Docket:	**R.12-03-014**
Witness:	**Julia May**
Exhibit No.:	

Order Instituting Rulemaking to Integrate and Refine Procurement Policies and Consider Long-Term Procurement Plans	R.12-03-014 (Filed March 22, 2012)

SELECTED SOURCES SUPPORTING PREPARED DIRECT TESTIMONY OF JULIA MAY ON BEHALF OF THE CALIFORNIA ENVIRONMENTAL JUSTICE ALLIANCE

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

July 25, 2012

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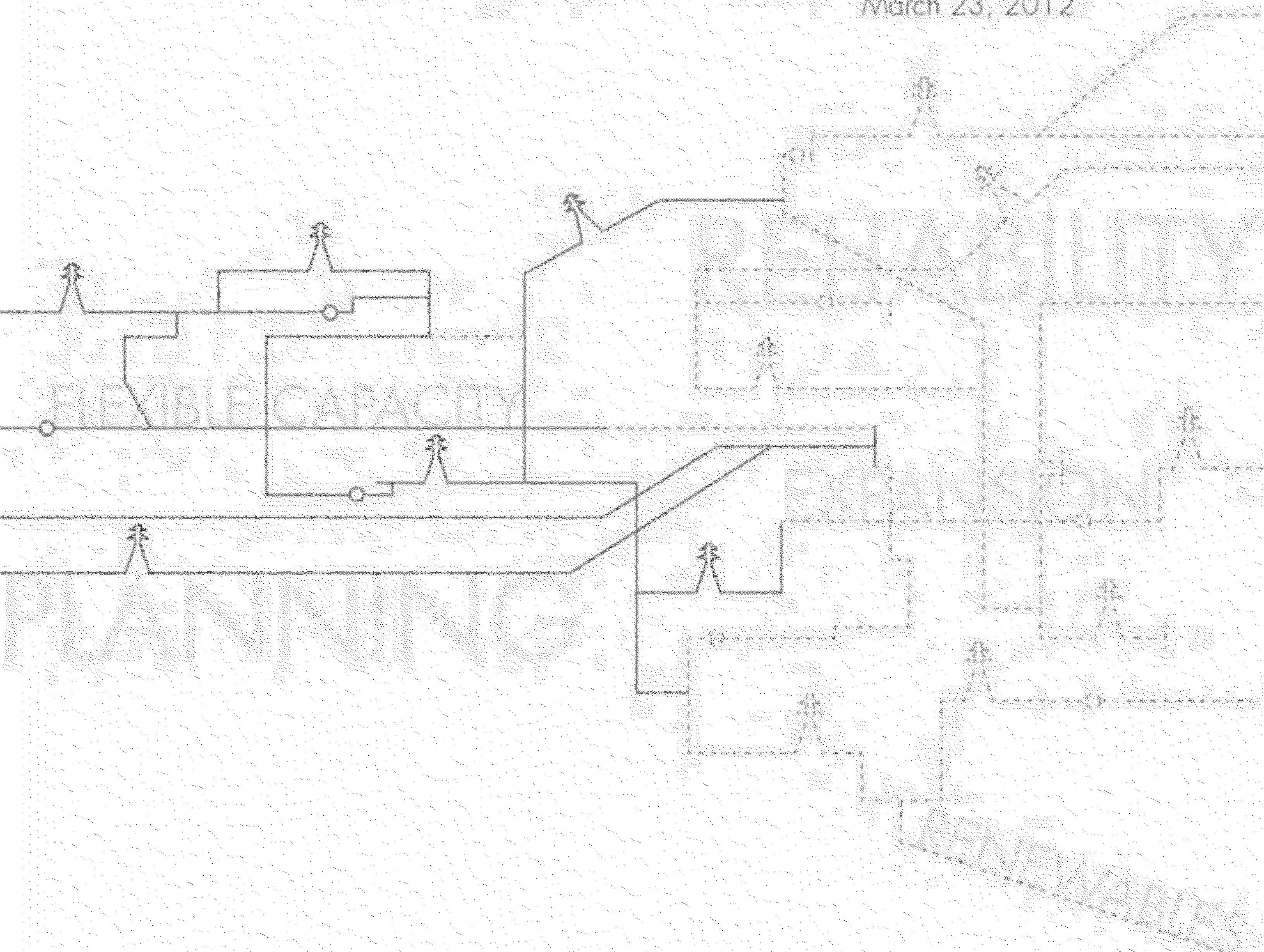
2011-2012 TRANSMISSION PLAN

March 23, 2012



California ISO

Shaping a Renewed Future

Prepared by: Infrastructure Development

Approved by ISO Board of Governors

The majority of identified reliability concerns are related to facility overloads or low voltage. Therefore, many of the specific projects that comprise the totals in Table 2 include line reconductoring and facility upgrades for relieving overloading concerns, as well as installing voltage support devices for mitigating voltage concerns. Additionally, some projects involve building new load-serving substations to relieve identified loading concerns on existing transmission facilities. Several initially identified reliability concerns were mitigated with non-transmission solutions. These include generation redispatch and, for low probability contingencies, possible load curtailment.

Economic Studies

Economic studies of transmission needs are another fundamental element of the ISO transmission plan. The objective of these studies is to identify transmission congestion and analyze if the congestion can be cost effectively mitigated by network upgrades. Generally speaking, transmission congestion increases consumer costs because it prevents lower priced electricity from serving load. Resolving congestion bottlenecks is cost effective when ratepayer savings are greater than the cost of the project. In such cases, the transmission upgrade can be justified as an economic project.

The ISO economic planning study was performed after evaluating all policy-driven transmission (i.e., meeting RPS targets) and reliability-driven transmission. Network upgrades determined by reliability and renewable studies were modeled as an input in the economic planning database to ensure that the economic driven transmission needs are not redundant and are beyond the reliability- and policy-driven transmission needs. The engineering analysis behind the economic planning study was performed using a production simulation and traditional power flow software.

Grid congestion was identified using production simulation and congestion mitigation plans were evaluated through a cost-benefit analysis. Economic studies were performed in two steps: 1) congestion identification; and 2) congestion mitigation. In the congestion identification phase, grid congestion was simulated for 2016 (the 5th planning year) and 2021 (the 10th planning year). Congestion issues were identified and ranked by severity in terms of congestion hours and congestion costs. Based on these results, the five worst congestion issues were identified and ultimately selected as high-priority studies.

In the congestion mitigation phase, congestion mitigation plans were analyzed for the five worst congestion issues. In addition, six economic study requests were submitted in the 2010 request window, and were evaluated in the 2011/2012 planning cycle. Based on the costs-benefits analyses performed by the ISO for all of the proposed congestion mitigation proposals, the ISO has concluded that none of the studied projects warrant approval in the 2011/2012 planning cycle. As part of the 2012/2013 transmission planning cycle a comprehensive study plan will be developed for the Central California area.

Therefore, the ISO is not recommending any economic upgrades as part of the 2011/2012 planning cycle.

2.3.1 Study Methodology

As noted earlier, the assessment of the backbone and local areas were performed using conventional analysis tools and widely accepted generation dispatch approaches. These methodology components are briefly described below.

2.3.1.1 Generation Dispatch

All generating units in the area under study were dispatched at or close to their maximum power (MW) generating levels. Qualifying Facilities (QFs) and self-generating units were modeled based on their historical generating output levels.

2.3.1.2 Power Flow Contingency Analysis

Conventional and governor power flow contingency analyses were performed on all backbone and local areas consistent with NERC TPL-001 through TPL-004, WECC regional criteria and ISO planning standards as outlined in section 2.2. Transmission line and transformer bank ratings in the power flow cases were updated to reflect the rating of the most limiting component or element. All power system equipment ratings were consistent with information in the ISO Transmission Register.

Based on historical forced outage rates of combined cycle power plants on the ISO-controlled grid, the G-1 contingencies of these generating facilities were classified as an outage of the whole power plant, which could include multiple units. Examples of such power generating facilities are the Delta Energy Center, which is composed of three combustion turbines and a single steam turbine.

2.3.1.3 Post Transient Analyses

For the ISO controlled-grid backbone system assessment, post transient analyses were performed to ascertain compliance with the WECC post transient voltage deviation criteria. The WECC criteria specify maximum post transient voltage deviation of 5 percent and 10 percent for Categories B and C contingencies, respectively, of allowable effects on other systems. The 5 percent WECC criterion was not used in the post transient analyses of the SCE system. Instead, consistent with the SCE guidelines for 7 percent deviation requirements for N-1[14] contingencies, the 7 percent and 10 percent voltage deviation guidelines were applied for the N-1 and N-2 [illegible] transient voltage deviation guidelines apply to its own system and not to other systems. For impacts on other systems, all PTOs follow WECC criteria on post transient voltage deviations.

2.3.1.4 Transient Stability Analyses

Transient stability simulations were also performed as part of the backbone system assessment to ensure system stability and positive dampening of system oscillations for critical contingencies. This ensured that the transient stability criteria for performance levels B and C as shown in table 2.3-1 were met.

[14] N-1 is a single transmission circuit outage.

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Table 2.3-5: Major paths and power transfer capabilities for the SCE area assessment

Import Path	2016 Summer Peak	2016 Spring Off-Peak	2021 Summer Peak
Path 26 Flow (N-S) (MW)	3,980	1,314	3,087
West of River (E-W) (MW)	8,224	8,377	9,669
East of River (E-W) (MW)	4,810	5,086	4,982
Pacific DC Intertie Flow (N-S) (MW)	3,000	3,000	3,084

Table 2.3-6 lists the major paths in the SDG&E service territory in southern California and the corresponding power transfer capabilities (MW) under various system conditions as modeled in the base cases for the assessment.

Table 2.3-6: Major paths and power transfer capabilities for the SDG&E area assessment

Import Path	Path Flow (MW)	
	2016 Summer Peak	2021 Summer Peak
Midway-Los Banos (Path 15)	-200	1602
Arizona-California (Path 21)	2715	2370
Northern-Southern California (Path 26)	4000	3272
IPP DC (Intermountain-Adelanto)	1804	1928
Sylmar-SCE	510	687
IID-SCE	394	692
North of San Onofre	1521	1368
South of San Onofre	628	782
ISO-Mexico (CFE)	-1.8	1.4
West of Colorado River (WOR)	5254	5022
East of Colorado River (EOR)	4035	3743
Lugo-Victorville 500 kV line	1113	1013
Eldorado-Mc Cullough 500 kV line	-224	200
Perkins-Mead 500 kV line	74	199

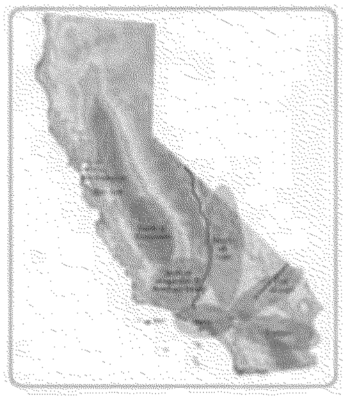
2.3.2.11 Protection Systems

To ensure reliable operation of the system, many remedial action schemes (RAS) or special protection systems (SPS) have been installed in certain areas of the system. These protection systems drop load or generation upon detection of system overloads by strategically tripping circuit breakers under selected contingencies. Some SPS are

2.6 SCE Area (Bulk Transmission)

2.6.1 Area Description

Southern California Edison (SCE) serves over 13 million people in a 50,000 square mile area of central, coastal and southern California, excluding the city of Los Angeles and certain other cities. In 2011, the SCE system load peaked at 23,388 MW on September 7, 2011. The bulk transmission system consists of 500 kV and 230 kV transmission facilities. Most of the SCE load is located within the Los Angeles Basin. However, the fastest load growth occurs in the eastern part of the SCE service territory in the Inland Empire area. The SCE service area is shown in map on the left. The CEC load growth forecast for the entire SCE area is about 350 [illegible] -in-10 heat wave load forecast includes the SCE service area, the Pasadena Water and Power Department and the California Department of Water Resources pump load. The 2016 and 2021 summer peak forecast loads are 26,987 MW and 28,878 MW, respectively. Most of the SCE area load is served by local generation that includes nuclear, qualifying facilities, hydro and oil/gas-fired power plants. The remaining demand is served by power transfers into southern California on DC and AC transmission lines from the Pacific Northwest and Desert Southwest.



In general, the SCE transmission system includes 500 kV and 230 kV facilities, with small pockets of 115 kV and 66 kV network transmissions. The bulk system includes seven areas: Metro, North of Magunden, South of Magunden, Antelope-Bailey, North of Lugo, East of Lugo and Eastern. The Metro area consists of the major load centers in Orange, Riverside, San Bernardino, Los Angeles, Ventura and Santa Barbara counties. The boundary of the Metro area is marked by Vincent, Lugo and Devers 500 kV substations. The North of Magunden, South of Magunden and Antelope-Bailey areas are composed of 500 kV, 230 kV and 66 kV transmission systems north of Vincent. North of Lugo consists of 230 kV, 115 kV and 55 kV transmission system stretching from Lugo to Kramer and Inyokern and into Nevada. East of Lugo consists of 500 kV, 230 kV and 115 kV transmission systems from Lugo to Eldorado. The eastern area includes 500 kV, 230 kV and 115 kV transmission systems from Devers to Palo Verde in Arizona and 230 kV transmission systems from Devers to Julian Hinds.

2.6.2 Area-Specific Assumptions and System Conditions

The SCE area study was performed consistent with the general study methodology and assumptions described in section 2.3.

The contingencies that were performed as part of this assessment are listed on the ISO-secure website. In addition, specific assumptions and methodology that applied to the SCE area study are provided below.

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 nee[illegible] udies are shown in Table 3.2-2.

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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 3.3-20: 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. [illegible] 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 High (MW)	Trajectory Low (MW)	Environmental High (MW)	Environmental Low (MW)	ISO Base Case High (MW)	ISO Base Case Low (MW)	Time-Constrained High (MW)	Time-Constrained 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

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

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

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

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

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

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

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

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

Conclusions

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

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

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

3.3.2.3.4 LCR Study Results San Diego Area

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

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

The following areas were examined for LCR generation requirements:

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

Area Definition for San Diego

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

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

The substations that delineate the San Diego area are:

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

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

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

3.4.2 AB 1318 Reliability Assessment ┐ Study Results

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

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

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

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

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

3.4.2.1 Study Results

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

Table 3.4-→+¶ ♂□□┘□♬● ♂●□┘┐□☼♬┴┼←□←♂* ☼├┘└┘┐♬ □┘♂╤┬89<

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

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

For study conclusions, please refer to section 3.3.2.

Estimate of Premature Deaths Associated with Fine Particle Pollution (PM2.5) in California Using a U.S. Environmental Protection Agency Methodology

August 31, 2010

California Air Resources Board

California Environmental Protection Agency

Printed on Recycled Paper

EXECUTIVE SUMMARY

The United States Environmental Protection Agency's (U.S. EPA) recently released "Quantitative Health Risk Assessment for Particulate Matter" provides national estimates of premature mortality associated with fine particulate matter pollution (PM2.5), supported by its finding that the scientific evidence shows a causal connection between mortality and exposure to PM2.5. This report describes the U.S. EPA's risk assessment methodology for calculating premature mortality, and its 2009 Integrated Science Assessment for particulate matter that provides the underlying scientific basis for the calculations. These U.S. EPA reports were prepared as part of U.S. EPA's periodic review of the National Ambient Air Quality Standards (NAAQS) for particulate matter. The U.S. EPA risk assessment estimated premature deaths associated with PM2.5 nationwide, and in 15 urban areas including Los Angeles and Fresno. This report applies the U.S. EPA methodology to California on a statewide basis.

The U.S. EPA's reports were peer reviewed in a public process by the Clean Air Scientific Advisory Committee (CASAC) Particulate Matter Review Panel, an independent peer review body of national scientists. The methodology described in this report is used to quantify the premature deaths associated with current levels of PM2.5 in California, and to estimate the premature deaths avoided by achieving compliance with the current annual air quality standard for PM2.5. This report also describes the method used by U.S. EPA to calculate the health benefits of PM2.5 emission reductions from specific source categories.

The foundation of the methodology is the association between long-term PM2.5 concentrations and premature death, which is provided by peer reviewed health studies. There are a large number of published health studies that estimate the additional risk of mortality due to long-term exposure to PM2.5. U.S. EPA's new quantitative health risk assessment for particulate matter uses a 2009 study (Krewski et al., 2009) for the core analysis. This study is an extension of a 2002 study (Pope et al., 2002) used in the previous PM2.5 NAAQS risk assessment. This report estimates premature death from PM2.5 in California based on the 2009 Krewski study.

Using U.S. EPA's methodology, the estimated number of annual PM2.5-related premature deaths in California is 9,200 with an uncertainty range of 7,300 – 11,000. This estimate of premature deaths is based on the latest exposure period in the 2009 Krewski study with data from 116 U.S. cities and about 500,000 people.

Krewski et al. (2009) published several risk estimates that reflect different degrees of adjustment for confounders. U.S. EPA selected the concentration-response functions that are most thoroughly adjusted for individual and ecologic covariates. The effect estimates from the two exposure periods differ slightly, but the difference is not statistically significant. Because there is no compelling reason to select one exposure period over the other, both were used in making the range of estimates presented in the U.S. EPA PM NAAQS risk assessment.

III. APPLICATION OF U.S. EPA METHODS IN CALIFORNIA

U.S. EPA's quantification methods can be applied at different scales provided the input data are available. The risk assessment included a national scale analysis and individual analyses of 15 urban areas. The method can be applied on a statewide basis to quantify the premature mortality associated with PM2.5 in California, as well as to estimate the number of premature deaths that would be avoided by attaining the PM2.5 NAAQS. Table 3 compares the elements of the mortality calculation used by U.S. EPA and ARB.

Calculation of the current statewide mortality estimates involves several steps:

- Estimate exposure at the census tract level using measured air quality data and population
- Estimate incidence of premature death by applying concentration functions to estimated exposures and baseline mortality rates
- Aggregate results to air basin and statewide totals

Table 3: Comparison of U.S. EPA and ARB Mortality Calculation Method

Elements	**U.S. EPA**	**ARB**
Source of Concentration-Response functions	Krewski et al., 2009	Krewski et al., 2009
Threshold	5.8 ffg/m^3	5.8 ffg/m^3
Model	BenMAP	BenMAP
PM2.5 exposure	Air quality modeling and measured data	All measured data

Premature mortality associated with long-term exposure to PM2.5 was estimated using the same concentration response functions from Krewski et al. (2009) used by U.S. EPA in the risk assessment. Relative risk is expressed as the percent change in the baseline mortality rate associated with a 10 µg/m^3 change in ambient PM2.5 concentration.

Calculation of the number of deaths associated with PM2.5 exposure also requires estimation of population exposure to PM2.5, which is estimated from monitored or modeled concentrations of PM2.5. ARB and U.S. EPA use the software program BenMAP, a GIS-based program developed by U.S. EPA, which uses input exposure data and concentration-response functions to calculate estimated mortality.

Exposure Assessment

For its national scale analysis U.S. EPA used an exposure assessment approach that combined ambient data with modeled PM2.5 concentrations, which is a so-called "fusion" approach. To some extent this is necessitated by the large areas of the country where PM2.5 monitoring is sparse, which introduces uncertainties in the exposure assessment.

In contrast, California has the most extensive PM2.5 monitoring network in the nation, comprising approximately 100 monitors that collect PM2.5 mass data using federally approved methods. For the present analysis, air quality data from California's PM2.5 monitoring network for the years 2006, 2007, and 2008 were used to estimate population exposure using spatial interpolation, which is a method of estimating concentrations based on nearby monitors. PM2.5 monitors are not evenly distributed throughout the state, but are mainly located in heavily populated areas that have the highest PM2.5 levels. Approximately half the population of California lives in a zip code that is within 6 miles of a PM2.5 monitor. For example, during the 2006-2008 period there were 19 monitoring sites operating in the South Coast Air Basin.

Even with an extensive air quality monitoring network, the quantification method requires use of a technique for applying the monitoring results across a geographic area. Using a method called spatial interpolation, population exposure in areas between monitors can be estimated. ARB uses a standard spatial interpolation method known as inverse distance-squared weighting (Shepard, 1968; Goodin and McRae, 1979). This method yields reasonable accuracy in estimating pollutant concentrations near monitoring stations, although when distance from the monitoring station increases the uncertainty in the interpolated concentration also increases. This method gives more accurate estimates of concentration in areas with a large number of monitors with good spatial coverage as is the case in populated areas in California.

Use of Concentration-Response Function

To calculate PM2.5-related deaths, the ARB employs the same method used by the U.S. EPA. The method links changes in PM2.5 concentration with predicted changes in the number of premature deaths. The method has 4 elements: 1) a concentration-response (C-R) function (explained below), 2) a predicted change in PM2.5 concentration, 3) death rates for people older than 30 years of age, and 4) number of people in affected counties from the U.S. Census Bureau.

Health studies show that when the PM2.5 concentration decreases so does the death rate. The C-R function describes how much the death rate changes when the PM2.5 concentration changes. The concentration-response functions used by U.S. EPA are listed in Table 4. They relate the change in the baseline mortality rate for every decrease of 1 $\mu g/m^3$ of PM2.5. Using the C-R function and knowing the death rate, the change in PM2.5 concentration, and the number of people over 30, the U.S. EPA is able to make predictions about health outcomes when PM2.5 improves.

Table 4: Concentration-response functions per $\mu g/m^3$ used in U.S. EPA Risk Assessment (Krewski et al., 2009)

Endpoint	Lower Bound	Coefficient	Upper Bound
First exposure period			
Mortality, all-cause	0.00276	0.00431	0.00583
Mortality, cardiopulmonary	0.00677	0.00898	0.01115
Mortality, ischemic heart disease	0.01363	0.01689	0.02005
Mortality, lung cancer	0.00325	0.00880	0.01432
Second exposure period			
Mortality, all-cause	0.00354	0.00554	0.00760
Mortality, cardiopulmonary	0.01007	0.01293	0.01587
Mortality, ischemic heart disease	0.01748	0.02167	0.02585
Mortality, lung cancer	0.00554	0.01293	0.02029

Premature Deaths in California Associated with Current PM2.5 Levels

Mortality estimates are calculated in three ways which reflect the nature and scope of epidemiological studies: cardiopulmonary, ischemic heart disease, and all-cause mortality. PM2.5 exposure has been most closely associated with cardiopulmonary deaths, which are also the most frequent causes of death in the U.S. In addition, the cardiopulmonary deaths represent an endpoint judged to be causally related to PM2.5 exposure[13]. The greater scientific certainty for this effect, along with the greater specificity of the endpoint, leads to an effect estimate for cardiopulmonary deaths that is both higher and more precise than that for all-cause mortality. Cardiopulmonary mortality and all-cause mortality are estimated separately, and the estimates represent independent measures of the effect of PM2.5 exposure.

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[13] Available at: http://www.epa.gov/ttn/naaqs/standards/pm/data/PM RA FINAL June 2010.pdf, pages 3-20 to 3-22.

The estimates for cardiopulmonary mortality are generally larger, although not distinguishable considering the overlapping confidence intervals, than for all-cause mortality, particularly in analyses based on the second exposure period in Krewski et al. (2009), for several reasons. For example, the incidence data for all-cause mortality includes categories which would not plausibly be linked to PM2.5 exposure. Deaths due to such causes as complications of surgery, gastrointestinal diseases, homicides, and accidents are included in all-cause mortality, although it is unlikely that PM2.5 exposure has any influence on these deaths.

Including these unrelated causes of death has the effect of "diluting" the effect estimate for all-cause mortality related to PM2.5 exposure, as can be seen in the results in Appendix B of this report. This effect is particularly evident in the results using the second period exposure data, possibly related to the influence of the larger number of people in the second time period analyses (about 500,000 people in the second time period versus about 300,000 in the first time period), which would tend to increase the precision and robustness of the estimates from the second exposure period compared to the first.

Another factor that could influence these results is changes in the criteria for coding cause of death. The standards for coding specific causes of death have changed and become better defined over the period of the study. Because of this, the more precise categories into which more recent deaths are attributed would tend to increase the robustness and precision of estimates of the effect of PM2.5 exposure on these specific causes of death.

The third type of mortality found by U.S. EPA to be causally linked to long-term PM2.5 exposures is ischemic heart disease, which can lead to a heart attack due to inadequate blood flow to the heart. It is a subset of cardiopulmonary deaths, and represents a large fraction of cardiopulmonary deaths. Cardiopulmonary disease and ischemic heart disease are subsets of all-cause mortality, and ischemic heart disease is a subset of cardiopulmonary disease. Consequently these numbers should not be added together, and the results are each shown in separate tables. The three estimates presented are those associated with exposure down to 5.8 $\mu g/m^3$, which is the threshold for quantification used in U.S. EPA's risk assessment.

Estimates using a calculation threshold of 5.8 $\mu g/m^3$ assume that there is an effect down to that level of exposure. The U.S. EPA risk assessment discusses the issue of threshold of effect.[14] This level was chosen as the calculation threshold because it is the lowest annual-average PM2.5 concentration reported by Krewski et al. (2009). The tables show a mean estimate and a low and a high

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[14] Available at: http://www.epa.gov/ttn/naaqs/standards/pm/data/PM_RA_FINAL_June_2010.pdf, page 3-1 to 3-3. See also footnote 8.

estimate that represent the upper and lower 95% confidence intervals. The mortality estimates in Tables 5 through 10 are based on monitored PM2.5 data from years 2006 through 2008. The estimates presented reflect use of the C-R functions derived from the second exposure period (1999-2000) of Krewski et al. (2009). Estimates based the first exposure period are in Appendix B of this report. The baseline rates used for the analysis were supplied by the California Department of Public Health (CDPH, 2010).

The estimates of the number of premature deaths that would be avoided by reducing PM2.5 levels to the calculation threshold of 5.8 μg/m^3 (Tables 5-7) are larger than the estimated number of premature deaths avoided by reducing PM2.5 levels to the annual-average NAAQS of 15 μg/m^3 (Tables 8-10). This is because reduction to the calculation threshold represents a larger reduction in PM2.5 concentration than reduction to the level of the NAAQS. The larger the reduction in concentration, the greater the reduction in premature deaths predicted by the C-R function.

Table 5: Cardiopulmonary – Current Estimates of Annual Cardiopulmonary Deaths in California Associated with PM2.5 Exposure

Scenario	Low	Mean	High
Current Air Quality	7,300	9,200	11,000

*Presented here is the estimated mean (Mean) and the 95% confidence interval (Low, High). Air quality data from years 2006 to 2008. Health impacts were assessed only in areas with ambient PM2.5 levels greater than 5.8 μg/m^3. Population data from the 2000 U.S. Census were extrapolated to each corresponding year in BenMAP. The results are averages of annual impacts.

Table 6: Ischemic Heart Disease – Current Estimates of Annual Ischemic Heart Disease Deaths in California Associated with PM2.5 Exposure

Scenario	Low	Mean	High
Current Air Quality	5,500	6,800	7,900

*See footnote to Table 5

Table 7: All-Cause – Current Estimates of Annual All-Cause Deaths in California Associated with PM2.5 Exposure

Scenario	Low	Mean	High
Current Air Quality	5,400	8,400	11,000

*See footnote to Table 5

Most of the estimated premature deaths are in the South Coast Air Basin in southern California. This is because PM2.5 concentrations are high there, and a large portion of California's population lives there. The region with the next largest number of premature deaths is the San Joaquin Valley, with the remainder distributed around the state. No premature deaths were estimated in census tracts where the annual-average PM2.5 concentration was below the threshold of 5.8 μg/m^3. Premature mortality was estimated by census tract for all of California, and then aggregated into estimates at the county, air basin and statewide levels. Estimates of the number of deaths by air basin are presented in Appendix B.

Deaths Avoided in California with PM2.5 NAAQS Compliance

To estimate the benefits of achieving the federal air quality standards requires calculating the difference between current PM2.5 levels and the level at which the standard is met, in this case an annual average of 15 μg/m^3. For its nationwide analysis, the U.S. EPA uses a calculation approach called "proportional rollback" to compute such estimates. The U.S. EPA risk assessment describes the proportional rollback calculation.[15] A rollback calculation was applied to California monitoring data to estimate the statewide benefits of achieving the federal PM2.5 annual air quality standard shown below.

The estimated number of premature deaths avoided by achieving the current PM2.5 NAAQS is shown in Tables 8-10. Table 8 shows the reduction in premature deaths due to cardiopulmonary disease. Table 9 shows the reduction in premature deaths due to ischemic heart disease, a subset of cardiopulmonary disease. Table 10 shows the reduction in premature deaths from all causes. Although cardiopulmonary mortality is a subset of all-cause mortality, the mean estimate for cardiopulmonary mortality is higher than all-cause deaths. While counterintuitive, this is not an error. The two numbers are independently estimated, with statistical uncertainty that overlap between the ranges of the two numbers.

Table 8: Cardiopulmonary – Annual Cardiopulmonary Deaths Avoided in California by Attainment of the Annual-Average Federal PM2.5 NAAQS

Scenario	Low	Mean	High
National standard (15 μg/m^3)	2,100	2,700	3,300

*See footnote to Table 5.

Table 9: Ischemic Heart Disease – Annual Ischemic Heart Disease Deaths Avoided in California by Attainment of the Annual-Average Federal PM2.5 NAAQS

Scenario	Low	Mean	High
National standard (15 μg/m^3)	1,700	2,100	2,500

*See footnote to Table 5.

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[15] Available at: http://www.epa.gov/ttn/naaqs/standards/pm/data/PM_RA_FINAL_June_2010.pdf, page 3-18.

Table 10: All-Cause – Annual All-Cause Deaths in California Avoided by Attainment of the Annual-Average Federal PM2.5 NAAQS

Scenario	Low	Mean	High
National standard (15 μg/m^3)	1,500	2,400	3,300

*See footnote to Table 5.

IV. CLEAN AIR ACT BENEFITS ANALYSIS

U.S. EPA Regulatory Impacts Analysis

In the 1997 report, "Benefits and Costs of the Clean Air Act, Retrospective Analysis 1970 – 1990," U.S. EPA used the first ACS study publication to estimate mortality related to long-term exposure to PM2.5 (Pope et al., 1995), as well as other health effects. This was done as part of a report required by the Clean Air Act (Section 812). The Clean Air Act requires the U.S. EPA Administrator, in consultation with the Secretaries of Commerce and Labor and the Council on Clean Air Compliance Analysis (CCACA), which operates through the U.S. EPA Science Advisory Board, to conduct a "comprehensive analysis of the impact of this Act on the public health, economy, and environment of the United States."

In 1999, U.S. EPA published the first prospective analysis of the benefits and costs of the Clean Air Act (U.S. EPA, 1999). This analysis continued to rely on the relative risk in Pope et al. (1995) to assess premature mortality associated with improvements in ambient PM2.5 concentrations, although the relative risk from Dockery et al. (1993) was included for sensitivity analyses. These regulatory analysis reports include estimates for a variety of other health effects based on single city studies that were conducted prior to 1997, and were reviewed during the 1997 PM NAAQS process.

In U.S. EPA's May 2004 regulatory impact analysis (RIA) for the Clean Air Non-Road Diesel Rule, the agency updated its methodology by using an update to the ACS study (Pope et al., 2002) to estimate premature mortality associated with long-term exposure to PM2.5, although U.S. EPA continued to use the same studies first applied in the retrospective analysis (U.S. EPA, 1997) for other health effects.

U.S. EPA is currently updating the Section 812 report, with a draft of the report reviewed by the CCACA in May 2010. The goal of this process is to bring the assessment, and the health effects included, into greater alignment with the NAAQS process. U.S. EPA staff indicated that some health effects currently used will be dropped, and others may be added. The RIA associated with the ongoing PM NAAQS review is scheduled for release in early 2011.

To obtain quantitative estimates of regulatory control benefits, the U.S. EPA developed a methodology which may be used instead of a full modeling analysis. The methodology is described in detail in Fann et al. (2009). Fann et al. (2009) estimate pollutant concentrations for nine urban areas (including one in

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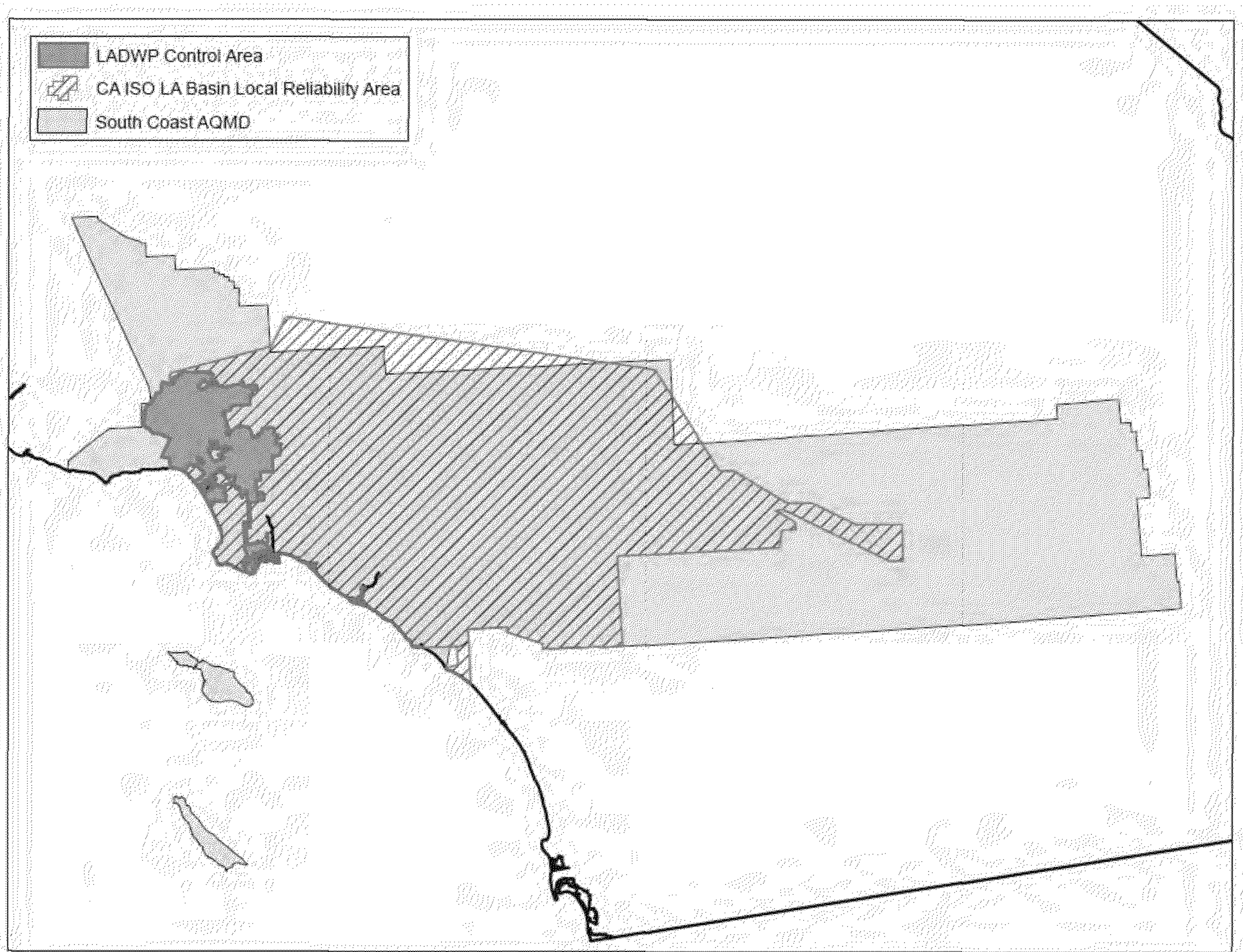
LADWP Control Area
CA ISO LA Basin Local Reliability Area
South Coast AQMD

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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				

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

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Sensitivity

Load Serving Entities	2021 Incremental EE (MW)	2021 Demand Response (MW)
SCE	2,461	2,829

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Portfolios	Area	LCR			Existing OTC Units Needed?
		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
	Western LA	5,589	869	6,458	Yes
	Western LA OTC Range			802 - 1,275 MW	
	Ellis	470	124	594	Yes
	El Nido	336	91	427	No

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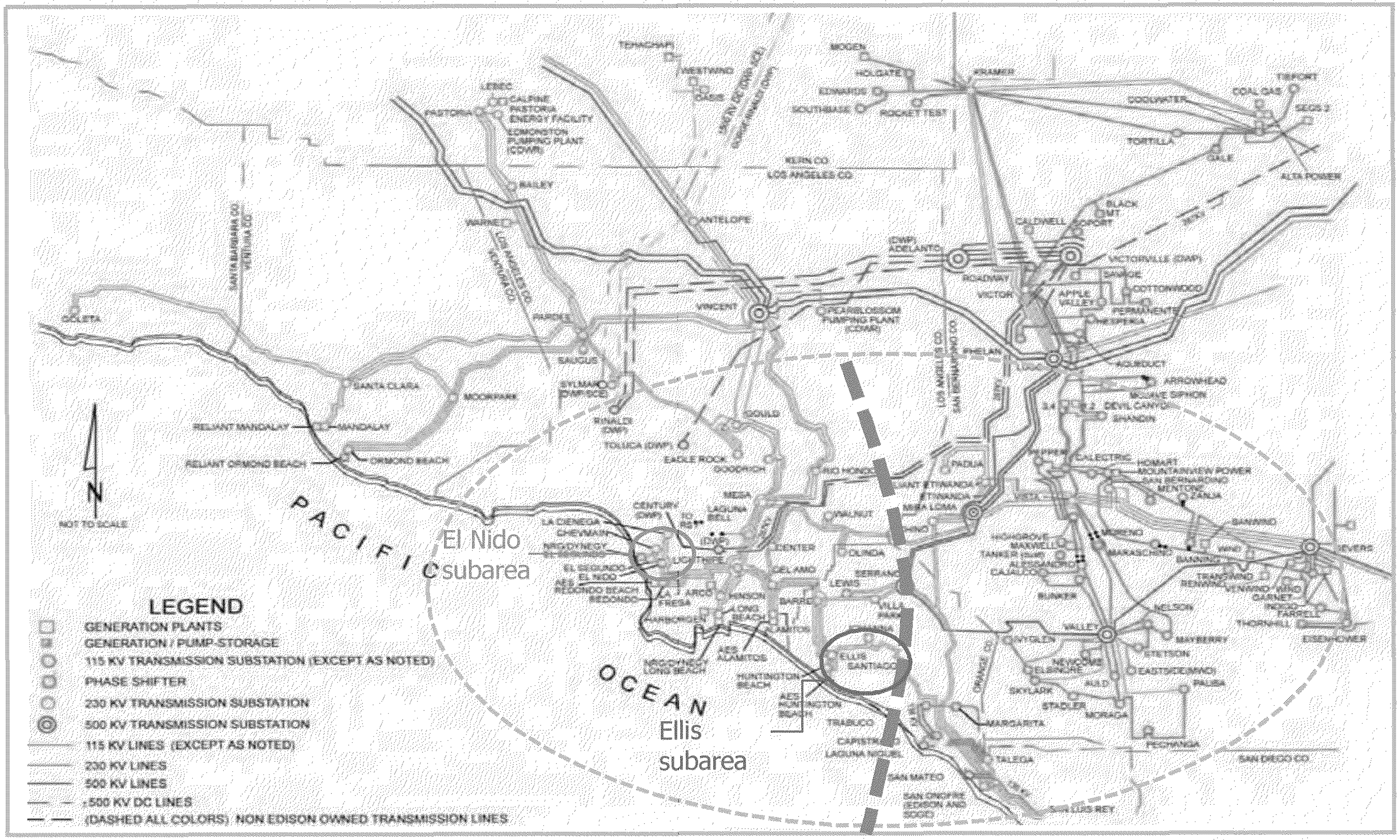

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Itemized Details	Trajectory (MW)	Environmentally Constrained (MW)	ISO Base Case (MW)	Time Constrained (MW)
Total 1-in-10 Load + losses	[illegible]	[illegible]	[illegible]	[illegible]
Generation				
[illegible]	[illegible]			
[illegible]	[illegible]			
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]

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

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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

** Mira Loma 500/230kV Bank #2 has a 1-Hr emergency rating that can be utilized by assuming up to 600 MW load shed/transfer after 1-Hr.

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

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

** Mira Loma 500/230kV Bank #2 has a 1-Hr emergency rating can be utilized by assuming up to 600 MW load shed/transfer after 1-Hr.

Gen Name	Serrano _ villa Park 230kV line
BARPKGEN 13.8 #1	32
BARRE 66.0 #11	32
ANAHEIMG 13.8 #1	31
LWIS ANM 69.0 #RT	30
ALAMT5 G 20.0 #5	24
HUNT1 G 13.8 #1	23
ORCOGEN 13.8 #1	22
ELLIS 66.0 #D7	22
JOHANNA 66.0 #D6	20
SANTIAGO 66.0 #10	17
COYGEN 13.8 #1	17
LITEHIPE 66.0 #10	15
ICEGEN 13.8 #D1	15
DELAMO 66.0 #D9	15
BRIGEN 13.8 #1	15
LBEACH5G 13.8 #R5	15
HARBOR 230.0 #F1	15
HINSON 66.0 #D8	15
CARBGEN1 13.8 #1	15
SERRFGEN 13.8 #D1	15
THUMSGEN 13.8 #1	15
CARBGEN2 13.8 #1	15
ARCO 6G 13.8 #6	15
CENTER 66.0 #D3	15
SIGGEN 13.8 #D1	15
CTRPKGEN 13.8 #1	15
LCIENEGA 66.0 #D9	14
VENICE 13.8 #1	14
EL NIDO 66.0 #D5	14
LA FRESA 66.0 #D2	14
MOBGEN1 13.8 #1	14
OUTFALL1 13.8 #1	14
PALOGEN 13.8 #D1	14
REDON1 G 13.8 #R1	14
CHEVGEN2 13.8 #2	14
ELSEG4 G 18.0 #4	14
NRG ELS7 18.0 #7	14
LAGUBELL 66.0 #RT	12
FEDGEN 13.8 #1	12
REFUSE 13.8 #D1	12
MALBRG3G 13.8 #S3	12
MESA CAL 66.0 #D7	10
RIOHONDO 66.0 #RT	9
GOODRICH 33.0 #RT	9
BRODWYSC 13.8 #1	9
PASADNA2 13.8 #1	9
GOULD 66.0 #D1	7
EAGLROCK 66.0 #D1	7
OLINDA 66.0 #D7	7
WALNUT 66.0 #D1	7
HILLGEN 13.8 #D1	7
EME WCG2 13.8 #1	6

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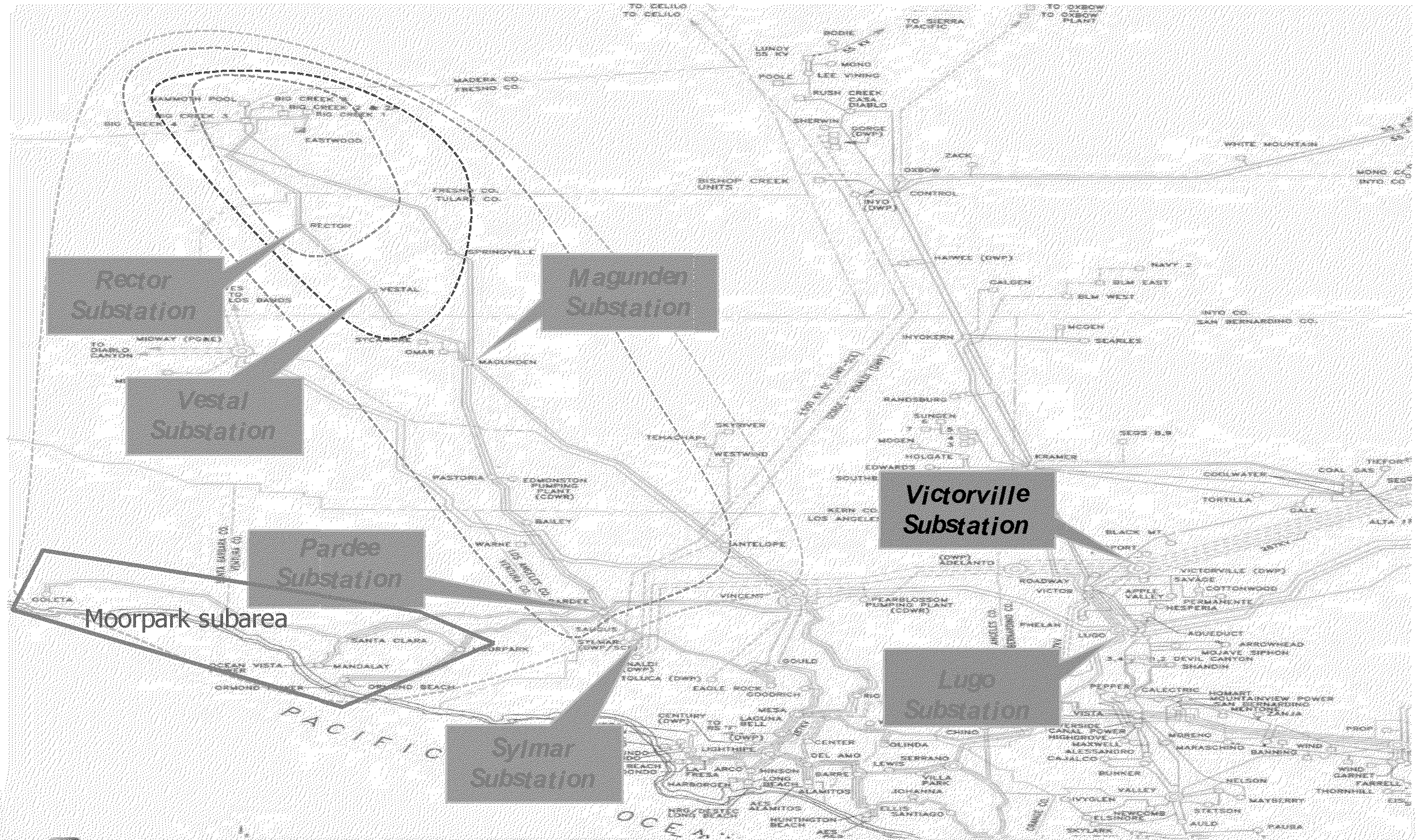
LCR Area	Trajectory		Environmental		ISO Base Case		Time-Constrained	
	High (MW)	Low (MW)	High (MW)	Low (MW)	High (MW)	Low (MW)	High (MW)	Low (MW)
LA Basin	10,743	10,263	11,246	10,891	11,010	10,516	12,165	11,663
Western LA Basin	9,168	7,797	8,482	7,468	8,831	7,421	8,833	7,397
Ellis	531		597		511		556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

Note: Mira Loma 500/230kV Bank #2 has a 1-Hr emergency rating that can be utilized by assuming up to 600 MW load shed/transfer after 1-Hr.


Rector Substation
Magunden Substation
Vestal Substation
Victorville Substation
Pardee Substation
Moorpark subarea
Lugo Substation
Sylmar Substation
PACIFIC
OCEAN

[illegible]

Itemized Details	Trajectory (MW)	Environmentally Constrained (MW)	ISO Base Case (MW)	Time Constrained (MW)
Total 1-in-10 Load + losses	[illegible]	[illegible]	[illegible]	[illegible]
Generation				
[illegible]	[illegible]			
[illegible]	[illegible]			
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]

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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

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

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

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

[illegible]

LCR Area	Trajectory (MW)	Environmental (MW)	ISO Base Case (MW)	Time- Constrained (MW)
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]

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STATE OF CALIFORNIA

ENERGY COMMISSION

PUBLIC UTILITIES COMMISSION

ENERGY ACTION PLAN II

IMPLEMENTATION ROADMAP FOR ENERGY POLICIES

October 2005

I. INTRODUCTION AND SUMMARY

In 2003, the three key energy agencies in California – the California Energy Commission (CEC), the California Power Authority (CPA), and the California Public Utilities Commission (CPUC) – came together in a spirit of unprecedented cooperation to adopt an "Energy Action Plan" (EAP)[1] that listed joint goals for California's energy future and set forth a commitment to achieve these goals through specific actions.

The EAP was a living document meant to change with time, experience, and need. The CPUC and the CEC have jointly prepared this Energy Action Plan II to identify the further actions necessary to meet California's future energy needs.[2] EAP II supports and expands the commitment to cooperation among state agencies embodied in the original EAP and reflected in the State's coordinated actions over the past two years. The development of EAP II has benefited from the active participation of the Business, Transportation, and Housing Agency, the Resources Agency, the State and Consumer Services Agency, the California Independent System Operator (CAISO), the California Environmental Protection Agency (Cal EPA), and other agencies with energy-related responsibilities.

EAP II describes a coordinated implementation plan for state energy policies that have been articulated through the Governor's Executive Orders, instructions to agencies, public positions, and appointees' statements; the CEC's Integrated Energy Policy Report (IEPR); CPUC and CEC processes; the agencies' policy forums; and legislative direction. This document also is intended to be consistent with the energy policies embodied in the Governor's August 23, 2005, response to the 2003 and 2004 IEPRs.[3] We expect to update or revise this action plan to reflect any changes needed to further implement the Governor's 2004 IEPR response, future energy policies, and decisions related to the forthcoming 2005 IEPR, as well as other relevant events that may arise in the future.

In preparing EAP II, we do not assume that work undertaken in EAP I is complete or, conversely, to dismiss the accomplishments to date of EAP I. Rather, EAP II is intended to look forward to the actions needed in California over the next few years, and to refine and strengthen the foundation prepared by EAP I. Appendix A provides a status report on the progress of the EAP I activities to date.

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[1] EAP I can be viewed at the CPUC's website at <http://www.cpuc.ca.gov/PUBLISHED/REPORT/28715.htm> or at the CEC's website at <http://www.energy.ca.gov/energy_action_plan/2003-05-08_ACTION_PLAN.PDF>.

[2] The Consumer Power and Conservation Financing Authority was a co-agency in EAP I. Funding for the agency was eliminated in SB 1113 (Chesbro) Chapter 208, the 2004-2005 budget. No additional funding is proposed in the Governor's 2005-2006 budget.

[3] Governor Schwarzenegger's "Review of Major Integrated Energy Policy Report Recommendations" in his August 23, 2005, letter to Senator Don Perata, President pro tempore of the California State Senate.

Our overarching goal is for California's energy to be adequate, affordable, technologically advanced, and environmentally-sound. Energy must be reliable – provided when and where needed and with minimal environmental risks and impacts. Energy must be affordable to households, businesses and industry, and motorists – and in particular to disadvantaged customers who rely on us to ensure that they can afford this fundamental commodity. Our actions must be taken with clear recognition of cost considerations and trade-offs to ensure reasonably priced energy for all Californians. We need to develop and tap advanced technologies to achieve these goals of reliability, affordability and an environmentally-sound energy future. These goals affirm the original objectives of EAP I.

The State will achieve these goals by taking specific and measurable actions throughout California's energy sector. To do this we have expanded the scope of the EAP. The fuels used in the transportation of California's goods and population constitute a third energy sector, in addition to electricity and natural gas. We have incorporated into EAP II specific actions reflecting the importance of transportation fuels to California's economy and the need to mitigate the environmental impacts caused by their use. EAP II further expands the scope of the original EAP to describe research, development and demonstration activities that are critical to realizing our energy goals. In addition, EAP II highlights the importance of taking actions in the near term to mitigate California's contributions to climate change from the electricity, natural gas and transportation sectors.

EAP II continues the strong support for the loading order – endorsed by Governor Schwarzenegger – that describes the priority sequence for actions to address increasing energy needs. The loading order identifies energy efficiency and demand response as the State's preferred means of meeting growing energy needs. After cost-effective efficiency and demand response, we rely on renewable sources of power and distributed generation, such as combined heat and power applications. To the extent efficiency, demand response, renewable resources, and distributed generation are unable to satisfy increasing energy and capacity needs, we support clean and efficient fossil-fired generation. Concurrently, the bulk electricity transmission grid and distribution facility infrastructure must be improved to support growing demand centers and the interconnection of new generation, both on the utility and customer side of the meter.

We also see the need to provide open, transparent, and compelling information and education to all stakeholders and consumers in the State. The agencies are committed to providing more effective information dissemination through increased cooperation among all branches of government, businesses, and energy organizations. In particular, we pledge to remove the remaining barriers to transparency in the electricity resource procurement processes in the State and to increase outreach to consumers by providing improved education and services regarding energy efficiency, demand response, rates, climate change, and opportunities to reduce the environmental impacts of energy use.

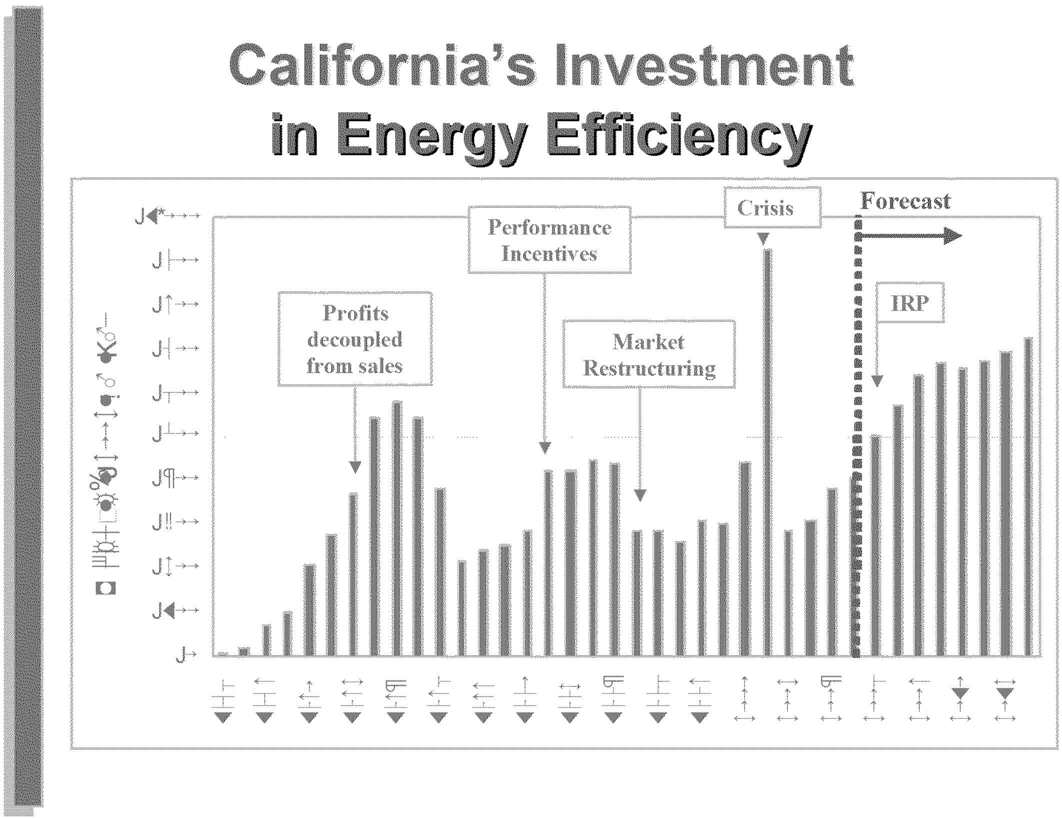
The EAP II is intended as an implementation roadmap for the entire State. While some of the electricity and natural gas actions are described in the context of the investor-owned utilities, in general they should be seen as applying equally to all load serving entities, such as customer-owned utilities and energy service providers.

Once this new EAP is adopted, our next step will be to prepare a workplan that ascribes responsibility for each of these key action items, determines the specific roles that will be played by each agency, and develops a timeline that ensures the agencies' prompt attention.

II. SPECIFIC ACTION AREAS

1. Energy Efficiency

As stated in EAP I and reiterated here, cost effective energy efficiency is the resource of first choice for meeting California's energy needs. Energy efficiency is the least cost, most reliable, and most environmentally-sensitive resource, and minimizes our contribution to climate change. California's energy efficiency programs are the most successful in the nation and we want to continue to build upon those successes.



For the past 30 years, while per capita electricity consumption in the US has increased by nearly 50 percent, California electricity use per capita has been approximately flat. This achievement is the result of continued progress in cost-effective building and appliance standards and ongoing enhancements to efficiency programs implemented by investor-owned utilities (IOUs), customer-owned utilities, and other entities. Since the mid-1970s, California has regularly increased the energy efficiency requirements for new appliances sold and new buildings constructed here. In addition, in a creative and precedent-setting move, the CPUC in the 1980s de-coupled the utilities' financial results from their direct energy sales, facilitating utility support for efficiency programs. These efforts have reduced peak capacity needs by more than 12,000 MW and continue to save about 40,000 GWh per year of electricity. Most recently, in

September 2004, the CPUC adopted the nation's most aggressive energy savings goals for both electricity and natural gas. In achieving these targets, the IOUs will save an additional 5,000 MW and 23,000 GWh per year of electricity, and 450 million therms per year of natural gas by 2013.

However, to achieve the full energy efficiency potential that exists in California, we must continue to ratchet up our efforts. We need to focus not only on developing and supporting programs, but also on increasing public outreach and education; promoting research, development, and demonstration; and improving the evaluation, measurement, and verification of efficiency programs.

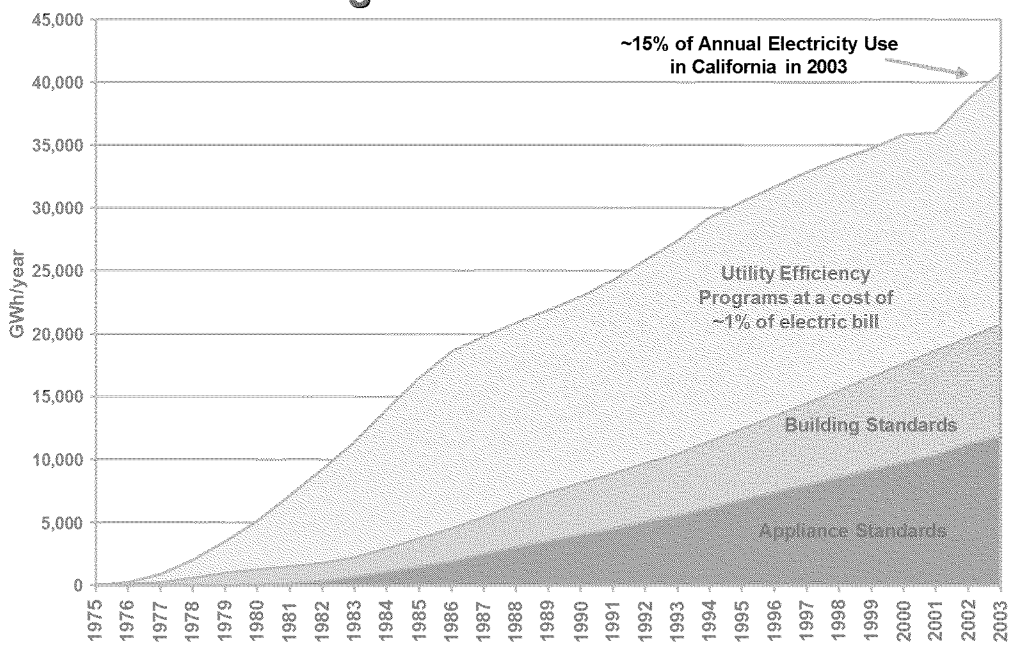
KEY ACTIONS:

1. Require that all cost-effective energy efficiency is integrated into utilities' resource plans on an equal basis with supply-side resource options.
2. Adopt 2006-2008 energy efficiency program portfolios and funding by late 2005.
3. Expand efforts to improve public awareness and adoption of energy efficiency measures.
4. Promote a balanced portfolio of baseload energy, demand, and peak demand reductions to obtain both reliability and long-term resource benefits of energy efficiency for both electricity and natural gas.
5. Integrate demand response programs with energy efficiency programs.
6. Implement actions outlined in the Governor's Green Buildings Action Plan to improve building performance and reduce grid-based electrical energy purchases in all State and commercial buildings by 20 percent by 2015.[4]
7. Work with customer-owned utilities in the implementation of all cost-effective energy efficiency programs so that they treat energy efficiency savings as a resource and help California reach its goal of a reduction in per capita electricity use.
8. Adopt new appliance standards by 2006, supplementing those adopted in December 2004.
9. Adopt new building standards for implementation in 2008 that include, among other measures, cost effective demand response technologies and integrated photovoltaic systems.
10. Increase the availability of State-sponsored low-interest loans for energy efficiency and clean distributed generation projects.
11. Improve energy efficiency programs for low income, non-English speaking, and other hard-to-reach communities.

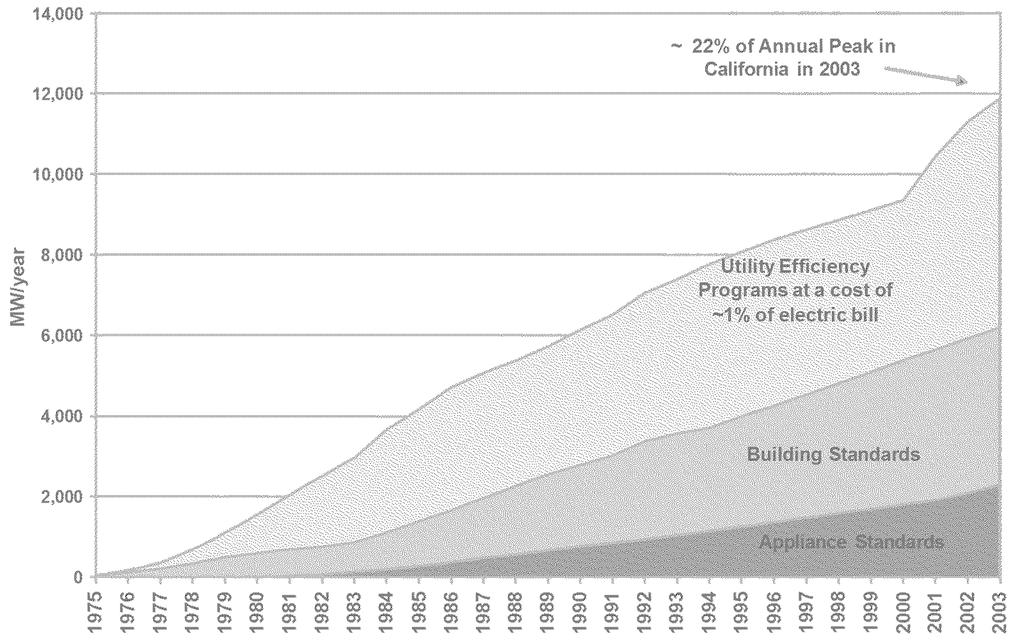
[4] See Executive Order S-20-04, dated December 14, 2004, at <http://www.dot.ca.gov/hq/energy/ExecOrderS-20-04.htm>.

12. Adopt verifiable performance-based incentives in 2006 for IOU energy efficiency investments, with risks and rewards based on performance that will align the utility incentives with customer interests.
13. Update and augment, as necessary, utility evaluation, measurement and verification protocols to assure that energy efficiency continues to be fully integrated into resource planning, emission reduction benefits are quantified, and compliance goals are verified.
14. Identify opportunities and support programs to reduce electricity demand related to the water supply system during peak hours and opportunities to reduce the energy needed to operate water conveyance and treatment systems.
15. Adopt a report on improving efficiency in existing buildings, as required by Assembly Bill 549, and pursue legislation and regulations to implement its recommendations.

Annual Energy Savings from Efficiency Programs and Standards



Annual Peak Savings from Efficiency Programs and Standards



2. Demand Response

California is in the process of transforming its electric utility distribution network from a system using 1960s era technology to an intelligent, integrated network enabled by modern information and control system technologies. This transformation can decrease the costs of operating and maintaining the electrical system, while also providing customers with accurate information on energy use, time of use, and cost. With the implementation of well-designed dynamic pricing tariffs and demand response programs for all customer classes, California can lower consumer costs and increase electricity system reliability. To achieve this transformation, state agencies will ensure that appropriate, cost-effective technologies are chosen, emphasize public education regarding the benefits of such technologies, and develop tariffs and programs that result in cost-effective savings and inducements for customers to achieve those savings.

KEY ACTIONS:

1. • Issue decisions on the proposals for statewide installation of advanced metering infrastructure for all small commercial and residential IOU customers by mid-2006 and expedite adoption of concomitant tariffs for any approved meter deployment.
2. • Expedite decisions on dynamic pricing tariffs to allow increased participation for summer 2006 for customers with installed advanced metering systems and

encourage load shifting that does not result in increases in overall consumption.

3. Identify and adopt new programs and revise current programs as necessary to achieve the goal to meet five percent demand response by 2007 and to make dynamic pricing tariffs available for all customers.

4. Educate Californians about the time sensitivity of energy use and the ways to take advantage of dynamic pricing tariffs and other demand response programs.

5. Create standardized measurement and evaluation mechanisms to ensure that demand response savings are verifiable.

6. Provide that the utilities' demand response investment opportunities offer returns commensurate with investments in traditional plant.

7. Integrate demand response into retail sellers' electricity resource procurement efforts so that these programs are considered equally with supply options.

8. Provide customer access to their energy use information and allow participation in demand response programs, regardless of retail provider.

9. Evaluate and, if appropriate, incorporate demand response technologies such as programmable communicating thermostats into the 2008 building standards.

10. Incorporate demand response appropriately and consistently into the planning protocols of the CPUC, the CEC, and the CAISO.

11. Encourage the integration of demand response programs into a capacity market or other mechanisms.

12. Coordinate IOU demand-response programs with customer-owned utility demand-response efforts to provide a comprehensive, statewide contribution to California's resource adequacy portfolio.

3. Renewables

California can reduce its greenhouse gas emissions, moderate its increasing dependence on natural gas, and mitigate the associated risks of electricity price volatility by aggressively developing renewable energy resources to meet the Renewables Portfolio Standard (RPS) requirements. As originally established, the RPS requires 20 percent of electricity sales to come from renewable sources by 2017. In the first EAP, we set a goal of accelerating the 20 percent target from 2017 to 2010. We are now identifying the steps necessary to achieve that target, as well as higher goals beyond 2010, such as Governor Schwarzenegger's proposed goal of 33 percent of electricity sales by 2020. To reach these goals, we must streamline and make transparent all of our approval processes, provide funding for renewable resources that reflects these policy priorities, and establish the necessary infrastructure for delivery of power from new renewable projects. We intend that our increasing reliance on renewable resources within California and from the western region will help mitigate energy impacts on climate change and the environment. We expect that all California load serving entities will contribute to these goals.

KEY ACTIONS:

1. Expeditiously approve contracts from the initial IOU RPS solicitations and interim renewable solicitations, and approve agreements for any necessary supplemental energy payments.
2. Expeditiously approve the IOU RPS solicitations for 2005 and the next three years so that California IOUs will meet the accelerated RPS goal of 20 percent renewables by 2010.
3. Consider improvements to the renewables solicitation process.
4. Ensure that operations protocols and tariffs do not discriminate against renewable resources and study the effects of increasing penetration of renewable resources on the reliable operation of the electricity grid.
5. Evaluate and develop implementation paths for achieving renewable resource goals beyond 2010, including 33 percent renewables by 2020, in light of cost-benefit and risk analysis, for all load serving entities.
6. Monitor and support existing renewable resources, including facilitating re-powering projects and addressing contract renewals in a timely fashion.
7. Ensure new transmission lines are built to access renewable resources through a comprehensive, integrated transmission planning process, including the creation of state-led study groups to examine tapping particular resource regions.
8. Implement a cost-effective program to achieve the 3,000 MW goal of the Governor's "Million Solar Roofs" initiative.[5]

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[5] View the Governor's press release at <http://www.governor.ca.gov/state/govsite/gov_htmldisplay.jsp?sCatTitle=Press%20Release&sFilePath=/govsite/spotlight/august20_update.html>.

9. Implement RPS standards for energy service providers and community choice aggregators so that all load serving entities are contributing proportionally to California's renewable goals.

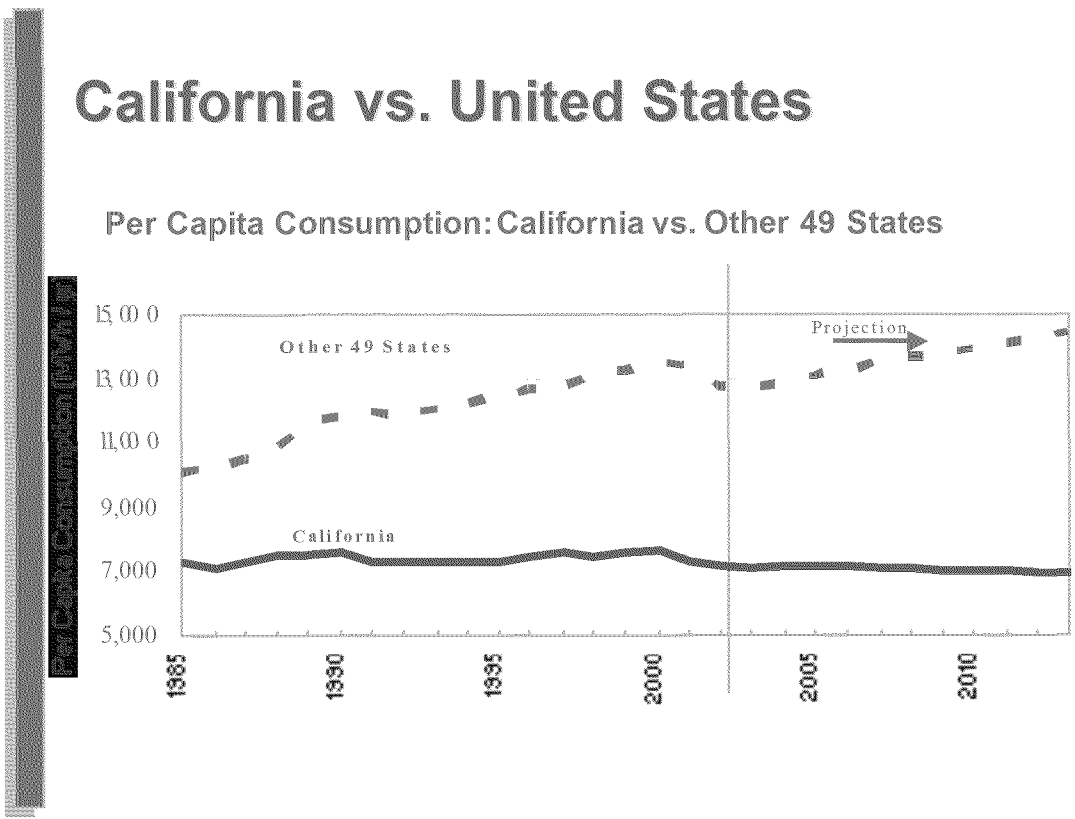
10. Work with customer-owned utilities in the development of their renewable plans and incorporate their results into a comprehensive statewide RPS review.

11. Complete the Western Renewable Generation Information System to accurately account for renewable generation through an electronic certificate tracking system.

12. Implement a renewable energy certificates trading system for meeting RPS goals.

13. Assist local permitting agencies in implementing methods of mitigating the avian impacts of wind energy generation.

14. Develop and implement forestry, agriculture, and waste management policies to encourage the generation of electricity from landfills, biomass and biogas.



4. Electricity Adequacy, Reliability and Infrastructure

Significant capital investments are needed to augment existing facilities, replace aging infrastructure, and ensure that California's electrical supplies will meet current and future needs at reasonable prices and without over-reliance on a single fuel source. Even with the emphasis on energy efficiency, demand response, renewable resources, and distributed generation, investments in conventional power plants will be needed. The State will work to establish a regulatory climate that encourages investment in environmentally-sound conventional electricity generation resources.

An expanded, robust electric transmission system is required to access cleaner and more competitively priced energy, mitigate grid congestion, increase grid reliability, permit the retirement of aging plants, and bring new renewable and conventional power plants on line. Streamlined, open and fair transmission planning and permitting processes must move projects through planning and into construction in a timely manner. The state agencies must work closely with the CAISO to achieve these objectives and to benefit from its expertise in grid operation and planning. Finally, the distribution system, which has the most direct effect on reliable service for consumers, must be continually upgraded and reinforced.

KEY ACTIONS:

1. Ensure that all load serving entities meet the state's adopted reserve and resource adequacy requirements of a 15-17 percent planning reserve no later than June 2006, through a reasonable mix of short-, medium- and long-term resource commitments.
2. Provide for the continued operation of cost-effective and environmentally-sound existing generation needed to meet current reliability needs, including combined heat and power generation.
3. After incorporating higher loading order resources, encourage the development of cost-effective, highly-efficient, and environmentally-sound supply resources to provide reliability and consistency with the State's energy priorities.
4. Establish appropriate incentives for the development and operation of new generation to replace the least efficient and least environmentally sound of California's aging power plants.
5. Evaluate the potential for California's access to clean coal energy resources and recommend a California clean coal policy in the 2005 IEPR.
6. Manage California's aging electricity infrastructure to coordinate maintenance and outages and to provide orderly retirements.
7. Adopt a long-term policy for existing and new qualifying facility resources, including better integration of these resources into CAISO tariffs and deliverability standards.
8. Promote adequate investment in the utility distribution system, with an emphasis on translating those expenditures into higher levels of reliability.

9. Develop tariffs and remove barriers to encourage the development of environmentally-sound combined heat and power resources and distributed generation projects.

10. The CEC supports legislation to consolidate the permitting process for all new bulk transmission lines within the CEC, while the CPUC believes existing permitting authority should remain in place. Irrespective of the status of legislative efforts, the two Commissions agree to continue to work together to improve the transmission planning and permitting processes under existing authorities.

11. Improve the State's transmission line planning and permitting processes by integrating the CAISO's transmission planning and modeling capabilities, the CEC's power plant licensing, environmental and planning expertise, and the CPUC's ratemaking function and by ensuring that the processes are adaptable, flexible and representative of broad stakeholder input.

12. Adapt the state's transmission planning process to better evaluate strategic benefits, as well as economic costs and benefits, of proposed projects over multiple decades, including recommending a range of discount rates to be used to evaluate transmission lines.

13. Support legislation to expand the CEC's transmission corridor planning process, coordinated with applicable federal and state agencies, local governments and other stakeholders, to designate and preserve critical corridors for potential development in the future.

14. Coordinate the state's transmission planning process with regional efforts in the interconnected western states and identify and recommend means to increase California's participation in the broader western regional energy planning efforts.

15. Apply the GHG adder as a resource selection criterion in IOU procurement decisions to more appropriately value the risk of future environmental regulation in long-term investment decisions made now.

16. Acknowledge the interdependent nature of the energy needs among all the Western states, Canadian provinces, and Mexico by collaborating with our regional partners on regional resource and transmission planning, in particular by addressing overall resource adequacy and deliverability in the West, including cost allocation, planning, and routing of inter-regional transmission projects.

5. Electricity Market Structure

To promote dependable, affordable, environmentally-responsible wholesale and retail markets, the agencies must foster sound market rules, increase regulatory certainty, and improve coordination with the rest of the West's electrical system. These goals are not possible without working closely with the CAISO, which plays the fundamental role of operating most of

California's electricity grid and its critical energy markets. The agencies will continue to cooperate with and assist the CAISO in its core missions.

Californians pay some of the highest utility rates in the nation and the State must take action to decrease overall retail energy bills and to reform rate structures while providing consumers tools to manage their energy usage. The agencies will work to reduce total retail energy bills by supporting programs for energy efficiency, demand response, and self-generation; ensuring that utilities' supply portfolios promote the delivery of energy at the least cost; and increasing education and outreach about energy usage. Partnering with private industry, the State will also identify, assess, and, where appropriate, implement actions, such as the development of capacity markets, to enhance reliability, and promote investment in energy infrastructure serving California.

KEY ACTIONS:

1. Restructure the IOU rate-making process to reduce the number of proceedings, create more transparency in consumer electricity rates, adopt rates based on clear cost-causation principles, and identify steps to reduce electricity costs.
2. Complete and refine, as necessary, the current IOU electricity procurement process to provide that it is competitive, transparent, fair, proceeds in a timely fashion, and achieves California's resource adequacy requirements.
3. Complete and implement, by February 2007, the CAISO's Market Redesign and Technology Upgrade to reform California's wholesale electricity market and to ensure adequate market power mitigation to protect California consumers.
4. Promote the continued viability and efficient operation of the existing direct access market for retail electricity supply.
5. Develop rules to promote an effective core/non-core retail market structure, including mechanisms to guard against cost-shifting, preserve reliability, pursue energy efficiency goals, achieve RPS goals, and maintain the loading order for all load serving entities.
6. Develop capacity markets, with tradable capacity rights and obligations, to create appropriate incentives and flexibility for power plant development and utility procurement.

6. Natural Gas Supply, Demand, and Infrastructure

To ensure reliable, long-term natural gas supplies to California at reasonable rates, the agencies must reduce or moderate demand for natural gas. Because natural gas is becoming more expensive, and because much of electricity demand growth is expected to be met by increases in natural gas-fired generation, reducing consumption of electricity and diversifying electricity generation resources are significant elements of plans to reduce natural gas demand and lower consumers' bills. California must also promote infrastructure enhancements, such as additional pipeline and storage capacity, and diversify supply sources to include liquefied natural gas (LNG).

KEY ACTIONS:

1. Adopt additional natural gas and electric efficiency programs and standards to reduce the reliance on natural gas for various end uses.
2. Establish a program to encourage solar hot water heating to reduce the reliance on natural gas for water heating.
3. Provide that the natural gas delivery and storage system is sufficient to meet California's peak demand needs.
4. Encourage the development of additional in-state natural gas storage to enhance reliability and mitigate price volatility.
5. Continue the State's LNG Interagency Permitting Working Group and develop a process to facilitate the prompt and environmentally-sensitive evaluation and siting of needed LNG facilities.
6. Establish standards for the timing of and payment for new transmission and storage capacity additions and for access to natural gas transmission systems.
7. Evaluate the appropriateness of current rules for natural gas quality.
8. Provide ongoing assessments of global natural gas markets.

7. Transportation Fuels Supply, Demand, and Infrastructure

The fuels used in the transportation of California's goods and population constitute a third facet of our energy sector, in addition to electricity and natural gas. Today, California's gasoline and diesel markets are characterized by increasing demands, tight supplies, and volatile and record high prices. California imports more than half of its crude oil and over 15 percent of its refined products and its dependence on this increasingly expensive energy resource continues to grow. Moreover, fossil fuel-based transportation of products and people is a major contributor of carbon dioxide, the principal catalyst to climate change. While we must ensure sufficient and economic supplies of gasoline and diesel to sustain California's economic vitality, we also must take steps to build an efficient, multi-fuel transportation market to serve the future needs of its citizens. Governor Schwarzenegger has tasked the Energy Commission to take the lead in crafting, by March 31, 2006, a workable long-term plan to achieve significant reductions in gasoline and diesel use and increase the use of alternative fuels so that California is working toward a set of realistic, achievable objectives with identifiable and measurable milestones. It is expected that the plan will include actions to be undertaken by state agencies.

KEY ACTIONS

1. Prepare by March 31, 2006 a long term transportation fuels plan to increase the use of alternative fuels, increase vehicle efficiency, increase the use of

mass transit, reduce dependence on petroleum fuels, and improve land use planning.

2. Increase coordination of petroleum infrastructure permitting among state, local, and regional agencies, including developing guiding principles for approval of new petroleum facilities.

3. Continue to work with other states and stakeholders to convince the federal government to double the Corporate Average Fuel Economy (CAFE) standards.

4. Work in conjunction with Cal EPA to implement the California Hydrogen Highway Blueprint.

5. Increase the use of high-efficiency, fuel flexible vehicles, and dedicated non-petroleum-fueled vehicles in the state's fleet of passenger cars and light-duty trucks. Increase the use of non-petroleum fuels in the state's fleet of medium- and heavy-duty on-road and off-road vehicles.

6. Complete testing to evaluate tire rolling resistance and fuel economy potential, establish standards, and implement a voluntary reporting program. Consider a rulemaking for mandatory reporting in the event voluntary compliance is inadequate.

7. The CPUC, in conjunction with the CEC, Cal EPA, and local air districts, will continue to evaluate and implement policies to promote the development of equipment and infrastructure needed to facilitate the use of electric power and natural gas to fuel low-emission vehicles as required by Public Utilities Code sections 740.3, 740.8, and 451.

8. Research, Development and Demonstration

California's continued success in supplying an efficient and diverse mix of resources to meet our energy needs is dependent upon technological innovations. The agencies are committed to encouraging research, development, and demonstration (RD&D) projects in technologies that will allow California to achieve its policies to make energy efficiency, demand response and renewable resources more effective and cost-competitive. We must also encourage RD&D for conventional generation sources and transportation fuels to reduce emissions, increase efficiency, and mitigate environmental impacts.

KEY ACTIONS

1. Transform RD&D projects on energy efficiency technologies into energy efficiency tools and standards.

2. Allocate and prioritize RD&D funding for energy efficiency and demand response, including new communication and control technologies, planning models, end-use technologies, and validation methodologies.

3. Align RD&D funding with public policy goals for new renewable technologies and greenhouse gas mitigation technologies, including efficiency, renewable generation technologies, and energy storage.
4. Align public purpose funded natural gas RD&D to reflect supply policies affecting biogas and syngas; to improve long-term storage reservoir management, safety and efficiency; and to ensure high quality natural gas.
5. Support RD&D to improve the efficiency of petroleum-fueled vehicles and to reduce the cost and promote the availability of non-petroleum fuels.
6. Support clean coal technology research and development, and continue to develop methods for capturing and storing significant amounts of CO_2, either as an integral part of the energy conversion process or in pairing with external CO_2 sequestration.
7. Encourage the development of cost-effective dry-cooling technologies and reduce once-through cooling practices to minimize the impact of new generation on California's water resources.
8. Align RD&D funding with public policy goals for transmission technology development to maximize efficient use of the bulk electricity grid.
9. Support and the Interagency Working Group in developing an integrated and comprehensive state policy on biomass that encompasses electricity, natural gas and transportation fuel substitution potential, and encourage the participation of the Biomass Collaborative.

9. Climate Change

Governor Schwarzenegger signed Executive Order S-3-05 on June 1, 2005, clearly establishing California's leadership in and commitment to the fight against climate change. The Executive Order establishes greenhouse gas (GHG) emission reduction targets that call for a reduction of GHG emissions to 2000 levels by 2010; to 1990 levels by 2020; and to 80 percent below 1990 levels by 2050. The Executive Order also directs Cal EPA to lead a multi-agency Climate Action Team to conduct an analysis of the impacts of climate change on California and to develop strategies to achieve the targets and mitigation and adaptation plans for the State.

Joining Cal EPA on the Climate Action Team are high-level representatives from the Business, Transportation and Housing Agency, CPUC, CEC, Department of Food and Agriculture, and Resources Agency. The Team is responsible for developing a plan to achieve the Governor's GHG emissions targets by implementing state agency programs that reduce or avoid greenhouse gas emissions. The Climate Action Team has established subgroups specifically to evaluate options for a statewide "cap-and-trade" program and adaptation and mitigation scenarios.

Climate change is the most serious threat to our environmental future, and demands immediate action. Its symptoms are already evident in California. The transportation sector is the primary source of our GHG emissions in California. An important step in reducing GHG emissions from this sector was the adoption by the Air Resources Board in December 2004 of its motor vehicle

GHG emission regulations. Increasing energy efficiency, demand response, and renewable resources to the maximum extent possible in California and the western region will further reduce our contribution to climate change. Due to the strong connection between energy use and climate change, many necessary actions to reduce greenhouse gas emissions have already been outlined in previous sections.

KEY ACTIONS:

1. Implement the motor vehicle greenhouse gas regulations.
2. Implement all strategies identified by the Climate Action Team as needed to meet the Governor's GHG emission reduction goals, including recommendations developed as part of the 2005 IEPR.
3. Report to the Governor and the Legislature in January 2006, and biennially thereafter to provide regular updates on the progress made toward meeting the Governor's target and other directives in Executive Order S-3-05.
4. Report to the Governor on the findings of the Climate Action Team subgroup on cap and trade options for the State.
5. Consider 2010, 2020, and 2050 GHG reduction targets for retail sellers of electricity to contribute to meeting the Governor's GHG emission reduction targets.
6. Coordinate with the Climate Action Team on the regulatory proceeding that is considering establishment of a cap and trade program for IOUs.
7. Ensure that energy supplies serving California, from any source, are consistent with the Governor's climate change goals.
8. Require reporting of GHG emissions as a condition of state licensing of new electric generating facilities.
9. Participate in public outreach efforts to educate the public and businesses in California on climate change impacts and actions to mitigate emissions and encourage stakeholder participation in the development of programs to meet California's climate change goals.
10. Encourage all participants in the electricity, natural gas, and transportation fuels industries, as well as other regulated industries, to participate in the California Climate Action Registry and to improve reporting of GHG emissions.
11. Identify western state policies and strategies to achieve production of 30,000 MW of clean energy across the west by 2015, consistent with the Western Governors' Association Clean and Diversified Energy Advisory Committee and West Coast Climate Initiative goals.[6]

[6] See WGA Policy Resolution 04-14, June 22, 2004, at http://www.westgov.org/wga/policy/04/clean-energy.pdf and WGA's Clean and Diversified Energy Initiative webpage at <http://www.westgov.org/wga/initiatives/cdeac/index.htm>. Also see

12. Identify methodologies to quantify the expected costs and benefits of climate change policies.

13. Continue research performed by the California Climate Change Center in evaluating the economic and ecological consequences of climate change and adaptation and mitigation strategies to preserve and improve quality of life.

<http://www.climatechange.ca.gov/westcoast/index.html> for information on the West Coast Governors' Initiative.

NAVIGANT

ANALYSIS TO UPDATE ENERGY EFFICIENCY POTENTIAL, GOALS, AND TARGETS FOR 2013 AND BEYOND

TRACK 1 STATEWIDE INVESTOR OWNED UTILITY ENERGY EFFICIENCY POTENTIAL STUDY

Prepared for:
California Public Utilities Commission

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Walnut Creek, CA 94596

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May 8, 2012

- **Agricultural Sector Potential** represents a source of EE potential that has not been previously estimated prior to the 2011 potential study and accounts for approximately 4% of statewide IOU territory market potential in 2013.
- **Codes and Standards (C&S) Programs** provide technical support and advocacy for the adoption of energy efficiency measures into California Title 20 & 24 building codes and federal appliance standards. The IOUs receive credit toward their goals for the C&S savings that can be attributed to their code related program activities.

Navigant Consulting, Inc.'s (Navigant's), approach to the 2011 potential study builds upon the standard bottom-up modeling methodology that has been used in many states and is consistent with the CPUC's past goal-setting approach. The bottom up methodology identifies all energy efficiency measures—possible changes that can be made to a building, equipment or process that could saving energy—and calculates the total possible energy savings available above the baseline. The baseline is established by the maximum energy use permitted by building code or appliance standards.

Consistent with the 2008 potential study, the 2011 potential study provides forecasts energy efficiency potential based on three levels of screens, as illustrated in Figure 1 below.

1. <u>Technical Potential Analysis</u>: Technical potential is defined as the amount of energy savings that would be possible if all technically applicable and feasible opportunities to improve energy efficiency were taken, including retrofit measures, replace-on-burnout measures, and new construction measures[6].
2. <u>Economic Potential Analysis</u>: Using the results of the technical potential analysis, the economic potential is calculated as the total energy efficiency potential available when limited to only cost-effective measures[7]. All components of economic potential are a subset of technical potential[8].
3. <u>Market Potential Analysis</u>: The final output of the potential study is a market potential analysis which is defined as the energy efficiency savings that could be expected to occur in response to specific levels of program funding and customer participation based on assumptions about market influences and barriers. All components of market potential are a subset of economic potential. Some studies also refer to this as "Maximum Achievable Potential"[9].

[6] For reference, technical potential typically ranges between 15 to 25% of annual sales depending on the market sector and market baseline conditions.

[7] As discussed in Section 3.6, the default cost effectiveness threshold for economic potential is that a measure must a total resource cost test value of 0.80 or greater.

[8] For reference, economic potential typically ranges between 13% to 23% of annual market sector sales depending on the amount of technical potential available, the cost test used to screen for economic feasibility, the value of avoided energy costs to an energy provider and the cost of energy to consumers.

[9] For reference, incremental annual market potential typically ranges between 0.5% to 2.5% of annual market sector sales depending on the amount of economic potential and customer acceptance and barriers to implementing EE measures and initiatives.

Table 1. Incremental Market Potential Results

Incremental Market Potential	IOU	2013	2014	2015	2016	2017	2018	2019	…	2024
ffiffl┘├■ ♂□☼ ◄↕ ‼¶●┬	PG&E	599	593	599	609	596	583	587	…	629
	SCE	660	678	712	728	744	752	743	…	705
	SDG&E	162	156	152	143	142	158	153	…	138
	Total	**1,422**	**1,427**	**1,464**	**1,480**	**1,482**	**1,493**	**1,484**	…	**1,472**
┤┘♂↑ ♂□☼ ╫ ↕ ¶●┬	PG&E	114	100	100	101	97	99	100	…	107
	SCE	149	144	148	147	146	147	141	…	129
	SDG&E	36	33	31	29	28	33	31	…	25
	Total	**300**	**277**	**279**	**278**	**272**	**279**	**272**	…	**261**
◄♂☼♂□☼ →│ffl← □ →┘●♂│■┘ ffi ┘│☼ ╫ ├ ├ ¶●┬	PG&E	21.0	20.3	20.0	21.1	21.0	21.5	22.5	…	26.9
	SCG	24.0	22.3	21.4	21.0	20.9	21.3	21.8	…	25.2
	SDG&E	2.2	2.1	2.2	2.4	2.7	3.1	3.3	…	4.8
	Total	**47.2**	**44.8**	**43.5**	**44.5**	**44.6**	**45.9**	**47.6**	…	**56.9**

The following factors have played a key role in the changes in energy efficiency potential shown in Figure 2 and Figure 3 and are further discussed in the referenced sections.

1. **Changes in Underlying Savings Assumptions for Energy Efficiency Measures:** The 2006-2008 evaluation results, as well as several other recent studies, have led to downward adjustments to savings assumptions for many energy efficiency measures and is further discussed in Section 4.
2. **Changes in Codes and Standards:** The adoption of new Title 24 Codes and Federal appliance standards has led to the uptake of several EE measures that were previously components of the technical potential. As these codes go into effect, they become the baseline, reducing the technical and economic potential that can be achieved by traditional utility-incentive-driven programs. The application of codes and standards is addressed in Section 4.7.
3. **Potential for Emerging Technologies:** As emerging technologies become technically and economically viable, they cause an upward shift in technical, economic, and market potential. Emerging technologies are addressed in Section 4.4.
4. **Potential for Usage-Based Behavioral Impacts:** Estimates of the potential for usage-based behavioral initiatives based on recent studies have been included in potential estimates and the method and select research topics are further addressed in Section 4.5.
5. **Potential for the Agricultural Market Sector:** Section 9 of the study includes an estimate of technical, economic, and market potential for the agricultural sector. Potential in the agricultural sectors constitutes about 4% of IOU service territory market potential.
6. **Decrease in Forecasted Loads:** The CEC IEPR demand forecast has found a significant decline in the forecasted load from 2008 to 2011 due to the economic downturn, which is further addressed in Appendix M: EERAM Model Algorithm and Input Details.
7. **Changes in the Modeling Methodology:** The 2008 potential study was developed by Itron using their ASSET model[14]. While Navigant has used a consistent approach, there are variations on

[14] The ASSET model was developed by Regional Economic Research, Inc. (RER). RER was acquired by Itron in 2003. California Energy Efficiency Potential Study, Submitted to Pacific Gas & Electric Company, Submitted by:

technical demand potential over the entire forecast. Cumulative market demand potential follows the trend of the energy potential for cumulative market, increasing from 1,500 MW in 2010 to just over 3,000 MW in 2024.

Figure 61. SCE Total Gross Technical, Economic, and Cumulative Market Demand Potential for 2010-2024 (MW)

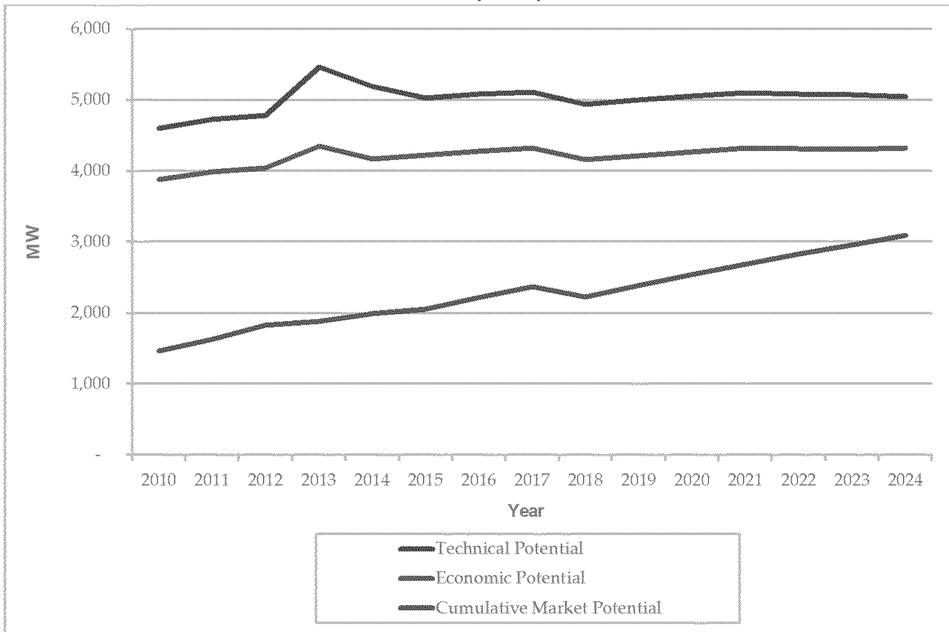
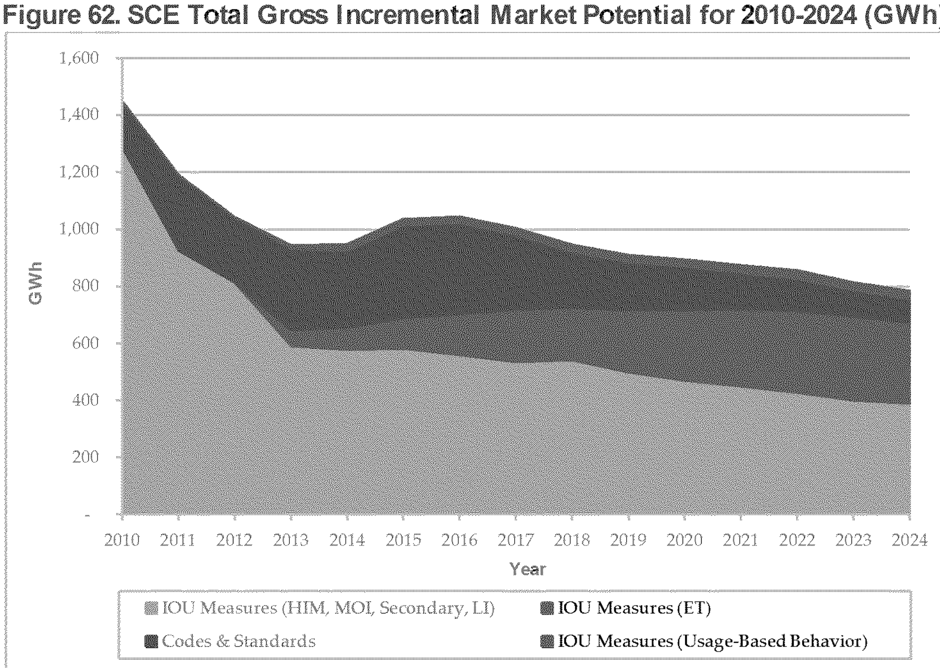


Figure 62 presents the incremental market potential for SCE (in GWh) for 2010 to 2024. The market potential follows a trend of gradual decline from 2010 (approximately 1,450 GWh) to 2024 (approximately 800 GWh), with a slight bump in 2014-2016 as emerging technologies start to have a significant impact. The increase in savings potential in 2018 for HIMs, is due to increase in commercial indoor lighting potential. This is explained in the text accompanying Figure 38, Section 7.2.1.

Figure 62. SCE Total Gross Incremental Market Potential for 2010-2024 (GWh)



California ISO
Shaping a Renewed Future

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

3.4 Assembly Bill 1318 (AB1318) Reliability Studies

3.4.2.1 Study Results

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Table 3.4-14

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

sensitivity

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Table 3.4-24

Portfolios	Area	LCR Non-D.G. (MW)	LCR D.G. (Mw)	LCR 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.

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[illegible]

Table 3.4-34 [illegible]

Portfolios	Area	LCR Non-D.G. (MW)	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.

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Table 3.4-44

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

Notes:

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

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

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

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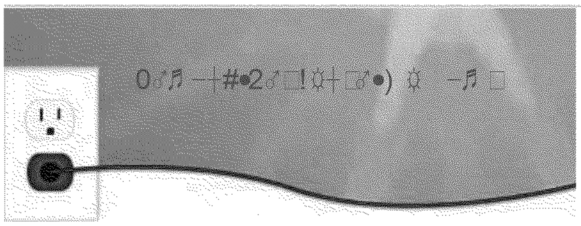
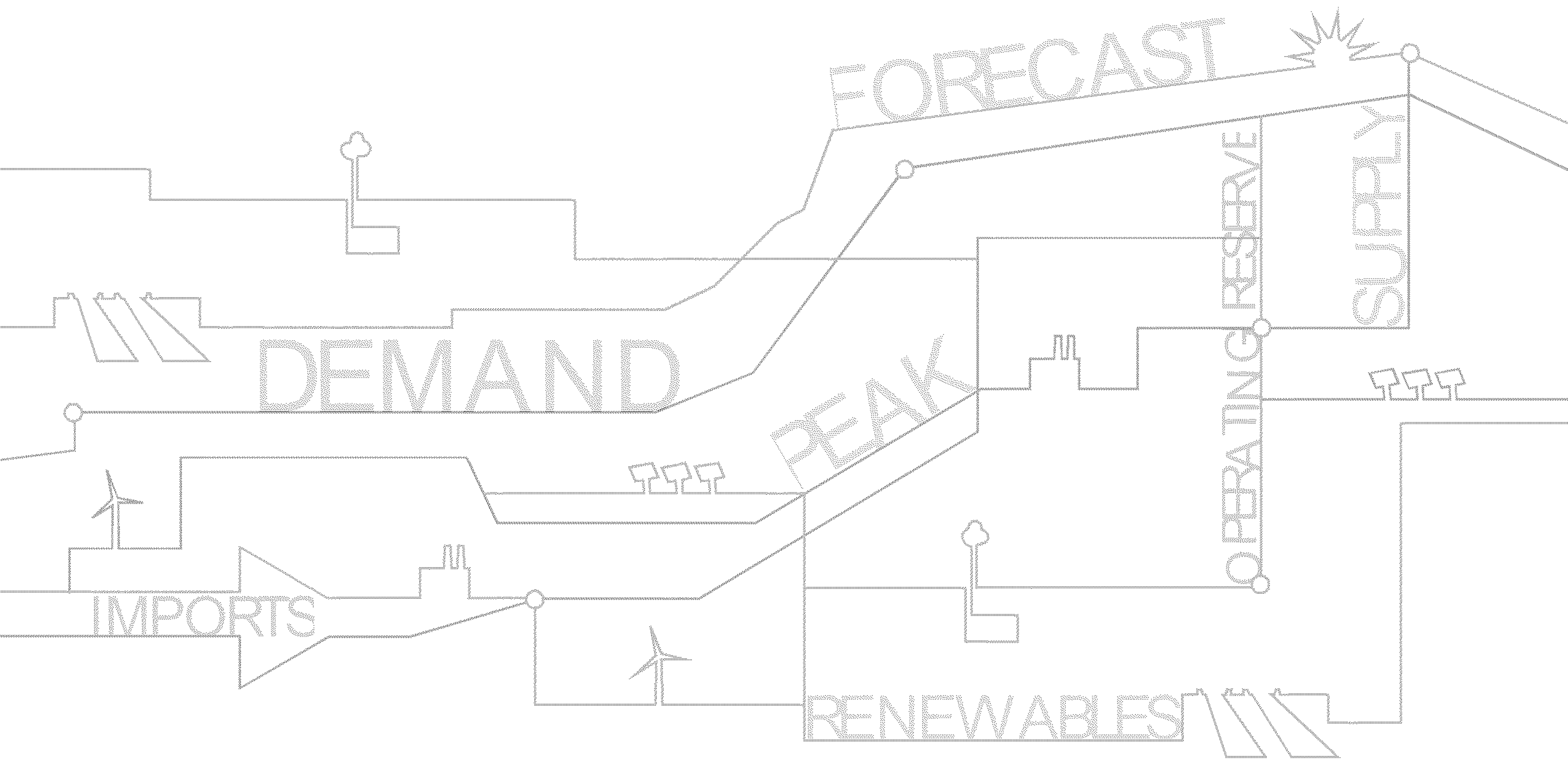


2012 SUMMER LOADS AND RESOURCES ASSESSMENT

March 15, 2012



California ISO
Shaping a Renewed Future

Prepared by: Market & Infrastructure Development
Grid Assets Department
Version: 1

I. EXECUTIVE SUMMARY

The *2012 Summer Loads and Resources Assessment* provides an analysis of the upcoming summer supply and demand outlook in the California Independent System Operator balancing authority. The ISO works with generation, transmission owners, load serving entities and other balancing authorities to formulate the summer forecast and identify any concerns regarding upcoming operating conditions. The hydrologic situation, renewable expansion and economic impact on demand are of particular interest in 2012 and are addressed in this report.[1]

This report projects an adequate supply for summer 2012 to handle a broad range of operating conditions. The probability of involuntary load curtailment in 2012 is lower than that in 2010 and 2011 assuming moderate import levels. Under normal peak demand conditions, both the planning reserve margin and the operating reserve margin are projected to be greater than the California Public Utility Commission's 15% resource adequacy requirement. The operating reserve margins from 2005 to 2012 are shown in *Figure 1*.

The summer 2012 supply and demand outlooks are shown in Tables 1 through 3. Under the normal peak demand scenario, the planning reserve margin are expected to be 32.7% for the ISO system as a whole, 28.9% for southern California (SP26) and 36.7% for northern California (NP26).[2] The operating reserve margins are expected to be 22.5% for the ISO system, 21.5% for SP26 and 23.7% for NP26. The normal scenario for operating reserves is defined as moderate net imports to the ISO system, 1-in-2 year generation and transmission outages, and 1-in-2 year peak demand. A 1-in-2 year event means the event has a probability of occurring once in two years.

Under an extreme peak demand scenario, operating reserve margins are projected to drop to 9.3% for the ISO system, 2.8% for SP26 and 9.1% for NP26. The operating reserve margins for SP26 is below the firm load shedding threshold of 3%. The extreme scenario is defined as low imports, 1-in-10 generation and transmission outages, and 1-in-10 peak demand. The probability of the extreme scenario is very low.

The expected probability of experiencing involuntary load curtailments because of low operating reserve margins in summer 2012 is extremely low at 0.54 for ISO system, 0.50% for SP26 and 0.14% for NP26, assuming moderate imports (*Figure 2)*. The decrease in the probability of the ISO system experiencing a 3% or less operating reserve margin in 2012 is mainly attributed to a generation additions outpacing projected peak demand growth due to the continuing economic downturn.

The ISO peak demand is projected to reach 46,352 MW during summer 2012 1-in-2 conditions, which is 923 MW more than the actual peak 45,429 MW recorded in 2011, but less than the 2011 1-in-2 forecast. The decrease in ISO peak demand forecast is a result

[1] *Economic Outlook,* website: http://www.ebudget.ca.gov/pdf/BudgetSummary/EconomicOutlook.pdf

[2] SP26 and NP26 refer to geographic zones south and north of transmission Path 26 in the ISO control area, respectively. Path 26 is composed of three 500 kV transmission lines that cross the service territory boundaries between SCE and PG&E. The NP26 zone represents the entire PG&E service territory. The SP26 zone represents the service territories of SCE and SDG&E.

in a more conservative economic recovery forecast for 2012 from Moody's Analytics as compared to their 2011 economic base case forecast. [3]

Figure 1

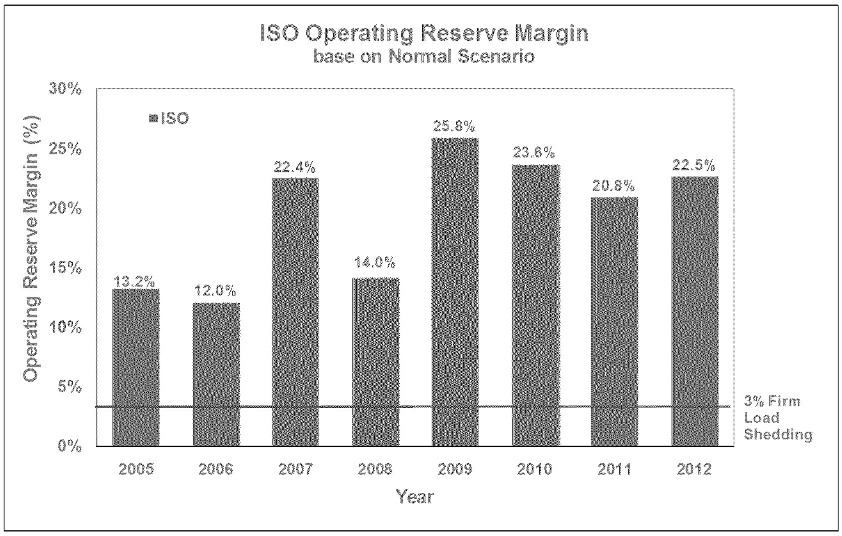


Figure 1 shows that the 2012 forecast indicates ISO operating reserve margin since 2005, under the normal scenario, followed a gradual decline since 2009 and increased in 2012.

Figure 2

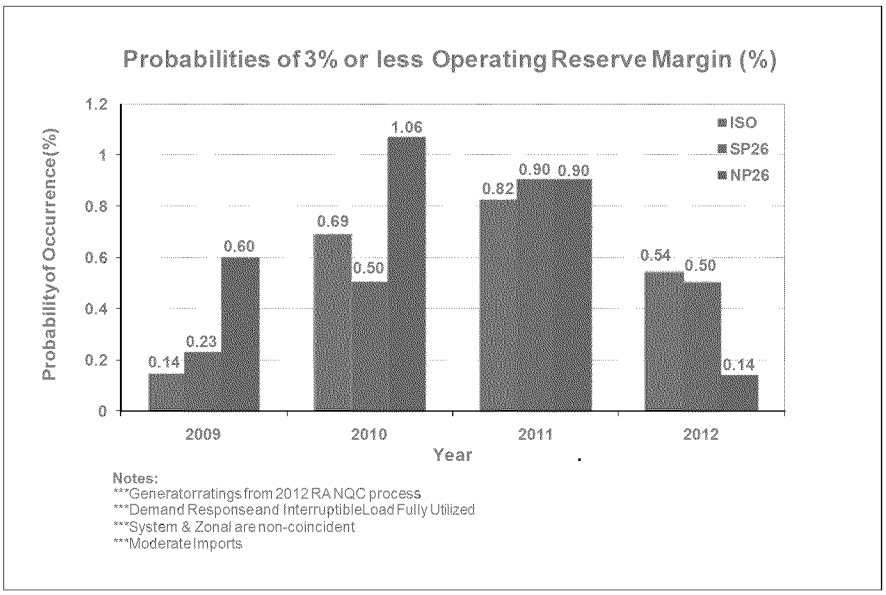


Figure 2 shows that the probabilities of triggering 3% firm load shedding threshold have increased since 2009 for ISO, SP26 and NP26, but it dropped significantly in 2012 because of generation additions outpacing projected peak demand growth due to the continuing economic downturn.

[3] The load foreca … are not intended for use in resource planning decisions.

Table 1

Planning Reserve Margins

Summer 2012 Supply & Demand Outlook			
Resource Adequacy Planning Conventions	ISO	SP26	NP26
Existing Generation	49,867	24,066	25,801
Retirements (known/expected)	(452)	(452)	0
High Probability CA Additions	926	240	686
Hydro Derates	(1,137)	(267)	(870)
Net Interchange (Moderate)	10,000	10,000	2,100
Total Net Supply (MW)	59,204	33,588	27,716
DR & Interruptible Programs	2,296	1,721	576
Demand (1-in-2 Summer Temperature)	46,352	27,399	20,702
Planning Reserve Margin[4]	**32.7%**	**28.9%**	**36.7%**

Table 2
Normal Scenario Operating Reserve Margins

Summer 2012 Outlook - Normal Scenario 1-in-2 Demand, 1-in-2 Generation & Transmission Outage and Moderate Imports			
Resource Adequacy Conventions	ISO	SP26	NP26
Existing Generation[5]	49,867	24,066	25,801
Retirements (Known/Expected)	(452)	(452)	0
High Probability CA Additions	926	240	686
Hydro Derates	(1,137)	(267)	(870)
Outages (1-in-2 Generation & Transmission)[6]	(4,698)	(2,033)	(2,677)
Moderate Net Interchange[7]	10,000	10,000	2,100
Total Net Supply (MW)	54,506	31,555	25,039
DR & Interruptible Programs[8]	2,296	1,721	576
Demand (1-in-2 Summer Temperature)[9]	46,352	27,399	20,702
Operating Reserve Margin[10]	**22.5%**	**21.5%**	**23.7%**

[4] Planning Reserve Margin = (Total Net Supply + Demand Response + Interruptible) / Demand -1
Total Net Supply = Existing Generation + High Probability Generation Additions – Retirements + Net Interchange

[5] refer to Table 8

[6] refer to Table 9. Outages of ISO, SP26 and NP26 are not coincident.

[7] refer to Table 10. Net Interchanges of ISO, SP26 and NP26 are not coincident.

[8] refer to Table 11

[9] refer to Table 12

[10] Operating Reserve Margin = (Total Net Supply + Demand Response + Interruptible) / Demand -1
Total Net Supply = Existing Generation + High Probability Generation Additions – Retirements - Outages + Net Interchange

Table 3
Extreme Scenario Operating Reserve Margins

Summer 2012 Outlook - Extreme Scenario 1-in-10 Demand, 1-in-10 Generation & Transmission Outage and Low Imports			
Resource Adequacy Conventions	ISO	SP26	NP26
Existing Generation	49,867	24,066	25,801
Retirements (Known)	(452)	(452)	0
High Probability CA Additions	926	240	686
Hydro Derates	(1,137)	(267)	(870)
High Outages (1-in-10 Generation & Transmission)	(6,844)	(3,872)	(3,616)
Net Interchange	8,600	8,800	1,400
Total Net Supply (MW)	50,960	28,515	23,401
DR & Interruptible Programs	2,296	1,721	576
High Demand (1-in-10 Summer Temperature)	48,744	29,414	21,977
Operating Reserve Margin	**9.3%**	**2.8%**	**9.1%**

The ISO projects that 50,341 MW of net qualifying capacity (NQC) will be available for summer 2012, which covers the addition of 283 MW from June 1, 2011 to January 9, 2012, along with an additional 926 MW of anticipated new generation and 452 MW of expected retirements from the January 9, 2012 to September 1, 2012 timeframe. The striking thing about the 926 MW of generation additions is that 49% of the capacity comes from renewable resources such as solar and wind generation.

The NQC is the maximum capacity eligible and available for meeting the CPUC resource adequacy requirement counting process. The ISO determines the qualifying capacity by testing and verification. This effort includes applying performance criteria and deliverability restrictions as outlined in the ISO tariff and the applicable business practice manual.

A hydro derate for 2012 was estimated to be 1,137 MW. Current statewide snow water content, as measured on March 1, 2012, was 30% of the April 1 average. The runoff forecasts in the early summer months are well below average for all the basins. As of the date of this report California is facing one of lowest snowpack levels in historical records. While key reservoir levels are currently not of concern and the estimated hydro derate will be less than the estimate during the early part of the summer season, the 1,137 MW derate could become a reality during late August and September, particularly if California experiences extended hot weather.[11]

The 2012 summer imports are projected to vary from 8,600 MW to 11,400 MW for the ISO, 8,800 MW to 11,300 MW for SP26, and 1,400 MW to 3,400 MW for NP26. The projected 2012 moderate import for the ISO is 10,000 MW, which is 300 MW more than last year. Actual ISO, SP26 and NP26 imports in 2011 increased from 2010 because of

[11] http://www.water.ca.gov/news/newsreleases/2012/022812snow.pdf

higher generation and transmission outages at the peak time. Having sufficient energy imports are essential in maintaining system reliability under extreme conditions.

An estimated 2,296 MW of demand response and interruptible load programs will be available to deploy during summer 2012. Demand response can reduce summer peak demands and provide grid operators with additional system flexibility during periods of limited supply. Demand response can provide economic day-ahead and real-time energy and ancillary service.

In conclusion, this report projects an adequate supply for summer 2012 to handle a broad range of potential peak demand conditions. It also projects a very low probability of involuntary load curtailments. These favorable findings are the result of an anticipated addition of 926 MW of net dependable generation capacity from January 9, 2012 to September 1, 2012 and reduced peak demand projections due to the continuing economic downturn.

Producing this report and presenting its results to stakeholders is one of many activities the ISO undertakes each year to prepare for the summer operations. Other activities include coordinating meetings on summer preparedness with the WECC, Cal Fire, state fire fighters, natural gas providers and neighboring balancing authorities. The ongoing relationships help ensure everyone is ready during times of system stress.

It is important for new generation investment to keep pace with future anticipated load growth when economic conditions improve and future anticipated generation retirements. A noteworthy challenge in this area will be the roughly 17,500 MW of capacity subject to once-through-cooling regulations, which will require those power plants to be retired or repowered over the next 10 years. The ISO is working closely with state agencies and plant owners in evaluating the reliability impacts of implementing these regulations to ensure it does not compromise electric grid reliability.

Demand Response: a decisive breakthrough for Europe

How Europe could save Gigawatts, Billions of Euros and Millions of tons of CO_2

In collaboration with

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Executive summary

The price for electricity in Europe is expected to continue rising rapidly as member states commit to replacing cheap and CO_2 intensive fossil fuel generation with low emissions or renewable alternatives, and as prices for fuel continue to increase. Peak pricing is especially serious as peak demand reaches even higher levels. The competitiveness of European industries is thus in danger, and further predicted increases of peak demand will be a strain on the economy as well as increasing the risk of power blackouts.

To invest in more capacity would be an expensive solution to the above challenges, both for utilities and consumers, requiring heavy expenditure on power generation capabilities, which will most likely be used only a few hours per year. To invest in Demand Response (DR) to curb peak load requirements and overall load consumption, would on the other hand present a more proactive and constructive solution.

Capgemini, VaasaETT and Enerdata have partnered to explore the current development of DR throughout the EU-15, to quantify its future potential, and to identify the pre-requisites for the efficient fulfilment of its potential by 2020. The outcome is a dynamic scenario which is ambitious albeit theoretically compelling, and in our view a necessary goal for Europe. In this scenario, our calculations show that DR alone achieves 25-50% of the EU's 2020 targets concerning energy savings and CO_2 emission reductions, as well as pre-empting the need for the equivalent of 150 medium size thermal plants in EU-15.

Key findings

We conclude that by 2020, DR will in our Dynamic Scenario facilitate:

- **202 TWh of annual energy savings:** which can be translated to the combined annual residential consumption of Germany (140 TWh) and Spain (61 TWh)[1], or the electricity needed to run all kitchen appliances plus washing machines in EU-15[2] for one year;
- **100 million tons of CO_2 emission reductions annually** - 50% of the reduction target in the 3x20 directive devoted to Utilities;
- **€50bn in avoided investment** relating to peak generation capacity and T&D which is equivalent cost of 150 medium sized gas power plants;
- **€25bn annual savings in electricity bills for customers.** Using the 2006 electricity rates, this would pay for Finland's 5 million residential customers' electricity annual consumption[3].

In addition to these benefits, it is further acknowledged in the dynamic scenario that DR related measures represent a major opportunity for the energy industry to mitigate some of the relative unpredictability of renewable energy, through effective demand side measures. This in turn will reduce the need for investment in compensatory schedulable energy sources, typically fossil fuel generation.

We conclude however in this study that our dynamic scenario is a major challenge, and that the results are unfortunately unlikely to be achieved with current commitment by the member states and the energy industry.

The reason for this pessimism is illustrated by the barriers we need to surpass to gain full effect from a DR program. Of these barriers, the primary factor is the slow application of smart meters in Europe. Hence we expect that DR will deliver only a part of its full potential illustrated through our moderate scenario, which suggests more modest results such as:

- Half the potential compared to the dynamic scenario in terms of peak shaving and consumption avoided (100 TWh);
- A reduction of 30 million ton CO_2 annually. Due to this unsettling reality, this comprehensive list of barriers hindering us from reaching the dynamic scenario and means to overcome them, are discussed in the concluding section of this study. The result of this discussion highlights the complexity of DR and our suggested way forward, including a multifaceted approach where we clearly conclude that regulators, utilities and consumers in all member states need to pull together to accomplish the results of the dynamic scenario by 2020.

Despite the realisation that the current evolution will not bring us the results described through the dynamic scenario, we are hopeful that the three major groups of stakeholders will acknowledge the opportunities available and increase their pace in achieving a more dynamic market for power production and consumption. The added bonus is a sustainable future both from an economical as well as an environmental perspective.

Demand Response has proved its potential

Our review of existing research indicates that research on DR is conducted on a global scale[10].We have included researchers in a wide selection of countries for this report[11], and all of those had DR research projects or studies underway. Thanks to this broad sample, conclusions can now be drawn as to DR and its affects.

Demand Response methods are now quantifiably a success

- **Energy Savings:** 20-50% (the later usually includes automated energy reductions) peak clipping and a 10-15% reduction of overall consumption have now been recorded repeatedly in a wide range of studies. This includes studies done over longer periods of time, where drop off or a loosing of interest by the consumer might be a problem. In some studies energy savings objectives have been exceeded by up to 200%,
- **Customer satisfaction:** 85-99% of customers questioned were positive towards DR programs. DR can be an effective tool against consumer suspicion and distrust of their utilities. It can improve customer relations and loyalty;
- **Cost/benefit results are still mixed:** Three factors determine cost benefit outcome – the original level of energy use, the regulatory environment, and the efficiency of the program (highly developed or highly simplified is best here, though low consumption environments will not support costly DR programs).

Regulatory support is key to Demand Response success

If regulators do not succeed in structuring the market so that energy savings benefit the utilities – the utilities have no compelling reason to implement DR programs. Where regulators succeeded – the results were apparent.

Repetition of research is questionable

There is a problem with repetition of research within the industry as pilot projects are conducted using very similar methods and achieving consistent results – reinventing the wheel as it were. This has had the benefit of proving the consistency of DR results but those designing new research plans might now wish to concentrate on increasing the understanding of the home market and refining DR methods.

Geographical tendencies

Studies carried out in North America and Australia are larger in size and use a wide range of technological solutions; they are more likely to use automation technologies than their European counterparts. They often concentrate on peak clipping driven by security of supply concerns.

Northern Europe's research is often carried out on a smaller scale and is more likely to investigate active DR programs, which educate the customer in order to improve and inform consumption habits. Some of these experiments have now been developed into fully launched programs and met with success.

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Of the 30 or so studies, which were made available, only 8 representative examples have been selected for figure 1 and 2. The figures outline: who has done the research, how it was conducted, what the researchers felt were the most important lessons learned and the results. The results are *not* exceptional but are simply examples of effective programs. A variety of DR programs and even regulatory measures have been chosen, from a wide range of countries in order to give as broad a view of the field as possible.

Figure 1: Examples of representative Demand Response programs

Type of DR	Source	Objectives Included	Sample Size	Method	Keys to Success identified	Short-comings	Results
[illegible]	[illegible] USA 2008	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible] USA 2007	[illegible]	[illegible]	[illegible]	[illegible]		[illegible]
[illegible]	[illegible] Denmark 2004	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]

[illegible]

Figure 2: Examples of representative Demand Response programs

Type of DR	Source	Objectives Included	Sample Size	Method	Keys to Success identified	Short-comings	Results
[illegible]	[illegible] Sweden 2007	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible] Norway 2004	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible] Finland 2007	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible] Australia 2007	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible] Australia 2007	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]

[illegible]

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California's Climate and Energy Policy Under Governor Brown

Robert B. Weisenmiller, Ph.D.
Chair
California Energy Commission

Mary D. Nichols, J.D.
Chair
California Air Resources Board

California Environmental Protection Agency
Air Resources Board

AB 32

- Overarching climate policy directive for California
- Implementation status
- Energy policy an essential part
  - Energy efficiency
  - Renewables and distributed generation
  - Transportation

California Environmental Protection Agency
Air Resources Board

California AB 32 GHG Reduction Plan Sees Key Role for 33% Renewable Portfolio Standard (RPS) and Energy Efficiency

ARB 32 Scoping Plan

Recommended Actions for Electricity Sector

MEASURE	GHG REDUCTIONS (MMTCO2E)
Energy Efficiency	**15.2**
(32,000 GWh of Reduced Demand) - Increased Utility Energy Efficiency Programs - More Stringent Building & Appliance Standards - Additional Efficiency and Conservation Programs	
Combined Heat and Power	**6.7**
Increase Combined Heat and Power Use by 30,000 GWh	
Renewables Portfolio Standard	**21.3**
Achieve a 33% renewables mix by 2020	
Million Solar Roofs	**2.1**
(Including California Solar Initiative, New Solar Homes Partnership, and solar programs of publicly owned utilities)	
- Target of 3,000 MW Total Installation by 2020	3
TOTAL	**45.3**

California Environmental Protection Agency

Air Resources Board

Renewables Senate Bill X1 2 (Simitian): Codified 33% RPS by 2020 in April 2011

Retail sellers and POUs to adopt RPS goals of

- 20% by December 31, 2013*
- 25% by December 31, 2016**
- 33% by December 31, 2020***

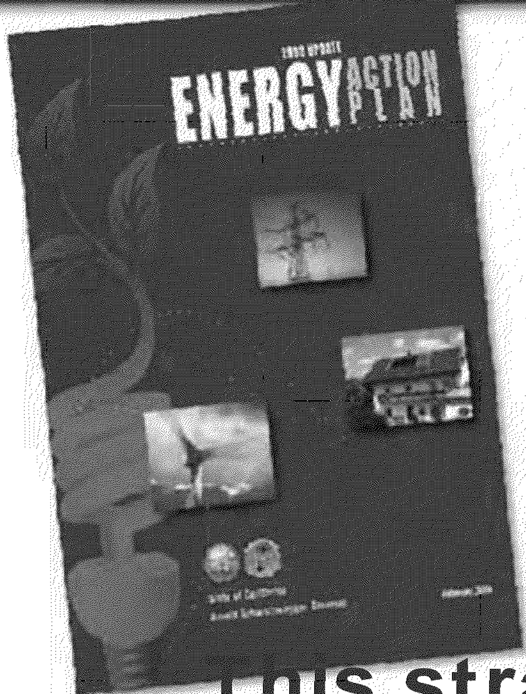
Energy Commission must provide a report to the legislature by June 30, 2011****, analyzing run of river hydroelectric generating facilities in British Columbia, including whether these facilities are, or should be, included as eligible renewable energy resources.

*Maximum TRECs allowed is 25%
**Maximum TRECs allowed is 15%
***Maximum TRECs allowed is 10%
****Simitian has authored clean up language, SB 32 that, would extend the report deadline to June 30, 2012.

California Environmental Protection Agency
Air Resources Board

CA's Energy Policy Relies on a *Loading Order*

In 2003, California's *Energy Action Plan* defined a loading order to address the state's increasing energy needs



1. Energy efficiency and demand response
2. ***Renewable energy and distributed generation***
3. Clean fossil fueled sources and infrastructure improvements

This strategy benefits CA by reducing CO_2 emissions and diversifying energy sources.

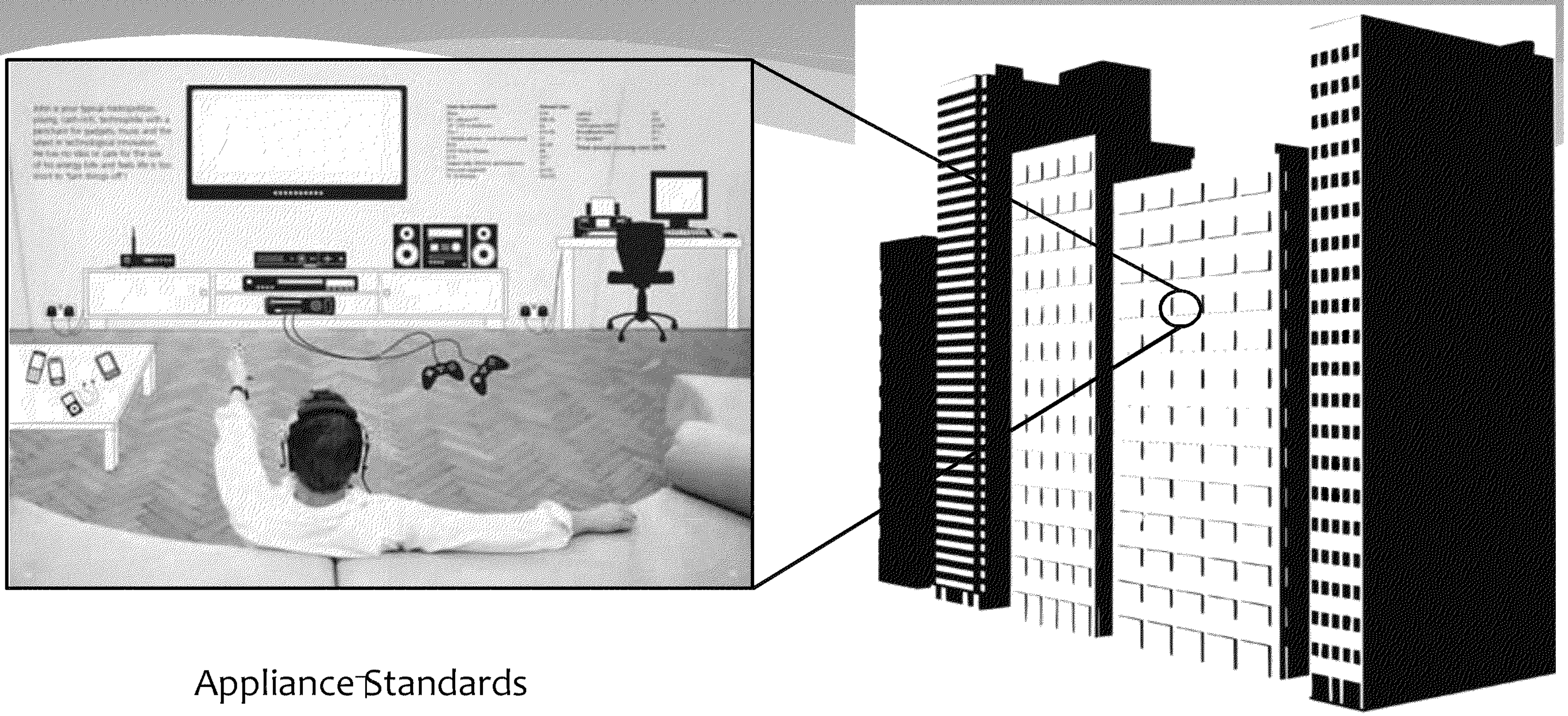
California Environmental Protection Agency
Air Resources Board

California's Clean Energy Future

- Collaboration between ARB, Energy Commission, CPUC, CalEPA, and CAISO
- Outlines how CA's energy agencies will achieve the state's environmental and energy policy goals by 2020
- Calls for an integrated approach to energy issues
- Points the way toward new investments in transmission, energy efficiency, smart grid applications, and increased use of renewable resources.
- Upcoming IEPR public workshop on July 6

California Environmental Protection Agency
Air Resources Board

Energy Efficiency



Appliance Standards

- Refrigerators
- Light bulbs
- Televisions
- Battery chargers
- Water heaters
- HVAC systems

Next standard: computers and data centers

California Environmental Protection Agency
Air Resources Board

Energy Supply

- 33% RPS by 2020
  - Expected to provide about 50% of the electricity sector reductions identified in the AB 32 Scoping Plan
  - 8,000 MW new large scale renewables by 2020
  - 12,000 MW new Distributed Generation by 2020
- New Renewable Distributed Generation
  - $3.35 billion effort by CPUC (California Solar Initiative), CEC (New Solar Homes Partnership, and publicly owned utilities
- Transmission and distribution issues and needs

California Environmental Protection Agency
Air Resources Board

Renewable Distributed Generation – Senate Bill 1

Enacted in 2006, SB 1 is the Largest Solar Program of its kind in the Country

- $3.35 billion effort by CPUC (California Solar Initiative), CEC (New Solar Homes Partnership, and publicly owned utilities
- Residential and nonresidential customers
- 3,000 MW combined public/investor owned utilities goal
- Solar industry self sufficiency in 10 years
- Has resulted in about 50,000 PV system installations since its inception

California Environmental Protection Agency
Air Resources Board

ARRA Solar Thermal Projects Permitted in California during 2010

Project	Capacity (MW)	Annual RE generation (MWh)	Annual GHG emissions avoided (tons)	Peak Jobs	Permanent Jobs
Abengoa	250	630,000	261,450	1,162	68
Beacon	250	600,000	249,000	836	66
Blythe	1000	2,100,000	871,500	1,066	295
Calico	663	1,435,000	595,525	400	136
Genesis	250	600,000	249,000	1,085	50
Imperial Valley	709	1,525,000	632,875	900	164
Ivanpah	370	880,000	365,200	1,000	86
Palen	500	1,000,000	415,000	566	134
Rice	150	450,000	186,750	280	47
Alta (Oak Creek Mojave)	800	1,787,500	741,813	Unavailable	50
AV Solar Ranch One	245	515,000	140,000	300	20
Total	5,200	11,500,000*	4,700,000**	7,600	1,100

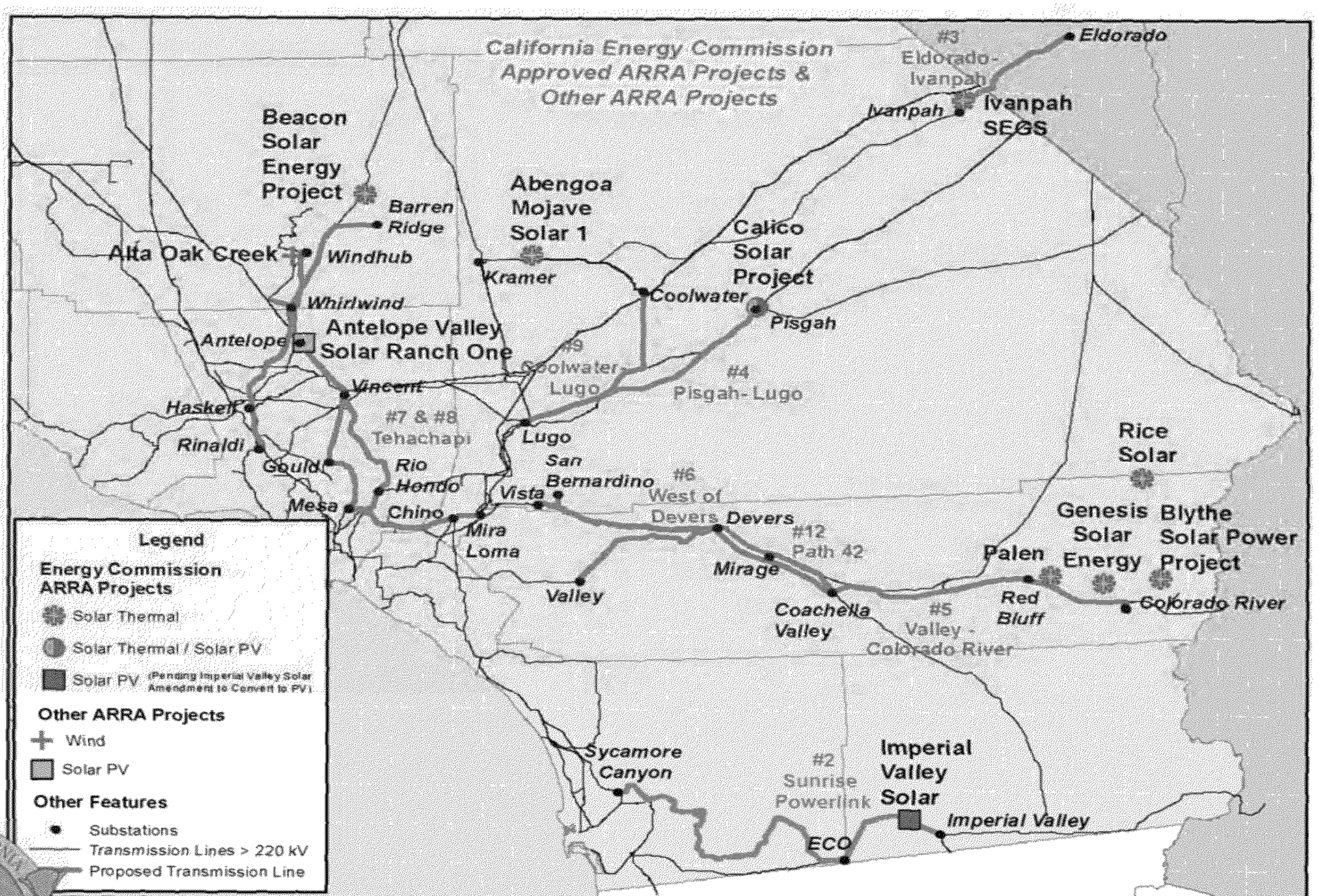
*Equals about 25% of new renewable generation needed to meet the 33% RPS.

**Represents about 22% of the avoided GHG emission reduction accounted for RPS under the ARB's 2008 Climate Change Scoping Plan

California Environmental Protection Agency

Air Resources Board

Increasing Large Scale Renewables and Necessary Transmission



California Environmental Protection Agency
Air Resources Board

Climate Change Proposed Scoping Plan

a framework for change

october 2008

Pursuant to AB 32

The California Global Warming Solutions Act of 2006

Prepared by

the California Air Resources Board
for the State of California

Arnold Schwarzenegger
Governor

Linda S. Adams
Secretary, California Environmental Protection Agency

Mary D. Nichols
Chairman, Air Resources Board

James N. Goldstene
Executive Officer, Air Resources Board

On September 27, 2006, Governor Schwarzenegger signed Assembly Bill 32, the Global Warming Solutions Act of 2006 (Núñez, Chapter 488, Statutes of 2006). The event marked a watershed moment in California's history. By requiring in law a reduction of greenhouse gas (GHG) emissions to 1990 levels by 2020, California set the stage for its transition to a sustainable, clean energy future. This historic step also helped put climate change on the national agenda, and has spurred action by many other states.

The California Air Resources Board (ARB or Board) is the lead agency for implementing AB 32, which set the major milestones for establishing the program. ARB met the first milestones in 2007: developing a list of discrete early actions to begin reducing greenhouse gas emissions, assembling an inventory of historic emissions, establishing greenhouse gas emission reporting requirements, and setting the 2020 emissions limit.

ARB must develop a Scoping Plan outlining the State's strategy to achieve the 2020 greenhouse gas emissions limit. This Proposed Scoping Plan, developed by ARB in coordination with the Climate Action Team (CAT), proposes a comprehensive set of actions designed to reduce overall greenhouse gas emissions in California, improve our environment, reduce our dependence on oil, diversify our energy sources, save energy, create new jobs, and enhance public health. It will be presented to the Board for approval at its meeting in December 2008. The measures in the Scoping Plan approved by the Board will be developed over the next two years and be in place by 2012.

This plan calls for an ambitious but achievable reduction in California's carbon footprint. Reducing greenhouse gas emissions to 1990 levels means cutting approximately 30 percent from business-as-usual emission levels projected for 2020, or about 15 percent from today's levels. On a per-capita basis, that means reducing our annual emissions of 14 tons of carbon dioxide equivalent for every man, woman and child in California down to about 10 tons per person by 2020. This challenge also presents a magnificent opportunity to transform California's economy into one that runs on clean and sustainable technologies, so that all Californians are able to enjoy their rights in the future to clean air, clean water, and a healthy and safe environment.

Significant progress can be made toward the 2020 goal relying on existing technologies and improving the efficiency of energy use. A number of solutions are "off the shelf," and many – especially investments in energy conservation and efficiency – have proven economic benefits. Other solutions involve improving our state's infrastructure, transitioning to cleaner and more secure sources of energy, and adopting 21st century land use planning and development practices.

[illegible]

Getting to the 2020 goal is not the end of the State's effort. According to climate scientists, California and the rest of the developed world will have to cut emissions by 80 percent from today's levels to stabilize the amount of carbon dioxide in the atmosphere and prevent the most severe effects of global climate change. This long range goal is reflected in California Executive Order S-3-05 that requires an 80 percent reduction of greenhouse gases from 1990 levels by 2050.

Reducing our greenhouse gas emissions by 80 percent will require California to develop new technologies that dramatically reduce dependence on fossil fuels, and shift into a landscape of new ideas, clean energy, and green technology. The measures and approaches in this plan are designed to accelerate this necessary transition, promote the rapid development of a cleaner, low carbon economy, create vibrant livable communities, and improve the ways we travel and move goods throughout the state. This transition will require close coordination of California's climate change and energy policies, and represents a concerted and deliberate shift away from fossil fuels toward a more secure and sustainable future. This is the firm commitment that California is making to the world, to its children and to future generations.

Making the transition to a clean energy future brings with it great opportunities. With these opportunities, however, also come challenges. As the State moves ahead with the development and implementation of policies to spur this transition, it will be necessary to ensure that they are crafted to not just cut greenhouse gas emissions and move toward cleaner energy sources, but also to ensure that the economic and employment benefits that will accompany the transition are realized in California. This means that particular attention must be paid to fostering an economic environment that promotes and rewards California-based investment and development of new technologies and that adequate resources are devoted to building and maintaining a California-based workforce equipped to help make the transition.

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Addressing climate change presents California with a challenge of unprecedented scale and scope. Success will require the support of Californians up and down the state. At every step of the way, we have endeavored to engage the public in the development of this plan and our efforts to turn the tide in the fight against global warming.

In preparing the Draft Scoping Plan, ARB and CAT subgroups held dozens of workshops, workgroups, and meetings on specific technical issues and policy measures. Since the release of the draft plan in late June, we have continued our extensive outreach with workshops and webcasts throughout the state. Hundreds of Californians showed up to share their thoughts about the draft plan, and gave us their suggestions for improving it. We've received thousands of postcards, form letters, emails, and over 1,000 unique comments posted to our website or sent by mail. All told, more than 42,000 people commented on the draft Plan.

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Measure No.	Measure Description	Reductions
T-1	Pavley I and II – Light-Duty Vehicle Greenhouse Gas Standards	31.7
	Total	**31.7**

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Maximize energy efficiency building and appliance standards, and pursue additional efficiency efforts including new technologies, and new policy and implementation mechanisms. Pursue comparable investment in energy efficiency from all retail providers of electricity in California (including both investor-owned and publicly-owned utilities).

Energy-efficiency measures for both electricity and natural gas can reduce greenhouse gas emissions significantly. In 2003, the CPUC and CEC adopted an Energy Action Plan that prioritized resources for meeting California's future energy needs, with energy efficiency being first in the "loading order," or highest priority. Since then, this policy goal has been codified into statute through legislation that requires electric utilities to meet their resource needs first with energy efficiency.[31]

This measure would set new targets for statewide annual energy demand reductions of 32,000 gigawatt hours and 800 million therms from business as usual[32] – enough to power more than 5 million homes, or replace the need to build about ten new large power plants (500 megawatts each). These targets represent a higher goal than existing efficiency targets established by CPUC for the investor-owned utilities due to the inclusion of innovative strategies above traditional utility programs. Achieving the State's energy efficiency targets will require coordinated efforts from the State, the federal government, energy companies and customers. ARB will work with CEC and CPUC to facilitate these partnerships. A number of these measures also have the potential to deliver significant economic benefits to California consumers, including low-income households and small businesses. California's energy efficiency programs for buildings and appliances have generated more than $50 billion in savings over the past three decades. Tables 7 and 8 summarize the reduction of greenhouse gas emissions.

[31] SB 1037 (Kehoe, Chapter 366, Statutes of 2005) and AB 2021 (Levine, Chapter 734, Statutes of 2006) directed electricity corporations subject to CPUC's authority and publicly-owned electricity utilities to first meet their unmet resource needs through all available energy efficiency and demand response resources that are cost effective, reliable and feasible.

[32] The savings targeted here are additional to savings currently assumed to be incorporated in CEC's 2007 demand forecasts. However, CEC has initiated a public process to better determine the quantity of energy savings from standards, utility programs, and market effects that are embedded in the baseline demand forecast.

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Achieving the energy efficiency target will require redoubled efforts to target industrial, agricultural, commercial, and residential end-use sectors, comprised of both innovative new initiatives that have been embraced by CEC's energy policy reports and CPUC's long-term strategic plan, and improvements to California's traditional approaches of improved building standards and utility programs.

High-efficiency distributed generation applications like fuel cell technologies can also play an important role in helping the State meet its requirements for reduction of greenhouse gas emissions. Key energy efficiency strategies, grouped by type, include:

Cross-cutting Strategy for Buildings
- "Zero Net Energy" buildings[33]

Codes and Standards Strategies
- More stringent building codes and appliance efficiency standards
- Broader standards for new types of appliances and for water efficiency
- Improved compliance and enforcement of existing standards
- Voluntary efficiency and green building targets beyond mandatory codes

Strategies for Existing Buildings
- Voluntary and mandatory whole-building retrofits for existing buildings
- Innovative financing to overcome first-cost and split incentives for energy efficiency, on-site, renewables, and high efficiency distributed generation

Existing and Improved Utility Programs
- More aggressive utility programs to achieve long-term savings

Other Needed Strategies
- Water system and water use efficiency and conservation measures
- Local government programs that lead by example and tap into local authority over planning, development, and code compliance
- Additional industrial and agricultural efficiency initiatives
- Providing real time energy information technologies to help consumers conserve and optimize energy performance

With the support of key State agencies, utilities, local governments and others, the CPUC has recently adopted the *California Long Term Energy Efficiency Strategic Plan*.[34] Released September 2008, this Plan sets forth a set of strategies toward maximizing the achievement of cost-effective energy efficiency in California's Electricity and Natural Gas sectors between 2009 and 2020, and beyond. Its

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[33] Zero net energy refers to building energy use over the course of a typical year. When the building is producing more electricity than it needs, it exports its surplus to the grid. When the building requires more electricity than is being produced on-site, it draws from the grid. Generally, when constructing a ZNE building, energy efficiency measures can result in up to 70% savings relative to existing building practices, which then allows for renewables to meet the remaining load.

[34] California Public Utilities Commission. *California Long Term Energy Efficiency Strategic Plan.* September 2008. http://www.californiaenergyefficiency.com/docs/EEStrategicPlan.pdf (accessed October 12, 2008).

recommendations are the result of a year-long collaboration by energy experts, utilities, businesses, consumer groups, and governmental organizations in California, throughout the west, nationally and internationally.

For many of the above goals and others, the Strategic Plan discusses practical implementation strategies, detailing necessary partnerships among the state, its utilities, the private sector, and other market players and timelines for near-term, mid-term and long-term success. While the Strategic Plan is the most current and innovative summary of energy efficiency strategies needed to meet State goals, additional planning and new strategies will likely be needed, both to achieve the 2020 emissions reduction goals and to set the State on a trajectory toward 2050.

Other innovative approaches could also be used to motivate private investment in efficiency improvements. One example that will be evaluated during the development of the cap-and-trade program is the creation of a mechanism to make allowances available within the program to provide incentives for local governments, third party providers, or others to pursue projects to reduce greenhouse gas emissions, including the bundling of energy efficiency improvements for small businesses or in targeted communities.

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Solar water heating systems offer a potential for natural gas savings in California. A solar water heating system offsets the use of natural gas by using the sun to heat water, typically reducing the need for conventional water heating by about two-thirds. Successful implementation of the zero net energy target for new buildings will require significant growth in California's solar water heating system manufacturing and installation industry. The State has initiated a program to move toward a self sustaining solar water heater industry. The Solar Hot Water and Efficiency Act of 2007 (SHWEA) authorized a ten year, $250-million incentive program for solar water heaters with a goal of promoting the installation of 200,000 systems in California by 2017.[35]

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Combined heat and power (CHP), also referred to as cogeneration, produces electricity and useful thermal energy in an integrated system. The widespread development of efficient CHP systems would help displace the need to develop new, or expand existing, power plants. This measure sets a target of an additional 4,000 MW of installed CHP capacity by 2020, enough to displace approximately 30,000 GWh of demand from other power generation sources.[36]

[35] Established under Assembly Bill 1470 (Huffman, Chapter 536, Statues of 2007).

[36] Accounting for avoided transmission line losses of seven percent, this amount of CHP would actually displace 32,000 GWh from the grid.

California has supported CHP for many years, but market and other barriers continue to keep CHP from reaching its full market potential. Increasing the deployment of efficient CHP will require a multi-pronged approach that includes addressing significant barriers and instituting incentives or mandates where appropriate. These approaches could include such options as utility-provided incentive payments, the creation of a CHP portfolio standard, transmission and distribution support payments, or the use of feed-in tariffs.

[illegible]

Measure No.	Measure Description	Reductions
E-1	Energy Efficiency (32,000 GWh of Reduced Demand) • Increased Utility Energy Efficiency Programs • More Stringent Building & Appliance Standards • Additional Efficiency and Conservation Programs	15.2
E-2	Increase Combined Heat and Power Use by 30,000 GWh	6.7
	Total	**21.9**

[illegible]

Measure No.	Measure Description	Reductions
CR-1	Energy Efficiency (800 Million Therms Reduced Consumption) • Utility Energy Efficiency Programs • Building and Appliance Standards • Additional Efficiency and Conservation Programs	4.3
CR-2	Solar Water Heating (AB 1470 goal)	0.1
	Total	**4.4**

[illegible]

Achieve 33 percent renewable energy mix statewide.

CEC estimates that about 12 percent of California's retail electric load is currently met with renewable resources. Renewable energy includes (but is not limited to) wind, solar, geothermal, small hydroelectric, biomass, anaerobic digestion, and landfill gas. California's current Renewables Portfolio Standard (RPS) is intended to increase that share to 20 percent by 2010. Increased use of renewables will decrease California's reliance on fossil fuels, thus reducing emissions of greenhouse gases from the Electricity sector. Based on Governor Schwarzenegger's call for a statewide 33 percent RPS, the Plan anticipates that California will have 33 percent of its electricity provided by renewable resources by 2020, and includes the reduction of greenhouse gas emissions based on this level.

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Senate Bill 107 (Simitian, Chapter 464, Statutes of 2006) obligates the investor-owned utilities (IOUs) to increase the share of renewables in their electricity portfolios to 20 percent by 2010. Meanwhile, the publicly-owned utilities (POUs) are encouraged but not required to meet the same RPS. The governing boards of the state's three largest POUs, the Los Angeles Department of Water and Power (LADWP), the Sacramento Municipal Utility District (SMUD), and the Imperial Irrigation District (IID), have adopted policies to achieve 20 percent renewables by 2010 or 2011. LADWP and IID have established targets of 35 and 30 percent, respectively, by 2020.

In 2005, CEC and CPUC committed in the Energy Action Plan II to "evaluate and develop implementation paths for achieving renewable resource goals beyond 2010, including 33 percent renewables by 2020, in light of cost-benefit and risk analysis, for all load serving entities." The proposed opinion in the CPUC/CEC joint proceeding lends strong support for obtaining 33 percent of California's electricity from renewables, and states the two Commissions' belief that this target is achievable if the State commits to significant investments in transmission infrastructure and key program augmentation. As with the energy efficiency target, achieving the 33 percent goal will require broad-based participation from many parties and the removal of barriers. CEC, CPUC, California Independent System Operator (CAISO), and ARB are working with California utilities and other stakeholders to formally establish and meet this goal.

A key prerequisite to reaching a target of 33 percent renewables will be to provide sufficient electric transmission lines to renewable resource zones and system changes to allow integration of large quantities of intermittent wind and solar generation. The Renewable Energy Transmission Initiative (RETI) is a broad collaborative of State agencies, utilities, the environmental community, and renewable generation developers that are working cooperatively to identify and prioritize renewable generation zones and associated transmission projects. Although biomass, geothermal, and small-scale hydroelectric generation can provide steady baseload power, other renewable generation is intermittent (wind) or varies over time (solar). Therefore, integration of intermittent generation into the electricity system will require grid improvements so that fluctuations in power availability can be accommodated. Improved communications technology, automated demand response, electric sub-station improvements and other modern technologies must be implemented both to facilitate intermittent renewables, and to improve grid reliability.

Another key action that may help to achieve the renewable energy goals is to reduce the complexity and cost faced by small renewable developers in contracting with utilities to supply renewable generation. This is particularly important for projects offering below 20 megawatts of generation capacity. One such option may be a feed-in tariff for all RPS-eligible renewable energy facilities up to 20 megawatts in size. This mechanism was recommended in CEC's 2007 Integrated Energy Policy Report. Such a tariff, set at an appropriate level, could benefit small-scale facilities by allowing them to be brought into the electricity grid more rapidly.

For the purposes of calculating the reduction of greenhouse gas emissions in this Proposed Scoping Plan, ARB is counting emissions avoided by increasing the percentage of renewables in California's electricity mix from the current level of 12 percent to the 33 percent goal, as shown in Table 9.

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Measure No.	Measure Description	Reductions
E-3	Achieve a 33% renewables mix by 2020	21.3
	Total	**21.3**

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Develop and adopt the Low Carbon Fuel Standard.

Because transportation is the largest single source of greenhouse gas emissions in California, the State is taking an integrated approach to reducing emissions from this sector. Beyond including vehicle efficiency improvements and lowering vehicle miles traveled, the State is proposing to reduce the carbon intensity of transportation fuels consumed in California.

To reduce the carbon intensity of transportation fuels, ARB is developing a Low Carbon Fuel Standard (LCFS), which would reduce the carbon intensity of California's transportation fuels by at least ten percent by 2020 as called for by Governor Schwarzenegger in Executive Order S-01-07.

LCFS will incorporate compliance mechanisms that provide flexibility to fuel providers in how they meet the requirements to reduce greenhouse gas emissions. The LCFS will examine the full fuel cycle impacts of transportation fuels and ARB will work to design the regulation in a way that most effectively addresses the issues raised by the Environmental Justice Advisory Committee and other stakeholders. ARB identified the LCFS as a Discrete Early Action item, and is developing a regulation for Board consideration in March 2009. A 10 percent reduction in the intensity of transportation fuels is expected to equate to a reduction of 16.5 $MMTCO_2E$ in 2020. However, in order to account for possible overlap of benefits between LCFS and the Pavley greenhouse gas standards, ARB has discounted the contribution of LCFS to 15 $MMTCO_2E$.

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Install 3,000 MW of solar-electric capacity under California's existing solar programs.

As part of Governor Schwarzenegger's Million Solar Roofs Program, California has set a goal to install 3,000 megawatts (MW) of new solar capacity by 2017 – moving the state toward a cleaner energy future and helping lower the cost of solar systems for consumers. The Million Solar Roofs Initiative is a ratepayer-financed incentive program aimed at transforming the market for rooftop solar systems by driving down costs over time. Created under Senate Bill 1 (Murray, Chapter 132, Statutes of 2006), the Million Solar Roofs Program includes CPUC's California Solar Initiative and CEC's New Solar Homes Partnership, and requires publicly-owned utilities (POUs) to adopt, implement and finance a solar incentive program. This measure would offset electricity from the grid, thereby reducing greenhouse gas emissions. The estimated emissions reductions are shown in Table 14.

Obtaining the incentives requires the building owners or developers to meet certain efficiency requirements: specifically, that new construction projects meet energy efficiency levels that exceed the State's Title 24 Building Energy Efficiency Standards, and that existing commercial buildings undergo an energy audit. Thus, the program is also a mechanism for achieving the efficiency targets for the Energy sector. By requiring greater energy efficiency for projects that seek solar incentives, the State would be able to reduce both electricity and natural gas needs and their associated greenhouse gas emissions.

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Measure No.	Measure Description	Reductions
E-4	Million Solar Roofs (including California Solar Initiative, New Solar Homes Partnership and solar programs of publicly owned utilities) • Target of 3000 MW Total Installation by 2020	2.1
	Total	**2.1**

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Adopt medium and heavy-duty vehicle efficiency measures.

Medium- and heavy-duty vehicles account for approximately 20 percent of the transportation greenhouse gas inventory. Requiring retrofits to improve the fuel efficiency of heavy-duty trucks could include a requirement for devices that reduce aerodynamic drag and rolling resistance. In addition, hybridization of medium- and heavy-duty vehicles would also reduce greenhouse gas emissions through increased fuel efficiency. Hybrid trucks would likely achieve the greatest benefits in urban, stop-and-go applications, such as parcel delivery, utility services, transit, and other and the use of offsets. Due to time and resource constraints, the modeling was limited to the eight WCI Partner jurisdictions in the Western Electric Coordinating Council (WECC) area, thereby excluding from the analysis three Canadian provinces, Manitoba, Quebec, and Ontario. Future analyses are planned that will integrate these provinces so that a full assessment of the WCI Partner jurisdictions can be performed.

The WCI modeling work is not directly comparable to the ARB results reported here. The WCI analysis relies on a more aggregated set of greenhouse gas emissions reduction measures rather than the specific individual policies recommended in the Proposed Scoping Plan; it uses somewhat different assumptions regarding what measures are included in the "business-as-usual" case, and it models the entire WECC rather than California. Nevertheless, the results of the WCI modeling provide useful insight into the economic impact of greenhouse gas emissions reduction policies.

Consistent with the conclusions of the ARB evaluation, overall the WCI analysis found that the WCI Partner jurisdictions can meet the regional goal of reducing emissions to 15 percent below 2005 levels by 2020 (equivalent to the AB 32 2020 target) with small overall savings due to reduced energy expenditures exceeding the direct costs of greenhouse gas emissions reductions. The savings are focused primarily in the residential and commercial sectors, where energy efficiency programs and vehicle standards are expected to have their most significant impacts. Energy-intensive industrial sectors are estimated to have small net costs overall (less than 0.5 percent of output).

The WCI analysis does not examine the potential macroeconomic impacts of the costs and savings estimated with ENERGY 2020. The WCI Partner jurisdictions are planning to continue the analysis so that macroeconomic impacts, such as income, employment, and output, can be assessed. Once completed, the macroeconomic impacts can be compared to previous studies of cap-and-trade programs considered in the United States and Canada.

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The development of green technologies and a trained workforce equipped to design, develop and deploy them will be key to the success of California's long-term efforts to combat global warming. Bold, long-range environmental policies help drive innovation and investment in emission-reducing products and services in part by attracting private capital. Typically, the private sector under invests in research and development for products that yield public benefits. However, when environmental policy is properly designed and sufficiently robust to support a market for such products, private capital is attracted to green technology development as it is to any strategic growth opportunity.

California's leadership in environmental and energy efficiency policy has helped attract an increasing share of venture capital investment in green technologies. According to statistics from PricewaterhouseCoopers and the National Venture Capital Association, California's