Docket:	**R.12-03-014**
Witness:	**Bill Powers**
Exhibit No.:	

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

**PREPARED DIRECT TESTIMONY OF BILL POWERS
ON BEHALF OF
THE CALIFORNIA ENVIRONMENTAL JUSTICE ALLIANCE**

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

JUNE 25, 2012

Table of Contents

I. Introduction

My testimony addresses the testimony submitted by the California Independent System Operator (CAISO) in R.12-03-014 on May 23, 2012.[1]

Before discussing my comments related to CAISO's testimony, I will summarize my experience and qualifications. I began my career converting Navy and Marine Corps shore installation power plants from oil-firing to domestic waste, including woodwaste, municipal solid waste, and coal, in response to concerns over the availability of imported oil following the Arab oil embargo. I am a registered professional mechanical engineer in California with over 25 years of experience in the energy and environmental fields. I have permitted five 50 MW peaking turbine installations in California, as well as numerous gas turbine, microturbine, and engine cogeneration plants around the state. I organized conferences on permitting gas turbine power plants (2001) and dry cooling systems for power plants (2002) as chair of the San Diego Chapter of the Air & Waste Management Association.

I am also the author of the March 2012 Bay Area Smart Energy 2020 strategic energy plan. This plan uses the zero net energy building targets in the California *Energy Efficiency Strategic Plan* as a framework to achieve a 60 percent reduction in GHG emissions from Bay Area electricity usage by 2020. I authored the October 2007 strategic energy plan for the San Diego region titled "San Diego Smart Energy 2020." The plan uses the state's Energy Action Plan as the framework for accelerated introduction of local renewable and cogeneration distributed resources to reduce greenhouse gas emissions from power generation in the San Diego region by 50 percent by 2020. I am the author of several articles in Natural Gas & Electricity Journal on use of large-scale distributed solar photovoltaics (PV) in urban areas as a cost-effective substitute for new gas turbine peaking capacity. I currently serve on the San Diego Environmental and Economic Sustainability Task Force. The mission of the task force is to produce a Climate Mitigation and Adaptation Plan for San Diego. I have a B.S. in mechanical engineering from Duke University and an M.P.H. in environmental sciences from the University of North Carolina – Chapel Hill. My resume is attached as Exhibit A to this testimony.

II. Background – Relevant Requirements

California law now requires that 33 percent of retail electricity sales are procured from renewable resources by 2020. It also sets a requirement of 20 percent of sales from renewables in 2013 and 25 percent in 2016. This 33 percent renewable portfolio standard (RPS) is one of the highest in the nation. California's initial RPS, which was established in 2002, set a RPS of 20 percent of retail electricity sales by 2017. In 2006, the target date was accelerated to 2010. Then-Governor Schwarzenegger signed an executive order in 2008 setting a new RPS target of 33 percent by 2020. On April 12, 2011, Governor Jerry Brown signed the 33 percent RPS requirement into law.

[1] CAISO served an addendum to its testimony on June 19, 2012. Due to the short time frame, I have not been able to fully analyze the addendum in this report.

California's Assembly Bill (AB) 32 climate action legislation, the *California Global Warming Solutions Act*, was passed into law in 2006. AB 32 mandates that California reduce GHG emissions to 2000 levels by 2010, to 1990 levels by 2020, and reach 80 percent below 1990 levels by 2050.

The California Air Resources Board (CARB) is the lead agency tasked with implementing AB 32. The December 2008 *AB 32 Scoping Plan* developed by CARB proposed the following targets related to energy: 1) reduce demand by 32,000 GWh via energy efficiency measures, 2) add 4,000 MW of combined heat and power to displace 30,000 GWh of conventional generation, 3) reduce natural gas consumption by 800 million therms via energy efficiency measures, 4) add 200,000 solar hot water heaters in compliance with AB 1470, 5) achieve 33 percent RPS by 2020, 6) achieve one million solar roofs, 3,000 MW, by 2017, and 7) implement a CO_2 cap-and-trade program.[2]

Consistent with the State's focus on renewables and greenhouse gas reduction, California has instituted an *Energy Action Plan*, which establishes the electricity resource priority list, or loading order, that defines how California's energy needs are to be met. *Energy Action Plan I* was published in May 2003.[3] The CEC and the California Public Utilities Commission (Commission) developed the *Energy Action Plan* to guide strategic energy planning in California. The loading order is summarized in Table 1.

Table 1. Energy Action Plan Loading Order

1. Energy efficiency, including onsite renewable generation, and demand response
2. Renewable energy
3. Combined heat and power
4. Utility-scale natural gas-fired generation
5. Transmission (as needed to support other elements)

The Plan is explicit that rooftop PV is an element of energy efficiency standards for new buildings. *Energy Action Plan I* states that California should "[i]ncorporate distributed generation or renewable technologies into energy efficiency standards for new building construction."

California law also requires utilities to file a procurement plan with the Commission. The plan is required to demonstrate that the utility, "to fulfill its unmet resource needs, shall procure resources from eligible renewable energy resources in an amount sufficient to

[2] *See* California Air Resources Board, *AB 32 Climate Change Scoping Plan* (Dec. 2008) pp. 28, 41–53 <http://www.arb.ca.gov/cc/scopingplan/scopingplan.htm> [as of June 21, 2012] ["The cap-and-trade program creates an emissions limit or 'cap' on the sectors responsible for the vast majority of California's greenhouse gas emissions and provides capped sources significant flexibility in how they collectively achieve the reductions necessary to meet the cap"] (hereafter *AB 32 Climate Change Scoping Plan*).
[3] State of California, *Energy Action Plan* (May 8, 2003) <http://www.energy.ca.gov/energy_action_plan/2003-05-08_ACTION_PLAN.PDF> [as of June 20, 2012].

meet its procurement requirements."[4] The plan is also required to demonstrate that the utility "shall first meet its unmet resource needs through all available energy efficiency and demand reduction resources that are cost effective, reliable, and feasible."[5] The Commission recently confirmed that the "loading order applies to all utility procurement, even if pre-set targets for certain preferred resources have been achieved."[6] Governor Jerry Brown has proposed specific measures to meet California's energy goals. He proposes through his *Climate Strategy* and *Clean Energy Jobs Plan* that a majority of the new renewable energy resources to be built in the state by 2020, 12,000 MW of total of 20,000 MW, be local renewable power.[7] Approximately 3,000 MW of energy storage would be added to the grid to meet peak demand and support renewable energy generation under the Governor's *Clean Energy Jobs Plan*.[8] The *Clean Energy Jobs Plan* also calls for the addition of 6,500 MW of new CHP over the next 20 years and substantial improvements in the energy efficiency of new and existing buildings.

The Commission and the IOUs jointly developed the *California Long-Term Energy Efficiency Strategic Plan* in 2008.[9] The *Plan* was updated in 2011.[10] It calls for 25 percent of existing homes to reach 70 percent reduction in energy usage by 2020, and 50 percent of existing commercial buildings to reach zero net energy by 2030. The *Plan* also calls for a 50 percent reduction in air conditioning loads by 2020. Governor Brown's April 25, 2012 Executive Order B-18-12 calls for 50 percent of California state government commercial buildings to reach zero net energy.[11]

Major additional goals of the *Plan* are:

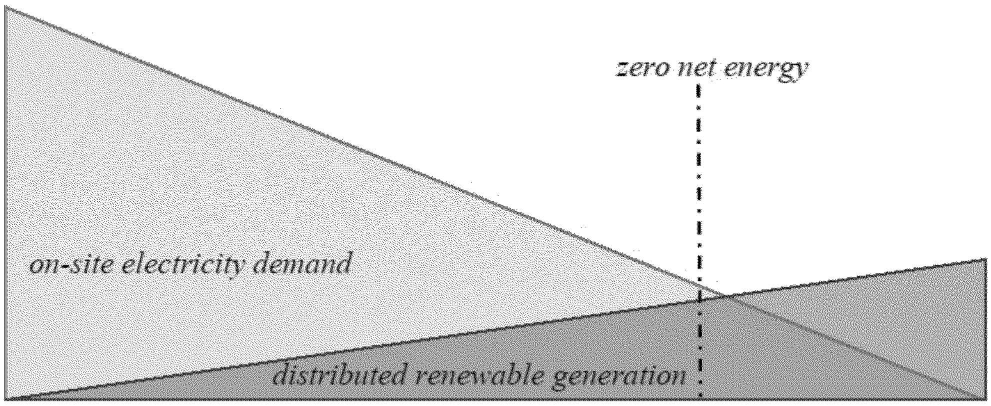
- All new residential construction will be zero net energy by 2020;
- All new commercial construction will be zero net energy by 2030;
- Efficiency of heating, ventilation, and air conditioning systems will 50 percent by 2020 and 75 percent by 2030.

The concept of net zero energy is shown graphically in Figure 1.

---

[4] Pub. Util. Code § 454.5(9).
[5] *Id.*
[6] *See* California Public Utilities Commision (CPUC), *Commission Decision 12-01-033* at pp. 18–21.
[7] Governor Edmund G. Brown Jr., *Support Letter for DRECP Process* (Apr. 25, 2012) p. 2 <http://www.drecp.org/meetings/2012-04-25-26_meeting/presentations/04_Office_of_the_Governor_Paper.pdf> [as of June 20, 2012]; Governor Edmund G. Brown Jr., *Clean Energy Jobs Plan* (June 2010) <http://gov.ca.gov/docs/Clean_Energy_Plan.pdf> [as of June 21, 2012] (hereafter *Clean Energy Jobs Plan*).
[8] *Clean Energy Jobs Plan*, *supra*, [The Plan calls for energy storage equivalent to 5 percent of peak load. California peak load is approximately 60,000 MW. Five percent of 60,000 MW is 3,000 MW].
[9] *See* CPUC, *California Energy Efficiency Strategic Plan* (Sept. 18, 2008) <http://www.cpuc.ca.gov/PUC/energy/Energy+Efficiency/eesp/> [as of June 20, 2012]..
[10] CPUC, *California Energy Efficiency Strategic Plan* (Jan. 2011) [Update 2011].
[11] *See* Governor Edmund G. Brown Jr., *Executive Order B-18-12* (Apr. 25, 2012) <http://gov.ca.gov/news.php?id=17508> [as of June 20, 2012] ["State agencies shall also take measures toward achieving Zero Net Energy for 50% of the square footage of existing state-owned building area by 2025"] (hereafter *Executive Order B-18-12*).

Figure 1. Graphical Representation of Net Zero Energy Concept



The *Solar Hot Water and Efficiency Act* of 2007 authorized a ten-year incentive program for solar water heaters with a goal of promoting the installation of 200,000 systems in California by 2017. This is an average installation rate statewide of 20,000 systems per year. By way of comparison, Germany has installed as many as 200,000 solar hot water systems in one year.[12] A Petition to Modify D.10-01-022 proposes to increase residential incentives for solar water heating by 100%, and commercial incentives by 30%.

III. CAISO's Resource Procurement Assumptions Do Not Account for Energy Efficiency, Demand Response, and Energy Storage and Do Not Properly Account for Distributed Generation and Combined Heat and Power.

A. CAISO Should Have Included More Energy Efficiency.

In its May 23, 2012 testimony, CAISO considered no uncommitted energy efficiency in its modeling.[13] By not having considered energy efficiency, CAISO's results are inherently conservative and call for greater MW than what will actually be needed.

In the 2010 LTPP, the Commission used an uncommitted EE assumption of 2,648 MW for SCE in all scenarios considered.[14] This value was based on the mid-case results from

[12] Powers, *Bay Area Smart Energy 2020* (Mar. 2012) p. 164.

[13] *See* Response of CAISO to the Second Set of Data Requests of the California Environmental Justice Alliance (hereafter "CEJA Requests 2"), Response to Request No. 3; Response of CAISO to the California Environmental Justice Alliance Data Requests (hereafter "CEJA Requests 1"), Response to Request No. 1; Updated Response of CAISO to the California Environmental Justice Alliance Data Requests First Set (hereafter "CEJA Requests 1 Update", Response to Request No. 3; Response of CAISO to the First Set of Data Requests of the Sierra Club California (hereafter "Sierra Club Requests 1"), Response to Request No. 28(b). See Attachment C for the full text of all cited data requests and responses. CAISO did include some uncommitted EE in its addendum (CEJA Requests 1 Update), but it did identify the precise amount considered in this scenario and whether all available uncommitted EE was accounted for. The addendum does show that the LCR was reduced after CAISO considered additional EE in the area.

the CEC's 2009 Integrated Energy Policy Report (IEPR), which includes that last adopted uncommitted energy efficiency forecast by the CEC. The CEC's 2009 uncommitted EE forecast was also conservative. For instance, it did not include industrial program savings. Also, it relied on the low realization scenario in California's Big Bold EE Strategies (BBEES).[15] The BBEES initiatives relate to new construction and heating, ventilation, and air conditioning.[16]

Since this assumption was developed, the CEC published the 2011 IERP. The 2011 IERP found the IOUs saved approximately 3,770 MW and 4,610 MW in 2009 and 2010 respectively.[17] For uncommitted EE, the 2011 IERP found that:

> By 2022, consumption in the mid-demand case would be reduced 3.3 percent if adjusted by the low savings scenario and 6.2 percent using high incremental uncommitted savings. For peak, the reductions range from 4.8 percent to 9.5 percent.[18]

As discussed by Julia May, CAISO should have included the percentage of uncommitted EE attributable to the LA Basin in its estimate.[19] The LA Basin is approximately 79% of SCE's total load.[20]

In addition, as an example of more recent uncommitted EE estimates, in December 2011, the CEC staff released the *Achieving Cost-Effective Energy Efficiency for California 2011–2020* final report, which summarizes utility progress and recommends improvements for publicly-owned utility (POU) efficiency efforts.[21] The report shows that the POUs reported 4,607 GWh of annual energy savings and 837 MW of peak savings for 2010, which exceeded the Commission's 2010 savings goals for POUs of 2,276 GWh and 502 MW.[22]

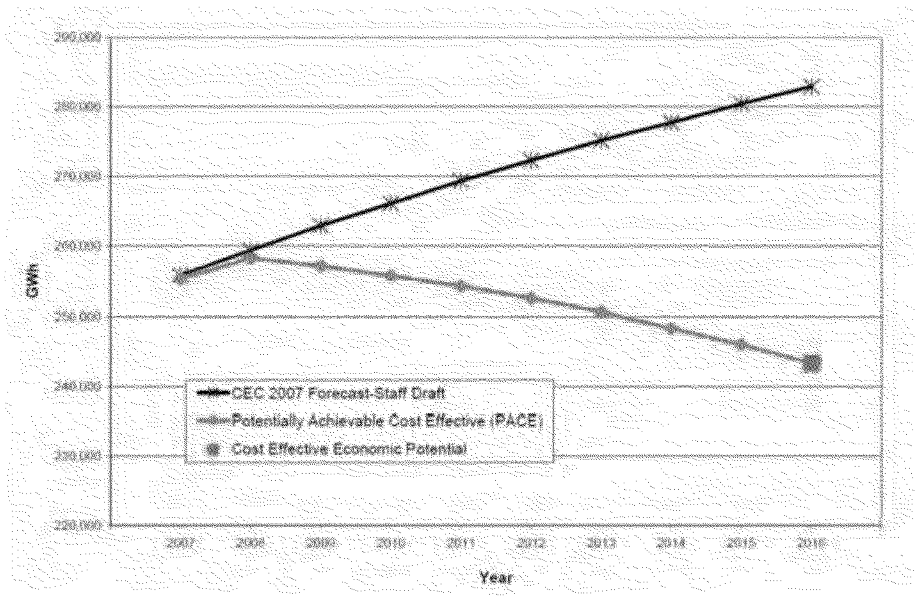
A CEC projection of the effect of achieving cost-effective energy efficiency measures statewide prepared in 2007 and is shown in Figure 2.[23] This projected pre-dates the more ambitious energy efficiency goals in the *Energy Efficiency Strategic Plan*. The CEC

---

[14] CPUC, *Scoping Memo in Rulemaking 10-05-006, Attachment 1 Standardized Planning Assumptions (Part 1) for System Resource Plans* (Dec. 3, 2010) <http://docs.cpuc.ca.gov/efile/RULC/127543.pdf> [as of June 22, 2012] p. 10 (hereafter "Scoping Memo to Rulemaking 10-05-006, Attachment 1").
[15] CPUC, *supra*, Scoping Memo in Rulemaking 10-05-006, Attachment 1, at p. 10.
[16] California Energy Commission (CEC), *Incremental Impacts of Energy Efficiency Policy Initiatives Relative to the 2009 Integrated Energy Policy Report Adopted Demand Forecast* (May 2010) p. 31–32; *see* Commission Decision 12-05-015 at p. 13 (summarizing the BBEES programs).
[17] CEC, *The 2011 Integrated Energy Policy Report* (2011) p. 53 <http://www.energy.ca.gov/2011publications/CEC-100-2011-001/CEC-100-2011-001-CMF.pdf> [as of June 20, 2012] (hereafter *2011 IEPR*).
[18] 2011 IERP at p. 112.
[19] See CEJA Requests 1 Update, Response to Request No. 3.
[20] *See* June 25, 2012 Expert Report of Julia May on behalf of CEJA in R.12-03-014.
[21] *2011 IEPR*, supra, at p. 8.
[22] *Ibid.*
[23] CEC, *Achieving All Cost-Effective Energy Efficiency for California* (Dec. 2007) p. 103, Figure 38.

projected an absolute rate of decline in electricity demand due to achieving all cost-effective energy efficiency is about 10,000 GWh every four years from 2013 forward.

Figure 2. Projected Absolute Decline in California Electricity Demand if All Cost-Effective Energy Efficiency Is Achieved



There are a host of EE programs and measures being implemented by IOUs in California. EE is also a key component of state environmental policies, such as the loading order and AB 32 compliance. While CAISO has argued that it is too difficult to estimate the exact level of EE in effect in 2020, it will certainly be more than the 0 MW CAISO has assumed.[24]

Any EE assumptions must consider the *Energy Efficiency Strategic Plan*. This *Plan* has been cited as one of the Commission's main methods of meeting its GHG goals.[25] In addition, other recent statewide policies are mandating greater energy efficiency measures. In particular, Governor Brown's April 25, 2012 Executive Order B-18-12 calls for half of California state government commercial buildings to reach zero net energy by 2025.[26]

A major element of the state's *Energy Efficiency Strategic Plan* is to advance residential and small commercial heating, ventilating, and air conditioning systems to ensure optimal equipment performance. As noted, the *Plan* targets a 50 percent improvement in efficiency of heating, ventilating, and air conditioning systems by 2020, and a 75 percent

---

[24] *See* CEJA Requests 1, Response to Request No. 1; CEJA Requests 1 Update, Response to Request No. 3; CEJA Requests 2, Response to Request No. 3; Sierra Club Requests 1, Responses to Request Nos, 6, 11, 12, 23(c).

[25] *See* CPUC & CEC, *Final Opinion on Greenhouse Gas Regulatory Strategies* <http://www.energy.ca.gov/2008publications/CEC-100-2008-007/CEC-100-2008-007-F.PDF>.[as of June 22, 2012].

[26] *See Executive Order B-18-12*, *supra*, ["State agencies shall also take measures toward achieving Zero Net Energy for 50% of the square footage of existing state-owned building area by 2025"].

improvement by 2030. Air conditioning loads are the cause of over 30 percent of California's total peak power demand in the summer. Meeting this air conditioning load is a primary driver behind procurement of additional high-cost generation, transmission, and distribution resources.[27]

Like the rest of California, a significant portion of SCE's peak load is attributable to air conditional loads. SCE can and should expect a significant decrease in this load, at a minimum, due to energy efficiency advancements. This significant decrease is not considered by the uncommitted energy efficiency value that the Commission assumed in the 2010 LTPP because the Commission's 544 MW assumed the low BBEES as discussed above, and that value is based on only accelerating penetration of an older technology, SEER 15 central air conditioning units.[28]

The average SEER rating for in-use central air conditioning units in California is approximately SEER 10, not the 2006 federal minimum standard of SEER 13 for new units.[29] Competitively-priced central air conditioning units with ratings as high as SEER 21 and greater are commercially available. There is about a 20 percent installed price difference between a SEER 13 or 14 unit and a SEER 21 unit. An incremental energy efficiency improvement of nearly 30 percent is realized by selecting a SEER 21 unit over SEER 13 when compared to the SEER 10 basecase.[30]

The difference in the installed cost (prior to rebates) of a reference case Carrier Corporation 3-ton SEER 13 residential central air and heating unit, which costs approximately $9,000, and a state-of-the-art Infinity® 21 unit (SEER 21) is around $2,000.[31] Carrier offers a rebate on high efficiency units that reduces the cost difference between the SEER 13 and SEER 21 alternatives by about $1,000.

CAISO's assumption of 0 MW of uncommitted EE also does not address thermal storage air conditioning systems now on the market that could nearly eliminate cooling- related peak demand if installed in new and existing buildings. The Southern California Public Power Authority (SCPPA) has contracted with Ice Energy for 53 MW of ice storage air conditioning units. SCPPA will install more than 6,000 Ice Bear units at 1,500 government and commercial buildings in its member communities.[32] The City of Glendale is a member of SCPPA. Glendale Water & Power (GWP) has installed 180 Ice

---

[27] *See, e.g.,* CEC, *Achieving All Cost-Effective Energy Efficiency for California* (Dec. 2007) p. 53.

[28] CEC, *Incremental Impacts of Energy Efficiency Policy Initiatives Relative to the 2009 Integrated Energy Policy Report Adopted Demand Forecast* (May 2010) p. 31 [SEER means "Summer Energy Efficiency Ratio." The SEER rating is linear in terms of electricity consumption. This means that a central air conditioning unit with a SEER 20 rating uses one-half the electricity that a SEER 10 unit uses to achieve the same cooling capacity].

[29] S. Okura, M. Brost (RLW Analytics, Inc.) & R. Rubin (SDG&E), *What Types of Appliances and Lighting Are Being Used in California Residences?* (2005) [In 2005, 53% of California residences had some form of cooling system].

[30] [(21 – 10)/21] – [(13 – 10/13)] = 0.52 – 0.23 = 0.29 (29 percent).

[31] Avalanche Mechanical (Carrier installer) quote to B. Powers for 3-ton SEER 21 central air conditioning and heating unit, September 4, 2007. Quote includes cost of new insulated ductwork.

[32] Ice Energy, *Public Power Daily SCPPA to Rollout 53-MW Storage Project* (Jan. 27, 2010).

Bear units in commercial buildings and reduced peak air conditioning load by 1.5 MW.[33] GWP makes these Ice Bear units available free of charge to qualified commercial customers due to their cost-effectiveness at reducing peak load.[34]

Substantial peak load reduction can also be achieved by upgrading existing commercial and institutional cooling systems. Many commercial buildings use electric motor-driven centrifugal chillers to provide cooling. Centrifugal chillers typically consume more electricity than any other single energy-consuming device in a commercial building.[35] The California Center for Sustainable Energy in San Diego has conducted hundreds of energy efficiency evaluations on chillers. Over 90 percent of these systems operate with relative low efficiency, in the range of 1.0 to 1.2 kW/ ton of cooling, using oversized pumps, constant speed equipment, and controls that do not work well.[36]

Central air conditioning units have a typical operational lifetime of 10 to 14 years.[37] Assuming this average age is representative of replacement frequency, more than 50 percent of current central air conditioning units will be replaced over the next 10 years. If each replacement on average reduces unit electricity consumption by 50 percent,[38] the electricity consumption of the entire population of central air conditioning units would drop about 25 percent over the next decade.[39]

Integrating air conditioning cycling capability into each new state-of-the-art central air conditioning unit sold would ensure near universal capability to participate in the air conditioner cycling program. SCE already has a limited cycling program that allows the utility to remotely cycle off-and-on the central air conditioning units of participating customers.[40] Air conditioner cycling capability could also easily be incorporated into each new unit prior to sale. This capability, if fully utilized, could reduce the instantaneous electricity demand from this population of air conditioners by 50 percent

---

[33] *See* City of Glendale, California, *Leading Energy Storage Company to Relocate to Glendale* (Apr. 25, 2012) <http://www.ci.glendale.ca.us/mgmt-svcs/press_release.aspx?AnnouncementID=958> [as of June 22, 2012].
[34] City of Glendale Water & Power, *Ice Bear Thermal Energy Storage Program* <http://www.glendalewaterandpower.com/businesses/ice_bear_program.aspx> [as of June 22, 2012].
[35] Platts Purchasing Advisor, *HVAC: Centrifugal Chillers* (2004) <www.reliant.com/en_US/**Platts**/PDF/P_PA_14.pdf> [as of June 22, 2012].
[36] The term "kW per ton of cooling" is a measure of the electric energy necessary to operate a commercial or institutional chiller plant. One ton of cooling load is the amount of heat absorbed to melt one ton of ice in one day, which is equivalent to 12,000 Btu per hour.
[37] Sears Home Services, *Central Heating & Air Conditioning Systems – A/C & Heating System Replacement* <http://www.searshomeservices.com/dslp?pid=8&lst=2625&partnerId=shsHvac&gclid&OVMTC=p&OVKEY=fix> [as of June 22, 2012] ["The average service life of a whole house HVAC unit is 10-14 years"].
[38] Assume the average rating of replacement units is SEER 20 and the population being replaced has an average rating of SEER 10. This represents a 50 percent reduction in electricity demand per ton of cooling capacity.
[39] If 50 percent of the central air conditioner population reduces demand by 50 percent through replacement with high efficiency units, and there is no change in the demand of the remaining 50 percent of existing central air conditioner units, the overall demand reduction is 25 percent.
[40] Southern California Edison (SCE), *Summer Discount Plan: Off the Air* <http://www.sce.com/info/PowerOutages/Facts-Resources/SDP.htm> [as of June 22, 2012].

beyond energy efficiency reductions, as half these units would be in offline at any given time while the other half are operational.

Air conditioning efficiency improvement is only one of many ways that SCE will realize energy efficiency gains in its service territory. By discounting energy efficiency measures as an effective method of reducing need, CAISO has ignored large potential reductions in peak demand as it asserts the need for new peaking generation. CAISO's numbers are based on flawed assumptions that result in an inappropriately high level of forecasted need.[41]

EE goals will also be met through the continued implementation of California's zero net energy building goals. In September 2011, the Commission released its *2010–2012 Zero Net Energy Action Plan* for the commercial building sector to support the state's zero net energy goals.[42] According to the Commission, California has more zero net energy buildings than any other state.[43]

The CEC is also contributing to zero net energy goals by regularly updating its building efficiency standards to reflect new technologies and strategies with the goal of achieving 20 to 30 percent energy savings in each triennial update, and by updating appliance standards to include electronics and other devices plugged into electrical outlets that represent an increasing portion of California's energy use.[44] "In 2010, appliance efficiency standards alone saved an estimated 18,761 gigawatt-hours (GWh) of electricity, representing nearly 7 percent of California's electric load, and saved consumers about $2.6 billion in energy costs."[45] Following along this path, on May 31, 2012, the CEC adopted new energy efficiency standards that require all new residential and commercial construction be "rooftop solar ready."

To meet the demand for more efficient electric devices, in 2012, the CEC adopted standards for the estimated 58 million battery chargers sold each year in California that, when implemented, will save state ratepayers an estimated $306 million each year, provide annual electricity savings of more than 2,000 GWh, and eliminate 1 million metric tons of carbon emissions.[46]

Finally, new legislation continues to push EE forward. For instance, AB 758 directed the CEC to develop, adopt, and implement a comprehensive program to reduce energy consumption in existing buildings, including regulations for energy ratings and improvements in existing buildings.[47] AB 1109 requires an 11 percent reduction in

---

[41] *See, e.g.,* CEJA Requests 1, Response to Request No. 1; CEJA Requests 2, Response to Request No. 3.
[42] CPUC, *Zero Net Energy Action Plan 2010–2012* (Sep. 2011) <http://www.cpuc.ca.gov/NR/rdonlyres/6C2310FE-AFE0-48E4-AF03-530A99D28FCE/0/ZNEActionPlanFINAL83110.pdf> [as of June 20, 2012].
[43] *2011 IEPR, supra*, at p. 9.
[44] *Ibid.*
[45] *Ibid.*
[46] *2011 IEPR, supra*, at p. 9.
[47] CEC, *AB 758 Comprehensive Energy Efficiency Program for Existing Buildings* <http://www.energy.ca.gov/ab758/> [as of June 20, 2012].

electricity consumption from residential lighting and an 8.6 percent reduction from commercial lighting.[48]

B. CAISO Should Have Included More Demand Response in its Analysis.

CAISO considered no demand response (DR) in its analysis presented in its May 23, 2012 testimony.[49] DR can and will be used in the future to meet local needs. DR can help meet reliability needs. The Commission recently summarized:[50]

> We are also taking steps to update our current Resource Adequacy program rules to conform to the CAISO's wholesale market and place DR on equal footing with generation resources. – in D.11-10-003, we directed that beginning in 2013 retail non-dynamic pricing DR resources must be dispatchable locally in order to qualify for local Resource Adequacy credits.

Importantly, DR can also help integrate renewable energy. The Commission has stated:

> Looking ahead to our pursuit of SB 1X's requirement that the Utilities obtain 33% of the energy they deliver from renewable sources by 2020, we also expect that DR will likely be called upon to meet new needs beyond its historic role as an emergency resource and peak shaving tool. DR is ideally suited to support grid integration of renewable generation, much of which will be intermittent or variable.[51]

The Commission has also stated that:[52]

> DR will be an increasingly valuable resource as we pursue future policy challenges. . . . The California Clean Energy Future plan expressly acknowledges that in addition to its historic role as an emergency and peak demand management tool, DR will be able to provide a range of services that can support grid integration of large quantities of intermittent and variable renewable resources. The plan also articulates our collective commitment to integrating DR into the CAISO's wholesale energy markets.

DR will be a key component in meeting RPS goals of 33 percent renewable energy by 2020.[53] As the Commission has stated, "DR is ideally suited to support grid integration

---

[48] *2011 IEPR*, *supra*, at p. 67.
[49] CEJA Requests 1, Responses to Request Nos. 2, 4; CEJA Requests 1 Update, Response to Request No. 4; CEJA Requests 2, Responses to Request Nos. 3, 7; Sierra Club Requests 1, Responses to Requests Nos. 7, 12, 21, 28(b); Response of CAISO to the First Set of Data Requests of the Vote Solar Initiative (hereafter "Vote Solar Requests 1"), Response to Request No. 11.
[50] CPUC, *Commission Decision 12-04-045* (Apr. 19, 2012) p. 15 (hereafter.*Commission Decision 12-04-045*).
[51] *Commission Decision 12-04-045, supra,* at p. 77.
[52] *Id.* at p. 12.

of renewable generation, much of which will be intermittent or variable."[54] Further, "DR programs are an essential element of California's energy resource strategy. Energy Efficiency and DR are our preferred resources for meeting California's energy needs, ranking at the top of the Loading Order."[55]

In the 2010 LTPP, to estimate the DR in 2020, the Commission considered available DR programs. It estimated that 2842 MW of DR resources would be available in the SCE territory in 2020.[56] In addition to numerous Commission DR programs, FERC has required integration of DR into the grid. CAISO is thus working on increasing the dispatch capability of DR. The Commission's assumption of 2842 MW for SCE in the 2010 LTPP, given all of the DR program advancements, is reasonable and should have been considered by CAISO. Furthermore, this DR estimate from the 2010 LTPP is conservative because it is based on a 1-in-2 forecast rather than a 1-in-10 forecast.

DR can also be expected to increase due to the advent of Advanced Metering Infrastructure (AMI).[57] AMI is a key component of the Commission's goal of increasing DR "as a means of reducing electricity demand during peak periods."[58] In the settlement between DRA and SCE over SCE's AMI plan, the parties agreed that SCE's AMI program could be "expected to generate $1,174 million in operational benefits and $816 million in energy conservation, load control, and DR related benefits."[59]

Other reports indicate the integrate DR technology into existing facilities may not be a major challenge. For instance, a report by Lawrence Berkeley National Laboratory found that "[t]he vast majority of facilities surveyed have either fully or semi-automated control systems in place, indicating that they have technical capability for either fully or semi-automated DR programs."[60]

CAISO is also engaged in integrating DR into the grid:

> Over the last five years, as part of its Market Redesign and Technology

---

[53] *Id.* at p. 77 ["Looking ahead to our pursuit of SB 1X's requirement that the Utilities obtain 33% of the energy they deliver from renewable sources by 2020, we also expect that DR will likely be called upon to meet new needs beyond its historic role as an emergency resource and peak shaving tool"].

[54] *Ibid.*

[55] *Id.* at p. 16.

[56] CPUC, R.10-05-006, December 2010 Scoping Memo, Appendix 1 at p. 60.

[57] See CPUC, *Commission Decision 08-09-039* (Sep. 18, 2008) (Approving settlement allowing $1.63 billion in ratepayer funding for SCE's proposed AMI project) (hereafter *Commission Decision 08-09-039*); CPUC, *CPUC Approves Advanced Metering Infrastructure for SoCalGas* (Apr. 8, 2010) <http://docs.cpuc.ca.gov/word_pdf/NEWS_RELEASE/116085.pdf> [as of June 22, 2012]; CPUC Smart Grid Workshop, *Smart Grid Implementation at the Sacramento Municipal Utility District* (Mar. 18, 2010) (SMUD received a $127 Smart Grid Investment Grant from DOE to implement $308 M worth of projects," including AMI and demand response).; *see also* 2010 LTPP Scoping Memo at p. 20 (stating that the benefits of the AMI program need to be accounted for in the DR assumptions).

[58] *Commission Decision 08-09-039, supra*, at pp. 2–3.

[59] *Id.* at p. 16.

[60] Ernest Orlando Lawrence Berkeley National Laboratory, *Assessing the Control Systems Capacity for Demand Response in California Industries*, (Jan. 2012) p. 22 <http://drrc.lbl.gov/sites/drrc.lbl.gov/files/LBNL-5319E.pdf> [as of June 20, 2012].

> Upgrade (MRTU), CAISO has engaged stakeholders in designing market products where capacity represented by DR can be bid into wholesale markets, just as traditional generation can be done today. The CAISO expects that integrating DR into its wholesale markets will increase competition, promote efficiency and reduce costs. Through its stakeholder process CAISO has developed two wholesale market products: (1) Proxy Demand Resource (PDR) and (2) Reliability Demand Response Resource (RDRR). PDR enables DR participation as a single resource or an aggregation of resources in the wholesale day-ahead and/or real-time energy markets and in the Ancillary Services market. In July 2010, the Federal Energy Regulatory Commission (FERC) approved CAISO's PDR.[61]

The Commission as well has stated that it is "working to facilitate the next phase of DR wholesale integration - direct participation in CAISO whole electricity markets."[62]

SCE has a host of ongoing DR activities, as do the other IOUs. The Commission recently approved the budget for DR activities for the IOUs for 2012-2014, including a budget of $196,338,052 for SCE.[63] In that decision, the Commission found that:

> SCE also proposes continuation of most of its DR programs from the 2009-2011 budget years with an eye toward incorporating many of these current programs into CAISO's PDR or RDRR requirements. To support CAISO market integration, SCE proposes an Ancillary Services tariff. SCE proposes a new price-responsive Residential Summer Discount Plan, for both legacy and newly enrolled customers. SCE also requests to launch a PLS program. With these programmatic proposals, SCE estimates to increase its load impacts from its current 1,530 MW to 1,824 MW by 2014 with approximately 1,360 MW of its portfolio available to be bid in the CAISO markets with full locational dispatch capability. SCE's application proposes two pilot programs: Smart Charging Pilot and the Workplace Charging Pilot. SCE claims these two pilots facilitate the adoption of new technologies.[64]

SCE projects that it will have 1,900 MW of DR by 2014, a corresponding 250,000 MWh per year of energy savings by 2014, and an additional 1,000 MW of AMI-enabled DR by 2017.[65]

The shutdown of the SONGS facility demonstrates the extent to which alternative resources such as DR can be used to replace traditional generation. In response to the shutdown as SONGS and the loss of its 2,200 MW of capacity, CAISO has recommended

---

[61] *Commission Decision 12-04-045, supra,* at p. 13.
[62] *Id.* at p. 14.
[63] *Id.* at p. 2.
[64] *Commission Decision 12-04-045, supra*, at pp. 19-20.
[65] SCE Smart Grid Deployment Plan Application (A.) 11-07-001, at p. 9

voluntary conservation through Flex Alerts and DR in order to mitigate the potential for outages.[66]

Specifically, CAISO recommends fully funding the Flex Alerts system and restarting the PUC 20/20 program. In addition, CAISO recommends "[f]ully utilize[ing] available demand response . . . [s]eek additional military and public agency demand response . . [and] [t]ake longer-term steps to increase available demand response system-wide."[67]

The Commission's Energy Division requested that both SCE and SDG&E submit Advice Letters "proposing augmentations and improvements to their existing DR programs in response to the planned outage at SONGS. Specifically, the Energy Division letter proposed the consideration of targeted incentive energy conservation programs (e.g., a 20/20 program or similar variation) and/or the expansion of existing PTR programs to additional customer classes."[68] SCE, as well as SDG&E, has filed for new DR programs for the summer.[69] The Commission approved SCE's and SDG&E's requests.[70]

A recent California Currents article summarizes the SCE and SDG&E DR programs and their potential:[71]

> Southern California Edison demand-response programs are estimated to produce more than 1,060 megawatts. Where the energy savings are occurring has not been revealed. SDG&E's price responsive programs are said to curb 84 MW, with another 20 MW cut from programs triggered when CAISO warns of supply constraints and calls a stage one emergency. On top of that, publicizing the need for conservation from the public via TV and radio can save up to 1,000 MW, said Greenlee (CAISO spokesman).

The public will provide a substantial DR contribution if asked to do so. California electricity consumers dropped usage 10 percent during the 2001 energy crisis in response to IOU media campaigns calling for conservation.[72] This is far more cost-effective for SCE customers than paying for new generation or transmission and distribution upgrades.

---

[66] CAISO, *Briefing on Summer 2012 Operations Preparedness* (Mar. 22–23, 2012) p. 3 <http://www.caiso.com/Documents/BriefingSummer2012OperationsPreparedness-Presentation-Mar2012.pdf> [as of June 20, 2012] ["San Diego is at risk of outages under heavy load conditions . . . Conservation and demand response will provide additional margin"]. See also Sierra Club Requests 1, Response to Request No. 23.
[67] CAISO, *supra*, *Briefing on Summer 2010 Operations Preparedness*, at p. 5.
[68] CPUC, Final Resolution E-4502 (May 24, 2012) p. 3 <http://docs.cpuc.ca.gov/PUBLISHED/FINAL_RESOLUTION/167572.htm> [as of June 22, 2012] (hereafter *Final Resolution E-4502*).
[69] The New York Times, *Southern California Edison Files Request for New Demand Response Program for this Summer* (Apr. 28, 2012) <http://markets.on.nytimes.com/research/stocks/news/press_release.asp?docTag=201204271930BIZWIRE_USPRX____BW6139&feedID=600&press_symbol=97164> [as of June 20, 2012].
[70] *See Final Resolution E-4502, supra* [approving SCE (AL 2721-E) and SDG&E (AL 2351-E) rebate programs in response to SONGS planned outage]
[71] California Current, *SoCal Grid's Parameters Tighten* (May 4, 2012).
[72] Jennings, et. al., *Conservation Motivations and Behavior During California's Energy Crisis* <http://eec.ucdavis.edu/ACEEE/2002/pdfs/panel08/11_39.pdf> [as of June 20, 2012].

Because CAISO has failed to incorporate any DR into its modeling, CAISO's modeling is unrealistically conservative and calls for more MW than will actually be needed.[73]

C. CAISO Should Have Considered More Energy Storage in Its Analysis.

CAISO did not consider any energy storage being available or added to the grid before 2021.[74] This is not a reasonable assumption.

The potential application of energy storage technologies ranges from bulk storage within the transmission system to smaller storage projects within the distribution system. The development of large-scale energy storage systems is moving forward in California. For example, in 2010 FERC approved incentive rates for Western Grid Development's utility-scale battery storage projects in California.[75] These projects are intended to address specific transmission reliability problems identified by CAISO.

Storage is an ideal way to backup intermittent renewable power. The CEC's Public Interest Energy Research Program released a strategic analysis of energy storage that reports that "[s]tudies indicate that California may require between 3,000 to 4,000 megawatts of fast-acting energy storage by 2020 to integrate the projected increase in renewable energy."[76]

Further, storage has been found to be more effective than conventional peaking generation, and may therefore not be needed on a one–to-one to ratio. A report by SCE found that CAISO's "control area may require between 3,000 and 5,000 MW of additional regulation/ramping services from fast (5-10 MW per second) resources in 2020. . . Fast (defined as 10 MW per second) storage is two to three times more effective than conventional generation in meeting ramping requirements. Consequently, 30-50 MW of storage is equivalent to 100 MW of conventional generation."[77]

In the same report, SCE made several findings related to storage:

---

[73] *See* CEJA Requests 1, Response to Request No. 2; CEJA Requests 1 Update, Response to Request No. 4; CEJA Requests 2, Responses to Request Nos. 3, 7; Sierra Club Requests 1 Nos. 7, 12, 21; Vote Solar Requests 1, Response to Request No. 11.
[74] *See* CEJA Requests 1, Response to Request No. 6; Sierra Club Requests 1, Responses to Request Nos. 5, 11; Vote Solar Requests 1, Response to Request No. 4(d)..
[75] SNL Financial, *FERC approves incentive rates for Western Grid Development's battery storage projects* (Jan. 22, 2010).
[76] Public Interest Energy Research (PIER) Program Final Project Report, *2020 Strategic Analysis of Energy Storage in California* (Nov. 2011), p. 6 <http://www.energy.ca.gov/2011publications/CEC-500-2011-047/CEC-500-2011-047.pdf>, [as of June 22, 2012].
[77] Southern California Edison, *Moving Energy Storage from Concept to Reality* (May 20, 2011) p. 14 <http://www.energy.ca.gov/2011_energypolicy/documents/2011-04-28_workshop/comments/TN_60861_05-20-11_Southern_California_Edison_Company_Comments_Re_Energy_Storage_for_Renewable_Integration.pdf> [as of June 20, 2012] (hereafter *Moving Energy Storage*).

"*Many [storage] technologies are approaching commercial availability*. These have been tested for viability, are actively looking for partnerships, and are beginning to sign substantial contracts with customers.

Energy storage companies are actively targeting the utility storage market and have established strong external support and momentum. Storage companies are developing internal knowledge about utility interests and priorities and are providing more sophisticated value propositions for their products.

The vast majority of energy storage products are not in direct competition with one another, due to different power-to-energy ratios, cycling capabilities, and other attributes (see the technology comparison sidebar)."[78]

AB 2514, signed into law in September 2010, directs the Commission to open a proceeding by March 2012 to determine the amount of energy storage, if any, to be developed by the IOUs.[79] Similar language is included for POUs. The Commission initiated this energy storage proceeding in December 2010.[80] The bill initially contained specific energy storage targets. These targets included energy storage equivalent to 2.25 percent of the daily peak load by 2014, and 5 percent of the daily peak load by 2020.[81] Daily peak load is defined as a utility's average peak electrical demand over the previous five years. On a statewide level, assuming an average statewide peak load of 50,000 MW, this is equivalent to somewhat over 1,000 MW of energy storage in 2014 and 2,500 MW of energy storage in 2020.[82] Specific percentage energy storage targets were dropped from the final version of AB 2514.

The Governor's *Clean Energy Jobs Plan* also "envisions, accelerated development of energy storage capacity to support integration of renewable resources into the California grid."[83]

Despite recognizing the value of storage and the increasing availability of storage technology, CAISO fails to consider storage as a viable option.[84] Storage projects are being developed and will be on-line to potentially meet bundled need. For example,

---

[78] *Id.* at p. 29.

[79] Assembly Bill 2514 (Sep. 29, 2010) <http://www.leginfo.ca.gov/pub/09-10/bill/asm/ab_2501-2550/ab_2514_bill_20100929_chaptered.html> [as of June 20, 2012].

[80] CPUC, *R.10-12-007* (Dec. 2010).

[81] Megawatt Storage Farms, Inc., *Comments of MegaWatt Storage Farms on CAISO Conceptual Statewide Transmission Plan*, (Feb. 17, 2011) p. 5.

[82] Assembly Bill 2514, Introduced February 19, 2010 <http://www.leginfo.ca.gov/pub/09-10/bill/asm/ab_2501-2550/ab_2514_bill_20100219_introduced.html> [as of June 22, 2012].

[83] CEC, *Renewable Power in California: Status and Issues* (Dec. 2011) p. 27; *see also 2011 IEPR, supra*, p. 75 n. 92.

[84] CEJA Requests 1, Response to Request No. 6; Sierra Club Requests 1, Responses to Request Nos. 5, 11; Vote Solar Requests 1, Response to Request No. 4(d).

Beacon Power constructed flywheels connected to a California wind farm,[85] and PG&E is installing 4 MW of sodium-sulfur utility scale battery projects in 2012.[86]

In addition, storage projects such as the 53 MW distributed storage project by Ice Energy was not considered by CAISO as a resource. SCE also has a number of demonstration projects that incorporate energy storage, SCE has also made storage a major aspect of its Smart Grid plan. The failure to consider *any* storage projects that are on-line or being constructed as an available resource makes CAISO's analysis unrealistically conservative. These resources need to be considered since they are a viable way to meet load requirements and are an integral part of SCE's Smart Grid plan.

Funding for storage initiatives is increasing in California. Investments in energy storage have increased by 13 fold over the past year, accounting for 11 percent of total investment dollars in clean technology in 2011.[87] A bill has also been introduced in Congress that would provide for an energy investment credit for energy storage that connected to the grid.[88]

The Commission also granted eligibility to Advanced Energy Storage to be included as a qualifying facility in the Self-Generation Incentive Program, citing the ability to "reduce peak demand and GHGs.[89]

FERC has also begun examining how storage can be integrated into the grid. For instance, in 2010, FERC put out a request for comments on rates and other issues related to new energy storage technologies.[90]

In partnership with the DOE, SCE is currently testing 8 MW of "large-scale lithium-ion batteries for storing intermittently-generated wind energy."[91] The project stores wind energy generated in the Tehachapi Wind Resource Area.[92]

---

[85] *See* CEC, *Energy Commission Awards $2 Million to PG&E for Battery Storage Research* (Feb. 9, 2010) <http://www.energy.ca.gov/releases/2010_releases/2010-02-09_battery_storage.html> [as of June 20, 2012].

[86] Pacific Gas and Electric Company, *PG&E Smart Grid Deployment Plan 2011-2010* (June 2011), <http://www.pge.com/includes/docs/pdfs/shared/edusafety/electric/SmartGridDeploymentPlan2011_06-30-11.pdf> [as of June 20, 2012]

[87] Next 10, *2012 California Green Innovation Index* (2012) p. 16 <http://next10.org/sites/next10.huang.radicaldesigns.org/files/2012_GII%20Report_mech_final.pdf> [as of June 20, 2012]; *see also id.* at p. 20 ["California has been a consistent leader in battery technology patent registrations. Reaching 258 total patents in the 2008-10 period, filings increased by 55 percent from the prior period. Lithium Battery represents the second largest category of battery patents. The largest category represents a mix of technologies"].

[88] *See Storage Technology of Renewable and Green Energy Act of 2009* ("STORAGE Act of 2009") <http://wyden.senate.gov/imo/media/doc/storage.pdf> [as of June 20, 2012].

[89] CPUC, *Commission Decision 11-09-015* (Sep. 8, 2011) p. 19, 62.

[90] Federal Energy Regulatory Commission (FERC), *Request for Comments Regarding Rates, Accounting and Financial Reporting for New Electric Storage Technologies Docket No. AD10-13-000* (Jun. 11, 2010) <http://www.ferc.gov/media/headlines/2010/2010-2/06-14-10-notice.pdf> [as of June 20, 2012].

[91] Southern California Edison, *Energy Storage is Key to More Efficient Grid* <http://www.sce.com/PowerandEnvironment/smartgrid/energy-storage.htm> [as of June 20, 2012].

SCE also has a Home Battery Pilot Project to assess the potential for use of lithium ion batter cells used in Plug-in Electric Vehicles for energy storage in residential and small commercial applications.[93] "SCE proposed to test the concept by integrating home energy storage with Demand Response (DR) strategies, renewable energy generation (wind and solar) and SCE's advanced metering infrastructure."[94] The pilot projects will include up to 50 sites by the end of 2012.[95] "The program assumes that peak demand can be reduced by up to 4 kW per home for up to two hours per day."[96]

SCE has also stated that it "launched a dedicated energy storage strategic planning effort in January 2010."[97] Drivers for this project included federal stimulus funds targeting the "green tech" sector through 2009's American Recovery and Reinvestment Act, "totaling $620 million explicitly for energy storage projects with a further $3.5 billion in related smart grid investment."[98]

In addition, SCE's Irvine Smart Grid Demonstration is a $79 million pilot project that "will comprehensively test various storage operational uses and applications within a Smart Grid over a 3-year time frame.[99] SCE's current R&D initiatives also include community energy storage (distributed units of 25 to 50kW/50 to 100kWh), and residential home energy storage units.[100]

BrightSource Energy Inc. has also added its SolarPLUS thermal energy storage capability to three of its power purchase agreements with SCE. "The new set of contracts . . . consist of two BrightSource solar thermal plants scheduled to deliver electricity in 2015 and three plants with energy storage scheduled to deliver electricity in 2016 and 2017."[101]

---

92 Southern California Edison, *Tehachapi Wind Energy Storage (TSP) Project* (Nov. 3, 2010) <http://energy.gov/sites/prod/files/ESS%202010%20Update%20Conference%20-%20Tehachapi%20Wind%20Energy%20Storage%20-%20Loic%20Gaillac,%20SCE.pdf> [as of June 20, 2012].

93 *See* Southern California Edison, *Home Battery Pilot Technical Requirements* (Nov. 3, 2009) p. 5 <http://asset.sce.com/Documents/Environment%20-%20Smart%20Grid/HomeBatteryPilotTechnicalRequirements.pdf> [as of June 20, 2012].

94 *Ibid.*

95 *Ibid.*

96 *Ibid.*

97 Rittershausen & McDonagh, *Moving Energy Storage from Concept to Reality: Southern California Edison's Approach to Evaluating Energy Storage*, at p. 12 <http://www.edison.com/files/WhitePaper_SCEsApproachtoEvaluatingEnergyStorage.pdf> [as of June 20, 2012]..

98 *Ibid.*

99 Southern California Edison, *Panel Discussion: The Economics of Distributed Energy Storage* (Sept. 7, 2011) p. 12 <http://eosenergystorage.com/documents/SCEPresentation-The-Economics-of-Distributed-Storage.pptx> [as of June 21, 2012].

100 Southern California Edison, *SCE Evaluation of CES Batteries and Systems* (May 2 – 4, 2012) p. 8 <http://www.electricitystorage.org/site/download.php/2012_presentations/i47_gaillacv1.pdf> [as of June 21, 2012].

101 The Daily Energy Report, *BrightSource, SCE Add Energy Storage Capabilities to Power Purchase Agreements* <http://www.dailyenergyreport.com/2011/11/brightsource-sce-add-energy-storage-capabilities-to-power-purchase-agreements/> [as of June 21, 2012].

Brightsource has stated that by adding storage, it will be able to forego building an additional 200 MW plant.[102]

Other SCE storage projects include a contract "to furnish a turnkey 1 MW S&C Smart Grid SMS™ Storage Management System on Catalina Island, off the coast of California. The Smart Grid SMS is a fast-responding automatic controller that uses built-in intelligence to control charging and discharging of sodium-sulfur batteries."[103]

Finally, both CAISO and SCE have recognized that increasing storage potential in California is necessary and have identified market barriers to storage development.[104] CAISO as well has elaborated at length on growing opportunities for energy storage in California and the steps it is taking to remove barriers to storage development. In the energy storage proceeding, CAISO has stated that: [105]

> It has recently undertaken the following initiatives that have already facilitated, or will soon facilitate, the ability of energy storage to participate in ISO markets. In July 2010, the ISO sought approval to revise several aspects of its tariff requirements for ancillary services in order to expand the pool of resources able to participate in the ISO's ancillary services markets. The revisions, which FERC approved in September 2010, relaxed certain requirements that the ISO concluded were no longer required for reliable operation . . . These changes were designed specifically to enhance the ability of energy storage and other non-traditional resources to participate in the ISO's ancillary services markets, consistent with the ISO's operational and reliability needs. In addition, in August 2011, the ISO filed a proposal with FERC for approval of a market enhancement known as regulation energy management . . . this enhancement will facilitate the ability of limited energy storage resources to participate in the ISO's regulation market by enabling them to bid their capacity more effectively while still meeting the ISO's continuous energy requirements for regulation. In November 2011, FERC approved the ISO's regulation energy management proposal, based on findings that it reduces barriers to the ISO's ancillary services markets for 'non-generator resources' and 'allows non-generator resources to participate more fully in CAISO's regulation market, consistent with continuous energy requirements.' The ISO is currently working with stakeholders to initiate a market simulation of

---

[102] Sustainable Business, *Brightsource Signs Big Energy Storage Deal* (Nov. 29, 2011) <http://www.sustainablebusiness.com/index.cfm/go/news.display/id/23193> [as of June 21, 2012].

[103] Energy Central, *S&C Electric Company Helps Southern California Edison Reduce Greenhouse Gas Emissions* (Jun. 27, 2011) <http://www.energycentral.com/generationstorage/energystorage/news/vpr/11151/S-C-Electric-Company-Helps-Southern-California-Edison-Reduce-Greenhouse-Gas-Emissions> [as of June 21, 2012].

[104] Shigekawa & Allred, *Comments of Southern California Edison Company to the California Public Utilities Commission on the Energy Storage Framework Staff Proposal, R.10-12-007* (Jan. 31, 2012), p. 3 <http://docs.cpuc.ca.gov/efile/CM/158861.pdf> [as of June 21, 2012] ("Opportunities currently exist for energy storage, and more will develop as barriers are overcome").

[105] CAISO, *Comments of the California Independent Systems Operator Corporation on Initial Staff Proposal, R.10-12-007* (Jan. 13, 2012) pp. 4–6 <http://docs.cpuc.ca.gov/efile/CM/158871.pdf> [as of June 21, 2012].

> regulation energy management and expects to bring this functionality into production later this year.
>
> In addition to these two FERC-approved tariff revisions, the ISO has recently commenced two initiatives to refine its markets that should facilitate the participation of energy storage. In December 2011, the ISO initiated a Pay for Performance Regulation stakeholder initiative in response to FERC Order No. 755, which directs independent system operators and regional transmission organizations to revise their frequency regulation services to ensure that faster ramping resources are compensated for the greater amount of frequency regulation they provide in comparison to resources with longer ramp rates.
>
> Although the stakeholder process is still ongoing, the ISO's most recent straw proposal includes design elements that would compensate resources depending on both the total movement of a resource in response to automatic generation control signals over a given period and the accuracy with which the resource responds to the regulation signal. Such refinements in compensation should facilitate the participation of non-traditional generation resources – such as energy storage – in the regulation market, provided that those resources are able to ramp more quickly and respond more accurately than traditional generation resources.
>
> The ISO also has recently initiated a stakeholder process to develop a market-based flexible ramping capacity product to address reliability concerns and operational needs in the ISO's real-time market. This product, once developed, will provide an additional means for fast-ramping resources to participate in the ISO's markets in a manner that meets an important operational need.

As demonstrated by the multitude of projects, CAISO's assumption of no energy storage is unreasonable. CAISO should have included at a minimum all of the existing projects. In addition, as shown above, many other projects are being constructed and planned for the system before 2021. These projects should have been evaluated for inclusion into the modeling assumptions.

D. CAISO Should Have Considered More Local Renewable Energy in its Analysis.

CAISO should have considered more renewable energy capacity in its analysis.[106]

Regarding distributed PV generally, the Commission observed with its approval of the PG&E 500 PV project that:

> This solar development program has many benefits and can help the state meet its aggressive renewable power goals," said CPUC President Michael R. Peevey. 'Smaller scale projects can avoid many of the pitfalls that have plagued larger renewable projects in California, including permitting and transmission challenges.

[106] *See, e.g.,* Sierra Club Requests 1, Responses to Request Nos. 26, 27, 33, 35, 36 (describing CAISO's assumptions).

Because of this, programs targeting these resources can serve as a valuable complement to the existing Renewables Portfolio Standard program.'[107]

PV should be counted towards meeting RA peak needs. The CEC has recognized the value of energy generated from distributed PV as a cost-effective substitute for natural gas-fired peaking generation. The CEC denied an application for a 100 MW natural gas-fried peaking gas turbine plant, the Chula Vista Energy Upgrade Project (CVEUP) in San Diego County, in June 2009. The application was denied in part because the CEC opined that rooftop PV could potentially achieve the same objectives for comparable cost.[108]

The June 2009 CEC decision implies that any future applications for gas-fired generation in California should be measured against using distributed PV to meet the demand. The final CEC decision in the CVEUP proceeding states:[109]

> "Photovoltaic arrays mounted on existing flat warehouse roofs or on top of vehicle shelters in parking lots do not consume any acreage. The warehouses and parking lots continue to perform those functions with the PV in place. . . . Mr. Powers (expert for intervenor) provided detailed analysis of the costs of such PV, concluding that there was little or no difference between the cost of energy provided by a project such as the CVEUP (gas turbine peaking plant) compared with the cost of energy provided by PV.. . . PV does provide power at a time when demand is likely to be high—on hot, sunny days. Mr. Powers acknowledged on cross-examination that the solar peak does not match the demand peak, but testified that storage technologies exist which could be used to manage this. The essential points in Mr. Powers' testimony about the costs and practicality of PV were uncontroverted."

The CEC concluded in the CVEUP final decision that PV solar arrays on rooftops and over parking lots may be a viable alternative to the gas turbine project proposed in that case, and that if the gas turbine project proponent opted to file a new application, a much more detailed analysis of the rooftop PV alternative would be required.

In 2009, the Commission evaluated a renewable energy strategy that relies primarily on distributed PV, known as the "High DG" strategy, to achieve the state's 33 percent by 2020 goal.[110] The High DG alternative substitutes 15,000 MW_{ac} of distributed PV for a comparable amount of remote utility-scale solar and wind projects in the utility 33 percent by 2020 reference case scenario.[111] The Commission determined that the cost of the High DG alternative would be comparable to the cost of the utility reference case scenario if the capital cost of PV was about one-half the cost assumed by the Commission in its analysis.

---

[107] CPUC, *CPUC Approves Solar PV Program for PG&E* (Apr. 22, 2010) [Docket A.09-02-019.]
[108] CEC, *Chula Vista Energy Upgrade Project – Application for Certification (07-AFC-4) San Diego County, Final Commission Decision* (Jun. 2009).
[109] *Id.* at pp. 29–30 (internal citations omitted). .
[110] CPUC, *33% Renewable Portfolio Standard Implementation Analysis Preliminary Results*, (Jun. 2009) p. 19, Table 2 (hereafter *33% Renewable Portfolio*).
[111] *Id.* at p. 52.

The LCOE for distributed PV assumed by the Commission in reaching this conclusion was $168/MWh.[112] The cost of PV has dropped dramatically since 2009. Solar panel cost dropped 46 percent in 2011 alone.[113]

The Commission determined that the cost of the High DG alternative would be comparable to the cost of the utility reference case scenario if the capital cost of PV was about one-half the $7/Wac capital cost assumed by the Commission in its analysis. $306/MWh was the levelized cost-of-energy assumed for the $7/Wac distributed PV capital cost. The Commission stated that a distributed PV capital cost of $3.70/Wac would result in cost parity with the utility 33 percent reference case scenario. The distributed PV levelized cost-of-energy assumed by the CPUC for distributed PV with a capital cost of $3.70/Wac was $168/MWh.[114]

The Commission prepares quarterly summary reports on the state's progress toward RPS goals. The fourth quarter 2011 report includes pricing data on RPS contracts for the first time, in conformance with SB 836 (2011) RPS contract price reporting requirements.[115] SB 836 requires that average RPS contract prices be reported by contract year, technology type, and size range by each IOU. The average 2011 contract prices reported by PG&E for 0-3 MW solar PV was $129/MWh. The average 2011 contract prices reported by SCE for 0-3 MW solar PV was $142/MWh. The average price reported by PG&E for 3-20 MW solar PV projects was $114/MWh. The average price reported by SCE for 3-20 MW solar PV projects was $124/MWh.[116]

Competitive power purchase contract prices for commercial rooftop PV systems in California at the end of 2011 were: $130/MWh for 1 MW systems, $140/MWh for 500 kW systems, and $150/MWh for 100 kW systems.[117] The 2012 tariff price for commercial rooftop PV systems that are 100 kW or greater is $0.14/kWh, or

---

[112] *Id.* at p. 31 [The CPUC PV sensitivity analysis assumed a thin-film PV capital cost of $3.70/Wac with a cost-of-energy of $268/MWh. The report defines High DG in this manner,"[a]ssumes limited new transmission corridors are developed to access additional renewable resources to achieve a 33% RPS. Instead, extensive, smaller-scale renewable generation is located on the distribution system and close to substations." (*Id.* at 19).]

[113] Bloomberg, *First Solar Latest Casualty in Renewable Energy Shakeout* (Apr. 18, 2012).

[114] *33% Renewable Portfolio, supra,* at p. 31. [The CPUC PV sensitivity analysis assumed a thin-film PV capital cost of $3.70/Wac with a cost-of-energy of $168/MWh. "Thus, the Solar PV Cost Reduction sensitivity results in the High DG Case having similar overall costs to the 33% RPS Reference Case and other renewable resource mixes that depend on central station renewable generation." (*Id.* at p. 31). The report defines High DG in this manner, "Assumes limited new transmission corridors are developed to access additional renewable resources to achieve a 33% RPS. Instead, extensive, smaller-scale renewable generation is located on the distribution system and close to substations."(*Id.* at p. 19).]

[115] CPUC, *Renewable Portfolio Standard Quarterly Report – 4th Quarter 2011—Attachment A* (Feb. 2012) <http://www.cpuc.ca.gov/NR/rdonlyres/3B3FE98B-D833-428A-B606-47C9B64B7A89/0/Q4RPSReporttotheLegislatureFINAL3.pdf> [as of June 22, 2012.]

[116] *Id.* at p. A-4, Table A-2.

[117] Lewis C. – Clean Coalition, *Making Clean Local Energy Accessible Now*, (Dec. 8–9, 2011) p. 8 [PowerPoint presentation, California Foundation for the Economy and Environment workshop on distributed renewable generation, Sausalito, California.]

$140/MWh.[118] This clean payment rate for commercial rooftop PV systems is well below the parity price of $168/MWh identified by the Commission for the utility reference case 33 percent RPS compliance strategy. Due to continued cost declines and policy support, the Solar Energy Industry Association projects that distributed generation in California will reach 5.3 GW by 2016 alone.[119]

The actual availability of the solar resource in SCE territory during the top 100 demand hours is approximately 96 percent.[120] The actual availability of peaking natural gas-fired resources is at best equivalent to that of rooftop PV systems. Recent natural gas-fired peaking turbine projects in the Bay Area, including 200 MW Mariposa Energy Center and 760 MW Marsh Landing Generating Station, state expected availability in the range of 92 to 98 percent. The projected availability of Marsh Landing is 94 to 98 percent.[121] The projected availability of Mariposa Energy Center is 92 to 98 percent.[122]

The loss of one large natural gas-fired plant has potentially major implications for grid reliability. For example, the Sempra 600 MW combined cycle plant in Mexicali, Mexico, which is under CAISO operational control and connects directly to the SDG&E Imperial Valley substation, was in forced outage due to a steam turbine generator problem on September 8, 2011.[123] September 8, 2011 was the third day of the most intense heat wave of 2011 in SDG&E service territory. The lack of voltage support at the Imperial Valley substation on that day led contributed to a cascading series of trips that caused the largest blackout in many years in Southern California and Northern Baja California.

The high reliability of solar PV, combined the grid reliability benefits of distributing output over many smaller sources instead of a single unit, make rooftop PV an excellent substitute for conventional natural gas-fired peaking units in SCE territory.
Numbers from the California Solar Initiative demonstrate an on-peak capacity factor for distributed PV of at least 50 percent.[124] Solar PV is predictably available during periods of peak demand. The reason the PV capacity factor is lower than the solar availability of

---

118 *See* City of Palo Alto, *Palo Alto CLEAN Program* <http://www.cityofpaloalto.org/news/displaynews.asp?NewsID=1877&targetid=223> [as of June 21, 201 [describing Palo Alto's CLEAN program]; Greentech Media, *It's Official: Palo Alto, Calif. Has a Feed-In Tariff for PV* (Mar. 6, 2012) <http://www.greentechmedia.com/articles/read/Its-Official-Palo-Alto-Calif.-Has-a-Feed-In-Tariff-for-PV-/> [as of June 21, 2012].

119 SEIA, *California DG and Utility Solar Capacity* (May 2012) [attached hereto as Attachment A.]

120 *See* Exhibit B (attached to this report).

121 CEC, *Marsh Landing Generating Station – Commission Decision* (Aug. 2010) p. 8. ["The overall annual availability of the MLGS as measured by equivalent availability factor (EAF) is expected to be approximately 94 to 98 percent".]

122 CEC, *Mariposa Energy Project – Commission Decision* (May 2011) pp. 1–2 ["Applicant intends that the Mariposa Energy Project (MEP) provide operating flexibility and rapid start capability, i.e. the ability to quickly start up and provide efficient part load and base load power. It expects an annual availability factor of 92 to 98 percent for the project"]

123 Federal Energy Regulatory Commission, *Arizona – Southern California Outages on September 8, 2011 – Causes and Recommendations*, April 2012, p. 4. Map of affected area shows Sempra Termoelectrica (TDM) combined cycle plant in Mexicali "on outage."

124 *See* Itron, *CPUC California Solar Initiative Report* (Jun. 2010) pp. 5-6 to 5-10 <http://www.cpuc.ca.gov/NR/rdonlyres/70B3F447-ADF5-48D3-8DF0-5DCE0E9DD09E/0/2009_CSI_Impact_Report.pdf> [as of June 22, 2012].

at least 96 percent is because peak production from a fixed PV array occurs at mid-day and the demand peak generally occurs in mid-afternoon. Distributed PV is also predictably available at a reduced level on partly cloudy days when the output of multiple dispersed PV systems is averaged together.

A number of state goals are currently increasing the amount of PV across the state, including Governor Brown's goal of the development of 12,000 MW of local renewable energy by 2020, the SB 32 feed-in tariff program, the Commission's Renewable Auction Mechanism, and the SB1 target of 3,000 MW of net-metered solar DG by 2017.[125] As the CEC has found:[126]

> Recent trends indicate increasing market interest in renewable development. The 2009 RPS solicitation by the investor-owned utilities (IOUs) drew bids from developers offering to supply enough renewable generation to meet half of the IOUs' total electrical load in 2020, and IOUs currently have signed contracts for roughly 14,000 MW of new renewable capacity. In 2010, state and local entities issued permits for 9,435 MW of renewable capacity, and another 28,000 MW is being tracked in various permitting processes.

Similarly, in-state renewable generation represented about 75 percent of total renewable generation from more than 10,000 MW of renewable generating capacity.[127] Renewable energy has a projected annual growth rate of 18 percent per year from 2010–2016,[128] while California is currently adding approximately 25 MW per *month* of PV.[129] Further, CAISO's interconnection queue includes about 57,000 MW of renewable capacity, and there are 450 active interconnection requests for DG systems in the Wholesale Distribution Access Tariff queue totaling about 5,200 MW.[130]

One recent Los Angeles Business Council report found that the City of Los Angeles has approximately 5,536 MW of rooftop solar potential.[131] The same study estimated a rooftop solar potential for Los Angeles County of 19,113 MW.[132] Navigant, under

---

[125] See *AB 32 Climate Change Scoping Plan, supra*, at pp. 41-53. .
[126] *2011 IEPR*, *supra*, at p. 34–35. [Citing California Energy Commission, *Renewable Energy Action Team-Generation Tracking for Renewable Projects* (Jun. 11, 2012) <www.energy.ca.gov/33by2020/documents/renewable_projects/REAT_Generation_Tracking_Projects_Report.pdf> (as of June 22, 2012).]
[127] *Id.* at p. 29.
[128] *Id.* at p. 76.
[129] See CPUC, *About the California Solar Initiative* <http://www.cpuc.ca.gov/PUC/energy/Solar/aboutsolar.htm> [i.e. general CSI plus NSHP].
[130] *2011 IEPR*, at p. 35.
[131] Los Angeles Business Council, *Bringing Solar Energy to Los Angeles: An Assessment of the Feasibility and Impact of an In-Basin Solar Feed-in Tariff Program* (Jul. 8, 2010) p. x <http://www.labusinesscouncil.org/online_documents/2010/Consolidated-Document-070810.pdf> [as of June 21, 2012].
[132] *Ibid.*

contract to the CEC, determined the California statewide rooftop solar technical potential to be 60,929 MW.[133]

The Solar Electric Industry Association estimates that distributed solar generation will reach 5,300 MW by 2016.[134] Thus, a high case of 6,000 MW in 2020 is reasonable, as is the mid case of 4,500 MW by 2020.

The construction of new generation and transmission in California is primarily justified by utilities on projections of rising peak load. Therefore, it is necessary to understand what percentage of solar and wind capacity will be reliably available during peak demand to avoid excessive construction of conventional generation and transmission infrastructure.

Hot summer days are cloud-free or nearly cloud-free in the greater Los Angeles area. This results in maximum output from solar resources during peak demand periods.[135] In contrast, wind intensity is generally lowest during summer mid-day and afternoon periods. As a result, the solar resource would have the predominant market price depression effect on summer afternoons when market prices are highest. The PV system output peak is mid-day, while the summer demand peak usually occurs in the mid-afternoon.

The reduction in German electricity market prices caused by renewable energy depressing market prices in 2009 is estimated at approximately $5 billion by the German government.[136] Germany produced approximately 16 percent, or 94,000 GWh, of its total electricity demand with renewable energy resources in 2009.[137] The $5 billion per year reduction in the market price of power is a $5 billion per year savings to German ratepayers. Germany has an electricity market that is approximately twice the size of the California market at about 526,000 GWh per year of end user consumption.[138]

Many California jurisdictions are supporting renewable DG by expediting permitting barriers. The California County Planning Directors Association is also coordinating a multi-stakeholder effort to draft a model ordinance for solar electric facilities for cities

---

[133] Navigant, *Distributed Renewable Energy Assessment Final Report*, prepared for the Public Interest Energy Research Program, California Energy Commission, August 11, 2009, p. 43. "NCI's (Navigant's) PV technical potential is significantly higher than other PV estimates because these other studies are not true technical potentials. Rather, they are constrained by the distribution system."
[134] Solar Energy Industries Association, *California DG and Utility Solar Capacity* (May 2012).
[135] *See* Attachment B.
[136] German Federal Ministry for the Environment, Nature Conservation, and Nuclear Safety, *Cost and benefit effects of renewable energy expansion in the power and heat sectors,* June 2010. Merit order effect of renewable energy estimated at 3.6 to 4 billion Euros in 2009. 1 Euro = 1.334 dollars as of January 16, 2011. Therefore 3.6 to 4 billion Euros = 4.8 to 5.3 billion dollars.
[137] Yale Global, *Germany Leads With Its Goal of 100 Percent Renewable Energy*, September 7, 2010. Approximately 9,800 MW of solar and 25,800 MW of wind resources were online in Germany by the end of 2009; UPI.com, *German renewable industry booming*, March 24, 2010.
[138] See International Energy Agency, *Statistics Germany 2009* <http://www.iea.org/stats/electricitydata.asp?COUNTRY_CODE=DE> [as of June 21, 2012] [Final 2009 consumption of electricity = 526,000 GWh].

and counties across the state.[139] Further, the Commission is engaged in making ongoing improvements to PV interconnection policies, including a "best practice" for DG penetration levels, and "[n]ew rules under which distributed generation developers obtain and retain queue position."[140]

SCE's service territory is an ideal region for distributed PV systems. SDG&E states, "Renewable DG penetrations (in particular solar photovoltaic (PV) generation) are projected to steadily increase across SCE's service territory."[141]

Distributed DG is increasing across SCE's territory due to a variety of renewable programs. For instance, SCE's CREST program allows applicants to sell renewable power to SCE for DG facilities not greater than 1.5 MW.[142] SCE is installing 500 MW of solar PV over the next 5 years.[143]

The city of Los Angeles is also working to rapidly expand its solar PV, demonstrating the great potential for solar development exhibited by the greater Los Angeles area. On April 3, 2012, the LA City Council approved the Department of Water & Power to move forward with its feed-in tariff program of up to 150 MW by 2016.[144] Similarly, LADWP's Solar Incentive Program has installed 25 MW at over 3,100 customer locations as of February 2011.[145] The LA Business Council has also found that the City of LA has more than 12,000 acres of "prime space" for solar development on rooftops, "with capacity to create as much as five gigawatts of clean, locally generated power."[146]

The report goes on to call rooftop PV:

---

[139] 2011 IERP at p. 36, http://www.energy.ca.gov/2011publications/CEC-100-2011-001/CEC-100-2011-001-CMF.pdf.

[140] *See* CPUC, *Rule 21 Settlement Filed* <http://www.cpuc.ca.gov/PUC/energy/Procurement/LTPP/rule21.htm> [as of June 21, 2012].

[141] Moving Energy Storage from Concept to Reality, Southern California Edison, at p. 22 (May 20, 2011) http://www.energy.ca.gov/2011_energypolicy/documents/2011-04-28_workshop/comments/TN_60861_05-20-11_Southern_California_Edison_Company_Comments_Re_Energy_Storage_for_Renewable_Integration.pdf

[142] SCE, *SCE's California Renewable Energy Small Tariff (CREST) Program* (Jan. 3, 2012) p. 1 <http://asset.sce.com/Documents/Shared/CRESTParticipantInstructions1207.pdf> [as of June 21, 2012].

[143] U.S. Department of Energy, *DOE Perspective on High Penetration PV* (Mar. 2011) <http://www.cpuc.ca.gov/NR/rdonlyres/2B8F9E63-6FE9-4F9D-B569-BEFE9A185BA6/0/DOEReDecKWL20110304.pdf> [as of June 21, 2012].

[144] Los Angeles Business Council, *Policy Priority: CLEAN LA Solar Program for the City of LA* <http://www.labusinesscouncil.org/sustainability/index.php> [as of June 21, 2012]; see also Council of the City of Los Angeles, *Ordinance No. 182108* (Apr. 12, 2012) <http://clkrep.lacity.org/onlinedocs/2011/11-0617-s2_ord_182108.pdf> [as of June 21, 2012].

[145] Implementation Plan for the Statewide Water Quality Control Policy on the Use of Coastal and Estuarine Waters for Power Plant Cooling, LADWP, at p. 4 (April 1, 2011) http://www.waterboards.ca.gov/water_issues/programs/ocean/cwa316/powerplants/harbor/docs/hgs_ip2011.pdf

[146] More than 12,000 Acres Atop LA City Rooftops Provide Huge Opportunity for Solar Development, Los Angeles Business Council (April 16, 2012) http://www.labusinesscouncil.org/online_documents/2012/12000-Acres-of-Rooftop-Solar-Potential-in-LA-20120426.pdf

A massive, underutilized resource that belongs exclusively to Greater Los Angeles. While the integration of this much distributed solar into the electricity grid in the short-term could be a considerable challenge, *Los Angeles can still feasibly incorporate gigawatts of this latent rooftop solar capacity more cost-effectively than virtually any other place in North America.*[147]

E. CAISO Should Have Considered More Combined Heat & Power in Its Analysis.

CAISO considered no uncommitted CHP in its May 23, 2012 testimony.[148] In its Addendum, CAISO considered an incremental 209 MW of uncommitted combined heat and power being added to the LA Basin in 2021: 195 in Western LA Basin, 6 MW in Big Creek/Ventura, 8 MW is in Overall LA Basin but not Western.[149]

CHP refers to facilities that use a small gas turbine, engine, or fuel cell to generate electricity and convert exhaust heat to useful steam or hot water. Combined heat and power facilities are commonly found at college campuses, hospitals, and commercial and industrial complexes. The state of California has set ambitious CHP targets. The *AB 32 Scoping Plan* CHP target is 4,000 MW of new CHP in California by 2020.[150] The economic potential for new CHP in California was identified as 6,500 MW by 2030 in the ICF International April 2010 report prepared for the CEC on California CHP potential.[151] Governor Brown called for the addition of 6,500 MW of CHP in California by 2030 in his *Clean Energy Jobs Plan*.[152] The AB 32 target of 4,000 MW of new CHP by 2020 is consistent with a 2030 target of 6,500 MW of new CHP.

This growth trajectory for CHP development is also consistent with the California Air Resources Board's 2008 Scoping Plan adopting a CHP goal of an additional 4,000 MW of installed CHP capacity by 2020 as a key measure to reduce the state's emissions of greenhouse gases.[153]

SCE has 1,489 MW of existing CHP, as included in the 2010 LTPP assumptions.[154] SCE is expected to add additional incremental CHP in its territory before 2021. In light of the

---

[147] Los Angeles Business Council, *Bringing Solar Energy to Los Angeles: An Assessment of the Feasibility and Impact of an In-Basin Solar Feed-in Tariff Program* (Jul. 8, 2010) p. 15 <http://www.labusinesscouncil.org/online_documents/2010/Consolidated-Document-070810.pdf> [as of June 21, 2012].
[148] See Response of CAISO to Second Set of Data Requests of CEJA, Response to Request No. 3.
[149] See CAISO 5/25/12 Response to CEJA Data Requests 1, Dated BLANK 2012, Question 5.
[150] California Air Resources Board, *AB 32 Climate Change Scoping Plan*, December 2008, p. 44. *See* http://www.arb.ca.gov/cc/scopingplan/scopingplan.htm
[151] CEC PIER, *Combined Heat and Power Assessment – Final Consultant Report*, prepared by ICF International, April 2010, p. C-9.
[152] Clean Energy Jobs Plan, http://gov.ca.gov/docs/Clean_Energy_Plan.pdf
[153] CARB Scoping Plan, at pages 43-44. This plan is available at http://www.arb.ca.gov/cc/scopinplan/document/adopted_scoping_plan.pdf
[154] *See* CPUC, *supra*, Scoping Memo to Rulemaking 10-05-006, Attachment 1, at p. 57.

recent CHP settlement, SCE, along with the other utilities has launched its CHP Request for Offers.[155]

In the 2010 LTPP, the Commission used an assumption of 322 MW for additional CHP in 2020, and 360 MW of incremental demand-side CHP for 2020 for SCE.[156] This assumption is reasonable in light of the CHP settlement and in light of the recent ICF analysis, which confirms that SCE has significant room for growth in CHP capacity.[157]

F. CAISO's Assumption That All Once-Through Cooling Facilities Will Retire Is Not Reasonable.

CAISO's modeling assumptions are largely built around the need to replace once through cooling (OTC) capacity that will presumptively retire in order to comply with the State's OTC policy.[158]

The State's OTC policy however, does not require any coastal OTC power plants to actually retire. Instead, the State's policy allows OTC plants to remain operating should they comply with one of two "tracks" in the OTC policy. Track I requires the implementation of an acceptable cooling technology, such as closed cycle wet cooling system or closed cycle dry cooling.[159] Track II encompasses measures such as using operation or structural controls, or both to reduce impingement mortality and entrainment of marine life for the facility on a unit-by-unit basis if Track I is not feasible.[160]

Pursuant to the State's policy, many OTC generating units plan not to retire but to comply with the State's OTC policy through one of the two tracks. For instance, AES-South Land (AES-SL), which owns and operates approximately 4,200 MW of OTC-based generation in SCE territory, will comply with the State's OTC policy through Track 1.[161]

---

[155] See Southern Calfiornia Edison, *Renewable & Alternative Power – Combined Heat and Power (CHP): Combined Heat and Power Facilities Request for Offers* (Dec. 15, 2011) <http://www.sce.com/EnergyProcurement/renewables/chp.htm> [as of June 22, 2012].

[156] See CPUC, *supra*, Scoping Memo to Rulemaking 10-05-006, Attachment 1, at p. 49.

[157] See CEC, *Combined Heat & Power: Policy Analysis and 2011-2030 Market Assessment* (Feb. 2012) at p. 46 <http://www.energy.ca.gov/2012publications/CEC-200-2012-002/CEC-200-2012-002.pdf> [as of June 22, 2012] ("The two regions with the largest amount of technical potential are PG&E and SCE. . . Since PG&E also has the largest amount of existing CHP installations, the remaining CHP potential indicates that SCE has more room for growth in CHP capacity . . .").

[158] CEJA Requests 1, Responses to Request Nos. 1, 2, 3, 5, 6; CEJA Requests 1 Update, Response to Requests Nos. 3, 4, 5; CEJA Requests 2, Responses to Request Nos. 2, 5; Sierra Club Requests 1, Response to Request Nos. 2, 34; Vote Solar Requests 1, Responses to Request Nos. 2, 8.

[159] State Water Resources Control Board, Resolution No. 2011-0033 (July 19, 2011) <http://www.swrcb.ca.gov/water_issues/programs/ocean/cwa316/docs/amdplcy052512.pdf> [as of June 22, 2012].

[160] *Id.*

[161] AES Southland, *Implementation Plan Statewide Policy Use of Coastal and Estuarine Waters Power Plant Cooling: AES Alamitos Generating Station* (June 16, 2011) at p. 1 <http://www.waterboards.ca.gov/water_issues/programs/ocean/cwa316/powerplants/alamitos/docs/ags_revisedip2011.pdf> [as of June 22, 2012].

AES-SL's OTC compliance plan for the Alamitos Generating Station (ALGS) would replace the six OTC existing units at the facility with 1,000 MW simple-cycle or combined-cycle units between June 2018 and March 2019.[162] Additional MW would be installed between May 2022 and 2024.[163] "In total, ALGS is anticipated to be repowered to 2,042 MW with an estimated 600 MW of simple cycle gas turbine and 470 MW of combined cycle technology."[164]

Similar plans exist for other OTC facilities in SCE's territory. The Huntington Beach Generating Station (HBGS) intends to comply with Track I of the OTC policy by replacing two of the four existing units to simple-cycle or combined-cycle technology with 470 MW of new generation commercially available for dispatch by the second quarter of 2019.[165] The additional construction and commercial operation of 400 MW of new generation would occur by the second quarter of 2022.[166] "In total, the HBGS is anticipated to be repowered to 870 MW with an estimated 300 MW of simple-cycle gas turbine and 570 MW of combined-cycle technology."[167]

The Redondo Beach Generating Station's (RBGS) compliance plan would replace four existing units at the facility, with an initial 300 MW coming online in the third quarter of 2018, another 300 MW in the fourth quarter of 2018, and 300 MW in the second quarter of 2019, for a total of 900 MW of new generation.[168] An additional 270 MW of new generation would come online by the second quarter of 2024. "In total, RBGS is anticipated to be repowered to 1,170 MW."[169]

Further, site operator AES-SL has also found that it "may have the available space to construct approximately 2,300 MW across all three [of its] sites without the demolition of existing generating units."[170] AES-SL predicts that "other than the approximate ninety days between the shutdown of the existing units and the commercial operations of the new units to support commissioning activities, AES-SL is not aware of any time periods when electrical generation will be infeasible at the ALGS."[171] In other words, compliance with the State's OTC policy can feasibly be accomplished with minimal shut-down or service interruption.

---

[162] *Id.* at p. 1, 6.
[163] *Id.* at p. 6.
[164] *Ibid.*
[165] AES Southland, *Implementation Plan Statewide Policy Use of Coastal and Estuarine Waters Power Plant Cooling: AES Huntington Beach Generating Station* (June 16, 2011) at p. 2, 6 <http://www.waterboards.ca.gov/water_issues/programs/ocean/cwa316/powerplants/huntington_beach/docs/hb_revisedip2011.pdf> [as of June 22, 2012].
[166] *Id.* at p. 6.
[167] *Ibid,*
[168] AES Southland, Implementation Plan Statewide Policy Use of Coastal and Estuarine Waters Power Plant Cooling: AES Redondo Beach Generating Station (June 16, 2011) at p.6 <http://www.waterboards.ca.gov/water_issues/programs/ocean/cwa316/powerplants/redondo_beach/docs/rgs_revisedip2011.pdf> [as of June 22, 2012] (hereafter *AES Redondo Beach Implementation Plan*).
[169] *Ibid.*
[170] AES Southland, *supra*, *AES Alamitos Implementation Plan*, at p. 6.
[171] *Id.* at p. 8.

AES Southland also states that these:

> new units will provide operating flexibility to effectively integrate increasing amounts of renewable energy into the electrical transmission and distribution system. AES-SL believes the redevelopment of the existing OTC projects in the South Coast Air Basin (SCAB) will be effective in meeting California's future needs forecasted for the 2020 planning horizon within the Los Angeles Basin LCR.[172]

Further, "[t]he new units will provide operating flexibility to effectively integrate increasing amounts of renewable energy into the electrical transmission and distribution system."[173]

Other plant operators are intended to keep units running through compliance with Track I or II. The El Segundo Generating Station intends to comply with Track I with the new generation will subsequently be commissioned to be online by the summer of 2013.[174] Like AES-SL's facilities, El Segundo will implement rapid response technology intended to be "compatible with California's increased reliance on renewables in that when adequate renewable power is not available, ESEC can quickly come on line and provide replacement electricity."[175]

The Ormond Beach Generating Station (OBGS) intends to comply with Track II.[176] OBGS in all has a capacity of 1,520 MW. GenOn intends to achieve compliance under Track 2 no later than December 31, 2020.[177] The Mandalay Generating Station intends to comply with the OTC policy under Track II by the prescribed deadline of December 31, 2020.[178]

In addition, it is not clear that even if OTC plants are retired, that the same amount of MW will be needed to replace them. Many existing OTC facilities are currently running

---

[172] *Id.* at p. 2.
[173] *Ibid.*
[174] Plant Manager Ken H. Reisz, El Segundo Power, Letter to Philip Isorena, Chief of NPDES Unit for State Water Resources Board re California 316(b) Policy – Implementation Plan, El Segundo Generating Station (Mar. 30, 2011) at p. 2 <http://www.waterboards.ca.gov/water_issues/programs/ocean/cwa316/powerplants/el_segundo/docs/esgs_ip2011.pdf> [as of June 22, 2012].
[175] *Ibid.*
[176] Ormond Beach Generating Station Implementation Plan for the Statewide Water Quality Control Policy on the Use of Coastal and Estuarine Waters for Power Plant Cooling (April 1, 2011) http://www.waterboards.ca.gov/water_issues/programs/ocean/cwa316/powerplants/ormond_beach/docs/ob_ip2011.pdf
[177] *Id.* at p. 16.
[178] Mandalay Generating Station Implementation Plan for the Statewide Water Quality Control Policy on the Use of Coastal and Estuarine Waters for Power Plant Cooling, at p. 4 (April 1, 2011) http://www.waterboards.ca.gov/water_issues/programs/ocean/cwa316/powerplants/mandalay/docs/mgs_ip2011.pdf

far below capacity. For instance, in 2007, most units ran less than 10 percent of the time.[179]

Furthermore, a report prepared for the State Water Resources Control Board found that several OTC facilities could retire by 2015 with no need for additional replacement capacity. The report concluded that a more than adequate reserve margin would still exist "with as little as $135 million in in-state transmission upgrades."[180]

IV. Reliance on CAISO's Modeling Will Lead to Over-Procurement of Fossil-Fuel Resources in Violation of the Loading Order

The Commission should ensure that resource planning in being conducted in the context of California's *Energy Action Plan*. On paper, support for the *Energy Action Plan* is unanimous. Fidelity to the *Energy Action Plan* is stated in virtually every state energy agency planning document and every application by the state's IOUs for conventional infrastructure projects, including natural gas-fired generation and new transmission. However, no fundamental redesign of IOU financial incentives accompanied development of the *Energy Action Plan*. For the last century that IOU model has remained relatively unchanged – the sole source supplier of vertically integrated electricity generation, transmission, and distribution services.

As a result, California energy policy operates in a form of parallel universe – all actors pledge support to the *Energy Action Plan* in concept, while finding avenues to continue and even go beyond the status quo. The IOU business model is based on private monopoly control of generation, transmission, and distribution of electricity. Revenue is generated by steel-in-the-ground projects owned by the IOU. These include T&D infrastructure, power plants, and meters.

Historical utility practice demonstrates that the utilities need more specific requirements to ensure they follow the loading order. In 2006, the Commission admonished the IOUs for filling their net short positions with conventional resources, as opposed to the other resources in the loading order, without providing reasonable analysis to support such a position.[181] It held that strict compliance with the preferred resource loading order would be necessary for all future LTPPs and required the IOUs to "conform to the energy and environmental policies in place."[182] This order stemmed from the Commission's concern that filling the IOUs' net short positions with conventional resources would lead to "the

---

[179] *See* CEC, *Comments to State Water Resources Control Board Concerning Its Coastal Power Plant Preliminary Draft Policy and Related Scoping Document* (May 2008) at pp. 18-19, *available at* http://www.energy.ca.gov/siting/documents/2008-05-20_CHAIRMAN_SWRCB.PDF.
[180] *Id.* (quoting California Ocean Protection Council & State Water Resources Control Board, *Electric Grid Reliability Impacts from Regulation of Once-Through Cooling in California* (ICF Jones & Stokes, April 2008) at p. 3, *available at* http://www.swrcb.ca.gov/water_issues/programs/tmdl/docs/power_plant_cooling/reliability_study.pdf).
[181] D. 07-12-052 at p. 3.
[182] *Id.* at pp. 3-4.

effect of there being no room in an IOUs' portfolio for other resources, or the conventional resources [becoming] obsolete and result[ing] in large stranded costs."[183]

For example, California's high reserve margins of natural gas capacity demonstrate its over-procurement of natural gas plants, which is inconsistent with the loading order.[184]

Investment in excessive and unnecessary natural gas-fired capacity will undermine investment in renewables, energy efficiency, and new CHP, and is inconsistent with California's energy strategy. Ratepayers will shoulder the burden of a project approval process that does not carefully weigh the need for new natural gas-fired projects or transactions before committing ratepayers to major, long-term financing obligations.

Other options cost less and are consistent with California's energy goals. Distributed PV resources, for example, have a lower overall cost (when transmission costs and transmission losses are considered) than remote renewable generation technologies, do not require back-up peaking turbines, and can be used to meet SCE's unmet needs.

CAISO's modeling results call for additional MW in unneeded resources. Not only did CAISO rely on overly conservative, and therefore, inaccurate assumptions, it also fails to consider whether preferred resources under the loading order could be used to meet the purported need. Today, the IOUs continue to build and contract for utility-scale natural gas fired plants and remote utility-scale solar and wind plants, and the transmission lines necessary to reach them, while extolling the virtues of energy efficiency, rooftop PV, and CHP. The reality is that energy efficiency measures and onsite generation, owned by customers in the form of solar panels on the roof or CHP, undercut the justification for an IOU to build more utility-owned infrastructure.

CAISO's model fails to consider how alternative resources such as DR could be used in lieu of additional traditional generation, in compliance with the loading order.[185] Unmet needs in its service territory through a strategy that prioritizes energy efficiency, rooftop and distributed PV of all types, and CHP, rather than through natural gas-fired plants. CAISO's model is not consistent with the Commission's continued commitment to the *Energy Action Plan*'s loading order that prioritizes energy efficiency and DR to meet California's energy needs.[186]

This prioritization would result in ratepayer savings and significant reductions in GHG emissions. The reduction in demand for electricity and natural gas, achieved through energy efficiency measures and the addition of PV, CHP, geothermal, and wind, also

---

[183] *Id.* at p. 6.
[184] California Clean Energy Future Metrics, California Energy Commission at p. 3, *available at* http://www.energy.ca.gov/2011_energypolicy/documents/2011-07-06_workshop/background/Metrics_July_IEPR_Reserve_Margin_v5.pdf (showing the reserve margin for summer 2011 to be approximately 30 to 45%).
[185] CEJA Requests 1, Response to Request No. 2; CEJA Requests 1 Update, Response to Request No. 4; CEJA Requests 2, Responses to Request Nos. 3, 7; Sierra Club Requests 1, Responses to Request Nos. 7, 12, 21; Vote Solar Requests 1, Response to Request No. 11.
[186] D.12-04-045 at p. 36.

reduces the price of electricity and natural gas in wholesale energy markets. This is known as the "merit order effect." It reduces the cost of electricity and natural gas for all ratepayers.

V. The Commission Should Not Authorize New Procurement When CAISO Failed to Consider All the Available Resources, Have Not Followed the Loading Order, and Are Inappropriately Relying on a 1-in-10 Demand Scenario with Transmission Failures

CAISO's assumptions result in a reserve margin that is more conservative than the 15 to 17 percent reserve margin required by the Commission. Even the Commission's 15-17 percent reserve margin for a 1-in-2 year is conservative. WECC only requires a 7 percent reserve margin for a 1-in-2 year. This level of planning reserve ten years out is inconsistent with Commission decisions that have set the required long-term reserve margin.

In addition, there is no need to procure new natural gas generation resources now when other resources such as DR can be procured in a shorter time frame.[187]

Finally, over-procurement of fossil-fuel resources will continue to crowd out renewables and other preferred resources from the market. In order to meet AB 32 goals of 80 percent below 1990 levels by 2050, it is likely that we will need to reduce GHG emissions to a greater degree than can be achieved through a 33 percent RPS.[188]

In sum, reliance on CAISO's modeling results will lead to over-procurement of unneeded fossil fuel generation, which in turn will undermine *Energy Action Plan* loading order and AB 32 goals. More accurate modeling should be completed prior to considering any new fossil fuel procurement.

VI. Conclusion

For all of the above reasons, the Commission should not authorize new procurement based on the results of CAISO's modeling.

---

[187] *See* News Release: Summer Grid Outlook Complicated by Possible Extended Outage of Nuclear Power Plan (March 22, 2012) http://www.caiso.com/Documents/SummerGridOutlookComplicated-PossibleExtendedOutage-
NuclearPowerPlant.pdf (describing resources that can be available in a couple of months in response to a potential outage).
[188] *See* California Council on Science and Technology, *California's Energy Future – The View to 2050*, p. 22 (May 2011) http://www.ccst.us/publications/2011/2011energy.pdf

BILL POWERS, P.E.

PROFESSIONAL HISTORY

Powers Engineering, San Diego, CA 1994-
ENSR Consulting and Engineering, Camarillo, CA 1989-93
Naval Energy and Environmental Support Activity, Port Hueneme, CA 1982-87
U.S. Environmental Protection Agency, Research Triangle Park, NC 1980-81

EDUCATION

Master of Public Health – Environmental Sciences, University of North Carolina
Bachelor of Science – Mechanical Engineering, Duke University

PROFESSIONAL AFFILIATIONS

Registered Professional Mechanical Engineer, California (Certificate M24518)
American Society of Mechanical Engineers
Air & Waste Management Association

TECHNICAL SPECIALTIES

Thirty years of experience in:

- Distributed solar photovoltaics (PV) siting and regional renewable energy planning
- Power plant air emission control system and cooling system assessments
- Combustion equipment permitting, testing and monitoring
- Air pollution control equipment retrofit design/performance testing
- Petroleum refinery air engineering and testing
- Latin America environmental project experience

DISTRIBUTED SOLAR PV SITING AND REGIONAL RENEWABLE ENERGY PLANNING

Owner's engineer for 5 MW solar PV project on brownfield site. Served as owner's engineer to company pursuing development of 5 MW fixed ground-mounted polycrystalline silicon PV array on brownfield land in Southern California. Assisted client in the selection of the PV system contractor, determination of interconnection point and expected interconnection integration study costs, preparation of utility RPS application documents, and identification of appropriate $/kWh payment for project to work financially for the client.

Photovoltaic technology selection and siting for SDG&E Solar San Diego project. Served as PV technology expert in California Public Utilities Commission proceeding to define PV technology and sites to be used in San Diego Gas & Electric (SDG&E) $250 million "Solar San Diego" project. Recommendations included: 1) prioritize use of roof-mounted thin-film PV arrays similar to the SCE urban PV program to maximize the installed PV capacity, 2) avoid tracking ground-mounted PV arrays due to high cost and relative lack of available land in the urban/suburban core, 3) and incorporate limited storage in fixed rooftop PV arrays to maximizing output during peak demand periods. Suitable land next to SDG&E substations capable of supporting 5 to 40 MW of PV (each) was also identified by Powers Engineering as a component of this project.

Photovoltaic arrays as alternative to natural gas-fired peaking gas turbines, Chula Vista. Served as PV technology expert in California Energy Commission (CEC) proceeding regarding the application of MMC Energy to build a 100 MW peaking gas turbine power plant in Chula Vista. Presented testimony that 100 MW of PV arrays in the Chula Vista area could provide the same level of electrical reliability on hot summer days as an equivalent amount of peaking gas turbine capacity at approximately the same cost of energy. The preliminary decision issued by the presiding CEC commissioner in the case recommended denial of the application in part due to failure of the applicant or CEC staff to thoroughly evaluate the PV alternative to the proposed turbines. No final decision has yet been issued in the proceeding (as of May 2009).

San Diego Smart Energy 2020 Plan. Author of October 2007 "San Diego Smart Energy 2020," an energy plan that focuses on meeting the San Diego region's electric energy needs through accelerated integration of renewable and non-renewable distributed generation, in the form of combined heat and power (CHP) systems and solar photovoltaic (PV) systems. PV would meet approximately 28 percent of the San Diego region's electric energy demand in 2020. CHP systems would provide approximately 47 percent. Annual energy demand would drop 20 percent in 2020 relative to 2003 through use all cost-effective energy efficiency measures. This target is based on City of San Diego experience. San Diego has consistently achieved energy efficiency reductions of 20 percent on dozens of projects. Existing utility-scale gas-fired generation would continue to be utilized to provide power at night, during cloudy whether, and for grid reliability support. Report is online at: http://www.etechinternational.org/new_pdfs/smartenergy/52008_SmE2020_2nd.pdf

San Diego Area Governments (SANDAG) Energy Working Group. Public interest representative on the SANDAG Energy Working Group (EWG). The EWG advises the Regional Planning Committee on issues related to the coordination and implementation of the Regional Energy Strategy 2030 adopted by the SANDAG Board of Directors in July 2003. The EWG consists of elected officials from the City of San Diego, County of San Diego and the four subareas of the region. In addition to elected officials, the EWG includes stakeholders representing business, energy, environment, economy, education, and consumer interests.

Development of San Diego Regional Energy Strategy 2030. Participant in the 18-month process in the 2002-2003 timeframe that led to the development of the San Diego Regional Energy Strategy 2030. This document was adopted by the SANDAG Board of Directors in July 2003 and defines strategic energy objectives for the San Diego region, including: 1) in-region power generation increase from 65% of peak demand in 2010 to 75% of peak demand in 2020, 2) 40% renewable power by 2030 with at least half of this power generated in-county, 3) reinforcement of transmission capacity as needed to achieve these objectives. The SANDAG Board of Directors voted unanimously on Nov. 17, 2006 to take no position on the Sunrise Powerlink proposal primarily because it conflicts the Regional Energy Strategy 2030 objective of increased in-region power generation. The Regional Energy Strategy 2030 is online at: http://www.energycenter.org/uploads/Regional_Energy_Strategy_Final_07_16_03.pdf

POWER PLANT EMISSION CONTROL AND COOLING SYSTEM CONVERSION ASSESSMENTS

Biomass Plant NO_x and CO Air Emissions Control Evaluation. Lead engineer for evaluation of available nitrogen oxide (NO_x) and carbon monoxide (CO) controls for a 45 MW Aspen Power biomass plant in Texas where proponent had identified selective non-catalytic reduction (SNCR) for NO_x and good combustion practices for CO as BACT. Identified the use of tail-end SCR for NO_x control at several operational U.S. biomass plants, and oxidation catalyst in use at two of these plants for CO and VOC control, as BACT for the proposed biomass plant. Administrative law judge concurred in decision that SCR and oxidation catalyst is BACT. Developer added SCR and oxidation catalyst to project in subsequent settlement agreement.

Biomass Plant Air Emissions Control Consulting. Lead expert on biomass air emissions control systems for landowners that will be impacted by a proposed 50 MW biomass to be built by the local East Texas power cooperative. Public utility agreed to meet current BACT for biomass plants in Texas, SCR for NOx and oxidation catalyst for CO, in settlement agreement with local landowners.

Combined-Cycle Power Plant Startup and Shutdown Emissions. Lead engineer for analysis of air permit startup and shutdown emissions minimization for combined-cycle power plant proposed for the San Francisco Bay Area. Original equipment was specified for baseload operation prior to suspension of project in early 2000s. Operational profile described in revised air permit was load following with potential for daily start/stop. Recommended that either fast start turbine technology be employed to minimize start/stop emissions or that "demonstrated in practice" operational and control software modifications be employed to minimize startup/shutdown emissions.

IGCC as BACT for Air Emissions from Proposed 960 MW Coal Plant. Presented testimony on IGCC as BACT for air emissions reduction from 960 MW coal plant. Applicant received air permit for a pulverized coal plant to be equipped with a baghouse, wet scrubber, and wet ESP for air emissions control. Use of IGCC technology at the emission rates permitted for two recently proposed U.S. IGCC projects, and demonstrated in practice at a Japanese IGCC plant firing Chinese bituminous coal, would substantially reduce potential emissions of NO_x, SO_2, and PM. The estimated control cost-effectiveness of substituting IGCC for pulverized coal technology in this case was approximately $3,000/ton.

Analysis of Proposed Air Emission Limits for 600 MW Pulverized Coal Plant. Project engineer tasked with evaluating sufficiency of air emissions limits and control technologies for proposed 600 MW coal plant Arkansas. Determined that the applicant had: 1) not properly identified SO_2, sulfuric acid mist, and PM BACT control levels for the plant, and 2) improperly utilized an incremental cost effectiveness analysis to justify air emission control levels that did not represent BACT.

Eight Pulverized Coal Fired 900 MW Boilers – IGCC Alternative with Air Cooling. Provided testimony on integrated gasification combined cycle (IGCC) as a fully commercial coal-burning alternative to the pulverized coal (PC) technology proposed by TXU for eight 900 MW boilers in East Texas, and East Texas as an ideal location for CO2 sequestration due to presence of mature oilfield CO2 enhanced oil recovery opportunities and a deep saline aquifer underlying the entire region. Also presented testimony on the major increase in regional consumptive water use that would be caused by the evaporative cooling towers proposed for use in the PC plants, and that consumptive water use could be lowered by using IGCC with evaporative cooling towers or by using air-cooled condensers with PC or IGCC technology. TXU ultimately dropped plans to build the eight PC plants as a condition of a corporate buy-out.

Utility Boilers – Conversion of Existing Once-Through Cooled Boilers to Wet Towers, Parallel Wet-Dry Cooling, or Dry Cooling. Provided expert testimony and preliminary design for the conversion of four natural gas and/or coal-fired utility boilers (Unit 4, 235 MW; Unit 3, 135 MW; Unit 2, 65 MW; and Unit 1,65 MW) from once-through river water cooling to wet cooling towers, parallel wet-dry cooling, and dry cooling. Major design constraints were available land for location of retrofit cooling systems and need to maintain maximum steam turbine backpressure at or below 5.5 inches mercury to match performance capabilities of existing equipment. Approach temperatures of 12 °F and 13 °F were used for the wet towers. SPX Cooling Technologies F-488 plume-abated wet cells with six feet of packing were used to achieve approach temperatures of 12 °F and 13 °F. Annual energy penalty of wet tower retrofit designs is approximately 1 percent. Parallel wet-dry or dry cooling was determined to be technically feasible for Unit 3 based on straightforward access to the Unit 3 surface condenser and available land adjacent to the boiler.

Utility Boiler – Assessment of Air Cooling and Integrated Gasification/Combined Cycle for Proposed 500 MW Coal-Fired Plant. Provided expert testimony on the performance of air-cooling and IGCC relative to the conventional closed-cycle wet cooled, supercritical pulverized coal boiler proposed by the applicant. Steam Pro™ coal-fired power plant design software was used to model the proposed plant and evaluate the impacts on performance of air cooling and plume-abated wet cooling. Results indicated that a conservatively designed air-cooled condenser could maintain rated power output at the design ambient temperature of 90 °F. The IGCC comparative analysis indicated that unit reliability comparable to a conventional pulverized coal unit could be achieved by including a spare gasifier in the IGCC design, and that the slightly higher capital cost of IGCC was offset by greater thermal efficiency and reduced water demand and air emissions.

Utility Boiler – Assessment of Closed-Cycle Cooling Retrofit Cost for 1,200 MW Oil-Fired Plant. Prepared an assessment of the cost and feasibility of a closed-cycle wet tower retrofit for the 1,200 MW

Roseton Generating Station. Determined that the cost to retrofit the Roseton plant with plume-abated closed-cycle wet cooling was well established based on cooling tower retrofit studies performed by the original owner (Central Hudson Gas & Electric Corp.) and subsequent regulatory agency critique of the cost estimate. Also determined that elimination of redundant and/or excessive budgetary line items in owners cost estimate brings the closed-cycle retrofit in line with expected costs for comparable new or retrofit plume-abated cooling tower applications.

Nuclear Power Plant – Assessment of Closed-Cycle Cooling Retrofit Cost for 2,000 MW Plant. Prepared an assessment of the cost and feasibility of a closed-cycle wet tower retrofit for the 2,000 MW Indian Point Generating Station. Determined that the most appropriate arrangement for the hilly site would be an inline plume-abated wet tower instead of the round tower configuration analyzed by the owner. Use of the inline configuration would allow placement of the towers at numerous sites on the property with little or need for blasting of bedrock, greatly reducing the cost of the retrofit. Also proposed an alternative circulating cooling water piping configuration to avoid the extensive downtime projected by the owner for modifications to the existing discharge channel.

Kentucky Coal-Fired Power Plant – Pulverized Coal vs IGCC. Expert witness in Sierra Club lawsuit against Peabody Coal Company's plan to construct a 1,500 MW pulverized-coal fired power plant in Kentucky. Presented case that Integrated Gasification Combined Cycle (IGCC) is a superior method for producing power from coal, from environmental and energy efficiency perspective, than the proposed pulverized-coal plant. Presented evidence that IGCC is technically feasible and cost competitive with pulverized coal.

Power Plant Dry Cooling Symposium – Chair and Organizer. Chair and organizer of the first symposium held in the U.S. (May 2002) that focused exclusively on dry cooling technology for power plants. Sessions included basic principles of wet and dry cooling systems, performance capabilities of dry cooling systems, case studies of specific installations, and reasons why dry cooling is the predominant form of cooling specified in certain regions of North America (Massachusetts, Nevada, northern Mexico).

Utility Boiler · Best Available NO_x Control System for 525 MW Coal-Fired Circulating Fluidized Bed Boiler Plant. Expert witness in dispute over whether 50 percent NO_x control using selective non-catalytic reduction (SNCR) constituted BACT for a proposed 525 MW circulating fluidized bed (CFB) boiler plant. Presented testimony that SNCR was capable of continuous NO_x reduction of greater than 70 percent on a CFB unit and that tail-end selective catalytic reduction (SCR) was technically feasible and could achieve greater than 90 percent NO_x reduction.

Utility Boilers – Evaluation of Correlation Between Opacity and PM_{10} Emissions at Coal-Fired Plant. Provided expert testimony on whether correlation existed between mass PM_{10} emissions and opacity during opacity excursions at large coal-fired boiler in Georgia. EPA and EPRI technical studies were reviewed to assess the correlation of opacity and mass emissions during opacity levels below and above 20 percent. A strong correlation between opacity and mass emissions was apparent at a sister plant at opacities less than 20 percent. The correlation suggests that the opacity monitor correlation underestimates mass emissions at opacities greater than 20 percent, but may continue to exhibit a good correlation for the component of mass emissions in the PM_{10} size range.

Utility Boilers · Retrofit of SCR and FGD to Existing Coal-Fired Units.
Expert witness in successful effort to compel an existing coal-fired power plant located in Massachusetts to meet an accelerated NO_x and SO_2 emission control system retrofit schedule. Plant owner argued the installation of advanced NO_x and SO_2 control systems would generate > 1 ton/year of ancillary emissions, such as sulfuric acid mist, and that under Massachusetts Dept. of Environmental Protection regulation ancillary emissions > 1 ton/year would require a BACT evaluation and a two-year extension to retrofit schedule. Successfully demonstrated that no ancillary emissions would be generated if the retrofit NO_x and SO_2 control systems were

properly sized and optimized. Plant owner committed to accelerated compliance schedule in settlement agreement.

Utility Boilers – Retrofit of SCR to Existing Natural Gas-Fired Units.
Lead engineer in successful representation of interests of California coastal city to prevent weakening of an existing countywide utility boiler NO_x rule. Weakening of NO_x rule would have allowed a merchant utility boiler plant located in the city to operate without installing selective catalytic reduction (SCR) NO_x control systems. This project required numerous appearances before the county air pollution control hearing board to successfully defend the existing utility boiler NO_x rule.

COMBUSTION EQUIPMENT PERMITTING, TESTING AND MONITORING

EPRI Gas Turbine Power Plant Permitting Documents – Co-Author.
Co-authored two Electric Power Research Institute (EPRI) gas turbine power plant siting documents. Responsibilities included chapter on state-of-the-art air emission control systems for simple-cycle and combined-cycle gas turbines, and authorship of sections on dry cooling and zero liquid discharge systems.

Air Permits for 50 MW Peaker Gas Turbines – Six Sites Throughout California.
Responsible for preparing all aspects of air permit applications for five 50 MW FT-8 simple-cycle turbine installations at sites around California in response to emergency request by California state government for additional peaking power. Units were designed to meet 2.0 ppm NO_x using standard temperature SCR and innovative dilution air system to maintain exhaust gas temperature within acceptable SCR range. Oxidation catalyst is also used to maintain CO below 6.0 ppm.

Kauai 27 MW Cogeneration Plant – Air Emission Control System Analysis. Project manager to evaluate technical feasibility of SCR for 27 MW naphtha-fired turbine with once-through heat recovery steam generator. Permit action was stalled due to questions of SCR feasibility. Extensive analysis of the performance of existing oil-fired turbines equipped with SCR, and bench-scale tests of SCR applied to naphtha-fired turbines, indicated that SCR would perform adequately. Urea was selected as the SCR reagent given the wide availability of urea on the island. Unit is first known application of urea-injected SCR on a naphtha-fired turbine.

Microturbines · Ronald Reagan Library, Ventura County, California.
Project manager and lead engineer or preparation of air permit applications for microturbines and standby boilers. The microturbines drive the heating and cooling system for the library. The microturbines are certified by the manufacturer to meet the 9 ppm NO_x emission limit for this equipment. Low-NO_x burners are BACT for the standby boilers.

Hospital Cogeneration Microturbines – South Coast Air Quality Management District.
Project manager and lead engineer for preparation of air permit application for three microturbines at hospital cogeneration plant installation. The draft Authority To Construct (ATC) for this project was obtained two weeks after submittal of the ATC application. 30-day public notification was required due to the proximity of the facility to nearby schools. The final ATC was issued two months after the application was submitted, including the 30-day public notification period.

Gas Turbine Cogeneration – South Coast Air Quality Management District. Project manager and lead engineer for preparation of air permit application for two 5.5 MW gas turbines in cogeneration configuration for county government center. The turbines will be equipped with selective catalytic reduction (SCR) and oxidation catalyst to comply with SCAQMD BACT requirements. Aqueous urea will be used as the SCR reagent to avoid trigger hazardous material storage requirements. A separate permit will be obtained for the NO_x and CO continuous emissions monitoring systems. The ATCs is pending.

Industrial Boilers · NO_x BACT Evaluation for San Diego County Boilers.
Project manager and lead engineer for preparation of Best Available Control Technology (BACT) evaluation for three industrial boilers to be located in San Diego County. The BACT included the review of low NO_x burners, FGR, SCR, and low temperature oxidation (LTO). State-of-the-art ultra low NO_x burners with a 9 ppm emissions guarantee were selected as NO_x BACT for these units.

Peaker Gas Turbines – Evaluation of NO_x Control Options for Installations in San Diego County.
Lead engineer for evaluation of NO_x control options available for 1970s vintage simple-cycle gas turbines proposed for peaker sites in San Diego County. Dry low-NO_x (DLN) combustors, catalytic combustors, high-temperature SCR, and NO_x absorption/conversion ($SCONO_x$) were evaluated for each candidate turbine make/model. High-temperature SCR was selected as the NOx control option to meet a 5 ppm NO_x emission requirement.

Hospital Cogeneration Plant Gas Turbines – San Joaquin Valley Unified Air Pollution Control District.
Project manager and lead engineer for preparation of air permit application and Best Available Control Technology (BACT) evaluation for hospital cogeneration plant installation. The BACT included the review of DLN combustors, catalytic combustors, high-temperature SCR and $SCONO_x$. DLN combustion followed by high temperature SCR was selected as the NO_x control system for this installation. The high temperature SCR is located upstream of the heat recovery steam generator (HRSG) to allow the diversion of exhaust gas around the HRSG without compromising the effectiveness of the NO_x control system.

1,000 MW Coastal Combined-Cycle Power Plant – Feasibility of Dry Cooling.
Expert witness in on-going effort to require use of dry cooling on proposed 1,000 MW combined-cycle "repower" project at site of an existing 1,000 MW utility boiler plant. Project proponent argued that site was two small for properly sized air-cooled condenser (ACC) and that use of ACC would cause 12-month construction delay. Demonstrated that ACC could easily be located on the site by splitting total of up to 80 cells between two available locations at the site. Also demonstrated that an ACC optimized for low height and low noise would minimize or eliminate proponent claims of negative visual and noise impacts.

Industrial Cogeneration Plant Gas Turbines · Upgrade of Turbine Power Output.
Project manager and lead engineer for preparation of Best Available Control Technology (BACT) evaluation for proposed gas turbine upgrade. The BACT included the review of DLN combustors, catalytic combustors, high-, standard-, and low-temperature SCR, and $SCONO_x$. Successfully negotiated air permit that allowed facility to initially install DLN combustors and operate under a NO_x plantwide "cap." Within two major turbine overhauls, or approximately eight years, the NO_x emissions per turbine must be at or below the equivalent of 5 ppm. The 5 ppm NO_x target will be achieved through technological in-combustor NO_x control such as catalytic combustion, or SCR or SCR equivalent end-of-pipe NO_x control technologies if catalytic combustion is not available.

Gas Turbines · Modification of RATA Procedures for Time-Share CEM.
Project manager and lead engineer for the development of alternate CO continuous emission monitor (CEM) Relative Accuracy Test Audit (RATA) procedures for time-share CEM system serving three 7.9 MW turbines located in San Diego. Close interaction with San Diego APCD and EPA Region 9 engineers was required to receive approval for the alternate CO RATA standard. The time-share CEM passed the subsequent annual RATA without problems as a result of changes to some of the CEM hardware and the more flexible CO RATA standard.

Gas Turbines · Evaluation of NO_x Control Technology Performance. Lead engineer for performance review of dry low-NO_x combustors, catalytic combustors, high-, standard-, and low-temperature selective catalytic reduction (SCR), and NO_x absorption/conversion ($SCONO_x$). Major turbine manufacturers and major manufacturers of end-of-pipe NO_x control systems for gas turbines were contacted to determine current cost and performance of NO_x control systems. A comparison of 1993 to 1999 "$/kwh" and "$/ton" cost of these control systems was developed in the evaluation.

Gas Turbines · Evaluation of Proposed NO_x Control System to Achieve 3 ppm Limit. Lead engineer for evaluation for proposed combined cycle gas turbine NO_x and CO control systems. Project was in litigation over contract terms, and there was concern that the GE Frame 7FA turbine could not meet the 3 ppm NO_x permit limit using a conventional combustor with water injection followed by SCR. Operations personnel at GE Frame 7FA installatins around the country were interviewed, along with principal SCR vendors, to corroborate that the installation could continuously meet the 3 ppm NO_x limit.

Gas Turbines · Title V "Presumptively Approvable" Compliance Assurance Monitoring Protocol. Project manager and lead engineer for the development of a "presumptively approval" NO_x parametric emissions monitoring system (PEMS) protocol for industrial gas turbines. "Presumptively approvable" means that any gas turbine operator selecting this monitoring protocol can presume it is acceptable to the U.S. EPA. Close interaction with the gas turbine manufacturer's design engineering staff and the U.S. EPA Emissions Measurement Branch (Research Triangle Park, NC) was required to determine modifications necessary to the current PEMS to upgrade it to "presumptively approvable" status.

Environmental Due Diligence Review of Gas Turbine Sites · Mexico. Task leader to prepare regulatory compliance due diligence review of Mexican requirements for gas turbine power plants. Project involves eleven potential sites across Mexico, three of which are under construction. Scope involves identification of all environmental, energy sales, land use, and transportation corridor requirements for power projects in Mexico. Coordinator of Mexican environmental subcontractors gathering on-site information for each site, and translator of Spanish supporting documentation to English.

Development of Air Emission Standards for Gas Turbines - Peru. Served as principal technical consultant to the Peruvian Ministry of Energy in Mines (MEM) for the development of air emission standards for Peruvian gas turbine power plants. All major gas turbine power plants in Peru are currently using water injection to increase turbine power output. Recommended that 42 ppm on natural gas and 65 ppm on diesel (corrected to 15% O_2) be established as the NO_x limit for existing gas turbine power plants. These limits reflect NO_x levels readily achievable using water injection at high load. Also recommended that new gas turbine sources be subject to a BACT review requirement.

Gas Turbines · Title V Permit Templates. Lead engineer for the development of standardized permit templates for approximately 100 gas turbines operated by the oil and gas industry in the San Joaquin Valley. Emissions limits and monitoring requirements were defined for units ranging from GE Frame 7 to Solar Saturn turbines. Stand-alone templates were developed based on turbine size and NO_x control equipment. NO_x utilized in the target turbine population ranged from water injection alone to water injection combined with SCR.

Gas Turbines · Evaluation of NO_x, SO_2 and PM Emission Profiles. Performed a comparative evaluation of the NO_x, SO_2 and particulate (PM) emission profiles of principal utility-scale gas turbines for an independent power producer evaluating project opportunities in Latin America. All gas turbine models in the 40 MW to 240 MW range manufactured by General Electric, Westinghouse, Siemens and ABB were included in the evaluation.

Stationary Internal Combustion Engine (ICE) RACT/BARCT Evaluation. Lead engineer for evaluation of retrofit NO_x control options available for the oil and gas production industry gas-fired ICE population in the San Joaquin Valley affected by proposed RACT and BARCT emission limits. Evaluation centered on lean-burn compressor engines under 500 bhp, and rich-burn constant and cyclically loaded (rod pump) engines under 200 bhp. The results of the evaluation indicated that rich burn cyclically-loaded rod pump engines comprised 50 percent of the affected ICE population, though these ICEs accounted for only 5 percent of the uncontrolled gas-fired stationary ICE NO_x emissions. Recommended retrofit NO_x control strategies included: air/fuel ratio adjustment for rod pump ICEs, Non-selective catalytic reduction (NSCR) for rich-burn, constant load ICEs, and "low emission" combustion modifications for lean burn ICEs.

Development of Air Emission Standards for Stationary ICEs - Peru. Served as principal technical consultant to the Peruvian Ministry of Energy in Mines (MEM) for the development of air emission standards for Peruvian stationary ICE power plants. Draft 1997 World Bank NO_x and particulate emission limits for stationary ICE power plants served as the basis for proposed MEM emission limits. A detailed review of ICE emissions data provided in PAMAs submitted to the MEM was performed to determine the level of effort that would be required by Peruvian industry to meet the proposed NO_x and particulate emission limits. The draft 1997 WB emission limits were revised to reflect reasonably achievable NO_x and particulate emission limits for ICEs currently in operation in Peru.

Air Toxics Testing of Natural Gas-Fired ICEs. Project manager for test plan/test program to measure volatile and semi-volatile organic air toxics compounds from fourteen gas-fired ICEs used in a variety of oil and gas production applications. Test data was utilized by oil and gas production facility owners throughout California to develop accurate ICE air toxics emission inventories.

AIR ENGINEERING/AIR TESTING PROJECT EXPERIENCE · GENERAL

Reverse Air Fabric Filter Retrofit Evaluation · Coal-Fired Boiler. Lead engineer for upgrade of reverse air fabric filters serving coal-fired industrial boilers. Fluorescent dye injected to pinpoint broken bags and damper leaks. Corrosion of pneumatic actuators serving reverse air valves and inadequate insulation identified as principal causes of degraded performance.

Pulse-Jet Fabric Filter Performance Evaluation · Gold Mine. Lead engineer on upgrade of pulse-jet fabric filter and associated exhaust ventilation system serving an ore-crushing facility at a gold mine. Fluorescent dye used to identify bag collar leaks, and modifications were made to pulse air cycle time and duration. This marginal source was in compliance at 20 percent of emission limit following completion of repair work.

Pulse-Jet Fabric Filter Retrofit - Gypsum Calciner. Lead engineer on upgrade of pulse-jet fabric filter controlling particulate emissions from a gypsum calciner. Recommendations included a modified bag clamping mechanism, modified hopper evacuation valve assembly, and changes to pulse air cycle time and pulse duration.

Wet Scrubber Retrofit · Plating Shop. Project engineer on retrofit evaluation of plating shop packed-bed wet scrubbers failing to meet performance guarantees during acceptance trials, due to excessive mist carryover. Recommendations included relocation of the mist eliminator (ME), substitution of the original chevron blade ME with a mesh pad ME, and use of higher density packing material to improve exhaust gas distribution. Wet scrubbers passed acceptance trials following completion of recommended modifications.

Electrostatic Precipitator (ESP) Retrofit Evaluation · MSW Boiler. Lead engineer for retrofit evaluation of single field ESP on a municipal solid waste (MSW) boiler. Recommendations included addition of automated power controller, inlet duct turning vanes, and improved collecting plate rapping system.

ESP Electric Coil Rapper Vibration Analysis Testing - Coal-Fired Boiler. Lead engineer for evaluation of ESP rapper effectiveness test program on three field ESP equipped with "magnetically induced gravity return" (MIGR) rappers. Accelerometers were placed in a grid pattern on ESP collecting plates to determine maximum instantaneous plate acceleration at a variety of rapper power setpoints. Testing showed that the rappers met performance specification requirements.

Aluminum Remelt Furnace Particulate Emissions Testing. Project manager and lead engineer for high temperature (1,600 °F) particulate sampling of a natural gas-fired remelt furnace at a major aluminum rolling mill. Objectives of test program were to: 1) determine if condensable particulate was present in stack gases, and 2) to validate the accuracy of the in-stack continuous opacity monitor (COM). Designed and constructed a customized high temperature (inconel) PM_{10}/Mtd 17 sampling assembly for test program. An onsite natural gas-fired boiler was also tested to provide comparative data for the condensable particulate portion of the test program. Test results showed that no significant levels of condensable particulate in the remelt furnace exhaust gas, and indicated that the remelt furnace and boiler had similar particulate emission rates. Test results also showed that the COM was accurate.

Aluminum Remelt Furnace CO and NO_x Testing. Project manager and lead engineer for continuous week-long testing of CO and NO_x emissions from aluminum remelt furnace. Objective of test program was to characterize CO and NO_x emissions from representative remelt furnace for use in the facility's criteria pollution emissions inventory. A TECO Model 48 CO analyzer and a TECO Model 10 NO_x analyzer were utilized during the test program to provide $\pm$1 ppm measurement accuracy, and all test data was recorded by an automated data acquisition system.

.

PETROLEUM REFINERY AIR ENGINEERING/TESTING EXPERIENCE

Big West Refinery Expansion EIS. Lead engineer on comparative cost analysis of proposed wet cooling tower and fin-fan air cooler for process cooling water for the proposed clean fuels expansion project at the Big West Refinery in Bakersfield, California. Selection of the fin-fin air-cooler would eliminate all consumptive water use and wastewater disposal associated with the cooling tower. Air emissions of VOC and PM_{10} would be reduced with the fin-fan air-cooler even though power demand of the air-cooler is incrementally higher than that of the cooling tower. Fin-fan air-coolers with approach temperatures of 10 °F and 20 °F were evaluated. The annualized cost of the fin-fin air-cooler with a 20 °F approach temperature is essentially the same as that of the cooling tower when the cost of all ancillary cooling tower systems are considered.

Criteria and Air Toxic Pollutant Emissions Inventory for Proposed Refinery Modifications. Project manager and technical lead for development of baseline and future refinery air emissions inventories for process modifications required to produce oxygenated gasoline and desulfurized diesel fuel at a California refinery. State of the art criteria and air toxic pollutant emissions inventories for refinery point, fugitive and mobile sources were developed. Point source emissions estimates were generated using onsite criteria pollutant test data, onsite air toxics test data, and the latest air toxics emission factors from the statewide refinery air toxics inventory database. The fugitive volatile organic compound (VOC) emissions inventories were developed using the refinery's most recent inspection and maintenance (I&M) monitoring program test data to develop site-specific component VOC emission rates. These VOC emission rates were combined with speciated air toxics test results for the principal refinery process streams to produce fugitive VOC air toxics emission rates. The environmental impact report (EIR) that utilized this emission inventory data was the first refinery "Clean Fuels" EIR approved in California.

Development of Air Emission Standards for Petroleum Refinery Equipment - Peru. Served as principal technical consultant to the Peruvian Ministry of Energy in Mines (MEM) for the development of air emission standards for Peruvian petroleum refineries. The sources included in the scope of this project included: 1) SO_2 and NO_x refinery heaters and boilers, 2) desulfurization of crude oil, particulate and SO_2 controls for fluid catalytic cracking units (FCCU), 3) VOC and CO emissions from flares, 4) vapor recovery systems for marine unloading, truck loading, and crude oil/refined products storage tanks, and 5) VOC emissions from process fugitive sources such as pressure relief valves, pumps, compressors and flanges. Proposed emission limits were developed for new and existing refineries based on a thorough evaluation of the available air emission control technologies for the affected refinery sources. Leading vendors of refinery control technology, such as John Zink and Exxon Research, provided estimates of retrofit costs for the largest Peruvian refinery, La Pampilla, located in Lima. Meetings were held in Lima with refinery operators and MEM staff to discuss the proposed emission limits and incorporate mutually agreed upon revisions to the proposed limits for existing Peruvian refineries.

Air Toxic Pollutant Emissions Inventory for Existing Refinery. Project manager and technical lead for air toxic pollutant emissions inventory at major California refinery. Emission factors were developed for refinery heaters, boilers, flares, sulfur recovery units, coker deheading, IC engines, storage tanks, process fugitives, and catalyst regeneration units. Onsite source test results were utilized to characterize emissions from refinery combustion devices. Where representative source test results were not available, AP-42 VOC emission factors were combined with available VOC air toxics speciation profiles to estimate VOC air toxic emission rates. A risk assessment based on this emissions inventory indicated a relatively low health risk associated with refinery operations. Benzene, 1,3-butadiene and PAHs were the principal health risk related pollutants emitted.

Air Toxics Testing of Refinery Combustion Sources. Project manager for comprehensive air toxics testing program at a major California refinery. Metals, Cr^{+6}, PAHs, H_2S and speciated VOC emissions were measured from refinery combustion sources. High temperature Cr^{+6} stack testing using the EPA Cr^{+6} test method was performed for the first time in California during this test program. Representatives from the California Air Resources Board source test team performed simultaneous testing using ARB Method 425 (Cr^{+6}) to compare the results of EPA and ARB Cr^{+6} test methodologies. The ARB approved the test results generated using the high temperature EPA Cr^{+6} test method.

Air Toxics Testing of Refinery Fugitive Sources. Project manager for test program to characterize air toxic fugitive VOC emissions from fifteen distinct process units at major California refinery. Gas, light liquid, and heavy liquid process streams were sampled. BTXE, 1,3-butadiene and propylene concentrations were quantified in gas samples, while BTXE, cresol and phenol concentrations were measured in liquid samples. Test results were combined with AP-42 fugitive VOC emission factors for valves, fittings, compressors, pumps and PRVs to calculate fugitive air toxics VOC emission rates.

OIL AND GAS PRODUCTION AIR ENGINEERING/TESTING EXPERIENCE

Air Toxics Testing of Oil and Gas Production Sources. Project manager and lead engineer for test plan/test program to determine VOC removal efficiency of packed tower scrubber controlling sulfur dioxide emissions from a crude oil-fired steam generator. Ratfisch 55 VOC analyzers were used to measure the packed tower scrubber VOC removal efficiency. Tedlar bag samples were collected simultaneously to correlate BTX removal efficiency to VOC removal efficiency. This test was one of hundreds of air toxics tests performed during this test program for oil and gas production facilities from 1990 to 1992. The majority of the volatile air toxics analyses were performed at in-house laboratory. Project staff developed thorough familiarity with the applications and limitations of GC/MS, GC/PID, GC/FID, GC/ECD and GC/FPD. Tedlar bags, canisters, sorbent tubes and impingers were used during sampling, along with isokinetic tests methods for multiple metals and PAHs.

Air Toxics Testing of Glycol Reboiler· Gas Processing Plant. Project manager for test program to determine emissions of BTXE from glycol reboiler vent at gas processing facility handling 12 MM/cfd of produced gas. Developed innovative test methods to accurately quantify BTXE emissions in reboiler vent gas.

Air Toxics Emissions Inventory Plan. Lead engineer for the development of generic air toxics emission estimating techniques (EETs) for oil and gas production equipment. This project was performed for the Western States Petroleum Association in response to the requirements of the California Air Toxics "Hot Spots" Act. EETs were developed for all point and fugitive oil and gas production sources of air toxics, and the specific air toxics associated with each source were identified. A pooled source emission test methodology was also developed to moderate the cost of source testing required by the Act.

Fugitive NMHC Emissions from TEOR Production Field. Project manager for the quantification of fugitive Nonmethane hydrocarbon (NMHC) emissions from a thermally enhanced oil recovery (TEOR) oil production field in Kern County, CA. This program included direct measurement of NMHC concentrations in storage tank vapor headspace and the modification of available NMHC emission factors for NMHC-emitting devices in TEOR produced gas service, such as wellheads, vapor trunklines, heat exchangers, and compressors.

Modification of the existing NMHC emission factors was necessary due to the high concentration of CO_2 and water vapor in TEOR produced gases.

Fugitive Air Emissions Testing of Oil and Gas Production Fields. Project manager for test plan/test program to determine VOC and air toxics emissions from oil storage tanks, wastewater storage tanks and produced gas lines. Test results were utilized to develop comprehensive air toxics emissions inventories for oil and gas production companies participating in the test program.

Oil and Gas Production Field · Air Emissions Inventory and Air Modeling. Project manager for oil and gas production field risk assessment. Project included review and revision of the existing air toxics emission inventory, air dispersion modeling, and calculation of the acute health risk, chronic non-carcinogenic risk and carcinogenic risk of facility operations. Results indicated that fugitive H_2S emissions from facility operations posed a potential health risk at the facility fenceline.

•

TITLE V PERMIT APPLICATION/MONITORING PLAN EXPERIENCE

Title V Permit Application · San Diego County Industrial Facility. Project engineer tasked with preparing streamlined Title V operating permit for U.S. Navy facilities in San Diego. Principal emission units included chrome plating, lead furnaces, IC engines, solvent usage, aerospace coating and marine coating operations. For each device category in use at the facility, federal MACT requirements were integrated with District requirements in user friendly tables that summarized permit conditions and compliance status.

Title V Permit Application Device Templates - Oil and Gas Production Industry. Project manager and lead engineer to prepare Title V permit application "templates" for the Western States Petroleum Association (WSPA). The template approach was chosen by WSPA to minimize the administrative burden associated with listing permit conditions for a large number of similar devices located at the same oil and gas production facility. Templates are being developed for device types common to oil and gas production operations. Device types include: boilers, steam generators, process heaters, gas turbines, IC engines, fixed-roof storage tanks, fugitive components, flares, and cooling towers. These templates will serve as the core of Title V permit applications prepared for oil and gas production operations in California.

Title V Permit Application - Aluminum Rolling Mill. Project manager and lead engineer for Title V permit application prepared for largest aluminum rolling mill in the western U.S. Responsible for the overall direction of the permit application project, development of a monitoring plan for significant emission units, and development of a hazardous air pollutant (HAP) emissions inventory. The project involved extensive onsite data gathering, frequent interaction with the plant's technical and operating staff, and coordination with legal counsel and subcontractors. The permit application was completed on time and in budget.

Title V Model Permit - Oil and Gas Production Industry. Project manager and lead engineer for the comparative analysis of regional and federal requirements affecting oil and gas production industry sources located in the San Joaquin Valley. Sources included gas turbines, IC engines, steam generators, storage tanks, and process fugitives. From this analysis, a model applicable requirements table was developed for a sample device type (storage tanks) that covered the entire population of storage tanks operated by the industry. The U.S. EPA has tentatively approved this model permit approach, and work is ongoing to develop comprehensive applicable requirements tables for each major category of sources operated by the oil and gas industry in the San Joaquin Valley.

Title V Enhanced Monitoring Evaluation of Oil and Gas Production Sources. Lead engineer to identify differences in proposed EPA Title V enhanced monitoring protocols and the current monitoring requirements for oil and gas production sources in the San Joaquin Valley. The device types evaluated included: steam generators, stationary ICEs, gas turbines, fugitives, fixed roof storage tanks, and thermally enhanced oil recovery (TEOR) well vents. Principal areas of difference included: more stringent Title V O&M requirements for parameter monitors (such as temperature, fuel flow, and O_2), and more extensive Title V recordkeeping requirements.

RACT/BARCT/BACT EVALUATIONS

BACT Evaluation of Wool Fiberglass Insulation Production Line. Project manager and lead engineer for BACT evaluation of a wool fiberglass insulation production facility. The BACT evaluation was performed as a component of a PSD permit application. The BACT evaluation included a detailed analysis of the available control options for forming, curing and cooling sections of the production line. Binder formulations, wet electrostatic precipitators, wet scrubbers, and thermal oxidizers were evaluated as potential PM_{10} and VOC control options. Low NO_x burner options and combustion control modifications were examined as potential NO_x control techniques for the curing oven burners. Recommendations included use of a proprietary binder formulation to achieve PM_{10} and VOC BACT, and use of low-NO_x burners in the curing ovens to achieve NO_x BACT. The PSD application is currently undergoing review by EPA Region 9.

RACT/BARCT Reverse Jet Scrubber/Fiberbed Mist Eliminator Retrofit Evaluation. Project manager and lead engineer on project to address the inability of existing wet electrostatic precipitators (ESPs) and atomized mist scrubbers to adequately remove low concentration submicron particulate from high volume recovery boiler exhaust gas at the Alaska Pulp Corporation mill in Sitka, AK. The project involved thorough on-site inspections of existing control equipment, detailed review of maintenance and performance records, and a detailed evaluation of potential replacement technologies. These technologies included a wide variety of scrubbing technologies where manufacturers claimed high removal efficiencies on submicron particulate in high humidity exhaust gas. Packed tower scrubbers, venturi scrubbers, reverse jet scrubbers, fiberbed mist eliminators and wet ESPs were evaluated. Final recommendations included replacement of atomized mist scrubber with reverse jet scrubber and upgrading of the existing wet ESPs. The paper describing this project was published in the May 1992 TAPPI Journal.

Aluminum Smelter RACT Evaluation - Prebake. Project manager and technical lead for CO and PM_{10} RACT evaluation for prebake facility. Retrofit control options for CO emissions from the anode bake furnace, potline dry scrubbers and the potroom roof vents were evaluated. PM_{10} emissions from the coke kiln, potline dry scrubbers, potroom roof vents, and miscellaneous potroom fugitive sources were addressed. Four CO control technologies were identified as technologically feasible for potline CO emissions: potline current efficiency improvement through the addition of underhung busswork and automated puncher/feeders, catalytic incineration, recuperative incineration and regenerative incineration. Current efficiency improvement was identified as probable CO RACT if onsite test program demonstrated the effectiveness of this approach. Five PM_{10} control technologies were identified as technologically feasible: increased potline hooding efficiency through redesign of shields, the addition of a dense-phase conveying system, increased potline air evacuation rate, wet scrubbing of roof vent emissions, and fabric filter control of roof vent emissions. The cost of these potential PM_{10} RACT controls exceeded regulatory guidelines for cost effectiveness, though testing of modified shield configurations and dense-phase conveying is being conducted under a separate regulatory compliance order.

RACT/BACT Testing/Evaluation of PM_{10} Mist Eliminators on Five-Stand Cold Mill. Project manager and lead engineer for fiberbed mist eliminator and mesh pad mist eliminator comparative pilot test program on mixed phase aerosol (PM_{10})/gaseous hydrocarbon emissions from aluminum high speed cold rolling mill. Utilized modified EPA Method 5 sampling train with portion of sample gas diverted (after particulate filter) to Ratfisch 55 VOC analyzer. This was done to permit simultaneous quantification of aerosol and gaseous hydrocarbon emissions in the exhaust gas. The mesh pad mist eliminator demonstrated good control of PM_{10} emissions, though test results indicated that the majority of captured PM_{10} evaporated in the mesh pad and was emitted as VOC.

Aluminum Remelt Furnace/Rolling Mill RACT Evaluations. Lead engineer for comprehensive CO and PM_{10} RACT evaluation for the largest aluminum sheet and plate rolling mill in western U.S. Significant sources of CO emissions from the facility included the remelt furnaces and the coater line. The potential CO RACT options for the remelt furnaces included: enhanced maintenance practices, preheating combustion air, installation of fully automated combustion controls, and energy efficiency modifications. The coater line was equipped with an afterburner for VOC and CO destruction prior to the initiation of the RACT study. It was determined that the afterburner meets or exceeds RACT requirements for the coater line. Significant sources of PM_{10} emissions included the remelt furnaces and the 80-inch hot rolling mill. Chlorine fluxing in the melting and holding furnaces was identified as the principal source of PM_{10} emissions from the remelt furnaces. The facility is in the process of minimizing/eliminating fluxing in the melting furnaces, and exhaust gases generated in holding furnaces during fluxing will be ducted to a baghouse for PM_{10} control. These modifications are being performed under a separate compliance order, and were determined to exceed RACT requirements. A water-based emulsion coolant and inertial separators are currently in use on the 80-inch hot mill for PM_{10} control. Current practices were determined to meet/exceed PM_{10} RACT for the hot mill. Tray tower absorption/recovery systems were also evaluated to control PM_{10} emissions from the hot mill, though it was determined that the technical/cost feasibility of using this approach on an emulsion-based coolant had not yet been adequately demonstrated.

BARCT Low NO_x Burner Conversion – Industrial Boilers. Lead engineer for evaluation of low NO_x burner options for natural gas-fired industrial boilers. Also evaluated methanol and propane as stand-by fuels to replace existing diesel stand-by fuel system. Evaluated replacement of steam boilers with gas turbine co-generation system.

BACT Packed Tower Scrubber/Mist Eliminator Performance Evaluations. Project manager and lead engineer for Navy-wide plating shop air pollution control technology evaluation and emissions testing program. Mist eliminators and packed tower scrubbers controlling metal plating processes, which included hard chrome, nickel, copper, cadmium and precious metals plating, were extensively tested at three Navy plating shops. Chemical cleaning and stripping tanks, including hydrochloric acid, sulfuric acid, chromic acid and caustic, were also tested. The final product of this program was a military design specification for plating and chemical cleaning shop air pollution control systems. The hydrochloric acid mist sampling procedure developed during this program received a protected patent.

BACT Packed Tower Scrubber/UV Oxidation System Pilot Test Program. Technical advisor for pilot test program of packed tower scrubber/ultraviolet (UV) light VOC oxidation system controlling VOC emissions from microchip manufacturing facility in Los Angeles. The testing was sponsored in part by the SCAQMD's Innovative Technology Demonstration Program, to demonstrate this innovative control technology as BACT for microchip manufacturing operations. The target compounds were acetone, methylethylketone (MEK) and 1,1,1-trichloroethane, and compound concentrations ranged from 10-100 ppmv. The single stage packed tower scrubber consistently achieved greater than 90% removal efficiency on the target compounds. The residence time required in the UV oxidation system for effective oxidation of the target compounds proved significantly longer than the residence time predicted by the manufacturer.

BACT Pilot Testing of Venturi Scrubber on Gas/Aerosol VOC Emission Source. Technical advisor for project to evaluate venturi scrubber as BACT for mixed phase aerosol/gaseous hydrocarbon emissions from deep fat fryer. Venturi scrubber demonstrated high removal efficiency on aerosol, low efficiency on VOC emissions. A number of VOC tests indicated negative removal efficiency. This anomaly was traced to a high hydrocarbon concentration in the scrubber water. The pilot unit had been shipped directly to the jobsite from another test location by the manufacturer without any cleaning or inspection of the pilot unit.

Pulp Mill Recovery Boiler BACT Evaluation. Lead engineer for BACT analysis for control of SO_2, NO_x, CO, TNMHC, TRS and particulate emissions from the proposed addition of a new recovery furnace at a kraft pulp mill in Washington. A "top down" approach was used to evaluate potential control technologies for each of the pollutants considered in the evaluation.

Air Pollution Control Equipment Design Specification Development. Lead engineer for the development of detailed Navy design specifications for wet scrubbers and mist eliminators. Design specifications were based on field performance evaluations conducted at the Long Beach Naval Shipyard, Norfolk Naval Shipyard, and Jacksonville Naval Air Station. This work was performed for the U.S. Navy to provide generic design specifications to assist naval facility engineering divisions with air pollution control equipment selection. Also served as project engineer for the development of Navy design specifications for ESPs and fabric filters.

CONTINUOUS EMISSION MONITOR (CEM) PROJECT EXPERIENCE

Process Heater CO and NO_x CEM Relative Accuracy Testing. Project manager and lead engineer for process heater CO and NO_x analyzer relative accuracy test program at petrochemical manufacturing facility. Objective of test program was to demonstrate that performance of onsite CO and NO_x CEMs was in compliance with U.S. EPA "Boiler and Industrial Furnace" hazardous waste co-firing regulations. A TECO Model 48 CO analyzer and a TECO Model 10 NO_x analyzer were utilized during the test program to provide $\pm$1 ppm measurement accuracy, and all test data was recorded by an automated data acquisition system. One of the two process heater CEM systems tested failed the initial test due to leaks in the gas conditioning system. Troubleshooting was performed using O_2 analyzers, and the leaking component was identified and replaced. This CEM system met all CEM relative accuracy requirements during the subsequent retest.

Performance Audit of NO_x and SO_2 CEMs at Coal-Fired Power Plant. Lead engineer on system audit and challenge gas performance audit of NO_x and SO_2 CEMs at a coal-fired power plant in southern Nevada. Dynamic and instrument calibration checks were performed on the CEMs. A detailed visual inspection of the CEM system, from the gas sampling probes at the stack to the CEM sample gas outlet tubing in the CEM trailer, was also conducted. The CEMs passed the dynamic and instrument calibration requirements specified in EPA's Performance Specification Test - 2 (NO_x and SO_2) alternative relative accuracy requirements.

LATIN AMERICA ENVIRONMENTAL PROJECT EXPERIENCE

Preliminary Design of Ambient Air Quality Monitoring Network · Lima, Peru. Project leader for project to prepare specifications for a fourteen station ambient air quality monitoring network for the municipality of Lima, Peru. Network includes four complete gaseous pollutant, particulate, and meteorological parameter monitoring stations, as well as eight PM_{10} and TSP monitoring stations.

Evaluation of Proposed Ambient Air Quality Network Modernization Project · Venezuela. Analyzed a plan to modernize and expand the ambient air monitoring network in Venezuela. Project was performed for the U.S. Trade and Development Agency. Direct interaction with policy makers at the Ministerio del Ambiente y de los Recursos Naturales Renovables (MARNR) in Caracas was a major component of this project.

Evaluation of U.S.-Mexico Border Region Copper Smelter Compliance with Treaty Obligations · Mexico. Project manager and lead engineer to evaluate compliance of U.S. and Mexican border region copper smelters with the SO_2 monitoring, recordkeeping and reporting requirements in Annex IV [Copper Smelters] of the La Paz Environmental Treaty. Identified potential problems with current ambient and stack monitoring practices that could result in underestimating the impact of SO_2 emissions from some of these copper smelters. Identified additional source types, including hazardous waste incinerators and power plants, that should be considered for inclusion in the La Paz Treaty process.

Development of Air Emission Limits for ICE Cogeneration Plant - Panamá. Lead engineer assisting U.S. cogeneration plant developer to permit an ICE cogeneration plant at a hotel/casino complex in Panama. Recommended the use of modified draft World Bank NO_x and PM limits for ICE power plants. The modification consisted of adding a thermal efficiency factor adjustment to the draft World Bank NO_x and PM limits. These proposed ICE emission limits are currently being reviewed by Panamanian environmental authorities.

Mercury Emissions Inventory for Stationary Sources in Northern Mexico. Project manager and lead engineer to estimate mercury emissions from stationary sources in Northern Mexico. Major potential sources of mercury emissions include solid- and liquid-fueled power plants, cement kilns co-firing hazardous waste, and non-ferrous metal smelters. Emission estimates were provided for approximately eighty of these sources located in Northern Mexico. Coordinated efforts of two Mexican subcontractors, located in Mexico City and Hermosillo, to obtain process throughput data for each source included in the inventory.

Translation of U.S. EPA Scrap Tire Combustion Emissions Estimation Document · Mexico. Evaluated the Translated a U.S. EPA scrap tire combustion emissions estimation document from English to Spanish for use by Latin American environmental professionals.

Environmental Audit of Aluminum Production Facilities · Venezuela. Evaluated the capabilities of existing air, wastewater and solid/hazardous waste control systems used by the aluminum industry in eastern Venezuela. This industry will be privatized in the near future. Estimated the cost to bring these control systems into compliance with air, wastewater and solid/hazardous waste standards recently promulgated in Venezuela. Also served as technical translator for team of U.S. environmental engineers involved in the due diligence assessment.

Assessment of Environmental Improvement Projects · Chile and Peru. Evaluated potential air, water, soil remediation and waste recycling projects in Lima, Peru and Santiago, Chile for feasibility study funding by the U.S. Trade and Development Agency. Project required onsite interaction with in-country decisionmakers (in Spanish). Projects recommended for feasibility study funding included: 1) an air quality technical support project for the Santiago, Chile region, and 2) soil remediation/metals recovery projects at two copper mine/smelter sites in Peru.

Air Pollution Control Training Course · Mexico. Conducted two-day Spanish language air quality training course for environmental managers of assembly plants in Mexicali, Mexico. Spanish-language course manual prepared by Powers Engineering. Practical laboratory included training in use of combustion gas analyzer, flame ionization detector (FID), photoionization detector (PID), and occupational sampling.

Stationary Source Emissions Inventory · Mexico. Developed a comprehensive air emissions inventory for stationary sources in Nogales, Sonora. This project requires frequent interaction with Mexican state and federal environmental authorities. The principal Powers Engineering subcontractor on this project is a Mexican firm located in Hermosillo, Sonora.

VOC Measurement Program · Mexico. Performed a comprehensive volatile organic compound (VOC) measurements program at a health products fabrication plant in Mexicali, Mexico. An FID and PID were used to quantify VOCs from five processes at the facility. Occupational exposures were also measured. Worker exposure levels were above allowable levels at several points in the main assembly area.

Renewable Energy Resource Assessment Proposal · Panama. Translated and managed winning bid to evaluate wind energy potential in Panama. Direct interaction with the director of development at the national utility monopoly (IRHE) was a key component of this project.

Comprehensive Air Emissions Testing at Assembly Plant · Mexico. Project manager and field supervisor of emissions testing for particulates, NO_x, SO_2 and CO at turbocharger/air cooler assembly plant in Mexicali, Mexico. Source specific emission rates were developed for each point source at the facility during the test program. Translated test report into Spanish for review by the Mexican federal environmental agency (SEMARNAP).

Air Pollution Control Equipment Retrofit Evaluation · Mexico. Project manager and lead engineer for comprehensive evaluation of air pollution control equipment and industrial ventilation systems in use at assembly plant consisting of four major facilities. Equipment evaluated included fabric filters controlling blast booth emissions, electrostatic precipitator controlling welding fumes, and industrial ventilation systems controlling welding fumes, chemical cleaning tank emissions, and hot combustion gas emissions. Recommendations included modifications to fabric filter cleaning cycle, preventative maintenance program for the electrostatic precipitator, and redesign of the industrial ventilation system exhaust hoods to improve capture efficiency.

Comprehensive Air Emissions Testing at Assembly Plant · Mexico. Project manager and field supervisor of emissions testing for particulates, NO_x, SO_2 and CO at automotive components assembly plant in Acuña, Mexico. Source-specific emission rates were developed for each point source at the facility during the test program. Translated test report into Spanish.

Fluent in Spanish. Studied at the Universidad de Michoacán in Morelia, Mexico, 1993, and at the Colegio de España in Salamanca, Spain, 1987-88. Have lectured (in Spanish) on air monitoring and control equipment at the Instituto Tecnológico de Tijuana. Maintain contact with Comisión Federal de Electricidad engineers responsible for operation of wind and geothermal power plants in Mexico, and am comfortable operating in the Mexican business environment.

PUBLICATIONS

Bill Powers, "*Today's California Renewable Energy Strategy—Maximize Complexity and Expense*," Natural Gas & Electricity Journal, Vol. 27, Issue 2, September 2010, pp. 19-26.

Bill Powers, "*Environmental Problem Solving Itself Rapidly Through Lower Gas Costs*," Natural Gas & Electricity Journal, Vol. 26, Number 4, November 2009, pp. 9-14.

Bill Powers, "*PV Pulling Ahead, but Why Pay Transmission Costs?*" Natural Gas & Electricity Journal, Vol. 26, Number 3, October 2009, pp. 19-22.

Bill Powers, "*Unused Turbines, Ample Gas Supply, and PV to Solve RPS Issues*," Natural Gas & Electricity Journal, Vol. 26, Number 2, September 2009, pp. 1-7.

Bill Powers, "*CEC Cancels Gas-Fed Peaker, Suggesting Rooftop Photovoltaic Equally Cost-Effective*," Natural Gas & Electricity Journal, Vol. 26, Number 1, August 2009, pp. 8-13.

Bill Powers, "*San Diego Smart Energy 2020 – The 21st Century Alternative*," San Diego, October 2007.

Bill Powers, "*Energy, the Environment, and the California – Baja California Border Region*," Electricity Journal, Vol. 18, Issue 6, July 2005, pp. 77-84.

W.E. Powers, *"Peak and Annual Average Energy Efficiency Penalty of Optimized Air-Cooled Condenser on 515 MW Fossil Fuel-Fired Utility Boiler,"* presented at California Energy Commission/Electric Power Research Institute Advanced Cooling Technologies Symposium, Sacramento, California, June 2005.

W.E. Powers, R. Wydrum, P. Morris, *"Design and Performance of Optimized Air-Cooled Condenser at Crockett Cogeneration Plant,"* presented at EPA Symposium on Technologies for Protecting Aquatic Organisms from Cooling Water Intake Structures, Washington, DC, May 2003.

P. Pai, D. Niemi, W.E. Powers, *"A North American Anthropogenic Inventory of Mercury Emissions,"* presented at Air & Waste Management Association Annual Conference in Salt Lake City, UT, June 2000.

P.J. Blau and W.E. Powers, *"Control of Hazardous Air Emissions from Secondary Aluminum Casting Furnace Operations Through a Combination of: Upstream Pollution Prevention Measures, Process Modifications and End-of-Pipe Controls,"* presented at 1997 AWMA/EPA Emerging Solutions to VOC & Air Toxics Control Conference, San Diego, CA, February 1997.

W.E. Powers, et. al., *"Hazardous Air Pollutant Emission Inventory for Stationary Sources in Nogales, Sonora, Mexico ,"* presented at 1995 AWMA/EPA Emissions Inventory Specialty Conference, RTP, NC, October 1995.

W.E. Powers, *"Develop of a Parametric Emissions Monitoring System to Predict NO_x Emissions from Industrial Gas Turbines,"* presented at 1995 AWMA Golden West Chapter Air Pollution Control Specialty Conference, Ventura, California, March 1995.

W. E. Powers, et. al., *"Retrofit Control Options for Particulate Emissions from Magnesium Sulfite Recovery Boilers,"* presented at 1992 TAPPI Envr. Conference, April 1992. Published in *TAPPI Journal*, July 1992.

S. S. Parmar, M. Short, W. E. Powers, *"Determination of Total Gaseous Hydrocarbon Emissions from an Aluminum Rolling Mill Using Methods 25, 25A, and an Oxidation Technique,"* presented at U.S. EPA Measurement of Toxic and Related Air Pollutants Conference, May 1992.

N. Meeks, W. E. Powers, *"Air Toxics Emissions from Gas-Fired Internal Combustion Engines,"* presented at AIChE Summer Meeting, August 1990.

W. E. Powers, *"Air Pollution Control of Plating Shop Processes,"* presented at 7th AES/EPA Conference on Pollution Control in the Electroplating Industry, January 1986. Published in *Plating and Surface Finishing* magazine, July 1986.

H. M. Davenport, W. E. Powers, *"Affect of Low Cost Modifications on the Performance of an Undersized Electrostatic Precipitator,"* presented at 79th Air Pollution Control Association Conference, June 1986.

AWARDS

Engineer of the Year, 1991 – ENSR Consulting and Engineering, Camarillo
Engineer of the Year, 1986 – Naval Energy and Environmental Support Activity, Port Hueneme
Productivity Excellence Award, 1985 – U. S. Department of Defense

PATENTS

Sedimentation Chamber for Sizing Acid Mist, Navy Case Number 70094

Attachment B. Solar Resource Availability During Peak Demand Hours in SCE Territory

2007 Peak Day/Hour Loads				Burbank Airport Solar Availability at Peak					Ontario Airport Solar Availability at Peak				
2007 peak day	peak hour ending @:	CAISO load	PG&E load	cloud cover during actual peak load hour %	global irradiance (GI) during actual peak load hour	closest clear day (0% cloud cover), same hour	closest clear day GI at same hour	% actual GI at peak hour vs clear day GI at peak hour	cloud cover during actual peak load hour %	GI during actual peak load hour	closest clear day (0% cloud cover), same hour	closest clear day GI at same hour	% actual GI at peak hour vs clear day GI at peak hour
6/14/2007	15	40,895	19,778	0	727	6/14/07, 15	727	100	0	734	6/14/07, 15	734	100
7/2/2007	16	41,485	16,935	0	536	7/2/07, 16	536	100	12.5	547	6/30/07, 16	549	100
7/3/2007	15	42,748	17,993	0	722	7/3/07, 15	722	100	12.5	732	6/30/07, 15	742	99
7/5/2007	17	44,696	21,184	0	320	7/5/07, 17	320	100	44	339	6/30/07, 17	339	100
7/6/2007	15	43,696	19,758	0	710	7/6/07, 15	710	100	44	732	6/30/07, 15	742	99
7/31/2007	14	41,834	18,900	0	811	7/31/07, 14	811	100	44	720	8/6/07, 14	849	85
8/1/2007	15	41,710	18,475	0	687	8/1/07, 15	687	100	44	708	8/6/07, 15	698	101
8/2/2007	16	42,113	18,268	0	507	8/2/07, 16	507	100	12.5	517	8/5/07, 16	510	101
8/3/2007	16	42,952	18,901	0	505	8/3/07, 16	505	100	12.5	515	8/5/07, 16	510	101
8/13/2007	16	41,996	16,782	0	479	8/13/07, 16	479	100	44	488	8/11/07, 16	494	99
8/14/2007	16	42,889	17,084	0	447	8/14/07, 16	447	100	75	400	8/11/07, 16	494	81
8/15/2007	16	43,481	17,218	0	471	8/15/07, 16	471	100	12.5	482	8/11/07, 16	494	98
8/16/2007	15	42,951	16,647	0	648	8/16/07, 15	648	100	12.5	672	8/10/07, 15	689	98
8/17/2007	15	42,439	16,344	0	662	8/17/07, 15	662	100	12.5	668	8/10/07, 15	689	97
8/20/2007	16	44,294	18,411	0	454	8/20/07, 16	454	100	0	446	8/20/07, 16	446	100
8/21/2007	16	44,707	19,380	0	454	8/21/07, 16	454	100	12.5	461	8/20/07, 16	446	103
8/22/2007	15	43,478	19,807	0	642	8/22/07, 15	642	100	0	647	8/22/07, 15	647	100
8/23/2007	14	42,195	19,100	0	761	8/23/07, 14	761	100	0	808	8/23/07, 14	808	100
8/24/2007	15	41,325	18,290	0	451	8/27/07, 15	617	73	12.5	646	8/23/07, 15	650	99
8/27/2007	15	42,245	17,715	0	617	8/27/07, 15	617	100	0	619	8/27/07, 15	619	100
8/28/2007	16	46,033	19,651	0	427	8/28/07, 16	427	100	12.5	419	8/23/07, 16	454	92
8/29/2007	16	48,553	21,230	0	422	8/29/07, 16	422	100	44	341	8/23/07, 16	454	75
8/30/2007	15	48,074	20,489	0	344	9/01/07, 15	575	60	44	578	8/27/07, 15	619	93
8/31/2007	16	48,823	20,553	0	415	8/31/07, 16	415	100	44	408	8/23/07, 16	454	90
9/1/2007	15	44,758	18,443	0	575	9/1/07, 15	575	100	44	615	8/27/07, 15	619	99
9/2/2007	15	43,940	17,626	0	247	9/1/07, 15	575	43	75	608	8/27/07, 15	619	98
9/3/2007	14	44,874	17,588	0	778	9/3/07, 14	778	100	44	640	9/2/07, 14	784	82
9/4/2007	14	44,616	16,731	0	775	9/4/07, 14	775	100	N	776	9/2/07, 14	784	99
9/5/2007	14	41,114	17,260	0	771	9/5/07, 14	771	100	0	772	9/5/07, 14	772	100
							average =	96				average =	96

Global Irradiance: Solar radiation incident outside the Earth's atmosphere is called extraterrestrial radiation. On average the extraterrestrial irradiance is 1,367 Watts/square meter (W/m^2). Near noon on a day without clouds, about 25% of the solar radiation is scattered and absorbed as it passes through the atmosphere. Therefore about 1,000 W/m^2 of the incident solar radiation reaches the Earth's surface without being significantly scattered. This radiation, coming from the direction of the sun, is called direct normal irradiance. The scattered radiation reaching the earth's surface is called diffuse radiation. The total solar radiation on a horizontal surface is called global irradiance and is the sum of incident diffuse radiation plus the direct normal irradiance projected onto the horizontal surface.
Reference: http://solardat.uoregon.edu/SolarRadiationBasics.html

2007 global irradiance hourly data for Oakland Airport and San Jose Airport was obtained from the Solar Anywhere online database: https://www.solaranywhere.com/Public/About.aspx

SolarAnywhere generates global irradiance estimates using NOAA GOES visible satellite images. The global irradiance hourly data is provided for 5 mile x 7 mile blocks (~100 square km), or "tiles." The hourly satellite images are processed using the algorithms developed and maintained by Dr. Richard Perez at the University at Albany (SUNY). The algorithm extracts cloud indices from that satellite's visible channel using a self-calibrating feedback process that is capable of adjusting for ground surfaces. The cloud indices are used to adjust the irradiance transfer models and calculate the expected hour-by-hour irradiance for each 100 square km. tile.

2007 cloud cover hourly data for Burbank Airport and Ontario Airport is U.S. National Climate Data Center (NCDC) data purchased from Weather Warehouse. Code used for NCDC cloud cover values:
0: CLEAR - No clouds. 1: FEW - 2/8 or less coverage (not including zero). 2: SCATTERED - 3/8-4/8 coverage. 3: BROKEN - 5/8-7/8 coverage. 4: OVERCAST - 8/8 coverage.
To convert this cloud cover code to % cloud cover:
FEW: 2/8 or less, so 1/8 on average: 12.5% (Weather Warehouse reports worst case of 25%) BROKEN: 6/8: 75%
SCATTERED: 3.5/8 on average: 44% (Weather Warehouse reports worst case of 50%) OVERCAST: 100%

During a number of peak hour events, either no cloud cover was registered despite reduced GI (Burbank Airport), or significant cloud cover was registered even though global irradiance (GI) for the 100 square km. GI tile was near or at 100%. The presence of scattered clouds in the vicinity of the Ontario Airport, with generally clear skies in the remainder of the 100 square km. GI tile that contains the Ontario Airport, is the probable explanation for this discrepancy between irradiance and cloud cover. The situation at Burbank Airport is the reverse, with no cloud cover at the Burbank Airport but scattered cloud cover throughout the 100 square km. tile that contains the Burbank Airport.