating energy efficiency savings potential; and as input into the Energy Commission's infrastructure needs assessment.

The forecast is also used by the CPUC and the California ISO in annual resource adequacy proceedings addressing capacity needs, which depend on projected peak demand. Demand for electricity varies over time with daily, weekly, and seasonal cycles and fluctuates even within a given hour. It is generally lower at night and on weekends and holidays, with the maximum usually occurring on hot summer weekday afternoons. Expected peak demand is a critical factor in electricity and transmission planning, since it determines generation and transmission capacity requirements.

Such an analysis cannot be conducted in isolation. The Energy Commission augments its own expertise with input from other government agencies, utilities, advocacy groups, and consultants. Regular meetings of the Demand Analysis Working Group, formed by the Energy Commission in 2008, provide stakeholders the opportunity to share information, data, ideas, and methods, and to suggest changes in the existing process.

In the most recent forecast and accompanying report, *CED 2011 Preliminary*, staff incorporated stakeholder feedback on a number of important issues, including the uncertainty surrounding near-term economic conditions (which are difficult to predict) and the relative impacts of various efficiency efforts (which are difficult to measure). Staff devoted public workshops to consider all stakeholder opinions on these two issues, as they carry sufficient consequence.

Demand Forecast Results

The *CED 2011 Preliminary* forecast includes three demand scenarios: high, mid, and low. The high demand case incorporates relatively high economic/demographic growth, low electricity and natural gas rates, and low efficiency program and self-generation impacts. The low demand case includes lower economic/demographic growth, higher assumed rates, and higher efficiency program and self-generation impacts. The mid-case uses input assumptions at levels between the high and low cases.

Table 8 compares projected electricity consumption and noncoincident[120] peak demand under the three forecast scenarios. Historical and forecasted values from the previous IEPR forecast (2009) provide points of reference.

Figure 8 compares projected consumption under the three scenarios alongside *California Energy Demand 2010–2020: Adopted Forecast (CED 2009)*. Consumption grows at a faster average annual rate from 2010 to 2020 in the mid- and high-energy

120 A region's coincident peak is the actual peak for the region, while the noncoincident peak is the sum of actual peaks for subregions, which may occur at different times.

Table 8: Statewide Electricity Demand Forecast Comparison

	Consumption (GWh)			
	CED 2009 (December 2009)	CED 2011 Preliminary High (August 2011)	CED 2011 Preliminary Mid (August 2011)	CED 2011 Preliminary Low (August 2011)
1990	228,473	227,586	227,586	227,586
2000	264,230	260,408	260,408	260,408
2010	280,843	272,342	272,342	272,342
2015	299,471	296,821	292,286	286,100
2020	316,280	321,268	310,462	305,932
2022	—	332,514	318,396	313,493
Average Annual Growth Rates				
1990-2000	1.46%	1.36%	1.36%	1.36%
2000-2010	0.61%	0.45%	0.45%	0.45%
2010-2015	1.29%	1.74%	1.42%	0.99%
2010-2020	1.20%	1.67%	1.32%	1.17%
2010-2022	—	1.68%	1.31%	1.18%
	Noncoincident Peak (MW)			
	CED 2009 (December 2009)	CED 2011 Preliminary High (August 2011)	CED 2011 Preliminary Mid (August 2011)	CED 2011 Preliminary Low (August 2011)
1990	47,521	47,520	47,520	47,520
2000	53,703	53,703	53,703	53,703
2010*	62,459	60,455	60,455	60,455
2015	66,868	66,569	65,701	64,246
2020	71,152	72,006	69,818	68,498
2022	—	74,220	71,280	69,738
Average Annual Growth Rates				
1990-2000	1.23%	1.23%	1.23%	1.23%
2000-2010	1.52%	1.19%	1.19%	1.19%
2010-2015	1.37%	1.95%	1.68%	1.22%
2010-2020	1.31%	1.76%	1.45%	1.26%
2010-2022	—	1.72%	1.38%	1.20%

Historical values are shaded blue.

Source: California Energy Commission

*The 2011 forecasts use 2010 weather-normalized peak rather than actual to estimate growth.

Figure 8: Statewide Annual Electricity Consumption

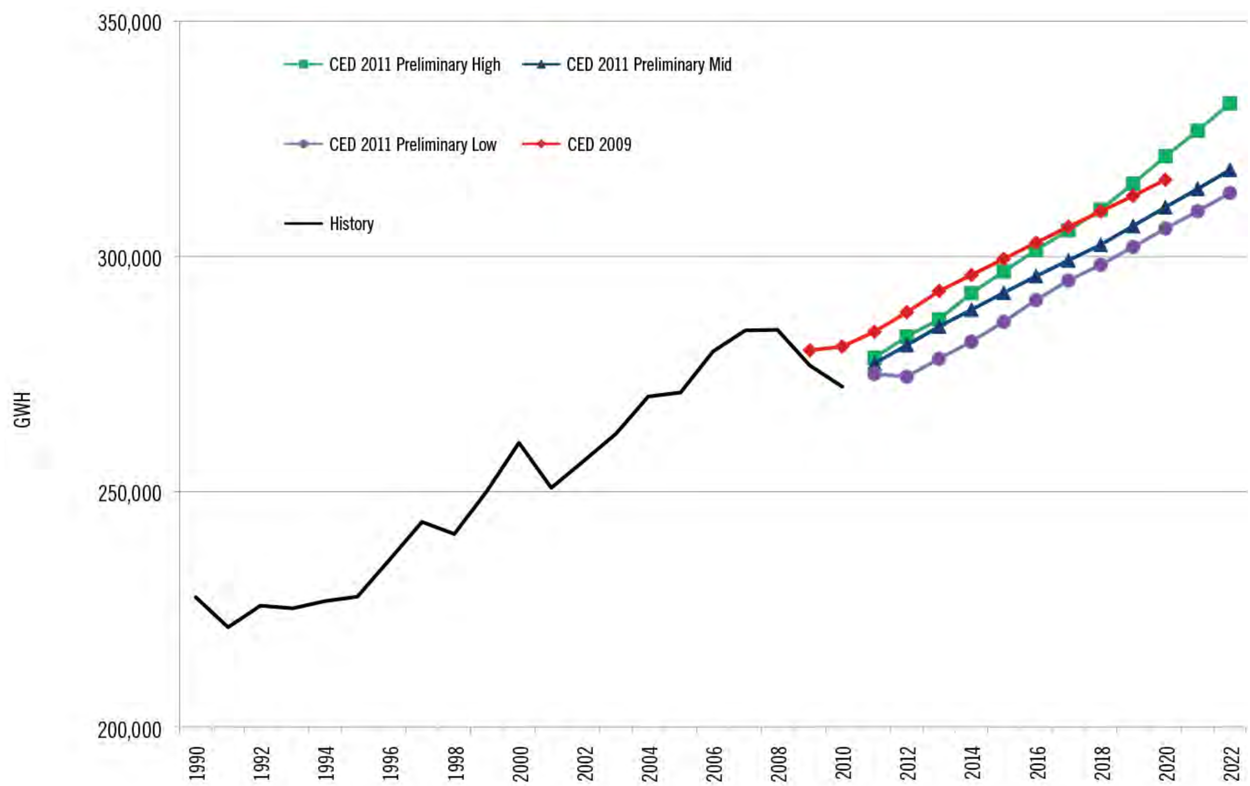
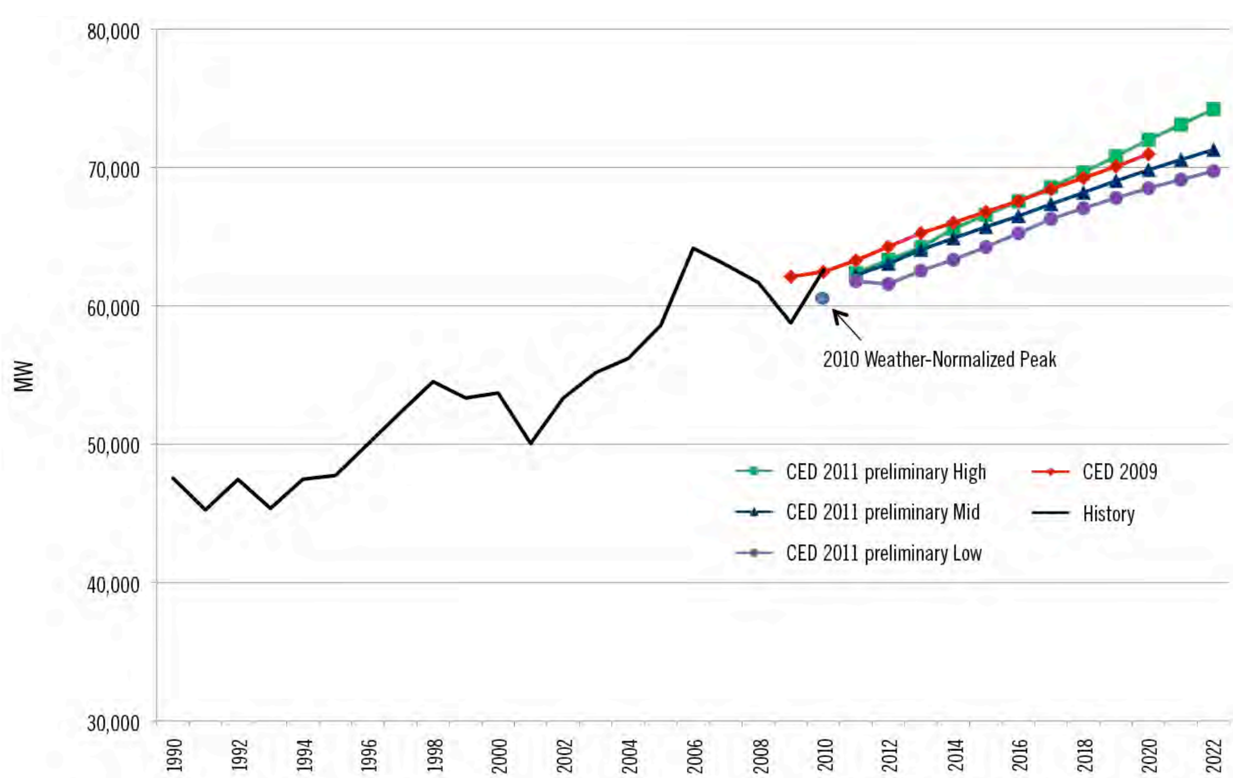


Figure 9: Statewide Annual Noncoincident Peak Demand



Source: California Energy Commission

demand cases (1.32 and 1.67 percent, respectively) compared to *CED 2009* (1.20 percent). In the low demand scenario, annual growth is higher than in *CED 2009* after 2012. Higher projected growth rates in the 2011 forecast reflect a deeper recession in 2009 than assumed as well as a very mild weather year in 2010 and therefore faster growth in reverting to expected long-term weather and economic trends. Forecast consumption reaches *CED 2009* projected levels by 2018 in the high-demand scenario and surpasses the 2020 *CED 2009* projection in the mid-case by 2022. By the end of the forecast period, California's electricity consumption is expected to reach between 313,000 and 333,000 GWh.

Consumption is the main driver for peak demand projections, so the depiction in Figure 9 of the preliminary peak forecast scenarios looks much like Figure 8. Growth in peak demand from 2010–2020, relative to a weather-normalized 2010, is faster in the high and mid cases (1.76 percent and 1.45 percent, respectively) than in *CED 2009* (1.31 percent). Statewide peak demand is projected to reach the *CED 2009* level by 2017 in the high-demand scenario and to surpass the 2020 *CED 2009* projection in the mid-case by 2022. Average annual growth rates from 2010–2020 relative to actual peak in 2010 are projected to be 1.41 percent, 1.10 percent, and 0.91 percent, respectively, in the high-, mid-, and low-demand scenarios. By 2022, peak demand is expected to reach between 69,700 and 74,200 MW.

The *CED 2011 Preliminary* natural gas forecast parallels the electricity consumption forecast. Historical data is incorporated up through 2010, and the same models are used to produce three scenarios (high-, mid-, and low-demand) under the same economic/demographic assumptions developed for the electricity forecast. Historical consumption in 2010 is higher than the value projected by *CED 2009*. Projected growth rates are higher, too, such that all three demand scenarios project greater consumption in 2020 than previously expected. By 2022, consumption is expected to reach between 13,773 million and 14,175 million therms. Table 9 compares projected natural gas consumption under the three scenarios.

Modifications to Forecast Method

Additional consumption data became available after publication of the *2009 Integrated Energy Policy Report*. The *CED 2011 Preliminary* adjusted the timeline so that 2010 is the historical base year and the forecast horizon extends to 2022, compared to 2020 in *CED 2009*. Beyond this routine adjustment, staff made several significant modifications to the *2011 IEPR* demand forecast method.

For one, staff developed the major economic sectors – residential, commercial, and industrial – by combining the Energy Commission's traditional end-use models and a new econometric approach (created by staff in 2011). Additionally, staff developed peak projections using its Hourly Electricity Load Model and a new econometric model. Staff made adjustments to results from existing models based on the econometric estimations. For example, price elasticities estimated in the residential and industrial econometric models replaced previous end-use elasticities. Recommendations from a recent evaluation of the demand model method motivated staff to develop a robust, multi-resolution modeling approach to demand forecasting.

Staff forecasted residential adoption of photovoltaic (PV) systems and solar water heaters using a predictive model rather than a trend analysis (as in previous forecasts). The new method is based on estimated payback periods and cost-effectiveness determined by upfront costs, energy rates, and various incentive levels. Staff developed scenarios using varied assumptions about electricity rates and new home construction.

Finally, *CED 2011 Preliminary* incorporates potential global climate change impacts more comprehensively. The Energy Commission demand forecasting process typically models these impacts by adjusting

Table 9: Statewide End-User Natural Gas Forecast Comparison

Historical values are shaded blue.

Consumption (MM Therms)				
	CED 2009 (December 2009)	CED 2011 Preliminary High (August 2011)	CED 2011 Preliminary Mid (August 2011)	CED 2011 Preliminary Low (August 2011)
1990	12,893	12,893	12,893	12,893
2000	13,913	13,914	13,914	13,914
2010	12,162	12,665	12,665	12,665
2015	12,751	13,372	13,338	12,891
2020	12,997	13,832	13,789	13,552
2022	—	14,175	13,992	13,773
Average Annual Growth Rates				
1990-2000	0.76%	0.76%	0.76%	0.76%
2000-2010	-1.34%	-0.94%	-0.94%	-0.94%
2010-2015	0.95%	1.09%	1.04%	0.36%
2010-2020	0.67%	0.89%	0.85%	0.68%
2010-2022	—	0.94%	0.83%	0.70%

Source: California Energy Commission

upward the number of cooling and heating degree days in the forecast period, based on the historical ratio of degree days in the last 12 years to that of the last 30 years. The result of this adjustment is an increase in the projected amount of cooling and a decrease in heating relative to the historical period. This correction attempts to account for the likelihood of a general warming trend.

However, temperatures assumed in the peak forecast (an average of daily temperatures over a 30-year period) are not affected by the adjustment, so the forecast may not fully capture the impact on peak demand of possibly more frequent heat storm weather events, in the form of higher maximum temperatures in a given year. Therefore, using climate change scenarios for maximum temperatures developed by the Scripps Institute, staff applied these to the peak econometric model (which includes a coefficient for maximum temperature) and used the projected climate change impacts to adjust the existing end-use peak model results.

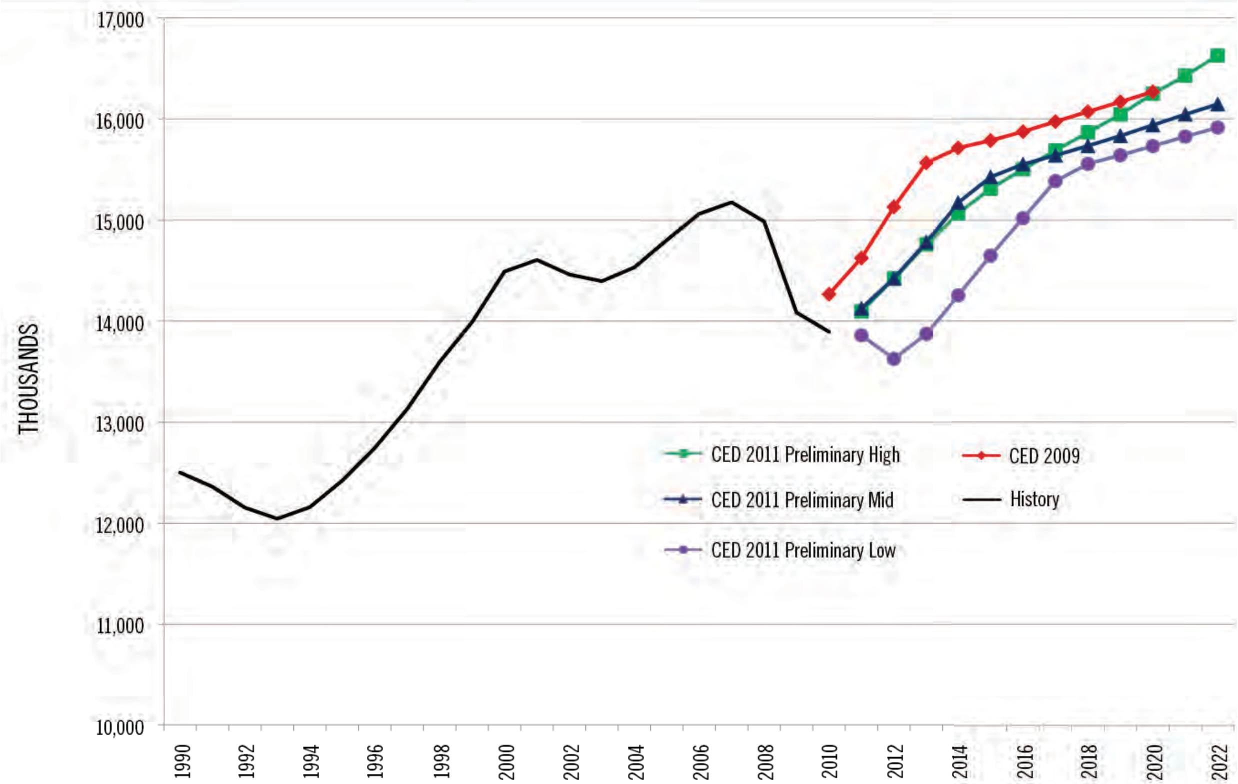
The *CED 2011 Preliminary* describes these changes, along with forecast results and modeling methodologies, in much greater detail.[121]

Energy and the Economy

Economic projections are one of the key inputs to the demand forecast. For the *CED 2011 Preliminary* forecast, staff examined multiple economic and demographic scenarios. The intent was to quantify the impacts from a reasonable range of assumptions

121 Kavalec, Chris, Tom Gorin, Mark Ciminelli, Nicholas Fugate, Asish Gautum, and Glen Sharp, 2011, op. cit.

Figure 10: Statewide Employment Projections



Source: California Energy Commission

on electricity demand. Staff selected three sets of economic projections from Moody's Economy.com and IHS Global Insight. Staff chose scenarios that captured the highest and lowest projected levels of economic growth.

Figure 10 shows historical and projected levels for nonagricultural employment, a key economic driver of the commercial and industrial forecasts. A comparison of the projections illustrates consistent expectations about the future of California's economy. Each case assumes California will experience a period of rapid growth as the economy begins to recover from the 2008 crisis, followed by a return to modest long-term growth at rates similar to those seen in recent history.

The most significant discrepancy between these economic projections lies in the duration of the recession and in the timing and rate of the recovery. Energy consumption trends with employment and other economic indicators, so these transitions are important factors, particularly in characterizing energy use over the next few years. Despite a great deal of economic uncertainty surrounding the current recession (for example, when and how California will recover), the alternative scenarios show a relatively narrow band by the end of the forecast period. This narrowing tends to reduce the differences among the forecast energy scenarios later in the forecast period, all else being equal.

Traditional indicators such as employment, personal income, and population are important, but are not the only economic factors that could affect the forecast. On January 19, 2011, the Energy Commission hosted a public workshop where several expert economists, researchers, policy makers, and business owners discussed ways in which the future of California's economy may deviate from its historical pattern. Staff considered some key points made during the discussion:

- The substantial drop in housing prices may affect migration patterns, specifically increasing in-migration. It is likely that California will not experience the same pattern of depressed population growth as seen in previous recessions.

- Changes to average home size and location may have a significant effect on demographic drivers.

- Over the coming decade, climate change may introduce constraints on water supplies.

- Alternative indicators, such as personal debt, may become more valuable at providing insight into energy consumption patterns.

As California's economy recovers and changes, it is critically important that the Energy Commission adapts its demand forecasting models appropriately. Staff will consider incorporating such factors in future IEPR forecasts while continuing to engage with a variety of economic and demographic experts.

Self-Generation Impacts

The *CED 2011 Preliminary* forecast includes the impacts of on-site distributed generation (DG) used in large-scale facilities and of the major incentive programs designed to promote self-generation. The forecast uses a trend analysis to project self-generation, except in the case of residential PVs and solar water heaters, where it uses a new predictive model. The incentive programs include:

- Emerging Renewables Program (ERP): This program is managed by the Energy Commission.

- California Solar Initiative (CSI): This program is managed by the CPUC.

- Self-Generation Incentive Program (SGIP): This program is managed by the CPUC.

- New Solar Homes Partnership (NSHP): This program is managed by the Energy Commission.

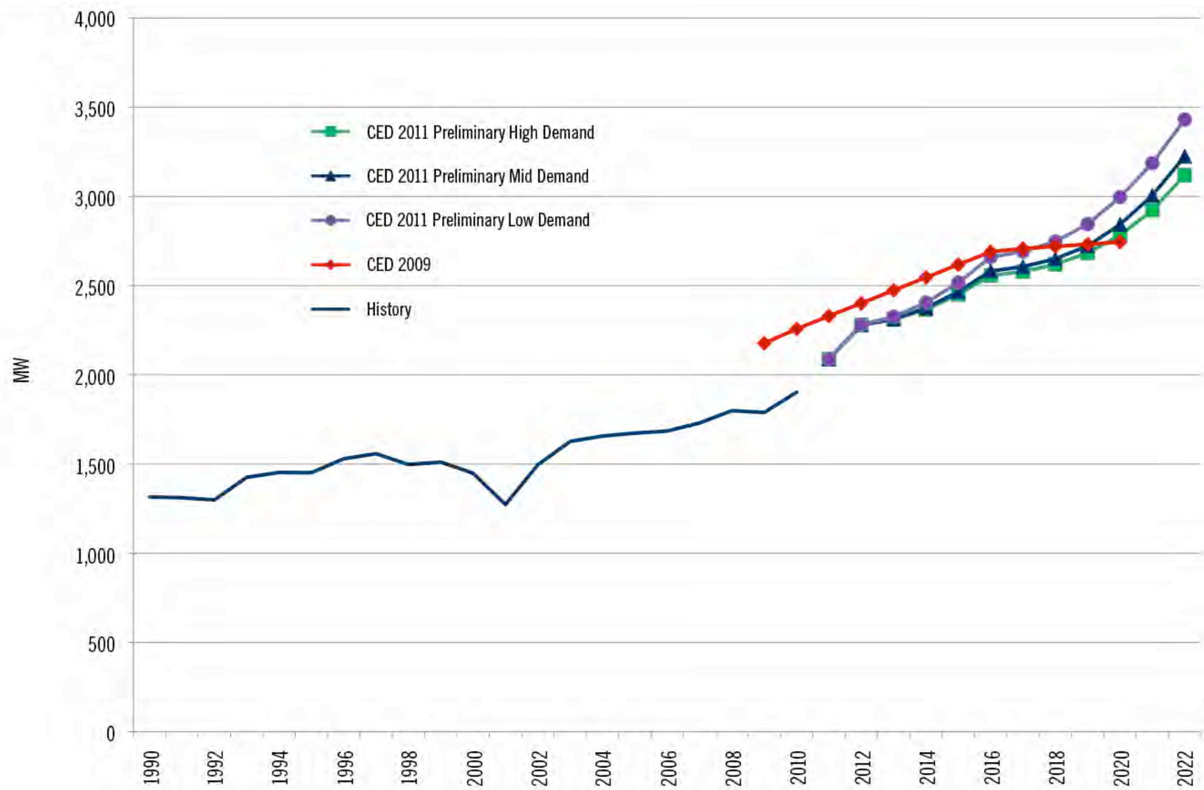
- Utility Incentives: Administered by publicly owned utilities such as Sacramento Municipal Utility District (SMUD), LADWP, Imperial Irrigation District, Burbank Water and Power, City of Glendale, and City of Pasadena.

The general strategy of the ERP, CSI, SGIP, and NSHP programs is to encourage demand for self-generation technologies, such as PV systems, with financial incentives until the market increases and achieves economies of scale and decreases the capital costs. The extent to which consumers see real price declines will depend on the interplay of supplier expectations, the future level of incentives, and demand as manifested by the number of states or countries offering subsidies.

Figure 11 shows historical and expected peak impacts of self-generation, which are projected to reduce peak load by more than 3,000 MW by 2022. Historical impacts were revised downward because some self-generation data was found to be misclassified, so *CED 2009* projections begin well above estimates of historical impacts. Higher projections for PV peak impacts in both the residential and commercial sectors drive total self-generation peak above *CED 2009* levels by 2020 in all three scenarios. The temporary flattening of the curves after 2016 corresponds to expiration of the CSI program.

Table 10 shows historical and projected statewide electricity consumption from self-generation, and is broken out into PV and non-PV applications. For traditional combined heat and power (CHP) technologies, self-generation is assumed constant, so that

Figure 11: Statewide Peak Impacts of Self-Generation



Source: California Energy Commission

Table 10: Electricity Consumption From Self-Generation (GWh)

	1990	2000	2010	2015	2020	2022
Non-Photovoltaic Self-Generation	8,242	9,179	9,651	10,366	10,852	11,065
Photovoltaic, Low Demand	3	10	1,110	3,063	4,691	6,060
Photovoltaic, Mid Demand	3	10	1,110	2,874	4,118	5,290
Photovoltaic, High Demand	3	10	1,110	2,817	3,894	4,896
Total Self-Generation, Low Demand	8,245	9,189	10,761	13,429	15,543	17,125
Total Self-Generation, Mid Demand	8,245	9,189	10,761	13,488	14,945	16,329
Total Self-Generation, High Demand	8,245	9,189	10,761	13,429	14,716	15,924

Source: California Energy Commission

retired CHP plants are replaced with new ones with no net change in generation in the current forecast. Given the Governor's policy goals for CHP and DG and the recent qualifying facility settlement to CHP, in future *IEPRs* there will be a more comprehensive assessment of the status of CHP in California. As part of this effort, the staff will be developing scenarios for this technology for the revised forecast. Growth in non-PV self-generation comes mainly from recent increases in the application of fuel cells and other low emissions technology, projected forward.

Energy Efficiency Impacts

California's energy policy identifies energy efficiency as the "resource of first choice" for meeting California's future energy needs. As such, efficiency codes and standards, programs, and other policies play a central role in California's energy procurement and transmission plans and are a strategic element in the state's greenhouse gas emission reduction goals. Unlike other resources that are deployed to meet demand, energy efficiency reduces consumption and is therefore considered in the demand forecast, either embedded directly within the forecasting models or as an incremental effect subtracted from the model output. In both cases, staff is ensuring that the demand forecast reflects reasonable levels of efficiency from a comprehensive set of efforts expected to occur.

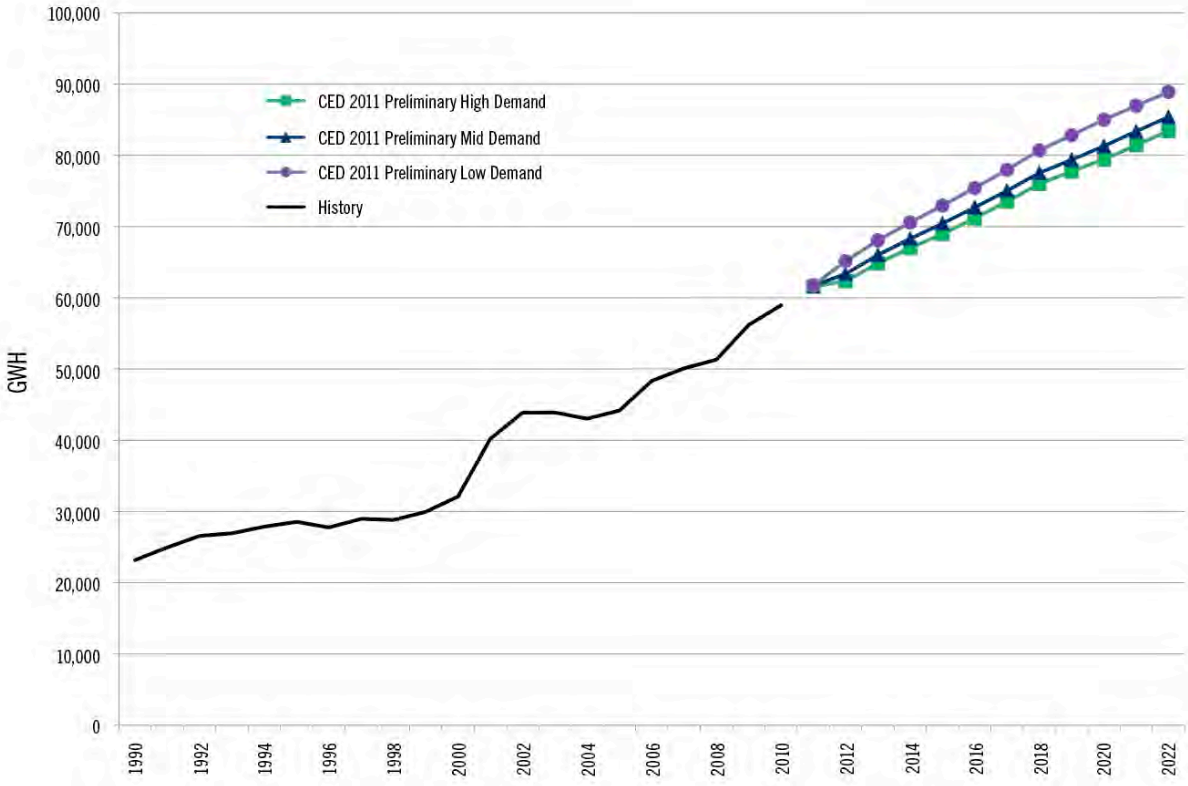
The *CED 2011 Preliminary* forecast continues the long-standing practice of distinguishing between two types of "reasonably-expected-to-occur" savings – committed and uncommitted. Committed efforts to reduce demand include authorized utility programs, finalized building and appliance standards, and other policy initiatives that have implementation plans, firm funding, and a design that can be technically assessed to determine probable future impacts. Committed savings also include price and market effects, which represent savings from rate increases and other market effects not related directly to standards and programs. These savings are incorporated directly into the forecast. Uncommitted savings – which, while plausible, have a great deal of uncertainty surrounding the method, timing, and relative impact of their implementation – are considered separately within the *CED 2011 Preliminary* analysis.

The Energy Commission developed the demand forecasting models in a way that promotes the inclusion of building and appliance efficiency standards. The models distinguish among vintages of floor space, housing, and equipment. As a new building or piece of equipment is added, the model assumes its energy use characteristics meet – at a minimum – the applicable standards. Following the effective implementation date, standards gradually affect an increasingly larger proportion of the total building and appliance stock. Each cycle of progressively tightened standards can be evaluated to determine the additional energy savings contributed from each vintage of standards by comparing model outputs.

Measuring the effects of utility programs poses a greater challenge, as customer participation is voluntary and is motivated by a complex set of interactive effects. Also, customers may replace appliances well before the end of their usefulness, and while data may be available on the efficiency of new appliances, the reference level of efficiency is often unknown for the replaced appliances.

To better measure program impacts, staff leveraged the CPUC's most recent efforts to measure utility program savings. The CPUC Energy Division's evaluation-based estimates of program savings from the 2006–2008 program cycle, as well as additional evaluation for 2009 programs, represent the most thorough and comprehensive effort to date. This unprecedented level of detailed evaluation data, however, applies only to programs implemented within the last four years. Therefore, staff modeled the uncertainty surrounding the performance of future programs using scenario analysis.

Figure 12: Statewide Committed Consumption Efficiency and Conservation Impacts



Source: California Energy Commission

Because a clear, consistent record of evaluated efficiency program achievements is not readily available,[122] there is a great deal of uncertainty around any estimate of historical program impacts. This uncertainty, along with uncertainty around attribution of savings among standards, programs, and price effects, has been the subject of debate in recent Demand Analysis Working Group meetings. Some parties have insisted that Energy Commission demand forecasts incorporate historical program impacts that are vastly underestimated and/or credit too much savings to standards and price effects, especially before 1998. A recent staff paper summarizes the positions of various parties.[123]

Staff believes that the forecasting process yields reasonable estimates of total savings but acknowledges and shares concerns voiced by stakeholders about savings attribution. Therefore, the *CED 2011 Preliminary* provides no attribution among the three sources (programs, codes and standards, and price and market effects) except for estimates of standards impacts. In other words, it provides no specific esti-

122 See discussion of EM&V requirements over time in Kavalec, Chris and Don Schultz, May 2011, *Efficiency Programs: Incorporating Historical Activities Into Energy Commission Demand Forecasts*, draft staff paper, California Energy Commission, Electricity Supply Analysis Division, CEC-200-2011-005-SD, available at: www.energy.ca.gov/2011publications/CEC-200-2011-005/CEC-200-2011-005-SD.pdf.

123 California Energy Commission, Electricity Supply Analysis Division, Chris Kavalec, *Energy Efficiency Program Characterization in Energy Commission Demand Forecasts: Stakeholder Perspectives and Staff Recommendations: Draft Staff Paper,* August 2011, CEC-200-2011-010-SD, available at: www.energy.ca.gov/2011publications/CEC-200-2011-010/CEC-200-2011-010-SD.pdf.

mates of program and price effects. Staff will continue to work with stakeholders on these issues, with the goal of showing attribution for at least some years in future reports. Figure 12 shows total historical and projected committed efficiency savings from the three sources starting in 1990. Annual totals are relative to conditions in 1975, before the state implemented the first efficiency standards.

Beyond these committed impacts, the CPUC, Energy Commission, California Air Resources Board, and the Legislature have set efficiency goals without approval of specific program designs or authorization of actual program funding levels. Staff must consider long-term utility savings goals, future updates to Title 20 and Title 24 codes and standards, and statewide policy initiatives in determining incremental uncommitted energy efficiency impacts – impacts that are in addition those already included in the baseline forecast.

During the *2009 IEPR* cycle, at the request of the CPUC, staff began to assess the effects of incremental uncommitted energy efficiency policy initiatives. Staff included policy initiatives in the analysis similar to those originally evaluated by Itron and adopted by the CPUC in the *2008 Energy Efficiency Goals Update Report* (*2008 Goals Study*).[124] The incremental uncommitted analysis for *CED 2011 Preliminary* also relies on the *2008 Goals Study* but is updated to account for the passage of time. Therefore, some initiatives considered uncommitted in 2009 are now incorporated in the committed forecast. (Figure 12 includes estimated savings.) The newly committed initiatives include Assembly Bill 1109 (Huffman, Chapter 534, Statutes of 2007) and the 2010 Title 24 Building Code Revisions. In addition, the *CED 2011 Preliminary* extends uncommitted analysis to publicly owned utilities. The uncommitted efficiency initiatives in *CED 2011 Preliminary* include:

- Utility programs beyond 2012, including residential, commercial, and industrial.
- Further updates to state Title 20 and 24 standards along with updated federal appliance standards.
- The CPUC's Big Bold Energy Efficiency Initiatives.

As in the *2008 Goals Study, CED 2011 Preliminary* assumed various levels of commitment to these policies to create three scenarios of uncommitted efficiency savings – high, medium, and low. By 2022, consumption in the mid-demand case would be reduced 3.3 percent if adjusted by the low savings scenario and 6.2 percent using high incremental uncommitted savings. For peak, the reductions range from 4.8 percent to 9.5 percent, higher than consumption because the end uses targeted by these initiatives tend to have higher-than-average peak-to-energy-consumption ratios.

Combining the high demand case with the low incremental uncommitted efficiency scenario and the low-demand case with the high efficiency scenario gives a range of "managed" forecasts. Statewide, adjusted consumption ranges from around 294,000 GWh to 322,000 GWh, compared to 313,000 GWh to 332,000 GWh for unadjusted consumption. For peak demand, the adjusted range is 63,000 MW to 71,000 MW, compared to the unadjusted range of 70,000 MW to 74,000 MW. In these adjusted mid- and low-demand cases, peak demand begins to drop slightly by the end of the forecast period. Peak demand in the low case drops slightly below the actual 2010 statewide (noncoincident) level.

The CPUC's new *Potential and Goals Study* is underway and is expected to be completed in late summer 2012. This schedule does not allow the study to be fully incorporated in the revised or final adopted IEPR demand forecasts, but CPUC staff intends to use interim study results to recommend changes to the incremental uncommitted efficiency impacts

124 Itron, Inc. *Assistance in Updating the Energy Efficiency Savings Goals for 2012 and Beyond*, adopted by CPUC in March 2007, www.cpuc.ca.gov/NR/rdonlyres/D72B6523-FC10-4964-AFE3-A4B83009E8AB/0/GoalsUpdateReport.pdf.

developed from the *2008 Goals Study*. Thus, the uncommitted results will likely differ in the revised and adopted IEPR forecasts compared to the preliminary.

CHAPTER 9

California's Electricity Infrastructure

Part One: Once-Through Cooling and Assembly Bill 1318

This chapter of the *2011 Integrated Energy Policy Report* provides an update on progress made by the Energy Commission and other energy agencies on implementation of the State Water Resources Control Board's (SWRCB) once-through cooling (OTC) policy and related emission offsets concerns (Part One) as well as a status report on Energy Commission electricity infrastructure activities (Part Two). This summary also highlights some challenges facing energy and environmental agencies for resolving some key issues, provides the next steps, and makes a recommendation for going forward.

Reducing the impacts on the marine and estuarine environments from the use of OTC technologies in older power plants and the scarcity of emission offsets for new fossil power plants are two of the most important challenges facing the electricity generating industry. To reduce impacts, many of the owners of California's aging power plants are choosing to retire rather than make capital investments in the facility, causing a need for new capacity to satisfy peak demand and appropriate reserves.[125] However, licensing new power plants is difficult, given the scarcity and corresponding cost of offsets required to avoid harmful impacts on air quality. Even repowering at the site of an aging power plant has its challenges. So, while policies to reduce the use of OTC are increasing the demand for new power plants, air quality constraints are restricting the development of fossil fuel power plants. This complexity is especially apparent in those areas of the state where existing air quality fails to satisfy ambient standards. Air pollution is a serious problem that has adverse health and economic effects. The South Coast Air Basin, for example, is experiencing the full effects of these opposing forces. To satisfy local capacity requirements (LCR)[126] and help integrate variable renewable generation, the region will have to replace some of its older capacity with dispatchable, flexible fossil power plants when existing OTC power plants retire. The *2009 Integrated Energy Policy Report* discussed the South Coast Air Basin's situation in detail and made recommendations to address the challenges, but uncertainties continue.

OTC is a form of power plant turbine condenser cooling technology that was considered conventional design when steam boiler power plants were built in California in the 1950s through the 1970s. This technology pumps water from a source (ocean, estuary, river, or lake) through a steam turbine condenser and then returns it to the source. The problem is that fish and small marine mammals are impinged and can suffocate and die on screens designed to keep them and people out of the water intake structure. In addition, smaller organisms are entrained in the cooling machinery itself and killed by turbulence, the pump, or the temperature increase of the water.[127] The federal Clean Water Act, Section 316(b), has long required existing power plants or other industrial facilities to reduce these environmental impacts, but the United States Environmental Protection Agency (U.S. EPA) and state agencies have been slow to act due to industry resistance to costly refits. In response to delays in U.S. EPA actions, the SWRCB undertook developing its own OTC policy and adopted a final policy in May 2010, which became effective on October 1, 2010.

For many years, local air quality districts, with some oversight from California Air Resources Board (ARB) and U.S. EPA, have developed and administered emission reduction mechanisms to prevent harmful impacts to air quality from new industrial facilities. Under these mechanisms, new facilities have had to "offset" their emissions by shutting down existing sources (or using offsets from previously shutdown sources), thus reducing overall net emissions and actually improving air quality. Yet, while the offset mechanism creates an incentive for older, inefficient, and unprofitable industrial facilities to retire, the amount of emission offsets that can be created by this approach in any region may be diminishing. In the South Coast Air Basin, where South Coast Air Quality Management District (SCAQMD) administers the air quality permitting and attainment programs, commercially available offsets have essentially disappeared for some criteria pollutants, since few existing power plants and refineries are willing to shut down just to provide offsets to new development.

Part 1 of this chapter provides a progress report and highlights some key challenges as these two top-

125 Many power plants will be "repowered," meaning they will essentially be torn down and a new one constructed on the same site. Some power plants are attempting to "refit" by modifying ocean water intake structures to reduce environmental impacts sufficient to satisfy the OTC policy.

126 Local capacity requirements define the minimum amount of generating capacity that must be available within the boundaries of a local capacity area. Such areas exist because the transmission system serving them is inadequate to satisfy loads under extreme peak load conditions.

127 For a more detailed description of potential impacts of OTC technologies, see California Energy Commission, *Issues and Environmental Impacts Associated with Once-Through Cooling at California's Coastal Power Plants*, Staff Report, June 2005, www.energy.ca.gov/2005publications/CEC-700-2005-013/CEC-700-2005-013.PDF.

ics are resolved in the electricity policy and planning processes of energy and environmental agencies.

OTC Policy Implementation

The SWRCB's adopted OTC policy incorporates the recommendations jointly proposed in 2009 by the Energy Commission, California Public Utilities Commission (CPUC), and California Independent System Operator (California ISO). The May 2010 OTC policy essentially has two dimensions – stringency of requirements and compliance timing. SWRCB determined that evaporative cooling towers (roughly a 93 percent reduction of water usage compared to OTC) should be established as a performance benchmark. Recognizing that compliance would probably result in the shutdown of existing power plants and not wishing to threaten reliability, SWRCB established compliance dates for specific power plants based on an initial review of the time horizon needed to get replacement infrastructure on-line.[128] Further, the OTC policy allows the interagency advisory committee to propose revisions to these dates, if necessary.[129]

Since the state adopted the policy, there have been two proceedings to revise compliance dates for power plants owned by Los Angeles Department of Water and Power (LADWP). In December 2010, SWRCB tabled LADWP's effort to extend the compliance schedule for: 1) any combined cycle power plant, or 2) any power plant that, once repowered, eliminates use of ocean water. On July 19, 2011, SWRCB modified the OTC policy (based on another proposal made by LADWP as part of its generation implementation plan filed with the SWRCB on April 1, 2011) to include: (a) an acceleration of two power plant repowering projects and a delay in the remainder of LADWP's repowering projects, compared to the compliance dates in the May 2010 OTC policy, and (b) broadening criteria for accepting compliance dates beyond 2022 for any generator that will entirely eliminate the use of ocean water for cooling, even as makeup for evaporative cooling towers. The delayed compliance dates for the three LADWP power plants will be examined again in 2012–2013 through mechanisms established in the policy.

The state required all generators to submit implementation plans on April 1, 2011, showing how they intended to comply with the OTC policy. Many generators provided plans conditional upon action by others. For example, most generator owners said they intended to repower if a CPUC-jurisdictional load-serving entity (LSE) would enter into a long-term power purchase agreement (PPA) with the generating unit; this presumes the CPUC will authorize procurement authority and establish oversight that leads to such a PPA. Without a PPA, no generator was willing to invest the money required to repower or refit intake structures to comply, thereby resulting in a plant shutdown. Some said matching the CPUC/LSE procurement mechanism with the existing SWRCB OTC compliance date for their power plant required the CPUC to establish procurement authority and provide direction to LSEs as part of a final decision in the 2010 Long-Term Procurement Plan (LTTP) – R.10-05-006.

Whether the CPUC does this, which would translate into opportunities to repower existing OTC capacity, depends upon finding a need for new dispatchable fossil power plants. Two likely justifications exist. One is the need to add capacity from highly flexible advanced single cycle or combined cycle power plants that can start and stop readily, and ramp over a wide

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128 The SWRCB's action applies primarily to fossil fuel plants using OTC. California's two nuclear power plants, Diablo Canyon and San Onofre, also use OTC and will be subject to SWRCB action, but they will be on different, still-to-be-defined schedules for compliance. During 2012, the California ISO will continue studying the electricity system effects of OTC phase out at the nuclear plants.

129 The Statewide Advisory Committee on Cooling Water Intake Structures (SACCWIS) includes staff representatives of the Energy Commission, CPUC, California ISO, Air Resources Board, State Lands Commission, California Coastal Commission, and SWRCB.

range easily, to help to integrate solar and other intermittent renewables. Other resources may be available to help meet these needs, including concentrated solar plants with salt storage, other forms of energy storage, and/or geothermal plants. Another is the need to add capacity in local capacity areas, or in even more narrowly drawn subareas, to assure local reliability given the limitations of the transmission system for meeting customer loads from remote power plants. Although the CPUC has yet to issue a final decision in Track 1 of the 2010 LTPP rulemaking, the parties submitted a settlement agreement that would defer such a decision until the California ISO submits another round of renewable integration analyses. This analysis is underway with completion expected in the spring of 2012.

The California ISO prepared an unpublished power flow/stability study for the CPUC 2010 LTPP proceeding (R. 10-05-006) in the spring of 2011 that demonstrated little need for new capacity in the 2020 time horizon, in part because of the relatively low load forecast (modified down further by demand-side policy impacts) caused by the extended slowdown of California's economy. No comparable power flow investigation of LCR in the 2012–2020 period was entered into the record of the 2010 proceeding.[130] Southern California Edison Company did submit results in its testimony using a more simplistic model developed by the CPUC, Energy Commission, and California ISO as a "screening" tool to understand the timing implications of alternative assumptions that would affect the viability of various OTC retirement dates.[131] The California ISO published the results of initial studies of local capacity requirements and their interaction with OTC facility retirement on December 6, 2011, as part of its 2011/12 Transmission Planning Process. These studies provide some indication of the degree to which existing capacity at OTC power plant sites should be maintained through repowering or refitting to satisfy LCR needs.

In the case of the Los Angeles area of the California ISO balancing authority area, studies based solely on the adopted *2009 IEPR* demand forecast found that some, but not all, of the existing amount of capacity needs to be replaced. In a "sensitivity study" the California ISO examined the needs for OTC replacement by subtracting the impacts of incremental energy efficiency from the base load forecast and considered projected growth of demand response measures. It found that the replacement capacity needed to satisfy local capacity area requirements was diminished still further.

In the case of the San Diego area, the California ISO's newly released results alter the conclusions of previous studies that all OTC capacity in the area could be replaced by alternative resources located elsewhere. The California ISO's new studies show that substantial capacity is needed in the northwestern portion of the San Diego area, if not at the precise location of the existing Encina power plant. The California ISO has explained that at least a portion of its results stem from an assessment of the sequence of actions that resulted in the September 8, 2011, outage in the San Diego and Imperial counties of California as well as portions of western Arizona. These results are at odds with information submitted by SDG&E in the CPUC's 2010 LTPP rulemaking. It is unclear whether California ISO and SDG&E have contrasting results from different variants of the same studies or if different analytic methods are causing different conclusions. If verified, the California ISO results have obvious consequences for OTC repowering and/or replacement infrastructure much more closely aligned to the Encina location and

130 The joint proposal of the Energy Commission, CPUC, and California ISO to SWRCB, supporting the 2020 OTC compliance dates for most Southern California OTC power plants, did not contemplate intensive analysis of long-term local capacity area requirements until the 2012 LTPP cycle.

131 See spreadsheet tool and narrative description of inputs for the December 23, 2010, version at: www.caiso.com/planning/Pages/TransmissionPlanning/Default.aspx.

interconnections to the bulk power system than were previously understood.

While the state is intently focused on OTC retirement and the analyses required for determining the need for dispatchable, fossil power plants that existing merchant generators want to develop, several uncertainties are making it difficult to justify new capacity commitments at this time. It is likely that the state will require another round of generator implementation plans at some point in the future.[132]

Constrained Emission Offsets in South Coast Air Basin

Recognizing the necessity for limited amounts of additional fossil power plant development, SCAQMD adopted rules that would provide special mechanisms to permit new power plants. Rule 1309.1 – the Priority Reserve – would have allowed access to air district internal account credits ("offsets") for a limited amount of new power plant development. However, these newly adopted rules were overturned by a 2010 court decision. Thus, SCAQMD is relying on a different rule provision for new power plant projects. Rule 1304(a)(2) provides air district internal account offsets for new replacement power plants using advanced gas turbine technologies to the extent their capacity does not exceed that of retired existing power plants. This rule allows for the repowering of old OTC power plants to develop dispatchable, fossil power plants needed within South Coast Air Basin.

Two recent events illustrate how Rule 1304(a)(2) can work. In one case, NRG Energy (NRG) could not obtain the increment of offsets required for its repowering project at El Segundo Units 1–2, since the new plant's capacity exceeded that of the retired units. The Rule 1304(a)(2) exemption did not cover all of the capacity of the new power plant. Eventually, NRG decided to retire Unit 3, in addition to Units 1 and 2, to eliminate its need to secure emission reduction credits in the commercial market for the difference in capacity between the new power plant and that of retired Units 1–2. Another innovative example is Edison Mission Energy's (EME) emission reduction credits for its recently licensed Walnut Creek power plant, which is under construction in City of Industry in Los Angeles County. After numerous failed attempts to purchase offsets because commercial emission reduction credits were unattainable or prohibitively expensive, EME purchased and retired Huntington Beach Units 3–4 from AES Corporation to use the exemption from offsets allowed by Rule 1304(a)(2) for Walnut Creek. Both power plants, long held up by offset issues, obtained Rule 1304 exemption from provision of offsets in spring 2011 and broke ground in June 2011.

All of the merchant generators and municipal utilities in the South Coast Air Basin affected by the OTC policy are proposing Rule 1304(a)(2) as the path to repowering, whether onsite, as per the El Segundo example, or in the form of two separate sites, as per the Walnut Creek example.[133] What is unclear about these expectations is whether SCAQMD's bank of internal credits can, or should, provide the offsets to satisfy U.S. EPA New Source Review (NSR) requirements to allow replacement of all existing power plants, rather than limiting internal account offsets to those

132 SACCWIS recommended in its July 5, 2011, resolution (2011-0001) that the SWRCB obtain additional implementation plan information from all generators. SACCWIS expanded its justification for needing further information from generator owners in its report to SWRCB dated September 29, 2011.

133 All of the generator owners with plants in the South Coast Air Basin explicitly cite SCAQMD Rule 1304 (a)(2) in their implementation plan submittals to SWRCB of April 1, 2011.

facilities actually required for system reliability.[134] Assembly Bill 1318 (V. Manuel Pérez, Chapter 285, Statutes of 2009) requires that ARB develop a report, in consultation with various agencies including the Energy Commission, to assess the need for new power plant capacity in South Coast Air Basin and how needed offsets compare to available amounts. The report will also examine whether recommendations are needed for changes in rules and other permitting mechanisms to allow power plants to be developed while safeguarding ambient air quality. The AB 1318 project has been underway since spring 2010.[135]

The OTC policy and offsets for replacement projects are not the only issues posed by new regulatory changes. In 2011, SCAQMD adopted Rule 1325 to address NSR requirements for particulate matter (PM2.5, particulate matter 2.5 microns in diameter). It implements a new federal rule that had not received wide attention in California. Unlike NSR rules for other criteria pollutants, Rule 1325 does not allow covered entities to be exempt from providing offsets through Rule 1304(a)(2). Rule 1325 is written to apply only to the largest facilities that either already exist or might be developed within South Coast Air Basin; however, this probably means that it applies to very large multi-unit power plant facilities like Haynes, Alamitos, and Redondo Beach, as well as several Los Angeles Basin refineries.

Applicability of Rule 1325 is dictated by reference to PM2.5 emissions, or its nitrogen oxide or sulfur oxide precursors, exceeding 100 tons per year. PM2.5 is measured by an emission test method not widely used in California; therefore, until facilities conduct a source test using the specified method, it will be unclear whether the rule applies to them or their proposed modifications. Also, the rule includes provisions relating to a facility's historical emissions and potential to emit that can encumber modifications affecting only one or a few units at a multiunit power plant. In short, SCAQMD's adoption of Rule 1325 will likely affect the largest power plant facilities in South Coast Air Basin, but to what extent remains to be determined.

The AB 1318 project, largely consisting of the interagency team established for OTC purposes and joined by ARB, is assessing the need for capacity in South Coast Air Basin, how emissions from new capacity match available offsets (or internal bank credits), and whether to develop rule and permitting mechanism changes. This effort has been slowed by the extraordinary analytic effort needed to identify renewable integration requirements for the mandated 33 percent renewable target by 2020, by the parallel assessment of transmission system upgrades needed to interconnect this renewable development to the bulk transmission system, and by the need to extend assessment of local capacity area requirements out to a 10-year horizon in a manner sensitive to the prospective impacts of demand-side and supply-side

134 Although Rule 1304(a)(2) exempts power plant owners from provision of some criteria pollutant offsets to the extent that new capacity does not exceed retired capacity, SCAQMD must provide the "missing" offsets from its internal bank of credits to satisfy U.S. EPA NSR requirements. Simply, SCAQMD enters as a "credit" the emission reductions associated with the retirement of the existing power plant and enters as a "debit" the potential to emit of the new power plant. The usual rules governing the computation of these credits and debits apply. Generally, some net reduction in the balance in the internal bank is to be expected as a result of new power plants "using up" limited credits.

135 The ARB and Energy Commission (2011 IEPR Committee) conducted a workshop on February 15, 2011, at SCAQMD's headquarters in Diamond Bar, California, to obtain public input about the draft AB 1318 project workplan.

policy initiatives.[136] Although delayed compared to original time schedules, the analytic work is underway jointly by the Energy Commission, CPUC, and California ISO to support possible modification to OTC compliance dates. The California ISO completed a portion of this effort when it released the LCR assessments as part of the 2011/12 transmission planning process. As of this writing, ARB anticipates developing a draft report that incorporates these assessments and estimates of offsets needed by new capacity in South Coast Air Basin by March 2012, with a final report to the Legislature in the summer of 2012.

Challenges

A fundamental issue that must be faced is the potential conflict between state policy goals and electric system reliability. As noted elsewhere in this report, the California Clean Energy Future (CCEF) effort brings together the policy goals of the state and its agencies and the reliability mission mandated by state and federal requirements on the California ISO. Both must be accomplished satisfactorily.

Another source of uncertainty regarding replacement of OTC plants arises from the state goals for energy efficiency and other demand-side policy initiatives. The incremental energy efficiency assessment prepared by the Energy Commission in the *2009 IEPR*, and used with minor modifications in the CPUC's 2010 LTPP rulemaking, shows roughly 2,000 MW of load reduction in the California ISO's L.A. Basin local reliability area. Presumably, such a major load reduction would reduce the amount of OTC capacity needing to be replaced, either through repowering of existing OTC units or by construction of new power plants in the Western L.A. Basin subarea.[137] A question that follows is to what extent should the effects of these policy initiatives be presumed to happen even though they have not yet been committed to by funding of energy efficiency programs or adoption of tighter building standards on new construction, or adoption of more stringent appliance efficiency standards? Failure of the Legislature to reauthorize the Public Goods Charge that historically has funded a substantial portion of IOU energy efficiency program activities and growing concern about increasing electricity rates to pay for policy goals raise questions whether the state will achieve energy efficiency goals at the level or pace previously desired.[138] The CPUC has recently authorized funding at the same levels as the Public Goods Charge for energy efficiency, renewables, and research and development, but has also initiated a proceeding to consider major redesigns of IOU programs.[139]

136 According to existing CPUC decisions and California ISO tariff requirements for the CPUC/ISO resource adequacy program, LSEs only are required to satisfy local capacity area requirements one year into the future. California ISO prepares the studies that create these regulatory requirements and also publishes a three- and five-year ahead study, but its uses are only informational and advisory. California ISO has not routinely prepared 10-year ahead local capacity area studies and is developing its capability to do so specifically as part of the AB 1318 project in conjunction with the Energy Commission and CPUC. The California ISO released the results of such studies as part of its 2011–12 TPP activities and presented the results at a stakeholder meeting on December 8, 2011. www.caiso.com/Documents/Draft2011_2012TransmissionPlan.pdf.

137 The California ISO studies released on December 8, 2011, show roughly 1,000 MW of reduction in OTC capacity that must be repowered as a result of 2,000 MW of load reduction at summer peak as a result of incremental energy efficiency policy initiative impacts.

138 The ARB's *AB 32 Scoping Plan,* adopted in December 2009, or the CPUC's electricity energy efficiency goals, adopted in 2008 by D.08-07-047, set high targets. In its 2008 LTPP rulemaking, the CPUC/ED popularized the concept of "deliverability risk assessment" to characterize this dilemma – what portion of aspirational goals should be used to determine actual generation resource additions needed to satisfy reliability standards in light of the risk of program impact shortfall risks?

139 R.09-11-014, Assigned Commissioner's Ruling and Scoping Memo Regarding 2013–2014 Bridge Portfolio and Post-Bridge Planning, Phase IV, October 25, 2011.

Table 11: Generation Project Development Timeline

Long-Term Procurement Proceeding	2012
Request for Offers Design	2013
Request for Offers and Contracting	2014
Interconnection and Permit Preparation	2015–2016
Permitting	2016–2017
Construction	2018–2019

Source: California ISO, Casey memo to California ISO board, 8/18/2011

Table 11 reproduces the expected time frame for power plant development as presented to the California ISO Board in August 2011 for an OTC power plant with a nominal 2020 compliance date. The California ISO staff pointed out to their Board that decisions need to be made soon if major new generation projects are to be operational by 2020. If construction of new gas plants in the Western L.A. Basin is deferred, but the expected incremental energy efficiency and demand response results are not achieved, the infrastructure will not be ready in time if it turns out to be necessary. As a result, reliability standards would not be satisfied, and various transmission or generation outages, if encountered, would result in higher probabilities of customer outages or greater extent of customer outages (or both). Although California ISO's analysis uses the same deliverability risk assessment concept as that first articulated by CPUC staff in their 2008 LTPP proposal, the California ISO assumed that no incremental demand-side policy impacts were obtained. In contrast, the CPUC guidance to IOUs (issued in the 2010 LTPP rulemaking) reflected a reduced amount of impacts being used for resource planning compared to aspirational goals, but not an elimination of such impacts altogether.

Renewable integration assessments and extensions of local capacity requirements out to 10-year time horizons are not fully mature analytic activities, so it is not yet apparent to what extent preferred resource types (energy efficiency, demand response, distributed generation [DG], combined heat and power generators, and forms of energy storage), occurring at the levels identified in the CCEF vision statement or Governor Brown's 2010 jobs/energy plan, reduce the need for dispatchable fossil generation. Analyses underway will reduce that uncertainty, shifting focus to the hard policy choices that have to be made in light of the benefits and costs of the choices.

Next Steps

The state must complete analyses and make certain policy decisions before a clear path forward exists for retiring and/or repowering aging power plants.

Analyses

The interagency team must complete two remaining key analytic steps to accomplish the emission offset mechanism review as required by AB 1318. In preparing these analyses, the interagency team is addressing numerous uncertainties by designing a "bounding" assessment that would lead to the largest and smallest credible amounts of offsets required. First, the interagency team must complete its initial assessment of LCR out to the 10-year time horizon for at least South Coast Air Basin and ideally some other areas of SP26.[140,141] Replacement infrastructure has already been identified and is in the planning/permitting pipeline for most OTC power plants in the rest of the state. Second, the team must complete its translation of the new capacity identified in these reliability-oriented studies into projected emissions for various criteria pollutants that would have to be offset in the permitting processes. These offset requirements will be compared against existing offsets available for power plants to use.

The interagency team plans to accomplish both steps so that the ARB can include a preliminary analytic result in the draft AB 1318 project report. The report would undergo appropriate public review and management oversight in the early months of 2012. Since these initial results will likely reveal a wide range of required capacity additions and offsets, the interagency staff may have to identify the most likely portion of this range during the first three quarters of 2012, due to its relevance to policy decisions and so that the CPUC's 2012 LTPP proceeding can issue appropriate procurement authority to the IOUs by the end of 2012. Such a decision would put the timeline of Table 11 into motion.

Although these analyses are highly overlapping with review of OTC power plant compliance dates for Southern California, there are also OTC issues in other portions of the state outside the South Coast Air Basin. More than 3,000 MW of fossil OTC capacity is operating along the Central California coastline with current OTC compliance dates between 2015 and 2017. No viable plans to replace this amount of capacity on this schedule are apparent. In its newly released studies, the California ISO did not assume retirement of all this capacity. The interagency OTC technical team has identified further needed assessments to determine whether the full amount of capacity can be retired without creating local, zonal, or system reliability issues.

Policy Decisions

Five interacting sets of policy decisions must be made once the analysis provides a range of offset requirements:

- Agencies (Energy Commission and CPUC), the California ISO, and SCAQMD should adopt a consistent approach to relying on load reductions resulting from demand-side policy initiatives for reliability planning purposes.

- Energy agencies (Energy Commission and CPUC), local land-use agencies, and the Legislature have some influence over resource development strategies, perhaps still implemented through competitive market mechanisms, which affect the extent of renewable development to satisfy local capacity area requirements. Governor Brown's renewable DG goals are reshaping the thinking about remote versus local resource development, which could affect the need for central station power plants in urbanized areas to satisfy the local capacity component of reliability standards.

- The California ISO and transmission owners have an ability to influence the extent to which local capacity area requirements can be diminished through transmission system development, upgrades, and

140 Although San Diego and Ventura areas are outside the South Coast Air Basin, thus the administrative requirements to provide offsets under SCAQMD rules do not apply to such capacity, these areas are linked to South Coast Air Basin electrically both for zonal and perhaps even local capacity area requirements. Options exist in which capacity development in San Diego or Ventura areas can substitute for capacity in the Western L.A. Basin. Further, transmission system changes (new lines or selective upgrades of existing lines) could reduce the capacity requirements or the actual boundaries of transmission-constrained local areas.

141 Path 26 is the limiting transmission path between Northern and Southern California, so SP26 refers to the region "south of Path 26" within the California ISO balancing authority area.

modifications.[142] Is it feasible for the California ISO to identify transmission system upgrades that IOUs can implement to reduce LCR requirements and provide greater geographic flexibility for generation additions?

- SWRCB has the ability to shift OTC compliance dates to affect the timing of existing power plant retirement and development of replacement capacity requiring offsets. Will SWRCB do so if it allows demand-side policies to defer fossil generation or enables greater use of remote renewable generation dependent upon transmission development?

Numerous agencies are involved in making these decisions. The initial track record of energy agency cooperation is good for developing a proposal for preliminary schedules and periodic review of compliance dates, along with SWRCB's acceptance of this approach in its OTC mitigation policy. The AB 1318 effort has broadened the OTC focus to address the offset issues, which are at the heart of any "solution." More entities must become involved as the issues turn to assessing criteria pollutant offsets needed and available and how to devote scarce amounts among competing interests. Devising common planning assumptions and better integration of planning processes is one means of getting multiple agencies "on the same page." The state agencies have embarked upon improved coordination of efforts through the CCEF process, but tighter coordination will be needed to surmount the challenges of OTC policy implementation while satisfying ambient air quality standards.

142 For example, the Tehachapi Transmission project, mainly thought of as a means to bringing wind power into load centers, also has the consequence of greatly reducing local capacity area requirements in the Ventura/Big Creek and L.A. Basin load pockets.

Conclusion

The analyses released by California ISO in December 2011 brought an abundance of improved information about the long-term need for new power plant capacity to replace OTC units for satisfying LCR, given various assumptions about the future. These results differ from ones previously released by suggesting that not all of the L.A. Basin OTC capacity has to be replaced, and that much of San Diego OTC capacity does have to be replaced. The magnitudes of these results differ depending upon the CPUC-defined renewable development scenario that was assumed, reflecting uncertainty about what mix and location of renewables will be developed to satisfy California's 33 percent by 2020 requirements. The next round of analyses planned for early 2012 will provide additional information about the extent to which capacity needed for renewable integration is incremental to that needed for LCR purposes. It will also inform assumptions used in the AB 1318 effort to estimate future offsets in the South Coast Air Basin for power plants that must be located in areas subject to SCAQMD's permitting requirements.

- Interagency coordination should continue on broader policy decisions that are inappropriate to the more narrow focus of a single agency. Interagency coordination should focus on achieving consistent decision-making in the proceedings that are underway.

Part Two: Status of Energy Commission Electricity Infrastructure Activities

California's commitment to reduce GHG emissions to 20 percent of 1990 levels by 2050[143] requires developing demand-side resources (for example, energy efficiency and demand response programs), retiring or divesting high emission generation, and developing renewable and other zero- or low-carbon resources. To this end, California has placed energy efficiency at the top of the state's loading order[144] and requires the utilities to limit long-term investments to power plants that meet the Emission Performance Standard (EPS). As a result, the Energy Commission expects more than 2,060 MW of capacity and 17,600 gigawatt hours (GWh) of energy to be divested between now and 2019,[145] reducing the share of California's electricity needs met by contracts with/ownership of coal-fired generation from roughly 10 percent to less than 4 percent. In addition, California's Renewables Portfolio Standard means that greater amounts of renewable energy will be needed over the longer term to realize GHG reduction targets. Finally, the SWRCB's policy on the use of OTC by power plants may encourage or require the retirement of as much as 13,300 MW of gas-fired generation by 2020.[146]

The potential retirement, replacement, or divestiture of more than 15,000 MW of fossil generation[147] requires an assessment how much replacement capacity will be needed to assure electric system reliability and ease the transition to a low-carbon electricity sector through 2020 and beyond. While California's energy needs will be increasingly met by renewable resources over the next decade and the development of dispatchable renewable resources (for example, geothermal and biomass) over the longer term, the existing system requires threshold amounts of such capacity to ensure system and local reliability. This need has three facets, which are described as follows:

- **Total capacity:** Given load growth (net of energy efficiency and demand response programs) and the capacity provided by other generation resources (both in- and out-of-state), sufficient capacity from in-state gas-fired resources must be available to meet systemwide capacity requirements. As the penetration of variable energy resources increases, this *may* require planning and operating reserve margins in excess of those historically held to provide desired levels of reliability.

143 Executive Order S-3-05, June 1, 2005, available at: gov.ca.gov/news.php?id=1861.

144 See *State of California Energy Action Plan* (2003), page 2, available at: www.energy.ca.gov/energy_action_plan/2003-05-08_ACTION_PLAN.PDF. Also see *State of California Energy Action Plan II*, September 21, 2005, available at: www.energy.ca.gov/energy_action_plan/2005-09-21_EAP2_FINAL.PDF.

145 This includes the expiration of relationships with the Boardman (OR), Four Corners (NM), Reid Gardner (NV) and Navajo (AZ) coal plants, reduced procurement from the Intermountain (UT) facility, and the expiration of contracts with 11 in-state qualifying facilities (totaling 324 MW) that burn coal or petroleum coke.

146 The policy also requires that 1,451 MW of gas-fired generation capacity at LADWP's Haynes, Scattergood, and Harbor, as well as Diablo Canyon and San Onofre nuclear facilities (4,486 MW) come into compliance during 2022 – 2029.

147 This total does not include an additional 2,654 MW of gas-fired generation that is 33 years old or more, identified by Energy Commission staff in 2004 as candidates for retirement. See *Resource, Reliability and Environmental Concerns of Aging Power Plant Operations and Retirements*, California Energy Commission, draft staff white paper, August 13, 2004, CEC-100-04-005D, available at: www.energy.ca.gov/publications/displayOneReport.php?pubNum=P100-04-005D.

- **Location:** Gas-fired generation capacity is needed in specific geographic areas to meet zonal (NP26,[148] SP26) and local capacity requirements. The California ISO has identified 10 local capacity areas (and 41 subareas); three of these areas (Los Angeles, San Diego, and Big Creek – Ventura) contain significant amounts of capacity that use OTC; most of these facilities are located in subareas within the larger area. There are also local capacity requirements for the LADWP's balancing authority area in the Los Angeles Basin.

- **Operational characteristics:** Gas-fired generation capacity must have the operating characteristics that allow it to provide the ancillary services necessary to integrate large amounts of renewable resources while maintaining reliability. This includes fast-start capability, allowing resources to cycle off when not needed and to "opt in" to ancillary service markets as close to real time as possible; the ability to efficiently operate over as wide a range as possible and change output levels as quickly as possible, allowing a resource to provide substantial amounts of spinning reserves and load-following services, and operation under automated generation control, allowing the resource to provide regulation services.[149] In addition, gas-fired generation resources vary in their provision of inertia, needed to provide voltage support and stabilize the system when sudden component outages cause changes in frequency.[150]

148 Path 26 is the limiting transmission path between Northern and Southern California, so NP26 refers to the region "north of Path 26" within the California ISO balancing authority area.

149 For a discussion of the services provided by gas-fired generation, see: *Framework for Evaluating Greenhouse Gas Implications of Natural Gas-Fired Power Plants in California*, consultant report, MRW & Associates, LLC, December 2009, CEC-700-2009-009-F, available at: www.energy.ca.gov/2009publications/CEC-700-2009-009/CEC-700-2009-009-F.PDF. For a discussion of the role gas-fired generation plays in integrating variable energy resources, see chapter 5 of *Renewable Power in California: Status and Issues*, August 2011, CEC-150-2011-002, available at: www.energy.ca.gov/2011publications/CEC-150-2011-002/CEC-150-2011-002.pdf.

The *2011 IEPR* Scoping Order calls for an assessment of needed additions to California's electricity infrastructure to transition to a low-carbon future while maintaining resource adequacy and reliability.[151] Other discussions have taken place regarding infrastructure needs, including transmission to support central-station renewables and upgrades to the distribution system to allow for the development of large amounts of distributed generation (DG).

This chapter of the *2011 IEPR* discusses the major uncertainties that affect estimates of the needed gas-fired generation to help integrate variable energy resources over the coming decade while maintaining system and local reliability. These uncertainties include:

- Demand growth.

- Potential retirement of generation units that use once-through cooling.

- Renewable energy development, including wind, central-station solar PV, solar thermal with and without storage, geothermal, and renewable DG.

- The need for dispatchable generation capacity to provide ancillary services in support of renewable resource integration, and the availability of other resources, such as energy storage or geothermal plants, which may need a different market to be economically run.

150 *Inertia* maintains system stability and reduces frequency deviations or oscillation. Inertia is provided through sufficient spinning mass (rotating turbines, for example) that effectively reduces frequency changes.

151 California Energy Commission, *Committee Revised Scoping Order*, 2011 Integrated Energy Policy Report proceeding (Docket 11-IEP-1), March 30, 2011, page 6.

Table 12: Comparison of Forecasts of California ISO 2020 Peak Demand

	Required for LTPP (2009 IEPR Unmanaged)	IOU Common Case for LTPP	Preliminary 2011 IEPR Forecast	2011/2012 Transmission Planning Process	CPUC Required High	CPUC Required Low
Unmanaged CAISO Peak Demand	55,298	60,853	54,566	55,298	60,828	49,768
Uncommitted Energy Efficiency	5,687	4,275	NA	—	5,687	5,687
New CHP	819	578	NA	—	819	819
CAISO Peak Net of EE and CHP	48,792	56,001	NA	55,298	54,322	43,262
Demand Response	5,145	4,490	NA	NA	5,145	5,145

Sources: CPUC Rulemaking 10-05-006; PG&E, SCE, and San Diego Gas & Electric (SDG&E) System Resource Plan; Joint IOU Supporting Testimony, July 1, 2011, p. A-44 and workpapers. California ISO 2011/2012 Transmission Planning Process, Unified Planning Assumptions and Study Plan, Final – May 20, 2011.Energy Commission 2012-2022 Preliminary Staff Electricity and Natural Gas Demand Forecast, coming in fall 2011.

Notes: Unmanaged forecast for the CPUC Required case uses the 2009 IEPR demand forecast (CEC-100-2009-012-CMF, December 2, 2009) and uncommitted DSM from the mid-case in Incremental Impacts of Energy Policy Initiatives Relative to the 2009 Integrated Energy Policy Report adopted demand; use of demand response impacts in the 2011/2012 TPP remains under consideration.

- The necessary composition of new gas-fired generation, including its ability to provide inertia.
- Combined heat and power development.

The remainder of this chapter discusses how these uncertainties affect electricity planning and the analysis needed during the current planning cycle to develop planning assumptions.

Demand Growth

The California ISO integration studies and the CPUC's Long-Term Procurement Proceeding (LTPP) are using the *2009 IEPR* demand forecast and associated estimates of the capacity value of uncommitted energy efficiency in their analyses of infrastructure needs.[152] The Energy Commission completed the forecast in late 2009 and, therefore, relied on historical data only through 2008 and economic projections that are now more than two years old. The Energy Commission staff is preparing a revised forecast that is expected to be completed in February 2012; it will be accompanied by uncommitted demand-side management (DSM) scenarios based on any updated assessments of energy efficiency potential that are available at that time.[153]

152 "Uncommitted" energy efficiency refers to programs that have yet to be funded nor perhaps even designed but whose funding and implementation can be reasonably expected to occur for planning purposes. Failure to consider uncommitted energy efficiency in planning can lead to the financing and construction of surplus generation capacity at ratepayer expense.

153 The final demand forecast to be adopted by the Energy Commission will not be completed until spring 2012.

Meanwhile, the IOUs have included in their LTTP filings an IOU case (the IOU Common Case) using an alternative, higher demand forecast with lower uncommitted demand side impacts. Table 12 compares the peak demand forecast for 2020 for the base and DSM impacts.

Two of the most significant uncertainties regarding demand growth are economic assumptions and demand-side impacts. The preliminary demand forecast is 1.4 percent lower than the *2009 IEPR* forecast because the effects of the recession have been more severe than previously predicted. Conversely, the IOU Common Case demand forecast is 7 percent higher than the *2009 IEPR*. In addition to higher growth in the base forecast, the IOU Common Case forecast assumes lower impacts from energy efficiency, self-generation, and demand response programs. The difference of 1,400 MW in energy efficiency is because the IOUs have found that some programs are not cost-effective and found issues associated with replacement of program decay. Energy Commission and utility staff are addressing these and other technical issues, including appropriate assumptions for incremental demand growth from electric vehicle penetration. Also, an updated analysis of goals is scheduled to be completed in late 2012, which will be incorporated into the uncommitted energy efficiency scenarios.

The *2012 IEPR Update* demand forecast will provide updated information regarding demand growth. (See Chapter 8 of this report for more details.) The potential need for gas-fired generation to meet local capacity requirements requires assessing the combined impacts of demand growth, energy efficiency, demand response, and DG at a much finer geographic resolution than was needed for traditional resource planning. Staff has begun working with utilities and the California ISO to develop the detailed data sets to account for demand side impacts at the local area/ substation level.

OTC Retirements and Local Capacity Requirements

The state's policy for addressing the effects of once-through cooling will greatly influence the need for new gas-fired generation capacity during the coming decade. The policy applies to 14,755 MW of existing gas-fired generation and may require 13,300 MW of this to comply with OTC policy by 2020.[154] Table 13 shows that a large share of this capacity is located in California ISO-defined local reliability areas or the transmission-constrained portion of the LADWP control area.

In May 2010, the SWRCB adopted a final policy that can be interpreted as requiring the phase-out of OTC; this policy became effective on October 1, 2010. SWRCB determined that evaporative cooling towers should establish the performance benchmark (using roughly 93 percent less water compared to OTC). Generation units can comply by reducing intake flow rates to this benchmark level (Track 1 compliance) or, if unable to do so, decrease impingement mortality and entrainment of marine life by reducing intake flow rates using a combination of structural and operational controls (Track 2 compliance).

There exists substantial uncertainty about when and how units will comply with the OTC policy. Owners filed compliance plans on April 1, 2011, but only a handful provided firm plans for the retirement and

154 On July 19, 2011, the SWRCB ruled that the compliance deadlines for 1,451 MW of capacity owned by LADWP would be extended to 2024 (Scattergood 1–2, 367 MW) and 2029 (Haynes 1–2, 444 MW; Haynes 8–10, 575 MW; Harbor 5, 65 MW).

Table 13: OTC Capacity With Compliance Deadlines in or Before 2022

Local Capacity Area	MW
Los Angeles Basin	4,940
San Diego	950
Big Creek/Ventura	1,947
Bay Area	1,303
LADWP	985
SUBTOTAL	10,124
None	3,180
TOTAL	**13,304**

Source: Energy Commission staff

replacement of existing capacity.[155] These include the following:

- Dynegy believes that its Moss Landing 1–2 units (1,020 MW) are already in compliance; the SWRCB must rule upon this contention.

- The owners of 10 units at 5 facilities totaling 4,737 MW are considering compliance through the use of structural and operational controls (Track 2).[156] It is uncertain, however, that (a) such measures can bring the units into compliance, and (b) that if they result in compliance, they will allow enough operational flexibility to provide ancillary services or do so on a scale that yields a revenue stream sufficient to warrant the necessary investment. Planning entities will work with the SWRCB over the coming months to determine if imposing structural and operational controls is a compliance option for these resources. Where Track 2 compliance is likely to be infeasible (for either of the above reasons), planners should consider their retirement and the need to replace them as a planning assumption.

Merchant owners indicated that much of the existing capacity will be retired, with replacement capacity being built only if they can procure long-term power purchase agreements. While studies have indicated the need for capacity in subareas containing El Segundo, Huntington Beach, and Encina,[157] the state must refine estimates of LCR through 2020. The LCR process has historically focused on near-term (one to three years) needs. During this planning cycle, the Energy Commission, CPUC, and the California ISO will develop long-run LCR estimates in conjunction with assisting the SWRCB in implementation of its OTC policy and assessing emission reduction credit needs in the South Coast Air Quality Management District (SCAQMD) under Assembly Bill 1318 (V. Manuel Pérez, Chapter 285, Statutes of 2009).[158]

More than 2,650 MW of aging, non-OTC gas-fired power plants in California are candidates for retirement. Some are owned by publicly owned utilities and

155 Contra Costa 6–7 (674 MW) will be replaced by Marsh Landing (760 MW nameplate), expected to come on line in 2013. El Segundo 3 (335 MW) will be replaced by new units (560 MW) at the same site, expected to come on line in 2015. LADWP is replacing Haynes 5–6 (535 MW) and Scattergood 3 (450 MW) with roughly equivalent amounts of capacity in 2013 and 2015, respectively.

156 Morro Bay (650 MW), Mandalay (430 MW), Ormond Beach (1,516 MW), Encina 4–5 (628 MW) and Moss Landing 6–7 (1,510 MW).

157 The California ISO's 2013 – 2015 Local Capacity Technical Analysis indicates local capacity requirements in 2015 as follows: the El Nido subarea (in which El Segundo is located) of the Los Angeles Basin needs 511 MW (net of existing qualifying facilities); the Ellis subarea (in which Huntington Beach is located) of the Los Angeles Basin needs 468 MW; the Encina subarea (in which Encina is located) of San Diego needs 20 MW.

158 For a more detailed discussion of interagency efforts related to OTC and emission reduction credits in the Los Angeles Basin, see Part One of this chapter.

will likely be replaced,[159] but a majority of these are merchant-owned.[160] In addition, newer plants without contracts or market revenues to cover going-forward costs may be at risk, as capacity factors may be well below those anticipated when the plant was brought on-line.

Renewable Energy Development

As California increases its reliance on renewable energy, the amount of dependable capacity provided by renewable resources will also increase.[161] The dependable capacity provided by new renewable resources and its location will affect the amount and location of dependable capacity needed from new dispatchable gas-fired generation to meet system and local capacity requirements. The composition of renewable resources with respect to technology (wind, solar PV, solar thermal with and without storage, geothermal, and so on) and location will affect the need for dispatchable gas-fired generation to provide ancillary services and inertia.

CPUC staff proposed four RPS scenarios in the 2010 LTPP proceeding. The dependable capacity associated with each scenario is different, with the most dramatic difference being that of the environmentally constrained portfolio, which assumes the development of DG on a scale proposed by the Governor's Clean Energy Jobs Plan.[162] Under the assumptions, DG resources are accorded no dependable capacity value on the supply-side of load-resource assessments.[163] Planning entities need to arrive at consensus regarding (a) the potential range of DG development during the current planning cycle, (b) the allocation of said development to customer and utility side of the meter resources, and (c) the effective dependable capacity value of each. The *2012 IEPR Update* demand forecast needs to make adjustments to account for DG on the customer side of the meter and to allocate both sets of resources to balancing authority and local capacity areas. Finally, the scenarios should consider revisions that incorporate information and analysis from the Desert Renewable Energy Conservation Plan and Federal Programmatic Environmental Impact Statement-adopted land use policies.[164]

The Energy Commission's Electricity Supply Analysis Division, the CPUC, and the California ISO will work together during the coming months to develop an appropriate set of planning assumptions related to DG development; the California ISO is starting a stakeholder process to evaluate the deliverability of DG and its impact on the grid.

159 Units totaling 437 MW at El Centro, Olive, Broadway, and Grayson.

160 Pittsburg 7, Etiwanda 3–4, Coolwater 1–4, and Long Beach 1–4, totaling 2,217 MW.

161 "Dependable capacity" here refers to the share of nameplate capacity that can be assumed to be available at the time of the system or local capacity area peak and, thus, available to meet resource adequacy requirements and assumed for planning purposes. For resources in the California ISO balancing authority, this is equivalent to net qualifying capacity.

162 Two of the scenarios proposed by the CPUC (trajectory, cost-constrained) contain 2,436 MW (nameplate) of new DG beyond that which is embedded in the 2009 IEPR demand forecast. The time-constrained scenario contains 5,305 MW; the environmentally constrained scenario 9,633 MW.

163 DG that is consumed on site or sold "over the fence" is treated as a demand-side resource, requiring an adjustment to the demand forecast; DG exported for wholesale is treated as a supply resource.

164 See the California Energy Commission comments on the California ISO 2011–2012 Transmission Planning Process, July 15, 2011, available at: www.caiso.com/Documents/CaliforniaEnergyComments_RenewablePortfolioAssumptions_2011-2012TransmissionPlanningProcess.pdf.

Renewable Integration Needs

Increased reliance on variable energy resources requires that dispatchable generation resources be available to balancing authorities in real time to provide additional regulation and load-following services to make up for differences in forecasted and actual output.[165] As OTC resources retire, new dispatchable resources *may* be necessary. In addition, the quantity of replacement capacity necessary may result in a planning reserve margin in excess of the 15–17 percent historically deemed necessary for desired levels of reliability.

The California ISO's recent studies of renewable integration concluded that the state does not need new dispatchable gas-fired generation for meeting the 33 percent by 2020 Renewables Portfolio Standard (RPS) *if certain conditions are met.* These conditions include:

- That load growth net of uncommitted energy efficiency, other DSM programs, and self-generation is consistent with the CPUC's "mid-case" assumptions for use in the 2010 Long-Term Procurement Planning Proceeding. According to the California ISO, if 2020 loads are 10 percent higher (the CPUC's "high case"), then 2,600 MW of new gas-fired generation will be necessary.[166]

- That California ISO can reduce load forecast error and that California ISO/scheduling coordinators can reduce wind and solar forecast error. If not addressed, the state will need increased amounts of dispatchable capacity to integrate large quantities of variable energy resources.

- The proposed changes in the California ISO's market rules will increase the willingness and ability of existing generation to provide additional ancillary services and less pure energy; the provision of these services is not limited by contract or cost conditions or permit restrictions.

- Reduced imports used for resource adequacy may require additional, existing in-state resources to provide energy, reducing their ability to provide ancillary services when needed.

In addition, the California ISO's renewable integration studies for 2020 do not consider local capacity requirements and assume continued operation of selected OTC capacity (Moss Landing 1–2) and availability of imports of more than 16,000 MW. The latter assumption yields a planning reserve margin in 2020 in excess of 17 percent. A different set of assumptions regarding local capacity requirements and available generation resources would possibly yield a need for new dispatchable capacity.

The settlement reached in the CPUC's 2010 LTPP Proceeding recognized that there is insufficient information for accurately estimating needed dispatchable capacity for integrating variable energy resources to meet the state's RPS. The Energy Commission anticipates that the CPUC's 2012 LTPP proceeding will evaluate this information and develop planning assumptions.

165 For a discussion of the relationship between variable energy resources an ancillary services needs, see chapter 5, Grid-level Integration Issues, in *Renewable Power in California: Status and Issues*, December 2011, CEC-150-2011-002-pLCF-REV1; for definitions of these and other ancillary services see page 103 of the same document, , www.energy.ca.gov/2011publications/CEC-150-2011-002/CEC-150-2011-002-LCF-REV1.pdf.

166 See the memorandum to the California ISO Board of Governors from Keith Casey, Vice President for Market and Infrastructure and Development, August 18, 2011, available at: www.caiso.com/Documents/110825BriefingonRenewableIntegration-Memo.pdf.

The Technological Characteristics of Gas-Fired Generation

There is substantial uncertainty regarding the quantity and technological characteristics of new gas-fired generation needed for meeting planning reserve margins, providing ancillary services for integrating large quantities of renewable resources, and providing sufficient inertia so as to maintain system stability in the face of component failures under extreme load and import conditions.

The system may require a share of new gas-fired generation exclusively to meet system, zonal, and local capacity requirements. As energy demand equals or exceeds 95 percent of forecasted peak demand only a handful of hours per year, these needs can be met with peaking resources. The system may also need gas-fired generation to provide ancillary services to support integration of new wind and solar resources; as discussed earlier, this requires combined cycle and hybrid generators that can cycle on and off and operate over a wide range of output. The Energy Commission will hold an IEPR workshop during the first quarter of 2012 to discuss the ability of new gas-fired generation to provide ancillary services.

The system may also need dispatchable gas-fired generation to provide inertia, especially in Southern California. The *2009 IEPR* first highlighted this issue in discussions during the proceeding.[167] The inertia provided by internal generation limits the imports into Southern California. This inertia requirement is binding during very high levels of demand in Southern California in the summer; while imports rise with demand, internal generation is needed to provide inertia. This constraint can also be binding during low load hours (early morning) in the spring – the low levels of internal generation during these hours can limit the ability to import abundant, low-cost hydro and coal-fired generation.[168]

Generation resources that use OTC provide a significant share of the inertia needed by the system. The retirement of OTC resources may require replacement capacity (largely gas-fired) to provide a similar amount of inertia. While solar thermal resources can provide substantial amounts of inertia, wind resources provide very little (if any), and solar PV does not provide any at all. The development of geothermal resources, on the other hand, would reduce the need for inertia from other sources; the shift from solar thermal to solar PV development may increase it.

The need for inertia from new generation resources has implications for the type and location of new gas-fired generation. The provision of inertia requires generators to be synchronized to the grid ("spinning"). To the extent that incremental amounts of inertia are needed in a large number of hours, new power plants should be load-following; for example, they should be designed for dispatch and operation at low levels of output, rather than peaking resources.[169] New gas-

167 Committee Workshop on the Potential Need for Emission Reduction Credits in the South Coast Air Quality Management District, September 24, 2009, see: www.energy.ca.gov/2009_energypolicy/documents/index.html#092409. For a discussion of inertia and the role it plays in reliability, see *Renewable Power in California: Status and Issues*, December 2011, CEC-150-2011-002-LCF-REV1, pp. 107–9. Also see Joseph H. Eto, et al, December 2010, *Use of Frequency Response* Metrics *to Assess the Planning and Operating Requirements for Reliable Integration of Variable Renewable Generation*, Ernest Orlando Lawrence Berkeley National Laboratory, LBNL-4142E, available at: www.ferc.gov/industries/electric/indus-act/reliability/frequencyresponsemetrics-report.pdf.

168 The amount of inertia needed in Southern California is indicated by the East of River/Southern California Import Transmission nomogram, developed to ensure sufficient reactive margin and inertia in the Southern California system for critical contingencies. This nomogram indicates the amount of inertia needed given electricity demand in and electricity imports into Southern California. Generation located near the Arizona and Nevada border can be located outside the area in which resources contribute inertia to meet Southern California Import Transmission requirements, instead serving only as additional imports.

169 Gas-fired generators designed for load-following also provide more inertia on a per-MW basis than peaking resources.

fired resources would also have to be located within the boundaries of the area affected by the Southern California Import Transmission nomogram.[170]

Studies are underway to help understand the future needs of the transmission grid. The California ISO is conducting a study with General Electric on frequency response and system inertia as part of the Renewable Integration Analyses. This study was expected to be completed by the end of 2011. The California ISO also is conducting analyses as a member of the interagency working group providing assistance to the ARB and SWRCB.

Combined Heat and Power Development

California has set targets for efficient combined heat and power (CHP), which can reduce GHG emissions by jointly producing electricity and capturing waste heat to power industrial, commercial, and institutional processes (with less fuel than would be required separately).[171] The ARB's *AB 32 Scoping Plan*[172] called for the development of 4,000 MW of new CHP by 2020 as a strategy for reducing GHG emissions by 6.7 million-metric tons (MMT). Governor Brown's Clean Energy Jobs Plan calls for the development of 6,500 MW of new CHP by 2030.

The CPUC's qualifying facility (QF) settlement[173] adopts the *Scoping Plan* target, allocating it based on retail sales to the state's large IOUs (4.3 MMT), energy service providers and community choice aggregators (0.5 MMT), and the state's publicly owned utilities (1.9 MMT).[174] The settlement establishes a near-term target of 3,000 MW for entities under CPUC jurisdiction, but this capacity includes not only new CHP, but the renewal of QF contracts due to expire during the next three years. From 2015 onward, "CHP request for offers" will procure more CHP to the extent that the GHG emissions reduction target has not been met.

The planning assumptions used in the CPUC's 2010 LTPP Proceeding[175] reflect a commitment to both maintaining existing CHP and developing new projects. The proceeding assumes the retention of existing CHP (totaling 5,233 MW)[176] through the

170 A *nomogram* is a two-dimensional diagram that allows the approximate computation of a function. California ISO, Operating Procedures Index List, updated January 3, 2012, available at: www.caiso.com/Documents/OperatingProcedureIndex.pdf.

171 There are nearly 1,200 active CHP projects in California totaling more than 8,800 MW, with nearly 90 percent of this capacity coming from systems greater than 20 MW. CHP has significant additional market potential, as high as 6,200 MW, despite significant barriers to entry; see *Combined Heat and Power Market Assessment*, ICF International, Inc., April 2010, available at www.energy.ca.gov/2009publications/CEC-500-2009-094/CEC-500-2009-094-F.PDF. A significant share of existing projects produce for on-site consumption only; the loads and capacity embodied in this self-generation are not included in load and resource accounting tables compiled and used by state energy agencies.

172 California Air Resources Board, *Climate Change Scoping Plan*, December 2008.

173 D.10-12-035, issued December 21, 2010, in A.08-11-011, modified by D.11-07-010 (July 14, 2011) and D.11-10-016 (October 6, 2011).

174 Parties to the QF settlement note that the CPUC does not have jurisdiction over publicly owned utilities but assert it can set GHG emissions reduction targets for the IOUs, electric service providers, and community choice aggregators.

175 For the CHP assumptions proposed for use by CPUC staff in the 2010 LTPP proceeding, see the CHP tab of the spreadsheet posted on December 7, 2010, at: www.cpuc.ca.gov/PUC/energy/Procurement/LTPP/ltpp_history.htm.

176 The 3,513 MW are on the supply-side, representing expected exports to the grid during the peak hour. Another 1,720 MW is on the demand side, reflecting on-site consumption during the peak hour adjusted upward to account for transmission and distribution losses of 7.7 percent.

planning period (2020). It assumes new CHP in place by 2020 is roughly half of the 4,000 MW originally targeted by the ARB.[177]

The amount of new CHP developed through 2022 will depend upon a number of factors besides the effect of the QF settlement. Although many existing CHP generators provide GHG reductions compared to the benchmark established in the QF settlement, some do not. The IOUs may meet their share of the emissions reduction target in part by terminating contracts with CHP resources that fail to meet the benchmark so these resources may or may not continue to operate. While failing to procure the remaining share of the 3,000 MW target cannot be based on conventional resources being lower-cost, best-fit, such consideration could be used to justify not reaching the GHG reduction target set forth in the settlement.[178] Further, although the settlement maintains a must-take obligation for CHP up to 20 MW in size, it has been more difficult to develop small CHP despite programs designed to encourage its development. Table 14 summarizes these programs and their yield to date.

Discussions with CHP generators and developers indicate that continued regulatory uncertainty and the lack of resolution on the high costs associated with standby charges and departing load fees negatively affect private sector CHP investment decisions in California. The largest barrier, especially for large CHP developers, continues to be uncertainty relating to GHG regulations and costs under AB 32. Others include local permitting issues, CHP program delays due to slow implementation and prolonged legal conflicts, and long waits for interconnection.

Energy Commission staff has commissioned an update of the 2009 Public Interest Energy Research (PIER)-funded *Combined Heat and Power Market Assessment*, which will be discussed in a staff workshop in February 2012.[179] This analysis will provide information for projections regarding potential ranges of CHP development in aggregate, as well as information on potential CHP development in local capacity areas, and thus the residual need for new, conventional gas-fired generation both systemwide and in local areas. Staff also plans to produce a white paper on CHP development and related issues in early 2012 and is working with CPUC staff to assess the potential disposition of existing CHP projects under the QF settlement. This body of work, along with input from stakeholders in future IEPR proceedings, will provide information for assessments of likely CHP development through 2022, the policy measures that will encourage development during this period, and reaching 2030 targets.

177 The 4,000 MW is reduced to 3,742 MW to account for new CHP assumed in the Energy Commission demand forecast. This number is then halved (to 1,871 MW) with 936 MW on both the supply- and demand sides, in keeping with ARB assumptions. Slightly more than 80 percent of this (1,505 MW) is allocated to the California ISO balancing authority area; the remainder is assumed to be developed in the four other balancing authority areas in the state.

178 See Section 6.9 of the QF settlement agreement.

179 ICF International, Inc., *Combined Heat and Power Market Assessment*, (CEC 500-2009-094-F, April 2010), available at: www.energy.ca.gov/2009publications/CEC-500-2009-094/CEC-500-2009-094-F.PDF.

Table 14: Programs for Small CHP

	Technology	Program Cap	Capacity to Date (MW)	Installed Capacity CHP (MW)	Number of CHP Projects
AB 1969 FIT[A]	Small Hydro, CHP, PV	750 MW	38.5	17.1	16
AB 1613[B]	CHP Only	N/A	0	0	0
Self-Generation Incentive Program[C]	Wind, Fuel-Cells, Gas Turbines, IC Engines, Microturbines, Energy Storage	Limit Based on Program Funding	191	171	337
CHP/QF Settlement[D]	CHP Only	3,000 MW			
SMUD FIT Solicitation[E]	Solar & CHP	0-100	100	0	0

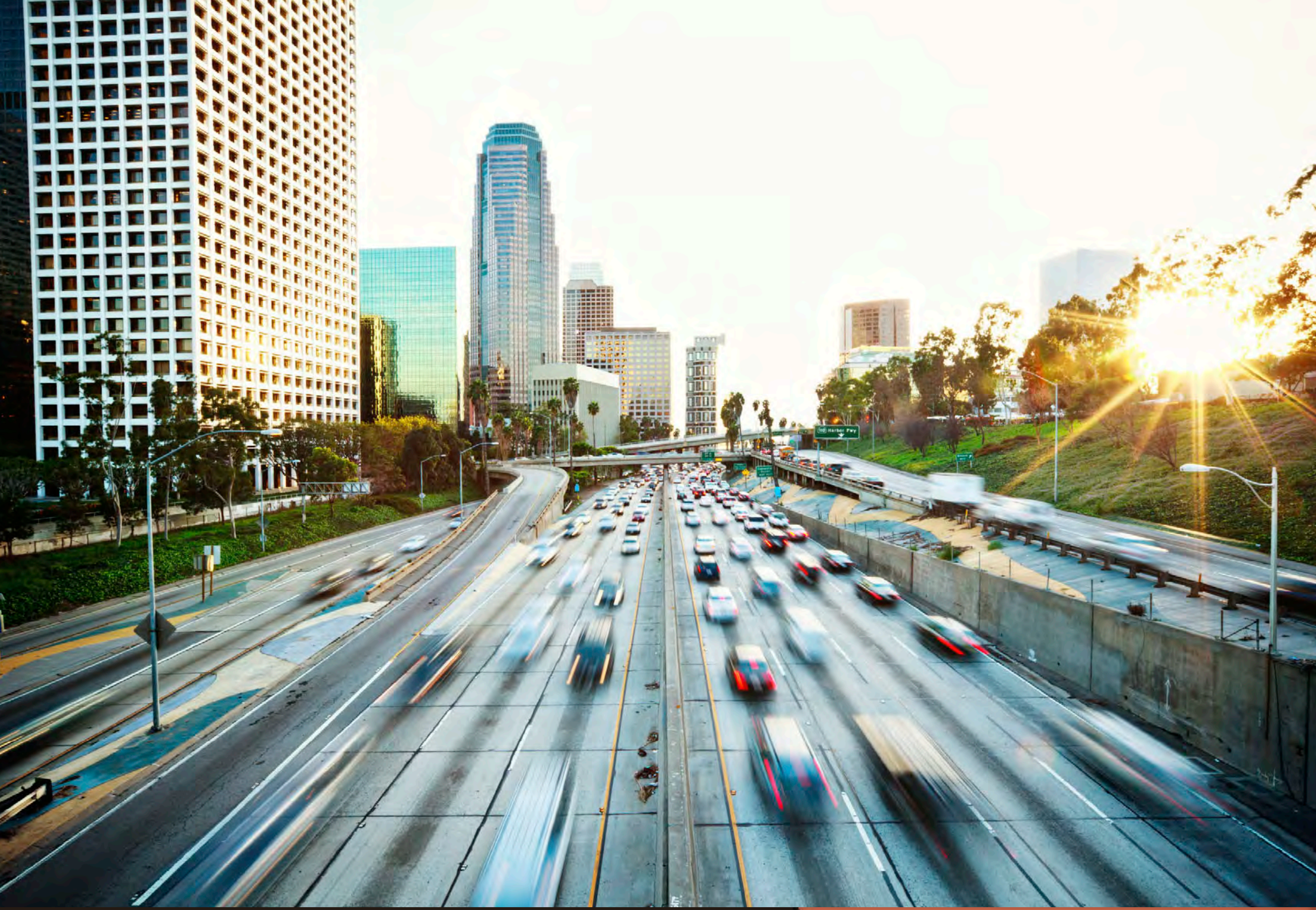
A AB 1969 was revised by SB 32, subsequent development is included.

B Program is still pending due to controversy over contract terms.

C The SGIP Proposed Decision brings back the inclusion of internal combustion engines, gas turbines, and microturbines that were all dropped from the program in 2008.

D The 3,000 MW is divided among the three IOUs based on load served. (1,387 for PG&E, 1,402 for SCE, and 211 for SDG&E) In addition, there is a GHG reduction target that may require additional capacity to be procured, but that amount is unknown at this time.

E Capacity is not yet in place, but the program is fully subscribed (30 projects total, all solar).



CHAPTER 10

Transportation Energy Forecasts and Analysis

This chapter provides a brief background and analysis of transportation energy issues with an emphasis on challenges that have the potential to affect the availability and market price of transportation fuels over the near to mid-term. California's transportation energy sector provides residents and businesses with the means and mobility for many essential activities. Industry, commercial businesses, households, transit agencies, and government all rely on transportation energy and expect that needed supplies will be available for movement of goods and people over highways, rail, waterways, and air. Transportation fuels also provide energy for off-road, industrial, agricultural, commercial, military, and recreational uses.

Any source of energy for transportation has economic, environmental, security, and infrastructure dimensions. Petroleum fuels refined from crude oil, currently the dominant transportation energy source in California and globally, have historically had many advantages. These include high energy content, portability, storability, established vehicle fleet and equipment stock, and established refining, transportation, storage, and distribution infrastructure. Until recently, petroleum was a lower-priced and well-supplied source of fuels; however, these advantages appear to be eroding. While petroleum will be available far into the future[180] and markets will fluctuate, higher prices may be a permanent feature of future fuels markets and offer greater incentives for increased use of alternative and renewable fuels. Some stakeholders and analysts have gone further and argued that world-wide crude oil production has peaked, or will shortly, and that the petroleum dependent global economy is at high risk for substantial disruption.[181] Petroleum use raises other considerations, since it is the source of about 40 percent of state GHG emissions, as well as other air, water, and land pollutants. Also, California relies heavily on foreign imports of petroleum from geopolitically sensitive areas, which can create significant supply and price vulnerabilities. As a consequence of these undesirable characteristics, state and federal policies and regulations have been implemented to reduce future petroleum use.

There are three general strategies for reducing petroleum use: 1) increasing fuel efficiency in the fleet of vehicles, engines, aircraft, and vessels;[182] 2) using nonpetroleum fuels; and 3) changing land use and urban design to reduce vehicle travel.[183] One common challenge among these approaches is developing new infrastructure, vehicle technologies, and markets. While existing systems still serve a need, the new systems are proposed to avert negative impacts from continuing business-as-usual trends. Moreover, while alternative strategies have many benefits, they also come with their own sets of economic, technical, and policy challenges.

Transportation Energy Demand and Policy Impacts

To better understand the effects of potential future trends in transportation energy use, the Energy Commission staff has developed two scenarios of transportation energy demand and fuel prices, as well as analyses of the impacts on supply and demand of a variety of federal and state policies and regulations. These scenarios are not intended to be explicit predictions of the future, but rather to explore the potential range, magnitude, and direction of trends in energy use and price, vehicle purchase, and supply and infrastructure requirements under a wide array of uncertain future conditions. Ideally, this will enable policy makers to better anticipate challenges and opportunities for implementing the significant changes being proposed to the transportation energy

180 Yergin, Daniel, 2011. *The Quest: Energy, Security, and the Remaking of the Modern World.* Penguin Press.

181 Written comments by Gary Goodson, dated December 20, 2011, and David Fridley, dated December 20, 2011, available at www.energy.ca.gov/2011_energypolicy/documents/comments_draft_iepr/.

182 The Energy Commission's PIER Program is funding the California High Efficiency Advanced Truck Research Center (CalHEAT) in Pasadena, which will research and deploy technologies that increase use of alternative fuels and reduce the impact of emissions near ports and major transportation corridors. Research includes demonstrating successful electric hybrid configurations with a variety of fuels to stimulate introduction of more efficient trucks and buses into early market niches, such as port trucks (drayage carriers).

183 Reducing vehicle miles traveled continues to be an important state policy for reducing petroleum dependence. Senate Bill 375 (Steinberg, Chapter 728, Statutes of 2008) calls for the integration of land use planning, housing planning, and transportation planning to reduce vehicle miles traveled. The Energy Commission's *Energy Aware Planning Guide* is a tool to help municipal governments achieve the policy goals of Senate Bill 375. Please see: www.energy.ca.gov/2009publications/CEC-600-2009-013/CEC-600-2009-013.PDF.

system and its related markets, as well as California's ability to reach the goals set by such policy guiding documents as the *Bioenergy Action Plan*, the *State Alternative Fuels Plan*, various *Integrated Energy Policy Reports*, and regulations such as the Low Carbon Fuel Standard (LCFS).

The transportation energy planning scenarios make assumptions about important variables such as fuel prices, demographics, the economy, and the effects of existing rules and policies, such as Assembly Bill 1493 (Pavley, Chapter 200, Statutes of 2002), the revised Corporate Average Fuel Economy standards, and the Zero Emission Vehicle (ZEV) mandates. The forecasting tools used to simulate these scenarios, however, do not account for the effects of all existing or proposed regulations. Staff modified the preliminary model-generated forecasts to assess the effects of several significant regulatory standards, in particular the federal Renewable Fuels Standards II (RFS2) and California's LCFS, among others, under a variety of assumptions.

Transportation Energy Demand – Historical and Forecast

Over the last several years, California's total transportation energy and travel demand has steadily declined, primarily the consequence of high prices and a prolonged economic downturn. Specifically, the consumption of gasoline, diesel and jet fuel has declined from a combined total of 23.2 billion gallons in 2006 to 21.5 billion gallons in 2010. This represents a 7.2 percent decline in consumption. However, the decline in petroleum dependence over the same period has been even greater at 9.8 percent. This additional drop is due to the increased use of ethanol in gasoline. Data for 2011 indicate that gasoline and diesel consumption for the first seven months of 2011 were down 2.0 and 2.1 percent, respectively, from 2010. This weakness results from the combination of sustained high fuel costs, low economic growth, and continued high unemployment (which stood at 11.9 percent as of September 2011 for California) leading to less movement of goods and people.

Forecasts of California's petroleum, renewable, and alternative transportation fuel demand by Energy Commission staff are based on scenarios of High and Low Petroleum Demand. Staff's preliminary forecasts for these two scenarios are not adjusted for the effects of the federal RSF2, whereas the final forecasts are. The unadjusted forecast for gasoline use in the "Low Petroleum Demand Scenario" falls 4.2 percent from 2009 to 14.2 billion gallons by 2030, largely as a result of high fuel prices, efficiency gains, and competing fuel technologies. In the "High Petroleum Demand Scenario," assumptions such as the recovering economy and lower relative fuel prices lead to gasoline consumption growing 15.8 percent to 17.1 billion gallons in 2030, again unadjusted for RFS2. However, for California obligated parties (refiners, importers, and blenders) to comply with RFS2 ethanol consumption requirements, staff concludes that its gasoline consumption forecast would need to be modified to reflect greater consumption of ethanol. Since staff assumed that ethanol blended in gasoline will be capped at 10 percent, satisfying the RFS2 obligations will require substantial increases in the use of ethanol, such as additional E85, expansion of ethanol blended gasoline to E15 levels or aggressive development of low carbon biofuel production in California and other states. All of these options face difficulties, and additional analyses should assess the potential impacts of all of these options and combinations of options.

After adjusting for the effect of California's RFS2 proportional share obligations, staff estimates the final forecast of gasoline consumption in the Low Petroleum Demand Scenario to decline 15.6 percent from 2009 to 12.5 billion gallons by 2030. This is substantially lower than the preliminary estimate prior to RFS2 compliance and, as noted, is primarily the result of increased ethanol consumption through one or more options to fulfill RFS compliance. The final

RFS2 adjusted annual gasoline consumption estimate in the High Petroleum Demand Scenario increases to about 16 billion gallons by 2030, an 8 percent increase from 2009.

The RFS2 has only a modest impact on forecasted diesel demand in California. In the preliminary forecast, total annual diesel consumption in the Low Petroleum Demand Scenario increases to 4.1 billion gallons by 2030, largely because of continued economic growth and freight movement. Adjusting for RFS2 proportional share obligations reduces the final diesel consumption forecast slightly in this scenario to 3.9 billion gallons by 2030, or an increase of 22.3 percent from 2009. In the High Petroleum Demand Scenario, which assumes a higher rate of economic growth, total unadjusted annual diesel consumption increases to 5.0 billion gallons by 2030. Adjusting for RFS2 proportional share obligations reduces diesel consumption to 4.8 billion gallons, an increase of 50.4 percent from 2009 levels.

The RFS2 requirements present California with a dilemma on how to make a commitment to a sizeable amount of ethanol and fulfill multiple state policy objectives such as the Low Carbon Fuel Standard, petroleum displacement goals, and *Bioenergy Action Plan* goals. All of the options to increase ethanol use face numerous challenges and involve some unintended consequences to fulfill the RFS2 requirement. The U.S. EPA's continual waivers of RFS2 requirements that obligated parties produce a minimum amount of advanced or cellulosic biofuels jeopardizes California's efforts to develop low-carbon biofuels from agricultural, forestry, and urban waste residue and some purpose-grown crops.

Available forecasts for electric vehicles vary widely both in magnitude and the split between plug-in hybrid electric vehicles (PHEVs) and full electric vehicles (FEVs). These differing projections reflect considerable variation in assumptions that can be made about the technology, including consumer acceptance, vehicle attributes and costs, fuel prices, manufacturer plans, vehicle use (especially vehicle miles traveled), and energy efficiency ratios compared to gasoline vehicles. Energy Commission staff forecasts incorporate current fuel efficiency standards, RFS2, and ZEV mandate but do not estimate potential effects of the LCFS program on EV populations. Between 2009 and 2025, various forecasts show that electric vehicle growth will increase rapidly, largely the result of substantial, cumulative market penetration of PHEVs and FEVs, ranging from 440,000 vehicles in 2020 to 1.4 million vehicles by 2025. Future analysis will be needed to evaluate and confirm the amount of electricity consumed by electric vehicles and the number of PHEVs and FEVs.

Staff forecasts annual transportation consumption of natural gas to increase at a compound annual rate of over 3 percent to between 243 million and 256 million gasoline gallon equivalents by 2030, a range of 87 to 96 percent above 2009 levels. Staff did not project hydrogen fuel cell vehicle (FCV) population or fuel use in this analysis because the 2009 California Vehicle Survey did not ask for consumer response to these types of vehicles. Surveys of automakers conducted by the Energy Commission and Air Resources Board (ARB) projected estimates of about 50,000 FCVs by 2017.

Staff's electric and natural gas fuel demand and vehicle projections were the focus of considerable oral and written comments by stakeholders; staff intends to further assess the wide range of uncertainties associated with these forecasts in future staff reports. Moreover, future consumer travel and vehicle choice surveys will be conducted collaboratively between the Energy Commission, the ARB, and Caltrans to develop more widely vetted and consistent forecasts.

Federal Regulation – Renewable Fuels Standard (RFS2)

The RFS2 permits a maximum volume of corn ethanol and mandates specific volumes of cleaner or more advanced biofuels. These volume mandates apply to all petroleum fuel producers nationwide. In California, the likely effect of RFS2 and LCFS combined will be greater consumption of lower-carbon-intensity (CI) ethanol. Energy Commission staff forecast that 2.7 billion to 3 billion gallons of increased volumes of ethanol from one or more options will be required by 2030. Increased consumption of E85 as one option is contingent upon availability of adequate numbers of vehicles, refueling facilities, appropriate fuel supplies, and California consumer demand for vehicles and fuel. Vehicle manufacturers would need to build more flexible fuel vehicles (FFV) to consume the greater E85 volumes.

To realize this RFS2-adjusted forecast, California's retail fueling infrastructure may require the installation of between 1,300 and 13,000 E85 dispensers by 2022, depending on total demand and dispenser throughput. The estimated average cost per E85 dispensing unit, including installation and permitting of tank, dispenser, and appurtenances at 23 existing stations funded by the Alternative and Renewable Fuel and Vehicle Technology Program, was about $330,000. Retail gas station owners and operators have no obligations under the RFS2 regulations to offer E85 for sale and little to no financial incentive to make an investment of this size. The difficulty facing station owners to consistently set the retail price of E85 low enough (relative to gasoline), while still making a profit, may be hard to overcome. The challenge comes about because consumers who use E85 in their FFVs will experience between 23 and 28 percent lower fuel economy compared to gasoline that contains only 10 percent ethanol. This means that a retail station owner would need to price E85 at least 23 percent lower than gasoline (E10). Recently, California E85 wholesale prices were calculated to be 20.2 percent lower than E10 in 2009, 24.3 percent lower during 2010, and 16.4 percent lower during the first 8 months of 2011. Ethanol prices over the last couple of years have not been low enough to provide a sufficient discount to enable retail sellers of E85 to consistently offer this fuel for sale to the public at a low enough discount to compensate for the decreased fuel economy.

The need to use more advanced types of ethanol to help achieve compliance with the RFS2 and LCFS regulations could necessitate increased use of new types of ethanol, such as sugarcane ethanol from Brazil and cellulosic ethanol, both of which may command an additional price premium compared to traditional corn-based ethanol. This would decrease the likelihood that E85 could be competitively marketed in California on a consistent and widespread basis without the use of even lower retail tax treatment and/or ongoing price discounting by petroleum suppliers that would need to supply ethanol for E85 at prices that induce owners of flexible-fuel vehicles to use E85. There is an increased risk that some or all of the elements necessary for significant penetration of E85 will not come to pass, complicating the ability of obligated parties in California to comply with the RFS2 mandates.

However, the LCFS does provide strong incentives for producers of low-carbon-intensity ethanol to price their products competitively. This is due to a number of reasons, including the LCFS provisions that provide greater credits for lower CI fuels and the lack of an expiration date on the credits. Because of this, ARB anticipates that E85 may play a significant role in pathways that LCFS regulated parties will likely take to comply with both the LCFS and RFS2 requirements.

Increased use of advanced biofuels will help reduce the need for substantial volumes of E85. Some advanced biofuels, such as sugarcane and cellulosic ethanol, have price structures that currently price them above corn ethanol. However, this effect could be moderated because the CIs for U.S.-produced corn ethanol have become considerably lower than originally anticipated as U.S. producers find ways to lower their production carbon footprint. This will result in increased value for LCFS credits based on lower CI ethanol, including lower CI corn ethanol. This will be particularly true as the LCFS compliance standards become more stringent, making lower CI fuels even more attractive since they generate more credits. Substantial U.S. and California investments in low CI ethanol and other fuels would further offset initial price differentials for the lower CI ethanol. Indeed, there are indications that such substantial investments have been occurring. It is anticipated that such investments will continue to occur if California, through the Energy Commission's Alternative and Renewable Fuel and Vehicle Technology Program, maintains its leadership role in transforming the transportation fuels sector and consistently sends clear market signals that provides investors with certainty.

The second challenge associated with the RFS2 is the ability of the biofuels industry to provide sufficient quantities of cellulosic biofuels necessary to achieve compliance with the federal annual minimum target volumes. Further technological advances are needed to overcome higher production costs relative to the costs for conventional biofuels such as corn-based ethanol. As a consequence, the U.S. EPA has had to downgrade the minimum cellulosic fuel requirements by 94 percent between 2010 and 2012. Staff has elected to use a lower projection of cellulosic fuel availability than the minimum standards set forth by Congress. Staff's proportional share RFS2 compliance analysis incorporated the cellulosic biofuel projections provided by the Energy Information Administration (EIA). A continuation of the slow pace of progress for commercialization of large volumes of cellulosic ethanol may present challenges for meeting California's LCFS towards the end of the decade. Energy Commission and ARB staff will continue to coordinate on these scenarios to refine them and identify additional scenarios that can be used to meet the LCFS goals beyond 2017–2018 and to anticipate the various challenges that may arise.

Another set of concerns about the higher mandated levels of biofuel use prescribed by the RFS2 includes effects on water use and water quality. A study sponsored by the National Academies of Science has identified several areas of uncertainty with regard to such impacts, including amount of added irrigation needed to provide mandated biofuels, types and amounts of fuel feedstocks required, additional fertilizer and pesticide requirements for feedstock crops, potential changes in farming methods, and water requirements of biorefineries.[184] Cellulosic feedstocks may have the potential to reduce some of these impacts. Staff should continue to monitor research into these subject areas, including any that are specific to California, and incorporate findings into future reports.

State Regulation – Low Carbon Fuel Standard

The LCFS requires a 10 percent reduction in the average CI, (as measured by both direct and indirect life cycle carbon emissions) of California transportation fuel between 2010 and 2020.[185] Staff has prepared case analyses to assess the feasibility of compliance with the LCFS using various types of biofuels and LCFS credits for transportation electricity and natural gas. Prices were projected for all of the biofuels included in the analysis and generally show an increase in value throughout the forecast due to an assumed rising value for fuels that have lower carbon intensities than traditional biofuels. The ARB approved amendments to the LCFS regulation on December 16, 2011, and presented fourteen plausible scenarios of potential low-carbon fuel options to achieve regulation compliance.

Compliance with LCFS throughout the entire forecast period will evolve over time and presents challenges not yet examined. It should be noted that 2011 is the initial year of CI reductions under any of

184 National Academies of Science, *Water Implications of Biofuels Production in the United States*, 2008; available at www.nap.edu/catalog.php?record_id=12039.

185 Please see the California Air Resources Board website that contains background information and regulations at: www.arb.ca.gov/fuels/lcfs/lcfs.htm.

the cases examined, and it is difficult to forecast with accuracy compliance with the LCFS over the long term. For these cases, Energy Commission staff assumed that all uses of electricity and natural gas for transportation would generate carbon credits for regulated parties. However, this assumption depends on ARB completing its assessment of what portion of existing transit electricity use may be eligible for credits and at what levels. Aggregate statewide compliance with the standard is achieved when the quantity of carbon credits (as measured in metric tonnes) yielded from the use of biofuels, electricity, and natural gas exceeds the quantity of carbon deficit generated from petroleum-based gasoline and diesel fuel.

The main challenge associated with the LCFS is ensuring that production and delivery to California of sufficient quantities of low-CI biofuels are ramped up to help achieve compliance in the later years of the program.

Biofuel Availability

Staff analyses for LCFS compliance cases assume that LCFS compliance feasibility through 2017 was accomplished through the use of up to 50 percent of the nation's available supply of cellulosic gasoline forecast by EIA.[186] If up to 50 percent of the other cellulosic biofuels (cellulosic ethanol and cellulosic diesel) forecast by EIA to be available in the United States were also used in California, compliance with the LCFS could be extended through 2019. A continuation of the slow pace of progress for commercialization of large volumes of cellulosic ethanol may present challenges for meeting California's LCFS toward the end of the current compliance period. The Energy Commission's Alternative and Renewable Fuel and Vehicle Technology Program (ARFVT Program) has awarded $45 million to cofund the initial stages of 17 biofuel projects in California that could produce up to 600 million gallons of advanced biofuels by 2020 if full-scale commercialization occurs in each project.

The diesel scenarios depend, in part, on relatively large quantities of renewable diesel from inedible tallow and biodiesel from corn oil. For example, staff has assumed that 50 percent of the feedstock that is theoretically available is used to produce these two types of biofuels and all of this production is sold to California for use in the LCFS program. Staff has calculated in Case 3 that 22 percent of the carbon credits generated by 2017 would be obtained from renewable diesel alone, underscoring their importance for compliance, assuming credits are not sufficiently available in the market.

There are several challenges to any reliance on higher biodiesel blends. The challenges include ensuring adequate volumes of specific fuel types; need for ensuring infrastructure compatibility with higher biodiesel concentrations; and manufacturer vehicle engine warranty concerns for biodiesel blends in excess of 10 percent. While these considerations present challenges to the increased use of biodiesel, particularly at the higher blends, sufficient time, testing and investments are expected to address these concerns. ARB also has identified the potential for increased oxides of nitrogen (NO_x) emissions in higher biodiesel blends but has expressed its intent to address and mitigate this potential when it pursues a rulemaking to establish standards for biodiesel blends greater than 6 percent by volume during the latter portion of 2012.[187]

The final challenge for biofuel availability has to do with Brazilian ethanol. Energy Commission

186 During the November 14 workshop, staff incorrectly noted during the LCFS presentation that "cellulosic fuel availability increased to 50 percent of U.S. supply" as one of the assumptions for Case 3. The correct assumption should have read "Cellulosic *gasoline* availability increased to 50 percent of U.S. supply." See slide 4 from the following link: www.energy.ca.gov/2011_energypolicy/documents/2011-11-14_workshop/presentations/Schremp-LCFS.pdf.

187 California Air Resources Board*, California Air Resources Board Guidance on Biodiesel Use*, October 2011, page 2. A link to the regulatory guidance advisory is as follows: www.arb.ca.gov/fuels/diesel/altdiesel/20111003Biodiesel%20Guidance.pdf.

scenario analysis shows that California could be using more than 1 billion gallons of Brazilian ethanol by 2016, which is nearly 75 percent of the record for Brazilian exports to the world during 2008 of 1.35 billion gallons. In this scenario, nearly 11 percent of the credits generated during 2016 are from Brazilian ethanol. These historical figures are all pre-LCFS, so it remains to be seen to what extent Brazilian ethanol production can be ramped up. Energy Commission and ARB staff will continue to monitor volumes of biofuels coming into California to ensure that adequate steps are taken to bring in sufficient quantities of advanced biofuels.

Biofuel Costs

Transportation fuel costs for consumers and businesses are forecast to continue rising due to higher crude oil prices. To the extent some biofuels may be more expensive to produce than the petroleum and renewable fuels they displace, at least in the early years of the RFS2 and the LCFS, consumers and businesses may be affected. For example, the estimated price to deliver Brazilian ethanol to California has averaged about $1 more per gallon greater than ethanol delivered to California from the Midwest during 2010 and about $1.50 per gallon greater[188] compared to ethanol delivered to California from the Midwest during the first eight months of 2011. The federal import tariff and ad valorem tax expired at the end of 2011, which could decrease the cost of importing Brazilian ethanol to California beginning in 2012. Given the historical variation in the price of Brazilian ethanol and the uncertainty of future tariffs, it is difficult at this time to make reliable projections on future impacts on fuel prices.

Although there are no prices yet for transactions involving cellulosic ethanol, the RFS2 program has a well-established credit trading platform that provides some insight into the potential incremental costs of this type of biofuel compared to traditional corn-based ethanol. Between January and August 2011, cellulosic ethanol Renewable Identification Number credits have averaged about $1.00 more when compared to traditional ethanol. This translates into a price of roughly $200 per ton of carbon credits produced, attributable to the federal RFS2 program alone.

Biodiesel is another example of a biofuel that currently costs more than conventional diesel. Its increased use in California is a natural result of the RFS2 volume mandates, and the LCFS will benefit from that increased use because of biodiesel's reduced GHG emissions. Prices of biomass-based biodiesel (such as soy biodiesel) have averaged nearly $3.00 more per gallon when compared to petroleum-based diesel fuel during 2011. California regulated parties may prefer to avoid the use of soy biodiesel due to the higher carbon intensity of that fuel and focus demand on biofuels that use corn oil and used cooking oil as feedstocks. These other types of biofuels may command an even higher premium than soy biodiesel. The extent to which those biofuels may cost more is unknown since there is no LCFS credit trading platform currently active that would establish a range of carbon values in the marketplace that could be used to estimate incremental costs for these lower CI biofuels. It should be noted that the ARB adopted regulatory amendments on December 16, 2011, that contain provisions for its Executive Officer to develop reporting requirements of prices for LCFS credit transactions, so staff will have a better idea of carbon intensity values as the market matures.[189]

The above discussion notwithstanding, substantial investments in advanced biofuels can significantly increase the volumes of such fuels being

188 The current higher cost of Brazilian ethanol is, in part, due to an import tariff imposed by the United States. This form of protectionism increases the cost of supplying ethanol to the United States market by at least 60 cents per gallon and is a type of trade challenge not applied to other types of foreign imports such as crude oil, gasoline, jet fuel, and diesel fuel.

189 California Air Resources Board, *Board Book*, page 64, see: www.arb.ca.gov/board/books/2011/121611/start.pdf.

delivered into California. That would have the benefit of lowering prices of these advanced biofuels, thereby reducing and offsetting the effects noted above. The ARFVT Program is one source of funding to stimulate development of California biofuel production plants. ARB staff has committed to evaluating improvements and refinements in the LCFS program with the express intent of incentivizing the substantial increase in advanced biofuel and alternative fuel production.

Expansion of Similar Standard Outside California

California is the only state with an active LCFS program. However, 22 other states are developing or considering LCFS programs that equate to 3.7 times the quantity of gasoline consumed in California and 7.2 times the quantity of diesel fuel consumed in California during 2009. One possible result is that the incremental demand for the same type of biofuels used to comply with California's LCFS program could increase if any other region of the United States carried out implementation of an LCFS-like program. This could increase competition and raise the market-clearing prices of these biofuels for California, if the volume of biofuels does not increase accordingly. This is an area of fundamental importance and uncertainty; that is, will increased demand for different types of biofuels increase fuel prices or induce production of these fuels at levels where economies of scale can reduce the price effects of higher demand, and over what time period will adjustments occur?

Next Steps

Staff will continue to assess compliance feasibility scenarios as part of its continuing analytical efforts associated with the current *IEPR* and beyond. This additional work will include an assessment of the potential effects of price changes for biofuels on LCFS compliance costs and the potential sources and likelihood of excess credit generation. Further work will be undertaken to assess the potential costs of compliance with both the RFS2 and the LCFS. Additionally, the ARB's recently adopted amendments to the LCFS regulation regarding the handling of high carbon intensity crude oil may affect overall LCFS compliance, and the Energy Commission staff will work with ARB staff in their assessments of those provisions.

On December 29, 2011, the U.S. District Court for the Eastern District of California issued several rulings in the federal lawsuits challenging the LCFS.[190] One of the court's rulings preliminarily prohibits the ARB from enforcing the regulation. While ARB intends to appeal these rulings and to seek an order staying the preliminary injunction, as long as the injunction remains in effect, ARB will withhold enforcement of the LCFS requirements. The potential effect on the regulation's enforcement and the behavior of LCFS obligated parties during the remaining period of litigation is uncertain. Energy Commission staff will continue to monitor additional legal developments and ARB regulatory advisories.

Finally, ARB's initial implementation period for the LCFS was projected up to 2020, with plans to revisit the program before then to consider long-term refinements to ensure the program can sustain/maintain CI reductions beyond 2020. Moreover, the LCFS regulation itself mandates a minimum of two formal program reviews, with the opportunity for ARB staff to conduct additional informal program reviews. These program reviews will help ensure that the LCFS program is monitored closely and, as necessary, adjustments can be made to the program to ensure long-term sustainability. Energy Commission staff will work closely with ARB during these formal and informal reviews.

190 *Low Carbon Fuel Standard (LCFS) Supplemental Regulatory Advisory 10-04B*, California Air Resources Board, Regulatory Advisory, December 2011, page 1. A link to this document is as follows: www.arb.ca.gov/fuels/lcfs/123111lcfs-rep-adv.pdf.

Transportation Energy Infrastructure Requirements

Renewable and Alternative Fuels Supply and Infrastructure

Demand for biofuels in the United States is expected to grow due to the RFS2 mandates, while the demand in California is forecast to grow at an even higher rate due to the LCFS. Certain biofuels (ethanol in low level blends, biodiesel, renewable diesel, and renewable gasoline) will require only modest fueling infrastructure investment and little to no modifications to motor vehicles to enable greater use. However, electricity, natural gas, and especially hydrogen are examples of alternative transportation energy that will require billions of dollars of investment in fueling infrastructure and initially higher prices for vehicles that run on these fuels over the next several years. The challenges faced by these types of alternative fuel technologies may restrict the extent of penetration in the transportation sector without continued and expanded government assistance to help defer some of these incremental costs. Although natural gas prices have declined to a substantial advantage over petroleum fuels and the cost of off-peak electricity – taking into account the greater efficiency of electric vehicle energy use – is very competitive with gasoline prices, the high retail price of hydrogen will also need to be overcome for expansion of FCV markets over the near to mid-term. The ARFVT Program's incentives can promote the development and use of alternative fuels through cofunding of projects in public/private partnerships. The Clean Fuels Outlet program indicates the program is feasible for hydrogen stations at prices for hydrogen ranging from roughly two or three times that of gasoline.

Ethanol Infrastructure

California ethanol use is widespread and blended with gasoline at a concentration of 10 percent by volume. The state's infrastructure to receive, distribute and blend ethanol is robust and adequate to accommodate a continued growth of ethanol use over the next several years. Foreign sources of ethanol (from Brazil and Caribbean Basin Initiative countries) are expected to play a more pivotal role for both RFS2 and LCFS compliance and have recently reappeared with deliveries of Brazilian ethanol to Florida and to California from El Salvador during July 2011. However, the inability of Brazil to routinely provide sufficient incremental exports of ethanol to the United States may require additional swapping of Midwest ethanol in exchange for Brazilian ethanol. Domestic fuel costs could rise, with no corresponding decline in total global carbon emissions; in fact, the increased tanker traffic could raise emissions. Much of Brazilian sugarcane has been recently diverted from ethanol production to sugar production because of attractive global sugar prices, which has already increased Midwest exports of ethanol to Brazil. Thus, there are multiple factors that may affect the global distribution of ethanol.

Rail imports have accounted for about 91 percent of California ethanol supply over the last seven years, followed by marine imports (5 percent) and in-state production (4 percent). There were no marine imports of ethanol during 2010 due to unfavorable economics in foreign source countries. However, marine imports could increase in the future if California transitions to greater use of lower-carbon-intensity ethanol from Brazil or Caribbean Basin Initiative countries. There are two pathways for foreign ethanol to enter California: marine vessels directly from Brazil and rail shipments from another marine terminal outside California. A proposed Sacramento renewable fuels hub terminal, if constructed, could greatly increase the marine ethanol import capability of Northern California and be more than sufficient to receive Brazilian ethanol over the near to mid-term period. Alternatively, ethanol from Brazil could be imported through the Houston ship channel and transferred to rail cars before delivery to California. Kinder Morgan has examined this business development scenario and could complete the necessary modifications in less than six months upon gaining sufficient client commitments.

Biodiesel Infrastructure

Biodiesel use has been minimal in California and the RFS2 mandates will not compel a significant increase in biodiesel demand. However, the LCFS is expected to result in greater biodiesel use due to the quantity of carbon credits that can be generated under the program. Unlike ethanol, California's biodiesel infrastructure is not nearly as developed and will need to be expanded to accommodate widespread blending of biodiesel. However, with sufficient lead time (12 to 24 months), modifications could be undertaken and completed to enable an expansion of biodiesel use. Indeed, Kinder Morgan has already undertaken steps to accommodate increased biodiesel volumes by converting all CARB diesel tanks at its Colton facility for use in storing and blending B5 (5 percent biodiesel) by mid-2012. A limited number of other terminals may follow suit, although the number of such facilities is unknown at this time. The majority of biodiesel use in California is believed to originate from production facilities located within the state. Roughly 5.4 million gallons of biodiesel were used as transportation fuel during 2010, less than 7 percent of the state's biodiesel production capacity. California's RFS2 obligations for biomass-based diesel can be met by the 16 existing biodiesel production facilities in California. However, the increased demand for biodiesel under various LCFS scenarios will require quantities that exceed the state's production capacity, necessitating imports from either domestic or foreign sources, which appear adequate to meet these needs and could be delivered in rail cars. These scenarios also may compel expansion of biodiesel production in California. Most distribution terminals would also need to be modified so that the biodiesel could be received and transferred to segregated storage tanks at the terminals, work that could require a minimum of 18 to 24 months to complete.

Retail diesel fuel dispensers and underground storage tanks are certified to handle diesel fuel that contains biodiesel at concentrations of up to 5 percent by volume, but not up to 20 percent. However, the California State Water Resources Control Board (SWRCB) has issued a temporary variance from this restriction. Assuming biodiesel fuel blends in California do not exceed 20 percent, required retail station modifications should be negligible. According to original equipment manufacturers' statements on the National Biodiesel Board website, 18 vehicle models sold in the United States accept B5, 15 models accept B20 (20 percent biodiesel), and four accept B100 (100 percent biodiesel).

Electric Vehicle Infrastructure

Plug-in electric vehicles (PEVs) will play an increasing role in the future transportation mix. Significant public and private investments are being made in California's electric charging infrastructure. A recent study by Next 10 reports that California took in $467 million in global EV venture capital investment in the first half of 2011 and that investment in this area has grown 712 percent since 2006 in the state.[191] The federal government's economic stimulus funds, matched with Energy Commission program funds and other private and public funds, are providing the charging infrastructure to support the deployment of PEVs in California. Table 15 summarizes the planned deployment of PEV charging infrastructure in four strategic regions.

The consulting firm ICF International estimates that in the early market years, roughly 95 percent of charging will take place at home or at fleet facilities.

191 Next 10, *Powering Innovation: California is Leading the Shift to Electric Vehicles From R&D to Early Adoption*, December 2011, available at: next10.org/next10/pdf/EV%20Report_2011_final.pdf.

Table 15: PEV Public Charging Infrastructure Deployment by California Region

	Existing	Planned		
Region	Public/Commercial Stations	Public/Commercial Points	DC Fast Charge Stations	Battery Switch
S.F. Bay Area	96	916	55	5
Los Angeles	237	972	–	–
San Diego	16	1,452	60	–
Sacramento	56	494	–	–
Other	28	3	2	–
Total	**433**	**3,837**	**117**	**5**

Sources: California Energy Commission and Nissan. Information based on estimates of known deployments planned through 2013.

However, a major challenge is that while the actual charging panels may take only a few hours to install, the overall residential charging infrastructure may still face a costly and protracted permitting, installation, and inspection process. To help overcome this issue, the California PEV Collaborative has identified actions, including the development of online tools and increased information dissemination, which can help standardize and consolidate the technical and administrative processes. The Energy Commission also is providing up to $2 million in grant funding to support regional plans to support PEV readiness under the ARFVT Program.

Natural Gas Vehicle Infrastructure

Primary barriers to the penetration of natural gas vehicles (NGVs) are the lack of a widespread fueling infrastructure and the costs required to upgrade aging existing facilities and install new fueling stations. Today, the use of NGVs is largely limited to medium- and heavy-duty vehicles, which can use CNG/LNG stations on a regular route. Ford Motor Company and other manufacturers plan to offer a suite of light-duty natural gas vehicles for 2012 and beyond, including vans, wagons, pickups, and utility vehicles. Currently there are 140 public and 424 private CNG fueling stations, and 13 public and 19 private LNG sites in the state. The Energy Commission has allocated funding to upgrade existing sites and install new natural gas fueling infrastructure closely tied toward identifiable needs, such as those of school districts and local governments, long-haul LNG goods movement corridors, and pairing new CNG stations with high-volume fleets that intend to convert from diesel to CNG. This funding will support 20 new stations and/or existing station upgrades.

According to the Board of Equalization, California users consumed about 27 million gallons of propane for transportation fuel in 2010. Propane can be a by-product of either natural gas processing or petroleum refining; however, current research is showing promise in the production of propane from renewable resources, such as sugarcane and corn. Propane is very attractive in terms of pricing compared to both diesel and gasoline. There are about 228 propane fueling stations already in place for vehicles in California. These numbers can be expanded with the addition of fuel capacity, a tank pump, and metering equipment at virtually any propane distributor or station in California, for between $37,000 and $52,000 per site. Propane can play an especially significant role in rural communities, where it is already widely available. The primary obstacles to further adoption of propane as a transportation fuel are vehicle availability, incremental vehicle costs, and ARB propane quality certification. At this time, there are four light-duty vehicles certified by the U.S. EPA and ARB. The incremental cost for purchasing a light-duty propane vehicle ranges from $7,500 to $10,400.

Hydrogen Vehicle Infrastructure

Currently, there are roughly 250 hydrogen FCVs operating in California, but only 15 were registered with the California Department of Motor Vehicles (DMV) in 2009. The *2011–2012 Investment Plan for the Alternative and Renewable Fuel and Vehicle Technology Program* identifies high fuel and vehicle costs as a major challenge for this technology. It also states that vehicle production and fueling infrastructure are still at a precommercial stage. However, costs are decreasing for both vehicles and fuel infrastructure. Discussions between original equipment manufacturers (OEMs) and Energy Commission staff indicate the costs of FCVs have declined to the $100,000 mark, and several OEMs plan to lease vehicles to the public at more publicly attractive lease rates. The Energy Commission has also seen the infrastructure cost per fueling station decrease, from a range of $3 million to $6 million to a range of $1 million to $2.5 million, over only a few years. Through a competitive solicitation released in June 2010, 11 stations that were strategically located in areas where automakers have committed to significant numbers of FCV deployments were awarded $15.7 million by the Energy Commission to develop fueling infrastructure.

In 2009, the ARB began investigating the possible modification of its Clean Fuels Outlet regulation to address the lack of fueling infrastructure available for vehicles meeting the ZEV Regulation. The current regulation requires that certain owner/lessors of retail gasoline stations equip an appropriate number of their stations with clean alternative fuels. The regulation does not require retail outlets for a designated clean fuel until the number of designated clean fuel vehicles projected to be certified on that fuel reaches 20,000 in a given year. Owner/lessors would be removed from the regulation language and a new definition added for "refiner/importers," which includes companies that produce in or import into California 500 million gallons or more of gasoline per calendar year. Proposed amendments planned for ARB adoption in 2012 would modify the regulation to apply only to dedicated clean fuel vehicles that operate on ZEV fuels. Once implemented, the regulation would pertain only to hydrogen and fuel cell vehicles; however, in the future it could be applied to electricity for plug-in hybrids and BEVs, depending on the outcome of a BEV needs assessment.

Petroleum Supply and Infrastructure

California's 20 refineries processed more than 1.7 million barrels per day of crude oil in 2010. Most of this crude oil must be imported by marine vessel, historically from Alaska and a variety of foreign sources.

Crude Oil Import Outlook

The quantity of crude oil imported into California is determined by the rate of decline of California oil production, processing capacities, and operating rates of refineries. California oil production has fallen 47.2 percent since 1985, and staff estimates a range of future decline of between 2.2 and 3.1 percent per year. In contrast to historical trends of gradually increasing state refinery oil processing capacity, staff now estimates that capacity in the future will range from flat to declining, largely as a result of declining demand for gasoline. Staff expects crude oil imports compared to 2010 levels to rise by between 22 million and 104 million barrels per year by 2030. At the high end, this increase is solely the result of declining California crude oil production, since refining capacity remains fixed. The forecast for the low end is driven primarily by the assumption of declining refining capacity, reducing the need for crude oil supply.

Staff believes higher oil imports will require expanded marine import within the next four to five years. California's marine import infrastructure for crude oil can receive a little more than 400 million barrels per year. Since waterborne imports of crude oil during 2010 amounted to nearly 376 million barrels, there should be sufficient existing spare import capability that the low estimate for imports could be met. However, petroleum marine terminals in the Ports of Los Angeles and Long Beach operate under long-term leases with staggered expiration dates and have periodically come under pressure either to be shuttered or relocated to make way for other types of port commercial activity. Moreover, "spare" import capacity should also be viewed as a type of insurance policy to ensure continuity of operations during potential natural or human-caused contingencies, which applies not just to crude oil, but all petroleum and renewable fuel import capacity.

Currently, there are two crude oil import infrastructure projects proposed in Southern California that are at early stages of development, Berth 408 at Pier 400 in the Port of Los Angeles and Berth T126 at Pier Echo in the Port of Long Beach. Based on Energy Commission analysis, the Southern California market should only require construction of one of these crude oil import facilities over the forecast period, not both.

High-Carbon-Intensity Crude Oils

The ARB has included provisions in the existing LCFS that regulate the use of new crude oil types that have significantly higher carbon intensities associated with their production when compared to the average mix of crude oil used by refineries in California during 2006. These types of crude oils are referred to as High-Carbon-Intensity Crude Oils (HCICO) and can include crude oil that is sourced from bitumen mines; crude oil upgraders; fields that use thermally enhanced oil recovery techniques; and countries that have excessive flaring of natural gas associated with their crude oil production operations. As originally proposed, the HCICO provisions had the potential to affect crude oil selection decisions, increase refinery operating costs, and cause a portion of the imported crude oil to be from sources from greater distances, a phenomenon referred to as "crude shuffling." Staff has been concerned that California refiners might not use potential HCICOs due to the difficulty of offsetting the carbon deficit incurred from their use and questioned whether HCICO requirements would induce oil producers outside of California to invest in projects to reduce the carbon intensity of their operations.

The ARB approved amendments to the LCFS regulation on December 16, 2011, to simplify and enhance the HCICO provisions with a "California Average Crude CI" approach. This approach involves the establishment of a baseline crude CI based on a specified baseline year; relative to the CI standard, a "baseline deficit" would be charged to all regulated parties for CARBOB and CARB diesel because the baseline crude CI is expected to be above the CI standard. The annual average crude CI would then be calculated for each year, starting in 2013, to reflect the overall CI of the crude oil that is delivered to and processed by California refiners in a given year. If the annual average crude CI does not exceed the baseline crude CI in a given year, the California producers would not realize an "incremental deficit" – just the baseline deficit. ARB staff has also proposed to establish a method, through the rulemaking process, to enable parties that implement innovative methods to reduce emissions for crude oil recovery using technologies such as carbon capture and sequestration to earn LCFS credits.[192]

192 Air Resources Board, *Staff Report: Initial Statement of Reasons for Proposed Rulemaking, Proposed Amendments to the Low Carbon Fuel Standard*, October 2011, page 36, www.arb.ca.gov/board/books/2011/121611/start.pdf.

Energy Commission staff will continue to work with ARB staff to evaluate potential impacts of the HCICO provisions as those provisions continue to evolve to achieve optimal results for the environment and public health while providing the petroleum refining and marketing industry with additional flexibility.

Energy Security

Energy security in transportation fuels policy has received greater attention in recent years. Energy security can be defined in many ways: for instance, as a peculiar vulnerability of excessive reliance on foreign crude oil imports, or more generally on imports of any fuel or feedstock from foreign sources, including non-petroleum fuels. This might take the form of reliance on countries that are not currently on especially good terms with the United States, but it might also hinge on dependence on sources that are risky geopolitically, economically, or from other potential disruptions or supply limitations. The Energy Commission last held a workshop on the peak oil debate in 2003, indicating it may be desirable to raise the topic in a future iteration of the Energy Commission's forecast of transportation fuel supply and demand.

All else being equal, diversification of sources of supply adds to energy security, if it equates to additional sources of supply to meet a given demand. If, however, diversification occurs as a result of limiting supply from some existing or potential sources through sanctions or regulations, then the energy security implications are more uncertain. If energy markets are inhibited from procuring lowest cost supplies, the first direct impact would be economic. Should the proposed policy actions limit foreign sources and avoid fair trade issues, there might be positive balance of trade effects that could offset higher direct costs. In some cases, diversification might viewed as an insurance policy against potential disruptions that might occur for a variety of reasons, but even prudent insurance is not free.

Staff's analysis has raised some issues that have energy security considerations. The LCFS appears to incentivize California regulated parties to pursue biofuels that have lower carbon intensities than the traditional corn-based ethanol sourced from numerous domestic producers located throughout several states. Energy Commission staff analysis shows that this current reliance on a diverse supply of domestic ethanol may need to shift to one that significantly increases demand for Brazilian sugarcane-based ethanol. On the other hand, reliance on Brazilian sugarcane is not the only strategy that can be employed by regulated parties under the LCFS. There is a host of responses industry may choose, including bringing in lower CI corn ethanol, which is the approach they are currently employing, and it will likely continue to play an important role for the next several years. Indeed, corn ethanol production processes registered with ARB indicate CIs that are significantly lower than anticipated at the onset of the LCFS.

Another example is that of crude oil refined from Canada's oil sands resources, a potential HCICO. Energy security might arguably be enhanced by developing Canada as an increased source of crude oil for California refiners, as current sources are predominately Middle Eastern and Latin American. Also, lengthy tanker trips for Canadian crude oil to less regulated East Asian refineries may result in more greenhouse gas emissions. However, achieving energy security and achieving GHG reductions are not mutually exclusive. The ARB staff anticipates that adopted amendments to the LCFS regulation will increase refiners' flexibility in securing a variety of crude oils, including HCICOs from Canadian oil sands. Further, the amendments include important incentives that recognize petroleum producers' efforts to employ innovative strategies to reduce GHG emissions, even from HCICOs, including carbon sequestration and other innovative technologies. Energy Commission staff should continue to work with ARB staff to advance the goals of energy security and carbon reduction.

Challenges and Opportunities

California faces several challenges and offers multiple opportunities to meet alternative fuel and carbon reduction goals in the transportation sector, including:

- Uncertainties in forecasting what future levels of alternative and renewable vehicle purchases and fuel use will be attained.

- Questions about the effect of RFS2 on California's ability to accomplish energy security objectives through diversifying transportation fuel supply and increasing alternative fuel options.

- Availability of sufficient low-carbon biofuels to comply with the LCFS at a reasonable cost to California consumers.

- Uncertainties of whether increased demand for different types of biofuels will increase fuel prices or induce production of these fuels to levels where economies of scale can reduce the price effects of higher demand.

- High initial investments required for infrastructure and vehicles to bring substantial electricity-, natural gas-, and hydrogen-fueled technologies into the transportation sector, technologies that could go a long way to achieving LCFS compliance.

- Supporting the development and use of alternative fuels and vehicles in California through incentives such as the ARFVT Program and local air district funding programs and federal incentives.

- Balancing renewable fuel and carbon reduction goals with energy security and other policy objectives.

The Energy Commission's forecasting and analytical units have attempted to estimate current and future transportation energy use for a range of technologies under a wide variety of assumptions. This work will continue, including consumer vehicle purchase and travel behavior surveys, vehicle and fuel demand modeling for multiple transportation energy technologies, and renewable fuel, carbon reduction, and energy security policy analysis, with the intentions of continuing to broaden interagency collaboration and stakeholder contributions. A variety of forums will be considered to make information publicly available on this important underlying technical analysis.

Further, the ARFVT Program (AB 118, Núñez, Chapter 750, Statutes of 2007), discussed in the next chapter, has enabled considerable strides to be made in deploying alternative, renewable, and advanced transportation technologies in California. These include electric drive, biomethane, diesel substitutes, ethanol, natural gas, propane, and hydrogen technologies. Program investments have incentivized 4,375 public and residential electric charging sites, 85 E85 refueling sites, 20 natural gas stations, and 11 hydrogen fueling sites, as well as 1,437 electric and natural gas cars and trucks, leading to substantial petroleum, greenhouse gas, and air pollution reduction benefits.

CHAPTER 11

Benefits From the Alternative & Renewable Fuel & Vehicle Technology Program

This chapter summarizes projects funded through the Energy Commission's Alternative and Renewable

Fuel and Vehicle Technology Program (ARFVT Program) and expected benefits from petroleum and greenhouse gas (GHG) emissions reductions, as well as economic benefits, and some of the challenges.

The California Legislature created the ARFVT Program in 2007 through passage of Assembly Bill 118 (Núñez, Chapter 750, Statutes of 2007). The statute authorized the Energy Commission to develop and deploy alternative and renewable fuels and advanced transportation technologies to help attain the state's climate change policies. AB 118 similarly authorized the ARB to develop the Air Quality Improvement Program (AQIP) to support development and deployment of zero emission and reduced emission light duty vehicles and trucks.[193] The Energy Commission's ARFVT Program has a budget of about $100 million annually, while the ARB's AQIP has a budget of $30 million to $40 million annually.

193 Air Resources Board, *2010 Biennial Report to the Legislature on the AB 118 Air Quality Improvement Program*, January 2011, available at: www.arb.ca.gov/research/apr/reports/January-2011-aqiprogram-report.pdf.

The Legislature amended the ARFVT Program with Assembly Bill 109 (Núñez, Chapter 313, Statutes of 2008), which requires the Energy Commission to evaluate the efforts and benefits of the program every two years. The Energy Commission released the draft of the first of these evaluations (the *Benefits Report*) in December 2011, which listed the funded projects; reported progress in achieving project goals and expected benefits, including contributions toward reducing GHG emissions and petroleum dependency in California; identified challenges facing the projects; and made recommendations intended to overcome those challenges.

Through the ARFVT Program, the Energy Commission is providing incentives to accelerate the development and deployment of clean, efficient, low-carbon alternative fuels and technology projects that will help reduce California's use and dependence on petroleum transportation fuels and increase the use of alternative and renewable fuels and advanced vehicle technologies. The Energy Commission produces an investment plan or update for each funding cycle to establish priorities and guide program funding allocations. This public process entails public workshops and features a multistakeholder Advisory Committee, which includes representatives from industry trade associations, academic institutions, nongovernmental, environmental, public health, and alternative energy organizations, labor, and other state energy and environmental agencies.

This summary provides a status report on the funded projects and expected benefits. It describes increases in the numbers of fueling infrastructure (including electric charging) and vehicles between 2009 (the baseline year for the program) and 2011. It also estimates a range of total potential petroleum reduction and GHG emissions reductions for each major fuel category – electric drive, natural gas, biofuels, and hydrogen – between 2010 and 2020. Finally, it summarizes job creation and workforce training benefits to California that result from the funding.

Summary of Program Funding

The Energy Commission has developed and adopted three investment plans since 2008 that guide $362 million in total funding for the first four years of the ARFVT Program. Table 16 shows the distribution of funding from the first investment plan for fiscal years 2008–2009 and 2009–2010 according to primary fuel category, plus funding for workforce development and program support. Using funds from this first investment plan, plus a portion of funds from the second investment plan, the Energy Commission has funded 86 projects totaling $198.4 million to date.

The ARFVT Program emphasizes projects in the commercial deployment phase of technology development but has also funded a number of vehicle and fuel projects in the research/feasibility, development, and demonstration phases. The program has allocated two-thirds of its funding (totaling $128.9 million) for fiscal years 2008 to 2010 to commercial deployment and production projects and about 23 percent to precommercial demonstration, research, and development projects.

AB 118 directs the Energy Commission to leverage state public investments against private financing and other public funding sources. Non-ARFVT Program contributions to the 86 projects total about $375.5 million, for a funding ratio of roughly 1:1.9. The largest public funds leveraged by the program thus far have been the federal dollars available through the American Recovery and Reinvestment Act (ARRA) of 2009. The ARFVT Program funded nine projects totaling $36.5 million that received a total of $105.3 million in ARRA funding. The South Coast Air Quality Management District, Bay Area Air Quality Management District, San Diego Air Pollution Control District, and San Joaquin Valley Air Pollution Control District have also partnered in funding projects supported by the program.

Table 16: Program Investments by Fuel Type

Fuel Type and Program Area	Total Funding Encumbered by September 2011 ($ millions)	No. of Projects
Electric Drive	62.4	31.5[A]
Biomethane[B]	36.8	10
Diesel Substitutes	8.1	8
Ethanol[C]	19.1	7
Gaseous Fuels (Natural Gas and Propane)	31.3	13.5[D]
Hydrogen[E]	22.7	5
Workforce Development	15.8	3
Program Support[F]	2.1	8
Totals	**198.4**	**86**

Source: California Energy Commission

A. One agreement provides funds for both electric drive and natural gas infrastructure.

B. This includes an interagency agreement for biofuels feedstock evaluation.

C. Project count includes the California Ethanol Producer Incentive Program's previous offers to four potential recipients as one project

D. The ARFVT Program's gaseous fuels vehicle incentive program is listed as three projects: natural gas vehicle incentives, propane school bus incentives, and nonbus propane vehicle incentives. To date, 16 dealerships or manufacturers made reservations for these incentives.

E. Includes an interagency agreement with the Division of Measurement Standards within the California Department of Food and Agriculture for the development of retail standards for hydrogen.

F. Includes technical support contracts, memberships, cosponsorships, and a vehicle preferences survey.

Increases in Alternative Fueling Infrastructure and Vehicles Between 2008 and 2011

An early indicator that California's fuel and vehicle markets are shifting toward alternative and renewable fuels and advanced vehicle technologies is the growth of key alternative fuel vehicle and infrastructure sectors. Although still in its early years, the ARFVT Program is playing a crucial role in accelerating this progress (as indicated in Table 17). California now has the largest networks of electric vehicle (EV) charging systems and hydrogen fueling stations in the country.

Table 17: ARFVT Program Funding Impact on Alternative Fueling Stations and Alternative Vehicle Deployment in California

	Fuel Area	Existing 2009-2010 Baseline Levels	Additions from ARFVT Program Funding	Percent Increase
Alternative Fueling Infrastructure	Electric	1,270 charging stations	4,375 charging stations (public and residential)[A]	244%
	E85	39 fueling stations	85 fueling stations	118%
	Natural Gas	443 fueling stations	20 stations	5%
	Hydrogen	6 public fueling stations[B] (plus 5 more under construction)	11 fueling stations	100%
Alternative Fuel Vehicles	Electric Cars	13,268	379	3%
	Electric Trucks	1,409	160	11%
	Natural Gas Trucks	13,995	898	6%

Source: Extrapolated from 2009 Department of Motor Vehicles data, plus actual deployment data. Electric truck and natural gas trucks extrapolated from 2009 data.

A. Based on project estimates for all electric vehicle supply equipment funded with ARFVT Program or match funds.

B. Based on Energy Commission and ARB staff estimates. Public accessibility of these situations may vary.

Estimated Benefits From ARFVT Program Investments

California's shift to a transportation system that is less dependent on petroleum fuels and more reliant on a suite of lower carbon alternative fuels and vehicles will take time and require substantial investments from the private and public sectors. The ARFVT Program investments of $198.4 million will produce tangible benefits through 2020 and beyond, but it is a modest investment compared to the billions of dollars that car and truck manufacturers and fuel producers are investing in next generation electric and fuel cell vehicles (FCVs), natural gas-fueled trucks, and sustainable, low-carbon biofuels.

Methods and Analytic Approach

It is likely that market dynamics for alternative fuels and vehicles will continue to be uncertain because of new technology breakthroughs and evolving state regulations. Moreover, the ARFVT Program is in its initial phase, and most of the funded projects have only begun their construction or implementation. Accordingly, the following series of analyses illustrates a low and high range of potential petroleum reduction and GHG emissions benefits resulting from the fuels and technologies supported by initial ARFVT Program investments in electric drive, natural gas, biofuels, and FCVs for the period from 2010 to 2020. The low-range scenarios reflect challenging market and technology conditions and continued high initial incremental costs for emerging alternative fuels and vehicles when compared to petroleum-based fuels and vehicles. The high range scenarios reflect optimal market conditions, a robust regulatory regime that obligates market participants to consume or fund low-carbon fuel and vehicles, higher costs for petroleum-based fuels, and continuing reductions in production and retail costs for alternative fuels and vehicles.

Staff calculated the estimates of alternative fuel increase (and resulting petroleum displacement) for each fuel type first and subsequently calculated the corresponding GHG and air pollutant reductions based on these numbers. Data for the analyses comes directly from ARFVT Program awardees, vehicle manufacturer surveys, the ARB, and published reports. The analyses for electric drive and FCVs are based primarily on vehicle deployment forecasts and surveys developed by industry or third-party stakeholders. The analyses for biofuels are based primarily on information provided by program awardees, regarding both their immediate expectations and their plans for expansion, while the analysis for natural gas is based on a combination of these methods.

The Energy Commission expects each project to be successful, and makes substantial and essential investments to achieve the successes. In most instances, the ARFVT Program accelerates progress in the development and use of alternative fuels and vehicles. The Energy Commission also acknowledges that other parties contribute investments (since most projects require comparable matching funds), and multiple sources are responsible for the benefits.

Estimated Petroleum Reduction Benefits

Electric Drive Vehicles

The increased deployment of plug-in electric vehicles (PEV) in California will improve air quality by reducing criteria pollutants, address climate change by reducing GHG emissions, advance energy security by reducing dependence on petroleum, and stimulate the California economy by providing a new industry and jobs. PEVs can help major vehicle manufacturers achieve ARB's Zero Emission Vehicle (ZEV) regulation mandate and California's mandated GHG and petroleum reduction goals. The Energy Commission's $62.4 million investment in PEVs covers a broad spectrum of technology commercialization, including market-ready chargers and vehicles, manufacturing support, component and battery development, and all-electric truck prototypes.

To estimate the potential range of petroleum and GHG reductions resulting from PEVs, a high and low EV deployment projection has been developed through 2020. The California Plug-in Electric Vehicle Collaborative's estimated range of 500,000 to 1,000,000 EVs on the road in California by 2020[194] binds the high and low deployment cases. The Collaborative developed this range with input from automakers in consideration of the ARB's ZEV regulation.[195] The ARB's estimated scenario of compliance for the ZEV mandate falls between these low and high scenarios for PEV deployment.

For this analysis, the projected PEV population is separated into two categories: battery electric vehicles (BEVs) that rely entirely on batteries and PHEVs that use both electricity and gasoline. Using the ARB's prediction of the likely compliance scenario for the ZEV mandate, the EV population will be about 26 percent BEVs and 74 percent PHEVs by 2020.[196]

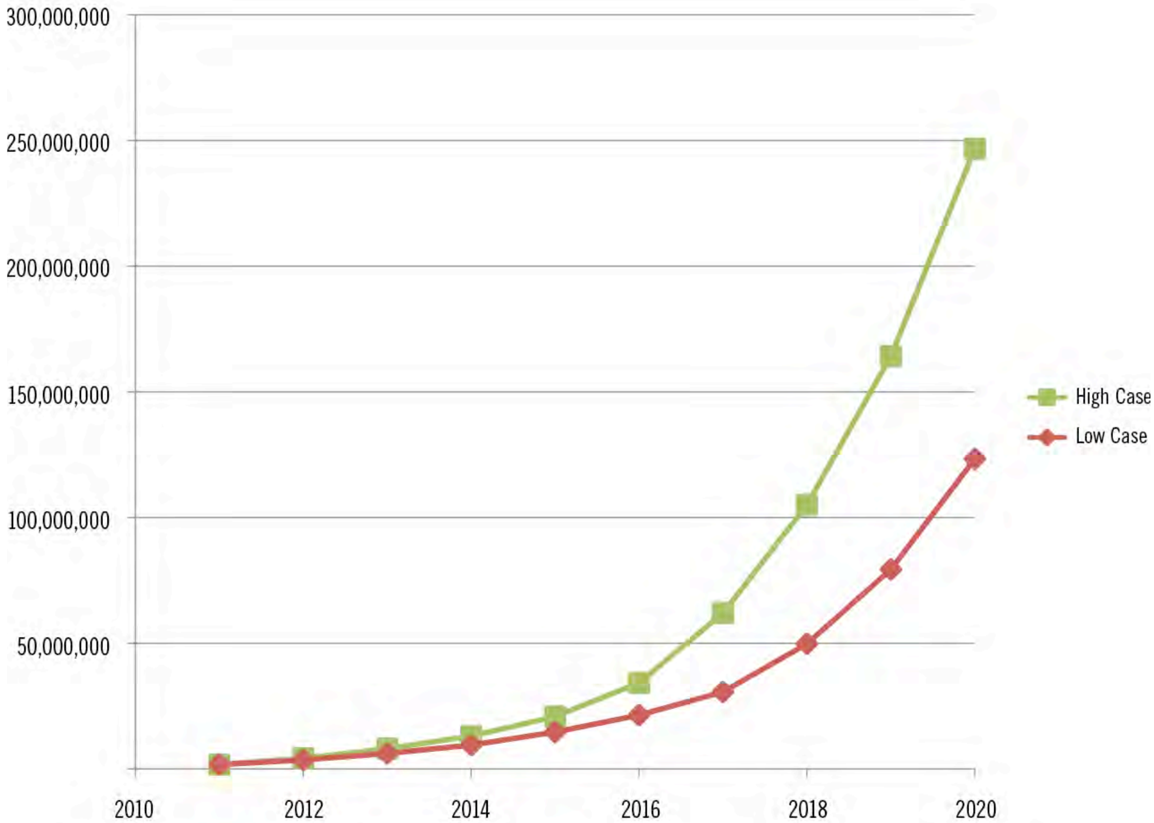
Figure 13 shows the potential petroleum reductions resulting from these vehicle populations. By

194 California Plug-In Electric Vehicle Collaborative, *Taking Charge: Establishing California Leadership in the PEV Marketplace*, www.evcollaborative.org/sites/all/themes/pev/files/docs/Taking_Charge_final2.pdf.

195 The Energy Commission has also conducted a separate analysis of consumer survey data, which suggests roughly 40,000 BEVs and 2.8 million PHEVs on the road by 2020.

196 California Air Resources Board, "ZEV Regulation 2010: Staff Proposal," www.arb.ca.gov/msprog/zevprog/2011zevreg/11_16_10pres.pdf.

Figure 13: Annual Petroleum Displacement From PEVs (Gallons)



Source: California Energy Commission

2020, potential reductions range from a low case of 123.4 million gallons per year to a high case of 246.7 million gallons.[197]

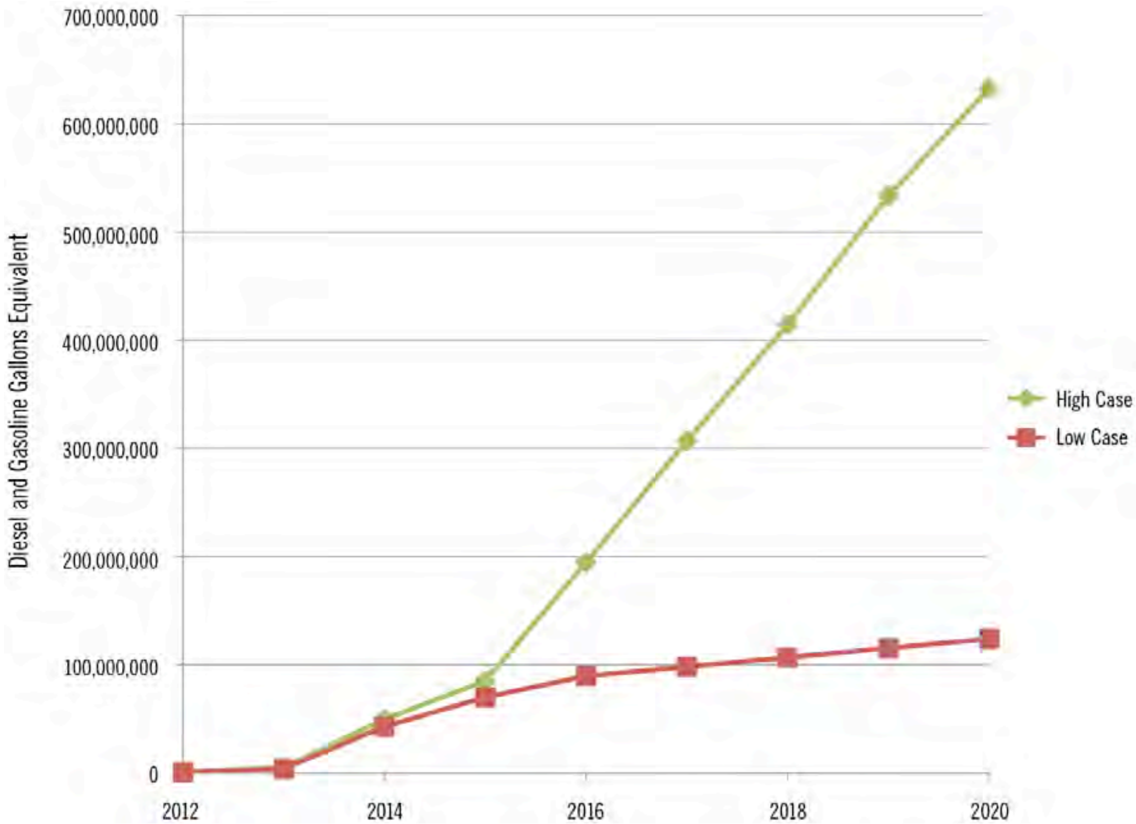
The ARFVT Program has helped address many of the challenges to PEV deployment identified by industry, such as the need for early investments in fueling infrastructure, vehicle demonstrations, vehicle purchase incentives, and manufacturing. The program's investments will help enable the PEV market to overcome these challenges and accelerate vehicle deployment. There are now roughly 3,200 Nissan Leaf BEVs and 1,300 Chevrolet Volt PHEVs in California, roughly one-half and one-third respectively of these vehicles nationwide.

197 BEVs are assumed to displace a vehicle consuming 391 gallons of gasoline per year (assuming 8,600 miles traveled per year at 22 miles per gallon). PHEVs are assumed to displace roughly 196 gallons of gasoline per year (assuming 12,000 miles traveled per year, 22 miles per gallon, and 36 percent of miles are driven by electricity).

Biofuels Production

Increasing the use of low-carbon, sustainably produced biofuels will help California achieve state and federal policy goals for GHG reduction, petroleum reduction, and biofuel use. For air quality purposes, California requires about 1.6 billion gallons per year to satisfy the oxygenate blendstock requirements for reformulated gasoline. At present, corn-derived ethanol is the only biofuel commercially available at industrial scales to meet this need. Through the ARFVT Program, the Energy Commission is investing heavily in companies that are developing low-carbon biofuels from waste-based biomass resources or alternative feedstocks that reflect lower GHG emissions, lower environmental impacts, and better

Figure 14: Annual Petroleum Reductions Biofuel Production Projects (Gallons)



Source: California Energy Commission

land use choices. Confirmed annual volumes of in-state, waste-based resources have the technical potential to be converted into 2.1 billion gallons of diesel gallon equivalent or 3.1 billion gallons of gasoline gallon equivalent each year.[198,199]

The ARFVT Program invested $44.8 million in the development and production of biofuels that use waste-based feedstocks or alternative bioenergy crops that can displace corn as an ethanol feedstock. The biogas production projects, with $35.3 million of program funds, use waste streams such as woody biomass, agricultural or dairy residues, wastewater treatment plant residues, prelandfill diverted municipal solid waste, or landfill gas. The program funded five diesel substitute production projects at $4.3 million, three of which use waste streams as feedstocks, while the other two are testing or demonstrating algae-based feedstocks. Three advanced ethanol awards, funded with $5.4 million, include the state's first cellulosic ethanol pilot production facility using agricultural waste feedstocks, the first commercial feasibility evaluation of sweet sorghum as a potential bioenergy crop, and an important feasibility evaluation of sugar beets coupled with agricultural residues to produce a carbon neutral mix of ethanol and biogas. These types of projects reduce GHG emissions by a

198 California Energy Commission, *2011–12 Investment Plan*, Table 21.

199 Based on data from the California Biomass Collaborative at UC Davis, the Energy Commission estimates that biomass waste-based feedstocks in California have the potential to displace up to 3.1 billion gallons of gasoline per year, or 2.7 billion gallons of diesel fuel. California consumes about 16 billion gallons of gasoline and 4 billion gallons of diesel fuel annually.

high percentage (typically 75–85 percent) compared to the petroleum baseline.

This analysis estimates the high and low range of biofuels production potential for the 17 ARFVT Program projects funded to date. The estimates come directly from the grant proposals and follow-up surveys and interviews with each company or public agency.

The estimated petroleum reduction by 2020 from these 17 biogas, diesel substitutes, and advanced ethanol development and production projects ranges from 124.1 million gallons to 632.8 million gallons (Figure 14).

In the high case, the rapid growth after 2015 represents the shift of several funding recipients from precommercial work into commercial-scale production. Since this analysis includes only projects funded by the ARFVT Program to date, it represents a conservative estimate of the true biofuel production potential within the state. For comparison, the in-state capacity for ethanol production is nearly 241 million gallons per year (of which 170 million gallons per year is on-line), while the in-state capacity for biodiesel production is roughly 85 million gallons per year (from which fewer than 5.5 million gallons were produced in 2010).[200,201]

Natural Gas Vehicles

The medium- and heavy-duty transportation sector represents a prime opportunity for the development and rollout of alternative fuel vehicles. The current fleet of such trucks totals about 632,000, about 4 percent of the state's total vehicle fleet, yet it accounts for about 16 percent of total fuel consumption and GHG emissions. Natural gas vehicles are an attractive alternative to medium- and heavy-duty fleet owners and operators who have concerns with the cost of diesel fuel resulting from price volatility and the economic downturn, as well as compliance with air quality standards. Additionally, natural gas vehicles have been shown to have GHG reductions of between 11 and 16 percent compared to their diesel counterparts. If using waste-derived biomethane instead of conventional natural gas, however, these vehicles can achieve GHG reductions of roughly 85 percent below diesel counterparts.

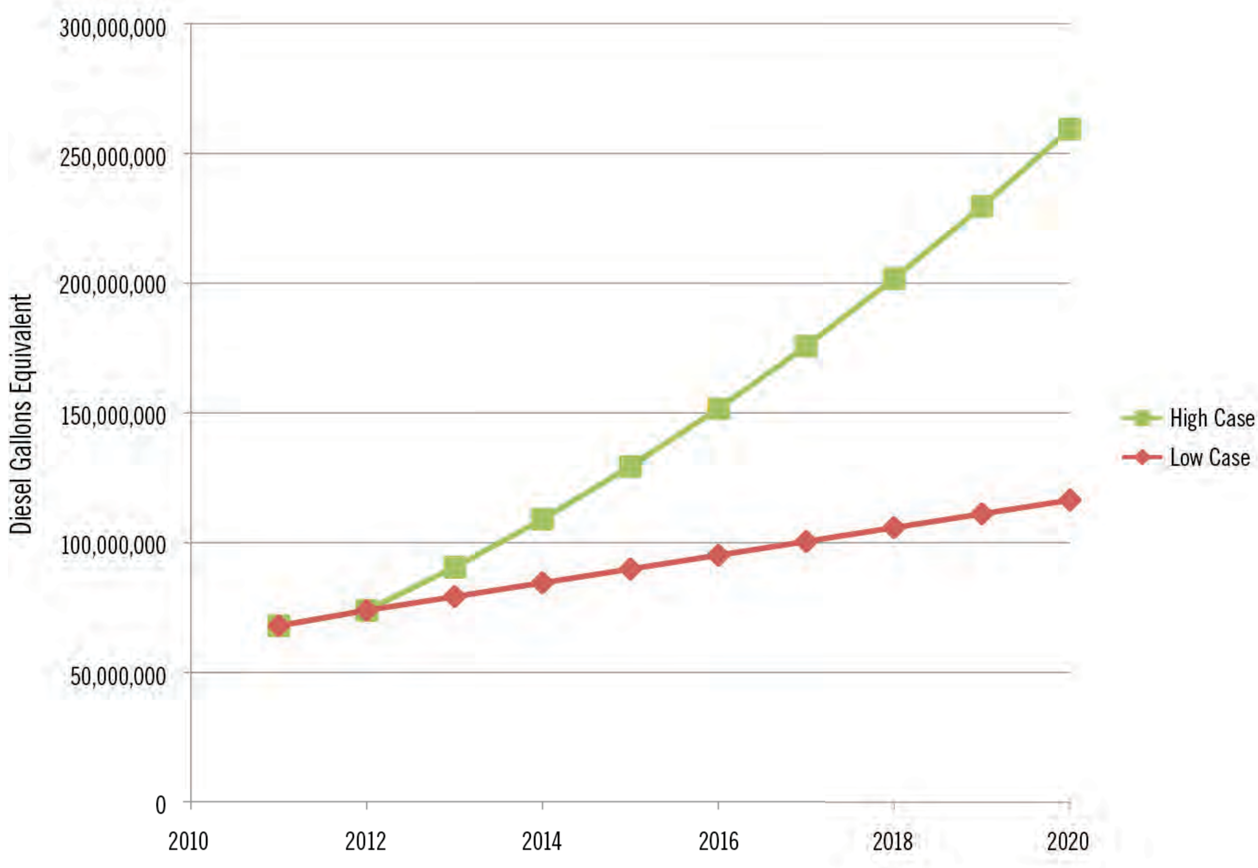
The ARFVT Program's investments in new natural gas applications for medium- and heavy-duty vehicles has helped increase the number of natural gas-powered vehicles on the road and the growth rate of the overall vehicle population. The ARFVT Program has directed investments toward developing and deploying new natural gas vehicle technologies, addressing established business needs, and expanding California's current medium- and heavy-duty natural gas fleet. To date, the program has funded the deployment of 898 medium- and heavy-duty natural gas vehicles. In addition, the program has funded the production of technologies that will increase the availability of natural gas engines for specialized fleet applications. The ARFVT Program has also funded an additional 19 compressed and liquefied natural gas (LNG) fueling stations, which will further promote the adoption of medium- and heavy-duty natural gas vehicles.

The Energy Commission developed two scenarios for the rollout of medium- and heavy-duty natural gas vehicles in California through 2020. The low scenario represents a "business-as-usual" environment, which incorporates the 898 vehicles funded by the ARFVT Program, and the growth rate remains

200 Schremp et al. 2011. *Transportation Energy Forecasts and Analyses for the 2011 Integrated Energy Policy Report.* California Energy Commission. CEC-600-2011-007-SD, www.energy.ca.gov/2011publications/CEC-600-2011-007/CEC-600-2011-007-SD.pdf.

201 Smith, Charles, Miles Roberts, Jim McKinney. 2011. *2011–2012 Investment Plan for the Alternative and Renewable Fuel and Vehicle Technology Program.* Commission Report. California Energy Commission, Fuels and Transportation Division. Publication Number: CEC-600-2011-006-CMF, www.energy.ca.gov/2011publications/CEC-600-2011-006/CEC-600-2011-006-CMF.pdf

Figure 15: Annual Petroleum Displacement From Natural Gas Trucks (Gallons)



Source: California Energy Commission

relatively steady.[202] The high scenario represents estimated new vehicle sales, as reported by awardees and based on expected fleet adoption rates. This scenario assumes the awardees' vehicle sales are units sold in addition to the expected normal population growth for the industry, and assumes the existence of optimal market conditions allowing for the sale of all vehicles available from the manufacturer. The petroleum displacement associated with these scenarios is presented in Figure 15.[203]

Hydrogen Fuel Cell Vehicles

FCVs that use hydrogen as fuel are a prominent prospect for encouraging the deployment of alternative fuels. One of the greatest benefits of FCVs is that they emit no GHG emissions or air pollutants from the tailpipe. Like the other alternative fuel

202 Vehicle counts from Energy Commission analysis of Department of Motor Vehicle data.

203 The duty cycles for medium- and heavy-duty trucks are much more variable than for light-duty vehicles, so the amount of petroleum displaced by an individual natural gas truck will also vary. Under the low scenario, natural gas vehicles are assumed to displace 4,750 gallons of diesel per year (based on historical averages). The incremental increase under the high scenario assumes that natural gas trucks expand into heavier-duty cycles, displacing 10,750 gallons per year.

vehicle technologies, they can also reduce California's dependence on foreign imports of crude oil since hydrogen can be derived from domestic sources.

One major challenge to ensuring the deployment of these vehicles is the development of sufficient fueling infrastructure. To meet the needs of anticipated FCVs, the Energy Commission provided funding for 11 new and upgraded hydrogen fueling stations. The total cost per station ranged from $2 million to $3 million, a significant drop from the range of $3 million to $6 million per station from just a few years earlier. All of these stations are located in regions identified by automakers as high-priority, early-adopter markets. Once constructed, these stations will represent about 73 percent of the statewide public fueling capacity.

A low case and high case for FCV deployment can be derived from the ARB's ZEV regulation and automaker surveys. Under the low case, the cumulative number of FCVs increases to 30,200 by 2020, displacing about 16.5 million gallons of gasoline per year. According to surveys of major automakers, the number of in-state FCVs will expand rapidly in the current decade, from roughly 250 in 2011 to more than 50,000 by 2017. Accordingly, the ARB has developed a scenario for 2017–2020, based on automakers' compliance with the ZEV regulation, in which the total on-road number of light-duty FCVs within California will reach roughly 124,000 by 2020.[204] This equates to roughly 67.6 million gallons of gasoline per year displaced by FCVs by 2020.

By providing fueling infrastructure early on, the Energy Commission's investments provide critical early support for expanded vehicle populations, to a point where private infrastructure suppliers can independently finance and construct additional stations to serve the increased numbers of vehicles.

204 California Air Resources Board, *Staff Report: Initial Statement of Reasons, Advanced Clean Cars, 2012 Proposed Amendments to the Clean Fuels Outlet Regulation,* December 8, 2011, www.arb.ca.gov/regact/2012/cfo2012/cfoisor.pdf.

Total Estimated Petroleum Reduction Benefits

The total estimated petroleum reduction associated with the fuels and vehicle technologies supported by the 86 ARFVT Program-funded projects range from roughly 380.4 million to 1.2 billion gallons per year in 2020. This estimated potential petroleum reduction cannot be directly attributed to the program's investment but should be considered as the range of future benefits in a market influenced by ARFVT Program funding. To put these estimates in context, current petroleum fuel consumption in California totals roughly 18.8 billion gallons per year.

Estimated GHG and Air Pollution Reduction Benefits

The petroleum reductions by alternative fuels and vehicle technologies (mentioned above) also serve as the basis for determining the estimated GHG emission and air pollution reductions associated with these fuels and technologies. Accordingly, the benefits associated with electric drive, hydrogen, and natural gas trucks still represent the overall market-level benefits of these alternative fuels that are supported by the ARFVT Program, while the benefits associated with biofuel production represent the projects (and their possible expansions) that are directly funded by the ARFVT Program.

To calculate GHG emission reduction benefits, the amount of fuel displaced is multiplied by the relative carbon intensity for each alternative fuel type, as provided by the Low Carbon Fuel Standard.[205] This calculation incorporates an energy efficiency ratio for electric drive and FCVs to account for the greater efficiencies of PEVs and FCVs in translating fuel energy

205 Where appropriate, the Energy Commission applied estimates of carbon intensity for projects that use fuel pathways not explicitly established by the LCFS.

Table 18: Annual Petroleum, GHG, and Criteria Emission Reductions by 2020 – Low Case

	Petroleum Reductions (Million Gallons)	(Metric Tons) GHG Reductions (CO2e)	VOC	CO	NOx	PM10
Electric Drive[A]	123.4	930,960	947.1	7,788.3	670.3	320.2
Biogas Production[B]	100.7	1,111,214	73.1	-3.6	15.7	2.4
Biodiesel Production[C]	9.4	100,402	9.8	20.5	-27.9	15.6
Ethanol Production[D]	14.0	115,076	11.4	77.6	-0.6	-0.3
Natural Gas Trucks[E]	116.4	349,093	84.5	-4.2	18.2	2.8
Hydrogen[F]	16.5	102,085	125.0	1,007.8	78.6	35.9
Total	**380.4**	**2,708,831**	**1,250.9**	**8,887.0**	**754.3**	**376.6**

Source: California Energy Commission

A. Electric drive GHG emissions from the LCFS "marginal electricity mix" pathway (ELC002).

B. Biogas production GHG emissions based on an estimated of average 12.4 g CO_2e/MJ for waste-based biogas to match funded projects.

C. Biodiesel production GHG emissions based on an estimated of average 15.0 g CO_2e/MJ for waste-based and algae-derived diesel substitutes to match funded projects.

D. Ethanol production GHG emissions based on an estimated of average 15.0 g CO_2e/MJ for waste-based and algae-derived diesel substitutes to match funded projects.

E. Natural gas GHG emissions based on an average of 72.3 g CO_2e/MJ, assuming a split of 70 percent CNG vehicles and 30 percent LNG vehicles.

F. Hydrogen GHG emissions estimated from the average carbon intensity of hydrogen infrastructure projects funded by the ARFVT Program (106.9 g CO_2e/MJ).

(in joules) into miles traveled.[206] GHG emissions are reported in carbon dioxide equivalents (CO_2e).

Staff uses a similar approach for calculating urban criteria pollutant reductions. The amount of fuel displaced by each alternative fuel type is multiplied by the relative criteria pollutant reduction of that alternative fuel against a petroleum baseline.[207] Estimated criteria pollutants include volatile organic compounds (VOC), carbon monoxide, nitrogen oxide (NOx), and particulate matter of 10 micron in diameter (PM10).

Looking forward to 2020, the low case estimate for annual petroleum displacement, GHG emission reductions, and reductions in criteria air pollutants are summarized in Table 18.

This includes 380.4 million gallons of petroleum fuels displaced, 2.7 million metric tonnes of CO_2e GHG emissions reduced, and 11,269 metric tonnes of urban air pollutants reduced each year by 2020. Table 19 presents the high case, with 1.4 billion gallons of petroleum

206 The energy efficiency ratio (EER) for electric drive is assumed to be 3.4, and the EER for fuel cell vehicles is assumed to be 2.5. These values were established during the December 2011 ARB LCFS revisions.

207 TIAX, LLC. August 2007. *Full Fuel Cycle Assessment: Well-to Wheels Energy Inputs, Emissions, and Water Impacts,* California Energy Commission. CEC-600-2007-004-REV, www.energy.ca.gov/2007publications/CEC-600-2007-004/CEC-600-2007-004-REV.PDF.

Table 19: Annual Petroleum, GHG, and Criteria Emission Reductions by 2020 – High Case

		(Metric Tons)				
	Petroleum Reductions (Million Gallons)	GHG Reductions (CO2e)	VOC	CO	NOx	PM10
Electric Drive	246.7	1,861,919	1,894.2	15,576.6	1,340.6	640.4
Biogas Production	195.5	2,157,323	141.9	-7.0	30.5	4.7
Biodiesel Production	378.1	4,038,539	392.5	823.5	-1,120.7	628.4
Ethanol Production	59.2	486,609	48.2	328.2	-2.6	-1.3
Natural Gas Trucks	259.4	777,864	188.3	-9.3	40.5	6.2
Hydrogen	67.6	419,155	513.4	4,138.1	322.9	147.3
Total	**1,206.5**	**9,741,410**	**3,178.5**	**20,850.1**	**611.2**	**1,425.7**

Source: California Energy Commission

fuels displaced, 9.7 million metric tonnes of CO_2e GHG emissions reduced, and 26,066 metric tonnes of urban air pollutants reduced each year by 2020.

The economic and environmental benefits resulting from the first round of ARFVT Program funding awards establish a good foundation and measurable progress toward achieving multiple state policy goals. The ARFVT Program funding can help achieve a goal of sourcing 26 percent of California's total transportation fuel from alternative sources by 2022. By 2020, diesel and gasoline demand is expected to reach roughly 18 billion gallons per year; the ARFVT Program projects will support alternative fuels that can displace 2 to 6 percent of these 18 billion gallons by 2020. Additionally, fuels and technologies supported by ARFVT Program projects can also reduce greenhouse gas emissions, representing a 1 to 4 percent decrease in expected transportation (business-as-usual) emissions by 2020. Furthermore, the commercialization potential of California biofuel production plants funded by the ARFVT Program represents 15 percent to 77 percent of the capacity needed to achieve a *Bioenergy Action Plan* goal to produce 40 percent of expected California biofuel consumption from in-state sources by 2020.

Workforce Training Benefits

Workforce development and training are critical elements in the Energy Commission's efforts to develop California's clean transportation market. A trained workforce is required to develop and respond to new technologies, improve efficiencies, minimize waste, and reduce the cost of production. A well-trained workforce will be critical to the industry's ability to manufacture low-emission vehicles and components, produce alternative fuels, build fueling infrastructure, service and maintain fleets and manufacturing equipment, and provide information for on-going innovation and refinement that will serve to increase the market acceptance of alternative fuels and new vehicle technologies.

The Energy Commission has allocated $15.8 million in program funding to support workforce development and training in the first two investment plans for the ARFVT Program. The Energy Commission used the funds to establish interagency agreements with California's top workforce training agencies, including the Employment Development Department (EDD) at $4.5 million, the California Community Colleges Chancellor's Office (CCCCO) at $4.5 million, and the Employment Training Panel (ETP) at $6.8 million. The interagency agreements have been structured to fund alternative fuel and low-emission vehicle specific training as a portion of the partner agencies' broader workforce projects. The EDD and ETP interagency agreements deliver workforce training, while the EDD and CCCCO interagency agreements provide workforce training development support activities, including surveying industry training needs, assessing existing training programs and resources, developing curriculum and training materials, instructor training, and regional industry cluster support planning grants.

To date, EDD and ETP have awarded 8 regional training grants, 4 regional industry cluster planning grants, and 12 direct employer training contracts to train more than 5,300 individuals. The grants and contracts awarded through the interagency agreements have also secured more than $13 million in nonstate matching funds.

Job Creation Benefits

Since the projects funded by the ARFVT Program are almost entirely in the early stages of implementation, this summary represents projected job benefits. The Energy Commission obtained projected jobs data through an electronic survey of its awardees, which was followed with telephone survey interviews. The survey respondents anticipate that they will create nearly 5,400 jobs to help implement their program-funded projects. Respondents expect job creation throughout the market spectrum, but especially in manufacturing, construction, engineering, and operations and maintenance, as shown in Table 20. As defined in the survey, short-term jobs include jobs expected to last for 1 to 18 months, while long-term jobs include jobs that last 18 to 60 months.

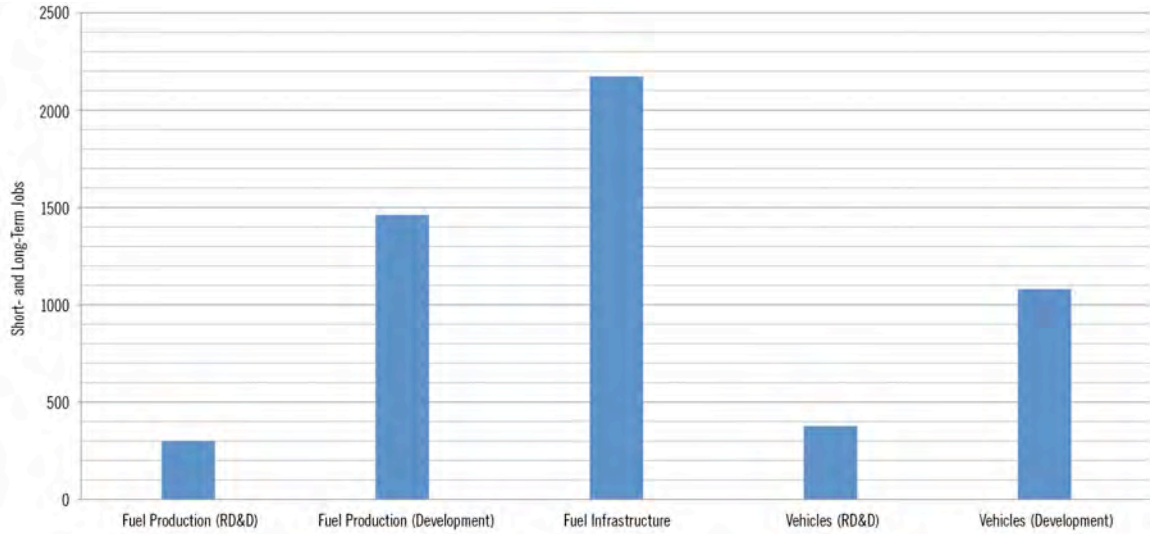
Table 20: Projected Job Creation by Type, as Reported by Recipients

	Short Term	Long Term	Total
Manufacturing	416	638	1,054
Construction	610	1306	1,916
Engineering	241	384	625
Operation and Maintenance	55	410	465
Other	590	744	1,334
Total	**1,912**	**3,482**	**5,394**

Source: California Energy Commission.

Respondents anticipate the highest numbers of jobs in manufacturing and construction, driven heavily by the construction of fuel production facilities and the production of batteries and components for the electric drive industry. Manufacturing and construction are universally recognized as two of California's most important industry sectors and the hardest hit in the recent economic downturn. As such, the ARFVT Program's investment is a timely benefit to these vital industries. The number of jobs anticipated by survey respondents can also be sorted based on the commercialization phase of the technology involved in the project, when reported (Figure 16).

Figure 16: Estimated Number of Jobs by Supply Chain Phase



Source: California Energy Commission.

The economic benefit is compounded beyond the initial funding when the program's investments promote additional outside investment, stimulate business expansion, and create new jobs. Using economic benefit multipliers, the Energy Commission's investment in 1,054 manufacturing jobs alone could actually create anywhere from 3,056 to 5,270 indirect jobs.[208]

In addition to jobs data, survey respondents also provided information on the number of businesses involved in the implementation of their program-funded projects. The respondents estimated that over 800 California businesses would participate in the projects, with 568 of those businesses identified as small businesses (200 or fewer employees).

Photo: Wireless Lighting Controls at Pleasanton Library. Courtesy of Energy Solutions

CHAPTER 12

Bringing Energy Innovation to California

Through the Public Interest Energy Research Program

This chapter of the 2011 IEPR provides an overview of the Public Interest Energy Research (PIER) Program.

The research portfolio continues to evolve and be flexible to address current energy and economic challenges to enhance the benefits to customers – the organizations, businesses, governmental agencies, residents, and others that make up California's energy marketplace.

Over the last 14 years, the PIER Program has responded to market needs and the state's energy policy goals. The program initially focused on research involving individual components and has progressed to emphasize integration of multiple energy technologies to maximize synergies and benefits. As an example, there are now energy research, development, and demonstrations (RD&D) involving large-scale integration of energy efficiency, renewable energy such as residential photovoltaics, and consumer technologies such as electric vehicles to build a smart grid that ensures reliability.

The Public Goods Charge (PGC) that provided funding for energy research and development expired on January 1, 2012. However, the Governor and key legislative leaders support continuing this charge,[209] and in October 2011 the CPUC opened a rulemaking to evaluate potential continuation of public benefits funding. On December 15, 2011, the CPUC approved the collection of an Electric Program Investment Charge (EPIC) to fund renewables and energy research, development, and demonstration programs on an interim basis, pending a final decision in Phase 2 of the proceeding. [210] The Energy Commission expects renewed research funding to continue, but if this does not happen, the state will lose a valuable source of funding support for businesses, clean energy technology innovation and development, job creation, energy-related environmental research, and increased electricity reliability.

PIER Program Makes a Difference

The PIER Program contributes to advancing electricity and natural gas science and technologies that may not have otherwise led to market acceptance. For example, the PIER Program was instrumental in bringing distributed generation (DG) to the California market. In 1996, the market structure did not support the interconnection of photovoltaic and other DG. Since that time, PIER-funded research established interconnection rules and standards[211] and helped establish benefits and devices to make DG practical and safe. For example, in 2003 PIER-funded research with Reflective Energies helped overcome interconnection barriers associated with combined technologies, such as net-metered and non-net-metered systems and network distribution system interconnection, and DG equipment certification requirements.

Contributions to Job Growth and Private Investment in the Clean Energy Economy

By investing in innovative, energy-related RD&D projects, the PIER Program attracts and grows businesses and creates jobs. Below are some of the PIER Program's success stories in the area of job creation:

- **Jobs Created From Successful Research Projects:** Significant job growth occurs when research results in the selling of advanced technologies in the marketplace. PIER Program staff interviewed representatives of 10 companies who attributed the creation of 1,342 jobs at least in part to PIER funding. These jobs created an additional 3,903 jobs as the firms and employees purchased goods and services, according to an estimate using IMPLAN®, a widely recognized economic impact assessment program.

- **Venture Capital Investment and Jobs From PIER-Funded Small Grants:** Since the PIER-funded Energy Innovations Small Grant (EISG) began in 1999, awardees have garnered more than $1.4 billion in subsequent investment, including $1.3 billion in private, nonutility investment. PIER-funded research has significantly contributed to the development of products worth $1.3 billion to the private sector – more than 40 times the $30 million that the EISG program invested. These new companies or new lines of business create private sector output and jobs.

209 Press release of Governor Brown's letter to CPUC President Peevey, September 26, 2011, gov.ca.gov/news.php?id=17237.

210 California Public Utilities Commission, News Release, December 15, 2011, docs.cpuc.ca.gov/PUBLISHED/NEWS_RELEASE/155619.htm.

211 California Rule 21 Generating Facility Interconnections; Institute of Electrical and Electronics Engineers (IEEE) 1547 – Series of Interconnection Standards; and Underwriters Laboratories (UL) 1741 - Inverters, Converters, Controllers and Interconnection System Equipment for Use With Distributed Energy Resources.

Energy RD&D Successes and Breakthroughs

Improving the Status Quo Through Energy Efficiency

The Energy Commission develops California's energy efficiency standards for appliances (California Code of Regulations, Title 20, Sections 1601 through 1608) and buildings (Title 24, Part 6). PIER-funded research plays a key role in developing and providing supporting data to justify the energy efficiency standards. For example, the 2008 Building Efficiency Standards used results of PIER-funded research including a compliance credit for residential cool roofs to help reduce air conditioning use; heating, ventilation, and air-conditioning (HVAC) fan efficiency requirements to improve the energy performance of air handlers and duct systems; an attic duct model to evaluate the interaction of all measures that affect the heat flow in the attic; and more efficient kitchen and underground pipe insulation. In addition, the 2010 Appliance Efficiency Standards included requirements for flat-screen televisions and the 2007 Appliance Efficiency Standards included requirements for external power supplies – all of these resulted directly from PIER-funded research. Overall, these seven measures will produce an estimated annual cost savings of more than $1 billion for California electric and natural gas ratepayers when fully implemented.

For the upcoming 2013 Building Efficiency Standards, PIER-funded research is contributing to potential measures for vent cooling using outside air, hot water distribution systems for centrally locating hot water heaters and pipe insulation, HVAC controls, economizers for small commercial systems, daylighting, and lighting.

In addition to the research associated with supporting the standards, the PIER Program funded breakthrough energy research that successfully brought products to the marketplace. For example, the PIER Program's recent support of a small business called Adura® Technologies contributed to the development of a wireless lighting control network that creates energy savings up to 70 percent. This breakthrough in lighting control is a perfect technology for building retrofits that led Adura to receive $20 million in subsequent venture capital. Another example is an initial PIER-funded demonstration of an innovative way to control cooling energy use in data centers developed by Federspiel Controls (now Vigilent Systems). As a result, this company received an American Recovery and Reinvestment Act grant to install this technology in eight data centers throughout California. The cooling energy use in these eight data centers was reduced by 19 to 78 percent or about $240,000 annually. These cooling control systems are used in data centers throughout California and the United States.[212]

The PIER Program has supported several energy-efficient products and technologies that help reduce electricity, natural gas, and water consumption; save money for California consumers; and improve the environment. The following systems are now available in the marketplace:

- Integrated office and classroom lighting systems (Figure 17)
- Hybrid smart wall switch and luminaire for hotels
- Bi-level stairwell and corridor lighting
- Smart lighting controls for exterior lighting
- Advanced evaporative air conditioners for California climate
- Radiant floor cooling
- Under-floor air distribution systems

212 https://www.vigilent.com/news.php.

- Cool roof materials for homes
- Hybrid optimized water heaters
- Advanced solar water heating components and distribution systems
- Commercial cooking equipment for restaurants
- Reverse Annulus Single-Ended Radiant Tube (RASERT) for efficient, cleaner process-heat burners
- Electrodialysis for tartrate stabilization in wine-making processes
- Advanced gas-fired drum dryer for food processing
- Cooling control technology with wireless network sensors
- ThermoSorber Gas-Fired Hot Water Heat Pump
- Ultra-low, nitrogen oxides (NOx) burner control technology for boiler

In addition to new products and technologies, the PIER Program also funded research to improve energy efficiency through better design and construction practices, development of tools and strategies, and analysis of data that support future building and appliance standards and utility incentive programs. Examples include:

- Identifying the potential energy savings in California's existing commercial buildings using cost-effective retrofit daylighting strategies that focus on occupant comfort
- Strategies to increase residential hot water heating efficiency
- Fault detection and diagnostic tools for commercial rooftop heating, ventilating and air conditioning systems
- Energy auditing tools and energy use reduction strategies for existing buildings and wastewater treatment facilities
- Standardized building commissioning tools
- Cost-effective efficiency strategies for affordable housing
- Community based strategies to increase energy efficiency and environmental quality

Breaking Barriers to Achieve California's Renewables Portfolio Standard

Since its creation in 1996, the PIER Program has helped California increase its use of renewable energy. The program performed initial resource assessments to help determine California's resource potential so that developers could find the best locations to site their renewable energy systems. PIER-funded research focused on wind and solar technology development, solar forecasting, and further assessments of California's solar, wind, geothermal, and biomass resources. Helping renewable technologies reach maturity led to faster market penetration and ultimately to more renewable energy in the state's overall electricity portfolio.

The PIER Program continues to refine its focus and support the state's increasingly aggressive renewable energy policies such as the RPS, the California Solar Initiative, and the Million Solar Roofs program. In the mid- to late 2000s, the PIER Program initiated the Intermittency Analysis Project, which evaluated transmission constraints to renewable energy development and recommended interconnection solutions. In 2009, the PIER Program initiated the Renewable Energy Secure Community (RESCO)

Figure 17: Integrated Classroom Lighting System

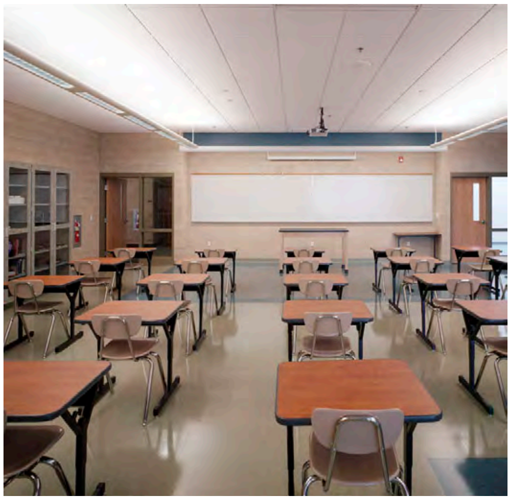


Photo Credit: Finelite

Figure 18: Concentrating Photovoltaic System

Photo Credit: GreenVolts, Inc.

program, which is helping communities overcome renewable energy deployment and integration challenges. The RESCO program is providing technical solutions – such as local energy action plans and pilot projects – so that communities can rely more on locally available renewable resources tailored to community resources and preferences.

The PIER Program's Energy-Related Environmental Research is helping the state address concerns relating to the environmental impact of energy production on air quality, water resources, terrestrial resources, and climate change. In particular, this research is assisting with sound practices for permitting renewable and nonrenewable generation.

One of the most daunting barriers renewable energy project developers face at every level is the high up-front costs. A way to address this challenge is by developing lower cost and higher-efficiency generation technologies. Additionally, innovative applications for waste by-products can result in additional benefits that translate into cost savings. For example, PIER Program participant GreenVolts, Inc., developed a new concentrating photovoltaic (CPV) system with low-cost installation, low-cost manufacturability, technical performance improvements, minimal ground footprint, and comprehensive "system" delivery.

This new CPV system will speed the deployment and adoption of CPV technology in various applications. Originally funded by the PIER Program, Green Volts received $40 million in venture capital funds to demonstrate and commercialize the product. The technology is now in full production, with six installations in California and Arizona (totaling 400 kilowatts) and several sites in development ranging in size from 200 kilowatts to 1 megawatt. A 2.5-megawatt operation is under contruction in Byron, California. The development of these projects resulted in 100 jobs at Green Volts, 20 manufacturing jobs, and more than 30 jobs for various installation contracts. Figure 18 shows one of GreenVolt's CPV installations.

The PIER Program has supported the following renewable energy projects to help overcome barriers that limit the deployment and integration of renewable energy into California's grid:

- Powerlight Corporation's photovoltaic (PV) tracker which tracks the sun to maximize the amount of energy produced by a photovoltaic system
- Advanced Energy Recovery System (AERS) converting onion waste to clean biogas, which feeds fuel cells
- Tecogen Inc.'s combined heat and power system coupled with inverter-based technology
- Clean Energy Systems' turbine using oxy-combustion technology
- Improved forecasting for variable solar and wind generation projects to optimize development and operation of the transmission grid system
- UC Davis West Village, a multiuse zero net energy community using on-site renewables and efficiency to optimize distributed energy resources
- Developing utility-scale solar concentrating systems on closed landfills
- Biomass to energy projects to create biogas for on-site electrical production
- Piloting the integration and use of renewables to achieve a flexible and secure energy infrastructure by integration of PV, electric vehicle charging, and thermal energy storage

Integrating Renewable Energy Through Smart Grid Infrastructure Development

PIER-funded research is making strides in the areas of advanced generation, transmission, distribution, and smart grid to promote renewable integration. For example, a recent PIER-funded solicitation resulted in contracts that developed a definition for California's Smart Grid of the Future from three perspectives: investor-owned utilities, publicly owned utilities, and the electric industry. In December 2010, the Energy Commission conducted a joint workshop with the California Public Utilities Commission (CPUC) to highlight the PIER Program's three smart grid RD&D road mapping projects that will support the state's goals to develop a smart grid and provide a research framework for smart grid deployment plans.[213] The Energy Commission will combine the three perspectives to create a definition for a single, coordinated "California Smart Grid." This effort is helping the state meet multiple energy policy goals established under Assembly Bill 32, Senate Bill 17, and Senate Bill 1250, as well as various technology and integration challenges. This effort also established a roadmap for technology development for the PIER Program to fill key technology gaps.

Synchrophasors Help Integrate Renewables and Reduce Power Outages

Variable generation causes anomalies in the electric power system that if not handled properly may lead to unplanned outages. Grid operators need real-time information to better manage and operate the electric grid.

Synchrophasor measurement systems on transmission lines provide detailed information about the electric system to help foresee and prevent power outages. The PIER Program funded the Phasor Real Time Dynamic Monitoring System (Phasor-RTDMS)

213 Workshop presentations and a full transcript are available at: www.energy.ca.gov/2011_energypolicy/documents/index.html#12172010.

from Electric Power Group, LLC, which provides synchrophasor information to the California Independent System Operator (California ISO) at a rate of up to 30 times per second. The status-quo Supervisory Control and Data Acquisition system only reports a status every four seconds. This new technology represented a game-changing environment for future grid management with respect to system reliability and renewable integration.

In January 2008, the Phasor-RTDMS system alerted California ISO operators about unusual oscillations that were making the electric system unstable. The California ISO temporarily shut down a major power line at the center of those oscillations to avoid a major blackout. The California ISO probably would not have detected this oscillation irregularity before the installation of the Phasor-RTDMS product. This event demonstrated the clear benefit of having this technology solution available for grid management.

The PIER Program expects synchrophasor technology to save future electricity consumers about $210 million to $370 million per year in avoided outage costs and $90 million per year in reduced electricity costs. Support from the Energy Commission and the United States Department of Energy was essential to this research. Without PIER Program leadership and active stakeholder involvement, synchrophasor and associated development would not have progressed to where it is today, it would not be tailored to California needs, and California might face serious problems integrating renewable generation and electric vehicles.

The PIER Program funded research in the following areas to develop a smart grid infrastructure and support renewable integration:

- Demand response as a spinning reserve, a key ancillary grid requirement
- Solar and wind forecasting
- Electric vehicle-to-grid services
- Microgrids
- Distribution upgrades and monitoring
- Utility-scale energy storage
- Real-time grid reliability management

Improving the Safety of Natural Gas Pipelines

The PIER Program responds to energy issues that are of concern to Californians, such as safety and reliability. The PIER Program is funding projects to support research on the safety and security of the state's natural gas system infrastructure, as California is the second largest natural gas-consuming state in the United States, making this a priority issue. The growing demand for natural gas and the aging natural gas pipeline infrastructure pose significant challenges for the state's natural gas users. The state needs public interest energy research to explore opportunities and apply new and emerging technologies that provide innovative options for natural gas pipeline integrity, operations, and safety.

Events following the September 2010 natural gas explosion in a Pacific Gas and Electric's (PG&E) pipeline in San Bruno led to two PIER-funded projects to help improve gas pipeline evaluation and monitoring. One project will develop a baseline assessment of current technologies used in California to manage pipeline integrity and safety including current methods to prevent, detect, and respond to pipe leaks and/or ruptures. Another project will design, build, and test a family of next-generation microelectromechanical systems (MEMS) devices that measure pressure, inspect seam welds, and detect corrosion in natural gas pipes with wireless communications for condition-based monitoring. These prototype devices can operate inside regular pipes during normal operations to monitor pipeline safety and integrity.

The Evolving PIER Program

Over the years, the PIER Program has continually evolved through increased transparency and by encouraging active stakeholder engagement.

Policy Advisory Board and Advisory Groups

The PIER Program convened three publicly noticed Policy Advisory Board (PAB) meetings over the past year to increase public participation and to provide transparency in PIER Program planning. The PAB includes Legislative members, energy agencies, utilities, and environmental, consumer, and business organizations.

The Energy Commission also formed three Policy Advisory Groups (PAGs) to augment the PAB and focus on three research program areas – Energy Efficiency, Renewable Energy, and Smart Infrastructure. The PAGs review and ensure relevancy of the PIER Program's research initiatives to the marketplace, find synergy and end-user opportunities, and avoid research duplication. Staff held public workshops in June 2011 with each PAG to discuss the proposed research initiatives for the upcoming fiscal year (2011–2012). The workshops brought together utilities, researchers, manufacturers, end users, and policy makers from state agencies, federal agencies, and the public. The results of the meetings provided information for the PIER Program's future research portfolio and solicitations.

RD&D Benefits Assessment

Energy Commission staff is refining how public benefits are assessed from PIER-funded RD&D projects and the overall program. The PIER Program developed a program wide approach to benefit and cost assessment, which includes integrating benefits assessment elements into work plans and databases, evaluating interviews and surveys, identifying required benefits metrics, and requiring researchers to provide a subsequent report on these metrics.

For example, in the first quarter of 2011, the Energy Commission calculated that PIER-funded research activities directly created 2,128 jobs. These jobs are assigned to projects providing the full time equivalent (FTE) of 970 job-years. Analysis using IMPLAN®, an economic analysis software tool for predicting regional economic effects, estimates that these 2,128 jobs lead to 1,250 indirect jobs, where the entities doing the work have to purchase goods and services, and 2,180 induced jobs, where business owners and employees purchase goods and services. About 5,600 people were employed at least part-time over the course of these PIER-funded contracts. Based on the FTE job-years worked, the IMPLAN model estimates state and local governments collected $2.3 million in taxes.

Public Outreach

The Energy Commission has considerably streamlined the report and publication process for project fact sheets to disseminate important research results to the public. To communicate the program's successes, the Energy Commission published a brochure, *PIER: How Public Research Powers California,*[214] along with many fact sheets, reports, and other brochures targeting success in specific topic areas such as smart infrastructure, overcoming renewable energy barriers, and efficiency projects.

214 California Energy Commission, *PIER: How Public Research Powers California*, CEC-500-2011-030-BR, July 2011, www.energy.ca.gov/2011publications/CEC-500-2011-030/CEC-500-2011-030-BR.pdf.

In August 2011, the PIER Program held a Venture Capital Forum in Sacramento to increase levels of California venture capital market investments in PIER-funded emerging technologies. The goal of the forum was to learn from venture capitalists how they evaluate prospective technologies, how to better invest and leverage PIER funds, and how to encourage higher levels of venture capital investment in PIER-funded technologies to help bolster the path to market. Because of the success of this forum, the program plans to have additional forums in the future.

On the Horizon

The PIER Program is committed to working with stakeholders and policy makers to tackle ongoing energy issues associated with the Renewables Portfolio Standard, Zero Net Energy buildings, smart grid implementation, environmental barriers to renewable energy implementation, and the Governor's goal for DG. Staff will also continue to fine-tune the administration of the PIER Program with the goal of maximizing its value to California businesses and residents.

From November 2011 through January 2012, the PIER Program released the following solicitations:

- Industrial, Agricultural, and Water – Emerging Technologies Demonstration Grant Program II
- Environmental Issues Related to Clean Energy Systems
- Hybrid Generation and Fuel-Flexible Distributed Generation/Combined Heat and Power/Combined Cooling, Heat, and Power Systems
- Liquefied Natural Gas Vehicle Infrastructure Improvement Research and Development

The PIER Program is also planning to release the following solicitations in 2012:

- Community Scale Renewable Energy Development, Deployment, and Integration
- PIER Buildings Grant Solicitation

While the Energy Commission is confident that research funding will emerge next year, if this does not happen, the agency will have to discontinue vital research and impartial evaluation, and will lose coordination of energy RD&D that benefits the entire state.

Recommendations

The Energy Commission recommends that California continue funding public interest energy research that helps meet state energy goals. Advancing energy RD&D activities in California will attract new businesses, create jobs, and allow California companies and research institutions to compete for and successfully attain federal funds.

The Energy Commission recommends continuing to manage a public interest energy research program in California because it advocates for Californians by acting as impartial evaluator when providing RD&D funding to California researchers. The Energy Commission also has the unique ability to select and coordinate research across various types of researchers (private businesses, institutional, government agencies, and so forth) to maximize the effectiveness of the program and ensure consistency with state policy goals.

Furthermore, the Energy Commission recommends the following for a renewed PIER Program:

- Prepare a Five-Year Strategic Investment Plan with active stakeholder engagement, which is guided by state energy policy and would achieve a balanced portfolio of investments including technology demonstrations and the more fundamental and applied research.

- Design metrics around strategic plan objectives that are tangible, quantifiable, and measureable. The metrics, when combined with periodic evaluations, will help refine programs, increase program effectiveness, make tough decisions to drop ineffective program elements, and develop credible evidence that communicates the value of the program to stakeholders.

- Increase outreach and awareness of RD&D projects and results by holding workshops, research forums and conferences, press events, and other activities with the public and stakeholders.

Conclusion

The state should continue funding public interest energy research. The state's public interest RD&D program plays a critical role in providing jobs and innovations for California by helping startup businesses move technologies from demonstration to deployment and meet state policy goals.

As administrator of the PIER Program, the Energy Commission will ensure that research supports and follows state energy policy, provides solutions for California's future energy problems, and provides benefits to Californians. The Energy Commission remains committed to continuing this clean energy-incubator program.

CHAPTER 13

2011 Bioenergy Action Plan

This chapter summarizes the Energy Commission's 2011 Bioenergy Action Plan, prepared for the Bioenergy

Interagency Working Group (Working Group)[215, 216] and adopted in March 2011, and outlines current activities and priorities of the Working Group during 2011. The summary includes key points from the report, background information, objectives for achieving state bioenergy goals, challenges, key findings and recommendations, and action items to be taken in the next two years.

Development of bioenergy supports state policies and goals. There are four types of bioenergy identified for California's

215 The full report can be accessed at: www.energy.ca.gov/2011publications/CEC-300-2011-001/CEC-300-2011-001-CTF.PDF.

216 The Working Group consists of the following state agencies: California Energy Commission, Air Resources Board, Environmental Protection Agency, Resources Agency, Department of Resource Recovery and Recycling, Department of Food & Agriculture, Department of Forestry and Fire Protection, Department of General Services, California Public Utilities Commission, and Water Resources Control Board.

Renewables Portfolio Standard, and biopower and biogas have the potential to provide renewable energy to help meet Governor Brown's Clean Jobs goals of 12,000 MW of local distributed energy generation. Biofuels and biogas can also play an important role in reducing the lifecycle carbon emissions from transportation fuels, helping California achieve the state's Low-Carbon Fuels Standard.

Bioenergy is energy produced from biomass in the form of electricity (biopower), renewable gas (biogas, biomethane, or synthetic natural gas), or liquid transportation fuels (biofuels). California has abundant biomass resources from the state's agricultural, forest, and urban waste streams. Increased bioenergy production could provide the state with several economic, environmental, and reliability benefits. For example, bioenergy creates clean energy jobs, enhances rural economic development, and promotes local economic stability. It can also help the state meet its climate change targets and ensure a more stable supply of energy by reducing the state's dependence on imported fossil fuels. Biopower can increase grid reliability because it is not intermittent and can therefore support the current "baseload" or other continuous energy demand.

Despite the state's policies to promote renewable energy and bioenergy, biomass is currently underused as an energy source, and increasing bioenergy production faces many challenges. Following publication of the *2006 Bioenergy Action Plan*, new bioenergy facilities were proposed and constructed; some idle facilities were restarted. However, by 2011, most of these biopower capacity gains were lost due to adverse market conditions, high transportation fuel costs, and, in some cases, competition with fossil fuels. Lower cost renewables may also make it difficult for biomass to compete in the RPS competitive bid process. However, biopower should be able to compete in the new Renewable Auction Mechanism, since the program is designed to separate bids into different product types (such as base load, intermittent peak, and intermittent off peak).

As part of the *2011 Plan*, Energy Commission staff developed five objectives to help accelerate the development of bioenergy projects by building on the successes and lessons learned from the *2006 Plan*. The five objectives are:

- Encourage increased bioenergy production at existing facilities.
- Promote and expedite the construction of new bioenergy facilities.
- Promote and encourage the integration of bioenergy facilities.
- Fund research and development.
- Remove statutory hurdles and streamline the regulatory process.

Developing the potential for new energy production in each objective will require overcoming many of the challenges facing the industry. The challenges to bioenergy have been discussed through workshops and forums held by the Energy Commission, California Integrated Waste Management Board (now CalRecycle), the California Department of Food and Agriculture, the Department of Forestry and Fire Protection (CAL FIRE), ARB, State Water Resources Control Board, the California Biomass Collaborative, the United States Environmental Protection Agency (U.S. EPA), industry groups, and others for many years. Through these forums, developers, stakeholders, and state and federal agencies have identified opportunities and challenges to increased bioenergy development in the state.

Key Findings and Recommendations

The *2011 Plan* identifies a number of key findings on how the challenges have affected in-state bioenergy development. The *2011 Plan* also finds that biomass is an abundant resource that can help the state achieve clean energy goals, but aggressive actions must be taken to increase biomass use. The findings are as follows:

- California has abundant biomass resources from the state's agricultural, forest, and urban waste streams. Increasing the state's bioenergy production will help California achieve the state's waste reduction, renewable energy, and climate change goals with a sustainable and dependable resource.

- Bioenergy has many benefits, both as a renewable energy source and an alternative disposal option for biomass. The benefits of bioenergy include displacing fossil fuels with a dependable renewable resource, providing distributed energy near demand, reducing greenhouse gas emissions, and providing green jobs in rural communities. The use of biomass has added benefits to surrounding communities by providing agriculture, industry, and forestry an alternative disposal option for biomass residues, indirect jobs needed to collect and transport the biomass, reduced demand on landfills, and improved water quality and ecosystem health.

- Market-based pricing mechanisms for electricity, transportation, and waste management do not currently consider all of the benefits bioenergy provides to local communities.

- There is a need for continued state research and funding to commercialize biomass technologies.

- Electric grid and natural gas pipeline interconnection challenges have inhibited the development of distributed biomass electricity and biogas projects. California must address these challenges to increase development of bioenergy projects.

- The cost to collect and transport biomass feedstock remains an economic challenge to the development of bioenergy projects in California.

- Regulatory uncertainty continues to reduce options to finance projects in the predevelopment stage, further inhibiting the development of bioenergy and other distributed energy projects.

- Efforts to streamline the permitting process, especially for anaerobic digesters using dairy and urban waste, continue to be supported by state agencies, local air districts, regional water control boards, and the U.S. EPA. However, additional actions will be needed by the Bioenergy Interagency Working Group and the Legislature to streamline permitting for distributed energy projects.

The *2011 Plan* makes recommendations to support the key findings and help provide solutions to the challenges facing the bioenergy industry. The following recommendations are supported by members of the Working Group:

- Action is needed by the California Public Utilities Commission to continue the Energy Commission's public interest research program and to develop programs that offset the cost of new and emerging biopower technologies. Members of the Working Group support funding for a new biopower commercialization program to develop agricultural, forestry, and urban bioenergy projects.

- Increased development of biofuels is important to fulfill goals established by the Low Carbon Fuels Standard and the AB 118 program. The state should continue to evaluate bioenergy feedstocks and markets to promote technologies, programs, and policies needed to enhance biofuels development.

- The Bioenergy Interagency Working Group will work with California gas utilities and other stakeholders through a public process to address real and perceived barriers to the development of biogas and landfill gas, and the injection of biomethane into the California natural gas pipeline.

- Permitting agencies will continue to improve coordination in the permitting process to reduce the time frame and costs to developers. The Working Group will take additional steps to expedite permits through programmatic environmental impact reports and creating a web-based portal for permit contacts.

- Explore various options to quantify the benefits bioenergy provides ratepayers and surrounding communities.

- Develop sustainable feedstock standards and waste use targets for biomass resources to ensure that its use supports California's renewable energy, the Low Carbon Fuel Standard, recycling and waste reduction goals, and creates new jobs.

- Develop a plan to reduce the cost of collection and transportation of biomass residues.

- Continue to convene regular meetings of the Working Group to continue agency coordination and collaboration.

- In cooperation with other state agencies, the Energy Commission should continue to monitor progress toward achieving the state's bioenergy goals through the Working Group.

Status of Biofuels

In 2010, California consumed roughly 1 billion gallons of biofuels (gasoline gallon equivalent [gge]), primarily as ethanol blended into gasoline as an oxygenate. Federal and state policy mandates will necessitate an increase in the consumption of renewable fuels for transportation in California. Biofuel development is more completely addressed in Chapter 10 on Transportation.

California has 150 million gge of annual ethanol production capacity, with less than 50 million gge produced in 2010. When the ethanol blend in California reformulated gasoline increased to 10 percent in 2010, the state's total ethanol use grew to nearly 1.5 billion gallons. However, California ethanol facilities contributed less than 4 percent of the state's needs in 2010. Since 2000, five corn ethanol refineries have been built in California. All five of these plants were idle for most of 2009 and 2010 due to adverse market conditions. Only one of these corn ethanol refineries produced fuel in 2010 with two more coming on-line in the first half of 2011. Total in-state biodiesel capacity is capable of producing 100 million gge per year. However, less than 5.7 million gge were produced in 2010. Table 21 summarizes the biofuel production and capacity in California. Biofuel consumption is expected to grow over the next decade.

In-state biofuel production will make up just 5.6 percent of California's estimated 1 billion gge biofuel demand in 2010, far below the biofuel goal of 20 percent (200 million gge).

Over the past two years, the Energy Commission, through its ARFVT Program, has begun investing in new projects to develop and deploy additional in-state biofuel production projects. To date, the Energy Commission has invested roughly $64 million toward biofuel production, fueling infrastructure, and related projects. This represents just over one-third of the total ARFVT Program awards.

Of the $64 million allocated toward biofuels proj-

Table 21: In-State Biofuel Production (millions gge)

	2006	2007	2008	2009	2010
Ethanol Production	27.7	27.7	90.4	20.1	<50
Biodiesel Production	20.8	18.6	12.4	7.3	5.7
Total In-State Biofuel Production	48.5	46.3	103	27.4	<55
Total Biofuel Consumption	659	652	702	680	1,017
Percent In-State Production to Total Biofuel Consumed	7.4%	7.1%	14.6%	4.0%	<5.5%

Source for in-state biofuel production, California Energy Commission; source for total biofuel consumption, California Energy Commission staff analysis of Board of Equalization taxable gasoline figures.

ects, $45 million has gone toward projects that will accelerate or expand the production of next-generation biofuels. These 17 projects will use waste-based feedstocks or alternative bioenergy crops (such as sugar beets, sweet sorghum, and algae), rather than corn or soy. While the carbon intensity of the resulting fuels will vary, they will typically range from 70 percent to 85 percent below the diesel and gasoline baseline.

Most of these projects are still in their early stages, but the Energy Commission's survey of awardees indicates their potential for market growth. The survey responses included a low and high range for the projects' market entrance and expansion, which ranged from a total of 123 million to 632 million gallons per year of petroleum displacement (either gasoline or diesel fuel) from new biofuel production by 2020. If achieved, this level of production would represent a significant step toward achieving the goal of having 40 percent (or roughly 820 million gge) of in-state biofuel consumption coming from in-state resources by 2020.[217]

Status of Biopower and Biogas

In 2010, most of the biopower in California was generated from solid-fuel biomass and landfill gas. Other biopower sources include dairy digesters, solid-fuel thermochemical conversion facilities, organic waste digesters, and wastewater digesters.

Since 2006, 22 new biopower facilities were built in California (15 landfill gas and 7 digester facilities), representing 44 MW of generating capacity. Although no new solid-fuel biomass facilities were constructed, four idle facilities restarted, including an idle coal facility converted to biomass.

Cofiring biomass or biogas at conventional power plants has been a growing trend since 2008. Three in-

217 O'Neill, Garry, John Nuffer, *2011 Bioenergy Action Plan*, California Energy Commission, Efficiency and Renewables Division, CEC-300-2011-001-CTF, available at: www.energy.ca.gov/2011publications/CEC-300-2011-001/CEC-300-2011-001-CTF.PDF.

state coal facilities have begun cofiring with biomass and have plans to convert to biomass as their sole energy resource by 2012. These facilities will contribute up to 130 MW of renewable capacity to the grid. Two additional coal facilities have indicated an interest in switching to renewable feedstocks, although the Energy Commission does not have an expected start date on the conversion. If successful, these facilities could add another 80 MW of renewable capacity. The conversions of in-state coal facilities will significantly reduce greenhouse gas emissions, allow the facilities to continue generating combined heat and power, and retain well-paying jobs in economically depressed communities. In addition, 10 in-state natural gas power plants began cofiring with pipeline biomethane produced and injected into the interstate natural gas pipeline out-of-state, with an effective capacity of 90 MW.

By the end of 2010, nine solid-fuel biomass facilities were idle, representing 100 MW. The facilities have idled for various reasons, such as poor economic conditions in the lumber industry and low contract prices for energy. Seven dairy manure digesters also idled due to financial difficulties and, in some instances, difficulties meeting San Joaquin Valley Air Pollution Control District nitrogen oxide (NOx) emission standards with purchased equipment. The capacity idled since 2006 is 100 MW.

Biopower generation increased 10 percent from 2006 through the end of 2010. Much of the generation increase came from out-of-state biopower facilities and in-state biomass cofiring at coal and biogas burned in natural gas facilities and restarted solid-fuel biomass facilities. While the total generation used to meet California load has increased since 2006, in-state biopower generation has remained level. The biomass share of renewable electricity generation in California has decreased from 20 percent to 17 percent.

In-state biopower generation is expected to increase in the short term as coal facilities complete full fuel conversion to biomass by the end of 2012. Additional biopower capacity has recently been proposed as the remaining existing in-state coal facilities look to convert to biomass by 2015. In addition, the Energy Commission expects that a small number of facilities that shut down due to low short-run avoided cost energy prices in 2009 and 2010 will restart if contract renegotiations are successful. While new projects have been proposed, they are not expected to contribute significant generation in the next two years.

Opportunities exist at public works projects, municipal wastewater treatment plants, and landfills to collect and capture fugitive methane emissions and produce biogas or biomethane. At this time, much of this potential energy resource is flared due to difficulties obtaining air permits and meeting air quality standards in some California air districts, and the economics of power generation. While on-site power generation may not be possible because of increases air pollutants compared to flaring, cleaning and upgrading this gas to meet pipeline or transportation fuel standards would allow beneficial use of this resource for energy production.

Progress on Implementing the 2011 Bioenergy Action Plan

The *2011 Bioenergy Action Plan* was intended to be updated and refreshed as needed to adapt to changing conditions. Parties are continuing to work on completing and updating measures, and the Energy Commission will report on updates and processes in future *IEPRs.*

Actions underway and completed are listed below.

Table 22: Biopower Generation Used to Meet California Load

	2006	2007	2008	2009	2010
In-State Biopower Generation (GWh)	5,735	5,398	5,720	5,940	5,745
Out-of-State Biopower Generation (GWh)	550	838	657	885	1,149
Total Biopower Generation (GWh)	6,285	6,236	6,377	6,825	6,894
Total Renewable Generation (GWh)	32,215	32,314	32,532	35,791	39,796
Percent of Renewable Generation	19.5%	19.3%	19.6%	19.1%	17.3%

Source: California Energy Commission Total System Power

Actions Initiated in 2011

Action: Governor's Office and the Bioenergy Interagency Working Group are developing the *2012 Bioenergy Action Plan*.
Completion Date: January 31, 2012

Action: California Department of Food and Agriculture has convened a state, federal, stakeholder working group of federal, state, and regional agencies and stakeholders to promote the development of dairy digesters. The working group is developing specific recommendations on actions that will streamline permitting, and address technology challenges and economic incentives or programs needed to finance projects.
Lead Agency: California Department of Food and Agriculture
Completion Date: Preliminary Report, March 2012.

Action: The Sierra Nevada Conservancy (SNC) is providing state agency leadership in working with a diverse group of stakeholders and government entities to promote small-scale bioenergy projects that are consistent with forest restoration, economic development, and social equity objectives.
Completion date: Ongoing

Actions Underway

Action 1.1: Develop a website to provide local governments with permitting, planning, and technical assistance documents for siting and developing new renewable facilities.
Lead agency: Energy Commission
New completion date: March 31, 2012

This action was changed to develop a program to offer planning and permitting assistance to local permitting agencies. The new completion date reflects the need to hold a stakeholder workshop in early 2012.

Action 1.2: Develop a comprehensive website to provide new project developers with permitting guidance, links, and contacts to permitting agencies.
Lead agency: Energy Commission
New completion date: March 31, 2012 (to fit in with the work plan of Action 1.1.)

This action will be included in the development of the Local Government Assistance Program in Action 1.1.

Actions Completed

➨ **Action 2.6 (a):** The *Program Environmental Impact Report for Anaerobic Digestion of Organic Waste* was completed, certified, and submitted to the State Clearinghouse in June 2011. This document is designed to expedite the permitting on anaerobic digestion projects within California.

➨ **Action 2.6 (g):** CalRecycle has updated guidance documents that outline how CalRecycle regulations are applied to anaerobic digesters and the statutory requirements that CalRecycle and local enforcement agencies have regarding anaerobic digesters when solid waste is used as a feedstock.

➨ **Action 5.4:** This action involved monitoring changes to federal bioenergy policies and regulations. In May 2011, U.S. EPA issued a stay delaying the effective date of the standards for major source boilers and commercial and industrial solid waste incinerators (also referred to as the Boiler MACT rules). On January 9, 2012, the U.S. District Court vacated the U.S. EPA's May 2011 stay, declaring that the reconsideration was unlawful. The effect of the ruling is that the March 2011 Boiler MACT Rules went into effect on May 20, 2011. It is unclear at this time whether the court is allowing the U.S. EPA to revise the rules before the new standards are incorporated into the State Implementation Plan (within 3 to 5 years of the effective date of May 2011). New sources constructed after June 4, 2010, will have to comply upon startup.

CHAPTER 14

Nuclear Issues & Status Report on Assembly Bill 1632 Report Recommendations

This chapter discusses the implications of recent events in Japan for California's nuclear plants regarding seismic and

tsunami hazards, spent fuel pool safety, potential station blackouts, liability coverage, long-term power outages, and emergency response planning.

In 2010, nuclear power provided 15.7 percent of California's in-state electricity generation and 13.9 percent of the entire California power mix (which includes out-of-state imports).[218] This electricity generation comes from three plants: the Diablo Canyon Power Plant (Diablo Canyon) and the San Onofre Generating Station (SONGS) in California, and the Palo Verde nuclear power plant in Arizona.[219]

218 See: energyalmanac.ca.gov/electricity/index.html, Electricity Generation by Resource Type (1997 – 2010, Excel file).

219 Diablo Canyon is located near San Luis Obispo and is owned by Pacific Gas and Electric Company. SONGS is located near San Clemente on land leased from the U.S. Marine Corps at the north end of Camp Pendleton. It is co-owned by Southern California Edison, San Diego Gas & Electric, and Riverside Public Utilities. The Palo Verde nuclear power plant, located near Phoenix, Arizona, and partially owned by Southern California Edison, the Los Angeles Department of Water and Power, and a consortium of Southern California municipal utilities.

These nuclear power plants are important to California's electricity supply and meeting the state's greenhouse gas emissions reduction goals and policies for climate change reduction. However, Diablo Canyon and SONGS are older plants located near major earthquake faults and have significant inventories of spent nuclear fuel stored onsite. Concerns about their safety and reliability have increased with the recent large earthquakes in Japan.

In 2007, a major earthquake resulted in the loss of nearly 8,000 MW of power at the Kashiwazaki-Kariwa nuclear power plant in Japan, with most of its units remaining shut down four years after the event. This event followed the California Legislature's passage in 2006 of Assembly Bill 1632 (Blakeslee, Chapter 722, Statutes of 2006), which required the Energy Commission to assess the vulnerability of California's major baseload plants to a major earthquake or plant aging.[220] As required by AB 1632, the Energy Commission completed *An Assessment of California's Nuclear Power Plants: AB 1632 Report (AB 1632 Report)* in 2008, which provided an independent scientific assessment of the seismic hazard and plant vulnerabilities at Diablo Canyon and SONGS.[221]

In 2008, Pacific Gas and Electric (PG&E) announced that the United States Geological Survey (USGS) had discovered the Shoreline Fault less than a mile offshore from Diablo Canyon. In 2003, the San Simeon earthquake (magnitude 6.5) occurred about 35 miles north of the Diablo Canyon site, and the tectonic setting where this earthquake occurred appears similar to the local tectonic setting at Diablo Canyon.[222] Better understanding of the fault zones in the vicinity of Diablo Canyon and SONGS is significant for plant engineering vulnerability assessments for these plants. The deep geometry of faults that bound the San Luis-Pismo block, where Diablo Canyon sits, is not understood sufficiently to rule out a San Simeon-type earthquake directly beneath the plant.[223] Similarly, data that has become available since SONGS was built indicate that the site could experience larger and/or more frequent earthquakes than anticipated in the plant design and the earthquake design basis for the plant may underestimate the seismic risk at the site. [224,225] To help resolve uncertainties about the seismic hazards at these plants, the Energy Commission's *2008 IEPR Update* recommended that PG&E and Southern California Edison (SCE) complete enhanced seismic and tsunami hazard and plant vulnerability studies including using three-dimensional seismic reflection mapping and other advanced techniques to supplement seismic research at the plants.[226]

On March 11, 2011, a magnitude 9.0 earthquake and tsunami in Japan knocked out power and emergency electrical equipment at the Fukushima Daiichi nuclear plant in Japan, resulting in reactor meltdowns, explosions, fires, and widespread radioactive contamination. Although a 9.0 magnitude earthquake from a subduction zone is not thought to be possible near

220 Pacific Gas and Electric Company, 2010a, Diablo Canyon Power Plant, *Responses to Kashiwazaki-Kariwa Nuclear Power Station Lessons Learned*, March 10, 2010.

221 California Energy Commission and MRW and Associates, *An Assessment of California's Nuclear Power Plants: AB 1632 Report*; and *AB 1632 Assessment of California's Operating Nuclear Plants: Final Consultant Report*, available at: www.energy.ca.gov/ab1632/documents/.

222 California Energy Commission, *2008 Integrated Energy Policy Report Update,* www.energy.ca.gov/2008_energypolicy/index.html, page 67.

223 *AB 1632 Assessment of California's Operating Nuclear Plants: Final Report*, consultant report, p. 6.

224 California Energy Commission, *2008 Integrated Energy Policy Report Update,* www.energy.ca.gov/2008_energypolicy/index.html, page 67.

225 California Coastal Commission, www.coastal.ca.gov/energy/E-00-014-3mmi.pdf, page 19.

226 California Energy Commission, *2008 Integrated Energy Policy Report Update*, www.energy.ca.gov/2008_energypolicy/index.html.

Diablo Canyon and SONGS, the Fukushima incident heightened concerns about seismic and tsunami hazards as well as safety issues for California's coastal nuclear plants. On July 26, 2011, two Commissioners from the Energy Commission and two from the CPUC jointly conducted a public workshop on the implications of the Fukushima Daiichi accident for California's nuclear power plants and the utilities' progress in carrying out the *AB 1632 Report* recommendations.[227] Three panels of experts representing PG&E, SCE, state and federal agencies, the nuclear industry, and public interest groups participated in this workshop along with members of the public. In addition, the utilities prepared responses to 2011 IEPR Committee data requests on nuclear issues.[228]

Events at Fukushima Daiichi and Implications for California Nuclear Plants

The 9.0 magnitude earthquake on March 11, 2011, in northern Japan and an estimated 40-foot tsunami run-up at the Fukushima Daiichi plant site resulted in spent fuel meltdowns at three of the plant's six reactors, overheating and damage to spent fuel storage pools, explosions and fires, large-scale releases of radioactive materials to the environment, and the evacuation of an estimated 80,000 people. The Japanese government rated the crisis at a Level 7: the highest possible level on the international scale for evaluating the seriousness of nuclear reactor incidents, equivalent to the 1986 Chernobyl plant accident in the Ukraine. The policy decisions resulting from the lessons-learned studies from these events will shape the next few decades of nuclear energy policies throughout the world.

Fukushima demonstrated that extraordinary and extreme events can pose unexpected challenges for nuclear plants. Historically, the Nuclear Regulatory Commission's (NRC)[229] emergency guidelines (instituted in the 1990s) for nuclear plants, including the Severe Accident Mitigation Guidelines, have been voluntary and not part of its program overseeing reactor safety.[230] After Fukushima, however, the NRC established a task force to evaluate what lessons might apply to the safety of U.S. reactors and instructed NRC plant inspectors to conduct immediate, independent assessments of each plant's level of emergency preparedness. NRC's regional and resident inspectors found several deficiencies at Diablo Canyon.[231]

The Fukushima events will likely cause increased industry vigilance and expanded federal government oversight of nuclear power plant safety. In 2011, NRC's Near-Term Task Force issued post-Fukushima recommendations for enhancing reactor safety and a

227 Meeting notice, agenda, transcripts, panel submittals, and public comments for the July 26, 2011, workshop at: www.energy.ca.gov/2011_energypolicy/documents/index.html#07262011.

228 Utility responses to the *2011 IEPR Data Request on Nuclear Issues* can be found at: www.energy.ca.gov/2011_energypolicy/documents/data_nuclear_power_plants/.

229 The Nuclear Regulatory Commission is the federal agency responsible for regulating nuclear power plant safety in the United States.

230 Nuclear Regulatory Commission, *NRC Inspection Manual, Temporary Instruction*, 2515/184, issued April 29, 2011, pbadupws.nrc.gov/docs/ML1111/ML11115A053.pdf.

231 Natural Resources Defense Council, Tom Cochran, July 26, 2011, *IEPR workshop on California Nuclear Power Plant Issues*.

priority list of actions.[232] The NRC Chairman, Gregory Jaczko, has urged an expedited timeline to work through the recommendations, but the industry is asking for more time to assess the lessons learned from Fukushima and the cost to plant owners from making the recommended changes.[233] There is no consensus yet among NRC Commissioners regarding the need for expedited action.[234]

Seismic and Tsunami Hazards

The recent earthquakes that affected the Fukushima Daiichi plant in March 2011, and the North Anna plant in Virginia on August 23, 2011, exceeded the levels assumed in plant designs and underscored the importance of updating seismic hazard estimates for reactor sites.[235] No significant safety concerns from the earthquake were identified at North Anna and the plant was restarted in November 2011. Fukushima experienced higher ground motion than the plant was designed to withstand. An international study combining monitoring data from around the world to estimate the scale and fate of radioactive emissions from Fukushima suggested that there was structural damage to the plant and radioactive material releases following the earthquake even before the tsunami hit.[236] The majority of faults in California are not considered capable of generating a magnitude 9.0 earthquake except for the subduction zone that begins north of Mendocino.[237] However, the significant uncertainties regarding geologic conditions near Diablo Canyon and SONGS warrant additional seismic studies.

For SONGS, the largest uncertainty for determining seismic hazard and plant vulnerability pertains to the offshore (and potentially onshore) thrust fault systems.[238] The existing seismic network in Southern California has few monitoring stations near SONGS. Therefore, detailed studies similar to those that led to the discovery in 2008 of the Shoreline Fault near Diablo Canyon are not possible. Similarly, the existing global positioning system (GPS) network in Southern California has few stations near SONGS, and no ocean floor GPS monitoring stations are in the vicinity of the plant.[239]

For Diablo Canyon, the largest uncertainty is the seismic hazard potential for the plant's identified fault systems. The existing seismic monitoring network in Northern California has numerous onshore stations in and around Diablo Canyon. However, there are no offshore stations west of the Hosgri and Shoreline faults. Sea floor seismometers west of

232 Nuclear Regulatory Commission, *Recommendations for Enhancing Reactor Safety in the 21st Century: Near-Term Task Force Review of Insights from the Fukushima Dai-ichi Accident*, July 12, 2011.

233 Reuters, "Analysis: After Fukushima, Glacial Change Seen for U.S. Nuclear," July 11, 2011, Roberta Rampton and Eileen O'Grady.

234 Bloomberg, "Jaczko Votes for NRC Fukushima Report, Spurns Calls to Delay," August 10, 2011, Brian Wingfield.

235 On August 23, 2011, following an earthquake, the two-reactor North Ana nuclear plant in Virginia shut down. The dry cask storage containers during the earthquake moved several inches. The earthquake exceeded design parameters for the plant. NRC is asking Dominion to demonstrate to the Energy Commission that no functional damage occurred to features necessary for continued operation without undue risk to the health and safety of the public. The NRC will complete a safety evaluation regarding restart of the plant.

236 Stohl, A., P. Seibert, G. Wotawa, D. Arnold, et. al, "Xenon-133 and Caesium-137 Releases into the Atmoshere from the Fukushima Dai-ichi Nuclear power Plant: Determination of the Source Term, Atmospheric Dispersion, and Deposition", *Atmos. Chem. Phys. Discuss.*, 11, 28319–28394, 2011, www.atmos-chem-phys-discuss.net/11/28319/2011/doil:10.5194/acpd-11-28319-2011.

237 California Coastal Commission, Mark Johnsson, presentation at Energy Commission's July 26, 2011, workshop.

238 United States Geological Survey, William Ellsworth, "Overview of Earthquake Hazards in California and Current Research Aimed at Reducing Uncertainty," presentation at Energy Commission's July 26, 2011, workshop.

239 Ibid.

these faults would greatly increase the ability to accurately locate known and unknown offshore faults by determining the precise locations of earthquake (most often microearthquake) epicenters.

To better understand crustal strain in the offshore environment, permanent GPS monitoring stations should be placed on the offshore sea floor. Offshore GPS stations are needed to measure crustal strain to better understand where the sea floor is deforming/moving.[240]

For years, scientists considered the Hosgri Fault as the dominant source of seismic shaking that could affect Diablo Canyon. Then the San Simeon earthquake in 2003 demonstrated the potential of strong seismic shaking on previously unidentified blind thrust faults in the region.[241] Identification of the Los Osos Fault indicated a San Simeon-style earthquake could occur very near or beneath the plant. The USGS' analysis of earthquake epicenters near Diablo Canyon led to the discovery of the previously unknown Shoreline Fault directly offshore from the plant in 2008. The USGS is also examining whether the Hosgri Fault is continuous with the San Simeon-San Gregorio Fault and ultimately tied into the San Andreas Fault in Bolinas. The results of these studies could change the magnitude of the maximum probable earthquake on the Hosgri Fault. Similarly, studies are being conducted to assess the continuity (as opposed to segmentation) of the Shoreline Fault and its potential connection to the Hosgri Fault, increasing the likelihood that an earthquake rupture may simultaneously occur along both faults.

The NRC's Task Force has noted an increased understanding of seismic hazards within the United States and is recommending an upgrade of the design basis and flooding protection of structures, systems, and components (SSCs) for each operating reactor (with a re-evaluation of the design basis every 10 years). The NRC is reviewing the adequacy of seismic safety margins at all U.S. plants with PG&E's and SCE's participation.[242] The additional seismic studies for Diablo Canyon and SONGS, as recommended by the *AB 1632 Report,* will contribute to these updated seismic evaluations.

Spent Fuel Pool Issues

Due to the unavailability of offsite storage or disposal facilities, most spent fuel is stored at reactors in cooling ponds in far greater densities than original plant designs and in significantly less protected buildings than the reactor cores. In 2003, an independent study of safety issues associated with spent fuel pool storage raised concerns about the trend toward higher-density spent fuel storage in pools and the possibility that under certain conditions in which the water is drained from a pool, the fuel could overheat, ignite the fuel cladding, and release large quantities of radioactive materials.[243] The National Academies in 2006 at the request of Congress completed a study on spent fuel safety and security and reported on the

240 United States Geological Survey, William Ellsworth, recommended at the July 26, 2011, workshop research for improved understanding of seismic hazard affecting the Central Coast including high-resolution bathymetry (marine), LIDAR (land) aeromagnetic surveys, marine and land gravity surveys, new and reviewing old oil industry's seismic reflection surveys, adding land-based and ocean bottom seismic stations, detailed geologic investigations to establish slip rates and to date fault offsets, adding land and ocean floor GPS, high-resolution seismic surveys and sampling marine deposits.

241 The December 22, 2003, San Simeon Earthquake was a magnitude 6.5 earthquake on the Central Coast of California, about 7 miles northeast of San Simeon.

242 Nuclear Regulatory Commission, Draft Generic Letter 2011-XX (GI-199), "Seismic Risk Evaluations for Operating Reactors," issued for public comment on September 1, 2011, Agencywide Documents; Access and Management System (ADAMS) Accession No. ML111710783 "Implications of Updated Probabilistic Seismic Estimates in Central and Eastern United States on Existing Plants."

243 Alvarez, Robert, "Reducing the Hazards from Stored Spent Power-Reactor Fuel in the United States," *Science and Global Security 11, 1–51*, 2003.

risks of a fire from overheated spent fuel in storage pools and the potential release of large quantities of radioactive materials. They concluded that dry cask storage is inherently safer and has security advantages over wet pool storage.[244] A high-priority measure would be to equip spent fuel pools with low-density racks for spent fuel storage.[245]

International researchers examining worldwide radiation monitoring stations found that the Unit 4 spent fuel pool at Fukushima played a significant part in the widespread release of radioactive materials to the environment.[246] However, an Institute of Nuclear Power Operations (INPO) study concluded that, "Subsequent analyses and inspections determined that the spent fuel pool water levels never dropped below the top of the fuel in any spent fuel pool and that no significant damage occurred."[247] Fukushima's spent fuel pools were not fully loaded,[248] whereas Diablo Canyon stores about four times more spent fuel than it was designed for.[249] SONGS has a spent fuel pool storage capacity that is nearly double that of the original storage capacity for the plant.[250]

An option for California's nuclear plants is to expedite the transfer of the older spent fuel from pools into dry storage casks (which are passively safe).[251] The Energy Commission's *2008 IEPR Update* recommended that PG&E and SCE return the spent fuel pools to open racking arrangements as soon as feasible. PG&E and SCE evaluated whether to modify the rate for moving Diablo Canyon's and SONGS' spent fuel from the pools into dry cask storage and determined that moving fuel at a faster rate would accelerate customer costs and employee exposure to radiation with no significant increase in safety.[252] However, if a Fukushima-scale event were to strike a typical U.S. nuclear plant spent fuel pool, there potentially would be a worse situation than occurred in Japan since there is considerably more fuel stored in U.S. reactor pools than at Fukushima. Storing more irradiated fuel in pools, which are less protected than dry casks, creates an undue hazard.

Another issue at Fukushima, as noted by the NRC Task Force, was that the plant's operators had great difficulty understanding the condition of the spent fuel pools during the accident because the instrumentation was lacking or not functioning properly.[253] To address instrumentation issues, the NRC Task Force is recommending that nuclear power plants provide sufficient safety-related instrumentation and seismically protected systems that will supply additional cooling water to spent fuel pools when necessary, and provide at least one electrical power system to

244 National Research Council, *Safety and Security of Commercial Spent Nuclear Fuel Storage*, National Academies Press, 2006.

245 Clark University, Center for Risk and Security, Gordon Thompson, "Potential Radioactive Releases From Commercial Reactors and Spent Fuel," June 2005, Worcester, Massachusetts, CRS Discussion Paper 2005-003.

246 Brumfiel, Geoff and Nature Magazine, "Fukushima Nuclear Plant Released Far More Radiation than Government Said," *Scientific American,* October 25, 2011, www.scientificamerican.com/article.cfm?id=fukushima-nuclear-plant-release4d-more-radiation-government-said.

247 Institute of Nuclear Power Operations, *Special Report on the Nuclear Accident at the Fukushima Daiichi Nuclear Power Station,* INPO 11-005, November 2011.

248 Macfarlane, Allison, "The Overlooked Back End of the Nuclear Fuel Cycle", *Science*, Vol. 333, September 2, 2011, pp. 1,225–1,226.

249 California Energy Commission, *IEPR* workshop transcripts, July 26, 2011, page 97.

250 Southern California Edison, *Response to IEPR Data Request*, August 8, 2011.

251 Macfarlane, Allison, "The Overlooked Back End of the Nuclear Fuel Cycle," *Science*, Vol. 333, September 2, 2011, pp. 1,225–1,226.

252 Southern California Edison, *Comments on 2011 IEPR*, December 23, 2011, page 27; Pacific Gas & Electric, *Comments on 2011 IEPR*, December 23, 2011, page 14.

253 Noted by NRC's Task Force.

operate spent fuel pool instrumentation and pumps at all times. PG&E reported that Diablo Canyon's spent fuel pool monitoring instruments that indicate abnormally high or low water temperatures and/or water level in the pool are not environmentally qualified and are subject to failure in a harsh temperature or radiation environment.[254] Similarly, SCE reported that, under severe accident conditions, the spent fuel pool monitors or instrumentation may not be available and reliable, but plant operators could be deployed to confirm water level and temperature, provided that radiological conditions allow the entry into the spent pool building.[255]

Station Blackout

The Fukushima accident resulted from what is considered to be an extreme event – a station blackout. A station blackout is a loss of off-site alternating current (AC) power and then a subsequent failure of onsite emergency backup power to support cooling and emergency safety systems in the reactor and spent fuel pools. Emergency crews at Fukushima following the station blackout and loss of emergency cooling struggled to stop a core meltdown from occurring at the plant.[256] After the earthquake, the Fukushima plant lost all offsite AC power and then had to transfer the electrical power to the onsite emergency diesel generators. The tsunami struck about 40 minutes later, flooding the electrical equipment rooms and thereby disabling the generators except for the one at Unit 6. When all AC power was lost, TEPCO and the Japanese government arranged for delivery of portable electric generators to the site but damaged roads and congested traffic prevented the generators from reaching the site quickly.[257] Although TEPCO arranged for delivery of some portable generators, they could not be connected to the station electrical distribution system as a result of the extensive damage the tsunami and flooding caused.

Diablo Canyon and SONGS have emergency backup diesel generators with cross ties, as well as underground tanks holding a seven-day diesel fuel supply. At Diablo Canyon, most of the electrical switch gear and batteries are located 85 feet above sea level. SCE and PG&E are reviewing their preparation for an extended station blackout and/or loss of emergency cooling.

The NRC requires that plants be capable of cooling the reactor core and maintaining containment integrity for the duration of four to eight hours.[258] However, NRC does not address the impact from certain external hazards, such as seismic and flooding, or from naturally occurring events leading to the loss of onsite or offsite power. In addition, reserve cooling water, for example, the back-up cooling pond at Diablo Canyon, could be vulnerable to a major seismic event. The NRC Task Force recommends that the NRC strengthen station blackout mitigation capability at all operating and new reactors for design-basis and beyond-design-basis external events (for example, floods, hurricanes, earthquakes, tornadoes, tsunamis). It is also recommending that plant emergency plans address prolonged station blackouts and events involving multiple reactors.

254 Pacific Gas and Electric, *Response to 2011 IEPR Data Request*, June 9, 2011, page 13.

255 Southern California Edison, *Comments on Committee Workshop on California Nuclear Power Plant Issues*, August 8, 2011, question B.03.

256 Mirsky, Steve, "Nuclear Experts Explain Worst-Case Scenario at Fukushima Power Plant," *Scientific American*, March 12, 2011.

257 Institute of Nuclear Power Operations, *Special Report on the Nuclear Accident at the Fukushima Daiichi Nuclear Power Station*, INPO 11-005, November 2011, available at: hps.org/documents/INPO_Fukushima_Special_Report.pdf.

258 Nuclear Regulatory Commission, "Enhancing Reactor Safety in the 21st Century," page 33, July 2011.

Nuclear Plant Liability Coverage

Japan's nuclear accident has highlighted concerns about the adequacy of liability coverage if another severe nuclear plant accident were to occur. Estimates of damage due to a catastrophic accident at a nuclear plant are in the hundreds of billions of dollars.[259] Recent compensation estimates show the Fukushima Daiichi nuclear plant disaster will cost at least $39 billion to $52 billion, not including plant decommissioning costs and other factors.[260] A major consideration in estimating liability claims is damage to agriculture, fisheries, and businesses and the cost of relocating thousands of people in the evacuation zones. The U.S. Price-Anderson Act coverage limits public liability claims from a nuclear power plant incident to roughly $12.6 billion.[261] The act covers bodily injury, sickness, disease or resulting death, or offsite property damage caused by nuclear material at the defined location.[262,263] Since U.S. homeowner insurance policies do not cover nuclear-related damages, it is unclear whether individuals affected by a nuclear accident will be sufficiently covered or reimbursed for damages under the Price-Anderson Act. According to SCE, complainants would be required to prove damages and to adjudicate claims in state court.

Replacement Power and Reliability

One of the lessons learned from Fukushima is the need to ensure replacement power and grid reliability in the event of a long-term outage. PG&E reports that it maintains adequate reserves to replace power from a unit if an outage lasts longer than 90 days.[264] For prolonged outages, PG&E would provide replacement power from a mix of its own resources, market purchases, and procurement.[265] PG&E does not expect that a long-term outage at Diablo Canyon would require additional transmission facilities to maintain voltage support or system or local reliability. They evaluated resource options, including gas-fired combined cycle plants, energy efficiency, renewable energy, and integrated coal gasification with carbon capture and sequestration, for replacing Diablo Canyon's roughly 2,200 MW capacity.[266] It does not anticipate needing new facilities for transmission support, grid stability, or local reliability from an extended shutdown of Diablo Canyon, although the replacement facilities may require additional transmission.

SONGS is located between two major load centers and is an integral part of the Southern California transmission system. A shutdown of SONGS restricts power flows coming from out-of-state, and a prolonged shutdown could cause serious grid reliability shortfalls unless the state improves the

259 Ayyub, Bilal M. and Lorne Parker, "Financing Nuclear Liability," Letters to the Editor, *Science*, December 16, 2011, Volume 334 p. 1494.

260 *Scientific American*, "Panel Sees Nuke Disaster Compensation at $39-$52 Billion: Nikkei," September 26, 2011.

261 Nuclear Regulatory Commission, see: www.nrc.gov/reading-rm/doc-collections/fact-sheets/funds-fs.html.

262 Pacific Gas and Electric, *Comments on the July 26, 2011, Committee Workshop on California Nuclear Plant Issues*, August 9, 2011, Docket 11-IEP-1J, pp. 12–13.

263 The Price-Anderson Act, enacted in 1957, was designed to ensure adequate funds would be available for public liability claims for personal injury and property damage in the event of a nuclear accident at a commercial nuclear power plant. The limit of liability for a nuclear accident is now more than $12 billion. The NRC's fact sheet on Price-Anderson Act coverage is available at: www.nrc.gov/reading-rm/doc-collections/fact-sheets/funds-fs.html.

264 Pacific Gas and Electric, *Response to 2011 IEPR Nuclear Data Request*, Docket 11-IEP-1J, page 12, August 9, 2011.

265 Pacific Gas and Electric, *Response to 2011 IEPR Nuclear Data Request*, Docket 11-IEP-1J, page 31, June 9, 2011.

266 Pacific Gas and Electric, *Diablo Canyon Power Plant License Renewal Prepared Testimony*, Chapter 4, "Replacement Energy Costs," Volume 1 of 3, January 29, 2010.

transmission system infrastructure.[267] SCE concluded that an unplanned long-term outage at SONGS would harm electric system reliability in Southern California, especially in the SCE and SDG&E service territories.[268] Under moderate to heavy electricity loads, SCE would likely implement controlled rolling blackouts in the short term to reduce stress on the electric grid. Further, SCE concluded that significant investment is required for new transmission and generation to replace SONGS.

Although the *2008 IEPR Update* highlighted the need to improve electricity planning and reliability assessments to fully understand the reliability risks and other consequences of lengthy, unplanned outages at these nuclear plants, these assessments have not been completed. As the Energy Commission stated then, the overall supply/demand balance in the Western interconnection is an important determinant of the impacts of a sudden, unplanned outage. Replacement power costs and other impacts will be higher if western resource surpluses are small, and replacement power costs and other impacts will be lower if there are extensive surpluses.[269] Which of these conditions can be expected in future years is highly uncertain. To the extent that replacement generation might be found to be needed, the type of replacement power would be the subject of further analysis and include such considerations as the lead times needed for planning, permitting, regulatory approval, and construction of facilities, as well as any potential environmental impacts and mitigation requirements for new replacement generation.

267 California Energy Commission, *2008 Integrated Energy Policy Report Update*, page 74, available at: www.energy.ca.gov/2008_energypolicy/index.html.

268 Southern California Edison, *Comments on 2011 IEPR Committee Workshop on California Nuclear Plant Issues*, page 10, August 8, 2011.

269 California Energy Commission, *AB 1632 Report*, pp. 19–24, available at: www.energy.ca.gov/2008publications/CEC-100-2008-009/CEC-100-2008-009-CMF.PDF.

In light of the extended outages (years) at nuclear power plants in Japan following major earthquakes in 2007 (Kashiwazaki) and in 2011 (Fukushima Daiichi), a comprehensive and updated analysis of the impacts and mitigation of unexpected, long-term, unplanned outages at one or both of California's nuclear plants is needed. Such an analysis would include an assessment of options for their replacement and the impacts of their shutdown (for example, reliability) and would involve multiple California agencies, particularly the California ISO. The California ISO is uniquely capable of examining the impact on electricity reliability of extended outages given its day-to-day operation of the electric grid for most of the state. Further, the CPUC would play a critical role in authorizing PG&E and SCE to secure additional capacity suitable for mitigating a sudden unplanned, extended outage of Diablo Canyon and SONGS. The Energy Commission also would play a role in providing the other energy agencies and the public energy supply and demand forecasts.

Emergency Response Planning

Large-scale radioactive materials releases from the Fukushima Daiichi nuclear plant along with high levels of radiation surrounding the plant resulted in mandatory evacuations, affecting people out to about 46 miles from the site.[270] The estimated contamination area is 2,000 square kilometers (200,000 hectares).[271] Following the earthquake, the NRC issued a travel advisory to evacuate American citizens out to 50 miles.[272] Although the NRC has not recommended any changes in the current regulatory framework for emergency preparation, the Fukushima event emphasized the importance of reviewing the adequacy of emergency response planning at Diablo Canyon and SONGS.

270 Tom Cochran, PowerPoint slides, presentation at Energy Commission's July 26, 2011, IEPR workshop, page 7.

271 Arjun Makhijami, transcripts from July 26, 2011, IEPR workshop, page 214.

272 Ibid.

The NRC is working with federal, state, and local authorities on a revised emergency preparedness rule. The NRC and Federal Emergency Management Agency require two emergency planning zones (EPZs) around commercial nuclear power plants: (1) a 10-mile EPZ where exposure to a radioactive plume would likely occur; and (2) a 50-mile EPZ for monitoring and protecting the public from secondary radiation exposure from contaminated food, milk, and surface water. Roughly 7.4 million people live within a 50-mile radius of SONGS, and about 842,000 people live within a 50-mile radius of Diablo Canyon.

PG&E recently examined how potential earthquake damage to roads and bridges around Diablo Canyon could affect evacuation plans. The study concluded that little or no damage would likely occur to the majority of bridges and roadways serving as evacuation routes.[273] Overall, PG&E found that the estimated evacuation time did not exceed what would be unacceptable.[274] SCE periodically reviews the roadways surrounding SONGS and has concluded they are adequate for emergency personnel access and for evacuation during an emergency.

In light of the long-range contamination and lessons learned from Fukushima and NRC's recommended 50-mile evacuation zone for U.S. citizens in Japan, both California plants must re-evaluate the adequacy of current evacuation and emergency response plans. In addition, the California Department of Health Services and Lawrence Livermore National Laboratory should consider the possibility of multi-reactor events in their radiation dose pathway assessments. PG&E noted that it will consider the impacts from multiple events,[275] while SCE reports to have procedures to handle multiple extreme events such as earthquake and flooding.

273 Pacific Gas and Electric, *Response to 2011 IEPR Nuclear Data Request*, June 9, 2011, page 9.

274 California Energy Commission, transcripts from July 26, 2011, IEPR workshop, page 105.

275 Ibid, page 100.

Nuclear Waste Issues

For decades, the United States has planned to eventually dispose of spent fuel in a permanent federal waste repository and forgo reprocessing due to nuclear weapons proliferation concerns. In 2010, however, the Obama Administration, in conjunction with the U.S. DOE, took important steps to terminate the license application process for a waste repository at Yucca Mountain, Nevada, citing a lack of public acceptance and a political stalemate surrounding the site. Even if Yucca Mountain again becomes a disposal option, an additional site must be found, as the United States already has more nuclear waste than a Yucca Mountain-type repository can hold.

Diablo Canyon and SONGS have generated about 2,839 metric tons of spent nuclear fuel or together about 94 metric tons annually. Through their current 40-year license period, both plants will generate about 4,228 metric tons of spent nuclear fuel. Through possible 20-year plant license extensions, they will generate another 2,140 for a total of 6,368 metric tons if they obtain 20-year license extensions. Until the United States develops a repository or away-from-reactor storage facility, this waste will continue to accumulate.

Spent fuel storage issues include the safety of long-term storage of high burn-up fuels and how these fuels might affect the integrity of fuel and fuel cladding, especially in corrosive marine environments, as well as the long-term storage costs. PG&E has not performed cost/benefit studies for long-term storage at Diablo Canyon and has assumed spent fuel will be stored onsite until the federal government removes it. PG&E has developed a dry storage facility to store the waste away from the reactor but plans to rely on pool storage for spent fuel generated during a 20-year license extension.

The federal government's Blue Ribbon Commission is rethinking the national policy for waste management and has recommended a new waste management plan that calls for developing one or more national geologic disposal facilities and one or more consolidated interim spent fuel storage facilities.

Plant Safety Issues

It is essential that plants establish and maintain a work environment where management and employees are dedicated to putting safety first. The NRC conducts annual safety assessments of the nation's nuclear power plants, including Diablo Canyon and SONGS. The third consecutive assessment of Diablo Canyon found that the plant is still facing human performance issues regarding identifying and resolving problems.[276] NRC found that PG&E has made some progress in this area, but more work is needed. PG&E completed a safety culture survey in February 2011.

Diablo Canyon, since 1988, has had an independent safety committee, established by the CPUC as part of a settlement agreement reached by CPUC's Division of Ratepayer Advocates, California's Attorney General, and PG&E. PG&E testified that the Diablo Canyon Independent Safety Committee (DCISC) is providing independent safety oversight to make certain that PG&E is examining the right things in assessing the lessons learned from Fukushima.[277] SONGS does not have an independent safety committee. The DCISC, as recommended by the *2009 IEPR*, completed an assessment in 2011 of the reactor pressure vessel integrity and pressurized thermal shock at Diablo Canyon in the context of seismic hazards. It concluded that the plant can operate out to 60 years, if relicensed, without the pressurized thermal shock posing a threat to plant safety that would violate NRC regulations.

For many years, SONGS has been under NRC scrutiny for failure to address several longstanding safety culture issues. On March 2, 2010, the NRC issued SONGS a "Chilling Effect" letter in response to employees expressing difficulty or inability to use the corrective action program, a lack of knowledge or mistrust of the Nuclear Safety Concerns Program, a substantiated case of a supervisor creating a chilled work environment in their work group, and a perceived fear of retaliation for raising safety concerns. During 2009, the NRC received an elevated number of safety-conscious work environment allegations from SONGS. The NRC conducted focus group interviews with about 400 workers in 2010 and found "a continued degradation in the safety-conscious work environment." The NRC advised SCE that these results potentially affect several safety-critical areas concerning human performance. The NRC has raised this issue in seven consecutive safety assessment periods. However, in September 2011 following NRC's inspections at SONGS and a significant reduction in safety culture allegations in 2010 and 2011, NRC determined that SCE has made reasonable progress in addressing the worker safety culture issues.[278] NRC will continue to monitor work environment conditions at SONGS. SCE has stated that it is committed to preserving and improving a strong safety culture at SONGS and encouraging workers to raise nuclear safety concerns.

276 NRC letter to Mr. Conway, *Annual Assessment Letter for Diablo Canyon*, March 4, 2011.

277 Loren Sharp, testimony at July 26, 2011, IEPR workshop.

278 NRC letter to Peter Dietrich, SONGS, September 6, 2011.

Progress in Completing AB 1632 Report Recommendations

The CPUC and the Energy Commission determined that Diablo Canyon and SONGs should complete the *AB 1632 Report*-recommended studies as required for the license renewal feasibility studies and review.[279] In June 2009, the CPUC directed PG&E and SCE to complete these studies so that the CPUC can meet its obligations to ensure plant reliability and, in turn, grid reliability, in the event of a prolonged or permanent outage.[280] This section summarizes progress on these recommendations and studies.

Seismic Studies Update

PG&E and SCE have provided periodic updates to the Energy Commission and the CPUC regarding their research plans, and preliminary results of their *AB 1632 Report*-recommended studies, including seismic research efforts and updates.

Diablo Canyon

PG&E completed a study of the Shoreline Fault in January 2011 for the NRC, which asserted that (based on newer seismic information) the plant can withstand more severe shaking than estimated when the plant was designed in 1977.[281] As required, PG&E will conduct additional seismic studies to identify the association between the Shoreline and Hosgri Faults and evaluate the existence/configuration of the southern continuation of the Shoreline Fault. Seismic studies are needed in the vicinity of Diablo Canyon including onshore faults. PG&E also intends to install submarine seismometers to enhance the understanding of the locations of coastal zone earthquakes and install GPS monitoring stations to measure crustal strain in the offshore environment. In addition, PG&E will use the updated Uniform California Earthquake Rupture Forecast (UCERF) model to better understand seismic hazards at the plant.[282]

SONGS

Throughout the operating history of SONGS 2 and 3, SCE has periodically assessed the adequacy of seismic safety margins based on new information. In 2010, SCE updated the SONGS probabilistic seismic hazard analysis (PSHA).[283] The results are comparable to the 1995 PSHA, indicating that the SONGS seismic hazard risk has not changed. SCE's ongoing Seismic Hazard Analysis Program periodically reviews and updates SONGS' seismic hazards, and SCE's advisory board of seismic experts reviews the plant's seismic information and identifies the need for additional research. SCE plans to use the most recent UCERF database to complete the seismic studies,[284] the

279 The *2009 IEPR*, letters from Michael Peevey, President, CPUC, June 25, 2009, to Peter Darbee, President and CEO of PG&E and Alan Fohrer, Chairman and CEO.

280 Ibid.

281 Original estimates based on the Hosgri Fault.

282 The updated model, UCERF-3, will include the Shoreline Fault and other new seismic data.

283 Southern California Edison, *Southern California Edison's Evaluation of California Energy Commission AB 1632 Report Recommendations*, February 2011.

284 Southern California Edison, *Committee Workshop on California Nuclear Power Plant Issues, Responses to Questions for July 26 Energy Commission Workshop*, Energy Commission Docket No. 11-1EP-1J, August 8, 2011.

results of which will be provided to the NRC as part of its regulatory process.

To decrease the seismic uncertainty at Diablo Canyon and SONGS, USGS and California Geological Survey scientists have recommended additional studies to identify active faults and determine seismic potential and the recency of faulting.[285,286] In addition, the Energy Commission recommended in 2008 that SCE should develop an active seismic hazards research program for SONGS similar to PG&E's Long Term Seismic Program to assess whether there are sufficient design margins at the plant to avoid major power disruptions.[287]

Tsunami Studies Update

Diablo Canyon is located on top of a high coastal bluff at an elevation of 85 feet above mean sea level. PG&E's plant design basis is for a combined tsunami, storm wave, and tidal wave height of about 35 feet.[288] Tsunami Inundation Maps show the plant to be outside the tsunami inundation zone.[289] In 2010, PG&E published a study of tsunami hazard for Diablo Canyon,[290] which considered the combined effects of tsunamis, storms, and tides and included the effects of submarine landslides, which were not specifically considered in the Diablo Canyon licensing analyses. While this study was done differently than previous analyses, it did not identify new hazard information that warranted inclusion into the Diablo Canyon design and license basis. PG&E concluded that a deterministic approach that combines the tsunami generated by a rare local submarine landslide with a large storm wave would lead to an unreasonably rare combination of events.

SCE and NRC evaluated the tsunami run-up and inundation for SONGS during plant licensing. More recent assessments conclude that, "…large local-source tsunamis could be generated by mechanisms other than those considered during licensing for SONGS Units 2 and 3, the basis for the 1995 SCE report." However, SCE reports that no local run-up studies based on these mechanisms are widely agreed upon, and certainly none for the SONGS site. The University of Southern California, in conjunction with the California Emergency Management Agency, is preparing tsunami runup maps for San Diego County, but they are not currently available.[291] The potential for landslide-generated tsunamis is uncertain, and SCE reports that additional studies are required to evaluate how such tsunamis may affect SONGS. It seeks approval of funding to perform additional seismological and tsunami studies, as recommended by the Energy Commission in the *AB 1632 Report*.[292]

285 United States Geological Survey, William Ellsworth, *Overview of Earthquake Hazards in California and Current Research Aimed at Reducing Uncertainty*, *Presentation to 2011 Integrated Policy Report Committee – Nuclear Issues Workshop*, June 13, 2011.

286 California Geological Survey, Chris Wills, presentation at the Energy Commission's July 26, 2011, IEPR workshop, www.energy.ca.gov/2011_energypolicy/documents/2011-07-26_workshop/presentations/.

287 California Energy Commission, *2008 IEPR Update*, page 78.

288 Pacific Gas and Electric, comments at the July 26, 2011, IEPR workshop, page 10.

289 Recently released by the California Emergency Management Agency, California Geological Survey, and the University of Southern California.

290 Pacific Gas and Electric, *Methodology for Probabilistic Tsunami Hazard Analysis: Trial Application for the Diablo Canyon Power Plant Site (PTHA)*, April 2010, available at: peer.berkeley.edu/tsunami/tasks/task-1-tsunami-hazard-analysis/.

291 California Coastal Commission, Mark Johnsson, *The Tohoku Earthquake of March 11, 2011: A Preliminary Report on Implications for Coastal California*, March 24, 2011.

292 Southern California Edison, *Response to Questions for July 26, 2011, Workshop*, August 8, 2011, page 3.

In February 2011, SCE presented an updated tsunami hazard analysis to the CPUC and the Energy Commission.[293,294] The map provides a "credible upper bound" to the potential tsunami inundation for any location along the Southern California coastline. At SONGS, the map indicates a maximum tsunami inundation elevation of 17 to 20 feet above sea level or an equivalent elevation of 19.9 to 22.9 feet above lower low water.[295] SCE has concluded that SONGS is protected, with the top of the wall 7.1 to 10.1 feet higher than the credible upper bound elevation of tsunami inundation, and with the North Industrial Area protected by 5.3 to 8.3 feet of sea wall above the inundation elevation.

Studies of Seismic Vulnerability of Plant Components

In March 2010, a PG&E report evaluated the probability of a prolonged post-earthquake outage at Diablo Canyon from damaged nonsafety-related structures, systems, and components (SSC). The report concluded that all of the SSCs are designed to the appropriate seismic criteria[296]and meet the required Design Earthquake and Double Design Earthquake criteria for accident mitigation or safe shutdown. The SSCs were found to withstand a 7.5 magnitude earthquake on the Hosgri Fault.

SCE completed a study to identify any "important-to-reliability," nonsafety-related SSCs that could cause a prolonged outage at SONGS from a seismic event.[297] The study evaluated those required for power generation, which are considered important to reliability. Additionally, SCE evaluated the nonpower block buildings needed to support power generation. SCE conducted further evaluation to assess the seismic capacity of offshore discharge conduits and reported on their findings in August 2011.[298]

SCE has not performed studies of the fragility of nonsafety-related SSCs when relocated for refueling or plant maintenance but did perform studies for plant operating conditions.

License Renewal

NRC issues operating licenses for commercial power reactors for up to 40 years and allows 20-year license extensions with no limit on the number of renewals. The operating licenses for California's nuclear plants will expire in 2022 (SONGS Units 2 and 3), in 2024 (Diablo Unit 1), and in 2025 (Diablo Unit 2). PG&E submitted a license renewal application for Diablo Canyon on November 24, 2009, to continue operations until 2044/2045. In June 2011, the NRC issued the *Safety Evaluation Report* for the license renewal

293 Letter to Michael Peevey, President of the CPUC, "SCE's Evaluation of Energy Commission AB 1632 Report Recommendations," Appendix 2, February 2, 2011.

294 National Oceanic and Atmospheric Administration, California Geological Survey, California Office of Emergency Services and the University of Southern California Tsunami Research Center, "Tsunami Inundation Map for Emergency Planning," published June 1, 2009.

295 The average of the lower low water height of each tidal day observed over the National Tidal Datum Epoch.

296 Enercon Services, Inc., *Seismic Assessment of Diablo Canyon Power Plant Non-Safety Related Structures, Systems, and Components*, March 2010.

297 Southern California Edison letter, "Evaluation of California Energy Commission AB 1632 Report Recommendations," submitted to the CPUC and Energy Commission on February 2, 2011; See section on "Seismic Reliability Evaluation" with an appendix providing the study titled, *Seismic Reliability Study of San Onofre Generating Station Non-Safety-Related Structures, Systems, and Components*.

298 Southern California Edison in a letter to Michael Peevey dated August 9, 2011, regarding its assessment of the conduits' seismic capacity concluded that the offshore discharge conduits "would be expected to maintain their integrity under the SONGS review level earthquake and would not be the cause of a prolonged outage."

application.[299] NRC has postponed its license renewal proceeding by 52 months to allow time for PG&E to complete the additional seismic studies. SCE has not yet applied for renewal and will continue to assess options for the timing of CPUC and NRC license renewal filings.[300] NRC issued license renewals for Palo Verde Units 1, 2, and 3 on April 1, 2011.

A major concern is whether the license reviews adequately address issues relevant to California (including seismic vulnerability). The NRC license renewal review process determines whether a plant meets the NRC license renewal criteria, including aging plant issues and environmental impacts related to an additional 20 years of plant operation. However, the process consistently excludes issues such as seismic vulnerability, plant vulnerability to terrorist attacks, and the adequacy of emergency evacuation plans.

Several California officials have requested the NRC to address a broader range of issues during nuclear power plant license renewal reviews that are of concern for California's operating plants. These issues include post-Fukushima safety issues, seismic and tsunami hazards, emergency response plans and evacuation timeliness, plant security, and spent fuel storage. NRC ultimately determined that the existing regulatory process was sufficient and that it considers these issues on an ongoing basis in connection with its oversight of operating reactors.[301]

California has a legitimate role in license renewal decisions in its broad authority to set electricity generation priorities based on economic, reliability, and environmental concerns. Both utilities must obtain CPUC approval to pursue license renewal before receiving California ratepayer funds to cover the costs of the NRC license application process. In addition, the California Coastal Commission must review the project for consistency with the federal Coastal Zone Management Act.

The CPUC considers whether it is in the best interest of ratepayers for the nuclear plants to continue operations another 20 years. Its proceedings address issues that are important to electricity planning but are not included in NRC's license renewal review, such as the cost-effectiveness of license renewal compared with alternatives. In letters to PG&E and SCE in June 2009, the CPUC stressed that the utilities must address in their feasibility assessments all issues raised in the *AB 1632 Report* and that this information is needed to allow the CPUC to properly undertake its obligations under AB 1632 to ensure plant reliability and, in turn, ensure grid reliability in the event Diablo Canyon or SONGS has a prolonged or permanent outage.[302] The adequacy and timeliness of the utilities completing the AB 1632 Report-recommended studies are critical to the CPUC's ability to make these decisions. However, the utilities' recent progress reports indicate they are not on schedule to complete the additional AB 1632 Report recommended seismic hazard studies until 2013 (PG&E) and 2015 (SCE) at the earliest.

Recommendations

In light of the accidents and/or plant shutdowns following earthquakes at Fukushima Daiichi (2011), Kashiwazaki-Kariwa (2007), and at the North Anna nuclear plant (August 23, 2011) and other considerations, the Energy Commission, in consultation with the CPUC, recommends the following:

299 Nuclear Regulatory Commission, *Safety Evaluation Report Related to the License Renewal of Diablo Canyon Nuclear Power Plant*, Units 1 and 2, June 2, 2011, available at: pbadupws.nrc.gov/docs/ML1115/ML11153A103.pdf.

300 Southern California Edison is a member of STARS (Strategic Teaming and Resource Sharing), which has reserved application submittal dates for late 2012 and fall 2013.

301 Letter to Senator Dianne Feinstein from NRC Chairman Gregory Jackzo, August 10, 2011.

302 Letter from CPUC to Alan Fohrer, CEO of Southern California Edison, June 25, 2009; Letter from CPUC to Peter Darbee, CEO of Pacific Gas and Electric, June 25, 2009.

Seismic Issues

- PG&E should provide in a timely manner to the Energy Commission, the CPUC, and the Independent Peer Review Panel (IPRP) the technical details and any significant updates of their proposed seismic hazard study plans and findings for Diablo Canyon.

- PG&E should submit to the Atomic Safety and Licensing Board (ASLB), as part of PG&E's final seismic report to the ASLB in the Diablo Canyon license renewal proceeding, the findings and recommendations from the California IPRP on PG&E's seismic studies. These studies include PG&E's onshore and offshore seismic studies funded by CPUC Decision 10-08-003.

- The CPUC should establish a SONGS IPRP, comparable to Diablo Canyon's IPRP, to review SONGS' seismic hazard study plans and findings as recommended in the *2008 IEPR Update*. SCE should provide in a timely manner to the Energy Commission, the CPUC, and the IPRP the technical details and any significant updates to their proposed seismic hazard study plans and findings for SONGS. SCE should include the IPRP's evaluations, findings, and recommendations in its seismic hazard analyses and submittals to the NRC. California's IPRPs for PG&E's and SCE's seismic studies for Diablo Canyon and SONGS should coordinate their seismic hazard evaluations.

- SCE should include greater representation on its SONGS' Seismic Advisory Board of independent seismic experts with no current or prior professional affiliation with utilities, including SCE or PG&E, or their consultants. The composition of SCE's SONGS' Seismic Advisory Board of independent seismic experts should exclude those with a continuing affiliation with SCE.

- PG&E and SCE should provide updates on their progress in completing the AB 1632 Report-recommended seismic studies to the Energy Commission as part of the *2012 IEPR Update*.

Spent Fuel Pool and Independent Spent Fuel Storage Installation

- PG&E and SCE should investigate adding safety-related instrumentation (capable of withstanding design basis natural phenomena) to monitor in the control room key spent fuel pool parameters, for example, water level, temperature, and radiation levels, during a severe accident in which radiation levels within the spent fuel pool building are unsafe.

- To reduce the volume of spent fuel packed into storage pools, and consequently the radioactive material available for dispersal in the event of an accident or sabotage, PG&E and SCE, as soon as practicable, should transfer spent fuel from pools into dry casks, while maintaining compliance with NRC spent fuel cask and pool storage requirements and report to the Energy Commission in the *2012 IEPR Update* on their progress.

- PG&E and SCE should evaluate, as part of the *2012 IEPR Update*, the potential long-term impacts and projected costs of spent fuel storage in pools versus dry cask storage of higher burn-up fuels in densely packed pools, and the potential degradation of fuels and package integrity during long-term wet and dry storage and transportation offsite.

Station Blackout

- SCE and PG&E should report to the Energy Commission, as part of the *2012 IEPR Update*, on progress made in addressing the lessons learned from the station blackout at Fukushima and how well-equipped their plants are to withstand safely a station blackout lasting longer than seven days. This includes reporting on any significant changes, including estimated costs, associated with NRC requirements to address station blackout. It also includes arrangements for accessing emergency backup generation and fuel, responding to multiple unit events, seismically and flooding protected equipment, and addressing the lessons learned from Fukushima.

- PG&E and SCE should report to the Energy Commission on the adequacy of trained people, equipment, and external support, including written agreements, for providing emergency power equipment and fuel for handling an extended station blackout.

Nuclear Plant Liability Coverage

- Based on the Fukushima experiences, PG&E and SCE should provide a comprehensive study to the Energy Commission, as part of the *2012 IEPR Update*, on the adequacy of Price-Anderson Act liability coverage for a severe event at Diablo Canyon or SONGS resulting in large offsite releases of radioactive materials.

Replacement Power and Reliability

- To support long-term energy and contingency planning, the California ISO (with support from PG&E, SCE, and planning staff of the CPUC and CEC) should report to the Energy Commission as part of its *2013 IEPR* and the CPUC as part of its 2013 Long-Term Procurement Plan on what new generation and/or transmission facilities would be needed to maintain system and/or local reliability in the event of a long-term outage at Diablo Canyon, SONGS, or Palo Verde. The utilities should report to the CPUC on the estimated costs of these facilities.

- As a contingency in the event that Diablo Canyon and SONGS experience a long-term outage following a major seismic or other event, California ISO with input from the Energy Commission and CPUC, in cooperation with PG&E and SCE, should further evaluate: (1) the uncertainties of a long-term loss of electricity from these plants, (2) the extent to which existing resources have an energy supply capability beyond that used in normal market conditions, and (3) the need for new resources or different types of resources to satisfy any remaining energy gap. If necessary, the long-term planning and procurement process at the CPUC should be modified to ensure that any replacement resources found necessary through these studies are acquired in a timely manner.

Emergency Response Planning

- The CPUC should approve funding for Cal EMA[303] or the affected counties to evaluate the adequacy of current evacuation and emergency response plans, emergency planning zones, and training for Diablo Canyon and SONGS, given the Fukushima accident and NRC's recommended 50-mile evacuation zone for U.S. citizens in Japan. This review should include the adequacy of plans for dealing with prolonged station blackouts (for example, powering communications equipment), multiple or multiunit events at one site, increased population densities and traffic flow configurations near the plants, and the possible loss of access roads and evacuation routes in a major event, such as an earthquake or flooding.

- The California Department of Public Health should evaluate the adequacy of equipment, staffing, aerial plume monitoring, and models for dealing with two-unit events at the Diablo Canyon or SONGS sites involving radioactive releases.

303 Governor Brown's proposed 2012–2013 budget eliminates CalEMA and makes it an office reporting directly to the Governor (www.ebudget.ca.gov/pdf/ BudgetSummary/Making-Government MoreEfficient.pdf).

Fukushima Lessons Learned

- PG&E and SCE should report to the Energy Commission, as part of the *2012 IEPR Update*, and the CPUC on their progress and estimated costs in carrying out the recommendations of the *NRC Near-Term Fukushima Task Force Report*.

- PG&E and SCE should report to the Energy Commission, as part of the *2012 IEPR Update*, on the adequacy of resources, training, and equipment to cope with severe plant events including a station blackout combined with natural or manmade events (earthquake, flooding, fires, or terrorist attack); for example, the availability of (1) seismically robust and flood protected essential safety systems and equipment; (2) suitably shielded, ventilated, and well-equipped facilities needed for the workers to manage the accident; (3) ability to respond to multiple events and multiple-unit events, and (4) trained onsite and offsite responders for a long-term station blackout or loss of all heat sinks.

- The NRC should expeditiously move forward on the Post-Fukushima Task Force recommendations, particularly the urgent recommendations.

Relicensing

- To help ensure plant reliability and minimize costs, PG&E and SCE should complete the remaining AB 1632 Report-recommended seismic studies and make their findings available for consideration by the Energy Commission, CPUC, California Coastal Commission, and the NRC during their reviews of PG&E's (and SCE's, if they apply) license renewal application(s) and related certificates. SCE should not file a license renewal application with the NRC without prior approval from the CPUC.

- Since the regulatory changes and requirements recommended by the NRC Near-Term Task Force on Fukushima could result in higher costs, for example, seismic retrofits, PG&E and SCE should provide cost estimates to the CPUC for complying with NRC's requirements and the costs of potential replacement power in the event of an extended outage. The CPUC should consider these additional costs during its license renewal evaluations for Diablo Canyon (and SONGS, if SCE applies for license renewal).

- The NRC should delay its decisions on license renewal applications pending completion of the post-Fukushima lessons learned studies. NRC's license renewal review for Diablo Canyon and SONGS (if SCE applies for license renewal) should examine updated site-specific information on seismic and tsunami hazards, emergency preparedness and evacuation timeliness, lessons learned from Fukushima, spent fuel storage options, and plant security. NRC should delay license renewal reviews to allow for consideration of findings from Fukushima studies.

Plant Safety

- PG&E and SCE should report, as part of the *2012 IEPR Update*, on their efforts to improve the safety culture at Diablo Canyon and SONGS and on the NRC's evaluation of these efforts and overall plant performance.

- The CPUC should consider establishing a SONGS Independent Safety Committee, modeled after the Diablo Canyon Independent Safety Committee, to provide an independent review of SONGS' safety, performance, and follow-up to the lessons learned from the Fukushima Daiichi plant accident.

Continuing Activities

- The Energy Commission will continue to monitor reviews of Diablo Canyon and SONGS by the NRC and the Institute of Nuclear Power Operations; in particular, the Energy Commission will monitor plant performance and safety culture at both plants.

- The Energy Commission will continue to monitor the federal waste management program and represent California in the Yucca Mountain licensing proceeding (in the event this proceeding resumes) to protect California's interests regarding potential groundwater and spent fuel transportation impacts to the state.

- The Energy Commission will continue to participate in United States Department of Energy and state regional planning activities for nuclear waste transportation.

- The Energy Commission will continue to update information on the comprehensive, "cradle-to-grave" or life-cycle economic and environmental impacts of nuclear energy generation compared with alternatives. These include impacts from uranium mining, reactor construction, fuel fabrication, reactor operation, maintenance and repair; reactor component replacement and disposal; spent fuel storage, transport and disposal; decommissioning; and "beyond design basis" accidents including an extended station blackout lasting longer than assumed.

Acronyms

AB	Assembly Bill
AC	alternating current
AEO 2011	Annual Energy Outlook 2011
AFC	Application for Certification
AQIP	Air Quality Improvement Program
ARB	California Air Resources Board
ARFVT Program	Alternative and Renewable Fuel and Vehicle Technology Program
ARRA	American Recovery and Reinvestment Act
BEVs	battery electric vehicles
BLM	Bureau of Land Management
Cal/EPA	California Environmental Protection Agency
CAL FIRE	The Department of Forestry and Fire Protection
California ISO	California Independent System Operator
Caltrans	California Department of Transportation
CCCCO	California Community Colleges Chancellor's Office
CCEF	California Clean Energy Future
CED	California Energy Demand
CEERT	Center for Energy Efficiency and Renewable Technologies
CEQA	California Environmental Quality Act
CHP	combined heat and power
CNG	compressed natural gas
CO2e	carbon dioxide equivalent
CMUA	California Municipal Utilities Association
CPUC	California Public Utilities Commission
CPV	concentrating photovoltaic
CREZ	competitive renewable energy zones
CSI	California Solar Initiative
CLTC	California Lighting Technology Center
DG	distributed generation
DRECP	Desert Renewable Energy Conservation Plan
DSM	demand-side management
E10	10 percent ethanol
EDD	Employment Development Department
EJ	environmental justice
EME	Edison Mission Energy
EIA	Energy Information Administration
EM&V	evaluation, measurement, and verification
EPS	external power supplies
EPZs	emergency planning zones
ERP	Emerging Renewables Program

ETP	Employment Training Panel
EUR	estimated ultimate recovery
EV	electric vehicle
FCV	fuel cell vehicles
FFV	flexible-fuel vehicle
FTD	Fuels and Transportation Division
FTE	full-time equivalent
gge	gasoline gallon equivalent
GHG	greenhouse gas
GPS	global positioning system
GWh	gigawatt hour(s)
HCICO	High Carbon Intensity Crude Oils
HVAC	heating, ventilation, and air conditioning
IEP	Independent Energy Producers
IEPR	*Integrated Energy Policy Report*
IOUs	investor-owned utilities
IPRP	Independent Peer Review Panel
LADWP	Los Angeles Department of Water and Power
LCFS	Low Carbon Fuel Standard
LCR	local capacity requirements
LED	light-emitting diode
LNG	liquefied natural gas
LSE	load-serving entity
LTPP	Long-Term Procurement Plan
MCF	1000 cubic feet of natural gas
MMBTU	million British thermal units
MMcf	million cubic feet
MMT	million metric tons
MPR	Market Price Referent
MW	megawatt(s)
NOx	nitrogen oxide
NGV	natural gas vehicles
NHSM	Non-Hazardous Secondary Materials
NRC	Nuclear Regulatory Commission
NRDC	Natural Resources Defense Council
NRG	NRG Energy
NSHP	New Solar Home Partnership
NSR	New Source Review
OEMs	original equipment manufacturers
OIR	Order Instituting Rulemaking
OII	Order Instituting Informational
OTC	once-through cooling

PAB	Policy Advisory Board
PAG	Policy Advisory Groups
PGC	Public Goods Charge
PEV	plug-in electric vehicle
PG&E	Pacific Gas and Electric
PHEV	plug-in hybrid electric vehicle
PM10	particulate matter of ten micron diameter
PM2.5	particulate matter 2.5 micron diameter
PIER	Public Interest Energy Research
Phasor-RTDMS	Phasor Real-Time Dynamic Monitoring System
PPA	power purchase agreement
PSHA	probabilistic seismic hazard analysis
PV	photovoltaic
QF	qualifying facility
R&D	research and development
RD&D	research, development, and demonstration
REAT	Renewable Energy Action Team
RESCO	Renewable Energy Secure Community
RETI	Renewable Energy Transmission Initiative
RFS	Renewable Fuels Standard
RFS2	Renewable Fuels Standards II
RPS	Renewables Portfolio Standard
RWGTM	Rice World Gas Trade Model
SA	Staff Assessment
SB	Senate Bill
SCAQMD	South Coast Air Quality Management District
SCE	Southern California Edison Company
SDG&E	San Diego Gas & Electric
SGIP	Self-Generation Incentive Program
SMUD	Sacramento Municipal Utility District
SONGS	San Onofre Nuclear Generating Station
SSCs	structures, systems, and components
SWRCB	State Water Resources Control Board
Tcf	trillion cubic feet
TDS	total dissolved solids
UCERF	Uniform California Earthquake Rupture Forecast-2
U.S. DOE	United States Department of Energy
U.S. EPA	United States Environmental Protection Agency
USGS	United States Geological Survey
VOC	volatile organic compounds
ZEV	Zero Emission Vehicle
ZNE	zero-net-energy

Rulemaking: 12-03-014
Exhibit No.: ISO-17
Witness:

Errata to Track I Direct Testimony of Mark Rothleder on Behalf of the California Independent System Operator Corporation

Exhibits 1 - 4

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE

STATE OF CALIFORNIA

Order Instituting Rulemaking to Integrate and Refine Procurement Policies and Consider Long-Term Procurement Plans.	)))	Rulemaking 10-05-006

ERRATA TO TRACK I DIRECT TESTIMONY OF MARK ROTHLEDER ON BEHALF OF THE CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION

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STATE OF CALIFORNIA

Order Instituting Rulemaking to Integrate and Refine Procurement Policies and Consider Long-Term Procurement Plans.	Rulemaking 10-05-006 (Filed May 6, 2010)

TRACK I DIRECT TESTIMONY OF MARK ROTHLEDER
ON BEHALF OF THE CALIFORNIAINDEPENDENT SYSTEM OPERATOR CORPORATION

I. BACKGROUND

Q. What is your name and by whom are you employed?

A. My name is Mark A. Rothleder and I am employed by the California Independent System Operator Corporation (ISO) as Director, Market Analysis and Development.

Q. Please describe your educational and professional background.

I am the Director of Market Analysis and Development for the ISO. Prior to this role, I was a Principle Market Developer for the ISO in the lead role in the implementation of market rules and software modifications related to the ISO's Market Redesign and Technology Upgrade ("MRTU"). Since joining the ISO over ten years ago, I have worked extensively on implementing and integrating the approved market rules for California's competitive Energy and Ancillary Services markets and the rules for Congestion Management, Real-Time Economic Dispatch, and Real-Time Market Mitigation into the operations of the ISO Balancing Authority Area ("BAA"). I also have held the position of Director of Market Operations. I am a registered Professional Electrical Engineer in the state State of

California. I hold a B.S. degree in Electrical Engineering from the California State University, Sacramento. I have taken post-graduate coursework in Power System Engineering from Santa Clara University and earned a M.S. in Information Systems from the University of Phoenix. I have co-authored technical papers on aspects of the California market design in professional journals and have frequently presented to industry forums. Prior to joining the ISO in 1997, I worked for eight years in the Electric Transmission Department of Pacific Gas & Electric Company, where my responsibilities included Operations Engineering, Transmission Planning and Substation Design.

Q. What is the purpose of your testimony?

I will describe the results of the ISO's evaluation of potential operational and resource capacity needs driven by the state of California's requirement that load serving entities (LSEs) develop 33% renewable resource portfolios by 2020. For the purposes of this testimony, I will refer to this requirement as "33% RPS" and the ISO's study of operational requirements and market impacts at 33% RPS in 2020, using its renewable integration model, as the ISO's "33% integration study."

Q. Why does the ISO conduct renewable integration studies?

A. As part of the ISO's continuing effort to understand and prepare for increasing levels of renewable integration consistent with California's energy and environmental policy objectives, the ISO performs renewable integrations studies to 1) identify operational requirements necessary to support increased variability and uncertainty in supply with increasing renewable penetration; 2) assess the expected generation fleet needed to meet simultaneously both the operational requirements for renewable energy integration and the forecasted demand for energy; and 3) identify any additional operational needs for integration of renewable resources.

The ISO released a study of grid impacts associated with a 20% RPS level in 2012 on August 31, 2010.[1] In support of this renewable integration study work, the ISO produced a technical appendix[2] that explained in detail the technical methodology. Also starting in 2010, the ISO performed some preliminary studies of operational requirements and needs to meet the 33% renewable integration objective in 2020. The 33% integration study builds on the work done in the 20% RPS analysis and was intended to accomplish the following four objectives:

- Provide information for the long-term procurement docket that could be used to identify potential planning needs, costs or other options.
- Inform other CPUC and state agency regulatory decisions.
- Inform ISO transmission planning decisions regarding the need for additional infrastructure to integrate renewable resources.
- Inform the ISO in potential energy and ancillary services market enhancements for needed renewable integration capabilities.

Q. How has the ISO participated in this proceeding?

A. The preliminary 33% integration study work was performed in coordination and support of this Long Term Procurement Plans (LTPP) proceeding using assumptions from the prior LTPP assumptions (Docket No. R. 08-02-007 and predecessor dockets). In the context of this case, in 2010 the 33% study work was primarily used to familiarize parties and gain agreement regarding the renewable integration study methodology. During the third and fourth quarters of 2010, the ISO conducted Step 1 modeling and Step 2 production simulation using 2009 vintage scenarios developed by the CPUC's Energy Division (ED) staff. The ISO described its 33% integration model at a workshop on August 24, 2010; the Step 1 modeling at a workshop on October 22, 2010; and the Step 2 results at a workshop on November 30, 2010. In addition, the ISO reviewed the Lawrence Berkeley National Lab's

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[1] See *Integration of Renewable Resources-Operational Requirements and Generation Fleet Capability at 20% RPS* at http://www.caiso.com/2804/2804d036401f0.pdf

[2] Draft Technical Appendices for Renewable Integration Studies - Operational Requirements and Generation Fleet Capability http://www.caiso.com/282d/282d85c9391b0.pdf

(LBNL) report and responded to comments and questions submitted by parties to the proceeding following each workshop.

On December 3, 2010, the CPUC issued a scoping memo in which new assumptions and scenarios were identified. The ISO has now revised its 33% integration study consistent with the CPUC's new assumptions and scenarios identified in the scoping memo. At the same time, the ISO has incorporated other identified data updates and methodological refinements to the 33% integration study. The preliminary study results based on these new assumptions and scenarios were distributed to the parties in this proceeding on April 29, 2011 and presented at a May 10, 2011 workshop. Here I describe the updates and refinements to the input data and methodology used for the 33% integration study to produce final study results, including the changes made to the preliminary study results.

Q. Do the 33% integration study methodology and the renewable portfolio scenarios that the ISO studied and that you describe in your testimony provide sufficient information to make procurement and infrastructure decisions?

A. As I describe in detail in this testimony, the study results show the flexibility requirements to support a 33% RPS result in a range of possibilities, from no additional capacity needs to the need for substantial capacity additions depending on the scenario assumptions. For this reason, the ISO believes that the study results should only be used making least regrets procurement decisions considering the lead time needed for such development . The study work that the ISO will be performing this year may provide additional insights to the plausible range of resource needs under different assumptions, which can also inform incremental procurement decisions. For example, the ISO, along with the CPUC, the CEC and other agencies, is in the process of conducting power flow and stability studies to evaluate local area capacity needs created by once through cooling (OTC) environmental restrictions. These study results will likely impact capacity input assumptions for future renewable scenarios that the ISO intends to run and will make available in the next LTPP proceeding.

In future studies, assumption areas needing further validation are the levels of energy efficiency and demand response captured in some of the renewable portfolio scenarios because such levels may take many years to achieve. Forecast error improvements should also be considered in future study work.

Because of the uncertainty around many of the study assumptions, the ISO believes that infrastructure decisions regarding the resources needed to support renewable integration is best determined on an incremental basis over the course of several years. For now it is important that the programs needed to achieve the levels of energy efficiency and demand response load reduction assumptions must be put in place as soon as possible. As the OTC study results become available, decisions about repowering or new generation siting must be considered. At the same time, the ISO will be developing market rules and integration policies that will align the operational and environmental objectives.

Q. Please describe how your testimony is organized.

A. The ISO's April 29, 2011 preliminary results were provided in the form of a slide deck. Those results now have been updated to account for the changes in modeling assumptions described in the May 31, 2011 ALJ ruling on the joint motion for extension of time to file testimony, and the ISO has updated the slide deck accordingly. In addition, the ISO has added summary information about the additional sensitivity scenarios that were modeled to test the results of the four scenarios. The updated slides are attached as Exhibit 1 and I describe them in this testimony. In the sections that follow, I will describe the 33% integration study methodology, input assumptions and the CPUC's renewable scenarios, study results, and how these results can be interpreted.

II. MODELING THE REQUIRED CPUC RENEWABLE PORTFOLIO SCENARIOS AND OTHER CASES

Q. You stated that the ISO ran the 33% integration model using 2009 vintage renewable scenarios, and these results were presented during workshops in 2010. What was the ISO's role with respect to the updated renewable scenarios described in the December 3, 2010 Scoping Ruling?

A. The ISO 33% integration study was updated to reflect the latest scenario assumptions developed by the ED staff and described in the December 3, 2010 scoping ruling[3]. Seven scenarios were specified:

1. 33% Trajectory Base Load
2. 33% Environmentally Constrained
3. 33% Cost Constrained
4. 33% Time Constrained
5. 20% Trajectory
6. 33% Trajectory High Load
7. 33% Trajectory Low Load

The assumptions for load and renewable resources vary depending on the scenario. There are a set of assumed resources that are common to all scenarios. This common assumption is referred to as the "discounted core." The discounted core consists of projects with signed power purchase agreements and filed applications for major permits. As a general observation, the load assumed in the 2010 scenarios is lower than the 2009 vintage scenarios. The ISO studied five of the seven 2010 scenarios: 33% Trajectory Base Load, Environmentally Constrained, Cost Constrained, Time Constrained, and 33% Trajectory High Load. Of these five, the first four were prioritized by the CPUC and are referred to in this testimony as the four priority scenarios. The preliminary results from modeling and production simulation runs for the four priority scenarios were provided to the parties on April

[3] http://www.cpuc.ca.gov/PUC/energy/Procurement/LTPP/LTPP2010/2010+LTPP+Tools+and+Spreadsheets.htm

29, 2011 and discussed at the workshop held on May 10, 2011. In addition to the five CPUC scenarios, the ISO also studied an "All Gas" scenario in support of development of metrics by the IOUs, and conducted a sensitivity analysis assuming all three Helms pumps are available year round. I discuss in this testimony the results of those studies.

Q. Please provide a general description of the five scenarios and the All Gas scenario?

A. The four priority scenarios described in the scoping memo and modeled by the ISO all have the same load assumption based on the 2009 California Energy Commission (CEC) load forecast. The priority scenarios differ with respect to the assumptions about the type and location of renewables needed to achieve 33% RPS. Of these scenarios, the Environmentally Constrained scenario relies more heavily on distributed solar (about 9000 MW), which includes small to medium sized solar photovoltaic (PV) plants selling their entire output to utilities. The Cost Constrained and Time Constrained scenarios have higher levels of out of state renewables. The fifth CPUC scenario studied, the 33% Trajectory High Load scenario, has a 10% higher load assumption than the four priority scenarios to reflect any combination of future uncertainties (*e.g.,* increased load growth and programmatic performance). The Trajectory High Load scenario also had 1,497MW of additional renewable resource versus the Trajectory Base Load scenario. Slide 5 in Exhibit 1 contains a list of the load and renewable assumptions for the five CPUC scenarios that the ISO ran. The All Gas scenario uses similar base load assumptions but does not include new renewable resources. The All Gas scenario does include existing renewables and 1750 MW of expected customer PV.

Q. How do these scenarios differ from the 2009 vintage scenarios?

A. The five CPUC scenarios assumed higher quantities of energy efficiency, behind the meter combined heat and power (CHP) and different assumptions about renewable portfolio build-out than the vintage scenarios. The increased energy efficiency and

CHP assumption reduce the peak load from the 70,180MW statewide peak in the vintage scenarios to a 63,755MW statewide peak for the 2010 scenarios. Slide 6 of Exhibit 1 compares assumptions between the two sets of scenarios.

Q. How did the ISO work with the utilities to model all the scenarios?

A. The ISO collaborated with the three investor-owned utilities (IOUs) - PG&E, SDG&E and SCE - and their consultant, Environmental Energy and Economics, Inc. (E3), through the working group. As I describe later in this testimony, the ISO conducted the Step 1 modeling and Step 2 production simulation for the five scenarios. Additionally, the ISO ran the All Gas scenario to support the cost metrics that E3 was retained to provide for the IOUs. E3 also assisted with reconciling the Step 2 model and the portfolio assumptions from the scoping memo.

Q. How did the ISO use the input assumptions in the December 3, 2010 Scoping Ruling (as modified in later rulings) to develop the database to run the renewables scenarios you described?

A. The ISO found that the input assumptions (or, at times, lack thereof) in the scoping memo fell into four general categories. Some of the assumptions could be used directly in developing the database. Other assumptions needed to be clarified with Energy Division staff in order to be consistent with the scoping memo. The third category consisted of input assumptions that were needed to successfully model and run the scenarios but were not in the scoping memo. Finally, some assumptions were simply incorrect and required revisions. For the last two categories, the ISO used its independent judgment and operational experience, supplemented by expertise from Nexant (the ISO's consultant), to develop the needed assumptions or to make the necessary changes.

Q. What was the basis for the changes made to the input assumptions?

A. Slides 36-39 set forth the changes to the assumptions in the scoping memo for accuracy.

Q. Did the ISO make additional input assumptions and clarifications?

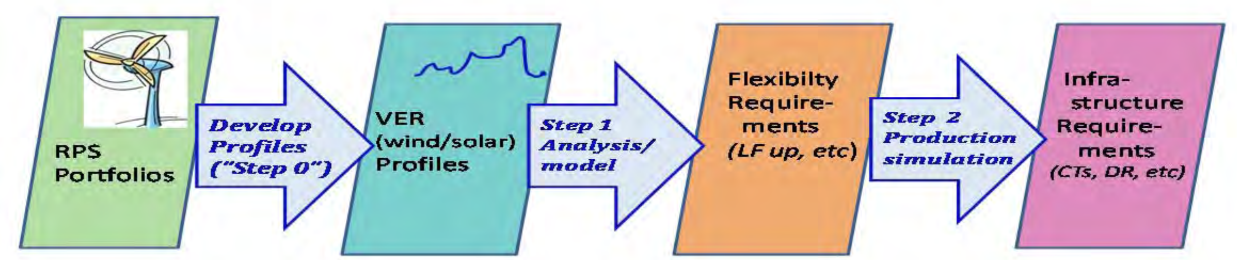
A. Yes. As I noted above, following the release of the preliminary study results on April 29, 2011, the ISO, in collaboration with the IOUs, developed a list of input assumption modifications required to finalize the studies. These assumption modifications were described in the May 31, 2011 ALJ ruling in this proceeding.

III. STUDY METHODOLOGY

Q. Can you provide an overview of the 33% integration model, and the study methodology steps followed by the ISO, to develop the results summarized in Exhibit 1?

A. Yes. The study methodology is divided into stages: Steps 0, 1 and 2, conducted by the ISO, and Step 3, undertaken by E3 and the IOUs. The first stage, Step 0, is the development of load, wind and solar profiles, based on the resource assumptions in each portfolio. The profiles are then used as inputs into the Step 1 statistical analysis to calculate regulation and load following requirements. These requirements, along with hourly load and other operating reserves, are then used as inputs to a production simulation in Step 2. Figure 1 illustrates the study process. The results of production simulation were then provided to the IOUs to develop integration metrics referred to as Step 3.

Figure 1: Renewable Integration Study Process



RPS-Renewable Portfolio Standard
VER-Variable Energy Resources
LF=Load Following
CT-Combust Turbine
DR-Demand Response

Q. What modeling tools and resources were used to conduct the study?

A. For Step 0, the ISO consulted with Nexant and used National Renewable Energy Laboratory (NREL) data and tools such as the Solar Advisory Model (SAM). To develop solar data, the ISO used 2005 Solar Anywhere satellite solar irradiance data. For the Step 1 analysis the ISO used Pacific Northwest National Laboratories' (PNNL) statistical analysis software. For Step 2, the ISO used PLEXOS Solutions production simulation package and also consulted with PLEXOS Solutions to assist in running the production simulation.

Q. How were out-of-state renewable resources considered in the study?

A. Four categories of out-of-state resources were considered: 1) 15% assumed to be import into California as a dynamic transfer, 2) 15% assumed to be import into California as a 15 minute intra-hour scheduled, 3) 40% assumed to be import into California as an hourly schedule, and 4) 30% assumed to be unbundled renewable energy credit (REC).

Q. How were the different categories of out-of-state renewable resources treated in the different steps of the study process?

A. Table 1 summarizes how the different categories were reflected in the study steps**.**

Table 1: Modeling of Out-of-State Renewable Resources

Type of Out-of-State Renewable	Step 1	Step 2	Post Processing Costs and Emissions
Dynamic Schedule/Pseudo Tie (15%)	Use 1 minute profiles as if the plant is in CA. Forecast error included.	Hourly profiled production should be modeled using import lines to carry this flow.	Zero production costs and emissions should all be attributed to CA related to imports.
15 minute intra-hour scheduled (15%)	Average 1 minute data over 15 minutes with appropriate schedule ramps. Forecast error not included.	Hourly profiled production should be modeled using import lines to carry this flow. (same as above).	Zero production costs and emissions should all be attributed to CA related to imports.
Hourly Schedule Type 2[4] (40%)	Not used in Step 1	Hourly production is modeled as if the plant's production will be injected in the bubble that the plant resides in and will have only an indirect impact on CA through any possible re-dispatch in the region the plant is located in.	Zero production costs and emissions should all be attributed to CA related to imports.
Unbundled RECs (30%)	Not used in Step 1	Hourly production is modeled as if the plant's production will be injected in the bubble that the plant resides in and will have only an indirect impact on CA through any possible re-dispatch in the region the plant is located in.	RECs should be attributed to CA. Imports would be at costs and emissions of the WECC.

[4] It is assumed that the schedule for these projects are such that the yearly production from the plant is scheduled into California without any other constraints on hourly, weekly, or monthly schedules. Within the hour balancing, and any additional balancing and shaping, is not supplied by California.

A. STEP 0 - IDENTIFYING RESOURCE CHARACTERISTICS TO BE USED IN EACH SCENARIO

Q. What is the purpose of Step 0?

A. The purpose of Step 0 profile development is to produce a series of 1 minute and hourly generation production profiles for each minute and hour of the of the year based on the resource location, quantity and a capacity factor identified in the CPUC scoping memo. The ISO has summarized the plant locations used in each CPUC scenario and capacity factors by technology in support used for this analysis at Exhibit 2 attached to this testimony. This information can also be found on the ISO website at http://www.caiso.com/23bb/23bbc01d7bd0.

Q. How did the ISO develop the Step 0 profiles?

A. As I discuss below, wind and solar 1 minute and hourly profiles were developed using different methods. In addition, the solar method was further refined to develop profiles for small-scale photovoltaic (PV), defined in the CPUC scoping memo as small distribution solar at the wholesale level. Four types of small-scale PV were specified depending on size and location: 1) large rooftop (0-2MW), 2) large ground (5-20MW), 3) mid ground (2-5MW), and 4) small ground (0-2MW). Due to the relatively small quantity and size of mid and small ground, the ISO combined the mid and small ground into the large ground profile development. The ISO modeled customer-side PV as supply in order to capture the intermittent nature of these facilities. The ISO and Nexant consulted with ED staff and E3 to clarify information provided in the scoping memo prior to developing the profiles.

Q. Please provide additional detail about how the ISO developed the Step 0 wind profiles.

A. For existing wind plant, the ISO used actual historical wind production from 2005. Aggregate data for existing wind resources is available at http://www.caiso.com/2b53/2b53c0f95d330.csv

For new wind resources, the ISO used wind generation profiles that were developed based upon NREL mesoscale wind data for 2005.[5] For new plants, wind plant production modeling was based on NREL 10 minute data production data from the year 2005 for 21 distinct locations in California and 22 distinct locations throughout the remainder of the WECC where wind plants were identified in the CPUC study scenarios.[6]

Q. What steps did the ISO take to develop profiles for new wind resources?

A. The 1 minute wind data used for all new wind plants was developed using a methodology that included the following steps or processes:

First, a representative number of plants and their geographical locations were developed, whose total capacities (MW) matched the MW in each Competitive Renewable Energy Zone (CREZ), based on the resources included in each of the scenarios developed by the CPUC. To identify the number of units and locations for the projected additions the CPUC used data from the IOU procurement processes as a starting point and generic plant information from the Renewable Energy Transmission Initiative (RETI) process and other sources. The number of plants that were ultimately used to represent the wind generation were chosen so that no one plant represented more than about 5% of the total wind generation.

[5] Data for the year 2005 was used in the ISO 33% RPS Studies because 2005 was designated as a normal hydro year. Thus load, wind, solar and hydro run of river profiles were based on conditions (wind speeds, solar irradiance, and hydro flows) that existed in 2005.
[6] NREL production data is based upon a wind farm using Vestas V-90 3 MW generators.

Second, geographic information system (GIS) software was used to find one or more appropriate NREL data sites for each CREZ to represent wind plants in that CREZ . Multiple NREL data sets within a CREZ were used to capture the diversity within a CREZ where there were multiple plants within a CREZ in the study definition. In selecting the NREL points to use from among the many NREL mesoscale points available, wind sites that represented likely sites for wind farms (ridge location, etc.) and that had capacity factors that were as close as possible to the plants specified in the scenario definitions were carefully selected.

Third, the 10 minute production data sets for the selected sites were downloaded from the NREL website. These data sets were then shifted in time to Pacific Standard Time and then the days of the week were shifted to match the days of the week for the study year – 2020. Fourth, necessary if there were any capacity factors that did not closely match the study definition plant capacity factors, the resulting data was adjusted as necessary. These adjustments were minimal since the data sets were chosen to closely match the desired capacity factors.

Fifth, the 10 minute production data for each site was curve fit with a cubic spline curve fit function to produce 1 minute data without 1 minute variability.

Sixth, a statistical model was developed using historical ISO data from several existing wind farms to capture the 1 minute variability (compared to a 10 minute average) as a function of the size of the plant/wind farm. This statistical model captures the standard deviation of the 1 minute variability as it varies with wind farm size.

Finally, using this 1 minute statistical model, variability was then added to each 1 minute splined set of data using a process that adds variability randomly as a function of the wind farm size. The final data set of 1 minute wind farm data for each plant, which includes 1 minute variability, was then used for the Step 1 statistical model to determine operational regulation and load following requirements. The hourly wind generation profiles were developed by averaging the 60 - 1 minute production data over each hour of the year.

Q. How did the ISO develop the Step 0 profiles for solar resources?

A. The solar profiles were developed based on upon satellite irradiation data. The 1 minute solar data used for all new large solar plants was developed using a methodology that includes the following steps or processes:

First, a representative number of plants and their geographical orientation were developed whose totals match the technology and number of megawatts in each CREZ[7] in the CPUC study definition. The process to identify the number of units, types, and locations for the projected additions uses as a starting point the renewable additions identified as per the renewable portfolios being modeled and assumptions about the renewable net short. Similar to wind, solar plants have a maximum size to ensure that no single profile represented more than 10% of the total solar generation to capture diversity properly.

Second, selected representative half-hourly satellite solar irradiance data points available in the 2005 Solar Anywhere solar data set were identified for each plant to be modeled. Table 2, below, shows the number of square miles of land needed by a solar plant that produces from 60-80 MWs, depending on the technology and location. Thus for a plant of 140 MWs two 1 km square areas that are adjacent to each other would be selected from the Solar Anywhere irradiance data set.

[7] Used solar CREZ info from RETI study http://www.energy.ca.gov/reti/documents/index.html

Table 2: Plant Area by Technology

Plant Technology	Area Required in Square Miles for 10 MW Facility
Solar Thermal	0.0855 Square Miles[8]
Solar PV without Tracking	0.093 Square Miles
Solar PV with Tracking	0.093 Square Miles

Third, using this information about the land area needed for specific technologies, the third step was to download the half-hourly irradiance data from the Solar Anywhere[9] website for all of the 1 square kilometer areas needed to model all of the large solar plants.

Fourth, hourly production data was developed for the plant for the appropriate technology in each CREZ using hourly average Solar Anywhere irradiation data sets for 2005 for each plant as input to the NREL SAM. The SAM model was used to develop production data for six types of technologies – Solar PV with tracking, Solar PV without tracking and Solar Thermal using a Trough, Central Tower, Central Tower with Storage, or Stirling engine.

Fifth, 1 minute production data was synthesized from the plant hourly production data using a smooth cubic spline curve fitting function. This data did not yet represent the minute to minute production variability that can be present in the output of solar plants due to clouds or other factors. What it does represent is a plant that captures the hourly variation of irradiance over its full plant footprint.

Sixth, Clear Sky profiles were developed for each plant by calculating the maximum production for each hour for each month under clear skies (without clouds, fog, or

[8] Average of solar thermal tower and trough technology.
[9] The Solar Anywhere satellite solar irradiance data can be found at: https://www.solaranywhere.com/Public/About.aspx

other factors that would reduce the amount of irradiance that falls on earth's surface).

Seventh, variability was introduced into the smoothed 1 minute plant production data using a process that inserted the variability captured from historical 1 minute irradiance data from measurements collected by NREL's Measurement and Instrumentation Data Center (MIDC)[10] at the SMUD Anatolia site in Rancho Cordova, CA, Loyola Marymount University in Los Angeles, and the SolarCAT station in Phoenix, AZ. At this stage in the process, the 1 minute data captures the variability of a plant that occupies the full plant footprint. This step is discussed in more detail below.

Eighth, to reflect the fact that certain technologies have inherent time delays in their response to changes in irradiance, the data described in step 7 was processed in an inertial delay algorithm to arrive at the final 1 minute production data. This step was applied only to solar thermal plants as it is believed that solar PV plants have negligible time delay in their response to changes in irradiance. For the three types of solar thermal technologies (trough, tower and Stirling) three different characteristics were used as shown in Figure 22.

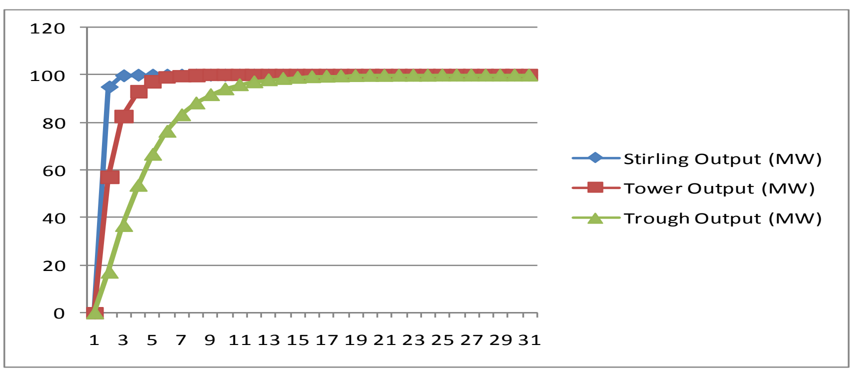


Figure 2: Response to Step Increase in Irradiance by Solar Thermal Technology v, Time in Minutes

[10] www.nrel.gov/midc

Q. Please provide additional detail about how the variability was introduced into the Step 0 solar profiles.

A. One minute variability is introduced into the smoothed 1 minute production data in Step 7 above. This step in turn is made up of several steps.

First, a Data Library was developed of 1 minute variability from historical 1 minute irradiance data collected by Sacramento Municipal Utility District (SMUD) in Sacramento, Loyola Marymount University in Los Angeles, and the SolarCAT in Phoenix, AZ. A summary plot of the raw historical irradiance data (in W/M^2) for the Sacramento sites for a single month is shown in Figure 3.

Second, this 1 minute data was converted to a normalized derate value by dividing the 1 minute actual irradiance data by the irradiance measurement that would have existed had there been no clouds in that minute (clear sky). The resulting data was a set of 1 minute historical per unit irradiance derate values that ranged from 0 to 1.0, with 0 representing full reduction from a clear sky level to a zero irradiance level and 1.0 representing no reduction from a clear sky level. Six different sets of this 1 minute derate data were developed for solar thermal and solar PV for the various sizes of plants (number of 1 kilometer squares in the plants footprint). A moving average was applied to each of the libraries, based on the number of 1km irradiance grids, to represent the 1 minute variability over the full footprint of the plant. Thus six libraries are developed for use in the subsequent steps.

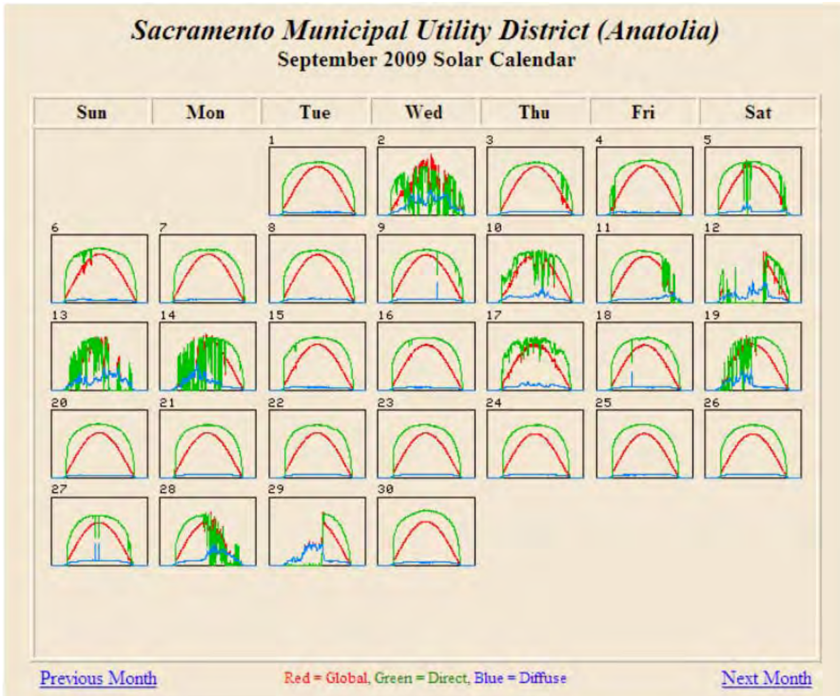


Figure 3: SMUD 1 Minute Irradiance Data for September 2009

The data plotted in the diagrams in Figure 3demonstrates that some days have little variability and other days have significant variability.   Figure 4 shows the variability of a single day.

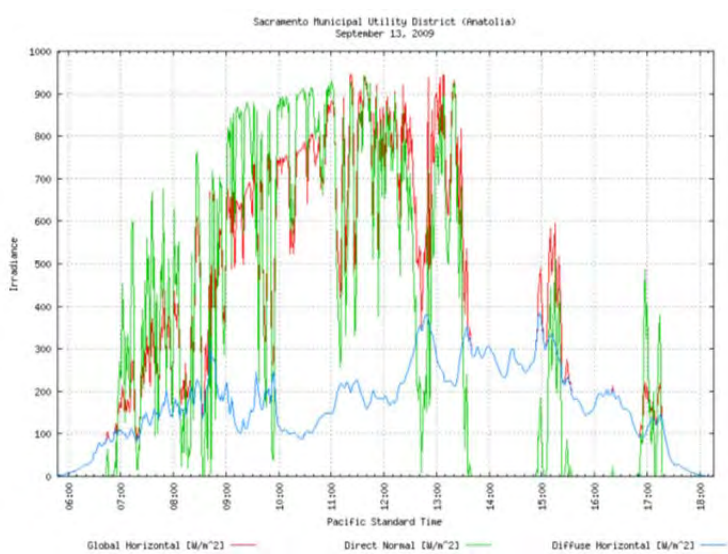


Figure 4: 1 Minute Irradiance for September 13, 2009

To capture the fact that some hours are cloudless and other hours have clouds which reduce the irradiance below its clear or cloudless sky level, variability was added to only those hours of production which show cloud cover impacts. The process first converted the 1 minute smoothed production data for the plant into 1 minute derate values that ranged from 0 to 1.0 similar to the 1 minute derate values in the irradiance data library discussed earlier. This was accomplished by dividing the smoothed 1 minute generation by the 1 minute generation that would have been produced if there were no clouds in that minute (clear sky).

Next, average production derate values were calculated on an hourly basis from the 1 minute derate values. Then for each hour of the year that had a derate value lower than 0.95, the 1 minute production derate values were replaced by an hour of irradiance derate values from the library developed that had the same hourly derate value. Which of the six libraries was used for this substitution depended on the plant size (number of 1 Kilometer squares in the plant footprint). This step added variability based upon historical data to the 1 minute production derate values while maintaining the average derate over the hour at the same level as in the production data.

Q. Did the ISO validate the variability results before finalizing the solar profiles?

Yes, we performed the following checks:

- To ensure that there were no significant step changes caused by the derate data substitution, the start minute and end minute derate values were tested to make sure they were within 1% of the minute before and the minute after the starting and ending minutes, respectively.

- To ensure that historical data was as representative as possible, substitution data was required to come from hours in the library that were within +/- 2 hours. For example, afternoon variability would not be applied to morning hours.

- To increase the number of library "hours" available for substitution, sets of 60 1 minute values (library hours) were created by shifting the start of the 60 minute period by 1 minute. For example, data from 2 hours could be used to construct 60 library hours.

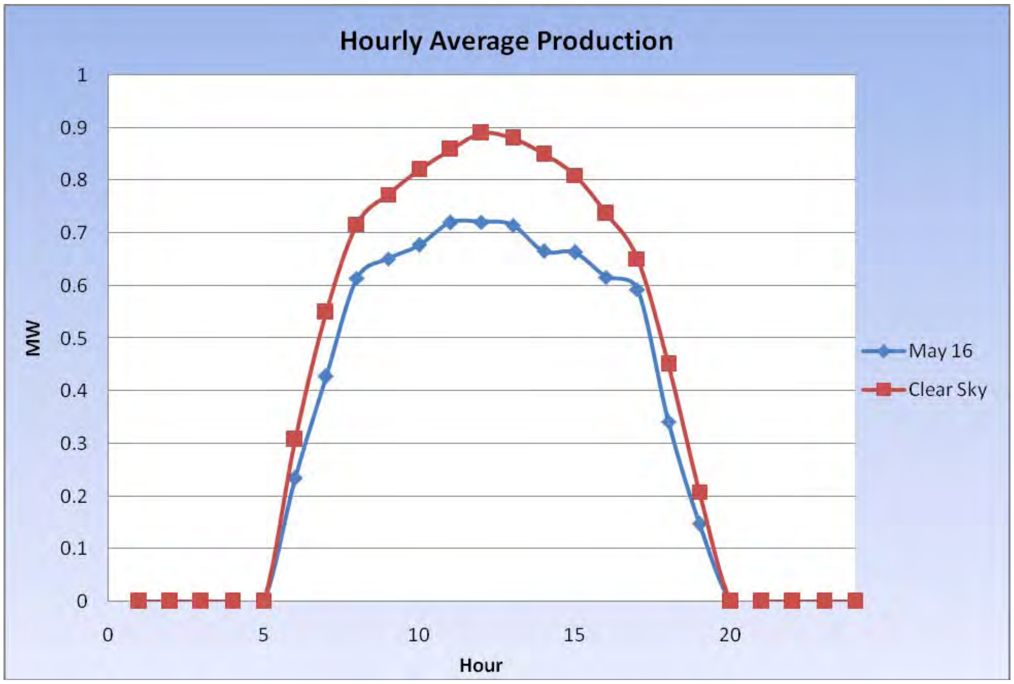
- To ensure that a bias was not introduced in the substitution process, a random selection process was used to find the derate data that met the end effects tolerances. This hourly process proceeded through the entire year to develop a full year of 1 minute production derate values.

Q. What was the final step in developing the variability results?

A. The final step converted the derate values into 1 minute production values by multiplying the derate values by the 1 minute production expected from a plant under clear sky conditions.

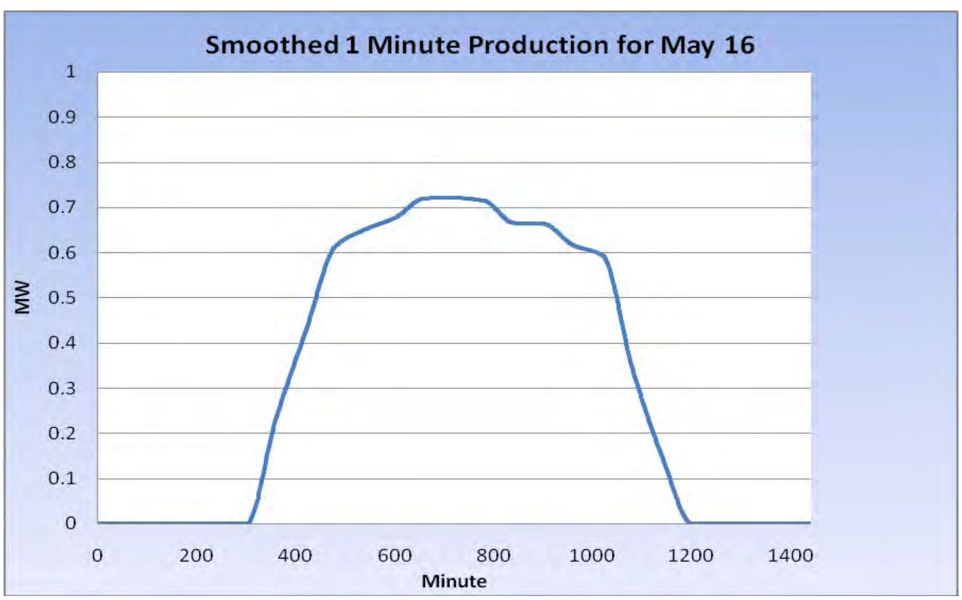
Q. Can you provide an example of the results of the variability process?

A. Yes. The results of this process are shown graphically in the figures below. Figure 5 shows the hourly production data output of the SAM for May 16, 2020. Figure 6 shows the smoothed 1 minute production data and Figure 7 shows the production data after historical variability has been added.



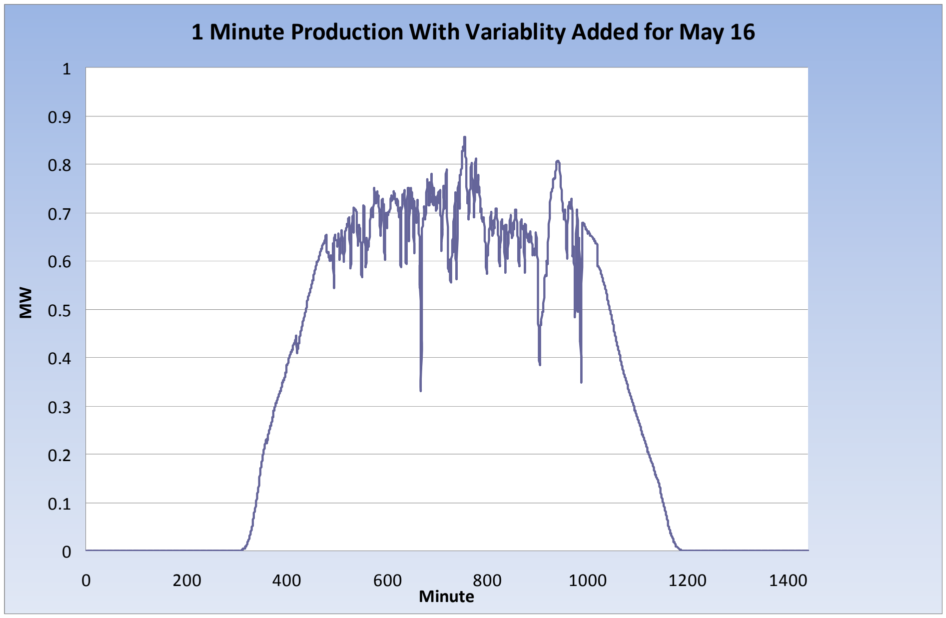
1 Minute Smoothed Production Data for a Tracking PV in the Mountain Pass/Tehachapi for May 16, 2020

Figure 5: Hourly Production Data Output from SAM Model



1 Minute Smoothed Production Data for a Tracking PV in the Mountain Pass/Tehachapi for May 16, 2020

Figure 6: Hourly Production Data Output from the SAM After Spline Fit



1 Minute Production Data With Historical Variability Added for a Tracking PV in the Mountain Pass/Tehachapi for May 16, 2020

Figure 7: Hourly Production Data Output from the SAM After Variability Is Added

Q. How did the ISO develop the Step 0 profiles for small solar PV?

A. Developing profiles for small solar PV resources presented a challenge. There are approximately 9000 MW of various types of small solar PV in the Environmentally Constrained Scenario and either 1000 MW or 2000 MW in the other scenarios. In addition, there are approximately 2000 MW of small PV on the customer side of the meter in all scenarios. The number of these plants is in the thousands, which precludes these plants from being analyzed or modeled on an individual plant basis. In addition, because of data confidentiality limitations, the supply side projects are not easily located geographically.

Q. What was the ISO's approach to modeling the small solar profiles?

A. Due to numbers, geographic and size diversity, and other factors, we decided to model these projects at an aggregate level.

For the supply side, we defined a number of rectangular geographical areas as shown in Table 3 below to cover about 4-500 MWs of generation in each rectangle. (The use of a predetermined shape allowed more efficient coding and data processing).

The numbers in the column labeled "Number of Sites" is not the actual number of sites, which are in the thousands, but the number of projects selected from RPS Calculator, each of which would be distributed over many sites. The first five columns of the Table contain clarifying information provided to Nexant by ED staff as the profiles were being developed. The last two columns, "grids" and "MWs/ grid," were developed by Nexant as part of their modeling effort.

Table 3: Small Supply Solar Projects as Defined by the CPUC

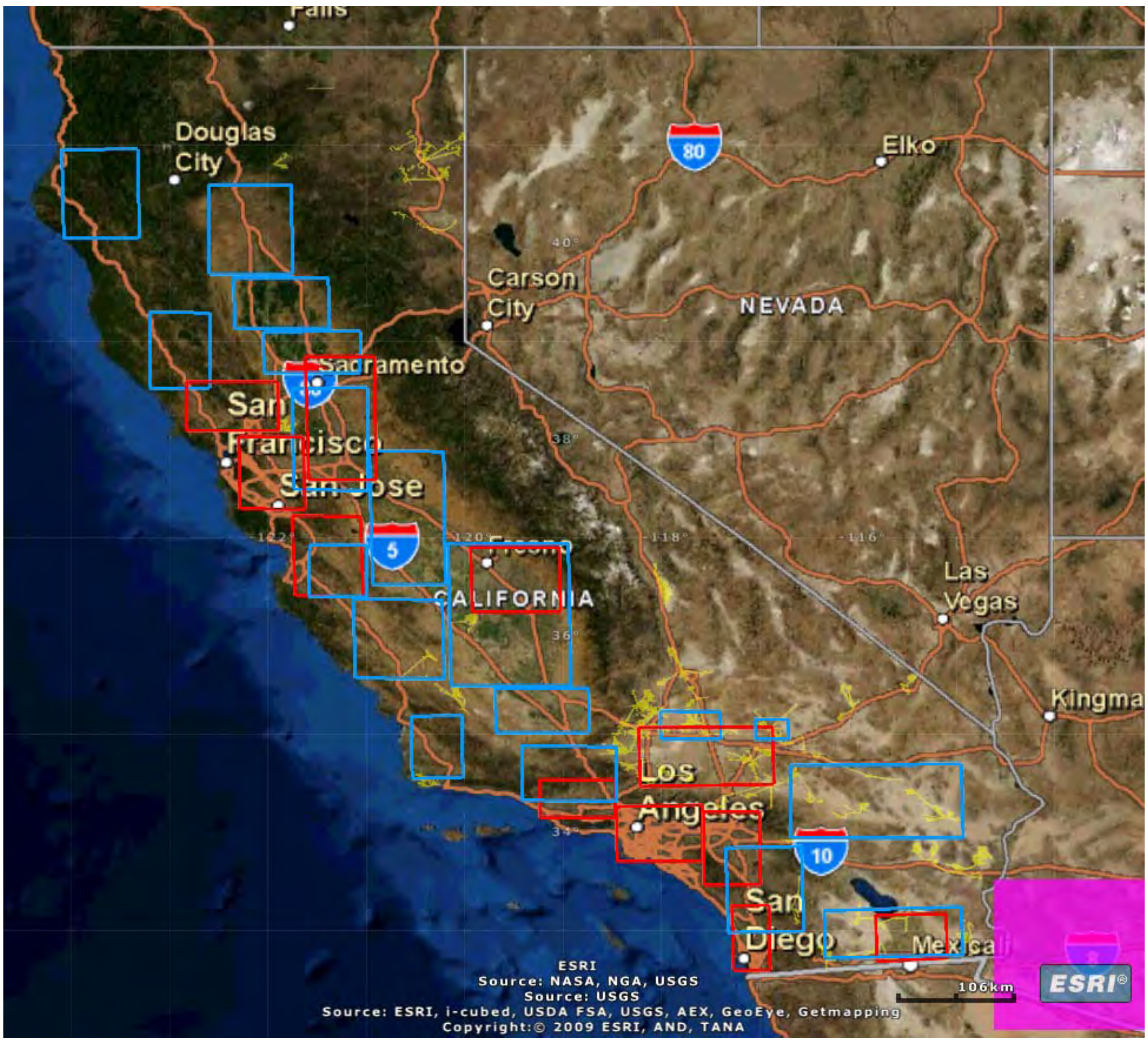
Location	Sub-Type	Number of Sites	Total MW	Capacity Factor	Grids	MWs/Grid
Central Valley	Large Ground	52	2677.7	23.56%	6	446
	Large Roof	7	710	20.37%	2	355
	Mid Ground	22	132.9	23.56%		Combine
	Small Ground	21	26.1	25.57%		Combine
Mojave	Large Ground	46	836.1	26.68%	2	418
	Large Roof	19	513.7	22.68%	1	514
	Mid Ground	21	12.5	26.68%		Combine
	Small Ground	21	3	29.36%		Combine
North Coast	Large Ground	31	725.2	21.87%	2	363
	Large Roof	19	929.9	19.56%	2	465
	Mid Ground	15	48.4	21.87%		Combine
	Small Ground	14	13.1	23.71%		Combine
South Coast	Large Ground	27	923.1	24.34%	2	462
	Large Roof	24	1517.7	21.17%	3	506
	Mid Ground	14	6.7	24.34%		Combine
	Small Ground	14	1.1	26.09%		Combine
Total		367	9077.2	Total	20	

For each square grid, we assumed that the plants are uniformly distributed over the grid. For the categories (rows) with relatively small amounts of generation, we decided that accuracy would not suffer if they were combined with other categories that had similar technologies and capacity factors. For example, under Central Valley there is 133 MW of Mid Ground and 26 MW of Small Ground. We determined that for modeling purposes these projects should be added to others in the same region with the same or similar characteristics.

Q. How were the grids distributed geographically?

Figure 8 shows the grids that are used for the 9000 MWs of solar PV.

Figure 8: Distributed Solar Geographic Areas



In this geographic representation, blue squares are for large ground projects and red squares are for large roof projects.

Q. Once the geographic boundaries were determined, what process did you follow to develop the profiles?

We selected 25 1 km by 1 km satellite irradiance data that was evenly distributed over the grid. For some grids this might be one every 5 km and others might be one every 20 km. That data was averaged on an hourly basis for each rectangle.

Next, we processed the averaged irradiance data in the SAM to develop hourly production for the MWs represented by the group. Using a cubic spline curve fit function on the hourly production, we then developed 1 minute profiles for each geographic area, which has no 1 minute variability.

We added 1 minute variability to the 1 minute production data using algorithms similar to those described above used for developing large solar plant profiles and, as the final step, we developed clear sky production for each geographic area in the same manner as with the large solar – by selecting the maximum production in each hour for each month.

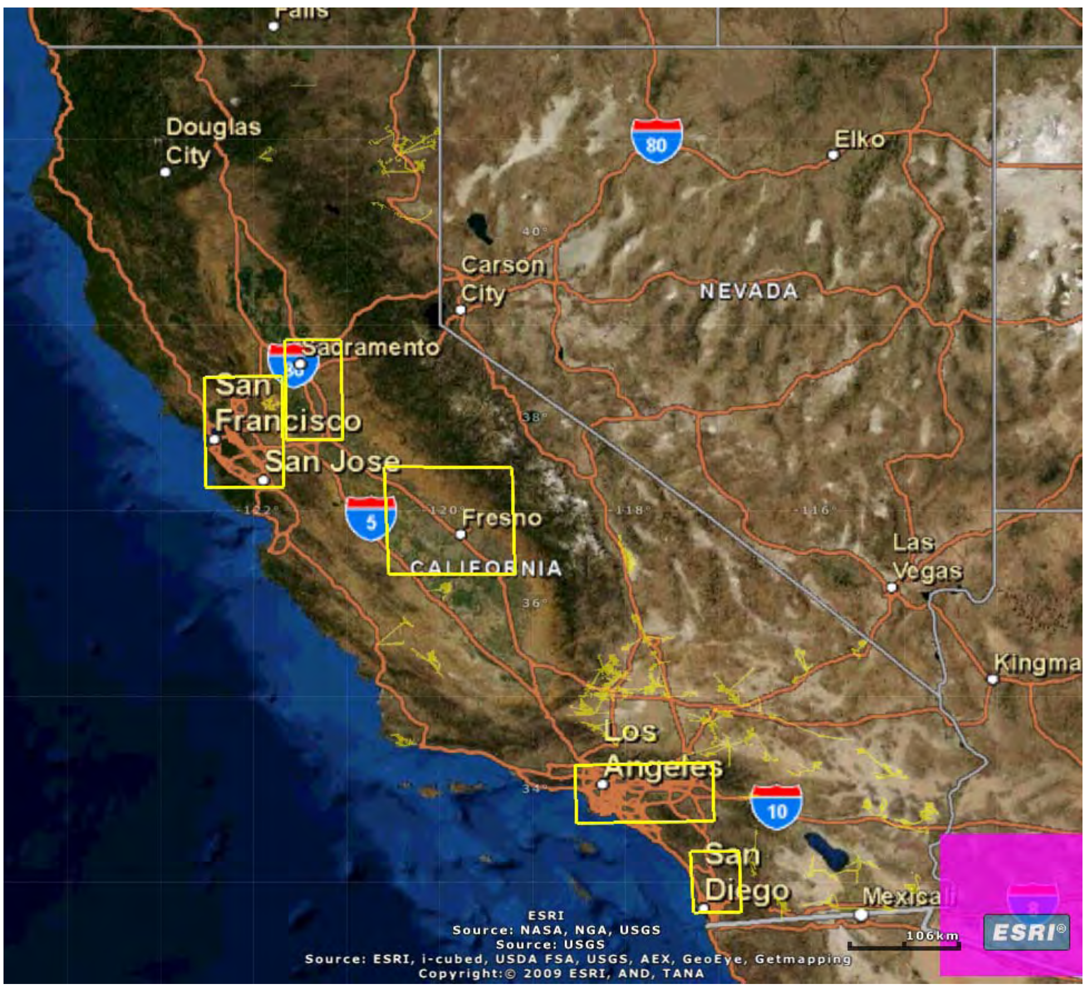
Q. What was the process used for developing small customer-side PV?

A. The process for small PV on the customer side of the meter was similar to the process used for small supply PV plants. Five grids were used, as presented on Figure 9. Table 4 provides the location, size and capacity factor planning assumptions for these customer side solar resources.

Table 4: Aggregated Customer Side Distributed Solar

Location	Profile Name	Size MW	Type	Capacity Factor
Central Valley	Distributed_Solar_1	349.9	fixed tilt	21.00%
Central Valley	Distributed_Solar_2	349.9	fixed tilt	21.00%
North Coast	Distributed_Solar_3	349.9	fixed tilt	21.00%
South Coast	Distributed_Solar_4	349.9	fixed tilt	21.00%
South Coast	Distributed_Solar_5	349.9	fixed tilt	21.00%

Figure 9: Customer Side PV Geographic Areas



Q. How were the 1-minute and hourly load profiles developed?

A. The 1-minute load profiles were developed from actual 1-2005 actual load data. The total system load was scaled up to match the hourly peak load in the CPUC defined scenarios. The 1-minute hourly data was then averaged over 60-minutes to produce an hourly load profile. The hourly load profiles were further adjusted to ensure the total energy over the year was consistent with the CPUC planning assumptions.

These load profiles were posted to the ISO website as the ISO conducted its Step 0 modeling: 1-minute load http://www.caiso.com/2b3e/2b3ed83725ee0.csv and hourly load: http://www.caiso.com/2b41/2b41d086444a0.zip.

B. STEP 1- MODELING LOAD FOLLOWING AND REGULATION REQUIREMENTS

Q. How did the ISO develop the Step 1 load following and statistical regulation requirements?

A. The Step 1 load following and regulation requirements were developed from the load, wind and solar 1 minute profiles developed in Step 0 along with distributions of load, wind and solar forecast errors. This step in the study uses a stochastic process developed by the ISO and PNNL that employs Monte Carlo simulation, a sampling over multiple trials or iterations used to estimate the statistical characteristics of a mathematical system. The simulation is designed to model aspects of the daily sequence of ISO operations and markets in detail, from hour-ahead to real-time dispatch. The objective is to measure changes in operations at the aggregate power system level, rather than at any particular location in the system. The model provides realistic representations of the interaction of load, wind, and solar forecast errors and variability in those time frames and evaluates their possible impact on operational requirements through a very large number of iterations. A summary of the regulation and load following requirements produced by Step 1 analysis is provided on Slides 3 and 4 of Exhibit 1. The detailed Step 1 hourly results for the following scenarios are available at:

Scenario	Step 1 Results
Trajectory	http://www.caiso.com/2b49/2b4980da2f1e0.xls
Environmentally Constrained	http://www.caiso.com/2b49/2b49906560a70.xls
Cost Constrained	http://www.caiso.com/2b49/2b4980da2f1e0.xls
Time Constrained	http://www.caiso.com/2b4c/2b4c96c04f880.xls
Trajectory High Load	http://www.caiso.com/2b59/2b59ed4521ce0.xls

Q. Are the load, wind and solar forecast errors inputs into the Step 1 stochastic modeling process you described above?

A. Yes. As I describe below, the ISO developed distributions of forecast errors that are defined by the standard deviation and correlation of error from time interval to the next based on actual forecast and load data for load and based on a T-1 persistence method using the wind and solar profiles developed in Step 0.

Q. What are forecast errors and why is this data important to the Step 1 determination of grid operating characteristics?

A. Forecast errors quantify the magnitude of uncertainty one can expect when forecasting load or generation production from variable resources such as wind and solar resources. To ensure the ISO can balance supply and demand in real-time, the ISO must consider the difference between supply and demand that can arise in case actual conditions differ from forecasted conditions.

Q. Did you observe differences in the level of forecast errors between the 2009 vintage scenarios and the priority scenarios?

A. Yes. These differences are depicted on Slide 59 of Exhibit 1. For the load forecasts, we observed a significant reduction in hour ahead load forecast error. This reduction is because our forecast is now based on forecasts that are produced 75 minutes prior to actual operating hour. The load forecast errors in the vintage scenarios were based on load forecast that was produced 2 hours prior the operating hour. In addition, the ISO has made improvements to its load forecasting tools.

However, the 5 minute ahead forecast errors have increased some from prior analysis. The 5-minute ahead forecast errors affect regulation more than load following requirements.

The wind forecast errors determined using the T-1 persistence method discussed above resulted in modest reduction in forecast when compared the wind forecast error used in vintage scenarios. However, the forecast errors observed in the T-1 persistence method have the level observed when compared to current Participating Intermittent Resource Program (PIRP) resource wind forecast errors.

Depending the technology and clear sky index, the solar forecast errors are in some cases lower and other cases higher than the forecast errors used in the 2009 vintage scenarios.

Q. **How did the changes in forecast errors affect the Step 1 regulation and load following requirements?**

A. The lower hour ahead and wind forecast errors contributed to a reduction in the load following requirements observed in these priority scenarios when compared to the vintage scenarios results. Only modest reductions in regulation requirements were observed in part due to the offsetting effects of the high 5 minute load forecast errors.

Q. How were the load forecast errors determined?

A. The load forecast errors were determined for two different timeframes, the hour ahead and each 5-minute interval within the operating hour. For each timeframe, the forecast errors were calculated by taking the difference between the forecast demand for that timeframe and the actual average demand for the corresponding timeframe. Four probability density functions were approximated using a truncated normal distribution that is defined by using the mean and standard deviation for the forecast errors for each season. The hour ahead and 5-minute aggregated load forecast errors were calculated using actual and forecast data for 2010.

Q. What were the load forecast errors that were calculated?

A. The hour-ahead and 5-minute load forecast errors determined are presented on Slide 59 of Exhibit 1.

Q. How were the wind forecast errors determined?

A. The hour ahead wind forecast errors are based on a T-1 persistence analysis.

Q. What is T-1 persistence analysis?

A. T-1 persistence analysis compares the average production for an hour "t" with the actual production from the previous hour "T-1 hour." The basis for this approach is that a forecasting approach should be able to at least be no worse than an assumption that what is produced in one hour will persist and reflect what is produced the next hour.

Q. Why was a 1 hour comparison used?

A. 1 hour is used because currently the market structure and scheduling timelines in the west require occurring on an hourly basis and are determined approximately 1 hour ahead of the actual operating hour.

Q. What were the wind forecast errors that were calculated using the T-1 hour persistence method?

A. The hour-ahead wind forecast errors we determined are presented on Slide 61 of Exhibit 1.

Q. How were the solar forecast errors determined?

A. The solar forecast errors were determined based on a T-1 persistence analysis of the clearness index for hours 12 though 16, separately for different solar technologies- PV, solar thermal, distributed solar and customer side PV- using the profiles developed in Step 0, and broken down into 4 different clearness index categories.

Q. Why were the solar forecast errors separated into the technology and clearness index groupings you described above?

A. The solar forecast error analysis was separated due to different solar technology production patterns and variability as a function of solar irradiance. As a result, separating the forecast error analysis by solar technology and clearness index allows the ISO to better reflect the impacts of the relative quantity of different solar technology.

Q. Why was the solar forecast error analysis limited to hours 12-16?

A. The forecast error analysis was limited to hours 12-16 to avoid introducing errors that result from sunrise and sunset which would distort T-1 persistence error analysis. Hours 12-16 are hours where the clear sky solar irradiance is relatively stable from one hour to the next and better reflects forecast conditions.

Q. Did the methodology for developing forecast error consider dispatch or thermal inertial capabilities of solar thermal resources?

A. No. In the analysis of solar forecast errors conducted so far, the ISO recognized that there is further research needed to refine the impact on forecasting modeling of plant-scale effects, operational properties and performance characteristics and capabilities of different solar technologies, including startup-up in the morning and shutdown-down during the evening hours.

Q. Did you consult with others to develop the application of T-1 persistence forecast error analysis method?

A. Yes, this method was developed in collaboration with Andrew Mills, Principle Research Associate with LBNL, who provided consultation services to ED staff.

Q. What were the solar forecast errors that were calculated using the T-1 hour persistence method?

A. The hour-ahead solar forecast errors determined are presented on Slide 65 of Exhibit 1.

Q. Please provide additional details about how the Step 1 modeling process was used to calculate operational requirements.

A. A detailed description of the statistical analysis methodology is found in the technical appendix to the ISO's 20% RPS integration study that I discussed earlier in my testimony. The basic method is as follows: First, the load and renewable production data is aggregated from the 1-minute data set to create averaged hour-ahead and 5-minute dispatch schedules for each hour of the year. Second, the probability distributions of forecast errors, and other statistical properties, such as autocorrelation, for load, and wind and solar production in the hour-ahead and 5-minute-ahead timeframes are constructed. Both wind and solar forecast errors are used in the hour-ahead random draws. However, in the 5-minute time frame, the ISO uses a wind persistence forecast, which is the basis for the simulation. Hence, in the 5-minute sampling, the wind variability is preserved but the forecast error is static for the period of the persistence model. For the solar resources, the 5-minute forecast errors are modeled explicitly because of the more extreme morning and evening ramp periods for solar in which persistence would not be an appropriate assumption.

Third, the Monte Carlo sampling then conducts random draws from the load, wind and solar forecast errors, with consideration of autocorrelations between the errors, to vary the initial hour-ahead and 5-minute schedules. The Monte Carlo sampling is done on each hour in the sequence individually.[11]

Each simulation of a seasonal case includes 100 iterations over all hours in the season to capture a large number of randomly generated values. Of these simulated values, five percent are eliminated as extreme points, using a methodology that considers all dimensions being measured in the analysis (capacity, ramp and ramp duration).

C. STEP 2 - USING PRODUCTION SIMULATION TO EVALUATE THE NETWORK AND DETERMINE OPERATIONAL NEEDS

Q. Please describe how the Step 2 production simulation analysis is used to determine grid needs.

A. Step 2 production simulation is an hourly deterministic production simulation of the WECC, including California hourly dispatch with the objective of minimizing cost while meeting the hourly load, spinning reserves, non-spinning reserves, regulation requirements and load following requirements, subject to resource and inter-regional transmission constraints. The regulation and load following requirements are determined in the Step 1 analysis. If the production simulation is not able to meet one or more of these requirements, a shortfall is identified and generic resource capacity is introduced to resolve the shortfall. The generic resource additions are identified as “needs” because additional resource capacity was needed to meet the simultaneous requirements. A more detailed description of the production

[11] However, the twenty (20) minute ramps that characterize the boundary between actual hourly schedules are represented in the model to ensure that in those periods, deviations between the underlying schedules and the random draws do not exaggerate the result.

simulation and its formulation can be found in Section D of the Integration of Renewable Resources: Technical Appendix for California ISO Renewable Integration Studies[12]

Q. What model was used in the production simulation?

A. The Step 2 underlying model is a Plexos Solutions representation of the WECC Transmission Expansion Planning Policy Committee (TEPPC) model version PC0 dated March 21, 2011.

Q. Was this TEPPC PC0 model modified in any way to support these studies?

A. Yes, the California portion of the model had to be reconciled and modified to comply with the assumptions for the renewable scenarios described in the December 3, 2010 scoping memo.

Q. What specific modifications to the TEPPC model were made to comply with the scoping memo?

A. The load pattern in California was modified to reflect assumptions in the scoping memo including accounting for energy efficiency and demand response. Supply resources and patterns were modified to reflect the renewable resource build out as well as planned retirement additions specified in scoping memo including expected retirements of once through cooled (OTC) resources. The maximum import capability into California was modified to reflect expected condition. The natural gas prices in California were modified to reflect Market Price Referent (MPR) method specified in the CPUC scoping memo. The natural gas prices used in California can be found on slide 42 of Exhibit 1. CO2 price assumptions were used. The details of these changes can be found at slides 32-43 of Exhibit 1.

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[12] http://www.caiso.com/282d/282d85c9391b0.pdf

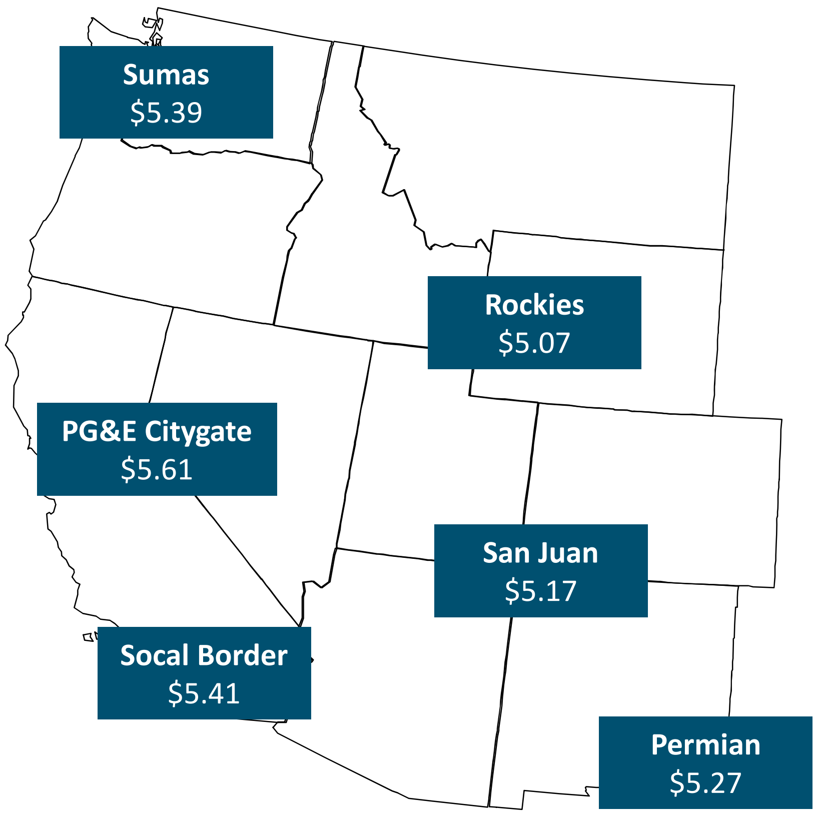
Q. **Were there any other modification made to the model that were not specified in the CPUC LTPP scoping memo?**

A. Yes. The allocation of regulation and load following reserves were distributed between ISO and municipal load. Generator operating characteristics, profiles and outage profiles were updated to reflect ISOs operational experience. Southern California Import Transmission (SCIT) and Path 26 interface limits were modified. Gas prices outside of California were updated to utilize a similar methodology used to develop the California gas prices. Coal resource assumptions, including planned retirements outside of California, were updated to reflect publicly available information about planned retirements. Details of these changes can be found at Slides 45-55 of Exhibit 1.

Q. **Do you have any more detail regarding how the gas prices outside of California were developed?**

A. Yes, the ISO found it necessary to extend the MPR methodology to develop natural gas prices for generators located outside of California. While the TEPPC PC0 case does have pre-loaded fuel prices for all generators, it was important to ensure that the natural gas prices used outside of California were consistent with those used inside of California in order to avoid introducing bias into the model's dispatch calculations. E3 assisted the ISO in developing these natural gas prices by obtaining basis spread prices from the New York Mercantile Exchange (NYMEX) for pricing points outside of California that are contemporaneous with the Henry Hub natural gas prices and basis spread prices used for California pricing points. The basis spread prices represent locational price differences between Henry Hub, Louisiana (the delivery location for the benchmark NYMEX natural gas futures contracts) and local market pricing points throughout the West: Sumas, Permian, San Juan, and Rockies. These basis spread prices are established through bilateral trading of basis "swaps," which are then cleared through the NYMEX Clearport clearing system. Figure 10, below, shows the wholesale natural gas prices derived using this methodology.

Figure 10: 2020 Average Wholesale Natural Gas Prices for Major Western Pricing Points (2010 Dollars per MMBtu, based on a Henry Hub price of $5.61/MMBtu)



E3 then applied the natural gas delivery charges from the TEPPC PC0 case, with two modifications to better reflect actual market conditions: (1) eliminated the TEPPC delivery charge for natural gas in British Columbia, and (2) established SoCal Border instead of Permian as the reference pricing point for Arizona. The table below shows the delivery charges applied in 2020.

Table 5: Natural Gas Delivery Charges in 2020 (2010 $/MMBtu)

Generator Location	Natural Gas Hub	Natural Gas Delivery Point	Delivery Charge (2010 $/MMBtu)
AESO	Rockies	AECO_C	-
APS	SoCal Border	Arizona	0.303
AVA	Sumas	Pacific_NW	0.094
BCTC	Sumas	Sumas	-
BPA	Sumas	Pacific_NW	0.094
CFE	SoCal Border	Baja	-
EPE	San Juan	San_Juan	-
IID	SoCal Border	SoCal_BurnerTip	0. 438
LDWP	SoCal Border	SoCal_Border	-
LDWP	SoCal Border	SoCal_BurnerTip	0.438
NEVP	SoCal Border	SoCal_Border	-
NWMT	Rockies	Idaho_Mont	0.512
PACE_UT	Rockies	Utah	0.271
PACW	Sumas	Pacific_NW	0.094
PG&E_BAY	PG&E Citygate	PGE_Citygate BB	0.069
PG&E_BAY	PG&E Citygate	PGE_Citygate LT	0.230
PG&E_VLY	SoCal Border	Kern_River	0.359
PG&E_VLY	PG&E Citygate	PGE_Citygate BB	0.069
PG&E_VLY	PG&E Citygate	PGE_Citygate LT	0.230
PG&E_VLY	SoCal Border	SoCal_BurnerTip	0.359
PGN	Sumas	Pacific_NW	0.094
PNM	San Juan	San_Juan	-
PSC	Rockies	Colorado	0.553
PSE	Sumas	Pacific_NW	0.094
SCE	SoCal Border	SoCal_BurnerTip	0.438
SDGE	SoCal Border	Baja	-
SDGE	SoCal Border	SoCal_BurnerTip	0.438
SMUD	PG&E Citygate	PGE_Citygate BB	0.069
SMUD	PG&E Citygate	PGE_Citygate LT	0.230
SPP	PG&E Citygate	Sierra_Pacific	0.167
SRP	SoCal Border	Arizona	0.303
TEP	SoCal Border	Arizona	0.303
TIDC	PG&E Citygate	PGE_Citygate LT	0.281
TREAS VLY	Rockies	Idaho_Mont	0.512
UT S	Rockies	Utah	0.271
WACM	Rockies	Wyoming	0.553
WALC	SoCal Border	SoCal_Border	-

In addition to the delivery charges, electric generators must pay state or local taxes in some areas. The following table lists these additional charges applied for the ISO's Step 2 analysis.

Table 6: Additional Natural Gas Costs (2010 $/MMBtu)

Natural Gas Delivery Point	Charge	Description
Arizona	5.6%	State excise tax
SoCal_BurnerTip	1.5%	Municipal Surcharge
PGE_Citygate BB	0.9%	Municipal Surcharge
PGE_Citygate LT	0.9%	Municipal Surcharge

The Natural Gas Prices in 2020 (2010 $/MMBtu) for locations external to California locations can be found on slide 52 of Exhibit 1.

Q. **Were there any other modifications made to the model after the presentation of the preliminary results at the workshop May 10, 2011?**

A. Yes. As I have previously described, certain proposed changes to the model were the basis for the ISO and IOU motion for extension of time to submit testimony and were described in the May 31, 2011 ALJ ruling. Details of these changes are presented in Slides 77-80 of Exhibit 1.

Q. **Were there any production simulation methodology improvements incorporated into running these scenarios?**

A. Yes. Based on what the ISO learned from running the 2009 vintage scenarios, the ISO worked with Plexos to develop improvements to the production simulation methodology to enhance performance. These improvements are presented in Slides 67-75 of Exhibit 1.

Q. **How was the production simulation run used to produce results?**

A. The production simulation was conducted for an 8760 hour/year long run using hourly time step intervals. The production simulation was first run to determine any shortfalls and incremental resource needs to resolve identified shortfalls. This run is referred to as the "need" run. For this "need" run, monthly maximum requirements for regulation and load following were used for each hour to ensure that the fleet had sufficient capability to meet a wide range of expected conditions for each month. After the "need" run was completed, a second production simulation run was performed to determine production costs, annual fuel burn, emissions and capacity factors. This second run is referred to as a "cost" run. For the "cost" run, the hourly regulation and load following requirements were used to better reflect the expected knowledge of requirements based on operational conditions.

Q. What was the ISO's involvement in Step 3?

A. The ISO provided the production simulation results to E3, who was consulting for the IOUs to perform the Step 3 metrics. The ISO did not independently perform or review the Step 3 metric analysis. As a working group member, E3 also performed reconciliation of the model and the resource planning assumptions, as well as developing the gas prices described above in my testimony. Because E3 produced its work product as part of the working group, the ISO had an opportunity to review the results and verify the reasonableness of the data before adopting it into the ISO's studies.

Q. Was the same load profile and distribution methodology used for the four priority scenarios?

A. Yes. For the peak demand calculation, Nexant consulted with ED staff and developed load profiles, based on the Statewide Net Peak Demand (70,964 MW) from Form 1.4[13] of the CEC's 2009 IEPR. Exhibit 3 attached to my testimony sets forth the load profile energy and demand assumptions and adjustments made to the Form 1.4 peak quantities:

[13] Form 1.4, Second Edition, http://www.energy.ca.gov/2009publications/CEC-200-2009-012/adopted_forecast_forms/Chap1Stateforms-Adopted-09.xls
Statewide Revised Demand Forecast Forms

- 1,131 MW of upward adjustment were made to account for behind the meter PV that was modeled as supply.
- 7005MW of downward adjustment was made to account for incremental energy efficiency.
- 1008MW of downward adjustment were made to account for behind the meter CHP.
- 327MW of downward adjustment was made to account for demand side programs.

Q. How was the load distributed in the model?

A. For the four priority scenarios, the load (hourly demand) was distributed on a pro-rata basis to the eight bubbles using allocation factors based, in part, on the energy data set forth on Exhibit 4 to this testimony. Exhibit 4 contains a set of data developed by the CEC which contains annual peak energy and demand data for each of the eight bubbles modeled in California. The peak energy values for each bubble were used after an adjustment for the customer side PV energy to calculate allocation factors for each of the eight bubbles used in the production simulation analysis. These allocation factors were then used to allocate the hourly California demand to the eight bubbles modeled. The customer side PV energy adjustment was made by allocating 52% of the total customer side PV energy to the Northern California bubbles and 48% to the Southern California bubbles based upon CEC historical data.

Q. Was the same load profile and distribution methodology used for the All Gas scenario?

A. No. For the All Gas scenario, the non-coincident peak demand for each bubble from Form 1.5b[14] was used. The total state wide, non-coincident peak demand in Form 1.5b is 70,799 MW. The load was adjusted to account for energy efficiency, CHP, demand response and customer side PV, using the same adjustments contained in Exhibit 3. Using this approach for the All Gas scenario resulted in a slightly lower total statewide load of 166MW versus the total load in the four CPUC priority scenarios discussed in the previous question.

Q. How was the Helms Pumps storage facility modeled?

A. The model contains the following assumptions about the Helms pumps:

- There are three pumps that can operate simultaneously from January to May and from October to December. There will be only one pump available for the rest of year 2020.

- PG&E provided the following pump and usage targets. The storage should reach reservoir maximum volume at the end of May.

Pump/Usage Target	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Pump (GWh)				30.2	29.9							
Usage (GWh)						13.5	18.0	18.0	10.6			

- Based on that, the monthly initial and end storage volumes are set as follows:

Reservoir Storage	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Initial Volume (GWh)	120	120	120	124	154	184	171	153	135	124	120	120
End Volume (GWh)	120	120	124	154	184	171	153	135	124	120	120	120

[14] Form 1.5b, Second Edition, http://www.energy.ca.gov/2009publications/CEC-200-2009-012/adopted_forecast_forms/Chap1Stateforms-Adopted-09.xls

Q. What was the basis for restricting Helms pumps in the scenarios?

A. Based on ISO transmission planning studies and planned transmission upgrades for 2020, the ISO determined that the Helms pumping window would be restricted to one pump due to the load level in the Fresno area.

IV. STUDY RESULTS

Q. Please describe the 33% integration study results for the four priority scenarios.

A. No upward incremental shortfalls were identified for the four priority scenarios, and, thus, no incremental needs of resources beyond capacity already planned were identified in any of these scenarios. However, the results show 506MW and 539MW shortfalls in downward load-following capacity in the Trajectory and Environmentally Constrained scenarios, respectively. No downward load-following shortfalls were observed in the Cost and Time Constrained scenarios. No regulation shortfalls were observed in any of the four priority scenarios. Slides 10 and 11 of Exhibit 1 provide additional details about these observations.

Q. Do you anticipate any resource needs resulting from the observed shortfalls in downward load following capacity?

A. No, not necessarily for these particular scenarios. Based on the magnitude and frequency of the observed shortfalls, storage or curtailment opportunities should be considered in lieu of additional capacity.

Q. Were any shortfalls or needs identified in the All Gas or Trajectory High Load scenarios that the ISO ran?

A. Yes. We observed 1400MW capacity need in the All Gas scenario and 4600MW capacity need in the High Load Trajectory scenario to resolve shortfalls in upward ancillary service and load following. No downward load following shortfall was observed in the All Gas. Downward load following shortfalls up to 856MW were observed in the Trajectory High Load scenario. Slides 10 and 11 of Exhibit 1 contain additional details about these observations.

Q. Can you explain why shortfalls are observed in the All Gas scenario and Trajectory High Load scenarios?

A. In the All Gas scenario, all new renewable resources were removed (except for 1750MW of customer side solar) while no additional resources were added from the base scenario. Due to the removal of such capacity, the flexible fleet capacity is being used to meet the load and does not remain available to meet the load following and regulation upward requirements. What this indicates is that qualified capacity in excess of the planning reserve margin in the four priority scenarios provides sufficient unloaded flexible capacity to meet the load following and regulation needs while the renewable resource capacity is meeting the load. In the All Gas scenario the planning reserve margin is significantly reduced while still maintaining the required planning reserve margin. In the Trajectory High Load scenario, the load was increased by 10% over Trajectory Base Load scenario. At these high load levels the flexible fleet capacity needs to produce energy to meet the load during higher load periods. As a result, remaining flexible capacity is insufficient to simultaneously meet the load following requirements.

Q. Can you conclude from the four priority scenarios that no needs above planning reserve margin exist to meet renewable integration?

A. No. The four priority scenarios reflect scenarios with resource capacity in excess of the required planning reserve margin (PRM) of 15%-17%. Table 7 and Figure 11, below, show the planning reserve margin of the different scenarios as calculated by E3. As a result, the excess capacity above PRM provides sufficient flexible capacity to meet the simultaneous energy, operating reserve, regulation and load following requirements of these four scenarios. However, we cannot conclude from these results whether sufficient flexible capability would exist to meet the simultaneous energy, operating reserve, regulation and load following requirements if the available generation capacity was not in excess of the 15-17% PRM. For example, if the utilities contract for less import qualifying capacity, just meeting their PRM of 117%, the ISO may need to dispatch the capacity that is currently unloaded and providing flexibility services in these cases, and therefore may be short the needed flexible capacity. The four priority scenarios were not analyzed assuming the PRM would just be met but not exceeded.

Table 7: Planning Reserve Margin Calculated by E3

	Trajectory-Base Load	Environmentally Constrained	Cost Constrained	Time Constrained	All Gas	Trajectory-High Load
Planning Reserve Margin	51%	46%	46%	46%	39%	35%

Figure 11: Planning Reserve Margin

Q. Do the results of the Trajectory High Load scenario reflect a realistic bookend?

A. Not necessarily. As stated in the scoping memo, while the Trajectory High Load scenario may be more reflective of any combination of future uncertainties, such as increased load growth or programmatic performance, the scenario also does not account for the possible local capacity resources that may be needed due to retiring OTC resources and therefore may reflect an overly conservative supply scenario. Once the ISO's OTC studies are completed, it may be appropriate to consider repowering or scenarios that consider local capacity resources to assess what if any needs may exist in a higher load scenario.

Q. How did the total WECC-wide production cost compare among the scenarios?

A. The total production cost of the four priority scenarios are all within 0.3% of each other, with WECC wide production costs ranging from $18.85 billion for Environmentally Constrained scenario to $18.89 billion for the Cost Constrained scenario. The production costs to meet WECC load in the All Gas scenario were $ 20.79 billion. The production costs to meet WECC load in the Trajectory High Load scenario were $19.63 billion. This information can be found on Slide 14 of Exhibit 1.

Q. How did the production costs to meet California load compare among the scenarios?

A. The total production costs to meet the California load of the four priority scenarios were within 4% of each other. The Time Constrained scenario had the highest costs to meet California load ($7.45 billion), while the Environmentally Constrained scenario had the lowest cost to meet California load ($7.17 billion). The production costs to meet California load in the All Gas scenario were $8.37 billion. The production costs to meet California load in the Trajectory High Load scenario were $8.07 billion. This information can be found on Slide 18 of Exhibit 1.

Q. **How did the total WECC-wide fuel usage compare among the scenarios?**

A. The total WECC fuel usage for the four priority scenarios ranged from 5.366 billion MMBtu in the Time Constrained scenario to 5.375 billion MMBtu in the Environmentally Constrained scenario. The total WECC fuel usage in the All Gas scenario was 5.810billion MMBtu. The total WECC emission in the Trajectory High Load scenario was 5.544billion MMBtu. This information can be found on Slide 19 of Exhibit 1.

Q. **How did the California fuel usage compare among the scenarios?**

A. The total California fuel usage for the four priority scenarios ranged from 1.326 billion MMBtu in the Environmentally Constrained scenario to 1.341 billion MMBtu in the Time Constrained scenario. The total California fuel usage in the All Gas scenario was 1.417 billion MMBtu. The total WECC emission in the Trajectory High Load scenario was 1.437billion MMBtu. This information can be found on Slide 20 of Exhibit 1.

Q. **How did the total WECC-wide emissions compare among the scenarios?**

A. The total WECC emissions for the four priority scenarios ranged from 364,684 million metric tons at a cost of $13.238 billion in the Time Constrained scenario to 366,059 million metric tons at a cost of $13.287 billion in the Environmentally Constrained scenario. The total WECC emission in the All Gas scenario was 398,089 million metric tons at a cost of $14.450 billion. The total WECC emission in the Trajectory High Load scenario was 377,070 at a cost of $13.687 billion. This information can be found on Slides 21 and 22 of Exhibit 1.

Q. **How did the emissions attributable to meet California load compare among the scenarios?**

A. The Environmentally Constrained scenario reflects the lowest emissions of 76,101 million metric tons while the Time Constrained scenario had the highest among the four priority scenarios of 80,987 million metric tons. The Trajectory High Load scenario had 85,822 million metric tons attributable to meet California load. The all gas scenario has a 92,299 million metric tons meet California load. This information can be found on Slide 24 of Exhibit 1.

Q. How did the California net import compare between the scenarios?

A. The maximum imports between the four priority scenarios had similar maximum California net import of approximately 12,000MW. The Cost and Time Constrained scenarios had the highest average net imports due the higher imports renewable capacity. Slide 17 of Exhibit 1 provides a comparison of California average net import for the different scenarios.

Q. Did the Step 2 results provide any insight into start-ups and capacity factors of the fleet?

A. A higher average number of annual starts on California gas turbines of approximately 80-100 starts/year are observed versus 40-55 starts/year observed for the WECC. A lower average number of starts on California combined cycle resources of 40 starts/year versus 70-80 starts/year observed for the WECC. The capacity factor of WECC coal resources is approximately 60% in the scenarios. The capacity factor for combined cycle resources in California and WECC are both in the range of 40%. The capacity factor for gas turbines in California are approximately 6.4% versus 8% for WECC. Slides 25 and 26 of Exhibit 1 provide a comparison of start-up and capacity factors for California and WECC for the different scenarios.

Q. Were there any sensitivity runs performed assuming Helms could pump with 3 pumps year round?

A. Yes. As I discussed earlier in my testimony, the ISO performed a sensitivity run on the Trajectory Base Load scenario assuming Helms could pump with 3 pumps year round. The total annual production costs to meet California load was reduced by $2.3 million when Helms was not restricted. However, additional scenarios and benefit considerations are needed to fully evaluate the incremental benefit of having greater access to Helms pumping capabilities.

Q. How will these sensitivity results be used by the ISO?

A. These results, plus additional simulations and benefit analyses, will be provided to ISO transmission planning engineers for consideration in the 2011/2012 planning cycle.

V. NEXT STEPS

Q. Will the ISO continue to work on the 33% integration study?

A. Yes. The ISO recognizes that these 33% integration studies are based on a set of planning assumptions that will continue to evolve. The ISO intends to run additional scenarios and sensitivities that are relevant to the ISO's operational responsibilities. For example, as I discussed above, the ISO believes it is operationally relevant to consider a case with local capacity resources needed to meet local reliability needs to offset the retirement of OTC resources, once the ISO completes the OTC studies. In addition, the ISO expects to perform assessments of the resource adequacy fleet to assess whether the capacity and characteristics of the current resource adequacy fleet will be adequate to meet the changing flexibility needs of the system. Importantly, this resource adequacy assessment will consider only the generation under resource adequacy contract in order to capture the potential reality that generation capacity not under a resource adequacy contract will not be available due to lack of sufficient revenues. As the ISO completes these and potentially other operational scenarios, the ISO will make the results available and can provide updates in the next LTPP case.

Q. Does this conclude your testimony?

A. Yes, it does.

Exhibit 1

2010 CPUC LTPP Docket No. R.10-05-006

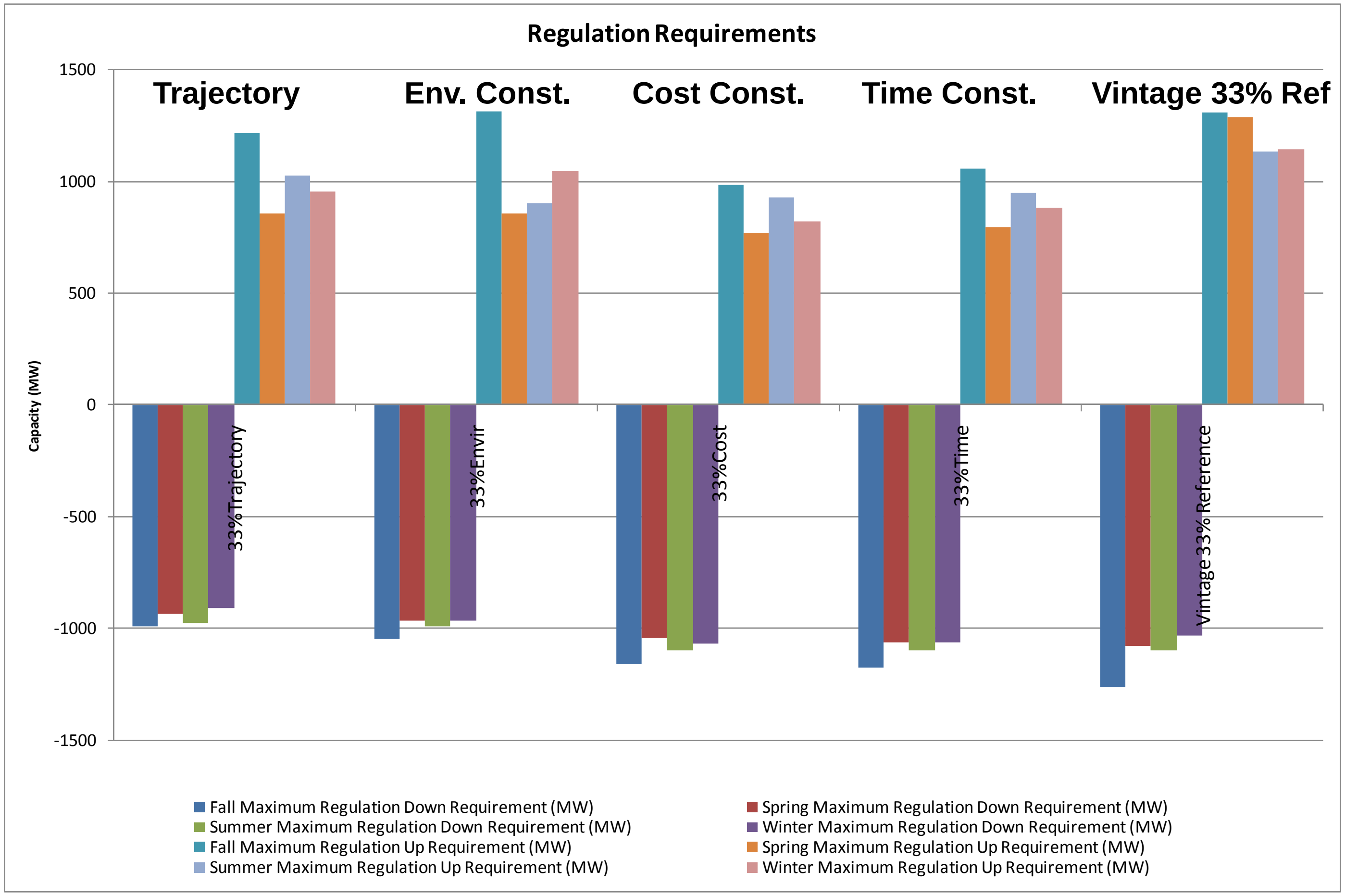
Exhibit 1– 2010 CPUC LTPP Docket No. R.10-05-006

July 1, 2011

Step 1 Operational requirement results

- Regulation and load following requirements determined 2010 CPUC-LTPP scenarios
- New load, wind and solar profiles were developed
- Updated load, wind and solar forecast errors were used to calculated requirements
- Refer to appendix for changes to profile and forecast error
- Load following requirement reduced from vintage cases due to reduced forecast errors
- Regulation requirements increased in some hours due to increase in 5 minute load forecast

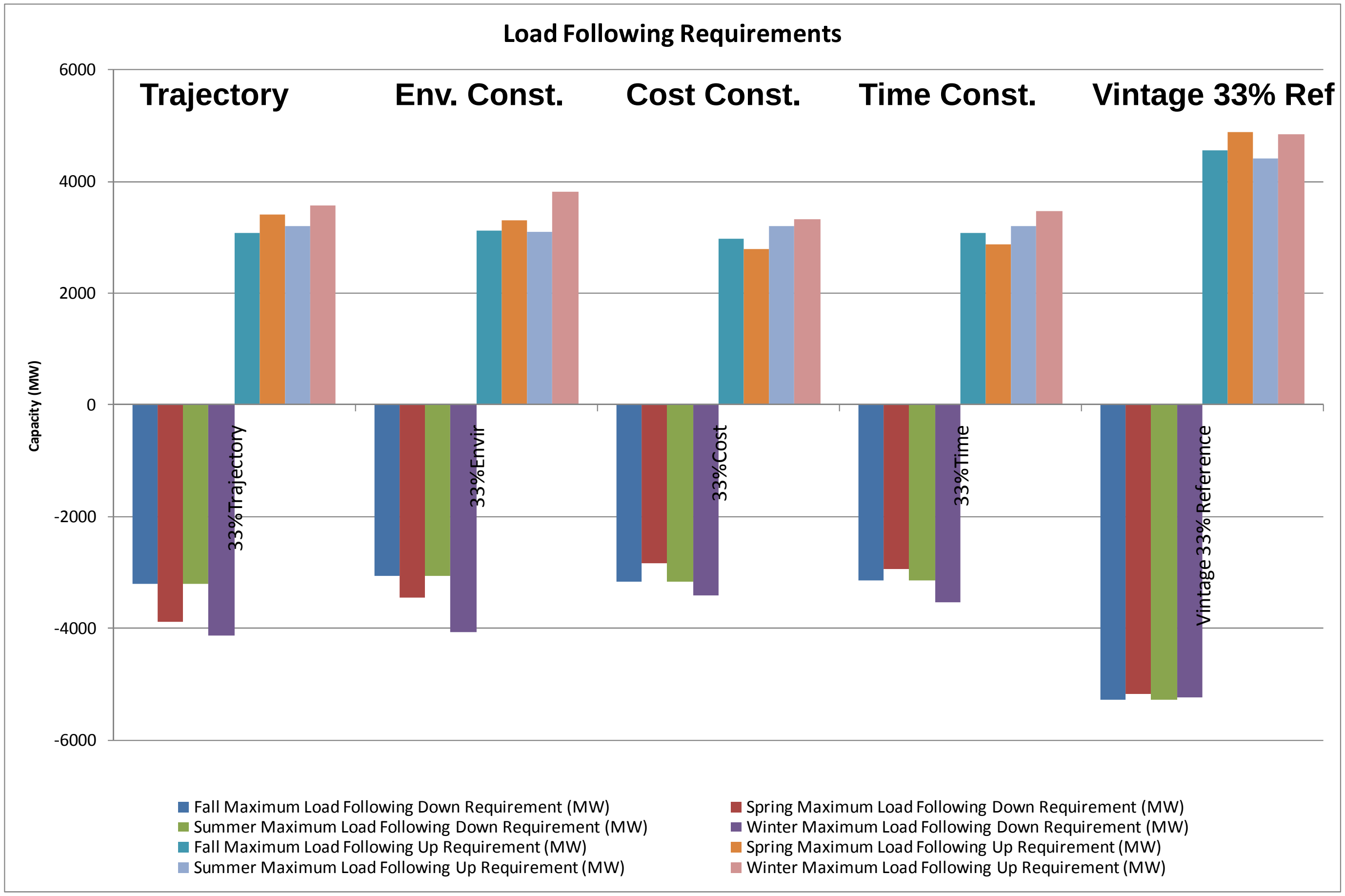
Step 1: Hourly regulation capacity requirements, by scenario



Notes:

- For purposes of comparison, the figures show the single highest hourly seasonal requirement from Step 1 for each season (using the 95th percentile)
- The actual cases use the maximum monthly requirement by hour for need determination and hourly value for production cost and emissions
- Discussion of sensitivity in Section 3

Step 1: Hourly load-following capacity requirements, by scenario



Notes:

- For purposes of comparison, the figures show the single highest hourly seasonal requirement from Step 1 for each season (using the 95th percentile)
- The actual cases use the maximum monthly requirement by hour for need determination and hourly value for production cost and emissions
- Discussion of sensitivity in Section 3

Renewable portfolios for 2020: 2010 LTPP Scenarios

Scenario	Region	Biomass/ biogas	Geothermal	Small Hydro	Solar PV	Distributed Solar	Solar Thermal	Wind	Total
Trajectory	CREZ-North CA	3	0	0	900	0	0	1,205	**2,108**
	CREZ-South CA	30	667	0	2,344	0	3,069	3,830	**9,940**
	Out-of-State	34	154	16	340	0	400	4,149	**5,093**
	Non-CREZ	271	0	0	283	1,052	520	0	**2,126**
	Scenario Total	338	821	16	3,867	1,052	3,989	9,184	**19,266**
Environmentally Constrained	CREZ-North CA	25	0	0	1,700	0	0	375	**2,100**
	CREZ-South CA	158	240	0	565	0	922	4,051	**5,935**
	Out-of-State	222	270	132	340	0	400	1,454	**2,818**
	Non-CREZ	399	0	0	50	9,077	150	0	**9,676**
	Scenario Total	804	510	132	2,655	9,077	1,472	5,880	**20,530**
Cost Constrained	CREZ-North CA	0	22	0	900	0	0	378	**1,300**
	CREZ-South CA	60	776	0	599	0	1,129	4,569	**7,133**
	Out-of-State	202	202	14	340	0	400	5,639	**6,798**
	Non-CREZ	399	0	0	50	1,052	150	611	**2,263**
	Scenario Total	661	1,000	14	1,889	1,052	1,679	11,198	**17,493**
Time Constrained	CREZ-North CA	22	0	0	900	0	0	78	**1,000**
	CREZ-South CA	94	0	0	1,593	0	934	4,206	**6,826**
	Out-of-State	177	158	223	340	0	400	7,276	**8,574**
	Non-CREZ	268	0	0	50	2,322	150	611	**3,402**
	Scenario Total	560	158	223	2,883	2,322	1,484	12,171	**19,802**
High Load	CREZ-North CA	3	0	0	900	0	0	1,205	**2,108**
	CREZ-South CA	30	1,591	0	2,502	0	3,069	4,245	**11,437**
	Out-of-State	34	154	16	340	0	400	4,149	**5,093**
	Non-CREZ	271	0	0	283	1,052	520	0	**2,126**
	Scenario Total	338	1,745	16	4,024	1,052	3,989	9,599	**20,763**

Renewable portfolios for 2020: 2010 LTPP Scenarios

Capacity (MW)	33% Trajectory		33% Env Constrained		33% Cost Constrained		33% Time		33% Trajectroy Low		33% Trajectory High		20% Trajectory		2009 Vintage 33%	
	In-State	Out-of-State	In-State	Out-of-State	In-State	Out-of-State	In-State	Out-of-State	In-State	Out-of-State	In-State	Out-of-State	In-State	Out-of-State	In-State	Out-of-State
Biogas	178	0	178	66	168	73	172	73	178	0	178	0	178	0	1409	
Biomass	126	34	404	156	291	129	212	103	126	34	126	34	126	34		
Geothermal	667	154	240	270	797	202	0	158	617	154	1,591	154	113	154	2598	
Hydro	0	16	0	132	0	14	0	223	0	16	0	16	0	16	680	
Large Scale Solar PV	3,527	340	2,315	340	1,549	340	2,543	340	3,147	340	3,684	340	1,509	340	5432	534
Small Scale Solar PV	1,052	0	9,077	0	1,052	0	2,322	0	1,052	0	1,052	0	1,052	0		
Solar Thermal	3,589	400	1,072	400	1,279	400	1,084	400	1,790	400	3,589	400	1,034	400	6902	
Wind	5,034	4,149	4,426	1,454	5,559	5,639	4,895	7,276	4,006	4,149	5,450	4,149	3,877	1,454	11291	3302
Total	14,173	5,093	17,711	2,818	10,696	6,798	11,228	8,574	10,916	5,093	15,670	5,093	7,889	2,398	28312	

Planning Reserve Margin for 2020 Portfolios: 2010 LTPP Scenarios

Note: Planning reserve margin calculated by E3

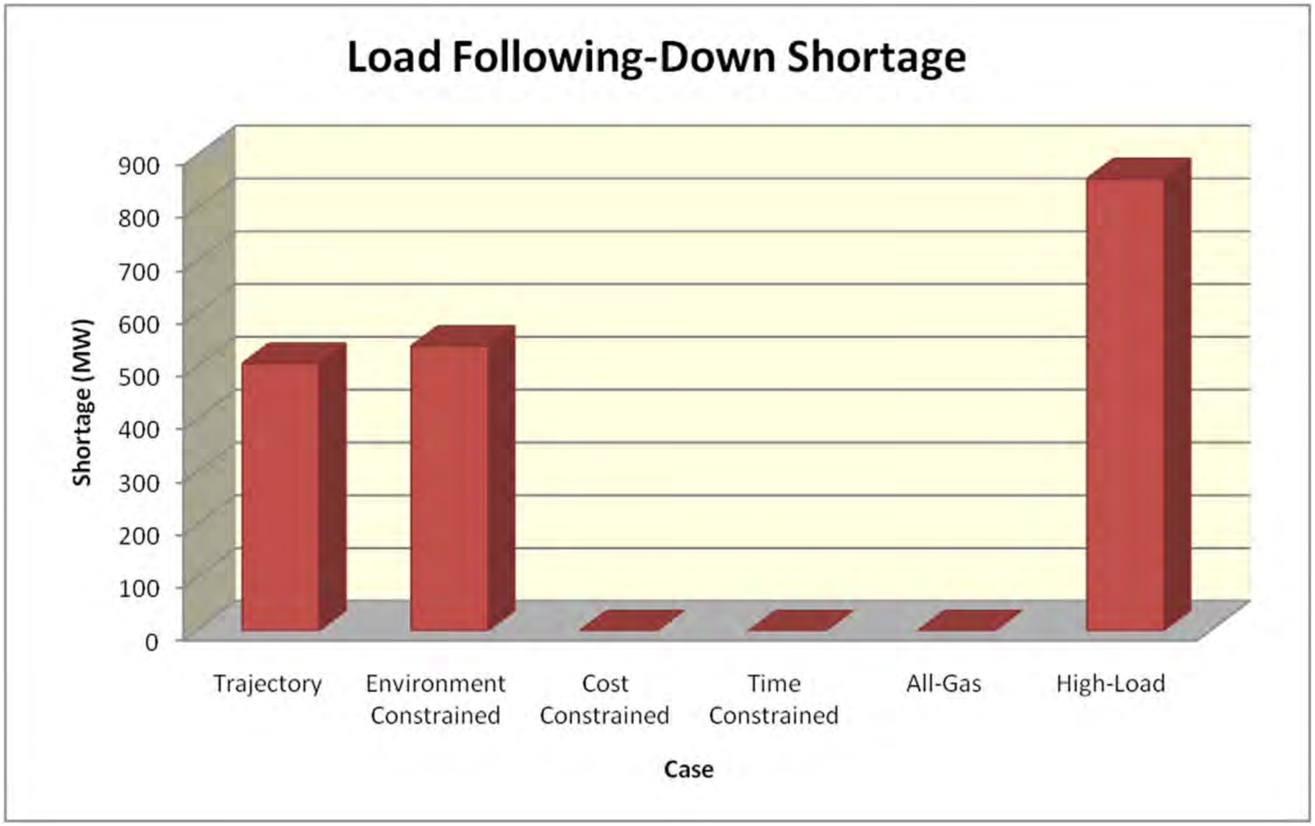
Production simulation results in this section reflect certain assumptions

- Intra-hourly operational needs from Step 1 assume monthly maximum requirements for each hour
  - Regulation, load-following
- Additional resources are added by the model to resolve operational constraints (ramp, ancillary services); this process determines potential need.
- Renewable resources located outside California to serve California RPS will create costs that will be paid for by California load-serving entities – see Step 3 results completed by California IOUs

The analysis adds resources above the defined case resource level to resolve an observed operational violations.

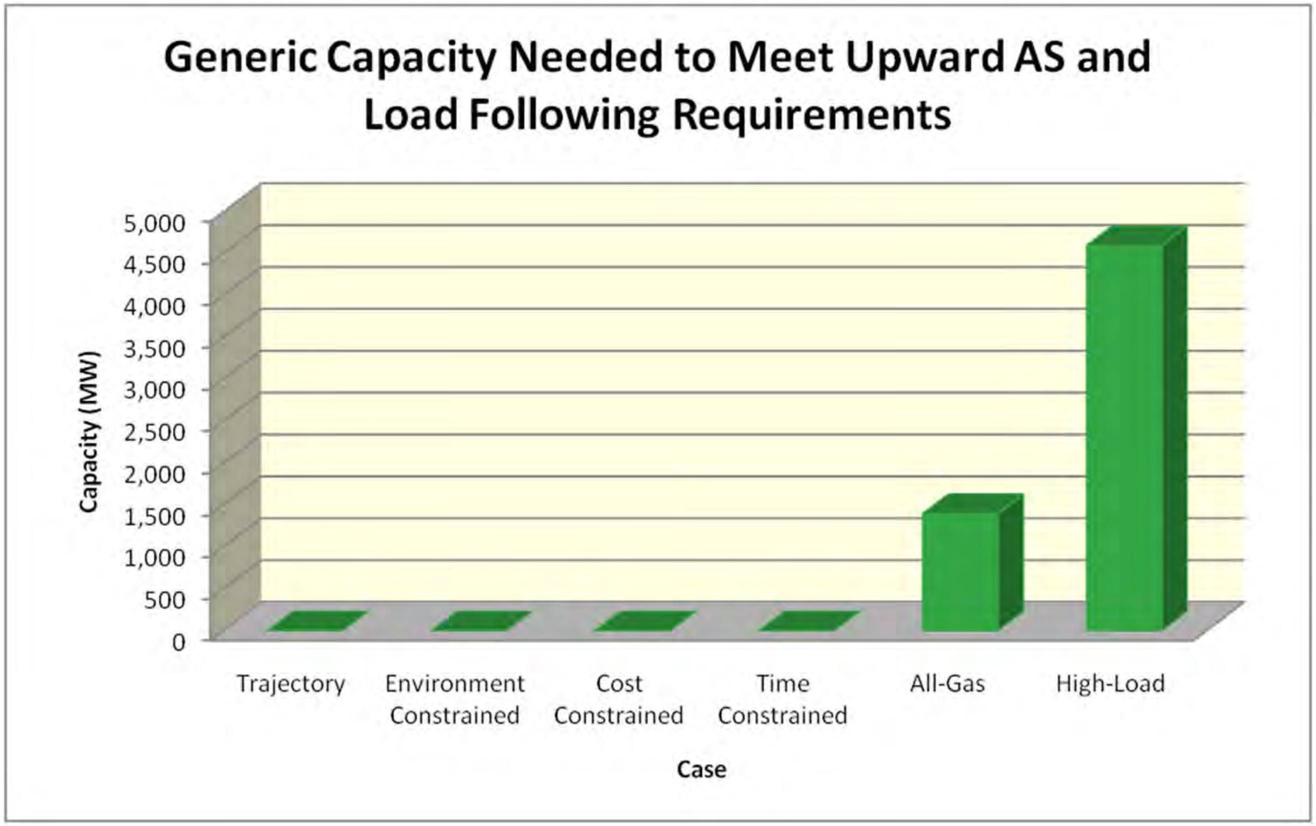
- LTPP analysis did not require adding any generic units to meet PRM because CPUC scoping memo assumptions create a 2020 base dataset that has a significant amount of capacity above PRM
- Next slide shows operational requirement shortages (constraint violations)
- Results for production costs, fuel use and emissions by scenario assume that these resources are added to generation mix

Under CPUC Scoping Memo assumptions, there are some hours with load following down shortages.



Note: No generic capacity is added to meet load following down shortage. Other measures, such as generation curtailment should be able to address this issue

Generic resources are added to meet upward ancillary services and load following requirements in the two additional cases.



Note: There is no upward ancillary service and load following shortage under CPUC Scoping Memo assumptions

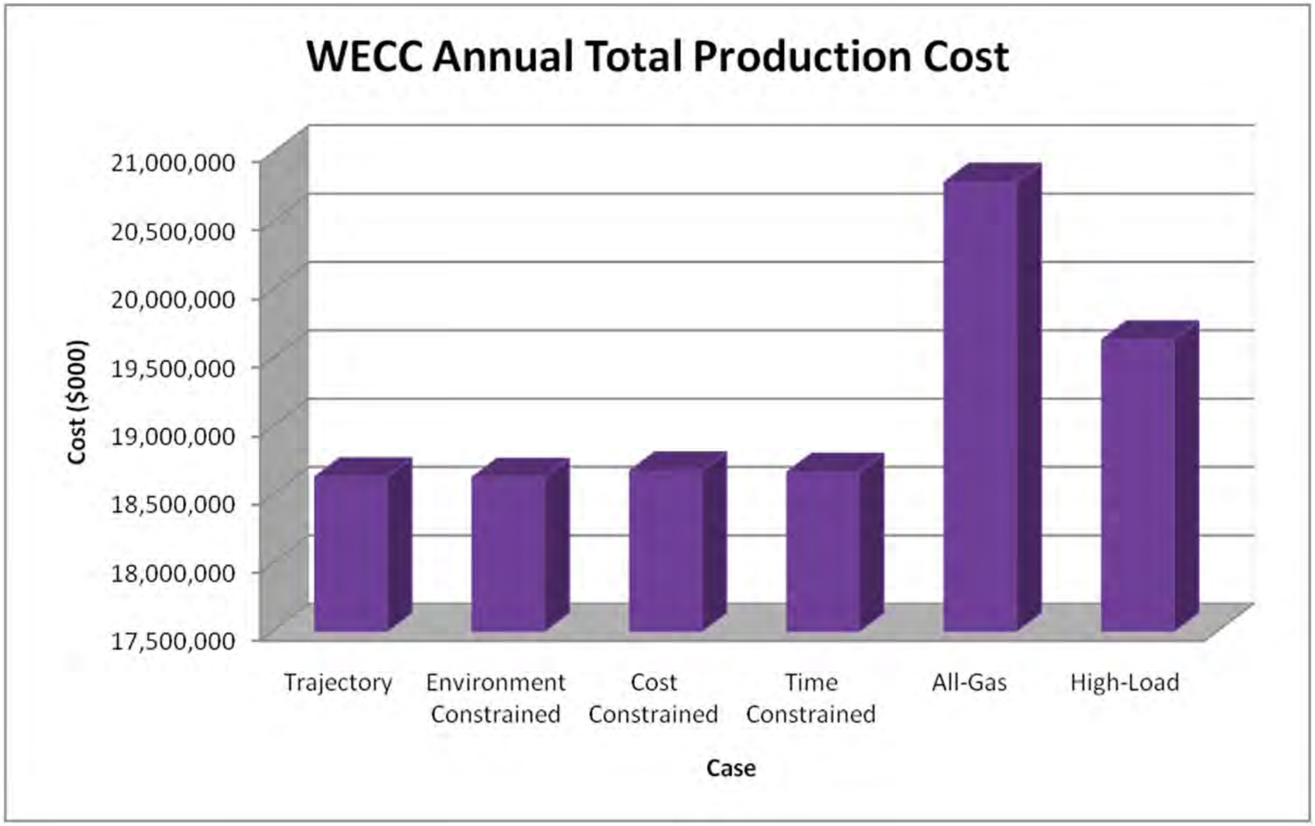
Discussion of results on additional resources

- No upward violations identified in the 2010 Trajectory, Environmental, Cost Constrained and Time Constrained scenarios due to combination of lower loads and reduced requirements
- Limited number of hours and magnitude of load following down violations warrant curtailment or other measures to resolve
- Results are sensitive to assumptions about load level, requirements based on forecast error, mix of resources, and maintenance schedules

Production costs and fuel consumption by scenario

- Production costs based primarily on generator heat rates and assumptions about fuel prices in 2020
- Trends in production costs related to fuel burn and variable O&M (VOM) costs are thus closely related
- Production costs have to be assigned to consuming regions by tracking imports and exports
- Costs associated with emission are tracked separately from fuel and VOM costs

WECC (including California) annual production costs (in 2020 dollars) by case



Notes: production cost includes generation cost and startup cost

Components for calculating California production costs

CA GENERATION COSTS

+

(**CA IMPORTS** – **CA EXPORTS**)

CA IMPORTS

- Dedicated Resources
  - Renewables
    - Firmed
    - Non-Firmed
  - Conventional Resources
    - *i.e.,* Hoover, Palo Verde
- Undesignated (or non-dedicated) Resources
  - Marginal resources in various regions

CA EXPORTS

- Undesignated (or non-dedicated) Resources
  - Marginal resources within CA regions

Calculating total California production costs

+ CA Generation Costs

- Costs to operate CA units (fuel, VOM, start costs)

+ Cost of Imported Power (into CA)

- Dedicated Import Costs
- Undesignated (or non-dedicated) Import Costs
- Out of State renewables (zero production cost)

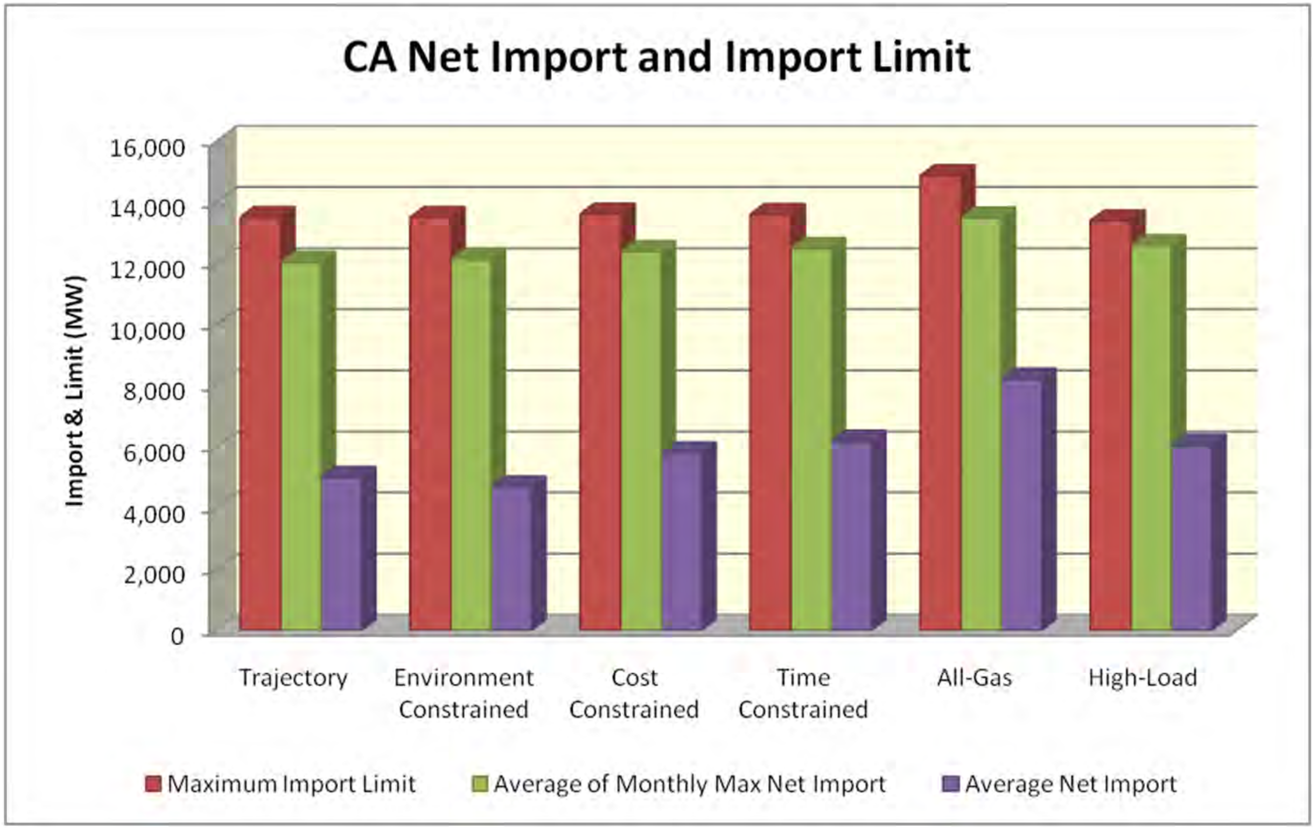
– Cost of Exported Power (out of CA)

- Undesignated (or non-dedicated) Export Costs

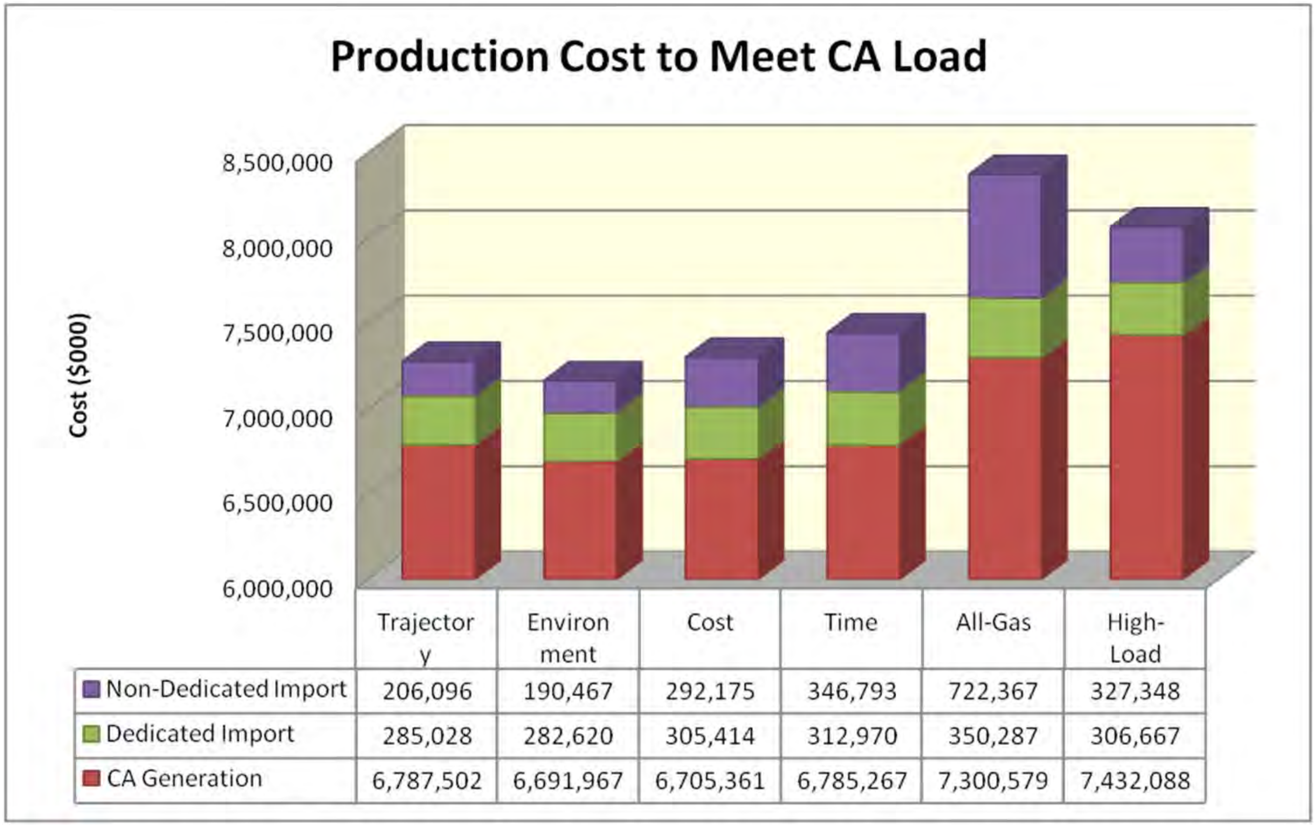
= Total Production Cost of meeting CA load

Note: Dedicated vs. Non-dedicated may also be known as specified or non-specified

California annual net import results by case



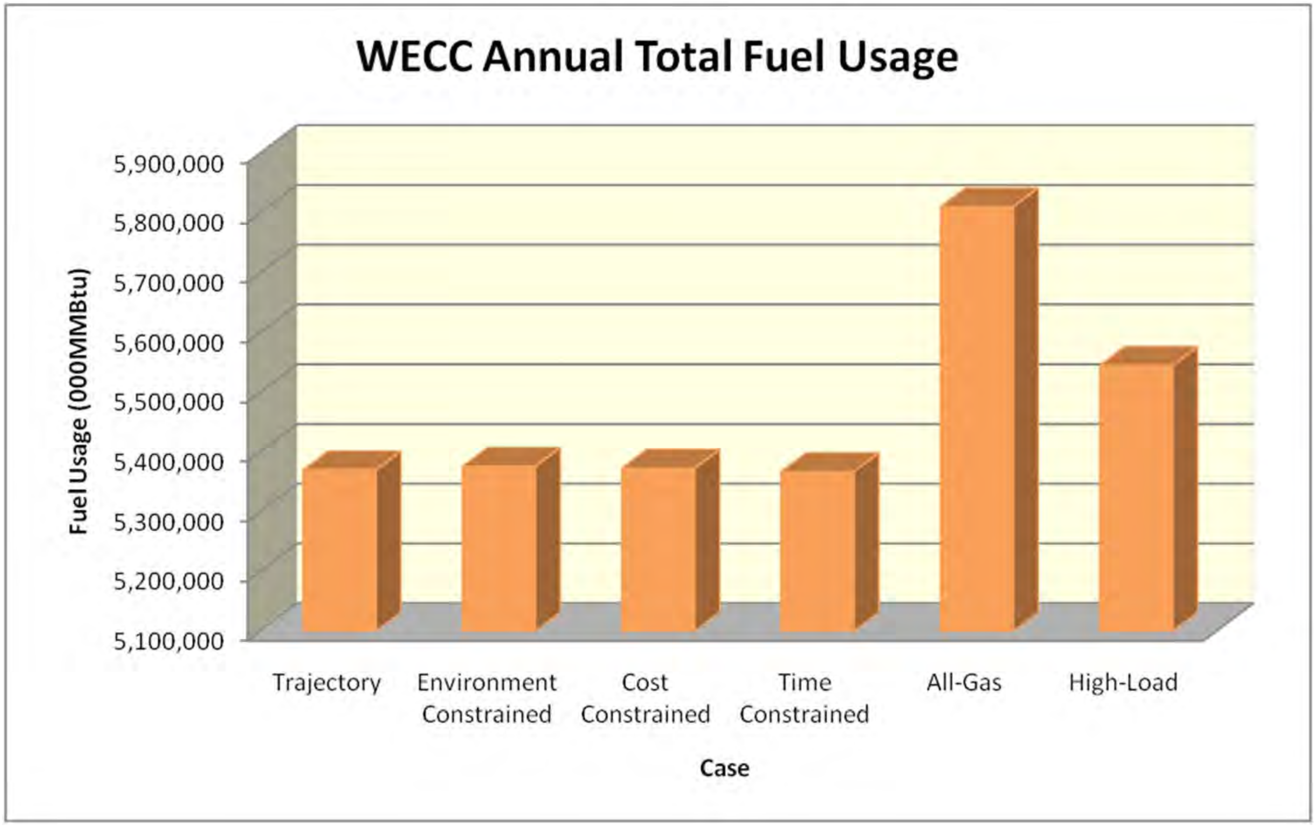
Annual production costs associated with California load (accounting for import/exports), by case



	Trajectory	Environment	Cost	Time	All-Gas	High-Load
Non-Dedicated Import	206,096	190,467	292,175	346,793	722,367	327,348
Dedicated Import	285,028	282,620	305,414	312,970	350,287	306,667
CA Generation	6,787,502	6,691,967	6,705,361	6,785,267	7,300,579	7,432,088

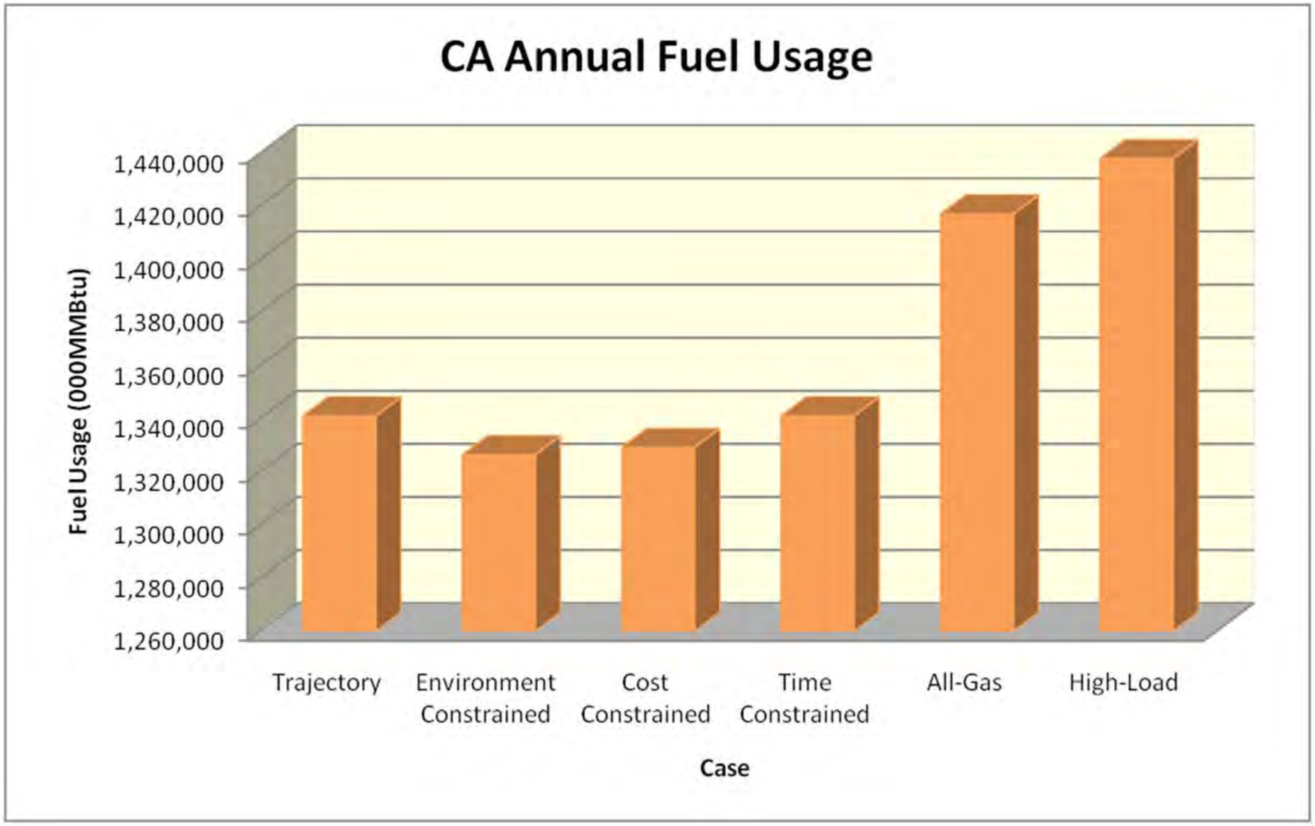
Note: Production cost associated with non-dedicated import is calculated based on the average cost ($/MWh) of each of the regions the energy is imported from; for dedicated import it is based on the actual production cost of each of the dedicated resource and its energy flows into CA

WECC (including California) annual fuel usage (MMBtu), by case



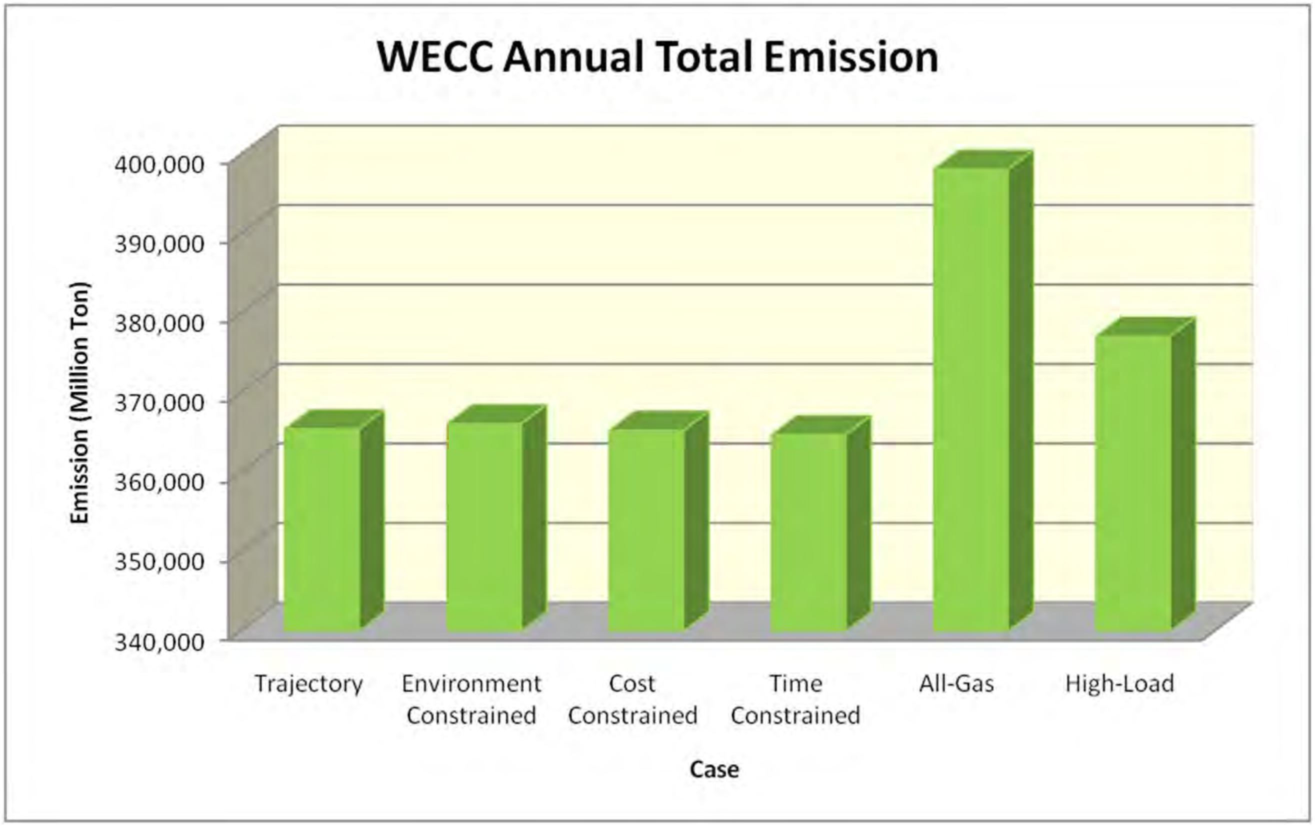
MMBtu = million BTU for conventional/fossil resources

California annual in-state generation fuel usage by case

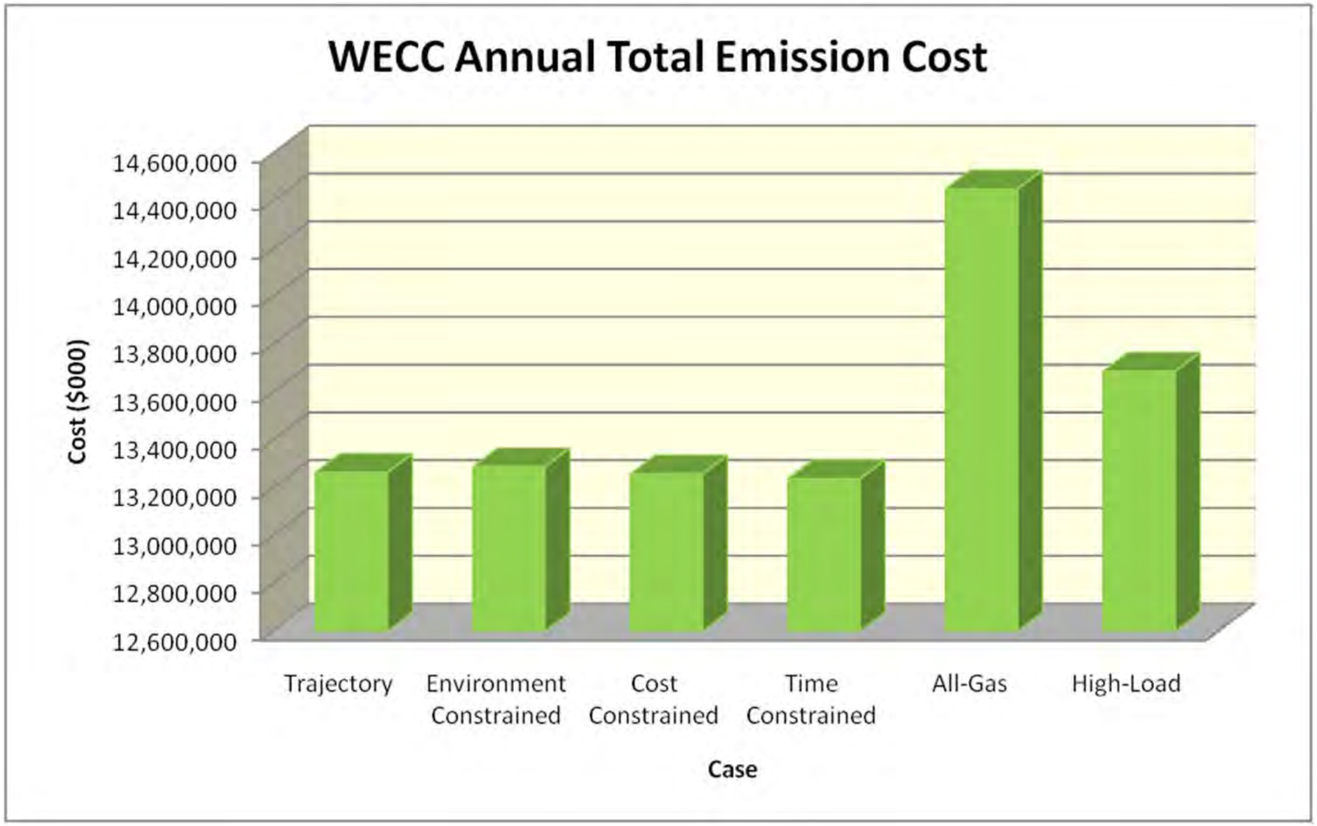


MMBtu = million BTU for conventional/fossil resources

WECC (including California) annual emissions by case



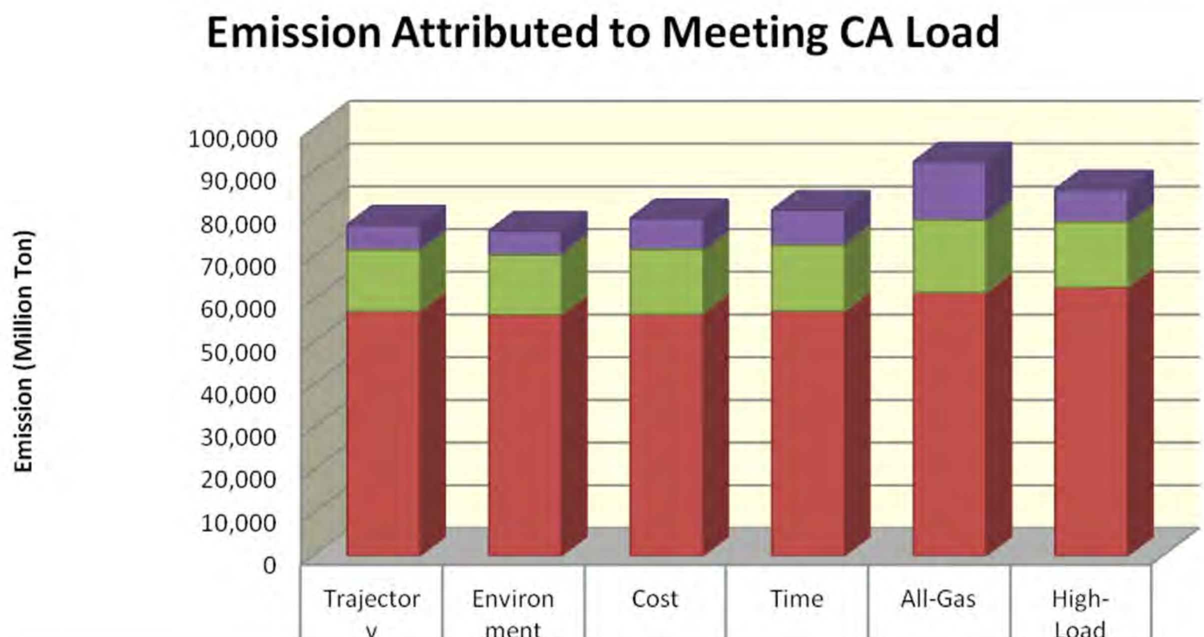
WECC (including California) annual emission costs by case



Calculation of emissions associated with California

- Production simulation modeling output includes GHG emissions (tons) per generator to capture WECC-wide emissions reductions, but:
  - The model solves production simulation for the WECC without considering contractual resources specifically dedicated to meet California load
  - Not all out of state (OOS) RPS energy dedicated to CA may "flow" into CA for every simulated hour as it could in actual operations (thus reducing emissions in CA)
- The emissions benefit of OOS RPS energy dedicated to California is counted towards meeting California load, the study uses an *ex post* emissions accounting method (next slide)

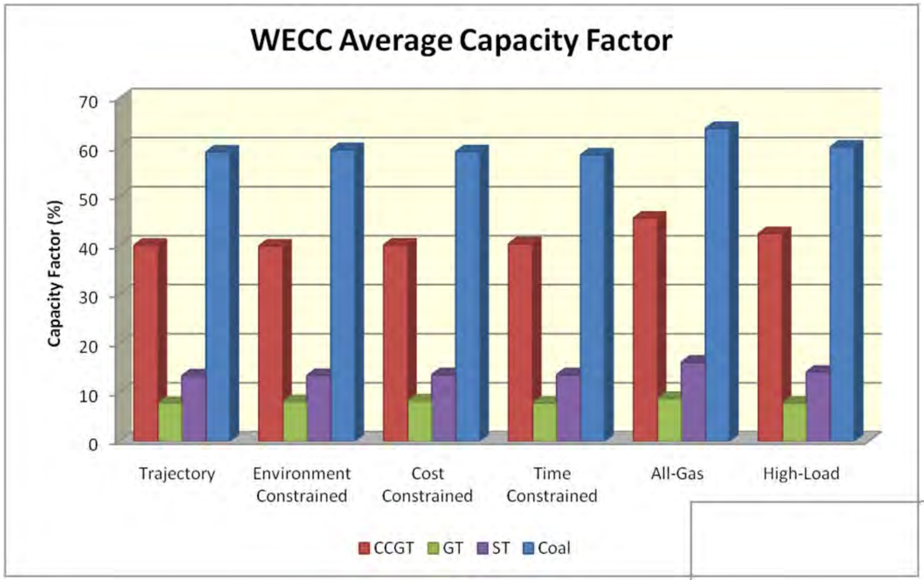
Emissions attributed to meet California load (accounting for Import/Exports), by scenario and emissions source

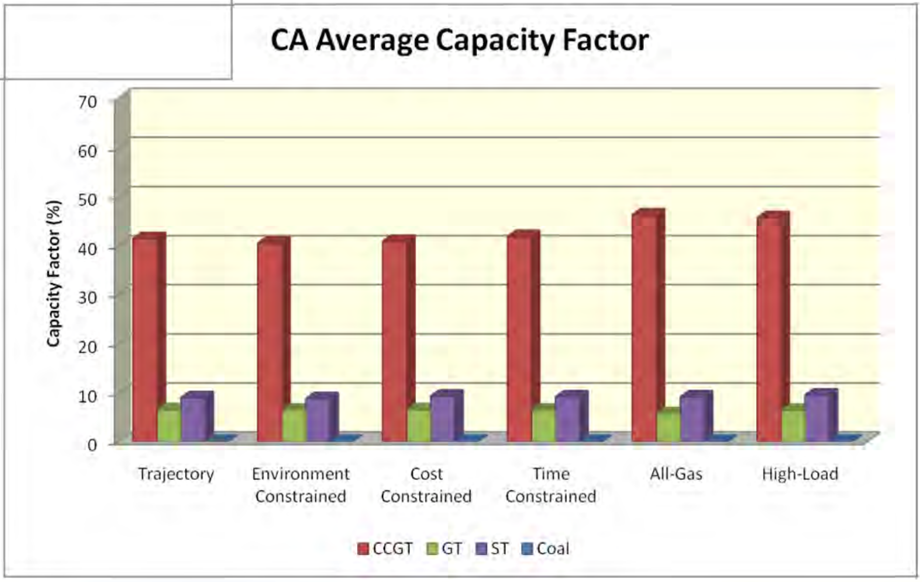


	Trajectory	Environment	Cost	Time	All-Gas	High-Load
Non-Dedicated Import	5,959	5,529	7,273	8,218	13,700	7,666
Dedicated Import	14,293	14,095	15,187	15,461	16,889	15,191
CA Generation	57,322	56,478	56,614	57,309	61,710	62,965

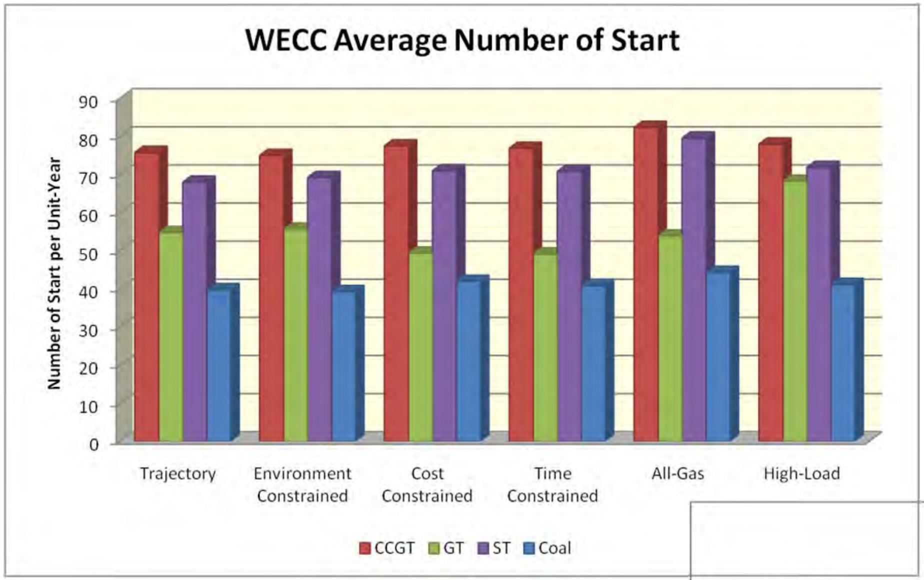
Note: Emissions associated with non-dedicated import is calculated based on the average emission rate (ton/GWh) of each of the regions the energy is imported from; for dedicated import it is based on the actual emission of each of the dedicated resource and its energy flows into CA

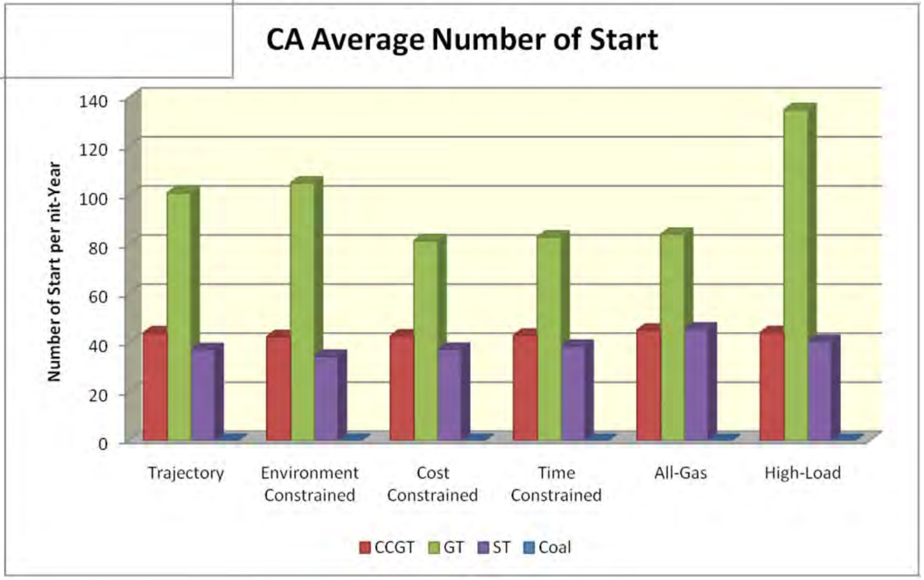
WECC and California annual average capacity factors by case





WECC and California annual average number of startup by case





Comparison of WECC (including CA) and CA results

Case	Trajectory	Environment	Cost	Time	All-Gas	High-Load
Annual Average Capacity Factor (%)						
WECC						
CCGT	39.9	39.8	40.0	40.3	45.5	42.3
GT	7.7	8.1	8.2	7.8	8.7	7.7
ST	13.3	13.4	13.5	13.5	16.1	14.1
Coal	59.0	59.5	59.0	58.4	63.7	60.0
CA						
CCGT	41.3	40.4	40.7	41.7	46.1	45.5
GT	6.4	6.3	6.4	6.3	5.6	6.3
ST	8.9	8.7	9.2	9.1	9.1	9.5
Coal	N/A	N/A	N/A	N/A	N/A	N/A
Number of Start per Unit per Year						
WECC						
CCGT	75.7	74.9	77.4	76.8	82.2	77.9
GT	54.7	55.6	49.3	49.0	53.8	68.1
ST	67.9	69.1	70.9	70.7	79.4	71.8
Coal	39.7	39.2	41.9	40.7	44.2	41.1
CA						
CCGT	43.9	42.3	42.6	42.8	44.9	44.0
GT	100.9	104.9	81.4	82.9	84.0	134.8
ST	37.0	34.2	37.1	38.4	45.5	40.4
Coal	N/A	N/A	N/A	N/A	N/A	N/A

APPENDIX:
PRODUCTION SIMULATION MODEL CHANGES

Overview of Step 2 Database and Modeling

- To conduct the LTPP Step 2 analysis, an up-to-date PLEXOS database was required
- ISO used the 33% operational study PLEXOS database as a starting point
- Input data from this database were changed to align with the assumptions in the CPUC scoping memo
- Non-specified assumptions were updated by the ISO to reflect operational feasibility and to include the best publically available data
- To ensure the April 29th deadline was met, PLEXOS implemented several modeling enhancements to improve simulation efficiency

Key Inputs

- Two sets of key inputs: CPUC specified assumptions and non-specified assumptions updated by the ISO
- Assumptions stated in the CPUC Scoping Memo
  - Load forecast that includes demand side reductions
  - Renewable resource build-out
  - Existing, planned and retiring generation
  - Maximum import capability to California
  - Gas price methodology for California
  - CO_2 price assumption
- Non-specified assumptions updated by the ISO
  - Allocation of reserve requirements between ISO and munis
  - Generator operating characteristics and profiles
  - Operational intertie limits
  - Loads, resources, transmission and fuel prices outside of California

CPUC SPECIFIED ASSUMPTIONS

Load – Load Profiles

- Nexant created a load profile that was consistent with the CPUC's forecasted load for the analysis of the four LTPP scenarios
- Load profile adjustment made to the CPUC specified demand side resources
  - Energy efficiency
  - Demand side CHP
  - Behind-the-meter PV – modeled as supply
  - Non-event based demand response

Generation - CPUC Generation Dataset

- CPUC provided data on existing, planned and retiring generation facilities
- Existing resources specified by the CPUC were drawn from two resources:
  - 2011 Net Qualifying Capacity (NQC) as of August 2^{nd}, 2010
  - ISO master generation list
- Additions and non-OTC retirements are drawn from the ISO OTC scenario analysis tool; other additions are resources with CPUC approved contracts that do not have AFC permits approved
  - Combined cycle resources in CPUC planned additions were modeled with generic unit operating characteristics taken from the MPR
- OTC retirements taken from the State Water Board adopted policy with several CPUC modifications

CPUC Supply Side CHP and DR Specifications

- Existing CHP and DR bundles in the 33% operational study PLEXOS database were scaled to match the incremental supply side CHP and DR goals in the CPUC scoping memo
- 761 MW of incremental supply side CHP was assumed to be online in 2020 with a heat rate of 8,893 Btu/kWh per the CPUC scoping memo
- 4,817 MW of incremental DR was modeled as supply in 2020 (including line losses)
  - Non-event based DR was included in the load profiles and not in the Step 2 database as supply side resource

Load and Resource Balance with CPUC assumptions

- The CPUC Scoping Memo assumptions estimate a 17,513 MW surplus above Planning Reserve Margin in 2020 in the ISO

Load and Resource Balance in the ISO using CPUC Resource Assumptions (MW)

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Load										
ISO Summer Peak Load	49,143	49,902	50,678	51,283	51,913	52,555	53,246	53,905	54,571	55,298
Total Demand Side Reductions	(3,432)	(4,712)	(5,650)	(6,374)	(7,187)	(8,036)	(8,936)	(9,874)	(10,776)	(11,651)
Net ISO Peak Summer Load	45,711	45,190	45,028	44,909	44,726	44,519	44,310	44,031	43,795	43,647
Resources										
Existing Generation	52,435	52,435	52,435	52,435	52,435	52,435	52,435	52,435	52,435	52,435
Retiring Generation	(1,260)	(1,425)	(1,425)	(2,434)	(4,694)	(5,646)	(10,378)	(11,329)	(12,280)	(14,357)
Planned Additions (Thermal, RPS, CHP)	1,747	4,388	6,728	7,336	10,558	11,280	12,207	12,283	13,471	13,547
Net Interchange (Imports - Exports)	16,955	16,955	16,955	16,955	16,955	16,955	16,955	16,955	16,955	16,955
Summary										
Total System Available Generation	69,877	72,353	74,693	74,292	75,254	75,024	71,219	70,344	70,581	68,580
Total System Capacity Requirement (PRM)	53,482	52,872	52,683	52,544	52,329	52,087	51,843	51,516	51,240	51,067
Surplus	**16,395**	**19,480**	**22,010**	**21,748**	**22,924**	**22,936**	**19,376**	**18,827**	**19,340**	**17,513**

Updating Generation Data in 33% Operational Database

- **The generation data in the 33% operational database were updated to reflect the specified existing, planned and retiring facilities in the CPUC scoping memo**
- **ISO also solicited feedback from the working group, stakeholders via ISO market notice and also all parties on the LTPP service list on generator operating characteristics which was incorporated into the Step 2 database**
- **ISO found some discrepancies in the CPUC generation assumptions which it has corrected in its Step 2 database and accounting:**
  - Double-counting of the Ocotillo facility
  - Renewable resource capacity additions above what is chosen in the 33% RPS calculator
  - Double counting of several resources as both imports and resources

Ocotillo/Sentinel Generation

- CPUC scoping memo includes two separate facilities in its planned additions for Ocotillo (455 MW) and Sentinel (850 MW)
- Ocotillo is a subset of the Sentinel facility (units 1-5)
  - SCE signed a contract with Sentinel for an additional three units in 2008
- ISO Step 2 database only includes eight Sentinel units (850 MW) because Ocotillo (455 MW) is already accounted for in Sentinel's nameplate capacity

RPS Resources above 33%

- CPUC included 287 MW of RPS resources in its planned additions that are not included in the 33% RPS scenarios:
  - CalRENEW-1(A) (5 MW)
  - Copper Mountain Solar 1 PseudoTie-pilot (48 MW)
  - Vaca-Dixon Solar Station (2 MW)
  - Blythe Solar 1 Project (21 MW)
  - Calabasas Gas to Energy Facility (14 MW)
  - Chino RT Solar Project (2 MW)
  - Chiquita Canyon Landfill (9 MW)
  - Rialto RT Solar (2 MW)
  - Santa Cruz Landfill G-T-E Facility (1 MW)
  - Sierra Solar Generating Station (9 MW)
  - Celerity I (15 MW)
  - Black Rock Geothermal (159 MW)
- If included, these resources will create RPS scenarios that are above 33% RPS
- These resources were not profiled in the Step 1 analysis
- ISO did not include these resources in the Step 2 database

Existing Generation/Imports Discrepancies

- The 2011 NQC list includes 2,626 MW of resources that are imports to the ISO
  - APEX_2_MIRDYN (505 MW)
  - MRCHNT_2_MELDYN (439 MW)
  - MSQUIT_5_SERDYN (1,182 MW)
  - SUTTER_2_PL1X3 (500 MW)
- The CPUC's original L&R tables counted the capacity of these resources twice:
  1. Directly, as specified resources with NQC capacity
  2. Indirectly, by assuming full transmission capability into the ISO
- For accounting purposes and to avoid double accounting, ISO has removed these resources from the available generation but maintains the assumption of full transmission capability into the ISO
- Modeled Coolwater 3 and 4 instead of assumed retired.

Load and Resource Balance After Assumption Modifications

- Accounting for all of these modifications, the load and resource balance has a surplus of 14,144 MW above PRM in 2020, compared to 17,513 MW above PRM using the CPUC assumptions

Load and Resource Balance in the ISO using CAISO Resource Modifications (MW)

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Load										
Summer Peak Load	49,143	49,902	50,678	51,283	51,913	52,555	53,246	53,905	54,571	55,298
Total Demand Side Reductions	3,432	4,712	5,650	6,374	7,187	8,036	8,936	9,874	10,776	11,651
Net Peak Summer Load	45,711	45,190	45,028	44,909	44,726	44,519	44,310	44,031	43,795	43,647
Resources										
Existing Generation	49,809	49,809	49,809	49,809	49,809	49,809	49,809	49,809	49,809	49,809
Retiring Generation	(1,260)	(1,425)	(1,425)	(2,434)	(4,694)	(5,646)	(10,378)	(11,329)	(12,280)	(14,357)
Planned Additions (Thermal, RPS, CHP)	1,618	4,259	6,440	7,048	9,815	10,537	11,464	11,540	12,728	12,804
Net Interchange (Imports - Exports)	16,955	16,955	16,955	16,955	16,955	16,955	16,955	16,955	16,955	16,955
Summary										
Total System Available Generation	67,122	69,598	71,779	71,378	71,885	71,655	67,850	66,975	67,212	65,211
Total System Capacity Requirement (PRM)	53,482	52,872	52,683	52,544	52,329	52,087	51,843	51,516	51,240	51,067
Surplus Above PRM with CAISO Modifications	13,640	16,726	19,096	18,834	19,556	19,568	16,007	15,459	15,972	14,144
Surplus Above PRM with CPUC Assumptions	16,395	19,480	22,010	21,748	22,924	22,936	19,376	18,827	19,340	17,513
Difference in Surplus between CPUC and CAISO	***2,755***	***2,755***	***2,914***	***2,914***	***3,369***	***3,369***	***3,369***	***3,369***	***3,369***	***3,369***

MPR Gas Forecast Methodology

- CPUC Scoping Memo specifies that the LTPP proceeding use a gas forecast calculated using the same methodology as the Market Price Referent (MPR) using NYMEX data gathered from 7/26/2010 – 8/24/2010
  - MPR methodology provides a transparent framework to derive a forecast of natural gas prices at the utility burner-tip in California
  - In the near term (before 2023), the forecast is based on:
    1. NYMEX contract data for natural gas prices at Henry Hub and basis point differentials between HH and CA
    2. A municipal surcharge, calculated as a percentage of the commodity cost
    3. A gas transportation cost based on the tariffs paid by electric generators

CA Gas Forecast

- 2020 natural gas forecast for CA delivery points (2010$/MMBtu)

Zone	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Gas - PGE_Citygate	$ 5.95	$ 5.92	$ 5.75	$ 5.31	$ 5.29	$ 5.34	$ 5.41	$ 5.45	$ 5.47	$ 5.54	$ 5.79	$ 6.04
Gas - PGE_Citygate_BB	$ 6.07	$ 6.04	$ 5.87	$ 5.43	$ 5.41	$ 5.46	$ 5.53	$ 5.57	$ 5.59	$ 5.66	$ 5.92	$ 6.17
Gas - PGE_Citygate_LT	$ 6.23	$ 6.20	$ 6.03	$ 5.59	$ 5.57	$ 5.62	$ 5.69	$ 5.73	$ 5.75	$ 5.82	$ 6.08	$ 6.33
Gas - SoCal_Border	$ 5.74	$ 5.70	$ 5.54	$ 5.13	$ 5.11	$ 5.16	$ 5.23	$ 5.27	$ 5.29	$ 5.36	$ 5.58	$ 5.83
Gas - SoCal_Burnertip	$ 6.18	$ 6.15	$ 5.98	$ 5.57	$ 5.54	$ 5.60	$ 5.67	$ 5.71	$ 5.72	$ 5.80	$ 6.02	$ 6.28

CO_2 Price

- A \$36.30/short ton of CO_2 (2010\$) cost was used in the PLEXOS simulations per the CPUC scoping memo

NON-SPECIFIED ASSUMPTIONS UPDATED BY ISO

Allocation of Reserves Between ISO and Munis

- Step 1 analysis created statewide load following and regulation requirements
- Step 2 is an ISO-wide analysis that requires an allocator to split the load following and regulation requirements between the IOUs and Munis
- Allocator calculated using two parts:
  - 50% of allocator = ratio of peak load between the ISO (83%) and Munis (17%)
  - 50% of allocator = fraction of wind and solar resources delivered to California that are integrated by the ISO (94%) and Munis (6%)
- This results in the following allocation of the reserve requirements: 88.5% to the ISO and 11.5% to the Munis

Update of Generator Operating Characteristics

- ISO received feedback from 4 stakeholders on information in the 33% operational study PLEXOS database
  - Comprehensive list of changes came from SCE and included updated information on individual generator operating characteristics and SP15 hydro dispatch
  - Calpine submitted a new start profile for CCGTs
- CT planned additions and generic units were mapped to the operating characteristics of an LMS100 or LM6000 depending on plant size

Helms modeling

- PG&E updated the maximum capacity of the Helms reservoir to 184.5 GWh
- PG&E provided end of spring reservoir energy storage target and summer monthly energy usage schedules
- ISO consulted with PG&E to develop the appropriate pumping windows in 2020
  - availability in the summer months, Helms pumping was restricted to 1 pump between May and September
  - 3 pumps were assumed to be available for October through April
- Continued discussions with PG&E suggest that three pump capability in 2020 in non-summer months may not be possible; may warrant additional sensitivities

Transmission Import Limits to CA

- ISO defined simultaneous import limits to CA
- ISO used a model developed by the ISO to estimate the Southern California Import Transmission (SCIT) limit based on
  - planned thermal additions
  - OTC retirements
  - renewable resources additions
  - neighboring transmission path flows into and around the SCIT area

Import Limits by Scenario and Time

Transmission Limits (MW)	Summer Pk	Summer Off Pk	Winter Pk	Winter Off Pk
Trajectory Case				
S. Cal Import Limit to be used for study	12,726	10,290	11,331	8,405
Total California Import Limit	13,526	11,090	12,131	9,205
Environmental Case				
S. Cal Import Limit to be used for study	12,724	10,224	11,349	8,340
Total California Import Limit	13,524	11,024	12,149	9,140
Cost Case				
S. Cal Import Limit to be used for study	12,833	10,186	11,457	8,302
Total California Import Limit	13,633	10,986	12,257	9,102
Time Case				
S. Cal Import Limit to be used for study	12,819	10,224	11,427	8,340
Total California Import Limit	13,619	11,024	12,227	9,140
All-Gas				
S. Cal Import Limit to be used for study	14,086	10,735	12,110	8,851
Total California Import Limit	14,886	11,535	12,910	9,651
High-Load				
S. Cal Import Limit to be used for study	12,610	10,237	11,270	8,352
Total California Import Limit	13,410	11,037	12,070	9,152

Assumptions of Gas Forecast Outside of CA

- The MPR methodology provides a forecast of gas prices for generators inside of California
- In order to avoid skewing the relative competitive position of gas fired generators inside and outside of California, WECC-wide gas prices outside of California must be updated to reflect the same underlying commodity cost of gas embedded in the MPR forecast

Gas Forecast Outside of CA (cont'd)

- Created an MPR-style forecast for gas prices elsewhere in the WECC drawing upon available NYMEX contract data over the same trading period (7/26/10 – 8/24/10):
  - In addition to the California gas hubs (PG&E Citygate and Socal Border), forecast hub prices at Sumas, Permian, San Juan, and Rockies hubs using the NYMEX basis differentials
  - For each bubble (geographic area), add appropriate delivery charges (based on TEPPC delivery charges) to the appropriate hub price to determine the burnertip price
- Two specific changes were made to this methodology based on IOU feedback:
  - Arizona gas hub was moved from Permian to SoCal Border
  - Delivery charge was removed from Sumas hub to British Columbia

Gas Forecast Outside of CA

- 2020 natural gas forecast for delivery points outside of California (2010$/MMBtu)

Zone	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Gas - AECO_C	$ 5.49	$ 5.46	$ 5.29	$ 4.72	$ 4.69	$ 4.75	$ 4.82	$ 4.86	$ 4.88	$ 4.95	$ 5.34	$ 5.59
Gas - Arizona	$ 6.06	$ 6.02	$ 5.85	$ 5.42	$ 5.39	$ 5.45	$ 5.52	$ 5.57	$ 5.58	$ 5.66	$ 5.89	$ 6.16
Gas - Baja	$ 5.74	$ 5.70	$ 5.54	$ 5.13	$ 5.11	$ 5.16	$ 5.23	$ 5.27	$ 5.29	$ 5.36	$ 5.58	$ 5.83
Gas - Colorado	$ 6.08	$ 6.04	$ 5.88	$ 5.42	$ 5.39	$ 5.45	$ 5.52	$ 5.56	$ 5.57	$ 5.65	$ 5.92	$ 6.17
Gas - Idaho_Mont	$ 6.00	$ 5.97	$ 5.81	$ 5.23	$ 5.21	$ 5.26	$ 5.33	$ 5.37	$ 5.39	$ 5.46	$ 5.85	$ 6.10
Gas - Kern_River	$ 5.74	$ 5.70	$ 5.54	$ 5.13	$ 5.11	$ 5.16	$ 5.23	$ 5.27	$ 5.29	$ 5.36	$ 5.58	$ 5.83
Gas - Malin	$ 5.98	$ 5.95	$ 5.79	$ 5.10	$ 5.07	$ 5.13	$ 5.20	$ 5.24	$ 5.26	$ 5.33	$ 5.83	$ 6.08
Gas - Pacific_NW	$ 6.11	$ 6.08	$ 5.91	$ 4.98	$ 4.95	$ 5.01	$ 5.08	$ 5.12	$ 5.14	$ 5.21	$ 5.96	$ 6.21
Gas - Permian	$ 5.58	$ 5.54	$ 5.38	$ 5.01	$ 4.99	$ 5.04	$ 5.11	$ 5.15	$ 5.17	$ 5.24	$ 5.42	$ 5.67
Gas - Rocky_Mntn	$ 5.49	$ 5.46	$ 5.29	$ 4.72	$ 4.69	$ 4.75	$ 4.82	$ 4.86	$ 4.88	$ 4.95	$ 5.34	$ 5.59
Gas - San_Juan	$ 5.52	$ 5.49	$ 5.32	$ 4.86	$ 4.84	$ 4.89	$ 4.96	$ 5.00	$ 5.02	$ 5.09	$ 5.37	$ 5.62
Gas - Sierra_Pacific	$ 6.12	$ 6.08	$ 5.92	$ 5.48	$ 5.46	$ 5.51	$ 5.58	$ 5.62	$ 5.64	$ 5.71	$ 5.96	$ 6.21
Gas - Sumas	$ 6.02	$ 5.98	$ 5.82	$ 4.89	$ 4.86	$ 4.92	$ 4.99	$ 5.03	$ 5.04	$ 5.11	$ 5.86	$ 6.11
Gas - Utah	$ 5.76	$ 5.73	$ 5.56	$ 4.99	$ 4.97	$ 5.02	$ 5.09	$ 5.13	$ 5.15	$ 5.22	$ 5.61	$ 5.86
Gas - Wyoming	$ 6.05	$ 6.01	$ 5.85	$ 5.27	$ 5.25	$ 5.30	$ 5.37	$ 5.41	$ 5.43	$ 5.50	$ 5.89	$ 6.14

TEPPC PC0 Case

- PC0, a recent TEPPC database, was used to populate the PLEXOS database with loads, resources and transmission capacity for zones outside of California
- Embedded in this case were several coal plant retirements
- ISO incorporated several adjustments to this case:
  - Included several additional coal plant retirements that were announced but not included in PC0
  - Excluded the resources assumed to contribute to California's RPS portfolio that are located outside of California

Exclusion of RPS Resources from PC0

- TEPPC's PC0 case includes enough renewables to meet RPS goals in California and the rest of the WECC
  - The portfolio for California is very similar to the Trajectory Case specified for the LTPP, which includes out-of-state renewables
- To develop consistent scenarios for LTPP, the RPS builds for CA in PC0 must be adjusted according to the following framework:

	WECC-Wide RPS Resources in PC0
—	PC0 RPS Resources in CA
—	PC0 OOS RPS Resources Attributed to CA
+	CPUC RPS Portfolio (Traj/Env/Cost/Time)
=	**RPS-Compliant LTPP Scenario**

State	Resource	MW	GWh
New Mexico	Biomass	39	231
Idaho	Geothermal	27	198
Nevada	Geothermal	76	561
Utah	Geothermal	120	885
British Columbia	Small Hydro	90	442
Oregon	Small Hydro	13	50
Nevada	Solar Thermal	285	933
Arizona	Solar PV	319	737
Nevada	Solar PV	23	41
Alberta	Wind	1,565	4,843
Colorado	Wind	517	1,298
Montana	Wind	262	818
Oregon	Wind	871	2,373
Washington	Wind	1,252	3,004
Wyoming	Wind	86	344
Total		5,544	16,760

OOS resources to remove from PC0

Coal retirements by 2020

- PC0 includes the following coal plant retirements:
  - **AESO:** Battle Units 3 & 4 and Wabamun Unit 4 **(586 MW)**
  - **NEVP:** Reid Gardner Units 1-3 **(330 MW)**
  - **PSC:** Arapahoe Units 3 & 4 and Cameo Units 1 & 2 **(216 MW)**
- Based on conversations with Xcel and announced retirements, ISO included the following retirements:
  - Arapaho Unit 4 repowers as a natural gas combined cycle **(109 MW)**
  - Cherokee Units 1-4 retire **(722 MW)**; unit 4 repowers as a natural gas combined cycle **(351 MW)**
  - Four Corners Units 1-3 retire **(560 MW)**
  - Valmont Unit 5 retires **(178 MW)**

REFINEMENTS OF THE STATISTICAL MODEL OF OPERATIONAL REQUIREMENTS (STEP 1)

Step 1 inputs and analysis of the four scenarios results are available

- Aggregate minute and hourly profile data
- Load, wind and solar forecast error
- Monthly and daily regulation and load following requirements
- Data available at: http://www.caiso.com/23bb/23bbc01d7bd0.html

Refinements to load profiles

- Load peak demand and energy adjusted to conform to CPUC scoping memo based on 2009 CEC IEPR
- LTPP net load reduction of approximately 6,500 MW in 2020 relative to “vintage” 33% reference case due to demand side programs specified in the CPUC scoping memo
- Statewide peak load in CPUC Trajectory Case is 63,755 MW versus 70,180 MW in vintage 33% ISO Operational Study reference case

Refinements to load forecast error

- Updated load forecast error based on 2010 actual load and forecast data
- Hour ahead forecast data based on T-75 minutes in updated LTPP analysis versus T-2 hours in vintage case
- 5-minute data shows increased forecast error based on actual load data

Comparison of Load Forecast Errors

LTPP Analysis

Season	HA STD 2010 ADJUSTED For PEAK (based on 2010 data)	RT (T-7.5min) STD 10% Improve 2020 (based on 2010 data)	HA autocorr	RT Autocorr
Spring	545.18	216.05	0.61	0.86
Summer	636.03	288.03	0.7	0.92
Fall	539.69	277.38	0.65	0.9
Winter	681.86	230.96	0.54	0.85

Vintage Analysis

Season	HA STD 10% Improve 2020 (based on Vitage 2006 data)	RT (T-7.5min) STD 10% Improve 2020 (based on Vitage 2006 data)
Spring	831.11	126
Summer	1150.61	126
Fall	835.11	126
Winter	872.79	126

Refinements to wind profiles

- Wind sites were expanded to include quantity and locations consistent with CPUC scoping memo
- For new plants, wind plant production modeling based upon NREL 10 minute data production was expanded to include 21 distinct locations in California and 22 locations throughout the rest of WECC.

Refinements to wind forecasting errors

- Recalibrated wind forecast errors using profiled data
- Applied a *T-1hr* persistence method for estimating forecast errors

Comparison of Wind Forecast Errors (Std Dev)

Region	Case	Technology	MW	Persistent	Hour	Spring	Summer	Fall	Winter
CA	33%Base	Wind	9436	T-1	All	0.040	0.038	0.032	0.031
					Vintage Cases	0.050	0.045	0.044	0.041

Note: Actual wind forecast error based on existing PIRP resources is higher than forecast *T-1hr* based on profiles

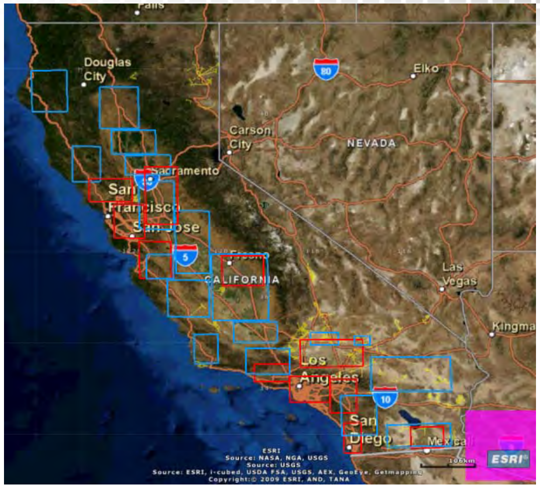
PIRP Forecast Error								
Region	Tech	MW	Persistent	Hour	Spring	Summer	Fall	Winter
CA	Wind	1005	T-2	All	11.1%	10.8%	8.1%	6.0%
CA	Wind	1005	T-1	All	8.4%	7.1%	5.3%	3.9%
CA	Wind	1005	PIRP	All	10.5%	8.9%	8.4%	6.7%

Refinements to solar profiles

- Profiles for 2010 scenarios are developed based on satellite irradiation data[1] rather than rather than NREL land based measurement data used previously.
- Variability was introduced based on a plant footprint rather than a single point
- Better represents diversity of resources
- Expanded use of 1 minute irradiance data to use three locations:
  - Sacramento Municipal Utility District (SMUD) in Sacramento
  - Loyola Marymount University in Los Angeles, and
  - in Phoenix, AZ

[1] The Solar Anywhere satellite solar irradiance data can be found at: https://www.solaranywhere.com/Public/About.aspx

Extended approach to profile small solar



- Extended method to profiling of small solar
- Define geographic boundaries of the 20 grids in Central, North, Mojave, and South area
- Choose each rectangular grid to represent an appropriate area. Each grid will have a different size rectangle
- Average the data on an hourly basis for each rectangle
- Follow similar process for developing solar profiles and adding 1-minute variability

Refinements to solar forecast errors

- Determined errors by analyzing 1-minute “clearness index” (CI) and irradiance data using *T-1 hr* persistence
- To address issues that arise using the *T-1 hr* persistence during early and later hours of the day, use 12-16 persistence to determine solar forecast error
- Results on next slide
  - CI persistence method for Hours 12-16 similar in outcome to “improved” errors
- Recommendations:
  - Since forecast errors are based on profiles and not actual production data, recommend calibrating the simulated to the actual forecast errors when more solar data is available
  - Continue to develop forecasting error for early and later hours of the day

Comparison of solar forecast error with persistence

Comparison of Solar Forecast Errors

Region	Case	Technology	MW	Persistent	Hour	0<=CI<0.2	0.2<=CI<0.5	0.5<=CI<0.8	0.8<=CI<=1
CA	33%Base	PV	3527	T-1	Hour12-16	0.035	0.069	0.056	0.023
CA	33%Base	ST	3589	T-1	Hour12-16	0.060	0.109	0.108	0.030
CA	33%Base	DG	1045	T-1	Hour12-16	0.022	0.047	0.039	0.018
CA	33%Base	CPV	1749	T-1	Hour12-16	0.016	0.033	0.031	0.016
		All			Vintage Cases	0.05	0.1	0.075	0.05

California ISO
Shaping a Renewed Future

IMPROVEMENTS TO SIMULATION EFFICIENCY

Modeling Improvements

- The model was modified to improve accuracy of modeling and efficiency of simulation while not compromising quality of results
- The major modifications implemented are:
  - Separation of spinning and non-spinning requirements
  - Generator ramp constraints for providing ancillary services and load following capacity
  - Simplified topology outside of California
  - Mixed integer optimization in California only
  - Tiered cost structure in generic resources in determining need for capacity

Separation of spinning and non-spinning requirements

- In the previous model, non-spinning includes spinning in both requirements and provision
- Spinning and non-spinning are separated in this model
  - The requirements for spinning and non-spinning are all 3% of load
  - The provision of non-spinning of a generator does not include its provision of spinning
- The separation is consistent with the ISO market definition and is needed to implement the ramp constraints as discussed below

Generator ramp constraints for providing ancillary services and load following capacity

- 60-minute constraint
  - The sum of intra-hour energy upward ramp, regulation-up, spinning, non-spinning, and load following up provisions is less than or equal to 60-minite upward ramp capability of the generator
  - The sum of intra-hour energy downward ramp, regulation-down, and load following down provisions is less than or equal to 60-minite downward ramp capability of the generator

Generator ramp constraints for providing ancillary services and load following capacity (cont.)

- 10-minute check constraint
  - The sum of upward AS and 50% of load following up provisions is less than or equal to 10-minite upward ramp capability
  - The sum of regulation-down and 50% of load following down provisions is less than or equal to 10-minite downward ramp capability

Generator ramp constraints for providing ancillary services and load following (cont.)

- 10-minute AS constraint
  - The sum of upward AS provisions is less than or equal to 10-minute upward ramp capability
  - Regulation-down provision is less than or equal to 10-minute downward ramp capability
- 20-minute constraint
  - The sum of upward AS and load following up provisions is less than or equal to 10-minute upward ramp capability
  - The sum of regulation-down and load following down provisions is less than or equal to 10-minute downward ramp capability

Simplified topology outside of California

- The topology was simplified by combining transmission areas (bubbles) outside CA according to the following rules:
  – The areas have no direct transmission connection to CA
  – The areas are combination by state or region (Pacific Northwest)
- There will be no transmission congestion within each of the combined areas

Mixed integer optimization in California only

- Model has mixed integer optimization in CA only
  - Mixed integer optimization applies to all CA generators and generators as dedicated import to CA only
  - These generators are subject to unit commitment decision in the optimization
  - Other generators outside CA are not subject to unit commitment decision
  - These generators are available for dispatch at any time (when they are not in outage)

Tiered cost structure in generic resources in determining need for capacity

- In the run to determine need for capacity, generic resources have high operation costs set up in a tiered structure such that:
  - The generic resources will be used only when they are absolutely needed to avoid violation of requirements
  - The use of generic resources will be in a progressive way (fully utilizing the capacity of one generic unit before starting to use the next one)
- The model using this method can determine the need for capacity in one simulation

Tiered cost structure in generic resources in determining need for capacity (cont.)

- The VOM cost and the cost to provide AS or load following of the generic resources are set up as

  Tier 1 – $10,000/MW   Tier 2 - $15,000/MW

  Tier 3 – $20,000/MW   Tire 4 - $25,000/MW
- In the run to determine the need for capacity startup costs of all generators are not considered for the method to work properly
- The run uses the monthly maximum regulation and load following requirements for each hour

ADDITIONAL CHANGES TO MODEL ASSUMPTIONS

Additional changes were implemented based on May 31, 2011 ALJ ruling

- Corrected the calendar year for load profile, renewable profiles, and Step 1 requirements
- Reset heat rate of El Segundo plant and the minimum capacity of the LMS100 and LM6000 units based on public available information
- Added CoolwtrS3 and CoolwtrS4 units according to ISO transmission planning assumptions
- Disallowed existing GT to provide off-line non-spinning, new GT is allowed
- Created a generic unit reflective of storage or curtailment to absorb load following down shortage

Additional changes were implemented based on May 31, 2011 ALJ ruling (cont.)

- Updated transmission wheeling rates as follows:
  - Using TEPPC PC0 Case non-zero rate for paths outside CA
  - Using vintage rates for paths in CA and for paths outside CA where PC0 Case has zero rates
- Separated BC and AESO and applied a $48/MW wheeling rate (based on PC0 Case) to prevent large quantity of energy from flowing into AESO
- Switched the following dynamic resources to providing load following and ancillary services to meet the ISO requirements

  - APEX_2_MIRDYN (505 MW) - MRCHNT_2_MELDYN (439 MW)

  - MSQUIT_5_SERDYN (1,182 MW) -SUTTER_2_PL1X3 (500 MW)

Additional changes were implemented based on May 31, 2011 ALJ ruling (cont.)

- Changed modeling of coal units with capacity greater than 300 MW to subject to commitment decision (integer variable)
- Updated SCIT and CA import limits based the revised SCIT model
- Revised generator outage rates to match monthly average outage (MW) with the ISO 2010 monthly minimum outage , no maintenance from Nov to Feb in Humboldt area

Outage profile used compared with actual outage profile

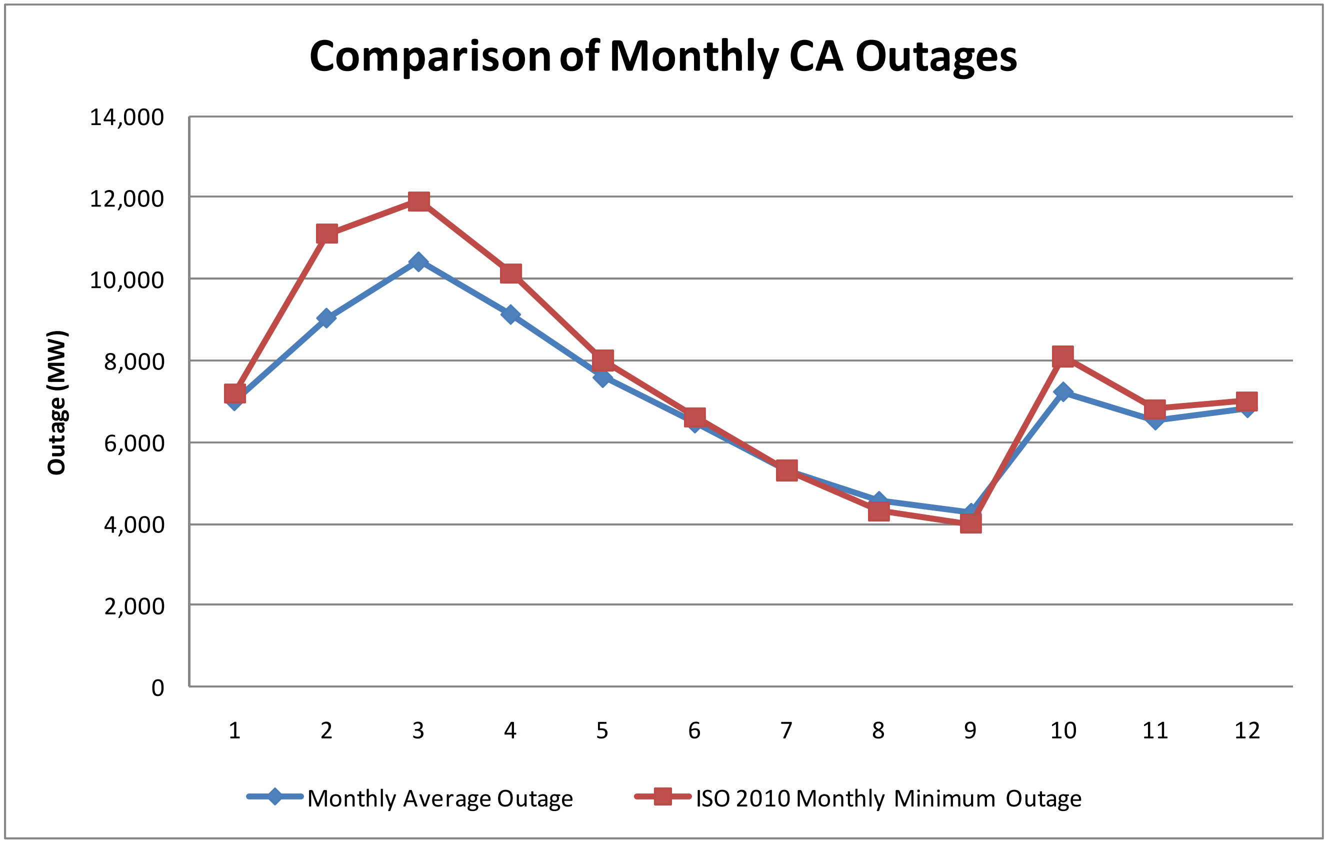


Exhibit 2

Large Solar Profiles (Spreadsheet 1)
Small Solar Profiles (Spreadsheet 2)
Projects All Cases – Final (Spreadsheet 3)

CREZ Number	Location	PV Profile Name	PV Plant	PV Size MW	PV Type	PV E3 Cap. Factor	PV 20%	PV 33% Base	PV 33% Environ.	PV 33% High	PV 33% Cost	PV 33% Time	PV Latitude	PV Longitude	ST Profile Name	ST Plant	ST Size MW	ST Type	ST E3 Cap. Factor	ST 20%	ST 33% Base	ST 33% Environ.	ST 33% High	ST 33% Cost	ST 33% Time	ST Latitude	ST Longitude	
		SOLAR - LARGE SCALE PV											Geographical Location		SOLAR THERMAL											Geographical Location		
1	Alberta																											
2	Arizona	Arizona_PV_1	2_PV_1	290	Crystalline Tracking	29.00%	x	x	x	x	x	x	32.886545	-114.90047	Arizona_ST_1	2_ST_1	200	Solar Thermal	26.68%	x	x	x	x	x	x	32.9322548	-114.9322913	Used Imperial East CREZ
		Arizona_PV_2	2_PV_2	50	Crystalline Tracking	29.00%	x	x	x	x	x	x	33.663188	-114.72181	Arizona_ST_2	2_ST_2	200	Solar Thermal	26.68%	x	x	x	x	x	x	33.7537524	-114.7514557	Used Riverside East CREZ
3	Carrizo South	Carrizo South_PV_1	3_PV_1	150	Thin-Film	23.50%	x	x	x	x	x	x	35.430045	-120.10157														
		Carrizo South_PV_2	3_PV_2	400	Thin-Film	23.50%		x	x	x	x	x	35.392808	-120.06802														
		Carrizo South_PV_3	3_PV_3	350	Crystalline Tracking	26.65%		x	x	x	x	x	35.337966	-120.00224														
		Carrizo South_PV_4	3_PV_4	87.9	Crystalline Tracking	26.65%	x						same as PV_3															
		Carrizo South_PV_5	3_PV_5	238	Thin-Film	23.50%	x						same as PV_2															
4	Colorado																											
5	Fairmont	Fairmont_PV_1	5_PV_1	38.8	Crystalline Tracking	29.00%				x			34.668333	-118.31013														
6	Imperial	Imperial_PV_1	6_PV_1	174.4	Crystalline Tracking	29.00%				x			33.072536	-115.79915	Imperial_ST_1	6_ST_1	300	Solar Thermal	26.68%		x		x	x		33.2206533	-116.0048792	
		Imperial_PV_2	6_PV_2	55.8	Crystalline Tracking	29.00%		x					32.785496	-115.82318	Imperial_ST_2	6_ST_2	92.7	Solar Thermal	26.68%			x				same as ST_1		
		Imperial_PV_3	6_PV_3	49.4	Crystalline Tracking	29.00%					x		same as PV_2															
		Imperial_PV_4	6_PV_4	15.3	Crystalline Tracking	29.00%			x				same as PV_2															
7	Kramer														Kramer_ST_1	7_ST_1	62	Solar Thermal	26.68%	x	x	x	x	x	x	35.1084332	-117.7163435	
8	Montana																											
9	Mountain Pass	Mountain Pass_PV_1	9_PV_1	300	Crystalline Tracking	29.00%		x		x			35.465079	-115.53964	Mountain Pass_ST_1	9_ST_1	110	Solar Thermal	26.68%		x		x			35.5866729	-115.446041	
															Mountain Pass_ST_2	9_ST_2	300	Solar Thermal	26.68%		x		x			35.4923461	-115.3113427	
10	New Mexico																											
11	Non CREZ*	Non CREZ_PV_1	11_PV_1	50	Crystalline Tracking	26.65%	x	x	x	x	x	x	35.803622	-120.06311	Non CREZ_ST_1	11_ST_1	150	Solar Thermal with storage	36.00%	x	x	x	x	x	x	34.0444487	-114.81998	Rice Solar Energy Project (Central Receiver)
		Non CREZ_PV_2	11_PV_2	232	Crystalline Tracking	26.65%		x		x			35.649326	-119.81615	Non CREZ_ST_2	11_ST_2	370	Solar Thermal	26.68%		x		x			35.0333172	-117.2707933	
12	Northwest																											
13	Palm Springs																											
14	Pisgah	Pisgah_PV_1	14_PV_1	75	Crystalline Tracking	29.75%		x		x			34.857423	-116.86747	Pisgah_ST_1	14_ST_1	250	Solar Thermal	26.68%		x		x			34.8126127	-116.4471117	
															Pisgah_ST_2	14_ST_2	250	Solar Thermal	26.68%		x		x			34.8416388	-116.552886	
															Pisgah_ST_3	14_ST_3	275	Solar Thermal	26.68%	x		x		x	x	same as 1		
															Pisgah_ST_4	14_ST_4	400	Solar Thermal	26.68%		x		x			34.8248006	-116.5620832	
															Pisgah_ST_5	14_ST_5	400	Solar Thermal	26.68%		x		x			34.7943576	-116.3915522	
															Pisgah_ST_6	14_ST_6	400	Solar Thermal	26.68%		x		x			34.7681692	-116.4275202	
15	Riverside East	Riverside East_PV_1	15_PV_1	300	Thin-Film	26.63%	x	x	x	x	x	x	33.814102	-115.40466	Riverside East_ST_1	15_ST_1	250	Solar Thermal	26.68%	x	x	x	x	x	x	33.7016856	-115.2151098	
		Riverside East_PV_2	15_PV_2	250	Thin-Film	26.63%	x	x	x	x	x	x	33.867651	-115.20561	Riverside East_ST_2	15_ST_2	242	Solar Thermal	26.68%	x	x	x	x	x	x	33.626464	-114.977981	
		Riverside East_PV_3	15_PV_3	83	Crystalline Tracking	28.73%						x	33.770942	-115.25427														
		Riverside East_PV_4	15_PV_4	375	Crystalline Tracking	27.42%						x	33.571726	-114.83828														
16	Round Mountain																											
17	San Bernardino-Lucern	San Bernardino-Lucerne_PV_1	17_PV_1	30	Crystalline Tracking	29.35%						x	34.396817	-116.8591														
18	San Diego South																											
19	Solano																											
20	Tehachapi	Tehachapi_PV_1	20_PV_1	341	Thin-Film	23.50%		x		x			34.966646	-118.24769	Tehachapi_ST_1	20_ST_1	105	Solar Thermal	26.68%		x		x		x	35.0600689	-117.9914446	
		Tehachapi_PV_2	20_PV_2	341	Thin-Film	23.50%		x		x			35.063749	-118.22219														
		Tehachapi_PV_3	20_PV_3	341	Thin-Film	23.50%		x		x			35.018323	-118.28698														
		Tehachapi_PV_4	20_PV_4	341	Thin-Film	23.50%		x		x			35.215425	-118.02372														
		Tehachapi_PV_5	20_PV_5	66	Crystalline Tracking	29.00%						x	34.881536	-118.39869														
		Tehachapi_PV_6	20_PV_6	244.2	Thin-Film	23.50%						x	same as PV_1															
		Tehachapi_PV_7	20_PV_7	244.2	Thin-Film	23.50%						x	same as PV_2															
21	Utah-Southern Idaho																											
22	Westlands	Westlands_PV_1	22_PV_1	400	Crystalline Tracking	25.42%			x				36.195572	-119.96354														
		Westlands_PV_2	22_PV_2	400	Crystalline Tracking	25.42%			x				36.142356	-119.92725														
23	Wyoming																											

	20%	33% Base	33% Enviro n.	33% High	33% Cost	33% Time
Total PV	1416	3867	2655	4024	1889	2882
Total ST	1379	3989	1472	3989	1679	1484
Total Large	2795	7856	4127	8013	3568	4366
(Solar Thermal columns)	1379	3989	1472	3989	1679	1484

Technology:	Large Ground	fixed tilt - 25 degrees cadmium telluride
	Large Roof	fixed tilt - 15 degrees polycrystalline

SMALL SOLAR

Area Number	Location	Profile Name	Plant	Size MW	Type	Number of Sites	E3 Cap. Factor	20%	33% Base	33% Envir	33% High	33% Cost	33% Time	Geographical Location Latitude X1	Latitude X2	Longitude Y1	Longitude Y2	Notes
1	Central Valley	Large_Ground_1	1_LG_1	406.5	fixed tilt - 25 degre	13	23.56%	x	x	x	x	x	x	35.486	36.921	-120.133	-118.954	
		Large_Ground_2	1_LG_2	461.9	fixed tilt - 25 degre	15	23.63%			x				36.516	37.86	-120.928	-120.215	(302.9+132.9+26.1)
		Large_Ground_3	1_LG_3	418.9	fixed tilt - 25 degre	5	23.56%			x				37.484	38.518	-121.732	-120.991	
		Large_Ground_4	1_LG_4	530.1	fixed tilt - 25 degre	1	23.56%			x				38.671	39.096	-122.031	-121.065	
		Large_Ground_5	1_LG_5	387.9	fixed tilt - 25 degre	2	23.56%			x				39.119	39.624	-122.332	-121.396	
		Large_Ground_6	1_LG_6	174.1	fixed tilt - 25 degre	9	23.56%			x			x	35.011	35.452	-119.676	-118.744	
		Large_Ground_7	1_LG_7	457.4	fixed tilt - 25 degre	6	23.56%			x				39.68	40.572	-122.591	-121.769	
		Mid_Ground		132.9		22	23.56%							merged with Large_Ground_2				
		Small_Ground		26.1		21	25.57%							merged with Large_Ground_2				
		Large_Roof_1	1_LR_1	165.2	fixed tilt - 15 degre	2	20.37%			x			x	36.237	36.888	-119.919	-119.047	
		Large_Roof_2	1_LR_2	544.8	fixed tilt - 15 degre	5	20.37%			x				37.584	38.838	-121.586	-120.92	
	Mojave	Large_Ground_8	2_LG_1	120	fixed tilt - 25 degre	7	26.68%	x	x		x	x	x	34.939	35.215	-117.999	-117.405	
		Large_Ground_9	2_LG_2	48.1	fixed tilt - 25 degre	9	26.68%			x			x	34.939	35.135	-117.035	-116.716	
		Large_Ground_10	2_LG_3	367.6	fixed tilt - 25 degre	14	26.68%			x				33.941	34.687	-116.682	-114.951	355.1+12.5
		Large_Ground_11	2_LG_4	433	fixed tilt - 25 degre	14	26.68%			x				32.71	33.227	-116.332	-114.944	
		Mid_Ground		12.5		21	26.68%			1				merged with Large_Ground_10				
		Small_Ground		3						1				not included				
		Large Roof		17.8	fixed tilt - 15 degre	5	22.80%	1	1	1	1	1	1	merged with Large_Roof_8				
		Large_Roof_3	2_LR_1	115.4	fixed tilt - 15 degre	4	22.80%			x			x	32.683	33.162	-115.803	-115.105	
		Large_Roof_4	2_LR_2	380	fixed tilt - 15 degre	10	22.80%			x				34.455	35.069	-118.216	-116.871	
	North Coast	Large_Ground_12	3_LG_1	88.5	fixed tilt - 25 degre	5	21.87%	x	x	x	x	x	x	36.395	36.908	-121.578	-120.999	
		Large_Ground_13	3_LG_2	59.6	fixed tilt - 25 degre	6	21.87%			x			x	38.518	39.272	-123.97	-122.603	
		Large_Ground_14	3_LG_3	356.6	fixed tilt - 25 degre	16	21.87%			x				35.563	36.349	-121.106	-120.228	
		Large_Ground_15	3_LG_4	302	fixed tilt - 25 degre	4	21.87%			x				40.056	40.951	-124.067	-123.326	240.5+48.4+13.1
		Mid_Ground		48.4		15	21.87%			1				merged with Large_Ground_15				
		Small_Ground		13.1		14	23.71%			1				merged with Large_Ground_15				
		Large Roof		18	fixed tilt - 15 degre	5	19.56%	1	1	1	1	1	1	merged with Large_Roof_8				
		Large_Roof_5	3_LR_1	212.2	fixed tilt - 15 degre	4	19.56%			x			x	38.092	38.582	-122.819	-121.893	
		Large_Roof_6	3_LR_2	341.2	fixed tilt - 15 degre	7	19.56%			x				37.291	38.001	-122.274	-121.643	
		Large_Roof_7	3_LR_3	358.6	fixed tilt - 15 degre	3	19.56%			x				36.416	37.2	-121.718	-121.071	
	South Coast	Large Ground		20		1	24.34%	1	1	1	1	1	1	merged with Large_Ground_12				
		Large_Ground_16	4_LG_1	151.2	fixed tilt - 25 degre	6	24.34%			x			x	34.543	35.18	-120.534	-120.031	
		Large_Ground_17	4_LG_2	424.7	fixed tilt - 25 degre	17	24.34%			x				34.309	34.85	-119.418	-118.454	
		Large_Ground_18	4_LG_3	335	fixed tilt - 25 degre	3	24.34%			x				32.977	33.837	-117.314	-116.581	
		Mid & Small Ground		7.8		28	24.34% and 26.1%			1				merged with Large_Ground_18				
		Large_Roof_8	4_LR_1	430	fixed tilt - 15 degre	15	21.17%	x	x	x	x	x	x	33.692	34.261	-118.449	-117.58	
		Large_Roof_9	4_LR_2	261.4	fixed tilt - 15 degre	4	21.17%			x			x	34.141	34.523	-119.226	-118.466	
		Large_Roof_10	4_LR_3	453.9	fixed tilt - 15 degre	4	21.17%			x				33.456	34.196	-117.559	-117.002	
		Large_Roof_11	4_LR_4	408.2	fixed tilt - 15 degre	7	21.17%			x				32.588	33.24	-117.261	-116.909	
					Total Small PV			1,045	1,045	9,074	1,045	1,045	2,232					

	MW	Energy
Total DG	1749.28	3218
	Nameplate at CF=21.0%	

DISTRIBUTED SOLAR

Area Number	Location	Profile Name	Plant	Size MW	Type	Number of Sites	E3 Cap. Factor	20%	33% Base	33% Enviro	33% High	33% Cost	33% Time	Geographical Location			
														Latitude X1	*Latitude X2*	*Longitude Y1*	*Longitude Y2*
	Central Valley	Distributed_Solar_1	1_DS_1	349.9	fixed tilt		21.00%	x	x	x	x	x	x	37.765	38.824	-121.638	-121.065
	Central Valley	Distributed_Solar_2	1_DS_2	349.9	fixed tilt		21.00%	x	x	x	x	x	x	36.308	37.45	-120.542	-119.224
	North Coast	Distributed_Solar_3	3_DS_1	349.9	fixed tilt		21.00%	x	x	x	x	x	x	37.248	38.435	-122.512	-121.706
	South Coast	Distributed_Solar_4	4_DS_1	349.9	fixed tilt		21.00%	x	x	x	x	x	x	33.631	34.278	-118.523	-117.067
	South Coast	Distributed_Solar_5	4_DS_2	349.9	fixed tilt		21.00%	x	x	x	x	x	x	32.661	33.32	-117.26	-116.781

Exhibit 3

CAISO 33% RPS Study Series
2020 Load Profile Parameters
High and Base Net Load Sensitivity 2011 Cases

Exhibit 3

CAISO 33% RPS Study Series
2020 Load Profile Parameters
High and Base Net Load Sensitivity 2011 Cases

Development of High and Base Net Load Sensitivity Profile for 2020 For Use in Analysis

Net Energy Calculations and Assumptions

Table 1 summarizes the assumptions for Gross Generation to be used in Base Load Case. This table is taken from the CEC's Form 1.2, Statewide Revised Demand Forecast Forms, Second Edition.

Table 1 Assumptions for Gross Generation to be used in Base Load Case

Year	Gross Generation	Non-PV & PV Self Generation	Net Energy For Load
2,020	341,778	14,896	326,882

The other adjustments made to the Total Generation to calculate the Total Net Energy to be used in the Load Profiles for Base Load and High Load cases are shown in Tables 2, 3, 4, and 5.

Table 2 Adjustments for Incremental Energy Efficiency for IOUs (CPUC's Technical Attachment V5)

	PG&E	SCE	SDG&E
Total Including Losses	**6,811**	**6,713**	**1,357**
Total	**6,214**	**6,286**	**1,267**
IOU Programs	2,805	3,599	722
Goals AB1109	846	613	169
Goals Standards	556	620	129
BBEES (Low)	754	916	177
Decay Replacement	1,253	538	70

The assumption for Line Loss factor Used in the above table is shown in Table 3

Table 3 Energy Efficiency (Line Loss Factors) (CPUC's Technical Attachment V5)

North	South	San Diego
9.6%	6.8%	7.1%

Energy Efficiency adjustments for Non-IOUs was calculating by subtracting the Decay Replacement component of EE savings for the IOUs and multiplying the resulting total for each IOU by 0.25. Table 4 summarizes the total EE related adjustments.

Table 4 Total Adjustments for Incremental Energy Efficiency (CPUC's Technical Attachment V5)

Total IOUs	Total Non- IOUs	Total EE Adjustment
14,881	3,214	18,095

The total adjustment for CHP is shown in Table 5.

Table 5 Total Adjustments for CHP (CPUC's Technical Attachment V5)

Year	Demand-side	Total including Losses
2020	7,556	8,198

The Net Energy to be used in the Base Load case is summarized in Table 6 and the Net Energy to be used in both Case Load case and High Load case is summarized in Table 7.

Exhibit 3

Table 6 Base Load Energy To Be Used in the Load Profiles

Case	Energy before adjustments (GWH)	Adjustments for PV behind the meter which will be modeled as generators (GWH)	Adjustments for Incremental EE (GWH)	Adjustments For Behind the Meter CHP (MW)	Adjustments for demand side (GWH)	Net Energy (GWH)
Base Load Case	326,882	(+) 3218	(-)18,095	(-)8,198	Assumed to have no energy impact	303,806

Table 7 Summary of Base Load and High Load Case Energy To Be Used in the Load Profiles

Case	Net Energy Load To BE Used in Profiling (GWh)
Base Load Case	303,806
High Load Case	334,187[1]

Peak Demand Calculations and Assumptions

According to CEC's 2009 IEPR, the maximum 2020 peak demand for the State of California is 70,964 MW[2] as shown in the following table.

CEC's 2020 Peak Demand from Tab Form 1.4

Year	Total End Use Load	Net Losses	Gross Generation	Non-PV Self Generation	PV Self Generation	Total Private Supply	Net Peak Demand
2020	67,993	5,716	73,709	1,935	810	2,745	70,964

[1] For High Load case, the net energy is assumed to be 110% of the net energy for Base Load case.
[2] Form 1.4, Second Edition, http://www.energy.ca.gov/2009_energypolicy/documents/, Statewide Revised Demand Forecast Forms

The "Net Peak Demand" was then adjusted to account for Incremental Energy Efficiency, EE (MW), Behind the Meter CHP (MW), Demand Response Programs, and PV Behind the Meter assumed for this project. These adjustments are explained in Tables 8, 9, 10, and 11. These three tables are taken from the CPUC's Technical Attachment Spreadsheet v5.xls.

Table 8 Assumptions Incremental Uncommitted EE (MW) for Year 2020 for IOUs (From CPUC Technical Attachment Spreadsheet v5.xls)

	PG&E	**SCE**	**SDG&E**
Total*	2,496	2,648	544
Total Before Line Loss	**2,275**	**2,461**	**496**
IOU Programs	853	951	270
Goals AB1109	119	93	23
Goals Standards	412	500	75
BBEES (Low)	648	792	114
Decay Replacement	243	125	14

* Totals are grossed up (by CPUC) to include line loss.

Table 9 Assumptions Incremental Uncommitted EE (MW) for Year 2020 (From CPUC Technical Attachment Spreadsheet v5.xls)

Total IOUs	Total Non- IOUs	Total EE Adjustment
5,687	1,318	7,005

Table 10 Assumptions Incremental Uncommitted DR (MW) for Year 2020 for IOUs (From Technical Attachment Spreadsheet v5.xls)

	PG&E	**SCE**	**SDG&E**
*Total DR**	313	14	0
Non-Event Based DR (PLS/TOU)	280	13	0

Exhibit 3

* Totals are grossed up to include line loss.

Table 11 Assumptions Incremental State-wide CHP (MW) (From Technical Attachment Spreadsheet v5.xls)

Year	Demand-side CHP (MW)	Total Including Losses (MW)
2020	936[3]	1,008

The peak demand to be used in the load profiles is shown in Table 12.

Table 12 Peak Demand To Be Used in the Load Profiles

Maximum Demand Before Adjustments (MW)	Adjustments For PV Behind the Meter (MW)	Adjustments For Incremental EE (MW)	Adjustments For Behind the Meter CHP (MW)	Adjustments For Demand Side Programs	Net Demand to be Profiled for Base Load Case (MW)	Net Demand to be Profiled for High Load Case (MW) (=Base Load *1.1)
70,964	(+)1,131	(-)7,005	(-)1,008	(-)327	63,755	70,131

Field Code Changed

Minimum Demand Calculations and Assumptions

Since minimum demand was not available, the minimum demand for the load profiles was calculated from the minimum demand used in previous study (CPUC 2009 Cases). For High Load case the minimum demand for the last study was 23,962 MW.

The calculation for minimum demand from previous demand is shown in Tables 13 for High Load Case and Base load case respectively.

[3] It is assumed that the supply side CHP will be modeled as generation in the Step 2 (Plexos) modeling.

Exhibit 3

Table 13 Calculation of Minimum Demand for High Load Case

Case	Peak Demand Used in 2010 Study (For High Load Case)	Peak Demand To be Used in 2011 Study	% reduction in Peak Demand	Assumed % change in Min. Demand (50 % of the change in Peak Demand)	Min. Demand Used in 2010 Study (for High Load Case)	Calculated Min. Demand for 2011 Study
Base Load Case	70,180	63,755	9.2%	4.6%	23,962	22,865
High Load Case	70,180	70,131	0.1%	0.05%	23,962	23,954

The minimum demand to be used in this study is shown in Table 14.

Table 14 Minimum Demand To Be Used in the Load Profiles

Case	Net Minimum Load To Be Used in Profiling (MW)
Base Load Case	22,727
High Load Case	23,801

Final 2020 Net High Load Profile Parameters

Table 15 Final 2020 Net High Load Profile Parameters

Year /Case	Peak (MW)	Energy(GW-hr)	Minimum(MW)
2020/Base	63,755	303,806	22,865
2020/High	70,131	334,187	23,954

Exhibit 3

Allocation of Energy and Demand to Production Simulation Bubbles

The methodology described below will be used unless there is more recent information from the CEC.

It is proposed to allocate the energy and demand on a pro-rate basis using the energy data in the CEC Spreadsheet CED 2010-2020 SumtoBubble Dated 10/20/2009 and with 52% of the PV energy for PV on the customer side of the meter to Northern California bubbles and the remainder to Southern California bubbles. These geographical allocation factors come from the PV energy analysis of the CEC contained in the file PV final IEPRo9 cappeak factors AT 10 14 09.xls.

Exhibit 4

California Energy Demand 2010 – 2020
Staff Forecast

California Energy Demand 2010-2020 Staff Revised Forecast

Summary by WECC Bubble

1-in-2 Net Peak Demand (MW)	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	Average Annual Growth
PGE Bay	8,981	8,639	8,675	8,768	8,880	8,988	9,060	9,133	9,209	9,294	9,372	9,448	9,537	1.0%
PGE Valley	12,978	12,900	13,019	13,220	13,449	13,680	13,864	14,052	14,245	14,456	14,658	14,862	15,088	1.5%
TIDC	647	640	648	660	674	687	699	711	723	736	749	762	776	1.8%
SMUD/WAPA Control Area	4,552	4,512	4,541	4,604	4,684	4,764	4,830	4,892	4,950	5,009	5,068	5,130	5,196	1.4%
SCE TAC Area	22,558	23,248	23,479	23,785	24,142	24,518	24,823	25,149	25,482	25,833	26,169	26,509	26,875	1.4%
SDG&E	4,371	4,487	4,516	4,578	4,658	4,738	4,797	4,856	4,911	4,973	5,032	5,094	5,157	1.3%
Total LADWP Control Area	6,608	6,450	6,428	6,488	6,579	6,644	6,681	6,718	6,755	6,792	6,829	6,869	6,912	0.7%
Imperial Irrigation District	977	965	985	1,012	1,042	1,067	1,090	1,114	1,141	1,169	1,197	1,226	1,256	2.5%
Net Energy for Load (GWH)	2,008	2,009	2,010	2,011	2,012	2,013	2,014	2,015	2,016	2,017	2,018	2,019	2,020	
PGE Bay	47,244	45,025	45,044	45,450	45,989	46,583	46,956	47,322	47,703	48,122	48,503	48,876	49,269	0.9%
PGE Valley	61,482	61,506	61,788	62,545	63,446	64,479	65,266	66,050	66,863	67,739	68,583	69,431	70,322	1.3%
TIDC	2,694	2,615	2,631	2,668	2,718	2,768	2,804	2,841	2,879	2,919	2,959	2,999	3,041	1.5%
SMUD/WAPA Control Area	18,712	18,044	18,100	18,359	18,715	19,073	19,347	19,600	19,841	20,085	20,322	20,563	20,816	1.4%
SCE TAC Area	110,618	108,057	108,123	109,141	110,505	112,165	113,417	114,727	116,068	117,453	118,783	120,134	121,538	1.2%
SDG&E	22,085	21,599	21,695	21,941	22,284	22,680	22,978	23,283	23,556	23,845	24,130	24,434	24,740	1.3%
Total LADWP Control Area	30,604	29,644	29,523	29,814	30,309	30,707	30,968	31,214	31,461	31,697	31,939	32,186	32,437	0.9%
Imperial Irrigation District	3,712	3,692	3,763	3,857	3,969	4,077	4,169	4,265	4,369	4,479	4,590	4,705	4,828	2.5%
Load Factor														
PGE Bay	0.600	0.595	0.593	0.592	0.591	0.592	0.592	0.591	0.591	0.591	0.591	0.591	0.590	-0.1%
PGE Valley	0.541	0.544	0.542	0.540	0.539	0.538	0.537	0.537	0.536	0.535	0.534	0.533	0.532	-0.2%
TIDC	0.475	0.466	0.463	0.461	0.461	0.460	0.458	0.456	0.455	0.453	0.451	0.449	0.447	-0.4%
SMUD/WAPA Control Area	0.469	0.457	0.455	0.455	0.456	0.457	0.457	0.457	0.458	0.458	0.458	0.458	0.457	0.0%
SCE TAC Area	0.560	0.531	0.526	0.524	0.523	0.522	0.522	0.521	0.520	0.519	0.518	0.517	0.516	-0.2%
SDG&E	0.577	0.550	0.548	0.547	0.546	0.546	0.547	0.547	0.548	0.547	0.547	0.548	0.548	0.0%
Total LADWP Control Area	0.529	0.525	0.524	0.525	0.526	0.528	0.529	0.530	0.532	0.533	0.534	0.535	0.536	0.2%
Imperial Irrigation District	0.434	0.437	0.436	0.435	0.435	0.436	0.437	0.437	0.437	0.437	0.438	0.438	0.439	0.1%
Minimum (MW)														
PGE Bay	3,460	3,298	3,299	3,329	3,368	3,412	3,439	3,466	3,494	3,524	3,552	3,580	3,608	0.9%
PGE Valley	4,450	4,452	4,472	4,527	4,592	4,667	4,724	4,781	4,839	4,903	4,964	5,025	5,090	1.3%
TIDC	180	175	176	178	182	185	187	190	192	195	198	200	203	1.5%
SMUD/WAPA Control Area	1,277	1,231	1,235	1,253	1,277	1,302	1,320	1,338	1,354	1,371	1,387	1,403	1,421	1.4%
SCE TAC Area	8,335	8,142	8,147	8,224	8,327	8,452	8,546	8,645	8,746	8,850	8,950	9,052	9,158	1.2%
SDG&E	1,623	1,587	1,594	1,612	1,638	1,667	1,689	1,711	1,731	1,752	1,773	1,796	1,818	1.3%
Total LADWP Control Area	2,267	2,196	2,187	2,208	2,245	2,275	2,294	2,312	2,330	2,348	2,366	2,384	2,403	0.9%
Imperial Irrigation District	201	200	204	209	215	221	226	231	237	243	249	255	261	2.5%

Source: CALIFORNIA ENERGY DEMAND 2010-2020 STAFF REVISED FORECAST
October 2009, CEC-200-2009-012-SF