Rulemaking	12-03-014
Exhibit Nos.:	ISO – 07, ISO – 08, ISO – 09, ISO - 11
Witness:	Robert Sparks

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 ON BEHALF OF THE CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION

Rulemaking 12-03-014

Exhibit No.: ISO - 07

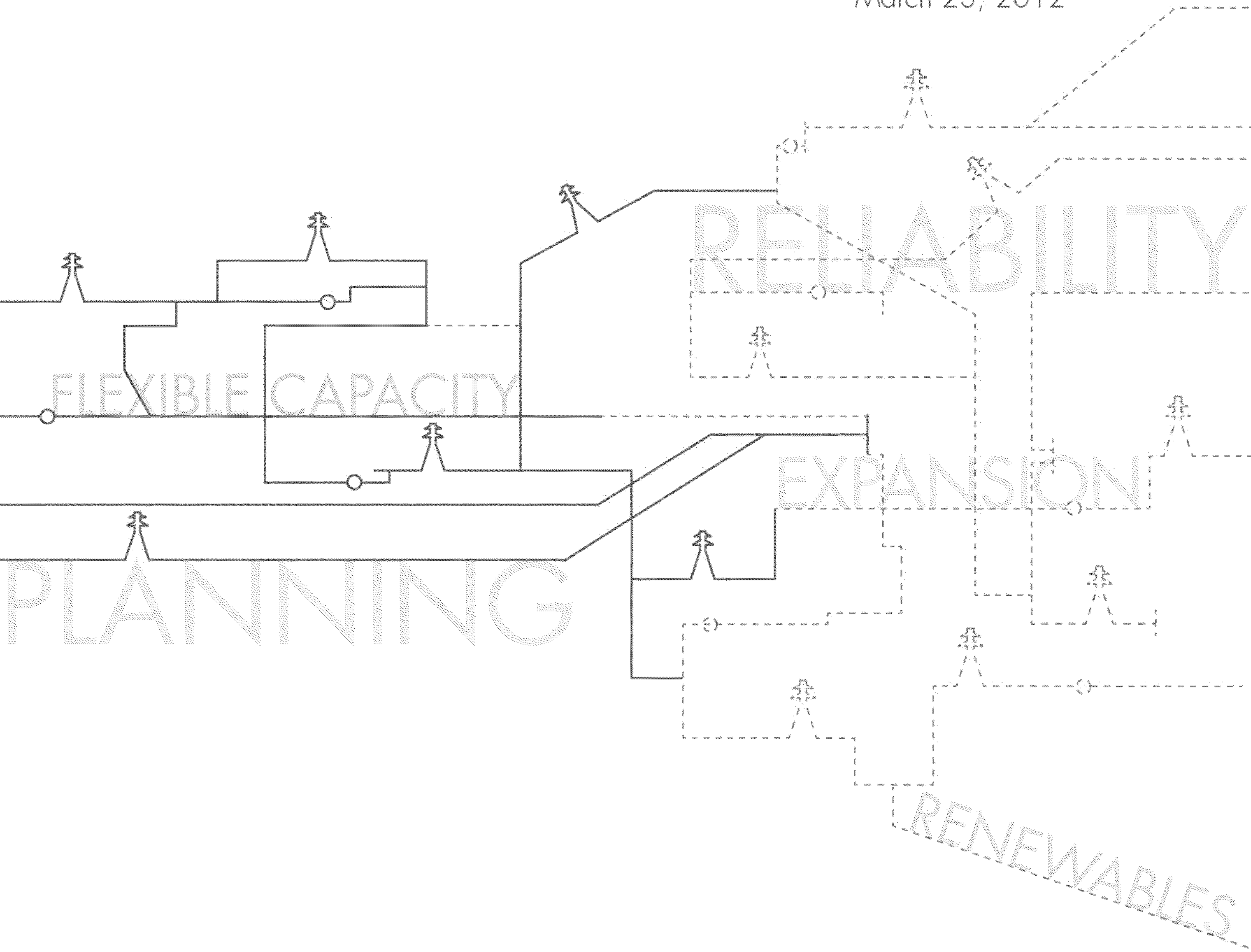
Witness: ____________________

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:

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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 f our 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 re liability 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 I SO 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 c ome 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

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

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

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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 wit h 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

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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 as sessments. 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 ev aluated, 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 margin s 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 plann ing 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:

[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 f ollowing 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

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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 respe ctive 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			Existing OTC Units Needed?	Constraint	Contingency
		Non-D.G. (MW)	D.G. (MW)	Total (MW)			
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			Existing OTC Units Needed?	Constraint	Contingency
		Non-D.G. (MW)	D.G. (MW)	Total (MW)			
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

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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. T hese 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 Non-D.G. (MW)	LCR D.G. (MW)	LCR Total (MW)	Existing OTC Units Needed?	Constraint	Contingency
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 Non-D.G. (MW)	LCR D.G. (MW)	LCR Total (MW)	Existing OTC Units Needed?	Constraint	Contingency
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 Non-D.G. (MW)	LCR D.G. (MW)	LCR Total (MW)	Existing OTC Units Needed?	Constraint	Contingency
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 areaand its sub-areas

Portfolios	Area	LCR Non-D.G. (MW)	LCR D.G. (MW)	LCR Total (MW)	Existing OTC Units Needed?	Constraint	Contingency
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 areaand 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 Power link 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 w as 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 legi slature 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 wit h 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 2011/20 12 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 determi ned 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 mor e 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 manage ment, 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/essc/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:

[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 p rovided 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 t he 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 resulti ng 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.

SB_GT&S_0558704

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?

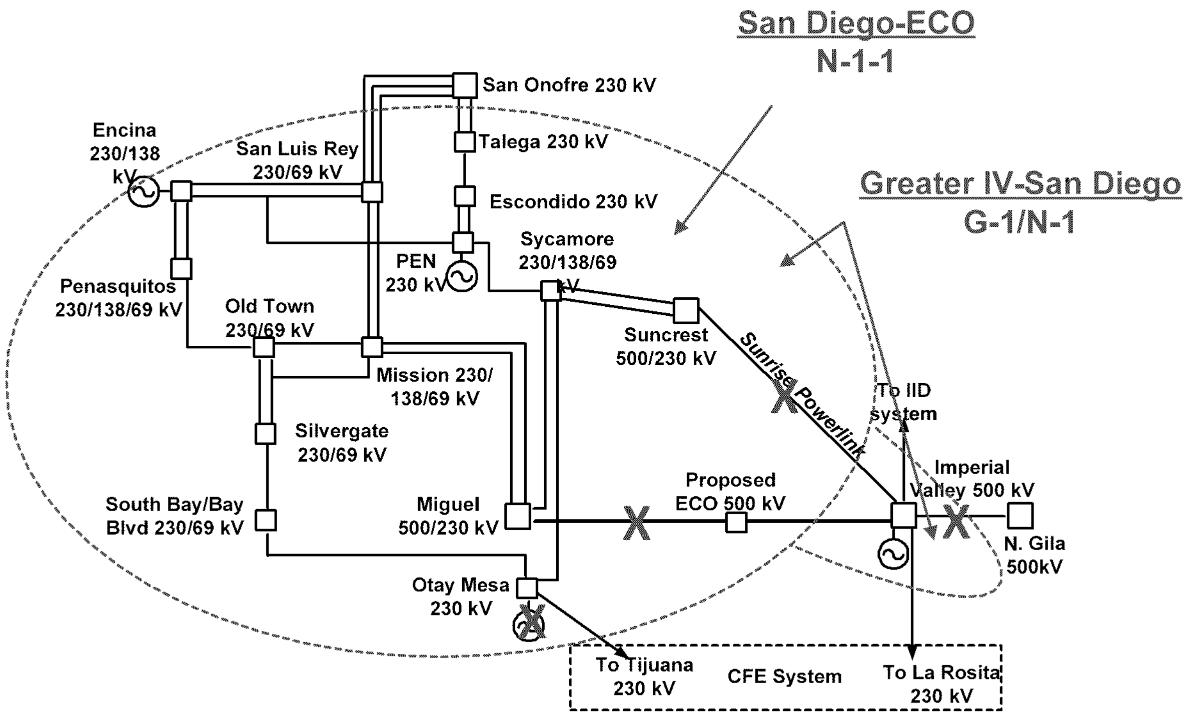
A. No. The most limiting contingency in the Greater Imperial Valley-San Diego (IV-San Diego) area is described by the outage of 500 kV SWPL between Imperial Valley and N. Gila substations overlapping with an outage of the Otay Mesa combined-cycle power plant (603 MW), while staying within the South of 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

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 incrementaluncommitted 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 Non-D.G. (MW)	LCR D.G. (Mw)	Total (MW)	New Gen. Required ?^	Constraint	Contingency
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 Non-D.G. (MW)	LCR D.G. (Mw)	Total (MW)	New Gen. Required ?^	Constraint	Contingency
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).

Rulemaking: 12-03-014
Exhibit No.: ISO-11
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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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.

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

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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.

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*

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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.

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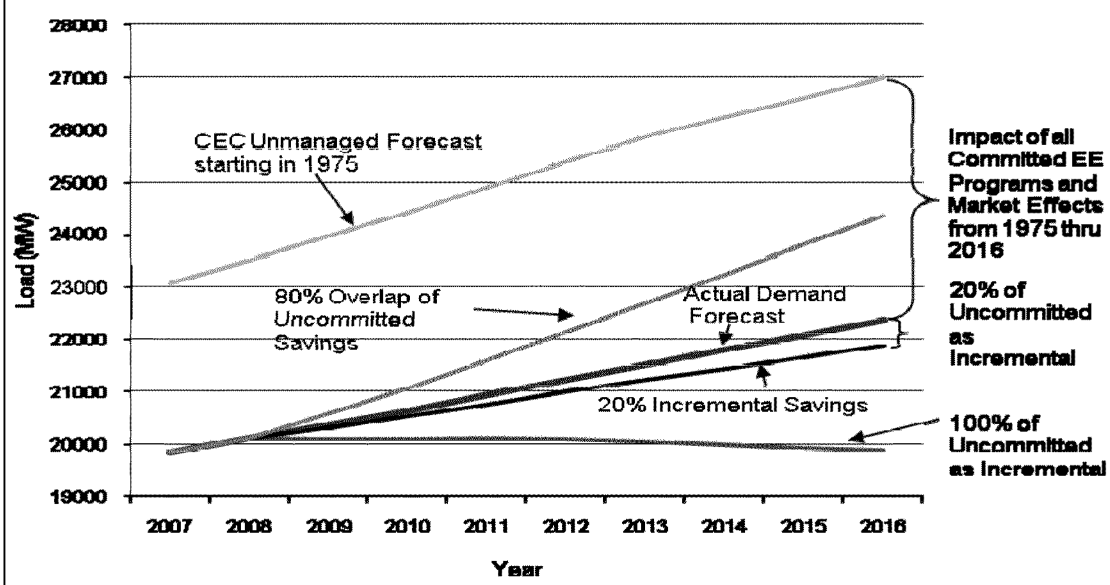
21. Figure 1 uses peak demand data for PG&E from D.07-12-052 to illustrate the issue. Similar graphs could be developed for SCE and SDG&E from the same source. An earlier version of this figure was included in the Energy Commission's *2008 IEPR Update*.

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

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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.

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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 *2009 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

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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.

$$\textit{Total residential energy use} = \sum_{ij} UEC_{ij} * SAT_{ij} * HH_j$$

$$\textit{Total commercial energy use} = \sum_{ik} EUI_{ik} * SAT_{ik} * FloorArea_k$$

$$\textit{Total industrial energy use} = \sum_{il} kWh_{il}$$

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/ft2)

$FloorArea$ = floor area of building type k (ft2)

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:

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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**

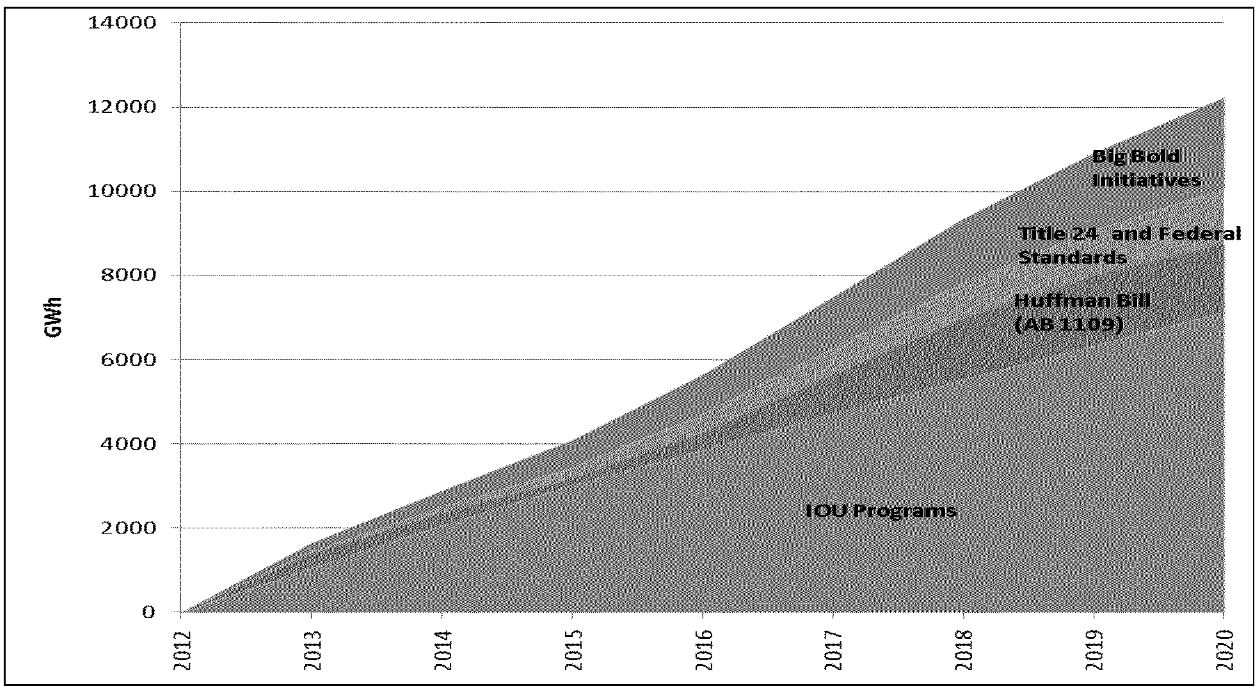
Source: Itron and California Energy Commission, 2009

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

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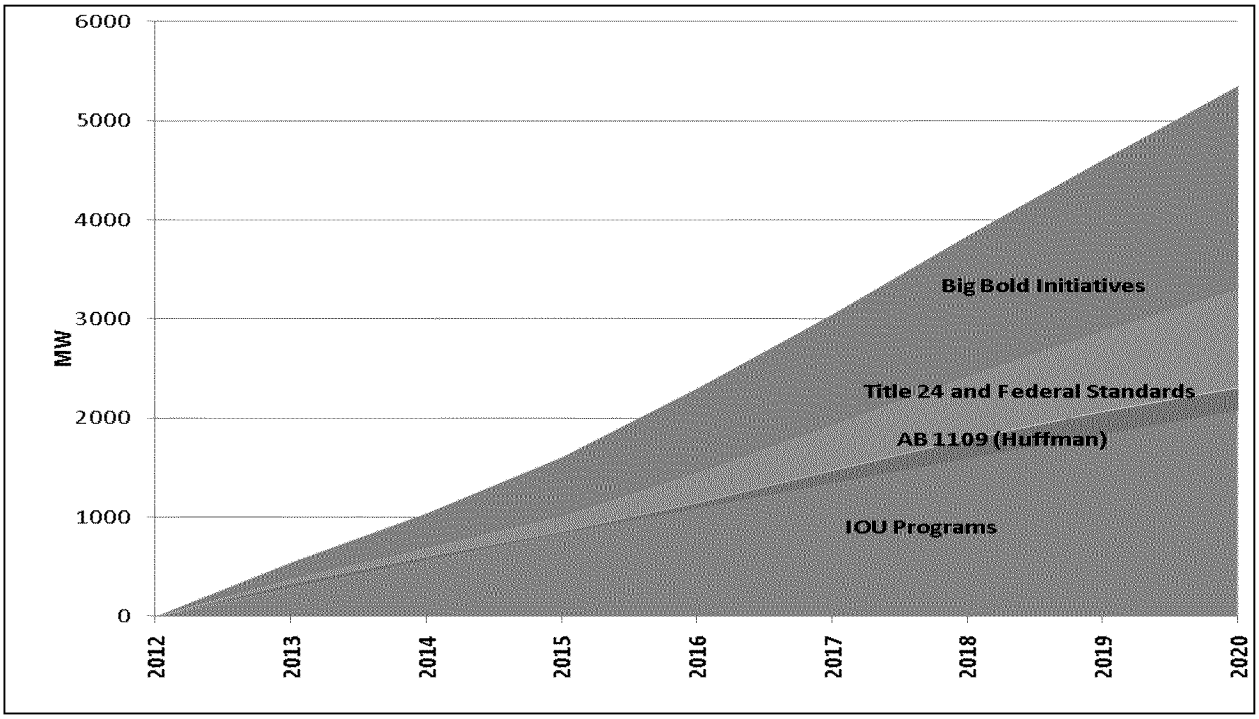
Figure 3: Uncommitted Peak Impacts Incremental to *2009 IEPR* Demand Forecast for Combined IOUs, Mid Savings Scenario



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.

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Table 10: Incremental Uncommitted Savings in 2020 and Impact Relative to Energy Commission *2009 IEPR* Forecast by Service Area

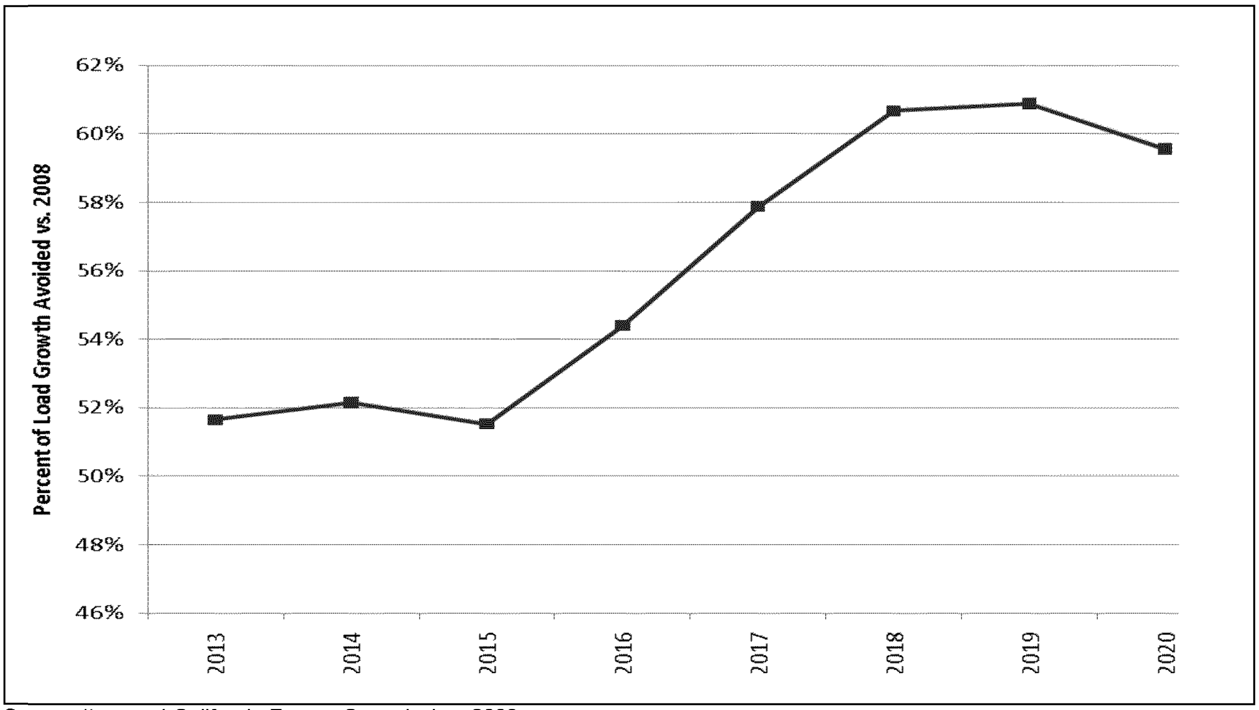
		2009 IEPR Forecast		2020 Incremental Uncommitted Impacts			Percent Load Growth Avoided		
Utility	Units	2008	2020	Low	Mid	High	Low	Mid	High
PG&E	Energy (GWh)	88,359	96,612	4,634	5,130	6,087	56%	62%	74%
	Peak (MW)	20,204	22,683	1,731	2,245	2,722	70%	91%	110%
SCE	Energy (GWh)	90,009	97,995	4,971	5,874	6,848	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.

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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]

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

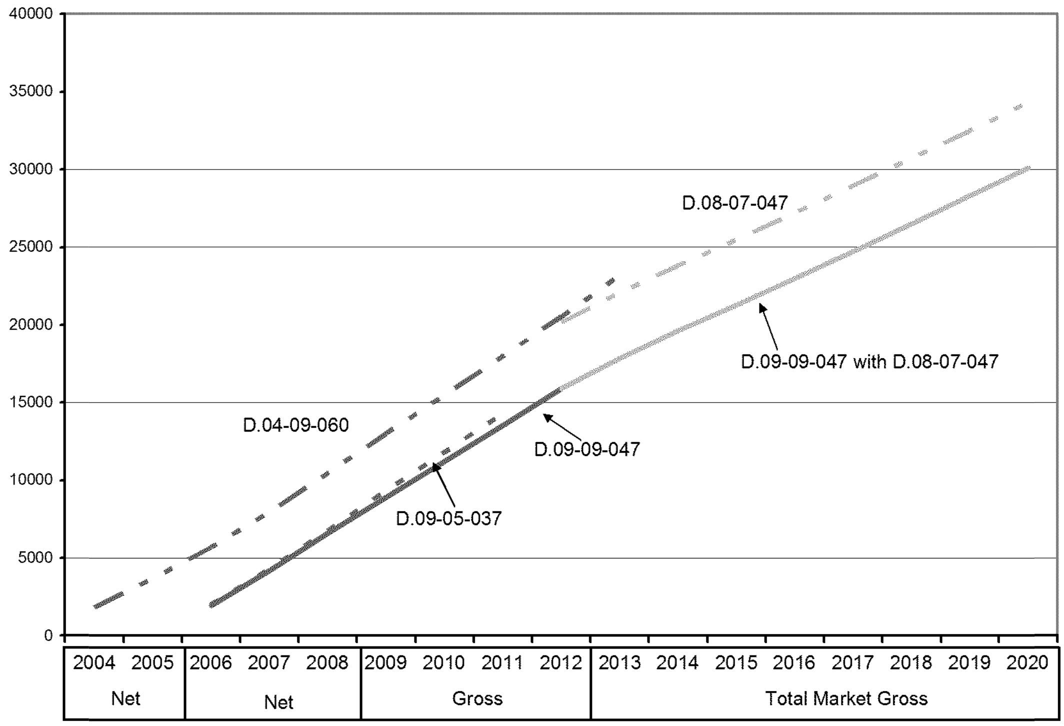


Figure 2. GWH Savings Goals [Projection]

Comparison of Original D. 04-09-060 to Current D. 09-09-047 [aggregate effects]

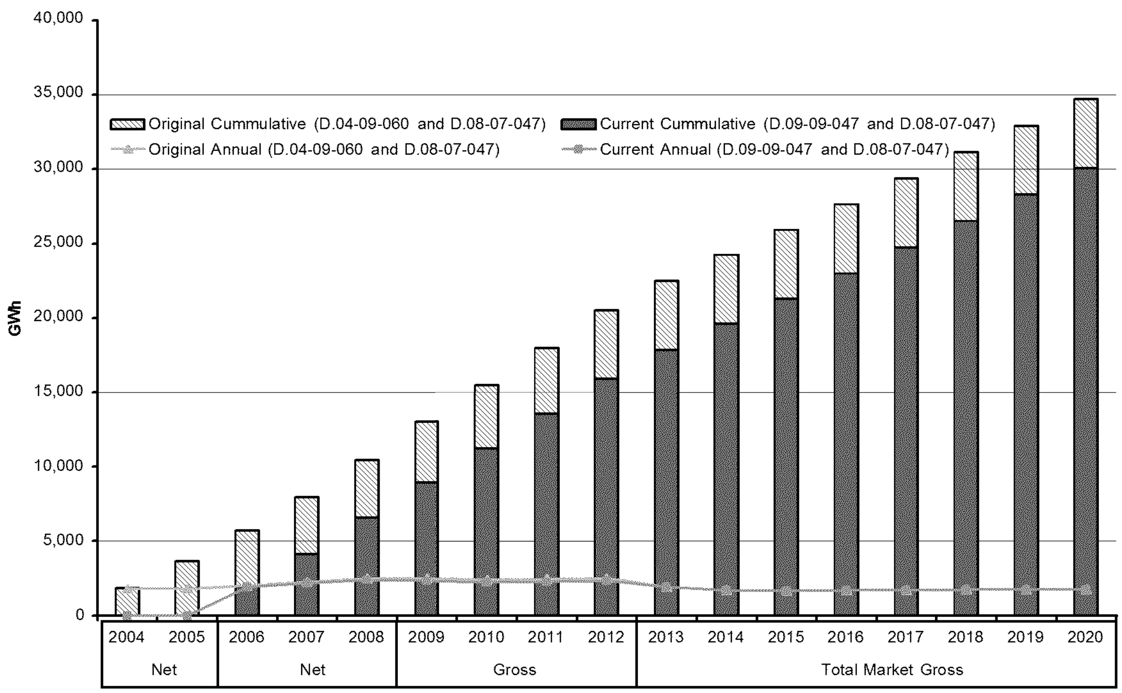


Figure 3. MW Savings Goals [Projection]

Comparison of Original D. 04-09-060 to Current D. 09-09-047 [aggregate effects]

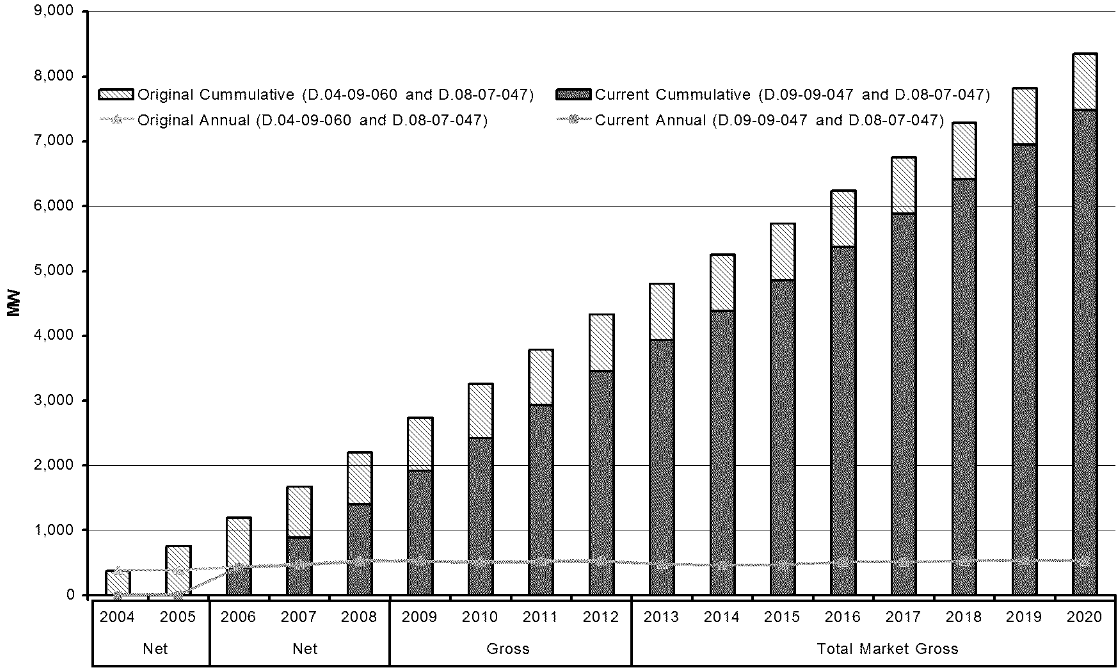
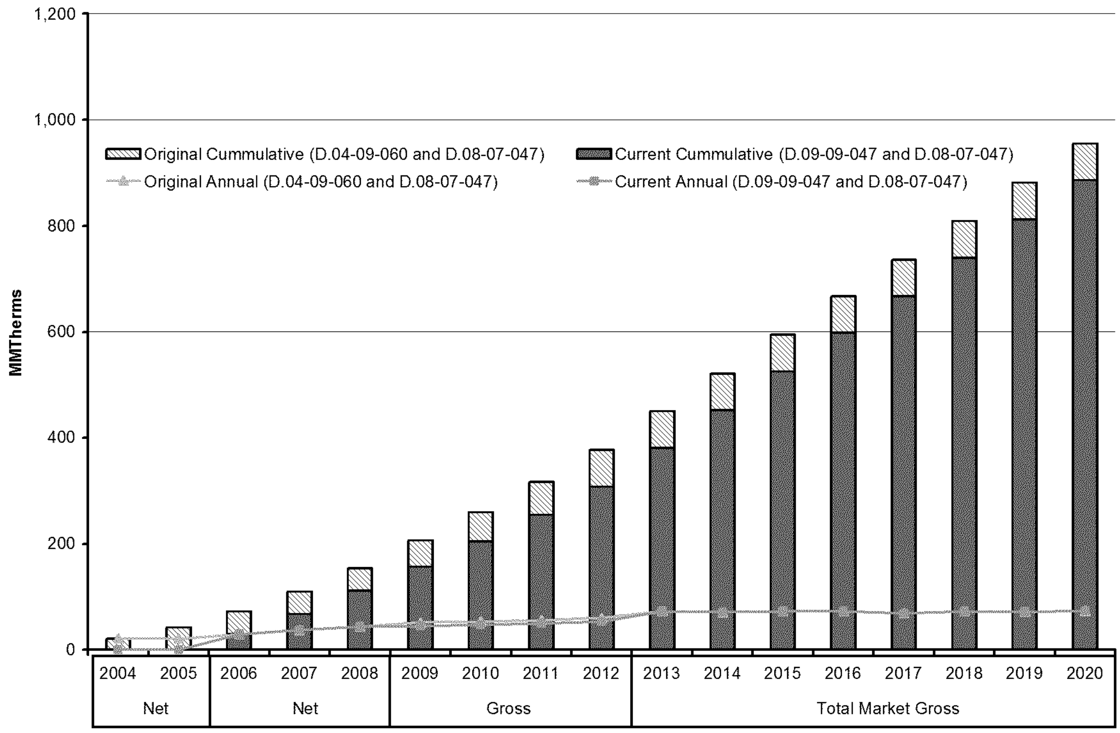


Figure 4. Therm Savings Goals [Projection]

Comparison of Original D. 04-09-060 to Current D. 09-09-047



Lifecycle Logged Savings by Utility by Fuel Type

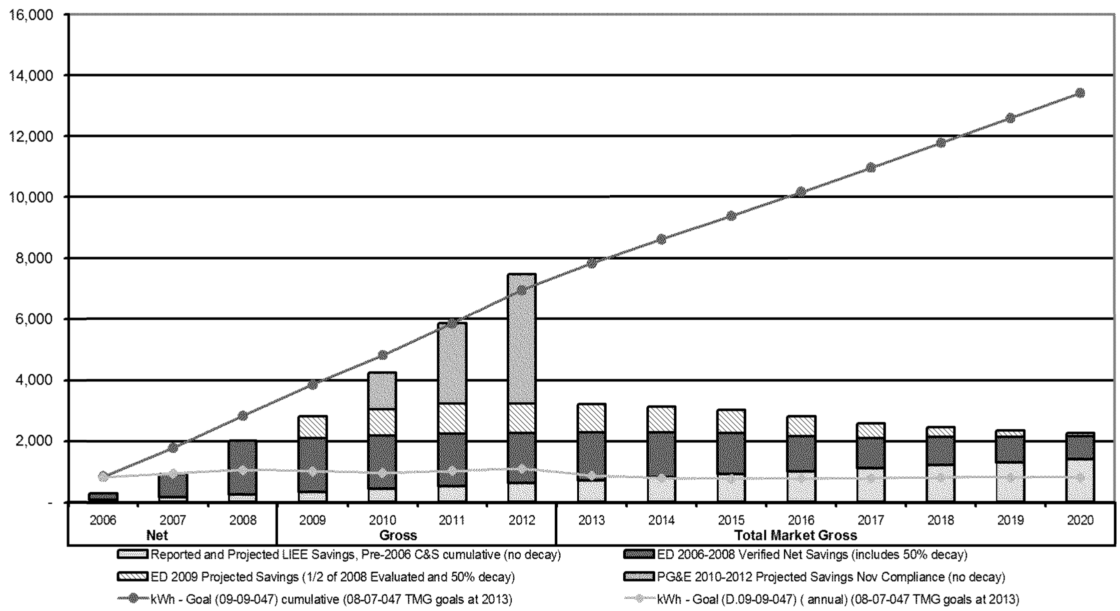
The following figures illustrate the *2006-2008 evaluated net* savings the Commission has reported for the 2006-2008 program period including 50 percent of the decay projected for these measures expiring over time. The savings in the 2010-2012 period are *projected* based on their July 2nd 2009 filings. 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.

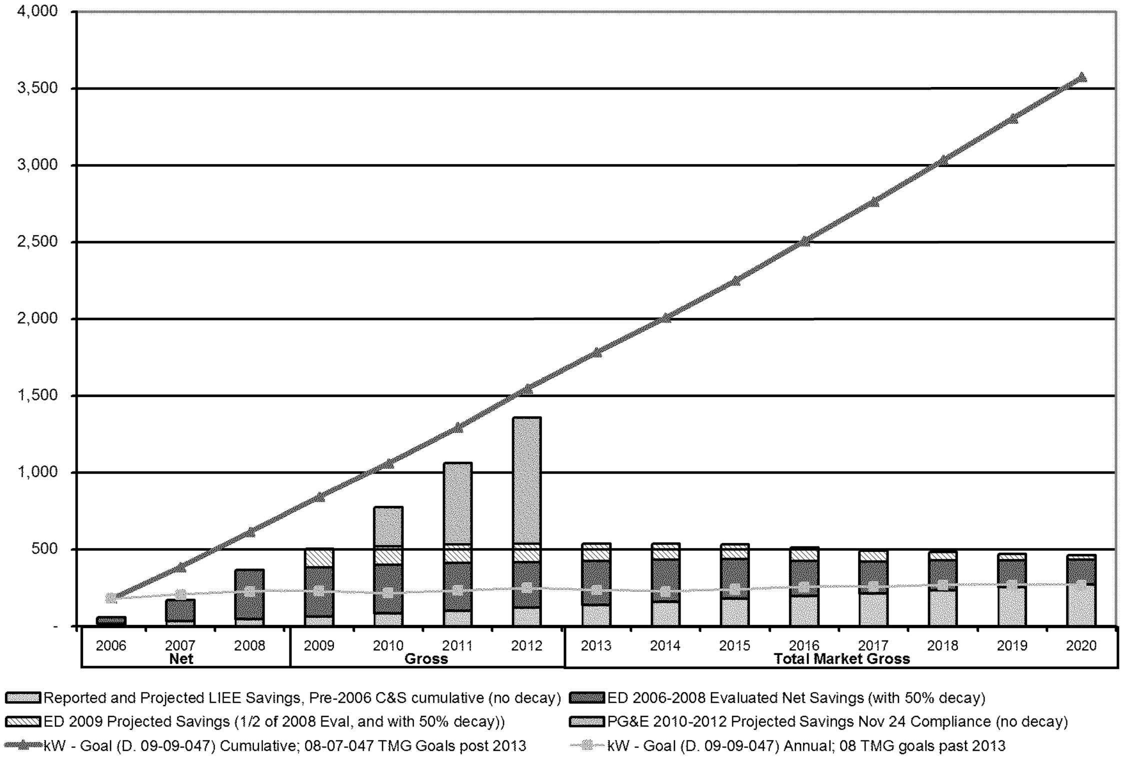
No assumptions about the decay or lifecycle savings for the 2010-2012 proposed programs are included in these figures; and pre-2005 C&S and Low Income projections past 2009 assume continued savings at the same pace with no decay.

PG&E Recorded and Projected Savings v. Commission Adopted Goals GWh

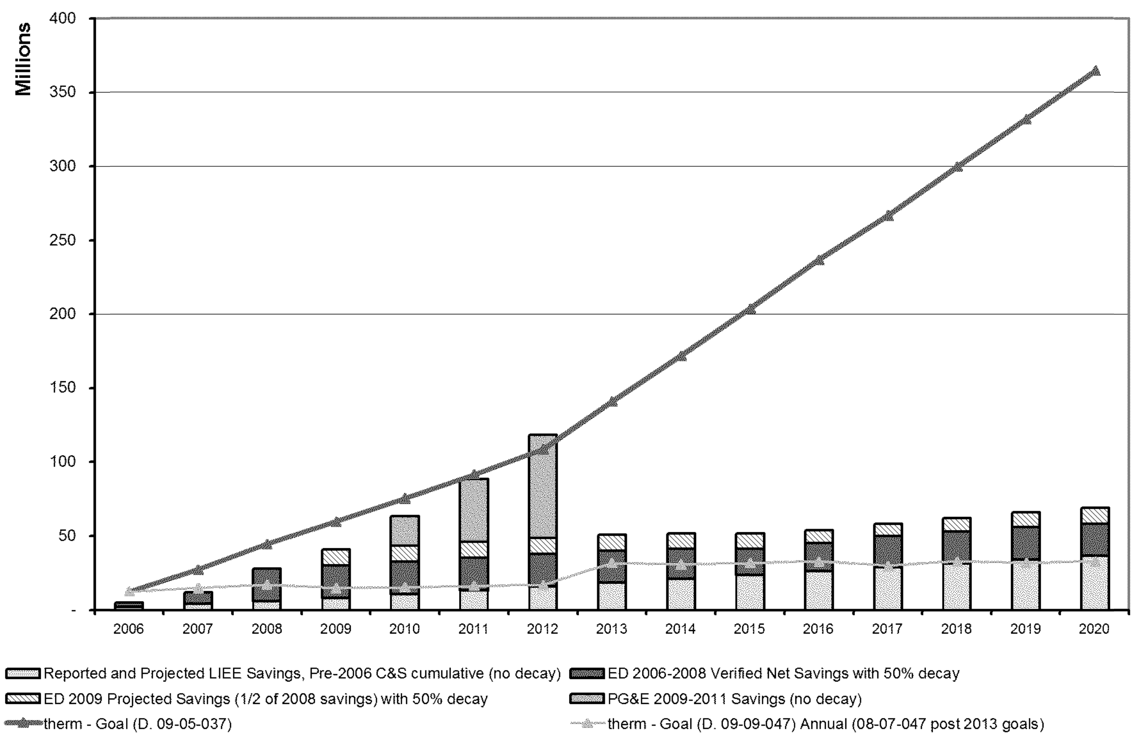


SB_GT&S_0558805

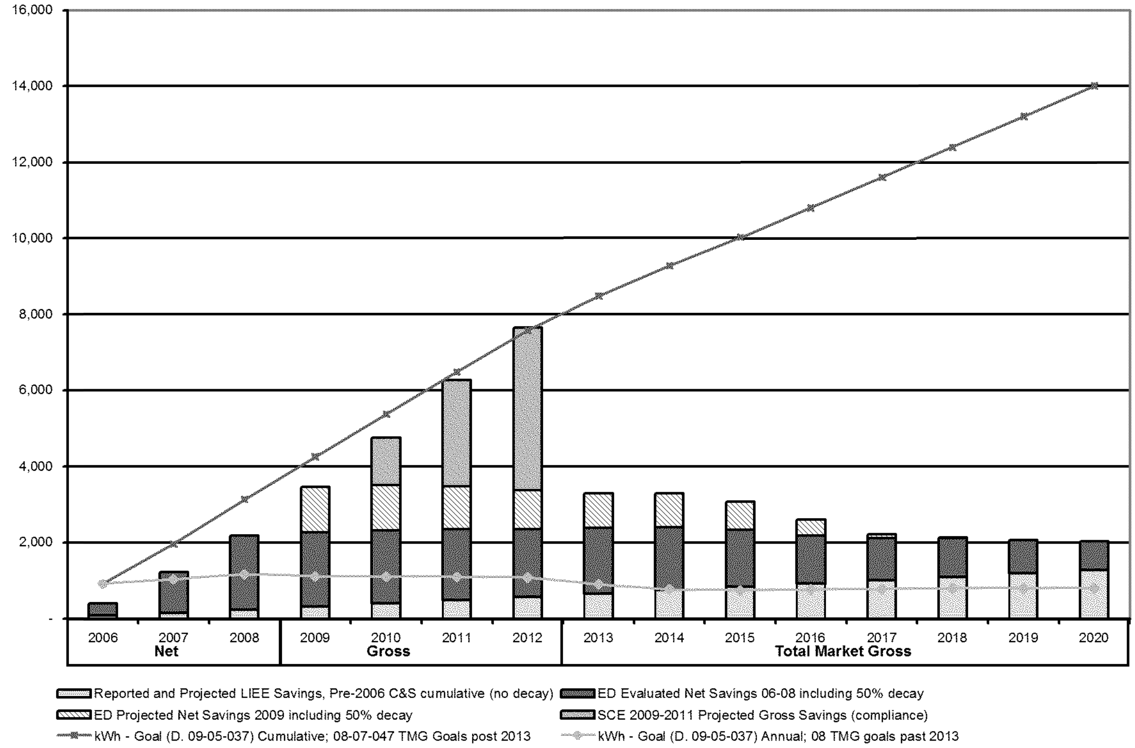
PG&E Recorded and Projected Savings v. Commission Adopted Goals MW



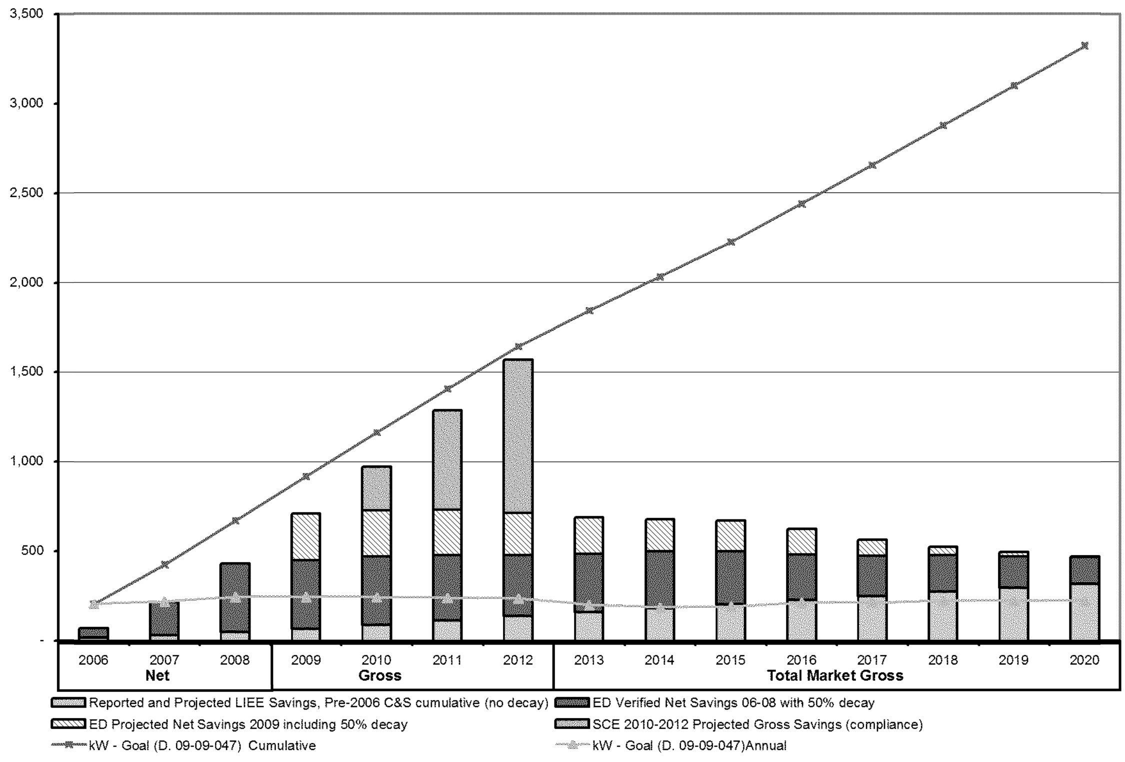
PG&E Recorded and Projected Savings v. Commission Adopted Goals MMTherms



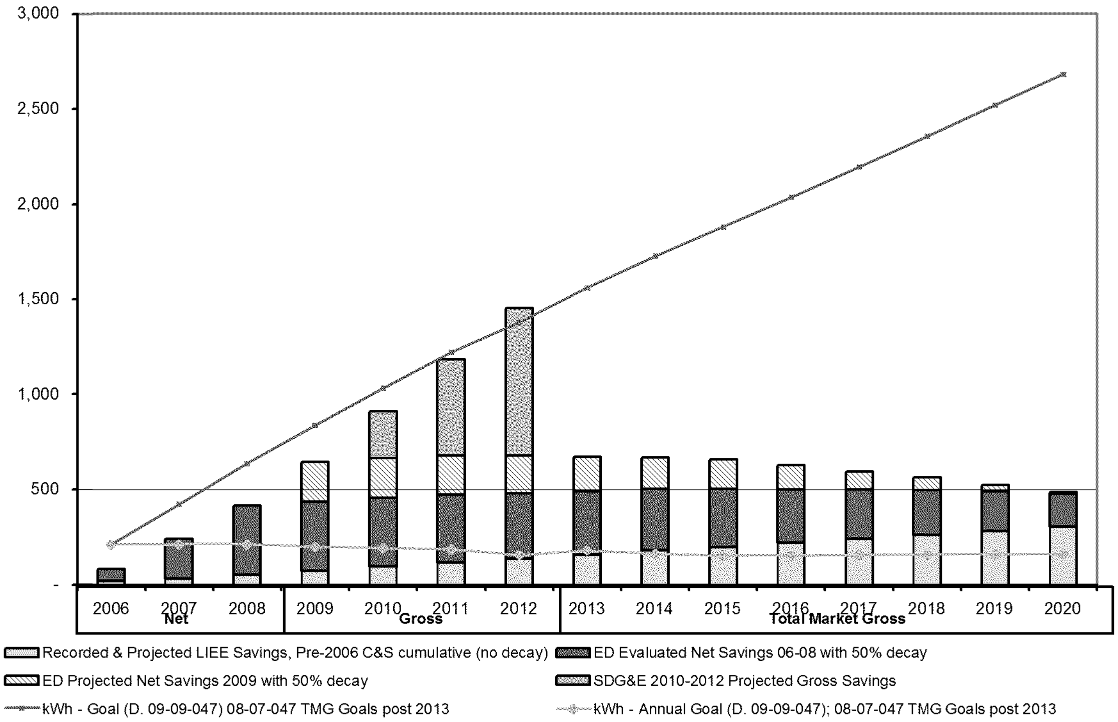
SCE Recorded and Projected Savings v. Commission Adopted Goals GWH



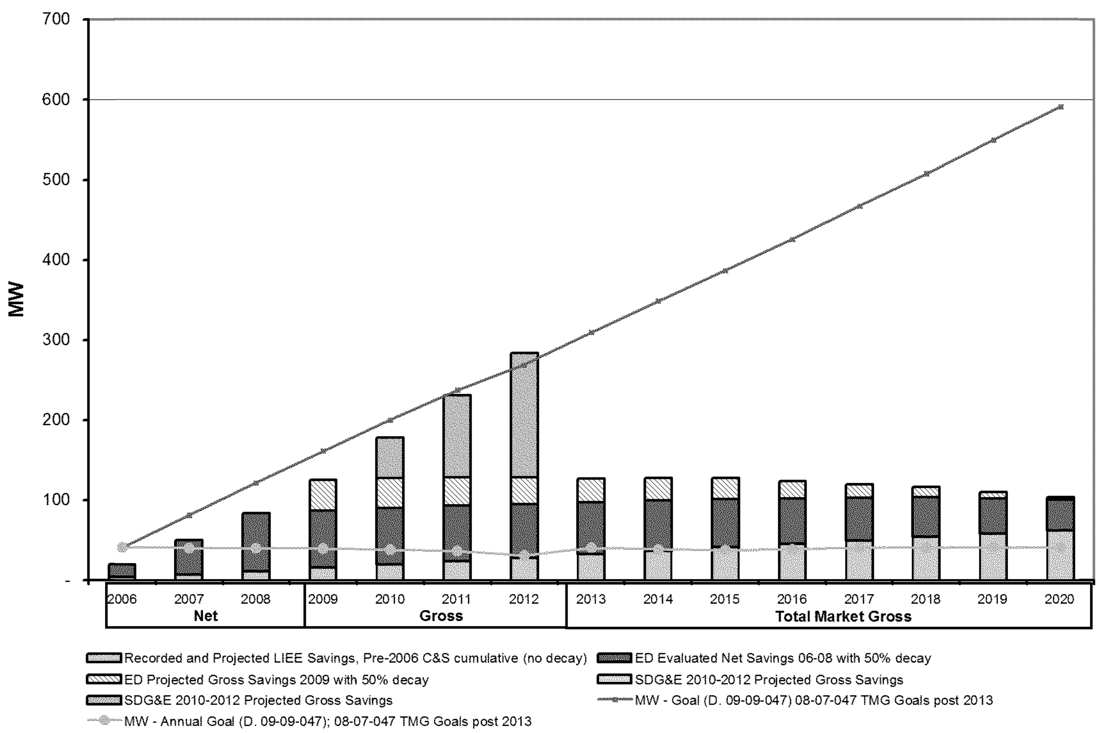
SCE Recorded and Projected Savings v. Commission Adopted Goals MW



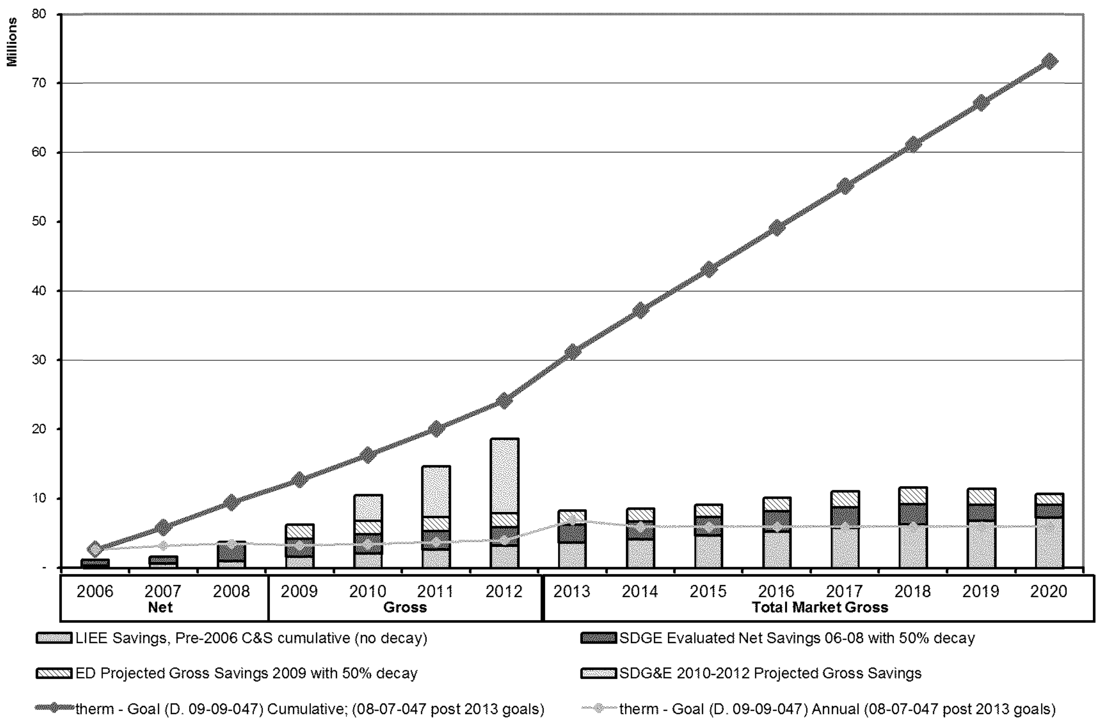
SDG&E Recorded and Projected Savings v. Commission Adopted Goals GWH



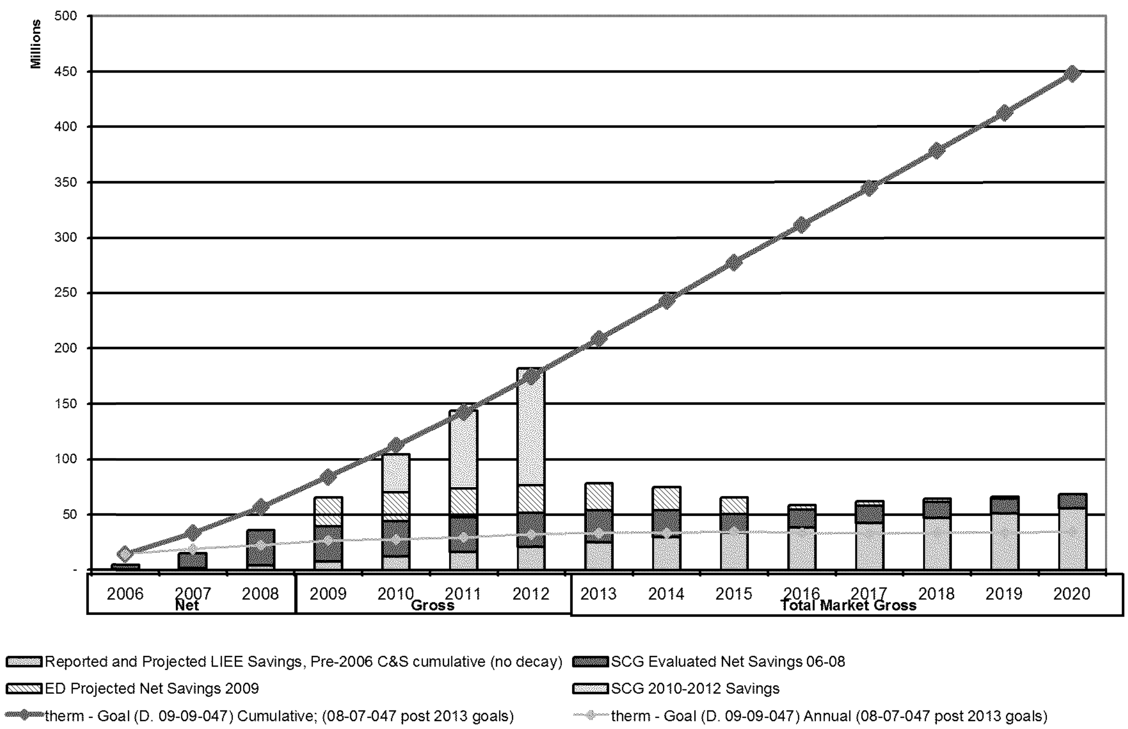
SDG&E Recorded and Projected Savings v. Commission Adopted Goals MW



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

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Nathaniel Skinner, CPUC Energy Division, Procurement

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]

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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 and 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

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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.

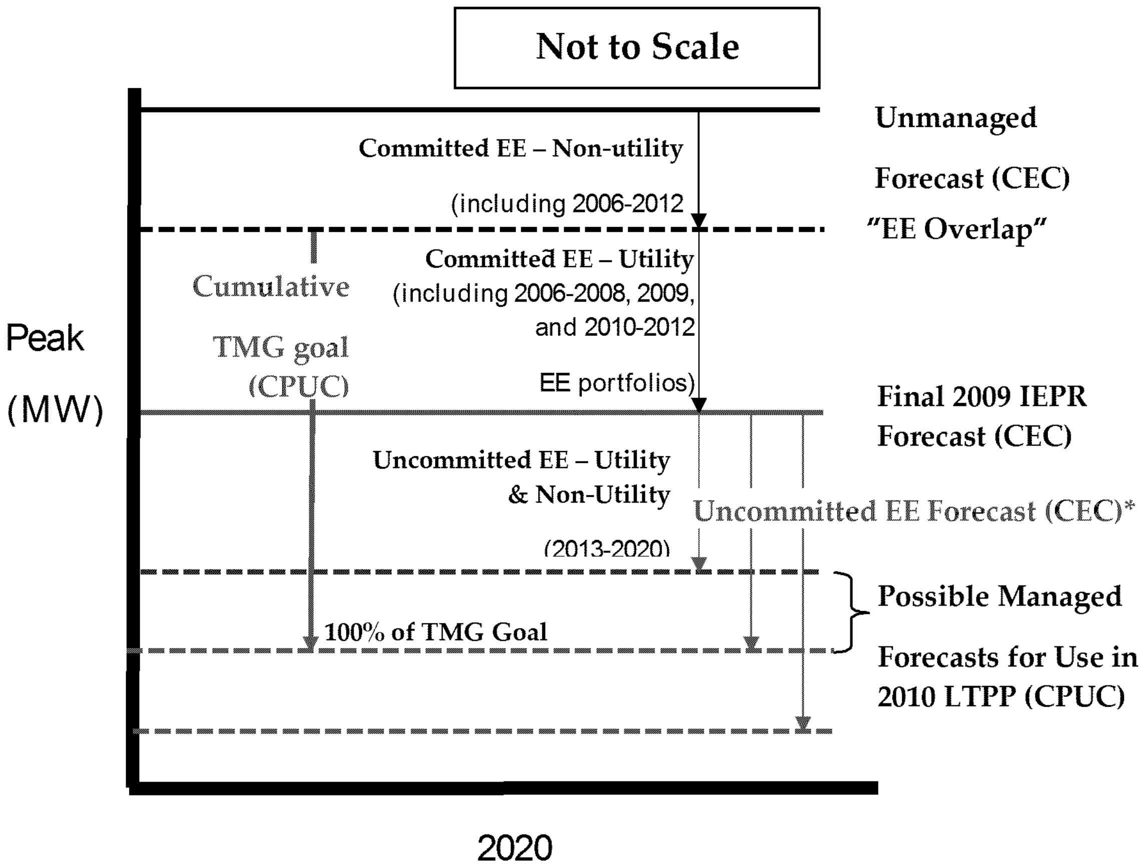
In the event of a mismatch, the Staff Proposal recommended using the lower of the two quantities for purposes of procurement planning. The rationale for using the lower of the two was "at worst, a conservative choice from among the two uncertain quantities would result in earlier procurement of resources 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.