Gretel Smith, Esq.
State Bar No. 272769
Staff Counsel
Helping Hand Tools
P.O. Box 152994
San Diego, CA 92195
619-822-6261
Attorney for Rob Simpson and Helping Hand Tools

BEFORE THE ENERGY RESOURCES CONSERVATION AND DEVELOPMENT COMMISSION OF THE STATE OF CALIFORNIA

1516 NINTH STREET, SACRAMENTO, CA 95814

1-800-822-6228 – WWW.ENERGY.CA.GOV

APPLICATION FOR CERTIFICATION	**Docket No. 11-AFC-01**

Rob Simpson's and Helping Hand Tools Supplement Comments to the PMPD
Part 2 of 5

The following 11 emails and attachments were submitted to all parties on or about September 5, 2012. Mr. Simpson and Helping Hand Tools submits this document for public comment.

Respectfully submitted.

Date: September 11, 2012 /s/ Gretel Smith , Esq.

Gretel Smith, Esq.

Attorney for Helping Hand Tools &

Rob Simpson

Email 2 of 11

Email 2 of 11

From: <rob@redwoodrob.com>
Date: Wed, Sep 5, 2012 at 9:04 AM
Subject: Pio Pico PMPD comments Rob Simpson 2 Docket Number 11-AFC-01
To: "Scott, Diane@Energy" <Diane.Scott@energy.ca.gov>, "djenkins@apexpowergroup.com" <djenkins@apexpowergroup.com>, "MFitzgerald@sierraresearch.com" <MFitzgerald@sierraresearch.com>, "jamckinsey@stoel.com" <jamckinsey@stoel.com>, "mafoster@stoel.com" <mafoster@stoel.com>, "e-recipient@caiso.com" <e-recipient@caiso.com>, "rob@redwoodrob.com" <rob@redwoodrob.com>, "Gretel.smith79@gmail.com" <Gretel.smith79@gmail.com>, "swilliams@scmv.com" <swilliams@scmv.com>, "Peterman, Carla@Energy" <Carla.Peterman@energy.ca.gov>, "Douglas, Karen@Energy" <Karen.Douglas@energy.ca.gov>, "Renaud, Raoul@Energy" <Raoul.Renaud@energy.ca.gov>, "Bartridge, Jim@Energy" <Jim.Bartridge@energy.ca.gov>, "Lemei, Galen@Energy" <Galen.Lemei@energy.ca.gov>, "Nelson, Jennifer@Energy" <Jennifer.Nelson@energy.ca.gov>, "Solorio, Eric@Energy" <Eric.Solorio@energy.ca.gov>, "kevinw.bell@energy.ca.gov" <kevinw.bell@energy.ca.gov>, "Allen, Eileen@Energy" <Eileen.Allen@energy.ca.gov>, Energy - Public Adviser's Office <PublicAdviser@energy.ca.gov>

Docket Number 11-AFC-01
Rob Simpson
Director
Helping Hand Tools (2HT)
1901 First Avenue, Ste. 219
San Diego, CA 92101
Rob@redwoodrob.com

1.18.12PDOC.Comments.pdf
1513K View Download

Attachment 1 of 1 to

Email 2 of 11

April Rose Sommer
Attorney at Law
P.O. Box 6937, Moraga, CA 94570
p (510) 423-0676 f (510) 590-3999
Environmental Litigation AprilSommerLaw@yahoo.com

January 18, 2012

Steven Moore
San Diego Air Pollution Control District
10124 Old Grove Road
San Diego, CA 92131.

Re: Preliminary Determination of Compliance for proposed development of the Pio Pico Energy Center (District Application No. APCD2010-APP-001251),

Dear Mr. Moore:

Please accept the following comments on the proposed Preliminary Determination of Compliance for Pio Pico Energy Center submitted on behalf of my clients Rob Simpson and Helping Hand Tools. Helping Hand Tools is a humanitarian and environmental non-profit corporation that extensively supports involvement in the licensing proceedings of new natural gas power plants in California.

I. APPLICATION OF THE PROPER RULES

Under Section 172 of the Clean Air Act (CAA), 42 U.S.C. § 7502, the San Diego Air Pollution Control District (the District) may issue non-attainment New Source Review permits as set forth in the approved California State Implementation Plan (CA SIP), sections specific to San Diego County. The District's Preliminary Determination of Compliance (PDOC) for the Pio Pico Energy Center (Pio Pico) functions as a draft non-attainment NSR permit.

The District's rules incorporate the CA SIP but have made revisions to SIP language that have not been approved by the EPA. Therefore, it is inappropriate for the SDAQMD to reference its owns rules where these rules purport to implement the SIP in issuing any NSR permit. Until revisions are approved, the official version of the SIP is the applicable law, not the District's unapproved revisions of the SIP. "A revision of a plan, or any portion thereof, shall not be considered part of an applicable plan until approved by the Administrator in accordance with this subpart." 40 CFR § 60.28(c).

Following the basic premises of federalism, the permit must comply first with the Clean Air Act, then with the terms of the CA SIP as they effectuate the CAA, and then with any non-conflicting

District Rules. The District has not complied with the CAA in a number of instances, some of which are described below. The PDOC must be revised to fully comply with the CAA and all terms of the CA SIP before a final version is approved.

II. THE DISTRICT CANNOT ISSUE A NON-ATTAINMENT NSR PERMIT FOR A SINGLE CYCLE POWER PLANT AND COMPLY WITH THE CAA, THE CA SIP, OR DISTRICT RULES

a. In violation of the Clean Air Act, this permit has been drafted without any alternatives analysis

The purported alternatives "analysis" is woefully inadequate and fails to meet the requirements of the Section 173 of the Clean Air Act, 42 U.S.C. § 7503. Pursuant to section 173(a)(5), a permit to construct and operate may be issued only if "an analysis of alternative sites, sizes, production processes, and environmental control techniques for such proposed source demonstrates that benefits of the proposed source significantly outweigh the environmental and social costs imposed as a result of its location, construction, or modification."

The entire "analysis" offered is as follows:

> Rule 20.3(e)(2) – Alternative Siting and Alternatives Analysis
> The Applicant has provided an analysis of various alternatives to the project. This analysis included a No Project alternative, alternative sites, and alternative technologies. Since all of San Diego County is currently classified as non-attainment for ozone, an alternative location within San Diego would not avoid the project being located in a non-attainment area.

PDOC, page 25.

The District's own cited rule, Rule 20.3(e)(2), generally mirrors the language of the CAA:

> (2) Alternative Siting and Alternatives Analysis
> The applicant for any new major stationary source required to satisfy the LAER provisions of Subsection (d)(1) or the major source offset requirements of Subsection (d)(5), shall conduct an analysis of alternative sites, sizes, production processes, and environmental control techniques for such proposed source which demonstrates that the benefits of the proposed source outweigh the environmental and social costs imposed as a result of its location or construction. Analyses conducted in conjunction with state or federal statutory requirements may be used.

Yet the PDOC pretends as if the District must only consider alternative sites for the project. The PDOC presents no analysis, discussion, or evidence that an alternatives analysis was conducted. Had such an analysis been conducted, the antiquated single cycle production process would not have been permitted over the use of rapid response combined cycle technology.

The Applicant's AFC does make a quick mention of combined cycle systems but the possibility of using such technology is immediately dismissed based on misinformation about the technology:

> Several proven CT configurations exist. Principal among these are (1) simple-cycle, (2) combined cycle, and (3) cogeneration. . . Combined-cycle facilities are efficient, but they cannot meet the multiple-fast startups required. SDG&E specifically asked for peaking generation in the RFO, and combined-cycle units will not meet this defined need. Simple-cycle CTs can meet these demands, and do so relatively cleanly and reliably. Simple-cycle machines, however, are not as efficient as combined-cycle machines. Thus, a trade-off is made for quick startups and load following capability versus base-load efficiencies of combined-cycle.

ACF, page 4-5.

It simply is not true that rapid response combined cycle is incapable of meeting multiple-startups – as the name implies, this is the point of the technology. As the CEC staff explains, "the new rapid response – combined cycle design provides comparable start-up rates to simple cycle units with the efficiency of a combined cycle power plant." El Segundo Power Plant, CEC Staff Assessment, page 16. This is discussed in detail below. This technology has been approved for use by the CEC in at least four cases and the PDOC fails to comply with the CAA in not analyzing, and ultimately, requiring this technology over single cycle.

<u>b. Single Cycle Is No Longer BACT And Does Not Achieve LAER</u>

Single cycle technology is not the best available technology and does not produce the lowest achievable emission rates generally, and specifically, for NOx. Rapid response combined cycle technology is far more efficient and produces lower emissions than single cycle while providing the same fast start desired for so called "peaker plants." As the CEC put it, a plant utilizing rapid response combined cycle is "a state-of-the-art power plant with BACT (BACT) pollution controls." CEC El Segundo 2010 Amendment Decision, page 15. While it may have been true at one point that single cycle technology was able to start much quicker than combined cycle, those days have long since passed. There simply is no justification for building dirty, wasteful single cycle plants based on outdated technology; doing so violates the CAA's crystal clear mandate that BACT and LAER must be implemented.

Rapid response combined cycle technology is currently in use throughout the United States and around the world. See attachment A for more information. In California, the CEC has approved the use of the technology for at least two plants – El Segundo and Lodi - and two modifications – Henrietta and Hanford. The CEC Commission and staff have definitively endorsed rapid response combined cycle as a much more efficient and environmentally friendly alternative to single cycle plants:

"The new rapid response – combined cycle design provides comparable start-up rates to simple cycle units with the efficiency of a combined cycle power plant; specifically, each unit can deliver 150 MWs of capacity within 10 minutes of startup." El Segundo Staff Assessment, page 16.

"The change will be beneficial to the public because the new facility would make the project considerably more efficient and more flexible from an operational standpoint. The new low-emission, dry-cooled combustion turbine equipment significantly reduces air pollutants from the combustion process, and will decrease environmental impacts. The rapid start capability also complements wind and solar renewable generation by providing reliable localized generation that can quickly respond should wind or solar resources not be available during peak electrical demand periods." CEC Order Approving El Segundo 2010 Amendment, page 2.

"The combined-cycle will provide superior fuel economy and environmental performance compared to the present simple-cycle configuration." El Segundo CEC Staff Assessment, page 9.

"Combined cycle technology results in the fast-start capability of a simple cycle gas turbine coupled with enhanced efficiency." CEC Lodi Decision, page 70

"In conclusion, the uncontradicted evidence shows that the LEC Project will increase NCPA's power supply as well as its dispatch and rapid start capabilities, and displace operation of older, less efficient power plants. It will provide these benefits in the most fuel efficient manner practicable, without creating adverse effects on energy supplies or resources." CEC Lodi Decision, page 71

Fuel efficiency

The Hanford Energy Park Peaker Project and Henrietta Peaker Project were both approved for conversion from single to combined cycle in 2010. Both Hanford and Henrietta had operated as 95 MW plants prior to the conversion. The conversions upped the capacity of each 25 MW to 120 MW ***with no additional fuel use.*** This is a 26% increase in capacity using the exact same amount of fuel resulting in an astounding 26% increase in efficiency.

Emissions – Nitrogen

A specific example of the superior efficiency and environmental performance of rapid response combined cycle technology, especially important in the context of these proceedings, is a marked decrease in NOx emissions. Rapid start combined cycle technology makes it possible to control oxides of nitrogen (NOx) emissions to less than 2 ppmvd at 15% O2 – all plants approved by the CEC using rapid response combined cycle technology (El Segundo, Lodi, Henrietta, Hanford) were approved with less than 2 ppmvd as the emissions limit for NOx as BACT achieving LAER. 2 ppmvd is standard as BACT for combined cycle plants (e.g. "A review of recent combined-cycle CTG NOx LAER determinations demonstrates that 2.0 ppm is the most stringent NOx limit to date, with varying averaging times." Palmdale; " The District is also proposing to establish a BACT emissions limit in the permit of 2.0 ppmvd @ 15% O2 (averaged over one hour), which is the most stringent limit that has been achieved in practice at any other similar facility and is the most stringent limit that would be technologically feasible." Avenal.)

The Henrietta upgrade made it possible to control oxides of nitrogen (NOx) emissions to less than 2 ppmvd. When it was initially approved in 2002 as a single cycle plant, the NOx emission limit was 3.6 ppmvd. The combined cycle allows for a >44% decrease in NOx emissions!

The story is even a little better at Hanford. The 2001 single cycle NOx emissions limit was 3.7 ppmvd and the 2010 combined cycle limit was less than 2 ppmvd. This is a >46% decrease in NOx emissions. (CEC 2001, San Joaquin Air Pollution Control District FDOC).

For Pio Pico, the District claims that 2.5 ppmvd NOx is appropriate based on comparisons with "a number of simple-cycle power plants of comparable size." PDOC, page 16. But this presupposes that a valid alternatives analysis concluded, based upon the statutory mandates of the CAA, that single cycle is appropriate. This analysis hasn't been done and there is no way that it could be done and conclude, based upon the actual evidence, not just the applicant's misstatement of facts, that there is any justification for single cycle.

The lowest achievable emissions rate is 2 ppmvd and any higher rate is not in compliance with 42 U.S.C. § 7503(a)(2). This rate is achieved by rapid response control technology, the best available control technology. The PDOC presents absolutely no evidence to the contrary and the Applicant's only passing comment on the issue serves only to disseminate misinformation as to the capabilities of the available technology.

II. PROPOSED OFFSETS ARE ILLEGAL

The law on emissions reduction offsets is quite clear – a "offset" that doesn't actually offset anything is no offset at all. Pursuant to 42 U.S.C. § 7503(c)(1) "The owner or operator of a new or modified major stationary source may comply with any offset requirement in effect under this part for increased emissions of any air pollutant only by obtaining emission reductions of such air pollutant from the same source or other sources in the same nonattainment area . . ."

The CA SIP Rule 20.1(c)(2) establishes the common sense rule that emissions reductions that are required by law are, obviously, not offsets: "Emission reductions resulting from measures contained in the State Implementation Plan (SIP), or required by adopted federal, state, or district law, rules or regulations shall not be allowed as emissions offsets." This is precisely what the

PDOC proposes – to use reductions required by federal and state law as offsets. A simple google search reveals this scheme and the District should be ashamed of itself for endorsing such a patently illegal plan. The PDOC proposes the following:

Summary of Emission Reduction Credits (ERCs) Proposed as Offsets

ERC Certificate number	Original Issue Date	Type	Pollutant	ERC Amount, tons	NOx Equivalent Amount,	Location of Emission Reductions	Description Emission	Current Owner
00019-01	4/8/2011	A	NOx	29.2	29.2	990 Bay Blvd Chula Vista, CA	Shut down of Units 3 &	Dynergy South Bay, LLC
00019-03	4/8/2011	A	VOC	8.1	8.1	990 Bay Blvd Chula Vista, CA	Shut down of Units 3 &	Dynergy South
00039-01	8/11/2011	A	NOx	24.6	24.6	990 Bay Blvd Chula Vista, CA	Shut down of Units 1 & 2	Dynergy South
00039-03	8/11/2011	A	VOC	5.6	5.6	990 Bay Blvd Chula Vista, CA	Shut down of Units 1 & 2	Dynergy South
090819-01 090819-02	9/22/2006	A	VOC	18.7	18.7	7757 St. Andrews Ave San Diego, CA 92154	Permanent reduction in emissions from furniture coating	IG&E GP, LLC

All but one of the proposes credit sources is from the "shut down" of the South Bay Power Plant that was ordered based upon violations of state and federal law. Units 1,2,3 and 4 were shut down upon order from the San Diego Regional Water Board to cease the use of once thru cooling, a process by which the plant could not operate without: "On December 16, 2009, the San Diego Water Board ratified modifications to Order No. R9-2004-0154 to 1) reflect a change in responsible party to Dynegy South Bay, LLC, 2) terminate discharges from Units 3 and 4 as of December 31, 2009, and 3) terminate discharges from Units 1 and 2 as of December 31, 2010 or on the date that the California Independent System Operator (CAISO) determines the units are no longer needed as reliability must-run (RMR) units, whichever occurs first. Order No. R9-2004-0154 cannot be extended to allow discharges from Units 1 and 2 beyond December 31, 2010." Attachment B. In other words, the South Bay Power Plant shut down as a result of being denied an NPDES permit, without which it would be illegal for it to operate.

Order No. R9-2004-0154 explains, "The waste discharge requirements in this Order implement all necessary terms and conditions of an NPDES permit for the combined discharge of heated once-through cooling water and other waste discharges from the South Bay Power Plant to San Diego Bay, and this Order is issued in lieu of an NPDES permit pursuant to Chapter 5.5, commencing with Section 13370, of the Porter Cologne Water Quality Control Act in Division 7 of the California Water Code and U.S. EPA approval of the state's water quality control program under subdivision (b) and (c) of Section 402 of the Clean Water Act [33 U.S.C. 1342(b) and (c)]." CAISO determined in September 29, 2010 that units 1 and 2 were no longer needed as reliability must-run units as of December 31, 2010 and those units were thus shut down. Attachment C.

The PDOC claims that credits were issued for the shut down of units 3 and 4 on April 8, 2011 and for units 1 and 2 August 11, 2011. This was long after the units had already been shut down by a state agency for failure to comply with state and federal law. Clearly, the emissions reductions from the shut down of the South Bay Power Plant were "required by adopted federal, state, or district law, rules or regulations" and therefore, "shall not be allowed as emissions offsets."

Thank you,

April Rose Sommer

Attachment A

Consultant's Report

Anaheim Canyon Power Project: Combined Cycle versus Simple Cycle Peaking Power Plant Configuration

DOCKET	
07-AFC-9	
DATE	May 2009
RECD.	May 26 2009

Prepared for

The City of Yorba Linda

Prepared by

Jerald A. Cole

Independent Consultant

May 2009

Synopsis

The City of Anaheim (Anaheim) has proposed to build a 200 MW natural gas fired turbine generator peaking power plant, the Canyon Power Project, on property located near the north central border of Anaheim adjacent to the City of Placentia and proximate to the City of Yorba Linda (Yorba Linda). The power plant is proposed to consist of four General Electric LM6000 Sprint PC turbine generator sets equipped with ammonia selective catalytic reduction for NOx control and CO oxidation catalyst for reduction of carbon monoxide and unburned hydrocarbon emissions. The proposed plant design represents current state of the art in terms of simple cycle power plant efficiency and emissions control, and has been designed to comply with all applicable air quality and plant efficiency standards.

Elected officials and the City Manager's Office in Yorba Linda have expressed concern about this plant and have requested an independent evaluation of the risks the plant poses to Yorba Linda residents. The expressed rationale for Yorba Linda's concern is simple: prevailing winds from the plant will carry the exhaust plume across the adjacent communities of Placentia and Yorba Linda. This will carry the plume across numerous schools, hospitals and regions of low-income housing. This means that any public health or other risk posed by the plant will most likely be borne by the residents of Placentia and Yorba Linda, while the benefits of the plant will largely be enjoyed by the residents of Anaheim. Some Yorba Linda officials and residents have stated that they are not objecting to construction of the plant, and have even recognized the need for additional electric capacity to support development of renewables and eventual displacement of out of state coal generation capacity. However, there has been express concern that the Canyon Power Project, as proposed, will not be as clean as it could be.

On 25 February 2009 the South Coast Air Quality Management District (SCAQMD) issued a notice of intent to issue a final permit to construct for the Canyon Power Project, subject to public comments received within 30 days, or a hearing request received within 15 days. This prompted the Yorba Linda City Manager to request a briefing on the power plant during a planned meeting of the Yorba Linda City Council.

At a meeting of the Yorba Linda City Council on Tuesday, 3 March 2009 it was reported that the health risks posed by the proposed plant should be *de minimus* and well within normally acceptable limits. However, it was also pointed out that even though pollution from the power plant was small, reducing that pollution even further might be less expensive than other options for reducing pollution in the area. It was further suggested that one straightforward approach to reducing pollution from the plant might be simply to increase its efficiency by designing it as a combined cycle, rather than simple cycle plant.

City officials (the mayor and city council, via the city manager's office) responded by requesting a rapid turnaround analysis of the permitting process of the Canyon Power Project to determine whether there might be justification for requesting a public hearing to air concerns and suggest alternatives for the project. That analysis yielded some seeming irregularities in the permitting process – in particular a distinct lack of transparency during the period from about July 2008 through February 2009. Negotiations with regulators during this period were spurred by a court ruling that voided the ability of the Canyon Power Project to obtain PM10 credits from the Priority Reserve Account of the SCAQMD. The Canyon Power Project at this time negotiated and received approval for substantive changes in the operating profile of the plant that eliminated the need to access the Priority Reserve. These changes and approvals were done without an opportunity for input from the public or other intervenors. As of early March 2009, most of the documents pertaining to these negotiations were still not a part of the public record and it was only in two documents released by the CEC in mid January[1] and late February 2009[2] that the existence of many of these documents was acknowledged.

This information, along with a suggestion that the Canyon Power Project may have improperly dismissed the option of installing a combined cycle power plant (citing specific examples of combined cycle peaking power plants elsewhere in the U.S.) were submitted to SCAQMD by Yorba Linda in a formal request for a public hearing on 12 March 2009.

In response to the Yorba Linda request for a public hearing, Anaheim prepared a document entitled "Canyon Power Plant Simple Cycle Plant Justification". That document was dated 16 April 2009 and submitted to the CEC on that date by the law firm Galati Blek LLP for inclusion in the project docket. The document was released to the public by the CEC on 22 April 2009.

Upon review of the Anaheim "Justification" document Yorba Linda requested that a more in depth independent review be conducted and a report prepared that would support an alternative interpretation of material facts concerning whether a combined cycle configuration could meet the requirements of the Canyon Power Project, while better protecting the residents of Yorba Linda and other affected communities. The following report is intended to address Yorba Linda's request.

[1] "Southern California Public Power Authority's Canyon Power Plant Status Report #1 Docket No. 07-AFC-9", dated November 5, 2008, and noted as received into the CEC docket on November 5, 2008. However, this document did not appear in the public record until 14 January 2009 and shows up on the CEC website with the filename 2009-01-14_CANYON_STATUS_REPORT_1.pdf

[2] "CANYON POWER PLANT (07-AFC-9) STATUS REPORT #3. February 26, 2009.

Introduction

Combustion turbines, also known as gas turbines (to distinguish them from steam turbines and water turbines) were originally developed in the 1930s and 1940 to power "jet" aircraft. As the technology matured, however, it became obvious that in some applications combustion turbine technology might have advantages over reciprocating engines and steam turbines for producing mechanical power, rather than jet propulsion. The introduction of combustion turbines for electricity generation was slow to take hold for a number of reasons. By the 1970s, however, combustion turbine generators became commonplace, and by the 1980s they began to replace conventional steam boiler technology for large power generation and even to replace reciprocating engines for smaller distributed and backup power generation.

The reasons for this change were largely economic. Combustion turbines, while not yet as efficient as extant boilers had become, could be much less expensive to build and install. During a period of relatively low fossil fuel costs this could be advantageous. And in comparison with reciprocating engines, combustion turbines were more suited to scaling to very large sizes, while also being able use a range of liquid and gaseous fuels without expensive modifications to the engine.

A solution to the lower efficiency of gas turbines had also long since been identified in the form of combined cycle technology. Combined cycle, in the simplest of terms is the use of two or more different thermodynamic cycles to generate power. An example familiar to many is using the hot high pressure exhaust of an automobile engine to drive a turbocharger. The turbocharger in turn compresses air for the engine, which increases engine power and improves fuel efficiency.

The advent of combined cycle for combustion turbines marked a new paradigm in electrical power generation. By combining the attributes of gas turbines with well-established steam boiler technology, electric power generation became significantly cleaner, more efficient, lower in installed capital cost, and easier and faster to install. Turbines could be delivered "just in time" to a prepared site, and as gas turbines, out of necessity, came in standardized configurations; it became practical to construct their associated boilers in standard configurations as well. In order to distinguish combined cycle turbines from their predecessors, the terms "combined cycle gas turbine" and "simple cycle gas turbine" came into common usage.

At its simplest, a combined cycle gas turbine, or CCGT consists of the following:

- a combustion turbine that drives an electric generator
- a boiler that uses the combustion turbine exhaust as its source of heat for generating steam; and
- a steam turbine that drives an electric generator

In other words, as with the automobile turbocharger example, the hot gases generated in the gas turbine get used twice: first to produce power in the gas turbine itself, and secondly to produce steam which powers a steam turbine.

In a combined cycle power plant it is also common to have auxiliary burners in the turbine exhaust to raise the temperature upstream of the boiler; thereby increasing power output further, though with some reduction in total fuel efficiency. When operated close to 100 percent of their full power output (i.e. near full load), the latest CCGTs have exceeded 60 percent efficiency, roughly twice that of simple cycle turbine technology of 30 years ago. Depending on the system design, a combined cycle power plant scaled for the Canyon Power Project would be about 20 – 25 percent more efficient that the simple cycle turbine alone, with a commensurate reduction in both pollutants and greenhouse gas emissions for the same amount of electricity generated.

In addition to base load power, CCGT could also be useful for dispatch power. In conventional steam boilers, the rate of steam production could be changed only slowly. However, gas turbines could respond in a matter of seconds to a needed load change. CCGT thus aided in improved electrical grid efficiency and stability. Smaller CCGTs could be distributed physically to be near the load and thus reduce transmission losses, while responding to local power requirements.

One area where CCGTs initially did not perform well, however, was in peak shaving power generation. Peak shaving is the practice of bringing an electric generation facility on line for only a few hours at a time to meet transient needs for power. The steam boilers and steam turbines used in CCGTs generally required an extended period to start up. Thermal stresses that can damage boiler tubes and other components are avoided by starting the gas turbine up slowly, and gradually bringing the boiler on line. The steam turbine, likewise generally needs to be started up slowly, so metal components can undergo coordinated thermal expansion, thereby avoiding excessive wear and reduction in useful operational life.

One way around the peaking shaving issue is to oversize the gas turbine so that it operates at part load most of the time, with the additional capacity available to rapidly bring it up to full load when demand is high. This partially negates the major advantages of CCGT, however. When a gas turbine is operated at part load, its efficiency can fall dramatically. For example, a large modern gas turbine that might be 48 percent efficient at full load, might be only 30 percent efficient at half load.

As a result, so-called peaking power plants, or "peakers", were developed using either used simple cycle gas turbines or reciprocating engines. While less efficient than CCGT, simple cycle peaking turbines could be relatively inexpensive. In addition, by handing the transient loads, peakers allowed the generally larger, more efficient CCGTs to operate closer to their "sweet spot" in terms of both efficiency and pollutant emission rates.

It thus became a "known fact" in both regulatory and industry circles, that combined cycle was not suitable for peaking power generation. Yet while this *known fact* became more and more deeply embedded in power generation consciousness, technology continued to change.

Combined Cycle Peaking Power Plant Technology

Nearly 30 years ago, the U.S. Navy, looking to reduce fuel consumption and extend the range of their gas turbine powered ships, began to explore CCGT technology. The program, initiated in the early 1980s was known as RACER (for RAnkine Cycle Energy Recovery)[3]. This project was carried out by Solar Turbines, in San Diego, CA.

The Navy program focused on advancing an alternative to conventional steam boiler technology known as the Benson Cycle. The Benson Cycle, now referred to as once-through steam generation, or OTSG, was developed in 1923 and subsequently sold to what is now Siemens AG. The Benson Cycle was interesting because it enabled rapid changes in the rate of steam production and could be started up faster than conventional boilers. A key challenge, however, was that the initial start up was still not fast enough to meet the needs of the Navy program.

Between 1923 and the early 1980s, however, tremendous advances had been made in materials science. New metal alloys were developed that, while more expensive than more conventional stainless steels, could not only tolerate higher temperatures and thermal stresses, but could also be heated up completely dry, with no water or steam to prevent overheating. With this new “run dry” boiler technology, combined cycle power generation systems could be started up as fast as the combustion turbine would allow, and the boiler and steam turbine could be brought on line simultaneously, later, or even not at all if the extra power was not needed[4].

With additional advances in technology methods were developed that made it possible to start both the boiler and turbine much more rapidly than had been possible with conventional boiler technology. Although their first installation in Okarche, Oklahoma was started in 1985, Solar Turbines eventually abandoned the RACER concept and their technology was acquired by Innovative Steam Technologies in 1992.

The underlying technology, the Benson Cycle, still remains the property of Siemens AG. Their list of licensees[5] for Benson Cycle heat recovery steam generators is shown in the following table.

---

[3] Pike, John, “RACER (Rankine Cycle Energy Recovery)” *GlobalSecurity.ORG*, 9 February 2007.

[4] Brady, Michael, “Once Through Steam Generators Power Remote Sites” *Power Engineering*, June 1998.

[5] Siemens AG 2007 – Corporate Information.

Siemens-Licensed Suppliers of Once Through Steam Generator HRSG Equipment	
ALSTOM Power	USA
Ansaldo Caldaie	Italy
Babcock Hitachi	Japan
Balcke-Dürr	Germany
CMI	Belgium
Doosan Heavy Industries	Korea
Innovative Steam Technologies (IST)	Canada
Kawasaki Heavy Industries	Japan
NEM	Netherlands
Nooter/Eriksen	USA
Siemens Power	Germany
STF	Italy
Vogt Power International	USA

Rapid Start Combined Cycle Peaking Power Plants

The earliest power plant capable of rapid start and peaking operation that was identified in this study is the York Cogen Facility, located in Pennsylvania. Cogen is short for cogeneration, a technology closely related to combined cycle, but in which the steam produced from the heat of the combustion turbine exhaust is used for a purpose other than electricity generation. The York Cogen Facility consists of six 8 MW turbines equipped with OTSG boilers provided by Solar Turbines in 1989. The first recipient of the Siemens OTSG peaking technology was the Cottam Development Centre in Nottinghamshire, UK, which employs the prototype SGT5-4000F combined cycle gas turbine package.

A plant similar to the proposed Canyon Power Project, at least in configuration, is the Las Vegas Cogen II Facility, consisting of four 43 MW GE LM6000 Sprint PC turbines. However, these turbines are also equipped with IST OTSG technology and two 26 MW steam turbines. The plant frequently starts up daily, though at times operates for extended periods depending on electrical demand.

In all, searching through vendor literature, trade publications, and (in the U.S.) government databases, 44 CCGT existing and planned power plants were identified worldwide that use (or will use) OTSG and that were installed with peaking (or rapid start) capability in mind. These are identified in the following table. The combustion turbines in these power plants range in size from 5 MW to 292 MW, indicating that scalability is not an issue.

Combined Cycle Peaking Power Plants

Plant Name	Location	Owner	Year Online	Configuration	Boiler Technology	City	State or Province	Country/ Region	Peaker	Combustion Turbine MW
Agawam Station	Massachusetts	Berkshire Power Associates Limited P	1999	1 x GT24	Alstom OTSG	Agawam	Massachusetts	US	Capable	1 x 270
AKSA Enerji Uretim A.S.	Turkey			4 x LM6000	IST OTSG	Antalya	Antalya	Turkey	Capable	4 x 48
Altek Alarko Power Plant	Turkey		2002	2 x LM2500	IST OTSG	Kitreli		Turkey	Capable	2 x 28
Ataer Enerji	Turkey			1 x LM6000	IST OTSG	Ismir	Ismir	Turkey	Capable	1 x 48
Balazac	Alberta	Encanna/EPCOR	2001	4 x LM6000	IST OTSG	Calgary	Alberta	Canada	Yes	4 x 43
Bear Creek Cogen	Alberta	EPCOR	2002	1 x Trent	IST OTSG	Grand Prarie	Alberta	Canada	Capable	1 x 50
Bethpage Expansion	New York	Calpine	2005	1 x LM6000	IST OTSG	Hicksville	New York	US	Yes	1 x 43
Big Hanaford Power Plant	Washington	Transalta	2002	4 x LM6000	IST OTSG	Centralia	Washington	US	Yes	4 x 43
Calstock Power Plant	Ontario	EPCOR		RB211, LM1600	IST OTSG	Calstock	Ontario	Canada	Capable	26, 13
Cottam Development Centre	Nottingham	Powergen	1998	1 x SGT5-4000F	Siemens Benson	Cottam	Nottinghamshire	UK	Yes	1 x 292
El Segundo Power Redevelopment	California	ESP II LLC	2010	2 x SGT6-5000F	Siemens Benson	El Segundo	California	US	Yes	2 x 280
Empresa Guaracachi S.A.	Bolovia	C.C. Guaracachi Project		2 x 6FA	IST OTSG	Santa Cruz		Bolivia	Capable	2 x 75
Entek Elektrik, Uretim A.S.	Turkey	Entek Elektrik		1 x LM6000	IST OTSG	Izmit		Turkey	Capable	1 x 48
Escatron Power Plant	Spain	Global 3 Energia	2006	4 x LM6000	IST OTSG	Escatron	Zaragosa	Spain	Capable	4 x 48
Gorizia Power Plant	Italy	ElecttroGorizia	2005	1 x LM6000	IST OTSG	Gorizia	Gorizia	Italy	Capable	1 x 43
GTAA Cogen Plant	Ontario	Greater Toronto Airport Authority	2005	2 x LM6000	IST OTSG	Mississauga	Ontario	Canada	Cogen/Capable	2 x 43
Hamm Uentrop Power Station	Germany	Trianel Energy	2007	2 x V94.3A	Ansaldo Benson	Hamm-Uentrop	Westphalia	Germany	Yes	2 x 266
Hanford Energy Peaker Project	California	GWF Energy LLC	2012	3 x LM6000	IST OTSG	Hanford	California	US	Yes	3 x 60
Hawaii Electric Light Company	Hawaii	Hawaii Electric Light Company		2 x LM2500	IST OTSG	Keahole	Hawaii	US	Capable	2 x 25
Henrietta Peaking Plant	California	GWF Energy LLC	2012	2 x LM6000	IST OTSG	Kings County	California	US	Yes	2 x 60
Irsching - 4	Bavaria	E.ON Kraftwerke	2007	1 x SGT5-8000H	Siemens Benson	Vohburg	Bavaria	Germany	Yes	1 x 340
Kapuskasing Power Plant	Ontario	EPCOR	1996	2 x RB211, 1 x FT8	IST OTSG	Kapuskasing	Ontario	Canada	Capable	2 x 26, 1 x 25
Lake Road Power	Connecticut	PG&E NEG	2002	3 x GT24	Alstom OTSG	Dayville	Connecticut	US	Yes	3 x 264
Las Vegas Cogen	Nevada	Black Hills Energy	2001	4 x LM6000	IST OTSG	Las Vegas	Nevada	US	Yes	4 x 43
Maalaea Power Plant	Hawaii	Maui Electric	2006	2 x LM2500	IST OTSG	Kihei	Hawaii	US	Capable	2 x 25
Murrin Murrin	Western Australia	Murrin Murrin Operations pty Ltd	1998	2 x GT10B	Alstom OTSG		Western Australia	Australia	Yes	2 x 37.5
Nipigon Power Plant	Ontario	EPCOR	1998	2 x RB211, 1 x LM2500	IST OTSG	Nipigon	Ontario	Canada	Capable	2 x 26, 1 x 21
North Bay Power Plant	Ontario	EPCOR	1996	1 x RB211, 1 x FT8	IST OTSG	North Bay	Ontario	Canada	Capable	1 x 26, 1 x 25
North Pole Power Plant	Alaska	GVEA	2005	1 x LM6000	IST OTSG	North Pole	Alaska	US	Capable	1 x 43
Nova Scotia Power	Nova Scotia	Nova Scotia Power		2 x LM6000	IST OTSG	Tuffs Cove	Nova Scotia	Canada	Capable	2 x 48
Osenberg D Statoil-Hydro	Norway	Statoil Hydro		2 x LM2500	IST OTSG	Osenberg		Norway	Capable	2 x 28
Phosphate Hill Power Station	Queensland	Western Mining Co.	1999	4 x Taurus 60	IST OTSG	Perth	Queensland	Australia	Capable	4 x 5
Pine Creek Power Station	Queensland	Energy Developments Ltd.	1995	2 x Mars	IST OTSG	Richlands	Queensland	Australia	Capable	2 x 10
Pinelawn Power Station	New York	Pinelawn Power LLC	2005	1 x LM6000	IST OTSG	Babylon	New York	US	Yes	1 x 43
Pulrose Power Station	Isle of Man	Manx Electric Authority	2002	2 x LM2500PK	IST OTSG	Douglas		Isle of Man	Capable	2 x 31
QE Power Station	Sasketchewan	SaskPower	2002	6 x H25	IST OTSG	Saskatoon	Saskatchewan	Canada	Yes	6 x 25
Ruswil Compressor Station	Switzerland	Nuovo Pignone	2001	1 x PGT25	IST OTSG	Ruswil	Lucerne	Switzerland	Capable	1 x 25
Sherritt Power	Cuba	Energas Boca de Jaruco	2010	5 x 6B	IST OTSG	Boca de Jaruco	Havana	Cuba	Capable	5 x 30
Sloe Power Plant	Netherlands	Delta N.V./EDFI	2009	2 x SGT5-4000F	CMI Benson	Sloe	Zeeland	Netherlands	Yes	2 x 292
Tanir Bavi Power Barge	India	Tanir Bavi Power Company	2000	4 x LM6000	IST OTSG	Bangalore	Karnataka	India	Capable	4 x 43
Tunis Power Plant	Ontario	EPCOR	1994	1x Avon, 1 x Mars, 1 x LM6000, 1 x RB211	IST OTSG	Timmons	Ontario	Canada	Capable	1 x 8, 1 x 14, 1 x 40, 1 x 26
Ugur Enerji	Turkey	Ugur Enerji		1 x LM6000	IST OTSG	Ugur		Turkey	Capable	1 x 43
Wuppertal-Barmen Heating Power Station	Germany	Wuppertaler Stadwerke AG	2005	2 x H25	IST OTSG	Wuppertaler	Rhine-Westphalia	Germany	Yes	2 x 25
York Cogen Facility	Pennsylvania	Caterpillar	1989	6 x Mars	Solar (IST) OTSG	York	Pennsylvania	US	Yes	6 x 8

Startup times for the power plants in this table are not all well documented. One of the plants, the Irsching-4, a Siemens SGT5-8000H, located in Bavaria was reported to have a 45 minute start up time, as was the Lake Road Power Station in Dayville, CT[6]. Alstom reports that their latest OTSG can reach full output in 25 minutes, with no restriction on combustion turbine start up. Siemens states that their rapid start combined cycle turbine packages prior to 2007 would achieve full steam load in 40 minutes, while their latest Flex-Plant™ 30 designs, that are being installed now, are capable of 20 – 25 minutes to full steam load[7] – in each case the combustion turbine is at full load in 10 minutes or less.

According to vendor information from IST, the CCGT power plants equipped with their OTSG boilers – which comprise the majority in the previous table – are able to achieve full combustion turbine power in about 10 minutes. In addition, those designed with "hot standby" capability can be at full steam power output in 35 minutes. Otherwise, according to IST, if the OTSG boiler and turbine were cold and completely depressurized it would take at least 55 minutes (and no longer than 95 minutes) to bring the steam boiler and turbine up to full load. This is significantly faster than conventional combined cycle, and whether hot or cold, OTSG technology still allows the combustion turbine to be generating electricity at full load within 10 minutes of receiving the start signal.

The CCGT/OTSG start sequences for both cold and hot start, provided by IST, are as follows (times are in minutes):

> *Hot Start (Pressure is maintained in BOP piping and the STG is warm and on turning gear)*
> *Time 0: GT start*
> *Time 5: OTSG ramp sequence can start if OTSG temperature is 550F and stack temp is 300F*
> *Time 10: GT at full load.*
> *Time 35: OTSG at 100% of unfired steaming capacity and the STG is at load.*
>
> *Cold Start (or any start where system has been completely de-pressured)*
> *Time 0: GT start*
> *Time ~5: OTSG ramp sequence can start if OTSG temperature is 550F and stack temp is 300F*
> *Time 10: GT at full load.*
> *Time ~17: OTSG has reached minimum turndown flow and is held here until the BOP is up to pressure and temperature. This can take anywhere from 20 minutes*

[6] McNeely, Mark, Reliability, Availability are Keys to Plant's Success *Diesel & Gas Turbine Worldwide*, January – February 2003

[7] McManus, Michael, Boyce, David, Baumgartner, Raymond, "Integrated Technologies that Enhance Power Plant Operating Flexibility" *POWER-GEN International 2007.* New Orleans, LA, Dec 11 – 13, 2007.

to an hour and beyond, depending on the configuration of the plant and size/model of the steam turbine.
Time ~37-77: BOP ready to accept steam and OTSG continues start-up ramp.
Time ~55-95: OTSG at 100% unfired steaming capacity and the STG is at load.

According to IST, the difference between 55 minutes and 95 minutes in the cold start sequence is a matter of overall hardware design. In other words, the shorter start up time is determined before the plant is built, and needs to be included in the specifications, so that omission of rapid start capability must be a conscious decision on the part of the project developer. *Regardless, however, the combustion turbine itself is still at full power in 10 minutes or less!* This philosophy, that designing to bring the steam turbine on line rapidly is only a matter of intelligent design, is reflected in many literature and marketing brochure references from both Siemens and Alstom as well.

One of the issues cited with respect to CCGT power plants – regardless of whether or not they are designed for peaking operation – is the need for additional personnel over and above what would be required to run and operate a simple cycle gas turbine power plant. This has been true in the past with conventional combined cycle, where establishing steam balance might even require manual operation of valves. However, current technology, as reported by both vendors and their customers is capable of single operator start/stop and even fully automated start sequencing – according to Siemens and Alstom.

Combined Cycle and Peaking Power Plants in California

Currently there are no peaking power plants located in California that employ combined cycle technology. However, the technology is gaining ground as project developers begin to recognize its benefits. Presently there is one fully new combined cycle peaking power plant planned in California, and two existing peaking power plants have applied to the California Energy Commission to upgrade to combined cycle operation using OTSG hardware. At least one other project in California considered OTSG but eventually rejected it for non-operational reasons as part of their CEQA evaluation. These are discussed below.

El Segundo Power Redevelopment Project

The El Segundo Power Redevelopment Project (ESPR) was originally approved by the California Energy Commission in 2005 as a 630 MW conventional combined cycle power plant comprising two GE 7FA gas turbines equipped with conventional drum-type HRSGs and a single steam turbine generator. Near the time of project approval, however, Siemens fully commercialized their R2C2 (rapid response combined cycle), which was being prototyped at the Cottam facility in Nottinghamshire in the U.K. In June 2007 ESPR submitted a petition to amend the project permit to instead utilize the Siemens technology, which will consist of two SGT6-5000F combustion turbines with separate Benson Cycle HRSGs and steam turbines. The plant generation capacity will be reduced to 560 MW. However, with the Benson Cycle HRSG and associated balance of plant the plant will be able to achieve 300 MW electrical output in 10 minutes or less.

There were many factors driving the decision to reconfigure. Most important, it would appear from the docket, was elimination of once-through cooling. However, the petition to amend includes a summary list of benefits as follows:

> *1. The use of the R2C2 technology eliminates the need for once-through cooling and the associated impingement and entrainment effects on marine resources.*
> *2. Unprecedented rapid response design that provides comparable start-up rates to simple cycle units with the efficiency of a combined cycle power plant; specifically, each unit can deliver 150 MWs of capacity within 10 minutes of startup;*
> *3. The rapid starting capability also supports wind and solar renewable generation by providing reliable localized generation that can quickly respond should wind or solar resources not be available during peak electrical demand periods.*
> *4. Elimination of the discharge of industrial wastewater to the ocean and the associated reliance on the existing intake/outfall 001. There will be no discharge of industrial wastewater from the project.*
> *5. Reduced onsite construction activity associated with ability to transport larger prefabricated modules via beach delivery and/or via the modified plant entrance road;*
> *6. Modified plant entrance road, which will improve the safety and efficiency of the plant entrance; and*
> *7. Significant improvement in the visual aesthetics associated with the change from the previously permitted vertical heat recovery steam generators (HRSGs) to the proposed R2C2 BENSON-type HRSG.*

ESPR also points out that the Benson Cycle HRSGs will allow the plant to bring full emission controls on line sooner, thus reducing start up emissions.

GWF Energy LLC

In July 2008, GWF Energy LLC submitted petitions to the California Energy Commission to modify three of their peaking power plants to combined cycle configurations in order to increase capacity and utility. Two of these are proposing to use OTSG technology so as to retain their peaking capability, while reducing fuel consumption and pollutant emission rates across the board. The Hanford Energy Peaker Plant and Henrietta Peaker Plant will each be modified by adding two OTSG HRSGs and a single steam turbine to two GE LM6000 Sprint PC combustion turbines.

This conversion will result in a roughly 24 percent increase in planned overall operating efficiency for the plants, with a concomitant reduction in emission rates for all priority pollutants. Water consumption as a result of conversion to combined cycle operation will increase from a current 150 AFY (acre feet per year) to 158 AFY – a mere 5.3 percent increase.

In the proposed license amendments for both the Hanford and Henrietta plants the justification for selecting OTSG was the same:

> ***"The reason for retaining the option to operate in simple****-cycle configuration is to* ***preserve the plant's current 10****-minute start capability to provide the Cal-ISO with* ***rapid response peak generation resources."***

Orange Grove Peaking Facility

The Orange Grove Peaking Facility, which has just recently received approval to construct, will be located in Northern San Diego County. This plant was originally envisioned as a simple cycle peaking power plant using two GE LM6000 Sprint PC combustion turbines. As part of due diligence, however, the developers considered the alternative of taking advantage of OTSG to improve efficiency, reduce carbon footprint, and lower the levelized cost of electricity generated by the plant. Upon review of the new plant layout, the developers realized that there would be significant changes in both stack height and physical appearance of the plant that could trigger reevaluation of visual impacts under CEQA[8]. As a result, the developers elected to stay with the original configuration in order to avoid potential schedule slippage.

Section 5.6.2.1 of the Orange Grove application to the CEC states in part:

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[8] Personal Communication April 2009 – Caleb Lawrence, Innovative Steam Technologies, commenting on the additional complication CEQA introduces in the power plant development process, and specifically citing his experience with the Orange Grove Peaking Project.

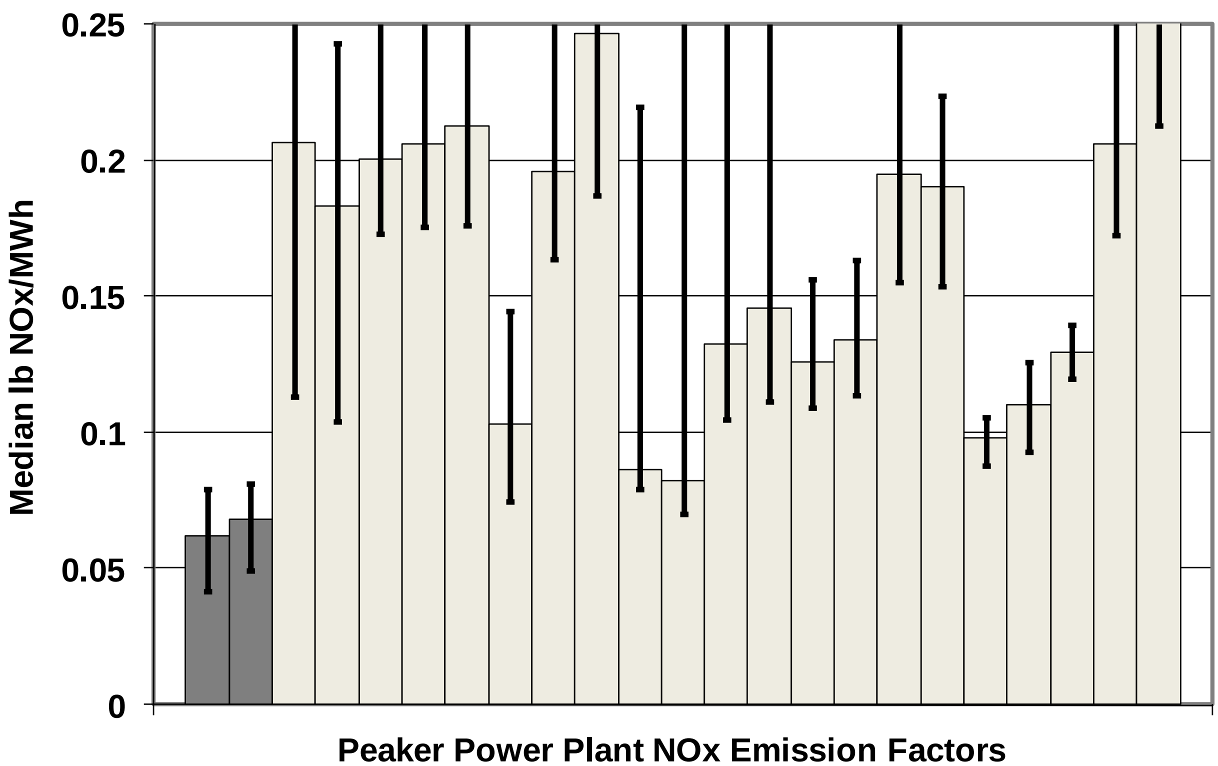
> *" **...some systems that include on**ce-through steam generators (OTSG) allow for relatively rapid start-**up times, at least to part load...***
>
> ***"... plant** footprint and vertical height are greatly increased, adversely affecting visual impact. Considering these factors, the proposed Project does not incorporate combined-**cycle technology."***[9]

[99] Author note: the Orange Grove document also *incorrectly* states that OTSG would result in greatly increased water usage at the site. Relative to simple cycle operation of the LM6000 Sprint PC, combined cycle utilizing OTSG results in only a 5 – 6 percent increase in water usage, as the makeup water for the boiler is significantly less than the amount of water injected into the turbine, which is not recovered.

Comparison of Emissions from Combined Cycle and Simple Cycle Power Plants

Emissions from different power plants are difficult to compare on a snapshot basis. Nor are emissions averaged over long periods of time necessarily relevant, since different plants operate under different loading schedules. However, in comparing combined cycle with simple cycle peaking power plants it is possible to see the benefits of the combined cycle configuration by looking at performance trends that transcend such distinctions as that between a "merchant" peaking plant and a municipal plant designed to provide reserve peaking capacity.

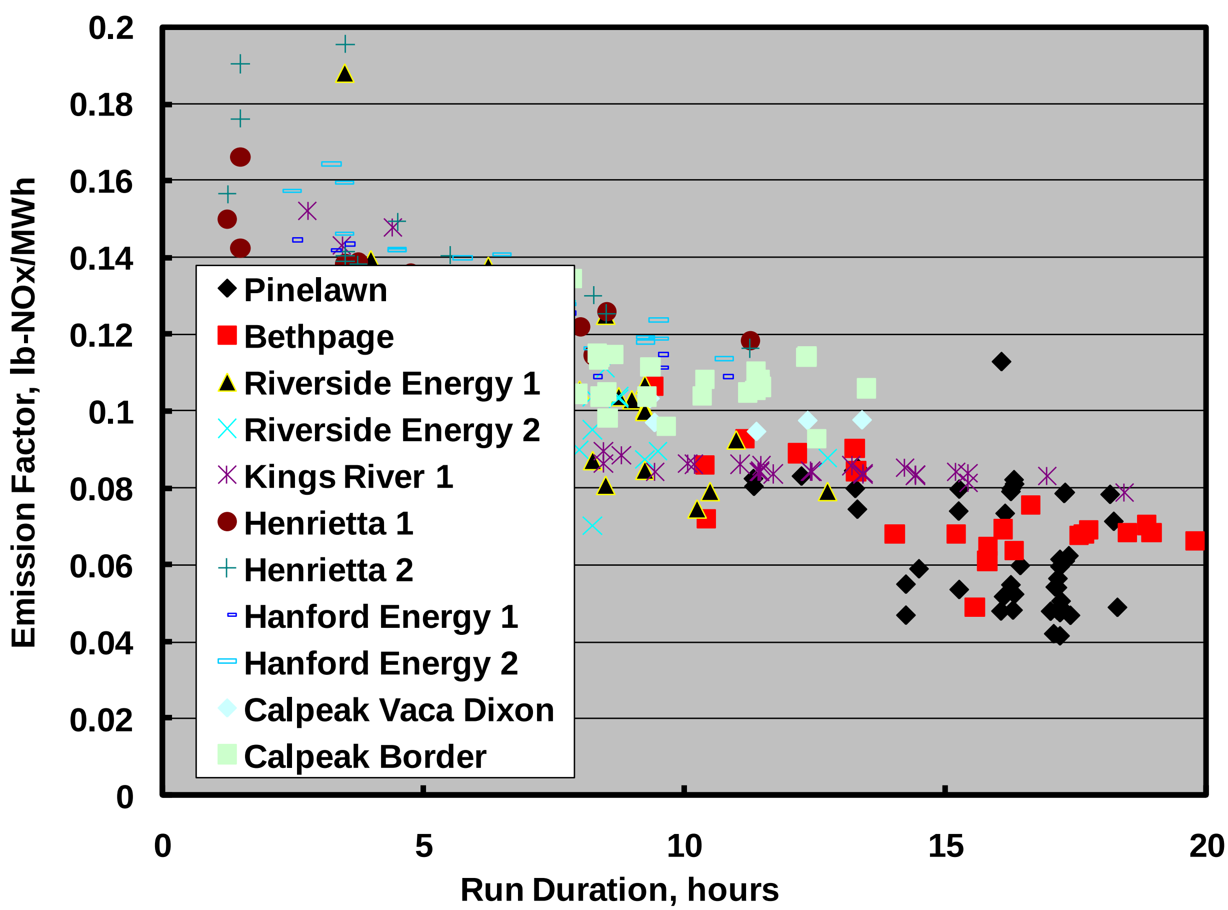
The figure below shows median NOx emission factors for a sample of both combined cycle and simple cycle peaking power plants. Data shown are taken from hourly reported performance and emissions data reported to the U.S. EPA for the months of July and August 2007, and downloaded from the EPA Clean Air Markets database. The darker shaded bars on the left of the graph are for the Pinelawn (first column) and Bethpage (second column) combined cycle peaking power plants located in the State of New York. These are both GE LM6000PC Sprint turbines equipped with OTSG and steam turbines. The remaining data are from peaking power plants across the State of California.



The main bars in this graph represent median NOx emission factors for each start/stop sequence reported over the two month period. Arithmetic mean data did not provide a satisfactory comparison, as some of the plants in California experience a few very short run periods with exceptionally high emission factors that strongly biased the data. The upper limits on the error bars represent one standard deviation above the median, while the low limits on the error bars represent the lowest value reported for any start/stop sequence over the two month period.

The California plants closest in emissions performance to the two combined cycle peaker plants are the Kings River units 1 and 2 indicated in columns 11 and 12 from the left. However, the best emissions factor from Kings River is only comparable to the median value from Bethpage. Some of this might be attributed to the longer average run times at Bethpage and Pinelawn, which allows the start up and shut down emissions to be averaged out over a longer period of time.

This is not borne out across the board, however, when we consider Calpine Gilroy units 3 and 4, shown in columns 17 and 18 from the left. These units frequently operated for durations in excess of 12 hours during the two month period under consideration; and yet in comparing emissions factors with those of Pinelawn and Bethpage for similar operating periods, the Calpine Gilroy units had emission factors more than twice as high. The next figure illustrates the distinction between combined cycle and simple cycle performance more clearly.



These results are NOx emission factors for individual start/stop cycles for the plants shown over the period of July – August 2007. At this level of granularity it can be seen that for individual one-on-one comparisons there are some cases where the cleanest peaking power plants in California can be comparable to or even cleaner than the combined cycle examples. This comparison does not factor in other externalities, however, which could include time since last shut down (which affects start up time and emissions), ambient temperature, and even the rapidity of the startup sequence. On the whole, nonetheless, combined cycle technology shows up as being on average on the order of 20 – 30 percent cleaner than simple cycle technology in peaking applications.

Combined Cycle Peaking and Canyon Power

In their "justification" document, Anaheim provide a series of figures labeled as Table 1A, Table 1B and Table 1C, that purport to show projected operational schedules for the four LM6000 turbines from 7/30/2012 through 9/3/2012. These figures show the turbines operating on approximately six days during each calendar week over this period. Over some of this time only one turbine is operated in a single day, and for as little as three hours. However, during much of the period one or more of the turbines are in fact operated for as much as 15 hours.

These figures are used in the "justification" document as evidence that operation of the Canyon Power Plant is inconsistent with combined cycle operation. But this is only supported if we consider combined cycle to be 1990s state of the art technology. It has been shown in the earlier section of this report, that advanced combined cycle peaking power plant technology has been in existence for nearly 30 years, and that the earliest examples of this technology were fielded over 20 years ago. The technology being proposed by Anaheim for the Canyon Power Project was deemed highly advanced and reliable in the 2000 – 2001 time frame, but by now has been superseded – and *that* needs to be recognized.

In the figures labeled as Tables 1A through 1C in the "justification" document, there are no examples of the turbines starting up in a ten-minute time frame. In fact, in the document "URS Project Emissions Information"[10] on page 4 it is stated:

> ***"Table 3****-1 has been revised to reflect the increase in startup time from 20 minutes assumed in the original application to 35 minutes which is necessary to achieve* ***full compliance with the steady state emission limit."***

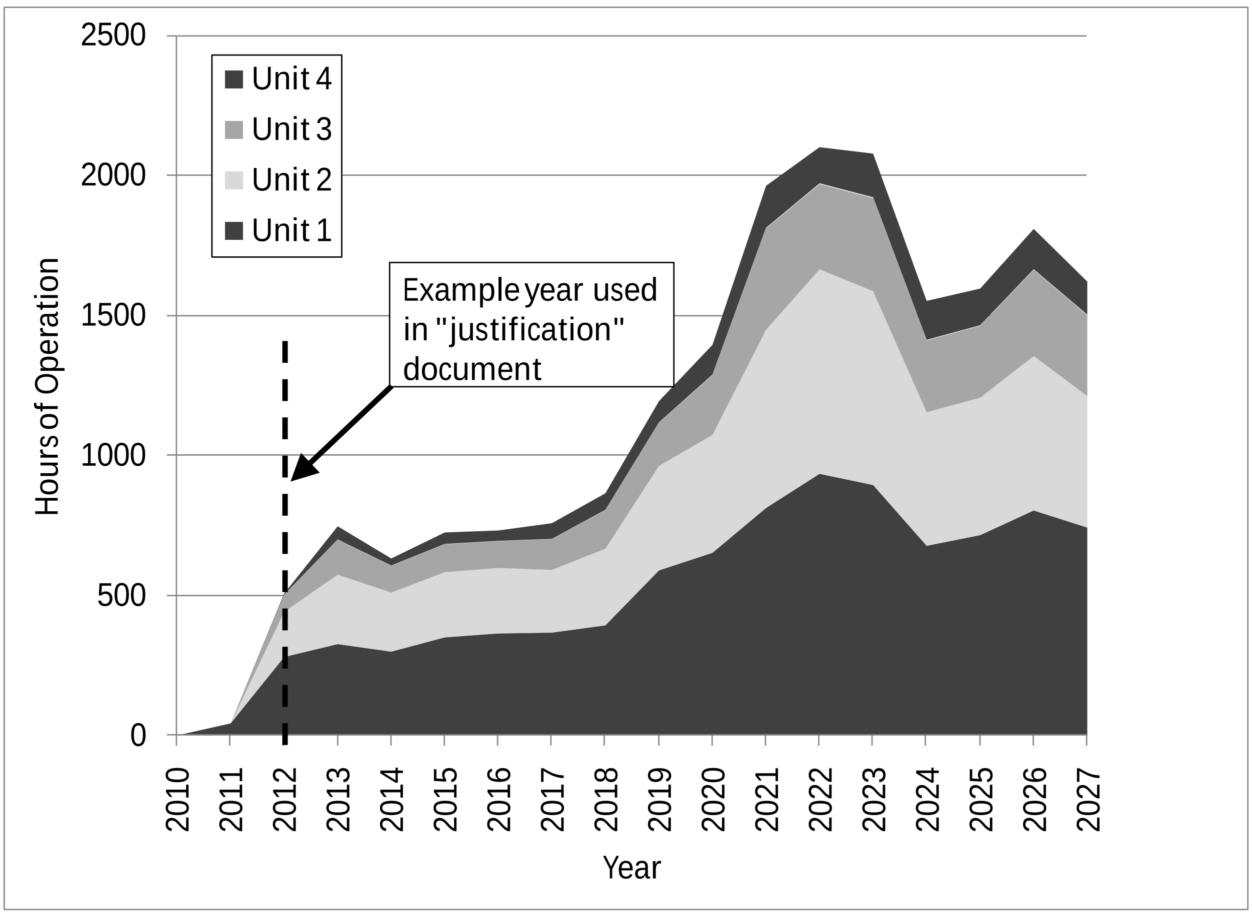
This operation is fully compatible with the capabilities of current combined cycle power plant operation where, with OTSG, these turbines can start up and meet these capabilities for power generation without sacrificing reliability or availability.

> *In fact, the Big Hanaford power plant in Centralia, Washington, cited in Yorba Linda's request for a public hearing, and again referenced in the "justification" document is an excellent example for this situation. Big Hanaford is in fact a large base loaded coal-fired power plant, that happens to have four GE LM6000 Sprint PC turbine equipped with OTSG and steam turbines. According to information on the U.S. EPA Clean Air Markets Database, these turbines normally start up rapidly and run with no steam turbine operation at all. In fact, the steam turbines are there "in case" there is need for the extra capacity. So that in fact, they present no hindrance at all to the peaking capability of the plant.*

[10] *URS Project Emissions Information*, California Energy Commission Docket 07-AFC-9 Log# 50457, March 10, 2009.

During the majority of this period of the year 2012, in fact, these turbines could be operating in combined cycle mode with all the consequent reductions in both GHG and priority pollutant emissions, while still generating the needed power and meeting the availability needs required under CAISO.

Even this picture is misleading however. Tables 1A – 1C presented by Anaheim in the "justification" document, with the accompanying text, fail to tell the entire story of the plant operations. Table 2 of that document points out that by 2022 the plant is expected to be operating at least four times as many annual hours as envisioned in the year 2012. The following figure illustrates the anticipated hourly operation of the Canyon Power plant, by turbine unit, from project conception through the year 2027. At 2000+ hours per year, Canyon Power Plant can hardly be considered to be a "peaking" power plant any longer. If operations are restricted to the summer months of peak demand, then the operating hours for units 1 and 2 will be consistent with extended periods of operation, perhaps up to 15 hours per day, at which point combined cycle is the technology of choice.



By this point the Canyon Power Plant will in fact be a part-time base load power plant with peaking capability. Long before it achieves that status – no later than 2015 or 2016 – it should have demonstrated its capability and have operators become familiar with operation as a true combined-cycle peaking power plant. It is no stretch to go even one step further and point out that even at 2,078 annual operating hours per year, as currently proposed for the year 2023, the plant will be only operating at half the annual capacity that was needed to economically justify construction of the plant as described in the *Fact Sheet* issued by Anaheim Public Utilities on April 15, 2008[11].

The Anaheim fact sheet states that the $200 million project will save Anaheim utility customers up to $12 million per year in fees to CAISO. In total it was projected to result in a potential net benefit to Anaheim of $17 million per annum, even after debt service. However, this was based on total operational hours in excess of 4,000 per year. Reducing the total operating hours to half those originally planned would reduce the total wholesale revenue benefits to *less than what would be required to service the debt* on the originally planned project – bringing the entire project into question.

Into question, that is, until we consider the modifications to the permit that were negotiated in order to make it possible to build the plant without needing to access the SCAQMD priority reserve under rule 1309.1. Those modifications included:

- An increase in the number of turbine starts/stops per year from 129 to 240 per turbine
- An increase in the maximum annual hours of operation per turbine from 602 hours per year to 90 hours of operation per turbine per month for a total maximum of 1080 hours per turbine per year – when startup and shutdown times are included the second revised application to the permit results in a maximum of 1260 hours of operation per year for any one turbine[12].
- A reduction in total combined turbine operating hours from 4,006 to either 2,000[13] or 2,408[14], depending on which document is the more accurate[15].

While the reduction in total operating hours will indeed reduce annual average emissions from the plant, the increase in the permitted number of starts and stops will in fact increase the levelized emissions from the plant in terms of mass emissions of pollutant per MW-hr of electricity produced. It also means that there will be a greater number of acute "bursts" of emissions, as each turbine operates

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[11] Canyon Power Project Fact Sheet, *Anaheim Public Utilities,* 15 April, 2008.

[12] Preliminary Determination of Compliance (PDOC) for Canyon Power Plant (CPP) Proposed 200 Megawatt Power Plant Project (Facility ID No. 153992), to be located at 3071 E. Miraloma Avenue, Anaheim, CA 92805 (07AFC-9). South Coast Air Quality Management District, February 18, 2009.

[13] Canyon Power Plant (07-AFC-9) Status Report #3. February 26, 2009.

[14] Southern California Public Power Authority's Canyon Power Plant Status Report #1 *op.cit.*

[15] Author's note: The California Energy Commission Preliminary Staff Assessment for the Canyon Power Plant, dated April 2009 and entered into the project docket on May 7, 2009, still states that the plant is intended to operate for a total 4,006 hours per year, with each turbine operating approximately 1,000 per year.

with essentially no emissions control until the pollution control system achieves “light off” at approximately 15 minutes into the start cycle.

These relaxed constraints on the number of plant start ups will provide the Canyon Power Project with more flexibility to respond to short term demands for electric power within CAISO. In fact, by maintaining both spinning and non-spinning reserves, the Canyon Power Project will be able to deliver power to the grid at short notice and for brief periods when the spot market price for electricity is quite high. This would enable the plant to better meet its debt service obligations and help provide justification for the public investiture needed to build the plant in the first place. This would not, however be done to service the electric power need of the rate payers of Anaheim and surrounding communities. Rather it would simply serve the purposes of revenue generation for the project developers and the city.

This admittedly cynical interpretation of the present circumstances is not, however, the most likely scenario to play out. In fact, there is every reason to expect that once the SCAQMD adequately revises its rules under Regulation XIII to the satisfaction of the courts and plaintiffs, including new source review (NSR) guidelines, the Canyon Power Project will apply for and receive a modified permit to operate that more closely resembles the original intent of the plant; and further, that this is likely to play out within the timeline for construction and commissioning of the plant.

Summary and Conclusions

If Canyon Power Project is reconfigured as a combined cycle power plant, under the operating scenario described in the modified permit application, turbine start up, time to power and emissions will be unaffected by OTSG in normal cold start operation.

Use of OTSG combined cycle technology in lieu of simple cycle turbines will result in a small, but real reduction in on site water consumption as a result of eliminating one combustion turbine and associated steam injection. Furthermore, the absence of a steam drum and blow-down tank in the OTSG configuration will reduce the demands for water quality and corrosion inhibitors in the boiler feedwater.

Personnel and maintenance requirements for OTSG- based combined cycle operation are manageable and not likely to be as great as projected by Anaheim.

All indications are that steam turbine start up times will be significantly shorter than envisioned in the "justification" document – especially if hot standby procedures are implemented during high demand periods when daily operation can reasonably be anticipated. In addition, hot standby can allow for earlier start up of the SCR emissions control system and earlier light off of the CO oxidation catalyst. This would result in reduced startup emissions that could provide justification for increasing hours of operation, as long as net annual emissions do not increase.

The year 2012 turbine operations profiles used as example by Anaheim are completely compatible with combined cycle operation with OTSG technology. On certain days during this profile turbines are running up to 15 hours per day. But even the shortest runs, at three hours would benefit from combined cycle operation, especially if the steam path were maintained in hot standby. It also needs to be emphasized that the year 2012 scenario is not typical of plant operation over its lifetime. In planning for future energy needs Anaheim should be thinking ahead and applying the most advanced and energy efficient technology currently proven and available – and not relying on ten year old approaches to handling peak power needs.

Installed costs will be higher, as suggested by Anaheim. However in later years this should result in reduced fuel consumption and, as other plant operators have found or are projecting. This translates into a reduced levelized cost of electricity over the life of the plant.

It is all but certain that the operating permit for Anaheim will be changed over time to permit increased operating hours. It can also be expected that likely that future circumstances, including natural disaster (fires, earthquakes, grid failure, other) will result in executive orders temporarily suspending restrictions on hours of operation. All of this points to a need to install a more efficient and cleaner power plant now.

It is recognized that a more efficient power plant will find a more favorable position on CAISO loading order. However, this still means displacing less efficient and more polluting plants in the basin, effectively reducing emissions regardless (as being more efficient will not result in greater electricity demand).

As more renewable energy resources come on line, Canyon will be needed to provide load leveling as well as peaking support to the local grid. Ramping of the simple cycle turbines results in emissions increases that can be at least partially mitigated by ramping the steam turbine as well.

While the City of Anaheim make many good points in their “justification” document, the evidence presented here supports a countervailing conclusion that in looking forward, the installation of combined cycle capability in the Canyon Power Plant *today* will provide the best *overall* solution to *current and future* needs for electrical power in Anaheim and across the South Coast Basin.

CALIFORNIA REGIONAL WATER QUALITY CONTROL BOARD
SAN DIEGO REGION

ORDER NO. R9-2010-0062

AN ORDER DETERMINING NO CHANGES ARE WARRANTED TO ORDER NO. R9-2004-0154 NPDES PERMIT NO. CA0001368

WASTE DISCHARGE REQUIREMENTS FOR DYNEGY SOUTH BAY, LLC (FORMERLY OWNED BY DUKE ENERGY SOUTH BAY, LLC)

SOUTH BAY POWER PLANT
SAN DIEGO COUNTY

The California Regional Water Quality Control Board, San Diego Region (hereinafter San Diego Water Board), finds that:

1. On November 10, 2004, the San Diego Water Board adopted Order No. R9-2004-0154, NPDES No. CA0001368, *Waste Discharge Requirements for Duke Energy South Bay, LLC, South Bay Power Plant, San Diego County* (Order No. R9-2004-0154). Order No. R9-2004-0154 established requirements for the discharge of up to 601.13 million gallons per day (mgd) of heated once-through-cooling water to San Diego Bay.

2. On December 16, 2009, the San Diego Water Board ratified modifications to Order No. R9-2004-0154 to 1) reflect a change in responsible party to Dynegy South Bay, LLC, 2) terminate discharges from Units 3 and 4 as of December 31, 2009, and 3) terminate discharges from Units 1 and 2 as of December 31, 2010 or on the date that the California Independent System Operator (CAISO) determines the units are no longer needed as reliability must-run (RMR) units, whichever occurs first. Order No. R9-2004-0154 cannot be extended to allow discharges from Units 1 and 2 beyond December 31, 2010. Continued operations would require that a new permit be issued after notice and opportunity to comment and a public hearing.

3. A Notice of Public Hearing was issued on January 22, 2010 scheduling a hearing and requesting testimony, technical evidence, and supporting documentation relevant to determining:

   a) Whether South Bay Power Plant intake and discharge operations endanger human health or the environment and can only be regulated to acceptable levels by NPDES permit modification or termination [see 40 Code of Federal Regulations, section 122.64(a)(3)]; and

b) Whether any effects identified in Item a above provide a sufficient basis for the Regional Water Board to require that South Bay Power Plant discharges be terminated earlier than December 31, 2010 and prior to California Independent System Operators (CAISO's) release of Units 1 and 2 from "Reliability Must Run" (RMR) status.

4. Testimony, technical evidence, and supporting documentation in response to the January 22, 2010 Notice of Public Hearing was submitted by the designated parties: Dynegy South Bay, LLC, No More South Bay Power Plant Coalition, CAISO, and the City of Chula Vista. Policy statements were submitted pursuant to the January 22, 2010 Notice of Public Hearing by interested persons: City of Coronado and National Oceanic and Atmospheric Administration.

5. Testimony, technical evidence, supporting documentation, and policy statements submitted pursuant to the January 22, 2010 Public Notice as well as information in the San Diego Water Board files and in Order No. R9-2004-0154 and Fact Sheet were considered in preparation of the "*STAFF REPORT, Dynegy South Bay, LLC, South Bay Power Plant, Evaluation of Water Intake and Wastewater Discharge Effects on San Diego Bay and Consideration of Termination of Discharge*" dated March 22, 2010 (Staff Report). The Staff Report evaluates the impacts to San Diego Bay and contains the rationale for terminating Order No. R9-2004-0154 on December 31, 2010 or earlier if the CAISO determines that Units 1 and 2 are no longer designated as RMR prior to December 31, 2010. The Staff Report is incorporated as if fully set forth in this order and included as Attachment 1 of this order.

6. On February 16, 2004 the USEPA published a final rule to implement Section 316(b) of the Clean Water Act. This rule, 40 CFR 125, Subpart J, *Requirements Applicable to Cooling Water Intake Structures for "Phase II Existing Facilities" Under Section 316(b) of the Act* (New 316(b) Rule), establishes location, design, construction and capacity standards, for cooling water intake structures at existing power plants that use the largest amounts of cooling water (i.e. greater than 50 MGD). The new rule went into effect on September 7, 2004.

7. Order No. R9-2004-0154 identified impacts in San Diego Bay and impaired beneficial uses due to the intake of once-through cooling water and discharge of heated effluent at the South Bay Power Plant.

8. Order No. R9-2004-0154 incorporated requirements to restore the beneficial uses including 1) an evaluation of changing the intake structure as required by the New 316(b) Rule and 2) a time schedule to change the compliance point for the thermal discharge limitations. Order No. R9-2004-0154 also contains language indicating a need to mitigate for impacts. The New 316(b) Rule was suspended by USEPA on March 20, 2007 following litigation and the San Diego Water Board suspended the requirement for a 316(b) evaluation by letter dated June 1, 2007. The compliance point for the thermal discharge limitations was

changed to the South Bay Power Plant property line as of November 10, 2007. The San Diego Water Board has not considered mitigation for the South Bay Power Plant nor has it required a new best technology available analysis be performed following suspension of the 316(b) rule to date.

9. By letter dated January 11, 2010, Dynegy reported that Units 3 and 4 were permanently shut down as of December 31, 2009, resulting in the reduction of maximum flow rate from 601 mgd to 225 mgd (63 percent reduction) as required by the modification to Order No. R9-2004-0154 approved by the San Diego Water Board on December 16, 2009. While not documented or quantified, the San Diego Water Board understands that this 63 percent reduction in intake and discharge flow results in a similar reduction of adverse impacts to beneficial uses.

10. The Staff Report, which evaluated all relevant file documents and evidence and written testimony from designated parties and comments from interested persons, did not identify any new or additional impacts beyond those already identified and considered in Order No. R9-2004-0154 and concludes that allowing discharges to continue through December 31, 2010 at the latest does not, in the short term, pose an unacceptable risk to human health or the environment within the meaning of 40 CFR section 122.64(a)(3) and therefore the permit will not be terminated earlier than December 31, 2010 or when RMR status for Units 1 and 2 is removed by CAISO, whichever occurs first.

11. Any proposal to operate Units 1 and/or 2 beyond 2010 will require evaluation under 40 CFR section 122.64(a)(3) and any permit to authorize discharges beyond 2010 must meet applicable legal requirements, including use of best technology available to minimize adverse environmental impacts from use of once through cooling structures as required by Clean Water Act section 316(b) applicable to existing power plants.

12. The San Diego Water Board has notified all known interested parties of its intent to consider termination of Order No. R9-2004-0154.

13. The San Diego Water Board, in a public hearing, heard and considered all comments pertaining to the termination of Order No. R9-2004-0154.

14. This action to adopt this Order is exempt from the provisions of CEQA, Public Resources Code sections 21100-21177 pursuant to California Water Code section 13389.

IT IS HEREBY ORDERED that the San Diego Water Board has determined that it is not necessary or appropriate to modify the terms of Order No. R9-2004-0154 and therefore, in accordance with its terms, discharges from Units 1 and 2 at SBPP shall terminate as of December 31, 2010 or on the date that the CAISO determines that Units 1 and 2 are no longer designated as reliability must run units, whichever occurs first.

I, David W. Gibson, Executive Officer, do hereby certify the foregoing is a full, true, and correct copy of an Order adopted by the California Regional Water Quality Board, San Diego Region, on May 12, 2010.

DAVID W. GIBSON
Executive Officer

Attachment C

California ISO
Your Link to Power

California Independent System Operator Corporation

Keith E. Casey, Ph.D.
Vice President, Market & Infrastructure Development

October 18, 2010

VIA ELECTRONIC MAIL

Members of the State Water Resources Control Board
Attn: Ms. Jeanine Townsend
Clerk to the Board
State Water Resources Control Board
1001 I Street, 24th Floor
Sacramento, CA 95814

Re: Draft National Pollutant Discharge Elimination System (NPDES) Permit for South Bay Power Plant

Dear Honorable Board Members:

The California Independent System Operator Corporation (ISO)[1] submits this comment letter regarding the draft NPDES permit order for the South Bay Power Plant issued on September 16, 2010 in response to the NPDES permit application of Dynegy South Bay LLC. Based on new analysis of load data for the San Diego area and the ISO's evaluation of required infrastructure to maintain reliable electric service, we have determined that the South Bay Power Plant is not needed for meeting San Diego local reliability requirements beyond December 31, 2010.

This determination is based on the ISO's analysis of San Diego's recent all-time record peak demand of 4,684 MW on September 27, 2010 and review of additional load forecast information recently received by the ISO that projected significantly lower demand for the San Diego area over the next two years. The September 27 record peak was approximately 300 MW below the CEC 2009 1-in-10 load forecast for 2011, which was used in the ISO's 2011 Local Capacity Technical Analysis for 2011 and 2012 that established the need to maintain the reliability must-run status of the South Bay Power Plant. Based on our analysis of peak demand on September 27, 2010 which included normalizing for weather conditions and comparing these results to other information received, we have determined that the reliability must-run requirement for the facility can be eliminated as of December 31, 2010.

As you are aware, the ISO has worked diligently with San Diego Gas & Electric Company to identify infrastructure necessary to eliminate the reliability must-run

[1] The ISO is a nonprofit public benefit corporation chartered under the laws of the State of California for the purpose of operating and maintaining the reliability of the statewide electric transmission grid for the benefit of the citizens of California. California Public Utilities Code §§ 330-352.

requirement for South Bay, including construction of the Sunrise Powerlink transmission line and other projects. Timely completion of these projects remains critical to ensure reliable electric service in San Diego over the coming years. Until the ISO's review of this new load data, the ISO expected South Bay to continue to operate during 2011 consistent with the final compliance schedule set forth in the Water Board's statewide policy on the use of coastal and estuarine waters for power plant cooling. By letter dated September 29, 2010, the ISO notified Dynegy of its decision to extend the reliability must-run contract for South Bay for calendar year 2011.[2] As described above, the ISO has reassessed this need and rescinded its notice of extension to Dynegy. As a result, the ISO anticipates Dynegy will withdraw its NPDES permit application.

On May 12, 2010, the San Diego Regional Water Quality Board issued an order that prohibits any future administrative extensions of Dynegy's NPDES permit. The ISO submitted a timely petition for review of Order No. R9-2010-0062 to the Water Board in anticipation that Dynegy would submit a new NPDES permit application and that an administrative extension of the current permit would be necessary while the Water board considered Dynegy's application. In light of the fact that the ISO expects Dynegy to withdraw its NPDES application, the ISO also intends to withdraw its petition for review of Order No. R9-2010-0062.

We greatly appreciate all the time and effort the Water Board has devoted to this matter. We specifically wish to recognize the professionalism of members of the Water Board staff and the staff of the San Diego Regional Water Quality Board and their efforts to balance environmental and local community concerns with the need to ensure reliable electric service for the citizens of San Diego and Chula Vista.

Thank you for your consideration of these comments. Please do not hesitate to contact me with any questions.

Respectfully submitted,

Keith E. Casey, Ph.D.
Vice President
Market & Infrastructure Development

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2 Section 2.1(b) of the reliability must-run contract requires the ISO to provide notification of its decision to extend the term of a reliability must- run contract for an additional contract year no later than October 1 of any given year.

Email 3 of 11

Email 3 of 11

From: <rob@redwoodrob.com>
Date: Wed, Sep 5, 2012 at 9:05 AM
Subject: Pio Pico PMPD comments Rob Simpson 3
To: "Scott, Diane@Energy" <Diane.Scott@energy.ca.gov>, "djenkins@apexpowergroup.com" <djenkins@apexpowergroup.com>, "MFitzgerald@sierraresearch.com" <MFitzgerald@sierraresearch.com>, "jamckinsey@stoel.com" <jamckinsey@stoel.com>, "mafoster@stoel.com" <mafoster@stoel.com>, "e-recipient@caiso.com" <e-recipient@caiso.com>, "rob@redwoodrob.com" <rob@redwoodrob.com>, "Gretel.smith79@gmail.com" <Gretel.smith79@gmail.com>, "swilliams@scmv.com" <swilliams@scmv.com>, "Peterman, Carla@Energy" <Carla.Peterman@energy.ca.gov>, "Douglas, Karen@Energy" <Karen.Douglas@energy.ca.gov>, "Renaud, Raoul@Energy" <Raoul.Renaud@energy.ca.gov>, "Bartridge, Jim@Energy" <Jim.Bartridge@energy.ca.gov>, "Lemei, Galen@Energy" <Galen.Lemei@energy.ca.gov>, "Nelson, Jennifer@Energy" <Jennifer.Nelson@energy.ca.gov>, "Solorio, Eric@Energy" <Eric.Solorio@energy.ca.gov>, "kevinw.bell@energy.ca.gov" <kevinw.bell@energy.ca.gov>, "Allen, Eileen@Energy" <Eileen.Allen@energy.ca.gov>, Energy - Public Adviser's Office <PublicAdviser@energy.ca.gov>

Docket Number 11-AFC-01

Rob Simpson
Director
Helping Hand Tools (2HT)
1901 First Avenue, Ste. 219
San Diego, CA 92101
Rob@redwoodrob.com

-------- Original Message --------
Subject: Pio Pico opening comments and request for extension of comment period
From: <rob@redwoodrob.com>
Date: Wed, July 18, 2012 12:56 am
To: Kohn.Roger@epa.gov

Hello Mr. Kohn,

This and the following emails, from me, constitute my opening comments and request for an extension of the public comment opportunity for the Pio Pico Proposed PSD permit.

An extension of the comment period is appropriate because there are live actions regarding this project, which may change its scope, at the state level in the California Public Utilities Commission (CPUC), California Energy Commission (CEC) and San Diego Air pollution Control District. Without germane information from those proceedings the public's ability to comment on PSD issues is unnecessarily restricted.

In its recent decision to license the Carlsbad Energy Center, despite a lack of a PSD determination, the CEC stated; "Power plant applicants at the Commission, when they are required to get a PSD permit, apply to EPA after they have obtained their state permit because it is EPA's preference that state and local permits be issued first. (12/12/2011 RT pp. 190-191.) In fact, EPA will typically wait until state permitting is finished before issuing its PSD. (Ibid.)" In this case the PSD comments are due one day after an evidentiary hearing at the CEC, and prior to evidentiary hearings at the CPUC, no state permitting is finished. As an intervenor in the CEC and CPUC proceedings and having submit comments to the air district it is beyond my ability to participate in 4 disjointed proceedings regarding the same project at the same time. I request that the EPA take Official Notice of all 3 proceedings. The air district proceeding may contain relevant air quality information, the CEC proceeding should contain relevant environmental information and the CPUC proceeding will demonstrate considerations of the need for the project.

The EPA should include all notice lists from all 3 proceedings in its Notice of this proposed action, as they have demonstrated that they are interested parties for this proposed project. At this point there appears to be no notice issued by the EPA to the officials or interested parties from any other proceeding. The proposal should first be determined as necessary by the CPUC, next the CEC and Air District should do their combined proceeding and if the EPA declines to participate in the combined proceeding, their proceeding should follow the state determinations. This is how the system was designed and the only way to for the public to effectively participate. It is how the CEC describes the procedure. It would also preserve EPA resources.

The San Diego Air Pollution Control District determination is not final and should not be relied on, at least, until the CEC issues a decision. I submit comments to the air district on their preliminary determination. The Air district failed to respond to my comments and issued their decision. I hereby submit the same comments regarding the Proposed PSD permit, in the following email, and request that the EPA revoke the air districts authority for its failure. The EPA is not in a position to make a final decision on this project and so should not require that the public make one in the form of comments at this time.

I contend that there is no need for this project. In response to my comments on the Palmdale proposed PSD permit the EPA stated;" EPA has previously recognized that it may consider the need for a facility and a "no build" alternative within the context of CAA section 165(a)(2). In re Prairie State Generating Company, 13 E.A.D. 1, 32 (EAB 2006) ("Prairie State"). However, we have also observed that it is appropriate to refrain from analyzing whether a proposed facility is needed where the State has tasked another State agency with the authority to consider that issue. Id. Consistent with this precedent, EPA believes that mechanisms within the State of California provide the appropriate vehicles through which to address issues regarding the need for natural gas-fired power plants in the State, as these mechanisms involve the entities specifically authorized and best equipped to consider the State's short- and long-term energy needs in the context of State renewable requirements, among other factors." In this case, as in Palmdale, the state has made not finished addressing the issue.

The response to comments further states; "In California, in order to conduct a reasoned analysis to determine the need for new natural gas-fired power plants in general, or a specific natural gas-fired power plant in particular, either within the State as a whole, or in a particular geographic location within the State, EPA would need to consider a myriad of extremely complex factors and detailed information that EPA has neither the resources nor the expertise to analyze." I request that the EPA take official notice of the Palmdale proceeding presently before the EAB.

There are at least 10,000 pages of documents of 4 different proceedings to review in order to effectively comment on this proposed action. I have made records requests to the air district and have not received the records yet. It is too much to review in such a short time period and without final determinations from the state agencies. It would require at least another 30 days to receive response to my records requests and review documents.

The extension or delay of comment period deadlines may expedite a final permit. In Palmdale the EPA denied my request for an extension of the comment period. I appealled that denial, and other issues, to the Environmental Appeals Board (EAB), eight months ago, on November 17, 2011. The EAB has still not made a decision. The EPA could preserve resources by cooperating with the public and considering state level decisions. Should the EPA have difficulty understanding the relevance of the above requests and following comments please inform me prior to the expiration of the comment opportunity so that I might clarify them.

Rob Simpson
Executive Director
Helping Hand Tools
27126 Grandview Avenue
Hayward CA. 94542
Rob@redwoodrob.com

Email 4 of 11

Email 4 of 11

From: <rob@redwoodrob.com>
Date: Wed, Sep 5, 2012 at 9:05 AM
Subject: Pio Pico PMPD comments Rob Simpson 4
To:
Cc: "Scott, Diane@Energy" <Diane.Scott@energy.ca.gov>, "djenkins@apexpowergroup.com" <djenkins@apexpowergroup.com>, "MFitzgerald@sierraresearch.com" <MFitzgerald@sierraresearch.com>, "jamckinsey@stoel.com" <jamckinsey@stoel.com>, "mafoster@stoel.com" <mafoster@stoel.com>, "e-recipient@caiso.com" <e-recipient@caiso.com>, "rob@redwoodrob.com" <rob@redwoodrob.com>, "Gretel.smith79@gmail.com" <Gretel.smith79@gmail.com>, "swilliams@scmv.com" <swilliams@scmv.com>, "Peterman, Carla@Energy" <Carla.Peterman@energy.ca.gov>, "Douglas, Karen@Energy" <Karen.Douglas@energy.ca.gov>, "Renaud, Raoul@Energy" <Raoul.Renaud@energy.ca.gov>, "Bartridge, Jim@Energy" <Jim.Bartridge@energy.ca.gov>, "Lemei, Galen@Energy" <Galen.Lemei@energy.ca.gov>, "Nelson, Jennifer@Energy" <Jennifer.Nelson@energy.ca.gov>, "Solorio, Eric@Energy" <Eric.Solorio@energy.ca.gov>, "kevinw.bell@energy.ca.gov" <kevinw.bell@energy.ca.gov>, "Allen, Eileen@Energy" <Eileen.Allen@energy.ca.gov>, Energy - Public Adviser's Office <PublicAdviser@energy.ca.gov>

Docket Number 11-AFC-01

Rob Simpson
Director
Helping Hand Tools (2HT)
1901 First Avenue, Ste. 219
San Diego, CA 92101
Rob@redwoodrob.com

-------- Original Message --------
Subject: Pio Pico PSD comments 1
From: <rob@redwoodrob.com>
Date: Wed, July 18, 2012 1:19 am
To: Kohn.Roger@epa.gov

Attached please find my initial Pio Pico PSD comments Pio Pico PSD comments

Rob Simpson
Executive Director
Helping Hand Tools
27126 Grandview Avenue
Hayward CA. 94542
Rob@redwoodrob.com

-------- Original Message --------
Subject: Pio Pico
From: <rob@redwoodrob.com>
Date: Wed, January 18, 2012 9:02 pm
To: "Steve Moore" <Steve.Moore@sdcounty.ca.gov>

Mr. Moore,

I will be sending a series of emails which constitute my comments for the Pio Pico PDOC. This attachment supports a no project alternative as the project is not needed. It is the PUC Standardized Planning Assumptions for System Resource Plans

Thank you

Rob Simpson

pio pico Standardized Planning Assumptions (Part 1).pdf
571K View Download

Attachment 1 to

Email 4 of 11

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Attachment 1

Standardized Planning Assumptions (Part 1) for System Resource Plans

Table of Contents

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

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[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.

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[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.

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[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.	

<u>(a) Natural Gas Fuel Price Forecast:</u> 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.

<u>(b) CO_2 Price Forecast:</u> 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.

<u>(c) GHG Policy Assumptions:</u> 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, NP26 or SP26. This includes the IOU service area and participating publicly owned utilities in the Path 26 region served by the CAISO.
4 through 8	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 2010; and 2) the CAISO master generation list as of July 12 2010.
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 & 19	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 CAISO's 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, 9, 12 through 17)	**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

SCE
Physical South of Path 26 (SP26) 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	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, 9, 12 through 17)	**30,619**	**31,358**	**32,638**	**32,584**	**33,704**	**33,060**	**32,848**	**31,929**	**32,080**	**30,034**
	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	32	64	97	129	161	193	226	258	290	322
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**	**28,222**	**29,374**	**29,326**	**30,334**	**29,754**	**29,564**	**28,737**	**28,872**	**27,031**
	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)	7,974	9,222	10,511	10,521	11,629	11,116	10,998	10,281	10,511	8,734
28	Percentage of Available Resources Exceeding Demand (Line 20 / Line 26)	140.7%	148.5%	155.7%	156.0%	162.2%	159.6%	159.2%	155.7%	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)	5,036	6,372	7,682	7,701	8,823	8,320	8,214	7,513	7,757	5,990
32	Lower Bound 1-in-2 Service Area Surplus (Deficit)	4,645	5,992	7,304	7,325	8,449	7,947	7,842	7,143	7,390	5,624

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, 9, 12 through 17)	**6,127**	**6,130**	**6,292**	**6,438**	**6,738**	**6,766**	**5,809**	**5,812**	**5,857**	**5,860**
	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	9	12	15	18	21	24	26	29
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**	**6,292**	**6,438**	**6,738**	**6,766**	**5,809**	**5,812**	**5,857**	**5,860**
	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	1,907	2,062	2,375	2,426	1,491	1,523	1,588	1,607
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%	137.8%
	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	1,249	1,406	1,720	1,775	843	880	948	969
32	Lower Bound 1-in-2 Service Area Surplus (Deficit)	1,027	963	1,161	1,318	1,633	1,688	757	794	863	884

Line	PG&E Physical North of Path 26 (NP26) Capacity Need Scenario: 33% Time-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	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, 9, 12 through 17)	**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, 9, 12 through 17)	**30,619**	**31,358**	**32,638**	**32,612**	**33,779**	**33,135**	**32,414**	**31,495**	**30,576**	**28,530**
	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	32	64	97	129	161	193	226	258	290	322
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**	**28,222**	**29,374**	**29,351**	**30,401**	**29,822**	**29,173**	**28,346**	**27,518**	**25,677**
	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)	7,974	9,222	10,511	10,547	11,696	11,183	10,607	9,890	9,158	7,381
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%	153.6%	149.9%	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)	5,036	6,372	7,682	7,726	8,890	8,387	7,823	7,122	6,403	4,636
32	Lower Bound 1-in-2 Service Area Surplus (Deficit)	4,645	5,992	7,304	7,350	8,516	8,014	7,451	6,752	6,036	4,270

	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, 9, 12 through 17)	**6,127**	**6,130**	**6,292**	**6,309**	**6,372**	**6,375**	**5,418**	**5,421**	**5,423**	**5,426**
	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	9	12	15	18	21	24	26	29
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**	**6,292**	**6,309**	**6,372**	**6,375**	**5,418**	**5,421**	**5,423**	**5,426**
	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	1,907	1,933	2,009	2,035	1,100	1,133	1,155	1,173
28	Percentage of Available Resources Exceeding Demand (Line 20 / Line 26)	140.6%	138.8%	143.5%	144.2%	146.0%	146.9%	125.5%	126.4%	127.0%	127.6%
	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	1,249	1,276	1,355	1,384	453	489	514	535
32	Lower Bound 1-in-2 Service Area Surplus (Deficit)	1,027	963	1,161	1,189	1,267	1,297	366	403	429	450

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, 9, 12 through 17)	**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, 9, 12 through 17)	**30,619**	**31,358**	**32,638**	**32,588**	**33,084**	**32,440**	**31,719**	**30,800**	**29,881**	**27,835**
	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	32	64	97	129	161	193	226	258	290	322
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**	**28,222**	**29,374**	**29,329**	**29,776**	**29,196**	**28,547**	**27,720**	**26,893**	**25,052**
	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)	7,974	9,222	10,511	10,524	11,070	10,557	9,982	9,265	8,532	6,755
28	Percentage of Available Resources Exceeding Demand (Line 20 / Line 26)	140.7%	148.5%	155.7%	156.0%	159.2%	156.6%	153.8%	150.2%	146.5%	136.9%
	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)	5,036	6,372	7,682	7,704	8,265	7,762	7,197	6,496	5,778	4,011
32	Lower Bound 1-in-2 Service Area Surplus (Deficit)	4,645	5,992	7,304	7,328	7,890	7,389	6,826	6,127	5,411	3,645

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, 9, 12 through 17)	**6,127**	**6,130**	**6,292**	**6,340**	**6,640**	**6,671**	**5,762**	**6,256**	**6,258**	**6,261**
	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	9	12	15	18	21	24	26	29
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**	**6,292**	**6,340**	**6,640**	**6,671**	**5,762**	**6,256**	**6,258**	**6,261**
	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	1,907	1,964	2,277	2,331	1,444	1,967	1,989	2,007
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%	145.9%	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	1,249	1,308	1,622	1,680	796	1,323	1,348	1,369
32	Lower Bound 1-in-2 Service Area Surplus (Deficit)	1,027	963	1,161	1,220	1,535	1,593	710	1,237	1,263	1,284

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, 9, 12 through 17)	**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

SCE
Physical South of Path 26 (SP26) 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	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, 9, 12 through 17)	**30,619**	**31,358**	**32,638**	**32,584**	**33,063**	**32,419**	**31,740**	**30,821**	**29,902**	**27,856**
	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	32	64	97	129	161	193	226	258	290	322
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**	**28,222**	**29,374**	**29,326**	**29,757**	**29,177**	**28,566**	**27,739**	**26,912**	**25,071**
	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)	7,974	9,222	10,511	10,521	11,051	10,539	10,001	9,284	8,551	6,774
28	Percentage of Available Resources Exceeding Demand (Line 20 / Line 26)	140.7%	148.5%	155.7%	156.0%	159.1%	156.5%	153.9%	150.3%	146.6%	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)	5,036	6,372	7,682	7,701	8,246	7,743	7,216	6,515	5,797	4,030
32	Lower Bound 1-in-2 Service Area Surplus (Deficit)	4,645	5,992	7,304	7,325	7,872	7,370	6,845	6,146	5,430	3,664

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, 9, 12 through 17)	**6,127**	**6,130**	**6,292**	**6,318**	**6,455**	**6,458**	**5,501**	**5,664**	**5,666**	**5,669**
	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	9	12	15	18	21	24	26	29
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**	**6,292**	**6,318**	**6,455**	**6,458**	**5,501**	**5,664**	**5,666**	**5,669**
	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	1,907	1,942	2,092	2,118	1,183	1,375	1,397	1,415
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%	132.1%	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	1,249	1,286	1,438	1,467	536	732	757	777
32	Lower Bound 1-in-2 Service Area Surplus (Deficit)	1,027	963	1,161	1,198	1,350	1,380	449	646	672	692

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, 9, 12 through 17)	**33,132**	**34,866**	**35,764**	**35,271**	**34,661**	**34,824**	**32,044**	**32,085**	**32,126**	**32,167**
	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	385	385	385	385	385
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**	**32,038**	**29,480**	**29,518**	**29,556**	**29,593**
	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	13,703	11,286	11,490	11,674	11,808
28	Percentage of Available Resources Exceeding Demand (Line 20 / Line 26)	163.0%	171.8%	176.4%	174.7%	172.6%	174.7%	162.0%	163.7%	165.3%	166.4%
	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	10,953	8,557	8,786	8,992	9,140
32	Lower Bound 1-in-2 Service Area Surplus (Deficit)	8,601	10,227	11,082	10,716	10,267	10,587	8,193	8,426	8,634	8,784

SCE

Physical South of Path 26 (SP26) Capacity Need

Scenario: 20% Trajectory

Line		2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
		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, 9, 12 through 17)	**30,619**	**31,358**	**32,638**	**32,584**	**32,802**	**32,158**	**31,437**	**30,518**	**29,599**	**27,553**
	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	866	1,141	1,338	1,338	1,338	1,338
16	Additional CHP	32	64	97	129	161	193	226	258	290	322
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**	**28,222**	**29,374**	**29,326**	**29,522**	**28,942**	**28,293**	**27,466**	**26,639**	**24,798**
	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)	7,974	9,222	10,511	10,521	10,816	10,303	9,728	9,011	8,278	6,501
28	Percentage of Available Resources Exceeding Demand (Line 20 / Line 26)	140.7%	148.5%	155.7%	156.0%	157.8%	155.3%	152.4%	148.8%	145.1%	135.5%
	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)	5,036	6,372	7,682	7,701	8,011	7,508	6,943	6,242	5,524	3,757
32	Lower Bound 1-in-2 Service Area Surplus (Deficit)	4,645	5,992	7,304	7,325	7,636	7,135	6,572	5,873	5,157	3,391

SDG&E
Physical Border 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	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, 9, 12 through 17)	**6,127**	**6,130**	**6,292**	**6,309**	**6,312**	**6,315**	**5,358**	**5,361**	**5,363**	**5,366**
	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	14	14	14	14	14	14
16	Additional CHP	3	6	9	12	15	18	21	24	26	29
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**	**6,292**	**6,309**	**6,312**	**6,315**	**5,358**	**5,361**	**5,363**	**5,366**
	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	1,907	1,933	1,948	1,974	1,040	1,072	1,094	1,112
28	Percentage of Available Resources Exceeding Demand (Line 20 / Line 26)	140.6%	138.8%	143.5%	144.2%	144.7%	145.5%	124.1%	125.0%	125.6%	126.1%
	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	1,249	1,276	1,294	1,323	392	428	454	474
32	Lower Bound 1-in-2 Service Area Surplus (Deficit)	1,027	963	1,161	1,189	1,207	1,236	306	343	368	389

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, 9, 12 through 17)	**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, 9, 12 through 17)	**30,619**	**31,358**	**32,638**	**32,584**	**33,704**	**33,060**	**32,848**	**31,929**	**32,111**	**30,065**
	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	32	64	97	129	161	193	226	258	290	322
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**	**28,222**	**29,374**	**29,326**	**30,334**	**29,754**	**29,564**	**28,737**	**28,900**	**27,059**
	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	7,059	8,313	8,295	9,372	8,829	8,679	7,931	8,158	6,348
28	Percentage of Available Resources Exceeding Demand (Line 20 / Line 26)	126.9%	133.4%	139.5%	139.4%	144.7%	142.2%	141.6%	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)	2,586	3,884	5,154	5,140	6,228	5,690	5,547	4,810	5,047	3,241
32	Lower Bound 1-in-2 Service Area Surplus (Deficit)	2,152	3,461	4,733	4,720	5,809	5,272	5,129	4,394	4,632	2,827

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, 9, 12 through 17)	**6,127**	**6,130**	**6,292**	**6,438**	**6,738**	**6,766**	**5,809**	**5,812**	**6,644**	**6,647**
	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	9	12	15	18	21	24	26	29
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**	**6,292**	**6,438**	**6,738**	**6,766**	**5,809**	**5,812**	**6,644**	**6,647**
	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	1,433	1,582	1,889	1,935	994	1,020	1,866	1,877
28	Percentage of Available Resources Exceeding Demand (Line 20 / Line 26)	127.2%	125.6%	129.5%	132.6%	139.0%	140.0%	120.6%	121.3%	139.0%	139.4%
	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	704	854	1,162	1,210	272	301	1,149	1,162
32	Lower Bound 1-in-2 Service Area Surplus (Deficit)	492	418	607	757	1,065	1,113	175	205	1,053	1,067

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, 9, 12 through 17)	**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, 9, 12 through 17)	**30,619**	**31,358**	**32,638**	**32,584**	**33,704**	**33,060**	**32,340**	**31,421**	**30,528**	**28,482**
	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	32	64	97	129	161	193	226	258	290	322
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**	**28,222**	**29,374**	**29,326**	**30,334**	**29,754**	**29,106**	**28,278**	**27,475**	**25,634**
	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)	10,104	11,385	12,709	12,748	13,885	13,402	12,859	12,173	11,495	9,752
28	Percentage of Available Resources Exceeding Demand (Line 20 / Line 26)	157.9%	167.6%	176.3%	176.9%	184.4%	182.0%	179.2%	175.6%	171.9%	161.4%
	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)	7,486	8,860	10,210	10,261	11,417	10,950	10,422	9,757	9,098	7,370
32	Lower Bound 1-in-2 Service Area Surplus (Deficit)	7,137	8,523	9,876	9,929	11,088	10,622	10,097	9,435	8,779	7,052

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, 9, 12 through 17)	**6,127**	**6,130**	**6,292**	**6,438**	**6,738**	**6,766**	**5,809**	**5,812**	**5,814**	**5,817**
	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	9	12	15	18	21	24	26	29
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**	**6,292**	**6,438**	**6,738**	**6,766**	**5,809**	**5,812**	**5,814**	**5,817**
	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	2,380	2,542	2,860	2,917	1,988	2,026	2,055	2,079
28	Percentage of Available Resources Exceeding Demand (Line 20 / Line 26)	157.1%	155.2%	160.9%	165.2%	173.8%	175.8%	152.0%	153.5%	154.7%	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	1,794	1,957	2,279	2,339	1,415	1,458	1,491	1,519
32	Lower Bound 1-in-2 Service Area Surplus (Deficit)	1,563	1,508	1,715	1,879	2,201	2,262	1,339	1,383	1,416	1,444

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**			
SOUTHBAY GAS TURBINE 1	Dynegy	San Diego	15	CT	12/31/2011	High probability (Agreement between Chula Vista and CAISO)
SOUTHBAY UNIT 1	Dynegy	San Diego	146	STEAM	12/31/2011	High probability (Agreement between Chula Vista and CAISO)
SOUTHBAY 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	Local Area/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
COOLWATER STATION 3 AGGREGATE	CAISO System	245	10	2015
COOLWATER STATION 4 AGGREGATE	CAISO System	246	10	2015
ETIWANDA GEN STA. UNIT 3	LA Basin	320	10	2015
ETIWANDA GEN STA. UNIT 4	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**	

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

* All on SWPL

ADLANTOSP_MSL; ADLANTOVICTVL-SP_MSL; FCORNERS5_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

Line Loss Factors

Energy Efficiency	
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

Incremental CHP

2010 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	3,513	
2011	1,796	3,589	
2012	1,872	3,665	
2013	1,948	3,741	
2014	2,024	3,817	
2015	2,100	3,893	
2016	2,176	3,969	
2017	2,252	4,045	
2018	2,328	4,121	
2019	2,405	4,198	
2020	2,481	4,274	
			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	1,888	136	1,489	
2011	1,929	139	1,521	
2012	1,970	142	1,553	
2013	2,011	145	1,586	
2014	2,052	148	1,618	
2015	2,092	151	1,650	
2016	2,133	154	1,682	
2017	2,174	157	1,715	
2018	2,215	160	1,747	
2019	2,256	162	1,779	
2020	2,297	165	1,811	
	53.7%	3.9%	42.4%	4,274
	40.87503877	2.944388386	32.236723	

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 Values (MW) Adjusted

Demand-side savings increased to reflect line losses.

Common Value: Demand-side (MW)

	North	South	San Diego
2011	40	36	6
2012	80	72	12
2013	120	108	17
2014	161	144	23
2015	201	180	29
2016	241	216	35
2017	281	252	41
2018	321	288	46
2019	361	324	52
2020	401	360	58

Common Value: Supply-side (MW)

	North	South	San Diego
2011	41	32	3
2012	82	64	6
2013	123	97	9
2014	164	129	12
2015	204	161	15
2016	245	193	18
2017	286	226	21
2018	327	258	24
2019	368	290	26
2020	409	322	29

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-residential 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
	Connection to POU Systems					44	44	366	675	675	675
33% Time-Constrained, Base Case Load	*North*	20	139	218	298	393	719	719	719	719	719
	South		6	174	451	1,844	2,119	2,316	2,316	2,316	2,316
	San Diego				14	74	74	74	74	74	74
	Connection to 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
	Connection to 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	318	318	318
	Connection to POU Systems					44	44	53	53	53	53
20% Trajectory, Base Case Load	*North*	20	94	123	263	263	385	385	385	385	385
	South		6	174	423	866	1,141	1,338	1,338	1,338	1,338
	San Diego				14	14	14	14	14	14	14
	Connection to POU Systems								-	-	-
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	3,851	3,851
	San Diego				143	440	465	465	465	1,295	1,295
	Connection to 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	2,269	2,269
	San Diego				143	440	465	465	465	465	465
	Connection to POU Systems					44	44	338	647	647	647