CALIFORNIA
ENERGY
COMMISSION

# AN ASSESSMENT OF RESOURCE ADEQUACY AND RESOURCE PLANS OF PUBLICLY OWNED UTILITIES IN CALIFORNIA

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Cover photo courtesy of Roseville Electric

Roseville Energy Park went online October 17, 2007 after a 24-month construction period. The power plant is a natural gas-fired, combined-cycle electrical generating facility. Normal nameplate output is 120 MW, with the ability to peak-fire to 160 MW during summer peak demand periods.

This is their first city-owned and city-operated power generating facility since Roseville began providing electric service in 1912. Roseville filed an Application for Certification on October 30, 2003, accepted as data adequate by the Energy Commission on December 17, 2003, siting docket 03-AFC-01. The Commission Decision on April 13, 2005 mandated zero liquid discharge standards and use of best available control technology for emissions. Roseville Energy Park is located on a 12-acre site adjacent to the Pleasant Grove Wastewater Treatment Plant, which supplies up to 1.5 million gallons per day during the peak season. A 17-minute video tour of the plant is available at:

http://www.roseville.ca.us/electric/about/rep.asp

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# Abstract

This is the second biennial report on resource adequacy actions by California's diverse publicly owned utilities. This report also describes and summarizes capacity and energy procurement commitments and plans with emphasis on the 10-year resource plans of the larger utilities. Historical data is presented on 2007 and 2008 peak loads and energy and energy demand, with forecast trends through 2018 for the larger utilities.

**Keywords**: Resource adequacy, electricity resource plans, publicly owned utilities, coal energy, renewable energy

# Executive Summary

This report describes 2008 and 2009 electricity resource adequacy for 40 publicly owned utilities in California and 2008–2018 supply and demand outlooks for the largest 15 publicly owned utilities. Two statutes require the publicly owned utilities to file these resource plans and resource adequacy reports with the Energy Commission as part of the *Integrated Energy Policy Report* process. After reviewing the filings and receiving comments through a public workshop process, this final report was prepared.

California's publicly owned utilities provide 23 percent of the state's retail electricity supplies. Publicly owned utilities produced or purchased 71,983 gigawatt-hours of electricity in 2008, with 89 percent delivered for sales to retail customers. Publicly owned utilities also met peak loads in 2008 that totaled 15,952 megawatts, or 23 percent of all statewide non-simultaneous peak loads. The 40 publicly owned utilities range from the third and fifth largest electric utilities in California, respectively Los Angeles Department of Water and Power and Sacramento Municipal Utility District, to very small load-serving entities such as the Port of Stockton and City of Industry.

Utility resource adequacy plans document the commitments by publicly owned utilities to have adequate generating supplies through utility ownership or contractual agreements. Utilities must demonstrate annually that they have sufficient reserve margins to meet both their service territory capacity requirements and support the capacity requirements of the larger interconnected balancing authority. The resource adequacy filings revealed that:

- The 15 largest publicly owned utilities in California began 2009 with a substantial capacity surplus over their forecast peak demand plus planning reserve margins. These 15 publicly owned utilities account for 95 percent of all publicly owned utilities' peak loads statewide. This 2009 capacity surplus totaled 1,359 MW.
- Since 2001, publicly owned utilities have built or contracted for more than 3,000 megawatts (nameplate) in new generating capacity. Most of this has been for natural gas resources, but an expanding amount has been for renewable energy.
- By early 2009, the next eight largest publicly owned utilities, with annual peak loads between 30 megawatts and 200 megawatts, had also acquired sufficient capacity to meet all peak load requirements for the year including planning reserve margins. Together, these eight publicly owned utilities had a combined capacity surplus of 349 megawatts beyond their firm peak requirements.
- The 17 smallest publicly owned utilities in California were also found to be resource adequate for 2009. When planning reserve margins are added, which are sometimes less than 15 percent, this group of publicly owned utilities had a capacity surplus of 31 MW. If all these publicly owned utilities used a 15 percent planning reserve margin, this group would still have a capacity surplus before counting on any short-term or spot market purchases. These 17 small publicly owned utilities comprise only 1 percent of all publicly owned utilities' peak loads in California.

The largest 15 publicly owned utilities provided 10-year resource plans through 2018 showing how forecast loads will be served by electricity supplies. Generally, publicly owned utilities expect to meet their new resource needs through natural gas units and a growing mix of renewables. Larger publicly owned utilities tend to rely on utility-controlled power plants or long-term contracts for most of their conventional resources and have been using more contracts for new renewables. Depending on their size, smaller entities usually purchase through contracts or joint ownership of projects.

The resource plans revealed that:

- Dependable capacity at utility-controlled gas-fired plants totaled 7,538 megawatts in 2009, equal to 41 percent of all their supply resources. By 2018, they expect to maintain 43 percent of their portfolio in natural gas. Additional capacity from natural gas-fired plants is planned to meet forecast peak loads while supporting integration of renewables and reducing dependence on coal-fired energy.
- Coal-fired generation in 2007 provided 2,364 megawatts of power and 21,010 gigawatt-hours of energy or 30 percent of all energy supplies. While some long-term commitments terminate during the outlook period, the majority of changes start in 2018. By 2022, as existing contracts expire, coal resources will supply 1,774 megawatts and 13,223 gigawatt-hours or 17 percent of all energy supplies.
- In aggregate, the publicly owned utilities have a load factor of 51 percent. This is the ratio of average load to annual peak load, and this level is not forecast to change markedly over the outlook period. This stability contrasts to a statewide trend which is orienting the system more towards peak energy.

## Meeting the Renewable Portfolio Standard

All 15 publicly owned utilities intend to have at least 20 percent of their portfolios to be renewables by 2017 at the latest, and four submitted plans to reach 30–35 percent by 2020. For many, this is a significant change in their procurement policies from a few years ago and a steep ramp-up from 2007 levels.

State law allows the governing board of each publicly owned utility to determine resource eligibility for its renewable portfolio standard. Some count all hydroelectric energy as renewable, including entitlements from Hoover Dam. However, only 30 percent of energy supply from hydropower plants larger than 30 megawatts nameplate counts as eligible for individual publicly owned utilities. Other energy categories sometimes defined as renewable by publicly owned utilities include combustion of renewable biofuels with natural gas in utility-owned facilities and purchase of tradeable renewable energy credits. The share of renewable energy from categories of eligibility defined by these utilities will decline from about 21 percent of all renewables in 2008, to 15 percent in 2010, to less than 8 percent in 2018. Nearly all long-term renewable energy procurement plans conform to categories defined as Energy Commission-eligible.

Renewable energy supplies for the 15 largest publicly owned utilities totaled 7,491 gigawatt-hours in 2008, equal to 12 percent of all retail sales. This was an increase from 6,962 gigawatt-hours in 2007. The trend is planned to accelerate dramatically in 2009 to 10,471 gigawatt-hours (17 percent), as publicly owned utilities bring online 430 megawatts (nameplate) from wind projects and 15 megawatts (dependable) from a geothermal project.

In 2010, the largest 15 publicly owned utilities plan to increase renewable energy supplies to 12,453 gigawatt-hours, which would equal 21 percent of all retail sales. It's expected that renewable energy procurement by the state's largest 15 publicly owned utilities will nearly triple between 2008 and 2018, with about 60 percent from contracts and about 25 percent from utility-controlled resources in 2018. The rest is from generic sources to be decided later.

Assuming all planned resources come to fruition, publicly owned utilities will use 20,600 gigawatt-hours of renewable energy in 2018, equal to 31 percent of retail sales. By energy volume, this would be a 175 percent increase from 2008. (When only Energy Commission-eligible renewables are counted, the share increases from 10 percent in 2008 to 30 percent in 2018.)

Utility-controlled supplies made up 16 percent of renewable energy procurement in 2008, and could be 21 percent in 2018. These volumes will more than triple in ten years from 1,300 gigawatt-hours to 4,400 gigawatt-hours.

Contracts provided 5,800 gigawatt-hours and 69 percent of all renewable supplies in 2008. If plans hold, these volumes will increase to 10,100 GWh in 2018. Contracts would then represent 57 percent of all renewable energy procurement.

Unlike the investor-owned utilities, which are counting heavily on large solar thermal units, publicly owned utilities favor wind, geothermal, and biomass as their preferred resources through 2018. Their solar programs tend to rely on photovoltaics.

While this report discusses general trends, the appendices describe the individual resource plans of the 15 largest publicly owned utilities.

# CHAPTER 1: POU Resource Adequacy

## Purpose and Structure of Report

Two laws require reports from the California Energy Commission regarding resources controlled by publicly owned utilities (POUs). Resource adequacy reporting requirements that apply to all POUs were established in Assembly Bill 380 (Núñez, Chapter 367, Statutes of 2005). This is the second report responsive to that statute. The first report described resource adequacy legislation, tariffs, conventions, and protocols.[1] Two additional data requests were made for the first time in 2009. All POUs were requested to provide historic data on annual peak loads in 2007 and 2008. All POUs were also asked to provide year-ahead load and resource data on capacity and energy requirements for 2009. The report summarizes their filings and then presents findings on resource adequacy.

AB 380 gives the Energy Commission the responsibility of reporting to the Legislature, as part of its biennial *Integrated Energy Policy Report (IEPR)*, on the progress of POUs in planning and acquiring resources to meet the needs of their end-use customers.

The Energy Commission is required by Senate Bill 1389 (Bowen, Chapter 568, Statutes of 2002) to prepare a biennial energy report that will assess current statewide conditions in electric generation system infrastructure, and identify major trends affecting electricity supply and reliability. Each load-serving entity that serves more than 200 MW of peak load was asked to file electricity supply forms showing their forecast of loads and resources for 2009 through 2018. Public Resources Code Sections 25216 and 25216.5 provide broad authority for the Energy Commission to collect data and information "on all forms of energy supply, demand, conservation, public safety, research, and related subjects."

This report summarizes the 10-year resource outlooks of the fifteen largest POUs, as filed with the Energy Commission. It emphasizes their new resources, near-term plans for acquiring higher levels of renewables, and status of coal in POU resource portfolios. An appendix provides additional information on the resource plans of the 15 largest POUs.

[1] Jim Woodward, *Progress Report on Resource Adequacy Among Publicly Owned Load-Serving Entities in California*, California Energy Commission, Electricity Supply Analysis Division, May 2008, at: http://www.energy.ca.gov/2007publications/CEC-200-2007-016/CEC-200-2007-016-SF.PDF

## Introduction to Resource Adequacy

Resource adequacy requirements specify the megawatts of generating capacity that a load-serving entity (LSE)[2] must control to ensure reliable service. When more capacity is available to serve demand at any given time the level of reliability increases and so does the associated cost. Therefore, the choice of a reliability standard reflects the value of uninterrupted service.

Resource adequacy standards are set to prevent one threat to reliability, that generation is not available to serve load. While electricity supply and demand must be kept in balance during real-time operations of a grid, an operating reserve of additional supply resources is always required. LSEs typically procure sufficient resources months ahead to meet a planning reserve margin (PRM). The PRM is the amount of generation capacity (and interruptible demand under the control of the LSE) that exceeds its forecasted peak demand, and is often expressed as a percentage of the peak demand.[3] A commonly used PRM, adopted by most LSEs in California, is 15 percent. The 15 percent PRM is often assumed to provide a "one day in 10 years" level of reliability, though that has not been confirmed by modeling studies.

Resource adequacy requirements may specify the amount of capacity that an LSE must procure before real time operation: for example, one month ahead, one year ahead, or five years ahead. Forward requirements of one year or less are largely designed to assure the balancing area operator that there are sufficient resources under LSE control to meet both the LSE's peak loads and the system peak loads in the balancing area.

The Energy Commission is required to report on progress by each local POU to procure adequate generation resources for their customers. The following sections describe POU procurement plans and actions intended to satisfy their ongoing electricity supply obligations.

## Resource Adequacy and Resource Plan Filings by POUs

Year-ahead resource adequacy filings were submitted by the 15 larger POUs and 25 smaller POUs. The 15 largest POUs include Los Angeles Department of Water and Power (LADWP), the third largest electricity utility in the state, and Sacramento Municipal Utility District (SMUD), the fifth largest. The 25 smaller POUs include 13 municipalities,

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[2] A load-serving entity has obligations to provide electricity to end-use customers. This term includes investor-owned utilities, publicly owned utilities, energy service providers, and rural electric cooperatives.

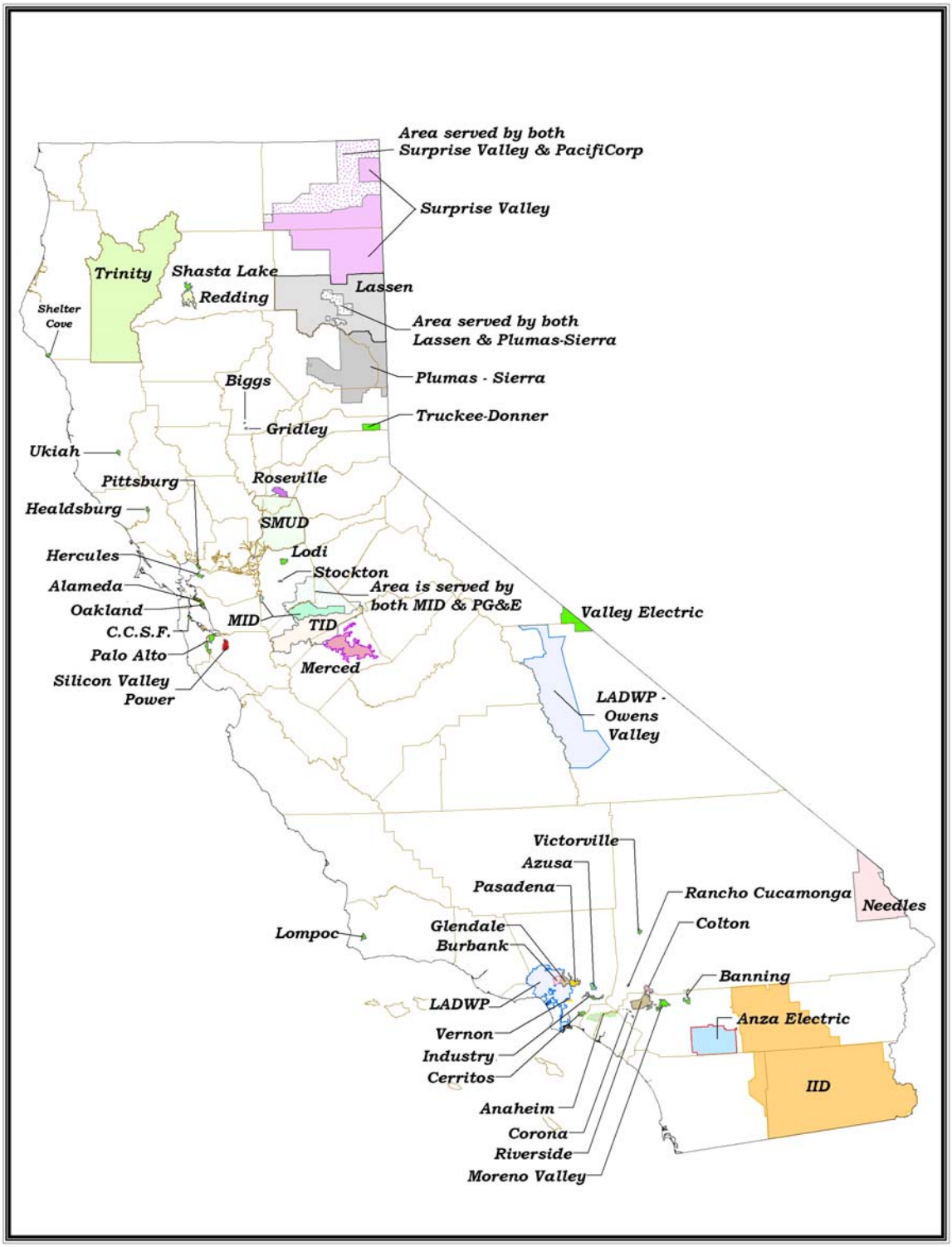
[3] For example, an LSE with a forecasted peak demand of 200 MW and 235 MW of generation under its control has a PRM of 35 MW or 17.5 percent ([235-200]/200).

3 municipal utility districts, 2 public utility districts, 1 irrigation district, 2 organized as a joint power authority (that include one or more of these agencies), 1 community aggregator, 1 resort improvement district, and 3 rural electric cooperatives The member-owned cooperatives are non-profit corporations that are not generally considered to be a publicly owned electric utility (POEU). For convenience, this report will refer to POEUs and all other publicly owned LSEs by the more common term publicly owned utilities (POUs). The service territories of these POUs (except for the joint power authorities) are presented in **Figure 1**.

Ten-year resource plans were submitted by 15 POUs in early 2009, including 10 municipalities, 1 municipal utility district, 3 irrigation districts, and a voluntary filing by the Northern California Power Agency (NCPA) on behalf of the NCPA Power Pool. [4]

[4] The NCPA Power Pool serves as scheduling coordinator for 10 individual POUs that have banded together for the purpose of long-term resource planning and short-term scheduling of loads and resources. For a more complete assessment of POU resource adequacy, this report counts NCPA as one of 15 POUs with an annual peak load larger than 200 MW. This report will sometimes refer to all 40 POUs in California, which counts NCPA but not the 10 individual members of the NCPA Power Pool. Service territories for these 10 POUs are shown in **Figure 1** from north-to south: Plumas-Sierra, Biggs, Gridley, Ukiah, Healdburg, Lodi, Alameda, Port of Oakland, Palo Alto, and Lompoc.

## Figure 1: California Publicly Owned Electric Utility Service Areas




Source: Energy Commission, Cartography Office, September 2009

## Resource Adequacy Loads and Resources for Larger POUs, 2008–2009

As shown in **Table 1**, the 15 largest POUs, which have annual peak loads larger than 200 MW, account for 95 percent of all POU peak loads in the state. In 2008, LADWP and SMUD provided 57 percent of peak power needs for all public power customers in California. For 2009, the sum of forecast peak loads for all 40 POUs is 15,462 MW as shown in **Table 1.** This amount includes end-use customer demand plus any firm sales obligations, but does not include a PRM. Adding a 15 percent PRM to 2009 peak loads would raise total resource need to 17,781 MW.

**Table 1: Peak Load and Annual Energy Requirements for the 15 Largest POUs, 2008 and 2009**

| 15 POUs with Peak Loads Larger than 200 MW | 2008 Peak MW | 2009 Peak MW [1] | 2008 Energy GWh | 2009 Energy GWh |
|---|---|---|---|---|
| LADWP | 6,006 | 5,690 | 28,230 | 27,908 |
| SMUD | 3,086 | 2,826 | 11,718 | 11,647 |
| Imperial ID | 979 | 938 | 3,736 | 3,716 |
| Modesto ID | 650 | 689 | 2,692 | 2,810 |
| Turlock ID | 602 | 558 | 3,336 | 2,344 |
| Anaheim | 581 | 524 | 2,700 | 2,792 |
| Riverside | 535 | 590 | 2,669 | 2,546 |
| NCPA | 501 | 495 | 2,678 | 2,621 |
| Silicon Valley Power | 490 | 477 | 3,005 | 3,035 |
| Roseville Electric [2] | 338 | 411 | 1,307 | 1,684 |
| Glendale | 306 | 335 | 1,239 | 1,126 |
| Pasadena | 310 | 316 | 1,245 | 1,275 |
| Burbank | 289 | 304 | 1,247 | 1,248 |
| Redding | 273 | 287 | 1,017 | 1,022 |
| Vernon | 204 | 189 | 1,121 | 1,092 |
| Sub-total for the largest 15 POUs | 15,150 | 14,629 | 67,940 | 66,866 |
| Total for all 40 POUs | 15,952 | 15,462 | 71,983 | 71,028 |
| Largest 15 as a % of all 40 POUs | 95% | 95% | 94% | 94% |

1 The 2009 Peak MW equals peak-hour demand for end-use customers plus firm sales, but does not include the planning reserve margin

2 The forecast increases for Roseville include a new firm sales obligation of 75 MW and 328 GWh, expiring in 2011.

Source: California Energy Commission, POU resource plan and resource adequacy filings, Spring 2009

Forecasted 2009 peak loads were down 905 MW from actual 2008 peak loads. Some of this apparent reduced demand is attributable to 333 MW in demand response/ interruptible programs available in 2009, none of which were called upon in 2008. Energy efficiency and conservation programs are also helping to reduce peak demand that utilities must serve. However, the largest factor for reduced 2009 peak demand in load forecasts is that current economic conditions are worse than in 2008.

LADWP forecasts 2009 adjusted peak demand at 5,690 MW, equal to a 316 MW reduction from 6,006 MW actual peak demand in 2008. But this 2009 forecast peak demand is only 207 MW less that LADWP's 1-in-2 forecast for 2008 at 5,897 MW. With no net increases in demand-side resources, this 207 MW reduction in forecast peak demand for 2009 can be attributed to reduced economic activity during the current recession, which would equal a reduction of 3 percent.

For 2009, SMUD has an adjusted peak-hour demand forecast of 2,826 MW, which includes 200 MW of demand response/interruptible programs and 29 MW of new energy efficiency programs; SMUD's 2008 actual peak-hour demand reached 3,086 MW without calling on those demand-side resources. This comports with the Energy Commission demand forecast for SMUD showing a 2 percent reduction from 2008 to 2009 in the weather-normalized 1-in-2 peak demand.

## *Meeting Peak Load Requirements with Utility-Owned Capacity Additions Since 2001*

Since 2001, California POUs have brought 3,014 MW online (**Table 2**). Collectively, POUs invested in 2,450 MW of new thermal generation, including 510 MW in 2007-2008. **Table 2** shows 559 MW (nameplate) of new renewable resources since 2001, but this does not include numerous small projects, especially landfill gas, that each added less than 10 MW.

## Table 2: POU Capacity Additions Greater Than 10 MW Since 2001

| POU | Facility | MW | Online Date | Technology |
|---|---|---|---|---|
| LADWP | Harbor 10-14 | 235 | Jan-02 | Combustion Turbine |
| Redding | Redding Power 1-4 | 40 | Jun-02 | Combustion Turbine |
| Burbank | Lake 1 | 47 | Jul-02 | Combustion Turbine |
| Riverside | Springs | 44 | Jun-02 | Combustion Turbine |
| Modesto ID | Woodland | 80 | Jun-03 | Combined-Cycle |
| Colton | Augua Mansa Peaker | 43 | Jul-03 | Combustion Turbine |
| Pasadena | Glenarm 3 & 4[1] | 20 | Oct-03 | Combustion Turbine |
| LADWP | Solar DG facilities | 17 | Jan-04 | Solar |
| Glendale | Grayson Unit 9[2] | 6 | Mar-04 | Combustion Turbine |
| LADWP | Valley 6-7-8 (net)[3] | 49 | May-04 | Combined-Cycle |
| LADWP | Haynes 3 & 4[4] | 49 | Jan-05 | Combined-Cycle |
| Corona | Clearwater Cogen | 30 | Feb-05 | Combined-Cycle |
| SVP | Von Rasefeld | 147 | Mar-05 | Combined-Cycle |
| Burbank, *et al*[5] | Magnolia | 328 | Sep-05 | Combined-Cycle |
| Vernon | Malburg | 134 | Oct-05 | Combined-Cycle |
| SMUD | Cosumnes 1 | 500 | Mar-06 | Combined-Cycle |
| LADWP | Pleasant Valley | 82 | May-06 | Wind |
| Modesto ID | Ripon | 95 | Jun-06 | Combined-Cycle |
| Riverside | Riverside Energy Center | 98 | Jun-06 | Combustion Turbine |
| SMUD | Solano Phase 1 | 39 | Jun-06 | Wind |
| Roseville | Roseville Energy Park | 160 | Oct-07 | Combined-Cycle |
| Turlock ID | Walnut | 250 | Feb-08 | Combined-Cycle |
| Imperial ID | Niland GT | 100 | Jun-08 | Combustion Turbine |
| LADWP | Castaic upgrades | 30 | Jul-08 | Hydro |
| SMUD | Solano Phase 2 | 62 | Apr-08 | Wind |
| LADWP | Willow Creek | 72 | Dec-08 | Wind |
| Turlock ID | Windy Point | 137 | May-09 | Wind |
| LADWP | Pine Tree | 120 | Jun-09 | Wind |
| | Total Nameplate MW | 3,014 | | |

[1]Net increase, 94 MW project resulted in retirement of Broadway Units 1 & 2.

[2]Net increase, 45 MW project resulted in retiring another Grayson Unit.

[3]Net increase, 501 MW (dependable) project resulted in retiring 4 other Valley Units.

[4]Net increase, 560 MW (dependable) project resulted in retiring 2 other Haynes Units.

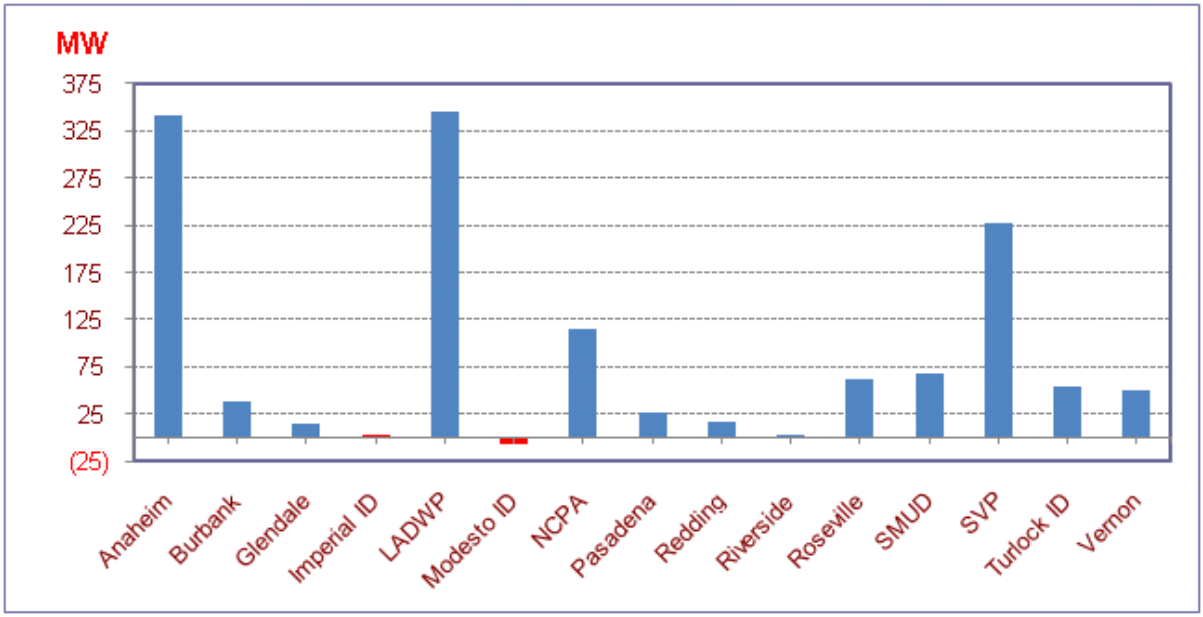
[5]Burbank, Anaheim, Glendale, Pasadena, Cerritos, and Colton own shares in Magnolia.

Source: California Energy Commission, Electricity Analysis Office, September 2009

## *Capacity Resource Surpluses in 2009*

The 15 largest POUs in California began 2009 with a 1,359 MW aggregate surplus over firm peak requirements including planning reserve margins. In the February 2009 filings as shown **Figure 2**, only Modesto ID indicated a residual resource need of 7 MW, and filled the deficit since the original information was submitted. This small amount is well within the bandwidth of its integration agreement with Western Area Power Administration (WAPA, or Western) to provide imbalance energy and capacity within the SMUD-Western balancing area.

**Figure 2: Surplus Capacity in 2009**




Source: California Energy Commission, Electricity Supply Analysis Division, August 2009

The substantial surplus capacity shown for Anaheim in 2009 is caused by Anaheim procuring additional capacity to comply with local capacity requirements set by the California ISO. A large portion of Anaheim's resources are located outside the California ISO balancing authority area. Anaheim's current local capacity requirement is 309 MW. For 2009, Anaheim purchased 75 MW from NRG, capacity that is required to bid the associated energy into the California ISO markets. Anaheim has no right to call on or use the energy associated with this resource adequacy capacity. LADWP and Silicon Valley Power (SVP) also have significant capacity surpluses in 2009.

Capacity resource plans through 2018 for each of these 15 POUs are detailed in **Appendix A** along with similarly detailed plans for expected energy supplies.

## Resource Adequacy Loads and Resources for Smaller POUs, 2008–2009

As shown in **Table 3**, there are eight smaller POUs with annual peak loads greater than 30 MW and less than 200 MW. In decreasing order by MW size, they are City & County of San Francisco (CCSF), Power & Water Resources Pooling Authority (PWRPA), Merced Irrigation District, Colton Electric Utility Department, Azusa Light & Water, City of Banning, Truckee Donner Public Utilities District, and City of Shasta Lake.

**Table 3: Peak Load and Annual Energy Requirements for 8 POUs with Peak Loads 30 MW to 200 MW, 2008 and 2009**

| 8 POUs with Peak Loads 30 MW to 200 MW | 2008 Peak MW | 2009 Peak MW [1] | 2008 Energy GWh | 2009 Energy GWh |
|---|---|---|---|---|
| City & County of San Francisco | 149 | 142 | 996 | 1,013 |
| Power & Water Pooling Authority | 102 | 112 | 530 | 531 |
| Merced ID | 88 | 94 | 442 | 452 |
| Colton | 77 | 85 | 372 | 377 |
| Azusa | 63 | 63 | 283 | 282 |
| Banning | 43 | 45 | 162 | 158 |
| Truckee Donner | 35 | 37 | 157 | 162 |
| Shasta Lake | 33 | 34 | 193 | 204 |
| Sub-total | 591 | 612 | 3,135 | 3,179 |
| Total for all 8 POUs | 15,952 | 15,462 | 71,983 | 71,028 |
| Median 8 as a % of all 40 POUs | 4% | 4% | 4% | 4% |
| | | | | |

1 The 2009 Peak MW equals peak-hour demand for end-use customers plus firm sales, but does not include the planning reserve margin

Source: California Energy Commission, POU resource plan and resource adequacy filings, Spring 2009

These utilities are remarkably diverse in geography, history, and customer loads. Three POUs are in Southern California within the California ISO balancing area, and more specifically within the ISO-defined Los Angeles Basin local reliability area: Azusa, Banning, and Colton. Two POUs serve end-use loads in Northern California within the California ISO balancing area, but these POUs do not have exclusive utility service areas: CCSF and PWRPA. Shasta Lake is north of Redding in the SMUD balancing area, Merced is southeast of Turlock Irrigation District (TID) in the TID balancing area, and Truckee Donner is in the Sierra Pacific Power balancing area.

The principle reason for aggregating these eight POUs is to distinguish them from the 15 largest POUs that submitted ten-year resource plans through 2018, and to describe them

separately from the 17 smallest POUs in California. These eight utilities have customer loads that are large enough and sufficiently stable to facilitate many long-term resource procurement commitments.

## *Smaller POU Capacity Resources in 2009*

For 2009, their aggregate annual non-coincident peak load was forecast to be 665 MW, equal to 4 percent of all POU peak load. By the spring of 2009, each utility had acquired sufficient capacity to meet their forecast 2009 peak loads including a 15 percent PRM. In aggregate, as shown in **Table 4**, these eight POUs have 1,014 MW in dependable capacity. This 349 MW surplus equates to a 34 percent planning reserve margin.

**Table 4: Supply Resources for 8 POUs with Peak Loads 30 MW–200 MW**

| RESOURCE TYPE | 2009 MW | Percent of Requirement | 2008 GWh | Percent of Requirement |
|---|---|---|---|---|
| Large Hydro | 470 | 46% | 1,492 | 40% |
| Non-Renewable Contracts | 297 | 29% | 1,110 | 30% |
| Utility-Controlled Fossil | 206 | 20% | 676 | 18% |
| Utility-Controlled Renewables | 18 | 2% | 31 | 1% |
| Renewable Contracts | 17 | 2% | 129 | 3% |
| Nuclear | 6 | 1% | 51 | 1% |
| Spot Market | 0 | 0% | 218 | 6% |
| Total Dependable MW | 1,014 | 152% | | |
| Firm Resource Requirement / Firm Energy Requirement | 665 | | 3,707 | 100% |

Source: California Energy Commission, Electricity Supply Analysis Division, September 2009

Three procurement categories account for 95 percent of all capacity supplies: large hydro, bilateral non-renewable contracts, and utility-controlled fossil fuel plants. This profile is skewed by including 375 MW from San Francisco's Hetch Hetchy hydroelectric power plants, which are fed by reservoirs in and near Yosemite National Park. The 2009 annual firm peak load for CCSF is only 142 MW. The firm peak includes 50 MW to 100 MW of municipal load within San Francisco, and 30 MW to 50 MW at San Francisco International Airport.[5]

[5] CCSF often sells non-firm energy directly to Modesto ID and Turlock ID. When non-firm sales are added to firm load-serving requirements, CCSF had a metered peak-hour load of 250 MW in 2008 and 377 MW in 2007. CCSF also has a banking agreement with PG&E that allows PG&E to take up to 75 MW at a time from CCSF transmission, with subsequent delivery of energy from PG&E's distribution system in the city. CCSF is not allowed to sell energy to an investor-owned utility according to terms of the 1913 U.S. Raker Act.

Merced has a bilateral contract with Western that supplies about 2 MW. All other supply requirements are provided by Turlock ID, including energy, operating reserves, regulation, scheduling, and black start capability. Merced has one connection to the TID balancing area, and has no utility-controlled generation.

Truckee Donner forecast a 2009 winter peak load of 36 MW. The Sierra Pacific balancing area typically peaks in summer, at which time Truckee Donner forecasts its load at 20 MW, a coincidence adjustment of 17 MW. Truckee Donner reported having 38 MW available from three contracts with Utah Associated Municipal Power Systems. Power deliveries are in eastern Nevada, at an intertie of Sierra Pacific's balancing area.

Shasta Lake does not have a formal planning reserve margin. Shasta Lake has supply contracts with Western, Shell Energy North America, and the City of Redding. Shasta Lake has a separate supplemental energy and scheduling agreement with Redding. Redding provides for Shasta Lake's unmet needs on a load following basis, which would include the reserve margin for Shasta Lake loads.

PWRPA counts on Western for 90 MW. PWRPA has 2 MW total from two utility-owned solar photovoltaic systems and 6 MW from a landfill in Sonoma County. All 15 PWRPA customers are irrigation districts or water districts. All but Sonoma County Water Agency and Santa Clara Valley Water District are in located in California's Central Valley. Much of this pump load occurs during the balancing authority's off-peak hours, with substantially greater pumping loads in dry years. If needed, PWRPA has 55 MW available from non-renewable distributed generation owned by its customers. PWRPA has committed to a 2 percent ownership share in Lodi Energy Center, expected online by summer 2012.

Azusa committed to a 3 percent share in Lodi Energy Center, but most other supplies are imports from the east. Azusa has long-term capacity supplies from coal-fired San Juan in New Mexico, Palo Verde nuclear in Arizona, and Hoover Dam on the Nevada—Arizona border. Azusa is an active market participant, securing capacity-only resources in the LA Basin to meet local reliability requirements. Historically, Azusa has laid-off the unit contingent San Juan Unit 3 to other parties in the southwest in exchange for firm power delivered at locations where Azusa has more firm transmission access, for example, Mead (23 kV), Marketplace (500 kV), or within Southern California. Local capacity is also available under contract from Ormond Beach, El Segundo, and La Rosita Power.

Banning also has long-term capacity supply from San Juan Unit 3 (19 MW), Palo Verde (2 MW), and Hoover (2 MW). Banning has 3.4 MW in baseload geothermal supply under contract through 2031. For 2009, Banning has 25 MW from Reliant's Ormond Beach to meet its local capacity procurement obligations.

Colton also takes power from San Juan Unit 3 (30 MW), Palo Verde (2 MW), and Hoover (2 MW). Colton has local capacity from its own Agua Mansa Peaker (43 MW, see **Table 2**), and the Colton landfill (1 MW). Colton owns a 10 MW share of the Magnolia Power Plant

located in Burbank, which is an import to the California ISO balancing area that does not count for local resource adequacy requirements.

### *Smaller POU Energy Supplies in 2008*

In 2008, this group of eight small POUs readily met a firm energy requirement of 3,135 GWh. Retail sales totaled 3,063 GWh. For seven of these POUs, the majority of their energy supplies came from bilateral contracts or utility-controlled fossil resources. In **Table 4**, the largest share of energy supplies is obviously large hydro, though 1,346 GWh of this 1,492 GWh component is San Francisco's Hetch Hetchy project. Even in dry 2008, all CCSF demand could be served by Hetch Hetchy with a 350 GWh surplus available for sales to others.

Utility-controlled fossil energy supplies in 2008 included 382 GWh from coal-fired San Juan Unit 3, though Azusa subsequently laid off 86 GWh in coal-based imports. In 2008, Colton took 69 GWh from the gas-fired Magnolia combined cycle plant, and generated 59 GWh from its Agua Mansa simple-cycle power plant. Truckee Donner purchased 158 GWh from Utah Associated Municipal Power Systems, which staff assumes is from coal-fired generation.

Renewable energy contracts supplied a modest 129 GWh in 2008, down from 219 GWh in 2007 as other contracts expired. This category includes 13 GWh of wind energy purchased by Merced from Iberdrola Renewables. Merced has contracted through 2028 for a 5 MW share of the 162 MW High Winds Energy Center Project in Solano County. Merced takes ownership of green electric energy with its environmental attributes, and then promptly sells back to Iberdrola an equivalent amount of brown energy without the environmental attributes. The 31 GWh slice representing utility-controlled renewables includes 11 GWh from small hydro, 3 GWh from new solar photovoltaic facilities (PWRPA and Colton), and 18 GWh from Azusa's ownership share in the Solano County wind project developed and operated by Iberdrola Renewables (formerly PPM). For 2009, Azusa expects 13 GWh from the new Garnet Hill wind project northeast of Palm Springs, a 6.5 MW project with 13 NedWind 500 kV wind turbines.

## Resource Adequacy Loads and Resources for the Smallest POUs, 2008–2009

As shown in **Table 5**, there are 17 publicly owned utilities with annual peak loads less than 30 MW. Some of these very small POUs have large but sparsely settled service territories as shown in **Figure 1**, such as Trinity, Lassen, Surprise Valley, Anza Electric, and Needles. Most of these very small POUs are relatively new urban enterprises, and serve only selected areas of their cities: Corona, Moreno Valley, Rancho Cucamonga, City of Industry, Cerritos, Victorville, Hercules, and Pittsburg (serving only the Mare Island community in Vallejo).

The other four POUs in this group are Port of Stockton, Shelter Cove on the southern coast of Humboldt County, Valley Electric in Eastern California southeast of Bishop,[6] and Eastside Power Authority. Eastside customers consist of three irrigation districts and three water districts in the Greater Fresno area. Eastside, Hercules and Cerritos do not have exclusive electric service territories.

**Table 5: Peak Load and Annual Energy Requirements for the 17 Smallest POUs, 2008 and 2009**

| 17 POUs with Peak Loads Smaller than 30 MW | 2008 Peak MW | 2009 Peak MW [1] | 2008 Energy GWh | 2009 Energy GWh |
|---|---|---|---|---|
| Surprise Valley | 29 | 29 | 95 | 95 |
| Lassen MUD | 27 | 27 | 148 | 149 |
| Moreno Valley | 19 | 24 | 74 | 88 |
| Trinity PUD | 18 | 19 | 94 | 99 |
| Rancho Cucamonga | 17 | 19 | 67 | 110 |
| Needles | 17 | 17 | 68 | 68 |
| Corona | 16 | 13 | 85 | 73 |
| Cerritos | 15 | 15 | 58 | 77 |
| Eastside Power Authority | 12 | 13 | 39 | 39 |
| Anza Electric | 11 | 13 | 52 | 57 |
| City of Industry | 7 | 7 | 34 | 30 |
| Victorville | 7 | 7 | 31 | 33 |
| Pittsburg (Island Energy) | 5 | 5 | 23 | 23 |
| Valley Electric | 4 | 4 | 8 | 8 |
| Port of Stockton | 3 | 4 | 14 | 14 |
| Hercules | 3 | 4 | 13 | 14 |
| Shelter Cove | 1 | 1 | 6 | 6 |
| Sub-total | 211 | 221 | 909 | 983 |
| Total for all POUs | 15,952 | 15,462 | 71,983 | 71,028 |
| Smallest 17 as a % of all POUs | 1% | 1% | 1% | 1% |

1 The 2009 Peak MW equals peak-hour demand for end-use customers plus firm sales, but does not include the planning reserve margin

Source: California Energy Commission, POU resource plan and resource adequacy filings, Spring 2009

[6] Valley Electric is a non-profit rural electric cooperative based in Pahrump, Nevada. Annual peak loads in Nevada are about 130 MW. Annual peak loads in California are about 4 MW. Surprise Valley Electrification Corporation also serves customers in two states, with California peak loads consistently at or slightly below 30 MW, and Oregon peak loads at about 8 MW.

### *Smallest POU Capacity Resources in 2009*

For 2009, the sum of forecast non-coincident peak loads for these 17 POUs is only 211 MW, equal to 1 percent of all POU peak loads in California. When the planning reserve margins are added, which are not always 15 percent in this group, the total firm peak requirement for 2009 is 231 MW. (If all these POUs used a 15 percent PRM, their combined firm peak requirement would be 243 MW.) In their spring 2009 resource adequacy filings to the Energy Commission, aggregate capacity resources totaled 262 MW, including 18 MW to be purchased under short-term contracts or in spot markets, and firm capacity procurement of 244 MW.

As shown in **Table 6**, the majority (56 percent) of dependable capacity to serve peak loads comes from non-renewable contracts. Many of these contracts are for system power procured by Sempra Energy Solutions or Shell Energy North America. Western fills all electricity supply requirements for Trinity, Lassen, Pittsburg, and Shelter Cove; Bonneville Power Administration provides the same supply services and commodities for Surprise Valley. In early 2009, only about 70 percent of Western's portfolio of supply resources procured for its Northern California preference customers was from Western's large hydroelectric resources. The other 30 percent was from short-term contracts. This 70-30 allocation between large hydro and non-renewable contracts is reflected in Error! Reference source not found.. Eastside and Needles have partial requirements supply contracts with Western. (All but Needles count the large hydro components of these supply contracts as renewable energy.)

**Table 6: Supply Resources for 17 POUs with Peak Loads Less Than 30 MW**

| RESOURCE TYPE | 2009 MW | Percent of Requirement | 2008 GWh | Percent of Requirement |
|---|---|---|---|---|
| Large Hydro | 42 | 18% | 160 | 18% |
| Non-Renewable Contracts | 146 | 63% | 547 | 60% |
| Utility-Controlled Fossil | 44 | 19% | 153 | 17% |
| Utility-Controlled Renewables | 9 | 4% | 0 | 0% |
| Renewable Contracts | 4 | 2% | 8 | 1% |
| Nuclear | 0 | 0% | 0 | 0% |
| Spot Market | 18 | 8% | 41 | 5% |
| Total Dependable MWs | 262 | 113% | | |
| Firm Resource Requirement / Firm Energy Requirement | 231 | | 909 | 100% |

Source: California Energy Commission, Electricity Supply Analysis Division, September 2009

Utility-owned fossil resources are far less common among very small utilities than among larger POUs. Cerritos owns a 13 MW unit-contingent share of the Magnolia combined cycle plant in Burbank, a share that does not cover all 15 MW of forecast peak load, but which

does generate more energy than Cerritos needs over the course of a year. Corona counts on 14 MW from the 30 MW Clearwater Cogen combined cycle plant (see **Table 2**).

For part of 2009, Victorville will have 7 MW of fossil capacity, down from 16 MW in 2008. Victorville is phasing out its 12 small generators, mostly diesel and some gas, as it switches from a non-grid-connected independent utility to a grid-connected POU using IOU-owned transmission and distribution infrastructure. Victorville may also be phasing out its biofuel distributed generation, which accounts for the only 9 MW of utility renewables in **Table 6**. By 2010, none of these very small POUs will solely own and operate a fossil-fuel or renewable-fuel plant. Only Rancho Cucamonga reported having renewable contracts, with 4 MW from local landfill gas under contract through 2012.

## *Smallest POU Energy Supplies in 2008*

In 2008, this group of 17 very small POUs procured 909 GWh, equal to just over 1 percent of all POU energy supply requirements. Three POUs had utility-controlled fossil fuel energy supply in 2008. Cerritos received 78 GWh from Magnolia, which was much larger than its annual 58 GWh energy requirement. Victorville generated 29 GWh on site using natural gas. Anza Electric belongs to the Arizona Electric Power Cooperative (AEPCO), which procures and schedules all of Anza Electric's supplies. In 2008, AEPCO generated 46 GWh on behalf of Anza Electric from its portfolio of coal, natural gas, and fuel oil generation. (A disaggregated attribution by fuel type is not available from AEPCO.)

In 2008, short-term and spot market purchases accounted for 5 percent of all energy procurement, which is comparable to averages for larger utilities.

Many bilateral supply contracts are relatively open-ended. The City of Industry has an evergreen contract (renews automatically month-to-month) with Sempra Energy Solutions to purchase up to 2 MW in spot markets, which supplements a 3 MW flat block contract with Sempra. Cerritos relies on the trading desk of Shell Energy North America (Shell) to purchase additional energy during peak hours, and to sell surplus energy during off-peak hours. POUs in the California ISO balancing area are required to schedule loads and resources in whole GWh number increments, such as 20 GWh in the hour ending at 12 noon (HE 12), then 22 GWh in HE 13, and 25 GWh in HE 14, etc. For the smallest POUs, this requirement would cause proportionally larger use of the California ISO's imbalance energy market, with its attendant costs. Several POUs avoid this scheduling difficulty by using a supplier that can aggregate loads and resources for several LSEs. Scheduling coordinators who provide these services to POUs include Sempra, Shell, Western, and NCPA.

Rancho Cucamonga received 8 GWh in 2008 from its Floristar landfill gas contracts, an amount expected to increase to 30 GWh in 2009.

## Findings Regarding 2009 Resource Adequacy

Utility resource adequacy plans documented the commitments by POUs to have adequate generating supplies through utility ownership or contractual agreements. These filings demonstrated that:

- The 15 largest POUs in California began 2009 with a substantial capacity surplus over their forecast peak demand plus planning reserve margins. These 15 POUs account for 95 percent of all POU peak loads statewide. This 2009 capacity surplus totaled 1,359 MW.
- Since 2001, publicly owned utilities have built or contracted for more than 3,000 megawatts (nameplate) in new generating capacity. Most of this has been for natural gas resources, but an expanding amount has been for renewable energy.
- By early 2009, the next eight largest POUs, with annual peak loads between 30 MW and 200 MW, had also acquired sufficient capacity to meet all peak load requirements for the year including planning reserve margins. Together, these eight POUs had a combined capacity surplus of 349 MW beyond their firm peak requirements.
- The 17 smallest POUs in California were also found to be resource adequate for 2009. When planning reserve margins are added, which are sometimes less than 15 percent[7], this group of POUs had a capacity surplus of 31 MW. If all these POUs used a 15 percent PRM, this group would still have a capacity surplus before counting on any short-term or spot market purchases. These 17 small POUs represent only 1 percent of all POU peak loads in California.
- In early 2009, the majority of these small POUs provided their first resource adequacy filings to the Energy Commission. This effort at completeness provides evidence that POUs, large and small, are acting prudently and responsibly to procure adequate supply resources.

[7] Anza Electric uses 12 percent; City of Industry uses 10 percent; Corona, Rancho Cucamonga, and Victorville use 7 percent; Hercules uses 5 percent; Moreno Valley uses 0 percent. WAPA uses 10 percent for its full requirements supply obligations to Lassen, Trinity, Pittsburg, and Shelter Cove. Surprise Valley, Shasta Lake, and Needles have contractual wholesale supplies from Bonneville Power Administration or WAPA whereby Bonneville and WAPA provide all appropriate reserves.

# CHAPTER 2: POU 10-Year Resource Assessment

This chapter reviews the capacity and energy plans of the larger POUs, those which serve peak loads greater than 200 MW. After an overall look at forecast capacity requirements, it addresses near-term capacity additions, expected energy needs and overall supplies, the expected role of natural gas-fired units, and the changing role of coal-fired generation. It closes with a focus on the expanding role of renewable generation. POU energy efficiency plans are not addressed in this report as they are covered in a separate 2009 IEPR report.[8] **Appendix A** summarizes each POU's current resource mix and plans.

## Aggregate Requirements for Capacity to Meet Peak-Hour Demand

Aggregate non-coincident peak load for the 15 largest POUs, not including CDWR, was forecast to drop in 2009 to 14,631 MW from a 2008 actual level of 15,042 MW. Due in part to the economy, total demand is not expected to exceed 15,000 MW again until 2014. In aggregate, POUs are forecasting peak-hour demand will increase to 15,476 MW in 2018, a net increase of 566 MW in 10 years. To scale that up to total firm requirements, utilities account for committed wholesale obligations, demand response, and a planning reserve margin. The total firm peak-hour requirement for the 15 largest POUs, including planning reserve margins, is 16,737 MW in 2009 and 17,935 MW in 2018.

POUs use two slightly different methods for computing the necessary levels of planning reserve margin (PRM); both methods are used within the Western Electricity Coordinating Council (WECC). While the WECC does not have a formal requirement for a planning reserve margin, the power supply assessment studies conducted by the WECC have used a 15 percent PRM to determine if the Western Interconnection is likely to have adequate resources. All the larger POUs in the California ISO's balancing area use a 15 percent PRM. This includes (from largest to smallest) Anaheim, Riverside, NCPA, Silicon Valley Power, Pasadena, and Vernon. In other balancing areas, a 15 percent PRM is used by SMUD, Imperial, Modesto, Turlock, and Redding.

In the LADWP balancing area, the LADWP, Burbank, and Glendale utilities use the WECC reliability criteria and reserve standards. These are detailed in the 2008 Energy Commission report on POU resource adequacy in **Appendix B**.[9] In short, these utilities plan to have

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[8] Kae Lewis and Irene Salazar, *Achieving Cost-Effective Energy Efficiency for California: Second Annual AB 2021 Progress Report*, California Energy Commission, Electricity Supply Analysis Division, June 2009, at: http://www.energy.ca.gov/2009publications/CEC-200-2009-008/CEC-200-2009-008-SD.PDF

[9] Jim Woodward, *Progress Report on Resource Adequacy Among Publicly Owned Load-Serving Entities in California*, California Energy Commission, Electricity Supply Analysis Division, May 2008, at: http://www.energy.ca.gov/2007publications/CEC-200-2007-016/CEC-200-2007-016-SF.PDF

enough resources to cover the loss of their largest generation or transmission facility without load shedding, while maintaining adequate spinning, replacement, and regulation reserves. For LADWP the system reserve requirement is normally 1,106 MW.[10]

These forecasts for peak supply were done as part of the POU resource plan filings early in 2009, using then-available utility and Energy Commission demand forecasts. These supply plans have not been changed to conform to the most recent *California Energy Demand (CED)* forecast posted by Energy Commission staff on September 14, 2009.[11] Over the entire forecast period, the revised forecasts are lower than the 2007 forecasts, primarily from worse economic conditions. Electricity consumption in *CED 2009 Revised* is down by almost 6 percent and peak demand by around 4.5 percent by 2018 compared to *CED 2007*.

# POU Capacity Plans, 2009–2018

Between 2004 and 2009, POUs added an average of 500 MW a year of utility-owned capacity. This came from 12 plants totaling 1,992 MW, through a combination of new combined-cycles, combustion turbines, repowered units, and a 101 MW wind unit. Over the next few years, the total amount of annual additions goes down compared to 2004– 2009, but the amount of renewable capacity increases.

## *Planned New Capacity Units*

Specific near-term capacity additions planned by POUs are listed in **Table 7** and **Table 8**. Some of the near-term additions are:

- By 2010, Redding expects to add 50 MW (44 MW dependable) of combustion turbines to its 135 MW Redding Power Plant.
- In 2012, Modesto plans to add a 48 MW reciprocating plant.
- By summer 2011, Anaheim expects to have 50 MW from its new Canyon Power Project, with an additional 150 MW in 2012.

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[10] For some POUs, two other factors can reduce the firm peak requirement to slightly less than 115 percent of the firm peak-hour demand. SMUD, NCPA, and Modesto have bilateral contracts for supplies that carry their own reserves. These firm imports, on which a 15 percent planning reserve margin is not required, total 137 MW in 2009, and decline to 75 MW in 2018. The other minor factor is a coincidence adjustment, used by two POUs for a 57 MW adjustment in peak demand, which translates to a 9 MW reduction in their forward procurement obligation.

[11] Chris Kavalec and Tom Gorin, *California Energy Demand 2010-2020, Staff Revised Forecast*, California Energy Commission, Electricity Supply Analysis Division, September 2009, at: http://www.energy.ca.gov/2009publications/CEC-200-2009-012/CEC-200-2009-012-SF.PDF

- By 2012, Imperial ID plans to repower the aging fossil plant El Centro #3, for an additional 180 MW, and to construct significant new geothermal resources including a utility-owned site on the east shore of the Salton Sea.
- By 2010, POUs plan to add 10 new renewable projects, including wind, geothermal, and biomass.

While these planned additions are site specific, the online dates are subject to some slippage. Looking further into the planning horizon, additions typically do not yet have governing board approvals, regulatory permits, or financing commitments, and could be affected by many load and price uncertainties.

By 2013, LADWP expects to add six combustion turbines at Haynes for 600 MW so that aging Haynes Units 5 and 6 with 565 MW can be retired. By 2014, LADWP plans to have a new 260 MW combined-cycle unit at Scattergood and a stand-alone 38 MW digester gas facility so that aging Scattergood Units 1 and 2 with 336 MW can be retired. LADWP's additions are listed in **Table 8**.

## Table 7: POU Planned Capacity Additions (Other Than LADWP), 2009–2015

| POU | Facility | MW | Year Online | Technology |
|---|---|---|---|---|
| Anaheim | Raser | 11 | 2009 | Geothermal |
| Glendale | Pebble Springs [2] | 18 | 2009 | Wind |
| NCPA | Iberdrola contract | 27 | 2009 | Wind |
| Riverside | Salton Sea additions | 26 | 2009 | Geothermal |
| Turlock ID | Tuolumne | 125 | 2009 | Wind |
| Imperial ID | Biomass unit | 15 | 2010 | Biomass |
| Pasadena | Chiquita Canyon | 7 | 2010 | Landfill gas |
| Redding | Redding Power 5-6 | 44 | 2010 | Combustion Turbines |
| Redding | Roseburg | 8 | 2010 | Biomass |
| Riverside | Energy Center addition | 98 | 2010 | Combined-Cycle |
| Anaheim | Canyon Power Project | 200 | 2011 | Combustion Turbine |
| Pasadena | Skunk Creek | 4 | 2011 | Landfill gas |
| Riverside | Shoshone Renaissance | 48 | 2011 | Geothermal |
| SMUD | Solano Phase 3 | 46 | 2011 | Wind |
| Turlock ID | Proposed Plant | 150 | 2011 | Combined-Cycle |
| Anaheim | Shoshone | 32 | 2012 | Geothermal |
| Anaheim | Ridgewood, Brea Power | 25 | 2012 | Landfill Gas |
| Imperial ID | El Centro 3 Repower [3] | 138 | 2012 | Combined-Cycle |
| Imperial ID | Geothermal unit | 100 | 2012 | Geothermal |
| NCPA [1] | Lodi Energy Center | 255 | 2012 | Combined-Cycle |
| Riverside | Shoshone additions | 48 | 2012 | Geothermal |
| SMUD | Iowa Hill | 390 | 2015 | Pumped Storage |
| | Total Nameplate MW | 1,815 | | |
| | Total MW for all POUs | 5,360 | | |

[1]Modesto ID and CDWR have 23.5 percent shares. Smaller shares will belong to NCPA Power Pool LSEs (22.9, SVP (19.6 percent), Azusa, Bay Area Rapid Transit, and Power & Water Resources Pooling Authority.

[2]Pebble Springs, Wyoming is being developed by Iberdrola Renewables under long term contract.

[3]Net increase after existing 42 MW El Centro 3 retires.

Source: California Energy Commission, POU resource plan filings, Spring 2009

**Table 8: LADWP Planned Capacity Additions, 2009–2015**

| POU | Facility | MW | Year Online | Technology |
|---|---|---|---|---|
| LADWP | Pine Tree | 120 | 2009 | Wind |
| LADWP | Willow Creek | 70 | 2009 | Wind |
| LADWP | Pebble Springs [1] | 70 | 2009 | Wind |
| LADWP | Windy Point Primary | 202 | 2009 | Wind |
| LADWP | Milford 1 | 185 | 2009 | Wind |
| LADWP | Windy Point Expansion | 60 | 2010 | Wind |
| LADWP | Linden | 50 | 2010 | Wind |
| LADWP | Project #1 phase 2 | 90 | 2010 | Wind |
| LADWP | Project #25 phase 2 | 135 | 2010 | Wind |
| LADWP | Project #28 phase 2a | 90 | 2010 | Solar |
| LADWP | Project #13 phase 1 | 25 | 2010 | Wind |
| LADWP | Project #29 | 50 | 2010 | Solar |
| LADWP | Project #27 phase 1 | 41 | 2010 | Geothermal |
| LADWP | Project #13 phase 2 | 30 | 2011 | Solar |
| LADWP | Project #11 | 150 | 2011 | Wind |
| LADWP | Project #8 | 150 | 2011 | Wind |
| LADWP | Project #10 | 250 | 2011 | Solar |
| LADWP | Project #24 | 100 | 2011 | Wind |
| LADWP | Project #27 phase 2 | 17 | 2011 | Geothermal |
| LADWP | Terminal Island Projects | 5 | 2012 | Biomass |
| LADWP | Project #3 | 175 | 2012 | Wind |
| LADWP | Project #7 | 35 | 2012 | Geothermal |
| LADWP | Project #12 | 250 | 2012 | Solar |
| LADWP | Haynes[2] | 35 | 2013 | Combustion Turbine |
| LADWP | Hyperion[3] | 38 | 2013 | Digester Gas |
| LADWP | Aqueduct Projects | 8 | 2013 | Small Hydro |
| LADWP | Solar (Owens Lake) | 200 | 2014 | Solar |
| LADWP | Pine Canyon | 150 | 2014 | Wind |
| LADWP | Pine Tree Additions | 150 | 2015 | Wind |
| LADWP | Solar (LADWP owned) | 200 | 2015 | Solar |
| LADWP | Solar (Rooftop Program) | 190 | 2015 | Solar |
| LADWP | Renew LA | 100 | 2015 | Biomass |
| LADWP | Frink Projects | 100 | 2015 | Geothermal |
| LADWP | Scattergood [4] | 81 | 2015 | Combined-Cycle |
| LADWP | Scattergood [5] | -57 | 2015 | Combustion Turbines |
| | Total Nameplate MW | 3,545 | | |
| | Total MW for all POUs | 5,360 | | |

Notes to Table 8:

[1]Net increase after existing 565 MW Haynes 5 & 6 are retired.

[2]Net increase after existing component in Scattergood is retired.

[3]Net increase after existing 179 MW Scattergood 2 retires.

[4]Net decrease after existing 157 MW Scattergood 1 retires.

Source: California Energy Commission, LADWP resource plan filing March 2009 and LADWP updates August 6, 2009

## *Total Capacity Resources 2009–2018*

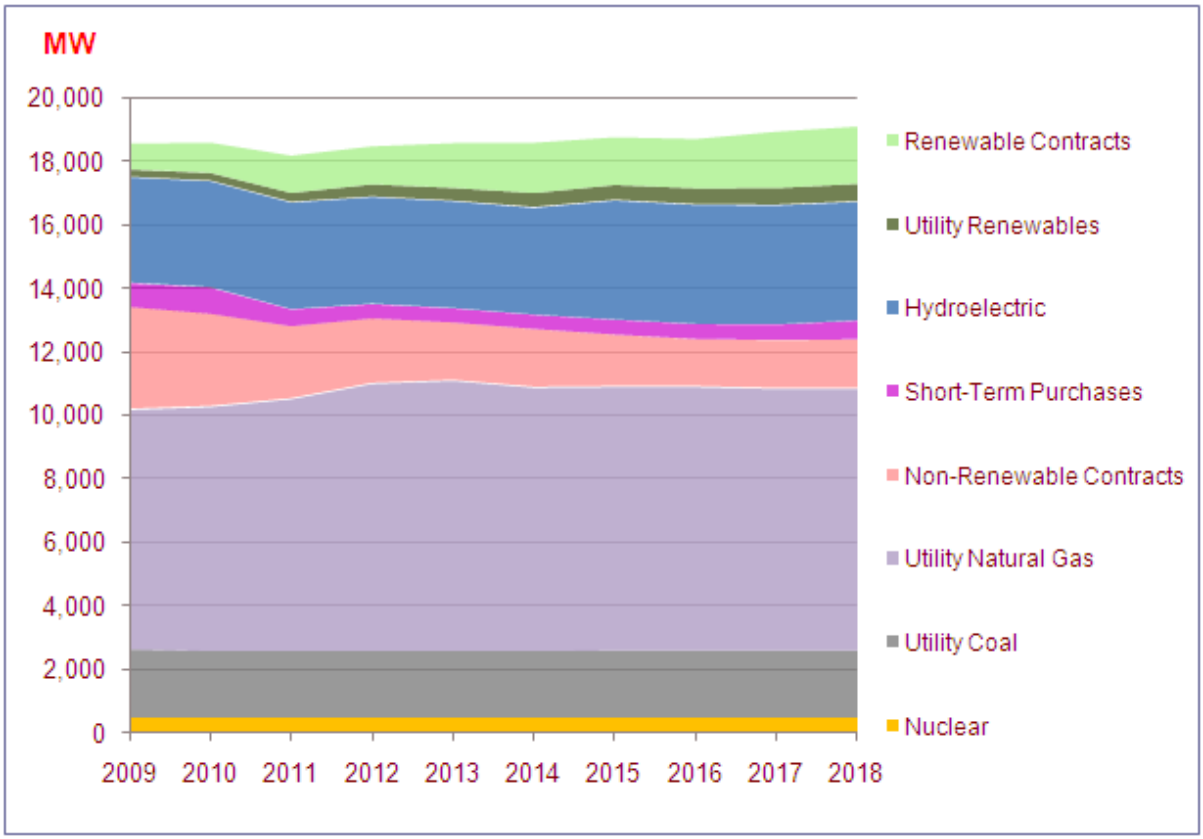
Over the forecast period, the share of conventional resources, such as gas- and coal-fired, nuclear, and hydropower capacity, will drop slightly and that of renewables will rise. However, this trend for peak capacity is much less pronounced than on the energy side, which will be discussed later. Until technology is developed either to provide storage or to increase access to renewables with higher capacity factors, conventional resources will be a backbone of capacity supplies.

POUs plan to rely on their own resources for the bulk of their capacity requirements. Utility-controlled gas- and coal-fired plants will provide 52 to 57 percent of their capacity requirements during the forecast period**. Figure 3** shows that utility fossil resources provide 9,691 MW in 2009. Utility natural gas power plants make up 41 to 46 percent of the capacity supply portfolio. By 2018, POUs plan to have 8,320 MW available from publicly owned gas plants, equal to 43 percent of all planned supply resources.

The total capacity of utility-controlled coal-fired resources is almost unchanged in the forecast period: 2,152 MW in 2009 and 2,119 MW in 2018. Coal also fuels 179 MW from four long-term contracts: Turlock counts on 56 MW from Boardman through 2018; Modesto counts on San Juan Unit 4 for 68 MW through 2030; Glendale counts on 20 MW from San Juan Unit 3 through 2030, and 35 MW from Intermountain through 2027.

On average, the POUs have an annual load factor of 51 percent to 53 percent throughout the forecast period. This is the ratio of aggregate energy requirements to the firm peak-hour demand for each year. For the largest POUs this level is not forecast to change markedly over the outlook period, though there is considerable variability among individual POUs in any given year. This stability contrasts to a statewide trend which is orienting the system more towards peak energy.

**Figure 3: Aggregate POU Capacity Resources, 2009–2018**




Source: Energy Commission, Electricity Supply Analysis Division, July 2009

Nuclear power provides approximately 2–3 percent of POU capacity during the forecast period. It is a baseload supply always expected to be available during summer months. No changes are anticipated in the amount of nuclear power to be delivered to POUs. Palo Verde and San Onofre Nuclear Generating Station provide 494 MW throughout the forecast period to seven Southern California POUs: LADWP (388 MW), Riverside (55 MW), and 9 to 14 MW each to Imperial, Burbank, Glendale, Pasadena, and Vernon. (Among the smaller POUs, Azusa, Banning, and Colton each own 2 MW shares of Palo Verde.)

Hydroelectric power is a significant resource for many northern California POUs. It provides 3,339 MW in 2009, equal to 16 percent of peak requirements. The only significant change through 2018 is SMUD's plan to add the 390 MW Iowa Hill pumped storage project in 2015. Unless there is a severe drought, hydropower can usually produce capacity for the peak summer hours, so it does not vary much from wet to dry years. On the other hand, energy production varies significantly depending on hydrological conditions.

California POUs are increasing their use of renewable resources, but the utility-controlled options they have, principally wind, provide a larger proportion of energy than peak day dependable capacity. Utility-controlled renewables other than hydro provide 217 MW of dependable capacity in 2009. By 2018, POUs expect this category to more than double to

543 MW, although it would still represent only 3 percent of annual peak requirements. Imperial is planning for significant new geothermal resources, with 100 MW in 2012 increasing to 250 MW in 2018. As a capacity resource, LADWP counts on Pine Tree Wind for 12 MW in 2009 and 27 MW after 2014, a peak power value equal to 10 percent of its maximum output. SMUD's Solano wind project is counted on for 47 MW in 2009, increasing to 91 MW in 2011.

Contracts for renewable energy have a combined capacity value of 800 MW in 2009, which more than doubles to 1,792 MW in 2018, or 9 percent of firm peak needs. By 2011, Riverside expects Shoshone geothermal energy to provide 36 MW in peak-hour power, with plans that increase this baseload supply to 96 MW in 2013. SMUD counts on existing renewable contracts for 147 MW in 2009. This increases to 194 MW during 2010-2014 as new biomass resources are developed, but then drops to 66 MW in 2016 as biomass, small hydro, and wind contracts expire.

LADWP expects the dependable capacity value of its renewable contracts to increase from 100 MW in 2009 to 925 MW in 2018. However, about 800 MW of this additional capacity is expected to be from biogas, geothermal, and wind projects that were not publicly named and under contract as of March 2009. Since then, contracts have been announced for the 55 MW nameplate Niland solar project in Imperial County to be completed in 2011, and the 50 MW Linden wind project in Washington to begin producing power in 2010.

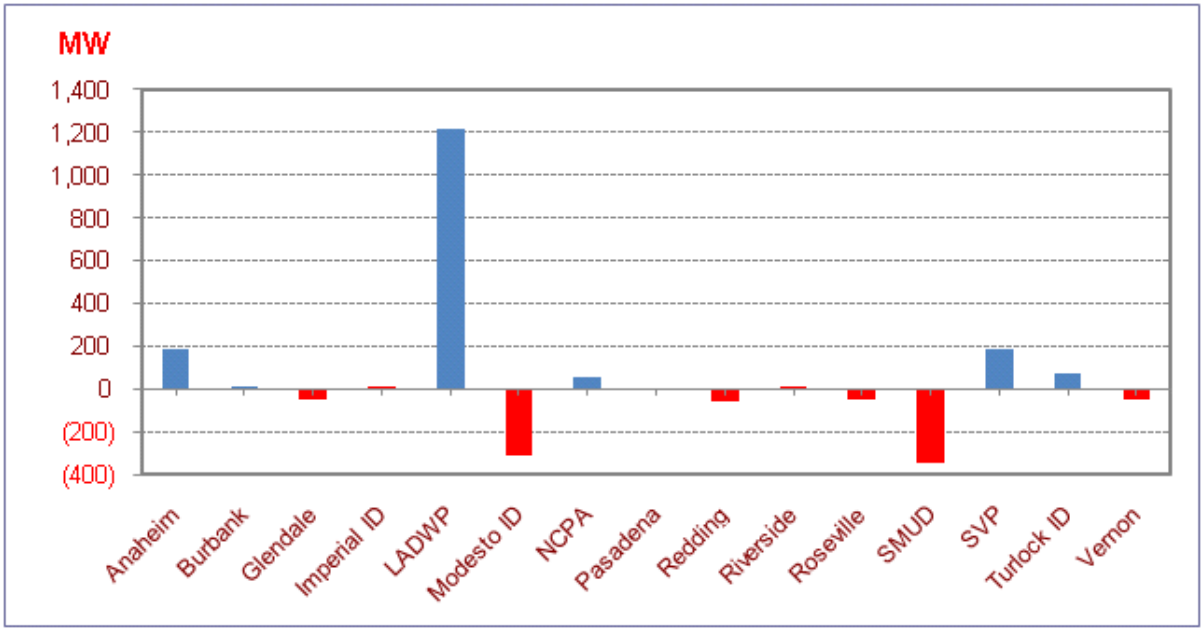
Bilateral contracts and short-term purchases provide 19 percent of 2009 forecast peak requirements. Most POUs have contracts that expire by 2018, so this share declines to 10 percent in 2018. However, three utilities count on bilateral contracts for a modest but steady supply of peak power. Every year Turlock counts on 56 MW from coal-fired Boardman in Oregon, plus 17–19 MW from San Francisco's Hetch Hetchy project, and 3 MW from Western. Silicon Valley Power has a capacity and energy exchange agreement with Seattle City Light that provides 30 MW at summer peak until 2019. LADWP has about 350 MW in customer-owned distributed generation under contract of which about 300 MW is from 20 MW or larger natural gas combustion engines. More than 700 LADWP customers have installed over 10 MW of solar photovoltaic energy systems. Typically, LADWP receives about 40 MW from all customer-owned facilities.

Short-term purchases shown in **Figure 3** represent contracts with durations less than 90 days. These aggregate amounts vary between 451 MW in 2014 and 602 MW in 2018. Short-term purchases do not identify in advance specific generating units or counterparties. When short-term purchases are included with all other existing and planned resources, these POUs in aggregate would have 103 to 108 percent of the firm peak requirement throughout the forecast period. When short-term purchases are excluded, the total of all existing and planned supply resources equals 100 to 103 percent of the firm peak requirement, which includes the planning reserve margin.

## *Capacity Resource Need/Resource Surplus in 2018*

Seven utilities will need to acquire an additional combined 866 MW by 2018. Those POUs that project a need for additional capacity have amounts shown negatively in **Figure 4**. The largest open positions are for SMUD (347 MW) and Modesto (307 MW). Although most POUs forecast slight increases in load growth, the majority of this need follows the expiration of near-term renewable contracts and other bilateral contracts in the mid-teen years. The other eight utilities project a 1,716 MW capacity surplus in 2018, if all planned resources are completed on schedule. Most of this planned surplus is from LADWP, which shows a 346 MW surplus in 2009 and a 1,211 MW surplus in 2018. As utilities move from plans to resource acquisition, the timing, type, or location of new resources may change.

**Figure 4: Surplus and Needed Capacity in 2018, Assuming All Planned Resources**




Source: California Energy Commission, Electricity Supply Analysis Division, July 2009

In general, there is no reason to believe that POUs will be unable to meet their 2018 capacity requirements either through construction or contracts. There is still an open issue, however, about how fossil-fired units needing emission credits for criteria air emissions will be constructed in the South Coast Air Basin. The South Coast power availability situation is being addressed by a forthcoming Energy Commission report.[12]

[12] For an overview of the issues, see Eileen Allen *et al*, *Potential Impacts of the South Coast Air Quality Management District Air Credit Limitations and Once-Through Cooling Mitigation on Southern California's Electricity System*, California Energy Commission, Staff Draft Paper, February, 2009, at: http://www.energy.ca.gov/2009publications/CEC-200-2009-002/CEC-200-2009-002-SD.PDF

### *Highlights of POU Capacity Resource Plans*

The following long-term trends in capacity resources needed for reliable service are based on assessment of long-term resource plans provided by California's largest 15 publicly owned utilities. In sum:

- Dependable capacity at utility-controlled gas-fired plants totaled 7,538 megawatts in 2009, equal to 41 percent of all supply resources. In 2018, the 15 largest POUs expect to maintain 43 percent of their portfolio in natural gas. Additional capacity from natural gas-fired plants is planned to meet forecast peak loads while supporting integration of renewables and reducing dependence on coal-fired energy.
- Coal-fired generation in 2007 provided 2,364 megawatts of power and 21,010 gigawatt-hours of energy. While some long-term commitments terminate during the outlook period, the majority of changes start in 2018. By 2022, as existing contracts expire, coal resources will supply 1,774 megawatts and 13,223 gigawatt-hours to the largest 15 publicly owned utilities.
- In aggregate, the publicly owned utilities have an annual load factor of 51 percent, and this level is not forecast to change markedly over the outlook period. This stability contrasts to a statewide trend which is orienting the system more towards peak energy.

## POU Energy Supplies 2008–2018

### *Energy Requirements*

The state's 15 largest POUs collectively are forecasting slow growth in the amount of energy required to meet customer demand through 2018. Dropping very slightly from 2008, combined retail sales are forecast to be 60,282 GWh in 2009 and then rising to 65,453 GWh in 2018, a 9 percent increase in ten years. They need to acquire more generation than just that to serve customer loads because of line losses and sales commitments. In 2008, the total firm energy requirement was 67,939 GWh, 10 percent more than pure retail sales.

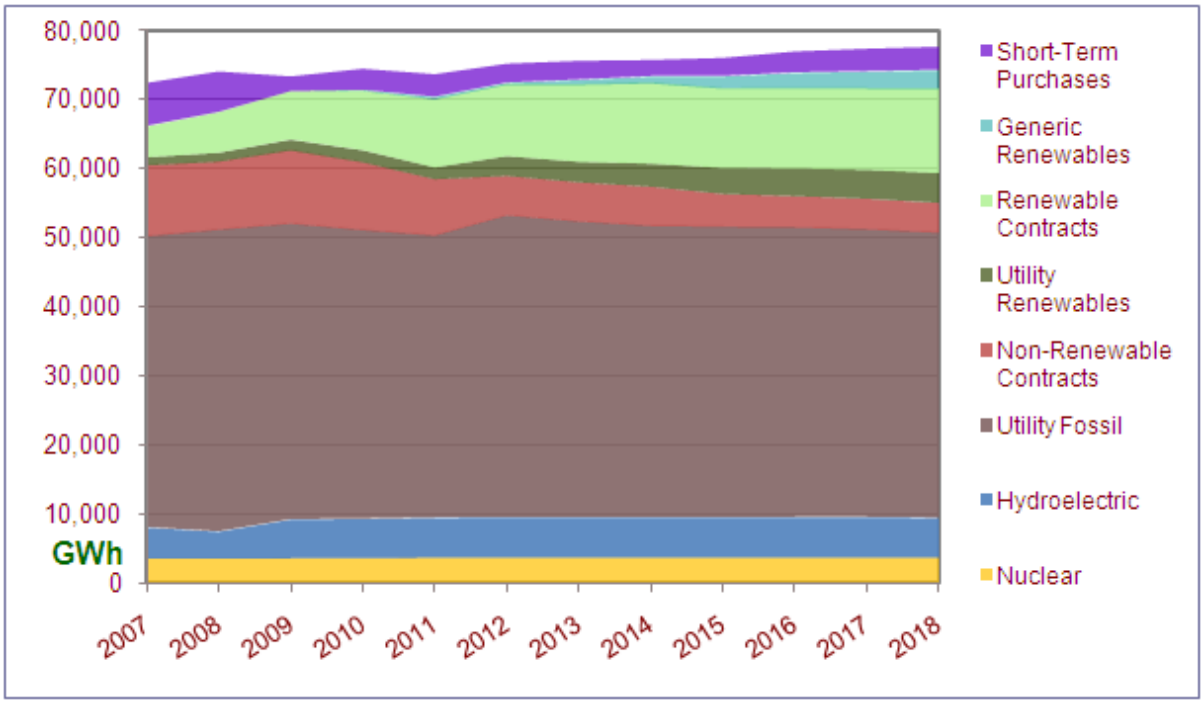
When utilities choose what resource to acquire, they have to take into account the shape of their loads, not only the absolute amounts. Loads which are steady around the clock are revealed by a high load factor, the metric comparing average to peak energy requirements. Conversely, loads that have a high peak but normally operate at a much lower level result in a low load factor. The average POU capacity factor is 51-53 percent. This does not change over the forecast period, suggesting that in aggregate these POUs are not subject to the increasing role of peak needs seen in the IOU resource plans. These average system load factors mask the tremendous difference from the heavy baseload shape and high capacity factor of Silicon Valley Power to the summer peaking pyramid and low capacity factor of the City of Redding.

## *Procurement Plans and Commitments for Energy Supplies*

Several POUs have recently developed utility-controlled fossil-fuel plants as part of their long-term resource portfolio, and some have been adding renewables. Through 2018, the content of energy supplies is expected to show more change than the portfolio of capacity resources. Utilities plan to add substantial quantities of renewable energy supplies, and this will reduce the share of electricity generated by fossil fuels.

**Figure 5** presents a combined profile of POU energy supplies, including all planned resources as reported on supply forms submitted to the Energy Commission in early 2009. The most significant trend is an increased supply of electricity from renewable sources, especially those to be developed under long-term contracts. The following sections describe the status of each major resource type within POU portfolios.

**Figure 5: Annual Energy Supply Procurement, 2007–2018**




Source: California Energy Commission, Electricity Supply Analysis Division, September 2009

## *Nuclear and Hydroelectric Energy Supplies*

Nuclear and hydropower are low carbon backbone resources for the POUs As shown at the base of **Figure 5**, Palo Verde and San Onofre are expected to provide a steady 3,600 GWh per year throughout the forecast period. Riverside is the only utility to own shares in both Palo Verde and San Onofre nuclear generating stations; all other POUs take their nuclear energy from Palo Verde, including Burbank, Glendale, Pasadena, Vernon, and Imperial.

LADWP takes the largest share among California POUs at 2,856 GWh. (Among the smaller utilities, Azusa, Banning, and Colton take about 17 GWh per year from Palo Verde.)

Hydroelectric energy is also a significant supply component for these utilities at an average 5,800 GWh per year. In dry 2007, these utilities still had 4,525 GWh and followed by 3,929 GWh in 2008. Large and small resources include SMUD's utility-owned hydro, entitlements from Hoover Dam, and aqueduct plants operated by water divisions of the LADWP and Imperial Irrigation District. Contracts with Western for energy from Hoover Dam expire in the fall of 2017, and POUs expect to renew these relatively low cost dispatchable supplies of clean energy. No significant new sources of hydroelectric energy are expected through 2018.

## *Fossil Fuel Energy Supplies Owned by POUs*

Owned and contractual coal-fired energy supplies are assessed in detail in a later section of this chapter.

Energy supply from collective utility fossil resources is expected to remain relatively unchanged, starting at 42,557 GWh in 2008, and ending the forecast period at 40,785 GWh in 2018. Utility fossil plants produced 63 percent of electricity required in 2008. Because of renewables, this share declines slightly to 57 percent in 2018. For individual utilities, the utility fossil share of total energy requirements will change by 5 percent or less, up or down, for Anaheim, Glendale, Pasadena, Riverside, SMUD, and Vernon.

For other utilities, the absolute amounts and the share of fossil resources in a portfolio will change significantly. Burbank plans to reduce energy supplies from coal-fired Intermountain and gas-fired Magnolia, from 1,048 GWh in 2008 to 748 GWh in 2018. Riverside forecasts utility fossil supply to decline from 1,333 GWh in 2008, to 1,096 GWh in 2018. By volume, the largest reductions in utility fossil supplies are forecast by LADWP, from 20,671 GWh in 2008, to 15,051 GWh in 2018.

In relative terms, the largest increase for utility fossil is in the NCPA portfolio, which has a very low carbon footprint. Adding any natural gas raises their fossil-fired share. Their fossil generation is expected to grow from 74 GWh in 2008 (3 percent of requirements) to 265 GWh in 2018 (9 percent of requirements) based on NCPA's share of the planned Lodi Energy Center. By volume, the largest increases in utility fossil energy over the next ten years are for Imperial (from 4,695 GWh to 5,662 GWh), for Redding (from 210 GWh to 883 GWh), and for Silicon Valley Power (from 816 GWh to 1,408 GWh).

One utility is noteworthy for having utility fossil energy supplies that exceed the annual energy requirement. Anaheim expects about 1,800 GWh from coal-fired Intermountain in Utah, 350 GWh from coal-fired San Juan Unit 4 in New Mexico, and 500 GWh from gas-fired Magnolia in Burbank. These are continuous baseload supplies of must-take energy, except when these plants are offline due to outages. The Anaheim combustion turbine plant is used to meet peak demand for about 50 GWh per year, and Canyon Power Project will provide

another 30 GWh of peak period energy starting in 2012. The Canyon Power Project will also help Anaheim meet its local capacity requirement, currently 308 MW. Together, this fossil energy supply equaled 102 percent of energy requirements in 2008. Given load growth, this share will decline to 86 percent in 2018. Anaheim used spot markets and short-term contracts to sell 473 GWh in 2007, a net amount over any purchases, and 114 GWh in 2008. As Anaheim increases its purchases of renewable energy supplies, Anaheim will continue to sell surplus energy in amounts that average 550 GWh per year.

## *Non-renewable Contractual Energy Supplies*

Non-renewable energy from existing bilateral contract supplies is typically expected to decline over time as contracts expire. Imperial's contracts with El Paso Electric and Shell Energy North America will expire by the end of 2011. The 1,708 GWh supplied annually from these contracts will largely be replaced by 1,261 GWh from repowered El Centro Unit 3, planned to be operational in 2012.

Short-term and spot market purchases in 2007 and 2008 averaged 6,376 GWh, much larger than the average for all forecast years: 3,395 GWh. This difference is not significant. Utilities plan to have adequate energy supplies for all hours in a year, primarily using utility-owned fossil plants to ramp up and down, synchronized to daily and seasonal rhythms in demand and to integrate intermittent renewable energy as it becomes available. While sometimes needed for local reliability, many of the older fossil plants have high heat rates and are expensive to operate. Whenever cheaper energy supplies are available from other parties, utilities will lower their costs by replacing utility-owned generation with market purchases from merchant generators, wholesale energy marketers, and from other utilities with surplus energy. For example, Turlock purchased 1,180 GWh and 1,021 GWh in 2007 and 2008 using short-term contracts, but does not plan to rely on such purchases for any of its energy needs.

## *Coal-Fired Energy Supply, 2007–2020*

Twelve POUs have coal generation in their portfolios in 2010. **Table 9** lists POU ownership and contracts for coal-fired generation, sorted by the final year when each resource is expected to be used, if known. Nine POUs have partial ownership of such resources, either directly or through their participation in groups of POUs, such as the Southern California Public Power Agency's ownership interests in a portion of the San Juan power plant. The remaining seven resources are all partially owned by POUs with life expectancies well beyond 2020. Even when an ownership share or contract ends, that does not mean necessarily that the plant will be retired. That decision will be made by the consortiums which own the units.

Five POUs hold eight contracts for four different coal-fired resources: Boardman, Navajo, Intermountain, and San Juan. Individual contracts will expire on December 31 in 2018, 2019, and 2024. Two more contracts expire on December 31, 2026.

For the 15 largest POUs in California, coal-fired generation provides 14 percent of their capacity in 2010, and 29 percent of the firm energy requirements. Between 2018 and 2020, some 555 MW (24 percent) and 5,949 GWh (31 percent) of coal-based electricity supply contracts will expire.

These long-term resources cannot be extended or replaced with other coal resources because of the state's Emission Performance Standard. The remaining forecasted capacity of 1,774 MW and 13,227 GWh will remain in the portfolios through the late 2020's and beyond, unless the utilities actively divest their ownership shares in coal-fired generation.

The City of Riverside's contract with Utah Power and Light for capacity and energy from the Deseret Power Plant expired in 2009, according to its resource plan filing. The City of Los Angeles has announced plans to reduce or eliminate its reliance on coal-fired generation by 2020.[13] Specifics about how LADWP intends to do this are unknown.

**Table 9: POU Coal-Fired Generation with Final Years of Use (If Known)**

| POU | Power Plant | Ownership or Contract | Dependable Capacity (MW) | Annual Energy (GWh) | Expected End of Contract or Ownership |
|---|---|---|---|---|---|
| Turlock ID | Boardman | Contract | 56 | 420 | 12/31/2018 |
| LADWP | Navajo | 21% Ownership | 477 | 3,760 | 12/31/2019 |
| Anaheim | Intermountain | Contract | 236 | 1,831 | 12/31/2024 |
| LADWP | Intermountain | 45% Ownership | 803 | 6,519 | 12/31/2026 |
| LADWP | Intermountain | 4% Purchase from Utah Power & Light | 72 | 579 | 12/31/2026 |
| Glendale | Intermountain | 3% Ownership | 35 | 158 | 6/15/2027 |
| Pasadena | Intermountain | 4% Ownership | 108 | 759 | 6/15/2027 |
| Glendale | San Juan | Contract | 20 | 78 | 10/31/2030 |
| Anaheim | San Juan | 10% Ownership | 50 | 336 | |
| Burbank | Intermountain | 3% Ownership | 64 | 487 | |
| Imperial ID | San Juan | Part of SCPPA 41.8% Ownership | 102 | 715 | |
| Riverside | Intermountain | 8% Ownership | 37 | 1,078 | |
| Modesto ID | San Juan | Part of M-S-R's 4% Ownership | 68 | 527 | |
| SVP | San Juan | Part of M-S-R's 4% Ownership | 51 | 390 | |
| Redding | San Juan | Part of M-S-R's 4% Ownership | 50 | 191 | |
| | | Totals | 2,229 | 17,829 | |

Source: California Energy Commission, Electricity Supply Analysis Division, September 2009.

## *Energy Supply Needs/Surpluses by 2018*

On supply form S-2, the Energy Balance Table, many utilities such as Anaheim used line 20 amounts for short-term purchases/sales to balance total supply and demand. Other utilities,

[13] See http://www.energy-business-review.com/news/ladwp_plans_to_eliminate_coalfired_power_generation_to_reduce_gas_emissions_090702, accessed July 14, 2009.

as was their choice, indicated net long and net open positions on line 22 to show additional energy procurement needs and surpluses. The annual sums of these remaining energy needs and surpluses are shown in **Figure 6**.

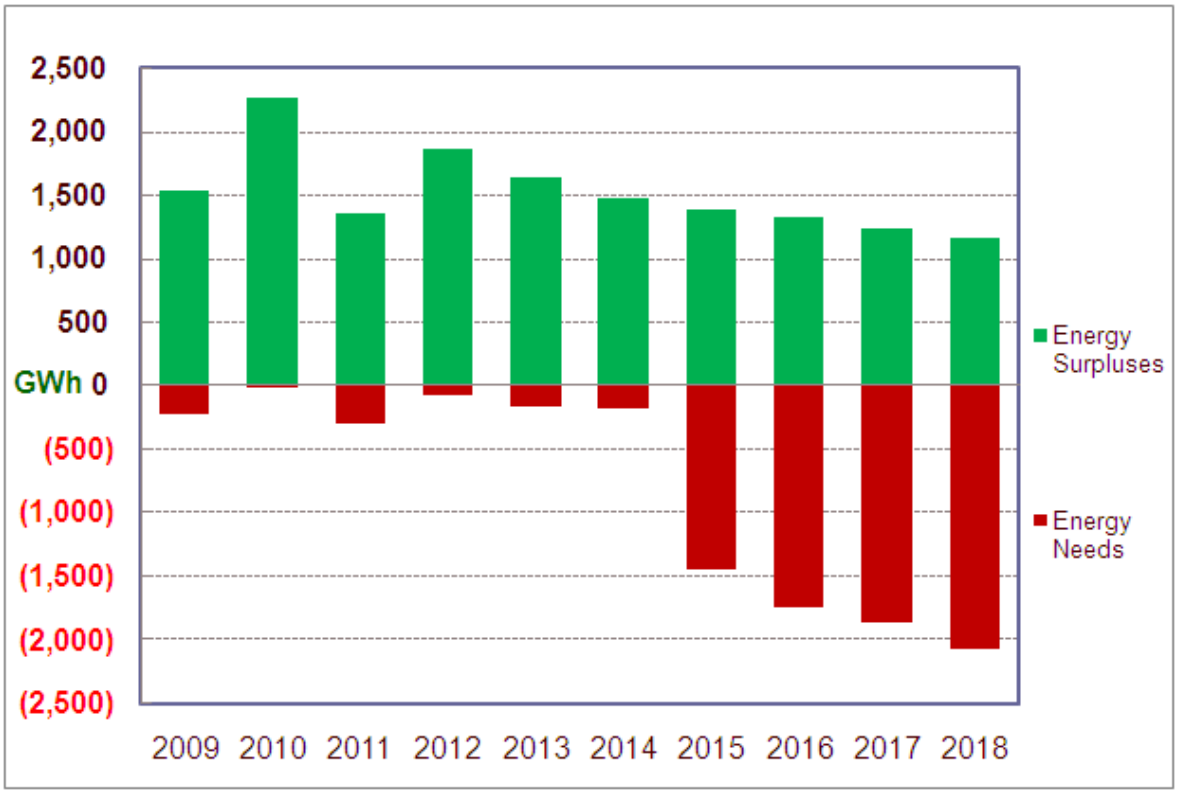
The bulk of surplus energy in **Figure 6** is attributable to Turlock Irrigation District, which shows an average annual surplus of 1,121 GWh, ranging from an 828 GWh surplus in 2009, to a 1,328 GWh surplus in 2012. Two factors explain most of this apparent surplus. First, the resource plan by TID shows the 238 MW Walnut Energy Center producing 1,540 GWh each year (73 percent capacity factor), the 49 MW Almond plant generating 173 GWh each year (40 percent capacity factor), and a 150 MW "Proposed Power Plant" generating 460 GWh each year after 2011 (35 percent capacity factor). Second, much of this surplus energy will likely be made available to Merced Irrigation District, which needs about 450 GWh per year. TID currently supplies Merced with 100 percent of Merced's capacity, energy, and ancillary services requirements beyond the 10 GWh supplied by Western. The Energy Balance Table submitted by TID shows a surplus of *potential* fossil-fuel energy that exceeds the requirements of serving its own end-use customers.

Imperial submitted a similar Energy Balance table, showing *potential* surplus energy that averages 3,615 GWh per year, an amount that was not included in **Figure 6**. Imperial's 102 MW share of San Juan Unit 3 provides 715 GWh of imported must-take energy each year. However, there is some discretionary dispatch for the utility's Brawley, Coachella, El Centro 3-4, Rockwood, Yuma Axis, and Niland fossil power plants, which together are shown at 3,686 GWh each year. For Imperial this *ex post* potential surplus was 3,241 GWh in 2007 and 3,743 GWh in 2008.

It is reasonable to attribute all the surplus energy depicted in **Figure 6** to utility-controlled fossil resources. It is also reasonable to expect most of the surplus energy will only be generated if total energy requirements increase, or when future buyers are found.

From the data filings, all the residual energy needs identified by POUs are for renewable energy. This generic need is established by the adopted renewable portfolio standard targets for each utility, and for which the utility has not yet identified matching supply resources.

**Figure 6: Additional Needs for Energy and Surplus Energy, 2009–2018**




Source: California Energy Commission, Electricity Supply Analysis Division, July 2009

## *Highlights of POU Energy Procurement Plans*

The following trends in energy procurement are based on an assessment of long-term resource plans provided by California's largest 15 publicly owned utilities. In sum:

- Utilities are forecasting slow growth in the amount of energy required to meet customer demand: a 9 percent increase in ten years to 65,453 GWh 2018.
- Energy supply from utility fossil resources is expected to remain relatively unchanged, starting at 42,557 GWh in 2008, and ending the forecast period at 40,785 GWh in 2018. Utility fossil plants produced 63 percent of electricity required in 2008. This share declines to 57 percent in 2018.
- Coal-fired generation in 2007 provided 21,010 gigawatt- hours of energy. While some long-term commitments terminate during the outlook period, the majority of changes start in 2018. By 2022, as existing contracts expire, coal resources will supply 13,223 GWh.

## Renewable Energy Supplies

Although POUs have flexibility under state law to define what counts as renewables under California's Renewables Portfolio Standard (RPS), they have largely chosen to set their plans using the same categories as those used by the IOUs. Some POUs count all hydroelectric energy as renewable, including entitlements from Hoover Dam. For example, Hoover is the only existing or planned renewable energy for Vernon. However, for all hydroelectric energy from hydropower plants larger than 30 MW nameplate, only 30 percent is counted by individual POUs for their individual RPS targets. LADWP does not count as energy from Hoover or Castaic, and SMUD does not count any large hydro energy supply as renewable.

Additional wind energy is in the forefront during the early years, especially from newly developed projects in Washington, Oregon, Wyoming, and Utah. Geothermal energy supplies will increase substantially in a few years from new projects near the Salton Sea and in Utah. LADWP and SMUD expect their solar project initiatives to ramp up significantly towards the end of the forecast period, using a mix of incentive programs and utility-financed development programs.

### *Renewable Energy and Retail Sales, 2007–2018*

Individual utility RPS targets are shown in **Table 10**. LADWP has a target to reach 35 percent or more in 2020. SMUD has a near-term target to reach 20 percent in 2010, and also has a goal of 33 percent in 2020.[14] Burbank, Riverside, and Imperial have adopted RPS targets of 30 percent or more by 2020.

The term "POU qualifying" includes all LSE-defined renewable energy that would not or may not be eligible for the RPS of an investor-owned utility (also called Energy Commission-eligible). For the largest 15 POUs, the annual amount of POU qualifying renewable energy is relatively small and stable over time. The subject is discussed in greater detail in a later section of this chapter.

Taken together, the resource plans for the 15 largest POUs show their renewable energy portfolios will increase significantly from 2007 to 2018. In 2007 renewable energy supplies for these 15 POUs equaled 12 percent of all retail sales (POU qualifying), or 8 percent (Energy Commission-eligible). In 2018, the weighted average of renewable energy indicated their combined resource plans would yield 31 percent (POU qualifying), or 30 percent (Energy Commission-eligible).

Ten POUs have resource plans indicating how their RPS targets can be met by 2012. Except for Vernon, each POU submitted resource plans that would reach at least 19 percent by 2017 counting all POU-qualifying renewables. Vernon provided a resource plan that does not show how its 20 percent in 2017 target would be met or increased from current levels.

[14] See http://www.smud.org/en/community-environment/climate-change/Pages/index.aspx

Vernon has recently rescinded its interim RPS target of 5 percent in 2009, but has subsequently purchased land for potential wind farm projects.[15]

**Table 10: POU-Defined RPS Targets and 2008 Procurement**

| POU | 2008 | *Target* | |
|---|---|---|---|
| Anaheim | 6.3% | 20% | 2015 |
| Burbank | 1.3% | 33% | 2020 |
| Glendale | 13.9% | 20% | 2017 |
| Imperial | 7.9% | 30% | 2020 |
| LADWP | 7.2% | 35% | 2020 |
| Modesto | 11.5% | 20% | 2017 |
| NCPA | 38.0% | various | |
| Pasadena | 13.2% | 20% | 2017 |
| Redding | 27.7% | 20% | 2017 |
| Riverside | 9.3% | 33% | 2020 |
| Roseville | 18.3% | 20% | 2017 |
| SMUD | 19.7% | 33% | 2020 |
| SVP | 27.8% | 33% | 2020 |
| Turlock | 4.4% | 20% | 2017 |
| Vernon | 1.7% | 20% | 2017 |

Source: California Energy Commission, Electricity Supply Analysis Division, September 2009

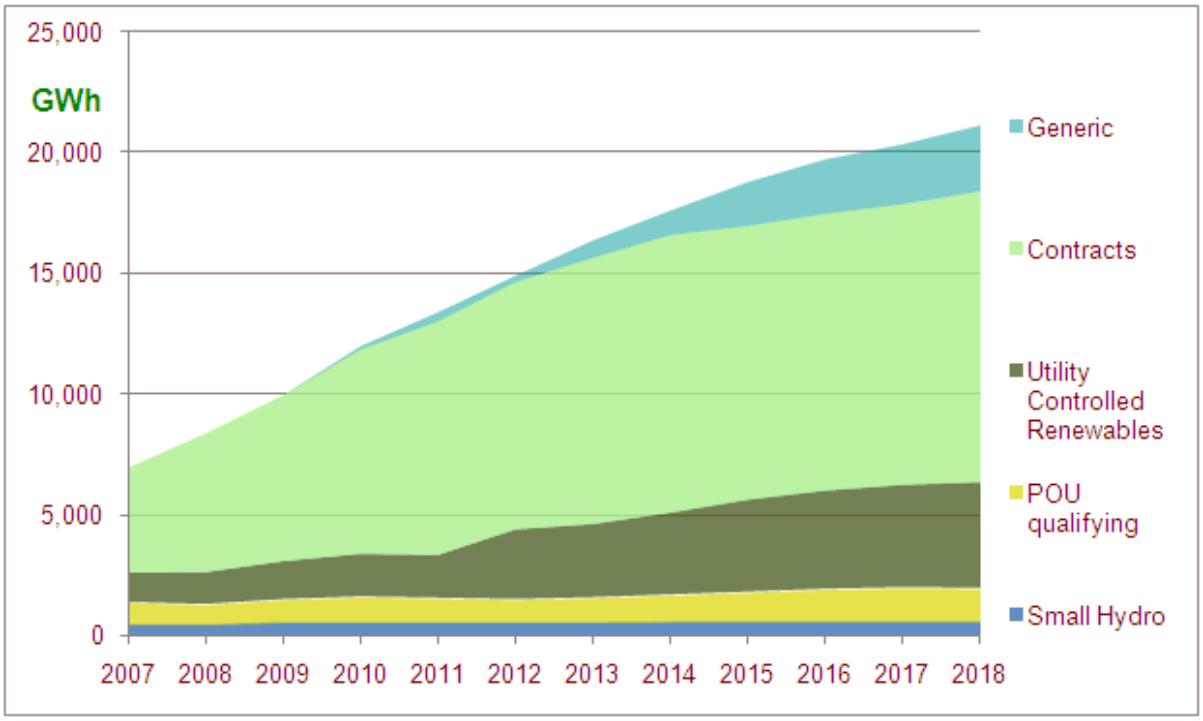
**Table 10** shows actual procurement in 2008 of POU qualifying renewable energy as a percent of retail sales. POUs in 2008 had widely varying amounts of renewables in their resource mixes. For many POUs, their adopted RPS targets represent a steep ramp from current renewables holdings. Redding and Silicon Valley Power have already met their RPS percentage targets, though continued renewable procurement will be needed to maintain these levels with forecast load growth, and to replace existing supply contracts that will expire.

POUs may acquire renewable energy supplies through utility-controlled facilities, specific contracts, and generic future acquisitions. Most POUs will be growing their renewables portfolios through contracting, unlike their high reliance on utility-controlled assets for resource adequacy. The second biggest growth strategy is utility-controlled sources. In addition to specific contractual and utility-controlled projects, a few POUs use renewable short-term contracts or spot market purchases to fill in the gaps from year to year. Plans to use short-term contracts and spot market purchases are similar to listing unspecified projects that will be needed to meet RPS targets in that all can be grouped as a generic procurement category.

[15] See http://www.latimes.com/news/local/la-me-wind15-2009sep15,0,839175.story?page=3

As shown in **Figure 7**, contracts account for the largest increases in renewable energy supplies when all planned resources are included. In 2008, contracts provided 5,765 GWh of renewable energy, equal to 65 percent of all such supplies for the 15 largest POUs. These aggregate amounts would rapidly increase to 10,312 GWh in 2012, with further gradual increases to 12,108 GWh in 2018. Renewable energy delivered under contractual terms provided 69 percent of POU renewable supplies in 2008. While contracted renewable energy supply is expected to grow in quantity, the share of all such energy would be 57 percent in 2018 under these combined assumptions.

**Figure 7: Actual and Planned POU Renewable Energy, 2007–2018**




Source: California Energy Commission, POU resource plan filings, Spring 2009

Over the next 10 years, significant increases in contracted renewables are expected by:

- Anaheim (163 GWh to 1,012 GWh)
- Burbank (15 GWh to 456 GWh)
- LADWP (2,498 GWh to 6,327 GWh)
- Modesto ID (299 GWh to 650 GWh)
- Riverside (170 GWh to 1,307 GWh)
- Turlock ID (60 GWh to 473 GWh)

SMUD has several existing renewable contracts that expire during the forecast period. Since SMUD did not include planned but unspecified future contracts in this category, renewable contractual supply to SMUD declines from 1,581 GWh in 2008 to 488 GWh in 2018. Imperial has no plans to begin contracting for renewable energy deliveries.

The 15 largest POUs are planning to ramp up utility-controlled renewables from 1,318 GWh in 2008 to 4,378 GWh in 2018 as shown in **Figure 7**. The largest 10-year increases would be in the portfolios of Imperial ID (0 GWh in 2008 to 1,973 GWh in 2018), LADWP (154 GWh to 913 GWh), and SMUD (266 GWh to 677 GWh). Glendale forecasts a steady 86 GWh per year from utility-controlled facilities. Riverside and Burbank have no utility-controlled renewable resources, and the resource plans indicate this may continue.

As shown in **Figure 7**, most total amounts of POU qualifying renewable energy is relatively small and stable over time. Most of this POU-defined renewable energy will be generated by large hydroelectric facilities such as Hoover. The slight increase in 2009 reflects a return to median 1-in-2 forecasts for this supply after two exceptionally dry years in 2007 and 2008.

## *Renewable Energy Supply by Source Technologies, 2007–2018*

Source technologies for renewable energy supplies are summarized through 2012 in **Figure** 8. The amounts in forecast years include all existing and planned resources with a specified technology type, though some project sites or counterparties are not yet publicly identified. In 2007, the largest share came from wind (1,668 GWh), closely followed by geothermal (1,613 GWh). Wind energy is expected to increase quickly and substantially, with several new projects coming online in 2009. Geothermal also scales up in the next few years, with solar emerging later in the decade.

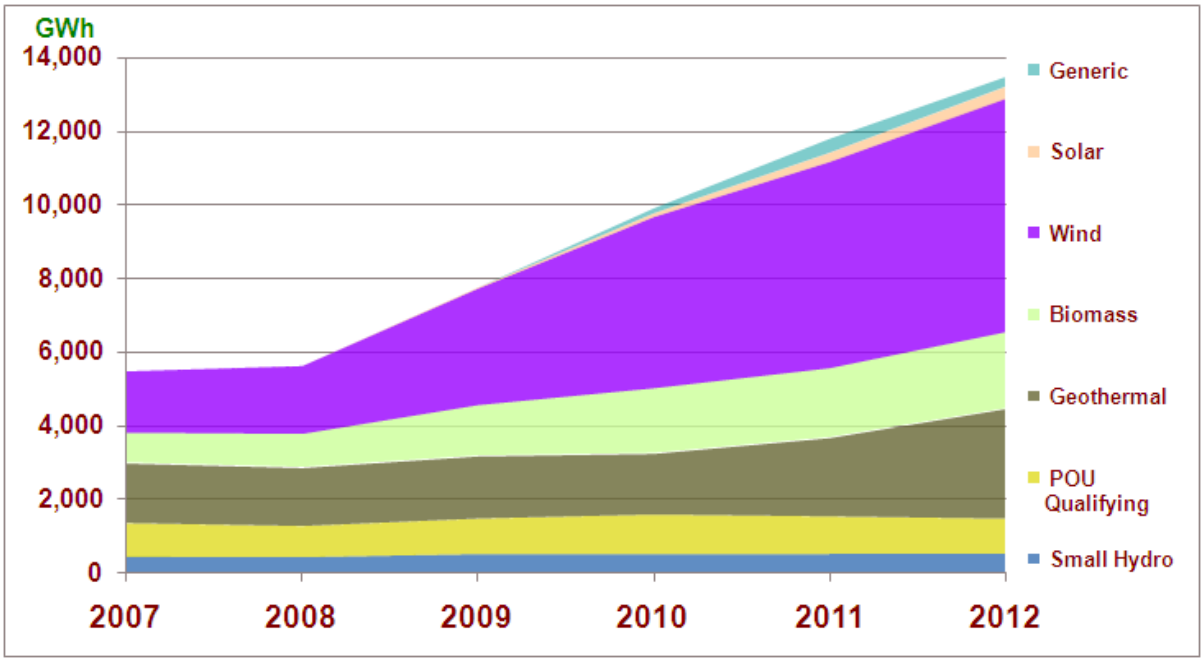
Riverside is the leader in contracts for new geothermal energy, with major increases expected in 2009, 2012, and 2013. NCPA and Silicon Valley Power have developed utility-owned geothermal resources in the Geysers. Imperial ID plans to develop its own geothermal resources expected to produce 745 GWh in 2012 and 1,862 GWh in 2018.

Biomass energy will more than double, from 818 GWh in 2007 and 906 GWh in 2008, to 1,764 GWh in 2010 and 2,347 GWh in 2018. This would include 800 GWh in as-yet-unspecified biogas projects for LADWP. The majority of resources in this category involve contracts with local landfills.

Solar projects are few through 2010, but are expected to grow rapidly thereafter to 919 GWh in 2014 and 1,855 GWh in 2018. This includes as-yet-unspecified projects by LADWP and Burbank. LADWP and SMUD include the renewable energy attributes of customer-owned distributed generation, especially solar roofs, being developed in the California Solar Initiative. In 2012, these solar projects will contribute 150 GWh and 54 GWh for LADWP and SMUD, respectively. In 2018, CSI may supply 648 GWh to LADWP and 183 GWh to SMUD. These would be significant increases from 2009: 18 GWh for LADWP and 9 GWh for

SMUD. For many projects, customers may be the facility owners while POUs retain the credits for renewable energy production, as envisioned by SMUD. For statistical purposes, all such solar initiatives are categorized in this report as Energy Commission-eligible.

**Figure 8: Renewable Energy Supplies by Technology Type, 2007–2012**




Source: California Energy Commission, POU resource plan filings, Spring 2009

Generic resources shown in **Figure 8** represent utility commitments to meet their adopted renewables portfolio standards. How these commitments will be met with specific resources under contract or being developed is often unknown for the later part of the planning horizon. This category includes plans and commitments by some to purchase as-available renewable energy in spot markets and with short-term contracts. It may also include renewable energy credits (RECs). Several POUs consider tradeable REC purchases to be a valid option for meeting adopted RPS targets in future years, but for now tradeable REC purchases are uncommon.

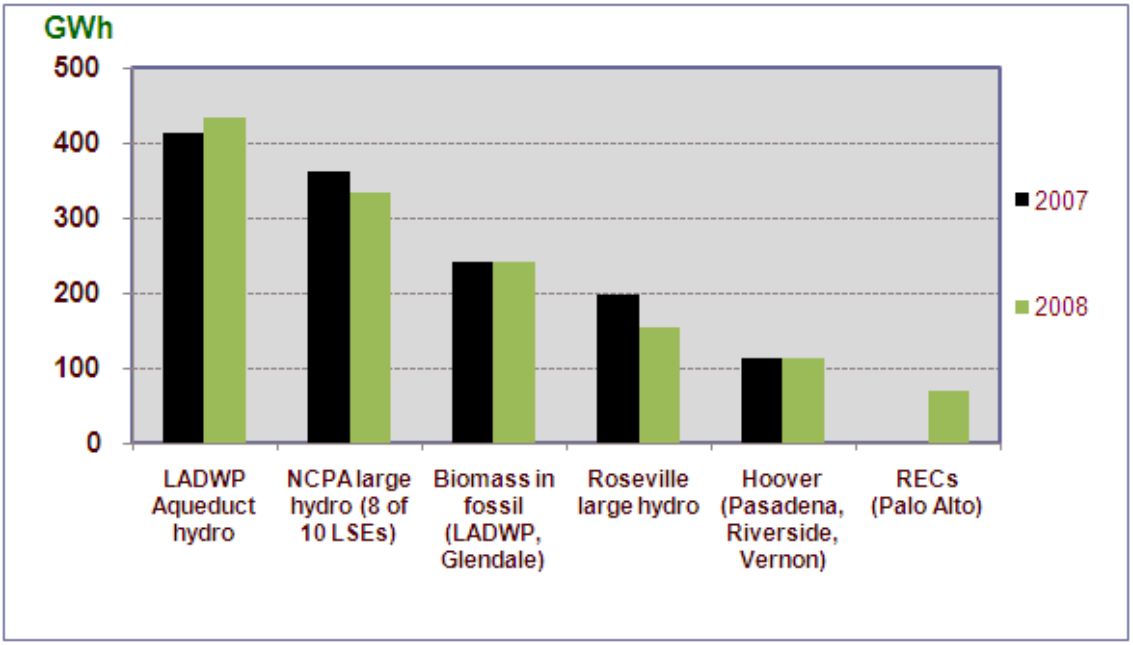
## *POU-Defined Renewable Energy Supply*

In accord with state law which gives POUs the latitude to define what counts as eligible for RPS, there are several conventions that define what counts as renewable energy. These conventions are summarized in **Figure 9**.

LADWP counts as renewable all the energy from its Gorge and Aqueduct hydroelectric plants. Those powerhouses with output larger than 30 MW nameplate annually generate about 650 GWh. (LADWP does not count as renewable approximately 1,100 GWh per year from Hoover or Castaic.)

Glendale and LADWP include energy from landfill gas and digester gas burned with fossil fuels in their Grayson and Scattergood plants, 86 GWh and 147 GWh, respectively. For CPUC-jurisdictional LSEs to count 100 percent of the biomass combustion as renewable energy, it must occur in a facility that does not use more than a de minimus of 2 percent fossil fuel. For multi-fuel facilities that use more fossil fuel than the de minimus, only the renewable portion of their generation will count as Energy Commission-eligible, and only when the Energy Commission has approved a method to measure the renewable portion.[16]

**Figure 9: POU-Defined Renewable Energy, 2007 and 2008**




Source: California Energy Commission, Electricity Supply Analysis Division, September 2009

The 10 POU members of NCPA Power Pool have each adopted their own RPS goals, with significant diversity in timeframes and counting conventions. In the NCPA Power Pool, eight POUs count large hydro as renewable, as shown in **Figure 9**, although these eight POUs make only 57 percent of all retail sales by Power Pool POUs. The largest utility in the NCPA Power Pool, Palo Alto, does not count large hydro as renewable. Palo Alto had a 195 MW peak load in 2008. Palo Alto's RPS aims for 20 percent in 2008, 30 percent in 2012, and 33 percent in 2020, without including energy from large hydroelectric facilities.

The NCPA filing includes a 10-year forecast of loads and resources, but does not include a disaggregated forecast of retail sales or LSE-defined renewable energy. The filing does, however, allow for calculations of procurement that would count as eligible renewable energy resources for IOUs and ESPs. In 2008, Energy Commission-eligible renewable energy

[16] For more details on multiple fuel facilities, see the *Renewable Portfolio Standard Eligibility Guidebook,* California Energy Commission, January 2008, at:
http://www.energy.ca.gov/2007publications/CEC-300-2007-006/CEC-300-2007-006-ED3-CMF.PDF

totaled 594 GWh, and is forecast to reach 751 GWh for 2010 through 2017. These amounts equal 23 percent of total energy consumption in 2008, and 27 percent in 2017. The 38 percent figure in 2008 for all POU qualifying energy is an estimate by Energy Commission staff.

As another example of POU-defined renewable energy procurement, the City of Palo Alto purchased RECs to help meet its RPS goals. In 2007 and 2008, SMUD purchased 219 GWh in unbundled renewable energy credits for customers enrolled in its "Greenergy" green pricing program. SMUD does not count REC purchases for the Greenergy program towards the utility-adopted RPS targets.[17]

Riverside, Roseville, Pasadena, Vernon, and LADWP include 982 GWh per year from large hydroelectric facilities as LSE-defined renewable energy. For LADWP this includes only aqueduct plants, and not Hoover or Castaic.

## *Highlights of POU Renewable Resource Plans*

The following milestones use weighted averages for the largest 15 POUs and include all planned procurement. The amounts and percentages use POU qualifying renewable energy (unless noted otherwise). In sum:

- The state's 15 largest POUs produced or purchased renewable energy equal to 11.6 percent and 12.4 percent of their retail customer sales in 2007 and 2008, respectively. In 2008, this constituted 7,500 GWh of renewable energy.
- For 2009, renewable energy was forecasted to be 10,400 GWh, equal to 17 percent of customer sales. This increase largely reflects new wind and geothermal in California and elsewhere that are coming on line in 2009.
- Assuming all planned resources come to fruition, POUs will use 20,600 GWh of renewable energy in 2018, equal to 31 percent of retail sales. By energy volume, this would be a 175 percent increase from 2008. (When only Energy Commission-eligible renewables are counted, the share increases from 10 percent in 2008 to 30 percent in 2018.)
- Utility-controlled supplies made up 16 percent of renewable energy procurement in 2008, and could be 21 percent in 2018. These volumes will more than triple in ten years from 1,300 GWh to 4,400 GWh.
- Contracts provided 5,800 GWh and 69 percent of all renewable supplies in 2008. If plans hold, these volumes will increase to 10,100 GWh in 2018. Contracts would then represent 57 percent of all renewable energy procurement.

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[17] SMUD's adopted RPS target is 20 percent by 2010, and 33 percent by 2020, not including the Greenergy program. SMUD notes this 20 percent target in 2010 is actually 23 percent renewable, with 3 percent attributed to the Greenergy program. The majority of Greenergy projects are bundled renewable energy. In formal comments to the Energy Commission on August 21, 2009, SMUD noted "SMUD's policy is to use the state's definition of eligible renewable in its adopted RPS program."

- Wind provided 30 percent of all renewable supplies in 2007 and 33 percent in 2008. The share of renewable energy from wind will increase to 47 percent in 2010–2012, and then decline back to 33 percent in 2018 as new geothermal and solar resources come online.
- Geothermal energy supplied 28 percent of all renewable supplies in 2008. This share declines to 17 percent in 2010 as new wind resources come online, and then gradually increases to 25 percent in 2018.
- Biomass combustion, including landfill, digester gas, and other organic wastes, provided 16 percent of all renewable energy in 2008. Volumes are expected to grow significantly from 900 GWh in 2008 to 2,300 GWh in 2018, an 11 percent share in 2018.
- Solar energy was a negligible supply in 2008. Solar is expected to pass the 100 GWh mark in 2010 for a 1 percent share that year. If solar is developed to supply 1,900 GWh in 2018, that would constitute a 9 percent share.
- The share from renewable energy small hydro will decline from 8 percent in 2008 to 3 percent in 2018 as few resources will be added or improved.
- The share of renewable energy from POU-defined categories of eligibility will decline from about 21 percent in 2008 to less than 8 percent in 2018. Nearly all long-term renewable energy procurement plans conform to categories defined as Energy Commission- eligible.
- Staff will request that future reports provide a greater differentiation among committed, planned, and generic acquisitions depending on where the project is on the time line from conceptual planning to online service. Possible distinctions could be among those projects that have local governing board approval, planned projects that would be utility-owned, and other projects without signed contracts or publicly disclosed development plans.

## Acronyms

| | |
|---|---|
| BPA | Bonneville Power Administration |
| California ISO | California Independent System Operator is the balancing area (control area) for which the ISO staff continuously maintain voltage stability on the high-voltage grid. It is the FERC-regulated authority that receives periodic reports by LSEs showing they have procured adequate capacity resources to meet their share of balancing area peak loads. |
| CCSF | City and County of San Francisco |
| CDWR | California Department of Water Resources |
| CPUC | California Public Utilities Commission |
| CSI | California Solar Initiative |
| DG | distributed generation |
| DR | demand response |
| EE | energy efficiency |
| ESP | electric service provider/energy service provider |
| FERC | Federal Energy Regulatory Commission |
| GWh | gigawatt hour: a measure of energy equal to 1,000 megawatt hours |
| LADWP | Los Angeles Department of Water and Power |
| LT | long-term: used for contracts longer than 90 days |
| ID | irrigation district |
| IID | Imperial Irrigation District |
| IOU | investor-owned utility |
| ISO | Independent System Operator |
| LSE | load-serving entity |
| MID | Modesto Irrigation District |
| MW | megawatt: a measure of electrical generating capacity, also used to measure and forecast demand for energy in a specific hour, especially the annual peak-hour demand |

| | |
|---|---|
| NCPA | Northern California Power Agency, used in this report in reference to the NCPA Power Pool that includes 10 POUs |
| POEU | publicly owned electric utility, as defined in the California Public Utilities Code, Article 8, Section 9604, subdivision (d) |
| POU | publicly owned utility: used in this report as a generic term for 40 non-profit government-chartered entities including 23 city electric utility departments, 3 municipal utility districts, 2 public utility districts, 4 irrigation districts, 2 joint powers authorities, 3 rural electric cooperatives, 1 community aggregator, 1 resort improvement district, and NCPA (but not the 10 POU members of the NCPA Power Pool) |
| PRM | planning reserve margin |
| RAR | resource adequacy requirements |
| REC | renewable energy credit: the purchase of renewable environmental attributes associated with production of renewable energy separate from purchasing or taking delivery of such energy. RECs are defined more narrowly for IOUs and ESPs in California Public Utilities Code, Section 399.12 (c)(1) |
| RPS | renewables portfolio standard: sets or adopts target amounts for renewable energy generation by a LSE, as defined in California Public Utilities Code, Article 8, Section 387 |
| SCPPA | Southern California Public Power Authority |
| SMUD | Sacramento Municipal Utility District |
| SP | spot market |
| SPP | Sierra Pacific Power Co. |
| SVP | Silicon Valley Power (City of Santa Clara) |
| TID | Turlock Irrigation District |
| UEG | utility-controlled electric generation |
| UP&L | Utah Power & Light |
| WAPA, Western | Western Area Power Administration |
| WECC | Western Electricity Coordinating Council |

# APPENDIX A: Publicly Owned Utility Capacity and Energy Summaries, 2010 and 2018

## City of Anaheim

### *Capacity*

Anaheim's total capacity requirement increases 9 percent from 585 MW in 2010 to 636 MW in 2018, while expected supplies provided by Utility Electric Generation (UEG) long-term and short-term resources slip slightly from 149 to 137 percent of the Firm Peak-Hour Requirement. Although these percentages would otherwise indicate an over-acquisition of resources, the NRG local capacity resource short-term contract, which accounts for 46 percent of the Firm Peak-Hour Requirement in 2010, is critical for meeting Anaheim's in-basin generation requirements.[18]

For 2010 only, Anaheim expects to have 75 MW from short-term and spot market purchases, and a surplus of 360 MW.

Anaheim is very dependent on coal-fired resources, getting 49 percent of its Firm Peak-Hour Requirement in 2010 from this category, and 45 percent in 2018. Coal-fired resources comprise 54 percent of UEG capacity in 2010 and 39 percent in 2018.

Total UEG capacity does not change between 2010 and 2018, and the share of Firm Peak-Hour Requirement from coal-fired and hydroelectric generation resources changes very little. However, UEG capacity from natural gas-fired power plants increases by 200 MW (96 percent), increasing its share of Firm Peak-Hour Requirement served by 29 percentage points.

Long-term contracts increase from 51 MW to 135 MW. Most of this increase will be from the Shoshone 1 geothermal contract. Contracts that expire in the short-term contribute 285 MW of capacity in 2010, and are primarily needed to meet local resource adequacy requirements.

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[18] Anaheim's contract with NRG for Local Capacity Resources has been for generation from El Segundo Units 3 and 4. Staff's expectation that the contract will be extended through 2011 is based on Anaheim's assigned share of local, in-basin local capacity requirements set annually by the California Independent System Operator (California ISO). Whether the contract is extended past 2011 is dependent on whether El Segundo, a power plant that uses once-through cooling, will be allowed to continue either operating in that mode, and the timing of the 200 MW Canyon Power Project which will satisfy most of Anaheim's local capacity procurement requirements.

Anaheim expects 264 MW in capacity additions by 2018. The 200 MW Canyon Power Plant alone will more than compensate for the expiration of existing short-term contracts during this interval.

### Table A-1: Anaheim Capacity Resources in 2010 and 2018

| **City of Anaheim** | **2010[a]** | **2018[a]** |
|---|---|---|
| **Firm Peak-Hour Requirement[1]** | **585** | **636** |
| **Percent Change** | | **9%** |
| **Utility Electric Generation (UEG)** | | |
| Coal-fired Plants[2] | | |
| *Intermountain Unit 1* | *118* | *118* |
| *Intermountain Unit 2* | *118* | *118* |
| *San Juan Unit 4* | *50* | *50* |
| Total Coal-fired Plants | 286 | 286 |
| | 49% | 45% |
| Nuclear Power Plants | | |
| *None* | *0* | *0* |
| Total Nuclear Plants | 0 | 0 |
| | 0% | 0% |
| Gas-fired Plants | | |
| *Canyon Power Plant (scheduled for 2011)* | *0* | *200* |
| *Magnolia Power Plant* | *118* | *118* |
| *Anaheim CTG* | *45* | *45* |
| Total Gas-fired Plants | 163 | 363 |
| | 28% | 57% |
| Hydroelectric Power Plants | | |
| *Hoover entitlement* | *40* | *40* |
| Total Hydroelectric | 40 | 40 |
| | 7% | 6% |
| Renewable Power | | |
| *None that are utility-owned* | *0* | *0* |
| Total UEG Renewable | 0 | 0 |
| | 0% | 0% |
| ***Total of Utility Electric Generation*** | ***489*** | ***689*** |
| | ***84%*** | ***108%*** |
| **Long-Term Renewable and Other Bilateral Contracts (LT)** | | |
| *PPM Wind* | *12* | *12* |
| *Shoshone 1 Geothermal (adds in 2012 at 32 MW, increases to 64 MW in 2013)* | *0* | *64* |
| *Ormat Geothermal* | *8* | *8* |
| *Thermo 1 Geothermal* | *16* | *16* |
| *Olinda Landfill Gas* | *5* | *25* |
| *MWD Small Hydro* | *10* | *10* |
| Total LT Contracts | 51 | 135 |
| | 9% | 21% |
| ***Subtotal (UEG + LT)*** | ***540*** | ***824*** |
| | ***92%*** | ***130%*** |

| City of Anaheim | 2010[a] | 2018[a] |
|---|---|---|
| **Short-Term to Expiration Contracts (ST)**[3] | | |
| *NRG (local resource adequacy capacity only, 1-year contract)*[4] | *235* | *0* |
| *BP Energy 1 & 2 (one year capacity contracts)* | *50* | |
| Total ST Contracts | 285 | 0 |
| | 49% | 0% |
| **Total (UEG + LT +ST)** | **825** | **824** |
| | **141%** | **130%** |
| **Short-Term and Spot Market Purchases (ST/SM)** | *75* | *0* |
| Total ST/SM | 75 | 0 |
| | 13% | 0% |
| **Total** | **900** | **824** |
| | **154%** | **130%** |
| **Scheduled Additions** | | |
| *Canyon Power Plant (2011)* | *0* | *200* |
| *Shoshone 1 Geothermal (adds in 2012 at 32 MW, increases to 64 MW in 2013)* | *0* | *64* |
| ***Total Scheduled Additions*** | ***0*** | ***264*** |
| | ***0%*** | ***42%*** |

Notes:

a. All capacity values are in MW. Percentages are of the Firm Peak-Hour Requirement for each category.

[1] The City of Anaheim's Line 14 entry incorporates a 15 percent PRM for both years.

[2] The Intermountain contract is expected to end on December 31, 2024. The City of Anaheim has a 10 percent ownership share of the San Juan power plant. (http://www.pnm.com/systems/sj-owners.htm, accessed 02 Jun 2009.)

[3] The City of Anaheim uses fiscal year starting July 1. Energy Commission staff adjusted FY dates to correspond with actual dates of contracted supply. This applies two short-term BP Energy contracts of Jul-Sep 2009 to 2009 rather than 2010 as shown in the S-1/S-2 forms.

[4] The City of Anaheim contracted with NRG for 235 MW of local capacity resources in the LA Basin in 2008 and 2009. Energy Commission staff expects the contract will be extended through at least 2011.

Source: Anaheim Resource Accounting Table Form S-1, February 10, 2009, updated March 24, 2009

## *Energy*

Anaheim's Firm Energy Requirement increases 10 percent from 2,867 GWh in 2010, to 3,150 GWh in 2018. Total supplies are expected to be almost 120 percent of the 2018 energy requirement, respectively. Anaheim plans to sell the excess energy.

Anaheim is heavily dependent on coal-fired generation with these resources providing 76 percent of the 2010 Firm Energy Requirement and 68 percent in 2018. Coal-fired generation provides 78 percent of all UEG in both years. By comparison, natural gas-fired generation provides about 20 percent of both the Firm Energy Requirement and UEG energy needs for both years.

Long-term contract energy resources increase by 224 percent from 313 GWh to 1,013 GWh, increasing this category's share of Firm Energy Requirement from 11 to 32 percent. Short-

term contracts provide only 2 percent of 2010's Firm Peak-Hour Requirement. The NRG short-term contract, being a local capacity resource, does not have an energy component.[19]

Whereas most additional capacity, 250 MW or 39 percent of Firm Peak-Hour Requirement in 2018 is from the Canyon Power Plant, the energy component of this resource provides only 36 GWh of peaking energy in 2018, or 1 percent of the Firm Energy Requirement. By contrast, the 64 MW Shoshone 1 geothermal project is expected to provide 519 GWh of baseload energy in 2018, equal to 16 percent of the Firm Energy Requirement.

**Table A-2: Anaheim Energy Supplies in 2010 and 2018**

| **City of Anaheim**[1] | **2010**[a] | **2018**[a] |
|---|---|---|
| **Firm Energy Requirement** | **2,867** | **3,150** |
| **Percent Change** | | **10%** |
| **Utility Electric Generation (UEG)** | | |
| Coal-fired Plants[2] | | |
| *Intermountain Unit 1* | *942* | *952* |
| *Intermountain Unit 2* | *889* | *857* |
| *San Juan Unit 4* | *336* | *328* |
| Total Coal-fired Plants | 2,167 | 2,137 |
| | 76% | 68% |
| Nuclear Power Plants | | |
| *None* | *0* | *0* |
| Total Nuclear Plants | 0 | 0 |
| | 0% | 0% |
| Gas-fired Plants | | |
| *Canyon Power Plant (scheduled for 2011)* | *0* | *36* |
| *Magnolia Power Plant* | *526* | *483* |
| *Anaheim CTG* | *48* | *53* |
| Total Gas-fired Plants | 574 | 572 |
| | 20% | 18% |
| Hydroelectric Power Plants | | |
| *Hoover entitlement* | *43* | *43* |
| Total Hydroelectric | 43 | 43 |
| | 1% | 1% |
| Renewable Energy Resources | | |
| *None that are utility-owned* | *0* | *0* |
| Total UEG Renewable | 0 | 0 |
| | 0% | 0% |
| ***Total of Utility Electric Generation*** | ***2,784*** | ***2,752*** |

[19] Anaheim's contract with NRG for Local Capacity Resources has been for generation from El Segundo Units 3 and 4, representing 2 percent of net electric load in 2010. Staff's expectation that the contract will be extended through 2011 is based on local, in-basin generation requirements. Whether the contract is extended past 2011 is dependent on whether El Segundo, a power plant that uses once-through cooling, will be allowed to continue either operating in that mode, or by using an alternative cooling technology.

| **City of Anaheim**[1] | **2010**[a] | **2018**[a] |
|---|---|---|
| | ***97%*** | ***87%*** |
| **Long-Term Renewable Energy Contracts (LT)** | | |
| *PPM Wind* | *80* | *80* |
| *Shoshone 1 Geothermal (starts at 38 GWh in 2012, then 297 GWh in 2013, and 519 GWh in 2014)* | 0 | 519 |
| *Ormat Geothermal* | 66 | 67 |
| *Thermo 1 Geothermal* | 106 | 130 |
| *Olinda Landfill Gas* | 38 | 194 |
| *MWD Small Hydro* | 23 | 23 |
| Total LT Contracts | 313 | 1,013 |
| | 11% | 32% |
| ***Subtotal (UEG + LT)*** | ***3,097*** | ***3,765*** |
| | ***108%*** | ***120%*** |
| **Short-Term to Expiration Contracts (ST)**[4] | | |
| *BP Energy 1 & 2 (one year contracts)* | *63* | *0* |
| Total ST Contracts | 63 | 0 |
| | 2% | 0% |
| **Total (UEG + LT +ST)** | **3,160** | **3,765** |
| | **110%** | **120%** |
| **Short-Term and Spot Market Purchases** (Net Planned Purchases, market purchases and market sales, with net sales shown as negative values.) **(ST/SM)** | *-293* | *-615* |
| Total ST/SM | -293 | -615 |
| | -10% | -20% |
| **Total** | **2,867** | **3,150** |
| | **100%** | **100%** |
| **Scheduled Additions** | | |
| *Canyon Power Plant (2011)* | *0* | *36* |
| *NRG Local Capacity (scheduled for 2010)*[3] | *0* | *0* |
| *Shoshone 1 Geothermal (adds in 2012 at 32 MW, increases to 64 MW in 2013)* | *0* | *519* |
| ***Total Scheduled Additions*** | ***0*** | ***555*** |
| | ***0%*** | ***18%*** |

Notes:

a. All energy values are in GWh. Each percentage value is of the Firm Energy Requirement for that category.

[1] Anaheim uses fiscal year starting July 1. Energy Commission staff adjusted FY dates to correspond with actual dates of contracted supply. This applies two short-term BP Energy contracts of Jul-Sep 2009 to 2009 rather than 2010 as shown in the S-1/S-2 forms.

[2] The Intermountain contract is expected to end on December 31, 2024. Anaheim has a 10 percent ownership share of the San Juan power plant. (http://www.pnm.com/systems/sj-owners.htm, accessed June 2, 2009.)

[3] Anaheim contracted with NRG for 235 MW Local Capacity Resources in the LA Basin in 2008 and 2009. Energy Commission staff expects the contract will be extended through at least 2011.

Source: Anaheim Energy Balance Resource Accounting Table Form S-2, February 10 updated March 24, 2009

# City of Burbank

## *Capacity*

From 2010 to 2018, Burbank's total capacity requirement increases 8 percent, from 330 MW to 355 MW. During these years, expected supplies provided by UEG, contracts, and unspecified generic renewable energy short-term resources decrease from 112 to 101 percent of the Firm Peak-Hour Requirement. (Without these generic renewable additions, Burbank's existing and specific planned resources would meet 103 percent of the annual peak-hour capacity need in 2010, and 85 percent in 2018.) When capacity values for all existing, planned, and generic resources are included, Burbank shows a surplus of 42 MW in 2010, and a surplus of 4 MW in 2018. These expected surpluses would be above Burbank's 35 MW single largest contingency planning reserve margin.

UEG capacities from coal-fired, nuclear and natural gas-fired generation resources do not change significantly between 2010 and 2018, but the current UEG hydroelectric Hoover Entitlement of 19 MW ends during 2017. Other LSEs have forecast a continuation of their Hoover entitlements starting in 2018. The Hoover entitlement is 6 percent of Burbank's 2010 Firm Peak-Hour Requirement, and if renewed at the same level would be 5 percent in 2018.

Burbank's dependence on coal-fired resources is relatively high at 19 and 17 percent of the Firm Peak-Hour Requirements for 2010 and 2018, respectively. Coal-fired resources also are 21 and 22 percent of the UEG for these same years.

Additional capacity comes from planned long-term contracts for renewable projects that increase from 33 MW to 79 MW between 2010 and 2018. This category represents 10 percent of the Firm Peak-Hour Requirement in 2010, and 22 percent in 2018. This increase more than makes up for the potential ending of the Hoover entitlement. One short-term contract in 2010 contributes 37 MW of capacity, or 11 percent of the Firm Peak-Hour Requirement.

**Table A-3: Burbank Capacity Resources in 2010 and 2018**

| **Burbank** | **2010[a]** | **2018[a]** |
|---|---|---|
| **Firm Peak-Hour Requirement[1]** | **330** | **355** |
| **Percent Change** | | **8%** |
| **Utility Electric Generation (UEG)** | | |
| Coal-fired Plants[2] | | |
| *Intermountain[2]* | *64* | *61* |
| Total Coal-fired Plants | 64 | 61 |
| | 19% | 17% |
| Nuclear Power Plants | | |
| *Palo Verde* | *9* | *9* |
| Total Nuclear Plants | 9 | 9 |
| | 3% | 3% |
| Gas-fired Power Plants | | |

| **Burbank** | **2010[a]** | **2018[a]** |
|---|---|---|
| *Olive 1* | *50* | *50* |
| *Olive 2* | *40* | *40* |
| *Lake CT* | *44* | *44* |
| *Magnolia (share)* | *75* | *75* |
| Total Gas-fired Plants | 209 | 209 |
| | 63% | 59% |
| Hydroelectric Power Plants | | |
| *Hoover entitlement (contract ends in 2017)* | *19* | *0* |
| Total Hydroelectric | 19 | 0 |
| | 6% | 0% |
| Renewable Power | | |
| *None that are utility-owned* | *0* | *0* |
| Total UEG Renewable | 0 | 0 |
| | 0% | 0% |
| ***Total of Utility Electric Generation*** | ***301*** | ***279*** |
| | ***91%*** | ***79%*** |
| **Long-Term Renewable and Other Bilateral Contracts (LT)** | | |
| *7 Renewable energy contracts* | *22* | *22* |
| Total LT Contracts | 22 | 22 |
| | 7% | 6% |
| ***Subtotal (UEG + LT)*** | ***323*** | ***301*** |
| | ***98%*** | ***85%*** |
| **Short-Term to Expiration Contracts (ST)** | | |
| *PowerEx Exchange (ends by 2013)* | *37* | *0* |
| Total ST Contracts | 37 | 0 |
| | 11% | 0% |
| **Total (UEG + LT +ST)** | **340** | **301** |
| | **103%** | **85%** |
| **Short-Term and Spot Market Purchases (ST/SM)** | *0* | *0* |
| Total ST/SM | 0 | 0 |
| | 0% | 0% |
| **Total** | **340** | **301** |
| | **103%** | **85%** |
| **Scheduled Additions** | | |
| *From generic (not yet specified) new renewables contracts (7 MW in 2010, plus 6 MW in 2011, plus 40 MW in 2013)* | *7* | *53* |
| ***Total Scheduled Additions*** | ***7*** | ***53*** |
| | ***2%*** | ***15%*** |

Notes:

a. All capacity values are in MW. Percentages are of the Firm Peak-Hour Requirement for each category.

[1] Burbank's Line 14 entry incorporates a 35 MW PRM for both years. This equates to a 12 percent PRM in 2010 and 11 percent PRM in 2018. Actual PRMs achieved to date with existing and planned resources are 13 and 1 percent, respectively.

[2] Burbank's generation entitlement share from the Intermountain Generating Station is approximately 3 percent. (http://www.ipautah.com/about/index.asp, accessed June 2, 2009.)

Source: Burbank Capacity Resource Accounting Table Form S-1, March 23, 2009, updated April 6, 2009

## *Energy*

Burbank's Firm Energy Requirement increases 8 percent from 1,266 GWh in 2010, to 1,371 GWh in 2018. Total supply is 100 percent of requirements for both years. Burbank expects to purchase 27 GWh in 2010 and 97 GWh in 2018 using short-term or spot market contracts.

Burbank relies on coal-fired generation for 38 percent of the 2010 Firm Energy Requirement, and 23 percent of the 2018 requirement. Coal-fired generation provides at least 40 percent of UEG in both years. By comparison, natural gas-fired generation provides 44 percent of the Firm Energy Requirement in 2010 and 28 percent in 2018. Hydroelectric generation from Hoover provides slightly more than one percent of the Firm Energy Requirements each year.

Long-term contract energy resources almost double in eight years, going from 158 GWh to 466 GWh and increasing this category's share of Firm Energy Requirement from 12 to 34 percent. Because Burbank sends out energy in 2010, the net short-term energy value is a negative 58 GWh or an increase in need of 5 percent. There are no short-terms contracts (neither additions nor subtractions) in 2018.

The only additions are the planned renewable contracts of four and 79 GWh in 2010 and 2018, respectively, and the 41 GWh Powerex contract in 2010. Combined these comprise 3 percent of the 2010 Firm Energy Requirement, and 6 percent of the 2018 requirement.

**Table A-4: Burbank Energy Supplies in 2010 and 2018**

| **Burbank** | **2010[a]** | **2018[a]** |
|---|---|---|
| **Firm Energy Requirement** | **1,266** | **1,371** |
| **Percent Change** | | **8%** |
| **Utility Electric Generation (UEG)** | | |
| Coal-fired Plants[1] | | |
| *Intermountain Unit 1* | *487* | *320* |
| Total Coal-fired Plants | 487 | 320 |
| | 38% | 23% |
| Nuclear Power Plants | | |
| *Palo Verde* | *73* | *73* |
| Total Nuclear Plants | 73 | 73 |
| | 6% | 5% |
| Gas-fired Plants | | |
| *Olive 1* | *0* | *0* |
| *Olive 2* | *9* | *0* |
| *Lake CT* | *38* | *38* |
| *Magnolia Power Plant (share)* | *515* | *350* |
| Total Gas-fired Plants | 562 | 388 |
| | 44% | 28% |
| Hydroelectric Power Plants | | |
| *Hoover entitlement* | *17* | *25* |
| Total Hydroelectric | 17 | 25 |

| **Burbank** | **2010[a]** | **2018[a]** |
|---|---|---|
| | 1% | 2% |
| Renewable Energy Resources | | |
| *None that are utility-owned* | *0* | *0* |
| Total UEG Renewable | 0 | 0 |
| ***Total of Utility Electric Generation*** | ***1,139*** | ***806*** |
| | ***90%*** | ***59%*** |
| **Long-Term Renewable and Other Bilateral Contracts (LT)[2]** | | |
| *Planned Renewables contracts (6 MW in 2011, 40 MW in 2013)* | *158* | *466* |
| Total LT Contracts | 158 | 466 |
| | 12% | 34% |
| ***Subtotal (UEG + LT)*** | ***1,297*** | ***1,272*** |
| | ***102%*** | ***93%*** |
| **Short-Term to Expiration Contracts (ST)[3]** | | |
| *Powerex (ends by 2013)* | *39* | *0* |
| *Exchange (energy sent out)* | *-97* | *0* |
| Total (Net) of ST Contracts | -58 | 0 |
| | -5% | 0% |
| **Total (UEG + LT +ST)** | **1,239** | **1,272** |
| | **98%** | **93%** |
| **Short-Term and Spot Market Purchases (ST/SM)** | *27* | *97* |
| Total ST/SM | 27 | 97 |
| | 2% | 7% |
| **Total** | **1,266** | **1,369** |
| | **100%** | **100%** |
| **Scheduled Additions** | | |
| *From generic (not yet specified) new renewables contracts (32 GWh in 2010, plus 65 GWh in 2011, 37 GWh in 2012, and 165 GWh in 2013)* | *32* | *299* |
| ***Total Scheduled Additions*** | ***32*** | ***299*** |
| | ***3%*** | ***22%*** |

Notes:

a. All energy values are in GWh. Each percentage value is of the Firm Energy Requirement for that category.

[1]Burbank's generation entitlement share from the Intermountain Generating Station is approximately 3 percent of capacity. (http://www.ipautah.com/about/index.asp, accessed 02 Jun 2009.)

[2]Long-term contracts include those that existed from 2007 but may end well before 2018.

Source: Burbank Energy Balance Resource Accounting Table Form S-2, March 23, 2009, updated April 6, 2009

# Glendale Water and Power

## *Capacity*

From 2010 to 2018, Glendale's total capacity requirement increases 4 percent from 375 MW to 389 MW. During this forecast period, Glendale's existing capacity resources meet 104 percent of the Firm Peak-Hour Requirement in 2010, and 87 percent in 2018. Glendale plans to add 50 MW to meet this need, of which 40 MW is expected to come from generic renewable additions.

UEG hydroelectric generation capacity from Glendale's Hoover entitlement is not expected to change in either MW or percent of the Firm Peak-Hour Requirement between 2010 and 2018. It remains 13 MW and 3 percent, respectively. Similarly, capacity provided by UEG natural gas-fired power plants does not change from 240 MW, and the category's share of the Firm Peak-Hour Requirement shrinks slightly from 64 to 62 percent.

**Table A-5: Glendale Capacity Resources in 2010 and 2018**

| **Glendale Water and Power** | **2010[a]** | **2018[a]** |
|---|---|---|
| **Firm Peak-Hour Requirement[1]** | **375** | **389** |
| **Percent Change** | | **4%** |
| **Utility Electric Generation (UEG)** | | |
| Coal-fired Plants[2, 3] | | |
| *Intermountain* | *35* | *35* |
| *San Juan Unit 3* | *20* | *20* |
| Total Coal-fired Plants | 55 | 55 |
| | 15 | 14% |
| Nuclear Power Plants | | |
| *Palo Verde* | *9* | *9* |
| Total Nuclear Plants | 9 | 9 |
| | 2% | 2% |
| Gas-fired Plants | | |
| *Grayson[4]* | *200* | *200* |
| *Magnolia* | *40* | *40* |
| Total Gas-fired Plants | 240 | 240 |
| | 64% | 62% |
| Hydroelectric Power Plants | | |
| *Hoover entitlement* | *13* | *13* |
| Total Hydroelectric | 13 | 13 |
| | 3% | 3% |
| Renewable Power | | |
| *None that are utility-owned* | *0* | *0* |
| Total UEG Renewable | 0 | 0 |
| | 0% | 0% |
| ***Total of Utility Electric Generation*** | *367* | *317* |
| | *98%* | *81%* |

| Glendale Water and Power | 2010[a] | 2018[a] |
|---|---|---|
| **Long-Term Renewable Energy Contracts (LT)** | | |
| *Iberdrola (3 wind contracts)* | *19* | *19* |
| *Ormat Geothermal* | *3* | *3* |
| Total LT Contracts | 22 | 22 |
| | 6% | 6% |
| ***Subtotal (UEG + LT)*** | ***389*** | ***339*** |
| | ***104%*** | ***87%*** |
| **Short-Term to Expiration Contracts (ST)** | | |
| *None* | *0* | *0* |
| Total ST Contracts | 0 | 0 |
| | 0% | 0% |
| **Total (UEG + LT +ST)** | **389** | **339** |
| | **104%** | **87%** |
| **Short-Term, Market, & Generic Resources** | *50* | *90* |
| Total Generic | 50 | 90 |
| | 13% | 23% |
| **Total** | **439** | **429** |
| | **117%** | **110%** |
| **Scheduled Additions** | | |
| *None* | *0* | *0* |
| ***Total Scheduled Additions*** | 0 | 0 |
| | 0% | 0% |

Notes:

a. All capacity values are in MW. Percentages are of the Firm Peak-Hour Requirement for each category.

[1]Glendale's Line 14 entry incorporates a 40 MW PRM for both years. This equates to PRMs of 12 percent in 2010 and 11 percent in 2018.

[2]Glendale listed the Intermountain and San Juan coal contracts as long-term and the Portland General Electric contract as short-term, but Energy Commission staff is treating all three as UEG.

[3]Glendale's generation entitlement share from the Intermountain Generating Station is approximately 3 percent. (http://www.ipautah.com/about/index.asp, accessed 02 Jun 2009.) The contract for San Juan Generating Station Unit 4 output is expected to end Oct 31, 2030.

[4]The Grayson project has both natural gas-fired and a biomass renewable components. The latter are Units 3, 4 and5. Although they do not provide capacity and are not shown on the S-1 Capacity forms, they do provide energy (GWh) and are shown in the S-2 Energy forms.

Source: Glendale Capacity Resource Accounting Table Form S-1, February 13, 2009, updated March 17, 2009

## *Energy*

Glendale's Firm Energy Requirement increases 4 percent from 1,287 GWh in 2010 to 1,339 GWh in 2018. Glendale expects to use short-term and spot market contracts to purchase 68 GWh in 2010 and 70 GWh in 2018, leaving an additional procurement need of 17 GWh in 2010 and 100 GWh in 2018.

Natural gas-fired generation provides 27 percent of Glendale's Firm Energy Requirement in 2010 and 2018, and about 32 percent of UEG energy in both years. UEG hydroelectric generation provides five percent of the Firm Energy Requirement and 6 percent of the UEG

category energy total, in both years. Renewable energy from utility-controlled resources is expected to remain steady at 86 GWh per year.[20]

Renewable energy supplies from long-term contracts increase slightly, from 120 to 125 GWh; this category's share of Firm Energy Requirement remains unchanged at 9 percent. There are no short-term contracts in either year.

**Table A-6: Glendale Energy Supplies in 2010 and 2018**

| **Glendale Water and Power** | **2010[a]** | **2018[a]** |
|---|---|---|
| **Firm Energy Requirement** | **1,287** | **1,339** |
| **Percent Change** | | **4%** |
| **Utility Electric Generation (UEG)** | | |
| Coal-fired Plants[1, 2] | | |
| *Intermountain* | *273* | *284* |
| *San Juan Unit 3* | *158* | *164* |
| Total Coal-fired Plants | 431 | 448 |
| | 34% | 34% |
| Nuclear Power Plants | | |
| *Palo Verde* | *84* | *87* |
| Total Nuclear Plants | 84 | 87 |
| | 7% | 6% |
| Gas-fired Plants | | |
| *Grayson[3]* | *70* | *76* |
| *Magnolia Power Plant* | *272* | *283* |
| Total Gas-fired Plants | 342 | 359 |
| | 27% | 27% |
| Hydroelectric Power Plants | | |
| *Hoover entitlement* | *60* | *62* |
| Total Hydroelectric | 60 | 62 |
| | 5% | 5% |
| Renewable Energy Resources | | |
| *Grayson Biomass, Units 3, 4 and 5[3]* | *86* | *86* |
| Total UEG Renewable | 86 | 86 |
| | 7% | 6% |
| ***Total of Utility Electric Generation*** | ***1,081*** | ***1,123*** |
| | ***84%*** | ***84%*** |
| **Long-Term Renewable Energy Contracts (LT)** | | |
| *Iberdrola (3 wind contracts)* | *96* | *100* |
| *Ormat Geothermal* | *24* | *25* |
| Total LT Contracts | 120 | 125 |
| | 9% | 9% |
| ***Subtotal (UEG + LT)*** | ***1,201*** | ***1,248*** |

[20] Glendale lists a solar UEG project, GLEN – Solar, at less than one-half GWh. This project is omitted from the table. The Grayson project has both natural gas-fired and a biomass renewable components. The biomass components are units 3, 4 and 5 and provide only energy. They are listed separately here. They are not listed as a resource in the capacity table.

| Glendale Water and Power | 2010[a] | 2018[a] |
|---|---|---|
| | ***93%*** | ***93%*** |
| **Short-Term to Expiration Contracts (ST)** | | |
| *None* | *0* | *0* |
| Total ST Contracts | 0 | 0 |
| | 0% | 0% |
| **Total (UEG + LT +ST)** | **1,201** | **1,248** |
| | **93%** | **93%** |
| **Short-Term and Spot Market Purchases (ST/SM)** | *68* | *70* |
| Total ST/SM | 68 | 70 |
| | 5% | 5% |
| **Total** | **1,269** | **1,318** |
| | **99%** | **98%** |
| **Scheduled Additions** | | |
| *None yet specified* | *0* | *0* |
| ***Total Scheduled Additions*** | ***0*** | ***0*** |
| | ***0%*** | ***0%*** |

Notes:

a. All energy values are in GWh. Each percentage value is of the Firm Energy Requirement for that category.

[1]Glendale listed Intermountain and San Juan as long-term contractual resources rather than utility-controlled generation.

[2]Glendale's generation entitlement share from the Intermountain Generating Station is approximately 3 percent. (http://www.ipautah.com/about/index.asp, accessed 02 Jun 2009.) The contract for San Juan Generating Station Unit 4 output is expected to end 31 Oct 2030.

[3]The Grayson project has both natural gas-fired and a biomass renewable components. The latter are Units 3, 4 and 5. Although they do not provide capacity and are not shown on the S-1 Capacity forms, they do provide energy (GWh) and are shown in the S-2 Energy forms.

Source: Glendale Energy Balance Resource Accounting Table Form S-2, February 13, 2009, updated March 17, 2009

# Imperial Irrigation District

## *Capacity*

The annual peak-hour capacity requirement for Imperial Irrigation District (IID) increases 17 percent from 1,095 MW in 2010 to 1,276 MW in 2018. In this planning horizon, expected supplies provided by UEG, long-term, and short-term resources increase from 70 to 90 percent of the Firm Peak-Hour Requirement. In 2010, IID has a resource need of 36 MW that it intends to fill using short-term and spot market purchases. IID forecasts a capacity surplus of 57 MW in 2018, due in part to short-term and spot market purchases of 125 MW.

UEG capacity provided by coal-fired, nuclear and hydroelectric sources and capacities from long-term contracts do not change to any significant degree between 2010 and 2018. However, capacity from UEG natural gas-fired power plants increases 32 percent with the El Centro repower in 2012. IID depends on the coal-fired San Juan Unit 3 power plant for

almost 10 percent of its Firm Peak-Hour Requirement in 2010. The San Juan import constitutes 13 percent and nine percent of its 2010 and 2018 UEG capacities, respectively.

IID is planning to develop new geothermal resources rated at 250 MW, equal to 20 percent of the 2018 Firm Peak-Hour Requirement. Planned repowering of 42 MW El Centro Unit 3 to 180 MW would provide a net capacity increase of 138 MW for the unit.

**Table A-7: Imperial ID Capacity Resources in 2010 and 2018**

| **Imperial Irrigation District** | **2010[a]** | **2018[a]** |
|---|---|---|
| **Firm Peak-Hour Requirement[1]** | **1,095** | **1,276** |
| **Percent Change** | | **17%** |
| **Utility Electric Generation (UEG)** | | |
| Coal-fired Plants[2] | | |
| *San Juan Unit 3* | *102* | *102* |
| Total Coal-fired Plants | 102 | 102 |
| | 9% | 8% |
| Nuclear Power Plants | | |
| *Palo Verde Units 1, 2 and 3* | *14* | *14* |
| Total Nuclear Plants | 14 | 14 |
| | 1% | 1% |
| Gas-fired Power Plants | | |
| *Various* | *568* | *526* |
| *El Centro Repower (scheduled for 2012)* | *0* | *180* |
| Total Gas-fired Plants | 568 | 706 |
| | 52% | 55% |
| Hydroelectric Power Plants | | |
| *All utility-controlled Hydro Plants* | *65* | *65* |
| Total Hydroelectric | 65 | 65 |
| | 6% | 5% |
| Renewable Power | | |
| *GreenHunter Mesquite Lake Biomass (adds in 2010)* | *15* | *15* |
| *"Unit 1" Geothermal (starts in at 100 MW in 2012)* | *0* | *250* |
| Total UEG Renewable | 15 | 265 |
| | 1% | 21% |
| ***Total of Utility Electric Generation*** | ***764*** | ***1,152*** |
| | ***70%*** | ***90%*** |
| | | |
| **Long-Term Bilateral Contracts (LT)** | | |
| *Shell (3 contracts at 25 MW each, ending 2017)* | *75* | *0* |
| *J Aron (ends in 2017)* | *25* | *0* |
| Total LT Contracts | 100 | 00 |
| | 9% | 0% |
| ***Subtotal (UEG + LT)*** | ***864*** | ***1,152*** |
| | ***79%*** | ***90%*** |
| **Short-Term to Expiration Contracts (ST)** | | |
| *Shell (1 at 25 MW, ends in 2012)* | *50* | *0* |

| Imperial Irrigation District | 2010[a] | 2018[a] |
|---|---|---|
| *El Paso Electric (ends in 2012)* | *145* | *0* |
| Total ST Contracts | 195 | 0 |
| | 18% | 0% |
| **Total (UEG + LT +ST)** | **1,059** | **1,152** |
| | **97%** | **90%** |
| **Short-Term and Spot Market Purchases (ST/SM)** | *40* | *125* |
| Total ST/SM | 40 | 125 |
| | 4% | 10% |
| **Total** | **1,099** | **1,277** |
| | **100%** | **100%** |
| **Scheduled Additions** | | |
| *GreenHunter Mesquite Lake Biomass (adds in 2010)* | *15* | *15* |
| *El Centro Repower (adds in 2012)* | *0* | *180* |
| *Unspecified Geothermal (starting at 100 MW in 2012)* | *0* | *250* |
| ***Total Scheduled Additions*** | ***15*** | ***445*** |
| | ***1%*** | ***35%*** |

Notes:

a. All capacity values are in MW. Percentages are of the Firm Peak-Hour Requirement for each category.

[1]IID's Line 14 entries incorporate a 15 percent PRM applied to Line 9, Adjusted Peak-Hour Demand. As the only LSE in its balancing area, IID does not make an adjustment for Coincident Peak-Hour Demand.

[2]IID's contract for San Juan Unit 3 is with Southern California Public Power Authority (SCPPA), which owns about 42 percent of the San Juan Generating Station. The contract's expiration date is listed as "undetermined." Other LSEs with contracts through SCPPA for San Juan capacity and energy indicate the contract expires October 31, 2030.

Source: IID Capacity Resource Accounting Table Form S-1, February 26, 2009, updated March 23, 2009

## *Energy*

IID's Firm Energy Requirement increases 17 percent from 3,862 GWh in 2010 to 4,521 GWh in 2018.The total amount of energy available from utility-controlled generation increases from 7,358 GWh in 2010 to 8,262 GWh in 2018, though clearly all this potential energy supply will not be scheduled for real-time dispatch. The net increase in available energy output from a repowered El Centro Unit 3 would be 967 GWh. IID expects long-term contracts to deliver 1,937 GWh in 2010. If new utility-owned resources can be developed as planned, IID's reliance on long-term contracts for energy imports can be reduced to zero in 2018. However, IID still expects to use short-term and spot market contracts to purchase 33 GWh in 2010 and 104 GWh in 2018.

IID relies on coal-fired generation from San Juan Unit 3 for 19 percent of its 2010 Firm Energy Requirement, and 16 percent of its 2018 requirement. This resource accounts for 13 percent of UEG needs in 2010 and 9 percent in 2018.

Natural gas-fired generation could theoretically provide 103 percent of the Firm Energy Requirement in 2010 and 109 percent in 2018, equal to 73 percent of UEG energy in 2010 and

60 percent in 2018. Hydroelectric generation provides about 13 percent of the Firm Energy Requirement in both years. Half of this hydroelectric energy is from IID plants located on water delivery canals. The other half is firm must-take energy from federal Parker and Davis dams on the Colorado River, delivered by the Western Area Power Administration under a contract that runs through 2028.

### Table A-8: Imperial ID Energy Supplies in 2010 and 2018

| **Imperial Irrigation District** | **2010[a]** | **2018[a]** |
|---|---|---|
| **Firm Energy Requirement** | **3,862** | **4,521** |
| **Percent Change** | | **17%** |
| **Utility Electric Generation (UEG)** | | |
| Coal-fired Plants[1] | | |
| *San Juan Unit 3* | *715* | *715* |
| Total Coal-fired Plants | 715 | 715 |
| | 19% | 16% |
| Nuclear Power Plants | | |
| *Palo Verde Units 1, 2 and 3* | *104* | *104* |
| Total Nuclear Plants | 104 | 104 |
| | 3% | 2% |
| Gas-fired Plants | | |
| *El Centro Unit 3 Repower (starting in 2011)* | *0* | *1,261* |
| *Various* | *3,981* | *3,686* |
| Total Gas-fired Plants | 3,981 | 4,947 |
| | 103% | 109% |
| Hydroelectric Power Plants | | |
| *All utility-controlled Hydro Plants* | *542* | *542* |
| Total Hydroelectric | 542 | 542 |
| | 14% | 12% |
| Renewable Energy Resources | | |
| *GreenHunter Mesquite Lake Biomass (starting in 2010)* | *112* | *112* |
| *Geothermal (starting at 742 GWh in 2012)* | *0* | *1,862* |
| Total UEG Renewable | 112 | 1,974 |
| | 3% | 44% |
| ***Total of Utility Electric Generation*** | ***5,454*** | ***8,282*** |
| | ***141%*** | ***183%*** |
| **Long-Term Contracts (LT)**[2] | | |
| *Shell (Contracts C, D, E, ends in 2017)* | *147* | *0* |
| *J Aron (ends in 2017)* | *52* | *0* |
| Total LT Contracts | 229 | 0 |
| | 49% | 0% |
| ***Subtotal (UEG + LT)*** | ***5,683*** | ***8,282*** |
| | ***147%*** | ***183%*** |
| **Short-Term to Expiration Contracts (ST)** | | |
| *Shell (Contract A at 438 GWh, ends in 2012)* | *438* | *0* |
| *El Paso Electric (ends in 2012): 1,270 GWh in 2010, 0 GWh in 2018* | *1,270* | *0* |

| Imperial Irrigation District | 2010[a] | 2018[a] |
|---|---|---|
| Total ST Contracts | 1,708 | 0 |
| | 50% | 0% |
| **Total (UEG + LT +ST)** | **7,358** | ***8,283*** |
| | **191%** | ***183%*** |
| **Short-Term and Spot Market Purchases (ST/SM)**[3] | *33* | *104* |
| Total ST/SM | 33 | 104 |
| | 1% | 2% |
| **Total** | **7,391** | **8,386** |
| | **191%** | **185%** |
| **Scheduled Additions** | | |
| *GreenHunter Mesquite Lake Biomass (starting in 2010)* | 112 | 112 |
| *El Centro Unit 3 Repower (starting in 2011)* | *0* | *1,261* |
| *Geothermal (starting at 742 GWh in 2012)* | *0* | *1,862* |
| ***Total Scheduled Additions*** | ***112*** | ***3,235*** |
| | ***3%*** | ***72%*** |

Notes:

a. All energy values are in GWh. Each percentage value is of the Firm Energy Requirement for that category.

[1] Long-term contracts include those that existed from 2007 but may end well before 2018.

[2] IID may have double-counted short-term and spot market purchases by adding these again as contracted resources.

Source: IID Energy Balance Resource Accounting Table Form S-2, February 26, 2009 updated March 23, 2009

# Los Angeles Department of Water & Power

## *Capacity*

Total capacity requirements for the Los Angeles Department of Water & Power (LADWP) increase by 3 percent from 6,726 MW in 2010 to 6,896 MW in 2018. Expected supplies from UEG decrease slightly during this period, from 104 percent to 103 percent of the annual peak-hour requirement.

LADWP uses the Most Severe Single Contingency criteria in determining its planning reserve margin, which is forecast to remain steady at 1,086 MW. LADWP shows a resource surplus of 455 MW in 2010. When capacity values for all planned resources are included, forecast surplus capacity increases to 1,032 MW in 2014 and to 1,211 MW in 2018. In the summer of 2020, after the Navajo contract expires, LADWP forecasts a potential capacity surplus of 704 MW.

Capacities and category shares of UEG meeting the Firm Peak-Load Requirement provided by all coal-fired and nuclear resources do not change from 2010 to 2018. LADWP relies on coal-fired UEG for a fifth of its Firm Peak-Load Requirement through 2018. Although the capacity from UEG natural gas-fired power plants increases by 97 MW (3 percent), the

contribution of meeting the Firm Peak-Load Requirement of 50 percent of this category does not change. During this time LADWP expects a very small increase in UEG hydroelectric and renewable generation capacity.

By 2018, long-term contracts increase substantially from 181 to 971MW, more than a four-fold capacity increase. Nearly all this capacity increase will be from renewable resources. As a share of the Firm Peak-Load Requirement, long-term contracts increase from three to 14 percent. These contracts are comprised of various resources. The largest two are a 100 MW geothermal project and a 152 MW (dependable) solar project. Generally, LADWP's renewable and non-renewable short-term power purchases are not during the summer peak hours. Thus they are not counted on to meet annual peak loads.

Most added capacity (95 percent) comes in the form of natural gas-fired generation, ranging from the Haynes combustion turbines (CT) at 600 MW in 2013, and the 100 MW Scattergood combustion turbine in 2015. This category represents 27 percent of the Firm Peak-Load Requirement in 2018.

## Table A-9: LADWP Capacity Resources in 2010 and 2018

| **Los Angeles Department of Water & Power** | **2010[a]** | **2018[a]** |
|---|---|---|
| **Firm Peak-Hour Requirement[1]** | **6,726** | **6,896** |
| **Percent Change** | | **3%** |
| **Utility Electric Generation (UEG)** | | |
| Coal-fired Plants[2] | | |
| *Navajo 1, 2 and 3 (ends after 2018)* | *477* | *477* |
| *Intermountain* | *875* | *875* |
| Total Coal-fired Plants | 1,352 | 1,352 |
| | 20% | 20% |
| Nuclear Power Plants[3] | | |
| *Palo Verde 1, 2 & 3* | *388* | *388* |
| Total Nuclear Plants | 388 | 388 |
| | 6% | 6% |
| Gas-fired Power Plants | | |
| *Harbor* | *506* | *506* |
| *Haynes 1 & 2* | *444* | *444* |
| *Haynes 5 & 6 (replaced in 2013* | *565* | *0* |
| *Haynes 8, 9 and 10 CC* | *560* | *560* |
| *Haynes CTs (600 MW adds in 2013)* | *0* | *600* |
| *Hyperion Digester (added in 2013)* | *0* | *38* |
| *Scattergood 1 (ends in 2015)* | *157* | *0* |
| *Scattergood 2 (ends in 2014)* | *179* | *0* |
| *Scattergood 3* | *450* | *450* |
| *Scattergood Combined Cycle (adds in 2014)* | *0* | *260* |
| *Scattergood CT (adds in 2015)* | *0* | *100* |
| *Valley 6, 7 & 8 Combined Cycle* | *501* | *501* |
| Total Gas-fired Plants | 3,362 | 3,459 |
| | 50% | 50% |
| Hydroelectric Power Plants | | |
| *Hoover entitlement & Castaic Pumped Storage* | *1,698* | *1,718* |
| *Aqueduct, Owens Valley & Gorge Plants* | *166* | *170* |
| *Future water system additions (adds in 2014)* | *0* | *4* |
| Total Hydroelectric | 1,864 | 1,892 |
| | 28% | 27% |
| Renewable Power | | |
| *Hyperion Digester Gas (2010 in Scattergood, alone in 2018)* | *22* | *22* |
| *Pine Tree Wind (10% of nameplate MW)* | *12* | *12* |
| *Pine Canyon Wind (10% of nameplate, adds in 2014)* | *0* | *15* |
| Total UEG Renewable | 34 | 49 |
| | <1% | <1% |
| ***Total of Utility Electric Generation*** | ***7,000*** | ***7,136*** |
| | ***104%*** | ***103%*** |
| **Long-Term Renewable and Other Bilateral Contracts (LT)** | | |
| *Numerous Renewable Resource Contracts* | *139* | *925* |
| *Distributed Generation (of about 350 MW nameplate)* | *42* | *42* |
| Total LT Contracts | 181 | 967 |

| Los Angeles Department of Water & Power | 2010[a] | 2018[a] |
|---|---|---|
| | 3% | 14% |
| ***Subtotal (UEG + LT)*** | ***7,181*** | ***8,107*** |
| | ***107%*** | ***118%*** |
| **Short-Term to Expiration Contracts (ST)** | | |
| *None* | *0* | *0* |
| Total ST Contracts | 0 | 0 |
| | 0% | 0% |
| **Total (UEG + LT +ST)** | **7,181** | **8,107** |
| | **107%** | **118%** |
| **Short-Term and Spot Market Purchases (ST/SM)**[4] | *0* | *4* |
| Total ST/SM | 0 | 4 |
| | 0% | <1% |
| **Total** | **7,181** | **8,111** |
| | **107%** | **118%** |
| **Scheduled Additions** | | |
| *Various Renewable Resources* | *89* | *807* |
| *Haynes CTs (600 MW adds in 2013)* | *0* | *600* |
| *Hyperion Digester (adds in 2013)* | *0* | *38* |
| *Scattergood Combined Cycle (adds in 2014)* | *0* | *260* |
| *Scattergood CT (adds in 2015)* | *0* | *100* |
| *Pine Canyon (wind adds in 2014)* | *0* | *15* |
| *Future water system additions (adds in 2014)* | *0* | *4* |
| ***Total Scheduled Additions*** | ***89*** | ***1,824*** |
| | ***1%*** | ***27%*** |

Notes:

a. All capacity values are in MW. Percentages are of the Firm Peak-Hour Requirement for each category.

[1] LADWP's Line 14 entry incorporates a 1,086 MW PRM for both years. This is the Most Severe Single Contingency criteria and equates to PRMs of 20 percent PRM in 2010 and 19 percent in 2018. Line 14 also adds 96 MW of Firm Sales Obligations to the California Department of Water and Power, capacity provided from Castaic.

[2] LADWP is the controlling agent of the Intermountain Generating Station. Its entitlement is 803 MW (44.62 percent) plus 72 MW (4 percent) purchase from UP&L. LADWP has a 21 percent purchase entitlement for output from the Navajo Generating Station. (http://www.srpnet.com/about/stations/navajo.aspx, and LADWP 2007 Integrated Resource Plan, http://www.ladwp.com/ladwp/cms/ladwp010273.pdf, accessed June 3, 2009.)

[3] LADWP's interest in the three-unit Palo Verde Nuclear Generation Station is 9.7 percent, of which 5.7 percent is through direct ownership, and 4 percent is through participation with the Southern California Public Power Agency (SCPPA). (LADWP 2007 Integrated Resource Plan, http://www.ladwp.com/ladwp/cms/ladwp010273.pdf, accessed June 3, 2009.

[4] Although LADWP does have some short-term and spot-market purchases, these are not made during the summer months and are not included in the peak load calculations. Staff has included 4 MW of "Future Water System Hydro" that LADWP adds in 2014.

Source: LADWP Capacity Resource Accounting Table Form S-1, February 27, 2009

## *Energy*

The Firm Energy Requirement for LADWP barely increases 1 percent over a span of eight years. Total energy supply meets 100 percent of the requirements for both years.

In 2010 and in 2018, almost 40 percent of the Firm Energy Requirements for both years are met by coal-fired generation. About half of all UEG electricity in both years will come from coal combustion. By comparison, natural gas-fired generation provides 24 percent of the Firm Energy Requirement in 2010 and 16 percent in 2018. Hydroelectric generation provides about 6 percent of the Firm Energy Requirement in both years, assuming a return to average hydrological conditions.

Energy supplies delivered under long-term contracts are forecast to nearly double from 3,469 GWh in 2010, to 6,577 GWh in 2018. All the increases in this category would be for renewable energy purchases.

**Table A-10: LADWP Energy Supplies in 2010 and 2018**

| **Los Angeles Department of Water & Power** | **2010[a]** | **2018[a]** |
|---|---|---|
| **Firm Energy Requirement** | **27,656** | **27,932** |
| **Percent Change** | | **1%** |
| **Utility Electric Generation (UEG)** | | |
| Coal-fired Plants[1] | | |
| *Navajo 1, 2 and 3* | *3,760* | *3,869* |
| *Intermountain* | *7,098* | *6,836* |
| Total Coal-fired Plants | 10,858 | 10,705 |
| | 39% | 38% |
| Nuclear Power Plants[2] | | |
| *Palo Verde 1, 2 & 3* | *2,801* | *2,856* |
| Total Nuclear Plants | 2,801 | 2,856 |
| | 10% | 10% |
| Gas-fired Power Plants | | |
| *Harbor Units and Valley 5 CT* | *145* | *1* |
| *Haynes 1 & 2; Haynes 5 & 6 (replaced in 2013)* | *679* | *128* |
| *Haynes 8, 9 and 10 CC* | *2,782* | *2,193* |
| *Haynes CTs (600 MW adds in 2013)* | *0* | *45* |
| *Hyperion Digester (adds in 2013)* | *0* | *117* |
| *Scattergood 1 (ends 2015), 2 (ends 2014), and 3* | *805* | *0* |
| *Scattergood Combined Cycle (adds in 2014)* | *0* | *561* |
| *Scattergood CT (adds in 2015)* | *0* | *1* |
| *Valley 6, 7 & 8 Combined Cycle* | *2,226* | *1,303* |
| Total Gas-fired Plants | 6,637 | 4,349 |
| | 24% | 16% |
| Hydroelectric Power Plants | | |
| *Hoover entitlement & Castaic Pumped Storage* | *1,139* | *1,087* |
| *Aqueduct, Owens Valley & Gorge Plants* | *628* | *658* |
| *Future water system additions (adds in 2014)* | *0* | *22* |
| Total Hydroelectric | 1,767 | 1,767 |
| | 6% | 6% |
| Renewable Energy Resources | | |
| *Hyperion Digester Gas* | *146* | *147* |
| *Lopez Canyon Biogas* | *2* | *2* |
| *Pine Tree Wind* | *340* | *340* |

| Los Angeles Department of Water & Power | 2010[a] | 2018[a] |
|---|---|---|
| *Pine Canyon Wind (adds in 2014)* | *0* | *424* |
| Total UEG Renewable | 488 | 913 |
| | 2% | 3% |
| ***Total of Utility Electric Generation*** | ***22,551*** | ***20,590*** |
| | ***82%*** | ***74%*** |
| **Long-Term Contracts (LT)** | | |
| *Numerous Renewable Resource Contracts* | *3,469* | *6,327* |
| *DG, Cogeneration, & Other Supplies* | *250* | *250* |
| Total LT Contracts | 3,719 | 6,577 |
| | 13% | 24% |
| ***Subtotal (UEG + LT)*** | ***26,270*** | ***27,167*** |
| | ***95%*** | ***97%*** |
| **Short-Term to Expiration Contracts (ST)** | | |
| *None* | *0* | *0* |
| Total ST Contracts | 0 | 0 |
| | 0% | 0% |
| **Total (UEG + LT +ST)** | **26,270** | **27,167** |
| | **95%** | **97%** |
| **Short-Term and Spot Market Purchases (ST/SM)** | *1,386* | *768* |
| Total ST/SM | 1,386 | 768 |
| | 5% | 3% |
| **Total** | **27,656** | **27,935** |
| | **100%** | **100%** |
| **Scheduled Additions** | | |
| *Haynes CTs (600 MW adds in 2013)* | *0* | *45* |
| *Hyperion Digester (adds in 2013)* | *0* | *117* |
| *Scattergood Combined Cycle (adds in 2014)* | *0* | *561* |
| *Scattergood CT (adds in 2015)* | *0* | *1* |
| *Pine Canyon (wind adds in 2014)* | *0* | *424* |
| *Future water system additions (adds in 2014)* | *0* | *22* |
| ***Total Scheduled Additions*** | ***0*** | ***1,170*** |
| | ***0%*** | ***4%*** |

Notes:

a. All energy values are in GWh. Each percentage value is of the Firm Energy Requirement for that category.

[1] LADWP is the controlling agent of the Intermountain Generating Station. Its entitlement is 803 MW (44.62 percent) plus 72 MW (4 percent) in purchases from UP&L. LADWP has a 21 percent purchase entitlement for output from the Navajo Generating Station. (http://www.srpnet.com/about/stations/navajo.aspx, and LADWP 2007 Integrated Resource Plan, http://www.ladwp.com/ladwp/cms/ladwp010273.pdf, accessed June 3, 2009.)

[2] LADWP's interest in the three-unit Palo Verde Nuclear Generation Station is 9.7 percent, of which 5.7 percent is through direct ownership, and 4 percent is through participation with the Southern California Public Power Agency (SCPPA). (LADWP 2007 Integrated Resource Plan, http://www.ladwp.com/ladwp/cms/ladwp010273.pdf, accessed June 3, 2009.

Source: LADWP Energy Balance Resource Accounting Table Form S-2, February 27, 2009

# Modesto Irrigation District

## *Capacity*

From 2010 to 2018, the total capacity requirement for Modesto Irrigation District (MID) increases 19 percent from 808 MW to 957 MW, while existing and specifically planned capacity resources decrease from 93 percent to 68 percent of the Firm Peak-Hour Requirement. Nearly all this apparent decrease can be attributed to nine long-term supply contracts that expire by 2018. MID is working on several contracts and resources to replace capacity from these expiring contracts. Expected supplies from UEG decrease slightly from 58 to 54 percent of the Firm Peak-Load Requirement.

MID is highly reliant on natural gas-fired generation for meeting its peak capacity needs. This category meets 42 percent the Firm Peak-Load Requirement in 2010 and 41 percent in 2018. Coal-fired resources account for about 8 percent of the Firm Peak-Load Requirement and about 14 percent of the UEG supplies in both years.

MID shows a residual resource procurement need of 57 MW in 2010 and 307 MW in 2018, but does not indicate how these needs will be filled.

Capacities from UEG coal-fired and hydroelectric generation capacity do not change between 2010 and 2018. MID's resource plan does not include UEG renewable resources during this time. Although MID plans to add more long-term renewable energy contracts by 2018, the existing renewable energy contracts with High Winds and Shiloh expire in 2015 and 2016, and negotiations to extend the contracts are currently underway.

By 2018, capacity from non-renewable long-term contracts decreases substantially from 289 MW to 68 MW. As a share of the Firm Peak-Hour Requirement, this is a decrease of more than 12 percent, and results in the combined UEG and long-term contract share of the Firm Peak-Hour Requirement dropping 16 percent from 81 to 65 percent. By 2018, MID needs another 307 MW in addition to all existing resources and planned renewable resources. Planned additions scheduled after 2010 will add 108 MW, or 11 percent of the Firm Peak-Load Requirement.

## Table A-11: Modesto ID Capacity Resources in 2010 and 2018

| **Modesto Irrigation District** | **2010[a]** | **2018[a]** |
|---|---|---|
| **Firm Peak-Hour Requirement[1]** | **808** | **957** |
| **Percent Change** | | **19%** |
| **Utility Electric Generation (UEG)** | | |
| Coal-fired Plants[2] | | |
| *San Juan[2]* | *68* | *68* |
| Total Coal-fired Plants | 68 | 68 |
| | 8% | 7% |
| Nuclear Power Plants | | |
| *None* | *0* | *0* |
| Total Nuclear Plants | 0 | 0 |
| | 0% | 0% |
| Gas-fired Power Plants | | |
| *McClure (2 CT Units)* | *108* | *108* |
| *Woodland 1 (1 CC Unit)* | *44* | *61* |
| *Woodland 2 (1 CC Unit)* | *83* | *70* |
| *Ripon (2 CT Units)* | *96* | *96* |
| *Small CT Unit* | *5* | *5* |
| *Reciprocating Engine[3] (adds in 2011)* | *0* | *48* |
| *Lodi Energy Center (adds in 2012)* | *0* | *60* |
| Total Gas-fired Plants | 336 | 448 |
| | 42% | 47% |
| Hydroelectric Power Plants | | |
| *All utility-controlled Hydro Plants* | *62* | *62* |
| Total Hydroelectric | 62 | 62 |
| | 8% | 6% |
| Renewable Power | | |
| *None that are utility-owned* | *0* | *0* |
| Total UEG Renewable | 0 | 0 |
| | 0% | 0% |
| ***Total of Utility Electric Generation*** | ***466*** | ***518*** |
| | ***58%*** | ***54%*** |
| **Long-Term (LT) Renewable Contracts** | | |
| *High Winds (ends in 2014)* | *13* | *0* |
| *Shiloh (ends in 2016)* | *25* | *0* |
| *Big Horn* | *8* | *8* |
| *Fiscalini* | *1* | *1* |
| *Board Approved Renewables* | *17* | *33* |
| *Future Renewables (adds in 2016)* | *0* | *30* |
| Total LT Renewable Contracts | 64 | 72 |
| | 8% | 8% |
| ***Subtotal (UEG + LT)*** | ***651*** | ***620*** |
| | ***81%*** | ***65%*** |
| **Long-Term (LT) Non-Renewable Contracts** | | |
| *9 of 10 contracts expire by 2018* | *289* | *68* |
| Total LT Non-Renewable Contracts | 289 | 68 |

| Modesto Irrigation District | 2010[a] | 2018[a] |
|---|---|---|
| | 36% | 7% |
| **Total (UEG + LT +LTN)** | **751** | **651** |
| | **93%** | **68%** |
| **Short-Term and Spot Market Purchases (ST/SM)** | *0* | *0* |
| Total ST/SM | *0* | *0* |
| | *0%* | *0%* |
| **Total** | **751** | **651** |
| | **93%** | **68%** |
| **Scheduled Additions** | | |
| *Reciprocating Engine[3] (adds in 2011)* | *0* | *48* |
| *Lodi Energy Center (adds in 2012)* | *0* | *60* |
| ***Total Scheduled Additions*** | ***48*** | ***108*** |
| | ***0%*** | ***11%*** |

Notes:

a. All capacity values are in MW. Percentages are of the Firm Peak-Hour Requirement for each category.

[1] MID's Line 14 entry incorporates a 15 percent PRM applied to Line 11, Coincident Peak-Hour Demand. Line 14 also includes 3 MW of capacity for imports that carry their own reserves.

[2] Coal-fired San Juan and gas-fired Lodi Energy Center were listed by MID under Other Bilateral Contract Resources. However, they are classified in this report as UEG to be consistent with other LSEs that have very long-term contractual ownership rights to the energy from a joint powers facility.

[3] The reciprocating engine is natural gas-fired.

Source: MID Capacity Resource Accounting Table Form S-1, January 31, 2009, updated March 23, 2009

## *Energy*

MID's Firm Energy Requirement increases by 16 percent between 2010 and 2018. Total energy supply is 105 percent of this requirement in 2010, and 104 percent in 2018.

MID relies on coal-fired generation for about 17 percent of the Firm Energy Requirements for both years. About half of the UEG for 2010 is met by coal-fired generation, but the percentage drops to 27 percent in 2018. By comparison, natural gas-fired generation provides 14 percent of the Firm Energy Requirement in 2010 and 36 percent in 2018; this equals 37 percent of UEG energy in 2010 and 62 percent in 2018. UEG hydroelectric generation provides about 6 percent of the Firm Energy Requirement in both years.

Long-term contractual energy supplies decrease almost 860 GWh between 2010 and 2018. MID has 19 contracts from which it expects 1,493 non-renewable GWh in 2010. The three contracts that continue through 2018 are estimated to supply 632 GWh that year. This category represents 52 percent of the 2010 Firm Energy Requirement, and just 19 percent of the 2018 requirement. Scheduled UEG additions by 2018 include two natural gas-fired resources totaling more than 100 GWh.

## Table A-12: Modesto ID Energy Supplies in 2010 and 2018

| **Modesto Irrigation District** | **2010[a]** | **2018[a]** |
|---|---|---|
| **Firm Energy Requirement** | **2,876** | **3,323** |
| **Percent Change** | | **16%** |
| **Utility Electric Generation (UEG)** | | |
| Coal-fired Plants[1] | | |
| *San Juan[2]* | *527* | *529* |
| Total Coal-fired Plants | 527 | 529 |
| | 18% | 16% |
| Nuclear Power Plants | | |
| *None* | *0* | *0* |
| Total Nuclear Plants | 0 | 0 |
| | 0% | 0% |
| Gas-fired Power Plants | | |
| *McClure (2 CT Units)* | *20* | *13* |
| *Woodland 1 (1 CC Unit)* | *39* | *346* |
| *Woodland 2 (1 CC Unit)* | *329* | *239* |
| *Ripon (2 CT Units)* | *23* | *22* |
| *Small CT Unit* | *0* | *0* |
| *Reciprocating Engine (adds in 2011)[2]* | *0* | *71* |
| *Lodi (adds in 2012)* | *0* | *509* |
| Total Gas-fired Plants | 411 | 1,200 |
| | 14% | 36% |
| Hydroelectric Power Plants | | |
| *All utility-controlled Hydro Plants* | *175* | *201* |
| Total Hydroelectric | 175 | 201 |
| | 6% | 6% |
| Renewable Energy Resources | | |
| *None that are utility-owned* | *0* | *0* |
| Total UEG Renewable | 0 | 0 |
| | 0% | 0% |
| ***Total of Utility Electric Generation*** | ***1,113*** | ***1,930*** |
| | ***39%*** | ***58%*** |
| **Long-Term Renewable Energy Contracts (LT)** | | |
| *High Winds (ends in 2014)* | *74* | *0* |
| *Shiloh (ends in 2015)* | *149* | *0* |
| *Big Horn* | *76* | *76* |
| *Fiscalini* | *5* | *5* |
| *Board Approved Renewables* | *153* | *305* |
| *Future Renewables (adds in 2016)* | *0* | *263* |
| Total LT Contracts | 457 | 649 |
| | 16% | 20% |
| ***Subtotal (UEG + LT)*** | ***2,450*** | ***2,418*** |
| | ***85%*** | ***73%*** |
| **Long-Term Non-Renewable Contracts (LTN)** | | |
| *16 of 19 contracts expire by 2018* | *1,493* | *632* |
| Total LTN Contracts | 1,493 | 632 |

| Modesto Irrigation District | 2010[a] | 2018[a] |
|---|---|---|
| | 52% | 19% |
| **Total (UEG + LT +LTN)** | **2,536** | **2,681** |
| | **88%** | **81%** |
| **Short-Term and Spot Market Purchases (ST/SM)** | *491* | *790* |
| Total ST/SM | 491 | 790 |
| | 17% | 24% |
| **Total** | **3,027** | **3,471** |
| | **105%** | **104%** |
| **Scheduled Additions** | | |
| *Reciprocating Engine (adds in 2011)*[2] | *48* | *48* |
| *Lodi (adds in 2012)* | *0* | *60* |
| *Various Contracts* | *0* | *263* |
| ***Total Scheduled Additions*** | ***48*** | ***371*** |
| | ***2%*** | ***11%*** |

Notes:

a. All energy values are in GWh. Each percentage value is of the Firm Energy Requirement for that category.

[1] San Juan Coal listed by MID under Other Bilateral Contracts.

[2] The reciprocating engine is natural gas-fired. (Telephone conversation with Gerry Stillwagon of Modesto Irrigation District staff on May 28, 2009. M. Pryor)

Source: MID Energy Balance Resource Accounting Table Form S-2, January 31, 2009, updated March 23, 2009

# Northern California Power Agency

## *Capacity*

Northern California Power Agency's (NCPA) total capacity requirement increases 5 percent from 532 MW in 2010 to 562 MW in 2018. For these two years, expected supplies are 118 percent and 114 percent of the Firm Peak-Hour Requirement. Existing resources are more than adequate to meet annual peak loads through 2018, including a 15 percent PRM.

UEG resources are a stable component of the NCPA portfolio, comprising 52 percent of the Firm Peak-Load Requirement in 2010 and 54 percent in 2018. UEG capacity from four hydroelectric power plants satisfy about one-fourth of the Firm Peak-Load Requirement, and make up 48 and 44 percent of UEG capacity for both years, respectively. UEG natural gas capacity increases from 76 MW to 99 MW, due entirely to NCPA's 23 MW share in the planned Lodi Energy Center. This new resource increases the category's share of the Firm Peak-Hour Requirement from 14 to 18 percent. UEG renewable resources (other than hydro) are entirely geothermal, remaining steady in their contribution at 67 MW.

At 310+ MW, long-term contracts provide more than 55 percent of the expected the Firm Peak-Hour capacity requirement throughout the forecast period. Most of this supply is filled by a contract for 215 MW from the Western Area Power Authority. Another large

component, 68 MW, is capacity from wind and landfill sources. Contracts that expire by 2012 account for 44 MW of capacity in 2010. This is about 7 percent of the total capacity supplies and 8 percent of the Firm Peak-Hour Requirement for that year.

All the additional capacity comes from the Lodi Energy Center natural gas-fired power plant.

**Table A-13: NCPA Capacity Resources in 2010 and 2018**

| **Northern California Power Agency** | **2010[a]** | **2018[a]** |
|---|---|---|
| **Firm Peak-Hour Requirement[1]** | **532** | **562** |
| **Percent Change** | | **5%** |
| **Utility Electric Generation (UEG)** | | |
| Coal-fired Plants | | |
| *None* | *0* | *0* |
| Total Coal-fired Plants | 0 | 0 |
| | 0% | 0% |
| Nuclear Power Plants | | |
| *None* | *0* | *0* |
| Total Nuclear Plants | 0 | 0 |
| | 0% | 0% |
| Gas-fired Power Plants | | |
| *NCPA Alameda CT Unit 1* | *14* | *14* |
| *NCPA Alameda CT Unit 2* | *15* | *15* |
| *NCPA Lodi CT Unit 1* | *13* | *13* |
| *Palo Alto COBUG, (NCPA MSSAA)* | *5* | *5* |
| *NCPA Lodi STIG* | *30* | *30* |
| *Lodi Energy Center (adds in 2012)* | *0* | *23* |
| Total Gas-fired Plants | 76 | 99 |
| | 14% | 18% |
| Hydroelectric Power Plants | | |
| *Collierville Hydro Unit 1 & 2 Aggregate* | *126* | *126* |
| *Spicer Hydro Units 1-3 Aggregate* | *3* | *3* |
| *Lake Mendocino Hydro* | *4* | *4* |
| Total Hydroelectric | 133 | 133 |
| | 25% | 24% |
| Renewable Power | | |
| *NCPA Geothermal Plants (GP 1 & 2, Unit 1-4)* | *67* | *67* |
| Total UEG Renewable | 67 | 67 |
| | 13% | 12% |
| ***Total of Utility Electric Generation*** | ***276*** | ***298*** |
| | ***52%*** | ***53%*** |
| **Long-Term Contracts (LT)** | | |
| *Iberdrola Renewables (wind, expected capacity)* | *48* | *48* |
| *Ameresco Half Moon Bay LLC (landfill gas)* | *11* | *11* |
| *Ameresco Keller Canyon LLC (landfill gas)* | *4* | *4* |
| *Ameresco Santa Cruz Energy LLC (landfill gas)* | *3* | *3* |
| *Republic Services, Inc (Richmond Landfill)* | *2* | *2* |

| Northern California Power Agency | 2010[a] | 2018[a] |
|---|---|---|
| *Seattle City Light Exchange (COB)* | *27* | *27* |
| *Western Area Power Authority Delivery (Tracy)* | *215* | *215* |
| *Morgan Stanley Capital Group, Inc. (ends in 2015)* | *2* | *0* |
| Total LT Contracts | 312 | 310 |
| | 59% | 55% |
| ***Subtotal (UEG + LT)*** | ***588*** | ***609*** |
| | ***111%*** | ***108%*** |
| **Short-Term to Expiration Contracts (ST)** | | |
| *Utah Assoc. Municipal Power Systems (ends in 2012)* | *5* | *0* |
| *Cargill Power Markets, LLC (ends in 2011)* | *5* | *0* |
| *Powerex (2010 only)* | *25* | *0* |
| *Sempra Energy Trading LLC (2010 only)* | *2* | *0* |
| *Shell Energy North America (ends in 2012)* | *5* | *0* |
| Total ST Contracts | 42 | 0 |
| | 8% | 0% |
| **Total (UEG + LT +ST)** | **630** | **609** |
| | **118%** | **108%** |
| **Short-Term and Spot Market Purchases (ST/SM)** | *0* | *30* |
| Total ST/SM | 0 | 30 |
| | 0% | 5% |
| **Total** | **630** | **639** |
| | **118%** | **114%** |
| **Scheduled Additions** | | |
| *Lodi Energy Center (adds in 2012)* | *0* | *23* |
| ***Total Scheduled Additions*** | ***0*** | ***23*** |
| | ***0%*** | ***4%*** |

Notes:

a. All capacity values are in MW. Percentages are of the Firm Peak-Hour Requirement for each category.

[1] NCPA's Line 14 entry incorporates a 15 percent PRM applied to Line 11, Coincident Peak-Hour Demand. Line 14 also includes 3 MW of capacity for imports that carry their own reserves.

Source: NCPA Capacity Resource Accounting Table Form S-1, February 13, 2009

## *Energy*

NCPA's Firm Energy Requirement increases by 7 percent from 2,642 GWh in 2010 to 2,832 GWh in 2018. A balanced energy supply table from NCPA shows firm loads are matched 100 percent to resources in both years. Supply resources include 325 GWh in short-term or spot-market purchases in 2010, and 922 GWh in 2018.

Combined, UEG hydroelectric and renewable energy generation provides about one quarter of the Firm Energy Requirement in both years; this combination equals 89 percent of the UEG category energy total in 2010 and 72 percent in 2018. When these amounts are further combined with contracted renewable resources, about 37 percent of the Firm Energy Requirement is met during both years by hydroelectric and other renewables sources.

Long-term contract energy resources barely change between 2010 and 2018, making up approximately 37 percent of NCPA's Firm Energy Requirement. Deliveries by Western Area Power Administration account for 22 percent of the Firm Energy Requirement during both years. Short–term contracts provide about 20 percent of 2010's requirement.

The sole addition is the Lodi Energy Center in 2012, adding 180 GWh of energy in 2018, accounting for about 6 percent of the Firm Energy Requirement that year.

**Table A-14: NCPA Energy Supplies in 2010 and 2018**

| **Northern California Power Agency** | **2010[a]** | **2018[a]** |
|---|---|---|
| **Firm Energy Requirement[1]** | **2,642** | **2,832** |
| **Percent Change** | | **7%** |
| **Utility Electric Generation (UEG)** | | |
| Coal-fired Plants | | |
| *None* | *0* | *0* |
| Total Coal-fired Plants | 0 | 0 |
| | 0% | 0% |
| Nuclear Power Plants | | |
| *None* | *0* | *0* |
| Total Nuclear Plants | 0 | 0 |
| | 0% | 0% |
| Gas-fired Power Plants | | |
| *NCPA Alameda CT Unit 1* | *3* | *3* |
| *NCPA Alameda CT Unit 2* | *2* | *2* |
| *NCPA Lodi CT Unit 1* | *1* | *1* |
| *Palo Alto COBUG, (NCPA MSSAA)* | *1* | *1* |
| *NCPA Lodi STIG* | *77* | *77* |
| *Lodi Energy Center (adds in 2012)* | *0* | *180* |
| *NCPA Alameda CT Unit 1* | *3* | *3* |
| Total Gas-fired Plants | 84 | 264 |
| | 3% | 9% |
| Hydroelectric Power Plants | | |
| *Collierville Hydro Unit 1 & 2 Aggregate* | *255* | *255* |
| *Spicer Hydro Units 1-3 Aggregate* | *10* | *10* |
| *NCPA Lake Mendocino Hydro Aggregate* | *9* | *9* |
| Total Hydroelectric | 274 | 274 |
| | 10% | 10% |
| Renewable Energy Resources | | |
| *NCPA Geothermal Plants (GP 1 & 2, Unit 1-4)* | *399* | *399* |
| Total UEG Renewable | 399 | 399 |
| | 15% | 14% |
| ***Total of Utility Electric Generation*** | ***757*** | ***937*** |
| | ***29%*** | ***33%*** |
| **Long-Term Contracts (LT)** | | |
| *Iberdrola Renewables (wind)* | *154* | *154* |
| *Ameresco Half Moon Bay LLC (landfill gas)* | *100* | *100* |
| *Ameresco Keller Canyon LLC (landfill gas)* | *35* | *35* |
| *Ameresco Santa Cruz Energy LLC (landfill gas)* | *25* | *4* |

| Northern California Power Agency | 2010[a] | 2018[a] |
|---|---|---|
| *Republic Services, Inc (Richmond Landfill)* | *18* | *18* |
| *Seattle City Light Exchange (COB)* | *41* | *41* |
| *Western Area Power Administration (WAPA)* | *571* | *619* |
| *Morgan Stanley Capital Group, Inc. (ends in 2015)* | *92* | *0* |
| Total LT Contracts | 1,036 | 971 |
| | 39% | 34% |
| ***Subtotal (UEG + LT)*** | ***1,793*** | ***1,908*** |
| | ***68%*** | ***67%*** |
| **Short-Term to Expiration Contracts (ST)** | | |
| *Utah Assoc. Muni. Power Systems (ends in 2012)* | *44* | *0* |
| *Cargill Power Markets, LLC (ends in 2011)* | *22* | *0* |
| *Conoco Phillips (ends in 2010)* | *109* | *0* |
| *Iberdrola Renewable (ends in 2010)* | *18* | *0* |
| *Powerex (ends in 2011)* | *132* | *0* |
| *Sempra Energy Trading LLC (ends in 2011)* | *64* | *0* |
| *Shell Energy North America (ends in 2012)* | *133* | *0* |
| | 522 | 0 |
| | 20% | 0% |
| **Total (UEG + LT +ST)** | **2,315** | **1,908** |
| | **88%** | **67%** |
| **Short-Term and Spot Market Purchases (ST/SM)** | *325* | *922* |
| Total ST/SM | 325 | 922 |
| | 12% | 33% |
| **Total** | **2,640** | **2,830** |
| | **100%** | **100%** |
| **Scheduled Additions** | | |
| *Lodi Energy Center (adds in 2012)* | *0* | *180* |
| ***Total Scheduled Additions*** | ***0*** | ***180*** |
| | ***0%*** | ***6%*** |

Notes:

a. All energy values are in GWh. Each percentage value is of the Firm Energy Requirement for that category.

[1] San Juan Coal listed by MID under Other Bilateral Contracts.

[3] The reciprocating engine is natural gas-fired. (Telephone conversation with Gerry Stillwagon of Modesto Irrigation District staff on May 28, 2009. M. Pryor)

Source: NCPA Energy Balance Resource Accounting Table Form S-2, February 13, 2009

# Pasadena Water and Power

## *Capacity*

Pasadena's total capacity requirement increases 6 percent from 368 MW in 2010 to 393 MW in 2018. Existing capacity resources are almost sufficient to cover the forecast annual peak load through 2018, including a 15 percent PRM. Pasadena expects a 34 MW capacity surplus

in 2010. Surpluses of at least 18 MW continue through 2015. By 2018, Pasadena has a 7 MW procurement need that by then may be secured by a variety of options.

Pasadena relies on coal-fired Intermountain for more than one-quarter of its UEG capacity and about 28 percent of its Firm Peak-Hour Requirement.[21] From 2010 to 2018, expected UEG supplies decrease from 98 to 92 percent of the Firm Peak-Load Requirement. Pasadena also relies on other imports to that part of the California ISO controlled grid designated as the LA Basin local reliability area. These imports include 10 MW in nuclear power from Palo Verde, 20 MW in hydropower from Hoover, up to 15 MW from the Bonneville Power Administration, and 19 MW from Magnolia in nearby Burbank connected to the LADWP balancing area.

Capacities and category shares of UEG meeting the Firm Peak-Hour Requirement provided by renewable resources and coal-fired, nuclear, natural gas-fired, and hydroelectric plants either do not change or change minimally between 2010 and 2018.

Long-term contracts decrease from 40 MW in 2010 to 29 MW in 2018. Pasadena's capacity resource accounting table does not include a reliance on short-term contracts or spot market purchases. The only scheduled generation addition is the small four MW Skunk Creek landfill gas project, in 2011.

[21] One goal stated in Pasadena's 2009 Integrated Resource Plan (IRP) is "[r]educing coal power purchases from a Utah plant by at least 35 MW by 2016." (Pasadena Water and Power 2009 Integrated Resource Plan, http://www.ci.pasadena.ca.us/waterandpower/IRP/default.as, accessed June 3, 2009. If this goal is realized, Intermountain's contribution in capacity would drop from 108 to 73 MW, a 32 percent decrease. This would reduce total capacity from 370 to 335 MW, a 9 percent decrease, and reduce the percentage of net electric load capacity to 98 percent from 108 percent. This would require obtaining replacement resources with assured delivery to Pasadena.

## Table A-15: Pasadena Capacity Resources in 2010 and 2018

| **Pasadena Water and Power** | **2010[a]** | **2018[a]** |
|---|---|---|
| **Firm Peak-Hour Requirement[1]** | **368** | **393** |
| **Percent Change** | | **6%** |
| **Utility Electric Generation (UEG)** | | |
| | | |
| Coal-fired Plants[2] | | |
| *Intermountain* | *108* | *108* |
| Total Coal-fired Plants | 108 | 108 |
| | 29% | 27% |
| Nuclear Power Plants[3] | | |
| *Palo Verde* | *10* | *10* |
| Total Nuclear Plants | 10 | 10 |
| | 3% | 3% |
| Gas-fired Power Plants | | |
| *Magnolia Power Project* | *19* | *19* |
| *Glenarm 7 Units 1 - 4* | *132* | *132* |
| *Broadway 7 Unit 3* | *65* | *65* |
| Total Gas-fired Plants | 216 | 216 |
| | 59% | 55% |
| Hydroelectric Power Plants | | |
| *Hoover entitlement* | *20* | *20* |
| *Azusa* | *7* | *7* |
| Total Hydroelectric | 27 | 27 |
| | 7% | 7% |
| Renewable Power | | |
| *None that are utility-owned* | *0* | *0* |
| Total UEG Renewable | 0 | 0 |
| | 0% | 0% |
| ***Total of Utility Electric Generation*** | ***361*** | ***361*** |
| | ***98%*** | ***92%*** |
| **Long-Term Contracts (LT)** | | |
| *PPM High Wind (wind)* | *2* | *2* |
| *Minnesota Methane (landfill gas)* | *10* | *10* |
| *Ormat Heber-South (geothermal)* | *2* | *2* |
| *Ameresco Chiquita Canyon (landfill gas)* | *7* | *7* |
| *UPC Milford I (wind)* | *5* | *5* |
| *Skunk Creek (landfill gas) (adds in 2011)* | *0* | *4* |
| *BPA Peaking Energy May-Sep (ends in 2016)* | *15* | *0* |
| Total LT Contracts | 40 | 29 |
| | 11% | 7% |
| ***Subtotal (UEG + LT)*** | ***401*** | ***390*** |
| | ***109%*** | ***99%*** |
| **Short-Term to Expiration Contracts (ST)** | | |
| *None* | *0* | *0* |
| Total ST Contracts | 0 | 0 |
| | 0% | 0% |

| Pasadena Water and Power | 2010[a] | 2018[a] |
|---|---|---|
| **Total (UEG + LT +ST)** | **401** | **390** |
| | **109%** | **99%** |
| **Short-Term and Spot Market Purchases (ST/SM)** | *0* | *4* |
| Total ST/SM | 0 | 4 |
| | 0% | 1% |
| **Total** | **401** | **394** |
| | **109%** | **100%** |
| **Scheduled Additions** | | |
| *Skunk Creek (landfill gas) (adds in 2011)* | *0* | *4* |
| ***Total Scheduled Additions*** | ***0*** | ***4*** |
| | ***0%*** | ***1%*** |

Notes:

a. All capacity values are in MW. Percentages are of the Firm Peak-Hour Requirement for each category.

[1] Pasadena's Line 14 entry incorporates a 15 percent PRM applied to Line 11.

[2] Pasadena's share of the Intermountain Generating Station's output is about 4 percent. (http://www.ipautah.com/about/, accessed June 3, 2009.)

[3] Pasadena's share of the Palo Verde Nuclear Generating Station is about 4 percent. (SCPPA 2007-2008 Annual Report, p. 9, http://www.scppa.org/Downloads/Annual%20Report/scppaar1208.pdf, accessed June 3, 2009.)

Source: Pasadena Capacity Resource Accounting Table Form S-1, February 11, 2009, updated April 23, 2009

## *Energy*

Pasadena's total Firm Energy Requirement increases 6 percent from 1,292 GWh in 2010 to 1,378 GWh in 2018. Although expected energy supplies keep pace in a balanced energy plan for loads and resources, Pasadena indicates a procurement need for 253 GWh in 2018 that for now is allocated to the short-term and spot market purchases category. This need is about 18 percent of the 2018 Firm Energy Requirement.

Pasadena is very dependent on electricity from fossil fuel resources, particularly coal-fired. Coal and natural gas-fired resources together provide approximately 70 percent of the Firm Energy Requirement for 2010 and 2018, and comprise about 90 percent of Pasadena's UEG for those years. Alone, the coal-fired Intermountain Power Plant provides almost 60 percent of Pasadena's Firm Energy Requirement, and 74 percent of its UEG energy. By comparison, Pasadena's share in gas-fired Magnolia provides about 10 percent of Pasadena's Firm Energy Requirement in all forecast years. This must-take energy from Magnolia is Pasadena's largest fossil-based electricity supply after Intermountain.

Hydroelectric resources supply just 55 GWh in 2010. With the ending of Pasadena's Hoover entitlement in fall 2017, Pasadena is not yet counting on any continuity in this supply in 2018.

Existing energy supplies from long-term contracts decrease 31 percent from 193 GWh in 2010 to 134 GWh in 2018. There are no long-term contracts that expire in the near future.

The only new scheduled energy supply is the 4 MW Skunk Creek landfill gas project in 2011, expected to provide 30 GWh, or 2 percent of the Firm Energy Requirement in 2018.

**Table A-16: Pasadena Energy Supplies in 2010 and 2018**

| **Pasadena Water and Power** | **2010[a]** | **2018[a]** |
|---|---|---|
| **Firm Energy Requirement** | **1,292** | **1,378** |
| **Percent Change** | | **6%** |
| **Utility Electric Generation (UEG)** | | |
| Coal-fired Plants[1] | | |
| *Intermountain* | *759* | *759* |
| Total Coal-fired Plants | 759 | 759 |
| | 59% | 55% |
| Nuclear Power Plants[2] | | |
| *Palo Verde* | *68* | *68* |
| Total Nuclear Plants | 68 | 68 |
| | 5% | 5% |
| Gas-fired Power Plants | | |
| *Magnolia Power Project* | *110* | *110* |
| *Glenarm 7 Units 1 – 4* | *42* | *42* |
| *Broadway 7 Unit 3* | *13* | *13* |
| Total Gas-fired Plants | 165 | 165 |
| | 13% | 12% |
| Hydroelectric Power Plants | | |
| *Hoover entitlement* | *54* | *0* |
| *Azusa* | *1* | *1* |
| Total Hydroelectric | 55 | 1 |
| | 4% | 0% |
| Renewable Energy Resources | | |
| *None that are utility-owned* | *0* | *0* |
| Total UEG Renewable | 0 | 0 |
| | 0% | 0% |
| ***Total of Utility Electric Generation*** | ***1,047*** | ***993*** |
| | ***81%*** | ***72%*** |
| **Long-Term Contracts (LT)** | | |
| *PPM High Wind (wind)* | *18* | *18* |
| *Minnesota Methane (landfill gas)* | *76* | *0* |
| *Ormat Heber-South (geothermal)* | *17* | *17* |
| *Ameresco Chiquita Canyon (landfill gas)* | *56* | *56* |
| *UPC Milford I (wind)* | *13* | *13* |
| *Skunk Creek (landfill gas) (adds in 2011)* | *0* | *30* |
| *BPA Peaking Energy May-Sep (ends in 2016)* | *13* | *0* |
| Total LT Contracts | 193 | 134 |
| | 15% | 10% |
| ***Subtotal (UEG + LT)*** | ***1,240*** | ***1,127*** |
| | ***96%*** | ***82%*** |
| **Short-Term to Expiration Contracts (ST)** | | |
| *None* | *0* | *0* |

| Pasadena Water and Power | 2010[a] | 2018[a] |
|---|---|---|
| Total ST Contracts | 0 | 0 |
| | 0% | 0% |
| **Total (UEG + LT +ST)** | **1,240** | **1,127** |
| | **96%** | **82%** |
| **Short-Term and Spot Market Purchases (ST/SM)** | *54* | *253* |
| Total ST/SM | 54 | 253 |
| | 4% | 18% |
| **Total** | **1,294** | **1,380** |
| | **100%** | **100%** |
| **Scheduled Additions** | | |
| *Skunk Creek (landfill gas) (adds in 2011)* | *0* | *13* |
| ***Total Scheduled Additions*** | ***0*** | ***13*** |
| | 0% | 1% |

Notes:

a. All energy values are in GWh. Each percentage value is of the Firm Energy Requirement for that category.

[1] Pasadena's share of the Intermountain Generating Station's output is about 4 percent. (http://www.ipautah.com/about/, accessed June 3, 2009.)

[2] Pasadena's share of the Palo Verde Nuclear Generating Station is about 4 percent. (SCPPA 2007-2008 Annual Report, p. 9, http://www.scppa.org/Downloads/Annual%20Report/scppaar1208.pdf, accessed June 3, 2009.)

Source: Pasadena Energy Balance Resource Accounting Table Form S-2, February 11, 2009, updated April 23, 2009.

# Redding Electric Utility

## *Capacity*

Redding's total capacity requirement increases from 329 MW in 2010 to 412 MW in 2017, and then drops to 377 MW in 2018. On supply form S-1, Redding listed a 35 MW firm sales obligation through 2017 that recognizes Redding's resource procurement and scheduling commitments to the nearby City of Shasta Lake publicly owned utility.

Redding's expected capacity supplies are more than adequate to meet the forecast Firm Peak-Load Requirement through 2014, including a 15 percent PRM. Redding foresees a capacity surplus above its peak-load requirement at 94 MW in 2010, a surplus that gradually diminishes due to load growth. By 2017, Redding sees a need to procure an additional 42 MW beyond existing and planned resources. Staff believes Redding will not have difficulty obtaining these needed capacity resources.

Redding's expected supplies from UEG increase from 176 to 198 MW, but remains at 53 percent of the Firm Peak-Load Requirement during both years. Beginning in 2015, Redding lists 22 MW of coal-fired generation as a direct supply import from San Juan. Through 2014, under terms of an exchange contract with PacifiCorp, Redding is able to "*bank*" some of the San Juan generation for delivery during peak and shoulder hours in the months of May through September. This banking and exchange delivery agreement boosts

the capacity value of the San Juan resource to 50 MW through 2014. This San Juan capacity is 6 percent of the 2018 Firm Peak-Load Requirement.

About half of Redding's Firm Peak-Load Requirements can be met by locally-sited utility-controlled resources. Redding's natural gas power plant is 98 percent of this local UEG. The other 2 percent is from a small hydro plant named Whiskeytown.

Capacity from existing long-term contracts decreases markedly from 224 MW in 2010 to 124 MW in 2018, a 53 percent reduction. As a share of meeting the Firm Peak-Load Requirement, this represents a decrease from 68 percent to 33 percent. Since 2004, Redding has had a contract with American Electric Power for 25 MW of firm, baseload power delivered to the California-Oregon border. This long-term contract ends in 2011 (listed in Table A-17 as a short-term contract for bilateral supplies with near-term expiration dates.)

**Table A-17: Redding Capacity Resources in 2010 and 2018**

| **Redding Electric Utility** | **2010[a]** | **2018[a]** |
|---|---|---|
| **Firm Peak-Hour Requirement[1]** | **329** | **377** |
| **Percent Increase** | | **15%** |
| **Utility Electric Generation (UEG)** | | |
| Coal-fired Plants | | |
| *San Juan Unit 4 [2]* | *0* | *22* |
| Total Coal-fired Plants | 0 | 22 |
| | 0% | 6% |
| Nuclear Power Plants | | |
| *None* | *0* | *0* |
| Total Nuclear Plants | 0 | 0 |
| | 0% | 0% |
| Gas-fired Power Plants | | |
| *Redding Power Units 1-6* | *173* | *173* |
| Total Gas-fired Plants | 173 | 173 |
| | 53% | 46% |
| Hydroelectric Power Plants | | |
| *Whiskeytown* | *3* | *3* |
| Total Hydroelectric | 3 | 3 |
| | 1% | 1% |
| Renewable Power | | |
| *None that are utility-owned* | *0* | *0* |
| Total UEG Renewable | 0 | 0 |
| | 0% | 0% |
| ***Total of Utility Electric Generation*** | ***176*** | ***198*** |
| | ***53%*** | ***53%*** |
| **Long-Term Contracts (LT) [3]** | | |
| *Iberdrola (PPM) (wind)* | *26* | *26* |
| *Roseburg RLC Industries (biomass) (adds in 2010)* | *8* | *8* |
| *PacifiCorp Exchange (linked to San Juan Unit 4 to 2014) [2]* | *50* | *0* |
| *CVP Hydro, Base Resource and Base Resource Assignment* | *124* | *124* |
| Total LT Contracts | 224 | 124 |

| Redding Electric Utility | 2010[a] | 2018[a] |
|---|---|---|
| | 68% | 33% |
| ***Subtotal (UEG + LT)*** | ***400*** | ***322*** |
| | ***122%*** | ***85%*** |
| **Short-Term to Expiration Contracts (ST)** | | |
| *AEP (ends in 2011)* | *25* | *0* |
| Total ST Contracts | 25 | 0 |
| | 8% | 0% |
| **Total (UEG + LT +ST)** | **425** | **322** |
| | **129%** | **85%** |
| **Short-Term and Spot Market Purchases (ST/SM)** | *14* | *0* |
| Total ST/SM | 14 | 0 |
| | 4% | 0% |
| **Total** | **439** | **322** |
| | **134%** | **85%** |
| **Scheduled Additions** | | |
| *Roseburg RLC Industries (biomass) (adds in 2010)* | *8* | *8* |
| *Redding Power Unit 6 (adds in 2010)* | *44* | *44* |
| ***Total Scheduled Additions*** | ***52*** | ***52*** |
| | ***16%*** | ***14%*** |

Notes:

a. All capacity values are in MW. Percentages are of the Firm Peak-Hour Requirement for each category.

[1] Redding's Line 14 entry incorporates a 15 percent PRM. Line 14 also incorporated Firm Sales Obligations of 35 MW in 2010, zero in 2018.

[2] San Juan Unit 4 is not scheduled to provide real-time capacity (MW) until 2015, but it does provide banked and shaped energy supplies (GWh) from 2007 through 2014, inclusive. This arrangement is made possible by a pre-paid exchange agreement with PacifiCorp.

[3] Redding lists both CVP Base Resource and CVP Base Resource Assignment as separate resources on the S-1 form with capacities of 114 MW and 10 MW in 2010, respectively, in all forecast years. For annual energy, these listings are combined on supply form S-2.

Source: Redding Capacity Resource Accounting Table Form S-1, February 9, 2009, updated July 28, 2009

## *Energy*

Redding's Firm Energy Requirement increases 39 percent from 1,022 GWh in 2010 to 1,426 GWh in 2018. Expected supplies are adequate for all forecast years, though they decrease from 128 percent to 100 percent of the Firm Energy Requirement. It is interesting that Redding lists 123 GWh of short-term and spot market purchases in 2010 through 2017, but none in 2018. Without these purchases, the 2010 aggregate supplies equal 116 percent of the 2010 Firm Energy Requirement. Through 2017, Redding has a firm sales obligation to the City of Shasta Lake for about 190 GWh annually.

Through 2014, Redding annually takes 71 GWh directly from coal-fired San Juan Unit 4 on a real-time, unit contingent basis. Also through 2014, another 120 GWh from San Juan is taken by PacifiCorp in real time, and shaped for delivery to Redding during higher demand periods in summer and fall months. Altogether, the total 191 GWh from San Juan each year

accounts for 19 percent of the Firm Energy Requirement in 2010, and 13 percent in 2018. San Juan provides about 22 percent of UEG energy in both years.

Coal and natural gas-fired resources together provide 21 percent of the 2010 Firm Energy Requirement; in 2018 it is 62 percent. This increase is largely due to expected generation increases from the expanded Redding Power Units. As the only UEG natural gas-fired resource, the Redding Power Units generate 69 percent of all UEG energy in 2010, and 76 percent in 2018. These units provide 20 percent of the 2010 Firm Energy Requirement and 49 percent of the 2018 requirement.

Staff believes Redding will not have difficulty obtaining 123 GWh from short-term and spot market purchases through 2017; these are purchases that effectively help meet the procurement obligations of the City of Shasta Lake.

**Table A-18: Redding Energy Supplies in 2010 and 2018**

| **Redding Electric Utility** | **2010[a]** | **2018[a]** |
|---|---|---|
| **Firm Energy Requirement** | **1,022** | **1,426** |
| **Percent Increase** | | **39%** |
| **Utility Electric Generation (UEG)** | | |
| Coal-fired Plants | | |
| *San Juan Unit 4[1]* | *71* | *191* |
| Total Coal-fired Plants | 71 | 191 |
| | 7% | 13% |
| Nuclear Power Plants | | |
| *None* | *0* | *0* |
| Total Nuclear Plants | 0 | 0 |
| | 0% | 0% |
| Gas-fired Power Plants | | |
| *Redding Power Units 1-6* | *210* | *692* |
| Total Gas-fired Plants | 210 | 692 |
| | 20% | 49% |
| Hydroelectric Power Plants | | |
| *Whiskeytown* | *25* | *25* |
| Total Hydroelectric | 25 | 25 |
| | 2% | 2% |
| Renewable Energy Resources | | |
| *None that are utility-owned* | *0* | *0* |
| Total UEG Renewable | 0 | 0 |
| | 0% | 0% |
| ***Total of Utility Electric Generation*** | ***306*** | ***908*** |
| | ***30%*** | ***64%*** |
| **Long-Term Renewable and Other Bilateral Contracts (LT)** | | |
| *Iberdrola (PPM) (wind)* | *201* | *201* |
| *Roseburg RLC Industries (biomass) (adds in 2010)* | *60* | *60* |
| *PacifiCorp Exchange (linked to San Juan Unit 4)[1]* | *120* | *0* |
| *CVP Hydro, Base Resource* | *282* | *257* |
| Total LT Contracts | 663 | 518 |

| Redding Electric Utility | 2010[a] | 2018[a] |
|---|---|---|
| | 64% | 36% |
| ***Subtotal (UEG + LT)*** | ***969*** | ***1,426*** |
| | ***94%*** | ***100%*** |
| **Short-Term to Expiration Contracts (ST)** | | |
| *AEP (ends in 2011)* | *219* | *0* |
| Total ST Contracts | 219 | 0 |
| | 21% | 0% |
| **Total (UEG + LT +ST)** | **1,188** | **1,426** |
| | **116%** | **100%** |
| **Short-Term and Spot Market Purchases (ST/SM)** | *123* | *0* |
| Total ST/SM | 123 | 0 |
| | 12% | 0% |
| **Total** | **1,311** | **1,426** |
| | **128%** | **100%** |
| **Scheduled Additions** | | |
| *Roseburg RLC Industries (biomass) (adds in 2010)* | 60 | 60 |
| ***Total Scheduled Additions*** | ***60*** | ***60*** |
| | ***6%*** | ***4%*** |

Notes:

a. All energy values are in GWh. Each percentage value is of the Firm Energy Requirement for that category.

1. Through 2014, PacifiCorp takes 120 GWh from San Juan in real-time, then banks and shapes this energy for 7x16 May-October deliveries to Redding. Redding also takes real-time deliveries of 71 GWh from San Juan through 2014. Total energy supply sourced to San Juan is 191 GWh in all forecast years.

2. Redding lists both CVP Base Resource and CVP Base Resource Assignment as separate line items in the S-1 form with capacities of 122 MW and 19 MW in 2010, respectively. (The latter is zero in 2018.) The associated "2009 Energy Balance Resource Accounting Table" Form S-2 lists only the former.

Source: Redding Energy Balance Resource Accounting Table Form S-2, February 9, 2009, updated July 28, 2009

# City of Riverside

## *Capacity*

Riverside's total capacity requirement increases 15 percent from 690 MW in 2010 to 794 MW in 2018, while expected supplies decrease slightly from 93 to 90 percent of the Firm Peak-Hour Requirement. Riverside lists short-term and spot market purchases of 46 and 82 MW in these two years to fill the need, along with a residual generic need of 32 MW in 2010.

Capacities and category shares of meeting the Firm Peak-Hour Requirement provided by all categories of UEG either do not change or change minimally between 2010 and 2018. The largest drop is in natural gas-fired generation's share of the Firm Peak-Hour Requirement, from 38 percent to 33 percent, entirely due to load growth. Long-term contracts increase from 128 to 230 MW.

Scheduled additions are the Shoshone geothermal project in 2011 at 48 MW, increasing to 96 MW in 2012, and the Badlands / Replacement Contract in 2013. The capacity from this project is 1 MW through 2012; then 10 MW through 2015, and 20 MW in 2016. The total for all these additions from 2010 to 2018 is 76 MW, equal to 10 percent of the Firm Peak-Hour Requirement in 2018.

### Table A-19: Riverside Capacity Resources in 2010 and 2018

| **City of Riverside** | **2010[a]** | **2018[a]** |
|---|---|---|
| **Firm Peak-Hour Requirement[1]** | **690** | **794** |
| **Percent Change** | | **15%** |
| **Utility Electric Generation (UEG)** | | |
| Coal-fired Plants[2] | | |
| *Intermountain* | *137* | *137* |
| Total Coal-fired Plants | 137 | 137 |
| | 20% | 17% |
| Nuclear Power Plants[3] | | |
| *San Onofre* | *40* | *40* |
| *Palo Verde* | *12* | *12* |
| Total Nuclear Plants | 52 | 52 |
| | 8% | 7% |
| Gas-fired Power Plants | | |
| *Springs* | *38* | *38* |
| *Riverside Energy Resource Center* | *196* | *196* |
| *Clearwater* | *28* | *28* |
| Total Gas-fired Plants | 262 | 262 |
| | 38% | 33% |
| Hydroelectric Power Plants | | |
| *Hoover entitlement/Replacement Contract-2018* | *30* | *30* |
| Total Hydroelectric | 30 | 30 |
| | 4% | 4% |
| Renewable Power | | |
| *None that are utility-owned* | *0* | *0* |
| Total UEG Renewable | 0 | 0 |
| | 0% | 0% |
| ***Total of Utility Electric Generation*** | ***481*** | ***481*** |
| | ***70%*** | ***61%*** |
| **Long-Term Renewable and Other Bilateral Contracts (LT)** | | |
| *Salton Sea Power (geothermal)* | *46* | *46* |
| *Wintec (wind)* | *1* | *8* |
| *Shoshone Renaissance (geothermal) (adds 48 MW in 2011 MW, and another 48 MW in 2012 MW)* | *0* | *96* |
| *Badlands (landfill gas) / Replacement Contract (increases to 10 MW in 2013, to 20 MW in 2016)* | *1* | *20* |
| *Bonneville Power Administration (BPA)* | *60* | *60* |
| Total LT Contracts | 108 | 230 |
| | 16% | 29% |
| ***Subtotal (UEG + LT)*** | ***609*** | ***711*** |

| City of Riverside | 2010[a] | 2018[a] |
|---|---|---|
| | ***88%*** | ***90%*** |
| **Short-Term to Expiration Contracts (ST)** | | |
| *None* | | |
| Total ST Contracts | 0 | 0 |
| | 0% | 0% |
| **Total (UEG + LT +ST)** | **609** | **712** |
| | **88%** | **90%** |
| **Short-Term and Spot Market Purchases (ST/SM)** | *46* | *82* |
| Total ST/SM | 46 | 82 |
| | 34% | 60% |
| **Total** | **690** | **794** |
| | **100%** | **100%** |
| **Scheduled Additions** | | |
| *Shoshone Renaissance (geothermal) (adds 48 MW in 2011, and another 48 MW in 2012)* | *0* | *48* |
| *Wintec (wind) increases from 1 MW to 8 MW in 2011* | *0* | *8* |
| *Badlands (landfill gas) (increases from 1 MW. to 10 MW in 2013, and to 20 MW in 2016)* | *0* | *20* |
| ***Total Scheduled Additions*** | ***0*** | ***76*** |
| | ***0%*** | ***10%*** |

Notes:

a. All capacity values are in MW. Percentages are of the Firm Peak-Hour Requirement for each category.

1. Riverside's Line 14 entry incorporates a 15 percent PRM.

2. Riverside's share of the Intermountain Generating Station's output is about 8 percent. (http://www.ipautah.com/about/, accessed June 3, 2009.)

3. Riverside has an ownership interest in the San Onofre Nuclear Generating Station of less than 2 percent. (http://www.sce.com/PowerandEnvironment/PowerGeneration/SanOnofreNuclearGeneratingStation/SONGSFactSheet.htm, accessed June 3, 2009.) It also has a 5 percent participation share of Palo Verde Nuclear Generating Station. (SCPPA 2007-2008 Annual Report, p. 9, http://www.scppa.org/Downloads/Annual%20Report/scppaar1208.pdf, accessed June 3, 2009.)

Source: Riverside Capacity Resource Accounting Table Form S-1, February 13, 2009, updated July 6, 2009

## *Energy*

Riverside's Firm Energy Requirement increases 14 percent from 2,595 GWh in 2010 to 2,967 GWh in 2018. For 2010, Riverside plans to procure 229 GWh using short-term contracts and spot market purchases, equal to 9 percent of the Firm Energy Requirement. The resource plan submitted by Riverside also shows a 30 GWh energy need in 2010 to be filled from sources not yet specified.

Riverside is decreasing its reliance on coal-fired and natural gas-fired generation. These fossil resources supply 51 percent of the 2010 Firm Energy Requirement and 37 percent of the 2018 requirement. As a share of Riverside's utility-controlled generation, fossil plants provide 76 percent of Riverside's energy needs in 2010 and 71 percent in 2018. Coal-fired Intermountain power plant alone is expected to provide 42 percent of the 2010 Firm Energy

Requirement and 30 percent in 2018. Intermountain generation is approximately 60 percent of Riverside's UEG energy in both years.

Nuclear power provides about one-quarter of the energy from UEG resources and about 15 percent of the Firm Energy Requirement. Hydroelectric resources provides very little firm energy and UEG energy. Riverside has no utility-owned renewable generation. However, renewable energy supplies under long-term contracts provide 16 percent of the Firm Energy Requirement in 2010 and 44 percent of the 2018 requirement. (These shares do not include hydroelectric energy from Hoover or the BPA portfolio.)

Scheduled additions are the Shoshone geothermal project in 2011 and 2012, Wintec (wind) in 2011, and the Badlands (landfill gas) 2013, 2014, and 2016. These renewable energy supplies, along with Salton Sea geothermal, are all procured under long-term contracts. Together they provide 16 percent of the 2010 Firm Energy Requirement, and 44 percent in 2018.

### Table A-20: Riverside Energy Supplies in 2010 and 2018

| **City of Riverside** | **2010[a]** | **2018[a]** |
|---|---|---|
| **Firm Energy Requirement** | **2,595** | **2,967** |
| **Percent Change** | | **14%** |
| **Utility Electric Generation (UEG)** | | |
| Coal-fired Plants[1] | | |
| *Intermountain* | *1,078* | *900* |
| Total Coal-fired Plants | 1,078 | 900 |
| | 42% | 30% |
| Nuclear Power Plants[2] | | |
| *San Onofre* | *288* | *318* |
| *Palo Verde* | *99* | *98* |
| Total Nuclear Plants | 387 | 416 |
| | 15% | 14% |
| Gas-fired Power Plants[3] | | |
| *Springs* | *0* | *0* |
| *Riverside Energy Resource Center* | *134* | *87* |
| *Clearwater* | *121* | *109* |
| Total Gas-fired Plants | 255 | 196 |
| | 10% | 7% |
| Hydroelectric Power Plants | | |
| *Hoover entitlement/Replacement Contract-2018* | *32* | *32* |
| Total Hydroelectric | 32 | 32 |
| | 1% | 1% |
| Renewable Power | | |
| *None that are utility-owned* | *0* | *0* |
| Total UEG Renewable | 0 | 0 |
| | 0% | 0% |
| ***Total of Utility Electric Generation*** | ***1,752*** | ***1,544*** |
| | ***68%*** | ***52%*** |
| **Long-Term Renewable and Other Bilateral Contracts** | | |

| City of Riverside | 2010[a] | 2018[a] |
|---|---|---|
| **(LT)** | | |
| *Salton Sea Power (geothermal)* | *403* | *403* |
| *Wintec (wind)* | *4* | *32* |
| *Shoshone Renaissance (geothermal) (begins in 2011 at 396 GWh, adds 396 GWh in 2012)* | *0* | *792* |
| *Badlands (landfill gas) / Replacement Contract (begins in 2013 at 30 GWh, then increases to 40 GWh in 2014, and to 80 GWh in 2016)* | *0* | *80* |
| *Bonneville Power Administration (BPA)* | *51* | *85* |
| Total LT Contracts | 458 | 1,392 |
| | 18% | 44% |
| ***Subtotal (UEG + LT)*** | ***2,295*** | ***2,937*** |
| | ***88%*** | ***100%*** |
| **Short-Term and Spot Market Purchases (ST/SM)** | *299* | *0* |
| Total ST/SM | 299 | 0 |
| | 12% | 0% |
| **Total** | **2,595** | **2,937** |
| | **100%** | **100%** |
| **Scheduled Additions** | | |
| *Shoshone Renaissance (geothermal) (begins at 396 GWh in 2011, increasing to 792 GWh in 2012)* | *0* | *792* |
| *Badlands / Replacement Contract-Renewable (landfill gas) (begins at 30 GWh in 2013, increasing to 40 GWh in 2014, and 80 GWh in 2018 MW)* | *0* | *80* |
| *Wintec (wind) (4 GWh in 2010, increasing to 32 GWh in 2011)* | *0* | *32* |
| *Salton Sea (geothermal) (adds 94 GWh in 2010)* | *94* | *94* |
| ***Total Scheduled Additions*** | | ***900*** |
| | | ***30%*** |

Notes:

a. All energy values are in GWh. Each percentage value is of the Firm Energy Requirement for that category.

1. Riverside's share of the Intermountain Generating Station's output is about 8 percent. (http://www.ipautah.com/about/, accessed June 3, 2009.)

2. Riverside has an ownership interest in the San Onofre Nuclear Generating Station of less than 2 percent. (http://www.sce.com/PowerandEnvironment/PowerGeneration/SanOnofreNuclearGeneratingStation/SONGSFactSheet.htm accessed June 3, 2009.) It also has a 5 percent participation share of Palo Verde Nuclear Generating Station. (SCPPA 2007-2008 Annual Report, p. 9, http://www.scppa.org/Downloads/Annual%20Report/scppaar1208.pdf, accessed June 3, 2009.)

3. Springs provides a capacity of 38 MW in all the years reported but provided energy only during 2007 and 2008.

Source: Riverside Energy Balance Resource Accounting Table Form S-2, February 13, 2009, updated July 6, 2009

# Roseville Electric

## *Capacity*

Roseville Electric has a forecast Firm Peak-Hour Requirement of 414 MW in 2010 that includes a 75 MW firm sales obligation through that year. Roseville's customer load is forecast to grow from 339 MW in 2010 to 441 MW in 2018. Roseville plans for a 1-in-10 peak demand (instead of 1-in-2).

The City of Roseville is in the Western (WAPA) sub-area of the SMUD balancing area. Although Roseville does not have a specified planning reserve margin, Roseville employs good utility practice in planning for its capacity needs, with policies that approximate a 15 percent PRM. The city purchases 10 MW of Regulation and Frequency Response service from Western, plus its contractually obligated share (currently 28 MW) of operating reserves. The city also imports, from the California ISO balancing area, capacity which includes reserves that currently does not count towards meeting its WAPA operating reserve requirement.

From 2010 to 2018, total generation capacity from Roseville's existing resources declines from 483 MW to 365 MW. All of this 25 percent decrease is from renewable and non-renewable contracts that expire after 2010.

Roseville still has a modest capacity surplus through 2013. In 2014, Roseville sees a 6 MW procurement need, and this need increases to 50 MW in 2018. Although Roseville does not identify how these needs may be met, there is adequate time to procure resources.

All of the Roseville's UEG capacity of 155 MW is provided by local natural gas-fired generation, the Roseville Energy Park pictured on the cover of this report. This power plant provides 37 percent of serving the Firm Peak-Hour Requirement in 2010 and 2018.

Most of the capacity for both years is provided by long-term contracts, with increases from 203 to 212 MW between 2010 and 2018, increasing this category's share of the Firm Peak-Hour Requirement served from 49 to 51 percent. Short-term contracts provide almost one third of the capacity needed in 2010. No capacity additions are scheduled.

## Table A-21: Roseville Capacity Resources in 2010 and 2018

| **Roseville Electric** | **2010[a]** | **2018[a]** |
|---|---|---|
| **Firm Peak-Hour Requirement** | **414** | **414** |
| **Percent Change** | | **0%** |
| **Utility Electric Generation (UEG)** | | |
| Coal-fired Plants[2] | | |
| *None* | *0* | *0* |
| Total Coal-fired Plants | 0 | 0 |
| | 0% | 0% |
| Nuclear Power Plants | | |
| *None* | *0* | *0* |
| Total Nuclear Plants | 0 | 0 |
| | 0% | 0% |
| Gas-fired Power Plants | | |
| *Roseville Energy Park* | *155* | *155* |
| Total Gas-fired Plants | 155 | 155 |
| | 37% | 37% |
| Hydroelectric Power Plants | | |
| *None* | *0* | *0* |
| Total Hydroelectric | 0 | 0 |
| | 0% | 0% |
| Renewable Power | | |
| *None that are utility-owned* | *0* | *0* |
| Total UEG Renewable | 0 | 0 |
| | 0% | 0% |
| ***Total of Utility Electric Generation*** | ***155*** | ***155*** |
| | ***37%*** | ***37%*** |
| **Long-Term Renewable and Other Bilateral Contracts (LT)** | | |
| *Energy 2001 (ends 2017)* | *2* | *0* |
| *NCPA Geothermal 1&2 (capacity changes during contract)* | *8* | *12* |
| *NCPA CT1* | *48* | *48* |
| *NCPA STIG* | *21* | *21* |
| *NCPA Calaveras (Collierville hydro)* | *30* | *30* |
| *Western Area Power Administration (increases in 2012)[1]* | *56* | *60* |
| *WAPA-Purchased Ancillary Services[2]* | *38* | *38* |
| Total LT Contracts | 203 | 210 |
| | 49% | 51% |
| ***Subtotal (UEG + LT)*** | ***358*** | ***365*** |
| | ***86%*** | ***88%*** |
| **Short-Term to Expiration Contracts (ST)** | | |
| *Morgan Stanley (ends in 2011)* | *100* | *0* |
| *Renewable Supply Contracts (ends in 2013)[2]* | *25* | *0* |
| Total ST Contracts | 125 | 0 |
| | 30% | 0% |
| **Total (UEG + LT +ST)** | **483** | **365** |
| | **117%** | **88%** |
| **Short-Term and Spot Market Purchases (ST/SM)** | *0* | *0* |

| Roseville Electric | 2010[a] | 2018[a] |
|---|---|---|
| Total ST/SM | 0 | 0 |
| | 0% | 0% |
| **Total** | **483** | **365** |
| | **117%** | **88%** |
| **Scheduled Additions** | | |
| *None* | *0* | *0* |
| ***Total Scheduled Additions*** | ***0*** | ***0*** |
| | ***0%*** | ***0%*** |

Notes:

a. All capacity values are in MW. Percentages are of the Firm Peak-Hour Requirement for each category.

1. The S-1 form has two Western line items, but the Energy Balance Resource Accounting Table Form S-2 has only one line for WAPA.

2. The Energy Balance Resource Accounting Table Form S-2 lists this line item as Renewable System Firm Wind.

Source: Roseville Electric Capacity Resource Accounting Table Form S-1, January 31, 2009, updated May 5, 2009

## *Energy*

Unique among all the electricity supply filings this year, Roseville reported historic and forecast energy values using its fiscal years (FY) that end on June 30. Roseville's Firm Energy Requirement decreases from FY 2010 to FY 2018 by 9 percent after its Firm Sales Obligation ends in FY 2011. The total amount of energy provided is 100 percent of the Firm Energy Requirement in FY 2010 and 97 percent in FY 2018. The short-fall in 2018 should be easy for Roseville to fill.

The natural gas-fired Roseville Energy Park power plant is Roseville's sole source of UEG energy, and provides 52 percent of the FY 2010 Firm Energy Requirement and 59 percent of the FY 2018 requirement.

About one-fifth of the energy requirement in both years is provided by long-term contracts, and about one-third of the FY 2010 requirement is filled by short-term contracts. Purchases of energy using short-term and spot market contracts energy are expected to add 60 GWh in FY 2010, and 261 GWh in FY 2018. No additional energy supplies are scheduled.

## Table A-22: Roseville Energy Supplies in FY 2010 and FY 2018

| **Roseville Electric** | **2010[a]** | **2018[a]** |
|---|---|---|
| **Firm Energy Requirement** | **1,687** | **1,536** |
| **Percent Change** | | **-9%** |
| **Utility Electric Generation (UEG)** | | |
| Coal-fired Plants | | |
| *None* | *0* | *0* |
| Total Coal-fired Plants | 0 | 0 |
| | 0% | 0% |
| Nuclear Power Plants | | |
| *None* | *0* | *0* |
| Total Nuclear Plants | 0 | 0 |
| | 0% | 0% |
| Gas-fired Power Plants | | |
| *Roseville Energy Park* | *869* | *905* |
| Total Gas-fired Plants | 869 | 905 |
| | 52% | 59% |
| Hydroelectric Power Plants | | |
| *None* | *0* | *0* |
| Total Hydroelectric | 0 | 0 |
| | 0% | 0% |
| Renewable Energy Resources | | |
| *None that are utility-owned* | *0* | *0* |
| Total UEG Renewable | 0 | 0 |
| | 0% | 0% |
| ***Total of Utility Electric Generation*** | ***869*** | ***905*** |
| | ***52%*** | ***59%*** |
| **Long-Term Renewable and Other Bilateral Contracts (LT)** | | |
| *Energy 2001 (ends in 2017)* | *19* | *0* |
| *NCPA Geo 1&2 (capacity changes during contract)* | *69* | *96* |
| *NCPA CT1* | *17* | *17* |
| *NCPA STIG* | *37* | *37* |
| *NCPA Calaveras* | *66* | *66* |
| *Western Area Power Administration (WAPA)[1]* | *102* | *102* |
| Total LT Contracts | 310 | 318 |
| | 18% | 21% |
| ***Subtotal (UEG + LT)*** | ***1,179*** | ***1,223*** |
| | ***70%*** | ***80%*** |
| **Short-Term to Expiration Contracts (ST)** | | |
| *Morgan Stanley (ends in 2011)* | *491* | *0* |
| *Renewable System Firm Wind (ends in 2013)[2]* | *77* | *0* |
| Total ST Contracts | 568 | 0 |
| | 34% | 0% |
| **Total (UEG + LT +ST)** | **1,747** | **1,223** |
| | **104%** | **80%** |
| **Short-Term and Spot Market Purchases (ST/SM)** | *-60* | *261* |
| Total ST/SM | -60 | 261 |

| Roseville Electric | 2010[a] | 2018[a] |
|---|---|---|
| | -4% | 17% |
| **Total** | **1,687** | **1,484** |
| | **100%** | **97%** |
| **Scheduled Additions** | | |
| *None* | *0* | *0* |
| ***Total Scheduled Additions*** | ***0*** | ***0*** |
| | ***0%*** | ***0%*** |

Notes:

a. All energy values are in GWh. Each percentage value is of the Firm Energy Requirement for that category.

1. The S-1 form has two WAPA line items, but the Energy Balance Resource Accounting Table Form S-2 has only one line for WAPA.

2. The Capacity Resources Accounting Table Form S-1 lists this line item as Renewable Supply Contracts.

Source: Roseville Electric Energy Balance Resource Accounting Table Form S-2, January 31, 2009, updated May 5, 2009

# Sacramento Municipal Utility District

## *Capacity*

The Firm Peak-Hour Requirement for the Sacramento Municipal Utility District's (SMUD) increases four percent from 3,129 MW in 2010 to 3,269 MW in 2018. Total generation capacity decreases slightly during these years from 2,680 MW to 2,672 MW. SMUD adds 525 and 250 MW of short-term and spot market purchases in these two years, bringing total existing plus planned capacities to 3,205 and 3,922 MW in 2010 and 2018, respectively. SMUD has a residual resource need of 347 MW in 2018, and sufficient time exists for SMUD to acquire the capacity needed.

SMUD's UEG resources do not include either coal or nuclear. Its UEG capacity requirements are met by natural gas-fired, hydroelectric and renewable resources. The natural gas-fired category remains unchanged in capacity from 2010 to 2018, resulting in a very small 1 percent decrease between 2010 and 2018in this category's contribution toward meeting the Firm Peak-Hour Requirement.

Both hydroelectric and renewable UEG resources show increases between 2010 and 2018, with the former increasing by 390 MW, or 57 percent. This increases the hydroelectric category's contribution toward meeting the Firm Peak-Hour Requirement from 22 to 33 percent. The renewable category doubles in dependable capacity between 2010 and 2018 because the Solano wind project adds 46 dependable MW (105 MW nominal) in 2011. This increase, combined with the PV capacity of 1 MW, increases this UEG category's share of meeting the Firm Peak-Hour Requirement capacity by about 2 percent.

Long-term contracts provide 23 percent of the contribution to the Firm Peak-Hour Requirement in 2010 and 15 percent in 2018. Of 2010's long-term contracts, 243 MW will end

before 2018, a reduction in capacity of 43 percent. Short-term contracts total 230 MW in 2010, being nine percent of the capacity obtained. However, the reduction in the short-term category share towards meeting the Firm Peak-Hour Requirement is only 7 percent.

The Solano wind project is the only scheduled addition from 2010 to 2018.

**Table A-23: SMUD Capacity Resources in 2010 and 2018**

| **Sacramento Municipal Utility District** | **2010[a]** | **2018[a]** |
|---|---|---|
| **Firm Peak-Hour Requirement[1]** | **3,129** | **3,269** |
| **Percent Change** | | **4%** |
| **Utility Electric Generation (UEG)** | | |
| Coal-fired Plants | | |
| *None* | *0* | *0* |
| Total Coal-fired Plants | 0 | 0 |
| | 0% | 0% |
| Nuclear Power Plants | | |
| *None* | *0* | *0* |
| Total Nuclear Plants | 0 | 0 |
| | 0% | 0% |
| Gas-fired Power Plants | | |
| *Campbell Soup* | *161* | *161* |
| *Carson Ice* | *93* | *93* |
| *Cosumnes* | *501* | *501* |
| *McClellan* | *72* | *72* |
| *Proctor & Gamble* | *180* | *180* |
| Total Gas-fired Plants | 1,007 | 1,007 |
| | 32% | 31% |
| Hydroelectric Power Plants | | |
| *All utility-controlled Hydro Plants* | *684* | *1,074* |
| Total Hydroelectric Power Plants | 684 | 1,074 |
| | 22% | 33% |
| Renewable Power | | |
| *Solano (wind) (45 MW in 2010, increases to 91 MW in 2011)* | *45* | *91* |
| *Solar PV (utility scale)* | *1* | *1* |
| Total UEG Renewable | 46 | 92 |
| | 1% | 3% |
| ***Total of Utility Electric Generation*** | ***1,737*** | ***2,173*** |
| | ***56%*** | ***66%*** |
| **Long-Term Renewable and Other Bilateral Contracts (LT)** | | |
| *Various Renewable & Small Hydro Resources* | *51* | *51* |
| *Western Area Power Administration (WAPA)* | *409* | *438* |
| *UC Davis Medical Center* | *10* | *10* |
| *PP&L (ends in 2015)* | *100* | *0* |
| *East Bay MUD 1 & 2 (ends in 2015)* | *22* | *0* |
| *PPM Wind (ends in 2015)* | *31* | *0* |
| *Avista Biomass & Hydro (ends in 2015)* | *75* | *0* |
| *SPI Biomass (ends in 2017)* | *15* | *0* |

| Sacramento Municipal Utility District | 2010[a] | 2018[a] |
|---|---|---|
| Total LT Contracts | 713 | 499 |
| | 23% | 15% |
| ***Subtotal (UEG + LT)*** | ***2,450*** | ***2,672*** |
| | ***78%*** | ***82%*** |
| **Short-Term to Expiration Contracts (ST)** | | |
| *Klamath Falls (ends in 2011)* | *50* | *0* |
| *PPM Iberdrola Renewables (portfolio) (ends in 2011)* | *50* | *0* |
| *Klamath Falls Peaking (ends in 2013)* | *30* | *0* |
| *PPM Iberdrola Renewables (gas/option) (ends in 2013)* | *100* | *0* |
| Total ST Contracts | 230 | 0 |
| | 7% | 0% |
| **Total (UEG + LT +ST)** | **2,680** | **2,672** |
| | **86%** | **82%** |
| **Short-Term and Spot Market Purchases (ST/SM)** | *525* | *250* |
| Total ST Contracts | 525 | 250 |
| | 17% | 8% |
| **Total** | **3,205** | **2,922** |
| | **102%** | **89%** |
| **Scheduled Additions** | | |
| *Solano (wind) (45 MW in 2010, increases to 91 MW in 2011)* | *45* | *91* |
| ***Total Scheduled Additions*** | ***45*** | ***91*** |
| | ***1%*** | ***3%*** |

Notes:

a. All capacity values are in MW. Percentages are of the Firm Peak-Hour Requirement for each category.

1. SMUD's Line 14 entry incorporates a 15 percent PRM.

Source: SMUD Capacity Resource Accounting Table Form S-1, March 3, 2009

## *Energy*

From 2010 to 2018, SMUD's Firm Energy Requirement increases 3 percent from 11,583 GWh to 11,396 GWh. Total energy supplies from existing and planned resources decrease from 12,011 GWh to 10,154 GWh. The percentage of the Firm Energy Requirement that can be met by existing and specifically planned resources is 104 percent in 2010 and 85 percent in 2018.

SMUD's UEG resources do not include coal or nuclear. Most of SMUD's energy requirements are met by UEG natural gas-fired, hydroelectric, and renewable resources. The natural gas-fired category provides more than one-half of SMUD's Firm Energy Requirement, and approximately three-quarters of the UEG resources each year, remaining almost unchanged in total GWh from 2010 to 2018.

Hydroelectric UEG resources, under median hydrological conditions, will supply about 14 percent of the Firm Energy Requirement throughout the planning horizon. However, in dry 2007, SMUD's hydropower plants produced only 1,054 GWh, equal to 9 percent of that

year's energy requirements. In drier 2008, SMUD's hydropower system produced 885 GWh, equal to 7.5 percent of that year's energy needs.

UEG renewable energy is expected to increase nearly three-fold between 2010 and 2018. Almost all of the increase in UEG renewable energy is attributable to Solano wind project additions in 2011. Nonetheless, UEG renewable resources at most make up less than 10 percent of either the Firm Energy Requirement or the UEG resources.

Electricity deliveries from existing long-term contracts will decline as these contracts expire. These existing renewable and non-renewable contractual supplies are counted on for 3,220 GWh in 2010 and 1,454 GWh in 2018. Two long-term contract line items in the table above show no change supply contributions. They are various renewable and hydroelectric resources, and a contract with the Western Area Power Administration.

**Table A-24: SMUD Energy Supplies in 2010 and 2018**

| **Sacramento Municipal Utility District** | **2010[a]** | **2018[a]** |
|---|---|---|
| **Firm Peak-Hour Requirement** | **11,583** | **11,936** |
| **Percent Change** | | **3%** |
| **Utility Electric Generation (UEG)** | | |
| Coal-fired Plants | | |
| *None* | *0* | *0* |
| Total Coal-fired Plants | 0 | 0 |
| | 0% | 0% |
| Nuclear Power Plants | | |
| *None* | *0* | *0* |
| Total Nuclear Plants | 0 | 0 |
| | 0% | 0% |
| Gas-fired Power Plants | | |
| *Campbell Soup* | *1,122* | *1,122* |
| *Carson Ice* | *398* | *434* |
| *Cosumnes* | *4,006* | *4,006* |
| *McClellan* | *2* | *2* |
| *Proctor & Gamble* | *879* | *869* |
| Total Gas-fired Plants | 6,407 | 6,433 |
| | 55% | 54% |
| Hydroelectric Power Plants | | |
| *All utility-controlled Hydro Plants* | *1,610* | *1,594* |
| Total Hydroelectric | 1,610 | 1,594 |
| | 14% | 13% |
| Renewable Energy Resources | | |
| *Solano wind (45 MW in 2010, increases to 91 MW in 2011)* | *281* | *670* |
| *Solar PV (utility scale)* | *3* | *3* |
| Total UEG Renewable | 284 | 673 |
| | 2% | 6% |
| ***Total of Utility Electric Generation*** | ***8,301*** | ***8,700*** |
| | ***72%*** | ***73%*** |
| **Long-Term Renewable and Other Bilateral Contracts (LT)** | | |

| Sacramento Municipal Utility District | 2010[a] | 2018[a] |
|---|---|---|
| *Various Renewable & Small Hydro Resources* | *517* | *517* |
| *Western Power Administration (WAPA)* | *937* | *937* |
| *UC Davis Medical Center* | *0* | *0* |
| *PP&L (ends in 2015)* | *569* | *0* |
| *East Bay MUD 1 & 2 (ends in 2015)* | *185* | *0* |
| *PPM Wind (ends in 2015)* | *224* | *0* |
| *Avista Biomass & Hydro (ends in 2015)* | *657* | *0* |
| *SPI Biomass (ends in 2017)* | *131* | *0* |
| Total LT Contracts | 3,220 | 1,454 |
| | 28% | 12% |
| ***Subtotal (UEG + LT)*** | ***11,521*** | ***10,154*** |
| | ***99%*** | ***85%*** |
| **Short-Term to Expiration Contracts (ST)** | | |
| *Klamath Falls (ends in 2011)* | *219* | *0* |
| *PPM Iberdrola Renewables (portfolio) (ends in 2011)* | *230* | *0* |
| *Klamath Falls Peaking (ends in 2013)* | *9* | *0* |
| *PPM Iberdrola Renewables (gas/option) (ends in 2013)* | *32* | *0* |
| Total ST Contracts | 490 | 0 |
| | 4% | 0% |
| **Total (UEG + LT +ST)** | **12,011** | **10,154** |
| | **104%** | **85%** |
| **Short-Term and Spot Market Purchases (ST/SM)** | *0* | *0* |
| Total ST Contracts | 0 | 0 |
| | 0% | 0% |
| **Total** | **12,011** | **10,154** |
| | **104%** | **85%** |
| **Scheduled Additions** | | |
| *Solano wind (45 MW in 2010, increases to 91 MW in 2011)* | *281* | *670* |
| ***Total Scheduled Additions*** | ***281*** | ***670*** |
| | ***2%*** | ***6%*** |

Notes:

a. All energy values are in GWh. Each percentage value is of the Firm Energy Requirement for that category.

Source: SMUD Energy Balance Resource Accounting Table Form S-2, March 3, 2009

# Silicon Valley Power

## *Capacity*

For the City of Santa Clara, doing business as Silicon Valley Power (SVP), the Firm Peak-Hour Requirement increases by 11 percent from 555 MW in 2010 to 617 MW in 2018. Existing and planned resources (not including 75 MW of short-term and spot market purchases) represent 122 percent of the 2010 Firm Peak Requirement, and 118 percent of the 2018 requirement. When planned short-term and spot market purchases are included, the

available capacity totals equal 135 percent of the 2010 requirement, and 130 percent of the 2018 requirement.

UEG hydropower provides 46 percent of the 2010 annual peak resource requirement. UEG gas-fired plants provide 38 percent, UEG geothermal provides 12 percent, and coal-fired capacity from the San Juan power plant provides less than 10 percent of SVP's capacity requirement.

Silicon Valley Power's capacity portfolio is very stable through 2018. The sole change in named resource additions is SVP's 50 MW share in the planned Lodi Energy Center, scheduled to be online for summer 2012.

### Table A-25: SVP Capacity Resources in 2010 and 2018

| **Silicon Valley Power** | **2010[a]** | **2018[a]** |
|---|---|---|
| **Firm Peak-Hour Requirement[1]** | **555** | **617** |
| **Percent Change** | | **11%** |
| **Utility Electric Generation (UEG)** | | |
| Coal-fired Plants[2] | | |
| *MSR San Juan* | *51* | *51* |
| Total Coal-fired Plants | 51 | 51 |
| | 9% | 8% |
| Nuclear Power Plants | | |
| *None* | *0* | *0* |
| Total Nuclear Plants | 0 | 0 |
| | 0% | 0% |
| Gas-fired Power Plants | | |
| *SVP Cogeneration* | *7* | *7* |
| *SVP DVR 1* | *62* | *62* |
| *SVP DVR 2* | *62* | *62* |
| *SVP Gianera 1 CT* | *24* | *24* |
| *SVP Gianera 2 CT* | *24* | *24* |
| *NCPA CT* | *29* | *29* |
| *NCPA Lodi (adds in 2012)* | *0* | *50* |
| Total Gas-fired Plants | 209 | 259 |
| | 38% | 42% |
| Hydroelectric Power Plants | | |
| *All utility-controlled Hydro Plants* | *253* | *253* |
| Total Hydroelectric | 253 | 253 |
| | 46% | 41% |
| Renewable Power | | |
| *NCPA Geothermal* | *69* | *69* |
| Total UEG Renewable | 69 | 69 |
| | 12% | 11% |
| ***Total of Utility Electric Generation*** | ***582*** | ***632*** |
| | ***105%*** | ***102%*** |
| **Long-Term Renewable and Other Bilateral Contracts (LT)** | | |
| *Western Geothermal Purchase* | *9* | *9* |

| Silicon Valley Power | 2010[a] | 2018[a] |
|---|---|---|
| *MSR Wind Purchase* | *45* | *45* |
| *Altamont Wind Purchase* | *6* | *6* |
| *G2 Landfill Gas Purchase* | *3* | *3* |
| *Ameresco Landfill Gas Purchase* | *1* | *1* |
| *SCL Exchange* | *30* | *30* |
| Total LT Contracts | 94 | 94 |
| | 17% | 15% |
| ***Subtotal (UEG + LT)*** | ***676*** | ***726*** |
| | ***122%*** | ***118%*** |
| **Short-Term to Expiration Contracts (ST)** | | |
| *None* | *0* | *0* |
| Total ST Contracts | 0 | 0 |
| | 0% | 0% |
| **Total (UEG + LT +ST)** | **676** | **726** |
| | **122%** | **118%** |
| **Short-Term and Spot Market Purchases (ST/SM)** | *75* | *75* |
| Total ST Contracts | 75 | 75 |
| | 14% | 12% |
| **Total** | **751** | **801** |
| | **135%** | **130%** |
| **Scheduled Additions** | | |
| *NCPA Lodi Energy Center (adds in 2012)* | *0* | *50* |
| ***Total Scheduled Additions*** | ***0*** | ***50*** |
| | ***0%*** | ***8%*** |

Notes:

a. All capacity values are in MW. Percentages are of the Firm Peak-Hour Requirement for each category.

1. SVP's Line 14 entry incorporates a 15 percent PRM.

2. SVP purchases wholesale power generated by the San Juan Generating Station from MSR Public Agency, which has a 29 percent ownership share of San Juan Unit 4. (http://www.pnm.com/systems/sj-owners.htm, and the City of Santa Clara, Electric Utility Enterprise Fund, for the fiscal year ending June 30, 2006, http://www.siliconvalleypower.com/pdf/2006SVPFinancials.pdf accessed June 3, 2009.)

Source: Silicon Valley Power Capacity Resource Accounting Table Form S-1, February 13, 2009

## *Energy*

SVP's Firm Energy Requirement increases by 11 percent, from 3,073 GWh in 2010 to 3,413 GWh in 2018. SVP submitted a balanced S-2 supply form showing how supplies match the need each year. SVP plans on short-term and spot market purchases of 597 GWh in 2010 and 602 GWh in 2018 to balance energy loads with adequate supply. These short-term purchases represent 11 to 18 percent of all energy supplies. By volume, most of these purchases are for energy deliveries in off-peak hours to serve SVP customer loads that are about 90 industrial and large commercial.

Fossil-fired resources provide about 40 percent of SVP's Firm Energy Requirement, and 54 percent of the UEG in 2010 and 59 percent of 2018's. SVP relies on the coal-fired San Juan

power plant for about 12 percent of both year's Firm Energy Requirement. The sole change in named resource additions is SVP's share in the new Lodi Energy Center. By 2013, the Lodi Energy Center may be generating 342 GWh for SVP, meeting over 10 percent of all energy requirements.

Long-term contracts remain at about 13 percent of the Firm Energy Requirement in each year. There are no short-term contracts for energy.

### Table A-26: SVP Energy Supplies in 2010 and 2018

| **Silicon Valley Power** | **2010[a]** | **2018[a]** |
|---|---|---|
| **Firm Energy Requirement** | **3,073** | **3,413** |
| **Percent Change** | | **11%** |
| **Utility Electric Generation (UEG)** | | |
| Coal-fired Plants[1] | | |
| *MSR San Juan* | *390* | *390* |
| Total Coal-fired Plants | 390 | 390 |
| | 13% | 11% |
| Nuclear Power Plants | | |
| *None* | *0* | *0* |
| Total Nuclear Plants | 0 | 0 |
| | 0% | 0% |
| Gas-fired Power Plants | | |
| *SVP Cogeneration* | *55* | *55* |
| *SVP DVR 1* | *341* | *311* |
| *SVP DVR 2* | *340* | *311* |
| *SVP Gianera 1 CT[2]* | *0* | *0* |
| *SVP Gianera 2 CT[2]* | *0* | *0* |
| *NCPA CT[2]* | *0* | *0* |
| *NCPA Lodi Energy Center (adds in 2012)* | *0* | *342* |
| Total Gas-fired Plants | 736 | 1,019 |
| | 24% | 30% |
| Hydroelectric Power Plants | | |
| *All utility-controlled Hydro Plants* | *558* | *658* |
| Total Hydroelectric | 558 | 658 |
| | 18% | 19% |
| Renewable Power | | |
| *NCPA Geothermal* | *386* | *320* |
| Total UEG Renewable | 386 | 320 |
| | 13% | 9% |
| ***Total of Utility Electric Generation*** | ***2,070*** | ***2,387*** |
| | ***67%*** | ***70%*** |
| **Long-Term Renewable and Other Bilateral Contracts (LT)** | | |
| *Western Geothermal Purchase* | *54* | *71* |
| *MSR Wind Purchase* | *320* | *320* |
| *Altamont Wind Purchase* | *22* | *22* |
| *G2 Landfill Gas Purchase* | *12* | *12* |
| *Ameresco Landfill Gas Purchase* | *0* | *0* |

| Silicon Valley Power | 2010[a] | 2018[a] |
|---|---|---|
| *SCL Exchange* | *-1* | *-1* |
| Total LT Contracts | 407 | 424 |
| | 13% | 12% |
| ***Subtotal (UEG + LT)*** | ***2,477*** | ***2,811*** |
| | ***81%*** | ***82%*** |
| **Short-Term to Expiration Contracts (ST)** | | |
| *None* | *0* | *0* |
| Total ST Contracts | 0 | 0 |
| | 0% | 0% |
| **Total (UEG + LT +ST)** | **2,477** | **2,811** |
| | **81%** | **82%** |
| **Short-Term and Spot Market Purchases (ST/SM)** | *597* | *602* |
| Total ST Contracts | 597 | 602 |
| | 19% | 18% |
| **Total** | **3,074** | **3,413** |
| | **100%** | **100%** |
| **Scheduled Additions** | | |
| *NCPA Lodi Energy Center (adds in 2012)* | *0* | *342* |
| ***Total Scheduled Additions*** | ***0*** | ***342*** |
| | ***0%*** | ***10%*** |

Notes:

a. All energy values are in GWh. Each percentage value is of the Firm Energy Requirement for that category.

1. SVP purchases wholesale power generated by the San Juan Generating Station from MSR Public Agency, which has a 29 percent ownership share of San Juan Unit 4. (http://www.pnm.com/systems/sj-owners.htm, and the City of Santa Clara, Electric Utility Enterprise Fund, for the fiscal year ending June 30, 2006, http://www.siliconvalleypower.com/pdf/2006SVPFinancials.pdf accessed June 3, 2009.)

2. The SVP Gianera plants and the NCPA combustion turbines are not counted on for energy attributes, but will deliver energy when called upon for the peak period capacity value.

Source: Silicon Valley Power Energy Balance Resource Accounting Table Form S-2, February 13, 2009

# Turlock Irrigation District

## *Capacity*

From 2010 to 2018, the Turlock Irrigation District's (TID) Firm Peak-Hour Requirement increases 18 percent from 655 MW to 772 MW. Total generation capacity increases by 21 percent, from 696 to 841 MW, providing 106 and 109 percent of the Firm Peak-Hour Requirement for 2010 and 2018, respectively.

Total capacity provided by UEG remains constant for the coal-fired, hydroelectric and renewable categories. The capacity of the UEG natural gas-fired category increases 150 MW, provided by the expansion of the Almond power plant in 2011. The total UEG contributions

towards meeting net electricity load capacity requirements are 82 percent in 2010 and 89 percent in 2018.

Most of the capacity provided by long-term contracts is also stable with only 5 MW expiring between the two years. This expiring contract would cover less than 1 percent of the 2010 or 2018 the Firm Peak-Hour Requirement. There are no short-term contracts.

Overall, TID shows surpluses of 41 MW in 2010 and 69 MW in 2018. Capacity surpluses may be as large as 173 MW in 2011 if the 150 MW expansion of the Almond power plant is completed on schedule. If the expansion is not online for summer 2013, TID will have resource deficit of 8 MW.

**Table A-27: Turlock ID Capacity Resources in 2010 and 2018**

| **Turlock Irrigation District** | **2010[a]** | **2018[a]** |
|---|---|---|
| **Firm Peak-Hour Requirement[1]** | **655** | **772** |
| **Percent Change** | | **18%** |
| **Utility Electric Generation (UEG)** | | |
| Coal-fired Plants | | |
| *Portland General Electric – Boardman[2]* | *56* | *56* |
| Total Coal-fired Plants | 56 | 56 |
| | 9% | 7% |
| Nuclear Power Plants | | |
| *None* | *0* | *0* |
| Total Nuclear Plants | 0 | 0 |
| | 0% | 0% |
| Gas-fired Power Plants | | |
| *Walnut Energy Center* | *238* | *238* |
| *Walnut* | *52* | *52* |
| *Almond* | *49* | *49* |
| *Almond - Proposed Expansion (adds in 2011)* | *0* | *150* |
| Total Gas-fired Plants | 339 | 489 |
| | 52% | 63% |
| Hydroelectric Power Plants | | |
| *All utility-controlled Hydro Plants* | *144* | *144* |
| Total Hydroelectric | 144 | 144 |
| | 22% | 19% |
| Renewable Power | | |
| *TID Fuel Cell* | *1* | *1* |
| Total UEG Renewable | 1 | 1 |
| | <1% | <1% |
| ***Total of Utility Electric Generation*** | ***540*** | ***690*** |
| | ***82%*** | ***89%*** |
| **Long-Term Renewable and Other Bilateral Contracts (LT)** | | |
| *Northern California Power Agency (geothermal)* | *6* | *5* |
| *Tuolumne Wind Project Authority (wind)* | *125* | *125* |
| *City and County of San Francisco (large hydro)* | *21* | *17* |
| *Western Area Power Administration (WAPA)* | *3* | *3* |

| Turlock Irrigation District | 2010[a] | 2018[a] |
|---|---|---|
| Total LT Contracts | 155 | 150 |
| | 24% | 19% |
| ***Subtotal (UEG + LT)*** | ***696*** | ***841*** |
| | ***106%*** | ***109%*** |
| **Short-Term to Expiration Contracts (ST)** | | |
| *None* | *0* | *0* |
| Total ST Contracts | 0 | 0 |
| | 0% | 0% |
| **Total (UEG + LT +ST)** | **695** | **840** |
| | **106%** | **109%** |
| **Short-Term and Spot Market Purchases (ST/SM)** | *0* | *0* |
| Total ST Contracts | 0 | 0 |
| | 0% | 0% |
| **Total** | **695** | **840** |
| | **106%** | **109%** |
| **Scheduled Additions** | | |
| *Almond - Proposed Expansion (adds in 2011)* | *0* | *150* |
| ***Total Scheduled Additions*** | ***0*** | ***150*** |
| | ***0%*** | ***22%*** |

Notes:

a. All capacity values are in MW. Percentages are of the Firm Peak-Hour Requirement for each category.

1. TID's Line 14 entry incorporates a 15 percent PRM.

2. TID includes the Boardman facility under "Other Bilateral Contractual Resources."

Source: TID Capacity Resource Accounting Table Form S-1, February 9, 2009

## *Energy*

From 2010 to 2018, TID's Firm Energy Requirement increases 19 percent from 2,257 GWh to 2,685 GWh. Total available generation also increases by 17 percent, from 3,254 GWh to 3,696 GWh. If all available energy supplies were scheduled and dispatched, TID would have an energy surplus of 997 GWh in 2010 and 1,012 GWh in 2018. These potential surpluses are made possible by the Almond power plant expansion in 2011. The numbers may indicate an over-procurement or over-generation scenario; the actual amount of energy provided by the Almond project may be less than this forecast.

Energy provided by UEG remains steady for the coal-fired, hydroelectric and renewable categories. Annual energy from UEG natural gas-fired resources increases by 460 GWh, provided by the expansion of the Almond power plant in 2011. Total UEG generation supplies 81 percent of the net energy for load in 2010 and 84 percent in 2018.

Most of the energy provided by long-term contracts is also expected to be stable, notably including 431 GWh annually from the Tuolumne Wind Project at Windy Point in Washington. There are no short-term contracts.

## Table A-28: Turlock ID Energy Supplies in 2010 and 2018

| **Turlock Irrigation District** | **2010[a]** | **2018[a]** |
|---|---|---|
| **Firm Energy Requirement** | **2,257** | **2,685** |
| **Percent Change** | | **19%** |
| **Utility Electric Generation (UEG)** | | |
| Coal-fired Plants | | |
| *Portland General Electric – Boardman[1]* | *420* | *420* |
| Total Coal-fired Plants | 420 | 420 |
| | 19% | 16% |
| Nuclear Power Plants | | |
| *None* | *0* | *0* |
| Total Nuclear Plants | 0 | 0 |
| | 0% | 0% |
| Gas-fired Power Plants | | |
| *Walnut Energy Center* | *1,540* | *1,540* |
| *Walnut* | *0* | *0* |
| *Almond* | *173* | *173* |
| *Almond - Proposed Expansion (adds in 2011)* | *0* | *460* |
| Total Gas-fired Plants | 1,713 | 2,173 |
| | 76% | 81% |
| Hydroelectric Power Plants | | |
| *All utility-controlled Hydro Plants* | *500* | *500* |
| Total Hydroelectric | 500 | 500 |
| | 22% | 19% |
| Renewable Power | | |
| *TID Fuel Cell* | *9* | *9* |
| Total UEG Renewable | 9 | 9 |
| | <1% | <1% |
| ***Total of Utility Electric Generation*** | ***2,642*** | ***3,102*** |
| | ***117%*** | ***116%*** |
| **Long-Term Renewable and Other Bilateral Contracts (LT)** | | |
| *Northern California Power Agency (geothermal)* | *53* | *42* |
| *Tuolumne Wind Project Authority (wind)* | *431* | *431* |
| *City and County of San Francisco (large hydro)* | *119* | *112* |
| *Western Area Power Administration (WAPA)* | *9* | *9* |
| Total LT Contracts | 612 | 594 |
| | 27% | 22% |
| ***Subtotal (UEG + LT)*** | ***3,254*** | ***3,696*** |
| | ***144%*** | ***138%*** |
| **Short-Term to Expiration Contracts (ST)** | | |
| *None* | *0* | *0* |
| Total ST Contracts | 0 | 0 |
| | 0% | 0% |
| **Total (UEG + LT +ST)** | ***3,254*** | ***3,696*** |
| | ***144%*** | ***138%*** |
| **Short-Term and Spot Market Purchases (ST/SM)** | *0* | *0* |
| Total ST Contracts | 0 | 0 |

| Turlock Irrigation District | 2010[a] | 2018[a] |
|---|---|---|
| | 0% | 0% |
| **Total** | **3,254** | **3,696** |
| | **144%** | **138%** |
| **Scheduled Additions** | | |
| *Almond - Proposed Expansion (adds in 2011)* | *0* | *460* |
| ***Total Scheduled Additions*** | ***0*** | ***460*** |
| | ***0%*** | ***17%*** |

Notes:

a. All energy values are in GWh. Each percentage value is of the Firm Energy Requirement for that category.

1. TID includes the Boardman facility under "Other Bilateral Contractual Resources."

Source: TID Energy Balance Resource Accounting Table Form S-2, February 9, 2009

# City of Vernon

## *Capacity*

Vernon's forecast capacity requirement increases 21 percent from 189 MW in 2010 to 228 MW in 2018. This peak-load forecast includes a 13 MW credit for Demand Response/Interruptible Programs. Expected generating supplies provided by UEG, long-term, and short-term resources decrease during these years from 205 MW to 180 MW, or from 108 percent to 79 percent of the Firm Peak-Hour Requirement. Vernon provides for short-term and spot market purchases of 10 MWs in each year. Vernon expects a surplus of 26 MW in 2010, including 25 MW from a contractual resource that expires at the end of 2010.

Vernon indicates a modest 11 MW resource need in 2011, a need that would increase to 38 MW in 2018 in the absence of additional procurement activity.

**Table A-29: Vernon Capacity Resources in 2010 and 2018**

| City of Vernon | 2010[a] | 2018[a] |
|---|---|---|
| **Firm Peak-Hour Requirement[1]** | **190** | **224** |
| **Percent Change** | | **18%** |
| **Utility Electric Generation (UEG)** | | |
| Coal-fired Plants | | |
| *None* | *0* | *0* |
| Total Coal-fired Plants | 0 | 0 |
| | 0% | 0% |
| Nuclear Power Plants | | |
| *Palo Verde[2]* | *12* | *12* |
| Total Nuclear Plants | 12 | 12 |
| | 6% | 5% |
| Gas-fired Power Plants | | |
| *Malburg Generating Station* | *134* | *134* |

| City of Vernon | 2010[a] | 2018[a] |
|---|---|---|
| *H. Gonzales Units 1 & 2* | *12* | *12* |
| Total Gas-fired Plants | 146 | 146 |
| | 77% | 64% |
| Hydroelectric Power Plants | | |
| *Hoover entitlement* | *22* | *22* |
| Total Hydroelectric | 22 | 22 |
| | 12% | 10% |
| Renewable Power | | |
| *None that are utility-owned* | *0* | *0* |
| Total UEG Renewable | 0 | 0 |
| | 0% | 0% |
| ***Total of Utility Electric Generation*** | ***180*** | ***180*** |
| | ***95%*** | ***79%*** |
| **Long-Term Renewable and Other Bilateral Contracts (LT)** | | |
| *None* | *0* | *0* |
| Total LT Contracts | 0 | 0 |
| | 0% | 0% |
| ***Subtotal (UEG + LT)*** | ***180*** | ***180*** |
| | ***95%*** | ***79%*** |
| **Short-Term to Expiration Contracts (ST)** | | |
| *AEP (ends after 2010)* | *25* | *0* |
| Total ST Contracts | 25 | 0 |
| | 13% | 0% |
| **Total (UEG + LT +ST)** | **205** | **180** |
| | **108%** | **79%** |
| **Short-Term and Spot Market Purchases (ST/SM)** | *10* | *10* |
| Total ST/SM | 10 | 10 |
| | 5% | 4% |
| **Total** | **215** | **190** |
| | **114%** | **83%** |
| **Scheduled Additions** | | |
| *None* | *0* | *0* |
| ***Total Scheduled Additions*** | ***0*** | ***0*** |
| | ***0%*** | ***0%*** |

Notes:

a. All capacity values are in MW. Percentages are of the Firm Peak-Hour Requirement for each category.

1. Vernon's Line 14 entry incorporates a 15 percent PRM.

2. Vernon's share of the Palo Verde Nuclear Generating Station is about 5 percent. (SCPPA 2007-2008 Annual Report, p. 9, http://www.scppa.org/Downloads/Annual%20Report/scppaar1208.pdf, accessed June 3, 2009.)

Source: Vernon Capacity Resource Accounting Table Form S-1, February 12, 2009, updated April 7, 2009

## *Energy*

Vernon's Firm Energy Requirement increases 21 percent from 1,118 GWh in 2010 to 1,356 GWh in 2018. Expected supplies decrease during the period from 1,330 GWh to

1,206 GWh, or from 119 to 89 percent of the annual Firm Energy Requirement. The decreases are solely related to the expiration of an AEP contract at the end of 2010.

The combination of load growth without identified new energy supplies means that Vernon expects to procure an additional 149 GWh annually by 2018. This procurement would be in addition to purchases of 80 GWh in short-term contracts or spot market purchases during all forecast years.

**Table A-30: Vernon Energy Supplies in 2010 and 2018**

| **City of Vernon** | **2010[a]** | **2018[a]** |
|---|---|---|
| **Firm Energy Requirement** | **1,118** | **1,356** |
| **Percent Change** | | **21%** |
| **Utility Electric Generation (UEG)** | | |
| Coal-fired Plants | | |
| *None* | *0* | *0* |
| Total Coal-fired Plants | 0 | 0 |
| | 0% | 0% |
| Nuclear Power Plants | | |
| *Palo Verde[1]* | *96* | *96* |
| Total Nuclear Plants | 96 | 96 |
| | 9% | 7% |
| Gas-fired Power Plants | | |
| *Malburg Generating Station* | *1,007* | *1,007* |
| *H. Gonzales Units 1 & 2[2]* | *0* | *0* |
| Total Gas-fired Plants | 1,007 | 1,007 |
| | 90% | 74% |
| Hydroelectric Power Plants | | |
| *Hoover entitlement* | *23* | *23* |
| Total Hydroelectric | 23 | 23 |
| | 2% | 2% |
| Renewable Energy Resources | | |
| *None that are utility-owned* | *0* | *0* |
| Total UEG Renewable | 0 | 0 |
| | 0% | 0% |
| ***Total of Utility Electric Generation*** | ***1,126*** | ***1,126*** |
| | ***101%*** | ***83%*** |
| **Long-Term Renewable and Other Bilateral Contracts (LT)** | | |
| *None* | *0* | *0* |
| Total LT Contracts | 0 | 0 |
| | 0% | 0% |
| ***Subtotal (UEG + LT)*** | ***1,126*** | ***1,126*** |
| | ***101%*** | ***83%*** |
| **Short-Term to Expiration Contracts (ST)** | | |
| *AEP (ends after 2010)* | *124* | *0* |
| Total ST Contracts | 124 | 0 |
| | 11% | 0% |
| **Total (UEG + LT +ST)** | ***1,250*** | ***1,126*** |

| City of Vernon | 2010[a] | 2018[a] |
|---|---|---|
| | ***112%*** | ***83%*** |
| **Short-Term and Spot Market Purchases (ST/SM)** | *80* | *80* |
| Total ST/SM | 80 | 80 |
| | 7% | 6% |
| **Total** | **1,330** | **1,206** |
| | **119%** | **89%** |
| **Scheduled Additions** | | |
| *None* | *0* | *0* |
| ***Total Scheduled Additions*** | ***0*** | ***0*** |
| | ***0%*** | ***0%*** |

Notes:

a. All energy values are in GWh. Each percentage value is of the Firm Energy Requirement for that category.

1. Vernon's share of the Palo Verde Nuclear Generating Station is about 5 percent. (SCPPA 2007-2008 Annual Report, p. 9, http://www.scppa.org/Downloads/Annual%20Report/scppaar1208.pdf, accessed June 3, 2009.)

2. The natural gas-fired H. Gonzales Units provide capacity but not energy. See the Capacity table and discussion.

Source: Vernon Energy Balance Resource Accounting Table Form S-2, February 12, 2009, updated April 7, 2009

# APPENDIX B: Peak Demand, Energy, and Retail Sales by IOUs and ESPs

### Table B-1: Investor-Owned Utility and Energy Service Provider Peak Demand, Energy Generation, and Retail Sales (2007–2008)

| LSE | 2007 Peak MW | 2008 Peak MW | 2007 Energy GWh | 2008 Energy GWh | 2007 Retail Sales GWh | 2008 Retail Sales GWh |
|---|---|---|---|---|---|---|
| **Large Investor-Owned Utilities** | | | | | | |
| SCE | 27,926 | 25,911 | 99,382 | 101,283 | 79,505 | 81,027 |
| PG&E | 18,900 | 19,431 | 86,225 | 87,724 | 79,451 | 81,935 |
| SDG&E | 4,102 | 3,764 | 18,372 | 18,708 | 17,056 | 17,410 |
| *Sub-Totals* | 50,928 | 49,106 | 203,979 | 207,715 | 176,012 | 180,372 |
| **Small & Multi-Jurisdictional Investor-Owned Utilities** | | | | | | |
| PacifiCorp | 187 | 187 | 1,065 | 988 | 885 | 883 |
| Sierra Pacific Power | 135 | 127 | 578 | 571 | 542 | 535 |
| Bear Valley Electric Service | 41 | 40 | 162 | 158 | 140 | 137 |
| Mountain Utilities | 4.8 | 4.5 | 8 | 7 | 7 | 6 |
| *Sub-Totals* | 367 | 359 | 1,812 | 1,724 | 1,575 | 1,562 |
| **Larger Energy Service Providers[1]** | | | | | | |
| *Sub-Totals* | 2,318 | 2,807 | 15,557 | 15,860 | 15,124 | 15,579 |
| **Small & Former Energy Service Providers** | | | | | | |
| Calpine Power America | | | | | 1,085 | confidential |
| Pacific Power | | | | | 885 | 883 |
| Commerce Energy | | | | | 587 | confidential |
| Corona, City of | | | | | confidential | confidential |
| 3 Phases Renewables | | | | | 25 | confidential |
| Praxair Plainfield | | | | | confidential | confidential |
| *Sub-Totals with other small ESPs[2]* | 670 | 840 | 3,950 | 5,853 | 4,421 | 5,770 |
| *Totals* | 54,283 | 53,112 | 225,298 | 231,152 | 197,132 | 203,282 |

1 Constellation NewEnergy, Direct Energy Services, Pilot Power, Sempra Energy Solutions, Shell Energy

2 Includes estimates by Energy Commission staff

Source: California Energy Commission, Electricity Supply Analysis Division, September 2009