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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 5 of 5 a

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 7 of 11

Email 7 of 11

From: <rob@redwoodrob.com>
Date: Wed, Sep 5, 2012 at 9:06 AM
Subject: Pio Pico PMPD comments Rob Simpson 7
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 PSD comments 5
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

1.18.12PDOC.Comments.pdf
1513K View Download

Attachment 1 to Email 7 of 11

April Rose Sommer
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P.O. Box 6937, Moraga, CA 94570
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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]

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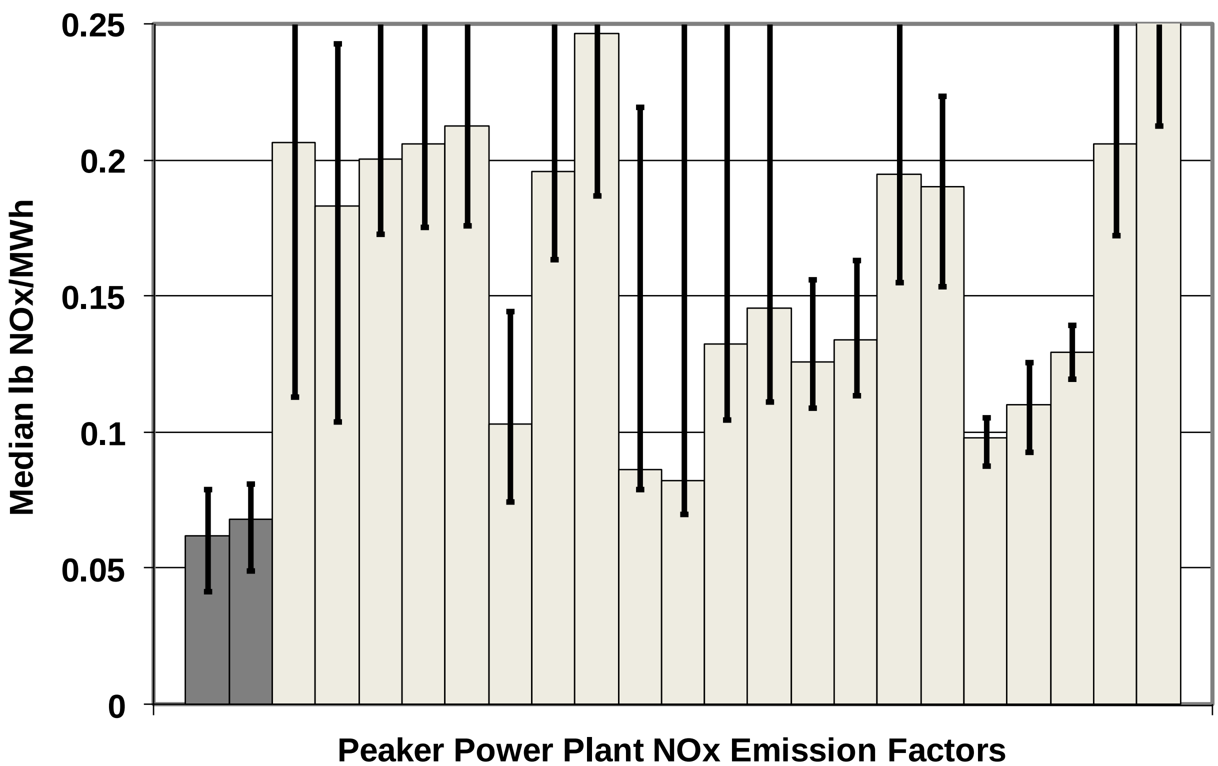
[99] Author note: the Orange Grove document also ***incorrectly*** states that OTSG would result in greatly increased water usage at the site. Relative to simple cycle operation of the LM6000 Sprint PC, combined cycle utilizing OTSG results in only a 5 – 6 percent increase in water usage, as the makeup 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.

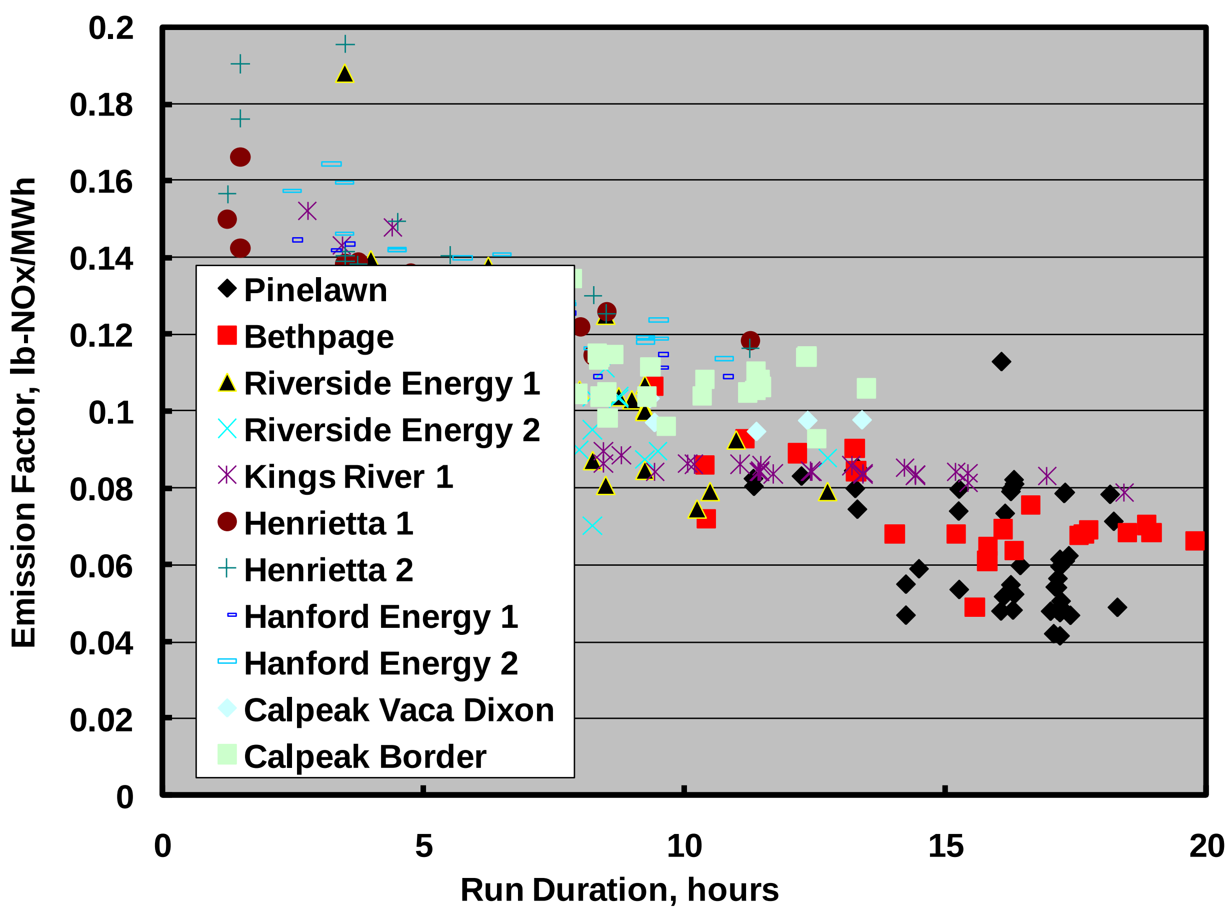
The figure below shows median NOx emission factors for a sample of both combined cycle and simple cycle peaking power plants. Data shown are taken from hourly reported performance and emissions data reported to the U.S. EPA for the months of July and August 2007, and downloaded from the EPA Clean Air 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."***

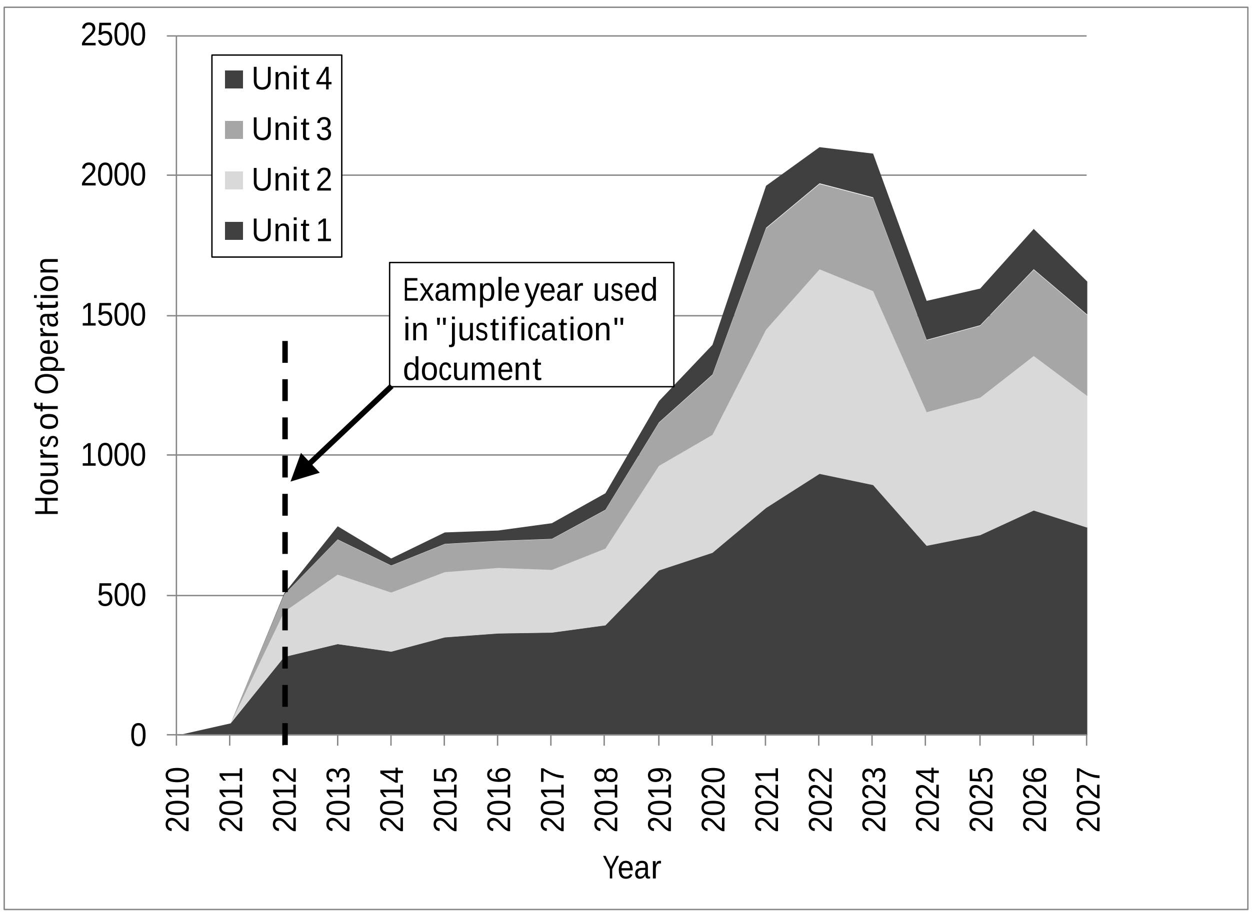
This operation is fully compatible with the capabilities of current combined cycle power plant operation where, with OTSG, these turbines can start up and meet these capabilities for power generation without sacrificing reliability or availability.

> *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

[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 8 of 11

Email 8 of 11

From: <rob@redwoodrob.com>
Date: Wed, Sep 5, 2012 at 9:08 AM
Subject: Pio Pico PMPD comments Rob Simpson 8
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 PSD comments 3
From: <rob@redwoodrob.com>
Date: Wed, July 18, 2012 1:20 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 9:34 pm
To: "Steve Moore" <Steve.Moore@sdcounty.ca.gov>
Cc: "Staff April" <2htlegal@gmail.com>

Mr. Moore,

The attached MOU is a part of my comments. Please identify why the District has a comment period, how commenting to the District could have a different effect than commenting with the CEC, EPA or CARB and how the public can affect the proposed permit with the District as opposed to the CEC, EPA or CARB.

Rob Simpson

CEC ARB MOUpdf.pdf
4665K View Download

Attachment 1 to Email 8 of 11

Exhibit 1

APPROVED ARB-CEC JOINT POLICY STATEMENT OF COMPLIANCE WITH AIR QUALITY LAWS BY NEW POWER PLANTS

I. Preamble

This policy will insure an adequate supply of electrical energy while allowing continued improvements in California's air quality. California air quality laws are essential to protect public health and welfare. At the same time, protection of the public health and welfare requires an adequate electrical energy supply. This statement sets forth a procedure for the expeditious approval of needed power plants in a manner that fully preserves the integrity of California's air quality program.

Under this statement, California's utilities are obligated to use the most advanced pollution controls on their new plants and to mitigate fully the adverse effects of the remaining air emissions. At the same time, however, the Energy Commission and air quality regulatory agencies have an obligation to inform utilities and the public early in the planning process of the permissible locations and conditions for new power plants. The actions of all involved parties must be directed toward expeditious, coordinated and well reasoned decisions. With the implementation of this procedure, any irreconcilable conflict between the needs for clean air and adequate electric power will be avoided.

II. General Provisions

A. Contents of Regulatory Documents: The Energy Commission shall be guided by the contents of this policy statement in adopting its amended NOI/AFC Regulations and in any other actions affecting compliance with air quality laws. The ARB shall be similarly guided in adopting its revised model New Source Review rule to be used by local districts and any other actions affecting siting of new power plants.

B. Reimbursement: Pursuant to the provisions of Public Resources Code Section 25538, each local district shall be reimbursed for such added costs, including lost fees, that are actually incurred by the district in complying with any request or duty specified in this statement.

III. NOI Proceeding

A. Filing Requirements: The NOI filing shall contain the information described in Appendix A. Failure of the NOI filing to contain all of the necessary information shall result in a rejection of the filing by the Commission.

B. Procedure: The Commission shall forward a copy of the NOI to each local district within which a site is located and request their participation in the NOI proceeding. Within fourteen days of receipt of the NOI, each district shall notify the ARB and the Commission of their intent to participate in the NOI proceeding. The ARB shall fulfill the NOI-related duties and obligations of each district that fails to participate. Each local district within which a site is located (or ARB) shall prepare and submit a report prior to the conclusion of the non-adjudicatory hearings specified in Section 25509.5 of the Public Resources Code. That report shall include, at a minimum:

(1) a preliminary specific definition of best available control technology (BACT) for the proposed facility;

(2) a preliminary discussion of whether there is substantial likelihood that the requirements of the applicable New Source Review rule and all other applicable air quality regulations can be satisfied by the proposed facility;

(3) a preliminary list of conditions which the proposed facility must meet in order to comply with the applicable New Source Review rule or any other applicable air quality regulation.

The preliminary determinations contained in the report shall be as specific as possible within the constraints of the information contained in the NOI. The ARB shall review and prepare written comments on all reports prepared by local districts.

If, in the opinion of the ARB, based on the determinations of the local districts, none of the proposed sites has a substantial likelihood of meeting the requirements of the applicable air quality regulations, the Commission staff and ARB, in consultation with the local districts and prior to the conclusion of the nonadjudicatory hearings, shall propose an alternative siting area for the proposed facility in or near the Applicant's service area which might have a greater likelihood of meeting the applicable air quality regulations and merits further study. That proposal shall include the reasons therefore. If such a proposal is filed, the presiding Commissioner may direct the Applicant to evaluate major siting constraints of the proposed alternative for presentation at the adjudicatory hearings described in Section 25513 of the PRC. Findings and conclusions on these proposed alternatives shall be included in the Commission's final report and decision.

At the request of the presiding Commissioner, any person submitting a report on air quality compliance shall testify in support of that report at any hearings on the NOI. In addition, the Air Pollution Control Officer and the ARB shall, at the direction of the presiding Commissioner, update the information provided in their respective reports in response to changes in the Applicant's proposal which may occur during the NOI proceeding. The Air Pollution Control Officer may also comment on the final report on the NCI consistent with the information contained in the District's report.

C. <u>Decision</u>: The Commission shall not approve any site and related facility unless there is a substantial likelihood that the facility will meet the applicable air quality regulations at that site. Only in the event that the Commission determines that the facility is urgently needed, the Applicant has made a good faith effort to find acceptable alternative sites and related facilities, and no approvable site has been identified as having a substantial likelihood of compliance may the Commission approve the single site and related facility that is otherwise acceptable and that is most likely to meet all applicable air quality regulations.

Notwithstanding the above, local regulations which the ARB determines are unnecessary for the protection of air quality shall not restrict the number of sites considered.

IV. AFC Proceeding

A. Filing Requirements: Immediately upon the filing of the AFC with the Commission, the Executive Director shall transmit a copy of the AFC to the local district for a Determination of Compliance review. The AFC shall contain all of the information required by the local district for an Authority to Construct under the applicable New Source Review rule; provided, however, that the Applicant need not submit information that requires final plant design or selection of equipment vendors. If the AFC fails to contain such information, the Air Pollution Control Officer shall so inform the Commission within 20 days of receipt of the filing, and the AFC shall be returned to the Applicant for resubmittal.

The APCO or ARB may request from the Applicant any information reasonably necessary for the completion of the Determination of Compliance review. If the APCO or ARB is unable to obtain the information, either agency may petition the presiding Commissioner for an order directing the Applicant to supply such information.

B. Procedure: Within 240 days of the filing date[1], or such shorter period as the ARB shall reasonably determine, the APCO shall issue and submit to the Commission a Determination of Compliance on whether the proposed facility meets the requirements of the applicable New Source Review rule and all other applicable district regulations. If the proposed facility complies, the APCO shall specify what permit conditions, including BACT and mitigation measures, are necessary. If the proposed facility does not comply, the APCO shall identify the specific regulations which would be violated by the proposed facility and the basis for determining such violation. In the event of such noncompliance, the APCO shall further identify those regulations with which the proposed facility would comply, including required BACT and mitigation measures. The APCO shall provide an opportunity to be heard to the Applicant and other interested parties. The APCO determination shall be subject to appeal to the ARB to the extent permitted by State Law.

At the direction of the Commission, the APCO and ARB shall make available a witness at the hearings held on the AFC to explain the Determination of Compliance. Any amendment to the Applicant's proposal related to compliance with air quality laws shall be

1/ If the decision on the AFC is required to be rendered within 12 months, the report shall be submitted within 6 months of the filing date.

transmitted to the APCO and ARB for consideration in the local district's Determination of Compliance.

C. Decision: The Commission AFC decision shall include findings and conclusions on conformity with air quality requirements based on the Determination of Compliance. If the Determination of Compliance concludes that the facility as proposed by the Applicant will comply with all applicable air quality requirements, the Commission shall include in its certification any and all conditions necessary to insure compliance. If the Determination of Compliance concludes that the proposed facility will not comply with all applicable air quality requirements, the Commission shall direct its staff to meet and consult with the applicant and agency concerned to attempt to correct or eliminate the noncompliance.

If the noncompliance cannot be corrected or eliminated, the Commission shall determine whether the facility is required for the public convenience and necessity and whether there are not more prudent and feasible means of achieving such public convenience and necessity. Only when such a determination is made and the proposed facility will meet all provisions and schedules required by the Clean Air Act, may the Commission certify the proposed new facility. When certifying a facility under such conditions the Commission shall require compliance with all applicable air quality requirements that can be met.

V. Enforcement:

The Determination of Compliance and the procedure described in this statement shall serve the purpose of an Authority to Construct. The issuance of a certificate by the Commission, using the procedure described in this statement, shall confer the same rights, privileges and enforcement powers as an Authority to Construct. The APCO shall issue a permit to operate if the facility complies with the conditions contained in the CEC Certificate.

The issuance of a Determination of Compliance shall not be considered a final determination of whether the facility can be constructed or operated. The final decision of the Commission based upon the procedure described in this statement shall be the final action on all issues related to certification of the facility.

Dated: 2/2/79

Richard Maullin

RICHARD L. MAULLIN
Chairman
California Energy Commission

Dated: 3/8/79

THOMAS QUINN
Chairman
California Air Resources Board

Appendix A: Information Requirements for NOI Filing

The following is a description of the requirements for submission of air quality information in a notice of intention filing as applicable to a fossil fueled power plant. These requirements are designed to lead to a determination of whether there is substantial likelihood of compliance with applicable air quality regulations.

1. Project description including typical fuel type and characteristics (BTU content, maximum sulfur and ash content), design capacity, proposed air emission control technologies, stack parameters (assumed height, diameter, exhaust velocity and temperature) and operational characteristics (heat rate, expected maximum annual and daily capacity factor). This information may be based upon typical data for a facility of the proposed type and design.
2. Description of cooling systems, including approximate drift rate, water flow and water quality (TDS content).
3. Projected facility-related emissions from the stack and combustion system, from cooling towers and from associated fuel and other material handling, delivery and storage systems to the extent that the applicable New Source Review rule requires attributing these sources to the proposed project. The emissions discussion should

include a discussion of the basis of the estimate, such as test results, manufacturers' estimates, extrapolations and all assumptions made.

4. A list of all applicable air quality rules, regulations, standards and laws.
5. A statement, including the reasons therefor, of what the Applicant considers best available control technology as defined in the applicable district's New Source Review rule.
6. Existing baseline air quality data for all regulated pollutants affected by the proposed facility including concentrations of pollutants, an extrapolation of that data to the proposed site, and a comparison of the extrapolated data with all applicable ambient air quality standards. This discussion should include a description of the source of the data, the method used to derive the data and the basis for any extrapolations made to the proposed site.
7. Existing meterological data including wind speed and direction, ambient temperature, relative humidity, stability and mixing height, and existing upper air data; and a discussion of the extent to which the data are typical conditions at the proposed site. This description should include a discussion of the source of the data and the method used to derive the data.

8. A worst case air quality analysis for each proposed site and related facility to determine whether the plant may cause or contribute to a violation of each applicable ambient air quality standard. Such analysis shall include a description of the methodology employed and the basis for the conclusions reached, and shall consider topography, meteorology and contributions from other sources in the area.

9. A discussion of the emission offset strategy or any other method of complying with the applicable New Source Review rule. The emission offset strategy shall be designed to show whether there are sufficient offsets available; contracts are not required. Offset categories (e.g. dry cleaners, degreasers) and an inventory of potential reductions may be used unless most of the potential offsets come from a very small number of sources. In the latter case, the offset sources should be more specifically identified. Potential offsets may be aggregated by geographic location as appropriate under the applicable rule.1/ The offset discussion should also include a brief description of the emissions controls to be used for each offset category and should account

1/ For example, all offsets in the basin may be aggregated together if the rule applies -- the same offset ratio to all offsets within the basin. However, if a small ratio is applied within a specified radius, offsets within that radius should be separately aggregated.

for applicable rules requiring emission reductions. In the event there is no emissions inventory available from the ARB or from the applicable local district, the Applicant may propose an alternative method for complying with this requirement.

10. Based upon worst case data for analysis for short-term averaging times and typical data for analysis for annual averaging times, a discussion of whether the proposed facility will be within PSD Class I and Class II increments.