Bay Area Smart Energy 2020

By Bill Powers, P.E.
Powers Engineering

April, 2011

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Bay Area Smart Energy 2020
Executive Summary

By Bill Powers, P.E.
Powers Engineering,
San Diego, California
April, 2011

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Dedicated to the memory of Charles McGlashan

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Forward

Bay Area Smart Energy 2020 is a roadmap to rapid, cost-effective reduction of greenhouse gas emissions from electricity usage in the Bay Area that relies on local resources to achieve the goal. One would think that there should be no need for *Bay Area Smart Energy 2020*. The San Francisco Bay Area is one of the world's leading centers for clean energy innovation and environmental awareness. The region has a long tradition of environmental leadership dating back to John Muir, and the Bay Area is host to hundreds of different environmental and social justice organizations. Yet for all the solutions that are in our backyard, the Bay Area still largely runs on dirty energy.

Silicon Valley is a lightning rod for clean energy innovation, hosting countless companies that are developing cutting-edge technologies in solar, wind, and energy efficiency, along with the software and integration technology to make it all work. Many of these successful and promising companies were nurtured with billions of dollars from local venture capitalists. UC Berkeley and Stanford are leading the way in clean energy research, while our elected leaders regularly enact laws and programs to incentivize a cleaner, greener environment. The concept of "green collar jobs" has caught fire in the Bay Area, thanks to the vision of groups like the Oakland-based Ella Baker Center and local leaders like Van Jones.

However, only 18 percent of the power provided by the Bay Area's major utility, PG&E, could be considered truly clean. The rest comes from natural gas power, nuclear power, coal plants, and large dams. If PG&E stays their current course there may be little change in GHG emissions over time. The company is pushing for several major new fossil fuel power plants in Contra Costa County and the Central Valley. PG&E already has far more power generation reserves than it needs to cover high demand contingencies. According to the California Public Utilities Commission, PG&E will have nearly 70 percent more power reserves than needed in the coming years to meet the highest hour of demand each year.

We know we can do better and the time to act is now. Given all of the good will, talent and resources in our region, we have the tools to create a fully-functioning green energy model. The technology is at hand and continues to become more efficient and cost-effective. By developing local clean energy projects, we will put people to work, reinvigorate our economy, and build a truly healthy and sustainable energy future.

That's why we need *Bay Area Smart Energy 2020*. This report takes a thoughtful look at all of the pieces of the Bay Area energy puzzle, and builds a solid, forward-thinking plan for the future from this mix. If we can indeed implement the concrete recommendations in *Bay Area Smart Energy 2020*, we will clean the air, mitigate climate change and dramatically reduce greenhouse gas emissions. Our local clean energy success will then be one more triumph to add to the long list of achievements that make Bay Area residents proud to live here.

For a Clean Energy Future,

Francesca Vietor
Interim Environment Program Officer, The San Francisco Foundation

Bill Powers, P.E., Biography

Mr. Powers is a registered professional mechanical engineer in California with over 25 years of experience in the energy and environmental fields. He is the author of the 2007 strategic energy plan, "San Diego Smart Energy 2020," for the San Diego region. The plan uses California's Energy Action Plan as the template for accelerated introduction of local distributed renewable and combined heat and power resources to reduce greenhouse gas emissions from power generation in the San Diego region by 50 percent by 2020. Mr. Powers served as an expert witness in a landmark California Energy Commission (CEC) proceeding where the CEC determined urban solar photovoltaics could potentially serve as a cost-effective alternative to conventional gas turbine peaking power. He has written numerous articles on the strategic cost and reliability advantages of local renewable energy over large-scale, remote, transmission-dependent renewable resources.

Mr. Powers began his career converting Navy and Marine Corps shore installation power plants from oil-firing to domestic waste, including woodwaste, municipal solid waste, and coal, in response to concerns over the availability of imported oil following the Arab oil embargo. He has permitted numerous peaking gas turbine, microturbine, and internal combustion engine cogeneration plants in California. Mr. Powers organized the first U.S. conference focused exclusively on dry cooling systems for power plants in 2002. Mr. Powers currently serves on the San Diego Environmental and Economic Sustainability Task Force. The mission of the task force is to produce a Climate Mitigation and Adaptation Plan for San Diego. Mr. Powers has a B.S. in mechanical engineering from Duke University and an M.P.H. in environmental sciences from the University of North Carolina – Chapel Hill.

Table of Contents

Chapter Page

1. Executive Summary 1
   1.1 BASE 2020 Sources of Energy 3
      1.1.1 Solar PV 3
      1.1.2 Combined Heat and Power (CHP) 3
      1.1.3 Geothermal 4
      1.1.4 Wind 4
      1.1.5 Energy Storage 4
      1.1.6 Solar Hot Water 5
   1.2 Energy Efficiency and Peak Demand Reduction 6
      1.2.1 Energy Efficiency 6
      1.2.2 Air Conditioning 6
   1.3 Independent Management of Clean Energy Programs 8
   1.4 Displacement of Fossil Fuel Generation by BASE 2020 9
   1.5 Mitigating Ratepayer Impacts 10
   1.6 Financing 11
   1.7 Public Power and Community Choice Aggregation 12
   1.8 GHG Reductions Achieved by BASE 2020 12

2. Introduction 15
   2.1 California's Energy Strategy 15
   2.2 Deregulation to the Present 16
   2.3 Reality of State Energy Policy 18

3. Bay Area Energy – The Players 19
   3.1 Geographic Scope of BASE 2020 19
   3.2 Electricity Demand in PG&E Service Territory 20
   3.3 Electricity Demand in Bay Area Counties 21
   3.4 Existing Generation Resources in the Bay Area 24
   3.5 Bay Area Electricity Providers 26
      3.5.1 Bay Area Publicly-Owned Utilities (POUs) 26
      3.5.2 San Francisco Public Utilities Commission (SFPUC) 27
      3.5.3 Alameda Municipal Power (AMP) 28
      3.5.4 Silicon Valley Power (SVP) 28
      3.5.5 City of Palo Alto Utilities (CPAU) 29
   3.6 Comparison of POU and PG&E Rates 30
   3.7 Community Choice Aggregation in PG&E Territory 31
   3.8 Investor-Owned Utility Business Model 33
   3.9 Role of the California Independent System Operator 34
   3.10 PG&E History and Overview 40
      3.10.1 Deregulation and 2000 – 2001 Energy Crisis 40
      3.10.2 Post-Energy Crisis 41

Table of Contents (cont.)

Chapter Page

3.11 PG&E Electricity Supply 43
3.12 PG&E Power Generation Sources and Contracted Supplies 43
3.13 Conclusions and Recommendations 47

4. PG&E Strategic Plan 48
4.1 Compliance with Energy Action Plan Loading Order 48
4.2 PG&E Renewable Energy Strategy 51
4.3 Conclusions and Recommendations 52

5. BASE 2020 Plan 48
5.1 Bay Area CO_2 Emissions from Electricity Usage in 2020 Without BASE 2020 50
5.2 CO_2 Reductions Achieved with BASE 2020 52
5.3 Conclusions and Recommendations 54

6. Comparative Capital Cost and Cost-of-Energy of Generation Technologies 55

7. Peak Demand Profile and Solar and Wind Profiles 60
7.1 Summer and Winter Output Profiles of PV Systems 61
7.2 Annual and Summer Day Output – Solano County Wind 61
7.3 Value of Electric Power Varies Depending on Time of Day 62
7.4 Highest Peak Loads Drop Off Rapidly in California 63
7.5 PV Resource Very Reliable During Summer Peak Load Events 64
7.6 Distributed PV Systems on Partly Cloudy Days 66
7.7 Back-Up Turbines for Wind Power – $25 to $55/MWh of Additional Cost 67
7.8 Distributed PV Meets Same Peak Ramping Function as Peaking Turbine 68
7.9 Conclusions and Recommendations 69

8. California's Strategy - Energy Efficiency and Rooftop PV 70
8.1 Profile of Residential and Commercial Electricity Demand 72
8.2 Tools Available to Achieve Energy Efficiency Reductions 73
8.2.1 Building Standards 73
8.2.2 Lighting 74
8.2.3 Refrigerator/Freezer 74
8.2.4 Air Conditioning 74
8.2.5 PG&E Energy Efficiency Rebate Programs 75
8.3 PG&E Energy Efficiency Programs Not Meeting Targets 79
8.4 Independent Administration of Energy Efficiency Funds 80
8.5 Property Assessed Clean Energy - PACE 81
8.6 Meeting California's Energy Efficiency Targets 82
8.7 Conclusions and Recommendations 85

Table of Contents (cont.)

Chapter Page

9. Demand Response - Reducing Peak Demand 86
9.1 Potential of Demand Response 86
9.2 PG&E Demand Response Programs 87
9.3 Conclusions and Recommendations 88

10. Integrating Distributed Generation (DG) Into the Grid 89
10.1 PV Capacity of Existing Distribution System 91
10.2 Cost to Upgrade Distribution System to Maximize Distributed PV 93
10.3 IOUs Positive about Distributed PV When They Will Own It 94
10.4 Conclusions and Recommendations 96

11. Bay Area PV Technical Potential 97
11.1 Potential of Rooftops, Parking Lots, Substations 97
11.2 Existing Distributed PV Programs 100
11.3 Detailed Inventories of Commercial PV Potential 100
11.4 Conclusions and Recommendations 101

12. Combined Heat and Power (CHP) 102
12.1 CHP Basics 102
12.2 CHP in California 103
12.3 4,000 MW of New CHP by 2020 – 840 MW in Bay Area 104
12.4 CHP Case Study - San Francisco 105
12.5 How CHP Fits in DG Strategy 107
12.6 Obstacles to Increasing CHP Use in Bay Area 107
12.7 CHP Fuel Options 109
12.8 State CHP Incentive Programs 110
12.9 Conclusions and Recommendations 111

13. DG Energy Payments – The Price Is Right 112
13.1 Cost of New Natural Gas-Fired Plants 114
13.2 Reference Price for Renewable Generation 114
13.3 Calculating What Distributed PV Is Worth 115
13.4 Calculating What CHP Is Worth 117
13.5 Merit Order Benefits of Distributed Energy 118
13.6 Availability of Solar and Wind at Peak Demand 120
13.7 Concept of FIT 121
13.7.1 Overview 121
13.7.2 German FIT Program 121
13.7.3 Ontario FIT Program 122
13.7.4 Financial Drivers Behind U.S. Renewable Energy Development 122
13.7.5 Developing Effective FITs in California 122

Table of Contents (cont.)

Chapter Page

13.8 Solar PV FIT - Lower Than PG&E's Avoided Cost 124
13.9 CHP FIT - Lower Than PG&E's Avoided Cost..... 128
13.10 Fuel Cell CHP 128
13.11 Conclusions and Recommendations..... 130
13.11.1 Conclusions..... 130
13.11.2 Recommendations..... 130

14. The Geysers Geothermal Power – Making It Sustainable 132
14.1 Evolution of The Geysers Geothermal Resource..... 133
14.2 Micro-Earthquakes at The Geysers..... 134
14.3 Achieving Sustainable Operation of The Geysers 134
14.4 Tragedy of the Commons 136
14.5 Cooling System Retrofits Could Add Inexpensive Geothermal Power 137
14.6 Conclusions and Recommendations..... 138

15. Energy Storage 139
15.1 Overview of Energy Storage Technologies..... 139
15.2 Economic Benefits of Energy Storage as Peaking Capacity 141
15.3 Electricity Demands of Electric Vehicles 142
15.4 400 MW of Battery Storage Integrated with Solano County Wind..... 142
15.5 200 MW of Battery Storage Integrated with Distributed PV..... 142
15.6 Conclusions and Recommendations..... 144

16. Solar Water Heating 145
16.1 Solar Hot Water Heating..... 145
16.2 Solar Space Heating 147
16.3 Solar and Geothermal Heat Pumps 148
16.4 Merit Order Cost Benefits of Natural Gas Reduction 149
16.5 Conclusions and Recommendations..... 149

17. Wind Power in the Bay Area 150
17.1 Altamont Pass and Montezuma Hills..... 150
17.2 Conclusions and Recommendations..... 151

18. Principal Conclusions..... 152

19. References..... 153

List of Tables

Page

Table 1-1. Total Bay Area GHG Emissions from Electricity Consumption in 2008 12
Table 1-2. CO_2 Reduction Achieved by Implementing BASE 2020 13
Table 1-3. Bay Area Peak Load Reduction Achieved by Implementing BASE 2020..... 13

Table 2-1. Energy Action Plan Loading Order 15

Table 3-1. PG&E Annual and Average Electricity Demand Trends..... 20
Table 3-2. 2000 – 2009 Electricity Consumption (GWh) in Nine Bay Area Counties..... 21
Table 3-3. 2000 – 2009 Population Growth in the Nine Bay Area Counties..... 22
Table 3-4. Type and Quantity (MW) of Existing Generation in the Bay Area..... 25
Table 3-5. Publicly-Owned Utilities in the Nine Bay Area Counties 26
Table 3-6. Comparison of Commercial Rates: PG&E, AMP, CPAU, and SVP..... 30
Table 3-7. California IOU Transmission Investment Compared to Electricity Demand Growth, 1999 – 2009..... 35
Table 3-8. Description and Status of PG&E Gas-Fired Power Purchase Agreements Approved by CPUC in 2006..... 41
Table 3-9. Top Fifty In-State Generation Sources Supplying Electricity to PG&E in 2008..... 44

Table 4-1. Status of Fast Track Solar Projects on BLM Land..... 51

Table 5-1. Total Bay Area CO_2 Emissions from Electricity Consumption in 2008..... 51
Table 5-2. CO_2 Reduction Achieved by Implementing BASE 2020 53
Table 5-3. Bay Area Peak Load Reduction Achieved by Implementing BASE 2020..... 53

Table 6-1. Comparative Capital Cost and Levelized Cost-of-Energy (LCOE) of Representative Generation Technologies..... 55

Table 7-1. Summer 2007 Peak Hour Solar Resource Availability in Bay Area..... 64
Table 7-2. LCOE of New Peaking Gas Turbines 67

Table 8-1. Steps to Receive Energy Efficiency Rebate through PG&E eRebates Program 76
Table 8-2. Hierarchy of Energy Savings Targets and Associated Financial Returns..... 79
Table 8-3. Targets in California's Energy Efficiency Strategic Plan 82
Table 8-4. BASE 2020 Targets - Purchased Electricity Reductions from Energy Efficiency Measures and Distributed PV if Applied Statewide..... 83
Table 8-5. Allocation of Statewide PV and Energy Efficiency Reductions in PG&E Planning Area and Bay Area..... 84
Table 8-6. Conversion of PV Energy Production (GWh) to PV Capacity (MW) 84

Table 10-1. Calculation of Distributed PV Interconnection Capacity to Existing IOU Substations with Minimal Interconnection Cost..... 92

List of Tables (cont.)

Page

Table 11-1. Estimate of Rooftop and Parking Lot PV Potential in Bay Area 97
Table 11-2. Assumptions Used to Estimate PV Potential of Parking Lots – San Francisco 98
Table 11-3. RETI Estimate of Rural Substation PV Potential in Bay Area 99
Table 11-4. Current Status of California Distributed PV Programs 100
Table 11-5. Estimate of Distributed PV Capacity to be Located in Bay Area 100

Table 12-1. Estimate of New CHP Installed in Each Bay Area County to Achieve 840 MW of New CHP by 2020 105
Table 12-2. Additional CHP Potential in San Francisco 106
Table 12-3. CHP Potential from Wastewater and Co-Digestion of Other Bio-Wastes 109

Table 13-1. Effect of Capacity Factor on LCOE from New Combined Cycle Plant 116
Table 13-2. Energy Efficiency T&D Avoided Costs in PG&E Divisions in the Bay Area 116
Table 13-3. Comparison of Peak Demand Capacity Factors for Solar and Wind 120
Table 13-4. PV FIT Categories, First Year Tariff, and Capacity Allocation 125
Table 13-5. PV FIT Decline Rate Over 10 Years of Program 125
Table 13-6. Revised PV FIT to Reduce Overall Program Cost 126
Table 13-7. SGIP Incentive Payments for Fuel Cells, Energy Storage, and Wind Turbines 128

Table 15-1. Three Categories of Energy Storage 139

Table 17-1. Actual and Planned Wind Projects in Montezuma Hills 151
Table 17-2. List of Potential Wind Sites Identified by RETI in Bay Area 151

List of Figures

Page

Figure 3-1. Map of PG&E Service Territory and Nine Bay Area Counties 19
Figure 3-2. PG&E System Peak Demand (MW): 2006 – 2012 20
Figure 3-3. Bay Area 2000 – 2009 Electricity Demand Trend (GWh) 21
Figure 3-4. Bay Area 2000 – 2009 Population Growth Trend 22
Figure 3-5. Exiting Generation Resources in the Nine Bay Area Counties 24
Figure 3-6. San Francisco Hydroelectric Generation Facilities and Transmission Lines 27
Figure 3-7. AMP Electricity Supply Sources 28
Figure 3-8. 400 MW Trans Bay Cable 36
Figure 3-9. New Transmission Additions for IOU 33 Percent Reference Case Scenario 36
Figure 3-10. 24-Hour PG&E Load Profile for August 25, 2010 39
Figure 3-11. PG&E Sources of Electricity in 2008 and 2009 43

Figure 4-1. CEC Projection of PG&E Distributed PV and CHP Additions, 2010 – 2020 49

Figure 7-1. Power Mix Stack to Meet California Peak Load 60
Figure 7-2. Summer 24-Hour Demand Profile in California and Sources of Demand 60
Figure 7-3. Output Profiles of PV Systems in July and December 61
Figure 7-4. Annual and Summer Day Output of Wind Power in Solano County 61
Figure 7-5. Solar PV Profile on the PG&E System (June through September) 62
Figure 7-6. CAISO Load-Duration Curves for Top 100 Hours of Year, 2006 - 2010 63
Figure 7-7. Multiple PV Sites Smooth Aggregate PV Output on Partly Cloudy Days 66

Figure 8-1. Graphical Representation of Net Zero Energy Concept 72
Figure 8-2. Profiles of California Residential and Commercial Electricity Demand 72
Figure 8-3. Projected Absolute Decline in California Electricity Demand if All Cost-Effective Energy Efficiency Is Achieved 75
Figure 8-4. Bay Area Climate Zones Map 77

Figure 9-1. Use of Critical Peak Pricing (CPP) to Reduce Demand on Peak Days 87

Figure 10-1. Distribution Substation, Feeders, and DG Sources 89
Figure 10-2. Two-Way Distribution System for DG Environment 90
Figure 10-3. IOU Substation Peak Loads and 30 Percent of Peak Load 92

Figure 11-1. Inventory of San Diego Commercial Rooftop PV Potential – Classification of Rooftops 101

Figure 12-1. CHP Schematic and Photo of Operational CHP System 102
Figure 12-2. Market Distribution of All Classes of CHP in California 103
Figure 12-3. Market Distribution of Industrial and Commercial CHP in California 103
Figure 12-4. Comparison of Thermal Efficiency of CHP and Combined Cycle 104
Figure 12-5. NRG San Francisco Energy Center and Downtown San Francisco Steam Loop 106
Figure 12-6. Tecogen 100 kW In Verde CHP 108

List of Figures (cont.)

Page

Figure 13-1. Merit Order Effect of DG Renewable Energy on Market Price of Electricity..... 119
Figure 13-2. German Renewable Energy Ownership Distribution 121
Figure 13-3. Comparison of Installed Cost of U.S. and German 5 kW Residential PV..... 127
Figure 13-4. DOE 2010 Cost of Distributed Utility-Scale and Commercial Rooftop PV..... 127
Figure 13-5. California Utility Retail Rates and 50 to 500 kW CHP Cost of Electricity 128

Figure 14-1. The Geysers Geothermal Resource Area..... 132
Figure 14-2. NCPA Plant No. 1..... 133
Figure 14-3. Parallel Wet-Dry Cooling System 135
Figure 14-4. Representative Parallel Wet-Dry Cooling System Performance 135

Figure 15-1. Range of Capabilities of Different Energy Storage Technologies 140
Figure 15-2. 34 MW Sodium-Sulfur Battery Storage System Supporting 51 MW Japanese Wind Farm 140

Figure 16-1. Profiles of California Statewide and Residential Natural Gas Demand 145
Figure 16-2. Solar Water Heating Systems Have Largest Potential for Reduction of Natural Gas Use in California Homes..... 146
Figure 16-3. Solar Hot Water Capacity by Country 146
Figure 16-4. Trend in German Hot Water Heater Installations 147
Figure 16-5. Absorption Heat Pump 148

Figure 17-1. Utility-Scale Wind Sites in Bay Area Identified in RETI Process..... 150

Appendices

Page

A. BASE 2020 Terminology A-1

B. 2000 – 2009 Population Growth in PG&E Service Territory B-1

C. Bay Area Substation Map and County Maps with Generation Sources C-1

D. Map Showing Location of Bay Area POUs D-1

E. Comparison of Bay Area Actual and Potential Solar Irradiance During 2007 Peak Demand Hours E-1

F. Graphic of Peak Demand Reduction Achieved by Thermal Storage Air Conditioning Systems F-1

G. Description of Natural Gas Savings from 60 kW CHP Project in Richmond, California G-1

H. Calculation of Net Capital Cost of Commercial PV System after Federal Tax Benefits H-1

I. Description of SolarWall™ Air Heating at NREL Research Support Facility I-1

1. Executive Summary

Bay Area Smart Energy 2020 (BASE 2020) is a distributed generation (DG) strategy for minimizing greenhouse gas (GHG) emissions from electricity usage in the nine counties surrounding San Francisco Bay. It prioritizes energy efficiency, rooftop and distributed solar photovoltaics (PV) of all types, and combined heat and power (CHP) over conventional power plants to meet the San Francisco Bay Area's electricity needs. The framework of BASE 2020 is California's strategic energy vision, embodied in the *Energy Action Plan* and the *Energy Efficiency Strategic Plan*.

BASE 2020 is a straightforward and cost-effective strategy, using proven off-the-shelf technologies and policies. Rigorous application of BASE 2020 will achieve a reduction of over 70 percent in GHG emissions from electricity usage by 2020 in the Bay Area relative to a 2008 baseline year. BASE 2020 would also lower utility costs for Bay Area ratepayers over a "business as usual" case. The proposed feed-in tariffs (FIT) for PV and CHP in BASE 2020 would begin at a cost 14 to 20 percent below the projected cost of the natural gas power these cleaner sources will replace.

Energy efficiency measures will reduce Bay Area electricity demand by over 17,000 gigawatt-hours (GWh) per year from the 2008 baseline of 57,316 GWh under BASE 2020. This represents an average energy efficiency reduction of 25 to 30 percent in residential, commercial, and industrial buildings.

The peak demand met by Bay Area utilities will decline by about two-thirds, from approximately 14,000 megawatts (MW) today to 5,000 MW in 2020, as energy efficiency, state-of-the-art air conditioning and chiller systems, local PV, CHP, and battery storage displace grid power.

A framework objective of BASE 2020 is achieving net zero energy buildings, both existing and new, following the timeline established in the California *Energy Efficiency Strategic Plan*. This plan uses a combination of energy efficiency measures and rooftop PV to achieve net zero energy buildings. Nearly 4,000 MW of local PV will be in use in the Bay Area by 2020 to achieve net zero energy in 25 percent of Bay Area homes and commercial buildings.

840 MW of new CHP will also be added in the Bay Area, using a fuel mix consisting of at least 50 percent biomethane or biogas. 300 MW of additional geothermal capacity will be added at the The Geysers in Sonoma County through cooling system upgrades. 300 MW of planned wind additions in Solano County are incorporated into BASE 2020. Finally, 400 MW of battery storage is integrated with the Solano County wind production area, and 200 MW of distributed battery storage is integrated with residential and commercial PV systems to offset the new load represented by plug-in hybrid electric vehicles (PHEVs).

California's *Energy Efficiency Strategic Plan* and BASE 2020 rely on local distributed PV to achieve net zero energy buildings. In contrast, Pacific Gas & Electric (PG&E) is currently relying primarily on remote utility-scale solar plants to meet Renewable Portfolio Standard (RPS) targets.[1] PG&E is the predominant electricity and natural gas provider in the Bay Area.

PG&E's renewable energy strategy needs to be brought into alignment with the state's *Energy Efficiency Strategic Plan* and BASE 2020. This will require shifting the focus from utility-scale remote renewable energy projects to rooftop and distributed PV. Local distributed PV would become the primary form of solar energy developed to meet the Bay Area's renewable energy needs. Local solar could be supplemented by utility-scale renewable energy projects that are economic relative to local PV and are located on sites with little or no environmental impact. Contaminated brownfields are one example of such sites.

1.1 BASE 2020 Sources of Energy

1.1.1 Solar PV

The Bay Area will displace nearly 8,000 GWh per year of electricity purchases through the installation of nearly 4,000 MW of rooftop PV. The addition of this amount of PV represents the quantity of PV necessary for 25 percent of existing Bay Area residential and commercial buildings to achieve net zero energy by 2020.[2]

The *California Solar Initiative*, also known as "Million Solar Roofs," will add 3,000 MW of primarily rooftop PV by the end of 2016. About 550 MW of this capacity will be added in the Bay Area. However, PV installed under this program does not count toward the utility's RPS targets. This creates a disincentive for PG&E to pursue rooftop PV as a substantive component of its renewable energy strategy.

PG&E's RPS program is producing some results, but at great cost to PG&E's ratepayers in the Bay Area. The California Public Utilities Commission (CPUC) Division of Ratepayer Advocates reports that recent renewable energy contracts signed by PG&E and California's other investor-owned utilities (IOUs) will incur $6 billion in additional costs above the baseline market reference price if they are built. PG&E has signed 77 percent of its power purchase contracts at prices above the market reference price. This price is set by the CPUC and is based on the cost of electricity produced by a baseload natural gas-fired combined cycle power plant.

Desert solar thermal projects, a core element of PG&E's RPS strategic plan, are approximately 50 percent more expensive than distributed PV projects that do not require new transmission. Transmission is expensive. The cost of new transmission lines to reach remote solar and wind sites could sum to $15 billion if the RPS compliance strategy being pursued by the IOUs is followed.

Conclusions/Recommendations:

- All forms of distributed PV, including *California Solar Initiative* rooftop PV, must be RPS-eligible.
- The avoided cost to PG&E of PV systems in the Bay Area ranges from $0.22 to $0.23 per kilowatt-hour ($/kWh). Any price paid for PV below $0.22 to $0.23/kWh would benefit all PG&E ratepayers by providing electricity at a lower cost than PG&E would charge, including time-of-use, line losses, and transmission and distribution (T&D) costs, if PG&E was supplying the same electricity.
- The state should adopt a composite tariff for PV of $0.19/kWh in 2011. The tariff assumes commercial rooftop PV will supply about half of total capacity, followed by larger ground-mounted systems, and residential rooftop PV. The composite tariff would decline to $0.13/kWh in 2020. The justification for this tariff is provided in Chapter 13.

1.1.2 Combined Heat and Power (CHP)

CHP refers to facilities that use a small gas turbine, engine, or fuel cell to generate both electricity and useful heat. They are commonly found powering college campuses and hospitals.

BASE 2020 adopts the *Assembly Bill 32 (AB 32) Scoping Plan* target of 4,000 MW of new CHP by 2020. This will result in approximately 840 MW of new CHP in the Bay Area by 2020. The fuel composition target for CHP in BASE 2020 is 50 percent biogas or biomethane, combined with natural gas, to reduce

the GHG footprint of new CHP to approximately 300 lb CO_2/MWh. This is less than half the GHG footprint of a state-of-the-art base load combined cycle plant.

Conclusions/Recommendations**:**

- The avoided cost to PG&E of CHP in the Bay Area ranges from $0.18 to $0.20/kWh. Any tariff paid to CHP operators below $0.18 to $0.20/kWh would benefit all PG&E ratepayers.

- The state should adopt a tariff for CHP of $0.15/kWh. This tariff would be adjusted over time to account for effects of inflation. The justification for this tariff is provided in Chapter 13.

1.1.3 Geothermal

Retrofits of existing geothermal plants at The Geysers with parallel wet-dry cooling systems are included in the scope of $_{BASE}$ 2020 to increase sustainable output from the current 900 MW to 1,200 MW, a 300 MW increase. These retrofits could potentially produce the lowest cost renewable energy in the state and would improve the sustainability of the geothermal resource.

Conclusions/Recommendations:

- The Governor's Office should commission an independent evaluation of the cost and benefits of retrofitting existing geothermal plants at The Geysers with parallel wet-dry cooling systems to increase sustainable output at The Geysers from the current 900 MW to 1,200 MW.

1.1.4 Wind

300 MW of new wind projects already planned for Solano County are incorporated into BASE 2020.

1.1.5 Energy Storage

400 MW of sodium-sulfide battery storage will be integrated to the Solano County wind production area to provide 400 MW of peaking power and to smooth output from the wind generators. 200 MW of battery storage will also be added to residential and commercial Bay Area buildings to offset the projected growth in peak demand of PHEVs over the next decade.

Conclusions/Recommendations:

- Energy storage is a good match for the high summertime output of Solano County wind farms. The Governor's Office should commission an independent study of the economic and grid reliability benefits of integrating 400 MW of sodium-sulfide battery storage with the Solano County wind farms.

- 200 MW of distributed battery storage should be added at the PHEV point-of-charge to assure that the strategic objective of net zero energy buildings is met even as PHEV loads are added to buildings.

1.1.6 Solar Hot Water

Solar hot water heating is a cost-effective and relatively untapped natural gas demand reduction measure. An analysis conducted of solar water heating natural gas savings potential in California determined a potential reduction of approximately 120 billion cubic feet of natural gas per year, about 20 days of natural gas supply for California. This is about 5 percent of the yearly statewide consumption of natural gas.

The *Solar Hot Water and Efficiency Act of 2007* authorized a ten-year incentive program for solar water heaters with a goal of promoting the installation of 200,000 systems in California by 2017. This is an average installation rate statewide of 20,000 systems per year. PG&E has over 5 million residential and commercial customers. Germany has achieved 200,000 solar hot water system installations in one year.

Conclusions/Recommendations:

- The state's current solar hot water program must grow to hundreds of thousands of installations per year over the next decade if solar hot water systems are to put significant downward pressure on residential and commercial natural gas consumption.
- The solar hot water target for the Bay Area should be 200,000 systems per year by 2020.

1.2 Energy Efficiency and Peak Demand Reduction

1.2.1 Energy Efficiency

The *Energy Efficiency Strategic Plan* target of 25 percent of residences reaching 70 percent reduction in electricity usage by 2020 is modified in BASE 2020 to 25 percent of residences achieving 100 percent reduction in electricity usage by 2020. The *Energy Efficiency Strategic Plan* target of 50 percent of existing commercial buildings reaching net zero energy by 2030 is expanded in BASE 2020 to establish a target of 25 percent of commercial buildings reaching net zero energy by 2020. The net effect of achieving these targets will be a 30 percent reduction in electricity demand in the Bay Area compared to the baseline year of 2008.

1.2.2 Air Conditioning

Air conditioning is a major source of peak energy demand in the Bay Area. The CPUC estimates air conditioning loads are responsible for more than 30 percent of the peak load in summer. BASE 2020 adopts the *Energy Efficiency Strategic Plan* target of a 50 percent reduction in air conditioning loads by 2020. Achieving this peak demand reduction target will reduce Bay Area peak load by over 2,000 MW.

Central air conditioning units have an average age of just over 10 years. About 50 percent of current central air conditioning units in the Bay Area will be due for replacement over the next 10 years. Incentive funds should be paid at the contractor level to cover the cost difference between a minimum efficiency unit and a state-of-the-art unit. This would mean that the net price of the most efficient unit offered by all heating and ventilation contractors to consumers in the Bay Area is the same as less efficient units. This will ensure that all new units are high efficiency units. Assuming each replacement on average reduces unit electricity consumption by 50 percent, and half the existing units are replaced due to natural attrition in ten years, the electricity consumption of the entire population of central air conditioning units in the Bay Area will drop about 25 percent over the next decade.

Adding cycling capability to all new central air conditioning units at the point of sale would provide the ability to reduce the instantaneous electricity demand from this population of air conditioners by an additional 50 percent, as half these units would be in off mode at any given time while the other half are operational.

Conclusions/Recommendations:

- Achieving the energy efficiency targets in BASE 2020 will reduce electricity demand in the Bay Area by approximately 30 percent in 2020 compared to the 2008 baseline year.
- Air conditioning loads are responsible for at least 30 percent of summer peak loads.

- Incentive funds should be used to cover the cost difference between a minimum efficiency central air conditioning unit and a state-of-the-art unit at the contractor level. This will ensure that all new units are high efficiency units, reducing demand in the units that are replaced by about 50 percent on average.

- Adding cycling capability to all new central air conditioning units at the point of sale would provide the ability to reduce the instantaneous electricity demand from this population of air conditioners by an additional 50 percent.

1.3 Independent Management of Clean Energy Programs

PG&E's actions on energy efficiency, distributed PV, and CHP indicate the company is not the appropriate entity to oversee these programs going forward. PG&E's energy efficiency program is not meeting minimum targets established by the CPUC. In contrast, an independent non-profit organization, the Energy Trust of Oregon, controls public goods funds collected by the Oregon IOUs for electricity and natural gas efficiency measures and administers programs that maximize efficiency gains. The Energy Trust of Oregon is well regarded by Oregon stakeholders as effective.

PG&E is challenging efforts by the CPUC to establish a CHP tariff that is sufficient to assure financing for CHP projects. PG&E also asserts, in challenging a recently approved CPUC distributed PV program - the Renewable Auction Mechanism (RAM) - that it is under no obligation to go beyond a 20 percent RPS target or to pay more than the established baseline renewable energy price, known as the market price referent, when contracting for distributed PV. These actions indicate that PG&E should have no substantive role in overseeing the development of non-PG&E owned distributed PV or CHP projects in its service territory.

Conclusions/Recommendations:

- PG&E should not be administering public goods funds for energy efficiency measures. An independent non-profit organization, similar to the Energy Trust of Oregon, should be put in place to administer these public goods funds. If a city or county forms a Community Choice Aggregator (CCA), the CCA should administer the public goods funds collected from CCA customers.

- PG&E should not administer distributed PV tariffs or RAM programs, or CHP tariff programs. An entity independent of PG&E should serve this function.

- California's Department of Water Resources (DWR) has administered power contracts imposed on California IOUs since 2001. DWR could serve as the state government entity that sets FIT rates for PV and CHP, purchases the energy at set rates, and requires each IOU to purchase a specific amount of these resources.

1.4 Displacement of Fossil Fuel Generation by BASE 2020

A significant source of PG&E's GHG emissions is imported coal power purchased on the wholesale power market and identified as "unspecified" in the 2009 PG&E power mix. These imported power purchases include a substantial coal power component and will be ramped-down over the next decade and replaced in BASE 2020 with baseload CHP, geothermal, and an integrated wind power/battery storage project in Solano County.

The second source of PG&E coal power purchases is long-term contracts with a few California coal-fired cogeneration plants. These contracts need to be phased-out over the next decade and replaced with the same clean baseload resources to be used to displace PG&E imported power purchases.

PG&E is proposing to contract for over 2,000 MW of new natural gas-fired gas turbine plants to be built in the Bay Area over the next few years. This is despite historically high electricity reserve margins and no growth in peak demand.

A primary justification for these new turbines, offered by PG&E and the California Independent System Operator, is the need to back-up solar and wind resources.

A second justification offered is the need to retire once-through cooled steam boiler plants in the Bay Area. PG&E has identified only two once-through cooled steam boiler units in its service territory, Pittsburg 5 and 6 at 325 MW each, as necessary for Bay Area grid reliability. The new gas turbines, in the case of the proposed 760 MW Marsh Landing project, would be less efficient than the existing Pittsburg 5 and 6 steam boilers. See the discussion of this issue in Chapter 3.

The bulk of the costs associated with the construction and operation of these natural gas-fired plants, approximately $600 million per year over 20 years, will be borne by PG&E ratepayers.

Conclusions/Recommendations:

- Four new gas turbine power plants planned for the Bay Area have long-term power purchase contracts with PG&E but have not yet begun construction. Actual reserve margins in 2009 and 2010 were 44 percent and 38 percent respectively. Peak demand in 2010 was significantly less than peak demand in 2006. Peak loads will steadily decline if BASE 2020 is implemented.

- Solar PV is completely reliable on hot summer afternoons when peak loads occur in the Bay Area. See the analysis of Bay Area solar resource availability during summer peak hours in Chapter 7. There is no reliability need to build peaking gas turbines to back-up PV.

The cost of retrofitting wet cooling towers on Pittsburg 5 and 6 to eliminate the marine impacts of once-through cooling would be about $125 million. This is one-tenth the cost of 650 MW of new gas turbine capacity.

- The first ten years of the $600 million per year of PG&E ratepayer funds that will be committed to four new gas turbine power plants in the Bay Area would be sufficient to pay for much of the 4,000 MW of local PV in BASE 2020. These gas turbine plants are unnecessary and should not be built.

1.5 Mitigating Ratepayer Impacts

The reduction of demand for PG&E-supplied electricity and natural gas, achieved through energy efficiency measures and the addition of PV, CHP, geothermal, and wind, also reduces the price of electricity and natural gas in wholesale energy markets. This is known as the "merit order effect." It reduces the cost of electricity and natural gas for all ratepayers.

The merit order effect of DG in Germany, an electricity market two times the size of the California market, reduced the wholesale electricity price to German customers by approximately $5 billion in 2009.

PG&E buys a significant amount of electricity and natural gas from wholesale markets. The market price benefits of reduced demand caused by energy efficiency measures and local clean energy will substantially outweigh the transaction costs, especially interconnection costs, that currently hamper or prevent the deployment of local PV and CHP projects.

Conclusions/Recommendations:

- The merit order benefit of distributed PV and CHP on wholesale electricity prices is substantially greater than the transaction costs, especially interconnection costs, imposed by PG&E on distributed PV and CHP developers. These transaction costs should be absorbed by PG&E ratepayers as the net economic benefit to all PG&E customers of having these PV and CHP systems online substantially outweighs the transaction costs.
- This same merit order benefit applies to natural gas demand reduction realized by use of CHP, solar hot water heating, and substitution of biomethane or biogas for pipeline natural gas. Payments for these technologies and fuels must incorporate the value of the merit order benefit to assure that the deployment of technologies and fuels that are bringing net price benefits to all natural gas consumers are not inappropriately constrained by inadequate incentive budgets.
- The Governor's Office should commission an independent verification of the merit order effect of the energy efficiency and DG targets in BASE 2020 on the wholesale market price of electricity. The results of this independent verification would serve as the basis for increasing funding for energy efficiency and demand response programs and for shifting all DG transaction costs, including interconnection costs, to PG&E ratepayers.
- The Governor's Office should commission a similar independent verification of the merit order effect of the BASE 2020 targets for solar hot water heating and natural gas substitution with biogas and biomethane on the wholesale market price of natural gas. The results would serve as the basis for increasing incentives for solar hot water systems and biogas and biomethane fuel production.

1.6 Financing

There are demonstrated-in-practice financing mechanisms available to make a fast transition to clean power. Germany is the gold standard in this regard with its successful FIT. This type of financing is also known as a CLEAN (Clean Local Energy Accessible Now) contract in California. Germany is about the same geographic size as California. Many nations, and the province of Ontario in Canada, have followed Germany's lead. As a direct result of this tariff structure, approximately 6,500 MW_{ac} of predominantly rooftop PV was installed in Germany 2010. Total PV capacity in Germany at the end of 2010 was about 14,000 MW_{ac}.

California also has FITs for PV and CHP. However, these FITs have not been successful in getting projects built due to inadequate pricing.

BASE 2020 uses FITs to achieve rooftop PV and CHP installation targets. The composite FIT for PV begins at $0.19/kWh in 2011 and declines to $0.13/kWh in 2020. The 2011 tariff is significantly less than the all-in cost to PG&E of about $0.22/kWh to provide the same power. The all-in cost of power provided by PG&E is expected to rise to about $0.30/kWh by 2020. The CHP FIT begins at $0.15/kWh and is adjusted annually for inflation.

Berkeley pioneered an innovative, no upfront cost funding mechanism where the city provides low-interest loans to property owners to finance energy efficiency improvements and rooftop PV installations. The loan repayments are added to their annual property tax bills. AB 811, *Property Assessed Clean Energy* (PACE), was passed into law in California in 2008 to make this financing mechanism available statewide. Resistance by federally-backed mortgage companies Fannie Mae and Freddie Mac has temporarily suspended development of PACE programs in the state and across the country. PACE programs offer a financially painless mechanism for homeowners and business owners to achieve net zero energy consumption in existing residential and commercial buildings.

Conclusions/Recommendations:

- The state should adopt the FITs proposed in BASE 2020 for PV and CHP.
- The Federal Energy Regulatory Commission (FERC) has acknowledged that a state requirement that IOUs purchase electricity from a state-owned corporation at specified rates would not be preempted by FERC's authority over wholesale power sales. Adopting this approach would provide a bridge over complex CPUC FIT proceedings that have consistently resulted in tariffs that are too low to get either PV or CHP projects built.
- Revival of PACE programs in the Bay Area is necessary to create a dynamic alternative route for achieving the goals of BASE 2020 that requires little intervention by local or state government to make rapid strides in energy efficiency and rooftop PV.

1.7 Public Power and Community Choice Aggregation

The cost of electric service provided by Bay Area publicly-owned utilities (POUs) is consistently at least 10 to 20 percent lower than equivalent service from PG&E. Some of the Bay Area POUs, most notably Alameda Municipal Power, are achieving substantially higher levels of renewable energy sales than PG&E. Two of the Bay Area POUs, Silicon Valley Power and City of Palo Alto Utilities, offer customers 100 percent renewable energy service at less cost than the standard PG&E tariff for equivalent service.

CCA offers a market competition alternative for Bay Area cities and counties currently served by PG&E. CCAs are public entities that provide electricity supply to customers while PG&E continues to provide T&D services to these same customers. The Marin Energy Authority is the first operational CCA in the Bay Area. San Francisco is pursuing a CCA. However, CCA formation is currently cumbersome and expensive. Legislative improvements to the current CCA model are necessary for this alternative to be viable for a greater number of cities and counties in the Bay Area.

Conclusions/Recommendations:

- CCA formation is currently cumbersome and expensive. Legislative improvements to the current CCA model are necessary for this alternative to be viable for a greater number of cities and counties in the Bay Area.

1.8 GHG Reductions Achieved by BASE 2020

Achieving BASE 2020 targets would result in a reduction of over 70 percent in Bay Area GHG emissions from electricity usage by 2020.

Table 1-1 summarizes estimated 2008 GHG emissions from electricity usage in the Bay Area. The term GHG is used interchangeably with carbon dioxide (CO_2) in BASE 2020.

Table 1-1. Total Bay Area GHG Emissions from Electricity Consumption in 2008

Source	GWh[3]	CO_2 emission factor (tons/MWh)	2008 PG&E CO_2 emissions (million tons)	Bay Area fraction	2008 Bay Area CO_2 emissions (million tons)
PG&E bundled customers	81,983	0.27	22	0.6	13
PG&E Direct Access customers	6,376	0.48	3	0.6	2
Bay Area POUs	5,327	0.27	NA	1.0	1
		PG&E total:	25	Bay Area total:	16

Table 1-2 summarizes the actions to be taken in BASE 2020 to reduce GHG emissions and the GHG reductions achieved. Net GHG emissions from electricity usage would decline from 16 million tons per year in 2008 to 4.5 million tons per year in 2020, a reduction of over 70 percent.

Table 1-2. CO_2 Reduction Achieved by Implementing BASE 2020

Source of CO_2 reduction	Quantity of reduction (GWh)	CO_2 emissions (million tons)	Fuel type displaced	Avoided CO_2 emissions (million tons)	Net CO_2 reduction (million tons)
Energy efficiency	9,760	0	natural gas	4.4	4.4
Rooftop PV	7,279	0	natural gas	3.3	3.3
CHP	6,770	1	imported gas/coal	3.3	2.3
New geothermal	2,234	0	imported gas/coal	1.1	1.1
New wind with energy storage	867	0	imported gas/coal	0.4	0.4
Total reduction:	26,910				11.5

The Bay Area peak load reductions on PG&E and Bay Area POU systems that would occur as a result of BASE 2020 are shown in Table 1-3. Electricity purchased from Bay Area utilities

Table 1-3. Bay Area Peak Load Reduction Achieved by Implementing BASE 2020

Source of reduction	Basis of reduction (MW)	Peak load reduction (MW)
Energy efficiency[4]	25 percent reduction in demand on average from energy efficiency measures	3,500
Air conditioner/ chiller plant efficiency improvement	Cooling load represents about 30 percent of peak load. Highest efficiency central air conditioning (CAC) units replace worn-out units, 50 percent reduction. 50 percent reduction targeted for commercial building chiller plants. Cycling capability built into new CAC units to allow 50 percent online, 50 percent offline at peak. Assumes 50 percent turnover in CAC population in 10 years.	2,100
Rooftop PV	3,800 MW_{ac} of rooftop PV added over ten years. 50 percent of this capability, 1,900 MW_{ac}, is available at peak.	1,900
Battery storage associated with rooftop PV	200 MW of battery storage integrated with PV systems added over decade to offset peak demand of plug-in electric vehicles and provide peak power to grid. Assumes 100 MW contributed at peak with integrated PV systems providing other 100 MW (50 percent of PV MW_{ac} capacity at peak).	100
CHP	840 MW of CHP is added to Bay Area, removing equivalent amount of load from utility demand at peak.	840
Geothermal	300 MW of geothermal is added at The Geysers, removing equivalent amount of load from utility demand at peak.	300
Wind with energy storage	400 MW of sodium-sulfide battery storage integrated with Solano County wind development area.	400
Total Bay Area peak load reduction:		9,140

would decline at peak from about 14,000 MW in 2008 to approximately 5,000 MW in 2020. About 60 percent of the peak load decline would result from energy efficiency measures in general combined with more efficient central air conditioner and chiller plant performance and management.[5] The remaining peak reduction would be demand met by rooftop PV, CHP, geothermal, wind, and energy storage.

2. Introduction

"There's an ongoing schizophrenia in state policy between what we say we want to do and what we actually allow to happen" - former California Energy Commission (CEC) Commissioner John Geesman[6]

2.1 California's Energy Strategy

The *Energy Action Plan* establishes the electricity resource priority list, or loading order, that defines how California's energy needs are to be met. *Energy Action Plan I* was published in May 2003.[7] The CEC and the California Public Utilities Commission (CPUC) developed the *Energy Action Plan* to guide strategic energy planning in California. The loading order is summarized in Table 2-1.

Table 2-1. Energy Action Plan Loading Order

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

The Plan is explicit that rooftop PV is an element of energy efficiency standards for new buildings. *Energy Action Plan I* states, "Incorporate distributed generation or renewable technologies into energy efficiency standards for new building construction."

The CEC's December 2009 *Integrated Energy Policy Report* (IEPR) underscores the integration of building PV as a critical component of net zero energy use targets for new residential and commercial construction, explaining:[8]

> "With the focus on reducing GHG emissions in the electricity sector, energy efficiency takes center stage as a zero emissions strategy. One of the primary strategies to reduce GHG emissions through energy efficiency is the concept of zero net energy buildings. In the 2007 IEPR, the Energy Commission recommended increasing the efficiency standards for buildings so that, when combined with on-site generation, newly constructed buildings could be zero net energy by 2020 for residences and by 2030 for commercial buildings.
>
> A zero net energy building merges highly energy efficient building construction and state-of-the-art appliances and lighting systems to reduce a building's load and peak requirements and includes on-site renewable energy such as solar PV to meet remaining energy needs. The result is a grid-connected building that draws energy from, and feeds surplus energy to, the grid. The goal is for the building to use net zero energy over the year."

Rooftop distributed PV is an integral component of California's *Energy Efficiency Strategy Plan* originally adopted by the CPUC in September 2008 and updated in January 2011.[9] Rooftop solar can be added rapidly. Germany, which is approximately the same size as California and has about double the electricity demand, about 6,500 MW_{ac} of distributed PV in the 2010.[10] Over four-fifths of this capacity is rooftop PV.[11]

2.2 Deregulation to the Present

California experimented with electricity deregulation in the 1996 – 2003 timeframe. The investor-owned utilities (IOUs) were required to sell-off most of their generation assets, with the principal exception of the Diablo Canyon and San Onofre nuclear plants, and become "wires only" transmission and distribution (T&D) companies. Electricity was purchased by the IOUs on the open market for residential and commercial customers. Larger commercial and industrial customers were permitted to bypass the IOUs and purchase electricity directly from third party energy service providers. These customers are known as Direct Access customers.

Extensive market manipulation in 2000 – 2001 resulted in huge price spikes, blackouts, and an end to deregulation. The state signed high cost, long-term contracts with numerous electricity generators in 2001 to end the immediate crisis. These contracts are administered by the Department of Water Resources (DWR). Many of these contracts will expire in 2011 and 2012.

Responsibility for long-term planning was returned to the IOUs in 2003. What has emerged in the intervening years is a hybrid market consisting IOU-owned generation and third party generation.[12] One complicating factor of this hybrid approach is that customers interested in departing the IOU are subject to substantial departing load charges to cover the cost of new IOU power plants or new long-term supply contracts between the IOU and third parties.

Community Choice Aggregator (CCA) legislation granting California cities and counties the option to provide electricity supply within their political jurisdiction was passed in 2002. The IOU remains responsible for T&D in the CCA framework. The Marin Energy Authority (MEA) is the first operational CCA in California. San Francisco is actively pursuing development of a CCA.

IOUs provide approximately 65 percent of the retail electricity consumed in California. Statewide publicly-owned utilities (POUs) provide approximately 25 percent.[13] POUs in the Bay Area include City of Healdsburg, Port of Oakland, Alameda Municipal Power (AMP), Silicon Valley Power (SVP), City of Palo Alto Utilities (CPAU), San Francisco Public Utilities Commission (SFPUC), and Bay Area Rapid Transit. Direct Access electricity providers, such as Constellation NewEnergy, Calpine PowerAmerica, and Shell Energy, supply the remaining 10 percent.

Legislation setting a RPS of 20 percent of retail electricity sales by 2017 was established in 2002. In 2006, the target date was accelerated to 2010. Governor Schwarzenegger signed an executive order in 2008 setting a new RPS target of 33 percent by 2020. The California legislature passed a RPS bill in 2009 that would have revised the RPS target to 33 percent by 2020, but it was vetoed by Governor Schwarzenegger due to concerns about the limits placed on the use of out-of-state renewable generation.[14] The legislature failed to pass a bill in the 2010 legislative session. The legislation was re-introduced in December 2010 and signed into law on April 12, 2011.[15]

The IOUs have almost exclusively proposed remote utility-scale renewable energy projects to achieve the 33 percent by 2020 RPS target. Many of these projects are large-scale desert solar installations that have generated controversy over impacts to undeveloped public lands.

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

The California Air Resources Board (CARB) is the lead agency tasked with implementing AB 32. The December 2008 *AB 32 Scoping Plan* developed by CARB proposed the following targets related to energy: 1) reduce demand by 32,000 GWh via energy efficiency measures, 2) add 4,000 MW of CHP to displace 30,000 GWh of conventional generation, 3) reduce natural gas consumption by 800 million therms via energy efficiency measures, 4) add 200,000 solar hot water heaters in compliance with AB 1470, 5) achieve 33 percent RPS by 2020, 6) achieve one million solar roofs, 3,000 MW, by 2017, and 7) implement a CO_2 cap-and-trade program.[16]

The *AB 32 Scoping Plan* also states that "zero energy new and existing buildings can be an overarching and unifying concept for energy efficiency in buildings."[17] The CPUC's *Energy Efficiency Strategic Plan* focuses on achieving net zero energy consumption in residential and commercial buildings through efficiency measures and use of rooftop solar.[18]

Bay Area cities have been leaders in building efficiency. San Francisco adopted the *Green Building Ordinance* for new buildings in 2008.[19] Berkeley for over two decades has had residential and commercial building ordinances requiring basic efficiency improvements, triggered at the time of property sale or significant renovations.[20]

Berkeley pioneered an innovative, no upfront cost funding mechanism where the city provides low-interest loans to property owners to finance energy efficiency improvements and rooftop solar installations, with long-term repayments added to their annual property tax bills. AB 811, *Property Assessed Clean Energy* (PACE), passed into law in California in 2008, made this financing mechanism available statewide.

Resistance by federally-backed mortgage companies Fannie Mae and Freddie Mac has temporarily suspended development of PACE programs in the state and across the country. Then-Attorney General Jerry Brown sued Fannie Mae and Freddie Mac over their rejection of PACE assessments in July 2010.[21] The lawsuit is ongoing. PACE programs offer a mechanism for homeowners and business owners to achieve net zero energy consumption without spending money upfront.

Governor Jerry Brown proposes through his *Clean Energy Jobs Plan* that a majority of the new renewable energy resources to be built in the state by 2020, 12,000 MW of total of 20,000 MW, be local renewable power.[22] Approximately 3,000 MW of energy storage would be added to the grid to meet peak demand and support renewable energy generation.[23] The *Clean Energy Jobs Plan* also calls for the addition of 6,500 MW of new CHP over the next 20 years and a substantial improvement in the energy efficiency of new and existing buildings.

2.3 Reality of State Energy Policy

The California *Energy Action Plan* forms the framework of BASE 2020. On paper, support for the *Energy Action Plan* is unanimous. Fidelity to the *Energy Action Plan* is stated in virtually every state energy agency planning document and every application by the state's IOUs for conventional infrastructure projects, including natural gas-fired generation and new transmission.

However, the *Energy Action Plan* is not law and is not legally binding on the IOUs. No fundamental redesign of IOU financial incentives accompanied development of the *Energy Action Plan*. For the last century that IOU model has remained relatively unchanged – sole source supplier of vertically integrated electricity generation, transmission, and distribution services.

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

Today, the IOUs continue to build and contract for utility-scale natural gas fired plants and remote utility-scale solar and wind plants, and the transmission lines necessary to reach them, while extolling the virtues of energy efficiency, rooftop PV, and CHP. The reality is that energy efficiency measures, and onsite generation owned by customers in the form of solar panels on the roof or CHP, undercut the justification for an IOU to build more infrastructure.

The primary obstacle to achieving the targets in BASE 2020 is the current form of the IOU business model. PG&E and other California IOUs have missed energy efficiency targets and resisted programs intended to expand usage of distributed PV and CHP. BASE 2020 would shift administration of EE programs from PG&E to an independent, non-profit entity. BASE 2020 also includes an option to shift administration of distributed PV and CHP programs away from PG&E if FIT proceedings at the CPUC continue to produce tariffs that are too low to get distributed PV and CHP built in the Bay Area.

3. Bay Area Energy – The Players

3.1 Geographic Scope of BASE 2020

BASE 2020 addresses the nine counties surrounding San Francisco Bay. These counties include Alameda, Contra Costa, Marin, Napa, San Francisco, San Mateo, Santa Clara, Solano, and Sonoma. The location of the nine Bay Area counties within PG&E service territory is shown in Figure 3-1.

Figure 3-1. Map of PG&E Service Territory and Nine Bay Area Counties[24]

3.2 Electricity Demand in PG&E Service Territory

Electric power demand is measured in two ways for resource planning purposes: 1) total electric energy usage over the course of a year, and 2) peak power demand during hot summertime conditions. Annual energy usage is analogous to the total gallons of fuel used by an automobile over the course of a year. Peak power demand is analogous to the maximum horsepower required of the automobile when it is fully loaded and must maintain a high rate of speed while driving up a hill. Electricity planning in California is largely guided by peak power demand.

Table 3-1 shows the current trend in annual and hourly energy consumption in PG&E service territory. There was a significant dip in demand in 2009 relative to 2008. The primary reason for this reduction in demand was the economic slowdown that began in late 2008.

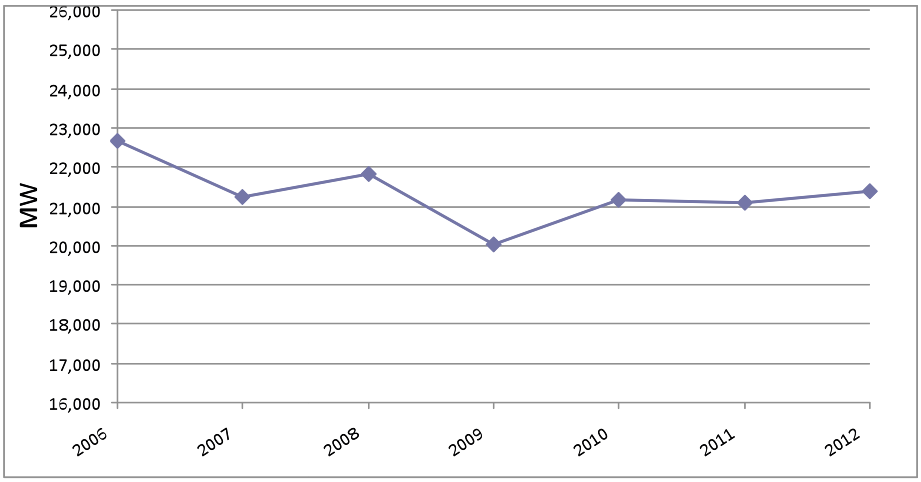
Table 3-1. PG&E Annual and Average Electricity Demand Trends[25]

Demand type	2008	2009
Annual energy demand in PG&E service territory, GWh per year	88,359	85,459
Average hourly demand in PG&E service territory, MW	10,087	9,756

The highest peak one-hour electricity demand in PG&E service territory, 22,650 MW, occurred in 2006.[26] This peak took place during a record-setting heat storm in California. PG&E estimates that the temperature conditions that led to this peak demand represented a 1-in-30 to 1-in-40 year occurrence.[27] Peak demand is primarily associated with heavy usage of air conditioning systems on hot summer afternoons.

The peak demand trend over the 2006-2012 period in PG&E service territory is shown in Figure 3-2. The peak forecast in 2012 is about 1,500 MW below the actual 2006 peak. PG&E had ample resources to meet the record peak load in 2006 without dropping below the minimum Western Electricity Coordinating Council operating reserves requirement of 6 to 7 percent.[28] A substantial number of gas turbine peaker units are located in the region. More are proposed for construction in the Bay Area, despite the demonstrated ability of PG&E to meet substantially higher peak demand with the resources available to it in 2006.

Figure 3-2. PG&E System Peak Demand (MW): 2006 – 2012[29,30]



3.3 Electricity Demand in Bay Area Counties

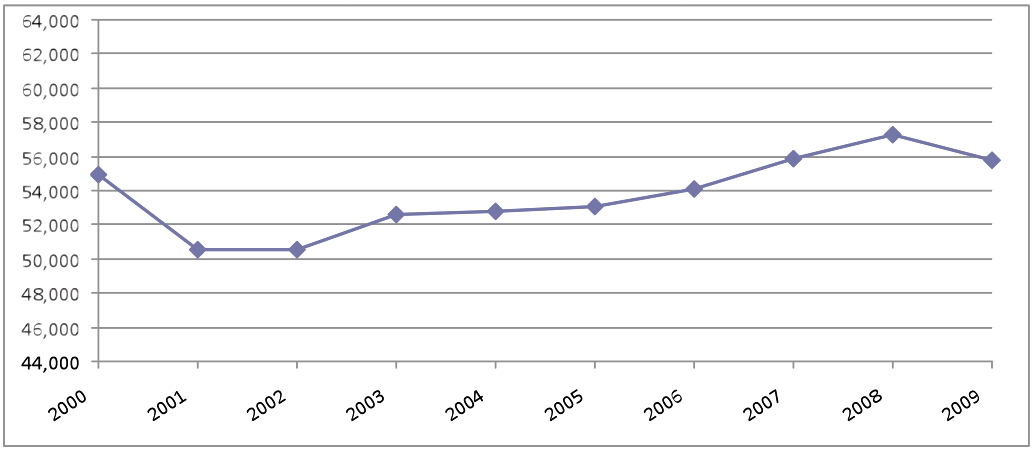
Collectively these nine counties account for approximately half of the electricity demand in the PG&E planning area. 2009 electricity consumption in the Bay Area counties was 55,817 GWh as shown in Table 3-2.[31] The total consumption in the PG&E planning area was 106,531 GWh in 2009.[32] The PG&E planning area includes all POUs in PG&E service territory except Sacramento Municipal Utility District (SMUD).

Table 3-2. 2000 – 2009 Electricity Consumption (GWh) in Nine Bay Area Counties

County	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	Annual Growth (%)
Alameda	10,488	9,948	10,305	10,642	10,577	10,921	11,098	11,864	11,682	11,535	1.0
Contra Costa	8,849	8,455	8,438	8,600	8,496	8,422	8,511	8,606	9,014	8,660	-0.2
Marin	1,486	1,347	1,399	1,373	1,418	1,392	1,412	1,407	1,482	1,482	0.0
Napa	937	849	885	912	931	932	962	957	1,038	1,006	0.7
San Francisco	5,522	5,346	5,407	5,220	5,242	5,711	5,515	5,586	5,694	5,550	0.1
San Mateo	4,943	4,137	4,133	4,742	4,824	4,511	4,629	4,917	5,116	4,961	0.0
Santa Clara	16,667	15,150	14,383	15,343	15,441	15,396	16,025	16,387	17,088	16,559	-0.1
Solano	3,108	2,717	2,828	3,004	3,035	3,045	3,090	3,317	3,232	3,210	0.3
Sonoma	2,890	2,586	2,735	2,758	2,863	2,756	2,842	2,847	2,970	2,853	-0.1
Total	54,890	50,535	50,513	52,593	52,828	53,085	54,082	55,887	57,316	55,817	0.2

The average annual electricity demand growth in the Bay Area in the 2000 to 2009 time period was 0.2 percent per year. The Bay Area electricity demand growth trend is shown in Figure 3-3.

Figure 3-3. Bay Area 2000 – 2009 Electricity Demand Trend (GWh)



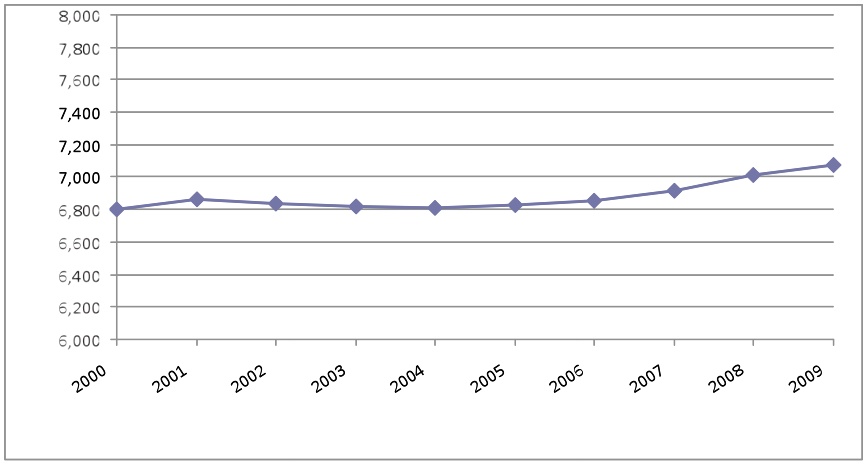
Population in the nine Bay Area counties grew at an average annual rate of 0.4 percent per year from 2000 through 2009.[33] The population data for each Bay Area county is provided in Table 3-3.

Table 3-3. 2000 – 2009 Population Growth in the Nine Bay Area Counties

County	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	Annual Growth (%)
Alameda	1,450	1,469	1,460	1,451	1,441	1,436	1,438	1,448	1,467	1,480	0.2
Contra Costa	953	971	980	988	993	1,000	1,002	1,010	1,025	1,036	0.9
Marin	248	248	246	245	244	244	244	246	248	249	0.0
Napa	125	127	128	130	130	130	130	131	133	134	0.8
San Francisco	777	784	778	773	771	775	783	796	805	810	0.4
San Mateo	708	707	699	695	693	693	694	699	709	714	0.1
Santa Clara	1,686	1,691	1,673	1,668	1,670	1,684	1,701	1,725	1,756	1,771	0.5
Solano	397	404	408	408	408	406	405	405	406	411	0.3
Sonoma	460	464	463	463	463	461	459	460	465	470	0.2
Total	6,805	6,864	6,836	6,821	6,812	6,828	6,857	6,920	7,013	7,074	0.4

A graphical presentation of Bay Area population growth from 2000 through 2009 is provided in Figure 3-4.

Figure 3-4. Bay Area 2000 – 2009 Population Growth Trend



PG&E projected an annual growth in peak electricity demand of 2.1 to 2.7 percent per year for the 2007-2016 timeframe in its *2006 Long-Term Procurement Plan*.[34] A peak demand growth rate of 1.7 percent per year was projected by the CEC over the same period.[35] The CEC projects a peak demand growth rate of 1.3 percent per year in its California electricity demand forecast for the 2010 to 2020 period published in December 2009.[36] An aging population is the primary reason cited by the CEC for a lower population growth rate in 2010 – 2020 compared to the previous decade and therefore a lower peak electricity demand growth rate.[37]

The U.S. Census population growth rate for counties in PG&E service territory for the period 2000 – 2009 was 0.9 percent.[38,39] The 2000 – 2009 population growth by county in PG&E territory is provided in Appendix B. As noted, the Bay Area population growth rate during the same period was 0.4 percent, and the electricity demand growth rate was 0.2 percent.

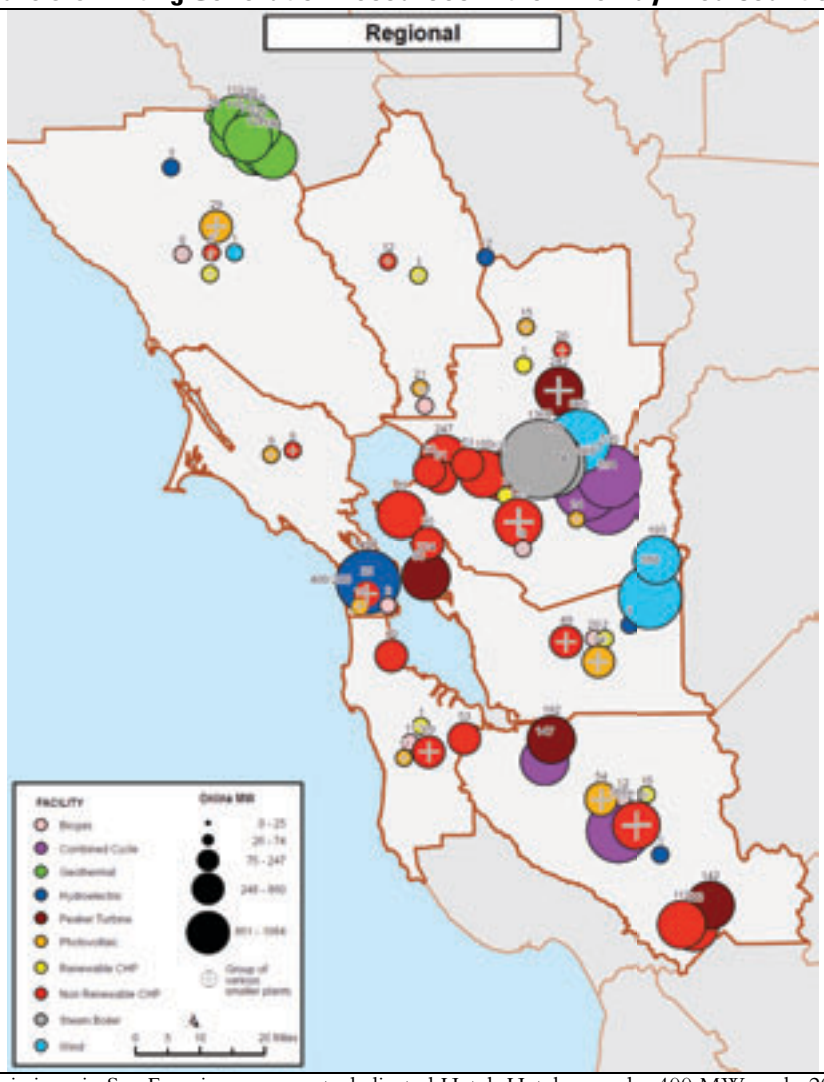
Four conclusions can be drawn from a comparison of actual data to the PG&E and CEC projections: 1) the assumption that electricity demand will increase linearly with population

demand may not be valid, as electricity demand may be increasing at a slower rate than population growth, 2) the actual PG&E service territory population growth rate of 0.9 percent per year in the 2000 – 2009 period is substantially less than either the PG&E projected peak demand growth rate of 2.1 to 2.7 percent, or the more recent CEC projected peak demand growth rate of 1.3 percent per year, 3) the population growth rate in the 2010 – 2020 period should be less than the population growth rate in the previous decade due to an aging population, and as a result, 4) the electricity demand growth rate should be no more than the actual 2000 – 2009 actual population growth rate and potentially less.

3.4 Existing Generation Resources in the Bay Area

Figure 3-5 is a map of the existing generation sources in the nine-county Bay Area. Circles with a "+" symbol represent an aggregate of multiple smaller sources. A PG&E Bay Area substation map and maps of generation sources in each Bay Area county are provided in Appendix C.

Figure 3-5. Exiting Generation Resources in the Nine Bay Area Counties[40]



Note: Blue hydroelectric icon in San Francisco represents dedicated Hetch Hetchy supply: 400 MW peak, 200 MW average.

Table 3-4 summarizes the existing generation sources in the nine-county Bay Area. The data on generator type and quantity provided in Table 3-4 for each county serves as the input for Figure 3-5. The data in Table 3-4 is current through January 2011.

Table 3-4. Type and Quantity (MW) of Existing Generation in the Bay Area[41]

County	Steam Boiler	Combined Cycle	Peaking Turbine	CHP	PV	Wind	Geo-thermal	Hydro	Renewable CHP[a]
Alameda			273	79	34	380		1	22
Contra Costa	2,040	1,984	47	1,038	24	193			11
Marin				8	9				
Napa				12	21			12	3
San Francisco				32	11			400[b]	2
San Mateo				99	11				11
Santa Clara		713	334	498	54			1	22
Solano			242	65	15	660			
Sonoma				3	29		1,158	3	6
Total:	2,040	2,697	896	1,834	208	1,233	1,158	417	77

a) Renewable CHP includes CHP units using biogas or biomethane as fuel.
b) This hydroelectric capacity represents dedicated Hetch Hetchy supply to San Francisco: 400 MW peak, 200 MW average.

3.5 Bay Area Electricity Providers

The Bay Area includes a wide mix of electricity providers. These include the POUs AMP, CPAU, SFPUC, and SVP, the Marin County CCA MEA, and energy service providers like Shell and Constellation Energy, and PG&E.

POUs are non-profit public providers of electric supply, and T&D services for a specific political or governmental jurisdiction. CCAs are non-profit public providers of electricity supply only. T&D services for the CCA are provided by the IOU. IOUs are private monopolies with shareholders. Energy service companies provide electricity directly to utilities, CCAs, and some commercial customers participating in the Direct Access program.

3.5.1 Bay Area Publicly-Owned Utilities (POUs)

The total amount of electricity delivered by PG&E in 2009 was 85,459 GWh.[42] Of this total, 50,681 GWh was delivered to PG&E bundled and Direct Access customers in the Bay Area.[43] There are also six POUs in the nine Bay Area counties that deliver electricity to customers. The total amount of electricity delivered by these six Bay Area POUs in 2008 was 5,136 GWh. These POUs are described in Table 3-5. A map showing the location of Bay Area POUs is provided in Appendix D.

Table 3-5. Publicly-Owned Utilities in the Nine Bay Area Counties

Name	Electricity Deliveries[44] (2009 GWh)	Description of Generation Assets
AMP	425	NCPA, geothermal power, landfill gas power, wind power, peaking gas turbines, power supply contracts
CPAU	953	NCPA, power supply contracts
Healdsburg	66	NCPA, power supply contracts
Port of Oakland	50	power supply contracts, 800 kW solar PV array (SunEdison)
SFPUC	872	Hetchy Hetchy reservoir hydroelectric, 400 MW peak, 200 MW average
SVP	2,770	NCPA, 147 MW combined cycle plant, power supply contracts
Total:	5,136	

These Bay Area POUs are all members of the Northern California Power Agency (NCPA) and purchase some of their electricity supply from NCPA generation resources. NCPA is a non-profit joint powers agency that represents seventeen cities and districts in Northern and Central California. NCPA states, "NCPA was founded in 1968 as an agency through which community-owned utilities could prevent costly market abuses employed by private utilities at that time, and to make investments to create an affordable, reliable and clean future energy supply for the electric ratepayers we serve."[45]

NCPA generation assets consist of two 110 MW geothermal plants at The Geysers in Sonoma County, 252 MW of hydroelectric capacity, and 174 MW of natural gas-fired peaking turbines. NCPA has also established a Green Pool, where member utilities can contract for a mix of renewable resources.[46]

3.5.2 San Francisco Public Utilities Commission (SFPUC)[47]

San Francisco receives electricity from the Hetch Hetchy water and power project to meet the demand of city-owned facilities. This electricity supply is administered by the SFPUC. The city first began generating power in 1921. The Raker Act granted San Francisco rights to federal lands in and adjacent to Yosemite National Park to develop the dam at Hetch Hetchy and associated reservoirs and hydropower generation facilities.

San Francisco operates three powerhouses – Mocassin, Holm and Kirkwood. These powerhouses contain seven turbines capable of producing a total of 401 MW of electricity during the spring run-off when the reservoirs behind the powerhouses are full. During a year with average rainfall, the Hetch Hetchy project is capable of producing 1.7 million MWh of electricity. This is an average output of about 200 MW over the course of the year.

San Francisco also owns approximately 150 miles of high voltage transmission lines that link the Hetch Hetchy power plants with the PG&E transmission grid at Newark. This power supply system is shown in Figure 3-6. The output of the Hetch Hetchy power plants exceeds San Francisco's municipal power demands on an annual basis. However, San Francisco supplements its power sources to meet municipal demand and its contractual obligations during the summer and fall months when power generation is reduced so that water can be stored.

Figure 3-6. San Francisco Hydroelectric Generation Facilities and Transmission Lines[48]

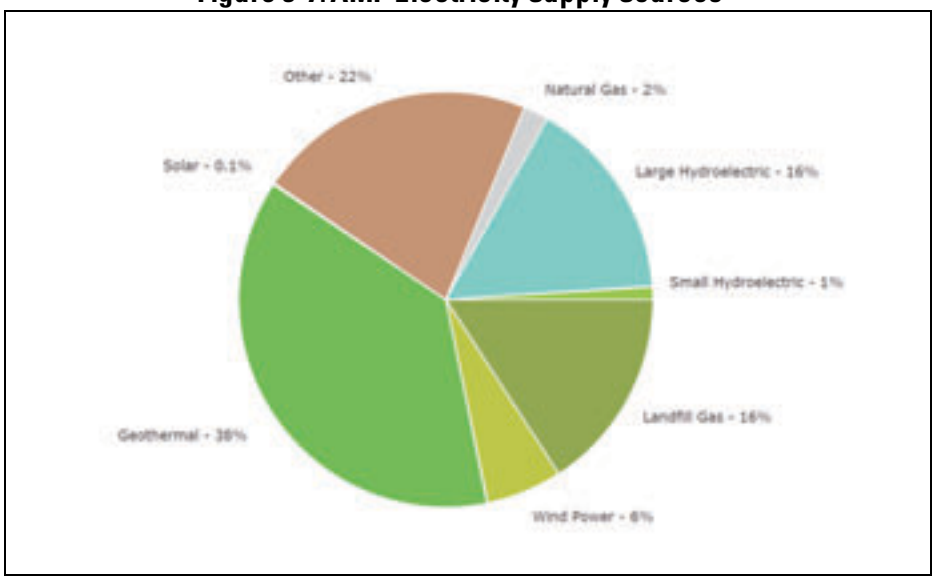
The Raker Act requires that any power that is surplus to the San Francisco's municipal needs be made available at cost to the Modesto and Turlock Irrigation Districts to meet their municipal needs. The Raker Act prohibits the sale of Hetch Hetchy-generated electricity to IOUs. As a result, San Francisco can not sell any surplus power to PG&E.

3.5.3 Alameda Municipal Power (AMP)

AMP serves approximately 30,000 residential customers, and 4,000 commercial, industrial, and municipal customers.[49] As shown in Figure 3-7, a high proportion of AMP's electricity supply is generated by renewable energy sources, with geothermal power from The Geysers, landfill gas, and wind power providing more than 60 percent of annual supply.

In addition, 16 percent of the AMP electricity supply is provided by wholesale energy broker Morgan Stanley under a 15-year contract. This contract ends in December 2014. Six percent of AMP's electricity supply is obtained through purchases made by AMP in the wholesale electricity market.[50]

Figure 3-7. AMP Electricity Supply Sources[51]



3.5.4 Silicon Valley Power (SVP)

The City of Santa Clara municipal utility launched its 6 MW CHP No. 1 power plant in 1980 to become a generating utility. In 1983, the 110 MW NCPA geothermal project entered service with Santa Clara as a lead partner. The utility changed its name to Silicon Valley Power in 1998. The utility's 147 MW Donald Von Reasfeld combined cycle plant came online in June 2005. SVP owns, operates and participates in more than 380 MW of generating resources and serves a peak load of approximately 460 MW.[52] SVP serves approximately 52,000 customers of all types.[53]

SVP offers its small commercial, large commercial, and industrial customers the option to purchase renewable energy. The renewable energy is from western state wind and California solar projects. It is available for an additional $0.015/ kWh for small businesses, or in 1,000 kWh blocks for $15 each for large businesses.[54]

3.5.5 City of Palo Alto Utilities (CPAU)

CPAU meets Palo Alto's electricity needs through its electric supply contracts and partnership in the NCPA.[55] The CPAU does not operate generation resources. The CPAU supplies approximately 1,000 GWh per year to about 30,000 customers and has a peak load of 186 MW. Approximately 24 percent of CPAU's electricity supplies are from renewable energy sources.[56]

The CPAU has also operated PaloAltoGreen since 2003. This program allows customers to purchase 100 percent renewable energy at a premium of $0.015/kWh. Twenty-one percent of CPAU's customers participate in the PaloAltoGreen program.[57]

3.6 Comparison of POU and PG&E Rates

Bay Area POU rates are consistently lower than PG&E rates for comparable service. Table 3-6 compares the commercial tariff of PG&E to the commercial service tariff for: 1) AMP, 2) CPAU Green Small Commercial, 3) CPAU Small Commercial Green, which is the CPAU program for commercial customers electing 100 percent renewable power, 4) SVP commercial, and 5) Santa Clara Green Power, which is the SVP program for customers electing 100 percent renewable power. In all cases the POU tariffs are lower than the comparable PG&E commercial tariff. The conventional POU commercial tariffs are 12 to 23 percent lower than the comparable PG&E tariff. The 100 percent renewable energy commercial tariffs available from the CPAU Green and Santa Clara Green Power programs are 3 to 14 percent lower than the PG&E commercial tariff.

Table 3-6. Comparison of Commercial Rates: PG&E, AMP, CPAU, and SVP

Basic commercial service	Energy charge, average ($/kWh)	Energy charge, summer ($/kWh)	Energy charge, winter ($/kWh)	POU rates compared to PG&E rate (%)
PG&E[58]	0.17230	0.19712	0.14747	base case
AMP[59]	0.14107	NA	NA	-18
CPAU Small Commercial[60]	0.13353	0.14045	0.12661	-23
CPAU Small Commercial Green[61]	0.14853	0.15545	0.14161	-14
SVP[62]	0.15136	NA	NA	-12
Santa Clara Green Power[63]	0.16636	NA	NA	-3

3.7 Community Choice Aggregation in PG&E Territory

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 T&D service to customers within the CCA. In contrast, an IOU provides both electricity supply and T&D service to its bundled customers.[64]

Three entities have pursued CCAs since AB 117 was passed into law in 2002: the San Joaquin Valley Power Authority (SJVPA), San Francisco, and Marin County. Of these three, to date only the Marin County CCA, MEA, is serving customers. San Francisco continues to develop its CCA. The SJVPA suspended development efforts in June 2009 due to weakness in the credit markets.[65]

MEA serves approximately 9,500 customers. This is about 20 percent of the electric load in the county jurisdiction.[66] MEA anticipates the roll-out of Phase 2 of the CCA in January 2012. MEA is contracting with Shell to provide electricity to customers.[67] Currently the renewable energy component of total electricity supplied is 26.5 percent.[68] MEA does offer a 100 percent green energy option, called Deep Green Renewable Energy, to customers for a $0.01/kWh premium over the base rate.[69]

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."[70] 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.[71]

The CPUC authorized its first CCA application under AB 117 on April 30, 2007. The CCA application was submitted by the Kings River Conservation District (KRCD) on behalf of SJVPA. The SJVPA is intended to serve the cities of Clovis, Hanford, Lemoore, Corcoran, Reedley, Sanger, Selma, Parlier, Kingsburg, Dinuba, Kerman, and Kings County. The introduction to the SJVPA implementation plan provides an excellent summary of the expected benefits of forming a CCA. The following paragraphs are excerpts from the implementation plan:

> "The Authority's primary objective in implementing this Program is to enable customers within its service area to take advantage of the opportunities granted by Assembly Bill 117 (AB 117), the *Community Choice Aggregation Law*. The benefits to consumers include the ability to reduce energy costs; stabilize electric rates; increase local electric generation reliability; influence which technologies are utilized to meet their electricity needs (including a potential increased utilization of renewable energy); ensure effective planning of sufficient resources and energy infrastructure to serve the Members' residents and businesses; and improve the local/regional economy.
>
> The Authority's rate setting policies establish a goal of providing rates that are lower than the equivalent generation rates offered by the incumbent distribution utility (PG&E or SCE). The target rates are initially at a five percent discount with the discount potentially increasing once additional KRCD owned resources are brought on line."

A major concern for San Francisco is that departing load charges levied by PG&E on CCA customers could be so high that these charges would derail the formation of the CCA. Departing load charges are assigned to customers that leave PG&E service after PG&E made 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.

PG&E is authorized by the CPUC to assess charges on customers that voluntarily leave in order avoid burdening remaining customers with higher costs. The cost to San Francisco for a bond to cover these charges could be over $200 million and could prevent the CCA from moving forward.[72]

Three valuable contributions a CCA can provide to customers relative to service from PG&E are: lower rates, a higher percentage of renewable energy, and more local control of the sources of electricity supply. Another important contribution is the value of competition in shaping the development strategy pursued by PG&E. If CCA becomes a readily accessible option for California cities and counties, PG&E is more likely to mimic the products and benefits that a CCA would provide in order to avoid further erosion of its customer base.

CCA will not become a readily accessible option for California cities and counties without reform of current CCA requirements. These reforms include: enforcement of the prohibition against the incumbent IOU from campaigning against formation of a CCA, elimination of departing load charges and bonding requirements levied by the IOU on the CCA, and regulatory recognition of the right of a CCA to administer its own energy efficiency program using the public goods charges paid by its customers for that purpose.

3.8 Investor-Owned Utility Business Model

PG&E is an IOU. An IOU earns a fixed profit based on the value of the property it owns. Examples of such property are IOU-owned power plants, T&D lines, and IOU-owned electric and gas meters. In other words, the more an IOU invests in such projects, the more money it earns. When the CPUC, the CEC and the Legislature adopted the *Energy Action Plan* and its associated loading order in 2003, no changes were made to the CPUC's existing ratebasing policies. As a result, the IOUs do not currently have an economic incentive to support the loading order.[73,74]

The CPUC's ratebasing policies have evolved over the last 100 years. The primary type of proceeding where ratebasing policies are addressed is the general rate-setting case. The regulated utility model, used in California up until the 1996 restructuring experiment, called for IOUs to invest shareholder funds in capital projects and to be allowed to recover those costs in rates charged to the ratepayers, along with a rate-of-return (profit) set by the CPUC.

The tendency of the traditional ratemaking formula to encourage over investment in utility capital projects is well known. Until 1981, California IOUs were focused on building revenues by convincing customers to use more of their product, as these IOUs had more capacity than needed to serve customer load. The IOUs spent money on marketing to get customers to use more gas and electricity. This included promoting all-electric "gold medallion" homes to increase electric demand, and promotions with rebates and discounts to get customers to buy more gas and electric appliances.

3.9 Role of the California Independent System Operator

The California Independent System Operator (CAISO) was created in 1996 to set up and operate a centralized electricity market in California with participation by closely regulated IOUs and less closely regulated market participants like independent power producers. CAISO operates in interstate commerce and for this reason is subject to the jurisdiction of the Federal Energy Regulatory Commission (FERC). The CAISO control area encompasses the transmission assets of PG&E, Southern California Edison (SCE), and San Diego Gas & Electric (SDG&E), and some of the California POUs.

The transmission systems of several major California POUs, including Los Angeles Department of Water and Power (LADWP), SMUD, Imperial Irrigation District, Turlock Irrigation District, and Merced Irrigation District, are not within the CAISO control area. In addition, some of the POU transmission lines that are within the CAISO control area, such as the SFPUC transmission lines connecting Hetchy Hetchy hydroelectric power to San Francisco, are operated outside of the CAISO's open access market structure. These transmission lines are operated under provisions that recognize pre-existing transmission contracts.

A central role of CAISO is to ensure the reliability of electricity supply for loads within the CAISO control area. The CAISO mission statement summarizes the purpose of the organization:[75]

> "For the benefit of our customers, we operate the grid reliably and efficiently, provide fair and open transmission access, promote environmental stewardship, facilitate effective markets, and promote infrastructure development."

The California legislature and the CPUC ended the expansion of Direct Access in 2001. Direct Access customers purchase electricity directly from third party suppliers and use only the T&D services of the IOU. Since 2001, CAISO has increasingly become a champion for the generation and transmission infrastructure expansion plans of the IOUs in its control area. CAISO was intended to serve as a neutral authority that would balance the predisposition of IOUs to build new transmission and natural gas-fired power plants by pooling generation resources to achieve cost savings for consumers.

California's transition to higher levels of renewable energy is now the primary rationale put forth by CAISO for major IOU transmission expansion projects. Yet the economic and technical support for this rationale is weak, as explained in a recent analysis of the transmission expansion underway in California:[76]

> "In the West, there is a widespread perception of a transmission shortage. This perception has grown out of the consistently repeated claims of the utilities, balancing authority operators such as the CAISO, and state agencies such as the CEC, that the lack of transmission is threatening the success of the region's renewable energy and clean air programs. A particularly troubling outcome of this perception is that many parties, including renewable generation developers, have come to believe that the slow pace of connecting new generation to the grid is the result of a widespread transmission shortage. . . In fact, the evidence points strongly in the opposite direction. Transmission investment has far outpaced the rate at which energy demand has been growing, and congestion-related impacts in most areas of the interconnected grid have been relatively minor, certainly not at levels that would justify massive increases in new transmission investment.
>
> Considering that renewable generation additions will displace fossil-fired generation throughout the Western Electricity Coordinating Council, thereby reducing the amount of fossil-fired generation imported into the state of California to serve loads, more transmission capacity will be available on the major import paths into California. This is significant for California because much of the

renewable resource development potential exists along these major import paths. If the major import paths can be used to deliver renewable energy to California's load centers, then the only significant transmission additions that are needed are those that will collect and connect the new renewable resources to the existing grid."

The conclusion of this analysis is that, as long as IOU profits are tied directly to the amount of transmission rate base they can accumulate, the motivation to find creative ways to avoid economic comparisons with alternatives will continue.

As shown in Table 3-7, the increase in the California IOU transmission rate base over the 1999–2009 period was over $5 billion, an 84 percent increase. The increase in electricity demand was about 9 percent over the same period.

Table 3-7. California IOU Transmission Investment Compared to Electricity Demand Growth, 1999 – 2009[77]

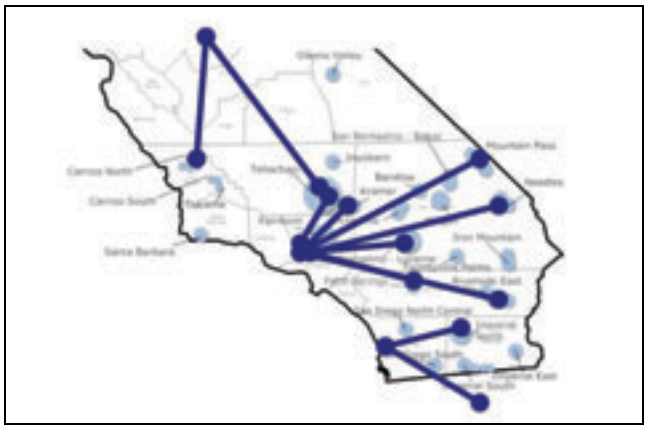
Year	Transmission rate base ($ million)	Transmission rate base growth rate	Net electricity supplied by IOUs	Growth in electricity supplied by IOUs
1999	6,176	1.00	214,826	1.00
2000	6,420	1.04	227,310	1.06
2001	6,633	1.07	211,812	0.99
2002	6,884	1.11	214,230	1.00
2003	7,224	1.17	218,316	1.02
2004	7,861	1.27	226,171	1.05
2005	8,459	1.37	227,787	1.06
2006	9,078	1.47	234,834	1.09
2007	10,024	1.62	239,540	1.12
2008	10,773	1.74	243,842	1.14
2009	11,371	1.84	235,093	1.09

The most recent major transmission project approved by CAISO in the Bay Area is the 400 MW Trans Bay Cable, shown in Figure 3-8. This $500 million, 53-mile undersea direct current transmission line began operation in November 2010.[78] The line is a public-private partnership between the City of Pittsburg and SteelRiver Infrastructure Partners.[79] It is being financed by a cost-based infrastructure recovery charge approved by CAISO in 2005. This charge is paid by all California IOU customers. CAISO has operational control over the Trans Bay Cable. The line connects a cluster of natural gas-fired power plants in the Pittsburg area, and wind generation across the Sacramento River in the Montezuma Hills area of Solano County, directly to San Francisco. The Potrero Power Plant in San Francisco was permanently shut down following start-up of the Trans Bay Cable.[80]

Figure 3-8. 400 MW Trans Bay Cable[81]

The rapid expansion in transmission investment shown in Table 3-6 will grow larger in the next ten years if current IOU transmission expansion plans are realized. Proposed lines are shown in Figure 3-9. The cost of proposed California transmission lines to be added by the year 2020 is estimated at over $15 billion.[82] Compared to 1999, the California IOU transmission rate base could increase by over 300 percent if the proposed lines are built. In contrast, the projected increase in electricity demand between 1999 and 2020 is about 25 percent.

Figure 3-9. New Transmission Additions for IOU 33 Percent Reference Case Scenario[83]



A similar pattern is occurring with CAISO advocacy for a new generation of peaking gas turbine resources to address the retirement of once-through cooled steam boiler plants, like the Pittsburg and Contra Costa steam boiler plants in Contra Costa County, and the perceived variability of solar and wind resources. These relatively inefficient steam boilers now serve primarily as summer peaking capacity, just as the relatively inefficient simple cycle gas turbines at proposed Marsh Landing and Mariposa Energy Center would primarily serve as summer peaking capacity.

A number of presumptions frame this debate: 1) the current levels of reserve capacity are insufficient to cover retirements of once-through cooled steam boiler units and/or the variability of incremental additions of solar and wind resources, 2) the once-through cooled steam boiler units must be retired and can not be upgraded with low cost cooling towers to eliminate once- through cooling, 3) solar and wind output is unpredictable and therefore a parallel system of fast start back-up natural gas-fired turbines must

be available at all times to handle rapid changes in output from these resources. All of these presumptions are wrong.

CAISO requires that the IOUs maintain a minimum level of local generation in urban load pockets, including the Bay Area, greater Los Angeles, and San Diego, to assure grid stability under all foreseeable load conditions. This requirement is known as the Local Capacity Requirement, or LCR. CAISO established a 2007 LCR of 4,771 MW for the Bay Area.[84] This LCR was established following the highest one-hour peak load ever recorded in PG&E service territory, 22,650 MW, recorded in July 2006.[85] The 2010 one-hour peak load in PG&E service territory was 21,180 MW, about 1,500 MW lower than the 2006 peak.[86] PG&E forecast a 2011 LCR of 4,025 MW for the Bay Area, nearly 750 MW below the 2007 LCR.[87]

The CEC forecasts a peak demand growth rate of 1.3 percent over the 2010 – 2020 period. Using 2010 as baseline year and assuming a 1.3 percent peak demand growth rate, PG&E would not reach or exceed the 2006 one-hour peak until the summer of 2016.[88]

PG&E identified the need, in late 2006, for Unit 7 at the Contra Costa power plant, a once- through cooled 340 MW steam boiler unit, to remain online until PG&E's 590 MW Gateway combined cycle plant, also known as Contra Costa Unit 8, came online.[89] The Gateway plant came online in 2009.[90] PG&E stated in its strategic plan that the Gateway plant would eliminate the need for the two steam boiler units at the Contra Costa plant to meet local reliability requirements.

CAISO minimizes the significance of the high levels of electricity supply reserves currently available to PG&E and other California IOUs. The PG&E reserve margin in 2010 was over 38 percent.[91] This means that PG&E had nearly 5,000 MW of reserves in the summer of 2010 beyond what it is required to assure grid reliability under all foreseeable peak demand conditions. These extra reserves are operational and already available to provide back-up as California transitions to higher levels of solar and wind power.

PG&E identified only two other once-through cooled steam boiler units in its service territory, Pittsburg 5 and 6 at 325 MW each, as necessary for LCR over the long term in its 2006 strategic plan.[92] A study commissioned by the California Ocean Protection Council determined in 2008 that the cost to convert Pittsburg 5 and 6 to wet cooling towers to eliminate the marine impacts of once- through cooling would be about $125 million.[93]

Pittsburg 5 and 6 are more efficient than the gas turbines that will replace them. Heat rate is a measure of the thermal efficiency of a fossil-fueled power plant. The higher the heat rate, the less thermally efficient the power plant. Pittsburg 5 and 6 are 50 year-old steam boilers with an average heat rate of 9,811 Btu/kWh at full load.[94] The simple cycle gas turbines to be used at proposed 760 MW Marsh Landing will have heat rates of 11,124 Btu/kWh.[95]

The grid reliability study commissioned by the State Water Resources Control Board (SWRCB) in 2008 determined that, due to extensive recent reinforcement of the transmission grid and the addition of thousands of MW of new natural gas-fired resources, all non-nuclear once-through cooled boiler plants in California could be permanently retired by 2015 with as little as $135 million in additional expense to California ratepayers.[96] CAISO was unaware of this grid reliability analysis when it was summarized at a CEC-sponsored once-through cooling workshop a year after its publication. Yet CAISO dismissed the study on-the-spot and unread as uninformed and not credible.[97]

At the workshop, owners of much of California's fleet of once-through cooled steam units stated that the steam units could be upgraded to cooling towers to eliminate once-through cooling at an retrofit cost ranging from $115 to 125/kW.[98,99] This is about one-tenth the cost of new natural gas-fired peaking gas turbine capacity.[100] The presumed mass retirement of the steam units is a primary rationale offered by CAISO to justify thousands of MW of new peaking turbine capacity in PG&E territory and statewide.

Solar and wind variability is another justification offered for building thousands of MW of new gas turbine capacity. In reality, solar resources are very reliable during peak summertime demand periods in California. Peak events are driven by air conditioning loads which are driven by solar intensity. Peak demand occurs during clear sky conditions in California's major load centers. An analysis of hour-by-hour solar intensity at the Oakland and San Jose Airports during the peak 100 hours in the PG&E service territory in 2007, which demonstrates the solar resource is fully available during peak hours, is provided in Chapter 7.

The wind resource in California and the Bay Area is also reasonably predictable. Production is typically diurnal in nature, with maximum production in evening, night, and morning, and a lull at mid-day. A 24-hour trace of the summertime wind output in Solano County showing this pattern is provided in Chapter 7.

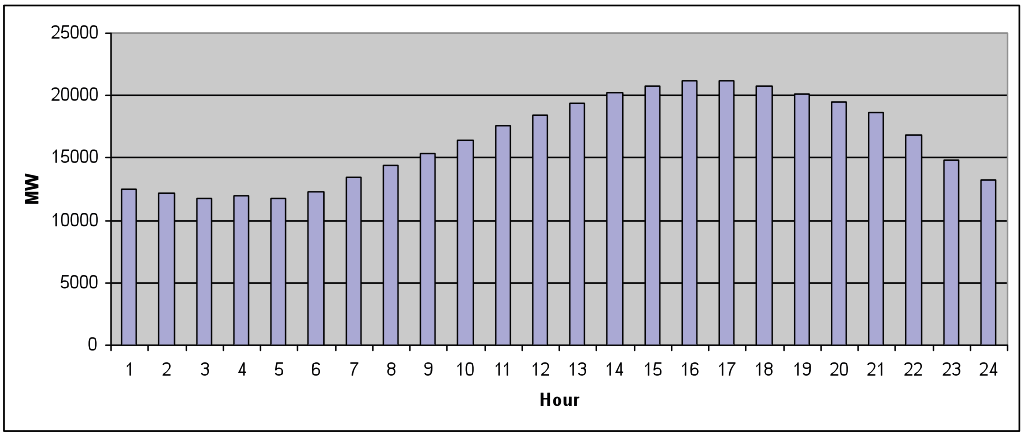
Both the solar and wind output can be predicted with a reasonable degree of accuracy one hour ahead and one day ahead. This is how utilities and CAISO schedule generation now. As higher and higher levels of solar and wind enter the system it may be necessary to schedule more frequently than one hour ahead.[101] However, this is a generator dispatch management issue. It is not a sufficient justification for building a new generation of peaking gas turbines.

The potential for rapid swings in wind and solar output is also put forth as a justification for building a new generation of fast start gas turbines. This is not a significant issue for distributed PV. There are already thousands of widely distributed PV systems in the Bay Area. The output of thousands of widely distributed PV systems is, collectively, relatively smooth on partly cloudy days. The reason for this is that at any given moment the proportion of PV systems exposed to direct sunlight is relatively constant.

Rapid changes in output may occur periodically from the Solano County and Altamont Pass wind production areas under strong and gusty wind conditions. However, the current grid must already accommodate these rapid changes in load, especially in summer. The highest 2010 one-hour load in PG&E territory was recorded on August 25, 2010. Figure 3-10 is the 24-hour load profile for PG&E service territory on August 25, 2010. As shown in Figure 3-10, the load increased at an average of approximately 1,000 MW per hour from 8 am to 2 pm, and decreased at over 2,000 MW per hour from 9 pm to 10 pm. The combined capacity of the Solano County and Altamont Pass wind production areas is about 1,200 MW. The PG&E system already routinely adds about 1,200 MW of load in an hour, and routinely drops this amount of load in 30 minutes.

It is reasonable to assume that wind conditions causing the combined 1,200 MW capacity of the Solano County and Altamont Pass wind production areas to go from maximum output to zero output in a matter of a few minutes would be infrequent events. PG&E has reported no power failures, brownouts, or blackouts resulting from rapid swings in wind power output in Solano County or Altamont Pass. At the current rate of wind production, output variability is within the tolerance limits of the existing PG&E supply mix.

Figure 3-10. 24-Hour PG&E Load Profile for August 25, 2010[102]



There are approximately 300 MW of new wind projects planned for Solano County that have a high probability of being built.[103] No new capacity additions are currently planned for Altamont Pass. It is not credible that the addition of 300 MW of wind power in the Montezuma Hills area of Solano County, a few miles from nearly 4,100 MW of natural gas-fired generation in eastern Contra Costa County, could affect grid reliability in the Bay Area or necessitate the addition of more gas-fired generation in the Bay Area.[104]

Methods available to prevent wind output variability from becoming an operational challenge include: 1) limiting the amount of new wind capacity added to below a threshold level where grid reliability may be affected, 2) disconnecting wind farms from the grid when infrequent gusty windy conditions have the potential to negatively impact grid reliability, and 3) adding limited energy storage to wind farms to smooth output and prevent gusty wind conditions from compromising grid reliability.

The National Renewable Energy Laboratory (NREL) released the *Western Wind and Solar Integration Study* in May 2010. This study examines the challenges of integrating sufficient wind and solar energy capacity into the grid to produce 35 percent renewable energy by 2017. The study found that the 35 percent target is technically feasible and does not necessitate extensive additional infrastructure, but does require key changes to current operational practice.[105]

NREL determined that utilities will have to substantially increase their coordination of operations over wider geographic areas and schedule their generation on a more frequent basis to accomplish the 35 percent by 2017 objective. Currently generators provide a schedule for a specific amount of power they will provide in the next hour. More frequent scheduling would allow generators to adjust that amount of power based on changes in system conditions such as increases or decreases in wind or solar generation.

Three key findings of the NREL study are: 1) existing transmission capacity can be more fully utilized to reduce the amount of new transmission that needs to be built, 2) to facilitate the integration of wind and solar energy, coordinating the operations of utilities can provide substantial savings by reducing the need for additional back-up generation, such as
natural gas-fired plants, and 3) use of wind and solar forecasts in utility operations to predict when and where it will be windy and sunny is essential for cost-effectively integrating these renewable energy sources.

3.10 PG&E History and Overview

PG&E was formed in 1905 by the merger of the San Francisco Gas and Electric Company and the California Gas and Electric Company.[106] A primary objective of the newly formed company was to develop the hydroelectric potential of rivers in the Sierra Nevada.[107] The state granted monopoly status to PG&E as a supplier of electricity in Northern California in the 1930s. The basic architecture of the high voltage transmission system bringing power into the Bay Area was formed by the 1950s.

PG&E built fossil fuel power plants in Pittsburg and Moss Landing in the 1950s and 1960s to serve the Bay Area. In San Francisco, PG&E built smaller plants at Hunters Point in 1958 and Potrero in 1965 to provide generation resources at the end of its transmission lines.

PG&E and SCE made a commitment to develop nuclear power in the late 1960s. Both California utilities faced challenges during construction that caused significant delays and cost escalation. At the beginning of the 1980s, slippage in the construction schedules at Diablo Canyon and San Onofre led to concerns about possible shortages of electricity in California.

The CPUC aggressively promoted non-utility development and ownership of power plants to spur the addition of more capacity. California led the nation in encouraging the development of geothermal, biomass, wind, and solar thermal generating capacity by taking advantage of a 1978 federal law, the Public Utility Regulatory Policy Act (PURPA). About 11 percent of California's electricity came from non-hydro renewable energy sources by the early 1990s. The CPUC also ordered PG&E to institute demand-side management programs.

PG&E Corporation, PG&E's parent company formed in 1997, is an active developer and operator of energy projects in and around PG&E service territory.[108] PG&E Corporation owns numerous affiliates in addition to PG&E. These include: PG&E Real Estate, LLC; PCG Capital, Inc.;Sequoia Pacific Solar I, LLC; SunRun Pacific Solar LLC; Pacific Energy Capital I, LLC; Pacific Energy Capital II; LLC, Pacific Energy Capital III, LLC; and Pacific Energy Capital IV; Midway Power, LLC; PG&E Strategic Capital, Inc.; and Ruby Pipeline LLC.[109] PG&E Pacific Venture Capital LLC, now Pacific Energy Capital I, LLC, was formed in 2010 and provides capital to solar PV leasing firms SolarCity and SunRun.[110] PG&E invested $60 million in SolarCity in January 2010 and $100 million in SunRun in June 2010.[111,112]

PG&E classified Pacific Venture Capital LLC as an affiliate subject to CPUC affiliate transaction rules in February 2010, but asserted that Solar City was not an affiliate. The CPUC rejected this claim in July 2010, asserting that the affiliate transaction rules should apply to SolarCity.[113]

3.10.1 Deregulation and 2000-2001 Energy Crisis

The California legislature unanimously passed legislation in 1996 to end the monopoly power of the IOUs, eliminate government supervision of electric resource planning, and give consumers a choice of electricity suppliers.[114] As specified in the legislation, PG&E sold-off most of its fossil fuel and geothermal power plants to private companies not regulated by the state.

PG&E transmission lines were placed under the control of the newly created CAISO.
PG&E retained responsibility for running the T&D system and procuring power from the wholesale market for customers who did not choose an alternate provider. The rates that PG&E could charge those default customers were still regulated by the CPUC. This deregulated system collapsed in early 2001 under the weight of market manipulation.

PG&E filed for bankruptcy in April 2001. The State of California, through long-term electricity supply contracts administered by the DWR, became the power buyer of last resort.

PG&E retained ownership of the Diablo Canyon nuclear plant, the Humboldt power plant, and the Hunters Point power plant under deregulation. PG&E entered into an agreement with San Francisco in 1998 to close Hunters Point when it was no longer needed for electric reliability in San Francisco. Hunters Point was permanently closed in 2006 with the start-up of the Jefferson-Martin 230 kV transmission line that connects San Francisco to a substation in San Carlos.[115] PG&E sold the Potrero power plant to Mirant in 1999. Potrero was permanently closed in December 2010 with the startup of the 400 MW Trans Bay Cable from Pittsburg to Hunters Point.[116]

A public goods charge was added to customers' electric bills in 1997 to fund the continuation of energy-efficiency and renewable programs in the deregulated era. PG&E has been collecting the public goods charge since 1997 and using the funds to administer PG&E energy efficiency programs under the direction of the CPUC.

3.10.2 Post-Energy Crisis

The period after 2001 is a hybrid mix of IOU ownership and third party electricity providers. The CPUC returned the long-range strategic planning function to PG&E, SCE, and SDG&E in 2003. Generation and transmission needs identified by the IOUs serve as the basis for new CPUC power plant and transmission line authorizations. The IOUs were also allowed by the CPUC to build or acquire new generation assets. Examples of new power plants built by PG&E include the 590 MW Gateway combined cycle plant in Antioch and the 660 MW Colusa combined cycle plant in Colusa County.

A fundamental tenet in the move toward a deregulated electricity market was the concept that market price signals alone would be sufficient to get new power plants built as they were needed. The CPUC ended this laissez-faire approach with a 2006 opinion that authorized the IOUs to pass on all fixed costs associated with new power plant power purchase agreements to ratepayers. In simple terms, with this 2006 opinion the CPUC removed all market risk from the developer and shifted that risk, in the form of guaranteed payment for all fixed costs, to the ratepayer.[117]

PG&E completed its 2004 long-term request for offers process in 2006. This process was intended to result in the construction of 2,250 MW of new peaking and load-following natural gas-fired generation. The identification and status of these proposed generation additions are provided in Table 3-8.[118]

Table 3-8. Description and Status of PG&E Gas-Fired Power Purchase Agreements Approved by CPUC in 2006

Facility	Capacity (MW)	Plant Type	Operational Date	Status
Calpine Hayward (Russell City Energy Center)	601	combined cycle	June 2010	delayed, 2013 projected start date
EIF Firebaugh (Panoche Energy Center)	400	combustion turbine	August 2009	operational
EIF Fresno	196	combustion turbine	September 2009	cancelled
Starwood Firebaugh (Starwood Power-Midway)	120	combustion turbine	May 2009	operational
Tierra Energy Hayward	116	reciprocating engine	May 2009	cancelled
E&L West Coast Colusa	660	combined cycle	May 2010	operational

Wartsila Humboldt (modernization project)	163	reciprocating engine	May 2009	operational

PG&E recommended in its *2006 Long-Term Procurement Plan* application that up to 2,300 MW of new natural gas-fired capacity, beyond the additions listed in Table 3-8, come on-line beginning in 2011. This new capacity is based on PG&E's proposed intent to meet a 16 percent reserve margin for a 1-in-10 temperature peak demand event, and not the CPUC planning requirement of a 15 to 17 percent reserve margin for a 1-in-2 temperature year peak demand event.[119]

The summer of 2006 heat storm was used by PG&E in its *2006 Long-Term Procurement Plan* application as a primary basis for substantial new additions of natural gas-fired capacity. PG&E estimates that the summer of 2006 heat storm was a 1-in-30 to 1-in-40 high temperature event.[120]

The CPUC in December 2007 authorized PG&E to procure 800 to 1,200 MW of additional gas-fired generation by 2015 to maintain a reserve margin of 15 to 17 percent.[121] The CPUC required that PG&E procure dispatchable ramping resources that can be used to adjust for the morning and evening "ramps" created by intermittent types of renewable resources. The CPUC also stated in the decision that preference should be given to procurement that will encourage the retirement of aging plants using once-through cooling, by providing qualitative preference for bids involving the repowering of the once-through cooled plants or bids for new facilities at locations in or near the load pockets where the once-through cooled plants are located.

The actual reserve margin in PG&E territory in 2009 was 44 percent.[122] The actual 2009 peak was somewhat below the peak forecast for a 1-in-2 temperature event year.[123] The actual 2010 reserve margin at the peak hour was 38.3 percent using the CAISO estimate of available supply in PG&E territory in August 2010.[124] The actual 2010 peak load of 21,180 MW was slightly higher than the 1-in-2 peak demand of 21,154 MW forecast by CAISO.[125]

Despite these exceptionally high actual reserve margins, the CPUC approved PG&E's application for a power purchase agreement for the simple cycle 200 MW Mariposa Energy Center in September 2009,[126] and for the 760 MW simple cycle project in July 2010 and the 624 MW Oakley combined cycle project in December 2010.[127,128]

The CPUC has also authorized a 500 MW distributed PV project in PG&E territory. The project includes a 250 MW IOU-owned component and a 250 MW competitively bid third party component. The PG&E 500 MW distributed PV project was approved by the CPUC in April 2010. The CPUC observed with its approval of the PG&E 500 PV project that:[129]

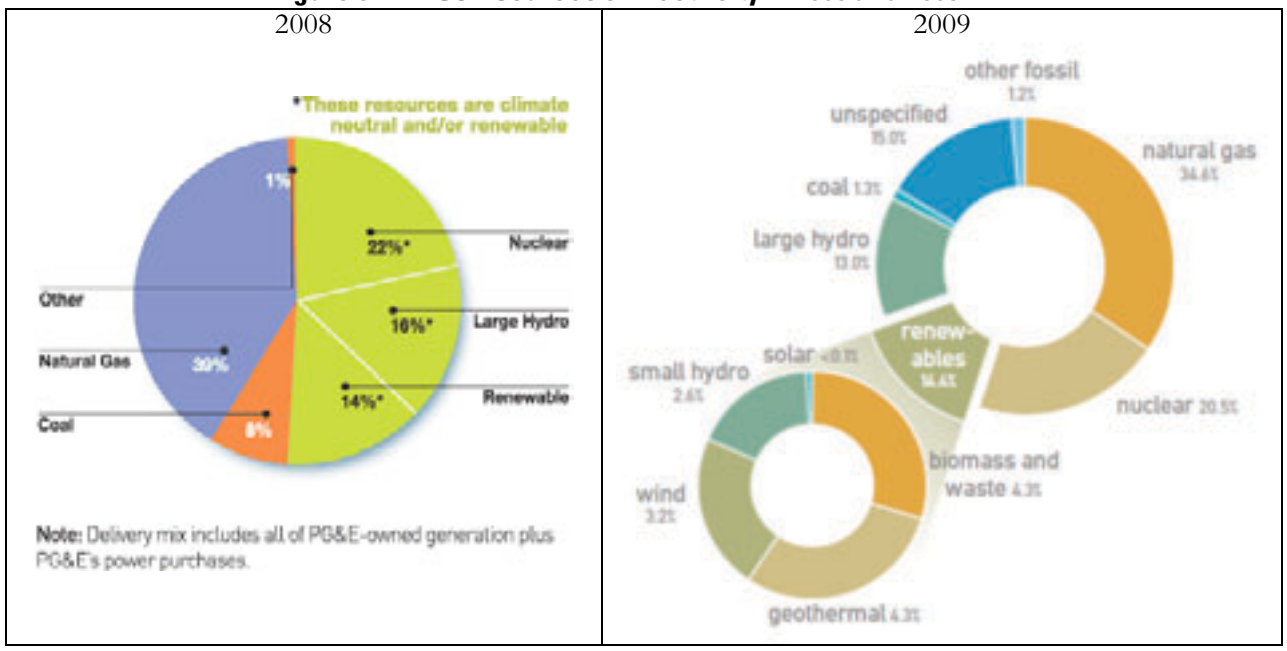
> "This solar development program has many benefits and can help the state meet its aggressive renewable power goals," said CPUC President Michael R. Peevey. "Smaller scale projects can avoid many of the pitfalls that have plagued larger renewable projects in California, including permitting and transmission challenges. Because of this, programs targeting these resources can serve as a valuable complement to the existing Renewables Portfolio Standard program."

The end result of approving too many new natural gas-fired generation projects is captured in the CPUC's *2010 Long Term Procurement Proceeding*.[130] Assuming only modest gains in energy efficiency over the next decade, and relatively little addition of new CHP, the projected reserve margins in PG&E service territory will be over 60 percent for every year between 2011 and 2020 in six of the seven PG&E scenarios evaluated by the CPUC. In one scenario, the 33 percent renewable energy trajectory low-load scenario, the reserve margin reaches 100 percent in 2016.[131] PG&E ratepayers will shoulder the burden of a project approval process that does not carefully weigh the need for new natural gas-fired projects before committing ratepayers to major long-term financing obligations.

3.11 PG&E Electricity Supply

PG&E delivers electricity that is: 1) generated at power plants owned by the company, and 2) purchased from third parties. The sources of electricity supplied by PG&E in 2008 and 2009 are shown in Figure 3-11.

Figure 3-11. PG&E Sources of Electricity in 2008 and 2009[132,133]



3.12 PG&E Power Generation Sources and Contracted Supplies

PG&E owns the 2,200 MW Diablo Canyon nuclear power plant, the 590 MW Gateway natural gas-fired combined cycle plant in Antioch, the 660 MW Colusa natural gas combined cycle plant in Colusa County, and the 163 MW Humboldt natural gas-fired engine power plant in Eureka. PG&E also owns and operates the 1,212 MW Helms Power Plant pumped storage project in Fresno County. In addition, the company owns 2,853 MW of baseload hydroelectric capacity distributed among 67 separate plants.[134]

PG&E has contracts with about 260 qualifying facilities totaling more than 4,100 MW of capacity.[135] These qualifying facilities are the outcome of the passage of PURPA in 1978. PURPA sought to reduce the country's dependence on oil through the development of new resources for electric generation, including renewable resources, including solar, wind, biomass, geothermal, and small hydro, and the more efficient use of oil and gas in CHP projects.

PURPA's key reforms included a requirement that the utilities must purchase the power output of qualifying CHP and other small power producers. Collectively these sources are known as qualifying facilities.[136] Most of California's qualifying facilities were developed and built between 1982 and 1990, under 20- to 30-year contracts which provided for the sale of excess electricity to the utility.

PG&E receives electricity supply under long-term power contracts signed in the wake of the 2000-2001 energy crisis. These contracts are administered by the DWR. Most of the DWR contracts expire in the 2010 to 2012 timeframe.[137] The amount of electricity supplied to PG&E under the DWR contracts is substantial. As shown in Table 3-9, four of the top seven PG&E electricity sources in 2008 were DWR contracts totaling nearly 20,000 GWh. These four DWR contracts represent nearly 25 percent of all electricity delivered by PG&E in 2008.[138]

PG&E also imports power from sources outside the region, identified in Figure 3-11 in the 2009 power mix graphic under the header "unspecified." This unspecified allocation includes coal power from neighboring western states. As shown in Figure 3-11, coal power accounted for 8 percent of PG&E's electric power sales in 2008.

In 2009, 14.4 percent of the electric energy sold by PG&E, around 11,500 GWh, was generated by renewable energy sources.[139] The renewable energy sources contributing to the 14.4 percent total are identified in Figure 3-11. PG&E's renewable energy percentage increased to 17.7 percent in 2010.[140] Much of this renewable energy is generated in PG&E service territory. Major renewable development areas include The Geysers in Sonoma County, wind in Solano County, and wind in Altamont Pass in Contra Costa and Alameda counties.

PG&E is required under SB 107 to generate 20 percent of its retail sales from renewable energy sources by 2010.[141] SB 107 also requires that all retail sellers of electricity in the state increase their renewable procurement each year by at least one percent of total sales. The 20 percent target is not expected to be achieved until 2013.[142] Executive Order S-14-08, signed by former Governor Schwarzenegger in November 2008, raises California's renewable energy goal to 33 percent by 2020.[143] The executive order does not have the force of legislation and PG&E does not recognize it as a binding requirement.[144] Proposed California Senate Bill (SB) 23, introduced in December 2010, would require PG&E, SCE, and SDG&E to meet a 33 percent RPS requirement by 2020.[145]

The top fifty in-state sources supplying electricity to PG&E in 2008 are shown in Table 3-9.

Table 3-9. Top Fifty In-State Generation Sources Supplying Electricity to PG&E in 2008[146]

Plant	Fuel Type	GWh supplied
PG&E: DIABLO CANYON – Unit 1	nuclear	9,895
PG&E: DIABLO CANYON – Unit 2	nuclear	8,496
DWR: CALPINE1 (PR1)	natural gas	7,610
DWR: CALPINE2 (PR1)	natural gas	7,610
DWR: CORAL	natural gas	3,217
PCWA: MIDDLE FORK	large hydroelectric	1,398
DWR: DISPATCHABLE CONTRACTS	natural gas	1,110
YCWA: COLGATE	large hydroelectric	902
TOLLING AGREEMENT: MOSS LANDING 6 & 7	natural gas	814

Table 3-9. Top Fifty In-State Generation Sources Supplying Electricity to PG&E in 2008 (cont.)

Plant	Fuel Type	GWh supplied
CALPINE KING CITY COGEN	natural gas	751
PG&E: CARIBOU 2 PH	large hydroelectric	745
YCWA: COLGATE	large hydroelectric	724
PG&E: HAAS PH	large hydroelectric	708
PG&E: BELDEN PH	large hydroelectric	679
PG&E: KERCKHOFF #2 PH	large hydroelectric	640
GEYSERS POWER COMPANY, LLC	geothermal	581
CROCKETT COGEN	natural gas	568
PG&E: ELECTRA PH	large hydroelectric	562
PG&E: PIT 5 PH	large hydroelectric	507
MID: EXCHEQUER	large hydroelectric	504
PG&E: JAMES B. BLACK PH	large hydroelectric	499
PG&E: PIT 5 PH	large hydroelectric	475
PG&E: STANISLAUS PH	large hydroelectric	474
CALPINE GEYSERS #13	geothermal	472
PG&E: CRESTA PH	large hydroelectric	440
PG&E: PIT 4 PH	large hydroelectric	419
PG&E: PIT 3 PH	large hydroelectric	416
PG&E: POE PH	large hydroelectric	406
PG&E: POE PH	large hydroelectric	403
STOCKTON COGEN	coal	340
MT. POSO COGENERATION	coal	383
MIRANT WRAP AGREEMENT: PITTSBURG 5 & 6	natural gas	377
TRI-DAM DONNELLS	large hydroelectric	372
WHEELABRATOR SHASTA	biomass & waste	361
PG&E: ROCK CREEK PH	large hydroelectric	355
BEAR MOUNTAIN LIMITED	natural gas	354
OWID: WOODLEAF	large hydroelectric	348
PG&E: ROCK CREEK PH	large hydroelectric	347
CHALK CLIFF LIMITED	natural gas	346
McKITTRICK LIMITED	natural gas	342
LIVE OAK LIMITED	natural gas	341
PG&E: BALCH 2 PH	large hydroelectric	338
PG&E: DRUM 2 PH	large hydroelectric	338

Table 3-9. Top Fifty In-State Generation Sources Supplying Electricity to PG&E in 2008 (cont.)

Plant	Fuel Type	GWh supplied
BADGER CREEK LIMITED	natural gas	332
PG&E: PIT 7 PH	large hydroelectric	330
HIGH SIERRA LIMITED	natural gas	319
KERN FRONT LIMITED	natural gas	319
PG&E: TIGER CREEK PH	large hydroelectric	319
DUKE TOLLING AGREEMENT: MORRO BAY 3 & 4	natural gas	318
COALINGA COGENERATION COMPANY	natural gas	314

3.13 Conclusions and Recommendations

- There was almost no growth in energy usage in the Bay Area from 2000 to 2009. Electricity demand in the Bay Area increased from 54,890 GWh in 2000 to 55,817 GWh in 2009.
- Peak load in the Bay Area in 2010 was significantly lower than the record peak in 2006.
- Population growth in the Bay Area averaged 0.4 percent per year from 2000 through 2009.
- Population growth in PG&E service territory averaged 0.9 percent per year from 2000 through 2009.
- The CEC states qualitatively that population growth in California will slow in the 2010-2020 forecast period compared to 2000-2009 due to an aging population. The CEC assumes a linear relationship between population growth and peak demand growth. The CEC forecasts peak demand growth of 1.3 percent per year for the 2010-2020 period.
- On peak summer days PG&E demand increases by more than 1,000 MW per hour, nearly 200 MW every ten minutes, and decreases by more than 2,000 MW per hour, greater than 300 MW every 10 minutes.
- The Governor's Office should convene an independent panel to weigh available evidence regarding the need to replace once-through cooled steam boiler capacity for grid reliability purposes. Available studies by CAISO and SWRCB reach such different conclusions that a technical consensus must be reached at strategic level before committing to build natural gas-fired replacement plants.
- This same panel should also weigh available evidence regarding CAISO and PG&E assertions that solar and wind variability require construction of numerous new natural gas-fired power plants. Available data also indicates that cloud cover is not a factor in the Bay Area on peak demand summer days and little variability in the aggregate output of distributed PV systems on partly cloudy days.

4. PG&E Strategic Plan

4.1 Compliance with Energy Action Plan Loading Order

PG&E's *2006 Long-Term Procurement Plan* is designed, according to PG&E, to implement the state's *Energy Action Plan*.[147] PG&E indicates it is pursuing energy efficiency as a preferred resource in its procurement strategy consistent with the *Energy Action Plan*, and that the company is fully committed to pursuing all cost-effective energy efficient opportunities.[148]

The CPUC issued a staff report in April 2010 that found that, for the 2006 to 2008 period, PG&E performed poorly in all energy efficiency categories.[149] The utility fell into the penalty zone for peak demand savings of 60 percent and natural gas savings of 63 percent, and into the deadband for energy savings of 71 percent.[150]

Residential and small commercial central air conditioning units are the primary contributor to summertime peak loads. The *Energy Efficiency Strategic Plan* targets a 50 percent improvement in efficiency of heating, ventilating, and air conditioning systems by 2020, and a 75 percent improvement by 2030.[151] PG&E offers no rebates for central air conditioner upgrades.[152]

PG&E acknowledges in its *2006 Long-Term Procurement Plan* that there appears to be continuing regulatory and customer interest in expanding reliance on CHP to meet future energy demand in California. The *Energy Action Plan* loading order specifically refers to cost-effective CHP as preferable to traditional sources of electricity generation.

However, PG&E notes that it has seen no indication that customers are more inclined recently to install CHP than they have been in prior years.[153] Consequently PG&E assumes customers will continue historic behavior. This translates into an annual rate of new CHP in PG&E territory of 28 MW per year.[154] At this rate of CHP additions, 280 MW of new CHP would be added over ten years in PG&E territory.

The CPUC issued a proposed settlement agreement in December 2010 for rates to be paid by the IOUs to existing and future CHP plants selling electricity to the IOUs.[155] The settlement agreement recognizes the state's AB 32 implementation target of adding 4,000 MW of new CHP by 2020.[156] PG&E would need to add approximately 1,200 MW of CHP over ten years to meet its proportion of the 4,000 MW target.[157]

The CHP settlement agreement includes a bidding process similar to the process in the CPUC's 1,000 MW Renewable Auction Mechanism (RAM) PV program.[158] CHP developers bid into an IOU request for offers solicitation at a price sufficient to finance and develop their facilities, and the IOUs pick which projects move forward based on selection process similar to the least cost, best fit framework used with RPS bids.[159] The agreement explicitly states that an IOU may use what it deems to be excessive bid prices as justification for failing to meet the MW and GHG reduction targets for CHP in the *AB 32 Scoping Plan*.[160]

PG&E has joined with SCE and SDG&E to challenge CHP tariffs that would provide CHP operators with rates that are at or above the market referent price of approximately $0.10/kWh.[161,162] The IOUs state that CHP electricity is less valuable than the output of a combined cycle natural gas-fired plant, which is the basis for the market referent price, and therefore should be paid less than this reference price. As shown in Chapter 14, a price of at least $0.12/kWh is necessary to assure that CHP projects receive sufficient income from electricity sales to make the project(s) economically viable.

PG&E included four scenarios in its most recent 2006 strategic plan.[163] The minimum distributed PV installation rate among these four scenarios is a constant 28 MW per year. The maximum distributed PV installation rate evaluated would be 40 MW per year in 2011, increasing to approximately 300 MW per year in 2016.

The RAM PV program was approved by the CPUC on December 16, 2010.[164] Under the RAM format, project developers submit bids in response to periodic IOU solicitations. The lowest bids are selected, even if the lowest bids are above the market referent price. PG&E is protesting the approval of this program. The January 6, 2011 PG&E rehearing request states:[165]

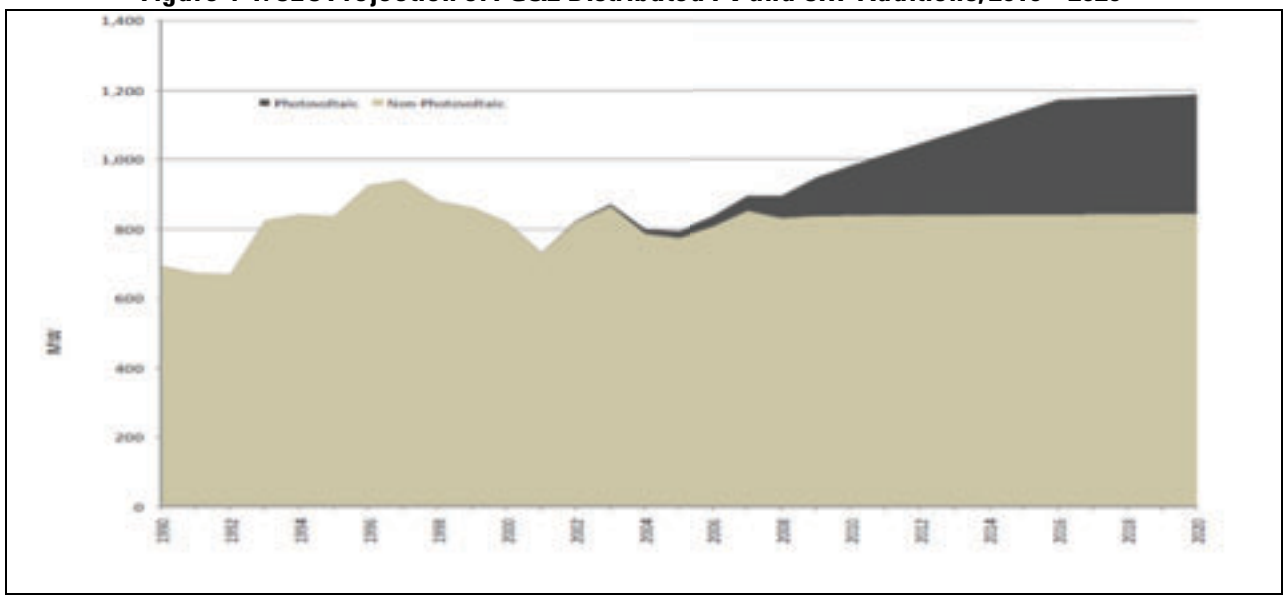
> "PG&E seeks rehearing of the Decision because it violates state law in three ways. First, PG&E's RAM procurement obligation is not limited to procuring only those resources whose prices are at or below the Commission-determined market price referent ("MPR"), which violates the RPS statute's cost limitation provisions. Second, the Decision does not permit the investor-owned utilities ("IOUs") to suspend their RAM programs if they achieve the 20 percent RPS target, which violates the RPS statute's clear directive that the IOUs cannot be required to procure greater than 20 percent renewables. Third, the Decision applies the RAM program to only the IOUs."

PG&E makes clear with this statement, made in January 2011, that it sees itself as legally obligated to suspend renewable energy procurement when it reaches 20 percent RPS, not 33 percent, and that it is only obligated to procure renewable energy resources at or below the market reference price.

Figure 4-1 is the projection of distributed PV and CHP additions to PG&E territory developed by the CEC for the 2010 – 2020 California electricity demand forecast. The CEC projection does appear reasonably accurate based on PG&E's current actions to limit deployment of CHP and distributed PV.

PG&E estimates in its *2006 Long-Term Procurement Plan* that, if it achieves all of its *Energy Action Plan* targets and the 20 percent RPS requirement, PG&E GHG emissions will increase by 14 to 23 percent by 2016.[166] Assuming the only change in this strategic plan is the achievement of a 33 percent RPS target in 2020, PG&E's GHG emissions in 2020 would be about 3 percent higher than 2010 GHG emissions in a low hydro year, and about 5 percent lower in a normal hydro year.[167,168] The primary reason for little or no reduction in GHG emissions is that projected PG&E load growth consumes much of the renewable energy increment from 20 percent to 33 percent.

Figure 4-1. CEC Projection of PG&E Distributed PV and CHP Additions, 2010 – 2020[169]



PG&E will be subject to cap-and-trade GHG emissions reduction requirements under AB 32. AB 32 mandates that California reduce GHG emissions to 1990 levels by 2020. CARB is required to develop emission limits and control measures by regulation to achieve this GHG reduction objective. The emission limits and control measures must be operational by January 1, 2012, and may include a cap-and-trade GHG emissions reduction program. CARB released a proposed cap-and-trade program resolution in December 2010 that includes GHG reduction targets for electricity utilities.[170]

It is unclear whether PG&E will be required to reduce GHG emissions at all by 2020 as a result of the cap-and-trade targets proposed by CARB for the electricity industry. Other California IOUs and POUs, with a few exceptions, use higher amounts of coal and natural gas-fired power than PG&E and would be the likely first-in-line candidates to reduce GHG emissions under a California electricity GHG cap.[171]

Fifty-two percent of the electricity sold by PG&E in 2009 came from fossil fuel sources, as shown in Figure 3-11. As a result of AB 162 and beginning in the 2009 reporting year, California IOUs are no longer required to report the fossil fuel content of wholesale market power purchases.[172] The IOUs now state "unspecified" for this category.[173] However, in 2008 PG&E reported that 8 percent of total electricity sales came from coal-fired sources. Coal-fired cogeneration plants in California under long-term contract to PG&E account for 1.3 percent of sales in 2009.

It is important to note that regulation of power imports is included in the scope of the cap-and-trade resolution. The resolution states that CARB staff is to develop requirements to prevent utilities from shifting GHG emissions to imported power to comply with cap and trade requirements.[174] However, AB 162 has eliminated the requirement that the CEC determine the fuel composition of imported power.

The approximate GHG emissions from PG&E electricity sales in 2008, assuming a composite natural gas-fired GHG emission factor of 0.45 tons CO_2/MWh and a coal-fired GHG emission factor of 1.06 tons CO_2/MWh, were 22 million tons per year.[175,176,177] The average CO_2 emission rate per MWh of electricity sold by PG&E in 2008 was approximately 0.27 tons CO_2/MWh.[178]

PG&E provides T&D service for Direct Access customers. Approximately 7 percent of the electricity supplied in PG&E service territory is supplied to Direct Access customers.[179] As a result, the GHG emission impact of Direct Access power purchases is substantial. Direct Access customers purchase electricity primarily based on low price.

4.2 PG&E Renewable Energy Strategy

PG&E's renewable energy strategy is to purchase a large amount of output from large-scale solar projects in the Mojave Desert, a substantial quantity of new wind power, and develop 500 MW of distributed PV in PG&E service territory.[180]

PG&E reached 17.7 percent renewable energy as a percentage of sales in 2010.[181] A significant portion of this renewable energy is generated in the Bay Area. Regional renewable energy resources include geothermal generation at The Geysers in Sonoma County and wind generation in Altamont Pass (Contra Costa and Alameda counties) and Solano County.

PG&E has agreed to pay more than the market reference price in 77 percent of the RPS power purchase agreements it has signed,[182] despite the PG&E statement in its January 2011 request to rehear the approval of the CPUC's distributed PV RAM program that it is not obligated to pay more than the market reference price for renewable energy. The CPUC projects that ratepayers will pay $6 billion beyond the reference price to meet the terms of renewable energy contracts signed by PG&E, SCE, and SDG&E.[183]

The utility reference case developed by the CPUC assumes that all IOU solar power developed to achieve the 33 percent by 2020 target will be utility-scale remote projects.[184] The availability

Table 4-1. Status of Fast Track Solar Projects on BLM Land[185]

Remote solar project	Technology	Capacity (MW)	Status
Ivanpah - PG&E	power tower	370	multiple lawsuits
Ridgecrest	solar trough	~~250~~	cancelled
Genesis - PG&E	solar trough	250	lawsuit
Calico	dish Stirling	~~663~~	cancelled
Blythe	solar trough	1,000	lawsuit
Palen	solar trough	500	lawsuit
Imperial County	dish Stirling	~~709~~	cancelled
Desert Sunlight - PG&E	PV	550	lawsuit
Chevron Lucerne Valley	PV	45	lawsuit
Total large remote solar:		2,715	

of federal cash grants and loan guarantees for renewable energy projects under the American Recovery and Reinvestment Act (ARRA), and preferential "fast track" access to undeveloped Bureau of Land Management (BLM) land, gave strong initial momentum to fast track PG&E solar projects.[186,187] However, as shown in Table 4-1, multiple project cancellations have reduced overall capacity in the fast track pool to just over 2,700 MW. Legal complications for the remaining fast track solar projects, related to concerns over endangered species and Native American cultural sites, have slowed development and created uncertainty over how many projects will be completed.[188]

4.3 Conclusions and Recommendations

- PG&E is not meeting energy efficiency targets set by the CPUC.
- PG&E is resisting an increase in distributed PV deployments through the RAM process.
- PG&E is resisting paying a CHP FIT rate that would be sufficient to get CHP projects built.
- The most important element of RPS legislation is the yearly progress requirement, if it is accompanied by substantial penalties for non-compliance.
- The CPUC is currently projecting IOU compliance with the 20 percent RPS standard in 2013. A 33 percent RPS standard, if passed into law, would require an average rate of progress of 2 percent per year between 2014 and 2020 to meet the 33 percent target.
- A 2 percent per year RPS progress rate with substantial penalties for non-compliance should be a requirement in 33 percent by 2020 RPS legislation.
- The 33 percent requirement should be identified as a minimum floor and not a ceiling.

5. BASE 2020 Plan

BASE 2020 is in its essence a combination, with slight modifications, of existing California state policy and plans. The *Energy Action Plan* loading order, which prioritizes energy efficiency, rooftop PV, demand response, and CHP over conventional gas-fired generation to meet California's electricity needs, is a core element of BASE 2020. The ambitious energy efficiency, rooftop PV, and air conditioning peak load reduction targets in BASE 2020 come directly from the California *Energy Efficiency Strategic Plan*.[189]

The CHP target for the Bay Area is derived from the *AB 32 Scoping Plan*, which calls for 4,000 MW of new CHP in California by 2020.[190] California has a large potential for biogas and biomethane production, principally from landfills and dairies. Extensive use of these biofuels in new CHP plants will minimize GHG emissions from these plants.

The energy storage additions in BASE 2020 are based on the recent passage of energy storage legislation in California, and action by FERC to support energy storage as an alternative to conventional generation. FERC envisions advanced energy storage as an integral part of an electricity supply system with substantial amounts of wind and solar power.

A FIT is the financing tool relied on in BASE 2020 to achieve the distributed PV and CHP targets. Germany has demonstrated that a properly calibrated FIT can lead to the sustained deployment of spectacular quantities of solar and wind power. Germany installed approximately 6,500 MW_{ac} of PV, primarily on rooftops, in 2010. This is one-third of the ten-year PV target included in BASE 2020.

There are two existing large-scale renewable energy development zones in the Bay Area where expansion is underway or could be achieved with technology upgrades. Approximately 300 MW of new wind development is underway in the Montezuma Hills area of Solano County. This wind capacity is included in BASE 2020 in light of the high probability that it will be built. The modification of the existing conventional wet cooling towers at the geothermal plants in The Geysers region of Sonoma County to parallel wet-dry cooling systems could substantially increase output. BASE 2020 includes upgrading of cooling systems at the The Geysers to increase output by up to 300 MW and improve the sustainability of the geothermal resource.

Finally, the Bay Area already has extensive conventional natural gas-fired resources and one large dedicated hydroelectric resource (Hetch Hetchy). Additional generation sources in PG&E territory that supply the Bay Area including nuclear, natural gas-fired, large hydroelectric, coal and biomass. These resources, with the exception of the coal power, will provide ample electric generation support as the Bay Area transitions to a higher percentage of local renewable power. An element of BASE 2020 is the substitution of Bay Area clean power for in-state coal electricity purchases by PG&E.

Actual peak reserve margins, without considering the additional capacity of four new gas turbine projects that have approved power purchase agreements with PG&E, are in the range of 40 percent. This translates into an actual PG&E electricity supply surplus of 5,000 MW beyond the reserves required by the CPUC to assure grid reliability under all foreseeable conditions.

Peak loads will drop methodically over the next decade, at an average rate of nearly 1,000 MW per year, as BASE 2020 is implemented. The PG&E reserve margin will grow rapidly without additions of new gas-fired generation as a result. This same pattern is evident, to a lesser degree, in the seven 2010 – 2020 demand scenarios developed by the CPUC for PG&E in the *2010 Long-Term Procurement Proceeding*.[191] PG&E peak demand drops at an average rate of about 100 MW per year in those scenarios.

There is no grid reliability or peak demand justification for building new conventional natural gas-fired generation to meet Bay Area electricity needs. The purpose of existing gas-fired generation will be to provide the electricity demand that can not be met by energy efficiency, demand response, CHP, distributed PV, existing utility-scale renewable energy supplying PG&E and the Bay Area POUs, and utility-scale additions in Solano County (wind) and Sonoma County (geothermal).

5.1 Bay Area CO_2 Emissions from Electricity Usage in 2020 Without BASE 2020

No significant change in PG&E Bay Area CO_2 emissions from electricity usage is expected between 2010 and 2020, even assuming that PG&E reaches a 33 percent RPS target by 2020. The principal reason for the lack of change in CO_2 emissions is that the growth in electricity demand projected by PG&E will neutralize the GHG reduction benefits of achieving the 33 percent RPS target.

Some assumptions had to be made to calculate current Bay Area CO_2 emissions from electricity usage. Estimates were developed for PG&E bundled customers, PG&E Direct Access customers, and POUs. Direct Access customers are presumed to purchase lowest-cost electricity. Lowest-cost electricity would generally be wholesale imported power. Data is available on the fuel mix composition of wholesale imported power. This data allows estimation of a CO_2 emission factor for electricity imports. This factor can also be used to estimate CO_2 emissions from Direct Access customer electricity usage.

Through 2008 the CEC estimated the fuel mix composition of imported power bought by California utilities from wholesale electricity providers or short-term market purchases.[192] The reason stated by the CEC for estimating the imported power fuel mix composition is:[193]

> "Since imports represent a significant portion of the electricity supply serving California demand, a *realistic* accounting of associated emissions will be important to design and implement in the greenhouse gas reduction program required under the *Global Warming Solutions Act of 2006* (AB 32). A flawed resource mix estimate may cause unintended market consequences that increase costs and provide no effect on total greenhouse gas emissions."

AB 162 eliminated the requirement that the fuel mix composition of imported power be determined by the CEC.[194,195] The last year the CEC calculated the fuel mix of imported power was 2008. The coal power content of imported power was estimated at 34 percent by the CEC for 2008.[196]

CARB uses a GHG emission factor of 960 lb CO_2/MWh for imported power, equivalent to 0.48 tons CO_2/MWh, in its emissions forecast for the proposed GHG cap-and-trade program.[197] This is the CO_2 emission rate used for imported power in BASE 2020.

The CO_2 emissions estimate for PG&E territory including both bundled and Direct Access customers, and for the Bay Area, is provided in Table 5-1. Bay Area POUs as a group are assumed to have a CO_2 emission rate equivalent to that of PG&E bundled customers. Direct Access customers are presumed to rely primarily on imported power. Total CO_2 emissions for PG&E bundled and Direct Access customers are estimated at 25 million tons per year in 2008. This CO_2 emission rate is expected to stay relatively constant through 2020 as indicated in PG&E's *2006 Long-Term Procurement Plan*. PG&E forecasts that load growth will nullify the CO_2 reduction benefits of the increased level of renewable energy, even assuming PG&E meets a 33 percent RPS target by 2020.

CO_2 emissions from electricity usage in the Bay Area, including PG&E bundled and Direct Access customers and Bay Area POUs, are about 16 million tons per year as shown in Table 5-1. The nine Bay Area counties represent about 60 percent of electricity usage in PG&E service territory, and about 50 percent of usage in the PG&E planning area, which includes POUs.[198]

Table 5-1. Total Bay Area CO_2 Emissions from Electricity Consumption in 2008

Source	GWh[199]	CO_2 emission factor (tons/MWh)	2008 PG&E CO_2 emissions (million tons)	Bay Area fraction	2008 Bay Area CO_2 emissions (million tons)
PG&E bundled customers	81,983	0.27	22	0.6	13
PG&E Direct Access customers	6,376	0.48	3	0.6	2
Bay Area POUs	5,327	0.27	NA	1.0	1
		PG&E total:	25	Bay Area total:	16

5.2 CO_2 Reductions Achieved with BASE 2020

A framework objective of BASE 2020 is achieving net zero energy existing and new buildings, following the timeline established in the *Energy Efficiency Strategic Plan*. The *Energy Efficiency Strategic Plan* uses a combination of energy efficiency measures and rooftop PV to achieve net zero energy buildings. The Bay Area 2008 electricity usage was 57,316 GWh. Under BASE 2020, the Bay Area would reduce electricity demand relative to the 2008 baseline by over 17,000 GWh through energy efficiency measures. This represents an average energy efficiency reduction of 25 to 30 percent in residential and commercial buildings. The Bay Area will also displace about 8,000 GWh per year of electricity purchases through the installation of nearly 4,000 MW of rooftop PV. This is equivalent to 25 percent of existing residential and commercial buildings achieving net zero energy by 2020.[200]

BASE 2020 adopts the *Energy Efficiency Strategic Plan* target of a 50 percent reduction in air conditioning loads by 2020. Achieving this peak demand reduction target will reduce Bay Area peak load by over 2,000 MW.

The *AB 32 Scoping Plan* target of 4,000 MW of new CHP by 2020 will result in approximately 840 MW of new CHP in Bay Area by 2020. The BASE 2020 fuel composition target for CHP is 50 percent biogas or biomethane, combined with natural gas, to reduce the GHG footprint of new CHP to approximately 300 lb CO_2/MWh. This is less than half the GHG footprint of a state-of-the-art baseload combined cycle plant.

Existing geothermal plants at The Geysers will be retrofit with parallel wet-dry cooling systems to increase sustainable output at The Geysers from the current 900 MW to 1,200 MW, a 300 MW increase. 300 MW of new wind projects planned for Solano County are also incorporated into BASE 2020.

400 MW of sodium-sulfide battery storage will be integrated into the Solano County wind production area to provide 400 MW of peaking power and to smooth output from the wind generators. 200 MW of battery storage will also be added to residential and commercial buildings to offset the projected growth in peak demand of plug-in hybrid electric vehicles (PHEVs) over the next decade. The purpose of adding this battery support at the point-of-charge is to assure that the strategic objective of net zero energy buildings is met even as PHEV loads are added to buildings.

Table 5-2 summarizes the actions to be taken in BASE 2020 to reduce GHG emissions. Achieving BASE 2020 targets would reduce Bay Area GHG emissions from electricity usage by more than 70 percent by 2020 relative to a 2008 baseline.

The 2008 PG&E peak load was 21,827 MW.[201] As noted, the nine Bay Area counties account for approximately 60 percent of PG&E service territory electricity usage. Therefore, the 2008 peak load attributable to PG&E Bay Area bundled and Direct Access customers is 0.60 × 21,827 MW = 13,096 MW. The CEC estimates a 2008 peak load attributable to Bay POUs of 899 MW.[202] The total nine-county Bay Area peak load in 2008, including PG&E peak loads and Bay Area POU peak loads, was approximately 14,000 MW.

Table 5-2. CO_2 Reduction Achieved by Implementing BASE 2020

Source of CO_2 reduction	Quantity of reduction (GWh)	CO_2 emissions (million tons)	Fuel type displaced	Avoided CO_2 emissions (million tons)	Net CO_2 reduction (million tons)
Energy efficiency	9,760	0	natural gas	4.4	4.4
Rooftop PV	7,279	0	natural gas	3.3	3.3
CHP	6,770	1	imported gas/coal	3.3	2.3
New geothermal	2,234	0	imported gas/coal	1.1	1.1
New wind with energy storage	867	0	imported gas/coal	0.4	0.4
Total reduction:	26,910				11.5

The Bay Area peak load reductions that would occur as a result of the implementation of BASE 2020 are shown in Table 5-3. Bay Area peak load would decline on the PG&E and Bay Area POU systems from the 2008 peak of approximately 14,000 MW to about 5,000 MW in 2020.

Table 5-3. Bay Area Peak Load Reduction Achieved by Implementing BASE 2020

Source of reduction	Basis of reduction (MW)	Peak load reduction (MW)
Energy efficiency[203]	25 percent reduction in demand on average from energy efficiency measures	3,500
Air conditioner/ chiller plant efficiency improvement	Cooling load represents about 30 percent of peak load. Highest efficiency central air conditioning (CAC) units replace worn-out units, 50 percent reduction. Same reduction targeted for commercial building chiller plants. Cycling capability built into new CAC units to allow 50 percent online, 50 percent offline at peak. Assumes 50 percent turnover in CAC population in 10 years.	2,100
Rooftop PV	3,800 MW_{ac} of rooftop PV added over decade. 50 percent of this capability, 1,900 MW_{ac}, available at peak.	1,900
Battery storage associated with rooftop PV	200 MW of battery storage integrated with PV systems added over decade to offset peak demand of plug-in electric vehicles and provide peak power to grid. Assumes 100 MW contributed at peak with integrated PV systems providing other 100 MW (50 percent of PV MW_{ac} capacity at peak).	100
CHP	840 MW of CHP is added to Bay Area, removing equivalent amount of load from utility demand at peak.	840
Geothermal	340 MW of geothermal is added at The Geysers, removing equivalent amount of load from utility demand at peak.	300
Wind with energy storage	400 MW of sodium-sulfide battery storage integrated with Solano County wind development area.	400
Total Bay Area peak load reduction:		9,140

About 60 percent of the peak load decline would result from energy efficiency measures combined with substantially more efficient central air conditioner performance and management.[204] The remaining peak reduction would be demand shifted from PG&E to rooftop PV, CHP, geothermal, wind, and energy storage. Table 5-3 summarizes the actions to be taken to achieve peak load reductions on PG&E and Bay Area POU systems.

5.3 Conclusions and Recommendations

- The CO_2 emission rate from coal power, 1.06 tons CO_2/MWh, is four times higher than the PG&E average CO_2 emission rate from all generation sources of 0.27 tons CO_2/MWh. Even though coal power provided only 8 percent of electricity sold be PG&E in 2008, coal power CO_2 emissions represented about 30 percent of total PG&E CO_2 emissions from electricity sales.

- The primary source of PG&E coal power is imported power purchased on the wholesale power market and identified as "unspecified" in the 2009 PG&E power mix. These market power purchases must be gradually displaced over the next decade by baseload CHP, geothermal power, and the proposed integrated wind power/battery storage project in Solano County.

- The second source of PG&E coal power purchases are long-term qualifying facility contracts with a handful of California coal-fired cogeneration plants. These contracts need to be phased-out over the next decade and displaced with baseload CHP, geothermal power, and the proposed integrated wind power/battery storage project in Solano County

- AB 162 should be amended to require the CEC to continue to calculate the GHG burden of PG&E wholesale power purchases. Crafting an efficient GHG reduction strategy for electricity generation will be hampered by the lack of precise information on the GHG impact of these power purchases.

6. Comparative Capital Cost and Cost-of-Energy of Generation Technologies

Table 6-1 summarizes available current capital cost values, in dollars per kW of installed capacity, and the levelized cost-of-energy (LCOE) production over a 20-year period, for principal renewable energy and conventional power generation technologies. Table 6-1 also includes the estimated cost adders to the LCOE where appropriate for: 1) new transmission, 2) back-up peaking gas turbine capacity for technologies with low availability during summer peak demand, and 3) transmission line losses. The "all-in" LCOE is provided for each technology in the far right column of Table 6-1.

Table 6-1. Comparative Capital Cost and Levelized Cost-of-Energy (LCOE) of Representative Generation Technologies

New generation technology		Capacity (MW)	Capital cost[a] ($/kW$_{ac}$)	Capacity factor[a] (%)	O&M cost, incl. fuel ($/MWh)	LCOE genera-tion ($/MWh)	New trans-mission adder[f] ($/MWh)	Avail-ability at peak[g] (%)	Requires back-up turbines for grid reliability?	Back-up turbine cost adder[j] ($/MWh)	Trans-mission losses, 5%[k] ($/MWh)	LCOE total ($/MWh)
1	Dry-cooled solar thermal, remote	generic	5,350 – 5,550	20 – 28	30	202	46	77	no	0	12	260
2	Distributed fixed thin-film PV	20	3,600 – 4,000	20 – 27[c]	17 - 25	138[d]	0	50	no[h]	0	0	138
3	Distributed 1-axis track polysilicon PV	20	4,500	23 – 31[c]	20 - 27	135[d]	0	77	no[h]	0	0	135
4	Utility-scale fixed thin-film PV, remote	250	3,600 – 4,000[b]	20 – 27[c]	17 - 25	138[d]	46	50	no[h]	0	9	193
5	Utility-scale 1-axis track polysilicon PV, remote	250	4,500[b]	23 – 31[c]	20 - 27	135[d]	46	77	no[h]	0	9	190

Table 6-1. Comparative Capital Cost and Levelized Cost of Energy (LCOE) of Representative Generation Technologies (cont.)

New generation technology		Capacity (MW)	Capital cost[a] ($/kW$_{ac}$)	Capacity factor[a] (%)	O&M cost, incl. fuel ($/MWh)	LCOE genera-tion ($/MWh)	New trans-mission adder[f] ($/MWh)	Avail-ability at peak[g] (%)	Requires back-up turbines for grid reliability?	Back-up turbine cost adder[j] ($/MWh)	Trans-mission losses, 5%[k] ($/MWh)	LCOE total ($/MWh)
6	Onshore wind, remote	200	2,371	33	21	95	46	4/ 29	yes[i]	55/ 25	10/ 8	206 /174
7	Biogas – landfill, local	generic	2,750	80	19	92	0	90+	no	0	0	92
8	Biomass, remote	generic	4,522	85	12	108	16	90+	no	0	6	130
9	Geothermal, remote	generic	6,379	81	5	148	17	90+	no	0	8	173
10	Natural gas combined cycle, remote	500	1,249	65	82	134[e]	21	90+	no	0	8	163
11	Natural gas simple cycle, local	100	1,204	5	150	795	0	90+	no	0	0	795
12	Pulverized coal, remote	1,000	4,000	80	42	112	15	90+	no	0	6	133
13	Nuclear, remote	1,000	7,500	90	47	151	46	90+	no	0	10	207

Table 6-1 notes:

a) Sources of data by generation type (except on-peak availability values): See CPUC Rulemaking R.10-05-006, 2010 Long-Term Procurement Planning (LTPP) proceeding, *Planning Standards for System Resource Plans – Part II, Long-Term Renewable Resource Planning Standards – Attachment 1*, prepared by Energy & Environmental Economics for CPUC, June 22, 2010, Table 1, p. 12, for generation technologies **1, 6, 7, 8, 9.** See Renewable Energy Transmission Initiative (RETI), *RETI Phase 2B Final Report*, May 2010, for generation technologies **2, 3, 4, 5**. See CEC, *Comparative Costs of California Central Station Electricity Generation*, January 2010, for generation technologies **10** and **11**. See Moody's Corporate Finance, *New Nuclear Generating Capacity: Potential Credit Implications for U.S. Investor-Owned Utilities*, May 2008, Table 9, p. 15, for generation technologies **12** and **13**.

b) It is assumed that economies of scale are fully realized at 20 MW and no additional economies are realized in larger PV configurations. This is the implicit assumption in the reference tables in the RETI Phase 2B Final Report, May 2010, Tables 4-7 and 4-8. At the time the RETI Phase 2B Final Report was issued, the largest PV array in the U.S. was 25 MW (FPL). Since publication of the RETI Phase 2B Final Report, Sempra Generation has brought online a 48 MW fixed, thin-film PV array in Boulder City, NV.

c) The highest capacity factor in range is for desert sites. Lowest capacity factor in range is for coastal sites. The fixed PV LCOE assumes a very good to excellent solar site. Examples: Southern California, Central Valley, and inland from East Bay.

d) PV systems prices have fallen significantly since RETI published the referenced LCOE's for distributed PV systems of 20 MW and greater in the RETI Phase 1A Final Report, May 2010. CPS Energy, the San Antonio public utility, signed contracts with SunEdison for three 10 MW PV arrays to be constructed in the greater San Antonio area in October 2007 for $150/MWh. San Antonio has about 10 percent less solar insolation on an annual basis than central California and Southern California coastal areas. The value of the CPS Energy – SunEdison contract, adjusted to the ~10 percent better solar intensity of Central California and Southern California coastal areas, would be about $135/MWh. See: SNL Financial, *In the news - CPS Energy partnering with SunEdison to build three 10 MW solar PV projects in its service area*, October 7, 2010.

e) The estimated LCOE for a conventional merchant 500 MW combined cycle plant in the CEC's *Comparative Costs of California Central Station Electricity Generation*, January 2010, is $124/MWh assuming a 75% capacity factor. Actual capacity factor of California's combined cycle fleet is approximately 65%. The CPUC assumes a 65% capacity factor for combined cycle units in *Inputs and Assumptions to 33% Renewables Portfolio Standard Implementation Analysis,* prepared by E3 for CPUC, July 2009. At a 65% capacity factor, the corrected LCOE for a conventional merchant 500 MW combined cycle plant with a 2009 online date is $134/MWh. For a 2018 online date, $183/kWh is projected by the CEC. The CPUC's MPR for a 20-yr power purchase agreement with start date of 2011 is $101/MWh at 92% capacity factor. The $101/MWh MPR value includes a $6/MWh CO_2 emissions charge.

f) The CPUC estimates a new transmission annual cost of $1.27 billion per year to transmit 36,870,000 MWh/year of new remote solar and wind resources by 2020. See: CPUC, *33% Renewables Portfolio Standard Implementation Analysis Preliminary Results,* June 2009, Tables 4 and 5, pp. 21-22. This is equivalent to a cost of $34.45/MWh for solar and wind resources transmitted over these lines. The CPUC assumes amortization of transmission capital expense over 40 years, while it amortizes renewable generation over 20 years. To level the investment cost recovery period between generation and transmission projects to allow an "apples-to-apples" annualized cost comparison, the new

transmission costs are adjusted in BASE 2020 to a 20-year amortization period. This results in an adjusted transmission penalty of $46.34/MWh (the amortization factor changes from 0.1246 for 40 years to 0.1676 for 20 years) using the RPS Calculator developed by Energy & Environmental Economics, Inc. for the CPUC. The assignment of a transmission cost of $0/MWh to 20 MW distributed PV arrays assumes these arrays are near load centers and are interconnected to the 12 kV distribution system. Remotely located 20 MW PV arrays would require either existing transmission or new transmission to reach demand centers. It is assumed for calculation purposes that the average capacity factor of solar and wind resources used to develop the CPUC transmission cost estimate is 30%. For load-following (combined cycle) or baseload resources, new transmission expense is scaled to account for the higher capacity factor. For example, in the case of a combined cycle unit with a 65% capacity factor, the adjusted new transmission penalty is: (30%/65%) x $46/MWh = $21/MWh.

g) On-peak availability factors for solar thermal (77%), tracking PV (77%), onshore wind (29%) are from Energy & Environmental Economics, Inc., *Inputs and Assumptions to 33% Renewables Portfolio Standard Implementation Analysis*, prepared for CPUC, July 2009, Table 7, p. 12. Onshore wind (4%) is from PG&E's *2006 Long-Term Procurement Plan*, Order Instituting Rulemaking to Integrate Procurement Policies and Considering Long-Term Procurement Plans – Volume I, Public Version Redacted, p. IV-77. On-peak availability factor for fixed PV (minimum 50%) is from Itron, *CPUC Self-Generation Incentive Program—Ninth-Year Impact Evaluation Report – Final Report,* submitted to PG&E, June 2010, Table 5-14, p. 5-32. PG&E peak hour fixed PV capacity factor in 2009 was 54%, July 14, 2009, 4 pm to 5 pm. All baseload units, including biomass, geothermal, combined cycle, simple cycle, coal, and nuclear, are assumed to have 90+ % availability at peak. Recent natural gas-fired applications for Bay Area projects, including Marsh Landing, Russell City Energy Center, Oakley, and Mariposa Energy Center, state expected availability in the range of 92 to 98%. Coal plant applicants around the country typically identify an availability design target of 90%. Nuclear plants reach 90%+ availability in years when refueling outages or major maintenance outages do not take place.

h) Analysis of hourly cloud cover and global irradiance data at the Oakland and San Jose airports during the top CAISO control area 100 peak one-hour demand events in 2007 shows little or no cloud cover in the Bay Area during peak demand events. This means that solar PV is reliably available during peak demand periods. This phenomenon is discussed in more detail in Chapter 7.

i) Wind power, unlike solar power, is generally not available during summer afternoon peak periods. For this reason, utilities typically use wind power as justification for adding gas turbines for reliability support. The added cost of back-up peaking gas turbine capacity is included in the LCOE for wind power provided in the table.

j) This cost adder represents the amount of back-up gas turbine capacity necessary for wind power to attain the 50% on-peak availability of fixed PV, assuming an on-peak availability for wind of either 4% (PG&E estimate) or 29% (CPUC estimate). The 2009 LCOE for new peaking turbine capacity at 5% capacity factor is $795/MWh. See: CEC, *Comparative Costs of California Central Station Electricity Generation*, January 2010, Table 4. A 200 MW wind farm, at a capacity factor of 33%, will generate 0.33 x 8,760 hr/yr x 200 MW = 578,160 MWh/yr. At a 4% on-peak capacity factor, the 200 MW wind farm will produce 8 MW on-peak and require 92 MW of peaker turbine back-up to match the 50% on-peak availability of fixed PV capacity. At a 5% capacity factor, 92 MW of peaking gas turbine capacity will have an annual cost of: 0.05 x 8,760 hr/yr x $795/MWh x 92 MW = $32 million/yr. The back-up peaker turbine adder in this case would be: $32 million/yr ÷ 578,160 MWh/yr = $55/MWh. At a 29% on-peak capacity factor, the 200 MW wind farm will produce 58 MW on-peak and require 42 MW of peaker turbine back-up to match the 50% on-peak availability of 200 MW of fixed PV capacity. At a 5% capacity factor, 42 MW of peaking gas turbine capacity will have an annual cost of: 0.05 x 8,760 hr/yr x $795/MWh x 42 MW = $14.6 million/yr. The back-up peaker turbine cost adder in this case would be: $14.6 million/yr ÷ 578,160 MWh/yr = $25/MWh.

k) The RETI Cost Calculator spreadsheet for renewable energy LCOE calculations assumes an average 5 percent transmission line loss, of total T&D losses, for remote renewable generation. See: http://www.energy.ca.gov/reti/documents/phase2B/CREZ_name_and_number.xls.

7. Peak Demand Profile and Solar and Wind Profiles

A generic California summertime 24-hour demand profile and power mix are shown in Figure 7-1. Demand generally peaks in the mid-afternoon. The generation units that supply this demand consist of: baseload units like the Diablo Canyon nuclear plant, hydroelectric units, and geothermal plants; energy purchases from the wholesale Western power market including coal plant output, intermediate and load following natural gas combined cycle units like Gateway and Colusa, and high-cost peaking gas turbines. Solar and wind resources displace portions of each segment of the conventional electricity supply portion of this power mix.

Figure 7-1. Power Mix Stack to Meet California Peak Load[205]

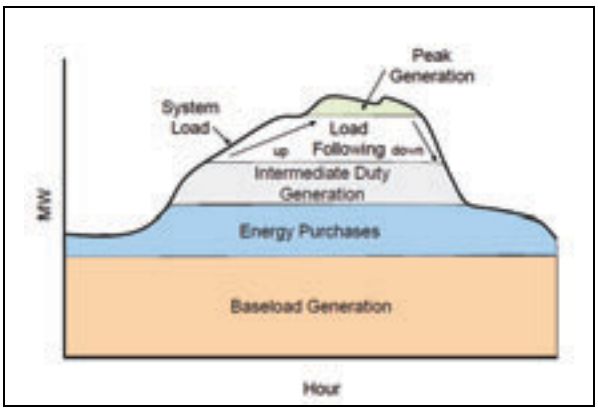
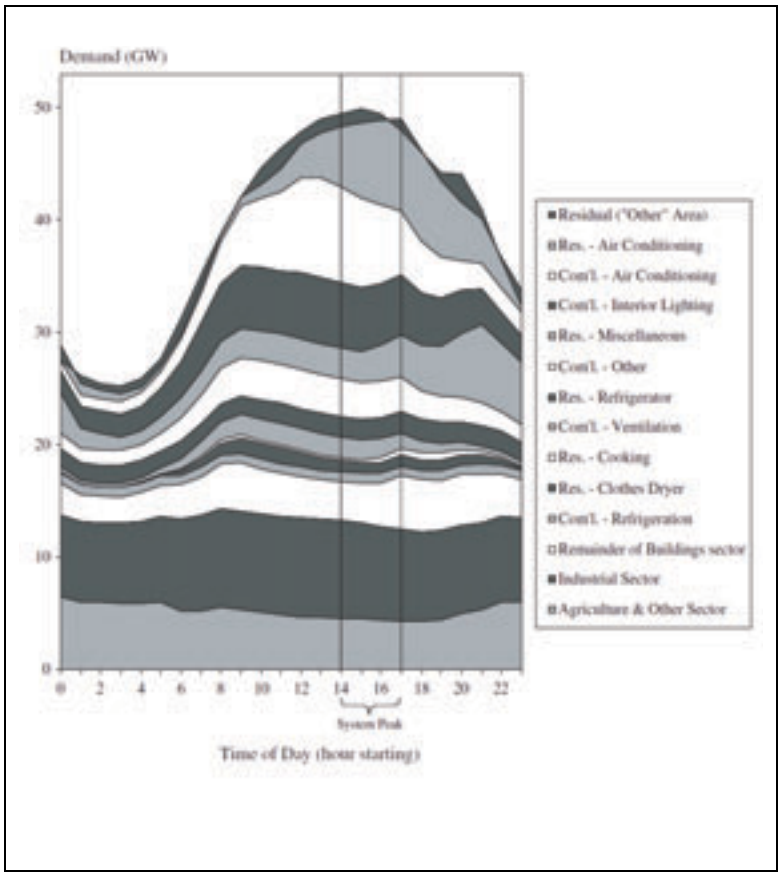


Figure 7-2 shows the sources of demand on California peak summer days. Air conditioning is the nearly exclusive additional summertime load, accounting for more than 30 percent of total load at the peak hour. Statewide load can increase at a rate of 4,000 to 5,000 MW per hour on peak summer days.

Utilities justify the construction of new generation and transmission assets based on projections of increased demand over time and potential shortages of electricity in the future if new assets are not brought online. The top few hours of demand drive this process. Any solution that eliminates growth in demand also eliminates the justification for authorizing the construction of new conventional generation and transmission infrastructure.

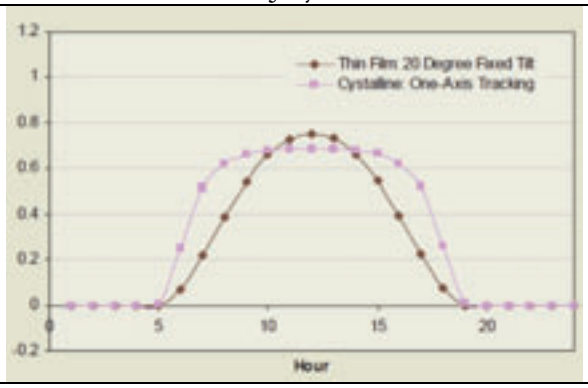
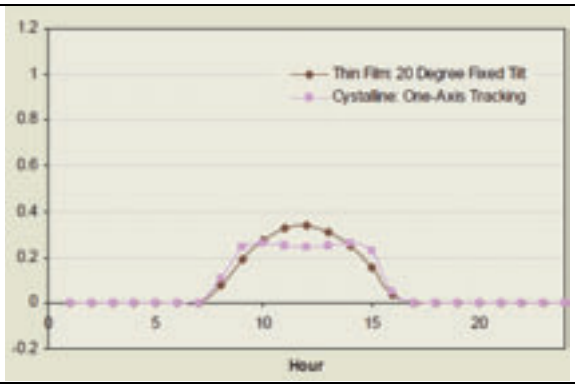
Figure 7-2. Summer 24-Hour Demand Profile in California and Sources of Demand[206]



7.1 Summer and Winter Output Profiles of PV Systems

The output of fixed PV systems is a reasonably good match for the summer peak load profile as can be seen in the July PV profile in Figure 7-3. In California the July profile is shifted one to the right, centered over 1 pm, due to the seasonal time change. The PG&E one-hour summer peak occurs consistently between 1 pm and 5 pm. In the 4 pm to 5 pm hour on a clear day, the fixed PV system is still generating over 50 percent of its rated capacity. A tracking PV system is generating about 80 percent of its rated capacity in the 4 pm to 5 pm hour.

Figure 7-3. Output Profiles of PV Systems in July and December[207]

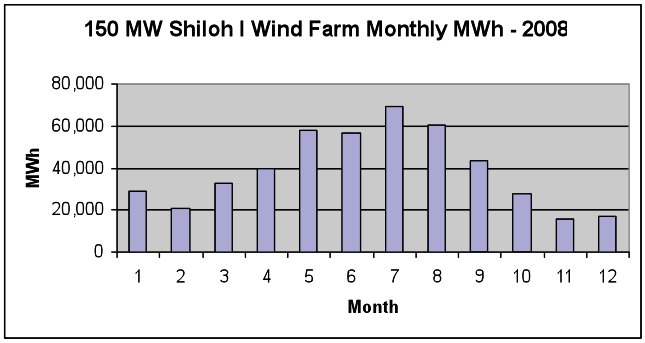
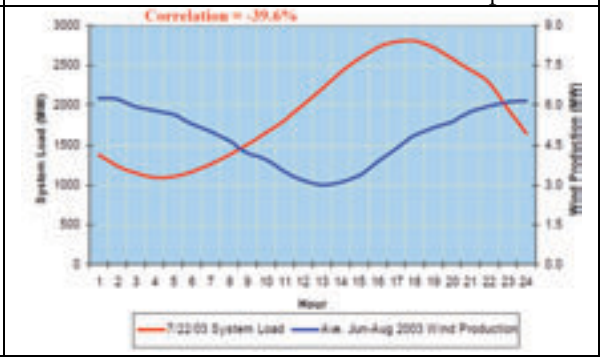
July	December
	

7.2 Annual and Summer Day Output - Solano County Wind

The wind production pattern in the Bay Area's largest and growing wind development area in Solano County is a good match to demand on a seasonal basis. Altamont Pass was the original focus of wind development in the Bay Area in the 1980s and 1990s. However, the Altamont wind resource is not as strong as Solano County wind, and there is little new development.

As shown in Figure 7-4a, Solano County wind farms are most productive in summer. However, wind output on an hour-to-hour basis does not track summertime peak demand. Output is at a minimum from noon to 3 pm, and then steadily increases. This characteristic is shown in Figure 7-4b.

Figure 7-4. Annual and Summer Day Output of Wind Power in Solano County[208,209]

a. Month-to-month wind farm output	b. Summer hour-to-hour wind farm output
	

7.3 Value of Electric Power Varies Depending on Time of Day

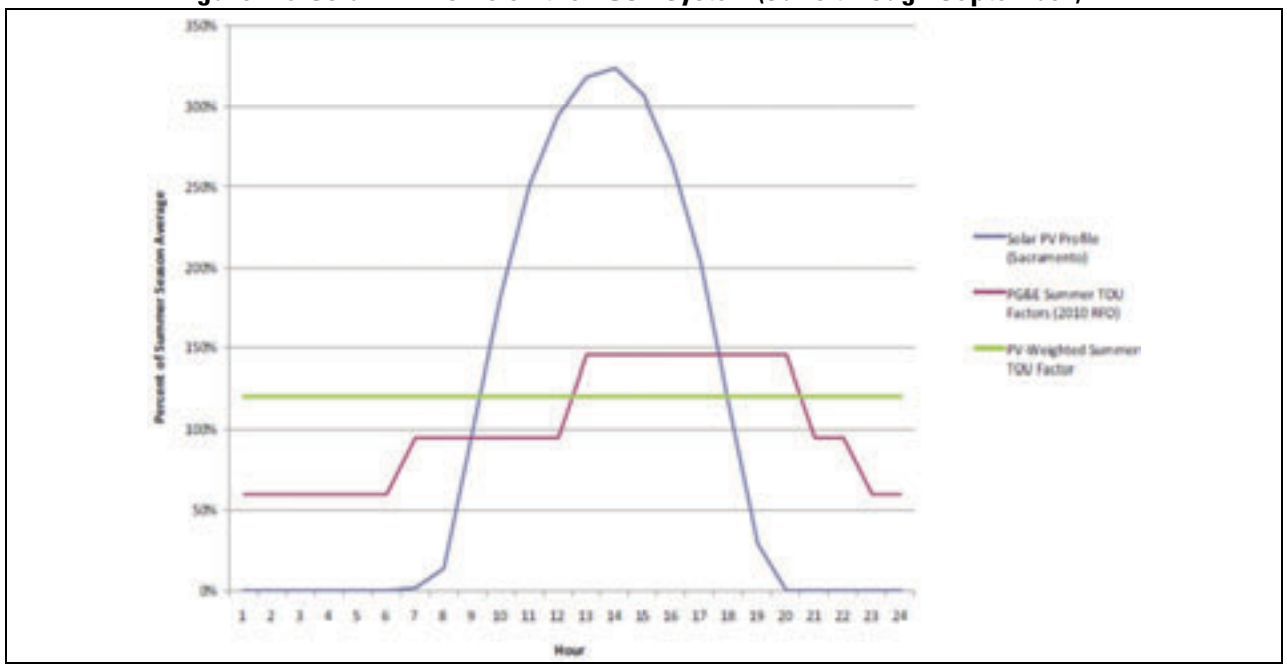
Electricity demand is lowest at night, on the weekends, and in winter. During these times there is an abundance of generating resources available and only least-cost generators are online. As the demand increases on hot summer workdays, progressively more expensive generation resources are brought online to meet demand. Utilities meet some of their demand requirements with wholesale power market purchases. All generators selling into the wholesale power market in any given hour receive the highest bid payment accepted in that hour. During peak hours on hot days, when high-cost peaking turbines are selling into the market, accepted bid prices may approach $1,000 per MWh or more.[210]

The output of a PV system roughly corresponds to the electricity demand periods when hour-to-hour summer electricity prices are highest, as shown in Figure 7-5. PG&E sets different tariffs for different times of day (purple line). These are known as "time-of-use" (TOU) tariffs. The average value of electricity during the periods when PV is generating is significantly higher over the course of a year than the average value of electricity over all the hours of the year.

The TOU factor that PG&E applies to PV is 1.24. However, SCE applies a TOU factor for PV of 1.32. SDG&E applies a factor of 1.12.[211] The wide variability in these TOU factors has raised concerns about the advisability of using these factors uncritically to determine the value of PV, as noted by solar industry advocates in 2010 testimony before the CPUC:[212]

> "Over time, it has become very clear that the IOUs' (summer on-peak time-of-delivery) TOD factors are problematic – they are not transparent, they vary widely from utility to utility even though the utilities operate in closely-linked markets . . . Even (The Utility Ratepayer Network) TURN acknowledges that the IOUs' TOD factors are not consistent."

Figure 7-5. Solar PV Profile on the PG&E System (June through September) [213]

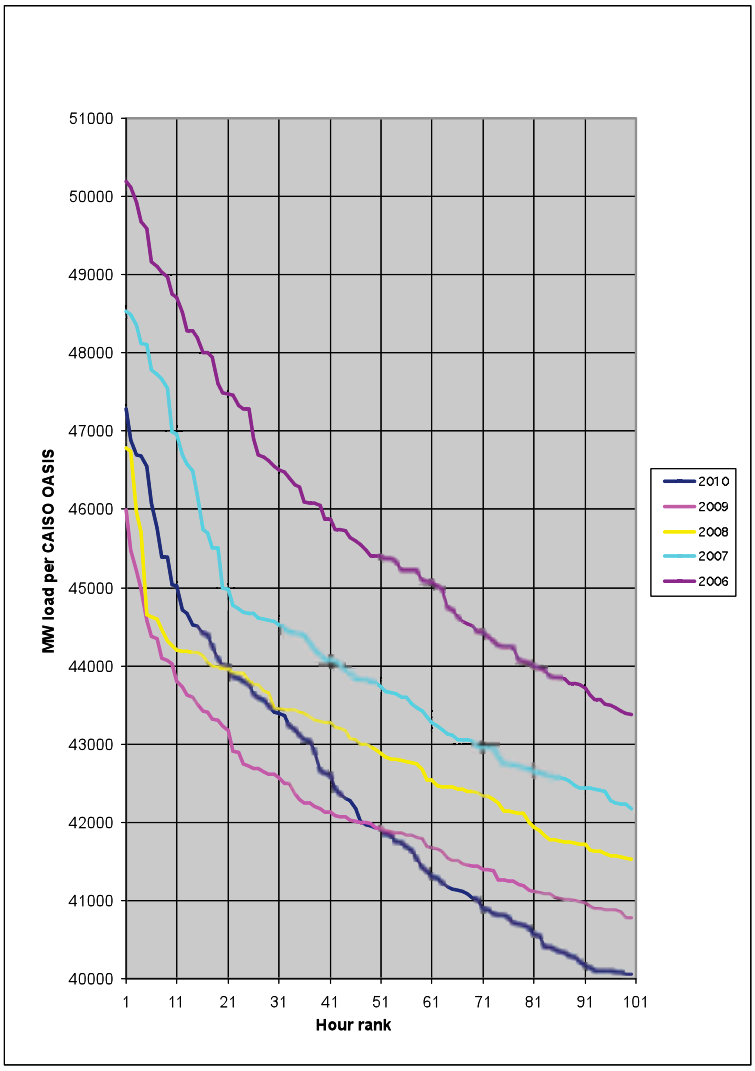


7.4 Highest Peak Loads Drop Off Rapidly in California

The CAISO control area consists of the combined service territories of PG&E, SCE, and SDG&E. Figure 7-6 shows how quickly the demand in the CAISO control area declines from the highest peak hour of the year to the one-hundredth highest peak hour of the year. As shown in the graphic, the load drops 5,000 to 7,000 MW for the highest hour to the one-hundredth hour. PG&E, SCE, and SDG&E collectively provide about two-thirds of the electricity used in California. Therefore, assuming the CAISO load decline pattern is represent-ative for other electricity providers in California, the statewide load decline across the highest 100 peak hours of the year would be in the range of 7,500 to 10,500 MW.

The portion of this CAISO load decline that occurs in the first 10 peak hours has been substantial in recent years, specifically 2008, 2009, and 2010, ranging from 2,000 to 3,000 MW. Extrapolated to California as a whole, this equates to a decline in the first 10 peak hours of 3,000 to 4,500 MW.

Figure 7-6. CAISO Load-Duration Curves for Top 100 Hours of Year, 2006 - 2010[214]



7.5 PV Resource Very Reliable During Summer Peak Load Events

Global irradiance, also known as solar insolation, is a measure of the solar intensity at the earth's surface at a specific site at a specific time of day. Clouds reduce the amount of irradiance reaching the earth's surface. Powers Engineering selected two representative Bay Area airports, Oakland and San Jose, as sample sites to evaluate whether cloud cover had a significant impact on PV system output on peak demand days in the Bay Area.

Summer of 2007 hour-by-hour global irradiance data and hour-by-hour cloud cover data was analyzed for the Oakland and San Jose airport sites.[215,216] 2007 was selected as the study year because hour-by-hour global irradiance data is publicly available for 2007 at no cost. Actual expected hour-to-hour global irradiance at specific sites is determined from weather satellite images that record cloud density. The actual modeled irradiance at the Oakland and San Jose Airports was divided by the clear day global irradiance expected for the same day and hour at each of those sites to calculate the reduction in solar intensity due to clouds.

The results of this comparison are that cloud cover was not a significant factor during the highest peak demand hours of the year in the Bay Area. As shown in Table 7-1, the solar resource was fully available in the Bay Area for the top 5,000 MW of peak load events in PG&E territory in 2007, from 21,230 MW down to 16,344 MW. The Bay Area solar resource is highly reliable during peak demand periods. A summary of this analysis is provided in Appendix E.

Table 7-1. Summer 2007 Peak Hour Solar Resource Availability in Bay Area

Day and hour of CAISO peak load	CAISO peak load (MW)	PG&E peak load (MW)	% of clear day global irradiance, Oakland Airport	% of clear day global irradiance, San Jose Airport
8/29/07, HE16	48,553	21,230	103	99
7/05/07, HE17	44,696	21,184	98	99
8/31/07, HE16	48,823	20,553	103	98
8/30/07, HE15	48,074	20,489	111	98
8/22/07, HE15	43,478	19,807	100	100
6/14/07, HE15	40,895	19,778	100	100
7/06/07, HE15	43,696	19,758	99	100
8/28/07, HE16	46,033	19,651	99	102
8/21/07, HE16	44,707	19,380	103	100
8/23/07, HE14	42,195	19,100	100	102
8/03/07, HE16	42,952	18,901	99	100
7/31/07, HE14	41,834	18,900	100	100
8/01/07, HE15	41,710	18,475	92	100
9/01/07, HE15	44,758	18,443	100	101
8/20/07, HE16	44,294	18,411	100	99
8/24/07, HE15	41,325	18,290	101	100
8/02/07, HE16	42,113	18,268	99	99
7/03/07, HE15	42,748	17,993	99	101
8/27/07, HE15	42,245	17,715	100	100
9/02/07, HE15	43,940	17,626	100	100
9/03/07, HE14	44,874	17,588	100	100
9/05/07, HE14	41,114	17,260	100	100

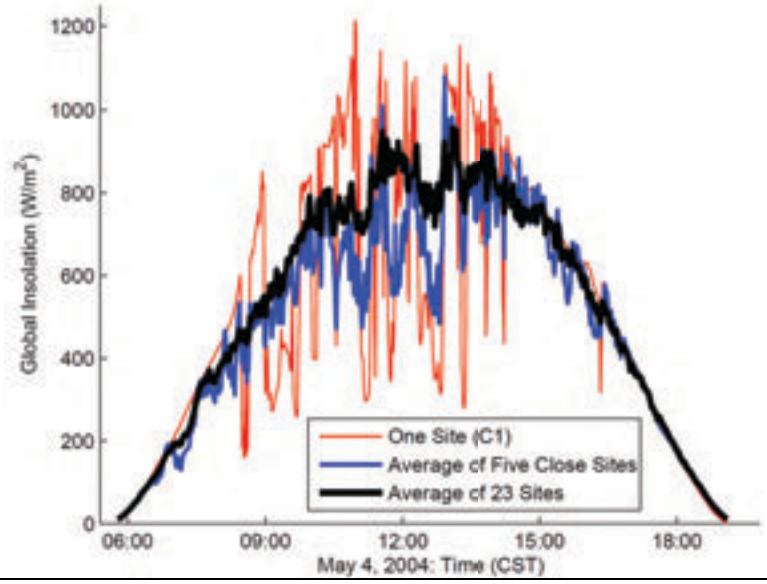
8/15/07, HE16	43,481	17,218	100	99
8/14/07, HE16	42,889	17,084	100	99
7/02/07, HE16	41,485	16,935	100	104
8/13/07, HE16	41,996	16,782	100	100
9/04/07, HE14	44,616	16,731	99	98
8/16/07, HE15	42,951	16,647	100	101
8/17/07, HE15	42,439	16,344	100	100

HE = hour ending

7.6 Distributed PV Systems on Partly Cloudy Days

A recent analysis conducted by Lawrence Berkeley National Laboratory determined that, even on partly cloudy days, the aggregate output from dispersed PV systems would follow a relatively smooth bell-shaped curve similar to a clear day PV profile, though with lower output depending on the density of cloud cover. This is an important finding, as one argument used against PV systems is the potential for a cloud to drop output from rated capacity to near zero in a matter of seconds. There are already thousands of PV systems spread over thousands of square miles in the Bay Area. As a result, partly cloudy conditions would cause little PV output variability in aggregate on a minute-to-minute or hour-to-hour basis. The modeled variability of PV system output on partly cloudy days relative to clear days, correlated to the number and distribution of PV sites, is shown in Figure 7-7.

Figure 7-7. Multiple PV Sites Smooth Aggregate PV Output on Partly Cloudy Days[217]



The reality of PV system output variability in regions that already have thousands of PV systems dispersed over a wide area, like the Bay Area and PG&E service territory, was summarized in a November 2010 renewable energy trade press article:[218]

> "Clouds don't cause that much variability if the PV is spread out over a wide enough area, and because they are visible, it's relatively straightforward to predict the impact on power generation on a short-term basis and even easier to predict the amount of power that will be generated the next day based on weather reports. That's fine because power markets operate on a day-to-day basis.
>
> Dan Shugar, CEO of Solaria (Fremont), a supplier of PV modules, said: "In PG&E's territory alone, which is pretty much north of LA up to Oregon, there's about 30,000 solar plants. If you look at a 10 x 10 mile area, statistically there's no variability."

7.7 Back-Up Turbines for Wind Power – $25 to $55/MWh of Additional Cost

PG&E states that gas turbine power plants are needed as back-up power to assure grid reliability when the wind does not blow and the sun does not shine.[219] However, during the hottest days of the year, the sun reliably shines. That is why it is hot. Leaving aside PG&E's current large margin of excess capacity, some form of backup power would be necessary for a utility with a renewable portfolio that relies heavily on wind power. It is straightforward to calculate the additional cost of backup power necessary so that wind generation can equal the reliability of fixed PV on hot summer days. This cost must be added to the LCOE of a wind project to accurately reflect the true cost of wind power compared to PV. The LCOE of new peaking gas turbines estimated by the CEC is shown in Table 7-2.

Table 7-2. LCOE of New Peaking Gas Turbines[220]

Combustion turbine (MW)	Capacity factor (%)	LCOE 2009 ($/MWh)	LCOE 2018 ($/MWh)
50	5	844	1,009
100	5	795	951

This cost adder represents the amount of back-up gas turbine capacity necessary for wind power to attain the 50 percent on-peak availability of fixed PV, assuming an on-peak availability for wind of either 4 percent (PG&E estimate) or 29 percent (CPUC estimate). The 2009 LCOE of new peaking turbine capacity at 5 percent capacity factor is $795/MWh. A 200 MW wind farm, at a capacity factor of 33 percent, will generate 0.33 x 8,760 hr/yr x 200 MW = 578,160 MWh/yr.

At a 4 percent on-peak capacity factor, the 200 MW wind farm will produce 8 MW on-peak and require 92 MW of peaking turbine back-up to match the 50 percent on-peak availability of fixed PV capacity. At a 5 percent capacity factor, 92 MW of peaking gas turbine capacity will have an annual cost of: 0.05 x 8,760 hr/yr x $795/MWh x 92 MW = $32 million/yr. The back-up peaking turbine adder in this case would be: $32 million/yr ÷ 578,160 MWh/yr = $55/MWh.

At a 29 percent on-peak capacity factor, the 200 MW wind farm will produce 58 MW on-peak and require 42 MW of peaker turbine back-up to match the 50 percent on-peak availability of 200 MW of fixed PV capacity. At a 5 percent capacity factor, 42 MW of peaking gas turbine capacity will have an annual cost of: 0.05 x 8,760 hr/yr x $795/MWh x 42 MW = $14.6 million/yr. The back-up peaker turbine adder in this case would be: $14.6 million/yr ÷ 578,160 MWh/yr = $25/MWh.

7.8 Distributed PV Meets Same Peak Ramping Function as Peaking Turbine

The CEC denied an application for a 100 MW natural gas-fired peaking gas turbine plant, the Chula Vista Energy Upgrade Project (CVEUP) in San Diego County, in June 2009. The application was denied in part because the CEC opined that rooftop PV could potentially achieve the same objectives for comparable cost.[221]

This June 2009 CEC decision implies that any future applications for gas-fired generation in California should be measured against using urban PV to meet the power need. This logic would also apply to other types of generation, including remote utility-scale solar energy generation, that would fill the same power supply niche as urban PV. The final CEC decision in the CVEUP proceeding states:[222]

> "Photovoltaic arrays mounted on existing flat warehouse roofs or on top of vehicle shelters in parking lots do not consume any acreage. The warehouses and parking lots continue to perform those functions with the PV in place. (Ex. 616, p. 11.)….Mr. Powers (expert for intervenor) provided detailed analysis of the costs of such PV, concluding that there was little or no difference between the cost of energy provided by a project such as the CVEUP (gas turbine peaking plant) compared with the cost of energy provided by PV. (Ex. 616, pp. 13 – 14.)….PV does provide power at a time when demand is likely to be high—on hot, sunny days. Mr. Powers acknowledged on cross-examination that the solar peak does not match the demand peak, but testified that storage technologies exist which could be used to manage this. The essential points in Mr. Powers' testimony about the costs and practicality of PV were uncontroverted."

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

7.9 Conclusions and Recommendations

- Wind farm output is not a good match for summer peak demand hours.
- PV systems are reliably available during summer peak demand hours.
- Large numbers of widely distributed PV systems would experience little output variability in aggregate under partly cloudy conditions.
- The cost of back-up peaking turbine capacity to address the relative lack of availability of wind power during peak demand hours adds $25 to $55/MWh to the net LCOE of wind generation, relative to distributed PV generation, depending on the assumed wind power capacity factor at peak.
- The reliability of distributed PV systems on hot summer afternoons means that distributed PV systems can serve the same peak power supply role as peaking gas turbines to meet summer afternoon peak loads.

8. California's Strategy - Energy Efficiency and Rooftop PV

The CEC and the CPUC developed the *Energy Action Plan* to guide strategic energy decision-making in California. The *Energy Action Plan* establishes the energy resource loading order, or priority list, that defines how California's energy needs are to be met. *Energy Action Plan I* was issued in May 2003, and describes the loading order in the following manner:[223]

> "The Action Plan envisions a 'loading order' of energy resources that will guide decisions made by the agencies jointly and singly. First, the agencies want to optimize all strategies for increasing conservation and energy efficiency to minimize increases in electricity and natural gas demand. Second, recognizing that new generation is both necessary and desirable, the agencies would like to see these needs met first by renewable energy resources and distributed generation. Third, because the preferred resources require both sufficient investment and adequate time to 'get to scale,' the agencies also will support additional clean, fossil fuel, central-station generation. Simultaneously, the agencies intend to improve the bulk electricity transmission grid and distribution facility infrastructure to support growing demand centers and the interconnection of new generation."

Energy Action Plan I, Under "Optimize Energy Conservation and Resource Efficiency," states:[224]

> "Incorporate distributed generation or renewable technologies into energy efficiency standards for new building construction."

Energy Action Plan I identifies rooftop PV as a de facto energy efficiency measure. *Energy Action Plan I* also states, under "Promote Customer and Utility-Owned Distributed Generation":[225]

> "Distributed generation is an important local resource that can enhance reliability and provide high quality power, without compromising environmental quality. The state is promoting and encouraging clean and renewable customer and utility owned distributed generation as a key component of its energy system. Clean distributed generation should enhance the state's environmental goals. This determined and aggressive commitment to efficient, clean and renewable energy resources will provide vision and leadership to others seeking to enhance environmental quality and moderate energy sector impacts on climate change. Such resources, by their characteristics, are virtually guaranteed to serve California load. With proper inducements distributed generation will become economic.
>
> - Promote clean, small generation resources located at load centers.
> - Determine system benefits of distributed generation and related costs.
> - Develop standards so that renewable distributed generation may participate in the Renewable Portfolio Standard program."

Energy Action Plan I prioritizes rooftop PV as the preferable renewable resource, but indicates obliquely that it is costly and that in any case distributed PV is not eligible to participate in the RPS program. Therefore IOUs have no incentive to develop distributed PV resources. Since *Energy Action Plan I* was approved in 2003, PV cost has dropped dramatically. Commercial distributed PV is half the cost it was in 2007 and costs continue to drop. Residential PV is experiencing comparable cost reductions in some U.S. markets. Some forms of distributed PV are also now eligible for the RPS program.[226]

Energy Action Plan II was adopted in September 2005.[227] The purpose of *Energy Action Plan II* is stated as: "EAP II is intended to look forward to the actions needed in California over the next few years, and to

refine and strengthen the foundation prepared by EAP I." *Energy Action Plan II* reaffirms the loading order stating:[228]

> "EAP II continues the strong support for the loading order – endorsed by Governor Schwarzenegger – that describes the priority sequence for actions to address increasing energy needs. The loading order identifies energy efficiency and demand response as the State's preferred means of meeting growing energy needs. After cost-effective efficiency and demand response, we rely on renewable sources of power and distributed generation, such as combined heat and power applications. To the extent efficiency, demand response, renewable resources, and distributed generation are unable to satisfy increasing energy and capacity needs, we support clean and efficient fossil-fired generation."

The CEC's 2009 IEPR underscores the integration of building PV as a critical component of net zero energy use targets for new residential and commercial construction, under the heading "Energy Efficiency and the Environment," explaining:[229]

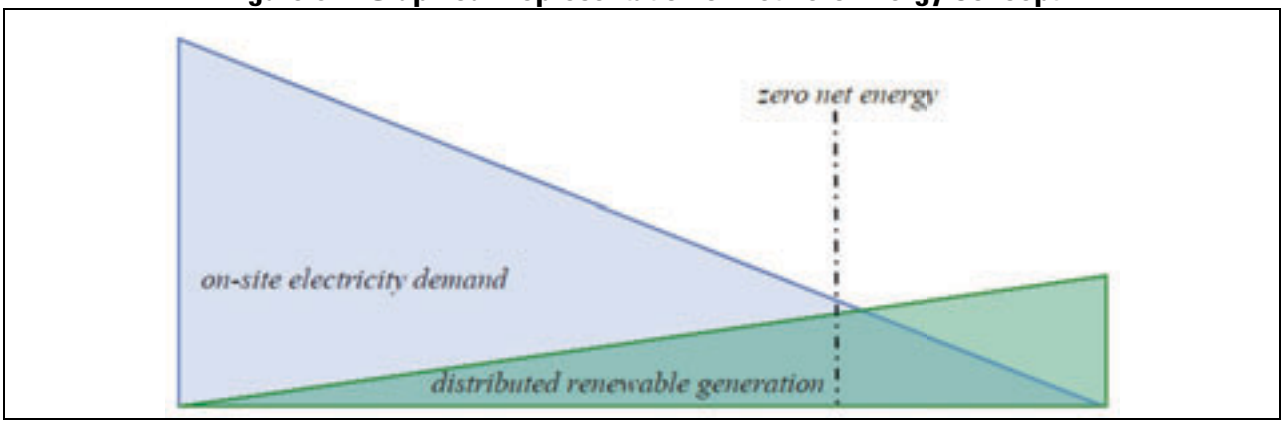
> "With the focus on reducing GHG emissions in the electricity sector, energy efficiency takes center stage as a zero emissions strategy. One of the primary strategies to reduce GHG emissions through energy efficiency is the concept of zero net energy buildings. In the 2007 IEPR, the Energy Commission recommended increasing the efficiency standards for buildings so that, when combined with on-site generation, newly constructed buildings could be zero net energy by 2020 for residences and by 2030 for commercial buildings.
>
> A zero net energy building merges highly energy efficient building construction and state-of-the-art appliances and lighting systems to reduce a building's load and peak requirements and includes on-site renewable energy such as solar PV to meet remaining energy needs. The result is a grid-connected building that draws energy from, and feeds surplus energy to, the grid. The goal is for the building to use net zero energy over the year."

The CPUC, with support from the Governor's Office, the CEC, and CARB, adopted the California *Energy Efficiency Strategic Plan* in September 2008.[230] An update to the *Energy Efficiency Strategic Plan* was published in January 2011.[231] Major goals of the plan are:

- All new residential construction will be zero net energy by 2020;
- All new commercial construction will be zero net energy by 2030;
- Heating, ventilation, and air conditioning industries will be re-shaped to deliver maximum performance systems;
- Eligible low-income customers will be able to participate in the Low Income Energy Efficiency Program and will be provided with cost-effective energy efficiency measures in their residences by 2020.

The concept of net zero energy is shown graphically in Figure 8-1.

Figure 8-1. Graphical Representation of Net Zero Energy Concept



8.1 Profile of Residential and Commercial Electricity Demand

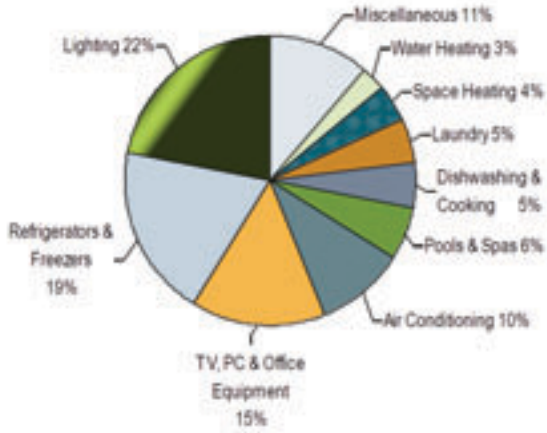
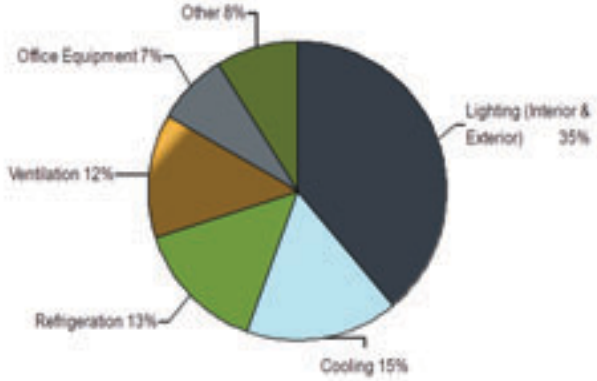
The California residential sector, 12.6 million households in 2008, represents approximately 32 percent of total state electricity consumption. The residential sector represents 36 percent of total state natural gas consumption.[232]

California has more than 5 billion square feet commercial building space. This category includes office buildings, stores, restaurants, warehouses, schools, hospitals, and public buildings. Commercial buildings account for 38 percent of the state's electricity use and over 25 percent of natural gas consumption. Four electric end uses - lighting, cooling, refrigeration, and ventilation - account for 75 percent of all commercial electricity use. Three of these - space heating, water heating, and cooking - account for over 90 percent of gas use.[233]

The industrial sector accounts for 16 percent of statewide electricity use and 33 percent of natural gas use.[234]

Profiles of residential and commercial electricity demand are provided in Figure 8-2.

Figure 8-2. Profiles of California Residential and Commercial Electricity Demand[235]

a. Residential electricity demand profile	b. Commercial electricity demand profile
	

8.2 Tools Available to Achieve Energy Efficiency Reductions

8.2.1 Building Standards

California has been a leader in energy efficient building standards since the 1970s. The Title 24 energy efficiency standards for residential and commercial buildings were established in 1978 in response to a legislative mandate to reduce California's energy consumption. The standards are updated periodically to incorporate new energy efficiency technologies and methods. The 2008 Title 24 standards, the most recent version of Title 24, went into effect on January 1, 2010. The CEC estimates that California's building efficiency standards, along with those for energy efficient appliances, have saved more than $56 billion in electricity and natural gas costs since 1978.[236]

Local governments can adopt building standards more stringent than state and federal mandates. Both San Francisco and Los Angeles have adopted green building ordinances for new buildings. However, relatively few other local governments have adopted local ordinances that exceed Title 24 requirements.[237]

Local governments can also adopt point-of-sale requirements. Berkeley has had residential and commercial building ordinances requiring basic efficiency improvements, triggered at the time of property sale or significant renovations, for over two decades. Sacramento and San Francisco have applied similar requirements at various times.

California's IOUs have ratepayer-funded programs to demonstrate the cost-effectiveness of energy efficiency, demand response, and onsite renewable generation technologies. PG&E has the Market Integrated Demand Side Management Initiative.[238] SCE and SDG&E promote the energy efficiency potential of new and remodeled commercial buildings through Sustainable Communities programs.[239]

One of the projects described on the SDG&E Sustainable Communities Program website is a model for the commercial building retrofits that would occur under BASE 2020. X-nth, Inc. of San Diego (formerly TKG Consulting Engineers, Inc.), was recognized by SDG&E for achieving a 30 percent reduction in energy usage beyond the California new building energy efficiency standard.[240] In regard to this retrofit project, SDG&E notes, "TKG's office building is a model for other San Diego County projects. It demonstrates that energy efficiency, occupant comfort, and environmentally friendly design is cost-effective, and be achieved even with a tight construction schedule."[241]

The energy efficiency of the X-nth, Inc. building was improved by: 1) adding insulation to the interior of the existing concrete walls, 2) adding a film to the existing single glazed windows, 3) use of a variety of high efficiency lighting strategies, 4) occupancy sensors for private offices, 5) and use of a high efficiency air conditioning system. SDG&E also installed a 40 kW PV array on the roof of the X-nth, Inc. building.

8.2.2 Lighting

California's strategic energy efficiency plan targets a 60 to 80 percent reduction in statewide lighting energy use by 2020. AB 1109 requires California to reduce average statewide electrical energy consumption by not less than 50 percent from the 2007 levels for indoor residential lighting and not less than 25 percent from the 2007 levels for indoor commercial and outdoor lighting by 2018. This legislation is a core element in the effort to achieve the 60-80 percent reduction in lighting energy consumption by 2020.[242]

8.2.3 Refrigerator/Freezer

Refrigerator energy efficiency is regulated by federal government standards. Refrigerators have become much more efficient over the past 20 years. More effort does need to be directed at further reducing refrigerator electricity demand. Current refrigerators use 60 percent less electricity on average than 20-year-old models.[243]

PG&E does have a recycling program for older refrigerators and freezers that includes a modest payment along with free hauling. PG&E will pick up units that are 10 years old or more and pay the customer $35 for recycling the unit.[244]

8.2.4 Air Conditioning

A major element of the state's *Energy Efficiency Strategic Plan* is to advance residential and small commercial heating, ventilating, and air conditioning systems to ensure optimal equipment performance. The plan targets a 50 percent improvement in efficiency of heating, ventilating, and air conditioning systems by 2020, and a 75 percent improvement by 2030. Air conditioning loads are the cause of over 30 percent of California's total peak power demand in the summer. Meeting this load has a costly impact in the form of additional generation, transmission, and distribution resources.[245]

PG&E relies on an Itron analysis of energy efficiency measures in evaluating its energy efficiency performance.[246] Itron largely avoids the issue of increasing the efficiency of central air conditioning units, by stating that the 2006 federal standard for new units is Seasonal Energy Efficiency Ratio (SEER) 13 and the highest SEER rating of economical central air conditioning units is 14.[247] Itron goes on to state there is little difference between SEER 13 and SEER 14 in terms of efficiency, and therefore no economic justification for upgrading from SEER 13 to SEER 14.

However, the average SEER rating for in-use central air conditioning units in California is approximately SEER 10, not the 2006 federal minimum standard of SEER 13 for new units.[248] Competitively-priced central air conditioning units with ratings as high as SEER 21 are commercially available. There is about a 20 percent installed price difference between a SEER 13 or 14 unit and a SEER 21 unit. An incremental energy efficiency improvement of nearly 30 percent is realized by selecting a SEER 21 unit over SEER 13 when compared to the SEER 10 basecase.[249] Itron does acknowledge that major energy efficiency reductions can be achieved in residential and commercial heating and air conditioning systems, though in the context of emerging technology instead of off-the-shelf technology.[250]

Itron does not address new thermal storage air conditioning systems now on the market which could nearly eliminate cooling-related peak demand if installed in new and existing buildings. The Southern California Public Power Authority (SCPPA) has contracted with Ice Energy for 53 MW of ice storage air conditioning units. SCPPA will install more than 6,000 Ice Bear units at 1,500 government and commercial buildings in its member communities.[251] Most of the units are being installed at existing

buildings. Graphs of the peak cooling demand reduction achieved by these commercially available thermal storage systems are presented in Appendix F.

Substantial peak load reduction can also be achieved by upgrading existing commercial and institutional cooling systems. Many commercial buildings use electric motor-driven centrifugal chillers to provide cooling. Centrifugal chillers typically consume more electricity than any other single energy-consuming device in a commercial building.[252] The Center for Sustainable Energy in San Diego has conducted hundreds of energy efficiency evaluations on chillers. Over 90 percent of these systems operate with relative low efficiency, in the range of 1.0 to 1.2 kW/ ton of cooling, using oversized pumps, constant speed equipment, and controls that do not work well.[253,254]

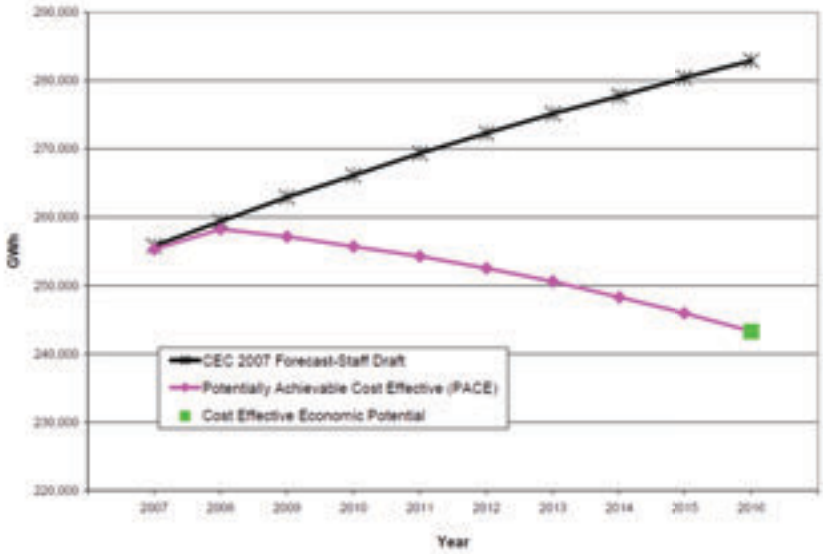
A current trend in these commercial and industrial chiller cooling systems is converting all devices to variable speed operation and a simplified control system. The initial conversions to this ultra-efficient operating format resulted in an average energy-use reduction of 54 percent over a three-year period.[255] The results indicate that ultra-efficient all-variable-speed systems are reliable and can be installed for the same cost as standard central plant chiller systems.

An example of effective application of all-variable-speed operation to an existing chiller plant is the County of San Diego's North County Regional Center, with 610,000 square feet of air-conditioned space, including a courthouse, offices, and a jail. The retrofit was completed and commissioned in 2003 at a cost of $423,700. Two years later, the entire plant was averaging less than 0.5 kW/ ton, saving the county more than $175,000 a year. The simple payback for this upgrade was less than two-and-a-half years.[256]

8.2.5 PG&E Energy Efficiency Rebate Programs

A projection of the effect of achieving all cost-effective energy efficiency measures statewide was prepared by the CEC in 2007 and is shown in Figure 8-3.[257] The absolute rate of decline in electricity demand due to achieving all cost-effective energy efficiency is about 10,000 GWh every four years from 2013 forward.

Figure 8-3. Projected Absolute Decline in California Electricity Demand if All Cost-Effective Energy Efficiency Is Achieved



Achieving all cost-effective energy efficiency measures will not happen over the next decade if PG&E and other utilities continue to rely on piecemeal energy efficiency rebate programs to deliver energy efficiency gains. PG&E provides modest rebates across a wide range of appliances, including (but not limited to) lighting, dishwashers, clothes washers, hot water heaters, and room air conditioners. For example, the rebate on a hot water heater ranges from $30 to $50.[258] PG&E offers no rebates for the biggest contributor to summertime peak load demand – central air conditioners.[259]

The process of applying for a PG&E energy efficiency rebate is not trivial. The complexity of the process, combined with the relatively low value of individual rebates, limits the effectiveness of the PG&E rebate program in motivating consumers to select high efficiency devices. The PG&E rebates page - How to Apply for eRebates - explains the process.[260] The rebate steps are shown in Table 8-1.

Table 8-1. Steps to Receive Energy Efficiency Rebate through PG&E eRebates Program

You'll need to login to My Account to use eRebates.

1. Login to My Account. From the left navigation bar, click "Energy Tips & Rebates"
2. Click "Rebates"
3. Click "Apply Online"
4. Begin the eRebates Application Process
5. Print the eRebates Confirmation Page (you will need access to a printer)
6. FAX or mail the eRebates Confirmation Page and all proofs of purchase to PG&E

The state's *Energy Efficiency Strategic Plan* notes the weakness of this approach to energy efficiency and outlines the solution:[261]

> "The IOUs currently offer a wide range of energy efficiency programs for existing homes, including audits, efficient appliance rebates, and consumer education. This Plan envisions a refocusing of these programs to move from a widget-based approach to a whole house approach to program delivery to offer comprehensive packages of audits, demand side management options and tools, rebates and financing options, and installation services."

One off-the-shelf solution that could have a substantial near-term impact would be for PG&E to use rebate funds to cover the difference between the cost of minimum federal standard central air conditioning units and state-of-the-art central air conditioning units. This would result in maximum energy efficiency reduction every time a new central air conditioning unit is purchased.

Carrier Corporation is a leading provider of central air conditioning systems. The energy demand of a 3-ton Carrier Corporation SEER 10 central air conditioning unit is approximately 4.0 kWh under hot summertime conditions.[262] The company advertises a 56 percent reduction in electricity demand for its Infinity® 21 (SEER 21) model compared to a SEER 10 unit.[263] In parts of the Bay Area where air conditioning is used through the summer, in the range of 800 to 1,000 hours per year, as much as 2,000 kWh of energy demand would be eliminated over the course of the summer peak season by selecting the Infinity® 21for the upgrade.[264]

The 2006 federal standard for new central air conditioning units is SEER 13. The difference in the installed cost prior to rebates of a reference case Carrier Corporation 3-ton SEER 13 residential central air and heating unit, which costs approximately $9,000, and a state-of-the-art Infinity® 21 unit (SEER 21) is around $2,000.[265] Carrier offers a rebate on high efficiency units that reduces the cost difference between the SEER 13 and SEER 21 alternatives by about $1,000.

The duration of the summer on-peak period in PG&E service territory is about 768 hours.[266] The SEER 21 unit would save approximately 900 kWh relative to the SEER 13 unit over 768 hours.[267] Summer peak savings would be $270 per year, assuming a Tier 3 residential rate of $0.30/kWh.[268] The simple payback for the $2,000 additional cost of the Infinity® 21, without the Carrier rebate, would be 8 years. With the $1,000 Carrier rebate, the simple payback would be 4 years.

In addition, the typical reduction of about 2 kW in residential electricity demand when upgrading from an existing 3-ton central air conditioning unit to a SEER 21 unit would eliminate $600 per year in peaking gas turbine fixed costs. This is the cost associated with new peaking gas turbine capacity, like 760 MW Marsh Landing or 200 MW Mariposa Energy Center, that would otherwise be built to meet the peaking load.[269]

At a minimum, the value of upgrading to a highly efficient 3-ton central air conditioning unit ranges from $600 to $870 per year. This includes the avoided cost of new peaking gas turbine capacity that would otherwise be built to meet the demand, and the value of high-cost electricity that is not needed because of the high efficiency of the unit.

Implementing a cost-effective, state-of-the-art requirement for residential central cooling system upgrades would be simple in concept. For example, PG&E would advise local heating and cooling system contractors that utility rebate funds will pay the difference between the base price for a central air conditioning system that meets the 2006 federal SEER 13 standard and a state-of-the-art SEER 21 unit. PG&E, or a third party service provider, would identify each municipality and area in the Bay Area where the upgrade is a priority, such as inland areas of Marin, Sonoma, Napa, Solano, Contra Costa, Alameda, and Santa Clara counties. Bay Area climate zones are shown in Figure 8-4.

The incentive payment would also be available in cooler areas where air conditioning systems are run only on the very hottest days, such as communities located around San Francisco Bay, as it is more cost and climate efficient to pay the increment between SEER 13 and SEER 21 than to pay for additional peaking gas turbine capacity.

Figure 8-4. Bay Area Climate Zones Map[270]

PG&E has a central air conditioning cycling program intended to reach 25 percent of the 1.6 million PG&E customers with central air conditioning units.[271] The 25 percent participation target is based on the expected result of an aggressive marketing campaign. Cycling the set-point of one-half of the central air conditioner population from 72 °F to 78 °F for 10 or 15 minutes, and repeating this cycling with the other half of the population for 10 to 15 minutes, reduces the instantaneous MW load during critical peak demand periods by hundreds of MW with almost no impact on the comfort of end users.

Residences with sensitive populations, such as the elderly or chronically sick, would be kept out of this type of program. Other customers could opt-out if a reason was provided after the customer had been included in the program for a time and had experienced the effect, or lack of effect, of air conditioning cycling on the comfort level within the residence.

Central air conditioning units have an average age of a bit over 10 years.[272] Assuming this average age is representative of replacement frequency, about 50 percent of current central air conditioning units will be replaced over the next 10 years. If each replacement on average reduces unit electricity consumption by 50 percent, the electricity consumption of the entire population of central air conditioning units will drop about 25 percent over the next decade.

Integrating air conditioning cycling capability into each new state-of-the-art central air conditioning unit sold would ensure near universal capability to participate in the air conditioner cycling program. Air conditioner cycling capability would be incorporated into each new unit prior to sale. This capability would reduce the instantaneous electricity demand from this population of air conditioners by 50 percent, as half these units would be in offline at any given time while the other half are operational.

California's *Energy Efficiency Strategic Plan* calls for a 50 percent reduction in air conditioning loads by 2020. The 3-ton central air conditioning unit example shows that a 50 percent demand reduction can be achieved cost-effectively over time as existing units wear out and are replaced with off-the-shelf high efficiency alternatives. Shifting rebate funds to the air conditioning unit wholesale distribution level would assure that every new central air conditioning unit sold incorporates maximum energy efficiency.

8.3 PG&E Energy Efficiency Programs Not Meeting Targets

The CPUC establishes targets for the IOUs to assure that they make adequate progress in achieving energy efficiency reductions in the ratepayer-financed energy efficiency and demand response programs the IOUs administer. A system of energy efficiency bonuses and penalties was established by the CPUC in September 2007.[273] The CPUC set the energy savings earnings levels using the hierarchy shown in Table 8-2:[274]

Table 8-2. Hierarchy of Energy Savings Targets and Associated Financial Returns

Level of energy savings	Return on net benefit (%)
Achievement > 100 percent of energy savings targets in all energy categories	12
Minimum of 85 percent of energy savings targets achieved	9
Achievement of energy savings targets between 65 and 85 percent	none
Achievement of energy savings targets below 65 percent	penalties assessed

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 them for failure to meet energy efficiency goals. A comprehensive CPUC staff report released in April 2010 found that from 2006 to 2008, PG&E did not make enough progress to trigger bonus payments.[275] According to the report, the utility fell into the penalty zone for both peak demand savings, 60 percent, and natural gas savings, 63 percent, and into the deadband for energy savings, 71 percent.[276]

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:[277]

> "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."

8.4 Independent Administration of Energy Efficiency Funds

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.[278] 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.[279] 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.[280]

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 public goods funds to an independent, non-government entity. Because economic pressures had discouraged Oregon IOUs from investing 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.[281]

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.[282] An independent, non-profit energy efficiency funds administrator is a critical element in Oregon's strategy for achieving GHG reduction targets.

8.5 Property Assessed Clean Energy - PACE

The PACE model was developed by the City of Berkeley in 2007.[283] Under a PACE financing program, the cost of energy efficiency home improvements is paid back in the homeowners' annual property taxes via a special tax assessment on the home. Under a PACE program the homeowner could install solar panels or additional insulation with little or no upfront costs and repayment over 15 or 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. Sixteen states had PACE-enabling legislation in place by March 2010.[284]

Government-backed mortgage-finance corporations Fannie Mae and Freddie Mac objected to PACE because PACE assessments have a senior lien status to mortgages, meaning they must be paid-off first if a borrower defaults. The regulator of Fannie Mae and Freddie Mac, the Federal Housing Finance Agency, sent letters to lenders warning them away from PACE and forcing all but a few programs to shut down.

San Francisco launched a $150 million program in March 2010 and Los Angeles was preparing to unveil its own program. The Obama Administration supported PACE with $150 million in ARRA funding.[285]

Sonoma County is the only region in the state still offering financing for energy efficiency and renewable energy retrofits through a PACE loan program. Through mid-January 2011, the county had awarded just over $42 million in loans. Sonoma County avoided the federal action principally because the loans are funded by the county treasury and not private lenders.[286]

A lawsuit seeking to restore the program, filed by then California Attorney General Jerry Brown and other plaintiffs including Sonoma and Placer Counties, the City of Palm Desert, and the Sierra Club, is moving through the federal court system. However, legislation is likely the quickest route to restore PACE programs.

There is strong interest among homeowners in PACE financing. A Pike Research survey of several hundred homeowners found that 42 percent were either extremely interested or very interested in accessing PACE financing. Solar panels and tankless water heaters were the most popular energy efficiency improvement options that homeowners would install under a PACE program.[287]

The *Energy Efficiency Strategic Plan* envisions that 25 percent of existing homes will reduce electricity use of 70 percent by 2020 and the other 75 percent will reduce electricity use of 30 percent. The PACE program would be an excellent vehicle for meeting these targets. PACE would also avoid any new charges being passed on to ratepayers for PG&E administered energy efficiency or rooftop solar PV programs.

8.6 Meeting California's Energy Efficiency Targets

The energy efficiency targets established in the California *Energy Efficiency Strategic Plan* serve as the basis for the GHG emission reduction targets in BASE 2020. Achievement of these targets will lead to an overall reduction in electricity usage from residential, commercial, and industrial categories of approximately 30 percent in 2020 relative to the baseline year of 2008. A description of the *Energy Efficiency Strategic Plan* targets for 2020 is provided in Table 8-3, along with quantification of the energy efficiency reductions these targets represent.[288]

Table 8-3. Targets in California's Energy Efficiency Strategic Plan[289]

Category	2008 statewide demand[290] (GWh)	Targets	2020 reduction in demand (GWh)	2020 statewide demand if targets achieved (GWh)
Residential	91,493	2020: 25 percent of existing homes have 70 percent decrease in purchased electricity from 2008 levels, 75 percent of existing homes have a 30 percent decrease in purchased energy from 2008 levels, and 100 percent of existing multi-family homes have a 40 percent decrease in purchased energy from 2008 levels. 100 percent of new homes will be net zero energy (NZE).	36,597	54,896
Commercial	106,569	2030: 50 percent of existing commercial buildings will be retrofitted to NZE through achievement of deep levels of energy efficiency and with the addition of clean DG. New construction will increasingly embrace NZE perform-ance, including clean, DG, reaching 100 percent penetration of new starts in 2030.	26,642 (calculation assumes 25 percent NZE by 2020)	79,927
Industrial	44,142	2020: Energy intensity of industrial facilities will be reduced at least 25 percent.	11,035	33,107
Total	242,204		74,274	167,930
Net reduction, 2008 to 2020:				~30 percent

There are two substantive differences between the targets in the *Energy Efficiency Strategic Plan* and BASE 2020:

- The *Energy Efficiency Strategic Plan* assumes that 25 percent of existing residences achieve a 70 percent reduction in grid electricity usage by 2020. BASE 2020 assumes these residences achieve net zero energy by 2020 through the addition of sufficient rooftop PV to achieve a net 100 percent reduction in grid electricity usage.
- The *Energy Efficiency Strategic Plan* assumes that 50 percent of existing commercial buildings achieve net zero energy by 2030 with no interim 2020 target. BASE 2020 sets a target of 25 percent of existing commercial buildings achieving net zero energy by 2020. The *Energy Efficiency Strategic Plan* target of 50 percent of existing commercial buildings achieving net zero energy by 2030 remains unchanged.

BASE 2020 also interprets the term "rooftop PV" more broadly than the *Energy Efficiency Strategic Plan* definition. The types of PV envisioned for the Bay Area in BASE 2020 include rooftop PV, parking lot

PV, and ground-mounted PV up to 20 MW near distribution substations. This broader definition of rooftop PV is more accurately described as distributed PV. The minimum criteria in the BASE 2020 definition of distributed PV are that the PV be located in the Bay Area and that it interconnect to the grid at the distribution level.

Table 8-4. BASE 2020 Targets - Purchased Electricity Reductions from Energy Efficiency Measures and Distributed PV if Applied Statewide

Category	Targets	Split between EE measures and PV to achieve 2020 target (GWh)
Residential	Assume 75 percent of existing homes achieve 30 percent EE reduction target through EE measures alone. 25 percent of existing homes are converted to NZE homes, with 30 percent of demand reduction from EE measures and 70 percent from PV. Existing multi-family homes achieve 30 percent EE reduction target through EE measures. Remaining 10 percent reduction necessary to achieve 40 percent target is captured in PV used to take 25 percent of detached homes to NZE.	a. 25 percent of housing stock attains NZE, a 22,873 GWh total purchased electricity reduction: PV: 16,011 GWh EE: 6,862 GWh b. 75 percent of housing stock achieves 30 percent reduction via EE alone: EE: 20,586 GWh
Commercial	2030: 50 percent of existing commercial buildings will be retrofit to NZE through energy efficiency and clean DG. In the report it is assumed that 25 percent of existing commercial buildings will retrofit to NZE by 2020.	25 percent of commercial stock attains NZE, 26,642 GWh: PV: 18,649 GWh EE: 7,993 GWh
Industrial	2020: Energy intensity of industrial facilities will be reduced at least 25 percent.	100 percent of industrial stock achieves 25 percent reduction via EE alone: EE: 11,035 GWh
Statewide energy efficiency and PV reductions:		PV: 34,660 GWh EE: 46,476 GWh

BASE 2020 energy efficiency targets are described in Table 8-4. These targets are applied to the 2008 statewide residential, commercial, and industrial electricity demand presented in Table 8-3 to calculate the statewide purchased electricity reductions that would be achieved. The statewide results provided in Table 8-4 serve as inputs to the calculation of purchased electricity reductions that would be achieved in PG&E's planning area and the Bay Area. The purchased electricity reductions that would be achieved in PG&E's planning area and the Bay Area are provided in Table 8-5.

Table 8-6 converts the GWh of purchased electricity reductions attributable to PV to MW_{ac} capacity, assuming an average annual output for fixed PV in the Bay Area of approximately 1,900 kWh per kW_{ac} of installed capacity.[291]

Table 8-5. Allocation of Statewide PV and Energy Efficiency Reductions in PG&E Planning Area and Bay Area[292,293]

2020 statewide reduction (GWh)	2020 PG&E planning area		2020 Bay Area	
	% of statewide reduction	allocation (GWh)	% of statewide reduction	allocation (GWh)
PV: 34,660 EE: 46,476	38	PV: 13,171 EE: 17,661	21	PV: 7,279 EE: 9,760

Table 8-6. Conversion of PV Energy Production (GWh) to PV Capacity (MW)

2020 statewide		2020 PG&E planning area		2020 Bay Area	
GWh	MW_{ac}	GWh	MW_{ac}	GWh	MW_{ac}
34,660	18,242	13,171	6,932	7,279	3,831

Over 3,800 MW_{ac} of distributed PV must be added in the Bay Area by 2020 to achieve the BASE 2020 energy efficiency target. By 2020, over 18,000 MW_{ac} of distributed PV would be necessary in California if BASE 2020 targets were applied on a statewide level.

In 2009 the CPUC evaluated a renewable energy strategy that relies primarily on distributed PV, known as the High DG strategy, to achieve the state's 33 percent by 2020 goal.[294] The High DG alternative substitutes 15,000 MW_{ac} of distributed PV for a comparable amount of remote utility-scale solar and wind projects in the utility 33 percent by 2020 reference case scenario.[295] The CPUC determined that the cost of the High DG alternative would be comparable to the cost of the utility reference case scenario if the capital cost of PV was about one-half the cost assumed by the CPUC in its analysis. The LCOE for distributed PV assumed by the CPUC in reaching this conclusion was $168/MWh.[296]

RETI confirmed in May 2010 that the actual cost of distributed PV was approximately one-half the cost assumed by CPUC in its 2009 analysis.[297,298] The price of PV has continued to drop since the RETI report was issued in May 2010. The San Antonio, Texas public utility, CPS Energy, signed a long-term power purchase agreement with SunEdison in October 2010 at $150/MWh for three 10 MW PV arrays to be constructed in the San Antonio area.[299] The sun intensity in San Francisco, on an annual basis, is about 5 percent better than that of San Antonio.[300]

8.7 Conclusions and Recommendations

- The central element of California's *Energy Efficiency Strategic Plan* is net zero energy buildings.

- Achieving 25 percent net zero energy in existing Bay Area homes and commercial buildings, combined with an average 30 percent reduction in electricity usage in all existing homes not achieving net zero energy by 2020, and a 25 percent reduction in energy usage at industrial facilities, will reduce electricity demand in the Bay Area by approximately 30 percent relative to a 2008 baseline year.

- Central air conditioning units have an average age of somewhat more than 10 years. About 50 percent of current central air conditioning units will be due for replacement over the next 10 years. Assuming each replacement on average reduces unit electricity consumption by 50 percent, the electricity consumption of the entire population of central air conditioning units will drop about 25 percent over the next decade.

- Integrating air conditioning cycling capability into each new state-of-the-art central air conditioning unit sold would ensure near universal capability to participate in the air conditioner cycling program, with little or no need for an aggressive marketing campaign. Air conditioner cycling capability would be incorporated into the new unit prior to sale.

- Adding cycling capability to all new central air conditioning units would reduce the instantaneous electricity demand from this population of air conditioners by 50 percent, as half these units would be offline at any given time while the other half are operational.

- PG&E should not be administering public goods funds for energy efficiency measures. An independent non-profit organization, similar to the Energy Trust of Oregon, should be put in place to administer these public goods funds. If a city or county forms a CCA, the CCA should administer the public goods funds collected from CCA customers.

9. Demand Response - Reducing Peak Demand

9.1 Potential of Demand Response

The demand for electricity is highly concentrated in the top one percent of hours of the year. In most parts of the United States, these 80 to 100 hours account for roughly 8 to 12 percent of the maximum or peak demand.[301] In California in 2010, the top 100 hours accounted for about 14 percent of peak demand.

California's three IOUs tested a variety of dynamic pricing designs in a $20 million pilot project that involved approximately 2,500 residential, small commercial, and industrial customers over a three-year period. The dynamic pricing rate structure hinges on the smart meter, which most PG&E customers now have. PG&E customers have raised concerns about high electricity bills and perceived meter and billing inaccuracies from PG&E's deployment of new meters.[302]

The IOU pilot project provided time-varying prices and smart meters to all participants. In addition, some of the participants also received enabling technologies such as smart thermostats and always-on gateway systems. Smart thermostats automatically raise the temperature setting on the thermostat by 2 or 4 degrees when the price becomes critical. Always-on gateway systems adjust the usage of multiple appliances in a similar fashion.

The experiment showed that the average IOU customer reduced demand during the top 60 summer hours by 13 percent in response to dynamic pricing signals that were 5 times higher than their standard tariff. Customers who had a smart thermostat reduced their load about twice as much, by 27 percent. Those who had the gateway system reduced their load by 43 percent.

The gateway smart meter system represents the maximum technical potential for demand reduction in the residential customer class. The smart meter system has the potential for lowering peak demand by 43 percent. In the commercial and industrial classes, automatic demand response programs that control multiple end-use loads while working with the energy management system that is installed in most facilities are projected to reduce demand by 13 percent.

The weighted average technical demand response potential for all classes is estimated at approximately 23 percent. The smart meter system, at a minimum, has the potential to facilitate a substantial reduction in electricity usage.

9.2 PG&E Demand Response Programs

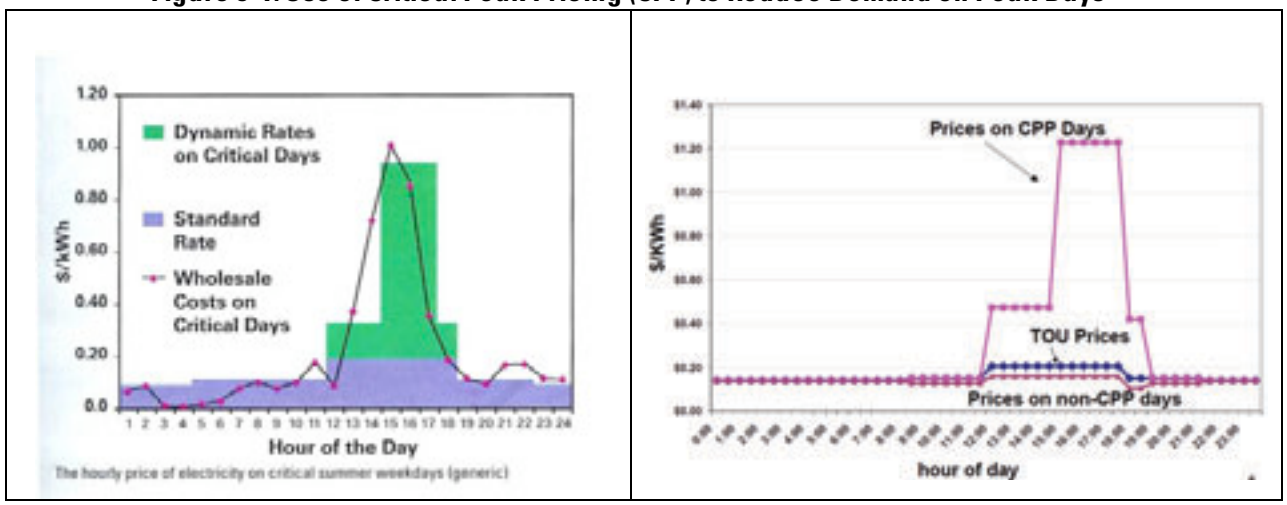
PG&E has numerous programs to reduce usage at times of peak demand.[303] These are known as demand response programs. The PG&E demand response program consists of three separate elements: 1) demand response from existing programs, 2) an air conditioning cycling program, and 3), additional demand reduction from Critical Peak Pricing (CPP). The application of CPP to small business and residential customers is possible with the introduction of smart meters. Collectively, the objective of these demand response programs is to reduce peak demand in PG&E service territory by approximately 5 percent by 2016.[304]

PG&E estimates that approximately 1.6 million of its nearly 4.5 million residential customers are equipped with central air conditioning. Mature utility air conditioning cycling programs in other jurisdictions have achieved market penetration of up to 25 percent. This penetration rate results in approximately 300 MW of load reduction from an air conditioning cycling program in PG&E territory.[305]

PG&E has long-running non-firm electricity supply programs that have been effective in reducing peak load at participating sites. In the initial non-firm program begun in 1997, participants were given a rate discount in exchange for dropping their loads to a pre-determined level when given 30 minutes notice by PG&E. Participants who did not comply with the curtailment order were penalized via a large energy charge on any power used in excess of their contracted amount. The program achieved a high compliance rate. The original non-firm program was phased-out several years ago and replaced with a revised program with a similar objective.[306]

One tool used by PG&E to reduce load on the very hottest peak days is to charge very high prices for electricity. The intent is to encourage customers to find ways to minimize usage during these periods to avoid high payments. This CPP pricing strategy is shown graphically in Figure 9-1.

Figure 9-1. Use of Critical Peak Pricing (CPP) to Reduce Demand on Peak Days[307,308]



The CPP rates are designed to provide incentives and penalties in the form of higher electricity costs to get non-residential customers to adjust their electric power usage schedules and become more energy efficient. The new CPP rates apply to all of PG&E's non-residential customers, including nearly 500,000 small-business customers. There are expected to be 9 to 15 days per year when prices will be especially high.[309] The price charged to the customer during CPP events is $1,200/MWh ($1.20/kWh).[310]

Optional peak day pricing rates that include TOU rates during non-peak day pricing periods are available for residential customers with smart meters, but are not required. Residential customers can opt to return to standard residential tiered rates if they choose to do so.

PG&E bills residential customers using tiered rates. Customers using large amounts of electricity pay a considerable premium in this rate system. PG&E is transitioning from a five-tier structure to a three-tier structure. Tier 1 and 2 usage will be billed at $0.12 to 0.135/kWh, and cover up to 130 percent of baseline usage. Tier 3 will be billed at $0.30/kWh and covers usage beyond 130 percent of the baseline.[311]

About a third of the 31,000 GWh per year of PG&E residential usage will be billed at the $0.30/kWh Tier 3 rate.[312] One-third of 31,000 GWh is about 10,000 GWh per year. To put this quantity of electricity in perspective, over 5,000 MW_{ac} of distributed PV capacity would be required to generate 10,000 GWh per year.[313]

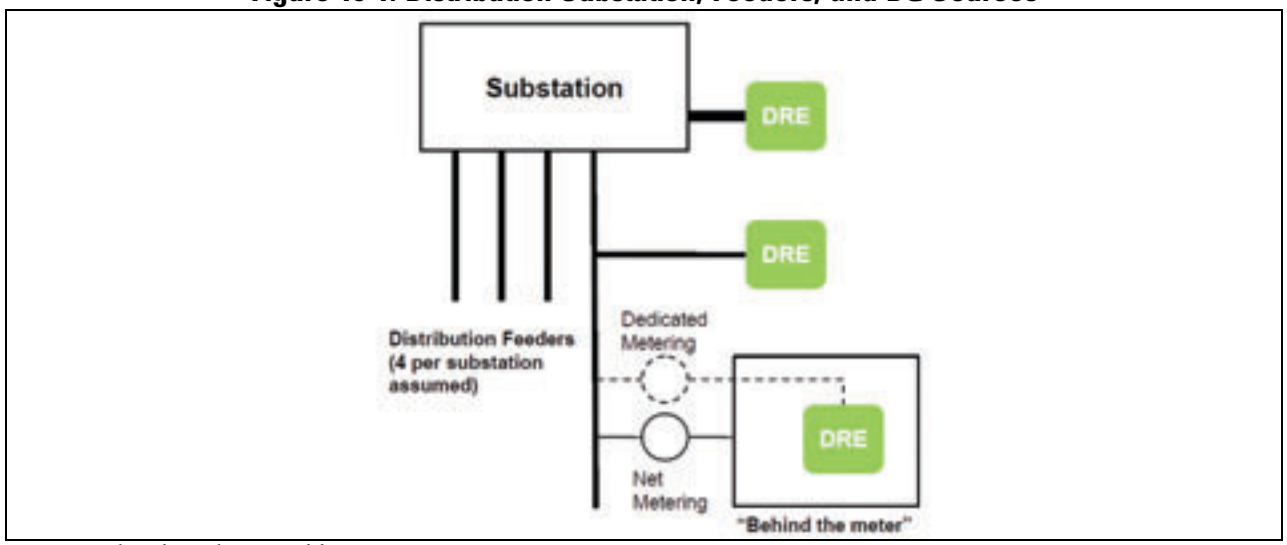
9.3 Conclusions and Recommendations

- Smart meters combined with automatic controllers have the potential to reduce residential peak demand by about 20 to 40 percent.
- Air conditioner cycling is an important tool for reducing peak demand.
- CPP is an effective method for shifting commercial peak loads from on-peak hours on the highest demand days.
- Air conditioner cycling should be maximized by integrating this capability into new air conditioners as a standard feature.
- Residential customers with significant consumption at the Tier 3 rate of $0.30/kWh are excellent candidates for rooftop PV systems under any pricing scheme (net metering or FIT).

10. Integrating Distributed Generation (DG) Into the Grid

The T&D system has changed little over the last century. It is configured to transmit electricity generated at large power plants over high voltage transmission lines to distribution substations where the voltage is reduced. The electricity then flows from the distribution substations along feeders to customers. Safety devices, like circuit breakers located at distribution substations and reclosers on the feeders, are currently constructed assuming electricity will always flow in one direction. To accept high levels of DG, at some point these safety devices must be upgraded to allow two-way flow. The relationship between distribution substations, feeders, and DG sources is shown in Figure 10-1.[314]

Figure 10-1. Distribution Substation, Feeders, and DG Sources



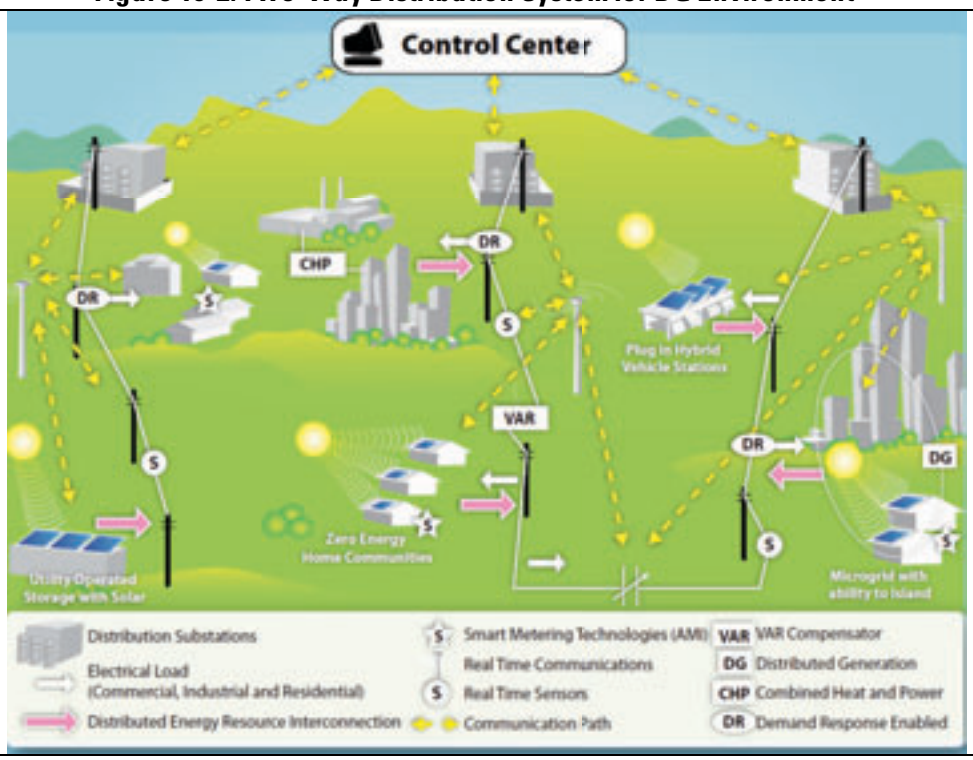
DRE = distributed renewable energy

The CEC made clear in 2007 that incorporating bidirectional capability into distribution substations and feeders is a commonsense need in a smart grid environment where higher-and-higher levels of DG are encouraged and expected, stating:[315]

- "Utilities spend approximately three-fourths of their total capital budgets on distribution assets, with about two-thirds spent on upgrades/new infrastructure in most years."
- "Investments will remain for 20 to 30 or more years."
- "Magnitude of these investments suggests need to require utilities, before undertaking investments in non-advanced grid technologies, to demonstrate that alternative investments in advanced grid technologies that will support grid flexibility have been considered, including from a standpoint of cost-effectiveness."

The CEC's vision of a two-way distribution system that is optimized for high levels of DG is shown in Figure 10-2.

Figure 10-2. Two-Way Distribution System for DG Environment[316]



The CEC correctly identified a fully two-way distribution grid as a priority in 2007. However, little progress on this issue has occurred to date. Some European countries are well ahead of California in analyzing and addressing this need.

The Netherlands is one example. The country has an average demand of about 14,000 MW.[317] Over a three-year period from 2004 through 2006, about 1,500 MW of 1 to 3 MW CHP plants were brought online in areas with a high density of greenhouses.[318] The country also has over 2,200 MW of installed wind capacity.[319]

The Netherlands has made a strategic commitment to the development of DG resources. The country is simulating where major DG development will occur and pro-actively planning necessary grid upgrades to avoid the grid becoming a bottleneck to DG development. This process is explained in the following paragraphs:[320]

> "In The Netherlands local authorities have designated specific areas for the development of greenhouses. Each greenhouse may contain a CHP plant with a capacity in the range of 1 to 3 MVA (MW) and thus to be connected to the local medium voltage grid. Due to the high density of greenhouses in such areas, the penetration level of CHP plants in the medium- voltage grid is very high. This can amount to a total generated power of 100 MW or even more, and with loads far less than the generation power."

> The Dutch regulatory framework requires the distribution system operators to provide a connection to the distribution grid within 18 weeks upon a client's request. The capacity and structure of today's (Dutch) distribution grids in these areas does not support a connection of a large number of CHP plants. The time it takes to execute projects in the grid to secure reinforcements does not match the legal time it takes to make a grid connection for a new DG unit.

> To mitigate these planning issues, proactive grid planning by both the distribution system operator and the transmission system operator is necessary. To plan the grid in a proactive way, several transmission development scenarios have to be established. With the aid of these scenarios, bottlenecks in current medium voltage grids and sub-transmission grids can be identified. In each scenario, alternative grid designs have to be generated for each bottleneck. These alternatives are to be generated in such a way that the expected
> growth of CHP plants in each scenario is covered."

The methodical, pro-active upgrade approach being utilized by the Dutch to assure the distribution grid can absorb large amounts of DG in concentrated locations is also needed in California. However, even without such upgrades, large amounts of DG can flow onto the existing one-way system without causing safety devices to mistaken DG power flows for ground faults. There is always some flow on the distribution circuits, and as long as the DG flow onto the circuit is less than the total demand on that circuit, the one-way flow will be maintained.

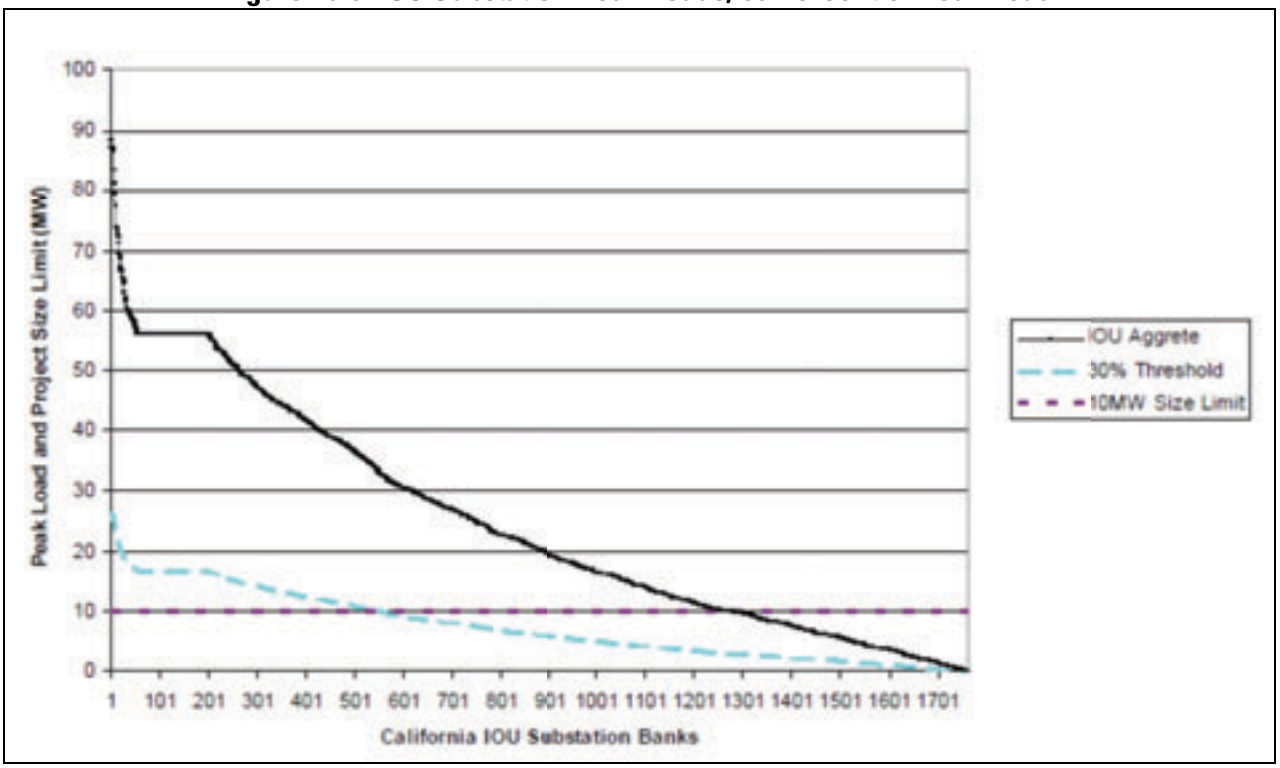
10.1 PV Capacity of Existing Distribution System

Rule 21 specifies standard interconnection, operating, and metering requirements for DG sources.[321] The CPUC has calculated in the context of Rule 21, for the entire inventory of approximately 1,700 existing IOU substations in California, the amount of distributed PV that could be accommodated with minimal interconnection cost. The CPUC states:[322]

> "Rule 21 specifies maximum generator size relative to the peak load at the point of interconnection at 15%. So, for example, if a generator is interconnected on the low side of a distribution substation bank with a peak load of 20 MW, the maximum Rule 21 interconnection criteria would allow a 3 MW system (3 MW = 15% * 20 MW).
>
> However, the 15% criterion, which is established for all generators regardless of type, was adjusted to 30% for the purposes of determining the technical potential of PV. The 15% limit is established at a level where it is unlikely the generator would have a greater output than the load at the line segment, even in the lowest load hours in the off-peak hours and seasons (such as the middle of the night and in the spring). Since the peak output for photovoltaics is during the middle of the day, PV is unlikely to have any output when loads are lowest. Therefore, a 30% criterion was used for technical interconnection potential estimates. The discussion was held with utility distribution engineers, however, we did not consider formal engineering studies or Rule 21 committee deliberation since the purpose of the analysis was only to define potential."

As a component of the distributed PV RAM program development process, the CPUC requested data on peak loads at all IOU substations from the IOUs and compiled that information graphically as shown in Figure 10-3. According to the CPUC, this data was obtained from IOU distribution engineers.[323] Approximately 13,300 MW of PV can be connected directly to IOU substation load banks based on the data in Figure 10-3. The supporting calculations for this estimate are provided in Table 10-1.

Figure 10-3. IOU Substation Peak Loads, 30 Percent of Peak Load



The IOUs provide about two-thirds of electric power supplied in California, with POUs like the Bay Area POUs, SMUD, LADWP, and others providing the rest.[324] Assuming the substation capacity pattern in Figure 10-3 is also representative of the non-IOU substations, the total California-wide distributed PV that could be interconnected at substation low-side load banks with no substantive substation upgrades would be [13,300/(2/3)] = 19,950 MW.

Table 10-1. Calculation of Distributed PV Interconnection Capacity to Existing IOU Substations with Minimal Interconnection Cost

Substation range	Number of substations	Calculation of distributed PV that could be interconnected with minimal substation upgrades (MW)	Total distributed PV potential (MW)
1-200	200	average peak ~60 MW x 0.30 = 18 MW	3,600
201-500	300	average peak ~45 MW x 0.30 = 13.5 MW	4,000
501-800	300	average peak ~30 MW x 0.30 = 9 MW	2,700
801-1,000	200	average peak ~20 MW x 0.30 = 6 MW	1,200
1,001-1,600	600	average peak ~10 MW x 0.30 = 3 MW	1,800
		Distributed PV total:	13,300

10.2 Cost to Upgrade Distribution System to Maximize Distributed PV

An upgrade at the substation would be necessary to accommodate higher power flows in cases where distributed PV, concentrated on clusters of large rooftops for example, could provide up to 100 percent of a single substation's peak load. A typical 100 MW, 12 kV/69 kV substation can be upgraded to allow two-way, also known as bidirectional, power flows for up to 100 MW of interconnected distributed PV.

The distribution substation upgrade would consist of retrofitting substation metering and protective equipment from one-way power flow to bidirectional power flow. The cost of such an upgrade for a typical 100 MW distribution substation would be approximately $500,000.[325] This is well under 1 percent of the gross capital cost of 100 MW of state-of-the-art PV at 2010 prices.

The cost to build a new 100 MW, 12 kV/69 kV substation is in the range of $25 million.[326] Even the cost of a new 100 MW distribution substation, at $25 million, is less than 10 percent of the gross capital cost of 100 MW of state-of-the-art PV at 2010 prices. The substation upgrade cost would be relatively minor compared to the gross capital cost of 100 MW of PV arrays, and would not present a substantive financial hurdle to developing a 100 MW distributed PV resource concentrated in an area served by a single existing distribution substation.

The CPUC assumes that larger PV arrays will be connected directly to the substation low-side 12 kV load bank. SDG&E estimated that the cost of a 10 MW feeder is $0.6 million per mile.[327] The cost of a 3-mile long dedicated feeder from multiple rooftop PV arrays with a combined capacity of 10 MW to the low-side bus of the substation would be less than $2 million.

The current capital cost for state-of-the-art commercial rooftop PV is approximately $3,700/kW$_{ac}$. The gross capital cost of 10 MW of rooftop PV at current prices would be $3,700/kW x (1,000 kW/MW) x 10 MW = $37 million. The cost to construct a dedicated feeder to interconnect 10 MW of rooftop PV would be approximately 5 percent of the gross project capital cost. This is a relatively minor cost and does not represent a financial impediment to maximizing the development of distributed PV resources.

10.3 IOUs Positive about Distributed PV When They Will Own It

SCE expressed a high level of confidence, in its March 2008 application to the CPUC for an urban PV project up to 500 MW, 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,"[328] 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."[329]

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.[330] 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."[331]

SCE also notes that it will be able to remotely control the output from individual PV arrays to prevent overloading distribution substations or affecting grid reliability:[332]

> "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."[333] 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:[334]

> 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, or air 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:[335]

> "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.

10.4 Conclusions and Recommendations

- IOUs spend about two-thirds of their total capital budgets on distribution system upgrades and new infrastructure.
- Existing California distribution substations can absorb up to approximately 20,000 MW of distributed PV without significant modification.
- The cost of upgrading a 100 MW distribution substation to full bidirectional flow is in the range of $500,000 or less.
- IOUs state they will employ advanced distribution circuit design and operation to handle large influxes of PV power from IOU-owned distributed PV.
- The CEC recommends that new distribution substations and existing substations to be upgraded must include advanced grid technologies that will support grid flexibility. This would include full bidirectional flow capability.
- IOUs and POUs should be required to include advanced grid technologies, including full bidirectional flow capability, that will support grid flexibility in all new distribution substations and all existing distribution substations to be upgraded.
- Rule 21 should be revised immediately to increase the DG limit to 30 percent of substation peak load for DG, specifically PV, operating only during daylight hours.
- Rule 21 should not apply to distribution substations and associated feeders that are fully bidirectional.

11. Bay Area PV Technical Potential

11.1 Potential of Rooftops, Parking Lots, Substations

There is about 18,000 MW_{ac} of PV potential in the Bay Area on rooftops, commercial parking lots, and at non-urban substations. This compares to a 2011 forecast peak load in the Bay Area of 8,606 MW.[336] Of this total, about 16,700 MW_{ac} is rooftop and commercial parking lot PV potential as summarized in Tables 11-1 and 11-2. Approximately 1,600 MW_{ac} of additional PV could be developed in arrays up to 20 MW at non-urban substations in the Bay Area. The quantity and distribution of these substation PV arrays around the Bay Area is shown in Table 11-3.

Moscone Center rooftop PV array. Photo: SFPUC.

Table 11-1. Estimate of Rooftop and Parking Lot PV Potential in Bay Area[337,338]

County and 2009 population	Residential (MW_{ac})	Commercial (MW_{ac})	Commercial parking lot (MW_{ac})	Total (MW_{ac})
Alameda 1,480,000	1,360	879	1,525	3,764
Contra Costa 1,036,000	756	438	1,070	2,264
Marin 249,000	180	111	260	551
Napa 134,000	100	78	140	318
San Francisco 810,000	453	635	835	1,923
San Mateo 714,000	431	465	735	1,631
Santa Clara 1,771,000	1,278	1,129	1,825	4,232
Solano 411,000	331	190	425	946
Sonoma 470,000	375	230	485	1,090
Total	5,264	4,155	7,300	16,719

The PV potential of open ground-level parking lots or parking structures have not been included in statewide PV potential assessments to date, despite a rapid increase in the number of parking lot PV arrays. An estimate of the PV potential of parking areas and parking structures is necessary to develop a complete understanding of the PV potential in the Bay Area. This estimate is provided in Table 11-1.

Parking lot, Milpitas High School. Photo: New York Times, *In California, carports that can generate electricity*, November 25, 2010.

The methodology utilized to calculate the PV technical potential of ground-level parking lots and parking structures is shown in Table 11-2. San Francisco is used as an example in the table. A core assumption in the methodology is that only 25 percent of total estimated parking surface is sufficiently open, meaning not shaded to a significant degree, so that its full solar potential can be realized. The estimated ground-level parking lot and parking structure PV potential in San Francisco, assuming 25 percent of the total surface area is utilized for PV, is 835 MW. This same calculation methodology is applied to the population of each Bay Area county to determine the parking lot PV estimates included in Table 11-1.

Table 11-2. Assumptions Used to Estimate PV Potential of Parking Lots – San Francisco

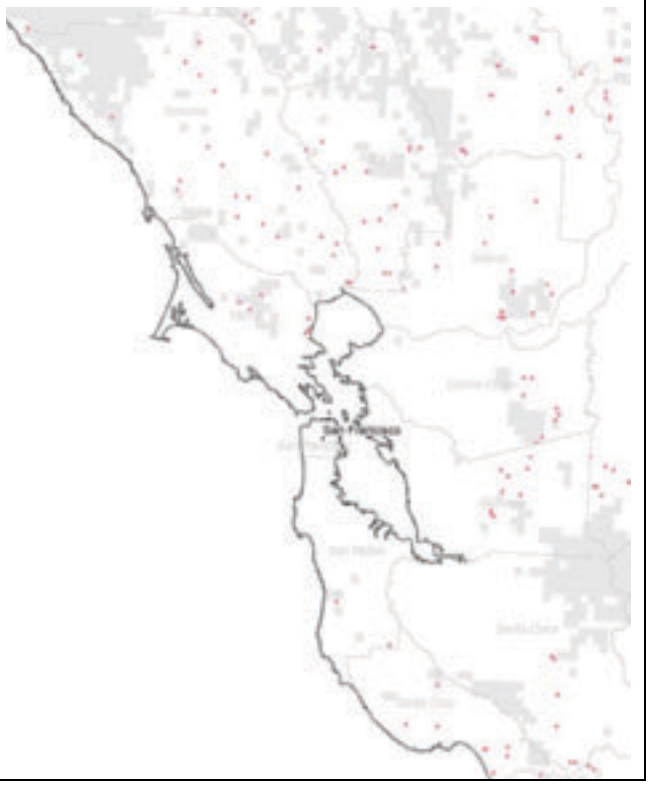
Assumption	Source
771 vehicles per 1,000 citizens	Dr. Donald Shoup, urban planning, UCLA[339]
At least 4 parking spaces per vehicle, one of which is residential space	Dr. Donald Shoup, urban planning, UCLA
810,000 people	Approximate San Francisco population, 2009 Moody's www.economy.com population data
162 square feet per parking space	Square footage of typical 9-foot by 18-foot parking space, Envision Solar, San Diego[340]
Approximately 1,874,000 non-residential parking spaces in San Francisco	calculated value: 810,000 × (771/1,000) × 3 spaces [4 total spaces per car – 1 residential space per car]
11 W_{ac} per square foot PV capacity per square foot of parking area	Envision Solar, San Diego
3,339 MW_{ac} parking lot PV theoretical potential without considering shading	calculated value: 1,874,000 spaces × 162 square feet per space × 11 W_{ac} per square feet × 1 MW_{ac} per million W_{ac}
835 MW_{ac} actual potential	Rough estimate of actual PV potential - assumes 25 percent of non-residential parking spaces are unshaded throughout the day and full PV potential can be realized at these sites

RETI evaluated the potential of distributed 20 MW_{ac} PV arrays located at non-urban substations around the state in 2008.[341] An initial screening conducted by the RETI contractor, Black and Veatch, determined that 20 MW_{ac} PV arrays could potentially be developed at 1,375 rural substations around the state. This is a total of 27,500 MW_{ac} of PV potential. As shown in Table 11-3, 1,640 MW of this potential is located in the Bay Area. Each orange square in the graphic associated with Table 11-3 represents 20 MW_{ac} of PV capacity.

PG&E's 2 MW Vaca□Dixon PV project. Photo: CPUC 1st Quarter 2010 RPS Status Report to Legislature, p. 3.

Table 11-3. RETI Estimate of Rural Substation PV Potential in Bay Area[342]

County	PV potential of non-urban substations (MW_{ac})
Alameda	180
Contra Costa	160
Marin	120
Napa	300
San Francisco	0
San Mateo	40
Santa Clara	120
Solano	260
Sonoma	460
Total	1,640



The U.S. EPA has also developed a nationwide inventory of brownfield sites that are potentially suitable for renewable energy development. The EPA inventory includes dozens of sites in the Bay Area totaling thousands of acres.[343] Many of these sites are suitable for the deployment of PV arrays.

11.2 Existing Distributed PV Programs

Table 11-4 summarizes the capacity of existing approved distributed PV programs in California and the approximate completion date of these programs. The *California Solar Initiative* is the largest of these PV programs and the only program where the PV capacity is not RPS-eligible.[344]

Table 11-4. Current Status of California Distributed PV Programs

PV project underway	Capacity (MW_{ac})	Completion date
California Solar Initiative	3,000	2016
Utility distributed PV ($PG\&E$ 500 MW_{dc}, SCE 500 MW_{dc}, SDG&E 100 MW_{dc})	~900	2014
SB 32 Feed-in Tariff	750	2014
CPUC Renewable Auction Mechanism[345]	1,000	2014
SMUD Feed-in Tariff	100	2012
Total committed DG PV	~5,800	by 2016

The proportion of existing California distributed PV programs that will be built in the Bay Area, assuming the capacity that is built is proportional to the demand, is provided in Table 11-5.

Table 11-5. Estimate of Distributed PV Capacity to be Located in Bay Area[346]

PV project underway	PG&E allocation (MW_{ac})	Estimated PG&E Bay Area allocation (MW_{ac})
California Solar Initiative[347]	921	550
PG&E 500 MW_{dc} distributed PV	~400	~240
SB 32 Feed-in Tariff[348]	250	150
CPUC Renewable Auction Mechanism[349]	421	250
Total estimated DG PV in Bay Area	~2,000	~1,200

11.3 Detailed Inventories of Commercial PV Potential

A number of studies have been conducted in California's principal urban centers to inventory the square footage of residential and commercial building roof space available for PV. An inventory of residential and commercial roof space in Los Angeles was prepared as a component of the UCLA/Los Angeles Business Council (UCLA/LABC) PV study in 2010.[350]

An inventory of available commercial roofspace was completed in San Diego in 2005.[351] Figure 11-1 shows how commercial rooftops were classified to determine PV capacity in the San Diego study. Black & Veatch also conducted a limited inventory of commercial rooftops near existing urban substations in the Bay Area and the Los Angeles Basin in 2009 as part of the CPUC's Re-DEC process.[352]

Figure 11-1. Inventory of San Diego Commercial Rooftop PV Potential – Classification of Rooftops

11.4 Conclusions and Recommendations

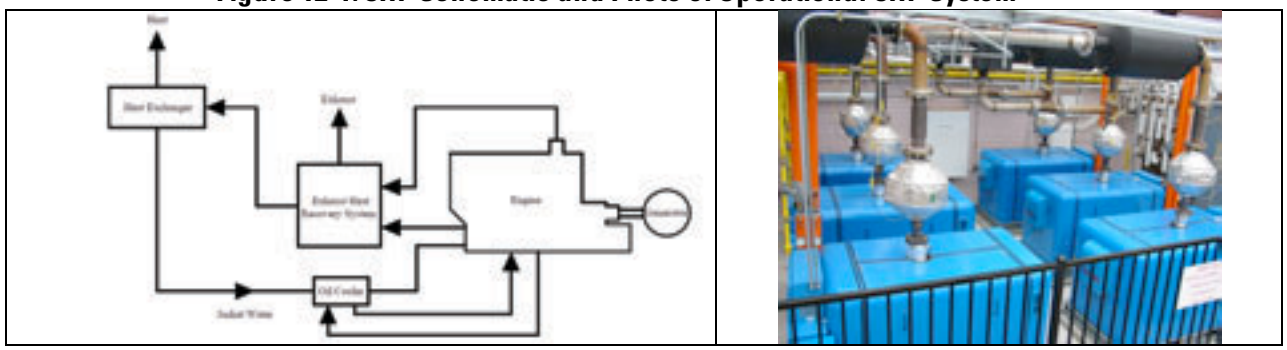
- Bay Area rooftop and parking lot PV potential, at over 16,000 MW_{ac}, far exceeds the BASE 2020 PV target of 3,800 MW_{ac}.
- Existing rooftop and distributed PV programs will add approximately 1,250 MW_{ac} of capacity to the Bay Area by 2016. This is about one-third of the BASE 2020 target of 3,800 MW_{ac}.
- Detailed quantification of roof-by-roof commercial PV potential and commercial-scale parking lot potential should be conducted by all cities and counties in the Bay Area.

12. Combined Heat and Power (CHP)

12.1 CHP Basics

CHP, also known as cogeneration, follows energy efficiency and renewable energy in the *Energy Action Plan* loading order. CHP systems can combust biogas or biomethane to qualify as renewable energy power systems. 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 12-1.

Figure 12-1. CHP Schematic and Photo of Operational CHP System[353,354]



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. 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 the Bay Area use either internal combustion engines or gas turbines, though fuel cells are becoming more common.[355] 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.

12.2 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 12-2. The market distribution within the industrial and commercial CHP categories is provided in Figure 12-3.

Figure 12-2. Market Distribution of All Classes of CHP in California[356]

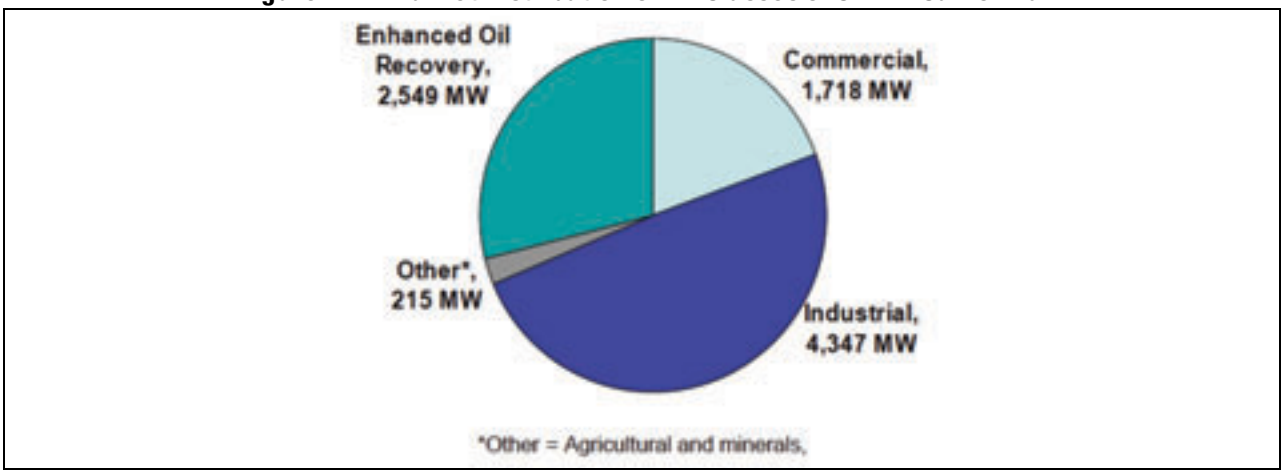
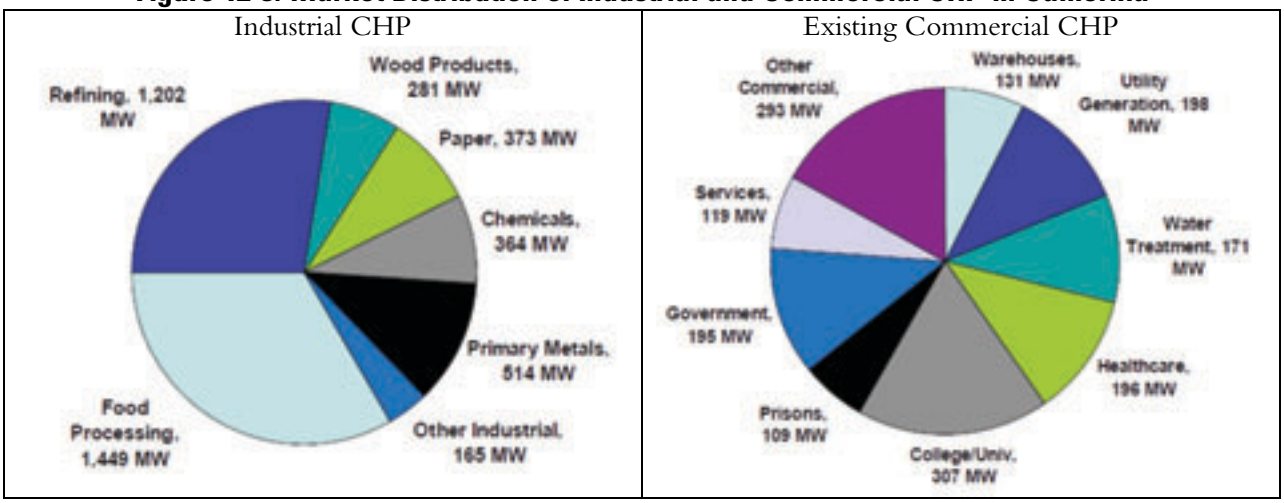


Figure 12-3. Market Distribution of Industrial and Commercial CHP in California

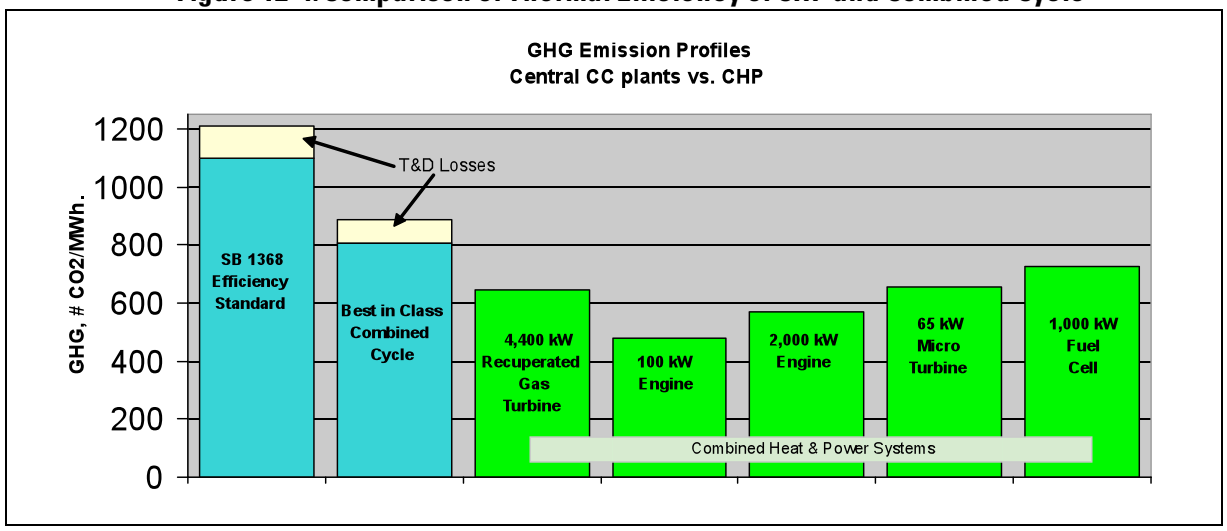


The carbon footprint of boiler plants and simple-cycle natural gas-fired peaking turbines is approximately 1,100 lb CO_2/MWh.[357] The carbon footprint of a baseload natural gas-fired combined cycle plant is approximately 820 lb CO_2/MWh.[358] However, California combined cycle plants have a relatively moderate capacity factor on average, in the range of 65 percent, indicative of a "load following" operating pattern that is less fuel efficient than baseload operation.[359]

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.[360] As a result, a combined cycle unit operating a substantial amount of time 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.[361] 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 12-4 provides a comparison of the carbon footprint of several CHP alternatives to that of a baseload combined cycle power plant.

Figure 12-4. Comparison of Thermal Efficiency of CHP and Combined Cycle[362]



12.3 4,000 MW of New CHP by 2020 – 840 MW in Bay Area

The *AB 32 Scoping Plan* CHP target is 4,000 MW of new CHP in California by 2020.[363] The economic potential for new CHP in California was identified as 6,500 MW by 2030 in the ICF International April 2010 report prepared for the CEC on California CHP potential.[364]

Governor Brown has called for the addition of 6,500 MW of CHP in California by 2030 in his *Clean Energy Jobs Plan*. The AB 32 target of 4,000 MW of new CHP by 2020 is consistent with a 2030 target of 6,500 MW of new CHP.

Achievement of this potential will require the implementation of a CHP FIT that assures CHP projects can be financed. A proposed FIT for CHP is discussed in Chapter 13.

The nine Bay Area counties accounted for about 21 percent of net statewide electricity demand in 2008.[365,366] The proportion of new CHP installations in the Bay Area by 2020, assuming that the new CHP capacity installed is proportionate to Bay Area electricity consumption, would be 0.21 × 4,000 MW = 840 MW.

The BASE 2020 target for new CHP is 840 MW. Table 12-1 identifies the approximate amount of new CHP that would installed in each Bay Area county, assuming CHP capacity is installed proportionate to county electricity demand, to meet the target of 840 MW of new CHP by 2020.

Table 12-1. Estimate of New CHP Installed in Each Bay Area County to Achieve 840 MW of New CHP by 2020

County	Electricity Consumption in 2008[367] (GWh)	Fraction of total Bay Area electricity consumption in 2009	Distribution of 840 MW of new CHP in Bay Area by 2020 (MW)
Marin	1,482	.03	25
Napa	1,038	.02	17
Sonoma	2,970	.05	42
Solano	3,232	.06	50
Contra Costa	9,014	.16	134
Alameda	11,682	.20	168
Santa Clara	17,088	.29	244
San Mateo	5,116	.09	76
San Francisco	5,694	.10	84
Total	57,316	1.00	840

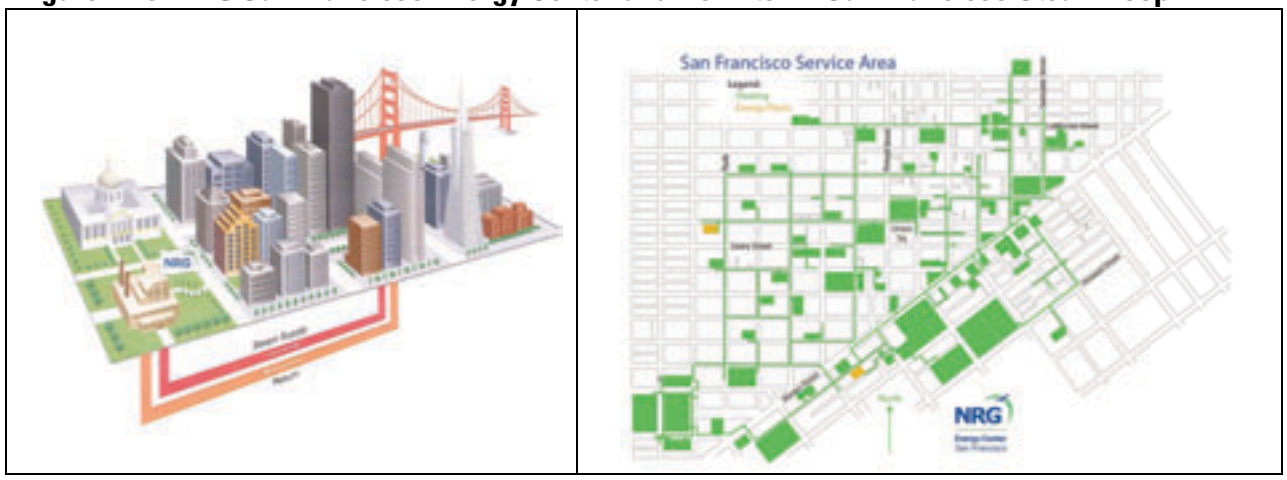
12.4 CHP Case Study - San Francisco

CHP represents a sizable local generation resource in San Francisco. Over 60 MW of CHP capacity is already in operation in the city according to a city-sponsored CHP study.[368] This capacity includes the San Francisco Airport 30 MW gas turbine CHP plant, the UC San Francisco 13.5 MW gas turbine CHP plant, twenty internal combustion engine CHP plants all under 2 MW, three microturbine CHP plants at 240 kW or less each, and one 250 MW fuel cell plant. The study identified the potential for at least 106 additional MW of CHP in San Francisco.

CHP opportunities also exist where natural gas is already used to produce steam. One project that has been under consideration for nearly a decade is a 50 MW CHP plant in downtown San Francisco. The city currently has a steam franchise agreement with NRG Thermal Corporation to produce steam at the 5th and Jessie plant between Market and Mission.[369] The existing plant consists of relatively low efficiency steam boilers that provide steam for heating and cooling to 170 buildings in downtown San Francisco as shown in Figure 12-5.

A gas turbine would be added to the NRG steam plant to produce electricity. Waste heat from the turbine would be used to produce steam in the existing boilers to supply the district heating and cooling system. This one CHP plant, at 50 MW electrical output, would provide 60 percent of the 84 MW of new CHP allocated to San Francisco in BASE 2020. A simplified schematic of the NRG steam plant and the downtown San Francisco steam loop is also shown in Figure 12-5.[370]

Figure 12-5. NRG San Francisco Energy Center and Downtown San Francisco Steam Loop



The San Francisco CHP study also identifies the categories of facilities where the 106 MW of additional CHP capacity would be located. These facility categories are shown in Table 12-2. This capacity does not include the 50 MW CHP addition to the NRG steam plant.

Table 12-2. Additional CHP Potential in San Francisco

Facility Type	CHP Potential (MW)
Hotels	20
Hospitals	4
Data centers	Significant (unquantified)
Airports	Airport has large CHP plant
Office buildings	80
Universities	Most have CHP already, though potential for expansion/addition
Schools	Significant (unquantified)
Residential high rises	>2
Wastewater treatment plants	Both plants have CHP
Health/fitness centers	Significant (unquantified)
Miscellaneous	Significant (unquantified) This category includes USPS distribution centers, warehouses with large heating or cooling loads.

The CHP potential identified in the study is for many small CHP plants in the 1 MW range or less. Small CHP plants will generally incorporate an internal combustion engine, microturbine, or fuel cell.

A 250 kW fuel cell is in operation at a U.S. Post Office distribution center in San Francisco.[371] Larger fuel cell CHP installations are in operation in other parts of California. For example, the Sheraton Hotel and Marina Hotel in San Diego has a long-term agreement with Alliance Power for a 1.5 MW stationary fuel cell power plant that supplies 70 percent of the hotel's electric power demand. The waste heat from the units is used to heat swimming pools and for domestic water heating. The plant consists of two fuel cells, a 1 MW unit and a second 0.5 MW unit. The 1 MW unit went online in December 2005, the 0.5 MW unit in mid-2006.[372]

Numerous Bloom Energy solid oxide fuel cells are now in operation in the Bay Area. The first commercial Bloom Energy 100 kW fuel cells were shipped to Google in July 2008 for use at its Mountain View campus.[373] As of January 2011 Bloom Energy had installed 200 of its 100 kW fuel cells in California. Bloom also provides customers with the option to utilize biogas or biomethane in the units. For example,

twenty 100 kW units are being installed at California Institute of Technology (CalTech). About half the gas to be used at the CalTech installation will be offset by biogas purchases.[374]

Microturbines combined with absorption chillers are another CHP option. United Technologies markets microturbine-absorption chiller packages under the trade name "PureComfort®." Systems are offered at 240 kW, 300 kW, and 360 kW. The hot exhaust gas is utilized in an absorption chiller/heater. The efficiency of this system can reach 90 percent. A PureComfort® system is in operation at the Ritz-Carlton Hotel in San Francisco.[375]

12.5 How CHP Fits in DG Strategy

CHP provides a reliable continuous source of power to counterbalance the non-continuous output of wind and solar energy systems. An increase in local CHP reduces congestion on existing transmission lines and eliminates the transmission losses associated with power imports. It also removes load from the grid, reducing demand pressure to add new peaker plants or other generation and transmission infrastructure. The benefits of CHP include:

- Reduced need to purchase grid electricity
- Reduced reliance on transmission system
- Reduced natural gas consumption
- Reduced CO_2 emissions
- Local, reliable round-the-clock baseload electricity

CHP reduces natural gas demand by effectively using waste heat for heating or cooling. An example of the natural gas savings potential of CHP is provided in Appendix G for a 60 kW CHP system in Richmond, California.

12.6 Obstacles to Increasing CHP Use in Bay Area

For financial reasons, IOUs prefer to sell power to customers from: 1) the IOU's own generation assets, or 2) more distant third party providers that is transmitted over IOU-owned transmission lines. Buying power from its customers runs counter to core IOU financial interest – the construction of new IOU-owned generation and transmission infrastructure. Construction of new infrastructure is the primary mechanism available to the IOU to increase its revenue stream. The cost of this infrastructure, including a guaranteed rate of return to the IOU in the range of 11 to 12 percent, is borne by ratepayers.[376] The removal of significant amounts of load from the grid, caused by IOU customers installing CHP, will over time undercut the need for new sources of IOU revenue.

Interconnecting CHP with the utility distribution system has been an obstacle for some CHP developers. The experience of CHP developer Tecogen is instructive. A 60 kW Tecogen CHP plant has been in successful operation at 1080 Chestnut Street, a residential high-rise on Russian Hill in San Francisco, since 1988. According to an independent energy auditor, the system resulted in $400,000 in energy savings in the 1991-2000 period when natural gas prices were very low relative to current prices.[377] Yet this is the only Tecogen system in San Francisco. The following quote summarizes the difficulties Tecogen has encountered attempting to develop CHP projects in California:[378]

> "Just a few years ago, Bob Panora was a sort of DE (distributed energy) poster child, embodying a whole segment of power-project developers shut out of markets, at least in part due to contrived utility obstacles. In testimony presented to the California Energy Commission at that time, Panora,

president and chief operating officer of Massachusetts-based Tecogen Inc., told commissioners of being made to run a gauntlet of technical hurdles time and again to get his company's 75-kW CHP engines grid-connected—only to be shot down in the end on one pretext or another.

Partly as a result of Panora's accounts, things soon began improving for DE developers. Changes to California's Rule 21 on interconnections were implemented in 2006, forcing utilities to lower some barriers."

The quote is from a CHP trade magazine article on a novel grid interconnection device incorporated into Tecogen cogeneration modules. The innovative Tecogen inverter-based controller was developed in part with CEC funding. It allows individual CHP modules to operate independent of the grid and each other while maintaining the ability to seamlessly reconnect with the grid at any time. As noted in the article:

"From a customer perspective, the result is indeed a "dream machine." It's an elegantly simple, inexpensive circuit of engines which a) can be positioned around a site for optimal CHP efficiency that will save money and b) will keep running robustly and automatically, powering critical services, regardless of what the grid does or doesn't deliver."

The control architecture for Tecogen CHP modules allows the Tecogen CHP systems to serve as autonomous micro-electric utilities, also known as microgrids. A 300 kW Tecogen CHP plant incorporating this microgrid capability, consisting of three 100 kW "In Verde" CHP modules, is currently being installed in the headquarters of SMUD. See Figure 12-6. The system is expected to operational in April or May of 2011.[379]

Figure 12-6. Tecogen 100 kW In Verde CHP

12.7 CHP Fuel Options

CHP technologies can use a wide variety of fuels to generate heat and power. The three primary candidate fuels are natural gas, biogas, and biomethane. Each of these fuel options is discussed in the following paragraphs.

Natural gas. Natural gas is currently the primary fuel used in CHP plants in the Bay Area. The natural gas infrastructure is well established and provides gas to most buildings in the region.

Biogas. Biogas is the gas produced by the anaerobic digestion of organic matter, typically at wastewater treatment plants and dairies, or from organic matter decomposition in landfills. Both forms of gas are referred to collectively as "biogas" in BASE 2020. Biogas is primarily composed of methane and CO_2, with trace amounts of nitrogen and hydrogen sulfide, and is produced and released into the atmosphere as a byproduct. Using this resource in a CHP system is an opportunity to take advantage of a fuel source that would otherwise be wasted. Biogas-fueled electricity is a significant percentage of AMP electricity supply. Wastewater treatment plant digester biogas powers CHP plants at San Francisco's two wastewater treatment plants.[380,381]

The total generation capacity from the existing 42 California landfill gas-to-electricity projects is about 210 MW. There are 70 landfills that continue to flare the landfill gas they produce. These 70 landfills have the potential for producing approximately 66 MW. There are also 164 landfills that either do not have a landfill gas control system or are venting the landfill gas. These 164 landfills have the potential to produce approximately 30 MW.[382] The total remaining potential for landfill gas electricity generation in California is about 100 MW.

There are 2,700 dairies in California, but only 12 have digesters producing biogas.[383]

The CEC estimates California has between 450 and 600 MW of CHP electric generation potential from biogas produced from dairy, wastewater, and bio-waste digestion. The sources of this potential are shown in Table 12-3.[384]

Table 12-3. CHP Potential from Wastewater and Co-Digestion of Other Bio-Wastes

Resource type	Technical potential (MW)	Market potential (MW)
Wastewater	125	95
Restaurant fat, oil, and grease	10	8
Food processing waste	129	97
Dairy waste manure	334	250
Combined Total	598	450

The combined remaining potential of landfill biogas and dairy biogas in California is approximately 700 MW.

Internal combustion engines are the most common prime mover in biogas CHP systems. However, biogas fuel cell CHP systems are cost-competitive with retail electricity rates in California. This is due in part to the substantial incentive payment available, $4,500/kW, for fuel cells using renewable fuel under the Self Generation Incentive Program (SGIP).

The largest biogas CHP fuel cell system in California, providing 4.5 MW of electricity to UC San Diego and the City of San Diego, is being built under a turnkey third party power purchase agreement. UC San Diego will use the byproduct heat from the fuel cell generation as a continuous source for 320 tons of cooling capacity for its buildings. The fuel cell will be paired with an additional 2.8 MW advanced energy storage system, which will allow UC San Diego to store off-peak power and discharge the energy during peak-demand hours.[385]

Biomethane. The most straightforward option for the large-scale use of biogas in the Bay Area would be to upgrade the biogas where it is generated to biomethane for injection into the PG&E natural gas pipeline network. The upgrade process involves stripping-out the CO_2 and trace contaminants in the biogas. Biomethane has similar heating value and composition to pipeline quality natural gas.

PG&E took its first delivery of biomethane derived from a dairy digester in 2008.[386] PG&E also takes delivery of biogas from Microgy's Huckabay Ridge project in Texas.[387] The company did support federal bill H.R. 1158, The *Biogas Production Incentive Act of 2009*, which would have provided a federal tax credit of $4.27 per MMBtu for biomethane that can be injected into natural gas pipelines.[388] H.R. 1158 did not become law, and no subsidies or tax credits are currently available to biomethane producers for pipeline injection.[389]

Biomethane can be purchased by a CHP plant owner in California, injected into the natural gas pipeline system virtually anywhere in the Western U.S., and count as renewable fuel for RPS compliance purposes. For example, SMUD has a 15-year contract with a landfill operator near Dallas, Texas to provide 6 million cubic feet per day of biomethane for use in SMUD's Consumes combined-cycle plant.[390] 6 million cubic feet per day is sufficient to supply about 60 MW of CHP capacity, or about 7 percent of the new CHP target of 840 MW for the Bay Area.[391] This same contract arrangement used by SMUD could be used by CHP owner/operators in the Bay Area to operate a 100 percent renewable energy CHP plant.

12.8 State CHP Incentive Programs

The AB 1613 *Waste Heat and Carbon Emissions Reduction Act* was signed into law by Governor Schwarzenegger in October 2007.[392] This legislation requires the IOUs to establish simple FITs for excess CHP power up to 20 MW at each site. POUs are required to: 1) establish programs that allow end-use customers to utilize CHP and 2) to provide a market for the purchase of excess CHP power at a just and reasonable rate.

AB 1613 also establishes a pay-as-you-save pilot program for eligible, non-profit customers. The pilot program enables the customer to finance all of the upfront costs for the purchase and installation of a CHP system by repaying these costs over time through on-bill financing at the difference between what an eligible customer would have paid for electricity and the actual savings derived for a period of up to 10 years. This is in essence a de facto PACE program for CHP. The IOUs must make on-bill financing of CHP available for up to a cumulative total of 100 MW of capacity. PG&E's estimated share of this 100 MW total is in the range of 45 MW.

SGIP provides incentives for fuel cells, distributed wind generation, and energy storage through 2012. Legislation to extend SGIP has been introduced.[393] The maximum system size is 5 MW. The minimum size is 30 kW for wind turbines and fuel cells using renewable fuels.[394]

12.9 Conclusions and Recommendations

- The Bay Area's proportion of the *AB 32 Scoping Plan* target of 4,000 MW of new CHP in California by 2020 would be approximately 840 MW.
- Biogas produced at California dairies is being upgraded to biomethane and injected into the PG&E natural gas pipeline system.
- Each Bay Area county government should identify and list existing in-county facilities using steam boilers to provide process heat. These lists of steam boiler facilities would form a priority list for conversion to CHP plants.
- New Bay Area CHP capacity should utilize at least 50 percent biogas or biomethane as a percentage of total heat input.
- Conversion of the NRG San Francisco steam loop boiler plant to CHP would provide 50 MW of baseload generation in downtown San Francisco. This is 60 percent of San Francisco's CHP allotment, a total of 84 MW, under BASE 2020. This project should move forward.

13. DG Energy Payments – The Price Is Right

The central issue in the debate over renewable energy and CHP in California is cost. The position of the IOUs is that these resources are more costly than business-as-usual natural gas-fired generation, and therefore the quantity of these resources should be limited to protect ratepayers from excessive cost. The IOU asserts an artificially low cost for the conventional generator – a level too low for most renewable resources to compete economically – while claiming, in the case of solar and wind, that the variability in output justifies a new generation of conventional peaking turbines to back-up these resources.

The reality that California already has excess capacity of conventional gas-fired generators online is generally ignored. The outcome of the cost debate, given the current rules, is predictable – while California ostensibly seeks more renewable energy, it continues to build new gas turbine capacity.

A utility incurs a variety of expenses in generating and delivering electricity from a conventional utility-scale power plant to the customer. These expenses include the cost of generating electricity at the power plant, the cost of transmitting the electricity, line losses along the transmission pathway, and delivery to the customer through an electricity distribution system. The total cost of the delivered electricity is the sum of all of these separate costs, and is known as the avoided cost. What this means in practical terms is that if another source of electricity such as rooftop PV is substituted for grid power, the utility avoids these costs and the substituted electricity has at least this avoided cost value to the utility.

A broader description of the cost of conventional power generation is captured in the SB 32 legislation, passed in 2009, which expands the IOU FIT program for distributed PV. A FIT is a long-term fixed price provided via a standard contract. The bill language instructs the CPUC to adjust the FIT payment beyond the market reference price, stating:[395]

"The bill would require that the payment be the market price referent established by the Commission pursuant to the renewables portfolio standard program and would require the price to include all current and anticipated environmental compliance costs. The bill would authorize the Commission to adjust the payment to reflect the value of the electricity on a time-of-delivery basis and require, with respect to rates and charges, that ratepayers that do not receive service pursuant to the tariff are indifferent to whether other ratepayers receive service pursuant to the tariff. The bill would require an electrical corporation to provide expedited interconnection procedures to an electric generation facility located on a distribution circuit that offsets peak demand on that circuit, if the electrical corporation determines that the electric generation facility will not adversely affect the distribution grid."

To date the CPUC has been reluctant to significantly adjust the market reference price to reflect other real costs associated with the generation and transmission of electricity from conventional power plants. However, the CPUC has taken steps to establish that it has the authority to set rates higher than the market reference price if those rates can be shown to be no higher than the "all-in" costs associated with a conventional generator.

The CPUC's attempt to set a FIT for small CHP (less than 20 MW) under AB 1613 was challenged by California's IOUs as unlawful. The IOUs asserted that only FERC has the power to set wholesale electricity rates. The CPUC requested that FERC issue a declaration that the CHP FIT program was not preempted by federal law.[396]

FERC determined in July 2010 that the CPUC was effectively setting the price at which electricity was sold by CHP facilities. FERC also determined that the program might be acceptable if it were set up in compliance with PURPA. PURPA requires utilities to purchase power from qualifying facilities at state-established rates that are no higher than the utilities' avoided costs.[397] FERC issued a clarifying order on October 21, 2010, where it made clear that states have wide latitude in establishing the level of avoided costs under PURPA and that a multi-tiered avoided cost rate structure is acceptable.

FERC clarified that the state may include in its avoided cost calculation the costs of transmission upgrades that would be avoided by the utility by purchasing power from local resources. These clarifications have the effect of allowing states to set higher rates for qualifying facilities. FERC also made clear that a state is free to establish a basis for providing additional compensation to favored resources through mechanisms that are outside of the avoided cost rate. One example is the creation of renewable energy credits that the generator can sell and that the utility must purchase.

There are other methods available besides the establishment of avoided cost for states to sidestep concerns over federal preemption of FIT programs. California can require the IOUs to purchase a specified amount of electricity from a governmental entity, at rates set by that entity, established for the purpose of encouraging the preferred generation resources. That entity would then purchase electricity from the favored resources at prices sufficient to encourage development of those resources. FERC does not have jurisdiction under the *Federal Power Act* over power sales by governmental entities that may be established by the states.[398]

This is what happened in California in 2001 to end the market manipulation-induced power crisis. DWR, which operates hydroelectric resources, entered into long-term power contracts with third party generators to deliver electricity to California IOUs. DWR purchases the power at a set tariff. The IOUs were assigned specific DWR contracts. The extra cost of these contracts was passed on to ratepayers in the form of a DWR bond charge. This charge appears as a line item on customer electric bills.

DWR could also serve as the state government entity that: 1) sets FIT rates for PV and CHP resources, 2) purchases the renewable and CHP electricity at the set rates, and 3) requires each IOU to purchase a specific amount of electricity from these resources. FERC acknowledges that a state requirement that the IOUs purchase electricity from a state-owned corporation at specified rates would not be preempted by FERC's authority over wholesale power sales.

13.1 Cost of New Natural Gas-Fired Plants

The economic and strategic stakes at play in establishing an appropriate FIT tariff are high. Four natural gas-fired power plants are in the queue to be built in the Bay Area: Russell City Energy Center (600 MW), Oakley Generating Station (624 MW), Marsh Landing Generating Station (760 MW), and Mariposa Energy Center (200 MW).[399] Russell City and Oakley will operate as load following units, with expected capacity factors in the 60 to 80 percent range.[400] Marsh Landing and Mariposa will be peaking facilities, with expected actual capacity factors of less than 10 percent.[401]

These plants all have long-term power purchase agreements with PG&E. This is a total of about 2,200 MW of capacity. If built, these plants will have expected operational lifetimes of 40 to 50 years. The collective capital cost of these four plants will be about $2.3 billion in 2009 dollars.[402]

The cost of having these gas-fired plants constantly at hand if needed – to have the capacity available whether or not it is actually used – will be borne by PG&E ratepayers over the life of these contracts.[403] Any customer desiring to leave PG&E and build a CHP plant, for example, will have to pay departing load charges levied against customers who were in the PG&E system when these long-term contract commitments were made.

The capacity charges associated with these four gas-fired plants will be substantial. These capacity charges cover the fixed costs associated with the generation resource, including the capital cost, operating personnel, and insurance. The CPUC has determined that it is necessary for ratepayers to pay the fixed costs of new generation to assure that the generation gets built.[404] The annual fixed costs of the four gas-fired plants will be approximately $600 million per year over a 20-year book life.[405]

The capacity charges associated with these four gas turbine projects will be borne by PG&E ratepayers. This $600 million per year charge will divert limited resources from clean energy alternatives. $600 million per year would purchase over 300 MW per year of PV at 2010 prices, or over 3,000 MW of cumulative PV over the 2011 – 2020 period.[406]

13.2 Reference Price for Renewable Generation

The CPUC has established that the LCOE from a new natural gas-fired combined cycle unit is the representative market price of electricity that renewable energy resource costs are compared to in the California RPS program. This representative LCOE is called the "Market Price Referent - MPR."[407] The MPR consists of the LCOE of a new combined cycle plant plus an adder of $15 per ton of CO_2 emissions.[408] The concept behind the MPR is that ratepayers should be protected from excessive green energy costs by requiring that renewable energy resources be no more costly than the conventional brown power they will replace.

Combined cycle units operate as intermediate-load plants in California. They typically operate at capacity factors of 60 to 70 percent.[409] The fleet average capacity factor in 2008 was 65 percent.[410,411] The capacity factor is a measure of actual annual electricity production compared to maximum possible output if the unit is operated every hour of the year at maximum output. Combined cycle units generally do not operate during off-peak, low demand periods. Low demand periods include midnight to 6 am most workdays as well as weekends. Lower-cost nuclear, large hydroelectric, and coal plants meet the need during these periods. Combined cycle units are not the high-cost generation resource during summer peak periods. Simple cycle peaking turbines and older conventional steam plants with higher operating costs are also online during peak hours.

13.3 Calculating What Distributed PV Is Worth

A representative avoided cost for a solar PV system in PG&E service territory can be calculated using: 1) the MPR, adjusted to reflect a typical 65 percent capacity factor for a combined cycle plant and adjusted for the TOD of solar generation, and 2) the line losses and T&D costs that are avoided when a PV system substitutes for grid power.

The CPUC and the CEC have both developed estimates of the LCOE for a new 500 MW combined cycle plant. The CPUC derived its combined cycle installed cost estimate by looking at three projects that were either operational (Palomar, Consumnes) or under construction (Colusa) at the time the 2009 MPR was developed.[412] The dates of the installed cost estimates for these projects are: Palomar –June 2004, Consumnes – January 2006, and Colusa – February 2008. The 2009 MPR calculation assumes a January 2010 online date.

In contrast, the CEC used a non-project specific combined cycle pricing model to develop LCOE projections for 2009 and 2018 online dates.[413] The CEC also examined a range of capacity factors. LCOE projections were developed for capacity factors of 55 percent, 75 percent, and 90 percent for an unfired 500 MW combined cycle unit. LCOE projections were also developed for capacity factors of 50 percent, 70 percent, and 85 percent for a duct-fired 550 MW combined cycle unit.[414]

The CPUC currently assumes a hypothetical capacity factor of 92 percent for a combined cycle unit when calculating the MPR.[415] However, the CPUC uses a capacity factor of 65 percent when calculating the actual expected electricity production from California's fleet of combined cycle plants.[416] The effect of using the unrealistically high capacity factor of 92 percent in the MPR calculation is to make the MPR reference price artificially low. The effect of capacity factor on the LCOE for a new 500 MW combined cycle plant is shown in Table 13-1 using the CEC combined cycle LCOE estimates.[417]

Use of a MPR based on a 65 percent capacity factor would accurately reflect typical usage rates of operating combined cycle plants in California. This value is $134/MWh for an online date of 2009, and is projected by the CEC to rise to $183/MWh for an online date of 2018. Powers Engineering has taken the mid-point between these two values to estimate the MPR for an online date in the 2013 to 2014 timeframe. This MPR value is $158/MWh. The proposed start dates for
600 MW Russell City, 624 MW Oakley, 760 MW Marsh Landing, and 200 MW Mariposa are 2013, 2016, 2013, and 2012 respectively.[418] Given the average start-up date for the PG&E gas-

Table 13-1. Effect of Capacity Factor on LCOE from New Combined Cycle Plant

Capacity factor (%)	LCOE, 2009 ($/MWh)	LCOE, 2013/2014 ($/MWh)	LCOE, 2018 ($/MWh)
92	118	140	161
75	124	147	169
65	134	158	183
55	146	173	199

Note: CEC provides LCOE values for online dates of 2009 and 2018. The values included for 2013/2014 were calculated by Powers Engineering and are the average of the 2009 and 2018 values.

fired capacity that could be substituted with DG is 2013 to 2014, the appropriate MPR value is for a combined cycle unit that will be online in 2013 or 2014. This is an MPR of $158/MWh.

The generation of power at or near the point-of-use, whether it is solar PV or CHP, eliminates the transmission line losses that would occur if the electricity is imported from more distant sources to serve the same load. The value of the line losses avoided by use of DG in PG&E territory is approximately $10/MWh.[419]

The addition of local generation also relieves load on the local distribution substation and the transmission line(s) serving that distribution substation. This effect is more pronounced in areas with inadequate transmission, or distribution substations approaching their capacity at times of peak demand. Energy and Environmental Economics, Inc. (E3), a CPUC contractor, developed the model adopted by the CPUC to determine the T&D avoided costs associated with energy efficiency programs. Ten separate PG&E divisions serve the nine-county Bay Area. The E3 model calculates energy efficiency avoided cost for each of these PG&E divisions. These T&D avoided costs are shown in Table 13-2.[420]

Table 13-2. Energy Efficiency T&D Avoided Costs in PG&E Divisions in the Bay Area

PG&E Division	T&D avoided cost ($/MWh)	Group
North Coast	27.84	1
North Bay	25.34	1
Sacramento	33.11	1
Diablo	30.67	1
Mission	37.57	1
San Jose	24.62	1
De Anza	32.35	1
Peninsula	11.16	2
San Francisco	9.02	2
East Bay	6.18	2

The average energy efficiency T&D avoided cost in Group 1 divisions is approximately $30/MWh. The average energy efficiency T&D avoided cost in Group 2 divisions is approximately $10/MWh. This avoided T&D credit is equally applicable to solar PV or CHP to the extent they are available during peak demand periods.

The T&D system is designed to meet peak demand loads. *California Solar Initiative* fixed PV systems in PG&E service territory have a demonstrated availability during the 4 pm to 5 pm peak hour of summer demand of more than 50 percent.[421] The peak availability of fixed PV is conservatively assumed to be 50 percent in BASE 2020. Therefore, the full avoided T&D value of $30/MWh in Group 1 areas and $10/MWh in Group 2 areas must be multiplied by 0.50 to accurately reflect the avoided T&D value of fixed PV. This means that the PV T&D avoided cost would be $15/MWh in Group 1 areas and $5/MWh in Group 2 areas. CHP would be credited with the full avoided T&D value, as CHP is fully available at the summer peak.

As noted, the GHG emissions component of the MPR is $15 per ton of CO_2. This converts to a cost adder of $6/MWh.[422]

The solar PV avoided cost calculation is:[423]

Avoided cost = (CEC LCOE × TOD factor) + CO_2 adder + avoided line losses + (avoided T&D × resource availability at peak)

Solar PV avoided cost, Group 1 area = ($158/MWh × 1.24) + $6/MWh + $10/MWh + $15/MWh

= $227/MWh

Solar PV avoided cost, Group 2 area = ($158/MWh × 1.24) + $6/MWh + $10/MWh + $5/MWh

= $217/MWh

The solar PV value to PG&E is $227/MWh, or $0.227/kWh, in Group 1 areas and $217/kWh, or $0.217/kWh, in Group 2 areas. Any PV project or program with a tariff of less than $0.227/kWh in Group 1 areas in 2011, or $0.217/kWh in Group 2 areas, is a lower-cost resource than buying the same electricity from PG&E.

The CEC forecasts a 36 percent rise in the LCOE for a new combined cycle plant between 2009 and 2018.[424] In contrast, PV panel prices have declined by as much as two-thirds over the last three years.[425] Prices for PV are forecast to continue drop by 15 percent per year until 2015 due to oversupply and cheaper production.[426]

13.4 Calculating What CHP Is Worth

The avoided cost to PG&E of CHP generation is somewhat different than that of PV. PV is a daytime resource with maximum output in the summer months. CHP is a round-the-clock baseload resource. For this reason, the TOD multiplier for CHP is 1.0. CHP can also be available continuously at rated capacity during the summer peak. CHP is therefore accorded full credit for avoided T&D expenditures. The CHP avoided cost is:

CHP avoided cost, Group 1 = $158/MWh × 1.0 + $10/MWh + $30/MWh × 1.0 = $198/MWh

CHP avoided cost, Group 2 = $158/MWh × 1.0 + $10/MWh + $10/MWh × 1.0 = $178/MWh

13.5 Merit Order Benefits of Distributed Energy

PG&E receives electric power from a wide variety of sources, both within its service territory and throughout the West. The generation mix in the western U.S. consists of nuclear plants, coal plants, large and small hydroelectric plants, baseload biomass boiler plants, baseload geothermal plants, baseload CHP plants, load-following natural gas-fired combined cycle plants, peaking natural gas-fired gas turbines and steam boiler plants, wind plants, and solar plants.

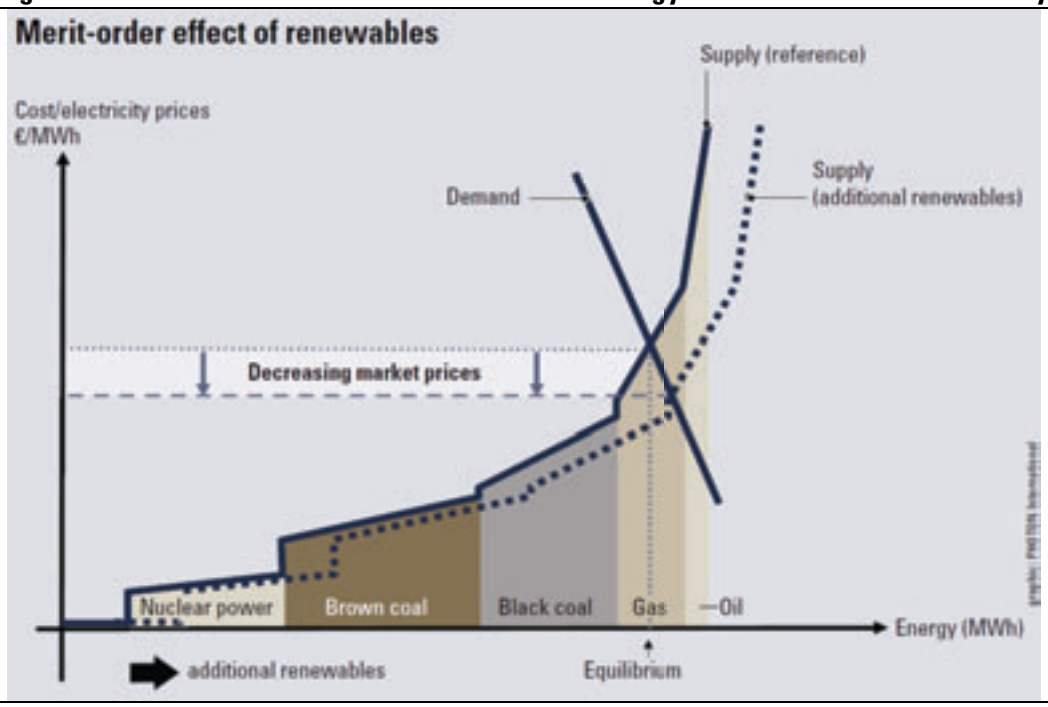
The price of power in a competitive wholesale power market is set by the generation source with the highest fuel cost that successfully bids into the market.[427] In the late evening, the market price of power is set by the low-cost base load units, as the demand is low and all higher-cost units are offline. Medium cost load-following combined cycle units will set the market price during much of the day most of the year. High cost peaking plants will set the price of power on hot summer afternoons when all lower-cost resources are already online. All operators online in any given hour are paid at the rate of the highest-cost unit that is online in that hour. Therefore keeping the highest-cost peaking units offline has the effect of lowering the cost of electricity, at times substantially, for all users.

This phenomenon is shown in Figure 13-1 for the German power market on a hot summer afternoon. The reduction in German electricity market prices caused by renewable energy depressing market prices in 2009 is estimated at approximately $5 billion by the German government.[428] Germany produced approximately 16 percent, 94,000 GWh, of its total electricity demand with renewable energy resources in 2009.[429,430] The $5 billion per year reduction in the market price of power is a $5 billion per year savings to German ratepayers.

Germany has an electricity market that is approximately twice the size of the California market at about 526,000 GWh per year of end user consumption.[431] Fall, winter, and spring market prices fluctuate between $30/MWh and $80/MWh, and summer prices fluctuate between $30 and $150/MWh.[432] The range of market prices for electricity in Germany is roughly comparable to the range in California.[433]

California consumed 287,000 GWh of electricity in 2008.[434] Estimates of 2009 renewable energy supply vary from 27,000 GWh to 37,000 GWh.[435] This translates into a renewable energy percentage of total California consumption of approximately 12 percent.[436] Scaling from the German experience with the merit order effect of renewable energy, the 12 percent renewable energy contribution to the California power market would depress electricity market prices by roughly $2 billion per year.[437] On a unit basis, this equals a price reduction of about $170 million per year per 1 percent increase in renewable energy percentage in the California electricity market.[438]

Figure 13-1. Merit Order Effect of DG Renewable Energy on Market Price of Electricity[439]



One percent of the California electricity market is 287,000 GWh per year × 0.01 = 2,870 GWh per year. The merit order effect would be achieved whether the distributed resource is renewable or natural gas-fired CHP. By way of example, a combination of 1,000 MW per year of new fixed solar PV and 150 MW of new CHP would add approximately 2,900 GWh per year of new DG resources. Assuming all of the projects are 1 MW in size, there would be 1,150 new projects each year.

What is the economic benefit of the electricity market price depression effect of these projects to California ratepayers? The economic benefit would be approximately $150,000 per MW of new DG capacity installed per year.[440] The financing period for these generation projects is typically 20 years. The net present value of 20 years of electricity market price depression caused by these projects, in 2011 dollars, would be approximately $1.6 million per MW of installed capacity.[441]

To put this value in perspective, the net capital cost of a 1 MW_{ac} commercial rooftop PV array, assuming a $3.50/$W_{dc}$ gross installed cost, would be approximately $1.8 million with the 30 percent investment tax credit and accelerated depreciation.[442]

Major DG projects in the Bay Area have been stalled for a number of reasons. Predominant among them are various fees and charges imposed by PG&E that undercut the economic attractiveness of the project. One such project, the proposed 50 MW CHP upgrade to the downtown San Francisco steam loop boiler plant, was identified in the *2002 Strategic Energy Plan* for San Francisco as a priority project but has yet to move forward.[443] The net present value of the economic benefit from electricity market price depression of this project would be in the range of $75 million based on the German experience. A major PG&E substation is located one-half mile from the project site. Yet the project has not moved forward due to issues related to interconnection.

Renewable energy production in Germany is almost exclusively distributed renewable energy. Over four-fifths of solar capacity in Germany is on rooftops in arrays less than 100 kW.[444] Wind farms average 9 MW.[445] Power flows from these local renewable energy systems are substantially reducing the need for market power purchases by German utilities and dampening wholesale electricity prices. In contrast, California IOUs are buying and developing substantial amounts of wind power far from California load centers. Wind generation in Oregon, Montana, and British Columbia will have less price reduction impact on the market price of power in California than local renewable energy.

13.6 Availability of Solar and Wind at Peak Demand

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

Hot summer days are cloud-free or nearly cloud-free in the Bay Area. This results in maximum output from solar resources during peak demand periods.[446] In contrast, wind intensity is generally lowest during summer mid-day and afternoon periods. As a result, the solar resource would have the predominant market price depression effect on summer afternoons when market prices are highest.

The availability of distributed PV and wind resources during summer peak demand periods is shown in Table 13-3. The PV system output peak is mid-day, while the summer demand peak usually occurs in the mid-afternoon. By way of example, the one-hour peak demand event in PG&E territory in 2009, the source of the 54 percent peak capacity factor for fixed rooftop PV shown in Table 13.3, occurred between 4 pm and 5 pm on July 14, 2009.[447]

Table 13-3. Comparison of Peak Demand Capacity Factors for Solar and Wind

Technology	Peak capacity factor	Reference
Tracking solar PV	77	E3, *Inputs and Assumptions to 33% Renewables Portfolio Standard Implementation Analysis*, July 2009, Table 7, p. 12.
Fixed rooftop PV	54	Itron, *CPUC Self-Generation Incentive Program Ninth-Year Impact Evaluation - Final Report, prepared for PG&E*, June 2010, Table 5-14, p. 5-32.
Onshore wind	4	PG&E, *2006 Long-Term Procurement Plan - Volume 1*, December 11, 2006, p. IV-77.

13.7 Concept of FIT

13.7.1 Overview

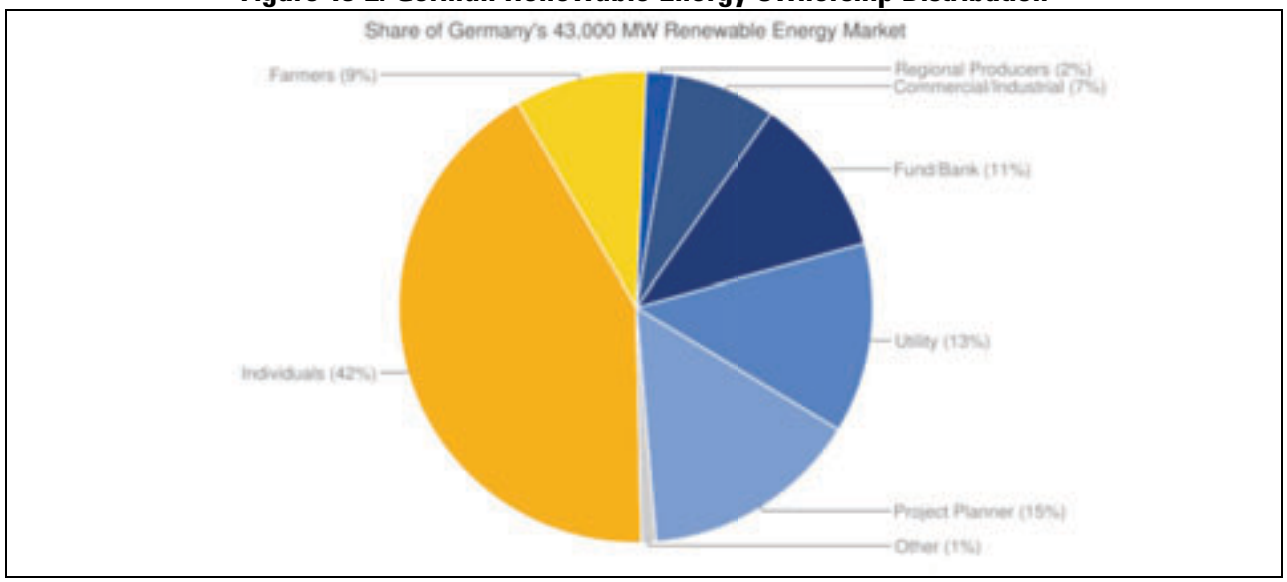
A FIT is a pre-established fixed long-term price for renewable energy or CHP. The use of fixed "standard offer" prices for renewable energy projects, the core of the FIT concept, is a proven model for assuring the financing of these projects. Thousands of MW of renewable wind, solar, and geothermal projects 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.[448] 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.

13.7.2 German FIT Program

Germany has the most effective FIT structure in the world. Germany added nearly 8,000 MW_{dc} of solar PV in 2010 for a cumulative total of 17,000 to 18,000 MW_{dc}.[449] Wind power capacity reached nearly 25,780 MW_{ac} by the end of 2009.[450] An additional 1,550 MW_{ac} of wind power was added in 2010.[451] One hallmark of the German FIT is that ownership of renewable generation is highly dispersed. Approximately half of the 40,000+ MW_{ac} of renewable energy generation in Germany is owned by individuals. See Figure 13-2.[452] Critical components of the FIT, in addition to an adequate price, are that the utilities have an obligation to interconnect the generator and there are no caps on the quantity of renewable power that can utilize the FIT.

Figure 13-2. German Renewable Energy Ownership Distribution



13.7.3 Ontario FIT Program

The province of Ontario, Canada has implemented a FIT program with many of the characteristics of the successful German program. Ontario installed 143 MW_{ac} (168 MW_{dc}) of solar PV systems in 2010, second only to California in North America.[453] The FIT program was enabled by the *Green Energy and Green Economy Act of 2009*. The Ontario Power Authority (OPA) is responsible for implementing the program.[454]

A primary objective of the FIT program is to assist Ontario to phase-out coal-fired electricity generation by 2014. Additional goals include boosting economic activity, the development of renewable energy technologies, and the creation of new green industries and jobs.

A critical component of the Ontario FIT is a transparent interconnection procedure. The available capacity on all substations in the OPA system is listed on a public website. If sufficient T&D capacity is available at the proposed connection point for a specific project, the project developer is offered a FIT contract.[455]

When connection availability is insufficient, the OPA determines the T&D upgrades required and, in conjunction with other applications that require the same upgrades, assesses whether the upgrades are economically justifiable. Upgrades that are justifiable are included in T&D expansion plans. FIT contracts are offered once the upgrades receive required approvals and the OPA is reasonably certain that they will be completed by the commercial operation target dates in the affected applications.

The Ontario program also includes domestic content provisions. Wind projects larger than 10 kW must include at least 50 percent domestic content starting in 2012. PV systems must include at least 60 percent domestic content starting in 2011.[456]

13.7.4 Financial Drivers Behind U.S. Renewable Energy Development

Renewable energy development in the U.S. is contingent on federal investment tax credits or production tax credits, and accelerated depreciation. This program has been essential in the U.S. for promoting solar and wind power. Historically it has been an "on again, off again" tax credit, subjecting the renewable energy industry to boom and bust cycles. This deficiency has been rectified to a degree as renewable energy tax credits are now available through 2016.[457] It also only applies to commercial (private) developers who can use tax credits. Government agencies and POUs like AMP, CPAU, SFPUC, SVP, and NCPA are ineligible.

13.7.5 Developing Effective FITs in California

The standard offer contracts pioneered in California in the 1980s were phased-out in the 1990s. There has been relatively slow growth in renewable energy production in California since the

phase-out of these contracts, despite RPS legislation mandates that have been in place since 2002.[458] FIT pilot programs have been established in California, both for renewable energy (AB 1969 and SB 32) and CHP (AB 1613). However, the CPUC adopted a narrow interpretation of avoided cost in establishing the FITs for this program. The result has been tariffs that are too low to stimulate significant investment.

SB 32 authorized the construction of up to 750 MW of solar PV using a FIT in 2009. The CPUC issued a ruling on January 27, 2011 requesting briefs to implement SB 32.[459]

In a separate program, the CPUC is implementing the 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.[460] Up to 1,000 MW of PV contracts will be awarded over two years.

RAM was conceived to avoid the perceived problem that FITs would be set at artificially high rates. The RAM program obligates developers to calculate the cost of their projects and then offer a bid high enough to generate a profit, yet low enough to win a contract.

Problems with FIT programs in Spain and Italy are cited in the December 2010 CPUC decision as the justification for substituting a conventional FIT with RAM.[461] The implication is that conventional FIT design inevitably results in over-paying and price shock to the ratepayer. Yet the decision approving the RAM program avoids mention of the successful FIT program in Germany that has effective cost controls and that has led to sustained growth in distributed PV deployments in that country. There is also no mention of the successful Ontario FIT program that is modeled on the German program. The Ontario FIT has led Ontario to be second only to California in PV installations in North America one year after the program began operating.[462]

There are a number of concerns with the RAM approach that would be eliminated by a well-designed FIT. The auction process is non-transparent and controlled by the IOUs. This same non-transparent framework is a core element of the heavily criticized RPS procurement process. A section header in the CEC's *2007 Integrated Energy Policy Report* effectively summarizes these criticisms: "RPS Program Structure: Need for Greater Transparency, Less Complexity, and Full Valuation of Renewable Energy." The lack of transparency in the RAM program creates the potential for gaming of the auction process. The uncertainty in the actual price hampers the ability of companies to make strategic commitments to adding PV to multiple facilities.

The 1,000 MW of PV to be developed under the RAM program will be split proportionately among the state's three IOUs.[463] The program will result in approximately 420 MW of new solar PV development in PG&E territory.[464]

However, the December 2010 RAM decision has already been challenged by PG&E. The company states in its rehearing request that:

> "First, PG&E's RAM procurement obligation is not limited to procuring only those resources whose prices are at or below the Commission-determined market price referent (MPR), which violates the RPS statute's cost limitation provisions. Second, the Decision does not permit the IOUs to suspend their RAM programs if they achieve the 20 percent RPS target, which violates the RPS statute's clear directive that the IOUs cannot be required to procure greater than 20 percent renewables."[465]

This challenge by PG&E is revealing. PG&E's reticence to pay more than the MPR in the RAM program is contradicted by recent PG&E contracts for large-scale solar power, where the company has voluntarily agreed to pay more than the MPR. In the case of these contracts, the CPUC has given PG&E

approval to pass on all costs above the MPR to ratepayers. For example, the CPUC approval of the contract between PG&E and the 250 MW Genesis Solar (Thermal) Energy Project states:

> "Based on a 2014 guaranteed commercial online date for the Project, the 25-year PPA exceeds the 2008 MPR and therefore has above-market costs associated with it. . . Therefore, PG&E will voluntarily incur the above-MPR costs of the PPA. . . Payments made by PG&E under the Genesis Solar, LLC power purchase agreement are fully recoverable in rates over the life of the agreement."[466]

In other CPUC proceedings PG&E makes clear the 33 percent RPS goal is part of its strategic plan, stating:

> "For the 2010 RPS Plan, the goal is similar and PG&E's strategy is to effectively address both the near-term 20 percent compliance mandate and the longer-term 33 percent state goal by balancing near-term compliance needs and longer-term portfolio expansion and maintenance."[467]

PG&E has been an active participant in both the CAISO and California Transmission Planning Group transmission planning processes.[468] Both entities advocate for approval of transmission projects justified on the need for achieving a 33 percent RPS in California by 2020.

Yet in the RAM proceeding PG&E argues that the 33 percent goal is not applicable, and that purchases of PV under the RAM should be suspended once the company meets 20 percent RPS.

13.8 Solar PV FIT - Lower Than PG&E's Avoided Cost

In July 2010 UCLA/LABC developed a proposed FIT for use in LADWP service territory. The tariff rates are structured to make the development of 3,300 MW of the City of Los Angeles estimated 5,536 MW of rooftop PV potential economically feasible over ten years. The study also estimates that 12,500 MW of 19,113 MW of a Los Angeles County rooftop PV potential could be economic to develop over ten years with the proposed FIT rates.

UCLA/LABC propose a program cap of 600 MW. The 600 MW is allocated across three proposed tariff categories as shown in Table 13-4. This allocation results in a 2010 composite tariff for the program of $0.22/kWh.

Table 13-4. PV FIT Categories, First Year Tariff, and Capacity Allocation

Category	Eligible systems	Typical participants	2010 tariff ($/kWh)	Capacity allocation (MW)
Small rooftops	< 50 kW	Single family homes, small office, retail, apartments	0.34	100
Large rooftops	≥ 50 kW	Warehouses, distribution facilities, light manufacturing, industrial	0.22	300
Large ground-mounts	Commercial ground-mounted	Large ground-mounted, installed for optimum efficiency	0.16	200
Composite tariff			0.22	

The UCLA/LABC study incorporated a tariff decline rate of 5 percent per year (in 2010 dollars) as shown in Table 13-5. The composite program tariff assumes the same relative capacity allocation shown in Table 13-4 throughout the 10-year duration of the program.

Table 13-5. PV FIT Decline Rate Over 10 Years of Program

Category	Tariff per kWh for a new contract in program year ($/kWh)									
	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Small rooftops	0.34	0.32	0.31	0.29	0.28	0.26	0.25	0.24	0.23	0.21
Large rooftops	0.22	0.21	0.20	0.19	0.18	0.17	0.16	0.15	0.15	0.14
Ground-mount	0.16	0.15	0.14	0.14	0.13	0.12	0.12	0.11	0.10	0.10
Composite (in 2010 dollars)	0.22	0.21	0.20	0.19	0.18	0.17	0.16	0.15	0.15	0.14

The FITs shown in Tables 13-4 and 13-5 are sufficient to facilitate rapid growth in distributed PV deployment in California.[469] The 2011 composite program tariff of $0.21/kWh is slightly less than the projected avoided cost of a new combined cycle power plant approved in 2011 and online in 2013 or 2014 (Marsh Landing) or 2016 (Oakley). The PV program tariffs steadily decline over time. In contrast, the avoided cost of a new combined cycle plant steadily rises.[470]

The FITs shown in Tables 13-4 and 13-5 assume the availability of the federal 30 percent investment tax credit for residential PV projects, and the federal 30 percent investment tax credit and accelerated depreciation for commercial projects. The effect of these tax benefits on the net capital cost of a commercial rooftop PV system is detailed in Appendix H. These tax benefits will expire in 2016 unless extended in federal legislation. The tariffs for 2017 through 2019 will have to be increased if these tax benefits are not extended beyond 2016. A reasonable guideline for resetting the tariff ceiling would be that the composite value of the FIT could not exceed the avoided cost to the IOU in the year the tax benefits expire.[471]

Adding two additional categories to the proposed UCLA/LABC FIT structure would lower overall program cost. Table 13-6 presents a revised BASE 2020 tariff structure with five categories. The objective of the revised tariff structure is to lower overall program costs. The relative PV capacity allocations would remain the same as those shown in Table 13-4. However, the large rooftop category in the UCLA/LABC FIT is expanded into three commercial rooftop categories. An even split of capacity is assumed across these three categories. The year 2011 is used as an example to demonstrate the calculation of the composite 2011 tariff:

$$\text{Composite 2011 tariff} = [\$0.32/\text{kWh} \times (100/600)] + [(\$0.21/\text{kWh} + \$0.18/\text{kWh} + \$0.16/\text{kWh})/3 \times (300/600)] + [(\$0.15/\text{kWh}) \times (200/600)] = \$0.19/\text{kWh}$$

Table 13-6. Revised PV FIT to Reduce Overall Program Cost

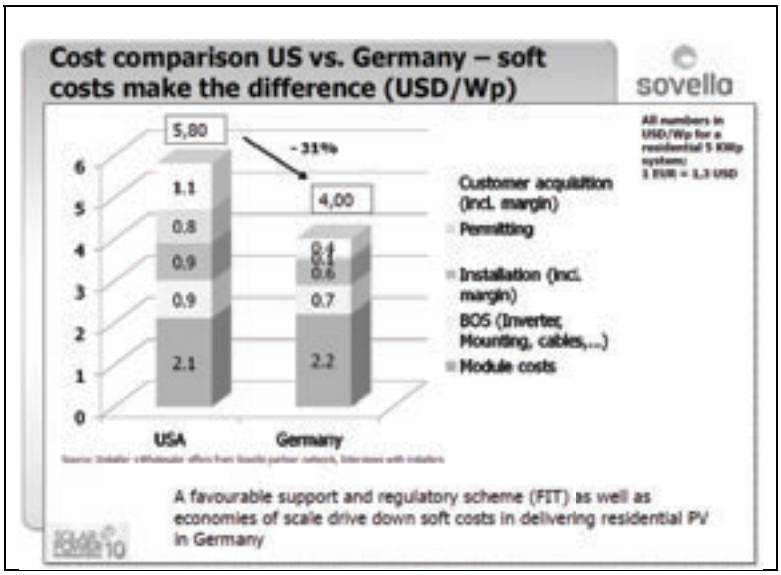
Category	Tariff per kWh for a new contract in program year ($/kWh)									
	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Residential, <10 kW	0.32	0.31	0.29	0.27	0.26	0.25	0.24	0.23	0.22	0.21
Commercial, 10 – 50 kW	0.21	0.20	0.19	0.18	0.17	0.16	0.15	0.15	0.14	0.14
Commercial, >50 – 200 kW	0.18	0.17	0.17	0.16	0.15	0.14	0.13	0.13	0.12	0.11
Commercial, >200 kW	0.16	0.15	0.15	0.14	0.13	0.12	0.12	0.11	0.11	0.10
Ground-mount, commercial	0.15	0.14	0.14	0.13	0.12	0.12	0.11	0.10	0.10	0.095
Composite (in 2010 dollars)	0.19	0.18	0.18	0.17	0.16	0.15	0.14	0.14	0.13	0.13

Note: The term "residential" includes rooftop or ground-mount installations at a single family residence. The term "commercial" includes rooftops, parking structures, and parking lots. The term "ground-mount" applies to installations on open land.

The practical viability of the FIT tariff shown in Table 13-6 was corroborated by: 1) reviewing current competitive pricing for principal PV market segments, and 2) communicating with PV system installers regarding the adequacy of the pricing. The proposed PV tariff assumes a 2011 residential PV system gross capital cost of $\$5/W_{dc}$. This is consistent with retail residential 2010 PV pricing in some U.S. markets.[472] The $\$5/W_{dc}$ assumption is higher than residential PV pricing in some group-buy PV programs, with offer prices as low as $\$4.67/W_{dc}$.[473]

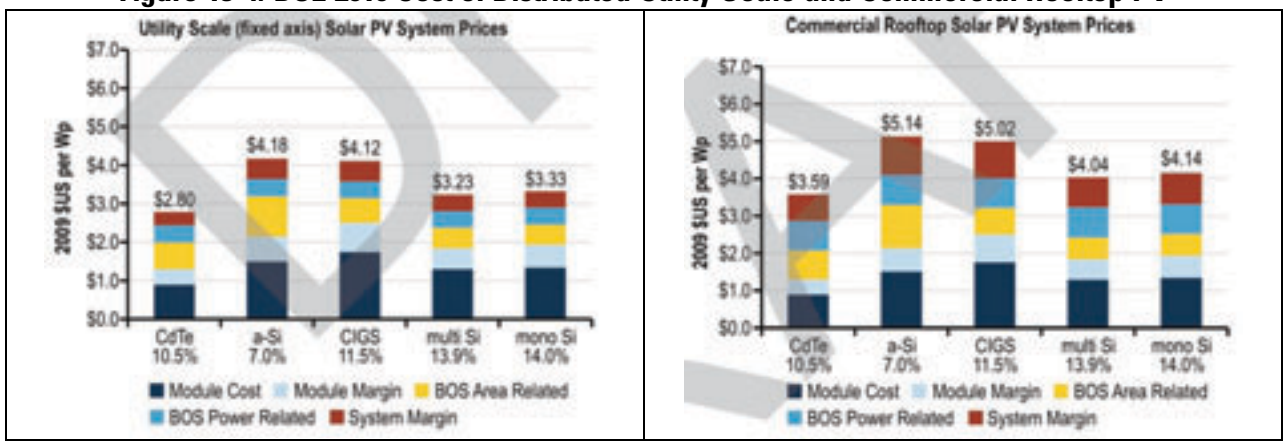
German residential PV systems, with the same PV panel and hardware costs as U.S. systems, are installed for about two-thirds the cost of a typical U.S. installation. The installed cost of a representative 5 kW_{dc} residential PV system in Germany is about $4/$W_{dc}$, while the same PV system in the U.S. would typically cost close to $6/$W_{dc}$. The difference in price is primarily related to higher U.S. costs of installation, permitting, marketing, and higher U.S. profit margins. See Figure 13-3. The higher volume of residential PV sales in Germany produce economies of scale that drive down costs.[474]

Figure 13-3. Comparison of Installed Cost of U.S. and German 5 kW Residential PV



Figures 13-4 shows best-case early 2010 PV pricing identified by DOE for distributed utility-scale (10 to 20 MW) and commercial rooftop PV.[475] This pricing is consistent with the PV capital cost range shown in Table 6-1 for fixed PV systems with a LCOE of less than $140/MWh at ideal sites. Two high volume solar installation firms also confirmed that the 2011 FIT pricing in Table 13-6 is adequate to stimulate a dynamic PV market based on their pricing.[476]

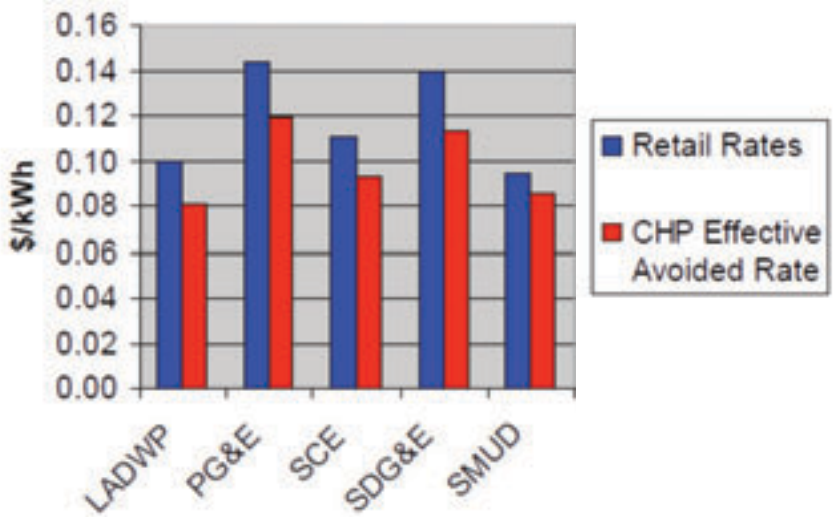
Figure 13-4. DOE 2010 Cost of Distributed Utility-Scale and Commercial Rooftop PV



13.9 CHP FIT - Lower Than PG&E's Avoided Cost

The average avoided cost of CHP to PG&E is just under $0.19/kWh. This means that the cost to PG&E to replace electricity that would otherwise be generated by a CHP plant is in the range of $0.19/kWh. The LCOE for a typical small natural-gas fired CHP plant in California powered by an internal combustion engine or gas turbine is shown in Figure 13-5.[477] The LCOE of CHP in PG&E territory is in the range of $0.12/kWh. The retail rate the customer would be charged for electricity if the CHP plant did not exist was over $0.14/kWh in 2009.[478] The $0.12/kWh LCOE for the CHP plant includes departing load surcharges and the impacts of demand charges incurred when the CHP system goes down during peak hours.[479]

Figure 13-5. California Utility Retail Rates and 50 to 500 kW CHP Cost of Electricity



13.10 Fuel Cell CHP

SGIP incentives are available for fuel cells, energy storage, and small wind turbines. These incentive payments are shown in Table 13-7.[480] As a result, even though fuel cell CHP projects are substantially more capital intensive than engine or gas turbine CHP projects, the net LCOE for a fuel cell CHP plant can be at or below the LCOE from a comparable engine or gas turbine CHP plant.

Table 13-7. SGIP Incentive Payments for Fuel Cells, Energy Storage, and Wind Turbines

Technology	Energy payment ($/kW)	System Size		Max. size for full incentive (MW)
		minimum (kW)	maximum (MW)	
Wind turbine	1,500	30	5	1
Fuel cell, renewable fuel	4,500	30	5	1
Fuel cell, non-renewable fuel	2,500	none	5	1
Energy storage	2,000	none	5	1

Note: 2010 incentive rate is capped at 3 MW. 0 – 1 MW 100%; >1 MW – 2 MW 50%; >2 MW – 3 MW 25%.

An example of fuel cell economics in California is the fuel cell CHP plant at UC San Diego described in Chapter 12. The project receives the maximum SGIP fuel cell incentive because it uses renewable fuel. Biogas from the nearby San Diego wastewater treatment facility will be piped to UC San Diego for use in the fuel cell. The cost of electricity to UC San Diego will be in the range of $0.12/kWh under a long-term contract between UC San Diego and the turnkey supplier of the fuel cell system. The project is expected to save UC San Diego and San Diego a combined $2 million over the life of the 10-year power purchase agreement relative to retail electricity rates.[481,482]

The UC San Diego project uses a dedicated pipeline for the biogas because the relatively low gas quality prevents injection of the biogas into the utility natural gas pipeline system. However biogas can also be upgraded to biomethane, as discussed in Chapter 12, to allow injection into the utility pipeline network. This is one option available to convert any CHP plant in the Bay Area to a renewable fuel without onsite modifications.

Biomethane is more costly than natural gas, with an estimated production cost of $12/MMBtu compared to a current natural gas cost in the range of $4 to $5/MMBtu.[483] However, use of biomethane eliminates the need to build a dedicated biogas pipeline, as was done for the UC San Diego fuel cell project, or generate electricity at the point where the biogas is produced. The combustion of biomethane in a CHP plant puts to productive use a fuel that is otherwise flared or vented.

The CPUC has proposed a complex pricing format for new CHP in its December 2010 settlement agreement decision with CHP operators.[484] A stated intent in the agreement is to facilitate the *AB 32 Scoping Plan* objective of adding 4,000 MW of new CHP by 2020.[485] However, the settlement agreement imposes the same IOU RPS procurement procedures on new CHP procurement. These procedures have contributed to slow progress on RPS procurement.[486] The IOUs will issue a request for offers for CHP projects and select projects based on some combination of least cost – best fit criteria. If the pricing of proposed projects is above the adopted market index pricing formula, the IOUs can use pricing as a reason to reject the project, and as an acceptable justification for failing to meet targets for new CHP capacity.

13.11 Conclusions and Recommendations

13.11.1 Conclusions

- The merit order effect of increased DG in the electricity supply mix reduces the wholesale cost of power to all customers. The merit order effect of DG in Germany, an electricity market two times the size of the California electricity market, reduced the wholesale electricity price to German customers by approximately $5 billion in 2009. The merit order effect of increased DG supply on wholesale electricity prices has not yet been quantified for the California power market.
- The RAM approach to PV pricing is inferior to a well-designed FIT due to the lack of transparency in the current program design, potential for gaming, and the inherent weakness of an auction mechanism in providing the investment security necessary for rapid and large-scale deployment of distributed PV systems.
- The cost to PG&E to provide electricity that would otherwise be provided by a PV system ranges from $0.22 to $0.23/kWh. A PV FIT of $0.22/kWh or less would meet the requirement in SB 32 that "ratepayers that do not receive service pursuant to the (FIT) tariff are indifferent to whether other ratepayers receive service pursuant to the tariff."
- The cost to PG&E to provide electricity that would otherwise be provided by a CHP system ranges from $0.18 to $0.20/kWh. A CHP FIT tariff of $0.18/kWh or less would assure that rates for ratepayers in general do not increase as a result of PG&E payments to CHP operators.
- A composite 2011 FIT of $0.19/kWh for distributed PV would be sufficient to spur rapid deployment of distributed PV systems in the Bay Area. The FIT would decline to $0.13/kWh in 2020.
- The current CHP LCOE in the Bay Area is about $0.12/kWh. A CHP FIT rate incrementally above this cost, at a rate of approximately $0.15/kWh, would be sufficient to spur a rapid increase in new CHP capacity in the Bay Area.
- Successful FIT programs in Germany and Ontario require prompt interconnection by the utility upon receipt of an interconnection application.
- The merit order benefits of DG to all IOU customers, at $1.6 million per MW of new DG capacity based on German data, are so large that all DG interconnection costs should be borne by PG&E for DG systems. This would eliminate the most common reason that DG projects of all types fail to move forward – economic and technical interconnection obstacles.

13.11.2 Recommendations

- The Governor's Office should commission an independent evaluation of the merit order effect of ever-increasing levels of DG in California on the wholesale electricity market price. The results of this evaluation would serve as the basis for shifting all DG interconnection costs to PG&E.
- The Governor's Office should commission an independent evaluation to corroborate the avoided cost of distributed PV and CHP calculated in BASE 2020. The purpose of this evaluation would be to verify that the PV and CHP FIT tariffs proposed in BASE 2020 would reduce electricity costs for all PG&E ratepayers relative to business-as-usual.

- The CPUC should re-open the Russell City, Marsh Landing, Oakley, and Mariposa power purchase agreement proceedings. The CPUC must consider the high actual reserve margins in PG&E territory in denying or re-affirming these power purchase agreements.
- The RAM program should be suspended and replaced with a PV FIT with a 2011 composite tariff of $0.19/kWh, declining to $0.13/kWh in 2020. The decline rate should be re-evaluated every 2 years to assure it reflects market conditions. The CHP FIT should be set initially at rate of approximately $0.15/kWh. Both the PV and CHP FIT tariffs should be adjusted at a set annual rate for inflation.
- The state should use the DWR as the public agency that serves as the buyer of PV and CHP FIT electricity generation, just as DWR has served as the buyer of electricity via the long-term power contracts negotiated to end the 2000-2001 electricity crisis. The DWR would require the IOUs to purchase the PV and CHP electricity at the FIT rates, following the same structure used with the long-term DWR power contracts.

14. The Geysers Geothermal Power – Making It Sustainable

An advantage of geothermal power is that it is a round-the-clock resource. The Bay Area has one geothermal production area – The Geysers in northeast Sonoma County. The Geysers has produced commercial geothermal power continuously since the early 1960s. Present generation is around 900 MW from eighteen geothermal plants owned by three operating companies: Calpine Corporation, NCPA, and U.S. Renewables.[487] The location of the geothermal plants in The Geysers is shown in Figure 14-1.

Figure 14-1. The Geysers Geothermal Resource Area[488]

Calpine owns and operates fifteen power plants at The Geysers with a net generating capacity of about 725 MW. This is sufficient to power 725,000 homes, or a city the size of San Francisco.[489] The output from this capacity is sold to PG&E and SCE.[490] The NCPA operates two geothermal plants at The Geysers with a net generating capacity of approximately 116 MW.[491] A portion of the output of the NCPA geothermal plants is sold to POUs in the Bay Area. U.S. Renewables owns one 55 MW geothermal plant at The Geysers.[492] Output from this plant is sold to PG&E under long-term contract.

Ram Power Corporation (formerly Western GeoPower) is developing a 25 MW plant at The Geysers. Output from this plant will be sold to NCPA under a 20-year power purchase agreement.[493] It is expected that the project will be completed by 2013 in order to qualify for the federal investment tax credit or production tax credit. The project will have access to an existing transmission line with no upgrades required.[494]

14.1 Evolution of The Geysers Geothermal Resource

The Geysers produced the first commercial geothermal electricity in the U.S. in 1960 at PG&E's 11 MW Unit No. 1 power plant. The Geysers went on to become the world's largest commercial geothermal field by the mid-1980s, with close to 20 power plants, nearly 2,000 MW of installed capacity, covering 30 square miles.

The NCPA built two 110 MW power plants in the southeast corner of The Geysers during this rapid growth phase. In January 1983, NCPA commissioned twin turbine generators at its 110 MW Plant No. 1, the first publicly-owned geothermal power facility to operate at The Geysers. Plant No. 1 is shown in Figure 14-2. In 1985, NCPA bought the geothermal wells, field production facilities and all rights for future development.[495]

Figure 14-2. NCPA Plant No. 1

Steam lines along road leading to NCPA Unit No. 1 at The Geysers. Photo: Ted J. Clutter.

Geothermal steam flow from production wells at The Geysers dropped precipitously in the late-1980s. Geologic investigations showed The Geysers reservoir was not recharging with surface water as quickly as believed. A nearly impervious carbonate cap beneath a layer of low permeability rock allowed little new water to percolate into the reservoir. Operators responded by closing inefficient power plants and throttling back others. Geysers geothermal plant operators were reinjecting only about 20 percent of the fluid being extracted back to the geothermal reservoir. The remainder was lost as evaporation in plant cooling towers.[496]

Injection from improved condensed steam collection and rainwater ponds raised replacement to the reservoir from around 20 percent to 33 percent by 1988. More water had to be found to reduce reservoir losses further. The problem was addressed by injected treated wastewater into the geothermal formation.[497]

Aging infrastructure and rapid population growth were overwhelming the Lake County Sanitation District's wastewater systems during the 1980s. A study in the early 1990s determined that injection of treated wastewater into The Geysers geothermal formation would help sustain the resource and avoid the need to upgrade Lake County Sanitation District's water treatment systems.[498]

The Southeast Geysers Effluent Project Pipeline, built from Clear Lake, California to The Geysers, started delivering secondary treated wastewater to injection wells in September 1997. The 26-mile-long, $45 million pipeline delivers around 8 million gallons a day of treated wastewater to the southeastern portion of The Geysers geothermal field.[499]

The treated wastewater injection has reduced reservoir decline to 3 to 4 percent per year. In the case of the NCPA geothermal plants, the pipeline provides 55 percent of the fluid NCPA injects back to The Geysers reservoir. NCPA now replaces 96 percent of fluid extracted from the reservoir each year. However, geothermal plants at The Geysers operate at production rates substantially lower than design capacity. Current production from the NCPA geothermal plants is only half of nameplate capacity of 220 MW.[500]

Calpine launched a multi-year $200 million program in 2007 to increase geothermal production at The Geysers by up to 80 MW.[501] The project involves rebuilding eight older steam turbines.

14.2 Micro-Earthquakes at The Geysers

Geothermal production at The Geysers does cause micro-earthquakes as pressures fluctuate within the deep geothermal formations. The U.S. Geological Survey recorded 1,007 seismic events at The Geysers in 2009. No major structural damage has been caused by micro-earthquakes at The Geysers to date. Geothermal operators work with the local community to address the nuisance that micro-earthquakes cause. Operators have established payments for repairs to cracked sidewalks, siding, chimneys and windows.[502]

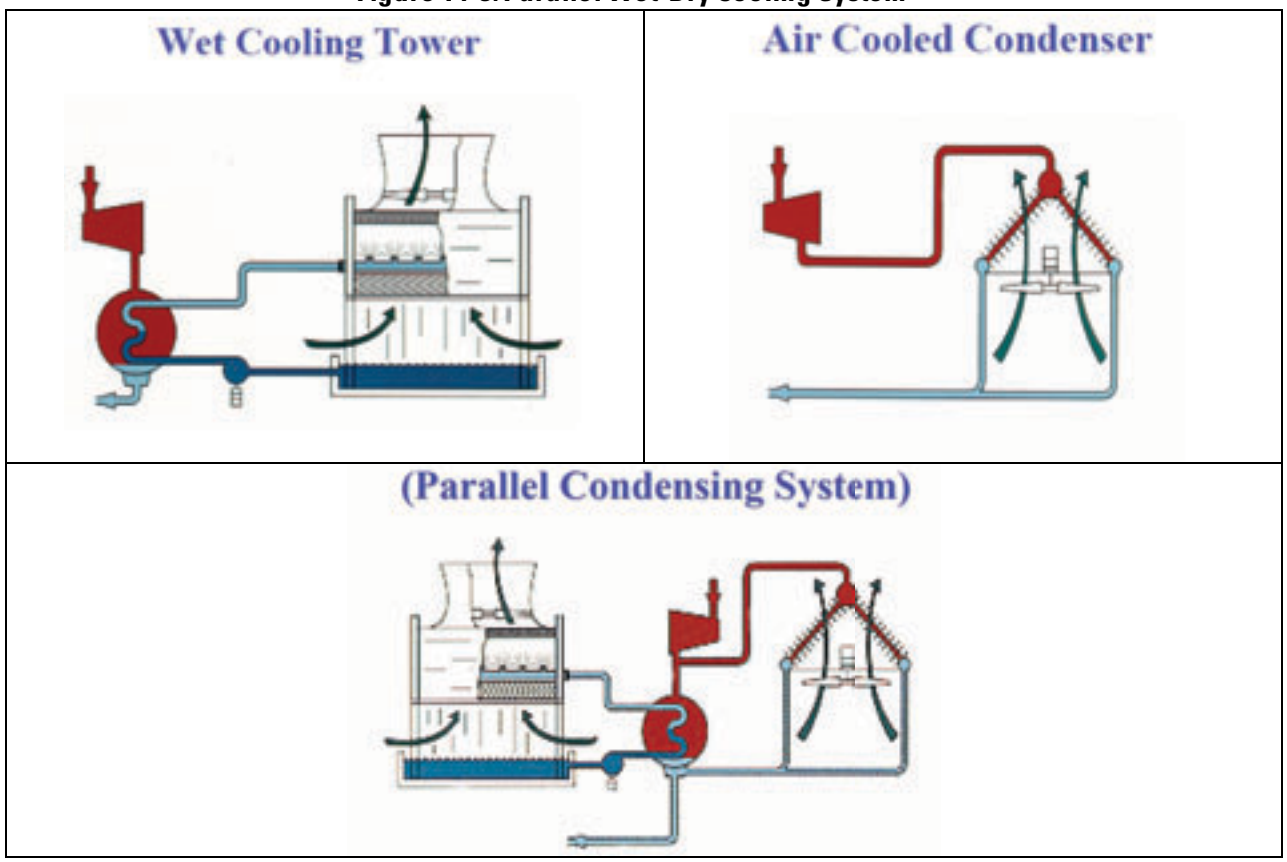
14.3 Achieving Sustainable Operation of The Geysers

Geothermal plants at The Geysers consume large volumes of water. This water is primarily consumed in the evaporative wet cooling towers that are used to condense the geothermal steam after it passes through the power turbine. Much of the water used in the cooling tower is condensed geothermal reservoir fluid. This is geothermal fluid that does not get recycled back into the geothermal reservoir to maintain reservoir pressure.

There is no state policy to assure the long-term viability of geothermal resources. As a result, private geothermal developers have built plants with relatively low capital cost wet cooling, even though the evaporative water loss from the cooling tower depletes the geothermal resource over time. The proposed 25 MW Ram Power geothermal project at The Geysers is a case in point. The project will use a wet cooling tower. Currently geothermal developers have no incentive or requirement to incorporate parallel wet-dry cooling or dry cooling into new or existing plants at The Geysers to minimize consumptive water use.

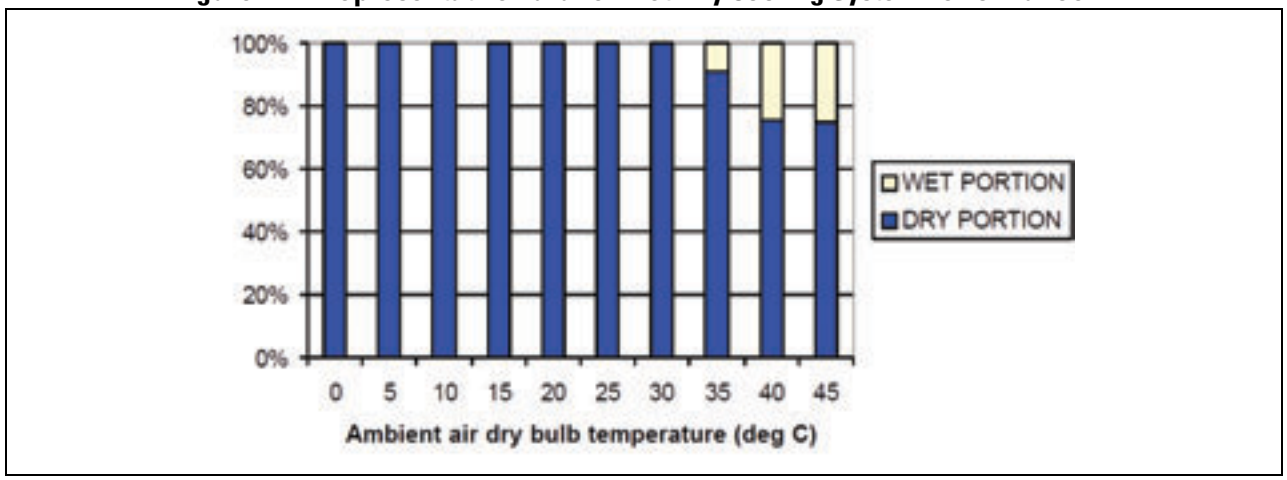
This issue can be addressed technically by retrofitting existing geothermal plants at The Geysers with parallel wet-dry cooling systems to substantially reduce cooling tower water consumption. Parallel wet-dry cooling systems have been in use on power plants since the mid-1990s. Retrofitting a dry cooling system, known as an air-cooled condenser, onto a plant equipped with a wet cooling tower is relatively straightforward. A schematic of a parallel wet-dry cooling system is shown in Figure 14-3. New geothermal plants would be built with dry cooling systems to reduce plant water consumption by up to 98 percent compared to the same plant equipped with a wet cooling tower.

Figure 14-3. Parallel Wet-Dry Cooling System[503]



Parallel wet-dry cooling systems can reduce consumptive water use relative to a wet cooling tower system by up to 90 percent. Figure 14-4 shows a representative parallel wet-dry cooling system where the dry cooling section can address the entire thermal load up to 90 °F (30 °C).

Figure 14-4. Representative Parallel Wet-Dry Cooling System Performance[504]



14.4 Tragedy of the Commons

Geothermal plants are very expensive to build. The CPUC estimates the capital cost of a new geothermal plant at $6,300/kW.[505] The cost of retrofitting an existing plant with an air-cooled condenser, or to build a new plant with an air-cooled condenser, would be in the range of $200/kW. In the case of a new plant, the dry cooling alternative would add about 3 percent more cost to an already expensive plant. However, new geothermal plants will not be built with dry cooling systems without state regulations or policies in place that require water use to be minimized in geothermal plant cooling systems.

This is a classic example of the tragedy of the commons. It is in the strategic interest of the state that its geothermal reservoirs are developed and operated in a manner that assures their long-term viability. That has not happened at The Geysers.

A single operator employing a state-of-the-art dry cooling system to minimize water use at The Geysers would make little difference in the long-term, as other operators with wet cooled plants located around the dry-cooled plant would continue withdrawing water at unsustainable rates. All existing plants would have to be retrofit with minimum water use cooling systems to achieve the objective of sustainable long-term pressure stability in the geothermal reservoir. Otherwise the operators with lower cost, high water consumption cooling towers will gain an unfair economic advantage over operators that are protecting the long-term sustainability of the geothermal resource.

Continuous injection of large amounts of treated wastewater imported via the Southeast Geysers Effluent Pipeline has allowed The Geysers to continue operating at an output of about 900 MW, approximately half its nameplate capacity of around 2,000 MW. The Geysers is on a form of artificial life support, and would eventually cease to be a significant power generation resource without this life support. This can not be considered a sustainable resource.

However, the Southeast Geysers Effluent Pipeline is an example of an effective collective response to a generalized geothermal resource decline problem that could not be resolved by individual plant operators. NCPA describes the partnership formed to build the pipeline, and significance of the pipeline to ongoing geothermal electricity production, in this passage:[506]

> "The most significant effect on increasing NCPA's recoverable steam reserves came from the construction and operation of the Southeast Geysers Effluent Pipeline project. This $34.1 million project with Calpine, Unocal and the Lake County Sanitation District as partners has delivered over 6 billion gallons of lake water and treated sanitation plant effluent to the Geysers since startup in September 1997, for increased injection and a resulting increase in injection-derived steam. NCPA's one-third share of the water doubled its availability of injectate, and the total amount of steam capable of being produced over the next twenty years is expected to be increased from 238 to 401 billion lbs., resulting in a 70 percent increase in the amount of electricity capable of coming from NCPA's geothermal operations."

Funding for the Southeast Geysers Effluent Pipeline came from NCPA, Calpine, Unocal, PG&E, California Energy Commission, BLM, U.S. Department of Energy, U.S. Environmental Protection Agency, U.S. Economic Development Agency, and Lake County ratepayer indebtedness.[507]

At some point, either due to population increase or drought conditions, Lake County Sanitation District may determine it can not afford to continue sending 8 million gallons a day of lake water and treated wastewater to The Geysers. At that time the geothermal plants at The Geysers would need to adapt to substantially less make-up water or permanently shut down.

14.5 Cooling System Retrofits Could Add Inexpensive Geothermal Power

A comprehensive retrofit of existing geothermal plants at The Geysers to parallel wet-dry cooling would result in a reduction in geothermal fluid consumptive use of up to 90 percent. Reduced fluid consumption would lead to the potential for significant additional geothermal output.

The geothermal power increase potential from a comprehensive retrofit of the eighteen 110 MW (design rating) geothermal plants at the Geysers may be substantial. If another 300 MW of additional output could be regained from the geothermal field by a comprehensive wet-dry cooling retrofit program, these 300 MW would be the least expensive new renewable energy in the state. This assumes around 16 to 20 cells per geothermal plant at an installed cost of about $1.5 million per cell.[508,509] This equates to a cost of approximately $500 million for the retrofit of the entire fleet of geothermal plants at The Geysers.

The total annual additional electricity production from 300 MW of new geothermal capacity would be about 2 million MWh.[510] The annual expense of the cooling system retrofits would be around $50 million per year.[511] Therefore, the cost of this additional geothermal electricity would be on the order of $50 million per year divided by 2 million MWh per year, or about $24/MWh. Even if only an additional 100 MW of output could be recovered, the LCOE of this additional output would still be inexpensive at around $60/MWh.

14.6 Conclusions and Recommendations

- Parallel wet-dry cooling retrofits of The Geysers geothermal plants would improve the sustainability of The Geysers and lead to an increase in production.
- Parallel wet-dry cooling retrofits could increase output from The Geysers at low cost.
- The environmental impact of a cooling retrofit program would be positive, as the cooling retrofits would improve the sustainability of existing plants at The Geysers with no new environmental impacts.
- New plants at The Geysers should be dry-cooled, to avoid further depletion of the geothermal resource.
- The CEC should conduct a technical evaluation to verify the cost of retrofits of geothermal plants to parallel wet-dry cooling and the likely increase in geothermal output made possible by the retrofits.
- If the CEC evaluation demonstrates that the parallel wet-dry cooling retrofit program would result in a substantial increase in output from The Geysers at reasonable cost, the CPUC should authorize PG&E and SCE to recover from ratepayers the cost to the geothermal plant operators of the cooling system retrofits.
- The same CEC evaluation should be used by NCPA to support recovery from NCPA member POU ratepayers of the cost to retrofit the two NCPA geothermal plants to parallel wet-dry cooling.

15. Energy Storage

The potential application of energy storage technologies ranges from bulk storage within the transmission system to smaller storage projects within the distribution system. The development of large-scale energy storage systems is moving forward in California. For example, in 2010 FERC approved incentive rates for Western Grid Development's utility-scale battery storage projects in California.[512] These projects are intended to address specific transmission reliability problems identified by CAISO. Also, the SCPPA signed an agreement with Ice Energy in January 2010 to develop 53 MW of load-shifting storage capacity.[513] PG&E or third parties can deploy energy storage systems in conjunction with fixed PV arrays or wind farms to assure high levels of availability during peak demand periods as an alternative to contracting for a new generation of peaking gas turbines to fulfill the same function.

AB 2514, signed into law in September 2010, directs the CPUC to open a proceeding by March 2012 to determine the amount of energy storage, if any, to be developed by the IOUs.[514] Similar language is included for POUs. The bill initially contained specific energy storage targets. These targets included energy storage equivalent to 2.25 percent of the daily peak load by 2014, and 5 percent of the daily peak load by 2020.[515] Daily peak load is defined as a utility's average peak electrical demand over the previous five years. On a statewide level, assuming an average statewide peak load of 50,000 MW, this is equivalent to somewhat over 1,000 MW of energy storage in 2014 and 2,500 MW of energy storage in 2020.[516]

Specific percentage energy storage targets were dropped from the final version of AB 2514. The CPUC proceeding will now set the energy storage targets.

15.1 Overview of Energy Storage Technologies

Table 15-1 describes the three common categories of energy storage applications.[517]

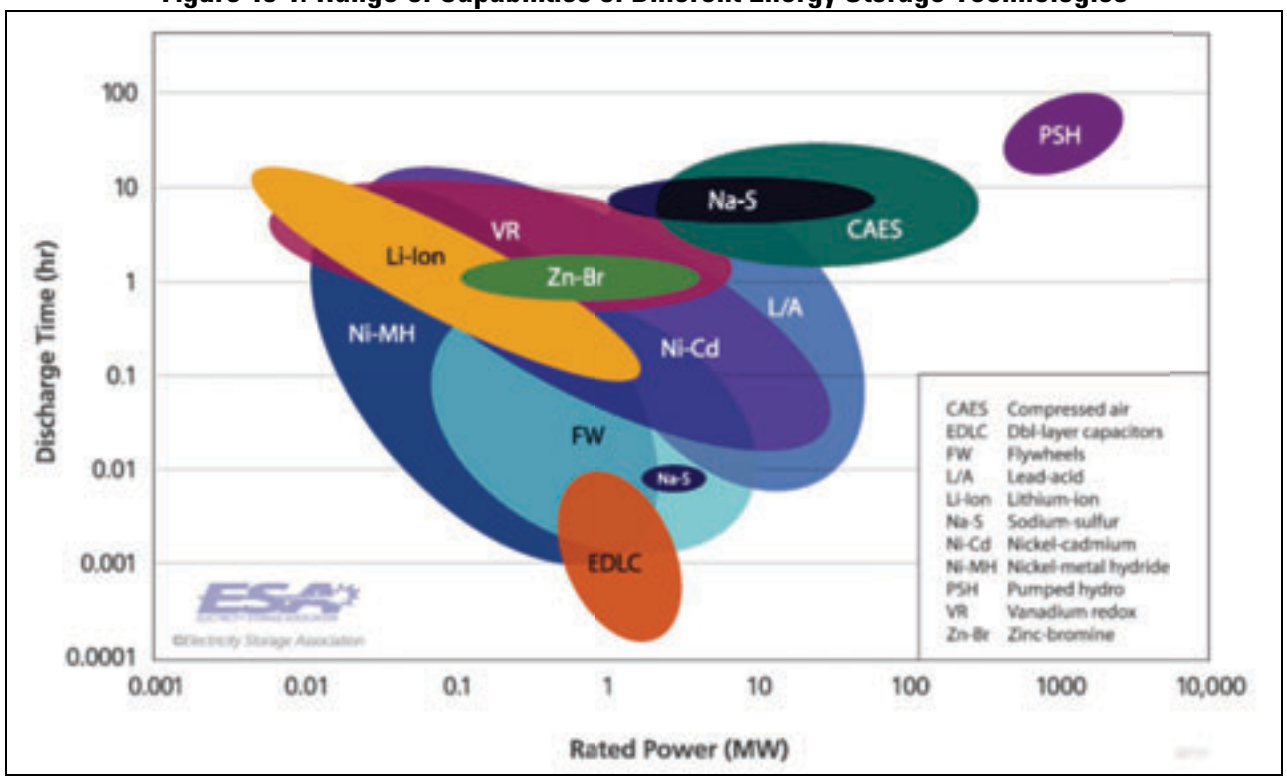
Table 15-1. Three Categories of Energy Storage

Common Name	Example Applications	Discharge Time Required
Power quality	transient stability, frequency regulation	seconds to minutes
Bridging power	contingency reserves, ramping	minutes to one hour
Energy management	Peak-shaving, firm capacity, T&D deferral	hours

Figure 15-1 identifies the range of capabilities of each energy storage category. The energy management category, which addresses the ability to shift bulk energy over periods of a few hours or more, is the category of interest in BASE 2020.

Lead-acid batteries are used in automotive applications and are also used extensively in off-grid PV systems. Thick plate sealed lead-acid batteries designed specifically for off-grid PV applications are relatively low cost and have a useful life of 15 to 20 years.[518]

Figure 15-1. Range of Capabilities of Different Energy Storage Technologies



For many batteries, there is considerable overlap between energy management and the shorter-term applications listed in Table 15-1. Batteries can generally provide rapid response, which means that batteries used for energy management can potentially provide services over all the applications and timescales. In the U.S., a primary application of energy management batteries has been the deferral of T&D system upgrades.[519]

The most mature high-temperature battery is the sodium-sulfur battery, which had more than 270 MW of worldwide installed capacity as of 2009.[520]

Concern among Japanese utilities over the frequency regulation challenges of wind power, due to output fluctuations under some weather conditions, has slowed wind power development in the country.

In an effort to increase wind power development, Japan constructed the first large-scale integrated wind and battery storage project at Futamata, Japan in 2008. As shown in Figure 15-2, 34 MW of sodium-sulfur battery storage is integrated with the 51 MW wind farm to allow the wind power output to be flattened into a near constant output, baseload profile.[521]

Figure 15-2. 34 MW Sodium-Sulfur Battery Storage System Supporting 51 MW Japanese Wind Farm[522]

Wind power concentrated in one or two primary development areas has the potential for large and rapid fluctuations in output. Therefore, wind power: 1) is a primary candidate for coupling with energy storage to dampen the impact of rapid output fluctuations on the grid, and 2) may need to be limited in the renewable energy mix to reduce the amount of back-up power necessary for frequency regulation and reliability support during peak demand periods.

15.2 Economic Benefits of Energy Storage as Peaking Capacity

Lead-acid batteries have been integrated into multi-MW storage systems for peak-shaving applications. An analysis prepared by the California Energy Storage Association, comparing the performance of an actual 10 MW peak-shaving system consisting of off-the-shelf lead-acid batteries to a simple cycle gas turbine, indicates that the lead-acid battery system produces lower cost peaking power.[523] Lead-carbon batteries may provide a cost-effective alternative to thick plate lead acid batteries when the lead-carbon alternative reaches mass production.[524]

Energy storage associated with PV systems or wind farms, that can be discharged as needed by the utility, serves the same function as a peaking gas turbine. Energy storage configured to be available to the utility at its discretion should receive the same capacity payments that would otherwise be directed to new peaking gas turbine capacity. The fixed cost of new peaking gas turbine capacity is $303/kW-yr.[525] Over a 15-year period, the total cost of this peaking gas turbine capacity to PG&E ratepayers would be: 15 years × $303/kW-yr = $4,545 per kW of capacity.[526] Therefore the value of battery storage to fill this same function, assuming a 15-year minimum battery lifetime, would be $4,545 per kW of battery capacity.

How much battery storage could a residential PV system owner buy for the capacity payment currently paid by PG&E to a new peaking gas turbine operator? Assume a 10 kW PV system in a regulatory environment where a sufficient FIT is in place for a homeowner to install a 10 kW PV system. The equivalent capital budget for the battery storage system, assuming a 15-year minimum lifetime, would be $4,545 per kW x 10 kW = $45,450.

An investment of less than $10,000 would be sufficient to add 3 hours of useable battery storage to a 10 kW PV system using thick plate lead-acid batteries with a minimum service life of 15 years.[527] This storage system would provide 3 hours of capacity at 10 kW, a total of 30 kWh of useful supply.

As of January 1, 2010, battery storage systems qualify under ARRA for the same 30 percent federal investment tax credit as solar systems.[528] The 30 percent investment tax credit would reduce the cost of the batteries in the example used here to less than $7,000. Use of batteries for peaking power would result in significantly less cost than relying on new peaking gas turbine capacity to fulfill the same function.

15.3 Electricity Demands of Electric Vehicles

PG&E asserts that it would take millions of PHEVs charging nightly on PG&E's system before there would be any concern about the need for additional off-peak procurement because of the large amount of excess generation available at night.[529]

The company projects that by 2015 the expected level of PHEVs in California will be about 75,500, and the optimistic achievable level by 2015 is 1,625,000 PHEVs.[530]

PG&E also indicates that PHEV vehicles, and electric substitution in a wide range of on-road and non-road vehicle applications, represent a potential total peak demand on PG&E's system of 250 to 380 MW by 2020 under the expected scenario.[531]

15.4 400 MW of Battery Storage Integrated with Solano County Wind

Hundreds or thousands of MW of wind turbines concentrated in the same area have the potential to cause abrupt changes in output. It is these areas that would be primary candidates to be matched with utility-scale energy storage, both to prevent instantaneous grid stability problems and to smooth output and shift more production to high demand, high value daytime periods.

The Solano County wind development area is a good candidate for a utility-scale energy storage project. This wind area is most productive in summer months when demand is highest. The recommended size of the storage project would be 400 MW. This is both sufficient to convert the existing 660 MW of wind capacity in Solano County to a base load resource and would match the transfer capacity of the nearby 400 MW Trans Bay Cable.

This project would effectively be a scale-up of the Futamata combined wind power and energy storage project in Japan using sodium-sulfide batteries. The purpose of this project would be to demonstrate the effectiveness of this combination to create a base load resource from wind power, and also to assess the economics of this approach compared to other alternatives, such as distributed PV with sufficient battery storage to serve as a base load resource.

15.5 200 MW of Battery Storage Integrated with Distributed PV

A fundamental tenet of the California *Energy Efficiency Strategic Plan* is net zero residential and commercial buildings. PHEVs represent a predictable future load that will make net energy consumers of net zero energy buildings unless sufficient rooftop PV is added to account for the PHEV loads. PG&E indicates that a limited number of PHEVs will not necessitate new generation to provide for the additional demand represented by the PHEVs, at least through 2016, but expanded use of PHEVs may require more new generation.[532]

FITs are the financial mechanism that will be used to maximize the deployment of distributed PV in the Bay Area under the BASE 2020 plan. Currently virtually all distributed PV systems installed in California are operating under net metering and provide no more than 100 percent of the annual electricity demand of the building where it is located. This will change with the transition to a FIT as the tool for financing PV installations.

The inverters used in most Bay Area rooftop PV systems are matched to the capacity of net-metered PV systems. Inverters can operate for up to 20 years. A FIT would allow a building owner to add more PV than necessary to meet the electricity demand of the building itself.

It is prudent for PV inverters to be oversized on new PV systems for two reasons: 1) to assure that PV system owners can easily expand net metered PV systems to take full advantage of a FIT, and 2) to accommodate the addition of battery storage at a pace that roughly matches the peak demand of PHEVs to assure that there is no net increased demand on the grid as a result of expanded use of PHEVs. It is also necessary that the PV inverter have sufficient capability to allow remote operation of the batteries to supply peaking power as needed by the utility. It is this capability that would qualify the PV system as a peaking power resource that is eligible for peaking power capacity payments.

There are thousands of existing off-grid PV systems that operate with battery storage. Nearly 100,000 off-grid PV systems were operational in the U.S. at the end of 2009.[533] Grid-tied PV systems with battery storage, for residential and commercial PV systems, are available.[534] Two commercial demonstration projects using battery storage for peak-shaving, a 15 kW system in Maui and a 30 kW system in Georgia, are operational.[535,536]

The Nissan Leaf PHEV is now available in the California market. The Nissan Leaf travels about 3.4 miles per kWh.[537] Assuming the average vehicle travels an average of 30 miles per day, the owner of the Leaf would require about 10 kWh of electricity production to achieve net zero electricity consumption for transportation.[538] In most parts of California, a 2 kW_{ac} PV array would provide an average daily output of approximately 10 kWh. In this example – to meet the net zero energy target – the owner of a PV system that purchases a PHEV would add 2 kW_{ac} of PV panels to address the demand of the PHEV.

Battery storage equivalent to one-day's PHEV electricity demand would be incorporated into PV the system to address the peak demand that could be imposed by the PHEV on the grid. The primary role of this battery storage would be to provide peaking capacity that could be dispatched as needed by the utility. The secondary role would be to charge the PHEV, as grid power would also be available for this purpose.

This would be the framework for adding approximately 400 MW of dispatchable distributed battery storage to PG&E territory by 2020. The Bay Area represents approximately 60 percent of PG&E's bundled and Direct Access customer demand, and about half of the demand in the PG&E planning area, which also includes numerous POUs. As a result, approximately 200 MW of the 400 MW of distributed battery storage would be located in the Bay Area.

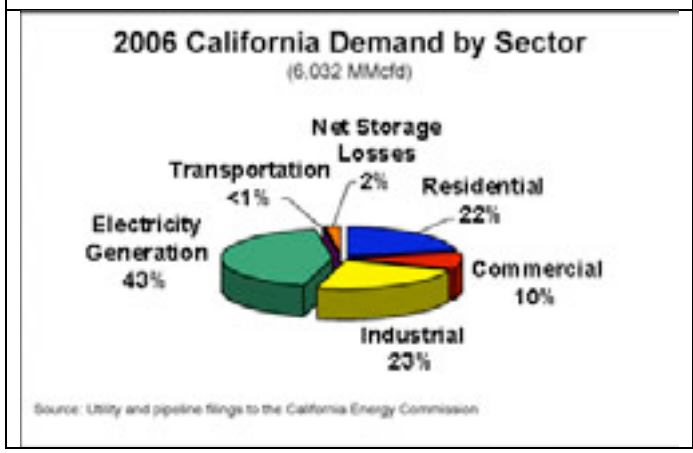
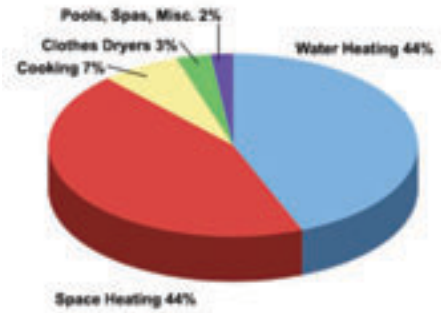
15.6 Conclusions and Recommendations

- Battery storage can be a lower cost alternative to peaking gas turbines.
- Sodium-sulfide batteries are a good match for wind farm output from a wind development area like Solano County with strong summertime electricity production.
- Adding battery storage to residential and commercial building PV systems is a viable approach for achieving and maintaining the net zero energy target while addressing the additional loads of PHEVs.
- The cost of this battery storage can be paid for through capacity payments that would otherwise be made to peaking gas turbine operators.
- 400 MW of sodium-sulfide battery storage should be integrated with the Solano County wind development area to convert this wind output into baseload power and provide 400 MW of reliable peaking power.
- 200 MW of residential and commercial building energy storage should be added to address the added loads of PHEVs and to provide 200 MW of reliable peaking power.

16. Solar Water Heating

Figure 16-1 shows the natural gas demand sectors that consume California's 6 billion cubic feet per day of demand, as well as the principal sources of natural gas consumption in California homes. About 44 percent of residential natural gas demand is associated with water heating.[539] This represents about 10 percent of California's overall natural gas demand.

Figure 16-1. Profiles of California Statewide and Residential Natural Gas Demand[540]

a. Statewide natural gas demand profile	b. Residential natural gas demand profile
	

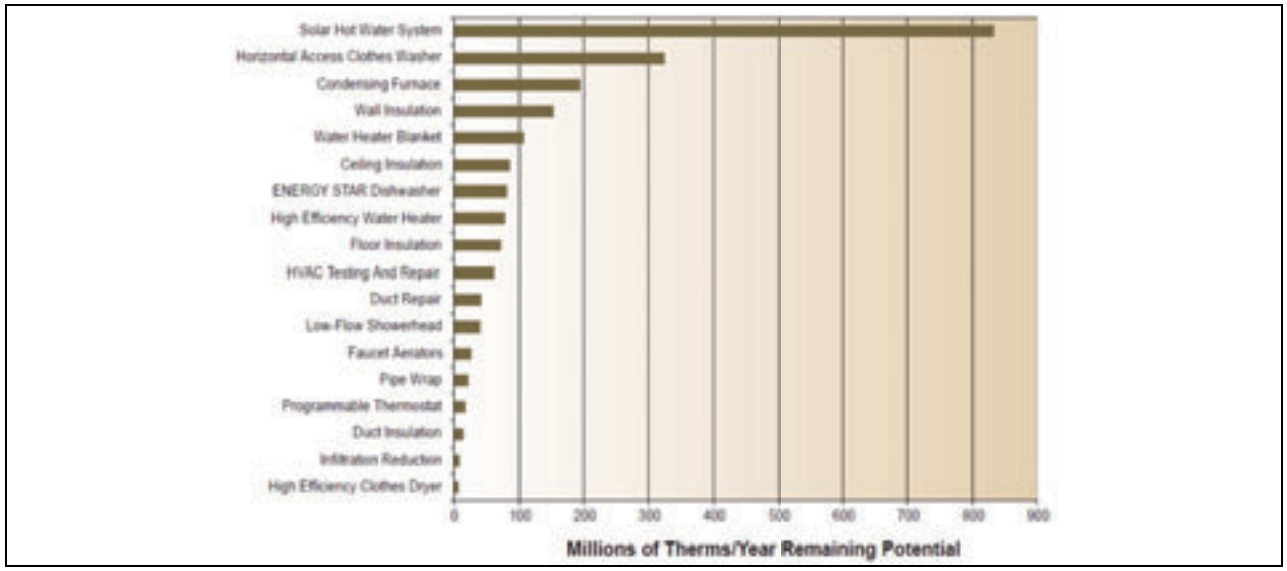
MMcfd = million cubic feet per day

16.1 Solar Hot Water Heating

Solar water heating systems offer the potential for substantial natural gas savings. Figure 16-2 shows the significance of solar water heating for reducing natural gas demand in California homes. An analysis conducted of solar water heating natural gas savings potential in California determined a potential reduction of approximately 1 billion therms per year in homes and 200 million therms per year in commercial buildings.[541] This is equivalent to 120 billion cubic feet of natural gas, about 20 days of natural gas supply for California. This is about 5 percent of the yearly statewide consumption of natural gas.[542]

Installing a solar hot water system on an existing home costs about $6,000. A system installed in a new home may cost as little as $3,000 because of reduced installation costs. The existing 30 percent federal tax credit reduces the cost of a typical system on an existing home from $6,000 to $4,200. This tax credit would reduce the cost of a system on a new home from $3,000 and $2,100.[543] The payback period for a solar hot water heater installed on an existing home is about eight years.[544]

Figure 16-2. Solar Water Heating Systems Have Largest Potential for Reduction of Natural Gas Use in California Homes[545]

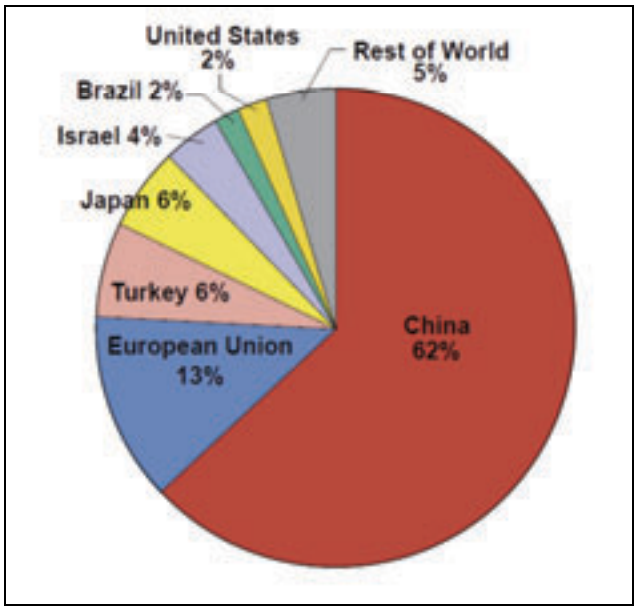


The *Solar Hot Water and Efficiency Act of 2007* authorized a ten-year incentive program for solar water heaters with a goal of promoting the installation of 200,000 systems in California by 2017.[546] This is an average installation rate statewide of 20,000 systems per year. The $350 million *California Solar Initiative (CSI) Thermal Program* is the instrument for achieving the installation of these 200,000 solar water heaters. The *CSI Thermal Program* began accepting rebate applications in May 2010.[547] Ratepayers can apply for cash rebates of up to $1,875 for the installation of solar water heating systems on single-family residential homes.[548] The *CSI Thermal Program* is administered by PG&E in PG&E service territory.

PG&E has over 5 million residential and commercial customers.[549] The state's current *CSI Thermal Program* will have to grow to hundreds of thousands of installations per year over the next decade to put substantial downward pressure on residential and commercial natural gas consumption. Successful implementation of the zero net energy target for new buildings will require major growth in California's solar water heating manufacturing and installation industry.

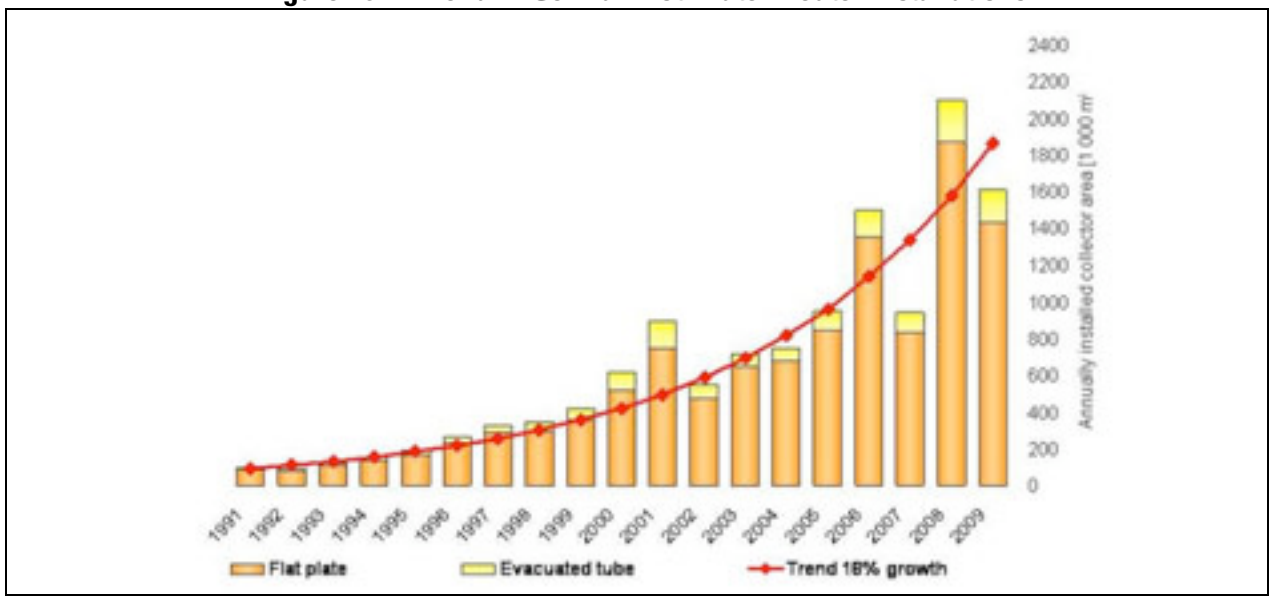
Many countries encourage increased use of solar hot water heating, as shown in Figure 16-3. China leads the worldwide market. On a per-person basis, Israel leads with 90 percent of all homes using solar hot water heating.

Figure 16-3. Solar Hot Water Capacity by Country[550]



Germany had about 1.4 million solar hot water installations online at the end of 2009.[551] The country installed approximately 200,000 solar hot water systems in 2008. The *1999 Market Incentive Program* supports solar heating for domestic hot water and space heating in existing single and multi-family residences.[552] The *2008 Renewable Energy Heat Act* requires that owners of new buildings meet some of the building heating requirement with renewable energy.[553] It applies to residential and commercial buildings. The owner can choose the type of renewable energy to be used. If solar power is used it must cover at least 15 per cent of the heating demand. The German trend in solar hot water installations is shown in Figure 16-4.[554]

Figure 16-4. Trend in German Hot Water Heater Installations



16.2 Solar Space Heating

Solar hot water systems can be used for central air heating. They are the same collectors used in solar domestic water heating systems. Flat-plate collectors are the most common, but evacuated tube and concentrating collectors are also available. A controller operates a circulating pump to move the fluid through the collector.[555]

The simplest storage system option for solar space heating is to use multiple standard domestic water heaters. They are readily available, designed to meet building codes for pressure vessel requirements, are lined to inhibit corrosion, and are configured so it is straightforward to attach pipes and fittings.

The solar heat can be distributed with a radiant floor or with a central forced-air system. In a radiant floor system, a solar-heated liquid circulates through pipes embedded in a thin concrete slab floor. The heat radiates to the room. Radiant floor heating is ideal for liquid solar systems because it performs well at relatively low temperatures. A conventional standard domestic water heater can supply backup heat.

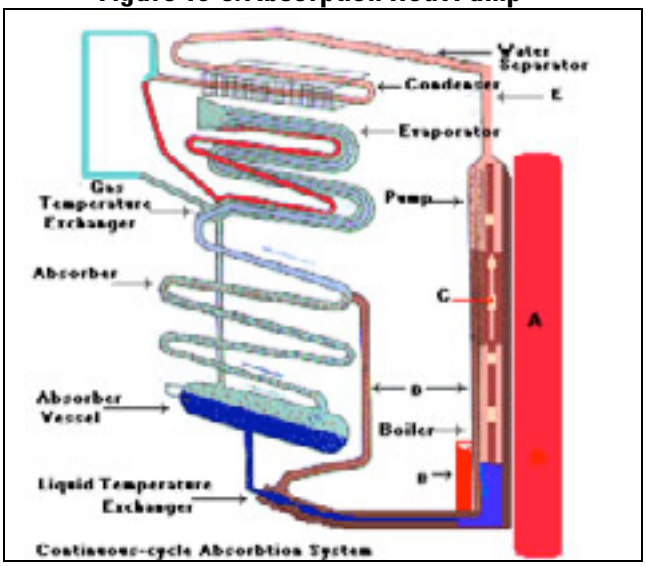
A liquid solar hot water system can be incorporated into a forced-air heating system. The basic design is to place a liquid-to-air heat exchanger, or heating coil, in the main room-air return duct prior to the furnace. Air returning from the living space is heated as it passes over the solar heated liquid in the heat exchanger.

Another alternative is direct solar heating of building make-up air. One example of this type of technology, the SolarWall™, is described in Appendix I.

16.3 Solar and Geothermal Heat Pumps

Absorption heat pumps are driven by a heat source such as natural gas, propane, solar-heated water, or geothermal-heated water. Residential absorption heat pumps use an ammonia-water absorption cycle to provide heating and cooling. The refrigerant, typically ammonia as in a standard heat pump, is condensed in one coil to release its heat. Its pressure is then reduced and the refrigerant is evaporated to absorb heat. If the system absorbs heat from the interior of the home, it provides cooling. If it releases heat to the interior of the home, it provides heating.[556]
Figure 16-5 is a schematic of an absorption heat pump.

Figure 16-5. Absorption Heat Pump[557]



The difference between a conventional refrigeration cycle and an absorption heat pump cycle is that the evaporated ammonia is not pumped-up in pressure in a compressor, but is instead absorbed into water. A relatively low-power pump can then pump the solution up to a higher pressure. The problem then is removing the ammonia from the water. That is where the heat source is necessary. The heat boils the ammonia out of the water, starting the cycle again.

A key component in the units available on the market is generator absorber heat exchanger technology. This technology boosts the efficiency of the unit by recovering the heat that is released when the ammonia is absorbed into the water.

Absorption coolers are now commercially available for large residential homes. The 5-ton residential cooler systems currently available are for homes on the scale of 4,000 square feet or more.

16.4 Merit Order Cost Benefits of Natural Gas Reduction

The merit order impact on the wholesale price of electricity of PV and CHP DG resources also holds true for natural gas. The natural gas savings realized by high levels of solar hot water heating in California would lead to large savings for all natural gas consumers by putting downward pressure on the wholesale price of natural gas.

A 2006 study by the American Council for an Energy-Efficient Economy (ACEEE) modeled the effects of natural gas savings in California, Oregon, and Washington on the price of the natural gas. The study found that efficiency measures leading to a 5 percent reduction in natural gas consumption would be accompanied by at least $5 billion per year in natural gas cost savings.[558] The California market accounts for about 80 percent of these savings.

The ACEEE study assumed a 2006 natural gas baseline price of about $7/MMBtu.[559] The average market price in the West has since declined to about $4/MMBtu. Assuming California represents 80 percent of the cost savings, and natural price decline has reduced the savings potential by half since the ACEEE study was conducted, the natural gas cost savings potential of a 5 percent reduction in California natural gas consumption would be on the order of $2 billion per year.

It is this merit order price reduction benefit from the conversion to solar hot water heating systems that should be the basis for a greatly expanded incentive budget for solar hot water heaters. A $2 billion per year incentive budget would be sufficient to completely pay for about 500,000 solar hot water heater installations per year.[560] There are 12.6 million homes in California.[561] An incentive program of this magnitude could convert about 40 percent of California homes to solar hot water heating by 2020.

16.5 Conclusions and Recommendations

- Solar hot water heating is a cost-effective approach to reducing natural gas usage.
- California has the potential to reduce natural gas consumption by 5 percent by adding solar hot water to homes and commercial buildings.
- California's current target under the *CSI Thermal Program* is to add 200,000 solar hot water heaters by 2017.
- Germany has added up to 200,000 solar hot water heaters in a single year.
- Natural gas savings caused by high levels of solar hot water heating in California will lead to large savings for all natural gas consumers by putting downward pressure on the wholesale price of natural gas.
- Natural gas efficiency measures leading to a 5 percent reduction in natural gas consumption could lead to a $5 billion per year or more savings in natural gas costs.
- The *CSI Thermal Program* will have to be increased by an order of magnitude to provide a significant reduction in natural gas consumption in California.
- The CEC should conduct an evaluation of the merit price effect of solar hot water heating in California on the market price of natural gas. The calculated merit price benefit to all California natural gas consumers should be included in the solar hot water heater incentive budget to increase the solar hot water heater installation rate.

17. Wind Power in the Bay Area

17.1 Altamont Pass and Montezuma Hills

The two principal wind development areas in the Bay Area are the Altamont Pass in eastern Contra Costa and Alameda counties, and the Montezuma Hills areas of Solano County.

The installed wind capacity of Altamont is 576 MW. [562] Altamont began wind power production in 1981. Annual generation is approximately 1,100 GWh.[563] The average capacity factor of Altamont Pass wind projects is about 22 percent.[564]

The Altamont Pass wind turbines were sited along a bird migratory route and in an area with a high concentration of raptors. The early generation wind turbines at Altamont use fast-spinning rotors. More than 1,000 birds are being killed annually by the wind turbines at Altamont. One-half of the birds killed are raptors.[565] The state brokered an agreement between wind developer NextEra and conservation groups in December 2010 to replace 2,400 older, fast-spinning wind turbines at Altamont.[566]

The Montezuma Hills area of eastern Solano County along the Sacramento River has become the primary wind development region in the Bay Area in the last decade. Approximately 660 MW of wind capacity is operating in Solano County.[567] The 2008 capacity factor of the first utility-scale wind farm in Solano County, the 150 MW Shiloh I project in operation since 2006, was 36 percent.[568] As shown in Figure 17-1, RETI identifies the Montezuma Hills as the primary area for new wind projects in the Bay Area. RETI estimates additional wind capacity in the Montezuma Hills of about 1,600 to 1,800 MW.[569]

The Montezuma Hills area is rural and agricultural. The Solano County wind projects have had far fewer avian deaths than those at Altamont. The projects have not been subject to environmental lawsuits or campaigns to date.

Figure 17-1. Utility-Scale Wind Sites in Bay Area Identified in RETI Process[570]

The operational and planned wind projects in Solano County are listed in Table 17-1.

Table 17-1. Actual and Planned Wind Projects in Montezuma Hills[571]

Wind project name	Number of turbines	Capacity (MW)	status
SMUD-Solano Phase 1 and 2	52	102	operational
High Winds	90	162	operational
enXco V	510 × 100 kW 6 × 1.5 MW	60	operational
Shiloh I	100	150	operational
Shiloh II	75	150	operational
Montezuma Wind I	16	37	operational
SMUD-Solano Phase 3	76	128	planned
Shiloh III	59	118	planned
Montezuma Wind II	34	85	planned
Shiloh IV	79	NA	speculative

The utility-scale wind potential in the Bay Area is listed in Table 17-2.[572]

Table 17-2. List of Potential Wind Sites Identified by RETI in Bay Area

RETI Wind Project Site Number	County	Potential (MW)
128	Marin/Sonoma	75
37/40/92/97/104/105/119/142/159	Solano	1,600 – 1,800

San Francisco is studying the wind intensity in the city in an effort to promote the use of smaller-scale distributed wind turbines in the urban environment. The San Francisco Department of the Environment is planning to use wind data gathered by the SFPUC and UC Davis to map the city's wind resources and provide wind resource data on a neighborhood-by-neighborhood or city block-by-city block level.[573]

17.2 Conclusions and Recommendations

- The addition of 300 MW of new wind capacity in Solano County over the next several years is highly likely.
- 300 MW of new wind capacity in Solano County should be assumed in BASE 2020.

18. Principal Conclusions

BASE 2020 is a DG strategy for minimizing GHG emissions from electricity usage in the Bay Area. It prioritizes energy efficiency, rooftop and distributed PV of all kinds, and CHP over conventional power plants to meet the electricity needs of the Bay Area. To a large degree the framework for BASE 2020 is California's strategic energy vision, embodied in California's *Energy Action Plan* and *Energy Efficiency Strategic Plan*.

Achieving BASE 2020 will reduce GHG emissions by more than 70 percent compared to PG&E by 2020, and will reduce peak Bay Area demand on the grid by nearly two-thirds. To achieve BASE 2020, the following overarching actions must be taken:

- Energy efficiency funds, currently administered by PG&E, must be transferred to an independent non-profit entity modeled on the Energy Trust of Oregon or to CCAs where they have jurisdiction.

- Effective FITs must be established for distributed PV and CHP.

- FITs at or below the avoided cost to PG&E will benefit all PG&E ratepayers. The average avoided cost of PV to PG&E is at least $0.22/kWh. The average avoided cost of CHP to PG&E is at least $0.18/kWh. FITs incrementally below these avoided costs to PG&E would be sufficient to create dynamic distributed PV and CHP markets in the Bay Area.

- The DWR should administer the FIT programs for distributed PV and CHP. Recent PG&E actions in the RAM and CHP proceedings at the CPUC indicate PG&E will resist distributed PV and CHP at the installation rates necessary to achieve the targets in BASE 2020.

- The Governor's Office should commission an independent evaluation to corroborate the avoided cost of distributed PV and CHP presented in BASE 2020. The purpose of this evaluation would be to verify that the PV and CHP FIT tariffs proposed in BASE 2020 would reduce electricity costs for all PG&E ratepayers relative to business-as-usual.

- The Governor's office should convene an independent panel to make a determination regarding the need to replace once-through cooled steam boiler capacity for grid reliability purposes. Available analyses by CAISO and SWRCB reach such different conclusions that, with a potential ratepayer impact of billions of dollars for new natural gas-fired capacity in the balance, a technical consensus must be reached at strategic level before committing to build these gas fired-plants.

- The Governor's Office should commission an independent quantification of the merit order effect of ever-increasing levels of energy efficiency, distributed PV, CHP, and solar hot water heating on the wholesale market price of electricity and natural gas in California.

- In the case of distributed PV and CHP, the results of this evaluation would serve as the basis for shifting all transaction costs, including interconnection costs, to PG&E ratepayers.

- In the case of solar hot water heating, biomethane production, and biogas production, the results of the independent quantification would serve as the basis for expanding incentive payments to these natural gas displacement alternatives.

19. References

[1] Utility-scale solar is defined in BASE 2020 as projects greater than 20 MW_{ac} (alternating current). Distributed PV is at or below 20 MW_{ac} and interconnected to the grid at the distribution substation level.
[2] The California *Energy Efficiency Strategic Plan* target of 25 percent of residences reaching 70 percent reduction in electricity usage by 2020, compared to a 2008 baseline, is modified in BASE 2020 to 25 percent of residences achieving 100 percent reduction in electricity usage by 2020. The California *Energy Efficiency Strategic Plan* target of 50 percent of existing commercial buildings reaching net zero energy by 2030 is expanded in BASE 2020 to establish a target of 25 percent of commercial buildings reaching net zero energy by 2020.
[3] CPUC, *California Electricity Demand 2010 – 2020 Adopted Forecast, December 2009*, Form 1.1c.
[4] 2020 energy efficiency reduction targets in California Energy Efficiency Strategic Plan, January 2011 Update, are: 30 percent – residential, 25 percent – commercial, 25 percent – industrial. Assume overall peak load reduction of 25 percent compared to 2008 peak load for combined residential, commercial, and industrial energy efficiency measures.
[5] "Management" in this case refers to widespread adoption of air conditioner cycling as a peak load reduction measure.
[6] California Energy Circuit, *State Sees DG Providing 25% Peak Power*, Volume 5, Issue 19, May 11, 2007, p. 8.
[7] Energy Action Plan I: http://www.energy.ca.gov/energy_action_plan/2003-05-08_ACTION_PLAN.PDF
[8] CEC, *2009 Integrated Energy Policy Report (IEPR) – Final Committee Report*, December 2009, p. 56.
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[12] CPUC Decision 06-07-029, *Opinion on New Generation and Long-Term Contract Proposals and Cost Allocation*, July 20, 2006. p. 2. "The electricity market crisis of 2000-2001 cut short the restructuring process envisioned by Assembly Bill (AB) 1890, and numerous developments since then have left California with a hybrid market structure subject to significant legislative mandates. Direct Access (DA) was frozen by the Legislature, several non-bypassable charges have been imposed on migrating customers, and the bankruptcies and litigation that followed the crisis have resulted in acquisition of new power plants by the investor-owned utilities."
[13] California Energy Commission, *2009 AB 2021 Progress Report: Achieving Cost-Effective Energy Efficiency for California*, December 14, 2010, p. 3.
[14] Stoel Rives LLP, *California Legislature Fails to Pass 33% Renewable Portfolio Standard*, September 2, 2010. Online at: http://www.lawofrenewableenergy.com/2010/09/articles/renewable/california-legislature-fails-to-pass-33-renewable-portfolio-standard/
[15] Text of Senate Bill 23 as introduced on December 6, 2010: http://www.aroundthecapitol.com/billtrack/text.html?bvid=20110SB2399INT
[16] California Air Resources Board, *Climate Change Scoping Plan*, December 2008, pp. 41-53. Cap-and-trade program defined: "The cap-and-trade program creates an emissions limit or "cap" on the sectors responsible for the vast majority of California's greenhouse gas emissions and provides capped sources significant flexibility in how they collectively achieve the reductions necessary to meet the cap."
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[18] *California Energy Efficiency Strategic Plan*, January 2011 Update, pp. 12-13. "Achieve a statewide standard of zero net energy (ZNE) for all new homes built in 2020. A ZNE home employs a combination of energy efficiency design features, efficient appliances, clean distributed generation, and advanced energy management systems to result in no net purchases of energy from the grid. By 2011, 50% of new homes will surpass 2005 Title 24 standards by 35%; 10% will surpass 2005 Title 24 standards by 55%. By 2015, 90% will surpass 2005 Title 24 standards by 35%."
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[20] CPUC, *California Energy Efficiency Strategic Plan*, January 2011 Update, p. 87.
[21] Bloomberg, *Fannie Mae, Freddie Mac Sued by California Over Energy Improvement Program*, July 14, 2010.
[22] Governor Jerry Brown, *Clean Energy Jobs Plan*, June 2010.
[23] The Plan calls for energy storage equivalent to 5 percent of peak load. California peak load is approximately 60,000 MW. Five percent of 60,000 MW is 3,000 MW.

[24] PG&E, *Annual Electric Distribution Reliability Report (R.96-11-004), submitted to CPUC for 2004*, map of PG&E service territory, p. 13.
[25] CEC, *California Energy Demand 2009-2020 Adopted Forecast*, December 2009, Form 1.1c - Electricity Deliveries to End Users by Agency* (GWh). Includes both PG&E supply PG&E, *PG&E Long-Term Procurement Plan, Volume I*, December 11, 2006, p. II-18. and Direct Access supply. PG&E bundled electricity deliveries in 2008 were 81,983 GWh. PG&E bundled electricity deliveries in 2009 were 79,976 GWh.
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[31] California Energy Consumption Database Management System, Electricity Consumption by County: http://www.ecdms.energy.ca.gov/elecbycounty.aspx
[32] CEC, *California Electricity Demand 2010 – 2020 Adopted Forecast*, December 2009. Forms 1.5s.
[33] Moodys.com purchased population datasets by county for 2000-2009 time period.
[34] PG&E, *PG&E Long-Term Procurement Plan, December 11, 2006, Volume I*, p. IV-7.
[35] Ibid, p. IV-7, CEC 2005 IEPR High Growth scenario.
[36] CEC, *California Energy Demand 2010-2020 Adopted Forecast*, December 2009, p. 2.
[37] Ibid, p. 24. "The declining growth rates over the forecast horizon reflect lower rates of fertility and immigration as the population of California and other regions age. Older age cohorts have a lower tendency to migrate."
[38] U.S. Census population data for the 44 counties completely or partially served by PG&E (Sacramento County is not included as Sacramento County is principally served by SMUD). The aggregate growth rate in those 44 counties is 0.93 per year from April 1, 2000 to July 1, 2009 using U.S. Census Bureau 2000 population data and U.S. Census population projections through 2009. See: http://www.census.gov/popest/counties/
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[40] Map prepared by J. Gilbreath, Cartography Unit, CEC Siting Transmission & Environmental Protection Division.
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[52] Silicon Valley Power webpage: http://www.siliconvalleypower.com/about/

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[55] City of Palo Alto Utilities webpage:
http://www.cityofpaloalto.org/depts/utl/news/details.asp?NewsID=48&TargetID=10
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[58] PG&E commercial tariff rate sheet: http://www.pge.com/nots/rates/tariffs/rateinfo.shtml. See Commercial/General Service (A-1, A-6, A-10, E-19), March 1, 2011. Average of summer and winter non-TOU energy charges is $0.1723/kWh.
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http://www.alamedamp.com/customer-service/your-rates/commercial-rates
[60] City of Palo Alto Utilities small commercial rate:
http://www.cityofpaloalto.org/depts/utl/business/business_rates.asp
[61] Ibid.
[62] Silicon Valley Power small commercial rate: http://www.siliconvalleypower.com/bus/?sub=busrates
[63] Santa Clara Green Power commercial rate: http://www.siliconvalleypower.com/res/?sub=green
[64] 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.
[65] San Francisco LAFCO meeting on San Francisco CCA, transcript, December 10, 2010. See:
http://sanfrancisco.granicus.com/TranscriptViewer.php?view_id=16&clip_id=11230. Comments of Dawn Weisz, Marin Energy Authority.
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[67] California Current, *Juice: Know your energy and enemy*, June 28, 2010.
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[76] J. Firooz, *Transmission in Short Supply or Do IOUs Want More Profits?,* Natural Gas & Electricity Journal, July 2010.
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[84] PG&E, *2006 Long-Term Procurement Plan, Volume 1, Section V*, Table Vol. 1, VH-1, p. V-43.

[85] CAISO OASIS database, System Load, July 25, 2006.
[86] CAISO OASIS database, System Load,, August 25, 2010.
[87] PG&E, *2006 Long-Term Procurement Plan, Volume 1, Section V*, Table Vol. 1, VH-1, p. V-43.
[88] CEC, California *Electricity Demand 2010 – 2020 Adopted Forecast*, December 2009, p. 2. "Peak demand will grow at 1.3 percent annually." The 2006 one-hour peak was 22,650 MW. The 2010 one-hour peak was 21,180 MW. The forecast peak one-hour load in PG&E territory would be not exceed the 2006 peak until 2016 when it would reach: 21,180 MW × $(1 + .013)^6$ = 22,887 MW. The actual population growth rate in PG&E territory from 2000-2009 was 0.9 percent. Assuming the peak demand growth rate from 2010-2020 is 0.9 percent per year, the peak demand would not exceed the 2006 peak one-hour load until 2018: 21,180 MW × $(1 + .009)^8$ = 22,754 MW.
[89] Ibid, p. V-44.
[90] PowerGen Worldwide, *2009 Projects of the Year*, January 1, 2010.
[91] CAISO, *2010 Summer Loads and Resources Operations Preparedness Assessment*, May 2010, Table 1, p. 4. NP26 (PG&E) total net summer supply is 29,289 MW, which includes 734 MW of demand response. The one-hour peak in NP26 in 2010 was 21,180 MW. 29,289 MW ÷ 21,180 MW = 1.383. This is an actual reserve margin of 38.3 percent. A total net supply of 24,357 MW would be necessary to maintain a 15% reserve margin with a 21,180 MW peak load. The additional supply beyond 15% available in PG&E territory at the 2010 one-hour peak was 29,289 MW – 24,357 MW = 4,932 MW.
[92] PG&E, *2006 Long-Term Procurement Plan, Volume 1, Section V*, Table Vol. 1, VH-2, p. V-44.
[93] TetraTech, *California's Coastal Power Plants: Alternative Cooling System Analysis*, prepared for the California Ocean Protection Council, February 2008. Installed capital cost of retrofit cooling towers for Pittsburg steam boilers, Units 5 and 6, 650 MW = $193/kW, Chapter L, p. L-25. 720 MW Pittsburg Unit 7 is equipped with wet cooling towers. 650 MW = 650,000 kW. Therefore, 650,000 kW × $193/kW = $125 million.
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[97] CEC, *Committee Workshop on Options for Maintaining Electric System Reliability When Eliminating Once-Through Cooling Power Plants - Transcript*, May 11, 2009, p. 204. Yakout Mansour, CAISO: "MR. MANSOUR: The second thing is that you mentioned that someone has $1.7 -- $117 million to fix all the transmission constraints in the system. Frankly, if you have the name of that person, I'm sure there's some kind of big sale or something like $117 million and let them fix all the stuff in the state as you're saying." B. Powers, p. 206: "MR. POWERS: And I think this is -- Mr. Mansour brings up a very important point, which is the environmental community is working with the ICF Jones and Stokes report -- reliability report. If the ISO doesn't have it or hasn't read it, that's a problem because what that reports states is that with a phase-out over the next years, we can retire all of the coastal OTC boiler plants. And what we would need is a minimum upgrade -- transmission reinforcement upgrade, a value of $135 million."
[98] Ibid, 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. So for our 4,000 megawatts you're looking at, you know, 500 million dollars, half a billion dollars to retrofit with wet cooling."
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[106] PG&E webpage: http://www.pgecorp.com/150_non_flash/index.html

[107] The text in Section 2.1 is excerpted from the following document: San Francisco Public Utilities Commission (SFPUC)/San Francisco Department of the Environment (SFE), *The Electricity Resource Plan – Choosing San Francisco's Energy Future*, December 2002, p. 19.

[108] PG&E webpage: http://www.pgecorp.com/150_non_flash/index.html.

[109] PG&E affiliates webpage: http://www.pge.com/about/rates/affiliate/

[110] http://www.pge.com/about/news/mediarelations/newsreleases/q4_2007/071227.shtml

[111] PG&E press release, *PG&E Corporation and SolarCity Announce $60 Million in Financing to Install Solar Power for Businesses and Homeowners*, January 20, 2010.

[112] PG&E press release, *PG&E Corporation and SunRun Create $100 Million Home Solar Financing Fund*, June 21, 2010.

[113] Letter from CPUC Energy Division Director Julie Fitch to PG&E Vice President Jane Yura, *Rejection of Advice 3091-G/3616-E without prejudice – new PG&E affiliate Pacific Venture Capital*, July 7, 2010.

[114] SFPUC/SFE, *The Electricity Resource Plan – Choosing San Francisco's Energy Future*, December 2002, pp. 20-21.

[115] PG&E press release*, PG&E, Community Celebrate Closure of Hunters Point Power Plant,* May 23, 2006.

[116] Greenwire, *Electricity: Undersea cable ends San Fran's grid isolation, provides cleaner power*, November 30, 2010.

[117] CPUC D.06-07-029*, Opinion on New Generation and Long-Term Contract Proposals and Cost Allocation*, Order Instituting Rulemaking to Integrate Procurement Policies and Consider Long-Term Procurement Plans, July 21, 2006, p. 3.

[118] Ibid, p. V-34.

[119] Ibid, p. IV-81. This recommendation is based on PG&E meeting a 16 percent reserve margin on a 1-in-10 temperature peak demand event, and not on the 15 to 17 percent reserve margin for a 1-in-2 temperature event.

[120] Ibid, p. IV-8. The PG&E peak load in 2006, 22,650 MW, is substantially higher than any of the PG&E peak loads experienced in the subsequent four years from 2007 through 2010.

[121] CPUC Decision D.07-12-052, *Opinion Adopting PG&E's, SCE's, and SDG&E's Long Term Procurement Plans (LTPP)*, December 20, 2007, p. 104. PG&E assumes in its need determination that it will require additional generation to meet a 16 percent reserve margin for a 1-in-10 weather forecast. The Commission requirement is 15 to 17 percent reserve margin for a 1-in-2 weather forecast.

[122] Decision D.10-07-045, *Decision on PG&E's 2008 Long-Term Request for Offer Results and Adopting Cost Recovery and Ratemaking Mechanisms*, July 29, 2010, p. 24.

[123] CAISO, *2009 Summer Loads and Resources Operations Preparedness Assessment*, May 7, 2009, Table 14, p. 27. 1-in-2 forecast demand for PG&E service territory = 21,370 MW. Expected demand reduction = 593 MW. Net 1-in-2 peak demand – 20,777 MW. Actual 2009 peak one-hour demand in PG&E service territory = 20, 012 MW on July 14, 2009. The 2009 PG&E peak one-hour load was somewhat below the 1-in-2 year forecast net peak load of 20,777 MW.

[124] CAISO, *2010 Summer Loads and Resources Operations Preparedness Assessment*, May 2010, Table 1, p. 4. NP26 total net summer supply is 29,289 MW, which includes 734 MW of demand response. CAISO identifies the forecast 1-in-2 summer peak in NP26 as 21, 154 MW. 29,289 MW ÷ 21,180 MW = 1.383. This is an actual reserve margin of 38.3 percent.

[125] Ibid.

[126] Decision D.09-10-017, *Decision Adopting All-Party Settlement Agreement Regarding PG&E's Request for Power Purchase Agreement with Mariposa Energy, LLC*, October 15, 2009.

[127] Decision D.10-07-045, *Decision on PG&E's 2008 Long-Term Request for Offer Results and Adopting Cost Recovery and Ratemaking Mechanisms*, July 29, 2010.

[128] Decision D.10-07-045 – Petition for Modification, *Decision Authorizing PG&E to Enter into a Purchase and Sale Agreement with Contra Costa Generating Station LLC*, December 16, 2010.

[129] CPUC Press Release – Docket A.09-02-019, *CPUC Approves Solar PV Program for PG&E*, April 22, 2010.

[130] CPUC Rulemaking R.10-05-006, *2010 Long-Term Procurement Proceeding Scoping Memo – Attachment 1, Standardized Planning Assumptions (Part 1) for System Resource Plans*, December 3, 2010, p. 17, p. 20, p. 23, p. 26, p. 29, p. 32, p. 35.
[131] Ibid, p. 35.
[132] PG&E customer bill insert, April 2009.
[133] E. Wendt – PG&E, *PG&E's Role in California's Clean Energy Future*, PowerPoint presentation, January 25, 2011.
[134] California Energy Almanac, *List of hydroelectric plants in California*, 2011: http://www.energyalmanac.ca.gov/renewables/hydro/index.html
[135] PG&E, PG&E *Long-Term Procurement Plan, December 11, 2006, Volume I*, p. V-33.
[136] 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.
[137] PG&E, *PG&E Long-Term Procurement Plan, Volume I*, December 11, 2006, p. V-31.
[138] CEC, *California Energy Demand 2009-2020 Adopted Forecast*, December 2009, Form 1.1c - Electricity Deliveries to End Users by Agency (GWH). PG&E bundled electricity deliveries in 2008 were 81,983 GWh. "Bundled" means PG&E both acquires electricity for the customer snd delivers that electricity to the customer.
[139] CPUC Renewable Portfolio Standard webpage: http://www.cpuc.ca.gov/PUC/energy/Renewables/index.htm. Total PG&E sales in 2009 were 79,976 GWh. See: CEC, *California Energy Demand 2009-2020 Adopted Forecast*, December 2009, Form 1.1c. Total renewable sales, at 14.4 percent of total sales = 0.144 x 79,976 GWh = 11,517 GWh.
[140] CPUC RPS webpage: http://www.cpuc.ca.gov/PUC/energy/Renewables/index.htm
[141] SB 107 as chaptered: http://energyalmanac.ca.gov/renewables/rps/sb_107_bill_20060926_chaptered.pdf
[142] CPUC Division of Ratepayer Advocates, *Green Rush – Investor-Owned Utilities Compliance with Renewable Portfolio Standard*, February 2011, p. 5.
[143] CEC webpage, Implementing the Renewable Energy Executive Order: http://www.energy.ca.gov/33by2020/index.html
[144] PG&E, *Application for Rehearing of Decision D.10-12-048 - Decision Adopting The Renewable Auction Mechanism*, January 18, 2011, p. 1. "PG&E seeks rehearing of the Decision because it violates state law in three ways. First, PG&E's RAM procurement obligation is not limited to procuring only those resources whose prices are at or below the Commission-determined market price referent ("MPR"), which violates the RPS statute's cost limitation provisions. Second, the Decision does not permit the investor-owned utilities ("IOUs") to suspend their RAM programs if they achieve the 20 percent RPS target, which violates the RPS statute's clear directive that the IOUs cannot be required to procure greater than 20 percent renewables. Third, the Decision applies the RAM program to only the IOUs."
[145] See: http://leginfo.ca.gov/pub/11-12/bill/sen/sb_0001-0050/sb_23_bill_20101206_introduced.pdf
[146] CEC, *2008 Power Source Disclosure Form*, PG&E.
[147] PG&E, *2006 Long-Term Procurement Plan, Volume 1*, December 11, 2006, p. V-1.
[148] Ibid, p. V-2.
[149] CPUC Energy Division, *2006-2008 Energy Efficiency Evaluation Report – Draft*, April 15, 2010.
[150] Ibid, Table 23, p. 96.
[151] CPUC, *California Long-Term Energy Efficiency Strategic Plan*, January 2011 Update, p. 53.
[152] PG&E central air conditioner webpage: http://www.pge.com/myhome/saveenergymoney/savingstips/centralair/index.shtml
[153] Ibid, p. IV-24, p. IV-25.
[154] Ibid, p. IV-26. Table IVC-5, Volume 1.
[155] CPUC, Decision D.10-12-035, *Decision Adopting Proposed Settlement*, December 16, 2010, p. 41. "The Short-Run Avoided Cost (SRAC) included in the Proposed Settlement is based on the current Commission-approved SRAC pricing formula and achieves the goal of ultimately transitioning to a market heat rate to determine SRAC by January 1, 2015."
[156] CPUC, *CHP Program Settlement Agreement Term Sheet*, October 8, 2010, p. 31. This document is an attachment to CPUC Decision D.10-12-035, *Decision Adopting Proposed Settlement*, December 16, 2010.
[157] CEC, *California Electricity Demand 2010 – 2020 Adopted Forecast*, December 2009, Form 1.1c. 2008 PG&E bundled delivered electricity = 81,983 GWh. Total statewide delivered electricity = 276,509 GWh. PG&E percentage of total = 81,983 GWh/276,509 GWh = 0.296. 4,000 MW x 0.296 = 1,184 MW.

[158] CPUC Renewable Auction Mechanism webpage: http://www.cpuc.ca.gov/PUC/energy/Renewables/hot/Renewable+Auction+Mechanism.htm
[159] CPUC Decision D.10-12-035, *Decision Adopting Proposed Settlement*, December 16, 2010, p. 41.
[160] Ibid, p. 41.
[161] CPUC Rulemaking R.08-06-024, *Rulemaking on the Commission's Own Motion into Combined Heat and Power Pursuant to AB 1613 – Motion of PG&E, SCE, and SDG&E for Stay of Decision D.10-12-055*, January 6, 2011.
[162] CPUC Market Price Referent webpage, 20-year MPR for projects with a 2011 start date is $0.10098/kWh: http://docs.cpuc.ca.gov/PUBLISHED/FINAL_RESOLUTION/111386.htm
[163] PG&E, *2006 Long-Term Procurement Plan, Volume 1, Section V*, December 11, 2006, p. V-28.
[164] CPUC Decision D.10-12-048, *Decision Adopting the Renewable Auction Mechanism*, December 16, 2010. See: http://docs.cpuc.ca.gov/word_pdf/FINAL_DECISION/128432.pdf
[165] PG&E, *Application for Rehearing of Decision D.10-12-048 - Decision Adopting The Renewable Auction Mechanism*, January 18, 2011, p. 1.
[166] PG&E, *2006 Long-Term Procurement Plan, Volume 1, Section V*, December 11, 2006, p. VI-11.
[167] CEC, *California Electricity Demand 2010 – 2020 Adopted Forecast*, December 2009, Form 1.1c. 2010 PG&E bundled delivered electricity = 80,192 GWh. 20%, or 16,038 GWh, is renewable energy, leaving of non-RPS energy resources of 64,154 GWh. 2020 PG&E bundled delivered electricity = 91,010 GWh. 33%, or 30,033 GWh, is renewable energy, leaving non-RPS energy resources of 60,977 GWh. This represents a 5 percent reduction in 2020 over GHG emissions in 2010 [(64,154 GWh – 60,977 GWh)/64,154 GWh = 0.0495].
[168] Ibid, p. VI-11. "Additional swings in hydro availability can further contribute to increase CO2 emissions in a given year. For example, a 5,000 GWh reduction in hydro from a normal to a dry hydro scenario would increase CO_2 emissions by another 12-13%." [(64,154 GWh – (60,977 GWh + 5,000 GWh))/64,154 GWh = -0.0284]. This represents an increase in GHG emissions in 2020 of approximately 3 percent in a low hydro year.
[169] CEC, *California Electricity Demand 2010 – 2020 Adopted Forecast*, December 2009, p. 72. Figure 44: PG&E Planning Area Self-Generation Peak Forecasts.
[170] CARB, *California Cap-and-Trade Program*, Resolution 10-42, December 16, 2010, pp. 1-2.
[171] CARB cap-and-trade program webpage, Table – California GHG Emissions – Forecast (2008-2020), October 28, 2010: http://www.arb.ca.gov/cc/inventory/data/tables/2020_ghg_emissions_forecast_2010-10-28.pdf
[172] AB 162 as chaptered: http://www.energy.ca.gov/power_source_disclosure/documents/ab_162_bill_20091011_chaptered.pdf
[173] Ibid.
[174] CARB, *California Cap-and-Trade Program*, Resolution 10-42, December 16, 2010, p. 12.
[175] CEC, *Comparative Costs of California Central Station Electricity Generation – Final Staff Report*, January 2010, Table C-12, p. C-16. Average combined cycle with duct firing heat rate = 7,050 Btu/kWh (7.05 MMBtu/MWh). Average simple cycle heat rate = 9,266 Btu/kWh (9.266 MMBtu/MWh). Natural gas CO_2 emission rate is 117 lb/MMBtu. The base load combined cycle CO_2 emission factor = 7.05 MMBtu/MWh × 117 lb/MMBtu = 825 lb/MWh. The simple cycle CO_2 emission factor = 9.266 MMBtu/MWh × 117 lb/MMBtu = 1,084 lb/MWh. Assume that the composite CO_2 emission factor of combined cycle base load + combined cycle load following + simple cycle peaking = 900 lb/MWh, or 0.45 ton/MWh.
[176] Energy Ventures Analysis, Inc. *Evaluation of Colorado Clean Air-Clean Jobs Act (HB 10-1365)*, March 25, 2010, p. 4 (footnote). "Actual 2008 emission rate for the two (Colorado) coal-fired stations were 4.17 lb NO_x/MWh and 1.06 tons CO_2/MWh."
[177] CEC, *California Electricity Demand 2010 – 2020 Adopted Forecast*, December 2009, Form 1.1c. 2008 PG&E bundled delivered electricity = 81,983 GWh. Natural gas-fired CO_2 emissions = 81,983,000 MWh/yr × 0.45 ton/MWh × 0.40 = 14.8 million tons/year. Coal-fired CO_2 emissions = 81,983,000 MWh/yr × 1.06 ton/MWh × 0.08 = 7.0 million tons/year. Total natural gas-fired + coal-fired CO_2 emissions = 14.8 million tons/yr + 7.0 million tons/yr = 21.8 million tons/yr of CO_2 in 2008.
[178] 22,000,000 tons CO_2/81,983,000 MWh = 0.27 tons CO_2/MWh.
[179] CEC, *California Electricity Demand 2010 – 2020 Adopted Forecast*, December 2009, Form 1.1c. 2008 PG&E bundled delivered electricity = 81,983 GWh. 2008 PG&E unbundled (Direct Access) delivered electricity = 6,376 GWh. Therefore Direct Access percentage is 6,376 GWh/(81,983 GWh + 6,376 GWh) = 7.2 percent of bundled delivered electricity.
[180] CPUC RPS webpage: http://www.cpuc.ca.gov/PUC/energy/Renewables/index.htm
[181] Ibid.

[182] CPUC Division of Ratepayer Advocates, *Green Rush - Investor-Owned Utilities' Compliance with the Renewables Portfolio Standard*, February 2011, Figure 2, p. 10.
[183] Ibid, p. 10.
[184] CPUC, *33% Renewable Portfolio Standard Implementation Analysis Preliminary Results*, June 2009, p. 87.
[185] BLM fast track renewable energy projects: http://www.blm.gov/wo/st/en/prog/energy/renewable_energy/fast-track_renewable.html
[186] BLM press release, *BLM Concentrating on Renewable Energy Projects That Could Meet Stimulus Funding Deadline*, December 29, 2009: http://www.blm.gov/wo/st/en/info/newsroom/2009/december/0.html
[187] CPUC, *Renewables Portfolio Standard Quarterly Report – 4th Quarter 2010*, p. 6. See: http://www.cpuc.ca.gov/NR/rdonlyres/CFD76016-3E28-44B0-8427-3FAB1AA27FF4/0/FourthQuarter2010RPSReporttotheLegislature.pdf. "The CPUC approved 22 contracts in the third quarter of 2010, the highest number of contracts approved in a quarter since the conception of the program. This spike in contract processing resulted from projects seeking the federal grant in lieu of the tax credit, which was set to expire December 31, 2010. As a result, the CPUC prioritized review and approval of those contracts so that they could qualify for the federal grant."
[188] www.sustainablebusiness.com, *Interior Sued Over Approval of Fast-Track Solar Projects*, January 5, 2011.
[189] CPUC, *California Energy Efficiency Strategic Plan,* January 2011 Update. See: http://www.cpuc.ca.gov/NR/rdonlyres/A54B59C2-D571-440D-9477-3363726F573A/0/CAEnergyEfficiencyStrategicPlan_Jan2011.pdf
[190] California Air Resources Board, *AB 32 Climate Change Scoping Plan*, December 2008, p. 44. See: http://www.arb.ca.gov/cc/scopingplan/scopingplan.htm.
[191] CPUC Rulemaking R.10-05-006, *2010 Long-Term Procurement Proceeding Scoping Memo – Attachment 1, Standardized Planning Assumptions (Part 1) for System Resource Plans*, December 3, 2010, p. 17, p. 20, p. 23, p. 26, p. 29, p. 32, p. 35.
[192] CEC, *2008 Net System Power Report*, July 2009.
[193] Ibid, p. 9.
[194] CEC, *Power Source Disclosure Program Draft Regulations – Workshop*, November 4, 2010. See: http://www.energy.ca.gov/power_source_disclosure/notices/2010-11-04_Notice_POU_Workshop.pdf. "AB 162 removes the requirement that retail suppliers provide net system power on customer disclosures."
[195] AB 162 as chaptered: http://www.energy.ca.gov/power_source_disclosure/documents/ab_162_bill_20091011_chaptered.pdf
[196] CEC, *2008 Net System Power Report*, July 2009, Table 4, p. 10. The CEC estimated that wholesale market power purchases in 2008 consisted of 33.7 percent coal power and 41.9 percent natural gas power. The composite CO_2 emission factor for this fuel mix composition is 0.55 ton CO_2 per MWh.
[197] ARB AB 32 Cap-and-Trade Program webpage, Table – California GHG Emissions – Forecast (2008-2020), October 28, 2010: http://www.arb.ca.gov/cc/inventory/data/tables/2020_ghg_emissions_forecast_2010-10-28.pdf. See footnote - unspecified imported electricity is assumed to have a CO_2 emission factor of 959.6 lb CO_2/MWh.
[198] CPUC, *California Electricity Demand 2010 – 2020 Adopted Forecast, December 2009*, Form 1.1c. See: http://www.energy.ca.gov/2009publications/CEC-200-2009-012/index.html. 2008 PG&E bundled and Direct Access deliveries = 88,359 GWh. 2008 Bay Area POU deliveries = 5,327 GWh. California Energy Consumption Database Management System, Electricity Consumption by County: http://www.ecdms.energy.ca.gov/. Nine Bay Area counties electricity consumption in 2008 = 57,316 GWh. Therefore, the percentage of PG&E bundled and Direct Access usage in the nine Bay Area counties = (57,316 GWh – 5,327 GWh)/88,359 GWh = 0.59.
[199] CPUC, *California Electricity Demand 2010 – 2020 Adopted Forecast, December 2009*, Form 1.1c.
[200] The California Strategic Energy Efficiency Strategic Plan target of 25 percent of residences reaching 70 percent reduction in electricity usage by 2020, compared to a 2008 baseline, is modified in BASE 2020 to 25 percent of residences achieving 100 percent reduction in electricity usage by 2020. The California Strategic Energy Efficiency Strategic Plan target of 50 percent of existing commercial buildings reaching net zero energy by 2030 is expanded in BASE 2020 to establish a target of 25 percent of commercial buildings reaching net zero energy by 2020.
[201] CAISO OASIS database, System Demand, July 8, 2008, 1 pm to 2 pm: 21,827 MW.
[202] CEC, *California Electricity Demand 2010 – 2020 Adopted Forecast*, December 2009, Form 1.5b. See: http://www.energy.ca.gov/2009publications/CEC-200-2009-012/index.html
[203] 2020 energy efficiency reduction targets in California Energy Efficiency Strategic Plan, January 2011 Update, are: 30 percent – residential, 25 percent – commercial, 25 percent – industrial. Assume overall peak load reduction of 25 percent compared to 2008 peak load for combined residential, commercial, and industrial energy efficiency measures.
[204] "Management" in this case refers to widespread adoption of air conditioner cycling as a peak load reduction measure.

[205] Sandia National Laboratory, *Energy Storage for the Electricity Grid: Benefits and Market Potential Assessment Guide - A Study for the DOE Energy Storage Systems Program*, February 2010, p. 27.
[206] Xenergy, Inc., *California's Secret Energy Surplus – The Potential for Energy Efficiency*, September 23, 2002, p. A-6.
[207] RETI, *RETI Phase 1B Final Report*, January 2, 2009, p. 6-23. Note that the profiles shown are for W_{ac} output, and assume a dc-to-ac conversion efficiency of approximately 80%.
[208] Monthly MWh data for 150 MW Shiloh I wind project: U.S. DOE, Energy Information Administration, 2008 Form 923 Monthly Time Series.
[209] Cliff Murley – SMUD, *Energy Storage Projects at SMUD*, presented at CEC Workshop: Wind Storage Enhanced Technologies on the Grid, October 3, 2007, pp. 6-7. Note that SMUD peak demand shown in graphic is later in the day, 5 pm to 6 pm, than the 2 pm to 5 pm peak range in PG&E territory.
[210] PG&E webpage, Facts - What Is Peak Day Pricing?: http://www.pge.com/mybusiness/energysavingsrebates/demandresponse/peakdaypricing/facts/. Peak day pricing adder for high demand (> 200 kW) commercial customers is $1.20/kWh.
[211] CPUC A.10-03-012, Application of PG&E to Implement Assembly Bill 920 (2009) Setting Terms and Conditions for Compensation for Excess Energy Deliveries by Net Metered Customers*, Proposal of the Solar Alliance and Vote Solar Initiative for a Net Surplus Compensation Rate and Responses to Scoping Memo Questions*, June 21, 2010, Table 1, p. 3.
[212] CPUC Rulemaking R.06-02-012, Order Instituting Rulemaking to Develop Additional Methods to Implement the California Renewable Portfolio Standards Program, *Opening Comments of the California Wind Energy Association, the California Cogeneration Council, the Large-scale Solar Association, and the Solar Alliance on the Proposed Decision of ALJ Simon*, prepared by Crossborder Energy, October 6, 2008, pp. 3-4.
[213] CPUC A.10-03-012, Application of PG&E to Implement Assembly Bill 920 (2009) Setting Terms and Conditions for Compensation for Excess Energy Deliveries by Net Metered Customers*, Proposal of the Solar Alliance and Vote Solar Initiative for a Net Surplus Compensation Rate and Responses to Scoping Memo Questions*, June 21, 2010, Figure 1.
[214] D. Marcus, consultant and CAISO OASIS database, October 2010.
[215] Solar Anywhere website, hour-by-hour global irradiance data for 2007: https://www.solaranywhere.com/Public/SelectData.aspx
[216] Weather Warehouse website, U.S. Weather Service hour-by-hour cloud cover data for U.S. weather station sites. Data purchased for June 14, 2007 through September 5, 2007 period to capture all PG&E peak events when CAISO load was above 40,000 MW. Weather Warehouse reports the highest cloud cover percentage within the cloud cover interval registered in a given hour. For example, the first interval is 0 – 25 percent cloud cover. The Weather Warehouse dataset lists 25 percent cloud cover instead of the average value of 12.5 percent if cloud cover falls within the 0 – 25 percent range. Powers Engineering used the average cloud cover value for comparison with the actual ground-level global irradiance.
[217] A. Mills, R. Wiser – Lawrence Berkeley National Laboratory, *Implications of Wide-Area Geographic Diversity for Short-Term Variability of Solar Power*, September 2010, p. 11.
[218] Renewable Energy World, *Energy Storage, The Grid, and PV*, November 17, 2010.
[219] California Current, *Over-capacity concerns face new CPUC members*, January 28, 2011. "(PG&E spokesperson Brian) Swanson said that new plants like Oakley are needed to integrate renewable power into the grid as backups when the wind doesn't blow and the sun doesn't shine."
[220] CEC, *Comparative Cost of Electric Generation Technologies – Final Staff Report*, January 2010, Table 4 and Table 5. Note – the dates shown in the table, 2009 and 2018, are commercial start dates.
[221] CEC, Chula Vista Energy Upgrade Project - Application for Certification (07-AFC-4) San Diego County, *Final Commission Decision*, June 2009.
[222] Ibid, pp. 29-30.
[223] Energy Action Plan I: http://www.energy.ca.gov/energy_action_plan/2003-05-08_ACTION_PLAN.PDF
[224] Ibid, p. 5.
[225] Ibid, p. 7.
[226] CPUC Press Release – Docket A.08-03-015, *CPUC Approves Edison Solar Roof Program*, June 18, 2009. "The energy generated from the project will be used to serve Edison's retail customers and the output from these facilities will be counted towards Edison's RPS goals."
[227] Energy Action Plan II: http://www.energy.ca.gov/energy_action_plan/2005-09-21_EAP2_FINAL.PDF
[228] Ibid, p. 2.
[229] CEC, *2009 Integrated Energy Policy Report (IEPR) – Final Committee Report*, December 2009, p. 56.
[230] CPUC, California Energy Efficiency Strategic Plan, September 2008.

[231] CPUC, *California Energy Efficiency Strategic Plan*, January 2011 Update.
[232] Ibid.
[233] Ibid.
[234] Ibid.
[235] Ibid, p. 95.
[236] CEC Title 24 webpage: http://www.energy.ca.gov/title24/
[237] CPUC, *California Energy Efficiency Strategic Plan*, January 2011 Update, p. 87.
[238] PG&E Market Integrated DSM Initiative – large commercial: http://www.pge.com/includes/docs/pdfs/about/rates/rebateprogrameval/programdescriptions/pge2007largecommercial0206.pdf
[239] http://www.sdge.com/construction/sustainable.shtml
[240] SDG&E, Sustainable Communities showcase webpage: http://www.sdge.com/environment/sustainablecommunities/projectsHome.shtml
[241] SDG&E Sustainable Communities Program Case Study, X-nth, Inc. (formerly TKG Consulting Engineers Inc.) office building retrofit, 2004.
[242] CPUC, *California Energy Efficiency Strategic Plan*, January 2011 Update, p. 87.
[243] CEC refrigerator webpage: http://www.consumerenergycenter.org/home/appliances/refrigerators.html
[244] PG&E refrigerator recycle page: http://www.appliancerecycling.com/weborder/rebatex.aspx?ProgramID=1
[245] Ibid, p. 53.
[246] PG&E, *PG&E 2007-2016 Long-Term Procurement Plan*, Volume I, p. IV-13, reference to "Itron Potential Study."
[247] SEER is relative measure of energy efficiency. A SEER 20 air conditioning unit uses one-half the energy required by a SEER 10 unit to produce the same amount of cooling.
[248] S. Okura, M. Brost – RLW Analytics, Inc., and R. Rubin – SDG&E, *What Types of Appliances and Lighting Are Being Used in California Residences?*, 2005. In 2005, 53% of California residences had some form of cooling system.
[249] [(21 – 10)/21] – [(13 – 10/13)] = 0.52 – 0.23 = 0.29 (29 percent)
[250] Itron, *California Energy Efficiency Potential Study*, May 24, 2006, Chapter 11 - Emerging Technology Energy Efficiency Potential, p. 11-5 and p. 11-6.
[251] Public Power Daily, *SCPPA to Rollout 53-MW Storage Project*, January 27, 2010.
[252] Platts Purchasing Advisor, *HVAC: Centrifugal Chillers*, 2004.
[253] The term "kW per ton of cooling" is a measure of the electric energy necessary to operate a commercial or institutional chiller plant.
[254] One ton of cooling load is the amount of heat absorbed to melt one ton of ice in one day, which is equivalent to 12,000 Btu per hour.
[255] B. Erpelding, P.E., San Diego Regional Energy Office, *Ultra-efficient All-Variable Speed Chilled-Water Plants – Improving the energy efficiency of chilled-water plants through the utilization of variable speed and the optimization of entire systems*, HPAC Engineering, March 2006, pp. 35-43.
[256] B. Erpelding, P.E., San Diego Regional Energy Office (now California Center for Sustainable Energy) , *Ultra-efficient All-Variable Speed Chilled-Water Plants – Improving the energy efficiency of chilled-water plants through the utilization of variable speed and the optimization of entire systems*, HPAC Engineering, March 2006, pp. 35–43.
[257] CEC, *Achieving All Cost-Effective Energy Efficiency for California*, December 2007, Figure 38, p. 103.
[258] PG&E hot water heater page: http://www.pge.com/myhome/saveenergymoney/rebates/appliance/waterheater/index.shtml
[259] PG&E central air conditioner webpage: http://www.pge.com/myhome/saveenergymoney/savingstips/centralair/index.shtml
[260] PG&E eRebates webpage: http://www.pge.com/myhome/saveenergymoney/rebates/erebates/
[261] CPUC, *California Energy Efficiency Strategic Plan*, January 2011 Update, p. 18.
[262] Carrier product bulletin for SEER 10 model 38TKB036-34 3-ton air conditioning unit, 2004, p. 24.
[263] San Diego Union Tribune, Carrier central air conditioner advertisement, p. A-17, September 9, 2007.
[264] (4.0 kWh × 1,000 hours) –[(4.0 kWh × 1,000 hours) (10/21)] = 2,100 kWh saved. This is the electricity savings of 3-ton SEER 21 unit compared to a 3-ton SEER 10 unit over 1,000 hours of operation.
[265] Avalanche Mechanical (Carrier installer) quote to B. Powers for 3-ton SEER 21 central air conditioning and heating unit, September 4, 2007. Quote includes cost of new insulated ductwork.

[266] PG&E defines the summer peak period as May 1 to October 31, noon to 6 pm, excluding weekends and holidays. This is approximately 768 hours per year.
[267] (4 kWh × 768 hr) × [(10/13) – (10/21)] = 900 kWh. This is the electricity savings of a 3-ton SEER 21 unit compared to a SEER 13 unit over 768 hours of operation.
[268] See the discussion of PG&E's tiered residential rate structure in Chapter 9.
[269] CEC, Comparative *Costs of California Central Station Electricity Generation*, January 2010. Table B-4, p. B-5. Fixed cost of a new conventional 50 MW peaking gas turbine in 2009 is $303/kW-yr. Therefore, annual cost of 2 kW of peaking capacity: 2 kW × $303/kW-yr = $606/yr.
[270] CEC, California Building Climate Zones map: http://www.energy.ca.gov/maps/building_climate_zones.html
[271] PG&E, *PG&E 2007-2016 Long-Term Procurement Plan*, Volume I, p. IV-16.
[272] S. Okura, M. Brost – RLW Analytics, Inc., and R. Rubin – SDG&E, *What Types of Appliances and Lighting Are Being Used in California Residences?*, 2005.
[273] See CPUC Decision D.07-09-043: http://docs.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/73172.htm
[274] CPUC Division of Ratepayer Advocates webpage: *DRA Continues to Fight Unearned Energy Efficiency Shareholder Bonuses*, January 2011: http://www.dra.ca.gov/DRA/energy/sim10.htm.
[275] CPUC Energy Division, *2006-2008 Energy Efficiency Evaluation Report – Draft*, April 15, 2010.
[276] Ibid, Table 23, p. 96.
[277] CPUC Division of Ratepayer Advocates – press release, *DRA Opposes $40 Million Bonus for PG&E*, November 15, 2010.
[278] 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
[279] Ibid, p. 3.
[280] Energy Trust of Oregon homepage, March 9, 20111: http://energytrust.org/about/
[281] 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.
[282] Ibid, p. 4.
[283] www.sustainableindustries.com, *PACE rescue bill could get Republican help*, January 5, 2011.
[284] Pike Research, *PACE Financing Consumer Survey – Consumer Preferences and Attitudes about Property Assessed Clean Energy Financing Programs*, Q1 2011.
[285] www.sustainableindustries.com, *PACE rescue bill could get Republican help*, January 5, 2011.
[286] California Current, *Advocates Expect Renewables' Remuneration Comeback*, Volume 9, Issue 3, January 21, 2011.
[287] Ibid, p. 3.
[288] For simplicity Table 8-3 does not show targets for a number of smaller usage categories, including mining, agricultural, transportation, communication, and utilities.
[289] Ibid, p. 20, p. 30, p. 34, p. 41.
[290] CEC, *California Energy Demand 2010-2020 Adopted Forecast*, December 2009. Form 1.1 - Statewide California Energy Demand 2010-2020 Staff Revised Forecast Electricity Consumption by Sector (GWh), p. 37.
[291] Assumes statewide average fixed PV output of 1,900 kWh per kW_{ac} of capacity. Source: NREL PV Watts V.1 Calculator: http://rredc.nrel.gov/solar/calculators/PVWATTS/version1/. Output in San Francisco, Los Angeles, and San Diego within ± 3% of 1,900 kWh/kW_{ac}. Assumed dc-to-ac conversion efficiency = 80%.
[292] Ibid, Form 1.1c – California Energy Demand 2010-2020 Staff Revised Forecast Electricity Deliveries to End Users by Agency* (GWH), p. 39. 2008 statewide: 276,509 GWh, 2008 PG&E planning area = 105,795 GWh. (105,795 GWh/276,509 GWh) = 0.38 (38 percent).
[293] Ibid (2008 statewide electricity deliveries) and California Energy Consumption Database Management System – Electricity Consumption by County, 2008: http://www.ecdms.energy.ca.gov/. 2008 nine Bay Area counties = 57,316 GWh. (57,316 GWh/276,509 GWh) = 0.207 (21 percent).
[294] CPUC, *33% Renewable Portfolio Standard Implementation Analysis Preliminary Results*, June 2009, Table 2, p. 19.
[295] Ibid, p. 96.
[296] Ibid, p. 31. The CPUC PV sensitivity analysis assumed a thin-film PV capital cost of $3.70/$W_{ac}$ with a cost-of-energy of $268/MWh. The report defines High DG in this manner (p. 19) "Assumes limited new transmission corridors are developed to access additional renewable resources to achieve a 33% RPS. Instead, extensive, smaller-scale renewable generation is located on the distribution system and close to substations."
[297] Black & Veatch, *RETI Phase 2B Final Report*, May 2010, p. 4-6. "Thin film solar PV was previously treated as a sensitivity study, but due to falling costs and the increased prevalence of thin film, it is now being considered as one

of the available commercial technologies in addition to tracking crystalline PV." Table 4-8, Solar Photovoltaic, Fixed-tilt Thin Film Assumptions, p. 4-7. Total installed capital cost = $3.60 to 4.0/Wac for PV systems 20 MW and greater in size.

[298] Black & Veatch and E3, *Summary of PV Potential Assessment in RETI and the 33% Implementation Analysis*, Re-DEC Working Group Meeting, December 9, 2009.

[299] San Antonio Express-News, *CPS Energy to announce new solar deal*, October 6, 2010.

[300] NREL PV Watts1 Calculator: http://rredc.nrel.gov/solar/calculators/PVWATTS/version1/. Annual production of 4 kW_{dc} fixed PV system in San Francisco = 5,784 kWh. Annual production of 4 kW_{dc} fixed PV system in San Antonio = 5,519 kWh. Annual PV production in San Francisco is about 5 percent better than San Antonio (5,784 kWh – 5,519 kWh)/5,519 kWh = 0.048.(4.8 percent).

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[302] SNL Financial, *California authorizes peak-day pricing for PG&E small-business customers*, February 25, 2010.

[303] PG&E, *2006 Long-Term Procurement Plan, Order Instituting Rulemaking to Integrate Procurement Policies and Consider Long-Term Procurement Plans - Volume 1*, Public Version Redacted, December 11, 2006. pp. IV-16, IV-17.

[304] Ibid, p. IV-20.

[305] Ibid, p. IV-16.

[306] Ibid. The non-firm program was replaced with the Base Interruptible Program (E-BIP).

[307] CEC Critical Peak Pricing webpage graphic: http://www.energy.ca.gov/research/esi/pricing/index.html

[308] Art Rosenfeld – CEC, *Demand Response Hardware and Tariffs: California's Vision and Reality*, presentation at PIER Demand Response Symposium, November 30, 2004, p. 6.

[309] SNL Financial, *California authorizes peak-day pricing for PG&E small-business customers*, February 25, 2010.

[310] PG&E webpage, Facts - What Is Peak Day Pricing?: http://www.pge.com/mybusiness/energysavingsrebates/demandresponse/peakdaypricing/facts/. Peak day pricing adder for high demand (> 200 kW) commercial customers is $1.20/kWh.

[311] PG&E Application A. 10-03-014, *2011 General Rate Case Phase 2 Prepared Testimony, Exhibit PG&E-1 – Revenue Allocation and Rate Design, Chapter 3*, March 22, 2010, p. 3-4.

[312] Ibid. p. 3-2 and p. 3-8.

[313] The assumed productivity of fixed solar PV systems in the Bay Area is 1,900 kWh per year per kW_{ac} of capacity.

[314] Navigant, *Distributed Renewable Energy Assessment Final Report*, prepared for PIER Program California Energy Commission, August 11, 2009, p. 21.

[315] CEC, *2007 Integrated Energy Policy Report*, December 2007, pp. 155-156.

[316] Ibid, p. 155.

[317] Central Intelligence Agency, CIA World Factbook 2011 – The Netherlands. See: https://www.cia.gov/library/publications/the-world-factbook/geos/nl.html. 2008 electricity consumption = 124.1 billion kWh, or 124,100,000 MWh. Average consumption: 124,100,000 MWh ÷ 8,760 hr/yr = 14,167 MW.

[318] E. Coster et al, *Integration Issues of Distributed Generation in Distribution Grids - This paper considers the probable operating problems and challenges in connecting distributed generation to low- and medium-voltage electric power grids*, published in Proceedings of the IEEE, Vol. 99, No. 1, January 2011, pp. 28-39.

[319] European Wind Energy Association, *Wind in Power – 2010 European Statistics*, February 2011, p. 4. A total of 2,237 MW of wind capacity was installed in The Netherlands at the end of 2010.

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[321] CEC distributed generation interconnection webpage: http://www.energy.ca.gov/distgen/interconnection/california_requirements.html

[322] CPUC Rulemaking R.08-08-009 – California RPS Program, Administrative Law Judge's Ruling on Additional Commission Consideration of a Feed-In Tariff, *Attachment A - Energy Division FIT Staff Proposal*, March 27, 2009, p. 15.

[323] CPUC Rulemaking R.08-08-009 – California RPS Program, Administrative Law Judge's Ruling on Additional Commission Consideration of a Feed-In Tariff, *Attachment A - Energy Division FIT Staff Proposal*, March 27, 2009, pp. 15-16.

[324] CEC, *2007 Integrated Energy Policy Report*, December 2007, Figure 1-11, p. 27.

[325] E-mail from M. Martyak, PowerSecure (www.powersecure.com), to B. Powers, Powers Engineering, January 13, 2010. Approximate cost to upgrade older 100 MW distribution substation to full bidirectional flow, assuming four 25 MW load banks with four circuit breakers each (16 total), would be $400,000 to $450,000.
[326] Application No. 06-08-010, Matter of the Application of San Diego Gas & Electric Company (U-902-E) for a Certificate of Public Convenience and Necessity for the Sunrise Powerlink Transmission Project**, *Chapter 5:*** *Prepared Rebuttal Testimony of SDG&E in Response to Phase 2 Testimony of Powers Engineering*, March 28, 2008, p. 5.21.
[327] Application No. 06-08-010, Matter of the Application of San Diego Gas & Electric Company (U-902-E) for a Certificate of Public Convenience and Necessity for the Sunrise Powerlink Transmission Project**, *Chapter 5:*** *Prepared Rebuttal Testimony of SDG&E in Response to Phase 2 Testimony of Powers Engineering*, March 28, 2008, p. 5.20.
[328] SCE Application A.08-03-015, *Solar Photovoltaic (PV) Program Application*, March 27, 2008, p. 6.
[329] SCE Application A.08-03-015, *Solar Photovoltaic (PV) Program Testimony*, March 27, 2008, p. 44.
[330] SCE Application A.08-03-015, *Solar Photovoltaic (PV) Program Application*, March 27, 2008, pp. 8-9.
[331] Ibid, p. 9.
[332] SCE Application A.08-03-015, *Solar Photovoltaic (PV) Program Testimony*, March 27, 2008, p. 27.
[333] Ibid, p. 6.
[334] CPUC Press Release – Docket A.08-03-015, *CPUC Approves Edison Solar Roof Program*, June 18, 2009.
[335] CPUC Press Release – Docket A.09-02-019, *CPUC Approves Solar PV Program for PG&E*, April 22, 2010.
[336] California Energy Commission, *Revised Short-Term (2011-2012) Peak Demand Forecast – Draft Staff Report, December 2010*, Table 5, p. 14. Forecast 2011 1-in-2 peak for Bay Area is 8,606 MW.
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[338] Source of 2009 population estimates: April 5, 2010 Moody's www.economy.com purchased population data for each Bay Area county.
[339] Dr. Donald Shoup, *The High Cost of Free Parking*, March 2005, published by American Planning Association, Chapter 1.
[340] Jim Trauth, Envision Solar, estimate of solar parking lot potential in San Diego County, e-mail to Bill Powers, June 13, 2007.
[341] RETI, *Renewable Energy Transmission Initiative RETI Phase 1B – Final Report*, January 2009, p. 6-25.
[342] Source of graphic: RETI, *Renewable Energy Transmission Initiative RETI Phase 1B – Draft Resource Report*, August 2008. Each pink square is 20 MW of distributed PV.
[343] EPA website, Siting Renewable Energy on Potentially Contaminated Land and Mine Sites: http://www.epa.gov/renewableenergyland/
[344] R. Ferguson – RETI Coordinator, *Renewable Energy Transmission Initiative (RETI) Criteria for Estimating Need - Discussion Draft*, November 11, 2010, p. 3, "private PV." See: http://www.energy.ca.gov/reti/steering/2010-11-18_meeting/documents/2010-11-10_Net_Short_Criteria-Ferguson.pdf
[345] CPUC Rulemaking R.08-08-009, Order Instituting Rulemaking to Continue Implementation and Administration of California RPS Program, *Decision Adopting Renewable Auction Mechanism*, December 16, 2010, p. 27. "Solar Alliance, Sierra Club, First Solar, FIT Coalition, LA Community College District, Vote Solar and others argue for a higher or no cap. For example, Solar Alliance recommends a cap of 2,000 MW; Sierra Club recommends 3,000 MW (with all FIT contracts included); FIT Coalition recommends 4,000 MW (with a minimum of 1,000 MW auctioned per year); LA Community College District and Vote Solar recommend no cap (i.e. unlimited)."
[346] PG&E total bundled + Direct Access demand 2009 = 85,459 GWh. Public utility demand within nine Bay Area counties in 2009 = 5,136 GWh. Total demand all types in nine Bay Area counties in 2009 = 55,817 GWh. Net PG&E demand in nine Bay Area counties = 55,817 GWh – 5,136 GWh = 50,681 GWh. Fraction of total PG&E demand in nine Bay Area counties = 50,681 GWh/85,459 GWh = 0.593 or 59.3 percent. Sources are: CEC, *California Energy Demand 2009-2020 Adopted Forecast*, December 2009, and CEC county demand database: http://ecdms.energy.ca.gov/elecbycounty.aspx
[347] Itron, *Impacts of Distributed Generation - Final Report*, prepared for CPUC, January 2010, p. 3-8, Table 3-4: All Solar Interconnections in Investor-Owned Utility (IOU) Territories. Itron identifies 299 MW of net metered PV of all types installed in PG&E territory as of September 2009, including installations that pre-date the CSI program, and identifies 622 MW remaining to be installed under the CSI program. Total is 921 MW.
[348] SB 32, Section 399.20(f). "The proportionate share (of 750 MW cap) shall be calculated based on the ratio of the electrical corporation's peak demand compared to the total statewide peak demand." PG&E demand is approximately one-third of statewide demand. For this reason, the PG&E allocation is assumed to be approximately 250 MW.

[349] CPUC Rulemaking R.08-08-009, Order Instituting Rulemaking to Continue Implementation and Administration of California RPS Program, *Decision Adopting Renewable Auction Mechanism*, December 16, 2010, p. 30. PG&E allocation is 420.9 MW.
[350] UCLA and Los Angeles Business Council, *Bringing Solar Energy to Los Angeles – An Assessment of the Feasibility and Impacts of an In-Basin Solar Feed-In Tariff Program*, July 2010.
[351] San Diego Regional Renewable Energy Study Group, *Potential for Renewable Energy in the San Diego Region*, August 2005. See Chapter 2, Solar Photovoltaic Electric: http://www.renewablesg.org/docs/Web/Ch2_Solar_PV_Electric.pdf
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[353] CEC PIER, *Combined Heat and Power Assessment – Final Consultant Report*, prepared by ICF International, April 2010, p. 20.
[354] K. Davidson, *Combined Heat and Power - Carlsbad Chamber of Commerce Sustainability Committee*, PowerPoint presentation, October 3, 2008.
[355] Ibid, p. 10.
[356] CEC PIER, *Combined Heat and Power Assessment – Final Consultant Report*, prepared by ICF International, April 2010.
[357] Natural gas CO_2 emission factor is 117 lb CO_2 per million Btu. The heat rate of a simple cycle combustion turbine is 9,000 to 10,000 Btu/kWh, or 9 to 10 million Btu/ MWh. This equates to a CO_2 emission rate of 1,050 to 1,170 lb CO_2 per MWh.
[358] 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.
[359] California Energy Commission, *Comparative Costs of California Central Station Electricity Generation Technologies*, January 2010, Table C-5, p. C-12.
[360] 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.
[361] K. Davidson, *Combined Heat and Power - Carlsbad Chamber of Commerce Sustainability Committee*, PowerPoint presentation, October 3, 2008.
[362] Ibid.
[363] California Air Resources Board, *AB 32 Climate Change Scoping Plan*, December 2008, p. 44. See: http://www.arb.ca.gov/cc/scopingplan/scopingplan.htm
[364] CEC PIER, *Combined Heat and Power Assessment – Final Consultant Report*, prepared by ICF International, April 2010, p. C-9.
[365] California Energy Consumption Database Management System, Electricity Consumption by County: http://www.ecdms.energy.ca.gov/elecbycounty.aspx
***[366]* CEC, *California Energy Demand 2010 - 2020 Commission-Adopted Forecast*, December 2009. Form 1.1c. - Electricity Deliveries to End Users by Agency(GWH).**
[367] California Energy Consumption Database Management System, sum of electricity demand for nine Bay Area counties: http://www.ecdms.energy.ca.gov/elecbycounty.aspx
[368] Dr. Philip Perea, *An Assessment of Cogeneration for the City of San Francisco*, prepared for the Department of the Environment for the City and County of San Francisco, June 2007.
[369] Ibid, p. 57.
[370] NRG San Francisco Energy Center webpage: http://www.nrgthermal.com/Centers/Sanfran/whysf.htm
[371] Dr. Philip Perea, *An Assessment of Cogeneration for the City of San Francisco*, prepared for the Department of the Environment for the City and County of San Francisco, June 2007.
[372] B. Powers, San Diego Smart Energy 2020, October 2007, p.
[373] Bloom Energy webpage: http://www.bloomenergy.com/about/company-history/
[374] California Current, *Bloom Boxes*, Volume 9, Issue 3, January 21, 2011, p. 8.
[375] UTC webpage, PureComfort® Solution Applications. See: www.fuelcellmarkets.com/united_technologies_utc
[376] FERC Docket No. ER05-985-000, *Order Accepting Operating Memorandum – Trans Bay Cable LLC*, July 2005. FERC approved a 13.5 percent rate of return for Trans Bay Cable. CPUC argued that Trans Bay's proposed 13.5

percent return on equity was exorbitant and should be no greater than the 11-12 percent return that SCE and other companies across the country earn on their transmission projects.

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[378] Distributed Energy Magazine, *Dream Machine - An inverter connection to the grid lets CHP stay on when the lights go out*, November-December 2007.

[379] Tecogen press release, *Tecogen Receives Multiple Unit Order from Sacramento Utility for Groundbreaking Microgrid Demonstration Project*, September 2010.

[380] California Energy Almanac, List of Biomass Power Plants in California: http://www.energyalmanac.ca.gov/renewables/biomass/index.html. SF Southeast WWT digester gas cogen project, 2.1 MW.

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[382] CEC, Renewable Energy Research – Biomass Landfill webpage: http://www.energy.ca.gov/research/renewable/biomass/landfill/index.html

[383] P. Kulkarni – CEC, *Biowaste CHP Systems Prospects and Barriers to a Community Energy Option*, presented at CADER Conference, April 29, 2010, p. 10. See: http://www.cader.org/documents2010/PramodKulkarni20100429.pdf

[384] P. Kulkarni - CEC, *Combined Heat and Power Potential at the California Wastewater Treatment Plants – Draft Staff Report*, July 2009, p. 10.

[385] California Center for Sustainable Energy, *San Diego Gets Clean Energy*, December 14, 2010.

[386] PG&E press release, *PG&E and Bioenergy Solutions Turn the Valve on California's First "Cow Power" Project - Renewable Natural Gas Made From Animal Waste to Flow Through PG&E's Pipelines*, March 4, 2008. See: http://www.pge.com/about/news/mediarelations/newsreleases/q1_2008/080304.shtml. "Under a long-term contract approved by the CPUC, BioEnergy Solutions will deliver up to three billion cubic feet of renewable natural gas a year to PG&E. A BioEnergy Solutions system reduces emissions of methane by 70 percent on a 5,000-cow dairy."

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[388] K. Brennan – PG&E, *Biomethane Injection Into Gas Utility Pipelines,* National Biomethane Summit, June 23, 2009, p. 7.

[389] H. Snyder – Sempra Energy Utilities, *Renewable Biogas: Pipeline Biomethane*, NARUC Staff Subcommittee on Gas, July 18, 2010, p. 9.

[390] SMUD news release, *SMUD to purchase green gas from Texas*, April 15, 2009. "SMUD will enter into a 15-year contract with Shell Energy for 6 billion British thermal units (Btu) of gas per day." 6 billion Btu per day equals 6 million cubic feet per day of biomethane, assuming a biomethane heating value of 1,000 Btu per cubic foot.

[391] T. John, P.E., Tommy John Engineering, Inc, *Using and Measuring the Combined Heat and Power Advantage*, presented at American Institute of Chemical Engineers, Spring National Meeting, March 2010, p. 5. of large and small CHP is 4,200 Btu/kWh. 6 billion Btu per day ÷ 4,200 Btu/kWh = 1.43 million kWh per day. This equals 1,430 MWh per day. 1,430 MWh per day ÷ 24 hours per day = 59.6 MW.

[392] California Legislative Counsel's Digest, text of AB 1613, November 15, 2007.

[393] AB 1150 (Perez), Self-Generation Incentive Program: www.aroundthecapitol.com/billtrack/Bills/AB_1150.

[394] http://www.dsireusa.org/library/includes/incentive2.cfm?Incentive_Code=CA23F&state=CA&CurrentPageID=1

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[396] Power Magazine, *Regulatory Options for Feed-In Tariffs*, December 2010.

[397] 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. "The 1978 Public Utilities Regulatory Policies Act (PURPA) sought to reduce the country's dependence on oil through the development of new resources for electric generation, including renewable resources (solar, wind, biomass, geothermal, and small hydro) and the more efficient use of oil and gas in cogeneration projects. PURPA's key reforms included a requirement that the utilities must purchase the power output of qualifying cogeneration and other small power production facilities (referred to as "qualifying facilities" or "QFs") – a key step designed to encourage the development of QFs by ensuring a buyer for QF power. PURPA also required the utilities to purchase QF power at the purchasing utility's avoided cost–that is, at the cost that the utilities would have incurred

themselves to produce or purchase the same energy and capacity."
[398] Ibid.
[399] See individual project descriptions on CEC power plant webpage: http://www.energy.ca.gov/sitingcases/alphabetical.html
[400] CEC, *Russell City Energy Center Presiding Member's Preliminary Decision*, August 2007, p. 7. "Amended project will be designed to operate in load following mode (not baseload). CEC, *Oakley Generating Station Preliminary Staff Assessment*, December 2010, p. 1-3. "Expected capacity factor is 60 to 80 percent."
[401] CEC, *Marsh Landing Generating Station Final Decision*, August 2010, p. 4. "The MLGS will be capable of operating at a maximum capacity factor of 20 percent." CEC, *Mariposa Energy Center Staff Assessment*, November 2010, p.4.1-15. "However, the applicant expects the proposed MEP combustion turbines to actually run only approximately 600 hours per year with 200 startup and shutdown events annually, based on MEP's review of data from 2004 on California simple-cycle power plants greater than 50 MWp." p. 5.4-3. "The applicant expects to operate the MEP approximately 600 hours per year, or about 7% of the year."
[402] CEC, *Comparative Costs of California Central Station Electricity Generation*, January 2010, p. 54, Table 14. Small simple cycle (Mariposa) = $1,292/kW, advanced simple cycle (Marsh Landing) = $827/kW, combined cycle duct-fired (Russell City and Oakley) = $1,080/kW.
[403] These charges are known as "capacity payments." Russell City and Oakley are combined cycle plants that would be expected to operate regularly in a load-following pattern. Marsh Landing, and Mariposa would operate infrequently, primarily during summer high temperature periods, as peaking power plants.
[404] CPUC Decision D.06-07-029, *Opinion on New Generation and Long-Term Contract Proposals and Cost Allocation*, July 20, 2006, pp. 3-4. "We therefore conclude that immediate and affirmative Commission action is required to assure construction of adequate new capacity during the time in which we are transitioning to more robust and durable market institutions. The only complete solution . . . make the IOUs the entities responsible for acquiring new generation capacity, on a temporary basis, for bundled and unbundled customers alike."
[405] CEC, *Comparative Costs of California Central Station Electricity Generation,* January 2010, p. B-5, Table B-4. Fixed cost of small simple cycle (200 MW Mariposa) = $303/kW-yr; conventional simple cycle (760 MW Marsh Landing) = $283/kW-yr, and combined-cycle with duct firing (600 MW Russell City and 624 MW Oakley) = $259/kW-yr. Total yearly fixed costs for all four units are $593 million per year over twenty years.
[406] Assumes commercial rooftop PV at $3.50/$W_{dc}$. Net capital cost, assuming 30 percent investment tax credit and accelerated depreciation, would be $1.47/$W_{dc}$. Net capital cost is $1.84/$W_{ac}$, or $1.84 million per MW_{ac}, assuming 80% dc-to-ac conversion. $600 million per year ÷ $1.84 million per MW_{ac} = 326 MW_{ac} per year.
[407] MPR is the cost-of-energy for a new natural gas-fired combined cycle that includes a greenhouse gas emissions adder. See CPUC MPR website: http://www.cpuc.ca.gov/PUC/energy/Renewables/mpr
[408] CPUC MPR webpage, 2009 MPR Documents, 2009 MPR Model, Appendix F – Non-Gas Inputs: http://www.cpuc.ca.gov/PUC/energy/Renewables/mpr
[409] William Marcus, JBS Energy, Inc. on behalf of TURN, *MPR Capacity Factor*, PowerPoint presentation given at CPUC MPR workshop, R.06-02-012, March 27, 2008.
[410] CEC, *Comparative Costs of California Central Station Electricity Generation,* January 2010, p. C-12. Table C-5: Combined Cycle Facility Capacity Factors. Average capacity factor for 15 California combined cycle plants in 2008 is 65 percent.
[411] CPUC assumes 65% capacity factor for combined cycle units in *Inputs and Assumptions to 33% Renewables Portfolio Standard Implementation Analysis,* prepared by E3 for CPUC, July 2009.
[412] CPUC MPR webpage, 2009 MPR Documents, 2009 MPR Model, "Install_Cap" tab: http://www.cpuc.ca.gov/PUC/energy/Renewables/mpr.
[413] CEC, *Comparative Costs of California Central Station Electricity Generation ,* January 2010, Appendix B.
[414] Ibid, Tables 11 - 13.
[415] CPUC MPR webpage, 2009 MPR Documents, 2009 MPR Model: http://www.cpuc.ca.gov/PUC/energy/Renewables/mpr.
[416] CPUC assumes 65 percent capacity factor for combined cycle units in *Inputs and Assumptions to 33% Renewables Portfolio Standard Implementation Analysis,* prepared by E3 for CPUC, July 2009.
[417] CEC, *Comparative Costs of California Central Station Electricity Generation ,* January 2010, Table 1, Table 5, Figure A-8. A 500 MW unfired merchant combined cycle plant with a 75 percent capacity factor is the average case in the CEC report. Note – the dates shown in the table, 2009 and 2018, are commercial start dates.
[418] CPUC Application A.09-09-021, Application by PG&E for Approval of 2008 Long-Term Request for Offers Results, *Alternate Proposed Decision of Commissioner Bohn*, November 2, 2010.

[419] See Table 7-1. Base load transmission line losses are 5 percent. The cost-of-energy from a remote solar thermal plant is $202/MWh. Therefore the value of avoided transmission line losses = 0.05 × $202/MWh = $10.1/MWh.
[420] CPUC R.06-02-12, Rulemaking to Develop Additional Methods to Implement the California Renewables Portfolio Standard Program, *Pre-Workshop Comments of GreenVolts, Cleantech America, and Community Environmental Council on the 2008 Market Price Referent*, March 6, 2008, p.15. Table - E3 Model T&D Values (Levelized 20-year in 2008$).
[421] Itron, *CPUC Self-Generation Incentive Program—Ninth-Year Impact Evaluation Report – Final Report,* submitted to PG&E, June 2010, Table 5-14, p. 5-32. PG&E peak hour fixed PV capacity factor in 2009 was 54 percent, July 14, 2009, 4 pm to 5 pm.
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[432] Photon International, *The bigger solar picture*, September 2010.
[433] California Independent System Operator OASIS website: http://oasis.caiso.com/mrtu-oasis/home.jsp?doframe=true&serverurl=http%3a%2f%2farptp10%2eoa%2ecaiso%2ecom%3a8000&volume=OASIS
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[435] Ibid, p. 78.
[436] The 12 percent estimate is based on using 32,000 GWh of renewable energy production, the mid-point of the 27,000 to 37,000 GWh CEC 2009 IEPR estimate (p. 78) of renewable energy production.
[437] (California market size/German market size) x (California renewable %/German renewable %) x 2009 German merit order consumer savings = (1/2) x (12/16) x $5 billion per year = $1.9 billion per year.
[438] $2 billion per year ÷ 12 percent = ~$170 million per year per percent of renewable energy.
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[440] $170 million per year ÷ 1,150 1 MW projects = $148,000 per MW per year.
[441] The net present value multiplier for a 20-year period, assuming 7 percent interest, is 10.594. The NPV in 2011 dollars of $150,000 per year for 20 years = $150,000 x 10.594 = $1,591,100.
[442] Net capital cost, assuming gross installed rooftop PV cost of $3.50/$W_{dc}$, 30 percent investment tax credit, and accelerated depreciation, would be $1.47/$W_{dc}$. Net capital cost is $1.84/$W_{ac}$, or $1.84 million per MW_{ac}, assuming 80% dc-to-ac conversion. See Appendix H for a sample calculation of the net effect of tax benefits on capital cost.
[443] San Francisco Public Utilities Commission (SFPUC)/San Francisco Department of the Environment (SFE), *The Electricity Resource Plan – Choosing San Francisco's Energy Future*, December 2002, p. 57.

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[445] German Windpower Database: http://www.thewindpower.net/country-datasheet-2-germany.php, January 28, 2011. Average of 3,368 wind farms in database through the end of 2009.
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[526] This present value assumes the initial peaking gas turbine cost of $303/kW-yr includes an inflation adjustment over time such that the inflation-adjusted cost in Year 15 of a 15-year amortization period would be equivalent to $303/kW-yr in 2011 dollars.

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[543] Ibid, p. 13.

[544] Ibid, p. 13.

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[563] Ibid.

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