STATE OF CALIFORNIA

ENERGY RESOURCES CONSERVATION
AND DEVELOPMENT COMMISSION

In the Matter of: The Application for Certification for the PIO PICO ENERGY CENTER	Docket No. 11-AFC-01

Rebuttal Testimony of Bill Powers, P.E.
Pio Pico Energy Center
Docket 11-AFC-01

July 6, 2012

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I. Introduction

Q: Please state your name, job title, and business address.

A: William A. Powers, P.E., principal of Powers Engineering, 4452 Park Blvd., Suite 209, San Diego, California, 92116.

Q: Please describe your qualifications.

A: I have a B.S. in mechanical engineering from Duke University and a Master of Public Health degree in environmental sciences from the University of North Carolina – Chapel Hill. I am a registered professional mechanical engineer in California with 30 years of experience in the energy and environmental fields. 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 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 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.

Q: What is the purpose of your testimony?

A: My testimony addresses the failure of the CEC to follow the *Energy Action Plan* loading order in its analysis of alternatives to the proposed Pio Pico Energy Center; b) failure of CEC to conduct detailed analysis of rooftop solar as alternative the in FSA consistent with the CEC determination regarding rooftop solar in the 2009 denial of 100 MW Chula Vista Energy Upgrade Project (CVEUP); c) failure of CEC to determine solar resource availability in top 100 demand hours or to corroborate whether Pio Pico can assure 98+ percent availability; d) failure of CEC to evaluate low cost demand response alternatives to Pio Pico, including but not limited to Ice Bear thermal storage units used extensively by public utilities in Southern California; and e) the failure of CEC to establish that the ancillary services to be provided by Pio Pico cannot be met by peak load reduction measures (DR, rooftop PV) or energy/thermal storage, or why the ancillary services issue eliminates rooftop solar from consideration in the case of Pio Pico but did not in the case of the CVEUP.

II. Renewable Distributed Generation and State Energy Goals

Q: Does priority emphasis on renewable distributed generation (DG) resources advance the state's energy goals?

A: Yes. Customer decisions to utilize DG to offset consumption of electricity from the grid is consistent with state energy goals, including the loading order, the Governor's 12 GW goal for DG, and the state's ambitious net zero energy building goals.

Q: How does DG contribute to the state's loading order?

A: The California Energy Commission ("CEC") and the California Public Utilities Commission ("CPUC") developed the *Energy Action Plan* in 2003 to guide strategic energy planning in California.[1] It establishes a resource priority list, or loading order, to guide strategic energy planning. The loading order prioritizes energy efficiency and demand response, renewable energy, combined heat and power, followed by utility natural gas-fired resources. The *Energy Action Plan* is explicit that rooftop PV is an element of building energy efficiency standards. *Energy Action Plan I* states that California should

[1] Energy Action Plan I: http://www.energy.ca.gov/energy_action_plan/2003-05-08_ACTION_PLAN.PDF

"[i]ncorporate distributed generation or renewable technologies into energy efficiency standards for new building construction." The CPUC confirmed in January 2012 that the "loading order applies to all utility procurement, even if pre-set targets for certain preferred resources have been achieved."[2] Customers utilizing renewable DG advance the loading order by reducing demand on the grid at the point-of-use with clean energy.

Q: Describe the Governor's 12,000 MW goal for new renewable DG resources.

A: Governor Jerry Brown 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.[3]

Q: Do you have an estimate for how much SDG&E might contribute to the Governor's 12 GW goal?

A: SDG&E demand represents about 8 percent of statewide electricity demand.[4,5] The proportionate SDG&E share of 12,000 MW of new local renewable energy in California by 2020 would be about 960 MW.

Q: Is SDG&E close to reaching this estimated goal of 960 MW new local renewable generation?

A: No. At the end of 2011, SDG&E territory had about 120 MW of net-metered (NEM) PV systems online.[6] It is unclear whether other smaller-scale renewable generation programs, such as the Renewable Auction Mechanism, will result in significant amounts of renewable generation in the San Diego Local Capacity Requirement (LCR) area.

Q: How does DG contribute to the state's net zero building goals?

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[2] *See* Commission Decision 12-01-033 at 20-21.

[3] Governor Jerry Brown, April 25, 2012 Support Letter for DRECP Process, at 2 (http://www.drecp.org/meetings/2012-04-25-26_meeting/presentations/04_Office_of_the_Governor_Paper.pdf.; Governor Jerry Brown, *Clean Energy Jobs Plan*, June 2010.

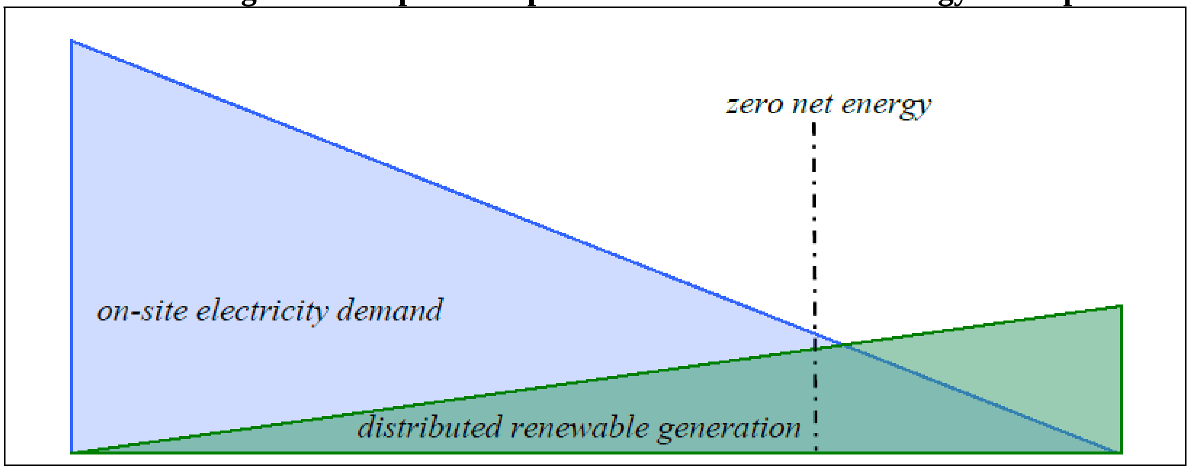
[4] CEC Final Staff Report, *California Energy Demand 2012-2022 Final Forecast - Volume 1: Statewide Electricity Demand and Methods, End-User Natural Gas Demand, and Energy Efficiency*, May 2012, p. 2. Statewide 2011 electricity demand was 273,103 GWh.

[5] SDG&E Application A.08-11-014 , *Prepared Direct Testimony of Greg Katsapis - Authority to Update Cost Allocation And Electric Rate Design*, November 14, 2008. Forecast 2009 SDG&E demand was 20,890 GWh.

[6] J.C Thomas – SDG&E, *San Diego/Solar Stakeholder Collaboration Rates & Educational Overview*, January 25 & 27. 2012, p. 48 (for current NEM level).

A: The CPUC and SDG&E, SCE, and PG&E jointly developed the *California Long Term Energy Efficiency Strategic Plan* in 2008.[7] The *Plan* was updated in 2011.[8] 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 concept of net zero energy is shown graphically in Figure 1.

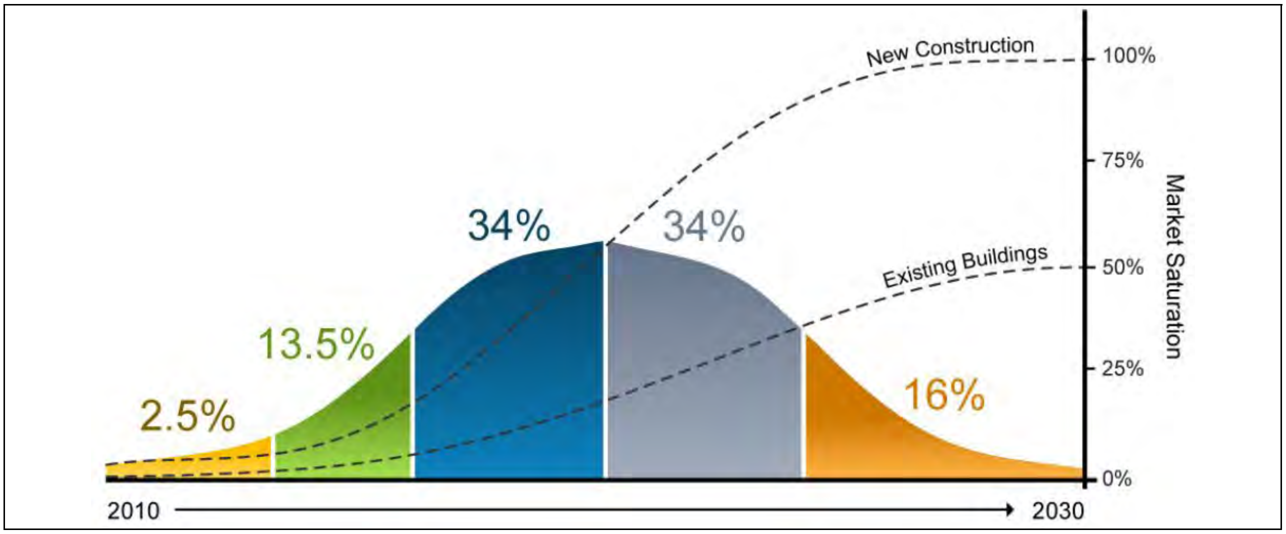
Figure 1. Graphical Representation of Net Zero Energy Concept[9]



The *Energy Efficiency Strategic Plan* assumes that 50 percent of existing commercial buildings achieve net zero energy by 2030 with no interim 2020 target. The CPUC projects that 15 to 20 percent of existing commercial buildings will reach net zero energy by 2020, as shown in Figure 2.

[7] See: http://www.cpuc.ca.gov/PUC/energy/Energy+Efficiency/eesp/ .
[8] CPUC, *California Energy Efficiency Strategic Plan*, January 2011 Update.
[9] *California Energy Efficiency Strategic Plan*, January 2011 Update: http://www.cpuc.ca.gov/PUC/energy/Energy+Efficiency/eesp/.

Figure 2. CPUC Estimate of Rate of Retrofit of Existing Commercial Buildings to ZNE from 2010 to 2030[10]



Q: How much DG is required to fully realize the net zero building goals?

A: Statewide, full implementation of the existing residential and commercial load reduction goals in the *Energy Efficiency Strategic Plan* would result in about 14,000 to 15,000 of rooftop PV by 2020.[11] This is consistent with the Governor's target of 12,000 MW of new local renewable energy, and would add about 960 MW of rooftop solar to San Diego by 2020.

Q: Does rooftop solar PV, in particular, advance these state energy goals?

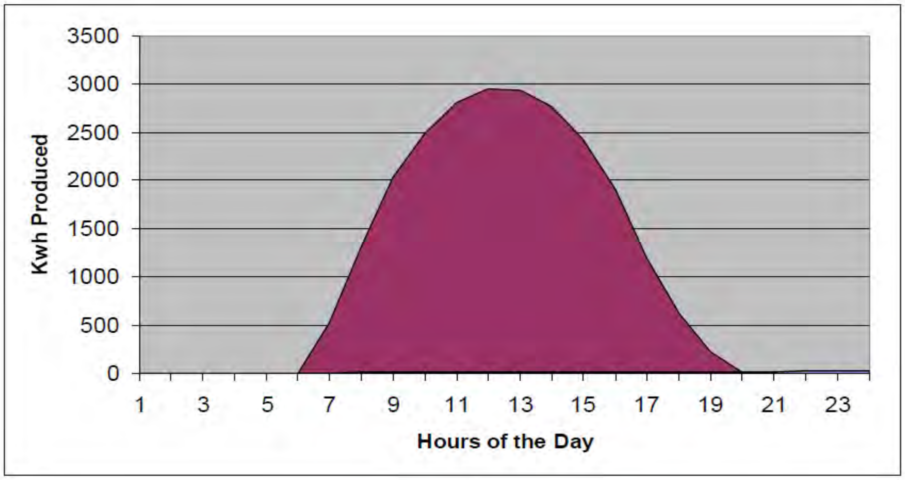
A: Yes. The only currently operational CPUC program available to achieve these *Energy Efficiency Strategic Plan* rooftop PV targets is net-metering (NEM).[12] The clear day electricity production profile of a south-facing rooftop PV system is shown in Figure 3. Output is at its maximum around 1 pm, and is about 50 percent of maximum at 5 pm.

[10] CPUC, *California Energy Efficiency Strategic Plan - Zero Net Energy Action Plan: Commercial Building Sector*2010-2012, August 31, 2010, Appendix C, p. 34. See: http://www.cpuc.ca.gov/NR/rdonlyres/6C2310FE-AFE0-48E4-AF03-530A99D28FCE/0/ZNEActionPlanFINAL83110.pdf.

[11] B.Powers, *Bay Area Smart Energy 2020*, March 2012, Table 10-1, pp. 88-89. Assume 15 percent existing commercial buildings are ZNE by 2020, and for the 25 percent of existing homes that reduce demand by 70 percent, 30 percent is achieved through energy efficiency and 40% is achieved with rooftop PV. Multi-family reduces demand by 40 percent, of which 30 percent is achieved through energy efficiency and 10 percent though rooftop PV. The amount of rooftop PV necessary to achieve these targets is 14,000 to 15,000 MW_{ac}, assuming an average PV output of 1,800 to1,900 kWh-yr per kW_{ac} installed. See: http://pacificenvironment.org/downloads/BASE2020_Full_Report.pdf

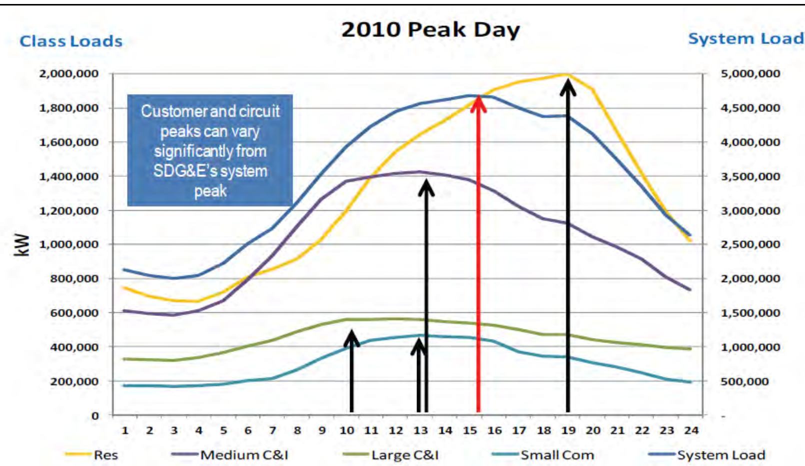
[12] The Commission approved a tariff structure for 750 MW (statewide) SB 32 feed-in tariff legislation in D.12-05-035, issued on May 31, 2012. The tariff structure is called the Renewable Market Adjusting Tariff (ReMAT). The capacity limit is 3 MW. Projects must be located at sites with minimal transmission and distribution interconnection costs. There is no pure requirement that the ReMAT projects be located in or near load centers.

Figure 3. Summer Profile for Large Commercial Rooftop PV Array[13]



The peak day demand of major SDG&E customer categories is shown in Figure 4. The three commercial SDG&E customer categories, Small Commercial, Medium Commercial & Industrial (C&I), and Large C&I, reach maximum demand at mid-day. Demand gradually decline over the course of the afternoon. Rooftop NEM PV is particularly well suited to following the commercial demand profile. Residential peak day load reaches a maximum in the early evening. It is for this reason that the coincident peak load across all customer classes occurs in the mid-afternoon.

Figure 4. SDG&E Peak Load Curves by Customer Category[14]



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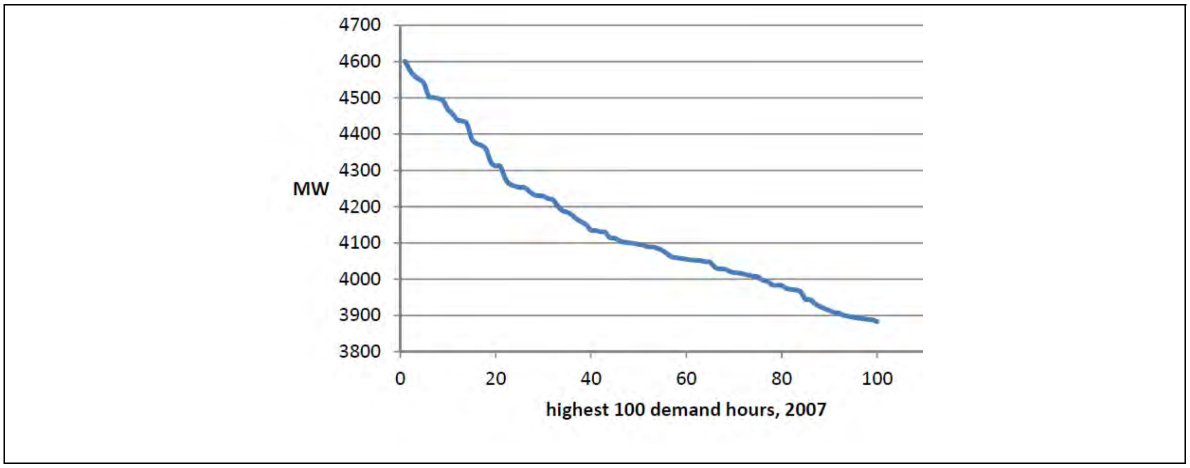
13 P. Shoemaker - PG&E, *Basics of Photovoltaic (PV) Systems for Grid-Tied Applications*, PowerPoint, 2008.
14 SDG&E Application A.11-10-002, *Revised Prepared Direct Testimony of Chris Yunker*, February 2012, p. 7.

Q: Is it appropriate to focus on the availability of the solar resource in the top 100 hours of peak demand when comparing the availability of rooftop solar to Pio Pico?

A: Yes. SDG&E allocates generation capacity charges based on use in the top 100 demand hours of the year. As SDG&E states, "The "Top 100 hours" methodology allocates revenues based on the customer classes' contribution to the top 100 hours of system load during a given annual period."[15] This makes sense, as peaking capacity resources like Pio Pico Energy Center are financed and maintained primarily to address demand during the highest demand hours of the year. SDG&E load drops rapid in the top 100 demand hours, as shown in Figure 5.

Figure 5. Load Decline in Top 100 Demand Hours in SDG&E Territory, 2007[16]



Q: Is rooftop PV at least as reliable as peaking gas turbine capacity during top 100 hours of demand?

A: Yes. NEM PV is at least as reliable as peaker capacity during top 100 demand hours in SDG&E territory. Powers Engineering correlated hourly 2007 SDG&E load data from the CAISO OASIS online database to hourly cloud cover and global irradiance data to assess the availability of the solar resource in San Diego County during peak demand hours. 2007 datasets were used because all datasets for 2007 were readily available at reasonable cost at the time the evaluation was initiated.

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[15] SDG&E Application A.11-10-002, *Application for Authority to Update Marginal Costs, Cost Allocation, and Electric Rate Design. Revised Prepared Direct Testimony of William G. Saxe - Chapter 3*, February 2012, p. 4.
[16] CAISO OASIS database, "System Load": http://oasishis.caiso.com/

"Availability of the solar resource" is defined here as the percentage of potential solar energy, also known as global irradiance, that was actually available to produce PV electricity in a given hour. The reason that the solar resource would not be fully available is cloud cover. To put the 2007 peak load data set in perspective, the 2007 SDG&E load, at 4,601 MW, was about 250 MW higher than the 2011 peak load of 4,355 MW. The lower cut-off load level in the analysis was 3,500 MW. In 2007, there were 239 hours where the SDG&E demand was at or above 3,500 MW. The results of the analysis are presented in Table 1.

Table 1. Availability of Solar Resource During Peak Demand Hours in SDG&E Territory

Demand hour range	Load Range (MW)	Average Solar Resource Availability (%)
Top 10 demand hours	4,468 – 4,601	98
Top 20 demand hours	4,312 – 4,601	99
Top 100 demand hours	3,883 – 4,601	99
Top 239 demand hours	3,500 – 4,601	99+

The actual availability of the solar resource across the top 10 demand hours in 2007 was 98 percent. It was 99 percent in the top 20 demand hours, and 99+ percent for the top 239 demand hours. As noted, the top 239 demand hours represent all one-hour SDG&E demand at or above 3,500 MW. 3,500 MW is over 1,150 MW below the all-time peak one-hour demand recorded to date in SDG&E territory, 4,687 MW in September 2010.[17]

There will be times during the on-peak period, which covers weekdays June 1 – October 1, 11 am – 6 pm, when skies are overcast and the NEM operator will draw all electricity from SDG&E. However, these are modest or low demand periods with system loads less than 3,500 MW where there is no stress on the distribution system and no peaking units are operational.[18] A subset of this on-peak period is the 100 highest demand hours of the

[17] SDG&E Comments on the Proposed Decision of Commission Peevey Regarding the Calculation of the Net Energy Metering Cap, May 1, 2012 in CPUC Docket R.10-05-044.
[18] See Powers Engineering hour-by-hour comparison of load and weather conditions in SDG&E service territory in 2007 with demand at or above 3,500 MW, included with this testimony as Attachment B.

year that determine the allocation of capacity costs among commercial customers. During this critical peak demand subset, commercial NEM PV is at least 98 percent available.

The actual availability of peaking natural gas-fired resources is at best equivalent to NEM PV systems. Pio Pico Energy Center, LLC, predicts an equivalent availability factor of at least 98 percent.[19] Quail Brush Generation Project is a proposed 100 MW internal combustion engine peaker project in the San Diego area. Pio Pico and Quail Brush each responded to a SDG&E solicitation seeking peaking resources that could maintain at least 98 percent availability.[20] However, 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.[21] The projected availability of Mariposa Energy Center is 92 to 98 percent.[22]

PioPico, Marsh Landing, and Mariposa will all use General Electric gas turbines. No technical support is provided in the FSA to validate that the Pio Pico General Electric gas turbines will achieve an availability of 98 percent or more on a continuous basis, while new General Electric gas turbines at Bay Area sites will achieve minimum availabilities of only 92 or 94 percent.

Q: Does rooftop PV provide reliable capacity during the top 100 hours of peak demand?

A: Yes. NEM PV systems provide capacity at an availability of at least 98 percent in aggregate during critical peak demand. This high availability is as good or better than natural gas-fired peaking resources. As SDG&E's states, the addition of 750 MW of new

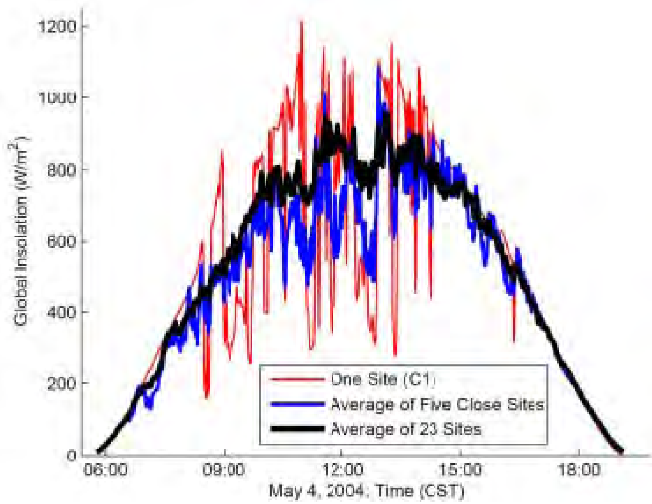
[19] CEC, *Pio Pico Energy Center (11-AFC-1) Final Staff Assessment - Power Plant Reliability*, May 2012, p. 5.4-1.
[20] CEC, *Quail Brush Generation Project – Application for Certification*, September 2011, p. 2-5. "The RFO (Request For Offer) sought projects that would be online no later than October 1, 2014, have an annual capacity of at least 30 percent and an availability of at least 98 percent."
[21] CEC, *Marsh Landing Generating Station – Commission Decision*, August 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."
[22] 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."

NEM PV capacity in SDG&E service territory would be expected to reduce the average peak hour load in August (3-4 pm) by over 400 MW.[23] Scattered cloud conditions do exist on occasion in SDG&E service territory during the top 100 hours of demand. However, the aggregate availability of the solar resource during these infrequent scattered cloud conditions is approximately 80 per cent or greater. A detailed analysis of solar resource availability during the 100 peak hours in SDG&E territory is provided in Exhibit B.

Distributed PV is also predictably available in aggregate on days with scattered clouds, when the output of multiple geographically-dispersed PV systems is combined.[24] This output characteristic of multiple-geographically dispersed distributed PV systems is shown in Figure 6.

The San Diego area already has at least 15,000 distributed PV systems.[25] The output from these dispersed PV systems on days with scattered clouds is reliable in aggregate due to the dispersion of these PV systems over hundreds of square kilometers of developed areas in San Diego County.

Figure 6. Multiple PV Sites Smooth Aggregate PV Output on Partly Cloudy Days



[23] *See* Ex. SDG&E-105, Table 5A-2 at DTB-5-A and Table 5A-6 at DTB-7-A.
[24] Lawrence Berkeley National Laboratory, *Implications of Wide-Area Geographic Diversity for Short-Term Variability of Solar Power*, September 2010, p. 25. See: http://eetd.lbl.gov/ea/emp/reports/lbnl-3884e.pdf.
[25] J.C Thomas – SDG&E, *San Diego/Solar Stakeholder Collaboration Rates & Educational Overview*, January 25 & 27. 2012, p. 48.

NEM PV is reliably available during the top 100 demand hours in SDG&E service territory. However, no capacity value is allocated to the NEM PV resource. NEM PV operators receive no capacity payments. The Commission decision in D.11-06-016 found that net surplus generation by net-energy metered customers has no capacity value because an individual net-energy metered customer has no obligation to provide energy to the utility.[26] This statement is made in the context of generation in excess of meeting 100 percent of the customer's annual electrical demand that is contractually obligated to deliver a specific quantity of electricity at a given time. As a practical matter, NEM PV systems will automatically provide electricity, individually on clear days and in aggregate on days with scattered clouds, at very high availability during periods of critical peak demand. Whether this electricity is used on-site or exported, it reduces demand on the grid.

Lawrence Berkeley National Laboratory (LBNL) recently completed an analysis of the capacity value of PV, solar thermal, and wind generation. The authors identify the purpose of the study as the quantification of the economic value of these renewable resources, noting that "Resource procurement and investment decisions are made more difficult by the variable and unpredictable nature of variable generation (VG). Part of what is missing from simple comparisons is an evaluation of the economic value of the energy generated." [27]

The LBNL study states that the marginal value of PV is high at low penetration due to high capacity value. The economic significance of this high capacity value is described as:

> This high value at low penetration is largely due to the ability of solar resources to reduce the amount of new non-renewable capacity that is

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[26] D.12-05-035, *Decision Revising Feed-In Tariff Program, Implementing Amendments to Public Utilities Code Section 399.20 Enacted by Senate Bill 380, Senate Bill 32, and Senate Bill 2 1X and Denying Petitions for Modification of Decision 07-07-027 by Sustainable Conservation and Solutions for Utilities Inc*., May 31, 2012, p. 37. "AB 920 amended § 2827 in order to pay net-energy metered customers for their excess generation over a one-year period. D.11-06-016 found that net surplus generation by net-energy metered customers has no capacity value because an individual net-energy metered customer has no obligation to provide energy to the utility."

[27] A. Miller and R. Wiser – Lawrence Berkeley National Laboratory, *Changes in the Economic Value of Variable Generation with Increasing Penetration Levels: A Pilot Study of California* (PowerPoint summary), June 2012.

> built, leading to a high capacity value. The magnitude of the capacity value of solar resources depends on the coincidence of solar generation with times of high system need, the cost of generation resources that would otherwise be built, and decisions regarding the retirement of older, less efficient conventional generation.[28]

Specifically LBNL indicates the capacity value of PV is higher than the capacity value of a combined cycle gas turbine until the PV penetration rate reaches the 5 to 10 percent penetration level. The penetration of NEM PV in SDG&E's territory is currently about 1 percent. The high capacity value of NEM PV is ignored by the applicant and in the FSA.

III. FSA Is Flawed for Failure to Corroborate Applicant's Assertion of Need

Q. Did the CEC reduce the SDG&E peak load projection following CPUC December 2007 decision that is basis of SDG&E 2009 RFO?

A. Yes. The applicant states that the SDG&E 2009 RFO it replied to was a response to the CPUC's December 2007 authorization to finance new dispatchable capacity in the San Diego LCA capable of providing local capacity and facilitating the integration of intermittent renewable resources. However, peak demand in SDG&E territory has remained static since 2007.

The CEC has decreased the projected 1-in-10 peak demand in SDG&E territory twice since the November 2007 forecast used in the Powerlink decision, once in December 2009 and again in March 2011. The November 2007 CEC forecast is shown in Table 2. The 2009 and 2011 CEC forecasts are shown in Tables 3 and 4, respectively. Between the 2007 and 2009 forecasts, SDG&E peak load estimates declined by 159 MW in 2012 and 185 MW in 2017.

[28] A. Miller and R. Wiser – Lawrence Berkeley National Laboratory, *Changes in the Economic Value of Variable Generation with Increasing Penetration Levels: A Pilot Study of California* (report), June 2012, p. 6.

Table 2. SDG&E 2008-2018 Peak Demand, CEC Forecast November 2007[29]

Year	1-in-2 Temperatures	1-in-5 Temperatures	1-in-10 Temperatures
2006	4,419	4,720	4,808
2007	4,506	4,812	4,902
2008	4,568	4,879	4,970
2009	4,641	4,956	5,049
2010	4,712	5,032	5,127
2011	4,784	5,109	5,205
2012	4,856	5,186	5,283
2013	4,925	5,260	5,358
2014	4,994	5,333	5,433
2015	5,063	5,407	5,509
2016	5,131	5,480	5,582
2017	5,198	5,551	5,655

Table 3. SDG&E 2010-2020 Peak Demand, CEC Forecast December 2009[30]

Year	1-in-2 Temperatures	1-in-5 Temperatures	1-in-10 Temperatures
2009	4,487	4,836	4,935
2010	4,516	4,868	4,967
2011	4,578	4,935	5,036
2012	4,658	5,021	5,124
2013	4,738	5,108	5,212
2014	4,797	5,171	5,277
2015	4,856	5,234	5,341
2016	4,911	5,294	5,402
2017	4,973	5,361	5,470
2018	5,032	5,424	5,535
2019	5,094	5,491	5,603
2020	5,157	5,559	5,673

The forecast peak demand in SDG&E territory was further reduced in the CEC's most recent March 2011 short-term peak demand forecast for 2011 and 2012. As shown in Table 4, the 1-in-10 peak demand projected for SDG&E territory in 2011 is 4,801 MW and for 2012 it is 4,882 MW. As noted in the CEC forecast (far right column), this

[29] CEC, *California Energy Demand 2008-2018 Staff Revised Forecast – Staff Final Report*, November 2007, p. 144, Form 1.5 SDG&E Planning Area, Peak Demand (MW). See: http://www.energy.ca.gov/2007publications/CEC-200-2007-015/CEC-200-2007-015-SF2.PDF.

[30] CEC, *California Electricity Demand 2010-2020 Adopted Forecast*, December 2009, p. 150, Form 1.5 SDG&E Planning Area, Extreme Temperature Peak Demand (MW). See: http://www.energy.ca.gov/2009publications/CEC-200-2009-012/index.html.

represents reductions of 235 MW for the 2011 peak and 242 MW for the 2012 peak compared to the December 2009 CEC forecast.

Table 4. SDG&E Peak Demand in 2011 and 2012, CEC Forecast March 2011[31]

TAC Area/Load Pocket	Year	Revised 1-in-2 Peak Demand	2009 IEPR 1-in-2 Peak Demand	1-in-2 Difference	Revised 1-in-10 Peak Demand	2009 IEPR 1-in-10 Peak Demand	1-in-10 Difference
SDG&E	2011	4,365	4,578	-213	4,801	5,036	-235
	2012	4,438	4,658	-220	4,882	5,124	-242

The March 2011 CEC forecast also includes a weather-adjusted 1-in-10 projection of 4,756 MW for the 2010 peak.[32] The most recent March 2011 CEC forecast of the 2010, 2011, and 2012 1-in-10 peak demand forecasts for SDG&E territory are compared in Table 5 to the same peak demand projections in the 2007 and 2009 CEC forecasts. As shown in Table 5, the March 2011 CEC forecast for peak demand in SDG&E territory is consistently about 400 MW less than the November 2007 CEC forecast adopted by the CPUC as the basis for approving the Powerlink on reliability need.

Table 5. Comparison of the 2011 and 2012 SDG&E 1-in-10 Peak Loads Projected in Energy Commission 2007, 2009, 2010 Peak Demand Forecasts

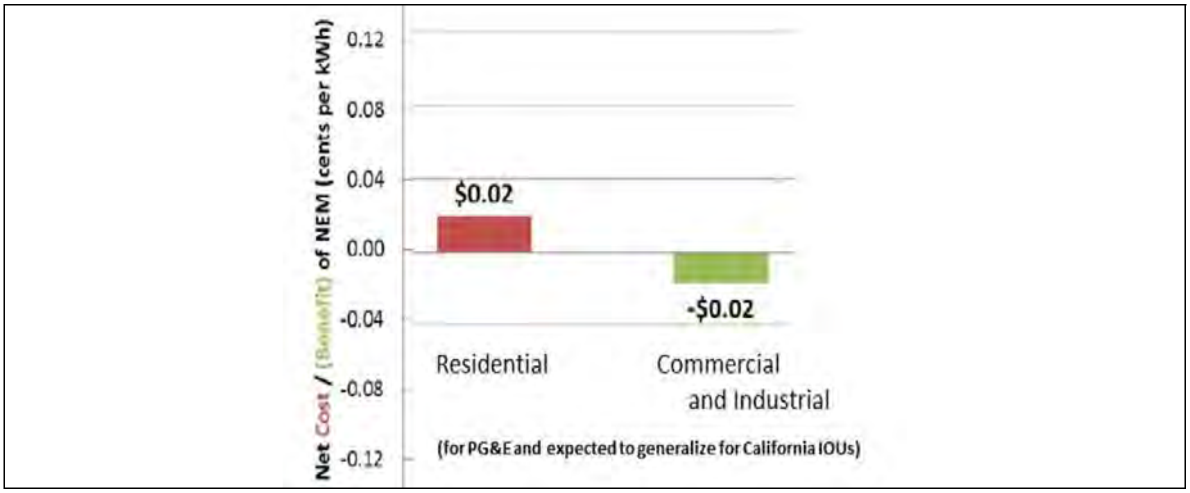
Date of Energy Commission Peak Demand Forecast for SDG&E	2010 (MW)	2011 (MW)	2012 (MW)
November 2007	5,127	5,205	5,283
December 2009	4,967	5,036	5,124
March 2011	4,756	4,801	4,882
Peak demand change between 2007 and 2011 forecasts	-371	-401	-401

31 CEC, *Revised Short-Term Peak Demand Forecast (2011-2012) – Final Committee Report*, March 2011, Table 6, p. 14. See: http://www.energy.ca.gov/2011publications/CEC-200-2011-002/CEC-200-2011-002-CTF.PDF.
32 CEC, *Revised Short-Term Peak Demand Forecast (2011-2012) – Final Committee Report*, March 2011, Table 3, p. 11.

Q. Would rooftop solar impose new costs on non-solar ratepayers?

A. No. Despite SDG&E claims to the contrary, net metering (NEM) imposes no net costs on utility customers without NEM PV systems, as shown in Figure 7.

Figure 7. Economic Impact of NEM PV on Utility Customers without Rooftop PV[33]



SDG&E co-authored a study of that estimates the 2010 rooftop PV potential in San Diego County at more than 4,400 MWac.[34] 4,400 MWac is equivalent to SDG&E's one-hour peak load.[35] The only potential brake on continued rapid growth of NEM rooftop PV in the San Diego local area is the NEM cap. Assuming California continues to increase its NEM cap as it has done in the past to accommodate foreseeable near-term growth in NEM PV systems, SDG&E would add in the range of 1,000 MW of NEM PV systems by 2020. Figure 8 shows the growth curve for NEM PV systems in San Diego.

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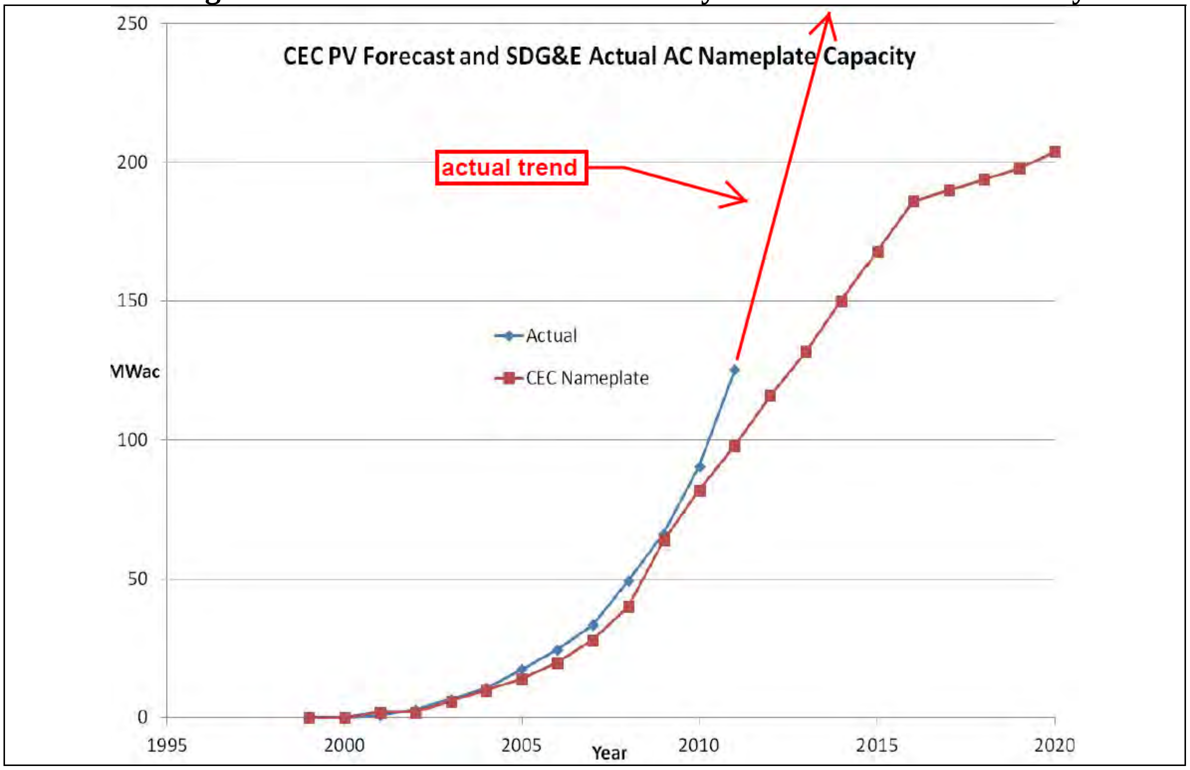
[33] GreenTech Media, *CPUC on verge of major decision about solar's net metering*, May 15, 2012. Graphic from: Crossborder Energy, *Re-evaluating the Cost-Effectiveness of Net Energy Metering in California*, December 22, 2011, Figure 3, p. 10. See: http://votesolar.org/wp-content/uploads/2012/01/Re-evaluating-the-Cost-effectiveness-of-Net-Energy-Metering-in-California-1-9-2012.pdf.

[34] San Diego Regional Renewable Energy Study Group, *Potential for Renewable Energy in the San Diego Region*, August 2005, Chapter 2: Solar Photovoltaic Electric. See: www.renewablesg.org.

[35] CAISO OASIS database. SDG&E 2011one-hour peak was 4,355 MW on September 7, 2011 (HE 16).

Figure 8. Growth Curve of NEM PV Systems in SDG&E Territory[36]



SDG&E currently has about 15,000 customers with NEM PV systems.[37] This is about 1 percent of SDG&E's 1.4 million customers. SDG&E projects that at a 15 percent NEM adoption level, the cost to non-NEM customers would be $120 million in additional transmission and distribution charges shifted from NEM customers to non-NEM customers.[38] As shown in Figure 7, at a 1 percent penetration rate, NEM PV systems are producing 120 MW of nameplate capacity. At 15 percent penetration, assuming a linear relationship, NEM PV systems will have a nameplate capacity of 1,800 MW in SDG&E territory. Without questioning here the validity of the SDG&E "cost shift" dollar amount, if 1,800 MW of NEM PV capacity imposes $120 million per year in cost shift to non-NEM customers, then 600 MW of NEM PV capacity would impose a proportionately smaller cost shift of $40 million per year.

[36] J.C Thomas – SDG&E, *San Diego/Solar Stakeholder Collaboration Rates & Educational Overview*, January 25 & 27. 2012, p. 48.
[37] Ibid, p. 48.
[38] Ibid. p. 51.

The CEC estimates the fixed cost of new peaking capacity at approximately $283/kW-yr.[39] 300 MW of new peaking resources have fixed cost, which will be borne by SDG&E ratepayers, of $85 million per year over 20 years.[40] 600 MW of NEM PV capacity in the San Diego LCR would provide at least 300 MW of Net Qualifying Capacity. It would be far more economically beneficial to SDG&E ratepayers collectively to locate 600 MW of NEM PV capacity in the San Diego LCR area under the existing NEM tariff structure and not build 300 MW of peaking natural gas-fired resources to address the lack of solar resources in the LCR area.

Regarding distributed PV generally, the Commission observed with its approval of the PG&E 500 PV project that:[41]

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

PV should be counted towards meeting Resource Adequacy 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-fired 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.[42]

This 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:[43]

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[39] CEC, *Comparative Costs of California Central Station Electricity Generation*, January 2010, Table B-4, p. B-5.
[40] $300/kW-yr x 450,000 kW = $135 million per year.
[41] CPUC Press Release – Docket A.09-02-019, *CPUC Approves Solar PV Program for PG&E*, April 22, 2010.
[42] CEC, Chula Vista Energy Upgrade Project - Application for Certification (07-AFC-4) San Diego County, *Final Commission Decision*, June 2009.
[43] *Id.* at pp. 29-30.

"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. (Ex. 616, p. 11.). . . . 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. (Ex. 616, pp. 13 – 14.). . . . 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.

Numbers from the California Solar Initiative demonstrate high on-peak availability for distributed PV, at least 50 percent.[44] Solar PV is predictably available during periods of peak demand. The Commission FEIR/FEIS for the Powerlink project conservatively assumes 50 percent of nameplate PV capacity is available at peak.[45] The reason for this is the fact that peak production from a fixed PV array occurs at mid-day and the demand peak generally occurs in mid-afternoon.

Q. Is NRG Planning to Shut Down the Encina Boilers in 2017 to Comply with State Once Through Cooling Phase-Out Policy?

A. No. The state's policy to reduce the impacts on marine life of coastal power plant once-through cooling systems, like the cooling system at Encina, is proffered by SDG&E as the reason that the 964 MW Encina Power Plant must be assumed to close permanently in 2017. Yet the state's once-through cooling policy does not require any coastal once-through cooled power plants to retire. There is no mention in SDG&E's testimony of the

[44] *See* Itron, *CPUC CSI Report* at p. 5-6 to 5-10 (June 2010) http://www.cpuc.ca.gov/NR/rdonlyres/70B3F447-ADF5-48D3-8DF0 5DCE0E9DD09E/0/2009_CSI_Impact_Report.pdf

[45] CPUC FEIR/FEIS for SDG&E Sunrise Powerlink Project, *E.5 New In-Area Renewable Generation Alternative*, October 2008, p. E.5-8. "In its PEA, SDG&E discounts the nameplate rated capacity of solar PV systems by 50 percent because only a fraction of a PV system's rated capacity is available during the utility's hour of peak demand." See: http://www.cpuc.ca.gov/environment/info/aspen/sunrise/toc-feir.htm. See also SDG&E 5/10/12 Response to CEJA's Second Set of Data Requests, Q14. The NQC of the NRG Borrego Solar project will be: 16 MW ÷ 26 MW = 0.62 (62 percent).

low-cost options available to Encina to reduce marine impacts to acceptable levels, such as adding cooling towers at one-tenth the cost of new peaking gas turbines, and continue operating indefinitely in full compliance with the state's once-through cooling policy.[46,47] NRG disputes SDG&E's claim of a 2017 closure date for Encina.[48] With this sleight-of-hand, SDG&E attempts to show a need for 450 MW of new peaking capacity, including the 300 MW capacity of Pio Pico.

Q. Can SDG&E Renew the Lease for the NRG Cabrillo II Peaker Units?

A. Yes. SDG&E incorrectly asserts that 188 MW of existing peaking gas turbine capacity must be retired in 2013.[49] SDG&E states these turbines were installed between 1968 and 1972 and operate less than 877 hours per year. These turbines are capable of operational lifetime of up to 100,000 hours, with major overhauls every 15,000 to 25,000 hours.[50] At up to 877 hours per year of operation, these turbines have accrued only about 36,000 hours of operating time, only one-third of their operating lifetime potential.[51]

The air quality regulations do not restrict the operation of the 188 MW of vintage gas turbine capacity. The only turbines that would be subject to any form of restriction are those that cannot pass the annual air emissions source test. Even these restrictions would be exempted during peak demand system emergencies where the potential for brownouts

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[46] CEC, *Committee Workshop on Options for Maintaining Electric System Reliability When Eliminating Once-Through Cooling Power Plants - Transcript*, May 11, 2009, p. 106, p. 108. "MR. PENDERGRAFT: Hello. Eric Pendergraft with AES. We own Alamitos, Redondo Beach and Huntington Beach, all in the LA basin about just over 4,200 megawatts I think, depending on what statistics you use. . . We have performed high level retrofit studies for closed cycle cooling, both wet and dry cooling. As one might expect there are significant land constraints as well as permitting issues. They're expensive, you know, a rough ballpark for wet cooling at our sites it's approximately $125 or $115 a kilowatt ($125 or $115/kW). So for our 4,000 megawatts you're looking at, you know, 500 million dollars, half a billion dollars to retrofit with wet cooling." See: http://www.energy.ca.gov/2009_energypolicy/documents/2009-05-11_workshop/2009-05-11_Transcript.pdf.

[47] CEC, *Comparative Costs of California Central Station Electricity Generation*, January 2010, Table 14, p. 54. Capital cost of 49.9 MW simple cycle turbine = $1,292/kW.

[48] NRG Response to A.11-05-023, June 2011.

[49] SDG&E, CPUC Application A.11-05-023, *Prepared Direct Testimony of SDG&E in Support of Application for Authority to Enter into Purchase Power Agreements with Escondido Energy Center, Pio Pico Energy Center and Quail Brush Power - Public Version*, May 19, 2011, pp. 10-11. "These units, which were built between 1968 and 1972, have heat rates of about 15,000 Btu/kWh and have very limited operating hours (less than 877 hours per year). The San Diego Air Pollution Control District ("APCD") recently imposed additional restrictions on the use of these units. For example, in 2010, the APCD passed a new regulation that limits the operation of these units on forecasted high ozone days. Thus, it is prudent for SDG&E to factor in the retirement of these older units in conjunction with the deployment of the new units." *See* CAISO's Response to CEJA's Second Set of Data Requests, Request 22.

[50] Power Plant Operations, Maintenance, and Materials Issues, *Gas Turbine Hot Section Life Assessment & Extension: Status & Issues*, OMMI (Vol. 3, Issue 2) August 2004, p. 2.

[51] 877 hours/yr × 40 yr = 35,080 hours.

or blackouts exists.[52]

The primary reason that this 188 MW of peaking capacity will be retired in 2013 is that the turbines are located on SDG&E property and SDG&E is opting not to renew the lease with the third party owner of the turbines.[53]

SDG&E has an economic incentive to promote the construction of new third party gas turbine capacity in San Diego County. SDG&E has established a pattern of purchasing new natural gas-fired generation built in San Diego County by third party developers and passing the cost of this generation on to SDG&E ratepayers. As noted in SDG&E's May 19, 2011 testimony supporting the application for authorization to enter into power purchase agreements for 450 MW of new peaking gas turbine capacity, SDG&E acknowledges that is in the process of purchasing the 50 MW CalPeak El Cajon peaking gas turbine.[54]

Another example of this phenomenon is the purchase by SDG&E of the 555 MW Palomar Energy Project in Escondido, California. The project was built by SDG&E affiliate Sempra Generation at an installed cost of $348 million.[55] Prior to completion of

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[52] San Diego Air Pollution Control District, *Rule 69.3.1 – Stationary Gas Turbine Engines – Best Available Retrofit Control Technology*, Revised February 24, 2010. See: http://www.sdapcd.org/rules/Reg4pdf/R69-3-1.pdf.

[53] A.06-08-010 Sunrise Powerlink, *SDG&E'S 7/8/07 Response to CPUC Division of Ratepayer Advocates Data Request No. 11*, July 8, 2007, p. 6. DRA request: Provide a copy of the current NRG-SDG&E lease provisions, and any related agreements, that call for the removal and site remediation of "173 MW of vintage peakers owned by NRG on SDG&E leased property" SDG&E response: Section 3.1 of the License Agreement, dated December 11, 1998, between SDG&E and Cabrillo Power II LLC provides that "unless sooner terminated as provided herein, the initial term of the License shall commence on the Closing Date and end on the earlier to occur of December 31, 2013 or the date on which Licensee decommissions or removes the Combustion Turbines from the Licensed Area and fails to replace them as permitted or required under any Must Run Agreement." At such termination or expiration of the License Agreement, Cabrillo Power II, LLC will no longer have any right to locate its combustion turbines on SDG&E land.

[54] SDG&E, CPUC Application A.11-05-023, *Prepared Direct Testimony of SDG&E in Support of Application for Authority to Enter into Purchase Power Agreements with Escondido Energy Center*, Pio Pico Energy Center and Quail Brush Power - Public Version, May 19, 2011, Appendix 9 - Van Horn Consulting, *Independent Evaluator's Report – Product 2: New Local Generation and SDG&E's June 9, 2009 RFO for Demand Response and Supply Resources*, May 18, 2011, p. 10. "CalPeak's El Cajon combustion turbine (CT) unit is located at SDG&E's El Cajon substation within SDG&E's Eastern O&M Center and is subject to a 10-year lease with SDG&E that expires on October 31, 2011.The land lease agreement grants SDG&E the option to purchase the plant at the end of the lease agreement. SDG&E has chosen to exercise this option, because the ECEF purchase meets the requirements of Product 5 and will be considerably less expensive than a PPA would be. SDG&E filed its Application (U 902 E) for the Authority to Acquire the CalPeak El Cajon Energy Facility (ECEF) with the CPUC on January 5, 2011."

[55] CPUC, "2009 MPR Model" – Installed Capital Costs tab, Palomar (San Diego) Combined-Cycle 555 MW. Total "Turn-Key" Capital Costs (2008$) = $627/kW. 555 MW × 1,000 kW/MW × $627/kW = $348 million. Allowance

construction, the Commission authorized SDG&E to purchase the Palomar Energy Project from Sempra at a cost of $483 million.[56] Purchasing natural gas-fired power plants constructed by third parties in San Diego County is a lucrative business for SDG&E. The company receives a guaranteed rate-of-return on infrastructure, including transmission lines, power plants, and meters, that it builds or purchases.

Q. Does SDG&E Account for Otay Mesa Simple Cycle Operating Capability in G-1 Designation?

A. No. SDG&E identify G-1 as the loss of all of the 561 MW Otay Mesa combined-cycle plant. FERC confirmed in 2009 that the two combined-cycle plants in SDG&E territory, the 541 MW Palomar Energy combined cycle plant and the 561 Otay Mesa combined cycle plant, are specifically designed to operate in simple-cycle mode with the steam turbine generator in forced outage.[57,58] SDG&E specifically requested that CAISO recognize that both Palomar and Otay Mesa have this capability.[59]

The CAISO policy of requiring an extensive operational history of low outages is inappropriate for combined cycle plants designed to allow operation in simple-cycle mode with the steam turbine generator in forced outage. Neither Palomar Energy or Otay Mesa should be required to establish a history of low outages prior to CAISO acknowledging that these plants can continue to operate with the 260 MW steam turbine generator in forced outage. This would make the Otay Mesa 260 MW steam turbine generator the G-1 event in SDG&E territory with Encina permanently offline. It would also add the output of two Otay Mesa gas turbines operating in simple cycle mode, a combined output of about 350 MW, to meet the SDG&E LCR.

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for Funds Used During Construction (AFUDC) is not included in the $348 million. See: http://www.cpuc.ca.gov/PUC/energy/Renewables/mpr.

[56] CPUC Energy Division, *Resolution E – 3980 - The 2005 Market Price Referents (MPR) are approved. 2005 MPR values have been calculated for use in the 2005 Renewable Portfolio Standard (RPS) solicitations*, April 13, 2006, Appendix C, p. 29. “It is the initial balance figure of $484.343 million that should be used to represent the total cost of the Palomar project, given that it is the amount that would be put into rate base.”

[57] J. Wellinghoff – FERC, Response letter to Congressman Bob Filner, February 20, 2009.

[58] Calpine is owner of Otay Mesa. Calpine lists the capacity of Otay Mesa as 608 MW. See: http://www.calpine.com/power/plant.asp?plant=247. For this reason Otay Mesa simple cycle capacity is assumed to be the combined output of two GE Frame 7FA gas turbines, ~175 MW × 2 = approximately 350 MW, and steam turbine generator capacity of approximately 260 MW.

[59] Congressman Bob Filner letter to FERC Chairman Kelliher dated January 16, 2009.

It appears that SDG&E applies the same outage history requirement on all combined cycle plants in its control area composed of multiple gas turbines and a single steam turbine whether or not these plants are specifically designed to operate with the steam turbine generator in forced outage. SDG&E assumes the loss of the entire combined cycle plant when a forced outage of the steam turbine occurs. It is incorrect to apply this standard to combined cycle plants like Palomar Energy and Otay Mesa that are designed to operate with the steam turbine generator in forced outage.

Studying the outage history of combined cycle plants that are designed to operate in simple-cycle mode with the steam turbine in forced outage may provide little insight into the plant's operating profile during an actual G-1, N-1 event. G-1, N-1 events at peak load conditions are rare. Neither Palomar Energy nor Otay Mesa is likely to continue operating with the steam turbine in forced outage except during special circumstances like a G-1, N-1 event at peak load conditions.

Operating Palomar Energy or Otay Mesa in simple-cycle mode would be inefficient. The likely protocol at either plant when a forced outage of the steam turbine generator occurred would be to shut down and let other generation assets in the CAISO control area substitute for the lost output while the problem is resolved. However, in special circumstances like a peak load G-1, N-1 situation where every available megawatt would be necessary to prevent a brownout/blackout situation in SDG&E service territory, the gas turbines would continue operating in simple-cycle mode until the peak demand situation eased sufficiently to allow shutdown of the turbines.

The former plant manager of the Pastoria Energy combined cycle plant described the operation of that plant in simple-cycle mode during a CEC hearing held in Chula Vista, California on October 2, 2008.[60] One 2×1 unit at the Pastoria Energy plant is the same

[60] Evidentiary Hearing Before the California Energy Resources Conservation and Development Commission, *Application for Certification for the Chula Vista Energy Upgrade Project*, Docket No. 07-AFC-4, Chula Vista City Hall, October 2, 2008, transcript, pp. 409-410. "DIRECT EXAMINATION, by MS. LUCKHARDT: Q Mr. Scarborough, were you the plant manager at Pastoria? MR. SCARBOROUGH: Yes, I was. MS. LUCKHARDT: And did you have situations where you had Pastoria operate in simple cycle mode? MR. SCARBOROUGH: We did have certain opportunities when that did occur. We had unexplained forced outages on the steam turbines. The plant

configuration as Palomar Energy and Otay Mesa, two gas turbines and one steam turbine. The units at the Pastoria plant have the capability to operate in simple-cycle mode with the steam turbine generator in forced outage.

The former Pastoria plant manager stated at the October 2, 2008 hearing that he had operated the Pastoria plant in simple-cycle mode on multiple occasions. He also described some of the challenges of operating the Pastoria plant in simple cycle mode. The fact that operating the plant in simple-cycle mode is challenging and would only be done under special conditions is understood. In the case of Palomar Energy and Otay Mesa, one of those special conditions would a peak load G-1, N-1 event where every available MW in SDG&E service territory would be necessary to avoid a brownout/blackout.

This situation is somewhat analogous to a hospital with a combined heat and power plant that is connected to the grid and has an emergency diesel generator. Under normal conditions, a forced outage of the combined heat and power plant would result in importing power from the grid to cover the hospital's power needs. The emergency diesel generator would not be used. However, if the forced outage occurred at a time when no power was available from the grid during a G-1, N-1 even during a period of peak demand, the emergency generator could be relied upon to cover the minimum power needs of the hospital. The ability of the Palomar Energy and Otay Mesa plants to operate in simple-cycle mode give these plants a minimum "emergency generator" power output capability that must be included in CAISO reliability calculations for the SDG&E service territory.

SDG&E should reclassify G-1 in SDG&E service territory in recognition of the fact that both Palomar Energy and Otay Mesa have the capability to operate in simple-cycle mode with the steam turbine generator in forced outage. Either of these plants can provide approximately 350 MW to the grid with the steam turbine in forced outage.

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was in a configuration of what's known as a two-by-one and one-by-one power blocks with two 7FAs supplying a D11 steam turbine and a one 7FA turbine supplying an A10 turbine."

IV. FSA Is Flawed for Failure to Corroborate Applicant's Assertion that More Peaking Capacity is Needed to Address Wind/Solar Intermittency

Q. Does SDG&E service territory have peaking resources and do these resources already address rapid load changes?

A. Yes. The applicant and the FSA raise the issue of the variability of wind and solar power to justifies the need for new peaker units that can respond quickly to rapid changes in output. However, the applicant and the FSA fail to state that there are already approximately 700 MW of existing peaking gas turbines in the San Diego area.[61] SDG&E also fails to state that demand already changes rapidly in SDG&E territory due to widely varying load over the course of a 24-hour day. Figure 9 is a bar chart showing hourly demand in SDG&E service territory over 24 hours on September 27, 2010, the day that SDG&E recorded the highest one-hour demand in 2010.[62] Demand increased nearly 450 MW per hour from 10 am to 11 am on September 27, 2010. Demand declined nearly 500 MW per hour from 10 pm to 11pm. SDG&E territory is already equipped with sufficient peaking resources to address rapid changes in load.

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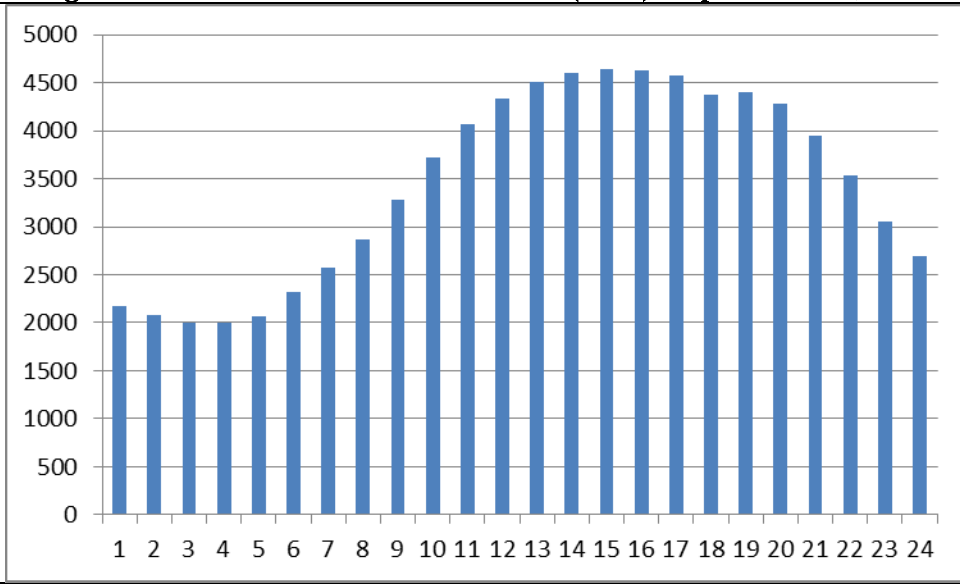
[61] SDG&E, CPUC Application A.11-05-023, *Prepared Direct Testimony of SDG&E in Support of Application for Authority to Enter into Purchase Power Agreements with Escondido Energy Center, Pio Pico Energy Center and Quail Brush Power - Public Version*, May 19, 2011, p. 11. "SDG&E has added 246 MW of new generation in its service area towards that need. Specifically, SDG&E has added the combustion turbine peaking facilities of J-Power Orange
Grove (99 MW), Wellhead El Cajon (48 MW), and SDG&E's Miramar II (48 MW)." SDG&E also identifies on p. 11 the existing 35 MW Wellhead Escondido peaker and 188 MW of existing Cabrillo II peakers. Additional peaking gas turbines installed in San Diego County since 2001 include the Wildflower Larkspur 90 MW plant and three 49 MW (each) Calpeak units. See CEC Power Plant database: http://www.energy.ca.gov/sitingcases/all_projects.html. The total existing gas turbine peaking capacity in San Diego County is: 246 MW +35 MW + 188 MW + 90 MW + 3×49 MW = 706 MW.

[62] California Independent System Operator OASIS database, September 27, 2010 "System Demand - Actual": http://oasis.caiso.com/mrtu-oasis/home.jsp?doframe=true&serverurl=http%3a%2f%2farptp10%2eoa%2ecaiso%2ecom%3a8000&volume=OASIS

Figure 9. SDG&E Hour-to-Hour Load (MW), September 27, 2010



The 700 MW of existing peaking gas turbine resources that SDG&E has at its disposal now far exceed the 150 to 206 MW of wind power that it has under contract, or has applied to contract for, in SDG&E territory. There is one operational wind farm in San Diego County, the 50 MW Kumeyaay wind farm in Boulevard. SDG&E recently received approval of a power purchase agreement with Sempra Generation for between 100 and 156 MW of wind power from Baja California, and with Ocotillo Wind for between 265 and 315 MW of wind power Imperial County.[63,64] The Baja wind power would be interconnected directly to the SDG&E grid near Jacumba. 700 MW of existing peaking gas turbine capacity can easily handle any output variability from up to 471 MW of wind power.

Due to the nature of the wind resource in the San Diego area, there is relatively less wind power generated in the summer months when electricity demand is highest, and even less produced during the summer mid-afternoon peak hours. This phenomenon is shown in Figure 10, the month-to-month wind energy production from the 50 MW Kumeyaay wind farm in eastern San Diego County, and Figure 11, a SDG&E peak summer day demand curve and 24-hour summer wind output curve for San Diego-area wind

[63] SDG&E Advice Letter 2247-E (U 902-E), California Public Utilities Commission, *Subject: Request for Approval of Renewable Power Purchase with Energía Sierra Juárez U.S., LLC*, April 19, 2011.
[64] CPUC Resolution E-4458, *SDG&E requests approval of a renewable energy power purchase agreement, as amended, with Ocotillo Express LLC,* January 12, 2012.

resources.[65] What this data means is that relatively little of the 471 MW of potential San Diego area wind power will be operating during summer peak demand periods. In any case, there is far more existing peaking gas turbine capacity in the San Diego area than the reasonably foreseeable wind capacity of up to 471 MW.

Figure 10. Month-to-Month 2008 Wind Energy Production, Kumeyaay Wind Farm[66]

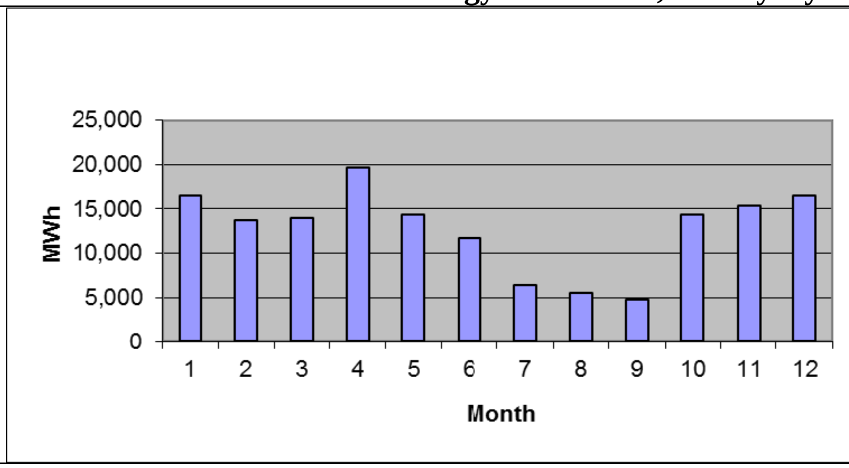
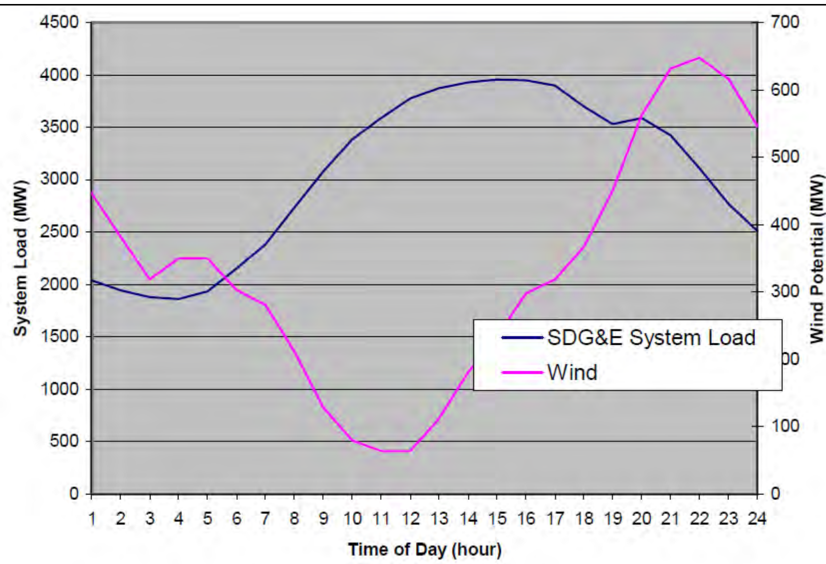


Figure 11. SDG&E Peak Summer Load and Summer Wind Profile[67]



[65] The summer wind output curve in Figure 11 assumes a hypothetical future scenario where San Diego County's full wind potential of 1,350 to 1,530 MW is developed (see: www.renewablesg.org). Even with this high level of installed wind capacity, the wind output during summer afternoon peak demand hours is no more than 300 MW as shown in Figure 11.
[66] U.S. DOE, Energy Information Administration, 2008 Form 923 Monthly Time Series, Kumeyaay Wind Farm.
[67] San Diego Regional Renewable Energy Study Group, *Potential for Renewable Energy in the San Diego Region – Chapter 4: Wind*, August 2005. The wind output shown on the right hand vertical axis assumes a total potential installed wind capacity of 1,350 to 1,530 MW. The near-term installed wind potential in the San Diego region is 206 MW, one-seventh the wind potential assumed in creating the purple wind output curve in Figure 4. See: http://www.renewablesg.org/.

Improved wind and solar resource forecasting reduces or eliminates the need to add more peaking capacity. KEMA is the consulting firm contracted by the CEC to report at the May 9, 2011 workshop on how Germany and Spain have achieved the integration of high levels of wind and solar resources.[68,69] Sophisticated and accurate wind and solar resource forecasts are key elements of the German and Spanish programs. German and Spanish wind and solar forecasting is substantially more accurate than California forecasting, as shown in Table 6.[70] Accurate forecasts reduce or eliminate the need for fast start peaking gas turbines that would otherwise be needed in an environment where the utility had little or no forewarning of changes in wind or solar intensity.[71] New peaking capacity is in effect a very expensive crutch that is made unnecessary when sophisticated wind and solar forecasting is employed.

Table 6. Comparison of Wind Forecast Accuracy, Germany/Spain and California[72]

RMSE Renewables Forecast Error	Germany, Spain²	California¹
Day-Ahead	< 5%	< 15%
1 Hour-Ahead	1.5%	<10%

Q. Is energy storage a more versatile and cost-effective approach to addressing wind/solar intermittency?

A. Yes. AB 2514, signed into law in September 2010, directs the CPUC to open a proceeding by March 2012 to determine the amount of energy storage, if any, to be

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68 KEMA, *European Experience Integrating Large Amounts of DG Renewables*, California Energy Commission Integrated Energy Policy Report (IEPR) Committee Workshop on Renewable Distributed Generation, PowerPoint, May 9, 2011. See: http://www.energy.ca.gov/2011_energypolicy/documents/2011-05-09_workshop/presentations/04_KEMA_Morning_5-9-11.pdf.

69 Germany and Spain had 27,215 MW and 20,700 MW of wind capacity online by the end of 2010. See: http://www.wwindea.org/home/images/stories/pdfs/worldwindenergyreport2010_s.pdf, p. 19. In contrast, California currently has 3,141 MW of wind capacity online. See: http://www.calwea.org/bigPicture.html.

70 Ibid, p. 22.

71 Ibid, p. 21. "Originally, a significant increase in reserve requirement as result of growing (German) wind power was expected in the future. However, latest studies have concluded that improved wind forecasts will not require any additional reserves until 2020."

72 KEMA, *European Experience Integrating Large Amounts of DG Renewables*, California Energy Commission Integrated Energy Policy Report (IEPR) Committee Workshop on Renewable Distributed Generation, PowerPoint, May 9, 2011, p. 22. See: http://www.energy.ca.gov/2011_energypolicy/documents/2011-05-09_workshop/presentations/04_KEMA_Morning_5-9-11.pdf.

developed by the IOUs.[73] Similar language is included for POUs. 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.[74] 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.[75]

Japan constructed the first large-scale integrated wind and battery storage project at Futamata, Japan in 2008. 34 MW of sodium-sulfur battery storage is integrated with the 51 MW wind farm to allow the wind power output to be flattened into a near constant output, baseload profile.[i] [76]

Batteries have been integrated into multi-MW storage systems for peak-shaving applications in California. An analysis prepared by the California Energy Storage Association, comparing the performance of an actual 10 MW peak-shaving system consisting of off-the-shelf lead-acid batteries to a simple cycle gas turbine, indicates that the lead-acid battery system produces lower cost peaking power.[77]

Q. Is thermal storage a cost-effective, off-the-shelf alternative for reducing peak demand?

A. Yes. 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.[78] The City of Glendale is a member of SCPPA. Glendale Water & Power (GWP) has installed 180 Ice Bear units in commercial buildings and reduced peak air

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[73] AB 2514 Chaptered, September 29, 2010: ftp://leginfo.public.ca.gov/pub/09-10/bill/asm/ab_2501-2550/ab_2514_bill_20100929_chaptered.html

[74] Megawatt Storage Farms, Inc., *Comments of MegaWatt Storage Farms on CAISO Conceptual Statewide Transmission Plan*, February 17, 2011.

[75] AB 2514, Introduced, February 19, 2010: http://www.aroundthecapitol.com/billtrack/text.html?bvid=20090AB251499INT

[76] Nikkei Electronics Asia, *Can Batteries Save Embattled Wind Power*, September 24, 2008.

[77] California Energy Storage Association, Energy Storage: a Cheaper and Cleaner Alternative to Natural Gas-Fired Peakers, June16, 2010.

[78] Public Power Daily, *SCPPA to Rollout 53-MW Storage Project*,January 27, 2010.

conditioning load by 1.5 MW.[79] GWP makes these Ice Bear units available free of charge to qualified commercial customers due to their cost-effectiveness at reducing peak load.[80]

Q. Are low-cost upgrades to existing commercial chiller systems also an off-the- shelf alternative for reducing peak demand?

A. Yes. 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.[81] 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.[82]

Q. Isn't it a state objective to reduce residential and small commercial air conditioning loads by 50 percent by 2020?

A. Yes. 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 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.[83]

[7979] City of Glendale press release, *Leading Energy Storage Company to Relocate in Glendale California*, April 25, 2012. See: http://www.ci.glendale.ca.us/mgmt-svcs/press_release.aspx?AnnouncementID=958.
[80] Glendale Water & Power "Ice Bear Thermal Energy Storage Program" webpage: http://www.glendalewaterandpower.com/businesses/ice_bear_program.aspx.
[81] Platts Purchasing Advisor, *HVAC: Centrifugal Chillers*, 2004.
[82] 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.
[83] CEC, *Achieving All Cost-Effective Energy Efficiency for California*, December 2007, p. 53.

V. Conclusion

The FSA is inadequate for its failure to follow the *Energy Action Plan* loading order in its analysis of alternatives to the proposed Pio Pico Energy Center and its failure to conduct detailed analysis of rooftop solar alternative.

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 ^oF and 13 ^oF 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 ^oF and 13 ^oF. 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 ^oF. 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 ^{o}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 ^{o}F and 20 ^{o}F were evaluated. The annualized cost of the fin-fin air-cooler with a 20 ^{o}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.

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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.

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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

EXHIBIT B

**To the Prepared Direct Testimony of Bill Powers
on behalf of San Diego Solar Coalition**

Description: Solar Resource Availability During Top 100 Hours of Demand

Attachment B: Solar Resource Availability During Top 100 Hours of Demand

Global irradiance, in the context of this testimony, is a measure of the solar resource strength available at a specific time and a specific location in San Diego County at times of peak demand.

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 percent 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 Montgomery Field, Lindberg Field, Gillespie Field, Brown Field, Palomar Airport, and Escondido 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'svisible 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 Montgomery Field, San Diego is U.S. National Climate Data Center (NCDC) data purchased from Weather Warehouse. Montgomery Field was chosen as a representative urban San Diego location a few miles from the coast. Whenever, the Montgomery Field cloud cover data indicated any condition than “clear,” the global irradiance levels at other urban sites in San Diego County, including Lindberg Field, Gillespie Field, Brown Field, Palomar Airport, and Escondido, were cross-checked to determine if the Montgomery Field data was consistent with the levels of irradiance in other urbanized parts of San Diego County in the same hour.

The following code is used for NCDC cloud cover values:

0: CLEAR - No clouds. 1: FEW - 2/8 or less coverage (not including zero). 2: SCATTERED - 3/8 to 4/8 coverage. 3: BROKEN - 5/8 to 7/8 coverage. 4: OVERCAST - 8/8 coverage.

To convert this cloud cover code to “% cloud cover”:

FEW: “2/8 or less,” converts to 1/8 on average, or 12.5 percent (Weather Warehouse reports worst case of 25 percent)

SCATTERED: “3/8 to 4/8” converts to 7/16 on average, or 44 percent (Weather Warehouse reports worst case of 50 percent)

The top 100 hours of peak demand occurred on fifteen days in SDG&E service territory in 2007. Twelve of these days were clear sky days during daylight hours. Scattered clouds did occur during one or more peak demand hours on three days. However, the aggregate solar resource availability in urbanized San Diego County in the peak hours on these three days where scattered clouds were recorded was approximately 80 percent or greater. The fifteen days with one-hour demand that contributed to the top 100 hours of demand in 2007 in SDG&E service territory, and the cloud conditions on those days, are listed in Table B-1. The 3,500 MW demand level was used as the threshold to analyze peak one-hour demand in SDG&E territory in 2007. There were a total of 239 hours of demand at or above 3,500 MW in 2007.

Table B-1. Days in 2007 with Demand in Top 100 Hours of Demand in SDG&E Territory

Date	Cloud Conditions
August 13, 2007	clear
August 15, 2007	clear
August 16, 2007	clear
August 17, 2007	clear
August 20, 2007	clear
August 21, 2007	clear
August 27, 2007	clear
August 28, 2007	clear
August 29, 2007	scattered clouds, 2-3 pm
August 30, 2007	clear
August 31, 2007	clear
September 1, 2007	scattered clouds, 2-3 pm
September 2, 2007	clear
September 3, 2007	scattered clouds, afternoon
September 4, 2007	clear

Details of cloud cover and global irradiance level during each of the 100 top demand hours of 2007 are provided in Table B-2.

Hourly GEOS satellite visible channel photos of San Diego County for each hour from noon to 5 pm were obtained for the two of the three days, August 29, 2007 and September 3, 2007, that registered the most pronounced presence of scattered clouds at Montgomery Field during peak demand hours.

The GEOS satellite visible channel photo sequence for San Diego County on August 29, 2007 and on September 3, 2007 are provided at the end of this attachment in Figures B-1 and B-2.

Table B-2. 2007 Montgomery Field San Diego Site: MW Demand, Cloud Cover, Global Irradiance

In hours where some level of cloud covered was registered, the GI level modeled for that hour is compared to the previous clear day or next clear day GI at the same hour to determine percentage of full GI available in hour when some level of cloud cover was registered. If GI measured for 100 km. tile containing Montgomery Field registered less than ~100 percent in any of the top 100 hours of demand, then the GI in the same hour at the other five GI sites included in this analysis, Lindberg Field, Gillespie Field, Brown Field, Palomar Airport, and Escondido, were averaged with the Montgomery Field GI reading to develop an average GI level for urbanized San Diego County in that hour. If the calculated GI is greater than 100 percent, when comparing clear day/hour GI to the GI registered at Montgomery Field with some level of cloud cover indicated, then 100 percent is used as the default value in Table B-2.

Hour	Date	HE (hour ending)	Load (MW)	Cloud cover (%)	global irradiance (%)	Notes
1	3-Sep-07	14	4601	0	100	
2	3-Sep-07	15	4577	0	79	average of 6 GI sites
3	3-Sep-07	12	4560	0	100	
4	3-Sep-07	16	4551	44	99	
5	3-Sep-07	13	4539	0	99	
6	3-Sep-07	17	4504	44	100	
7	4-Sep-07	14	4501	0	100	
8	4-Sep-07	15	4498	0	100	
9	4-Sep-07	16	4491	0	100	
10	4-Sep-07	13	4468	0	100	
11	4-Sep-07	17	4455	0	100	
12	31-Aug-07	16	4439	0	100	
13	31-Aug-07	15	4436	0	100	
14	31-Aug-07	14	4428	0	100	
15	4-Sep-07	12	4387	0	100	
16	31-Aug-07	13	4374	0	100	
17	3-Sep-07	18	4369	44	100	
18	31-Aug-07	17	4358	0	100	
19	3-Sep-07	20	4323	0	100	

20	2-Sep-07	15	4312	0	100	
21	2-Sep-07	14	4311	0	100	
22	1-Sep-07	15	4278	0	100	
23	2-Sep-07	16	4262	0	100	
24	31-Aug-07	12	4257	0	100	
25	3-Sep-07	11	4253	0	100	
26	4-Sep-07	11	4253	0	100	
27	20-Aug-07	16	4243	0	100	
28	30-Aug-07	15	4233	0	100	
28	20-Aug-07	15	4230	0	100	
30	1-Sep-07	16	4229	0	100	
31	30-Aug-07	16	4222	0	100	
32	1-Sep-07	14	4219	12.5	81	average of 6 GI sites
33	20-Aug-07	17	4202	0	100	
34	30-Aug-07	14	4189	0	100	
35	2-Sep-07	13	4185	0	100	
36	20-Aug-07	14	4177	0	100	
37	1-Sep-07	17	4166	0	100	
38	3-Sep-07	19	4158	0	100	
39	4-Sep-07	18	4150	0	100	
40	2-Sep-07	17	4135	0	100	
41	21-Aug-07	16	4134	0	100	
42	21-Aug-07	15	4131	0	100	
43	29-Aug-07	16	4129	0	99	
44	31-Aug-07	18	4114	0	100	
45	3-Sep-07	21	4113	0	100	
46	15-Aug-07	16	4106	0	100	
47	16-Aug-07	15	4102	0	100	
48	21-Aug-07	14	4100	0	100	
49	1-Sep-07	13	4099	0	100	
50	16-Aug-07	16	4096	0	100	
51	29-Aug-07	15	4094	44	96	
52	15-Aug-07	15	4089	0	100	
53	30-Aug-07	13	4089	0	100	
54	16-Aug-07	14	4085	0	100	

55	29-Aug-07	17	4079	0	97	
56	15-Aug-07	14	4070	0	100	
57	21-Aug-07	17	4061	0	100	
58	31-Aug-07	11	4059	0	100	
59	29-Aug-07	14	4057	0	98	
60	30-Aug-07	17	4055	0	100	
61	17-Aug-07	15	4053	0	100	
62	17-Aug-07	16	4052	0	100	
63	20-Aug-07	13	4051	0	100	
64	20-Aug-07	18	4048	0	100	
65	2-Sep-07	18	4047	0	100	
66	16-Aug-07	17	4033	0	100	
67	15-Aug-07	17	4028	0	100	
68	17-Aug-07	14	4028	0	100	
69	28-Aug-07	16	4022	0	100	
70	28-Aug-07	15	4018	0	100	
71	4-Sep-07	10	4017	0	100	
72	15-Aug-07	13	4014	0	100	
73	2-Sep-07	12	4011	0	100	
74	17-Aug-07	17	4008	0	100	
75	1-Sep-07	18	4007	0	100	
76	16-Aug-07	13	3997	0	100	
77	21-Aug-07	13	3994	0	100	
78	1-Sep-07	12	3984	0	100	
79	30-Aug-07	12	3983	0	100	
80	2-Sep-07	20	3983	0	100	
81	29-Aug-07	13	3974	0	100	
82	28-Aug-07	14	3972	0	100	
83	31-Aug-07	20	3970	0	100	
84	4-Sep-07	20	3965	12.5	100	
85	17-Aug-07	13	3944	0	100	
86	28-Aug-07	17	3944	0	100	
87	1-Sep-07	20	3932	0	100	
88	4-Sep-07	19	3925	0	100	
89	20-Aug-07	12	3919	0	100	

90	15-Aug-07	12	3914	0	100	
91	27-Aug-07	15	3908	0	100	
92	27-Aug-07	16	3907	0	100	
93	13-Aug-07	16	3900	0	100	
94	16-Aug-07	12	3898	0	100	
95	29-Aug-07	18	3895	0	100	
96	13-Aug-07	15	3893	0	100	
97	27-Aug-07	14	3891	0	100	
98	27-Jul-07	15	3889	0	100	
99	21-Aug-07	18	3888	0	100	
100	2-Sep-07	19	3883	0	100	

Resolution of August 29, 2007, for hour ending at 3 pm: scattered clouds reported at Montgomery Field while 96 percent GI modeled for same general area at same hour

SDG&E service territory hour-to-hour demand on August 29, 2007 (each hour is "hour ending at")

hour	12 noon	1 pm	2 pm	3 pm	4 pm	5 pm
MW	3,832	3,974	4,057	4,094	4,129	4,079

CAISO OASIS History webpage, click on "System Load": http://oasishis.caiso.com/

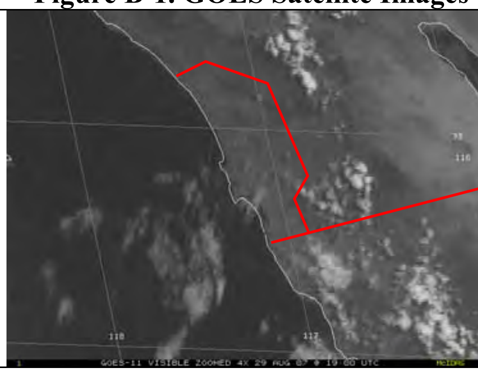
Cloud cover and global irradiance (GI) at Montgomery Field, August 29, 2007

Hour	12 noon	1 pm	2 pm	3 pm	4 pm	5 pm
Cloud cover (%)	0	0	0	44	0	0
GI (%)	98	100	98	96	99	97

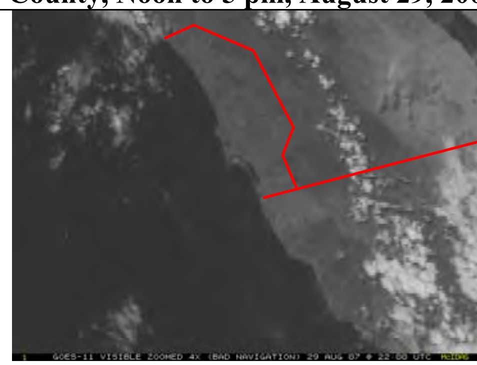
Weather Warehouse webpage, National Weather Service 1-hour cloud cover readings at Montgomery Field: http://weather-warehouse.com/
GI data from SolarAnywhere webpage, 100 km^2 quadrant w/Montgomery Field, 2007: https://www.solaranywhere.com/Public/SelectData.aspx

The degree of cloud cover in San Diego County from noon to 5 pm on August 29, 2007 is shown in the sequence of GOES satellite images in Figure B-1.

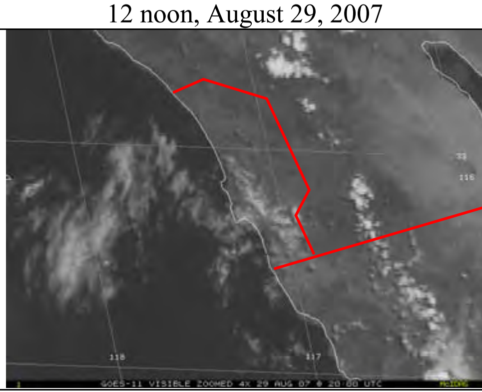
Figure B-1. GOES Satellite Images of San Diego County, Noon to 5 pm, August 29, 2007



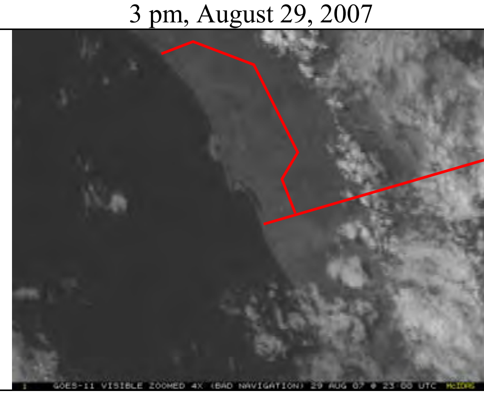
12 noon, August 29, 2007



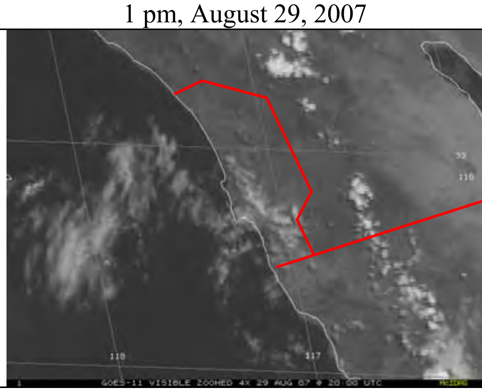
3 pm, August 29, 2007



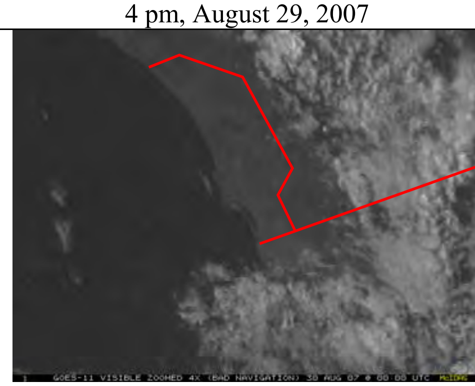
1 pm, August 29, 2007



4 pm, August 29, 2007



2 pm, August 29, 2007



5 pm, August 29, 2007

Source of GOES satellite images: Axel Graumann, meteorologist, Satellite Services Group, Data Access Branch, NOAA National Climatic Data Center, tel: 828-271-4850, ext. 3183. Images provided on June 6, 2012 by e-mail.

Resolution of September 3, 2007, 3 pm data: no cloud cover reported at Montgomery Field while ~80 percent GI and scattered clouds for San Diego County at same hour

SDG&E service territory hour-to-hour demand on September 3, 2007 (hour is "hour ending at")

hour	12 noon	1 pm	2 pm	3 pm	4 pm	5 pm
MW	4,560	4,539	4,601	4,577	4,551	4,504

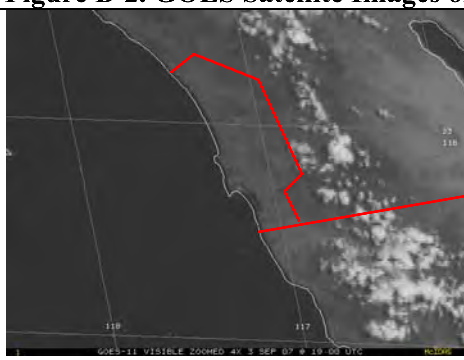
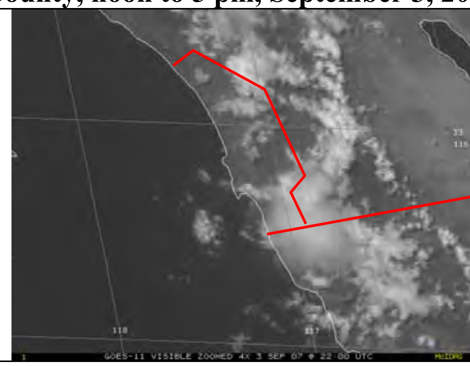
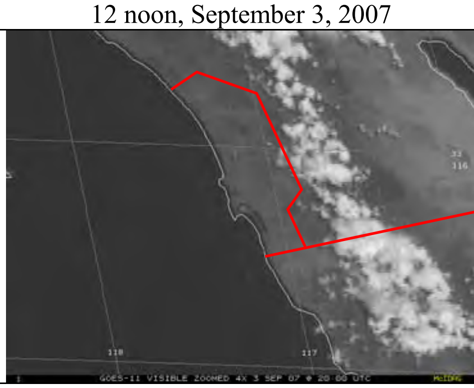
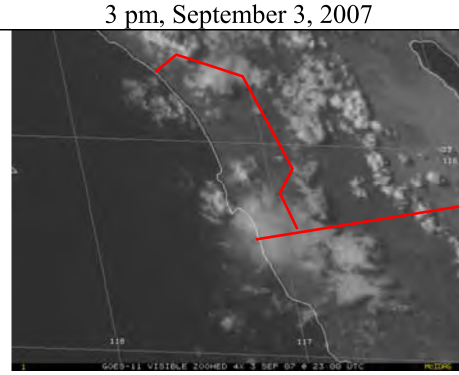
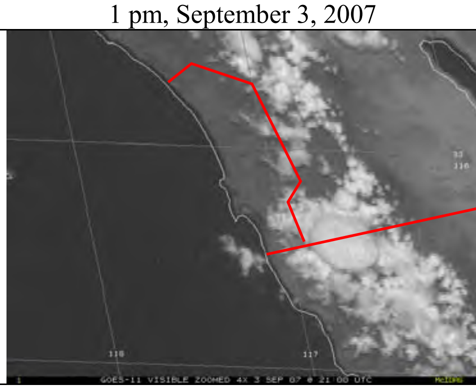
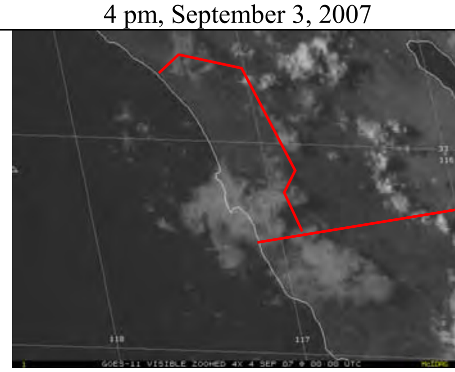
Cloud cover Montgomery Field and global irradiance San Diego County, September 3, 2007

Hour	12 noon	1 pm	2 pm	3 pm	4 pm	5 pm
Cloud cover (%)	0	0	0	0	44	44
GI (%)	100	99	100	79[a]	99	104

a) Average 3 pm GI at six dispersed urban sites in San Diego County: Lindberg Field (99%), Escondido (98%), Palomar Field – Carlsbad (78%), Brown Field (61%), and Montgomery Field (36%) = 79%.

The degree of cloud cover in San Diego County from noon to 5 pm on September 3, 2007 is shown in the sequence of GOES satellite images in Figure B-2.

Figure B-2. GOES Satellite Images of San Diego County, noon to 5 pm, September 3, 2007

	
12 noon, September 3, 2007	3 pm, September 3, 2007
	
1 pm, September 3, 2007	4 pm, September 3, 2007
	
2 pm, September 3, 2007	5 pm, September 3, 2007

Source of GOES satellite images: Axel Graumann, meteorologist, Satellite Services Group, Data Access Branch, NOAA National Climatic Data Center, tel: 828-271-4850, ext. 3183. Images provided on June 6, 2012 by e-mail.