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ATTACHMENT 1

Standardized Planning Assumptions (Part 1) for System Resource Plans

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Standardized Planning Assumptions (Part 1) for System Resource Plans

The resource plans filed by the IOUs, or any other respondent shall conform with the standardized planning assumptions in this document. In general, standardization addresses (I) definitions, (II) guiding principles, (III) portfolio evaluation criteria; (IV) common value assumptions, and (V) sensitivity analysis, as specified below. Additionally, L&R Tables are provided in (VI), and supplemental explanation for metrics calculation or more detailed information on values in the L&R Tables are provided in the attached Appendices.[1]

I. Definitions

System Plan – The system plans take a physical look at supply and demand, rather than the contractual look conducted in the bundled plans. System plans are exclusive of SMUD and LADWP, except as noted for imports and exports.

Bundled Plan – The bundled plans are assessed based on the needs of the IOUs' bundled customers. It is a contractual look, rather than a physical look, that is exclusive of departing load, such as CCAs and DA customers.

Scenario - A possible future state of the world encompassing assumptions about policy requirements, market realities and resource development choices. *Required scenarios* are those specified in the Scoping Memo. *Alternative scenarios* are any additional scenarios provided by parties, and evaluated in addition to those required in the Scoping Memo.

Portfolio - A set of electric resources, both supply-side and demand-side, that provides electric service to all system ratepayers, under a given scenario. *Utility-Preferred Portfolio* is a resource portfolio identified by the IOU as a preferred resource portfolio and submitted to the Commission for consideration and possible adoption.

Resource Plan – A filing before the Commission containing information and analysis on all portfolios developed and evaluated, including complete documentation of each portfolio's performance under required evaluation criteria.

Case – A set of input assumptions and parameters (e.g., gas price, or electricity demand) under a given scenario that drives the selection of a given portfolio of resources.

Common Values – A set of input assumptions and parameters that represent the expected or most likely values for each scenario. All required scenarios shall have the same common value assumptions, whereas supplemental scenarios may consider alternative assumptions.

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[1] Appendix A contains information on GHG-related calculations, Appendix B information on assumptions, and Appendix C more detailed spreadsheets on values used in the L&R Tables.

Sensitivity Analysis - A test to measure the change in output variable (e.g., cost, resource need) due to a change in input assumptions and parameters. Sensitivity analysis is conducted by changing one or more input assumptions from the common value to an alternative value.

II. Guiding Principles for Resource Plans

Resource plans filed in this proceeding shall follow these guiding principles:

A. Assumptions should take a realistic view of expected policy-driven resource achievements in order to ensure reliability of electric service and track progress toward resource policy goals.

B. Assumptions should reflect the behavior of market participants, to the extent possible.[2]

C. Resource plans should be informed by an open and transparent process.[3]

D. Resource plans should consider whether substantial new investment in transmission and flexible resources would be needed to reliably integrate and deliver new resources to loads.

E. Resource scenarios should provide useful information and resource portfolios should be substantially unique from each other.

F. Filed plans should include "active" or "live" spreadsheets for the metrics and portfolio results.

III. Portfolio Evaluation Criteria

Reliability shall be treated as a modeling input constraint, rather than as a separate evaluation metric. The Planning Reserve Margin (PRM), in conjunction with the resource adequacy (RA) program, is the mechanism by which the Commission ensures system reliability levels are maintained. In the system analysis, each resource portfolio should include sufficient levels of resources in order to meet the PRM requirement, currently 15-17% of peak demand.[4] While the IOUs may also choose to calculate and report a reliability metric (e.g. loss of load probability), or qualitatively assess the reliability benefits of a given portfolio above the PRM, the Commission discourages assessments of reliability benefits outside the PRM proceeding (R.08-04-012 or its successor).

All resource plans filed by the IOUs, or any other respondent shall evaluate and document the performance of each portfolio filed in terms of cost, risk, and GHG emissions metrics. These

[2] A possible exception is confidential market price data, which may be reasonably substituted with public engineering- or market-based price data.

[3] We believe that the renewable generation scenarios developed by Energy Division have been developed according to a transparent and vetted methodology. However, as stated in Guiding Principle B, there are benefits to having commercial activity reflected in renewable generation portfolios. These scenarios thus include some aggregated confidential information from the IOUs' RPS solicitations. Access to disaggregated market data may be restricted to non-market participants who sign a non-disclosure agreement, pursuant to D.06-06-066 and its successors.

[4] See D.04-01-050.

three categories of evaluation criteria are summarized in Table 1 and described in more detail below.

Table 1: Required Evaluation Criteria for Resource Plans

Criteria	Description
1. Cost	(a) Net Present Value Revenue Requirement (utility cost) (b) System average rate (c) Total Resource Cost (customer and utility cost) (d) Average, per ton cost of GHG emissions reductions (e) Total GHG-related Costs
2. Risk	Robust scenario and sensitivity analysis
3. GHG Emissions	(a) Total GHG emissions during each year of the planning horizon (b) Qualitative assessment of long-term GHG implications

1. Cost

Portfolios shall be evaluated on the basis of at least the following cost metrics: the net present value revenue requirement (PVRR), system average rate, PVRR plus customer cost, average, per ton cost of GHG emissions reduction, and the total GHG-related costs.

(a) Net Present Value Revenue Requirement: The PVRR includes all costs required to meet service area demand that are expected to enter into utility rates. The PVRR includes generation costs as well as transmission, distribution, and all other utility costs. To calculate PVRR, the total, utility revenue requirements are summed for each year of the planning horizon, and then discounted back to base year dollars using an appropriate discount rate.

A forecast of CO_2 allowance costs must be included in the PVRR calculation. (See Table 3 and discussion below for CO_2 price forecast methodology and GHG policy assumptions used to calculate the effect of CO_2 prices on generation costs and costs to utilities.)

Because fossil fuel and CO_2 allowance prices may continue to rise after the end of the normal 10-year planning period, cost metrics shall be calculated over 20 years, at a minimum. If a 20-year time period is selected, additional analysis to capture "end effects" after the end of the 20-year period should be done. A "salvage value" approach that credits ratepayers with the remaining market value of the resource, given appropriate assumptions for CO_2 price and natural gas price forecasts, is acceptable. We encourage the IOUs to work together to develop a common methodology; however, that methodology should incorporate the market value of the plant and not just the remaining book value.

(b) System Average Rate: The system average rate shall be calculated for each year of the model period as the revenue requirement of each portfolio divided by total sales in that year. A present value of the average rate shall also be calculated (present value of the revenue requirement divided by the present value of the total sales).

(c)PVRR Plus Customer Cost[5]: Many of California's policy goals are aimed at increasing the deployment of distributed energy resources such as EE, DR and renewable DG. Development of these resources often requires substantial customer contributions in addition to utility support. The PVRR Plus Customer Cost criteria includes both utility and net customer contributions toward the resource cost, but excludes any incentives that the utility pays to the customer. It is not necessary to calculate customer and utility costs for programs that are administered outside of the utility sector, such as building codes and standards. Customer and utility costs should be calculated for all utility-sector programs administered by the Commission, including EE, DR, CSI, CHP, and others.

(d) Average, Per-ton Cost of GHG Emissions Reduction: Resource plans shall calculate the average, per ton cost of CO_2 emissions reductions for each portfolio, relative to a benchmark portfolio constructed by meeting all resource needs with new natural gas fired resources. The "All-Gas" portfolio is similar to other portfolios submitted for the Commission's review, but is developed for benchmarking purposes only. To calculate the average cost of CO_2 emissions reduction, the change in PVRR relative to the All-Gas portfolio cost is divided by the change in total GHG emissions relative to the All-Gas portfolio. This metric shall be calculated for each year of the forecast period, and discounted to present day values using an appropriate discount rate. This is a useful evaluation criterion because it provides an indication of a portfolio's cost-effectiveness in reducing GHG emissions.

(e) Total GHG-related Costs: The total GHG-related costs metric will measure the carbon cost incorporated in each energy transaction. We expect that GHG costs will not simply be a function of the GHG emissions in a given procurement portfolio. Instead, GHG costs will be a function of both the embedded emissions in generation and the method of procurement. Under market purchases, GHG costs shall reflect the embedded GHG emissions of the marginal (price-setting) generator, rather than the emissions embedded in the power purchased. During periods in which the marginal generator has a compliance obligation (i.e. is a carbon-emitting resource), non-emitting generators that sell into the market will have a GHG cost embedded in their purchase price, despite having no direct emissions associated with generation.

[5] In this proceeding, this criteria refers to the sum of the utility cost and customer cost of the entire resource portfolio. This criteria is closely related to, but not precisely the same as, the Total Resource Cost criteria used in the context of cost-effectiveness determinations of individual EE and other demand-side resource programs.

2. Risk

Robust scenario and sensitivity analyses shall be conducted to assess a variety of risks associated with a given set of resource portfolios. More detailed guidance on scenarios and sensitivities is provided below in Sections III and V, respectively.

3. Greenhouse Gas Emissions

(a) Total GHG Emissions: Resource plans shall report the total GHG emissions associated with each portfolio during each year of the planning horizon. Since the Air Resources Board (ARB) has released a draft set of Global Warming Potential values on October 28, 2010 for GHGs, the evaluation criteria for Total GHG Emissions should be adjusted to comply with the draft ARB policy and its eventual final form.

(b) Qualitative Assessment of Long-Term GHG Implications: Resource plans shall include a qualitative assessment of the impacts of each portfolio on the ability of the state to meet long-term GHG reduction goals of 80 percent below 1990 levels by 2050 and the potential impact of portfolio resource choices to influence long-term technology transformation. Portfolios that rely heavily on existing, mature technologies would score poorly under this criterion, while portfolios that include emerging technologies with long-term potential for GHG benefits and substantial cost reductions and would score highly. We do not intend this assessment to be highly specific and quantitative in nature; rather, we are interested in the perspective of the IOUs' and parties as to which technologies hold the most promise for cost-effective, long-term, electric sector GHG reductions and whether increased investment in those technologies now would have long-term benefits for electric ratepayers in California.

IV. Required Scenarios

The Energy Division proposed a minimum set of four 33% renewable generation scenarios[6] in its draft report in June 2010. We have revised these scenarios, based on parties' comments, and the final RPS scenarios are included in the Standardized Planning Assumptions (Part 2 - Renewables) for System Resource Plans. The IOUs or any other party may propose alternative scenarios that the Commission should consider to achieve the goals of this proceeding. Alternative portfolios shall accompany the alternative scenarios, pursuant with the schedule in the Scoping Memo. The required scenarios and portfolios shall be consistent with the guiding principles set forth in Section II.

[6] The four 33% RPS scenarios presented were: Trajectory, Environmentally-Constrained, Cost-Constrained, and Time-Constrained.

1. Required Common Value Assumptions for Each Required Scenario

Tables 2 and 3 below summarizes our requirements for common value assumptions in required scenarios evaluated in the IOUs' resource plans. In general, these requirements apply to two categories of assumptions: (1) **load and resource variables** underlying assessments of need for new resources; and (2) **cost variables** underlying computations of total portfolio cost. See discussion below for more detailed descriptions of these requirements.

(a) Load and Resource Variables: Table 2 below summarizes our requirements for common value load and resource assumptions in the minimum set of required scenarios evaluated in the IOUs' resource plans. We note that preferred resources (e.g., CHP) not already identified in Table 2 shall be reflected in the IOUs' resource plans, as specified in Scoping Memo or its attachments.

Table 2: Requirements for common value assumptions: load and resource assumptions

Variable	Source for Common Value Assumptions
Load and Resource Assumptions	
Load forecast (energy and capacity)	For system RA need assessments, use the most recent IEPR base case 1-in-2 load forecast. For local RA need assessments, use local area forecasts that are consistent with the most recent IEPR base case 1-in-10 load forecast.
Energy efficiency (EE)	**Committed EE**[7] - Embedded utility EE program savings in the most recent IEPR base case load forecast.
	Uncommitted EE[8] – Assumed levels of EE savings that are incremental to the most recent IEPR base case load forecast, as specified below.
Demand response (DR)	The estimated ex-ante load impact forecast filed shall be based on the April 1, 2010 Load Impact Report Compliance Filing pursuant to Ordering Paragraph 4, D.08-04-050. The utilities should report DR load impact forecast for LTPP using the August Monthly System Peak Load Day under a 1-in-2 Weather Condition.

[7] In this OIR, we define *committed EE* as savings from IOU programs implemented in the 2006-2012 period. These are considered committed savings and are embedded in the CEC's 2009 IEPR demand forecast.

[8] In this OIR, we define *uncommitted EE* as savings from IOU and non-utility programs implemented in the 2013-2020 period to achieve the Commission's EE savings goals adopted in D.08-07-047, as modified by D.09-09-047 and subsequent decisions.

Variable	Source for Common Value Assumptions
Customer-side DG, including California Solar Initiative (CSI)	Embedded levels of self-generation in the most recent IEPR base case load forecast.
Existing Resources	Net Qualifying Capacity (NQC) values per the RA proceeding.[9]
Resource Additions and Retirements	IOUs propose assumptions on resource additions and retirements beyond what has been included in the L&R tables and Attachments B & C.
Planning Reserve Margin	15%-17% of peak demand, or as modified in R.08-04-012.

[9] The updated NQC list is published at www.cpuc.ca.gov/PUC/energy/Procurement/RA/ra_guides_2008-09.htm.

(b) Load Growth: Pursuant to D.07-12-052, the IOUs are directed to use energy and peak demand forecasts based on the forecast developed for the CEC's 2009 IEPR and subsequent reports. As part of the IEPR, the CEC documents the amount of EE and other behind-the-meter resources such as solar PV, CHP and other DG that are assumed to be embedded in the forecast.

(c) Energy Efficiency: Decision 08-07-047 states that "energy utilities shall use one hundred percent of the interim Total Market Gross [TMG] energy savings goals for 2012 through 2020 in future [LTPP] proceedings, until superseded by permanent goals."[10] However, the Commission has deferred to the CEC's IEPR process to generate load forecasting information necessary to interpret the impacts of TMG energy savings goals on procurement. Specifically, CEC and Commission staffs collaborated in the 2009 IEPR proceeding to develop forecasts of uncommitted EE (i.e., TMG energy savings not embedded in the forecast.)[11]

In this proceeding, common value assumptions for EE reflect the sum of (1) utility EE program savings embedded in the most recent IEPR demand forecast including savings decay , and (2) incremental EE savings reasonably expected to occur from implementing the IOUs' EE goals, relative to the most recent IEPR load forecast. For this proceeding, this value is the mid-case results for all values except Big Bold EE Strategies, for which the low-case results shall be used.

(d) Demand Response: The common values shall reflect the reasonable levels of DR resources that the Commission has authorized funding, directed in its DR policy decisions, and relied on the benefits for approving funding for other projects.

Specifically, the common value levels of demand response (DR) assumed in the required scenarios reflect currently adopted 2009-2011 DR programs in D.09-08-027 and DR programs approved through other Commission proceedings. The common value also includes load impacts from reasonably anticipated DR programs/resources such as those enabled by the IOUs' Advanced Metering Infrastructure (AMI) systems ("AMI Enabled DR"), of which the estimated benefits were included in the Commission-approved AMI decisions.

The estimated ex-ante load impact forecasts are based on the April 1, 2010 Load Impact Report Compliance Filing pursuant to Ordering Paragraph 4, D.08-04-050. These forecasts use the August Monthly System Peak Load Day under a 1-in-2 Weather Condition.

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[10] D.08-07-047, OP 3, at p. 39.

[11] See CEC Committee Report, *Incremental Impact of Energy Efficiency Policy Initiatives Relative to the* 2009 Integrated Energy Policy Report *Adopted Demand Forecast.* http://www.energy.ca.gov/2010publications/CEC-200-2010-001/index.html.

The forecasted values include AMI-enabled DR, such as price-responsive programs adopted or directed by the Commission, but yet to be implemented,[12] and any default and optional dynamic rates expected in the forecast period. In addition, the forecasts include the Peak Time Rebate (PTR) program and the Programmable and Communicating Thermostat (PCT) program underling the AMI related DR benefit assumptions in the Commission AMI decisions.[13]

Pursuant to the Commission orders in PG&E's and SCE's AMI decisions[14], we anticipated that the IOUs would include the ex-ante load impact forecasts for the AMI Enabled DR in their April 1 Load Impact Reports (April filings). However, except for SDG&E, some of these programs have not been implemented; therefore, PG&E and SCE did not include any ex-ante forecast for these programs in their April 2010 filings. Neither PG&E nor SCE provided the information in their initial comments on the OIR neither in June 2010 nor in the supplemental comments in July 2010.

In absence of the IOU inputs, we believe that it is reasonable to rely on the load impact forecast adopted in the AMI decisions to develop the common value for the AMI Enabled DR for this ruling. The common value also includes the ex-ante DR portfolio load impact forecast for other programs provided in the IOUs' April 2010 filings.

(e) Resource Additions and Retirements: System resource additions are considered "Known or High Probability" if they have a Commission approved contract in place, have been permitted, and are under construction. An alternative is projects outside of an IOU with an approved Application for Construction (AFC). "Utility Probable Planned Additions" are additions with an approved contract in place, but have not yet begun construction, or additions with an approved AFC. "Other Planned Additions" are resources with CPUC approved contracts, but currently do not have approved AFC permits.

The Scoping Memo specifies an approach to plant retirement assumptions for required scenarios in the IOUs' resource plans, consistent with implementation of the state's OTC policy.

All resource additions and retirements are a forecast, and are an estimate of what resources may come on- or off-line during the LTPP planning horizon. Generation owners have a variety of options when it comes to retiring plants. For example, they could repower instead of retiring the facility.

[12] These include, for example, PG&E's Peak Time Rebate (PTR).
[13] D.09-03-026 (PG&E), D.08-09-039 (SCE), and D.0704-043 (SDG&E).
[14] D. 09-03-026, Ordering Paragraph (OP) 10 and D. 08-09-039, OP 3.

2. Cost Variables

Table 3 below summarizes our requirements for common value cost assumptions in the minimum set of scenarios evaluated in the IOUs' resource plans. See discussion below for more detailed descriptions of these requirements.

Table 3: Requirements for common value assumptions: cost assumptions

Variable	Source for Common Value Assumptions
Cost Assumptions	
Renewable resource availability	As in the Standardized Planning Assumptions (Part 2 - Renewables) for System Resource Plans.
Renewable resource cost	As in the Standardized Planning Assumptions (Part 2 - Renewables) for System Resource Plans.
Conventional and other resource cost and performance *	MPR values for CCGT. IOUs propose a single common value for others.
New generation tax and financing assumptions *	For new renewables, use assumptions in the Standardized Planning Assumptions (Part 2 - Renewables) for System Resource Plans. For other technologies, IOUs propose a single common value.
Transmission cost assumptions *	For transmission to access new renewables, use assumptions in the Standardized Planning Assumptions (Part 2 - Renewables) for System Resource Plans. For other transmission, IOUs propose a single common value.
Distribution cost assumptions	Most recent EE Avoided Cost methodology
Natural Gas Price	Most recent MPR methodology
CO_2 Price	Most recent MPR methodology
GHG Policy Assumptions	Utilities ensure that the carbon cost schedule provided embeds the draft cost containment mechanisms developed by ARB, and that they revise their portfolios to reflect ARB's actual cost containment policies when they are available. We encourage the utilities to coordinate with Energy Division staff and each other to devise assumptions that appropriately

Variable	Source for Common Value Assumptions
	reflect ARB's AB 32 regulations.
* Includes inputs or assumptions for which the IOUs shall file initial proposals in Q4 2010, pursuant to the Preliminary Schedule in the OIR, or as modified by subsequent ruling.	

(a) Natural Gas Fuel Price Forecast: Subject to change by the Commission in subsequent MPR decisions, the IOUs shall use the MPR gas price forecasting methodology (not actual values) for the common value gas price forecast in the LTPP. We direct this in order to avoid re-litigating an issue that the Commission has already decided in another procurement-related proceeding.

The IOUs shall use the quote date specified in the Scoping Memo. It is expected that each IOU will have different gas forecast values due to each utility's unique basis differentials and gas delivery costs.

(b) CO_2 Price Forecast: When the IOUs file their 2010 resource plans, neither California nor the Western Climate Initiative, is expected to have a fully-functioning CO_2 market. Likewise, in the event that the federal government pursues a nation-wide cap and trade program, it is unlikely that such a program would be operational by this time. Therefore, the Commission does not expect that relevant, real price data will be available when the IOUs file their 2010 resource plans. With this in mind, the IOUs' common value analysis shall use the CO_2 price forecast methodology applied in the most recent MPR decision.

(c) GHG Policy Assumptions: The ARB announced draft GHG policies in the regulation on October 28, 2010. At this time, we expect the utilities rely on the ARB's draft carbon cost containment policy assumptions to the extent that the carbon cost schedule provided above embeds any cost containment mechanisms developed by ARB. Utilities should revise their portfolios to reflect ARB's final cost containment policies when they are available. Since ARB's cost compliance policies were just released, we encourage the utilities to coordinate with Energy Division staff and each other to devise assumptions that appropriately reflect ARB's AB 32 regulations.

V. Required Sensitivity Analysis

The IOUs shall test the robustness of the common value portfolio against changes in a limited and influential set of variables. IOUs may assume that the resource portfolios would not change under the sensitivity analysis. For example, sensitivity analysis of total portfolio cost would simply apply different gas or CO2 cost assumptions to a fixed resource portfolio. The demand level sensitivity will allow both portfolio and dispatch changes. The IOUs shall run six sets of sensitivities: two sets for each of the three variables. During the course of the proceeding, the IOUs may be directed to run additional combinations of sensitivities. Table 4 below specifies the required sensitivity analyses.

Table 4: Requirements for required sensitivity analysis

Variable	Requirement
1. Natural Gas Prices *	Each portfolio shall be evaluated using a "High Gas Price" and "Low Gas Price" sensitivity analysis, corresponding to feasible extremes of natural gas prices. The Scoping Memo establishes values to be used for sensitivity analysis, based on initial IOU proposals for High- and Low-Gas Price assumptions and parties' comments and/or alternative proposals.
2. CO_2 Prices *	Each portfolio shall be evaluated using a "High CO_2 Price" and "Low CO_2 Price" sensitivity analysis, corresponding to feasible extremes of CO_2 price. The Scoping Memo establishes values to be used for sensitivity analysis, based on initial IOU proposals for High- and Low-CO_2 Price assumptions and parties' comments and/or alternative proposals.
3. Demand Level *	The utility-preferred portfolio shall be evaluated using a "High-Demand" and "Low-Demand" sensitivity analysis, corresponding to levels of uncertainty in the achievements of policy-driven demand-side programs. The "Low-Demand" sensitivity should reflect more optimistic assumptions about policy-driven resource achievements (e.g., EE, DR, customer-side DG, and CHP). These sensitivities are designed to reflect total need adjustments, not as permutations of a single policy-driven resource assumption. The "High-Demand" sensitivity should reflect more conservative assumptions about policy-driven resource achievements. The Scoping Memo establishes values to be used for sensitivity analysis, based on initial IOU proposals as well as parties' comments and/or alternative proposals.
* Includes inputs or assumptions for which the IOUs shall filed initial proposals in June and July 2010, pursuant to the Preliminary Schedule in the OIR, or as modified by subsequent ruling.	

VI. Load and Resource Tables

This section contains the L&R Tables, by IOU service area and by scenario. The line notes apply to each individual table.

NOTES (by Line number):	
1	System peak demand represents peak demand in CAISO's control area, for the region indicated. This includes the IOU service area and participating publicly owned utilities in the Path 26 region served by the CAISO.
3	The existing resource NQC for each IOU's system planning area was drawn from the following resources: 1) the most current available 2011 NQC as of August 2; and 2) the CAISO master generation list as of July 12.
10	NQC of forecast OTC retirements.
11	NQC of any announced retirements, exclusive of OTC.
12	Known/High Probability Additions are plants under construction (Category 3) in the CAISO OTC scenario analysis tool. This total includes all CAISO balancing authority POU plants.
13	Other Utility Probably Planned Additions are resources with Contracts (Category 1) or have approved AFC's (Category 2) according to the CAISO OTC scenario analysis tool.
14	Those resources listed with CPUC approved contracts but do not currently have AFC permits approved AFC permits according to the CEC "Status of all Projects" list. These resources do not appear in the CAISO's OTC scenario analysis tool, since these resources did not have approved CPUC contracts or approved AFC permits as of the development of the OTC scenario analysis tool.
15	NQC of RPS Additions, as defined by the scenario.
16	Forecast of incremental CHP additions.
17	Sum of all physical imports and exports into service area, exclusive of imports and exports over Path 26.
18	The import/export capacity will be determined by allocating transmission from outside of the CAISO control area into either NP26 or SP26 based on the transmission resource's initial intertie location into the CAISO control area and its RA value.
20	Service Area Portion of System Resources = Total System Resources * (Service Area Demand/System Demand)
21	Service Area peak demand represents the service area's forecasted peak load, at the time of the CAIOS coincident peak, in the IOU service area, independent of LSE providing service. Service area peak demand includes bundled and direct access (DA) customer peak demand, and excludes publicly owned utility (POU) peak demand.
23	Incremental EE savings, beyond those embedded in the 2009 IEPR Demand Forecast. For the 2010 LTPP, this also includes additional savings from measure replacement decay, which typically would have been embedded in the base IEPR demand forecast.
24	DR savings based on the April 2010 Load Impacts, as well as load impact from reasonably anticipated DR programs/resources such as those enabled by the IOUs' Advanced Metering Infrastructure (AMI) systems ("AMI Enabled DR"), of which the estimated benefits were included in the Commission approved AMI decisions.
25	Forecast of incremental demand-side CHP savings. These savings are grossed up for line losses.
26	Residual Service Area Demand is based on the Commission's "managed forecast" which takes into account the incremental forecast savings from programs such as EE or DR.

PG&E
Physical North of Path 26 (NP26) Capacity Need
Scenario: 33% Trajectory

Line		MW									
	SYSTEM AND SERVICE AREA LOAD FORECASTS:	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
1	**System** 1-in-2 Peak Summer Demand	21,988	22,329	22,668	22,924	23,185	23,454	23,750	24,030	24,310	24,626
2	**Total System Resources** (Sum Lines 3, 8, 11 through 16)	**33,132**	**34,866**	**35,764**	**35,271**	**34,812**	**35,199**	**32,564**	**32,604**	**32,645**	**32,686**
	SYSTEM RESOURCES:										
3	Existing Generation (Sum of Lines 4 through 7)	26,623	26,623	26,623	26,623	26,623	26,623	26,623	26,623	26,623	26,623
4	*Existing Renewables (Excludes Hydro)*	1,426	1,426	1,426	1,426	1,426	1,426	1,426	1,426	1,426	1,426
5	*Existing Hydro (Includes RPS-eligible Hydro)*	6,461	6,461	6,461	6,461	6,461	6,461	6,461	6,461	6,461	6,461
6	*Existing CHP*	1,888	1,888	1,888	1,888	1,888	1,888	1,888	1,888	1,888	1,888
7	*Existing OTC*	7,064	7,064	7,064	7,064	7,064	7,064	7,064	7,064	7,064	7,064
8	*Other Generation*	9,784	9,784	9,784	9,784	9,784	9,784	9,784	9,784	9,784	9,784
9	Retirements (Includes Lines 10 & 11)	(497)	(662)	(662)	(1,336)	(1,986)	(1,986)	(4,807)	(4,807)	(4,807)	(4,807)
10	*OTC Retirements*	341	341	341	1,015	1,665	1,665	3,804	3,804	3,804	3,804
11	*Retirements*	156	321	321	321	321	321	1,003	1,003	1,003	1,003
12	Known/High Probability Additions	878	1,733	1,733	1,733	1,733	1,733	1,733	1,733	1,733	1,733
13	Utility Probable Planned Additions	0	784	784	784	784	784	784	784	784	784
14	Other Planned Additions	0	145	973	973	973	973	973	973	973	973
15	RPS Additions (In Service Territory)	20	94	123	263	414	760	904	904	904	904
16	Additional CHP	41	82	123	164	204	245	286	327	368	409
17	Net Interchange (Sum of Lines 18 & 19)	6,067	6,067	6,067	6,067	6,067	6,067	6,067	6,067	6,067	6,067
18	*Imports*	6,067	6,067	6,067	6,067	6,067	6,067	6,067	6,067	6,067	6,067
19	*Exports*	0	0	0	0	0	0	0	0	0	0
20	**Service Area Portion of System Resources (Line 2 * 92%)**	**30,481**	**32,077**	**32,903**	**32,450**	**32,027**	**32,383**	**29,959**	**29,996**	**30,034**	**30,071**
	SERVICE AREA SPECIFIC LINE ADJUSTMENTS:										
21	**Service Area** 1-in-2 Peak Summer Demand	20,193	20,510	20,829	21,071	21,318	21,572	21,851	22,117	22,383	22,683
22	Total Demand-Side Reductions	(1,492)	(1,836)	(2,178)	(2,496)	(2,839)	(3,237)	(3,657)	(4,090)	(4,501)	(4,898)
23	*Incremental Uncommitted EE*	98	128	388	620	871	1,180	1,511	1,857	2,184	2,496
24	*Total DR*	1,354	1,627	1,670	1,715	1,767	1,816	1,865	1,911	1,956	2,001
25	*Incremental Demand-Side CHP*	40	80	120	161	201	241	281	321	361	401
26	**Residual Service Area Peak Demand (Line 21 minus Line 22)**	**18,701**	**18,675**	**18,651**	**18,576**	**18,480**	**18,335**	**18,194**	**18,028**	**17,881**	**17,786**
	SERVICE AREA RESERVES:										
27	Amount of Available Resources Exceeding Demand (Line 20 minus Line 26)	11,780	13,402	14,252	13,874	13,548	14,049	11,764	11,968	12,152	12,286
28	Percentage of Available Resources Exceeding Demand (Line 20 / Line 26)	163.0%	171.8%	176.4%	174.7%	173.3%	176.6%	164.7%	166.4%	168.0%	169.1%
	1-in-2 SERVICE AREA SURPLUS (DEFICIT):										
29	Lower Bound of Planning Reserve Requirement (Line 26 * 15%)	21,506	21,476	21,448	21,362	21,251	21,085	20,923	20,732	20,564	20,453
30	Upper Bound of Planning Reserve Requirement (Line 26 * 17%)	21,880	21,849	21,821	21,734	21,621	21,452	21,287	21,092	20,921	20,809
31	Upper Bound 1-in-2 Service Area Surplus (Deficit)	8,975	10,601	11,455	11,088	10,776	11,299	9,035	9,264	9,470	9,618
32	Lower Bound 1-in-2 Service Area Surplus (Deficit)	8,601	10,227	11,082	10,716	10,406	10,932	8,671	8,904	9,112	9,262

Line	SCE Physical South of Path 26 (SP26) Capacity Need Scenario: 33% Trajectory										
		MW									
	SYSTEM AND SERVICE AREA LOAD FORECASTS:	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
1	**System** 1-in-2 Peak Summer Demand	23,785	24,142	24,518	24,823	25,149	25,482	25,833	26,169	26,509	26,875
2	**Total System Resources** (Sum Lines 3, 8, 11 through 16)	**30,618**	**31,355**	**32,633**	**32,578**	**33,696**	**33,051**	**32,837**	**31,916**	**32,066**	**30,019**
	SYSTEM RESOURCES:										
3	Existing Generation (Sum of Lines 4 through 7)	21,404	21,404	21,404	21,404	21,404	21,404	21,404	21,404	21,404	21,404
4	*Existing Renewables (Excludes Hydro)*	916	916	916	916	916	916	916	916	916	916
5	*Existing Hydro (Includes RPS-eligible Hydro)*	1,470	1,470	1,470	1,470	1,470	1,470	1,470	1,470	1,470	1,470
6	*Existing CHP*	1,489	1,489	1,489	1,489	1,489	1,489	1,489	1,489	1,489	1,489
7	*Existing OTC*	9,250	9,250	9,250	9,250	9,250	9,250	9,250	9,250	9,250	9,250
8	*Other Generation*	8,279	8,279	8,279	8,279	8,279	8,279	8,279	8,279	8,279	8,279
9	Retirements (Includes Lines 10 & 11)	(452)	(452)	(452)	(787)	(2,398)	(3,349)	(4,300)	(5,251)	(6,202)	(8,280)
10	*OTC Retirements*	452	452	452	787	1,122	2,073	3,024	3,975	4,926	7,004
11	*Retirements*	0	0	0	0	1,276	1,276	1,276	1,276	1,276	1,276
12	Known/High Probability Additions	717	917	1,997	1,997	1,997	1,997	1,997	1,997	1,997	1,997
13	Utility Probable Planned Additions	0	500	500	500	1,854	1,854	1,854	1,854	1,854	1,854
14	Other Planned Additions	0	0	0	0	0	0	0	0	0	0
15	RPS Additions (In Service Territory)	0	6	174	423	1,768	2,043	2,749	2,749	3,819	3,819
16	Additional CHP	31	61	92	123	153	184	215	245	276	307
17	Net Interchange (Sum of Lines 18 & 19)	8,918	8,918	8,918	8,918	8,918	8,918	8,918	8,918	8,918	8,918
18	*Imports*	8,918	8,918	8,918	8,918	8,918	8,918	8,918	8,918	8,918	8,918
19	*Exports*	0	0	0	0	0	0	0	0	0	0
20	**Service Area Portion of System Resources (Line 2 * 90%)**	**27,557**	**28,219**	**29,370**	**29,320**	**30,327**	**29,746**	**29,554**	**28,725**	**28,859**	**27,017**
	SERVICE AREA SPECIFIC LINE ADJUSTMENTS:										
21	**Service Area** 1-in-2 Peak Summer Demand	21,305	21,634	21,981	22,262	22,561	22,867	23,189	23,497	23,810	24,146
22	Total Demand-Side Reductions	(1,721)	(2,634)	(3,118)	(3,458)	(3,856)	(4,228)	(4,624)	(5,042)	(5,449)	(5,850)
23	*Incremental Uncommitted EE*	44	60	325	565	834	1,171	1,530	1,912	2,283	2,648
24	*Total DR*	1,641	2,502	2,685	2,749	2,842	2,842	2,842	2,842	2,842	2,842
25	*Incremental Demand-Side CHP*	36	72	108	144	180	216	252	288	324	360
26	**Residual Service Area Peak Demand (Line 21 minus Line 22)**	**19,584**	**19,000**	**18,863**	**18,805**	**18,705**	**18,639**	**18,565**	**18,456**	**18,361**	**18,296**
	SERVICE AREA RESERVES:										
27	Amount of Available Resources Exceeding Demand (Line 20 minus Line 26)	7,973	9,219	10,507	10,516	11,621	11,107	10,988	10,269	10,499	8,721
28	Percentage of Available Resources Exceeding Demand (Line 20 / Line 26)	140.7%	148.5%	155.7%	155.9%	162.1%	159.6%	159.2%	155.6%	157.2%	147.7%
	1-in-2 SERVICE AREA SURPLUS (DEFICIT):										
29	Lower Bound of Planning Reserve Requirement (Line 26 * 15%)	22,521	21,850	21,692	21,625	21,511	21,435	21,350	21,224	21,115	21,041
30	Upper Bound of Planning Reserve Requirement (Line 26 * 17%)	22,913	22,230	22,070	22,001	21,885	21,807	21,721	21,593	21,482	21,407
31	Upper Bound 1-in-2 Service Area Surplus (Deficit)	5,035	6,369	7,677	7,695	8,816	8,312	8,204	7,501	7,745	5,976
32	Lower Bound 1-in-2 Service Area Surplus (Deficit)	4,644	5,989	7,300	7,319	8,441	7,939	7,832	7,132	7,377	5,610

SDG&E
Physical Border Capacity Need
Scenario: 33% Trajectory

Line		MW									
	SYSTEM AND SERVICE AREA LOAD FORECASTS:	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
1	**System** 1-in-2 Peak Summer Demand	4,578	4,658	4,738	4,797	4,856	4,911	4,973	5,032	5,094	5,157
2	**Total System Resources** (Sum Lines 3, 8, 11 through 16)	**6,127**	**6,130**	**6,291**	**6,437**	**6,737**	**6,765**	**5,808**	**5,810**	**5,856**	**5,859**
	SYSTEM RESOURCES:										
3	Existing Generation (Sum of Lines 4 through 7)	4,410	4,410	4,410	4,410	4,410	4,410	4,410	4,410	4,410	4,410
4	*Existing Renewables (Excludes Hydro)*	21	21	21	21	21	21	21	21	21	21
5	*Existing Hydro (Includes RPS-eligible Hydro)*	4	4	4	4	4	4	4	4	4	4
6	*Existing CHP*	136	136	136	136	136	136	136	136	136	136
7	*Existing OTC*	1,271	1,271	1,271	1,271	1,271	1,271	1,271	1,271	1,271	1,271
8	*Other Generation*	2,978	2,978	2,978	2,978	2,978	2,978	2,978	2,978	2,978	2,978
9	Retirements (Includes Lines 10 & 11)	(311)	(311)	(311)	(311)	(311)	(311)	(1,271)	(1,271)	(1,271)	(1,271)
10	*OTC Retirements*	311	311	311	311	311	311	1,271	1,271	1,271	1,271
11	*Retirements*	0	0	0	0	0	0	0	0	0	0
12	Known/High Probability Additions	55	55	55	55	55	55	55	55	55	55
13	Utility Probable Planned Additions	0	0	159	159	159	159	159	159	159	159
14	Other Planned Additions	0	0	0	0	0	0	0	0	0	0
15	RPS Additions (In Service Territory)	0	0	0	143	440	465	465	465	508	508
16	Additional CHP	3	6	8	11	14	17	20	22	25	28
17	Net Interchange (Sum of Lines 18 & 19)	1,970	1,970	1,970	1,970	1,970	1,970	1,970	1,970	1,970	1,970
18	*Imports*	1,970	1,970	1,970	1,970	1,970	1,970	1,970	1,970	1,970	1,970
19	*Exports*	0	0	0	0	0	0	0	0	0	0
20	**Service Area Portion of System Resources (Line 2)**	**6,127**	**6,130**	**6,291**	**6,437**	**6,737**	**6,765**	**5,808**	**5,810**	**5,856**	**5,859**
	SERVICE AREA SPECIFIC LINE ADJUSTMENTS:										
21	**Service Area** 1-in-2 Peak Summer Demand	4,578	4,658	4,738	4,797	4,856	4,911	4,973	5,032	5,094	5,157
22	Total Demand-Side Reductions	(219)	(242)	(353)	(421)	(492)	(570)	(655)	(743)	(825)	(903)
23	*Incremental Uncommitted EE*	3	4	66	121	179	247	321	398	471	544
24	*Total DR*	210	226	270	277	285	289	293	298	302	302
25	*Incremental Demand-Side CHP*	6	12	17	23	29	35	41	46	52	58
26	**Residual Service Area Peak Demand (Line 21 minus Line 22)**	**4,359**	**4,416**	**4,385**	**4,376**	**4,363**	**4,340**	**4,318**	**4,289**	**4,269**	**4,254**
	SERVICE AREA RESERVES:										
27	Amount of Available Resources Exceeding Demand (Line 20 minus Line 26)	1,768	1,714	1,906	2,061	2,374	2,425	1,490	1,521	1,587	1,606
28	Percentage of Available Resources Exceeding Demand (Line 20 / Line 26)	140.6%	138.8%	143.5%	147.1%	154.4%	155.9%	134.5%	135.5%	137.2%	137.7%
	1-in-2 SERVICE AREA SURPLUS (DEFICIT):										
29	Lower Bound of Planning Reserve Requirement (Line 26 * 15%)	5,013	5,079	5,043	5,032	5,018	4,991	4,966	4,932	4,909	4,892
30	Upper Bound of Planning Reserve Requirement (Line 26 * 17%)	5,100	5,167	5,131	5,120	5,105	5,078	5,052	5,018	4,994	4,977
31	Upper Bound 1-in-2 Service Area Surplus (Deficit)	1,114	1,051	1,248	1,405	1,719	1,774	842	878	947	968
32	Lower Bound 1-in-2 Service Area Surplus (Deficit)	1,027	963	1,160	1,317	1,632	1,687	756	792	862	883

PG&E
Physical North of Path 26 (NP26) Capacity Need
Scenario: 33% Time-Constrained

Line		MW									
	SYSTEM AND SERVICE AREA LOAD FORECASTS:	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
1	**System** 1-in-2 Peak Summer Demand	21,988	22,329	22,668	22,924	23,185	23,454	23,750	24,030	24,310	24,626
2	**Total System Resources** (Sum Lines 3, 8, 11 through 16)	**33,132**	**34,880**	**35,843**	**35,302**	**34,788**	**35,158**	**32,378**	**32,419**	**32,459**	**32,500**
	SYSTEM RESOURCES:										
3	Existing Generation (Sum of Lines 4 through 7)	26,623	26,623	26,623	26,623	26,623	26,623	26,623	26,623	26,623	26,623
4	*Existing Renewables (Excludes Hydro)*	1,426	1,426	1,426	1,426	1,426	1,426	1,426	1,426	1,426	1,426
5	*Existing Hydro (Includes RPS-eligible Hydro)*	6,461	6,461	6,461	6,461	6,461	6,461	6,461	6,461	6,461	6,461
6	*Existing CHP*	1,888	1,888	1,888	1,888	1,888	1,888	1,888	1,888	1,888	1,888
7	*Existing OTC*	7,064	7,064	7,064	7,064	7,064	7,064	7,064	7,064	7,064	7,064
8	*Other Generation*	9,784	9,784	9,784	9,784	9,784	9,784	9,784	9,784	9,784	9,784
9	Retirements (Includes Lines 10 & 11)	(497)	(662)	(662)	(1,336)	(1,986)	(1,986)	(4,807)	(4,807)	(4,807)	(4,807)
10	*OTC Retirements*	341	341	341	1,015	1,665	1,665	3,804	3,804	3,804	3,804
11	*Retirements*	156	321	321	321	321	321	1,003	1,003	1,003	1,003
12	Known/High Probability Additions	878	1,733	1,733	1,733	1,733	1,733	1,733	1,733	1,733	1,733
13	Utility Probable Planned Additions	0	784	784	784	784	784	784	784	784	784
14	Other Planned Additions	0	145	973	973	973	973	973	973	973	973
15	RPS Additions (In Service Territory)	20	108	202	294	390	719	719	719	719	719
16	Additional CHP	41	82	123	164	204	245	286	327	368	409
17	Net Interchange (Sum of Lines 18 & 19)	6,067	6,067	6,067	6,067	6,067	6,067	6,067	6,067	6,067	6,067
18	*Imports*	6,067	6,067	6,067	6,067	6,067	6,067	6,067	6,067	6,067	6,067
19	*Exports*	0	0	0	0	0	0	0	0	0	0
20	**Service Area Portion of System Resources (Line 2 * 92%)**	**30,481**	**32,089**	**32,975**	**32,478**	**32,005**	**32,345**	**29,788**	**29,825**	**29,863**	**29,900**
	SERVICE AREA SPECIFIC LINE ADJUSTMENTS:										
21	**Service Area** 1-in-2 Peak Summer Demand	20,193	20,510	20,829	21,071	21,318	21,572	21,851	22,117	22,383	22,683
22	Total Demand-Side Reductions	(1,492)	(1,836)	(2,178)	(2,496)	(2,839)	(3,237)	(3,657)	(4,090)	(4,501)	(4,898)
23	*Incremental Uncommitted EE*	98	128	388	620	871	1,180	1,511	1,857	2,184	2,496
24	*Total DR*	1,354	1,627	1,670	1,715	1,767	1,816	1,865	1,911	1,956	2,001
25	*Incremental Demand-Side CHP*	40	80	120	161	201	241	281	321	361	401
26	**Residual Service Area Peak Demand (Line 21 minus Line 22)**	**18,701**	**18,675**	**18,651**	**18,576**	**18,480**	**18,335**	**18,194**	**18,028**	**17,881**	**17,786**
	SERVICE AREA RESERVES:										
27	Amount of Available Resources Exceeding Demand (Line 20 minus Line 26)	11,780	13,415	14,325	13,902	13,525	14,011	11,593	11,797	11,981	12,115
28	Percentage of Available Resources Exceeding Demand (Line 20 / Line 26)	163.0%	171.8%	176.8%	174.8%	173.2%	176.4%	163.7%	165.4%	167.0%	168.1%
	1-in-2 SERVICE AREA SURPLUS (DEFICIT):										
29	Lower Bound of Planning Reserve Requirement (Line 26 * 15%)	21,506	21,476	21,448	21,362	21,251	21,085	20,923	20,732	20,564	20,453
30	Upper Bound of Planning Reserve Requirement (Line 26 * 17%)	21,880	21,849	21,821	21,734	21,621	21,452	21,287	21,092	20,921	20,809
31	Upper Bound 1-in-2 Service Area Surplus (Deficit)	8,975	10,614	11,527	11,116	10,754	11,260	8,864	9,093	9,299	9,447
32	Lower Bound 1-in-2 Service Area Surplus (Deficit)	8,601	10,240	11,154	10,744	10,384	10,894	8,500	8,733	8,941	9,091

SCE
Physical South of Path 26 (SP26) Capacity Need
Scenario: 33% Time-Constrained

Line		MW									
	SYSTEM AND SERVICE AREA LOAD FORECASTS:	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
1	**System** 1-in-2 Peak Summer Demand	23,785	24,142	24,518	24,823	25,149	25,482	25,833	26,169	26,509	26,875
2	**Total System Resources** (Sum Lines 3, 8, 11 through 16)	**30,618**	**31,355**	**32,633**	**32,606**	**33,771**	**33,126**	**32,403**	**31,482**	**30,562**	**28,515**
	SYSTEM RESOURCES:										
3	Existing Generation (Sum of Lines 4 through 7)	21,404	21,404	21,404	21,404	21,404	21,404	21,404	21,404	21,404	21,404
4	*Existing Renewables (Excludes Hydro)*	916	916	916	916	916	916	916	916	916	916
5	*Existing Hydro (Includes RPS-eligible Hydro)*	1,470	1,470	1,470	1,470	1,470	1,470	1,470	1,470	1,470	1,470
6	*Existing CHP*	1,489	1,489	1,489	1,489	1,489	1,489	1,489	1,489	1,489	1,489
7	*Existing OTC*	9,250	9,250	9,250	9,250	9,250	9,250	9,250	9,250	9,250	9,250
8	*Other Generation*	8,279	8,279	8,279	8,279	8,279	8,279	8,279	8,279	8,279	8,279
9	Retirements (Includes Lines 10 & 11)	(452)	(452)	(452)	(787)	(2,398)	(3,349)	(4,300)	(5,251)	(6,202)	(8,280)
10	*OTC Retirements*	452	452	452	787	1,122	2,073	3,024	3,975	4,926	7,004
11	*Retirements*	0	0	0	0	1,276	1,276	1,276	1,276	1,276	1,276
12	Known/High Probability Additions	717	917	1,997	1,997	1,997	1,997	1,997	1,997	1,997	1,997
13	Utility Probable Planned Additions	0	500	500	500	1,854	1,854	1,854	1,854	1,854	1,854
14	Other Planned Additions	0	0	0	0	0	0	0	0	0	0
15	RPS Additions (In Service Territory)	0	6	174	451	1,843	2,118	2,315	2,315	2,315	2,315
16	Additional CHP	31	61	92	123	153	184	215	245	276	307
17	Net Interchange (Sum of Lines 18 & 19)	8,918	8,918	8,918	8,918	8,918	8,918	8,918	8,918	8,918	8,918
18	*Imports*	8,918	8,918	8,918	8,918	8,918	8,918	8,918	8,918	8,918	8,918
19	*Exports*	0	0	0	0	0	0	0	0	0	0
20	**Service Area Portion of System Resources (Line 2 * 90%)**	**27,557**	**28,219**	**29,370**	**29,346**	**30,394**	**29,813**	**29,163**	**28,334**	**27,506**	**25,664**
	SERVICE AREA SPECIFIC LINE ADJUSTMENTS:										
21	**Service Area** 1-in-2 Peak Summer Demand	21,305	21,634	21,981	22,262	22,561	22,867	23,189	23,497	23,810	24,146
22	Total Demand-Side Reductions	(1,721)	(2,634)	(3,118)	(3,458)	(3,856)	(4,228)	(4,624)	(5,042)	(5,449)	(5,850)
23	*Incremental Uncommitted EE*	44	60	325	565	834	1,171	1,530	1,912	2,283	2,648
24	*Total DR*	1,641	2,502	2,685	2,749	2,842	2,842	2,842	2,842	2,842	2,842
25	*Incremental Demand-Side CHP*	36	72	108	144	180	216	252	288	324	360
26	**Residual Service Area Peak Demand (Line 21 minus Line 22)**	**19,584**	**19,000**	**18,863**	**18,805**	**18,705**	**18,639**	**18,565**	**18,456**	**18,361**	**18,296**
	SERVICE AREA RESERVES:										
27	Amount of Available Resources Exceeding Demand (Line 20 minus Line 26)	7,973	9,219	10,507	10,541	11,689	11,175	10,597	9,878	9,145	7,367
28	Percentage of Available Resources Exceeding Demand (Line 20 / Line 26)	140.7%	148.5%	155.7%	156.1%	162.5%	160.0%	157.1%	153.5%	149.8%	140.3%
	1-in-2 SERVICE AREA SURPLUS (DEFICIT):										
29	Lower Bound of Planning Reserve Requirement (Line 26 * 15%)	22,521	21,850	21,692	21,625	21,511	21,435	21,350	21,224	21,115	21,041
30	Upper Bound of Planning Reserve Requirement (Line 26 * 17%)	22,913	22,230	22,070	22,001	21,885	21,807	21,721	21,593	21,482	21,407
31	Upper Bound 1-in-2 Service Area Surplus (Deficit)	5,035	6,369	7,677	7,720	8,883	8,379	7,813	7,110	6,391	4,623
32	Lower Bound 1-in-2 Service Area Surplus (Deficit)	4,644	5,989	7,300	7,344	8,509	8,006	7,441	6,741	6,024	4,257

SDG&E
Physical Border Capacity Need
Scenario: 33% Time-Constrained

Line		MW									
	SYSTEM AND SERVICE AREA LOAD FORECASTS:	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
1	**System** 1-in-2 Peak Summer Demand	4,578	4,658	4,738	4,797	4,856	4,911	4,973	5,032	5,094	5,157
2	**Total System Resources** (Sum Lines 3, 8, 11 through 16)	**6,127**	**6,130**	**6,291**	**6,308**	**6,371**	**6,374**	**5,417**	**5,419**	**5,422**	**5,425**
	SYSTEM RESOURCES:										
3	Existing Generation (Sum of Lines 4 through 7)	4,410	4,410	4,410	4,410	4,410	4,410	4,410	4,410	4,410	4,410
4	*Existing Renewables (Excludes Hydro)*	21	21	21	21	21	21	21	21	21	21
5	*Existing Hydro (Includes RPS-eligible Hydro)*	4	4	4	4	4	4	4	4	4	4
6	*Existing CHP*	136	136	136	136	136	136	136	136	136	136
7	*Existing OTC*	1,271	1,271	1,271	1,271	1,271	1,271	1,271	1,271	1,271	1,271
8	*Other Generation*	2,978	2,978	2,978	2,978	2,978	2,978	2,978	2,978	2,978	2,978
9	Retirements (Includes Lines 10 & 11)	(311)	(311)	(311)	(311)	(311)	(311)	(1,271)	(1,271)	(1,271)	(1,271)
10	*OTC Retirements*	311	311	311	311	311	311	1,271	1,271	1,271	1,271
11	*Retirements*	0	0	0	0	0	0	0	0	0	0
12	Known/High Probability Additions	55	55	55	55	55	55	55	55	55	55
13	Utility Probable Planned Additions	0	0	159	159	159	159	159	159	159	159
14	Other Planned Additions	0	0	0	0	0	0	0	0	0	0
15	RPS Additions (In Service Territory)	0	0	0	14	74	74	74	74	74	74
16	Additional CHP	3	6	8	11	14	17	20	22	25	28
17	Net Interchange (Sum of Lines 18 & 19)	1,970	1,970	1,970	1,970	1,970	1,970	1,970	1,970	1,970	1,970
18	*Imports*	1,970	1,970	1,970	1,970	1,970	1,970	1,970	1,970	1,970	1,970
19	*Exports*	0	0	0	0	0	0	0	0	0	0
20	**Service Area Portion of System Resources (Line 2)**	**6,127**	**6,130**	**6,291**	**6,308**	**6,371**	**6,374**	**5,417**	**5,419**	**5,422**	**5,425**
	SERVICE AREA SPECIFIC LINE ADJUSTMENTS:										
21	**Service Area** 1-in-2 Peak Summer Demand	4,578	4,658	4,738	4,797	4,856	4,911	4,973	5,032	5,094	5,157
22	Total Demand-Side Reductions	(219)	(242)	(353)	(421)	(492)	(570)	(655)	(743)	(825)	(903)
23	*Incremental Uncommitted EE*	3	4	66	121	179	247	321	398	471	544
24	*Total DR*	210	226	270	277	285	289	293	298	302	302
25	*Incremental Demand-Side CHP*	6	12	17	23	29	35	41	46	52	58
26	**Residual Service Area Peak Demand (Line 21 minus Line 22)**	**4,359**	**4,416**	**4,385**	**4,376**	**4,363**	**4,340**	**4,318**	**4,289**	**4,269**	**4,254**
	SERVICE AREA RESERVES:										
27	Amount of Available Resources Exceeding Demand (Line 20 minus Line 26)	1,768	1,714	1,906	1,932	2,008	2,034	1,099	1,131	1,154	1,172
28	Percentage of Available Resources Exceeding Demand (Line 20 / Line 26)	140.6%	138.8%	143.5%	144.1%	146.0%	146.9%	125.5%	126.4%	127.0%	127.5%
	1-in-2 SERVICE AREA SURPLUS (DEFICIT):										
29	Lower Bound of Planning Reserve Requirement (Line 26 * 15%)	5,013	5,079	5,043	5,032	5,018	4,991	4,966	4,932	4,909	4,892
30	Upper Bound of Planning Reserve Requirement (Line 26 * 17%)	5,100	5,167	5,131	5,120	5,105	5,078	5,052	5,018	4,994	4,977
31	Upper Bound 1-in-2 Service Area Surplus (Deficit)	1,114	1,051	1,248	1,275	1,354	1,383	452	487	513	534
32	Lower Bound 1-in-2 Service Area Surplus (Deficit)	1,027	963	1,160	1,188	1,266	1,296	365	401	428	449

PG&E
Physical North of Path 26 (NP26) Capacity Need
Scenario: 33% Cost-Constrained

Line		MW									
	SYSTEM AND SERVICE AREA LOAD FORECASTS:	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
1	**System** 1-in-2 Peak Summer Demand	21,988	22,329	22,668	22,924	23,185	23,454	23,750	24,030	24,310	24,626
2	**Total System Resources** (Sum Lines 3, 8, 11 through 16)	**33,132**	**34,866**	**35,764**	**35,286**	**34,757**	**35,144**	**32,512**	**32,553**	**32,594**	**32,635**
	SYSTEM RESOURCES:										
3	Existing Generation (Sum of Lines 4 through 7)	26,623	26,623	26,623	26,623	26,623	26,623	26,623	26,623	26,623	26,623
4	*Existing Renewables (Excludes Hydro)*	1,426	1,426	1,426	1,426	1,426	1,426	1,426	1,426	1,426	1,426
5	*Existing Hydro (Includes RPS-eligible Hydro)*	6,461	6,461	6,461	6,461	6,461	6,461	6,461	6,461	6,461	6,461
6	*Existing CHP*	1,888	1,888	1,888	1,888	1,888	1,888	1,888	1,888	1,888	1,888
7	*Existing OTC*	7,064	7,064	7,064	7,064	7,064	7,064	7,064	7,064	7,064	7,064
8	*Other Generation*	9,784	9,784	9,784	9,784	9,784	9,784	9,784	9,784	9,784	9,784
9	Retirements (Includes Lines 10 & 11)	(497)	(662)	(662)	(1,336)	(1,986)	(1,986)	(4,807)	(4,807)	(4,807)	(4,807)
10	*OTC Retirements*	341	341	341	1,015	1,665	1,665	3,804	3,804	3,804	3,804
11	*Retirements*	156	321	321	321	321	321	1,003	1,003	1,003	1,003
12	Known/High Probability Additions	878	1,733	1,733	1,733	1,733	1,733	1,733	1,733	1,733	1,733
13	Utility Probable Planned Additions	0	784	784	784	784	784	784	784	784	784
14	Other Planned Additions	0	145	973	973	973	973	973	973	973	973
15	RPS Additions (In Service Territory)	20	94	123	278	359	704	853	853	853	853
16	Additional CHP	41	82	123	164	204	245	286	327	368	409
17	Net Interchange (Sum of Lines 18 & 19)	6,067	6,067	6,067	6,067	6,067	6,067	6,067	6,067	6,067	6,067
18	*Imports*	6,067	6,067	6,067	6,067	6,067	6,067	6,067	6,067	6,067	6,067
19	*Exports*	0	0	0	0	0	0	0	0	0	0
20	**Service Area Portion of System Resources (Line 2 * 92%)**	**30,481**	**32,077**	**32,903**	**32,463**	**31,976**	**32,332**	**29,911**	**29,949**	**29,986**	**30,024**
	SERVICE AREA SPECIFIC LINE ADJUSTMENTS:										
21	**Service Area** 1-in-2 Peak Summer Demand	20,193	20,510	20,829	21,071	21,318	21,572	21,851	22,117	22,383	22,683
22	Total Demand-Side Reductions	(1,492)	(1,836)	(2,178)	(2,496)	(2,839)	(3,237)	(3,657)	(4,090)	(4,501)	(4,898)
23	*Incremental Uncommitted EE*	98	128	388	620	871	1,180	1,511	1,857	2,184	2,496
24	*Total DR*	1,354	1,627	1,670	1,715	1,767	1,816	1,865	1,911	1,956	2,001
25	*Incremental Demand-Side CHP*	40	80	120	161	201	241	281	321	361	401
26	**Residual Service Area Peak Demand (Line 21 minus Line 22)**	**18,701**	**18,675**	**18,651**	**18,576**	**18,480**	**18,335**	**18,194**	**18,028**	**17,881**	**17,786**
	SERVICE AREA RESERVES:										
27	Amount of Available Resources Exceeding Demand (Line 20 minus Line 26)	11,780	13,402	14,252	13,887	13,497	13,997	11,717	11,921	12,105	12,238
28	Percentage of Available Resources Exceeding Demand (Line 20 / Line 26)	163.0%	171.8%	176.4%	174.8%	173.0%	176.3%	164.4%	166.1%	167.7%	168.8%
	1-in-2 SERVICE AREA SURPLUS (DEFICIT):										
29	Lower Bound of Planning Reserve Requirement (Line 26 * 15%)	21,506	21,476	21,448	21,362	21,251	21,085	20,923	20,732	20,564	20,453
30	Upper Bound of Planning Reserve Requirement (Line 26 * 17%)	21,880	21,849	21,821	21,734	21,621	21,452	21,287	21,092	20,921	20,809
31	Upper Bound 1-in-2 Service Area Surplus (Deficit)	8,975	10,601	11,455	11,101	10,725	11,247	8,988	9,217	9,423	9,570
32	Lower Bound 1-in-2 Service Area Surplus (Deficit)	8,601	10,227	11,082	10,729	10,355	10,881	8,624	8,856	9,065	9,215

SCE
Physical South of Path 26 (SP26) Capacity Need
Scenario: 33% Cost-Constrained

Line		MW									
	SYSTEM AND SERVICE AREA LOAD FORECASTS:	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
1	**System** 1-in-2 Peak Summer Demand	23,785	24,142	24,518	24,823	25,149	25,482	25,833	26,169	26,509	26,875
2	**Total System Resources** (Sum Lines 3, 8, 11 through 16)	**30,618**	**31,355**	**32,633**	**32,582**	**33,076**	**32,431**	**31,708**	**30,787**	**29,867**	**27,820**
	SYSTEM RESOURCES:										
3	Existing Generation (Sum of Lines 4 through 7)	21,404	21,404	21,404	21,404	21,404	21,404	21,404	21,404	21,404	21,404
4	*Existing Renewables (Excludes Hydro)*	916	916	916	916	916	916	916	916	916	916
5	*Existing Hydro (Includes RPS-eligible Hydro)*	1,470	1,470	1,470	1,470	1,470	1,470	1,470	1,470	1,470	1,470
6	*Existing CHP*	1,489	1,489	1,489	1,489	1,489	1,489	1,489	1,489	1,489	1,489
7	*Existing OTC*	9,250	9,250	9,250	9,250	9,250	9,250	9,250	9,250	9,250	9,250
8	*Other Generation*	8,279	8,279	8,279	8,279	8,279	8,279	8,279	8,279	8,279	8,279
9	Retirements (Includes Lines 10 & 11)	(452)	(452)	(452)	(787)	(2,398)	(3,349)	(4,300)	(5,251)	(6,202)	(8,280)
10	*OTC Retirements*	452	452	452	787	1,122	2,073	3,024	3,975	4,926	7,004
11	*Retirements*	0	0	0	0	1,276	1,276	1,276	1,276	1,276	1,276
12	Known/High Probability Additions	717	917	1,997	1,997	1,997	1,997	1,997	1,997	1,997	1,997
13	Utility Probable Planned Additions	0	500	500	500	1,854	1,854	1,854	1,854	1,854	1,854
14	Other Planned Additions	0	0	0	0	0	0	0	0	0	0
15	RPS Additions (In Service Territory)	0	6	174	427	1,148	1,423	1,620	1,620	1,620	1,620
16	Additional CHP	31	61	92	123	153	184	215	245	276	307
17	Net Interchange (Sum of Lines 18 & 19)	8,918	8,918	8,918	8,918	8,918	8,918	8,918	8,918	8,918	8,918
18	*Imports*	8,918	8,918	8,918	8,918	8,918	8,918	8,918	8,918	8,918	8,918
19	*Exports*	0	0	0	0	0	0	0	0	0	0
20	**Service Area Portion of System Resources (Line 2 * 90%)**	**27,557**	**28,219**	**29,370**	**29,324**	**29,768**	**29,188**	**28,537**	**27,709**	**26,881**	**25,038**
	SERVICE AREA SPECIFIC LINE ADJUSTMENTS:										
21	**Service Area** 1-in-2 Peak Summer Demand	21,305	21,634	21,981	22,262	22,561	22,867	23,189	23,497	23,810	24,146
22	Total Demand-Side Reductions	(1,721)	(2,634)	(3,118)	(3,458)	(3,856)	(4,228)	(4,624)	(5,042)	(5,449)	(5,850)
23	*Incremental Uncommitted EE*	44	60	325	565	834	1,171	1,530	1,912	2,283	2,648
24	*Total DR*	1,641	2,502	2,685	2,749	2,842	2,842	2,842	2,842	2,842	2,842
25	*Incremental Demand-Side CHP*	36	72	108	144	180	216	252	288	324	360
26	**Residual Service Area Peak Demand (Line 21 minus Line 22)**	**19,584**	**19,000**	**18,863**	**18,805**	**18,705**	**18,639**	**18,565**	**18,456**	**18,361**	**18,296**
	SERVICE AREA RESERVES:										
27	Amount of Available Resources Exceeding Demand (Line 20 minus Line 26)	7,973	9,219	10,507	10,519	11,063	10,549	9,972	9,253	8,520	6,742
28	Percentage of Available Resources Exceeding Demand (Line 20 / Line 26)	140.7%	148.5%	155.7%	155.9%	159.1%	156.6%	153.7%	150.1%	146.4%	136.8%
	1-in-2 SERVICE AREA SURPLUS (DEFICIT):										
29	Lower Bound of Planning Reserve Requirement (Line 26 * 15%)	22,521	21,850	21,692	21,625	21,511	21,435	21,350	21,224	21,115	21,041
30	Upper Bound of Planning Reserve Requirement (Line 26 * 17%)	22,913	22,230	22,070	22,001	21,885	21,807	21,721	21,593	21,482	21,407
31	Upper Bound 1-in-2 Service Area Surplus (Deficit)	5,035	6,369	7,677	7,698	8,257	7,753	7,187	6,485	5,766	3,998
32	Lower Bound 1-in-2 Service Area Surplus (Deficit)	4,644	5,989	7,300	7,322	7,883	7,381	6,816	6,116	5,398	3,632

SDG&E
Physical Border Capacity Need
Scenario: 33% Cost-Constrained

Line		MW									
	SYSTEM AND SERVICE AREA LOAD FORECASTS:	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
1	**System** 1-in-2 Peak Summer Demand	4,578	4,658	4,738	4,797	4,856	4,911	4,973	5,032	5,094	5,157
2	**Total System Resources** (Sum Lines 3, 8, 11 through 16)	**6,127**	**6,130**	**6,291**	**6,339**	**6,639**	**6,670**	**5,761**	**6,254**	**6,257**	**6,260**
	SYSTEM RESOURCES:										
3	Existing Generation (Sum of Lines 4 through 7)	4,410	4,410	4,410	4,410	4,410	4,410	4,410	4,410	4,410	4,410
4	*Existing Renewables (Excludes Hydro)*	21	21	21	21	21	21	21	21	21	21
5	*Existing Hydro (Includes RPS-eligible Hydro)*	4	4	4	4	4	4	4	4	4	4
6	*Existing CHP*	136	136	136	136	136	136	136	136	136	136
7	*Existing OTC*	1,271	1,271	1,271	1,271	1,271	1,271	1,271	1,271	1,271	1,271
8	*Other Generation*	2,978	2,978	2,978	2,978	2,978	2,978	2,978	2,978	2,978	2,978
9	Retirements (Includes Lines 10 & 11)	(311)	(311)	(311)	(311)	(311)	(311)	(1,271)	(1,271)	(1,271)	(1,271)
10	*OTC Retirements*	311	311	311	311	311	311	1,271	1,271	1,271	1,271
11	*Retirements*	0	0	0	0	0	0	0	0	0	0
12	Known/High Probability Additions	55	55	55	55	55	55	55	55	55	55
13	Utility Probable Planned Additions	0	0	159	159	159	159	159	159	159	159
14	Other Planned Additions	0	0	0	0	0	0	0	0	0	0
15	RPS Additions (In Service Territory)	0	0	0	45	342	370	418	909	909	909
16	Additional CHP	3	6	8	11	14	17	20	22	25	28
17	Net Interchange (Sum of Lines 18 & 19)	1,970	1,970	1,970	1,970	1,970	1,970	1,970	1,970	1,970	1,970
18	*Imports*	1,970	1,970	1,970	1,970	1,970	1,970	1,970	1,970	1,970	1,970
19	*Exports*	0	0	0	0	0	0	0	0	0	0
20	**Service Area Portion of System Resources (Line 2)**	**6,127**	**6,130**	**6,291**	**6,339**	**6,639**	**6,670**	**5,761**	**6,254**	**6,257**	**6,260**
	SERVICE AREA SPECIFIC LINE ADJUSTMENTS:										
21	**Service Area** 1-in-2 Peak Summer Demand	4,578	4,658	4,738	4,797	4,856	4,911	4,973	5,032	5,094	5,157
22	Total Demand-Side Reductions	(219)	(242)	(353)	(421)	(492)	(570)	(655)	(743)	(825)	(903)
23	*Incremental Uncommitted EE*	3	4	66	121	179	247	321	398	471	544
24	*Total DR*	210	226	270	277	285	289	293	298	302	302
25	*Incremental Demand-Side CHP*	6	12	17	23	29	35	41	46	52	58
26	**Residual Service Area Peak Demand (Line 21 minus Line 22)**	**4,359**	**4,416**	**4,385**	**4,376**	**4,363**	**4,340**	**4,318**	**4,289**	**4,269**	**4,254**
	SERVICE AREA RESERVES:										
27	Amount of Available Resources Exceeding Demand (Line 20 minus Line 26)	1,768	1,714	1,906	1,963	2,276	2,330	1,443	1,965	1,988	2,006
28	Percentage of Available Resources Exceeding Demand (Line 20 / Line 26)	140.6%	138.8%	143.5%	144.9%	152.2%	153.7%	133.4%	145.8%	146.6%	147.2%
	1-in-2 SERVICE AREA SURPLUS (DEFICIT):										
29	Lower Bound of Planning Reserve Requirement (Line 26 * 15%)	5,013	5,079	5,043	5,032	5,018	4,991	4,966	4,932	4,909	4,892
30	Upper Bound of Planning Reserve Requirement (Line 26 * 17%)	5,100	5,167	5,131	5,120	5,105	5,078	5,052	5,018	4,994	4,977
31	Upper Bound 1-in-2 Service Area Surplus (Deficit)	1,114	1,051	1,248	1,307	1,621	1,679	795	1,321	1,347	1,368
32	Lower Bound 1-in-2 Service Area Surplus (Deficit)	1,027	963	1,160	1,219	1,534	1,592	709	1,235	1,262	1,283

PG&E
Physical North of Path 26 (NP26) Capacity Need
Scenario: 33% Environmentally-Constrained

Line		MW									
	SYSTEM AND SERVICE AREA LOAD FORECASTS:	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
1	**System** 1-in-2 Peak Summer Demand	21,988	22,329	22,668	22,924	23,185	23,454	23,750	24,030	24,310	24,626
2	**Total System Resources** (Sum Lines 3, 8, 11 through 16)	**33,132**	**34,866**	**35,789**	**35,277**	**34,681**	**35,062**	**32,916**	**32,957**	**32,998**	**33,039**
	SYSTEM RESOURCES:										
3	Existing Generation (Sum of Lines 4 through 7)	26,623	26,623	26,623	26,623	26,623	26,623	26,623	26,623	26,623	26,623
4	*Existing Renewables (Excludes Hydro)*	1,426	1,426	1,426	1,426	1,426	1,426	1,426	1,426	1,426	1,426
5	*Existing Hydro (Includes RPS-eligible Hydro)*	6,461	6,461	6,461	6,461	6,461	6,461	6,461	6,461	6,461	6,461
6	*Existing CHP*	1,888	1,888	1,888	1,888	1,888	1,888	1,888	1,888	1,888	1,888
7	*Existing OTC*	7,064	7,064	7,064	7,064	7,064	7,064	7,064	7,064	7,064	7,064
8	*Other Generation*	9,784	9,784	9,784	9,784	9,784	9,784	9,784	9,784	9,784	9,784
9	Retirements (Includes Lines 10 & 11)	(497)	(662)	(662)	(1,336)	(1,986)	(1,986)	(4,807)	(4,807)	(4,807)	(4,807)
10	*OTC Retirements*	341	341	341	1,015	1,665	1,665	3,804	3,804	3,804	3,804
11	*Retirements*	156	321	321	321	321	321	1,003	1,003	1,003	1,003
12	Known/High Probability Additions	878	1,733	1,733	1,733	1,733	1,733	1,733	1,733	1,733	1,733
13	Utility Probable Planned Additions	0	784	784	784	784	784	784	784	784	784
14	Other Planned Additions	0	145	973	973	973	973	973	973	973	973
15	RPS Additions (In Service Territory)	20	94	149	269	283	623	1,257	1,257	1,257	1,257
16	Additional CHP	41	82	123	164	204	245	286	327	368	409
17	Net Interchange (Sum of Lines 18 & 19)	6,067	6,067	6,067	6,067	6,067	6,067	6,067	6,067	6,067	6,067
18	*Imports*	6,067	6,067	6,067	6,067	6,067	6,067	6,067	6,067	6,067	6,067
19	*Exports*	0	0	0	0	0	0	0	0	0	0
20	**Service Area Portion of System Resources (Line 2 * 92%)**	**30,481**	**32,077**	**32,926**	**32,455**	**31,907**	**32,257**	**30,283**	**30,321**	**30,358**	**30,396**
	SERVICE AREA SPECIFIC LINE ADJUSTMENTS:										
21	**Service Area** 1-in-2 Peak Summer Demand	20,193	20,510	20,829	21,071	21,318	21,572	21,851	22,117	22,383	22,683
22	Total Demand-Side Reductions	(1,492)	(1,836)	(2,178)	(2,496)	(2,839)	(3,237)	(3,657)	(4,090)	(4,501)	(4,898)
23	*Incremental Uncommitted EE*	98	128	388	620	871	1,180	1,511	1,857	2,184	2,496
24	*Total DR*	1,354	1,627	1,670	1,715	1,767	1,816	1,865	1,911	1,956	2,001
25	*Incremental Demand-Side CHP*	40	80	120	161	201	241	281	321	361	401
26	**Residual Service Area Peak Demand (Line 21 minus Line 22)**	**18,701**	**18,675**	**18,651**	**18,576**	**18,480**	**18,335**	**18,194**	**18,028**	**17,881**	**17,786**
	SERVICE AREA RESERVES:										
27	Amount of Available Resources Exceeding Demand (Line 20 minus Line 26)	11,780	13,402	14,275	13,879	13,427	13,923	12,089	12,293	12,477	12,610
28	Percentage of Available Resources Exceeding Demand (Line 20 / Line 26)	163.0%	171.8%	176.5%	174.7%	172.7%	175.9%	166.4%	168.2%	169.8%	170.9%
	1-in-2 SERVICE AREA SURPLUS (DEFICIT):										
29	Lower Bound of Planning Reserve Requirement (Line 26 * 15%)	21,506	21,476	21,448	21,362	21,251	21,085	20,923	20,732	20,564	20,453
30	Upper Bound of Planning Reserve Requirement (Line 26 * 17%)	21,880	21,849	21,821	21,734	21,621	21,452	21,287	21,092	20,921	20,809
31	Upper Bound 1-in-2 Service Area Surplus (Deficit)	8,975	10,601	11,478	11,093	10,655	11,173	9,360	9,589	9,795	9,943
32	Lower Bound 1-in-2 Service Area Surplus (Deficit)	8,601	10,227	11,105	10,721	10,286	10,806	8,996	9,228	9,437	9,587

Line	SCE Physical South of Path 26 (SP26) Capacity Need — Scenario: 33% Environmentally-Constrained	MW									
	SYSTEM AND SERVICE AREA LOAD FORECASTS:	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
1	**System** 1-in-2 Peak Summer Demand	23,785	24,142	24,518	24,823	25,149	25,482	25,833	26,169	26,509	26,875
2	**Total System Resources** (Sum Lines 3, 8, 11 through 16)	**30,618**	**31,355**	**32,633**	**32,578**	**33,055**	**32,410**	**31,729**	**30,808**	**29,888**	**27,841**
	SYSTEM RESOURCES:										
3	Existing Generation (Sum of Lines 4 through 7)	21,404	21,404	21,404	21,404	21,404	21,404	21,404	21,404	21,404	21,404
4	*Existing Renewables (Excludes Hydro)*	916	916	916	916	916	916	916	916	916	916
5	*Existing Hydro (Includes RPS-eligible Hydro)*	1,470	1,470	1,470	1,470	1,470	1,470	1,470	1,470	1,470	1,470
6	*Existing CHP*	1,489	1,489	1,489	1,489	1,489	1,489	1,489	1,489	1,489	1,489
7	*Existing OTC*	9,250	9,250	9,250	9,250	9,250	9,250	9,250	9,250	9,250	9,250
8	*Other Generation*	8,279	8,279	8,279	8,279	8,279	8,279	8,279	8,279	8,279	8,279
9	Retirements (Includes Lines 10 & 11)	(452)	(452)	(452)	(787)	(2,398)	(3,349)	(4,300)	(5,251)	(6,202)	(8,280)
10	*OTC Retirements*	452	452	452	787	1,122	2,073	3,024	3,975	4,926	7,004
11	*Retirements*	0	0	0	0	1,276	1,276	1,276	1,276	1,276	1,276
12	Known/High Probability Additions	717	917	1,997	1,997	1,997	1,997	1,997	1,997	1,997	1,997
13	Utility Probable Planned Additions	0	500	500	500	1,854	1,854	1,854	1,854	1,854	1,854
14	Other Planned Additions	0	0	0	0	0	0	0	0	0	0
15	RPS Additions (In Service Territory)	0	6	174	423	1,127	1,402	1,641	1,641	1,641	1,641
16	Additional CHP	31	61	92	123	153	184	215	245	276	307
17	Net Interchange (Sum of Lines 18 & 19)	8,918	8,918	8,918	8,918	8,918	8,918	8,918	8,918	8,918	8,918
18	*Imports*	8,918	8,918	8,918	8,918	8,918	8,918	8,918	8,918	8,918	8,918
19	*Exports*	0	0	0	0	0	0	0	0	0	0
20	**Service Area Portion of System Resources (Line 2 * 90%)**	**27,557**	**28,219**	**29,370**	**29,320**	**29,750**	**29,169**	**28,556**	**27,727**	**26,899**	**25,057**
	SERVICE AREA SPECIFIC LINE ADJUSTMENTS:										
21	**Service Area** 1-in-2 Peak Summer Demand	21,305	21,634	21,981	22,262	22,561	22,867	23,189	23,497	23,810	24,146
22	Total Demand-Side Reductions	(1,721)	(2,634)	(3,118)	(3,458)	(3,856)	(4,228)	(4,624)	(5,042)	(5,449)	(5,850)
23	*Incremental Uncommitted EE*	44	60	325	565	834	1,171	1,530	1,912	2,283	2,648
24	*Total DR*	1,641	2,502	2,685	2,749	2,842	2,842	2,842	2,842	2,842	2,842
25	*Incremental Demand-Side CHP*	36	72	108	144	180	216	252	288	324	360
26	**Residual Service Area Peak Demand (Line 21 minus Line 22)**	**19,584**	**19,000**	**18,863**	**18,805**	**18,705**	**18,639**	**18,565**	**18,456**	**18,361**	**18,296**
	SERVICE AREA RESERVES:										
27	Amount of Available Resources Exceeding Demand (Line 20 minus Line 26)	7,973	9,219	10,507	10,516	11,044	10,530	9,991	9,272	8,539	6,761
28	Percentage of Available Resources Exceeding Demand (Line 20 / Line 26)	140.7%	148.5%	155.7%	155.9%	159.0%	156.5%	153.8%	150.2%	146.5%	137.0%
	1-in-2 SERVICE AREA SURPLUS (DEFICIT):										
29	Lower Bound of Planning Reserve Requirement (Line 26 * 15%)	22,521	21,850	21,692	21,625	21,511	21,435	21,350	21,224	21,115	21,041
30	Upper Bound of Planning Reserve Requirement (Line 26 * 17%)	22,913	22,230	22,070	22,001	21,885	21,807	21,721	21,593	21,482	21,407
31	Upper Bound 1-in-2 Service Area Surplus (Deficit)	5,035	6,369	7,677	7,695	8,238	7,735	7,206	6,504	5,785	4,016
32	Lower Bound 1-in-2 Service Area Surplus (Deficit)	4,644	5,989	7,300	7,319	7,864	7,362	6,835	6,134	5,417	3,650

SDG&E											
Physical Border Capacity Need											
Scenario: 33% Environmentally-Constrained											
Line		**MW**									
	SYSTEM AND SERVICE AREA LOAD FORECASTS:	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
1	**System** 1-in-2 Peak Summer Demand	4,578	4,658	4,738	4,797	4,856	4,911	4,973	5,032	5,094	5,157
2	**Total System Resources** (Sum Lines 3, 8, 11 through 16)	**6,127**	**6,130**	**6,291**	**6,317**	**6,454**	**6,457**	**5,500**	**5,662**	**5,665**	**5,668**
	SYSTEM RESOURCES:										
3	Existing Generation (Sum of Lines 4 through 7)	4,410	4,410	4,410	4,410	4,410	4,410	4,410	4,410	4,410	4,410
4	*Existing Renewables (Excludes Hydro)*	21	21	21	21	21	21	21	21	21	21
5	*Existing Hydro (Includes RPS-eligible Hydro)*	4	4	4	4	4	4	4	4	4	4
6	*Existing CHP*	136	136	136	136	136	136	136	136	136	136
7	*Existing OTC*	1,271	1,271	1,271	1,271	1,271	1,271	1,271	1,271	1,271	1,271
8	*Other Generation*	2,978	2,978	2,978	2,978	2,978	2,978	2,978	2,978	2,978	2,978
9	Retirements (Includes Lines 10 & 11)	(311)	(311)	(311)	(311)	(311)	(311)	(1,271)	(1,271)	(1,271)	(1,271)
10	*OTC Retirements*	311	311	311	311	311	311	1,271	1,271	1,271	1,271
11	*Retirements*	0	0	0	0	0	0	0	0	0	0
12	Known/High Probability Additions	55	55	55	55	55	55	55	55	55	55
13	Utility Probable Planned Additions	0	0	159	159	159	159	159	159	159	159
14	Other Planned Additions	0	0	0	0	0	0	0	0	0	0
15	RPS Additions (In Service Territory)	0	0	0	23	157	157	157	317	317	317
16	Additional CHP	3	6	8	11	14	17	20	22	25	28
17	Net Interchange (Sum of Lines 18 & 19)	1,970	1,970	1,970	1,970	1,970	1,970	1,970	1,970	1,970	1,970
18	*Imports*	1,970	1,970	1,970	1,970	1,970	1,970	1,970	1,970	1,970	1,970
19	*Exports*	0	0	0	0	0	0	0	0	0	0
20	**Service Area Portion of System Resources (Line 2)**	**6,127**	**6,130**	**6,291**	**6,317**	**6,454**	**6,457**	**5,500**	**5,662**	**5,665**	**5,668**
	SERVICE AREA SPECIFIC LINE ADJUSTMENTS:										
21	**Service Area** 1-in-2 Peak Summer Demand	4,578	4,658	4,738	4,797	4,856	4,911	4,973	5,032	5,094	5,157
22	Total Demand-Side Reductions	(219)	(242)	(353)	(421)	(492)	(570)	(655)	(743)	(825)	(903)
23	*Incremental Uncommitted EE*	3	4	66	121	179	247	321	398	471	544
24	*Total DR*	210	226	270	277	285	289	293	298	302	302
25	*Incremental Demand-Side CHP*	6	12	17	23	29	35	41	46	52	58
26	**Residual Service Area Peak Demand (Line 21 minus Line 22)**	**4,359**	**4,416**	**4,385**	**4,376**	**4,363**	**4,340**	**4,318**	**4,289**	**4,269**	**4,254**
	SERVICE AREA RESERVES:										
27	Amount of Available Resources Exceeding Demand (Line 20 minus Line 26)	1,768	1,714	1,906	1,941	2,091	2,117	1,182	1,373	1,396	1,414
28	Percentage of Available Resources Exceeding Demand (Line 20 / Line 26)	140.6%	138.8%	143.5%	144.4%	147.9%	148.8%	127.4%	132.0%	132.7%	133.3%
	1-in-2 SERVICE AREA SURPLUS (DEFICIT):										
29	Lower Bound of Planning Reserve Requirement (Line 26 * 15%)	5,013	5,079	5,043	5,032	5,018	4,991	4,966	4,932	4,909	4,892
30	Upper Bound of Planning Reserve Requirement (Line 26 * 17%)	5,100	5,167	5,131	5,120	5,105	5,078	5,052	5,018	4,994	4,977
31	Upper Bound 1-in-2 Service Area Surplus (Deficit)	1,114	1,051	1,248	1,285	1,437	1,466	535	730	756	776
32	Lower Bound 1-in-2 Service Area Surplus (Deficit)	1,027	963	1,160	1,197	1,349	1,379	448	644	671	691

PG&E
Physical North of Path 26 (NP26) Capacity Need
Scenario: 20% Trajectory

Line		MW									
	SYSTEM AND SERVICE AREA LOAD FORECASTS:	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
1	**System** 1-in-2 Peak Summer Demand	21,988	22,329	22,668	22,924	23,185	23,454	23,750	24,030	24,310	24,626
2	**Total System Resources** (Sum Lines 3, 8, 11 through 16)	**33,132**	**34,866**	**35,764**	**35,271**	**34,661**	**35,048**	**32,306**	**32,347**	**32,388**	**32,429**
	SYSTEM RESOURCES:										
3	Existing Generation (Sum of Lines 4 through 7)	26,623	26,623	26,623	26,623	26,623	26,623	26,623	26,623	26,623	26,623
4	*Existing Renewables (Excludes Hydro)*	1,426	1,426	1,426	1,426	1,426	1,426	1,426	1,426	1,426	1,426
5	*Existing Hydro (Includes RPS-eligible Hydro)*	6,461	6,461	6,461	6,461	6,461	6,461	6,461	6,461	6,461	6,461
6	*Existing CHP*	1,888	1,888	1,888	1,888	1,888	1,888	1,888	1,888	1,888	1,888
7	*Existing OTC*	7,064	7,064	7,064	7,064	7,064	7,064	7,064	7,064	7,064	7,064
8	*Other Generation*	9,784	9,784	9,784	9,784	9,784	9,784	9,784	9,784	9,784	9,784
9	Retirements (Includes Lines 10 & 11)	(497)	(662)	(662)	(1,336)	(1,986)	(1,986)	(4,807)	(4,807)	(4,807)	(4,807)
10	*OTC Retirements*	341	341	341	1,015	1,665	1,665	3,804	3,804	3,804	3,804
11	*Retirements*	156	321	321	321	321	321	1,003	1,003	1,003	1,003
12	Known/High Probability Additions	878	1,733	1,733	1,733	1,733	1,733	1,733	1,733	1,733	1,733
13	Utility Probable Planned Additions	0	784	784	784	784	784	784	784	784	784
14	Other Planned Additions	0	145	973	973	973	973	973	973	973	973
15	RPS Additions (In Service Territory)	20	94	123	263	263	609	647	647	647	647
16	Additional CHP	41	82	123	164	204	245	286	327	368	409
17	Net Interchange (Sum of Lines 18 & 19)	6,067	6,067	6,067	6,067	6,067	6,067	6,067	6,067	6,067	6,067
18	*Imports*	6,067	6,067	6,067	6,067	6,067	6,067	6,067	6,067	6,067	6,067
19	*Exports*	0	0	0	0	0	0	0	0	0	0
20	**Service Area Portion of System Resources (Line 2 * 92%)**	**30,481**	**32,077**	**32,903**	**32,450**	**31,888**	**32,244**	**29,722**	**29,759**	**29,797**	**29,835**
	SERVICE AREA SPECIFIC LINE ADJUSTMENTS:										
21	**Service Area** 1-in-2 Peak Summer Demand	20,193	20,510	20,829	21,071	21,318	21,572	21,851	22,117	22,383	22,683
22	Total Demand-Side Reductions	(1,492)	(1,836)	(2,178)	(2,496)	(2,839)	(3,237)	(3,657)	(4,090)	(4,501)	(4,898)
23	*Incremental Uncommitted EE*	98	128	388	620	871	1,180	1,511	1,857	2,184	2,496
24	*Total DR*	1,354	1,627	1,670	1,715	1,767	1,816	1,865	1,911	1,956	2,001
25	*Incremental Demand-Side CHP*	40	80	120	161	201	241	281	321	361	401
26	**Residual Service Area Peak Demand (Line 21 minus Line 22)**	**18,701**	**18,675**	**18,651**	**18,576**	**18,480**	**18,335**	**18,194**	**18,028**	**17,881**	**17,786**
	SERVICE AREA RESERVES:										
27	Amount of Available Resources Exceeding Demand (Line 20 minus Line 26)	11,780	13,402	14,252	13,874	13,409	13,910	11,528	11,732	11,916	12,049
28	Percentage of Available Resources Exceeding Demand (Line 20 / Line 26)	163.0%	171.8%	176.4%	174.7%	172.6%	175.9%	163.4%	165.1%	166.6%	167.7%
	1-in-2 SERVICE AREA SURPLUS (DEFICIT):										
29	Lower Bound of Planning Reserve Requirement (Line 26 * 15%)	21,506	21,476	21,448	21,362	21,251	21,085	20,923	20,732	20,564	20,453
30	Upper Bound of Planning Reserve Requirement (Line 26 * 17%)	21,880	21,849	21,821	21,734	21,621	21,452	21,287	21,092	20,921	20,809
31	Upper Bound 1-in-2 Service Area Surplus (Deficit)	8,975	10,601	11,455	11,088	10,637	11,159	8,798	9,028	9,233	9,381
32	Lower Bound 1-in-2 Service Area Surplus (Deficit)	8,601	10,227	11,082	10,716	10,267	10,793	8,435	8,667	8,876	9,026

SCE
Physical South of Path 26 (SP26) Capacity Need
Scenario: 20% Trajectory

Line		MW									
	SYSTEM AND SERVICE AREA LOAD FORECASTS:	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
1	**System** 1-in-2 Peak Summer Demand	23,785	24,142	24,518	24,823	25,149	25,482	25,833	26,169	26,509	26,875
2	**Total System Resources** (Sum Lines 3, 8, 11 through 16)	**30,618**	**31,355**	**32,633**	**32,578**	**32,920**	**32,276**	**31,553**	**30,632**	**29,712**	**27,665**
	SYSTEM RESOURCES:										
3	Existing Generation (Sum of Lines 4 through 7)	21,404	21,404	21,404	21,404	21,404	21,404	21,404	21,404	21,404	21,404
4	*Existing Renewables (Excludes Hydro)*	916	916	916	916	916	916	916	916	916	916
5	*Existing Hydro (Includes RPS-eligible Hydro)*	1,470	1,470	1,470	1,470	1,470	1,470	1,470	1,470	1,470	1,470
6	*Existing CHP*	1,489	1,489	1,489	1,489	1,489	1,489	1,489	1,489	1,489	1,489
7	*Existing OTC*	9,250	9,250	9,250	9,250	9,250	9,250	9,250	9,250	9,250	9,250
8	*Other Generation*	8,279	8,279	8,279	8,279	8,279	8,279	8,279	8,279	8,279	8,279
9	Retirements (Includes Lines 10 & 11)	(452)	(452)	(452)	(787)	(2,398)	(3,349)	(4,300)	(5,251)	(6,202)	(8,280)
10	*OTC Retirements*	452	452	452	787	1,122	2,073	3,024	3,975	4,926	7,004
11	*Retirements*	0	0	0	0	1,276	1,276	1,276	1,276	1,276	1,276
12	Known/High Probability Additions	717	917	1,997	1,997	1,997	1,997	1,997	1,997	1,997	1,997
13	Utility Probable Planned Additions	0	500	500	500	1,854	1,854	1,854	1,854	1,854	1,854
14	Other Planned Additions	0	0	0	0	0	0	0	0	0	0
15	RPS Additions (In Service Territory)	0	6	174	423	992	1,268	1,465	1,465	1,465	1,465
16	Additional CHP	31	61	92	123	153	184	215	245	276	307
17	Net Interchange (Sum of Lines 18 & 19)	8,918	8,918	8,918	8,918	8,918	8,918	8,918	8,918	8,918	8,918
18	*Imports*	8,918	8,918	8,918	8,918	8,918	8,918	8,918	8,918	8,918	8,918
19	*Exports*	0	0	0	0	0	0	0	0	0	0
20	**Service Area Portion of System Resources (Line 2 * 90%)**	**27,557**	**28,219**	**29,370**	**29,320**	**29,628**	**29,048**	**28,397**	**27,569**	**26,741**	**24,898**
	SERVICE AREA SPECIFIC LINE ADJUSTMENTS:										
21	**Service Area** 1-in-2 Peak Summer Demand	21,305	21,634	21,981	22,262	22,561	22,867	23,189	23,497	23,810	24,146
22	Total Demand-Side Reductions	(1,721)	(2,634)	(3,118)	(3,458)	(3,856)	(4,228)	(4,624)	(5,042)	(5,449)	(5,850)
23	*Incremental Uncommitted EE*	44	60	325	565	834	1,171	1,530	1,912	2,283	2,648
24	*Total DR*	1,641	2,502	2,685	2,749	2,842	2,842	2,842	2,842	2,842	2,842
25	*Incremental Demand-Side CHP*	36	72	108	144	180	216	252	288	324	360
26	**Residual Service Area Peak Demand (Line 21 minus Line 22)**	**19,584**	**19,000**	**18,863**	**18,805**	**18,705**	**18,639**	**18,565**	**18,456**	**18,361**	**18,296**
	SERVICE AREA RESERVES:										
27	Amount of Available Resources Exceeding Demand (Line 20 minus Line 26)	7,973	9,219	10,507	10,516	10,923	10,409	9,832	9,113	8,380	6,602
28	Percentage of Available Resources Exceeding Demand (Line 20 / Line 26)	140.7%	148.5%	155.7%	155.9%	158.4%	155.8%	153.0%	149.4%	145.6%	136.1%
	1-in-2 SERVICE AREA SURPLUS (DEFICIT):										
29	Lower Bound of Planning Reserve Requirement (Line 26 * 15%)	22,521	21,850	21,692	21,625	21,511	21,435	21,350	21,224	21,115	21,041
30	Upper Bound of Planning Reserve Requirement (Line 26 * 17%)	22,913	22,230	22,070	22,001	21,885	21,807	21,721	21,593	21,482	21,407
31	Upper Bound 1-in-2 Service Area Surplus (Deficit)	5,035	6,369	7,677	7,695	8,117	7,613	7,047	6,345	5,626	3,858
32	Lower Bound 1-in-2 Service Area Surplus (Deficit)	4,644	5,989	7,300	7,319	7,743	7,241	6,676	5,976	5,258	3,492

Line	SDG&E Physical Border Capacity Need Scenario: 20% Trajectory	MW									
	SYSTEM AND SERVICE AREA LOAD FORECASTS:	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
1	**System** 1-in-2 Peak Summer Demand	4,578	4,658	4,738	4,797	4,856	4,911	4,973	5,032	5,094	5,157
2	**Total System Resources** (Sum Lines 3, 8, 11 through 16)	**6,127**	**6,130**	**6,291**	**6,332**	**6,439**	**6,446**	**5,489**	**5,491**	**5,494**	**5,497**
	SYSTEM RESOURCES:										
3	Existing Generation (Sum of Lines 4 through 7)	4,410	4,410	4,410	4,410	4,410	4,410	4,410	4,410	4,410	4,410
4	*Existing Renewables (Excludes Hydro)*	21	21	21	21	21	21	21	21	21	21
5	*Existing Hydro (Includes RPS-eligible Hydro)*	4	4	4	4	4	4	4	4	4	4
6	*Existing CHP*	136	136	136	136	136	136	136	136	136	136
7	*Existing OTC*	1,271	1,271	1,271	1,271	1,271	1,271	1,271	1,271	1,271	1,271
8	*Other Generation*	2,978	2,978	2,978	2,978	2,978	2,978	2,978	2,978	2,978	2,978
9	Retirements (Includes Lines 10 & 11)	(311)	(311)	(311)	(311)	(311)	(311)	(1,271)	(1,271)	(1,271)	(1,271)
10	*OTC Retirements*	311	311	311	311	311	311	1,271	1,271	1,271	1,271
11	*Retirements*	0	0	0	0	0	0	0	0	0	0
12	Known/High Probability Additions	55	55	55	55	55	55	55	55	55	55
13	Utility Probable Planned Additions	0	0	159	159	159	159	159	159	159	159
14	Other Planned Additions	0	0	0	0	0	0	0	0	0	0
15	RPS Additions (In Service Territory)	0	0	0	38	142	146	146	146	146	146
16	Additional CHP	3	6	8	11	14	17	20	22	25	28
17	Net Interchange (Sum of Lines 18 & 19)	1,970	1,970	1,970	1,970	1,970	1,970	1,970	1,970	1,970	1,970
18	*Imports*	1,970	1,970	1,970	1,970	1,970	1,970	1,970	1,970	1,970	1,970
19	*Exports*	0	0	0	0	0	0	0	0	0	0
20	**Service Area Portion of System Resources (Line 2)**	**6,127**	**6,130**	**6,291**	**6,332**	**6,439**	**6,446**	**5,489**	**5,491**	**5,494**	**5,497**
	SERVICE AREA SPECIFIC LINE ADJUSTMENTS:										
21	**Service Area** 1-in-2 Peak Summer Demand	4,578	4,658	4,738	4,797	4,856	4,911	4,973	5,032	5,094	5,157
22	Total Demand-Side Reductions	(219)	(242)	(353)	(421)	(492)	(570)	(655)	(743)	(825)	(903)
23	*Incremental Uncommitted EE*	3	4	66	121	179	247	321	398	471	544
24	*Total DR*	210	226	270	277	285	289	293	298	302	302
25	*Incremental Demand-Side CHP*	6	12	17	23	29	35	41	46	52	58
26	**Residual Service Area Peak Demand (Line 21 minus Line 22)**	**4,359**	**4,416**	**4,385**	**4,376**	**4,363**	**4,340**	**4,318**	**4,289**	**4,269**	**4,254**
	SERVICE AREA RESERVES:										
27	Amount of Available Resources Exceeding Demand (Line 20 minus Line 26)	1,768	1,714	1,906	1,956	2,076	2,106	1,171	1,202	1,225	1,243
28	Percentage of Available Resources Exceeding Demand (Line 20 / Line 26)	140.6%	138.8%	143.5%	144.7%	147.6%	148.5%	127.1%	128.0%	128.7%	129.2%
	1-in-2 SERVICE AREA SURPLUS (DEFICIT):										
29	Lower Bound of Planning Reserve Requirement (Line 26 * 15%)	5,013	5,079	5,043	5,032	5,018	4,991	4,966	4,932	4,909	4,892
30	Upper Bound of Planning Reserve Requirement (Line 26 * 17%)	5,100	5,167	5,131	5,120	5,105	5,078	5,052	5,018	4,994	4,977
31	Upper Bound 1-in-2 Service Area Surplus (Deficit)	1,114	1,051	1,248	1,299	1,421	1,455	523	559	585	605
32	Lower Bound 1-in-2 Service Area Surplus (Deficit)	1,027	963	1,160	1,212	1,334	1,368	437	473	500	520

PG&E
Physical North of Path 26 (NP26) Capacity Need
Sensitivity: 33% Trajectory (High Load)

Line		MW									
	SYSTEM AND SERVICE AREA LOAD FORECASTS:	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
1	**System** 1-in-2 Peak Summer Demand	24,187	24,562	24,935	25,217	25,504	25,799	26,125	26,433	26,741	27,088
2	**Total System Resources** (Sum Lines 3, 8, 11 through 16)	**33,132**	**34,866**	**35,764**	**35,271**	**34,812**	**35,199**	**32,564**	**32,604**	**32,645**	**32,686**
	SYSTEM RESOURCES:										
3	Existing Generation (Sum of Lines 4 through 7)	26,623	26,623	26,623	26,623	26,623	26,623	26,623	26,623	26,623	26,623
4	*Existing Renewables (Excludes Hydro)*	1,426	1,426	1,426	1,426	1,426	1,426	1,426	1,426	1,426	1,426
5	*Existing Hydro (Includes RPS-eligible Hydro)*	6,461	6,461	6,461	6,461	6,461	6,461	6,461	6,461	6,461	6,461
6	*Existing CHP*	1,888	1,888	1,888	1,888	1,888	1,888	1,888	1,888	1,888	1,888
7	*Existing OTC*	7,064	7,064	7,064	7,064	7,064	7,064	7,064	7,064	7,064	7,064
8	*Other Generation*	9,784	9,784	9,784	9,784	9,784	9,784	9,784	9,784	9,784	9,784
9	Retirements (Includes Lines 10 & 11)	(497)	(662)	(662)	(1,336)	(1,986)	(1,986)	(4,807)	(4,807)	(4,807)	(4,807)
10	*OTC Retirements*	341	341	341	1,015	1,665	1,665	3,804	3,804	3,804	3,804
11	*Retirements*	156	321	321	321	321	321	1,003	1,003	1,003	1,003
12	Known/High Probability Additions	878	1,733	1,733	1,733	1,733	1,733	1,733	1,733	1,733	1,733
13	Utility Probable Planned Additions	0	784	784	784	784	784	784	784	784	784
14	Other Planned Additions	0	145	973	973	973	973	973	973	973	973
15	RPS Additions (In Service Territory)	20	94	123	263	414	760	904	904	904	904
16	Additional CHP	41	82	123	164	204	245	286	327	368	409
17	Net Interchange (Sum of Lines 18 & 19)	6,067	6,067	6,067	6,067	6,067	6,067	6,067	6,067	6,067	6,067
18	*Imports*	6,067	6,067	6,067	6,067	6,067	6,067	6,067	6,067	6,067	6,067
19	*Exports*	0	0	0	0	0	0	0	0	0	0
20	**Service Area Portion of System Resources (Line 2 * 92%)**	**30,481**	**32,077**	**32,903**	**32,450**	**32,027**	**32,383**	**29,959**	**29,996**	**30,034**	**30,071**
	SERVICE AREA SPECIFIC LINE ADJUSTMENTS:										
21	**Service Area** 1-in-2 Peak Summer Demand	22,212	22,561	22,912	23,179	23,450	23,729	24,036	24,329	24,621	24,952
22	Total Demand-Side Reductions	(1,492)	(1,836)	(2,178)	(2,496)	(2,839)	(3,237)	(3,657)	(4,090)	(4,501)	(4,898)
23	*Incremental Uncommitted EE*	98	128	388	620	871	1,180	1,511	1,857	2,184	2,496
24	*Total DR*	1,354	1,627	1,670	1,715	1,767	1,816	1,865	1,911	1,956	2,001
25	*Incremental Demand-Side CHP*	40	80	120	161	201	241	281	321	361	401
26	**Residual Service Area Peak Demand (Line 21 minus Line 22)**	**20,721**	**20,726**	**20,734**	**20,683**	**20,611**	**20,492**	**20,379**	**20,239**	**20,120**	**20,054**
	SERVICE AREA RESERVES:										
27	Amount of Available Resources Exceeding Demand (Line 20 minus Line 26)	9,761	11,351	12,169	11,767	11,416	11,892	9,579	9,757	9,914	10,017
28	Percentage of Available Resources Exceeding Demand (Line 20 / Line 26)	147.1%	154.8%	158.7%	156.9%	155.4%	158.0%	147.0%	148.2%	149.3%	150.0%
	1-in-2 SERVICE AREA SURPLUS (DEFICIT):										
29	Lower Bound of Planning Reserve Requirement (Line 26 * 15%)	23,829	23,835	23,844	23,785	23,703	23,566	23,436	23,275	23,138	23,062
30	Upper Bound of Planning Reserve Requirement (Line 26 * 17%)	24,243	24,249	24,258	24,199	24,115	23,975	23,844	23,680	23,540	23,463
31	Upper Bound 1-in-2 Service Area Surplus (Deficit)	6,653	8,242	9,059	8,664	8,324	8,818	6,522	6,721	6,896	7,009
32	Lower Bound 1-in-2 Service Area Surplus (Deficit)	6,238	7,828	8,645	8,251	7,912	8,408	6,115	6,316	6,494	6,608

SCE
Physical South of Path 26 (SP26) Capacity Need
Sensitivity 33% Trajectory (High Load)

Line		MW									
	SYSTEM AND SERVICE AREA LOAD FORECASTS:	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
1	**System** 1-in-2 Peak Summer Demand	26,163	26,556	26,970	27,305	27,664	28,031	28,416	28,786	29,160	29,563
2	**Total System Resources** (Sum Lines 3, 8, 11 through 16)	**30,618**	**31,355**	**32,633**	**32,578**	**33,696**	**33,051**	**32,837**	**31,916**	**32,097**	**30,050**
	SYSTEM RESOURCES:										
3	Existing Generation (Sum of Lines 4 through 7)	21,404	21,404	21,404	21,404	21,404	21,404	21,404	21,404	21,404	21,404
4	*Existing Renewables (Excludes Hydro)*	916	916	916	916	916	916	916	916	916	916
5	*Existing Hydro (Includes RPS-eligible Hydro)*	1,470	1,470	1,470	1,470	1,470	1,470	1,470	1,470	1,470	1,470
6	*Existing CHP*	1,489	1,489	1,489	1,489	1,489	1,489	1,489	1,489	1,489	1,489
7	*Existing OTC*	9,250	9,250	9,250	9,250	9,250	9,250	9,250	9,250	9,250	9,250
8	*Other Generation*	8,279	8,279	8,279	8,279	8,279	8,279	8,279	8,279	8,279	8,279
9	Retirements (Includes Lines 10 & 11)	(452)	(452)	(452)	(787)	(2,398)	(3,349)	(4,300)	(5,251)	(6,202)	(8,280)
10	*OTC Retirements*	452	452	452	787	1,122	2,073	3,024	3,975	4,926	7,004
11	*Retirements*	0	0	0	0	1,276	1,276	1,276	1,276	1,276	1,276
12	Known/High Probability Additions	717	917	1,997	1,997	1,997	1,997	1,997	1,997	1,997	1,997
13	Utility Probable Planned Additions	0	500	500	500	1,854	1,854	1,854	1,854	1,854	1,854
14	Other Planned Additions	0	0	0	0	0	0	0	0	0	0
15	RPS Additions (In Service Territory)	0	6	174	423	1,768	2,043	2,749	2,749	3,850	3,850
16	Additional CHP	31	61	92	123	153	184	215	245	276	307
17	Net Interchange (Sum of Lines 18 & 19)	8,918	8,918	8,918	8,918	8,918	8,918	8,918	8,918	8,918	8,918
18	*Imports*	8,918	8,918	8,918	8,918	8,918	8,918	8,918	8,918	8,918	8,918
19	*Exports*	0	0	0	0	0	0	0	0	0	0
20	**Service Area Portion of System Resources (Line 2 * 90%)**	**27,557**	**28,219**	**29,370**	**29,320**	**30,327**	**29,746**	**29,554**	**28,725**	**28,887**	**27,045**
	SERVICE AREA SPECIFIC LINE ADJUSTMENTS:										
21	**Service Area** 1-in-2 Peak Summer Demand	23,435	23,798	24,179	24,488	24,817	25,154	25,508	25,847	26,191	26,561
22	Total Demand-Side Reductions	(1,721)	(2,634)	(3,118)	(3,458)	(3,856)	(4,228)	(4,624)	(5,042)	(5,449)	(5,850)
23	*Incremental Uncommitted EE*	44	60	325	565	834	1,171	1,530	1,912	2,283	2,648
24	*Total DR*	1,641	2,502	2,685	2,749	2,842	2,842	2,842	2,842	2,842	2,842
25	*Incremental Demand-Side CHP*	36	72	108	144	180	216	252	288	324	360
26	**Residual Service Area Peak Demand (Line 21 minus Line 22)**	**21,714**	**21,164**	**21,061**	**21,031**	**20,961**	**20,925**	**20,884**	**20,805**	**20,742**	**20,711**
	SERVICE AREA RESERVES:										
27	Amount of Available Resources Exceeding Demand (Line 20 minus Line 26)	5,843	7,056	8,309	8,290	9,365	8,821	8,670	7,919	8,146	6,334
28	Percentage of Available Resources Exceeding Demand (Line 20 / Line 26)	126.9%	133.3%	139.4%	139.4%	144.7%	142.2%	141.5%	138.1%	139.3%	130.6%
	1-in-2 SERVICE AREA SURPLUS (DEFICIT):										
29	Lower Bound of Planning Reserve Requirement (Line 26 * 15%)	24,971	24,338	24,220	24,185	24,106	24,064	24,017	23,926	23,853	23,818
30	Upper Bound of Planning Reserve Requirement (Line 26 * 17%)	25,405	24,761	24,642	24,606	24,525	24,483	24,434	24,342	24,268	24,232
31	Upper Bound 1-in-2 Service Area Surplus (Deficit)	2,585	3,881	5,149	5,135	6,221	5,682	5,537	4,799	5,034	3,227
32	Lower Bound 1-in-2 Service Area Surplus (Deficit)	2,151	3,458	4,728	4,714	5,802	5,263	5,119	4,383	4,619	2,813

	SDG&E										
	Physical Border Capacity Need										
	Sensitivity 33% Trajectory (High Load)										
Line		**MW**									
	SYSTEM AND SERVICE AREA LOAD FORECASTS:	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
1	**System** 1-in-2 Peak Summer Demand	5,036	5,124	5,212	5,277	5,341	5,402	5,470	5,535	5,603	5,673
2	**Total System Resources** (Sum Lines 3, 8, 11 through 16)	**6,127**	**6,130**	**6,291**	**6,437**	**6,737**	**6,765**	**5,808**	**5,810**	**6,643**	**6,646**
	SYSTEM RESOURCES:										
3	Existing Generation (Sum of Lines 4 through 7)	4,410	4,410	4,410	4,410	4,410	4,410	4,410	4,410	4,410	4,410
4	*Existing Renewables (Excludes Hydro)*	21	21	21	21	21	21	21	21	21	21
5	*Existing Hydro (Includes RPS-eligible Hydro)*	4	4	4	4	4	4	4	4	4	4
6	*Existing CHP*	136	136	136	136	136	136	136	136	136	136
7	*Existing OTC*	1,271	1,271	1,271	1,271	1,271	1,271	1,271	1,271	1,271	1,271
8	*Other Generation*	2,978	2,978	2,978	2,978	2,978	2,978	2,978	2,978	2,978	2,978
9	Retirements (Includes Lines 10 & 11)	(311)	(311)	(311)	(311)	(311)	(311)	(1,271)	(1,271)	(1,271)	(1,271)
10	*OTC Retirements*	311	311	311	311	311	311	1,271	1,271	1,271	1,271
11	*Retirements*	0	0	0	0	0	0	0	0	0	0
12	Known/High Probability Additions	55	55	55	55	55	55	55	55	55	55
13	Utility Probable Planned Additions	0	0	159	159	159	159	159	159	159	159
14	Other Planned Additions	0	0	0	0	0	0	0	0	0	0
15	RPS Additions (In Service Territory)	0	0	0	143	440	465	465	465	1,295	1,295
16	Additional CHP	3	6	8	11	14	17	20	22	25	28
17	Net Interchange (Sum of Lines 18 & 19)	1,970	1,970	1,970	1,970	1,970	1,970	1,970	1,970	1,970	1,970
18	*Imports*	1,970	1,970	1,970	1,970	1,970	1,970	1,970	1,970	1,970	1,970
19	*Exports*	0	0	0	0	0	0	0	0	0	0
20	**Service Area Portion of System Resources (Line 2)**	**6,127**	**6,130**	**6,291**	**6,437**	**6,737**	**6,765**	**5,808**	**5,810**	**6,643**	**6,646**
	SERVICE AREA SPECIFIC LINE ADJUSTMENTS:										
21	**Service Area** 1-in-2 Peak Summer Demand	5,036	5,124	5,212	5,277	5,341	5,402	5,470	5,535	5,603	5,673
22	Total Demand-Side Reductions	(219)	(242)	(353)	(421)	(492)	(570)	(655)	(743)	(825)	(903)
23	*Incremental Uncommitted EE*	3	4	66	121	179	247	321	398	471	544
24	*Total DR*	210	226	270	277	285	289	293	298	302	302
25	*Incremental Demand-Side CHP*	6	12	17	23	29	35	41	46	52	58
26	**Residual Service Area Peak Demand (Line 21 minus Line 22)**	**4,817**	**4,882**	**4,859**	**4,856**	**4,849**	**4,831**	**4,815**	**4,792**	**4,778**	**4,769**
	SERVICE AREA RESERVES:										
27	Amount of Available Resources Exceeding Demand (Line 20 minus Line 26)	1,310	1,248	1,432	1,581	1,888	1,934	993	1,018	1,865	1,876
28	Percentage of Available Resources Exceeding Demand (Line 20 / Line 26)	127.2%	125.6%	129.5%	132.6%	138.9%	140.0%	120.6%	121.2%	139.0%	139.3%
	1-in-2 SERVICE AREA SURPLUS (DEFICIT):										
29	Lower Bound of Planning Reserve Requirement (Line 26 * 15%)	5,539	5,614	5,588	5,584	5,576	5,556	5,538	5,511	5,495	5,485
30	Upper Bound of Planning Reserve Requirement (Line 26 * 17%)	5,635	5,712	5,685	5,681	5,673	5,653	5,634	5,607	5,590	5,580
31	Upper Bound 1-in-2 Service Area Surplus (Deficit)	588	516	703	853	1,161	1,209	271	299	1,148	1,161
32	Lower Bound 1-in-2 Service Area Surplus (Deficit)	492	418	606	756	1,064	1,112	174	203	1,052	1,066

PG&E
Physical North of Path 26 (NP26) Capacity Need
Sensitivity 33% Trajectory (Low Load)

Line		MW									
	SYSTEM AND SERVICE AREA LOAD FORECASTS:	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
1	**System** 1-in-2 Peak Summer Demand	19,790	20,096	20,401	20,632	20,867	21,108	21,375	21,627	21,879	22,163
2	**Total System Resources** (Sum Lines 3, 8, 11 through 16)	**33,132**	**34,866**	**35,764**	**35,271**	**34,812**	**35,199**	**32,457**	**32,498**	**32,539**	**32,580**
	SYSTEM RESOURCES:										
3	Existing Generation (Sum of Lines 4 through 7)	26,623	26,623	26,623	26,623	26,623	26,623	26,623	26,623	26,623	26,623
4	*Existing Renewables (Excludes Hydro)*	1,426	1,426	1,426	1,426	1,426	1,426	1,426	1,426	1,426	1,426
5	*Existing Hydro (Includes RPS-eligible Hydro)*	6,461	6,461	6,461	6,461	6,461	6,461	6,461	6,461	6,461	6,461
6	*Existing CHP*	1,888	1,888	1,888	1,888	1,888	1,888	1,888	1,888	1,888	1,888
7	*Existing OTC*	7,064	7,064	7,064	7,064	7,064	7,064	7,064	7,064	7,064	7,064
8	*Other Generation*	9,784	9,784	9,784	9,784	9,784	9,784	9,784	9,784	9,784	9,784
9	Retirements (Includes Lines 10 & 11)	(497)	(662)	(662)	(1,336)	(1,986)	(1,986)	(4,807)	(4,807)	(4,807)	(4,807)
10	*OTC Retirements*	341	341	341	1,015	1,665	1,665	3,804	3,804	3,804	3,804
11	*Retirements*	156	321	321	321	321	321	1,003	1,003	1,003	1,003
12	Known/High Probability Additions	878	1,733	1,733	1,733	1,733	1,733	1,733	1,733	1,733	1,733
13	Utility Probable Planned Additions	0	784	784	784	784	784	784	784	784	784
14	Other Planned Additions	0	145	973	973	973	973	973	973	973	973
15	RPS Additions (In Service Territory)	20	94	123	263	414	760	798	798	798	798
16	Additional CHP	41	82	123	164	204	245	286	327	368	409
17	Net Interchange (Sum of Lines 18 & 19)	6,067	6,067	6,067	6,067	6,067	6,067	6,067	6,067	6,067	6,067
18	*Imports*	6,067	6,067	6,067	6,067	6,067	6,067	6,067	6,067	6,067	6,067
19	*Exports*	0	0	0	0	0	0	0	0	0	0
20	**Service Area Portion of System Resources (Line 2 * 92%)**	**30,481**	**32,077**	**32,903**	**32,450**	**32,027**	**32,383**	**29,861**	**29,898**	**29,936**	**29,974**
	SERVICE AREA SPECIFIC LINE ADJUSTMENTS:										
21	**Service Area** 1-in-2 Peak Summer Demand	18,174	18,459	18,746	18,964	19,186	19,415	19,666	19,906	20,145	20,415
22	Total Demand-Side Reductions	(1,492)	(1,836)	(2,178)	(2,496)	(2,839)	(3,237)	(3,657)	(4,090)	(4,501)	(4,898)
23	*Incremental Uncommitted EE*	98	128	388	620	871	1,180	1,511	1,857	2,184	2,496
24	*Total DR*	1,354	1,627	1,670	1,715	1,767	1,816	1,865	1,911	1,956	2,001
25	*Incremental Demand-Side CHP*	40	80	120	161	201	241	281	321	361	401
26	**Residual Service Area Peak Demand (Line 21 minus Line 22)**	**16,682**	**16,624**	**16,568**	**16,469**	**16,348**	**16,177**	**16,009**	**15,816**	**15,643**	**15,517**
	SERVICE AREA RESERVES:										
27	Amount of Available Resources Exceeding Demand (Line 20 minus Line 26)	13,799	15,453	16,335	15,981	15,680	16,206	13,852	14,083	14,293	14,456
28	Percentage of Available Resources Exceeding Demand (Line 20 / Line 26)	182.7%	193.0%	198.6%	197.0%	195.9%	200.2%	186.5%	189.0%	191.4%	193.2%
	1-in-2 SERVICE AREA SURPLUS (DEFICIT):										
29	Lower Bound of Planning Reserve Requirement (Line 26 * 15%)	19,184	19,117	19,053	18,939	18,800	18,604	18,410	18,188	17,990	17,845
30	Upper Bound of Planning Reserve Requirement (Line 26 * 17%)	19,518	19,450	19,384	19,268	19,127	18,928	18,731	18,505	18,302	18,155
31	Upper Bound 1-in-2 Service Area Surplus (Deficit)	11,297	12,960	13,850	13,511	13,228	13,779	11,450	11,710	11,946	12,129
32	Lower Bound 1-in-2 Service Area Surplus (Deficit)	10,963	12,627	13,519	13,181	12,901	13,456	11,130	11,394	11,634	11,819

	SCE Physical South of Path 26 (SP26) Capacity Need Sensitivity 33% Trajectory (Low Load)										
Line		MW									
	SYSTEM AND SERVICE AREA LOAD FORECASTS:	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
1	**System** 1-in-2 Peak Summer Demand	21,406	21,728	22,066	22,341	22,634	22,934	23,250	23,552	23,858	24,188
2	**Total System Resources** (Sum Lines 3, 8, 11 through 16)	**30,618**	**31,355**	**32,633**	**32,578**	**33,696**	**33,051**	**32,329**	**31,408**	**30,514**	**28,467**
	SYSTEM RESOURCES:										
3	Existing Generation (Sum of Lines 4 through 7)	21,404	21,404	21,404	21,404	21,404	21,404	21,404	21,404	21,404	21,404
4	*Existing Renewables (Excludes Hydro)*	916	916	916	916	916	916	916	916	916	916
5	*Existing Hydro (Includes RPS-eligible Hydro)*	1,470	1,470	1,470	1,470	1,470	1,470	1,470	1,470	1,470	1,470
6	*Existing CHP*	1,489	1,489	1,489	1,489	1,489	1,489	1,489	1,489	1,489	1,489
7	*Existing OTC*	9,250	9,250	9,250	9,250	9,250	9,250	9,250	9,250	9,250	9,250
8	*Other Generation*	8,279	8,279	8,279	8,279	8,279	8,279	8,279	8,279	8,279	8,279
9	Retirements (Includes Lines 10 & 11)	(452)	(452)	(452)	(787)	(2,398)	(3,349)	(4,300)	(5,251)	(6,202)	(8,280)
10	*OTC Retirements*	452	452	452	787	1,122	2,073	3,024	3,975	4,926	7,004
11	*Retirements*	0	0	0	0	1,276	1,276	1,276	1,276	1,276	1,276
12	Known/High Probability Additions	717	917	1,997	1,997	1,997	1,997	1,997	1,997	1,997	1,997
13	Utility Probable Planned Additions	0	500	500	500	1,854	1,854	1,854	1,854	1,854	1,854
14	Other Planned Additions	0	0	0	0	0	0	0	0	0	0
15	RPS Additions (In Service Territory)	0	6	174	423	1,768	2,043	2,241	2,241	2,267	2,267
16	Additional CHP	31	61	92	123	153	184	215	245	276	307
17	Net Interchange (Sum of Lines 18 & 19)	8,918	8,918	8,918	8,918	8,918	8,918	8,918	8,918	8,918	8,918
18	*Imports*	8,918	8,918	8,918	8,918	8,918	8,918	8,918	8,918	8,918	8,918
19	*Exports*	0	0	0	0	0	0	0	0	0	0
20	**Service Area Portion of System Resources (Line 2 * 90%)**	**27,557**	**28,219**	**29,370**	**29,320**	**30,327**	**29,746**	**29,096**	**28,267**	**27,463**	**25,620**
	SERVICE AREA SPECIFIC LINE ADJUSTMENTS:										
21	**Service Area** 1-in-2 Peak Summer Demand	19,174	19,471	19,783	20,036	20,305	20,580	20,870	21,148	21,429	21,731
22	Total Demand-Side Reductions	(1,721)	(2,634)	(3,118)	(3,458)	(3,856)	(4,228)	(4,624)	(5,042)	(5,449)	(5,850)
23	*Incremental Uncommitted EE*	44	60	325	565	834	1,171	1,530	1,912	2,283	2,648
24	*Total DR*	1,641	2,502	2,685	2,749	2,842	2,842	2,842	2,842	2,842	2,842
25	*Incremental Demand-Side CHP*	36	72	108	144	180	216	252	288	324	360
26	**Residual Service Area Peak Demand (Line 21 minus Line 22)**	**17,453**	**16,837**	**16,665**	**16,578**	**16,449**	**16,352**	**16,246**	**16,106**	**15,980**	**15,882**
	SERVICE AREA RESERVES:										
27	Amount of Available Resources Exceeding Demand (Line 20 minus Line 26)	10,103	11,383	12,705	12,742	13,877	13,394	12,849	12,161	11,483	9,739
28	Percentage of Available Resources Exceeding Demand (Line 20 / Line 26)	157.9%	167.6%	176.2%	176.9%	184.4%	181.9%	179.1%	175.5%	171.9%	161.3%
	1-in-2 SERVICE AREA SURPLUS (DEFICIT):										
29	Lower Bound of Planning Reserve Requirement (Line 26 * 15%)	20,071	19,362	19,165	19,065	18,917	18,805	18,683	18,522	18,377	18,264
30	Upper Bound of Planning Reserve Requirement (Line 26 * 17%)	20,420	19,699	19,498	19,397	19,246	19,132	19,008	18,844	18,696	18,582
31	Upper Bound 1-in-2 Service Area Surplus (Deficit)	7,485	8,857	10,205	10,255	11,410	10,941	10,412	9,745	9,086	7,356
32	Lower Bound 1-in-2 Service Area Surplus (Deficit)	7,136	8,520	9,872	9,924	11,081	10,614	10,087	9,423	8,766	7,039

SDG&E Physical Border Capacity Need Sensitivity 33% Trajectory (Low Load)											
Line		MW									
	SYSTEM AND SERVICE AREA LOAD FORECASTS:	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
1	**System** 1-in-2 Peak Summer Demand	4,120	4,192	4,264	4,317	4,370	4,420	4,476	4,529	4,585	4,641
2	**Total System Resources** (Sum Lines 3, 8, 11 through 16)	**6,127**	**6,130**	**6,291**	**6,437**	**6,737**	**6,765**	**5,808**	**5,810**	**5,813**	**5,816**
	SYSTEM RESOURCES:										
3	Existing Generation (Sum of Lines 4 through 7)	4,410	4,410	4,410	4,410	4,410	4,410	4,410	4,410	4,410	4,410
4	*Existing Renewables (Excludes Hydro)*	21	21	21	21	21	21	21	21	21	21
5	*Existing Hydro (Includes RPS-eligible Hydro)*	4	4	4	4	4	4	4	4	4	4
6	*Existing CHP*	136	136	136	136	136	136	136	136	136	136
7	*Existing OTC*	1,271	1,271	1,271	1,271	1,271	1,271	1,271	1,271	1,271	1,271
8	*Other Generation*	2,978	2,978	2,978	2,978	2,978	2,978	2,978	2,978	2,978	2,978
9	Retirements (Includes Lines 10 & 11)	(311)	(311)	(311)	(311)	(311)	(311)	(1,271)	(1,271)	(1,271)	(1,271)
10	*OTC Retirements*	311	311	311	311	311	311	1,271	1,271	1,271	1,271
11	*Retirements*	0	0	0	0	0	0	0	0	0	0
12	Known/High Probability Additions	55	55	55	55	55	55	55	55	55	55
13	Utility Probable Planned Additions	0	0	159	159	159	159	159	159	159	159
14	Other Planned Additions	0	0	0	0	0	0	0	0	0	0
15	RPS Additions (In Service Territory)	0	0	0	143	440	465	465	465	465	465
16	Additional CHP	3	6	8	11	14	17	20	22	25	28
17	Net Interchange (Sum of Lines 18 & 19)	1,970	1,970	1,970	1,970	1,970	1,970	1,970	1,970	1,970	1,970
18	*Imports*	1,970	1,970	1,970	1,970	1,970	1,970	1,970	1,970	1,970	1,970
19	*Exports*	0	0	0	0	0	0	0	0	0	0
20	**Service Area Portion of System Resources (Line 2)**	**6,127**	**6,130**	**6,291**	**6,437**	**6,737**	**6,765**	**5,808**	**5,810**	**5,813**	**5,816**
	SERVICE AREA SPECIFIC LINE ADJUSTMENTS:										
21	**Service Area** 1-in-2 Peak Summer Demand	4,120	4,192	4,264	4,317	4,370	4,420	4,476	4,529	4,585	4,641
22	Total Demand-Side Reductions	(219)	(242)	(353)	(421)	(492)	(570)	(655)	(743)	(825)	(903)
23	*Incremental Uncommitted EE*	3	4	66	121	179	247	321	398	471	544
24	*Total DR*	210	226	270	277	285	289	293	298	302	302
25	*Incremental Demand-Side CHP*	6	12	17	23	29	35	41	46	52	58
26	**Residual Service Area Peak Demand (Line 21 minus Line 22)**	**3,901**	**3,950**	**3,912**	**3,896**	**3,878**	**3,849**	**3,821**	**3,786**	**3,759**	**3,738**
	SERVICE AREA RESERVES:										
27	Amount of Available Resources Exceeding Demand (Line 20 minus Line 26)	2,226	2,180	2,379	2,541	2,859	2,916	1,987	2,024	2,054	2,078
28	Percentage of Available Resources Exceeding Demand (Line 20 / Line 26)	157.1%	155.2%	160.8%	165.2%	173.7%	175.7%	152.0%	153.5%	154.6%	155.6%
	1-in-2 SERVICE AREA SURPLUS (DEFICIT):										
29	Lower Bound of Planning Reserve Requirement (Line 26 * 15%)	4,486	4,543	4,498	4,481	4,459	4,427	4,394	4,354	4,323	4,299
30	Upper Bound of Planning Reserve Requirement (Line 26 * 17%)	4,564	4,622	4,577	4,559	4,537	4,504	4,470	4,429	4,398	4,373
31	Upper Bound 1-in-2 Service Area Surplus (Deficit)	1,641	1,587	1,793	1,956	2,278	2,338	1,414	1,456	1,490	1,518
32	Lower Bound 1-in-2 Service Area Surplus (Deficit)	1,563	1,508	1,714	1,878	2,200	2,261	1,338	1,381	1,415	1,443

Appendix A

Standardized Planning Assumptions: Greenhouse Gasses

GHG Metrics
The table below shows the relationship between procurement method, GHG cost and actual GHG emissions embedded by procurement type

	Carbon Price Pass Through for GHG Cost	**Embedded Emissions (to determine total portfolio GHG emissions)**
Self-Owned generation	(Carbon price)*(actual emissions)	Actual emissions of generator
Sales of self-owned generation	(Carbon Price)*(emissions of marginal generator for time/season interval)	LSE average per MWh emissions for given time/season interval
Purchases from Bilateral contracts	(Carbon Price)*(Emissions associated with specified heat rate)	Actual emissions of generator
Market Purchases from other LSEs	(Carbon Price)*(emissions of marginal generator for time/season interval)	LSE average per MWh emissions for given time/season interval
Bilateral Purchases from other LSEs	(Carbon Price)*(emissions of marginal generator for time/season interval)	Emissions of average generation for given time/season interval
Purchases from QFs	(Carbon Price)*(actual emissions)	Actual emissions
Market Purchases from CAISO market	(Carbon Price)*(emissions of marginal generator for time/season interval)	Average emissions of CAISO market pool for each time/season interval

Carbon Price Assumptions

These estimates are provided in the table below. The 2009 MPR results and the low and high carbon price are provided for illustrative purposes. When the IOUs and other parties file their portfolios, pursuant to the schedule, the most recent MPR methodology will be used. The High and Low values are plus and minus 25 percent from the MPR values.[15] The low estimate for 2012 was adjusted upward to align with the floor price applied in ARB's carbon cap and trade regulation.[16]

Year	Market Price Referent Model 2009 (nominal dollars)	Low Carbon Price Estimate	High Carbon Price Estimate
2011	0	0	0
2012	10.44	10.00	13.05
2013	17.83	13.37	22.29
2014	21.08	15.81	26.35
2015	24.35	18.26	30.44
2016	27.91	20.93	34.89
2017	31.49	23.62	39.36
2018	35.37	26.53	44.21
2019	39.29	29.47	49.11
2020	43.52	32.44	54.06

[15] The 25% variance is based off of Staff's analysis of the Economic and Allocation Advisory Committee final report (March 2010) and the Updated Economic Analysis of California's Climate Change Scoping Plan (March 2010).

[16] Air Resources Board, 2010. "Proposed Regulation to Implement the California Cap-and-Trade Program, Staff Report: Initial Statement of Reasons," page II-5. (http://www.arb.ca.gov/regact/2010/capandtrade10/capisor.pdf)

TOU and seasonal marginal emissions
Utilities should use the same time periods provided in the chart below, however, the following estimates are provided only as an example and are not intended to be used by the utilities.

Emissions of Marginal Purchases (Tons per MWh)[17]

	Shoulder (7am-11am)	Peak (11am-5pm)	Shoulder (5pm-10pm)	Nighttime (10pm-7am)
June thru August	.55	.62	.66	.53
Sept. thru Nov & Apr. thru May	.53	.61	.63	.52
Dec. thru Mar.	.59	.62	.63	.63

Allocation of GHG from CHP facilities
Method
In order to calculate electricity sector GHG emission for CHP facilities, it is first necessary to determine the percentage of input fuel that is attributable to electricity generation, versus that which is used for the production of heat. In order to make this calculation, two factors are needed: an average Heat Rate (HR) for CHP facilities and an average heat-to-power ratio (HPR) which is the ratio of process heat (thermal) output to the electrical output of the CHP unit. These factors can be used in the following formula to calculate the percentage of fuel attributable to electricity generated by the CHP system:

(HR – 3,413 * HPR) / HR = % fuel attributable to electricity in a CHP system

Once a percentage of fuel input for electricity generation is calculated, a conversion of fuel to emissions, using an emissions factor for natural gas, results in emissions associated with CHP-generated electricity:

(Fuel input * % fuel attributable to electricity) * NG emissions factor =
GHG emissions from electricity

[17] Derived from McCarthy, et al. 2009. "Interactions Between Electric-Drive Vehicles and the Power Sector in California."

Discussion
While it is difficult to determine a precise system average HR for CHP expected to come online in the next decade, the California Energy Commission's (CEC's) CHP Market Assessment[18] provides some guidance. This report assesses the technical potential for CHP in the State and compares this capacity with various market scenarios. The sum of these market scenarios, or the "All-In" case in the report, includes a mix of large and small CHP providing on-site and exported electricity. The weighted average HR for CHP systems in the All-In case is 8,893 Btu/kWh without line losses.[19] (For supply-side resources, a line loss factor may be added to the HR to account for less efficient electricity delivered to the grid.)

We believe the weighted average HR provided in the CEC report's All-In case represents an appropriate estimate for new CHP in the next decade. While the overall market penetration of CHP is higher in the All-In case than what is proposed in this proceeding, the characteristics of the market are reflective of we expect to see. That is, we expect a CHP build out roughly evenly split between new CHP above and below 20 MW, with an export market that is dominated by large systems and a carbon payment that will stimulate the CHP market based on the social value of the emissions reduction provided.

We also considered the power-to-heat ratio (PHR) provided in the CEC report. The report provides the power-to-heat ratio for CHP systems by size range:[20]

CHP Technology	<1 MW	1-5 MW	5-20 MW	>20 MW
PHR	0.68	0.80	1.00	1.20

The All-In case assumes 48.7% of new capacity above 20 MW and 51.3% below 20 MW. (CHP Market Assessment, p.91) Taking a weighted average of the PHR provided in the CEC report results in a ratio of 1.01. The inverse of this number is the heat-to-power ratio:

HPR = 1/PHR = 1 / 1.01 = 0.99

Using an 8,893 HR and 0.99 HPR in the formula provided in the method section above results in 62% of fuel attributable to electricity generation in an average CHP system.

(HR – 3,413 * HPR) / HR = (8,893 – 3,413 * 0.99) / 8,893 = 62%

[18] Combined Heat and Power Market Assessment, Draft Consultant Report, prepared by ICF International, Inc. for the California Energy Commission. (October 2009) http://www.energy.ca.gov/2009publications/CEC-500-2009-094/CEC-500-2009-094-D.PDF
[19] Ibid, p. 85, table 43.
[20] Ibid, p. 56, table 24.

Appendix B

Standardized Planning Assumptions: System Resources

System Resources

Simplified system resources numbers and resources are located in the Technical Attachment Spreadsheets, under tabs "Existing Generation", "OTC", "Retirements", "Additions", and "Net Interchange".

Existing Resources

The existing resource NQC for each IOU's system planning area was drawn from the following resources: 1) the most current available 2011 NQC [21] as of August 2; and 2) the CAISO master generation list [22] as of July 12. These were combined into an excel spreadsheet, which has been posted by ED staff.[23]

One modification was made to the NQC list, which was for the El Cajon Energy Center. El Cajon was modified from the CAISO NQC list to insert a NQC of 46 MW for the unit.

In order to determine the various NQC's staff has created the following list of selected fields for geographic area. Annual NQC values from Column E and August monthly NQC values from Column M were summed. They were then put into one of three categories:

PG&E

Resources designated as "North" in Column D.

SCE

Resources designated as "South" in Column D. SDG&E's resources were subtracted from the total.

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[21] http://www.caiso.com/1796/179688b22c970.html#1b8eaa2643ed0

[22] http://www.caiso.com/14d4/14d4c4ff59780.html

[23] http://www.cpuc.ca.gov/PUC/energy/Procurement/LTPP/ltpp_history.htm

SDG&E
Resources designated as "San Diego" in Column C plus the following three units which connect INSIDE SDG&E territory but OUTSIDE San Diego Local Area. All three connect to the Imperial Valley Substation. These three resources were labeled as "CAISO System" capacity on the final CAISO NQC list but were taken out of SCE service territory and added to SDG&E service territory:

Name of Resource	MW Capacity
TERMOELECTRICA DE MEXICALI 1	595
Ciclo Combinado Mexicali	165
CENTRAL LA ROSITA II COMBINED CYCLE	322

To determine which resources fell into which line for the L&R tables, staff is providing the following matrix. Although some hydro may be RPS-eligible, for existing resources in the system plan, all hydro has been allocated to the "Existing Hydro" line in the L&R tables.

NQC Resource Category	Name in L&R Table
Cogeneration	Existing CHP
Wind	Existing RPS
Solar	Existing RPS
Biomass	Existing RPS
Geothermal	Existing RPS
Peaker	Other Generation
Thermal	Other Generation
Nuclear	Other Generation
Various	Other Generation
Hydro	Existing Hydro

Additional Resources
Plants are characterized as high probability, probable, or other based on the "NewTXandGX" tab of the CAISO OTC scenario analysis tool (dated July 9, 2010).[24] The LADWP and other non-CAISO balancing authority planned additions from the OTC scenario analysis tool are not included in these totals.

There were some additional modifications to the CAISO OTC scenario analysis tool to remove plants that have come online and are in the CAISO NQC list, reclassification of units, and capacity reductions since the development of the CAISO OTC scenario analysis tool. They are listed below:

- Removed Inland Empire Unit 2;
- Removed Orange Grove;
- Reclassified Lodi NCPA from Category 2 to Category 3;
- Reclassified Pittsburg 7 from Category 11 to Category 10;
- Capacity increase of Sentinel from 273 MW to 850 MW[25];
- Capacity reduction of El Segundo Repower from 630 MW to 560 MW[26];
- Added Humboldt Bay Units 1-3 to Category 3 (163 MW in 2010); and
- Capacity reduction of Black Rock Geothermal from 215 MW to 159 MW [27]

Known/High Probability Additions
Known/High Probability Additions are plants under construction (Category 3) in the CAISO OTC scenario analysis tool. This total includes all CAISO balancing authority POU plants.[28]

Utility Probable Planned Additions
Other Utility Probably Planned Additions are resources with Contracts (Category 1) or have approved AFC's (Category 2) according to the CAISO OTC scenario analysis tool.

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[24] http://www.caiso.com/27ce/27ceb7806e50.xlsm
[25] Pursuant to the CEC database: http://www.energy.ca.gov/sitingcases/sentinel/index.html
[26] Pursuant to the CEC database: http://www.energy.ca.gov/sitingcases/elsegundo_amendment/
[27] Pursuant to the CEC database: http://www.energy.ca.gov/sitingcases/saltonsea_amendment/index.html
[28] At the time of analysis, all POU planned additions are currently under construction according to the CEC siting database.

Other Planned Additions
Those resources listed with CPUC approved contracts but do not currently have AFC permits approved according to the CEC "Status of all Projects" list. These resources do not appear in the CAISO's OTC scenario analysis tool, since these resources did not have approved CPUC contracts or approved AFC permits as of the development of the OTC scenario analysis tool.

OTC Retirements
OTC retirements are taken from the State Water Board adopted policy, with the following modifications: Certain OTC plants with permit restrictions or repowering agreements that would become active before the State Water Board adopted policy schedule are placed in earlier years, due to arrangements publically known to the CPUC; OTC in LA Basin remaining as of 2016 and slated to become compliant in 2020 was evenly spread over 2016 – 2019; several plants were assumed to not retire, such as the nuclear units and Moss Landing units 1 and 2. The 15 MW Southbay Gas Turbine is counted under OTC units retiring, although it itself is not an OTC unit.

As to non-OTC aging plants, the scoping memo directs use of the retirements listed in the CAISO's OTC scenario analysis tool, under Category 10.

Net Interchange
The net interchange import values were calculated from the CAISO's *Maximum RA Import Capability for year 2011*, with modifications to name the lines by service area.[29]

[29] http://www.caiso.com/27c6/27c675b81c230.pdf

Forecast Demand

Forecast demand values are taken from the CEC's *Statewide Revised Demand Forecast Forms, Second Edition*.[30] The Technical Attachment Spreadsheet shows the values and lines used in the "Demand Forecast" tab.

System Demand

System demand for each area was taken from Form 1.5b.

Area	Line
NP 26	Total North of Path 26
SP 26	Total SCE TAC Area
SDG&E	SDG&E Service Area

Service Area Demand

Service area demand for each area was taken by summing the following lines from Form 1.5b.

Area	Line
PG&E	Greater Bay Area
PG&E	Non Bay
PG&E	ZP26
SCE	LA Basin
SCE	Big Creek Ventura
SCE	Out of Basin
SDG&E	SDG&E Service Area

Incremental CHP Assumptions

The values presented in the Technical Attachment Spreadsheet are reliant upon several assumptions, as laid out in the Scoping Memo. The calculations are located under the "CHP" tab.

Incremental Energy Efficiency

The incremental EE values are drawn from the CEC's *Incremental Impacts of Energy Efficiency Policy Initiatives Relative to the 2009 Integrated Energy Policy Report Adopted Demand Forecast*, and the *Attachment A: Technical Report*.[31]

[30] http://www.energy.ca.gov/2009_energypolicy/documents/2009-12-02_business_meeting/forms/Chap1Stateforms-RF2-09.xls

[31] http://www.energy.ca.gov/2010publications/CEC-200-2010-001/index.html

Demand Response
The values presented in the Technical Attachment Spreadsheet are reliant upon several assumptions, as laid out in the Scoping Memo. The calculations are located under the "DR" tab.

Appendix C

Standardized Planning Assumptions: Technical Tables

Appendix C contains the technical tables with more detailed information on the values used to populate the L&R Tables.

Demand Forecast (CED 2010-2020, Form 1.5b)										
	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
PG&E Service Area - Greater Bay Area	7,873	7,970	8,066	8,131	8,196	8,263	8,339	8,409	8,477	8,558
PG&E Service Area - Non Bay	9,884	10,061	10,239	10,382	10,527	10,677	10,840	10,998	11,156	11,332
PG&E Service Area (ZP26)	2,436	2,480	2,524	2,559	2,595	2,632	2,672	2,711	2,749	2,793
Total PG&E Service Area	20,193	20,510	20,829	21,071	21,318	21,572	21,851	22,117	22,383	22,683
Total North of Path 26	21,988	22,329	22,668	22,924	23,185	23,454	23,750	24,030	24,310	24,626
SCE Service Area - LA Basin	16,703	16,961	17,233	17,454	17,688	17,928	18,180	18,422	18,667	18,930
SCE Service Area - Big Creek Ventura	4,048	4,111	4,176	4,230	4,287	4,345	4,406	4,464	4,524	4,588
SCE Service Area - Out of Basin	554	562	572	579	587	595	603	611	619	628
Total SCE Service Area	21,305	21,634	21,981	22,262	22,561	22,867	23,189	23,497	23,810	24,146
Total SCE TAC Area	23,785	24,142	24,518	24,823	25,149	25,482	25,833	26,169	26,509	26,875
SDG&E Service Area	4,578	4,658	4,738	4,797	4,856	4,911	4,973	5,032	5,094	5,157

Existing Resources NQC

Source: http://www.caiso.com/1796/179688b22c970.html#1b8eaa2643ed0

Source: http://www.caiso.com/14d4/14d4c4ff59780.html

	North	South	San Diego
Geothermal	835	244	0
Wind	180	140	6
Solar	2	382	0
Biomass	409	150	15
Renewable	**1,426**	**916**	**21**
Hydro	**6,461**	**1,470**	**4**
CHP (Cogen)	**1,888**	**1,489**	**136**
Thermal	10,965	12,083	3,541
Peaker	2,370	1,081	705
Nuclear	2,240	2,246	0
Various	6	98	3
#N/A	1,267	2,021	0
Other	**16,848**	**17,529**	**4,249**
Total	**26,623**	**21,404**	**4,410**

OTC Totals and Forecast Retirements

Source: http://www.caiso.com/27ce/27ceb7806e50.xlsm

Unit Name	Owner	LCR area or NP26/SP26	NQC	Technology	Retirement date	Probability (if different from SWRCB policy)
POTRERO UNIT 3	Mirant	Bay Area	206	STEAM	12/31/2010	High probability (Transbay cable and agreement between CAISO and SF)
Humboldt	PG&E	NP26	135	Steam	12/31/2010	
CONTRA COSTA UNIT 6	Mirant	Bay Area	337	STEAM	12/31/2014	
CONTRA COSTA UNIT 7	Mirant	Bay Area	337	STEAM	12/31/2014	
MORRO BAY UNIT 3	Dynegy	NP26	325	STEAM	12/31/2015	
MORRO BAY UNIT 4	Dynegy	NP26	325	STEAM	12/31/2015	
PITTSBURG UNIT 5	Mirant	Bay Area	312	STEAM	12/31/2017	
PITTSBURG UNIT 6	Mirant	Bay Area	317	STEAM	12/31/2017	
MOSS LANDING UNIT 6	Dynegy	NP26	754	STEAM	12/31/2017	
MOSS LANDING UNIT 7	Dynegy	NP26	756	STEAM	12/31/2017	
Diablo Canyon Unit 1	PG&E	NP26	1,122	Nuclear	Not retiring	
Diablo Canyon Unit 2	PG&E	NP26	1,118	Nuclear	Not retiring	
MOSS LANDING POWER BLOCK 1	Duke Energy	NP26	510	CCGT	Not retiring	
MOSS LANDING POWER BLOCK 2	Duke Energy	NP26	510	CCGT	Not retiring	
North Total OTC			**7,064**			
HUNTINGTON BEACH GEN STA. UNIT 3	AES	LA Basin	225	STEAM	10/1/2011	High probability (CEC emergency permit expires)
HUNTINGTON BEACH GEN STA. UNIT 4	AES	LA Basin	227	STEAM	10/1/2011	High probability (CEC emergency permit expires)
EL SEGUNDO GEN STA. UNIT 3	NRG	LA Basin	335	STEAM	6/1/2014	High probability (Contract with SCE to retire and repower)
EL SEGUNDO GEN STA. UNIT 4	NRG	LA Basin	335	STEAM	6/1/2015	
MANDALAY GEN STA. UNIT 1	RRI	Big Creek-Ventura	215	STEAM	12/31/2020	
MANDALAY GEN STA. UNIT 2	RRI	Big Creek-Ventura	215	STEAM	12/31/2020	
MANDALAY GEN STA. UNIT 3	RRI	Big Creek-Ventura	130	CT	12/31/2020	
ORMOND BEACH GEN STA. UNIT 1	RRI	Big Creek-Ventura	741	STEAM	12/31/2020	
ORMOND BEACH GEN STA. UNIT 2	RRI	Big Creek-Ventura	775	STEAM	12/31/2020	
Alamitos 1	AES	LA Basin	175	STEAM	12/31/2020	
Alamitos 2	AES	LA Basin	175	STEAM	12/31/2020	
Alamitos 3	AES	LA Basin	332	STEAM	12/31/2020	
Alamitos 4	AES	LA Basin	336	STEAM	12/31/2020	
Alamitos 5	AES	LA Basin	498	STEAM	12/31/2020	
Alamitos 6	AES	LA Basin	495	STEAM	12/31/2020	
HUNTINGTON BEACH GEN STA. UNIT 1	AES	LA Basin	226	STEAM	12/31/2020	
HUNTINGTON BEACH GEN STA. UNIT 2	AES	LA Basin	226	STEAM	12/31/2020	
REDONDO GEN STA. UNIT 5	AES	LA Basin	179	STEAM	12/31/2020	
REDONDO GEN STA. UNIT 6	AES	LA Basin	175	STEAM	12/31/2020	
REDONDO GEN STA. UNIT 7	AES	LA Basin	493	STEAM	12/31/2020	
REDONDO GEN STA. UNIT 8	AES	LA Basin	496	STEAM	12/31/2020	
SAN ONOFRE NUCLEAR UNIT 2	SCE/SDG&E	LA Basin	1,122	Nuclear	Not retiring	
SAN ONOFRE NUCLEAR UNIT 3	SCE/SDG&E	LA Basin	1,124	Nuclear	Not retiring	
South Total OTC			**9,250**			
SOUTH BAY GAS TURBINE 1	Dynegy	San Diego	15	CT	12/31/2011	High probability (Agreement between Chula Vista and CAISO)
SOUTH BAY UNIT 1	Dynegy	San Diego	146	STEAM	12/31/2011	High probability (Agreement between Chula Vista and CAISO)
SOUTH BAY UNIT 2	Dynegy	San Diego	150	STEAM	12/31/2011	High probability (Agreement between Chula Vista and CAISO)
ENCINA GAS TURBINE UNIT 1	NRG	San Diego	14	CT	12/31/2017	
ENCINA UNIT 1	NRG	San Diego	106	STEAM	12/31/2017	
ENCINA UNIT 2	NRG	San Diego	103	STEAM	12/31/2017	
ENCINA UNIT 3	NRG	San Diego	109	STEAM	12/31/2017	
ENCINA UNIT 4	NRG	San Diego	299	STEAM	12/31/2017	
ENCINA UNIT 5	NRG	San Diego	329	STEAM	12/31/2017	
San Diego Total OTC			**1,271**			

OTC Totals

North Total OTC	7,064
South Total OTC	9,250
San Diego Total OTC	1,271

OTC Retirements

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
North	341	341	341	1,015	1,665	1,665	3,804	3,804	3,804	3,804
South	452	452	452	787	1,122	2,073	3,024	3,975	4,926	7,004
South (LA Basin gradual retirement)						951	951	951	951	0
San Diego	311	311	311	311	311	311	1,271	1,271	1,271	1,271

Non-OTC Totals and Forecast Retirements				
Source: http://www.caiso.com/27ce/27ceb7806e50.xlsm				
ResName	**LocalArea/SubArea**	**MW LCR**	**Class**	**Proj COD / Retirement Year**
POTRERO UNIT 4	Bay Area	52	10	2010
POTRERO UNIT 5	Bay Area	52	10	2010
POTRERO UNIT 6	Bay Area	52	10	2010
OAKLAND STATION C GT UNIT 1	Bay Area	55	10	2012
OAKLAND STATION C GT UNIT 2	Bay Area	55	10	2012
OAKLAND STATION C GT UNIT 3	Bay Area	55	10	2012
PITTSBURG UNIT 7	Bay Area	682	10	2017
North Total Retirements		**1,003**		
COOLWATER GEN STA. UNIT 1	CAISO System	63	10	2015
COOLWATER GEN STA. UNIT 2	CAISO System	82	10	2015
COOLWATERSTATION3 AGGREGATE	CAISO System	245	10	2015
COOLWATERSTATION4 AGGREGATE	CAISO System	246	10	2015
ETIWANDAGEN STA. UNIT3	LA Basin	320	10	2015
ETIWANDAGEN STA. UNIT4	LA Basin	320	10	2015
South Total Retirements		**1,276**		
San Diego Total Retirements		**0**		

Non-OTC Retirements										
	2011	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
North	156	321	321	321	321	321	1,003	1,003	1,003	1,003
South	0	0	0	0	1,276	1,276	1,276	1,276	1,276	1,276
San Diego	0	0	0	0	0	0	0	0	0	0

Forecast Additions
Source: http://www.caiso.com/27ce/27ceb7806e50.xlsm

ResName	Local Area/SubArea	MW LCR	Class	Proj COD / Retirement Year	Zone
CalRENEW-1(A) / Cal RENEW-1 LLC/Cal RENEW-1 LLC	NP26	5	3	2010	NP26
Copper Mountain Solar 1 Pseudo Tie PILOT/El Dorado Energy LLC	NP26	48	3	2010	NP26
Vaca-Dixon Solar Station/	Bay Area	2	3	2010	NP26
Humboldt 1-3	Humboldt	163	3	2010	NP26
Colusa	NP26	660	3	2011	NP26
Avenal Energy Center	NP26	600	3	2012	NP26
Lodi NCPA	NP26	255	3	2012	NP26
North High Probability / Known Additions		**1,733**			
Russell City	Bay Area	600	2	2012	NP26
Mariposa Peaker Project	Bay Area	184	1	2012	NP26
North Utility Probable Additions		**784**			
Tracy	NP26	145	N/A	2012	NP26
Los Esteros	Bay Area	109	N/A	2013	NP26
Marsh Landing	Bay Area	719	N/A	2013	NP26
North Other Planned Additions		**973**			
Blythe Solar I Project/FSE Blythe 1, LLC	SP26	21	3	2010	SP26
Calabasas Gas To Energy Facility / LACSD/County Sanitation District No. 2 of Los Angeles County	LA Basin	14	3	2010	SP26
Chino RT Solar Project/Southern California Edison	LA Basin	2	3	2010	SP26
Chiquita Canyon Landfill / Ameresco Chiquita Energy, LLC/Ameresco Chiquita Energy, LLC	Big Creek-Ventura	9	3	2010	SP26
Inland Empire Unit 2	LA Basin	0	3	2010	SP26
Rialto RT Solar/Southern California Edison	LA Basin	2	3	2010	SP26
Santa Cruz Landfill G-T-E Facility/Santa Cruz Energy LLC	SP26	1	3	2010	SP26
Sierra Solar Generating Station/Sierra SunTower, LLC	SP26	9	3	2010	SP26
Riverside Energy Resource units 3 and 4	LA Basin	96	3	2011	SP26
Victorville Hybrid	SP26	563	3	2011	SP26
Canyon Power Plant	LA Basin	200	3	2012	SP26
El Segundo Repower	LA Basin	560	3	2013	SP26
FPL Blythe II	SP26	520	3	2013	SP26
South High Probability / Known Additions		1,997			
Walnut Creek Energy Center	LA Basin	500	2	2012	SP26
Delano 2	Big Creek-Ventura	49	1	2015	SP26
Ocotillo	SP26	455	1	2015	SP26
Sentinel	SP26	850	1	2015	SP26
South Utility Probable Additions		1,854			
South Other Planned Additions		0			
Celerity I	San Diego	15	3	2010	SP26
Olivenhain-Hodges Pumped Storage - Unit 1/San Diego County Water Authority	San Diego	20	3	2011	SP26
Olivenhain-Hodges Pumped Storage - Unit 2/San Diego County Water Authority	San Diego	20	3	2011	SP26
Orange Grove/Jpower	San Diego	0	3	2011	SP26
San Diego High Probability / Known Additions		55			
Black Rock Geothermal	San Diego	159	1	2013	SP26
San Diego Utility Probable Additions		159			
San Diego Other Planned Additions		0			

High Probability / Known Additions										
	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
North	878	1,733	1,733	1,733	1,733	1,733	1,733	1,733	1,733	1,733
South	717	917	1,997	1,997	1,997	1,997	1,997	1,997	1,997	1,997
San Diego	55	55	55	55	55	55	55	55	55	55
Utility Probable Additions										
	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
North	0	784	784	784	784	784	784	784	784	784
South	0	500	500	500	1,854	1,854	1,854	1,854	1,854	1,854
San Diego	0	0	159	159	159	159	159	159	159	159
Other Planned Additions										
	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
North	0	145	973	973	973	973	973	973	973	973
South	0	0	0	0	0	0	0	0	0	0
San Diego	0	0	0	0	0	0	0	0	0	0
Total Additions										
	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
North	878	2,662	3,490	3,490	3,490	3,490	3,490	3,490	3,490	3,490
South	717	1,417	2,497	2,497	3,851	3,851	3,851	3,851	3,851	3,851
San Diego	55	55	214	214	214	214	214	214	214	214

Max RA value of Transmission into CAISO

Source: http://www.caiso.com/27c6/27c675b81c230.pdf

BG/MSL Name	Into North or South of CAISO?	Net Import MW	Import ETC Sched MW	Import Unused ETC MW	Maximum Import Capability MW	OTC MW
GONDIPPDC_BG	South	0	0	0	0	4
IPPDCADLN_BG	South	514	0	0	514	647
MCCLMKTPC_MSL	South	0	0	0	0	817
MEADMKTPC_MSL	South	76	0	0	76	551
MEADTMEAD_MSL	South	34	0	0	42	182
MKTPCADLN_MSL	South	251	0	0	251	630
MONAIPPDC_MSL	South	132	0	0	132	236
WSTWGMEAD_MSL	South	131	0	0	131	186
BLYTHE_BG	South	107	0	0	107	210
CASCADE_BG	North	1	0	0	1	80
CFE_BG	South-SD	-55	0	0	90	800
ELDORADO_MSL	South	1158	0	0	1158	1555
IID-SCE_BG	South	315	0	0	502	600
IID-SDGE_BG	South-SD	-159	0	0	0	239
LAUGHLIN_BG	South	-22	0	0	0	0
MCCULLGH_MSL	South	30	0	316	346	2598
MEAD_MSL	South	469	208	505	1000	1460
MERCHANT_BG	South	439	0	0	439	797
NGILABK4_BG	South-SD	-140	0	168	223	366
NOB_BG	South	1469	0	0	1469	1591
PALOVRDE_MSL	South-SD1/2	3139	656	175	3313	3328
PARKER_BG	South	108	63	27	135	220
RNCHLAKE_BG	North	23	23	555	578	1271
SILVERPK_BG	South	0	0	0	0	17
SUMMIT_BG	North	-6	0	0	0	40
SYLMAR-AC_MSL	South	1	0	471	670	1200
VICTVL_MSL	South	0	0	171	289	2400
RDM230_BG	North	0	0	0	0	320
CTW230_BG	North	3	0	0	3	1594
LLNL_BG	North	0	0	0	0	164
PACI_MSL	North	2697	437	43	2739	3127
COTPISO_MSL	North	6	0	0	6	32
TRACY230_BG	North	-207	0	719	719	1366
TRACY500_BG	North	278	37	313	890	4257
NEWMELONP_BG	North	132	132	252	384	384
OAKDALE_BG	North	0	0	174	174	174
STANDIFORD_BG	North	0	0	306	306	306
WESTLYTSLA_BG	North	-100	0	102	102	591
WESTLYLBNS_BG	North	13	0	22	35	600
COTP_MSL	North	117	0	0	117	1531
MARBLE_BG	North	3	3	12	15	15
Total		10956	1559	4330	**16955**	

ADLANTOSP_MSL;ADLANTOVICTVL-SP_MSLFCORNERS5_MSL;MEADELDORD_BG; TRACYHRDLN_BG; VICTVL_BG; CFEROA_MSL; CFETIJ_MSL; FCORNER3_MSL; and SCISL_BG are either redundant entries or can not be scheduled upon

North	South	San Diego*
6,067	8,918	1,970

Line Loss Factors

EnergyEfficiency	
North	9.7%
South	7.6%
San Diego	9.6%

Source: CED 2010-2020, page 50.

Demand Response	
North	11.9%
South	11.2%
San Diego	6.6%

Source: http://www.cpuc.ca.gov/NR/rdonlyres/786A98AC-9F92-4D8D-A071-6A8065944CCE/0/2011IOUDRProgramTotalsFinal728.xls

CHP	
North	7.7%
South	7.7%
San Diego	7.7%

Source: ARB Climate Change Scoping Plan, December 2008, footnote 37

IncrementalCHP

Incremental Values (MW) Adjusted	Common Value: Demand-side (MW)				Common Value: Supply-side (MW)			
		North	South	San Diego		North	South	San Diego
Demand-side savings increased to reflect line losses.	2011	40	36	6	2011	41	31	3
	2012	80	72	12	2012	82	61	6
	2013	120	108	17	2013	123	92	8
	2014	161	144	23	2014	164	123	11
	2015	201	180	29	2015	204	153	14
	2016	241	216	35	2016	245	184	17
	2017	281	252	41	2017	286	215	20
	2018	321	288	46	2018	327	245	22
	2019	361	324	52	2019	368	276	25
	2020	401	360	58	2020	409	307	28

2011 Existing CHP NQC (MW)

	Demand-side	% of D-s	Supply-side	% of S-s
North	843	49.01%	1,888	53.74%
San Diego	122	7.09%	136	3.87%
South	755	43.90%	1,489	42.39%
Total	**1,720**	100.00%	**3,513**	100.00%

Other Assumptions:	MW	
ARB target:	4000	
ARB target adjusted:	3742	
% in IOUs territory:	81.3%	3042.246

Existing supply-side CHP capacity is calculated based on the CAISO NQC Local Area Data for Compliance Year 2011 and the CAISO Generation Capability List as of July 12, 2010.
Existing demand-side CHP capacity is based on the CED 2010-2020 Forecast, Form 1.4.

Total (MW)

	Demand-side	Supply-side	
2010	1,720	3,476	
2011	1,796	3,552	
2012	1,872	3,628	
2013	1,948	3,704	
2014	2,024	3,780	
2015	2,100	3,856	
2016	2,176	3,932	
2017	2,252	4,008	
2018	2,328	4,084	
2019	2,405	4,161	
2020	2,481	4,237	
			1,521
Yearly incre	76.05615	76.05615	
	761	761	1,521

Total: Demand-side (MW)

	North	San Diego	South	
2010	843	122	755	
2011	880	127	788	
2012	918	133	822	
2013	955	138	855	
2014	992	144	889	
2015	1,029	149	922	
2016	1,067	154	955	
2017	1,104	160	989	
2018	1,141	165	1,022	
2019	1,178	171	1,055	
2020	1,216	176	1,089	
	49.0%	7.1%	43.9%	2,481
	37.27636	5.39468	33.38511	

Total: Supply-side (MW)

	North	San Diego	South	
2010	1,868	136	1,489	
2011	1,909	139	1,520	
2012	1,950	142	1,550	
2013	1,991	144	1,581	
2014	2,032	147	1,612	
2015	2,072	150	1,642	
2016	2,113	153	1,673	
2017	2,154	156	1,704	
2018	2,195	158	1,734	
2019	2,236	161	1,765	
2020	2,277	164	1,796	
	53.7%	3.9%	42.4%	4,237
	40.88653891	2.801148989	30.668462	

Total: State-wide (MW)

	Demand-side	Supply-side
2010	1,720	3,513
2011	1,814	3,607
2012	1,907	3,700
2013	2,001	3,794
2014	2,094	3,887
2015	2,188	3,981
2016	2,281	4,074
2017	2,375	4,168
2018	2,468	4,261
2019	2,562	4,355
2020	2,656	4,449
	93.55	93.55
	936	936

Common Value Assumptions

Assumptions:

Ratio of demand-side and supply-side capacity remains constant at 2010 ratio.

Incremental additions are evenly split between supply-side and demand-side.

Values are evenly distributed backwards from 2020.

ARB target adjusted reflects adjustments in the 2009 IEPR demand forecasts.

% in IOU territory is based on the NP and SP 15 sales in 2020 from the CED 2010-2020, Form 1.5a

Common Value: Demand-side (MW)

	North	South	San Diego
2011	37	33	5
2012	75	67	11
2013	112	100	16
2014	149	134	22
2015	186	167	27
2016	224	200	32
2017	261	234	38
2018	298	267	43
2019	335	300	49
2020	373	334	54

Incremental State-wide (MW)

	Demand-side	Supply-side
2010	0	0
2011	94	94
2012	187	187
2013	281	281
2014	374	374
2015	468	468
2016	561	561
2017	655	655
2018	748	748
2019	842	842
2020	936	936

Incremental State-wide (GWh)

	Demand-side	Supply-side
2010	0	0
2011	756	756
2012	1,511	1,511
2013	2,267	2,267
2014	3,022	3,022
2015	3,778	3,778
2016	4,533	4,533
2017	5,289	5,289
2018	6,045	6,045
2019	6,800	6,800
2020	7,556	7,556

Incremental Uncommitted EE										
	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
PG&E Total	**98**	**128**	**388**	**620**	**871**	**1,180**	**1,511**	**1,857**	**2,184**	**2,496**
PG&E	89	117	354	565	794	1076	1377	1693	1991	2275
IOU Programs			116	229	340	443	548	651	752	853
Goals AB1109			25	24	16	35	71	107	122	119
Goals Standards			16	34	63	125	188	261	336	412
BBEES (Low)			56	114	191	272	356	449	547	648
Decay Replacement	89	117	141	164	184	201	214	225	234	243
SCE Total	**44**	**60**	**325**	**565**	**834**	**1,171**	**1,530**	**1,912**	**2,283**	**2,648**
SCE	41	56	302	525	775	1088	1422	1777	2122	2461
IOU Programs			131	258	382	497	614	727	839	951
Goals AB1109			19	17	10	25	53	83	95	93
Goals Standards			18	37	69	147	226	315	406	500
BBEES (Low)			67	137	231	329	432	547	667	792
Decay Replacement	41	56	67	76	83	90	97	105	115	125
SDG&E Total	**3**	**4**	**66**	**121**	**179**	**247**	**321**	**398**	**471**	**544**
SDG&E	3	4	60	110	163	225	293	363	430	496
IOU Programs			37	73	108	140	174	206	238	270
Goals AB1109			5	5	3	7	13	20	23	23
Goals Standards			3	6	11	22	34	48	61	75
BBEES (Low)			9	19	33	47	62	78	96	114
Decay Replacement	3	4	6	7	8	9	10	11	12	14

* Totals are grossed up to include line loss.

All values were taken from the CEC's Incremental Impacts of Energy Efficiency Policy Initiatives Relative to the 2009 Integrated Energy Policy Report Adopted Demand Forecast, and the Attachment A: Technical Report
http://www.energy.ca.gov/ 2010publications/CEC-200-2010-001/index.html

Decay Replacement is from the CEC's report, Table 12, at page 50.
All other values are from the Attachment A, at the following Tables and Pages:
PG&E: BBEES, Table 7-4, at page 139; all other values from Table 7-8, at page 142.
SCE: BBEES, Table 8-4, at page 150; all other values from Table 8-8, at page 153.
SDG&E: BBEES, Table 9-4, at page 161; all other values from Table 9-8, at page 164.
Decay Replacement is from the CEC's report, Table 12, at page 50.

Forecasted Demand Response Programs											
		2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
PG&E	*Total DR**	1,354	1,627	1,670	1,715	1,767	1,816	1,865	1,911	1,956	2,001
	Total DR	1,210	1,454	1,492	1,533	1,579	1,623	1,667	1,708	1,748	1,788
	Non-Emergency Demand Response (DR)	543	741	723	728	736	744	752	759	765	773
	Emergency DR	205	219	230	241	252	263	274	285	297	308
	Total AMI Enabled DR	210	231	259	284	311	336	361	384	406	427
	Non-Event Based DR (PLS/TOU)	252	263	280	280	280	280	280	280	280	280
SCE	*Total DR**	1,641	2,502	2,685	2,749	2,842	2,842	2,842	2,842	2,842	2,842
	Total DR	1,476	2,250	2,415	2,472	2,556	2,556	2,556	2,556	2,556	2,556
	Non-Emergency Demand Response (DR)	213	385	591	782	773	764	754	744	734	724
	Emergency DR	1,251	1,097	929	752	761	771	781	790	800	811
	Total AMI Enabled DR	0	755	883	925	1,009	1,009	1,009	1,009	1,009	1,009
	Non-Event Based DR (RTP)	13	13	13	13	13	13	13	13	13	13
SDG&E	*Total DR**	210	226	270	277	285	289	293	298	302	302
	Total DR	197	212	253	260	267	271	275	280	283	283
	Non-Emergency Demand Response (DR)	165	185	230	241	248	252	255	260	263	263
	Emergency DR	32	27	23	19	19	19	20	20	20	20
	*Total AMI Enabled DR***	0	0	0	0	0	0	0	0	0	0
	Non-Event Based DR	0	0	0	0	0	0	0	0	0	0
* Totals are grossed up to include line loss.											
** SDG&E included AMI enabled DR in the 2010 Load Impacts.											

AMI decisions are as follows: D.09-03-026 (PG&E), D.08-09-039 (SCE), and D.0704-043 (SDG&E)
PG&E Values:
PG&E's updated 2010-2010 ex-ante forecast, PG&E's LI forecast which included: residential and non-residential TOU, non-resident ial default PDP, residential voluntary PDP.
PG&E's emergency DR included BIP only assuming the Smart AC will have a "price trigger" (Application pending)
PG&E's AMI enabled DR is PTR and PCT
However, since PG&E did not provide any ex-ante forecast for some AMI-related DR programs, ED Staff developed the AMI-related MW from the AMI upgrade decision (D.09-03-026) and PG&E's workpapers.
SCE Values:
SCE's April 22, 2010 Ex-ante Portfolio Forecast, SCE's LI which included: non-residential default CPP
SCE emergency DR had the LI set at the cap, assuming AC cycling will have a "price trigger", and are based on the percentage from the Phase 3 settlement, with a peak load forecast consistent with the 2010 LTPP
SCE's AMI enabled DR includes CPP, PTR, and PCT
However, since SCE did not provide any ex-ante forecast for AMI-related DR programs, ED Staff developed the AMI-related MW from the SCE's AMI testimony & SCE AMI testimony (SCE-4 Errata) and the settlement adopted in D.08-09-039.
SDG&E Values:
SDG&E's April 2010 ex-ante portfolio forecast.
Emergency DR is set at the cap, assuming AC cycling will have a "price trigger", and are based on the percentage from the Phase 3 settlement.
In its supplemental comments, SDG&E indicated that the forecast for PTR reflects a degree of uncertainty since it is a new program.
However, SDG&E's forecast is in line with the estimated MWs in its AMI settlement.

Load for RPS Calculation
Values are in GWh

"BASE CASE" LOAD	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Total Statewide Retail Deliveries	276,509	269,250	269,705	272,572	276,407	280,650	283,767	286,908	290,084	293,410	296,617	299,869	303,253
Pumping loads	11,715	13,331	13,324	13,339	13,358	13,394	13,417	13,440	13,462	13,490	13,511	13,533	13,556
Sales from LSEs serving <200 GWh/yr*	2,008	1,969	1,981	2,004	2,031	2,063	2,089	2,115	2,143	2,172	2,201	2,229	2,260
EE Decay replacement	169	313	488	693	913	1,093	1,254	1,391	1,504	1,598	1,684	1,769	1,861
EE Uncommitted - IOU	0	0	0	0	0	1,613	2,823	3,983	5,490	7,294	9,101	10,607	11,867
EE Uncommitted - non-IOU, RPS obligated	0	0	0	0	0	391	684	965	1,330	1,767	2,204	2,569	2,874
EE Uncommitted - non-IOU, non-RPS obligated**	0	0	0	0	0	12	22	31	43	57	71	83	93
Incremental DG	0	0	0	0	0	0	0	0	0	0	0	0	0
CHP	0	0	0	756	1,511	2,267	3,022	3,778	4,533	5,289	6,045	6,800	7,556
TOTAL RPS Eligible Retail Sales	**262,617**	**253,636**	**253,912**	**255,780**	**258,594**	**259,830**	**260,478**	**261,236**	**261,622**	**261,800**	**261,870**	**262,362**	**263,280**
33% RPS Requirement												Expected	**86,882**

"LOW" LOAD	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
"Base Case Load" RPS Eligible Retail Sales	262,617	253,636	253,912	255,780	258,594	259,830	260,478	261,236	261,622	261,800	261,870	262,362	263,280
10% reduction	-26,262	-25,364	-25,391	-25,578	-25,859	-25,983	-26,048	-26,124	-26,162	-26,180	-26,187	-26,236	-26,328
TOTAL RPS Eligible Retail Sales	**236,356**	**228,273**	**228,521**	**230,202**	**232,735**	**233,847**	**234,430**	**235,112**	**235,460**	**235,620**	**235,683**	**236,125**	**236,952**
33% RPS Requirement													**78,194**

"HIGH" LOAD	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
"Base Case Load" RPS Eligible Retail Sales	262,617	253,636	253,912	255,780	258,594	259,830	260,478	261,236	261,622	261,800	261,870	262,362	263,280
10% increase	26,262	25,364	25,391	25,578	25,859	25,983	26,048	26,124	26,162	26,180	26,187	26,236	26,328
TOTAL RPS Eligible Retail Sales	**288,879**	**279,000**	**279,304**	**281,358**	**284,454**	**285,813**	**286,526**	**287,359**	**287,784**	**287,980**	**288,057**	**288,598**	**289,608**
33% RPS Requirement													**95,570**

All EE values were taken from the CEC's Incremental Impacts of Energy Efficiency Policy Initiatives Relative to the 2009 Integrated Energy Policy Report Adopted Demand Forecast, and the Attachment A: Technical Report, available here:
http://www.energy.ca.gov/ 2010publications/CEC-200-2010-001/index.html

Decay Replacement is from the CEC's report, Table 12, at page 50.
All other values are totalled from Attachment A to the CEC's Report, at the following Tables and Pages:
BBEES (Low Goals Case): Table 4-15, at page 62.
IOU Programs, AB 1009, Title 24 & Fed Standards (Mid Goals Case): Table 4-15, at page 62.

For Incremental CHP, see the Statewide tables under the "CHP" tab.

Non-IOU savings - the total of "non-IOU, RPS obligated" and "non-IOU, non-RPS obligated" - equals 25% of IOU savings, since the three large IOUs are roughly 75% of statewide electricity consumption (CEC report, at page 4.)

* LSEs with annual retail sales of less than 200 GWh/yr are assumed to be exempt from the RPS, consistent with the Air Resource Board's proposed regulations for a 33% Renewable Electricity Standard.

** These values represent the portion of the total non-IOU EE Uncommitted savings that are assumed to be achieved, based on their proportional shares of non-IOU load, by LSEs with annual retail sales less than 200 GWh/yr. Because these entities' retail sales have already been subtracted from the RPS obligation, their assumed energy efficiency reductions are not subtracted.

RPS NQC

Values are in MW

		2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
33% Trajectory, Base Case Load	*North*	20	94	123	263	414	760	904	904	904	904
	South		6	174	423	1,768	2,043	2,749	2,749	3,819	3,819
	San Diego				143	440	465	465	465	508	508
	Connectionto POU Systems					44	44	366	675	675	675
33% Time-Constrained, Base Case Load	*North*	20	108	202	294	390	719	719	719	719	719
	South		6	174	451	1,843	2,118	2,315	2,315	2,315	2,315
	San Diego				14	74	74	74	74	74	74
	Connectionto POU Systems					44	44	44	44	44	44
33% Cost-Constrained, Base Case Load	*North*	20	94	123	278	359	704	853	853	853	853
	South		6	174	427	1,148	1,423	1,620	1,620	1,620	1,620
	San Diego				45	342	370	418	909	909	909
	Connectionto POU Systems					44	44	44	44	44	44
33% Environ.-Constrained, Base Case Load	*North*	20	94	149	269	283	623	1,257	1,257	1,257	1,257
	South		6	174	423	1,127	1,402	1,641	1,641	1,641	1,641
	San Diego				23	157	157	157	317	317	317
	Connectionto POU Systems					44	44	53	53	53	53
20% Trajectory, Base Case Load	*North*	20	94	123	263	263	609	647	647	647	647
	South		6	174	423	992	1,268	1,465	1,465	1,465	1,465
	San Diego				38	142	146	146	146	146	146
	Connectionto POU Systems					44	44	53	110	110	110
33% Trajectory, High Load Sensitivity	*North*	20	94	123	263	414	760	904	904	904	904
	South		6	174	423	1,768	2,043	2,749	2,749	3,850	3,850
	San Diego				143	440	465	465	465	1,295	1,295
	Connectionto POU Systems					44	44	366	675	675	675
33% Trajectory, Low Load Sensitivity	*North*	20	94	123	263	414	760	798	798	798	798
	South		6	174	423	1,768	2,043	2,241	2,241	2,267	2,267
	San Diego				143	440	465	465	465	465	465
	Connectionto POU Systems					44	44	338	647	647	647

(END OF ATTACHMENT 1)