Meeting California's Electricity Needs Without San Onofre or Diablo Canyon Nuclear Power Plants

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Draft Report

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by

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Acronyms

CAISO	California Independent System Operator
CARB	California Air Resources Board
CCA	Community Choice Aggregation
CEC	California Energy Commission
CHP	Combined heat and power
CPUC	California Public Utilities Commission
DG	distributed generation
DOE	Department of Energy
DRA	Division of Ratepayers Advocates
DR	demand response
EE	energy efficiency
FERC	Federal Energy Regulatory Commission
FHFA	Federal Housing Finance Agency
FIT	feed-in tariff
GHG	greenhouse gases
GW	gigawatt, equals 1,000 megawatts.
GWh	gigawatt-hour
kV	Kilovolt
kW	kilowatt
kW-hr	kilowatt-hour
IEPR	Integrated Energy Policy Report
IOU	investor-owned utility
LADWP	Los Angeles Department of Water & Power
LCOE	levelized cost-of-energy
LCR	local capacity requirement
MEA	Marin Energy Authority
MW	megawatt, equals 1,000 kilowatts
MW-hr	megawatt-hour
NERC	National Electric Regulatory Council
PACE	property assessed clean energy
PG&E	Pacific Gas & Electric
POU	publicly-owned utility
PPA	power purchase agreement
PV	Photovoltaic
RPS	Renewable Portfolio Standard
SDG&E	San Diego Gas & Electric
SCE	Southern California Edison
SWRCB	State Water Resources Control Board
T&D	transmission & distribution

I. Executive Summary

This report addresses the feasibility of a near-term permanent shutdown of 2,150 MW San Onofre Nuclear Generating Station (SONGS) and 2,160 MW Diablo Canyon, respectively. A large current supply surplus, primarily gas-fired generation along with rapidly increasing additions of renewable resources, makes the permanent near-term permanent retirement of SONGS and Diablo Canyon feasible without compromising grid reliability.

The California Public Utilities Commission (CPUC) is responsible for assuring that California's investor-owned utilities (IOUs), Pacific Gas & Electric (PG&E), Southern California Edison (SCE), and San Diego Gas & Electric (SDG&E), procure sufficient power supplies to maintain grid reliability in their respective service territories under all reasonably foreseeable contingencies. One requirement is that these utilities maintain at least a 15 percent planning reserve margin. This means these utilities must maintain at least 15 percent more power reserves than necessary to meet the projected average 1-in-2 weather year peak demand.

The California Independent System Operator (CAISO) was created as grid oversight agency when the California IOUs were deregulated in the mid-1990s. The CAISO control area includes the service territories of PG&E, SCE, and SDG&E. A core function of CAISO is to assure grid reliability in the state.

California also has many publicly-owned municipal utilities that provide about one-third of the power consumed in the state. These public utilities include Los Angeles Department of Water & Power, Sacramento Municipal Utility District, Imperial Irrigation District, City of Anaheim, and the City of Palo Alto, among others. Many of these publicly owned utilities are responsible for assuring their own grid reliability, including Los Angeles Department of Water & Power, Sacramento Municipal Utility District, and Imperial Irrigation District, and are not subject to CPUC or CAISO jurisdiction. Some smaller publicly owned utilities are more dependent on the investor-owned utilities' large transmission lines, and are therefore subject to CAISO rules. California has been on a major natural-gas fired power plant construction boom over the last decade. The state added over 17,000 MW of new natural gas-fired combined cycle capacity in the 2001 – 2012 timeframe. Nearly 6,000 MW of simple cycle peaking turbines were also added during this period. Over 4,000 MW of gas-fired generation is under construction, of which about 2,000 MW will be added in the Los Angeles area in the first seven months of 2013.

California established a loading order of preferred resources in the state's 2003 Energy Action Plan. The loading order set the following hierarchy of preferred resources: energy efficiency, demand response, distributed generation, combined heat and power, renewable resources, and lastly, conventional gas-fired generation. Recognizing that the utilities have been resistant to the loading order, the CPUC has begun to issue more explicit directions to IOU's to begin to utilize resources higher in the loading order.

California is also in the midst of a major renewable energy construction boom to meet the state's target of producing 33 percent of its electricity needs from renewable energy by 2020. This target is known as the Renewable Portfolio Standard (RPS).About 2,000 MW of utility-scale RPS capacity began operation in the state in 2012. California is expected to add another 3,000 MW in 2013. In addition, hundreds of MW of net-metered rooftop solar were also installed in 2012 by home and business owners. Over 5,000 MW of net-metered solar should be online in California by the end of 2016. However, current policies do not allow this solar capacity to be counted as RPS generation.

In the meantime, peak load has declined from the all-time CAISO peak in the summer of 2006 of 50,000 MW to 47,000 MW in the summer of 2012. Annual statewide electricity consumption has declined over time, with consumption about 2 percent less in 2012 than in 2008.[1] Both peak loads and annual electricity consumption have been fluctuating for the last seven years with a flat trend. The lack of peak demand growth experienced in California over the last seven years is not an anomaly. Utilities companies throughout the U.S. are experiencing flat and declining demand. Customer attitudes toward electricity consumption, more rigorous building and appliance efficiency standards, larger state and federal expenditures for energy efficiency and the growth of rooftop solar are factors in what appears to be a fundamental change in electricity consumption and economic trends.

These are the two primary reasons, large new capacity additions and lower loads, that the estimated planning reserve margin for the summer of 2013, without SONGS and assuming below average hydroelectric production, is approximately 30 percent. The summer 2013 reserves will be at least double the planning reserve margin requirement of 15 to 17 percent. CAISO forecasts "healthy reserves" in Northern and Southern California, 38.8 percent and 31 percent respectively, in the summer of 2013. These planning reserve margins translate into approximately 5,000 MW of reserves above the minimum requirement in Northern California, and 4,300 MW of reserves above the minimum requirement in Southern California. The Southern California reserve margin was calculated by CAISO assuming that SONGS will not be available.

SONGS, Diablo Canyon, and Voltage Support

A primary concern with the loss of a major power plant like SONGS is the replacement of reactive power provided by the plant. Reactive power, also referred to as "voltage support," must be provided by sources reasonably close to the load being served. The purpose of reactive power is to keep the alternating current power being supplied in synchronization with the loads, such as motors and transformers, being served. In the case of transmission lines, the loss of this voltage support has the effect of reducing transmission line capacity under heavy load conditions.

SONGS is at the edge of a major urban area, greater Los Angeles, and provides significant reactive power support in the local area. Much of the critical reactive power provided by SONGS was replaced in 2012 by using the retired 450 MW Huntington Beach Units 3 and 4. The electric generators at these units were converted to "synchronous condensers," to provide continued voltage support to the local area, and came online in June 2013. Additional measures carried-out to address voltage support issues caused by the SONGS outage include the reconductoring of the 220 kV Barre-Ellis transmission line in southern Orange County, and the addition of shunt

[1] CAISO OASIS database, January 2008 through October 2012.

capacitors to three substations in southern Orange County. All of these actions had been completed as of July 2013.

CAISO has identified demand response and combined heat and power (CHP) as next steps for addressing future voltage support needs related to a permanent shutdown of SONGS, consistent with the state's preferred resources "loading order."

CAISO conducted studies in 2012 on the mid-term and long-term impact to California transmission system reliability of the permanent loss of SONGS and Diablo Canyon.[2] With respect to SONGS, CAISO determined that the loss of SONGS would create potential transmission impacts under worst case conditions in the LA Basin and San Diego by 2018 without remedial measures.[3] This analysis assumed substantial peak load growth year-to-year. These impacts include thermal overloading and voltage instability. In contrast, CAISO's preliminary conclusion with respect to the permanent loss of Diablo Canyon is that it would result in no material mid- or long-term transmission system impacts.

2018 is the trigger year for potential impacts in SDG&E territory because San Diego's largest existing power plant is assumed to retire in 2017. The 964 MW Encina Power Plant in Carlsbad, California must either comply with the state's once through cooling phase-out regulations by December 2017 or retire.

SONGS, Diablo Canyon and Once-Through Cooling Phase-Out

The lack of growth in grid peak demand, due in part to the trend of accelerating rooftop PV installation rates, and high reserve margins created by overbuilding gas-fired plants, has removed any technical justification for constructing new gas-fired plants. However, allowing some flexibility in the retirement dates of selected coastal steam boiler plants until at least the 2022 and 2024 compliance dates of SONGS and Diablo Canyon may be advisable. This may be necessary to provide sufficient time for a transition to reliance on battery storage for grid reliability functions including voltage support, load following, and peaking duty.

SONGS was the dominant source of once-through cooling (OTC) seawater withdrawals in Southern California, accounting for approximately 2.3 billion gallons per day. Diablo Canyon also accounts for approximately 2.5 billion gallons per day of OTC withdrawals, and is the dominant source of OTC withdrawals in Central and Northern California. California's two nuclear plants account for nearly 90 percent of power plant once-through cooling withdrawals along the California coast.

Numerous coastal steam boiler plants, including the 964 MW Encina plant in San Diego County, that have low usage rates and only a small fraction of the OTC withdrawal rate of either SONGS or Diablo Canyon, are scheduled to comply with the OTC phase-out requirement by December 2017. By contrast, SONGS was scheduled to comply with the state's OTC phase-out regulation by December 2022. Diablo Canyon must comply by December 2024. However, the State Water

[2] N. Millar - CAISO, *Briefing on Nuclear Generation Studies Preliminary Results*, Board of Governors Meeting General Session, December 13, 2012, p. 7.
[3] Ibid, p. 7.

Resources Control Board (SWRCB) is allowing Diablo Canyon to study “alternate mitigation.” that could allow continued use of OTC.

Green Power Replacing Nuclear Power

A recent change to California’s definition of the 5 percent net-metering cap will result in at least 2,000 MW of additional rooftop PV by the end of 2016. This is fully consistent with the state’s “loading order” for electricity supply. California established a loading order of preferred resources in the state’s 2003 Energy Action Plan. The loading order set the following hierarchy of preferred resources: energy efficiency and demand response, renewable resources, combined heat and power, conventional gas-fired generation, and the transmission infrastructure necessary to support these priorities.

The CPUC required that the IOUs follow the loading order in procurement decisions in December 2012. More recently in June 2013 the CPUC established an investor-owned utility procurement target of 1,300 MW of energy storage by 2020. The addition of energy storage on a large scale is essential to green power fully displacing baseload nuclear plants. Legislation has was introduced in June 2013, AB 177, to increase the RPS target to 51 percent by 2030.

Conclusion

Southern California demonstrated in 2012 the grid can function reliably even in periods of peak summer demand without SONGS. Remedial actions by CAISO have addressed the local voltage support provided by SONGS. Diablo Canyon is in a remote location and does not have a substantial voltage support role. Peak loads are not growing. Renewable resources are being added rapidly. Unless operational gas-fired plants that currently provide capacity are retired prematurely, the grid will continue to function with adequate reserves – with no new gas-fired plant additions – for the foreseeable future.

California is ahead of schedule to generate 33 percent of its energy from renewable sources by 2020. More than sufficient existing generation is available to substitute for the permanent retirement of SONGS and Diablo Canyon. However, a substantial portion of this displacement power is gas-fired. Increasing the renewable energy requirement to 51 percent would fully displace nuclear power with an equivalent quantity of green power.

II. Background

There are two nuclear plants in California, the 2,150 MW SONGS near San Clemente, California and 2,160 MW Diablo Canyon on the Central Coast near San Luis Obispo, California. Each plant consists of two units of equal output. Both nuclear plants began operations in the mid-1980s and are designed to operate as baseload, round-the-clock generators.[4] Photos of SONGS and Diablo Canyon are provided in Figure 1.

Figure 1. Photos of SONGS (top) and Diablo Canyon (bottom)[5]

The steam generators within the Unit 1 and 2 containment domes at Diablo Canyon were replaced in 2008 and 2009. The Unit 2 and 3 steam generators at SONGS were replaced in 2010 and 2011. Accelerated wear was detected in the new steam generators at SONGS Units 2 and 3 after only 12 to 18 months of operation. This resulted in the shutdown of SONGS in January 2012. Southern California experienced no grid reliability issues with SONGS offline in the summer of 2012. SCE made the decision to permanently retire SONGS in June 2013. CAISO

[4] See: http://www.energy.ca.gov/nuclear/california.html.
[5] TetraTech, *California's Coastal Power Plants: Alternative Cooling System Analysis*, February 2008, Chapter C (Diablo Canyon) p. C-4, and Chapter N (SONGS) p. N-4.

forecasts no power supply issues without SONGS in the summer of 2013, stating that summer 2013 reserve margins in both Northern and Southern California are healthy.[6]

SONGS withdrew about 2.3 billion gallons per day of cooling water from the Pacific Ocean when operational.[7] Diablo Canyon withdraws about 2.5 billion gallons a day.[8] Combined these two nuclear plants are responsible for about 90 percent of power plant seawater withdrawals along the California coast.[9] SONGS and Diablo Canyon must comply with the state's once-through cooling phase-out regulations, December 2022 and December 2024, respectively. SONGS permanent retirement has reduced power plant OTC withdrawals along the California coast by more than 40 percent.

A. Local Generation Requirements

Certain areas of California are required to maintain a minimum amount of local generation, known as "local capacity," to assure local grid reliability under high demand conditions with one or more major elements, either transmission line(s) and/or power plant(s), unavailable for whatever reason. Figure 2 is a map of the geographic areas in California with local capacity requirements. SONGS is located in the Los Angeles Basin load pocket and contributes local capacity to the Los Angeles Basin.[10] Diablo Canyon is not located in an area with local capacity requirements.

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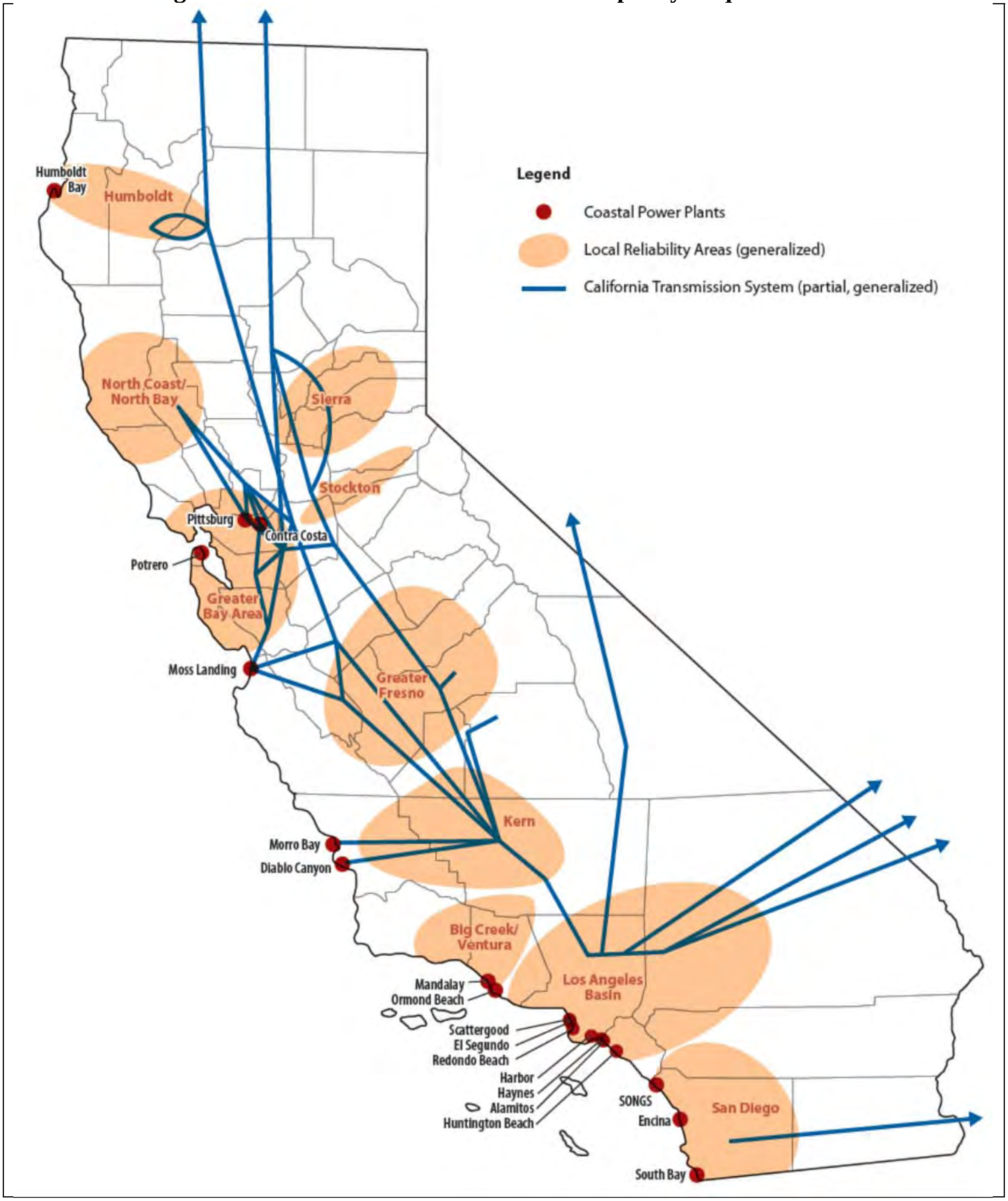
[6] N. Millar - CAISO, *Briefing on Summer 2013 Outlook & Update on SONGS Mitigation Planning*, Board of Governors Meeting General Session, March 21, 2013.
[7] TetraTech, *California's Coastal Power Plants: Alternative Cooling System Analysis*, February 2008, Chapter N (SONGS) p. N-3. SONGS cooling water flowrate: 2 × 795,600 gpm = 1,591,200 gpm (2.291billion gallons per day).
[8] Ibid, Chapter C (Diablo Canyon) p. C-4. Diablo Canyon cooling water flowrate: 2 × 862,690 gpm = 1,725,380 gpm (2.485billion gallons per day).
[9] ICF Jones & Stokes, *Electric Grid Reliability Impacts for Regulation of Once-Through Cooling in California*, April 2008, Table 3-1. Fourteen (14) operational coastal steam boiler power plants, such as 964 MW Encina (Carlsbad) in San Diego County and 1,970 MW Alamitos and 1,343 MW Redondo Beach in the Los Angeles area, now almost exclusively function as low usage back-up plants. There are also a handful of once-through cooled coastal combined cycle plants. These include 227 MW Harbor and 560 MW Haynes in the Los Angeles area and 1,080 MW Moss Landing 1 & 2 near Santa Cruz.
[10] CAISO, *Local Capacity Technical Analysis – Addendum to the Final Report and Study Results: Absence of San Onofre Nuclear Generating Station (SONGS)*, August 20, 2012, p. 6.

Figure 2. Areas in California with Local Capacity Requirements[11]



[11] ICF Jones & Stokes, *Electric Grid Reliability Impacts for Regulation of Once-Through Cooling in California*, April 2008, Figure 1.

B. Sources of California Electricity Supply

California in-state generators supply about 70 percent of the electricity consumed in the state. In-state generation is provided by four major supply categories: natural gas-fired turbines and boilers, renewable energy, large hydro, and nuclear. The 2011 percentage breakdown of each category is provided in Table 2.

Table 2. Percentage Breakdown of In-State Electricity Supply

Source category	Approximate percentage of 2011 in-state supply (%)	Approximate 2011 available capacity (MW)
Natural gas-fired turbines and boilers:[12]	45	
• post-2000 combined cycle units		17,000
• coastal steam boiler plants		16,000
• simple cycle peaker units		6,000
• cogen units		6,000
• other		1,000
Large hydro[13]	18	12,600
Nuclear	18	4,300
Renewable energy	17	
• geothermal		1,800
• wind[14]		5,500
• small hydro[15]		1,400
• biomass[16]		1,100
• solar		2,000

The CPUC states that about 2,000 MW of renewable portfolio standard (RPS) resources came online in California in 2012, and over 3,000 MW of new renewable resources will come online in 2013.[17] This 2,000 MW of RPS capacity does not include rooftop solar resources added in 2012 under California's net-metered rooftop solar programs. To meet the 33 percent RPS target under its assumed base case trajectory scenario, the CPUC projects that nearly 11,000 MW of solar resources will be operational by 2020.

As of January 1, 2013, about 3,000 MW of solar resources, including rooftop "behind the meter" solar installations, had been installed in California.[18,19] The additional 8,000 MW of solar

[12] CEC, *Staff Paper – Thermal Efficiency of Gas-Fired Generation in California: 2012 Update*, Table 1, p. 5.
[13] CEC, *Staff Report – Summer 2012 Electricity Supply and Demand Outlook*, May 2012, p. B-5.
[14] American Wind Energy Association, *4th quarter 2012 Public Market Report* , January 2013.
[15] http://www.energyalmanac.ca.gov/renewables/
[16] Ibid.
[17] CPUC, *Renewable Portfolio Standard Quarterly Report – 3rd & 4th Quarter 2012*, March 2013, p. 6. "Over 1,957 MW of new renewable capacity came online during 2012, and another 3,221 MW of capacity is forecasted to reach commercial operation by the end of 2013."
[18] Cite to "trajectory" scenario solar resource composition.
[19] Cite to SB1 totals, and all RPS solar installed as of December 31, 2012.

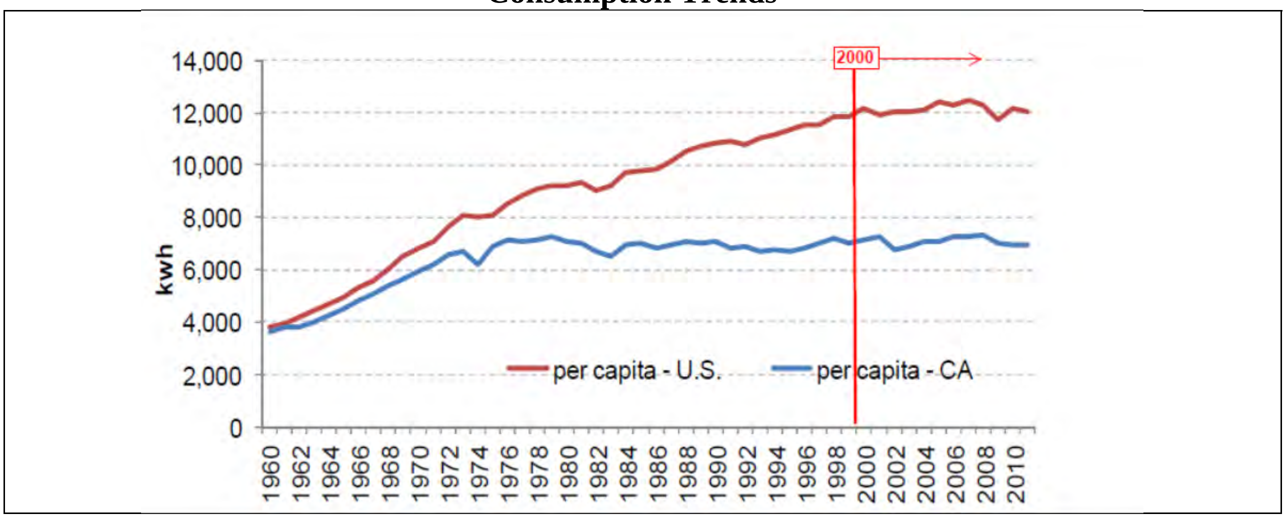
resources expected to be installed by 2020 will provide about 4,300 MW of new reliable supply during times of peak demand in 2020.[20]

California also imports significant amounts of electricity. California's wholesale power markets are relatively open and generation from outside the state is often less expensive. Some power plants located in adjacent states are wholly- or partially-owned by California utility companies or their holding companies. For example, SDG&E owns the 500 MW El Dorado combined cycle plant in Boulder City, Nevada. SDG&E parent company Sempra Energy owns the 600 MW TDM combined cycle plant in Mexicali. This plant is under CAISO dispatch control and connects directly to SDG&E's Imperial Valley substation. California utilities also own 18 percent of the 3,700 MW Palo Verde Nuclear Power Plant in Arizona.[21]

C. National and California per Capita Electricity Consumption Trends – Flat to Declining

National and California per capita electricity demand trends are shown in Figure 3. These trends are flat or declining. California's population is growing at less than 1 percent per year, primarily because of an aging population.[22] Customer attitudes toward electricity consumption, more rigorous building and appliance efficiency standards, efficiency programs and the behind-the-meter customer generation such as rooftop solar and CHP systems are factors in these reduced electricity consumption trends.

Figure 3. National (top curve) and California (bottom curve) Per Capita Electricity Consumption Trends[23]



[20] CPUC, RPS Calculator, May 16, 2012. On-peak availability: tracking solar = 65%, fixed solar = 51%. CAISO assumes CPUC environmental scenario solar mix, which is 80% fixed and 20% tracking. Therefore, on-peak availability in 2020 of additional 8,000 MW of solar will be: (8,000 MW × 0.80 × 0.51) + (8,000 MW × 0.20 × 0.65) = 3,264 MW + 1,040 MW = 4,304 MW.

[21] U.S. Energy Information Administration. *San Onofre nuclear outage contributes to Southern California's changing generation profile*, November 14, 2012: http://www.eia.gov/todayinenergy/detail.cfm?id=8770

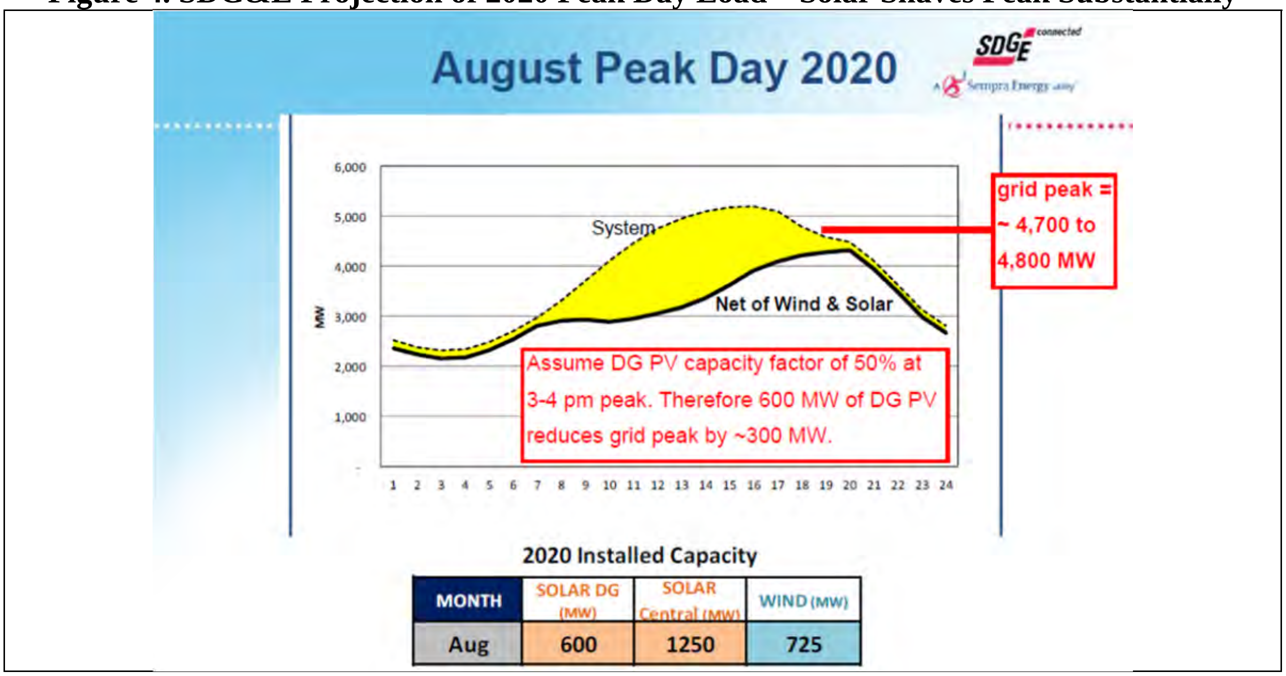
[22] U.S. Census QuickFacts California, last revised June 27, 2013: http://quickfacts.census.gov/qfd/states/06000.html

[23] K. Barker – California Energy Commission, *Facing California's Energy Challenges and Implications of Germany's Energiewende*, University of California Riverside presentation, April 26, 2013, p. 17. Vertical bar "2000" line added by B. Powers, Powers Engineering.

D. Actual Utility Peak Demand Trends – Fluctuating with Little or No Growth Through 2020

California electricity consumption and peak demand have declined from historic highs over the last 6 to 7 years, despite incremental population growth.[24] The CAISO control area peak load data for the last fifteen years is provided in Attachment A.
A primary reason for the lack of peak demand growth is shown in Figure 4 for SDG&E territory. Solar resources displace a substantial amount of the traditional summer mid-afternoon peak demand in 2020. The total peak demand is higher in 2020 than in 2013, but a significant portion of the peak load is met by behind-the-meter PV and not utility-supplied grid power. This is based on an SDG&E forecast of 600 MW of distributed, local PV online in SDG&E territory by 2020. As a result of 600 MW of distributed PV, the net grid-supplied peak demand in 2020 forecast by SDG&E is in the same range as the actual historic one-hour peak load recorded in SDG&E territory in 2010.

Figure 4. SDG&E Projection of 2020 Peak Day Load – Solar Shaves Peak Substantially

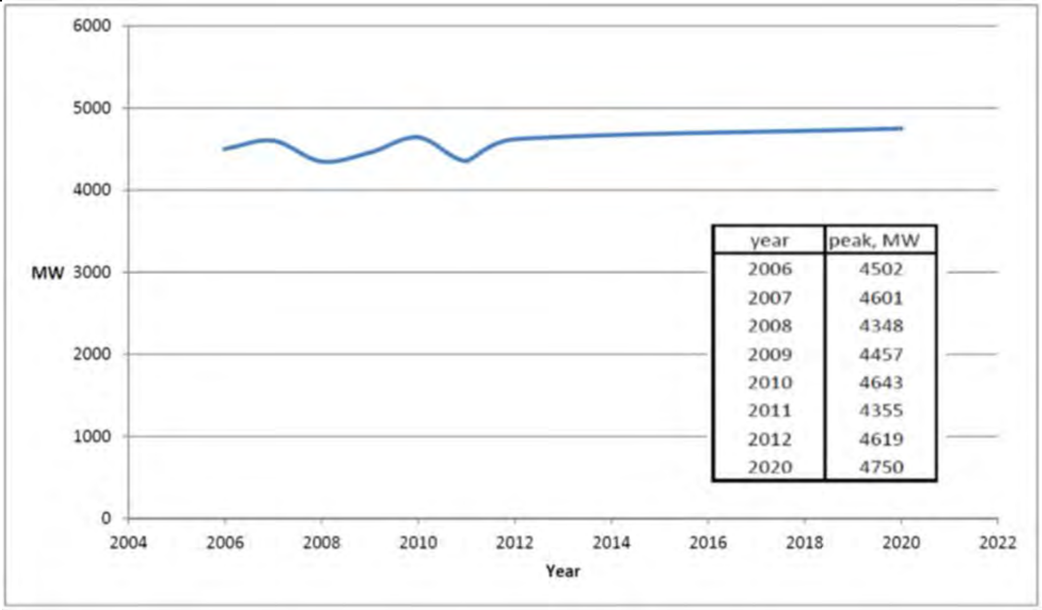


SDG&E forecasts the importation of 1,250 MW of utility-scale remote central solar in 2020 in addition to 600 MW of distributed solar, as shown in Figure 4. The utility-scale solar would be imported over the grid in the same fashion as power from a conventional combined cycle power plant. For this reason, utility-scale solar does not reduce grid power demand at peak. It offsets conventional power, but does not offset or affect the amount of grid power that must be supplied to meet the load. In contrast, distributed solar removes load from the grid at peak, reducing the amount of power that must be delivered by the utility to customers. A shift toward a greater proportion of distributed solar within the 1,850 MW solar resource total projected by SDG&E for 2020 would have the effect of further reducing the SDG&E grid demand peak in 2020.

[24] CEC, *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. 4.

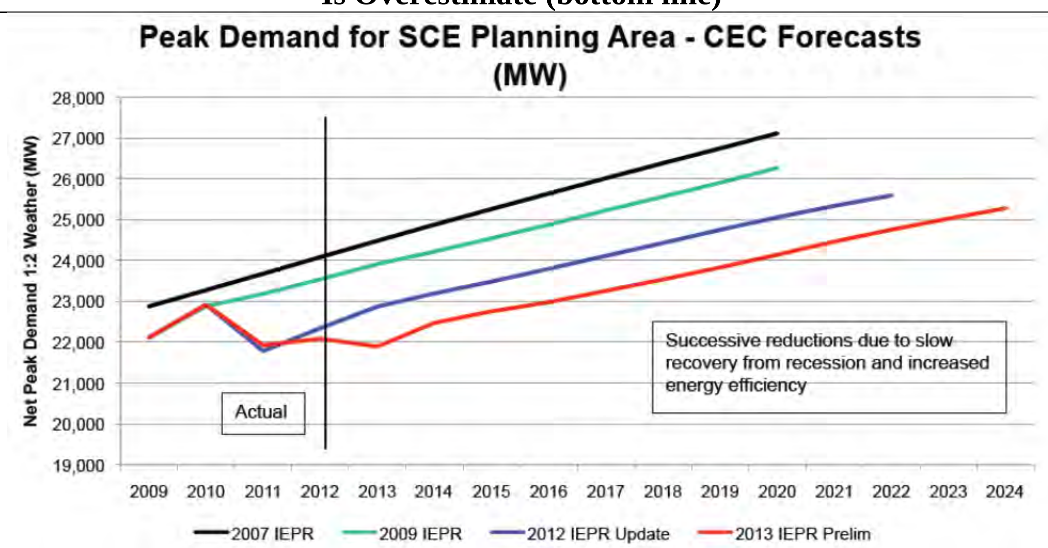
The net grid-supplied peak demand in 2020 forecast by SDG&E is in the same range as the actual historic one-hour peak load recorded in SDG&E territory in 2010, as shown in Figure 5.

Figure 5. SDG&E Peak Load Trend – Almost No Growth 2007 – 2020



This current investor-owned utility peak demand projection contrasts with the current California Energy Commission (CEC) projection shown in Figure 6 for SCE territory. CEC peak demand growth projections have been steadily declining over the last six years, as represented by the actual load lines in Figures 5 and 6. However, even the 2013 CEC peak load growth projection in Figure 6 is a substantial overestimate of grid power peak demand growth when a conservative and credible projection of distributed PV growth is included as shown in Figures 4 and 5.

Figure 6. CEC Peak Demand Project for SCE – Even 2013 Preliminary IEPR Forecast Is Overestimate (bottom line)[25]



[25] Ibid, p. 3.

State energy planners continue to treat the last 6 to 7 years of electricity consumption and peak demand trends as anomalies. A rapid return to the previous pattern of steady growth in both grid-supplied electricity consumption and peak demand is assumed to be the natural order. Nation-wide demand patterns trends showing a fundamental shift toward lower consumption are not yet being adequately reflected in California electricity demand forecasts. Overly optimistic CEC demand forecasts provide the justification for utilities to enter into contracts for unneeded new supply resources.

E. Reasons for High Reserve Margins

The state has built a tremendous amount of new natural gas-fired capacity over the last decade, both combined cycle plants and simple cycle peaker plants (aka "combustion turbines"). These units were justified on the presumption of steadily rising electricity consumption and peak load. The projected peak load increases have not materialized. In the meantime most of the older steam boiler plants along the California coast remain operational.

The result is thousands of MW of available resources beyond the level of reserves necessary to assure grid reliability in California. The state's planning reserve margin requirement, meaning the quantity of spare supply available to meet peak demand, is 15 to 17 percent. The planning reserve margin forecast by CAISO for Southern California in 2012 was approximately 30 percent. The 31 percent planning reserve margin forecast for Southern California in 2013 is essentially unchanged from 2012, despite the loss of SONGS, due to the addition of nearly 2,000 MW of new gas-fired plants in the Los Angeles Basin.[26] This 31 percent planning reserve margin equates to approximately 4,300 MW of excess capacity beyond what is needed to meet the 15 percent minimum reserve margin requirement.

The forecast 2013 planning reserve margin for Northern California is significantly higher than Southern California at 38.8 percent. This equates to over 5,000 MW of available capacity at peak beyond what is needed to meet the 15 percent planning reserve margin requirement. If 2,160 MW Diablo Canyon were shutdown in August 2013, Northern California would still have approximately 3,000 MW of additional capacity to meet forecast peak one-hour 2013 demand beyond what is necessary to meet the 15 percent planning reserve margin requirement.[27]

These high reserve margins, far beyond what the state has deemed necessary to assure grid reliability, are due to three factors: 1) flat or declining peak demand, 2) overbuilding of gas-fired

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[26] CAISO, *2013 Summer Loads and Resources Assessment*, May 6, 2013, Tables 1 and 2, pp. 4-5. "Southern California 2013 planning reserve margin = 31.0%, operating reserve margin = 23.3%. This forecast 2013 planning reserve margin for Southern California (SP26) is about 2,500 MW higher than the regulatory requirement of 15% without SONGS (reserves needed to meet 15% requirement = 27,253 × 1.15 = 31,341 MW. Reserves available = 35,696 MW). This is incrementally higher, without SONGS, than the CAISO 2012 planning reserve margin forecast of 28.9% and operating reserve margin forecast of 21.5% which assumed SONGS would be operational. See CAISO *2012 Summer Loads and Resources Assessment*, March 15, 2012, Tables 1&2, p. 4. The 2012 CAISO forecast assumed 452 MW Huntington Beach Units 3& 4 would be retired. In fact, these units were in service in summer 2012, resulting in an adjusted 2012 planning reserve margin of over 30%. Huntington Beach Units 3 & 4 have been converted to synchronous condensers to provide voltage support with SONGS offline.
[27] Ibid. Northern California reserves needed to meet 15% requirement = 21,328 MW × 1.15 = 24,527 MW. Northern California reserves available = 29,594 MW.

resources based on forecasts of continuous increase in peak demand year-after-year, and 3) ever-increasing quantities of new renewable energy generation that is replacing gas-fired generation.

The new gas-fired generation in Southern California is under construction within 40 to 80 miles of SONGS and will be online by the beginning of August 2013.[28] This is in addition to 200 MW of gas-fired generation that came online in Anaheim, 40 miles from SONGS, in late 2011. This new generation is the primary reason that Southern California reserve margins increased from 2012 to 2013 despite the loss of SONGS.

The loss of SONGS has not resulted in a substantial increase in the market price of power to supply the Southern California electricity market relative to the Northern California market, due primarily to the abundance of gas-fired generation available to serve the market and the relatively low cost of natural gas.[29]

The current low price of natural gas is also allowing natural gas-fired generators to compete with nuclear plants on price. Two medium-sized merchant nuclear plants, Crystal River and Kewaunee have announced their intent to shut down permanently due to price competition from gas-fired generators.[30]

The two California nuclear plants, primarily owned by IOUs, were built with the expectation that they would operate continuously as baseload units. Nuclear units are non-dispatchable and are either online at full load or offline. However, it is instructive to understand that the cost of electricity from nuclear plants, in an era when natural gas prices are low, is not presumptively lower than cost of electricity from gas-fired combined-cycle plants.

F. Once-Through Cooling Phase-Out for Coastal Power Plants – Plants Can Retrofit to Cooling Towers or Retire to Comply

The State Water Resources Control Board has adopted a policy to gradually phase-out the use of once-through cooling by coastal power plants. The phase-out schedule is shown in Table 3.[31] Coastal plants can meet the once-through cooling compliance schedule by shutting down, adding cooling towers to reduce water withdrawals by 95 percent or more, or by constructing a new power plant on the same site using dry cooling or a cooling tower to eliminate or minimize water withdrawals. Both California energy agencies and the IOUs frequently mischaracterize the OTC compliance date for coastal steam units as a definitive "retirement" date.

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[28] R. Sparks - CAISO, *San Diego Local Capacity Needs*, CPUC workshop presentation, April 17, 2012, p. 27. Major new generation projects coming online by mid-2013 in the Los Angeles area: Walnut Creek Energy Center (500 MW, City of Industry), NRG El Segundo Repowering Project (570 MW, El Segundo), Sentinel Peaker Project (850 MW, Desert Hot Springs).

[29] EIA Wholesale Market Price webpage, SP15 and NP15, California, July 1-18, 2013: http://www.eia.gov/electricity/wholesale/.

[30] SNL Financial, *Analyst: Entergy's Vermont Yankee, FitzPatrick nukes at risk of retirement*, January 4, 2013.

[31] R. Sparks - CAISO, *San Diego Local Capacity Needs*, presented at CPUC Workshop: Application of SDG&E for Authority to Enter into Purchase Power Tolling Agreements with Escondido Energy Center, Pio Pico Energy Center and Quail Brush Power, April 17, 2012, p. 24.

Table 3. Once-Through Cooling Phase-Out Schedule

Units	Compliance Date
El Segundo, Harbor (LADWP), Morro Bay	December 31, 2015
Encina, Contra Costa, Pittsburg, Moss Landing	December 31, 2017
Haynes (LADWP)	December 31, 2019
Huntington Beach, Redondo, Alamitos, Mandalay, Ormond Beach, Scattergood (LADWP)	December 31, 2020
San Onofre Nuclear Generating Station	December 31, 2022
Diablo Canyon Power Plant	December 31, 2024

More than 17,000 MW of high efficiency combined cycle power plants came online in California in the 2001 – 2011 period. Coastal boiler plants have substantially lower thermal efficiency than combined cycle units. Primarily for this reason, the usage rate of the coastal boiler plants has dropped to a low level over the last decade. In contrast, the two nuclear units operated at full power round-the-clock except during outages. This was equivalent to a capacity factor of nearly 90 percent.

SONGS and Diablo Canyon each generated about 17 million MW-hr per year during those years when extended planned or unplanned outages did not occur.[32] Total cooling water throughput by the two nuclear plants in these years is approximately 1,750 billion gallons per year.[33]

In contrast, the approximately 16,000 MW of coastal steam boiler capacity operates on average with a low capacity factor of about 4 percent.[34] This is equivalent to annual electricity production of about 6 million MW-hr per year. Annual coastal steam boiler once-through cooling water throughput, assuming the circulating water pumps are not in use when the coastal steam units are not producing electricity, would be about 154 billion gallons per year.[35]

There is approximately 1,900 MW of coastal combined cycle plant capacity. These combined cycle units operate with an average capacity factor of about 37 percent. This is equivalent to annual electricity production of about 6 million MW-hr per year. Annual coastal combined cycle once-through cooling water throughput, assuming the circulating water pumps are not in use

[32] ICF Jones & Stokes, *Electric Grid Reliability Impacts from Regulation of Once-Through Cooling in California*, prepared for California Ocean Protection Council and State Water Resources Control Board, April 2008, Table 3-1. For example, Diablo Canyon produced more than 17 million MW-hr per year in 2003, 2005, and 2006. SONGS produced more than 17 million MW-hr per year in 2002, 2003, and 2005.

[33] 4.8 billion gallon/day × 365 days/yr = 1,752 billion gallons per year.

[34] CEC, *Staff Report – Thermal Efficiency of Gas-Fired Generation in California: 2012 Update*, March 2013, Table 2, p. 5. 2011 coastal steam boiler capacity factor = 4.1%. 2011 combined cycle capacity factor = 36.8%.

[35] TetraTech, *California's Coastal Power Plants: Alternative Cooling System Analysis*, February 2008, Chapter O (803 MW Scattergood Generating Station) p. O-3. Scattergood cooling water flowrate = 344,000 gpm. Unit once-through cooling water usage rate = (344,000 gpm × 60 min/hr)/803 MW = 25,704 gallons/MW-hr. Assuming the Scattergood unit cooling water usage rate is representative of coastal steam units, the annual cooling water throughput for coastal steam boilers collectively would be: 16,000 MW × .8,760 hr/yr x 0.04 × 27,504 gallons/MW-hr = 154 billion gallons per year.

when the combined cycle units are not producing electricity, would be about 73 billion gallons per year.[36]

The two California nuclear plants accounted for about 90 percent of once-through cooling water flow from coastal once-through cooled power plants in years when both nuclear plants were operating normally. The coastal steam boiler plants accounted for about 7 percent of once-through cooling withdrawals and the once-through cooled coastal combined cycle plants accounted for about 3 percent.[37]

The older coastal units are useful as low-cost back-up capacity to meet local reliability requirements, as well as to provide inertia (or "voltage support") to maintain adequate levels of transmission import capability into Southern California when regional electricity demand is high. The rotation of the coastal steam turbine generators in Southern California produces inertia, necessary to stabilize voltage on the transmission grid and allow energy to be imported into the region. The OTC units are primarily steam turbines, which provide more voltage support per MW of capacity than combined-cycles or other generation technologies.[38]

Despite these advantages, especially to assure grid reliability during periods of peak demand, the coastal steam boiler units have been qualitatively characterized by California energy agencies and the IOUs as obsolete units that must be replaced. In fact, with adequate maintenance, these units can continue to provide reliable back-up power indefinitely. The capital cost of new units to replace the coastal boilers is estimated at about $1,200/kW, about ten times the cost of keeping the existing units in service as backup capacity (retrofit with cooling towers costing about $125/kW) until cleaner solutions, such as energy storage, are phased-in over time.[39,40] The CPUC recently proposed an energy storage procurement target of 1,300 MW for the IOUs by 2020.[41]

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[36] TetraTech, *California's Coastal Power Plants: Alternative Cooling System Analysis*, February 2008, Chapter J (Moss Landing Power Plant, 1,080 MW Units 1&2) p. J-2. Units 1&2 combined cycle once-through cooling water flowrate = 214,000 gpm. Unit once-through cooling water usage rate = (214,000 gpm × 60 min/hr)/1,080 MW = 11,889 gallons/MW-hr. Assuming the Moss Landing Units 1&2 unit cooling water usage rate is representative of coastal once-through cooled combined cycle units, the annual cooling water throughput for coastal combined cycle units collectively would be: 1,900 MW × 8,760 hr/yr x 0.37 × 11,889 gallons/MW-hr = 73 billion gallons per year.

[37] Nuclear plant once-through cooling withdrawals = 1,752 billion gallon/yr. Coastal steam boiler withdrawals = 154 billion gallons per year. Coastal once-through cooled combined cycle withdrawals = 73 billion gallons per year. Total annual withdrawals = 1,979 billion gallons per year. Percentage nuclear = 88.5%. Percentage steam boiler = 7.8%. Percentage combined cycle = 3.7%.

[38] Ibid, p. 30.

[39] 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 (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."

[40] 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. Capital cost of 100 MW simple cycle turbine = $1,231/kW.

[41] GreenTech Media, *California Sets Energy Storage Target of 1.3GW by 2020*, June 11, 2013.

The reason that CAISO and the CPUC have identified 2018 as the first year that a shortage of local capacity could be experienced in SDG&E territory is because the 964 MW Encina Generating Station, approximately 25 miles south of SONGS, is assumed to retire at the end of 2017. December 2017 is the current OTC phase-out compliance date for Encina. Encina represents about one-third of the 3,000+ MW of existing local capacity in SDG&E territory.

The compliance date for SONGS is December 2022. The compliance date for Diablo Canyon is December 2024. The early retirement of SONGS and Diablo Canyon would reduce coastal power plant OTC water withdrawals by approximately 90 percent, largely achieving the objectives of the OTC phase-out policy far ahead of the current OTC phase-out schedule.

Cost-effective responses to the permanent shutdown of SONGS, if determined necessary in addition to the accelerated development of energy efficiency, demand response, and local solar, would be either: 1) extend the Encina OTC phase-out compliance date to December 2022, applying the current SONGS OTC phase-out date to Encina, or 2) authorize Encina to incorporate the cost of a cooling tower retrofit in the capacity charge it is paid to be available as needed as a back-up generation resource.

SDG&E sold Encina and nearly 200 MW of peaker turbines (Cabrillo II) to NRG Energy in the late 1990s in the first phase of deregulation in California. SDG&E is now intent on forcing the retirement of these fully functional local power plants. The need to maintain near-term grid reliability in the face of the loss of SONGS has not been a factor in SDG&E's continued efforts to shut down these plants. The shutdown of these units could create a perceived need for new peaking units that would otherwise not exist.[42]

G. Southern California Grid Reliability without SONGS

There were no problems with grid reliability in Southern California in the summer of 2012 without SONGS, despite extended heat waves in August and September 2012. The reasons for this were the high level of reserve supply and the remedial measures taken to assure that effective substitutes for the voltage support provided by the SONGS electric generators were in place. California has demonstrated that the state's electricity supply is reliable at the hottest time of the year without SONGS.

The purpose of reactive power is to keep the alternating current power being supplied in synchronization with the loads, such as motors and transformers, being served. If insufficient reactive power is available, less of the electricity generated is actually available to do useful work. An analogy is the energy put into pushing a child on a swing. When a parent is in

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[42] NRG, *SDG&E Application A.11-05-023 – Response of NRG Energy, Inc. to Application for Authority to Enter into Purchase Power Agreements with Escondido Energy Center, Pio Pico Energy Center, and Quail Brush Power*, June 24, 2011, p. 3. "NRG submits that several of the assumptions presented in SDG&E's application, especially those regarding the Encina Power Station and the Cabrillo II Peakers, do not reflect the current commercial status. . . Corrects the presumption that the existing Encina Power Station will be retired by December 31, 2017 as referenced in the CA 316(b) Once Through Cooling ("OTC") policy. Encina'sretirement is not within the CPUC's or SDG&E's ability to determine . . . Clarifies that the timing of retiring the Cabrillo II peaking turbines is dependent not upon "air permit restrictions" but upon SDGE's decision not to renew the site leases and notes the importance of these units to various non-SDG&E load serving entities ("LSE") and the CAISO."

synchronization with the arc of the swing, force is applied at the peak of the child's arc and almost all applied force is converted to useful work. However, if force is applied too early or too late, a significant portion of the force applied is wasted effort, either prematurely braking the child before initiating the downward arc or providing a weak and late push on the downward arc.

According to CAISO, the non-generation solutions to the near-term local voltage support issues created by the SONGS outage were online as of July 2013. These non-generation solutions are listed in Table 4.

Table 4. Non-Generation Solutions to Voltage Support Issues Created by SONGS Outage[43]

Solution Element	Online Date
Convert Huntington Beach units 3 & 4 into synchronous condensers	June 1, 2013
Install capacitors: 80 MVAR each at Santiago and Johanna, 160 MVAR at Viejo	July 1, 2013
Split Barre-Ellis 220 kV circuits (from 2 to 4 lines)	mid-July 2013

Collectively these measures will assure adequate voltage support in the summer of 2013 in the southern Orange County region near SONGS. These measures will be adequate indefinitely if grid peak loads do not increase appreciably over time. The locations of these projects are shown in Figure 7.

Figure 7. Voltage Support Upgrades and New Generation that Offset Loss of SONGS[44]

CAISO states that its focus is on non-generation alternatives to mitigate the risk of meeting forecast demand without SONGS.[45] CAISO has identified numerous non-generation Southern

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43 N. Millar - CAISO, *Briefing on Summer 2013 Outlook – Update on SONGS Mitigation Planning*, Board of Governors Meeting General Session, February 7, 2013, p. 3.
44 P. Pettinggill – CAISO, *CEC/CPUC Joint Workshop on Electricity Issues Resulting from SONGS Closure – ISO 2013 Transmission Plan Nuclear Generation Backup Plan Studies (SONGS)*, PowerPoint presentation, July 15, 2013, p. 2.
45 K. Edson - CAISO, PowerPoint presentation to Sierra Club representatives, August 21, 2012, p. 5.

California strategies, beyond those already discussed, to address future voltage support needs if peak load growth occurs to the degree that such actions might be justifiable for grid reliability purposes. These non-generation actions are listed in Table 5.

Table 5. Additional Non-Generation Actions Identified by CAISO to Address Future Southern California Voltage Support Issues if Grid Peak Loads Increase Substantially[46,47]

Options	Description
1	Convert existing SONGS electric generators to synchronous condensers.
1	Provide 1,000 MVAR Static VAR Compensator support using existing SONGS and San Luis Rey/Talega facilities.
2	Maintain Huntington Beach Unit 3 and 4 synchronous condensers in service for the foreseeable future.
3	Reduce generation need in SDG&E territory by 700 MW by adding reactive support, transformer upgrades, and 66 kV transmission upgrades in the LA Basin, and upgrading line series capacitors and additional transformer upgrades.
4	SDG&E responds to N-1-1 contingency with controlled load shedding as allowed by NERC and CAISO transmission planning standards.
5	Classify 1,070 MW of combined cycle generation connected to SDG&E's Imperial Valley Substation as SDG&E local capacity.
6	SDG&E renews land lease for ~200 MW of existing Cabrillo II combustion turbines.
7	SDG&E extends capacity contract for 964 MW of existing Encina capacity is extended beyond current 2017 Encina OTC compliance date.
8	CAISO acknowledges that both combined cycle units in San Diego load pocket can continue to operate as simple cycle units if the single steam turbine generator is forced offline in either case. This administrative action would add approximately 280 MW to SDG&E local capacity.[48]

H. Need for New Fast-Start Peaking Units to Address Solar and Wind Integration Issues – Not Supported by the Facts

A relatively new justification for adding potentially thousands of MW of new fast response "flexible" gas-fired generation in California over the next several years is integration of large amounts of wind and solar resources while maintaining grid reliability.

[46] CAISO, *2012-2013 Transmission Plan*, March 20, 2013, Figure 3.5-5, p. 118 and p. 190.
[47] P. Pettinggill – CAISO, *CEC/CPUC Joint Workshop on Electricity Issues Resulting from SONGS Closure – ISO 2013 Transmission Plan Nuclear Generation Backup Plan Studies (SONGS)*, PowerPoint presentation, July 15, 2013, pp. 8-9.
[48] J. Wellinghoff - FERC, *Response letter to Congressman Bob Filner regarding corrected definition of G-1 in SDG&E service territory*, February 20, 2009. ". . . there is a disagreement between the transmission operator, CAISO, and the transmission owner SDG&E, on the appropriate reserve requirements or reserve impact of the combined cycle cogeneration units. In particular, each of the cogeneration plants consists of two gas turbine generators whose exhaust gases are directed into a heat recovery steam generator which drives a steam turbine generator. The units are designed so that the steam can be vented during a steam turbine generator trip, which will allow the gas turbines to continue to operate. The disagreement arises because the CAISO believes there are still common mode failures that will trip the entire plant (all three turbine generators) and SDG&E claims that a portion of the plant will continue to run (two turbine generators)."

SONGS and Diablo Canyon are designed to be baseload, steady-state units. They are not designed to follow changes in load over the course of the day, and for this reason are considered inflexible generation resources. As a result of this inflexibility, the availability or lack of availability of SONGS and Diablo Canyon play no substantive role in the debate over whether, or how much, new flexible resources should be added to meet grid reliability requirements with large amounts of solar and wind capacity in the system. The primary issue of concern is when solar output is declining in the late afternoon and gas-fired resources must ramp-up to replace the reduced solar output. The effect on the grid of the late afternoon solar output decline is most prominent during low demand periods like the early spring.

Under current state projections and policies, approximately 11,000 MW of utility-scale solar capacity and over 5,000 MW of net-metered rooftop solar capacity will be online by 2020.[49,50] In low demand springtime months with mid-day loads in the range of 25,000 to 30,000 MW in the CAISO control area, solar output could supply up to 50 percent or more of the mid-day demand in 2020.

This phenomenon is already occurring in Germany, where over 30,000 MW of solar capacity is online. Solar energy in Germany supplies up to 50 percent of mid-day demand on clear spring days. Germany has not added any new flexible gas-fired capacity specifically to address the effects of late afternoon solar output decline.[51] German electricity demand is about double that of California.

Germany and Spain have dedicated extensive resources to develop highly accurate wind and solar forecasting. This forecasting is used to adjust the output of existing dispatchable resources, like hydro and fossil fuel-fired plants, to maintain grid reliability. German and Spanish capability is substantially more accurate than California wind and solar forecasting. A comparison of German, Spanish, and California forecasting accuracy is provided in Table 6.

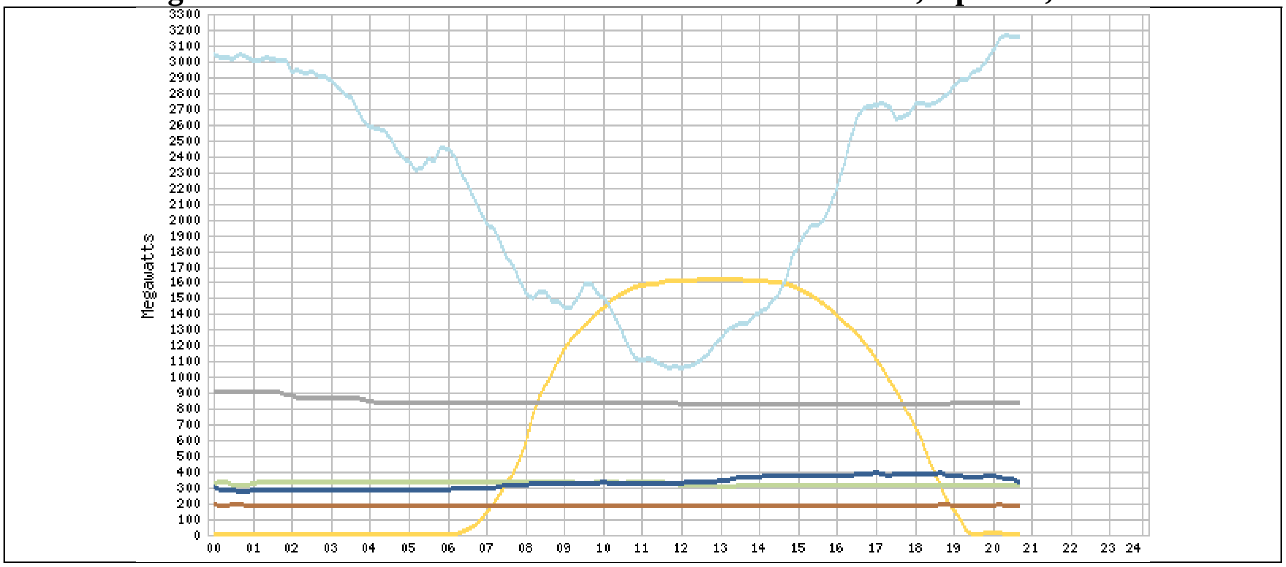
Table 6. Comparison of Renewable Production Forecasting Accuracy in Germany, Spain, and California[52]

RMSE Renewables Forecast Error	Germany, Spain[2]	California[1]
Day-Ahead	< 5%	< 15%
1 Hour-Ahead	1.5%	<10%

[49] CPUC 2010 LTPP "Environmental Scenario," solar PV is 80% fixed-tilt, 20% tracking.
[50] T. Beach – Crossborder Energy, *Evaluating the Benefits and Costs of Net Energy Metering in California*, January 2013, p. 1.
[51] Personal communication, B. Powers of Powers Engineering and Harry Lehmann, German Federal Environment Ministry, April 17, 2013.
[52] C. Hewicker et al – KEMA, *European Experience Integrating Large Amounts of DG Renewables*, CEC IEPR Committee Workshop on Renewable, Localized Generation, May 9, 2011, p. 22.

CAISO's anticipates that as solar output declines in the late afternoon, gas-fired and hydro units will ramp up to substitute for the solar output over a 2- to 3-hour period.[53] The characteristic clear day solar output pattern is shown in Figure 8 for April 29, 2013.

Figure 8. Renewable Generation in CAISO Control Area, April 29, 2013[54]



light blue = wind; yellow = solar; gray = geothermal; dark blue = small hydro; green = biomass; brown = biogas

Although this load change pattern is predictable and will be known to a high degree of accuracy a day in advance, CAISO currently presumes that primarily fast-response units, either gas-fired combined cycle units that are already online, gas-fired peaking units, or hydro units, would meet this ramping need.

This presumption is incorrect. CAISO already has the ability to predict with a high degree of accuracy a day in advance the load curve for the next day, as well as the hour-to-hour statewide output of wind and solar resources. Because the demand curve is known with a high degree of accuracy a day in advance, even the coastal steam units, some of which require up to 24 hours to go from a cold start to producing electricity, can be scheduled across their entire load range to meet the next day late afternoon ramping need.

This phenomenon is shown in Figure 9 for April 29, 2013. In the 4 pm to 7 pm period when the solar resource is declining rapidly, the difference between the day-ahead forecast and actual demand is less than 500 MW. In this same 4 pm to 7 pm time period, there is almost no difference between the hour-ahead forecast and actual demand. What this signifies in practical terms is that only 500 MW of flexible capacity is needed to account of an error margin of about 500 MW between the day-ahead forecast and the actual demand. Less than 100 MW of flexible fast ramping capacity is needed to account for the error margin between the hour-ahead forecast and actual demand.

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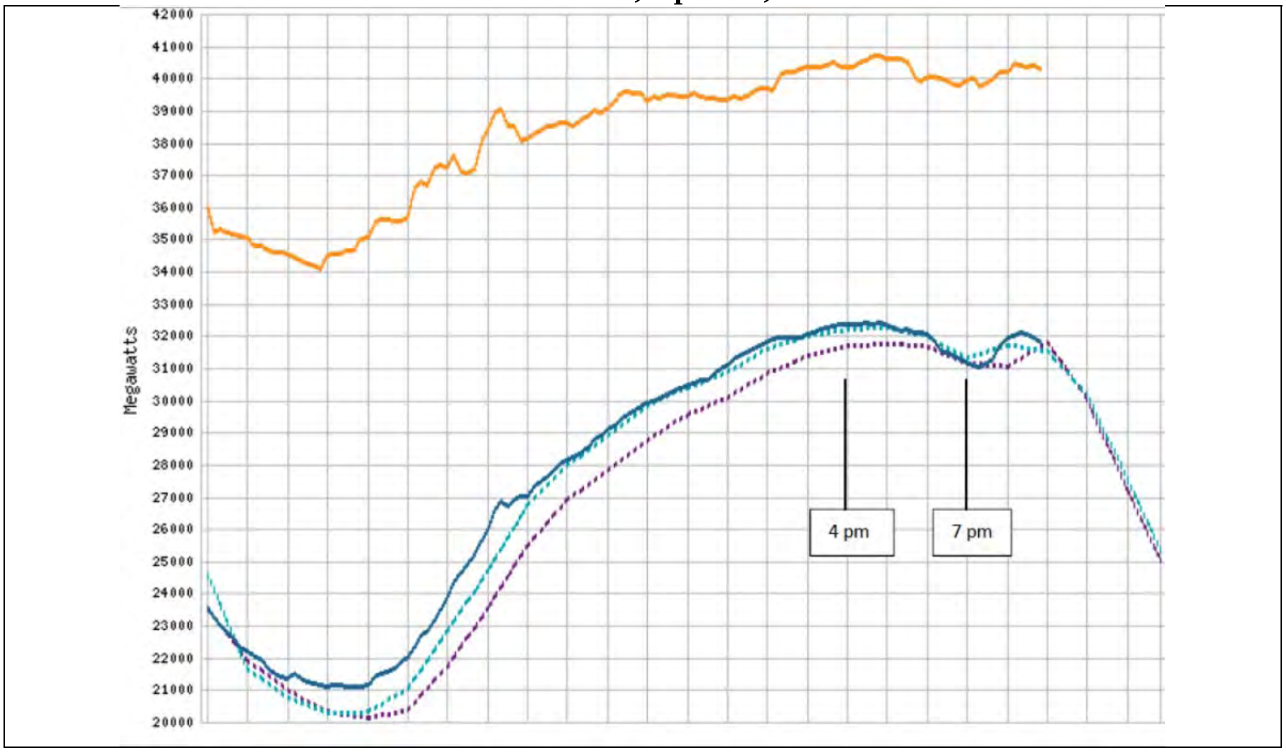
[53] CAISO, *CPUC Rulemaking R.11-10-023: Flexible Capacity Procurement Obligation - Initial CAISO Comments on Workshop Issues*, April 5, 2013.
[54] CAISO homepage graphic, April 29, 2013, 9 pm.

Figure 9. Comparison of CAISO Day-Ahead and Hour-Ahead Demand Forecasts to Actual Demand, April 29, 2013[55]



yellow = available resources; solid blue = actual demand; light blue dashed = hour-ahead demand forecast; purple dashed = day-ahead demand forecast.

III. California's Vision of Future Energy Development

A. California Energy Policy

The key policies and goals that embody California's energy strategy are summarized in Table 7.

Table 7. California Energy Strategy – Key Policies and Goals[56]

Energy Action Plan's Preferred Loading Order, 2003 & 2008	Prioritizes cost-effective investments in: 1) energy efficiency and demand response; 2) renewables and distributed generation; and 3) utility-scale gas-fired sources and infrastructure improvements (transmission & distribution).
Executive Order S-3-05 GHG Emissions, 2005	Issued by Gov. Schwarzenegger, establishes goal to reduce GHG emissions to 80% below 1990 levels by 2050.

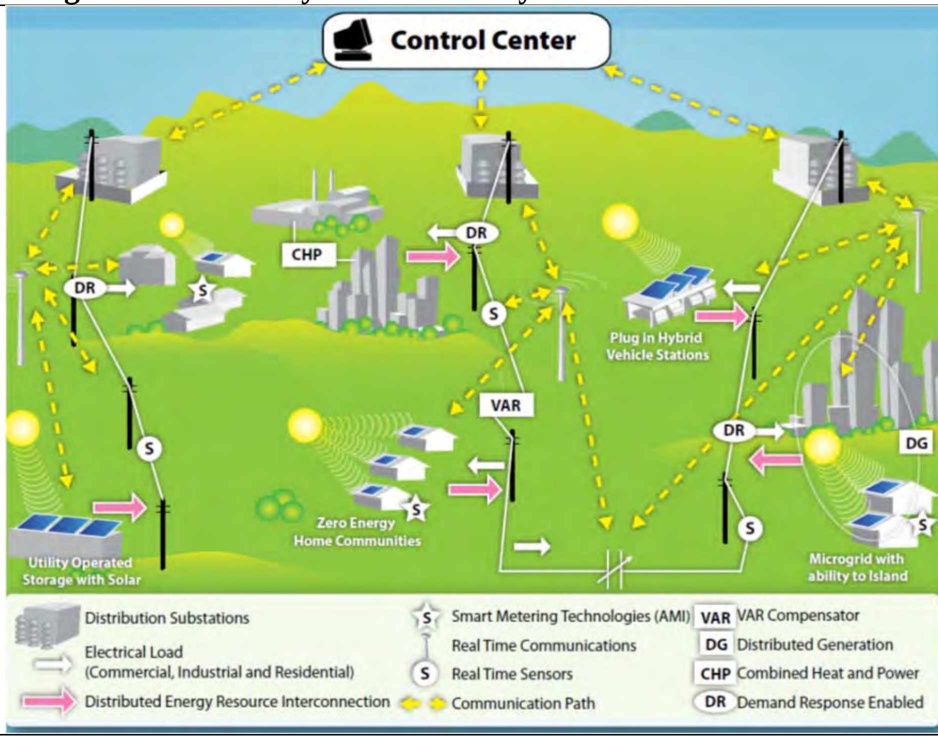
[55] CAISO homepage graphic, April 29, 2013, 9 pm.
[56] K. Barker – California Energy Commission, *Facing California's Energy Challenges and Implications of Germany's Energiewende*, University of California Riverside presentation, April 26, 2013, p. 4.

Assembly Bill 32, 2006	2006 legislation reducing GHG emissions to or below 1990 levels by 2020, and to 80% below 1990 levels by 2050.
State Lands Commission Resolution Regarding Phase-Out of Once-Through Cooling, 2006	State Water Resources Control Board directed to expeditiously develop and implement policies to eliminate the impacts of power plant once-through cooling.
CPUC Energy Efficiency Strategic Plan, 2008 & 2011	Sets efficiency goals, including zero net energy (ZNE) goals for new homes by 2020, and for new commercial buildings by 2030
Clean Energy Jobs Plan, 2010	Established in 2010 by Gov. Brown, directs production of 20,000 MW of new renewables by 2020, 12,000 MW of distributed energy, and 6,500 MW of CHP.
Senate Bill X1-2, 2011	Requites all electricity retailers to meet 33% of retail sales with renewable energy resources by 2020.
Executive Order B-18-2012 Green State Buildings, 2012	Issued by Gov. Brown, directs efficiency improvements in new or renovated state buildings larger than 10,000 square feet; sets target of 50% of existing state buildings ZNE by 2025.
Executive Order B-16-2012 Zero Emission Vehicles, 2012	Issued by Gov. Brown, sets long-term target of reaching 1.5 million zero-emission vehicles (ZEV) by 2025.

B. State Agencies – Future is Distributed Generation (DG)

The state's vision of a two-way distribution system that is optimized for high levels of local distributed generation is shown in Figure 10.

Figure 10. Two-Way Distribution System for DG Environment[57]



A December 2011 analysis on the integration of renewable distributed generation, conducted for the CEC, determined that accommodating back-flow conditions caused by large amounts of distributed generation on distribution circuits would not require major changes to California's basic distribution infrastructure.[58]

A primary concern expressed in the study is the lack of significant utility effort in California to monitor or control the dispatch of non-utility owned rooftop PV on distribution circuits. The monitoring and dispatch control of commercial-scale rooftop PV is considered essential to reliable grid operation in Germany, where approximately 33,000 MW_{dc} of distributed PV was online by the end of 2012.

The analysis prepared for the CEC states:[59]

> Unlike Germany, the CAISO has no visibility of the energy production of DG resources connected to the distribution system and cannot send dispatch commands to these DG resources. This is especially true for DG resources that are connected behind the meter at a customer site and the DG output is netted with the customer load. By virtue of its balancing area authority status, the CAISO must be prepared to cover the total load at the customer site in the event that the DG unit shuts down, but the amount of load being offset by DG output is typically unknown to the CAISO.

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[57] CEC, *Integrated Energy Policy Report*, December 2007, p. 155.

[58] KEMA, *European Renewable Distributed Generation Infrastructure Study – Lessons Learned from Electricity Markets in Germany and Spain*, prepared for CEC, December 2011, p. 17: http://www.energy.ca.gov/2011publications/CEC-400-2011-011/CEC-400-2011-011.pdf.

[59] Ibid, p. 114.

> The European experience shows that it is vital for the power system operator to be able to monitor the output of DG facilities as well as direct DG units to curtail dispatch when required for emergencies, such as grid reliability and safety.[60]

This analysis indicates that the current limitation on DG inflows to the existing transmission and distribution system is more administrative than technical.

C. Use of Smart Inverters in Renewable Energy Generators to Provide Reactive Power

Traditionally PV inverters were intentionally designed to feed as much active power, in kW or MW, as available from the solar array at unity power factor into the grid. More recently utilities and independent power providers have shown considerable interest in the three-phase inverter's capability to also absorb and provide reactive power from and to the grid.[61] Germany is setting the standard on use of smart inverters with distributed renewable energy sources. German rules as of April 2011 require that all distributed generation sources greater than 100 kW must provide reactive power to the grid.[62]

The flow of active power and reactive power in the grid are independent from one another and largely require different control schemes. Active power control is tied to controlling grid frequency, whereas reactive power control is linked with controlling the grid voltage.

1. Control of Active Power and Frequency

In a transmission and distribution network it is necessary to keep the frequency as stable as possible because the biggest generating resources, all of which are synchronous machines, work at their most efficient point when spinning at exactly 60 cycles per second. Also, the speed governors on these machines must operate in lock-step to share the generation load between machines to meet demand. For the frequency to remain stable the generated active power must match the power demand at all times. However, many electricity consuming devices operate out-of-synch with a standard alternating current waveform where the current and voltage waveforms are synchronized. The degree of synchronization between the current and voltage waveforms is called the "power factor." When current and voltage are not in synchronization, for example because an electricity consuming device creates induction, this "out of synchronization" effect must be countered with reactive power. Some loads requiring offsetting reactive power are shown in Table 8.

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[60] Ibid, p. 127.
[61] M. Zuercher-Martinson – Solectria Renewables, LLC, *Smart PV inverter benefits for utilities*, Photovoltaics World, November/December 2011, p. 18.
[62] K. Barker – California Energy Commission, *Facing California's Energy Challenges and Implications of Germany's Energiewende*, University of California Riverside presentation, April 26, 2013, p. 13.

Table 8. Typical Reactive Power Consuming Loads[63]

Load	Power factor
Fluorescent lighting	0.90
Heat pump and A/C	0.83
Washer	0.65
Industrial motor	0.85

2. *Control of Reactive Power and Alternating Current Voltage*

Although reactive power can be controlled in large generation stations, it is necessary to control voltage by injecting and absorbing reactive power at various points throughout the transmission and distribution network. Excessive voltage can adversely affect equipment and loads. Reactive power control also greatly enhances grid stability and reduces line transmission losses.

Transmission lines can, depending on load and length, either absorb or provide reactive power. The resistive power loss component, heat loss, is often insignificant in comparison to the reactive power component at very high voltage levels.

The reactive power capacity of a smart PV inverter can be used as a fast-acting static reactive power compensator, controlled through a supervisory control and data acquisition system. A major benefit of this implementation is that it comes at very little additional component cost. At the distribution line level, smart PV inverters are used to correct the power factor by providing reactive power close to where they are being used, rather than importing them from far away. Transformers and most electrical loads are inductive in nature and therefore consume reactive power.[64]

Power factor correction is typically done by connecting large, paralleled capacitor banks to many of the voltage levels of the distribution system. These capacitors are strategically placed to adjust voltage along the feeder. Power factor correction and alternating current voltage regulation can be performed much more economically by distributed three-phase smart PV inverters along the feeder. This regulation will also be done in a continuous and smooth fashion, without any step changes or noticeable switching events.[65]

Germany requires PV inverters on systems 100 kW or greater in capacity to utilize smart PV inverters.[66] This same requirement should also be applied in California to assure that high levels of power flow from rooftop PV systems will maintain or improve grid reliability.

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[63] Ibid.
[64] Ibid.
[65] Ibid.
[66] KEMA, *European Renewable Distributed Generation Infrastructure Study – Lessons Learned from Electricity Markets in Germany and Spain*, prepared for CEC, December 27, 2011, p. 35. See: http://www.energy.ca.gov/2011publications/CEC-400-2011-011/CEC-400-2011-011.pdf.
"DG plants with rated power of more than 100 kW must be equipped with remote telemetering and control capability to communicate their real-time output to the grid operator and allow for the TSO to send automatic power curtailment instructions to these generators. However, under current German law a PV project is only subject to this requirement if it has an individual PV panel rated 100 kW or larger (such as, the composite output of the PV project

D. IOU-Owned Distributed PV Projects

In its March 2008 application to the CPUC for an urban PV project up to 500 MW, SCE expressed a high level of confidence that it can absorb thousands of MW of distributed PV without additional distribution substation infrastructure. SCE indicated that "SCE's Solar PV Program is targeted at the vast untapped resource of commercial and industrial rooftop space in SCE's service territory,"[67] and "SCE has identified numerous potential (rooftop) leasing partners whose portfolios contain several times the amount of roof space needed for even the 500 MW program."[68]

The utility stated it has the ability to balance loads at the distribution substation level to avoid having to add additional distribution infrastructure to handle this large influx of distributed PV power.[69] SCE explains:

> SCE can coordinate the Solar PV Program with customer demand shifting using existing SCE demand reduction programs on the same circuit. This will create more fully utilized distribution circuit assets. Without such coordination, much more distribution equipment may be needed to increase solar PV deployment. SCE is uniquely situated to combine solar PV Program generation, customer demand programs, and advanced distribution circuit design and operation into one unified system. This is more cost-effective than separate and uncoordinated deployment of each element on separate circuits.[70]

SCE also noted that it will be able to remotely control the output from individual PV arrays to prevent overloading distribution substations or affecting grid reliability:[71]

> The inverter can be configured with custom software to be remotely controlled. This would allow SCE to change the system output based on circuit loads or weather conditions.

As SCE states, "Because these installations will interconnect at the distribution level, they can be brought on line relatively quickly without the need to plan, permit, and construct the transmission lines."[72] This statement was repeated and expanded in the CPUC's June 18, 2009 press release regarding its approval of the 500 MW SCE urban PV project:[73]

> Added Commissioner John A. Bohn, author of the decision, "This decision is a major step forward in diversifying the mix of renewable resources in California and spurring the development of a new market niche for large scale rooftop solar applications. Unlike other generation resources, these projects can get built quickly and without the need for expensive new transmission lines. And since they are built on existing structures, these projects are extremely benign from an environmental standpoint, with neither land use, water, nor air

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does not apply). However, the German legislature has recently passed legislation that, if signed by the executive branch, would essentially revoke this exemption for PV."

[67] SCE Application A.08-03-015, *Solar Photovoltaic (PV) Program Application*, March 27, 2008, p. 6.
[68] SCE Application A.08-03-015, *Solar Photovoltaic (PV) Program Testimony*, March 27, 2008, p. 44.
[69] SCE Application A.08-03-015, *Solar Photovoltaic (PV) Program Application*, March 27, 2008, pp. 8-9.
[70] Ibid, p. 9.
[71] SCE Application A.08-03-015, *Solar Photovoltaic (PV) Program Testimony*, March 27, 2008, p. 27.
[72] Ibid, p. 6.
[73] CPUC Press Release – Docket A.08-03-015, *CPUC Approves Edison Solar Roof Program*, June 18, 2009.

> emission impacts. By authorizing both utility-owned and private development of these projects we hope to get the best from both types of ownership structures, promoting competition as well as fostering the rapid development of this nascent market."

The CPUC made a similar observation with its approval of the PG&E 500 MW distributed PV project in April 2010:[74]

> 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.

The use of the term smaller scale in the CPUC press release is a misnomer. A 500 MW distributed PV project is the same size as a 500 MW solar thermal project at a remote desert site. Individual rooftop PV arrays in a large distributed PV project are functionally equivalent to single rows of reflective mirrors in a solar thermal project. Each rooftop or row is a contributor to a much bigger whole.

E. Combined Heat and Power (CHP) Basics

CAISO has identified CHP as a mid-to long-range solution to assure grid reliability in the absence of SONGS.[75] Governor Brown calls for 4,000 MW of new CHP by 2020 in his Clean Energy Jobs Plan. CHP, also known as cogeneration, follows energy efficiency and renewable energy in the *Energy Action Plan* loading order.

The key to the high efficiency of a CHP system is conversion of the heat in the hot exhaust gas generated by an engine, turbine, or fuel cell to steam or hot water for use in heating and cooling processes. CHP systems improve efficiency by significantly reducing the total natural gas, biomethane, or biogas consumption that would otherwise be necessary to produce heat or electric power in two separate systems. A schematic of a small CHP system is shown in Figure 11.

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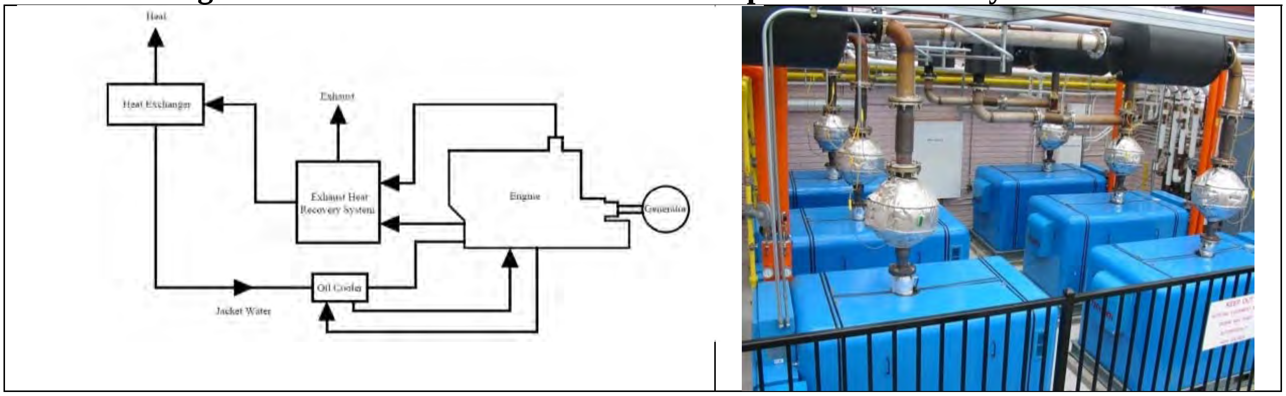
[74] CPUC Press Release – Docket A.09-02-019, *CPUC Approves Solar PV Program for PG&E*, April 22, 2010.
[75] K. Edson - CAISO, PowerPoint presentation to Sierra Club representatives, August 21, 2012, p. 6. "Least regrets solutions balance reliability needs without excessive reliance on load-dropping schemes . . . 5) Explore: increased public building demand response and energy efficiency, and additional energy from existing CHP facilities."

Figure 11. CHP Schematic and Photo of Operational CHP System[76,77]



Typical natural gas-fired electric generators convert from 35 percent, in the case of boilers and peaking gas turbines, to 55 percent, in the case of state-of-the-art baseload combined cycle plants, of the fuel's thermal energy into electricity. Thus 45 to 65 percent of the heating value of the natural gas fuel goes unused and is released into the environment as waste heat. California's older steam boiler power plants and nuclear reactors use many millions of gallons of seawater a day in once-through cooling systems to remove this heat. Wet cooling towers and air-cooled condensers are also used to remove the waste heat.

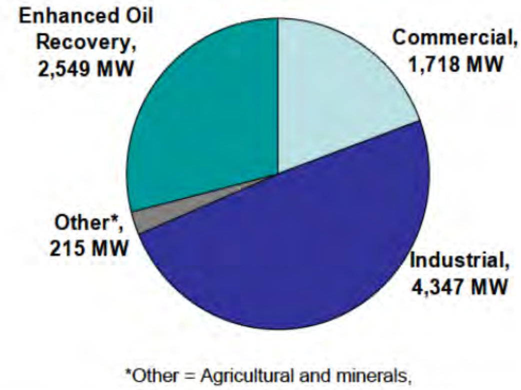
Nearly all of the CHP systems in operation in California use either internal combustion engines or gas turbines, though fuel cells are becoming more common.[78] The heat in the exhaust gas of these combustion units is used to heat the air in buildings, provide hot water or steam, drive a dehumidifier, or drive an absorption chiller to provide refrigeration and cooling. With this large range of uses for the exhaust heat, any building with a significant heating and/or cooling load is a candidate for CHP. CHP systems can achieve overall thermal efficiencies in the range of 80 to 90 percent.

F. CHP in California

There are approximately 8,800 MW of operational CHP plants in California. The market distribution of these plants is shown in Figure 12.

[76] CEC PIER, *Combined Heat and Power Assessment – Final Consultant Report*, prepared by ICF International, April 2010, p. 20.
[77] K. Davidson, *Combined Heat and Power - Carlsbad Chamber of Commerce Sustainability Committee*, PowerPoint presentation, October 3, 2008.
[78] Ibid, p. 10.

Figure 12. Market Distribution of All Classes of CHP in California[79]



The carbon footprint of a baseload natural gas-fired combined cycle plant is approximately 820 lbs. CO_2/MWh.[80] However, California combined cycle plants have a relatively moderate capacity factor on average, approximately 37 percent in 2011, indicative of a "load following" operating pattern that is less fuel efficient than baseload operation.[81]

Operating at partial load significantly reduces the efficiency of the combined cycle plant. The efficiency drops about 10 percent relative to baseload operation when the combined cycle plant is operating at 50 percent load.[82] As a result, a combined cycle unit operating frequently at part load could be expected to have an average CO_2 emission factor in the range of 860 to 900 lb CO_2/ MWh, or about 5 to 10 percent higher than the baseload CO_2 emission rate.

The carbon footprint of a properly designed baseload CHP plant can be as low as 500 lb CO_2/MWh on natural gas.[83] Properly designed in this context means the CHP plant is sized for the minimum thermal load at the site to ensure the plant is always operating at maximum efficiency. Properly designed CHP systems have a substantially lower carbon footprint than state-of-the-art combined cycle power plants. Figure 13 provides a comparison of the carbon footprint of several CHP alternatives to that of a baseload combined cycle power plant.

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[79] CEC PIER, *Combined Heat and Power Assessment – Final Consultant Report*, prepared by ICF International, April 2010.

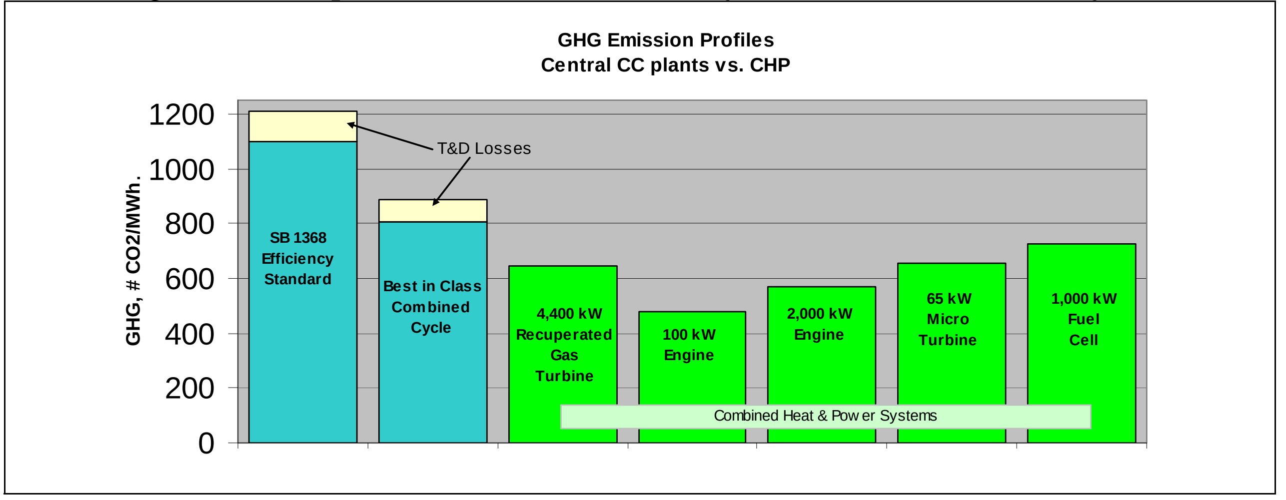
[80] Assumed heat rate of a combined cycle power plant is 7,000 Btu/kWh at baseload (full power) operating conditions. Multiplying by the natural gas CO_2 emission factor gives a CO_2 emission factor for combined cycle of approximately 820 lb CO_2 per MWh.

[81] California Energy Commission, *Comparative Costs of California Central Station Electricity Generation Technologies*, January 2010, Table C-5, p. C-12.

[82] R. Kehlhofer, et al, *Combined Cycle Gas & Steam Turbine Power Plants - 2nd Edition*, Figure 8-3, part load efficiency of GT and CC, p. 211. For example, a combined cycle unit with a baseload "high heating value" heat rate of 7,000 Btu/kWh would have a heat of 7,700 Btu/kWh, a 10 percent increase in fuel consumption on a unit basis, at 50 percent load.

[83] K. Davidson, *Combined Heat and Power - Carlsbad Chamber of Commerce Sustainability Committee*, PowerPoint presentation, October 3, 2008.

Figure 13. Comparison of Thermal Efficiency of CHP and Combined Cycle[84]

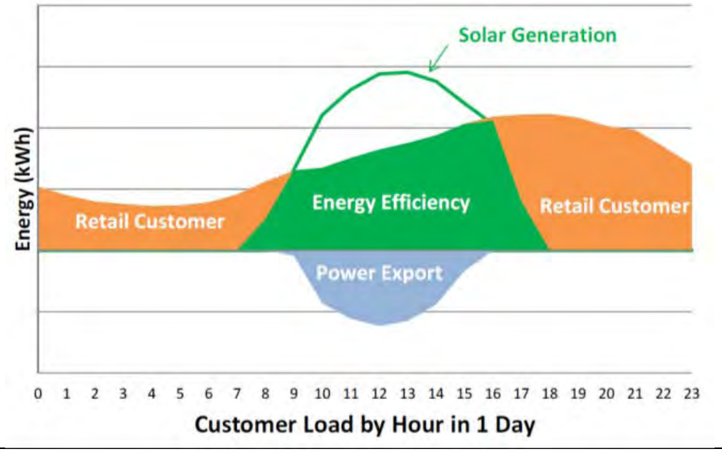


IV. Displacing Nuclear Power with Local Green Power

A. Net Metering ("behind the meter" customer generation)

The overwhelming majority of non-RPS customer-owned PV in California is net-metered. The California *Million Solar Roofs* program will add over 5,000 MW of primarily rooftop PV by the end of 2016 under net-metering.[85] Net metering means the solar generators swap electricity with the utility at retail electricity rates. The solar generator can net meter up to 100 percent of the building's annual electricity demand. Net metering at retail electricity rates is a core financial assumption in advancing zero net energy building retrofits as cost-effective. An example of how net metering works is shown in Figure 14.

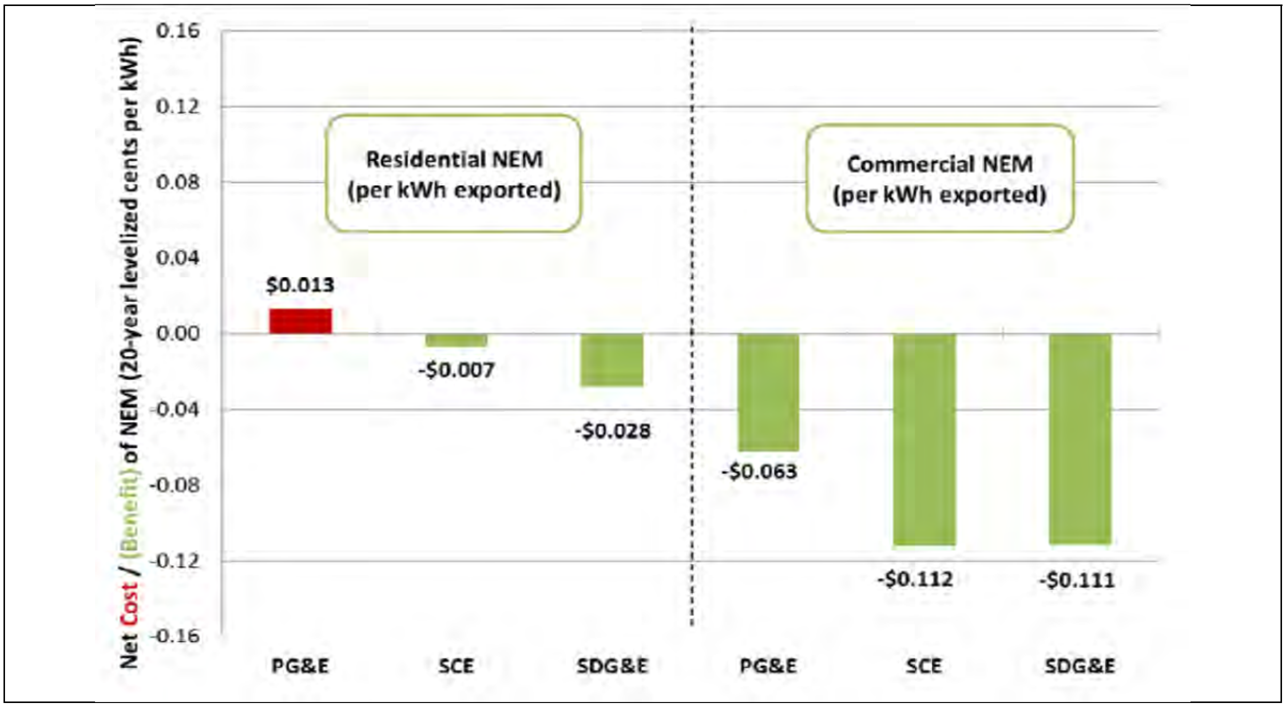
Figure 14. Three Phases of Operation of a Net-Metered PV System[86]



[84] Ibid.
[85] T. Beach – Crossborder Energy, *Evaluating the Benefits and Costs of Net Energy Metering in California*, January 2013, p. 1.
[86] T. Beach, P. McGuire - Crossborder Energy, *Re-evaluating the Cost-Effectiveness of Net Energy Metering in California*, December 20, 2011, Figure 1, p. 3.

Net-metered solar provides a net economic benefit to all IOU ratepayers. Figure 15 illustrates the net economic benefit of net-meter solar in PG&E, SCE, and SDG&E service territories on a kW-hr basis. The net annual economic benefits of net-metered solar capacity to non-participating residential IOU customers of the IOUs will be $2.1 million per year when the 5 percent net-metering cap is reached.

Figure 15. Net Economic Benefit of Net-Metered Solar on Non-Participating IOU Customers[87]



Currently PV installed under net metering does not count directly toward the utility's 33 percent RPS target. However, the green attribute of net-metered solar electricity, the renewable energy credit, may be purchased by PG&E to count toward the 33 percent RPS target as a result of CPUC regulatory action.[88] The tradable renewable energy credit (TREC) program was approved by the CPUC in January 2011.[89] These renewable energy credits are capped at $50 per MWh through 2013.

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[87] T. Beach – Crossborder Energy, *Evaluating the Benefits and Costs of Net Energy Metering in California*, January 2013, Figure ES-1, p. 2.

[88] See: http://www.cpuc.ca.gov/PUC/energy/Renewables/FAQs/05REcertificates.htm. "In D.07-01-018, the CPUC determined that facilities that serve onsite load (e.g. facilities receiving incentives from the California Solar Initiative or Self-Generation Incentive Program) own their RECs. In other words, the facility owner owns the RECs, and they are not transferred to the utility. That means that a facility owner can either make green claims (e.g. "our company is powered by solar") if it retains the RECs, or the owner can seller the RECs so another entity can make green claims. The CPUC does not regulate who the facility owner sells its RECs to."

[89] See: http://docs.cpuc.ca.gov/word_pdf/AGENDA_DECISION/129354.pdf.

B. Community Choice Aggregation

CCAs are in many respects similar to public utilities, in that they generate or purchase electricity supplies that are delivered to customers. However, CCAs rely on the IOUs serving their area to provide transmission and distribution (T&D) service to customers within the CCA. In contrast, an IOU provides both electricity supply and T&D service to its bundled customers.[90]

Three entities have CCAs in operation or under development: Marin County, San Francisco, and Sonoma County. Four valuable contributions a CCA can provide to customers relative to service from IOUs are: lower rates, a higher percentage of renewable energy, more local control of the sources of electricity supply, and the potential for more local economic benefit. Another important indirect contribution is the value of competition in shaping the development strategy pursued by the incumbent IOU. If CCA becomes a readily accessible option for California cities and counties, the investor-owned utilities are more likely to mimic the products and benefits that a CCA would provide in order to avoid further erosion of its customer base.

PG&E spent more than $46 million in 2010 on an unsuccessful effort to pass Proposition 16, "*New Two-Thirds Vote Requirement for Local Public Electricity Providers*."[91] Proposition 16 would have required cities and counties to win the approval of two-thirds of their voters before spending public money to start or join a public power agency. The specific focus of Proposition 16 was to stall the development of CCAs in California.[92]

The Marin Energy Authority launched its CCA program, *Marin Clean Energy*, in May 2010.[93] *Marin Clean Energy* is the state's first operational CCA and has demonstrated that the CCA concept can be successful in California. *Marin Clean Energy* expanded its customer base from 14,000 customers to approximately 100,000 customers in mid-2012, when all of Marin County residents were given the opportunity to participate.[94] In 2013 it is expanding to incorporate 38,000 customers in Richmond. *Marin Clean Energy* offers its customers three options with varying renewable energy content: "Light Green" --50 percent, or "Dark Green" -- 100 percent.

The San Francisco Public Utilities Commission is in the process of launching its CCA program, *CleanEnergySF*, with an initial participation target of 75,000 customers.[95] *CleanEnergySF* will

[90] The term "bundled" means both electricity supply and T&D service are provided to the customer as a package by the IOU. "Unbundled" means the customer independently arranges for electricity supply while continuing to receive T&D service from the IOU. Direct Acess customers are an example of unbundled customers.

[91] San Francisco Chronicle, PG&E's Prop. 16 lost big in its service area, June 10, 2010.

[92] San Francisco Chronicle, Fate of PG&E-backed Prop. 16 too close to call, June 9, 2010.

[93] See Marin Clean Energy website: http://marincleanenergy.info/.

[94] Marin Independent Journal, *Marin Energy Authority gearing up for major expansion*, November 4, 2011. See: http://marincleanenergy.info/images/stories/PDF/Marin_Energy_Authority_gearing_up_for_major_expansion.pdf.

[95] San Francisco Examiner, *San Francisco's public power program goes up against PG&E for residents' dollars*, July 25, 2011. See: http://www.sfexaminer.com/local/2011/07/public-power-program-goes-against-pge-residents-dollars.

offer a single option, 100 percent green energy.[96] Sonoma County has committed to forming a CCA, with an expected launch date in early 2014.[97]

Recent changes to CCA legislation ensure that the CCA may administer at least some of the surcharge "Public Purpose Program" funds collected from CCA customers. These funds have historically been controlled by the IOU. The CCA can now independently determine how these funds will be used to maximize energy efficiency (EE) reductions in the CCA jurisdiction

Two major issues of concern related to the formation of a CCA are: 1) departing load charges, also known as exit fees, levied by PG&E on CCA customers, and 2) the need to post a bond in case the CCA should fail and the customers by default abruptly return to PG&E service.[98]

Departing load charges are assigned to customers that leave PG&E service after PG&E has made financial commitments to build or contract for specific new generation and/or transmission projects. For example, if there were 5 million PG&E customers at the point in time when certain generation and transmission projects were approved, and then 500,000 customers shift to a CCA, the cost of the new projects would have to be recovered from the 4.5 million remaining customers until customer growth replaces the CCA customers.

The exit fee for Marin County CCA customers is currently in the range of $0.005/kWh.[99] The projected bond value for the proposed Sonoma County CCA is in the range of $700,000.[100] No bond value has yet been specified by the CPUC for the San Francisco CCA program, *CleanPowerSF*.[101]

CCAs in California are eligible to administer the public goods charges paid by their customers as a result of the SB 790 CCA legislation approved in 2011, as well as the original CCA law, AB 117 (2002, Migden).[102] If a city or county forms a CCA, the CCA is authorized by law to apply to the CPUC to administer EE funds, which are collected from a special surcharge collected from ratepayers each month. The CCA could administer the public goods funds collected from its customers, but Marin has been forced to fight to get just 13% of the funds collected for EE from its ratepayers.

C. Independent Administration of Energy Efficiency Funds

California's IOUs administer funds collected from ratepayers for energy efficiency programs. In order to persuade the IOUs to promote energy efficiency programs to consumers, the CPUC set up a bonus mechanism designed to reward utility shareholders for efficiency gains and penalize

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[96] CleanPowerSF website: http://cleanpowersf.org/about/.
[97] See Sonoma County Water Agency CCA website: http://www.scwa.ca.gov/cca/.
[98] San Francisco LAFCO meeting on San Francisco CCA, transcript, December 10, 2010. Comments of Michael Campbell, City of San Francisco.
[99] E-mail communication, M. Campbell, *CleanPowerSF* and B. Powers, Powers Engineering, February 27, 2012.
[100] Sonoma County Water Agency, *Report on the Feasibility of Community Choice Aggregation in Sonoma County*, October 2011, p.24. http://www.scwa.ca.gov/files/docs/carbon-free-water//cca/CCA%20Feasibility%20Report%20101211.pdf.
[101] E-mail communication, M. Campbell of *CleanPowerSF* and B. Powers, Powers Engineering, February 27, 2012.
[102] Chaptered version of SB 790, October 8, 2011: http://e-lobbyist.com/gaits/text/354030.

them for failure to meet energy efficiency goals. A comprehensive CPUC staff report released in April 2010 found that from 2006 to 2008, California IOUs did not make enough progress to trigger bonus payments.[103] According to the report, the utilities generally fell into the penalty zone for both peak demand savings and natural gas savings, and into the deadband for energy savings.[104] .[105] Nevertheless, the CPUC awarded them $240 million in bonuses, based on IOU self-reports, which differed from the independent consultants.

The CPUC designed shareholder bonuses as a means to put energy efficiency on an equal footing with IOU investment in natural gas-fired procurement. The concept is to persuade the IOUs to invest in energy efficiency instead of building new natural gas-fired power plants. The IOUs have failed to develop energy efficiency programs that produce long-term energy savings that would offset the need to build more conventional power plants.

The CPUC's Division of Ratepayer Advocates (DRA) is challenging the award of bonuses to the PG&E, SCE, and SDG&E for poor performance on energy efficiency targets. DRA states:[106]

> In addition to the hundreds of millions of dollars in unearned bonuses, the utilities receive billions of dollars to run energy efficiency programs," DRA acting director Como said. "Yet the utilities' energy procurement policies don't demonstrate that these expensive energy efficiency programs actually offset the need to invest in new power plants. If the utilities are allowed to continue on this path ratepayers will likely end up both paying billions for mediocre energy efficiency programs and building more power plants. . . DRA believes California's experiment with a shareholder bonus program to produce energy efficiency gains is fundamentally broken.

In contrast, independent administration of energy efficiency funds takes place in Oregon. Energy Trust of Oregon (Energy Trust) is an independent nonprofit organization dedicated to assisting Oregon IOU ratepayers invest in energy efficiency and renewable energy. Created in response to Oregon legislation and overseen by the Oregon Public Utility Commission (OPUC), Energy Trust began operation in 2002.[107] Energy Trust became the principal administrator of energy efficiency and renewable energy programs for the benefit of ratepayers of Oregon's two largest electric IOUs.[108] Separate agreements with gas utilities address natural gas efficiency programs. Energy Trust has assisted customers of Portland General Electric, Pacific Power, Northwest Natural and Cascade Natural Gas save nearly $600 million in energy costs.[109]

Oregon legislation required the IOUs to collect 3 percent of their electric rates for investments in energy conservation and renewable energy in 1999. OPUC was authorized to direct most of these

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[103] CPUC Energy Division, *2006-2008 Energy Efficiency Evaluation Report – Draft*, April 15, 2010. See: http://www.dra.ca.gov/NR/rdonlyres/07ED3986-1D4F-455B-B3FF-B1AA96482022/0/200608DraftFinalEDEvaluationReport.pdf.
[104] Ibid, Table 23, p. 96.
[105] Ibid, Table 23, p. 96.
[106] CPUC Division of Ratepayer Advocates – press release, *DRA Opposes $40 Million Bonus for PG&E*, November 15, 2010.
[107] Energy Trust of Oregon, *2010-2014 Strategic Plan*, December 18, 2009, p. 1. See: http://energytrust.org/library/plans/2010-14_Strategic_Plan_Approved.pdf
[108] Ibid, p. 3.
[109] Energy Trust of Oregon homepage, March 9, 20111: http://energytrust.org/about/

public goods funds to an independent, non-government entity. Citing economic pressures Oregon IOUs refused to invest in energy efficiency during the 1990s. The OPUC determined the 3 percent ratepayer charge should be managed by an entity devoted exclusively to ratepayer interests in energy conservation and renewable energy.[110]

The Oregon Legislature extended the life of Energy Trust's chief funding mechanism, a public goods charge paid by IOU customers, in 2007. Previously set to sunset in 2012, the fund was extended to 2026. At the same time, Oregon IOUs were authorized to collect supplemental funds for certain electric energy efficiency programs.

Oregon has similar GHG goals as California. The state must begin to reduce GHG emissions in 2010 and achieve GHG levels 10 percent less than 1990 levels by 2020. The long-range goal is to achieve GHG levels 75 percent below 1990 levels by 2050.[111] An independent, non-profit energy efficiency funds administrator is a critical element in Oregon's strategy for achieving GHG reduction targets.

D. Sources of Energy Efficiency Funding

1. "On-Bill Financing" and "On-Bill Repayment"

California IOUs offer limited On-Bill Financing (OFB) programs for energy efficiency projects for commercial customers and government agencies.[112] Utilities have set up a small fund of ratepayer surcharge money for these programs. A new system called On-Bill Repayment (OBR) is now being rolled out by the CPUC.[113] This program relies on outside financing although the utilities provide the billing services to collect the money. CCAs can offer this program and Marin Energy Authority is currently creating their version of it. On bill repayment provides a potentially much larger source of private capital than the limited pot of money available under OBF. A "loan loss reserve" of ratepayer money makes the program more attractive to private lenders. A loan loss reserve would pay the lender if a customer defaults on the loan.

2. Property Assessed Clean Energy – "PACE"

The PACE model was developed by the City of Berkeley in 2007.[114] Under the PACE model, no upfront investment is necessary to finance energy efficiency improvements and rooftop PV. The investment is repaid as property assessments semi-annually with property tax payments over 10 to 20 years. In the event of a transfer of ownership, remaining payments would be made by the new owner because the assessment is tied to the property. This financing approach alleviates concerns about upfront costs and return on investment.

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[110] Ibid, p. 3. Energy Trust invests about 74 percent of the three-percent fund. Another 16 percent goes to low-income housing and weatherization under the oversight of the Department of Housing and Community Services, and 10 percent goes to weatherization in K-12 schools under the direction of educational service districts.
[111] Ibid, p. 4.
[112] PG&E on-bill financing program webpage: http://www.pge.com/obf/.
[113] See CPUC ruling in R.09-11-014 , January 10, 2012, p. 13: http://docs.cpuc.ca.gov/efile/RULINGS/157047.pdf.
[114] www.sustainableindustries.com, *PACE rescue bill could get Republican help*, January 5, 2011.

California PACE legislation, AB 811, was passed into law in 2008. Sixteen states had PACE-enabling legislation in place by March 2010.[115, 116] San Francisco launched a $150 million program in March 2010 and Los Angeles was preparing to unveil its own program.

The Federal Housing and Finance Agency (FHFA), regulator of federal housing corporations Fannie Mae and Freddie Mac, instructed these entities in July 2010 to shut down residential PACE programs.[117] The FHFA objected to PACE because in its view PACE assessments were financial obligations senior to mortgages, meaning they must be repaid first if a borrower defaults.

The FHFA action suspended development of PACE programs, especially residential PACE, in most parts of California and across the country. Sonoma County is the only region in the state that continued financing for energy efficiency and renewable energy retrofits through a PACE program despite the FHFA opinion. Sonoma County avoided the federal action principally because the loans are funded by the county treasury and not private lenders.[118]

Lawsuits have resulted in a formal comment procedure at the FHFA that may lead to resolution of this controversy.[119] Federal legislation has also been proposed to resolve the issue.

The Sonoma County PACE program is known as the *Sonoma County Energy Independence Program*.[120] It has continuously operated PACE programs since 2009. The Sonoma County program is the model for the privately-financed, $100 million commercial PACE program launched in Sacramento in September 2011.[121] San Francisco launched its commercial PACE program, *GreenFinanceSF-Commercial*, in October 2011.[122]

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[115] Pike Research, *PACE Financing Consumer Survey – Consumer Preferences and Attitudes about Property Assessed Clean Energy Financing Programs*, Q1 2011.

[116] Subsequent California PACE legislation, SB 555 (2011), authorizes Mello-Roos community facilities districts to finance renewable energy, energy efficiency, and water efficiency improvements on private property.

[117] FHFA press release, *FHFA Statement on Certain Energy Retrofit Loan Programs*, July 6, 2010: "First liens established by PACE loans are unlike routine tax assessments and pose unusual and difficult risk management challenges for lenders, servicers and mortgage securities investors. The size and duration of PACE loans exceed typical local tax programs and do not have the traditional community benefits associated with taxing initiatives. FHFA urged state and local governments to reconsider these programs and continues to call for a pause in such programs so concerns can be addressed."

[118] California Current, *Advocates Expect Renewables' Remuneration Comeback*, Volume 9, Issue 3, January 21, 2011.

[119] New York Times, *Recent Court Ruling Favors White House-Backed Home Energy Efficiency Program*, September 6, 2011.

[120] See: http://www.sonomacountyenergy.org/.

[121] City of Sacramento, *Sacramento Signs Landmark Agreement to bring $100M, 1,500 jobs to Region*, September 27, 2011. See: http://www.cityofsacramento.org/mayor/documents/PressRelease_PACE_Program062711.pdf.

[122] GreenFinanceSF-Commercial program overview webpage: http://pacenow.org/blog/wp-content/uploads/11-14-11-GFSF-Two-Page-Overview.pdf.

E. Clean Energy Payment (Feed-In Tariff)

A clean energy payment, also known as a feed-in tariff (FIT), is a pre-established fixed long-term price for renewable energy or CHP. The use of fixed "standard offer" prices for renewable energy projects, the core of the FIT concept, is a proven model for assuring the financing of these projects. Thousands of MW of renewable wind, solar, and geothermal projects were built in California in the 1980s as a direct result of the standard offer contract structure that assured some profit for investors. This is the contract structure PG&E used with qualifying facilities.[123] Qualifying facilities are larger CHP plants that produce steam for industrial or commercial use and electric power primarily for export to the IOU, as well as biomass, geothermal, wind, and solar thermal projects.

FITs are set at a fixed price over a long term, generally 20 or 25 years. Price levels vary by technology, reflecting variation in technology costs. The challenge is setting a tariff that assures that system owner some profit while not over-paying. One mechanism used to avoid overpaying is to review payment levels frequently and to reduce levels over time to reflect lower costs.

1. German FIT Program

Germany has the most effective FIT structure in the world. Germany added 7,400 MW_{dc} of solar PV in 2010, 7,500 MW_{dc} in 2011, and 7,600 MW_{dc} in 2012. Germany had installed a cumulative total of about 33,000 MW_{dc} of solar PV by the end of 2012.[124,125] The average size of these installations is approximately 30 kW. Despite higher labor rates, installed PV system costs in Germany are substantially lower than in California.[126]

German wind power capacity reached nearly 25,780 MW_{ac} by the end of 2009.[127] An additional 1,550 MW_{ac} of wind power was added in 2010.[128]

The rapid expansion of solar and wind power in Germany is also more economic than a business-as-usual expansion of natural gas- and coal-fired generation. According to the German Environmental Ministry's guideline scenario, wind energy will reach 108,000 GWh in 2020.[129] The installed capacity of solar PV will reach 53,800 MW in 2020.[130] This PV will generate 47,000 GWh of solar electricity in 2020.

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[123] California Cogeneration Council, *Pre-Workshop Opening Comments of California Cogeneration Council*, June 4, 2004, CPUC R. 04-04-025, Rulemaking to Promote Consistency in Methodology and Input Assumptions in Commission Applications of Short-run and Long-run Avoided Costs, Including Pricing for Qualifying Facilities.
[124] Solar Observer, *German PV installations in 2011 even higher than in record year 2010*, January 10, 2012. See: http://www.solarserver.com/solar-magazine/solar-news/current/2012/kw02/german-pv-installations-in-2011-even-higher-than-in-record-year-2010-3-gw-installed-in-december.html.
[125] Renewables International Magazine, *German power exports to France increasing*, February 6, 2012. "Germany currently has around 25 gigawatts of PV installed."
[126] LBNL, *Why Are Residential PV Prices in Germany So Much Lower Than in the United States? A Scoping Analysis*, September 2012.
[127] Yale Global online, *Germany Leads With Its Goal of 100 Percent Renewable Energy*, September 7, 2010.
[128] German Wind Energy Association, *Annual balance for wind energy installed in 2010*, January 27, 2011. 1,551 MW of wind capacity was installed in Germany in 2010.
[129] DIW Berlin Weekly Report No. 6/2011, *German Electricity Prices: Only Modest Increase Due to Renewable Energy Expected*, March 16, 2011, pp. 40-41. See: www.diw.de.
[130] Ibid.

2. *Developing Effective Clean Energy Payments in California*

The standard offer contracts pioneered in California in the 1980s were the driver behind California's world leadership in wind and solar generation capacity in the 1980s and 1990s. The standard offer payments were fixed over a sufficiently long time horizon to assure the financial viability of the renewable energy projects.

California legislation established FIT pilot programs in 2006 for renewable energy projects with capacities up to 1.5 MW in 2006 (AB 1969) and for CHP projects with capacities up to 20 MW in 2007 (AB 1613). SB 32, passed into law in 2009, is an expansion of the AB 1969 FIT program. It authorizes the construction of up to 750 MW of solar PV, with individual project capacity up to 3 MW.

In a separate program, the CPUC is implementing the renewable auction mechanism (RAM) to establish the price of distributed PV. The concept behind RAM is that PV project proposals will bid against each other and the low bidder will be awarded a contract. In concept this will lead to the lowest cost to the ratepayer. The CPUC approved the RAM program in December 2010.[131] Up to 1,000 MW of PV contracts will be awarded over two years.

The 1,000 MW of PV to be developed under the RAM program will be split proportionately among the state's three IOUs.[132]

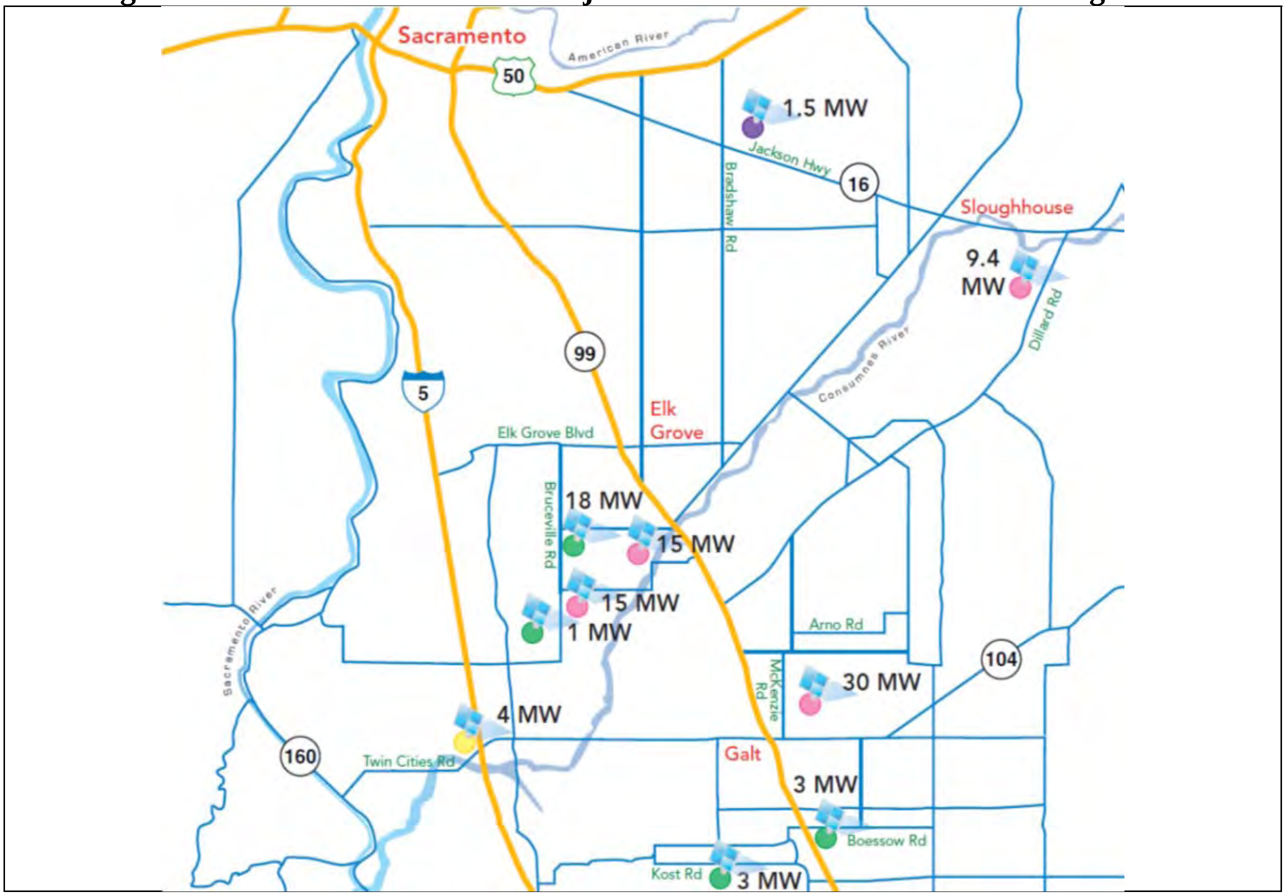
F. California Public Utility Feed-In Tariffs

1. *SMUD 100 MW*

Sacramento Municipal Utility District (SMUD) instituted a 100 MW solar PV FIT program in 2010. The equivalent FIT tariff in 2010 for these projects was $0.136/kWh.[133] All 100 MW of this PV capacity is now built and operational. A map showing locations of PV sites in the greater Sacramento area is provided in Figure 16.

[131] CPUC Decision D.10-12-048, *Decision Adopting the Renewable Auction Mechanism*, December 16, 2010.
[132] Reuters Environmental Forum, *California approves reverse auction renewable energy market*, December 16, 2010.
[133] E-mail communication from O. Bartholomy, SMUD to B. Powers, Powers Engineering, February 4, 2013.

Figure 16. Location of Solar PV Projects Installed Under SMUD FIT Program[134]



2. Palo Alto 4 MW

The Palo Alto public utility, City of Palo Alto Utilities, recently announced a revised 2013 FIT program for commercial rooftop PV, with a system capacity of 100 kW or greater, at a tariff price of $0.165/kWh.[135]

3. LADWP 150 MW

The Los Angeles Department of Water and Power (LADWP) 150 MW FIT pricing program was approved by the LADWP Board of Commissioners on January 11, 2013.[136] The initial phase of the program will consist of five 20 MW rounds. First round pricing is $0.17/kWh and will drop by one cent per kWh each round. 4 MW will be reserved for smaller projects between 30 and 150 kW in each 20 MW increment.

[134] SMUD graphic, Solar PV projects being developed under SMUD's Feed-In Tariff, 2011.
[135] See Palo Alto CLEAN Program webpage: http://www.cityofpaloalto.org/news/displaynews.asp?NewsID=1877&targetid=223.
[136] Renewable Energy World, *All the Details You Missed on LADWP's Feed-in Tariff Program*, January 18, 2013.

V. Conclusions

The extended loss of SONGS has demonstrated that nuclear plants in California are not essential to grid reliability. SONGS is on the edge of the largest urban area in California and provides two important services: 1) 2,150 MW of continuous electricity supply, and 2) local voltage support to assure that the regional transmission system can operate at its potential during periods of heavy demand. Diablo Canyon is located in a more remote area on the Central Coast. Diablo Canyon provides 2,160 MW of continuous supply. The voltage support role of Diablo Canyon is minimal.

The SONGS outage has had no effect on the high level of power supply reserves in Southern California. It has precipitated a series of relatively low-cost remedial measures to assure adequate substitutes for the local voltage support provided by SONGS. The principal reason that the loss of SONGS has had no effect on the reserve margin is that approximately 2,000 MW of additional gas-fired supply came online in the Los Angeles Basin in the first seven months of 2013.

The state's commitment to phasing-out the use of once-through cooling at coastal power plants, combined with the loss of SONGS, has been used by utilities and state energy agencies as the justification for the construction of a new generation of fast response gas-fired capacity. This new capacity will be ten times as costly as the aging, but fully reliable and low cost, once-through cooled steam boiler capacity.

Future demand for these fast response gas-fired units is also being justified by demand growth projections prepared by the CEC and CAISO that are much higher than actual demand growth rates have been in the last 6 to 7 years. In fact, electricity consumption in 2012 was lower than it was in 2008. Peak demand in 2012 was substantially lower than the historic peak in 2006. This reality undercuts any justification for building new utility-scale gas-fired generation based on demand growth projections.

The retirement of SONGS and Diablo Canyon will eliminate about 90 percent of the power plant once-through cooling withdrawals along the California coast, largely achieving the objective of the state's once-through cooling phase-out policy. As a result, more compliance deadline flexibility should be considered for critical coastal boiler plants, or authorization should be granted to allow these plants to recover the cost of cooling tower conversions in rates. These existing gas-fired plants can serve as a bridge for a few additional years if necessary, to allow for a smooth transition to clean power alternatives like battery storage.

The current industry pressure to build more fast start gas-fired generation to meet steep late afternoon ramps in the next few years, due to the late afternoon decline of solar output, is misplaced. California already has many thousands of MW of fast response peaking units that can go from cold start to 100 percent load in 10 minutes or less. Fundamentally the amount of fast response resources needed is equivalent to the error between actual demand and the day-ahead and hour-ahead forecasts. Currently this error margin is on the order of a few hundreds of MW. California already has many times the necessary capacity of fast start gas-fired resources to meet this need.

Finally, the state has a loading order of preferred resources and an established commitment to distributed generation and renewable resources. As the CAISO correctly notes in its description of additional measures to be used to replace the loss of SONGS, demand response and CHP can effectively provide load reduction and voltage support needs. It is standard practice in some countries in the vanguard of renewable energy development, like Germany, to require distributed solar PV resources to be equipped with smart inverters capable of automatically providing appropriate levels of voltage support. This same inverter capability needs to be standard practice in California as well.

Increasing the state's RPS target from 33 percent to 51 percent, as proposed in legislation, would completely displace nuclear output with renewable power output. The proposed IOU energy storage procurement target of 1,300 MW by 2020 is a major step toward displacing nuclear power on a round-the-clock basis with renewable power.

California ISO Peak Load History
1998 through 2011

Year	Megawatts at Peak Load*	Date	Time
1998	44,659	August 12	14:30
1999	45,884	July 12	16:52
2000	43,784	August 16	15:17
2001	41,419	August 7	16:17
2002	42,441	July 10	15:01
2003	42,689	July 17	15:22
2004	45,597	September 8	16:00
2005	45,431	July 20	15:22
2006	50,270	July 24	14:44
2007	48,615	August 31	15:27
2008	46,897	June 20	16:21
2009	46,042	September 3	16:17
2010	47,350	August 25	16:20
2011	45,545	September 7	16:30

* This value is an instantaneous MW value at the time specified in the Time column.

2012	**46,654**	**August 13, 2012, hour ending 5 pm [source: CAISO OASIS database]**