White Paper

Optimal Direct Access Buying Strategies in California

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I. Executive Summary

The chronicle of regulatory and legislative actions presented in this White Paper have profoundly affected the power market in California, now offering multiple consequences for generation resource development, consumer load shapes, market prices, regulated utility conservation programs, air quality standards and attainment, renewable resource development, and the availability of energy. California is now steaming forward with binding legislative and regulatory plans to limit the type of electric generation that will challenge the market capacity to keep up with growing consumer demand, such that savvy buyers of energy will prosper in both the economy of purchases and the dependability and certainty of electric supply.

The matrix summary of Optimal Direct Access Electric Buying Strategies on page 19 of this White Paper details legislative, regulatory and market actions as well as market conditions; intended actions of those actions and conditions, affects of those actions and conditions; and finally mitigation of risks and capitalization of energy buying opportunities in California.

I am fully prepared to support _______ program to minimize its electric operating costs and to ensure that critical legislative and regulatory actions and energy market conditions are identified early, critically analyzed, and effectively recommended and implemented to ensure reliable, economical electric service with emphasis on long term, comprehensive cost savings.

This White Paper has been prepared from extensive experience with utility programs throughout the United States, and specifically California. As an intervener at the California Public Utilities Commission, and a former witness at the Federal Energy Regulatory Commission and U.S. Senate Energy Commission, I am confident that the material contained in this paper is well-documented, objective and conclusive. I welcome comments and questions.

Sincerely,

Jackson W Mueller Jr.

II. The Report

A. History of Meeting Customer Needs with Electricity in California

In 1911, the California Public Utilities Commission was established by Constitutional Amendment as the Railroad Commission. In 1912, the California Legislature passed the Public Utilities Act, expanding the Commission's regulatory authority to include natural gas, electric, telephone, and water companies as well as railroads and marine transportation companies. In 1946, the Commission was renamed the California Public Utilities Commission (CPUC.) The CPUC was structured as follows: The Governor appoints the five Commissioners, who must be confirmed by the Senate, for six year staggered terms. The Governor appoints one of the five to serve as Commission President. The CPUC employs economists, engineers, administrative law judges, accountants, lawyers, and safety and transportation specialists. (The CPUC is currently organized into several advisory units, an enforcement division, and a strategic planning group. The Division of Ratepayer Advocates is an independent arm of the PUC that represents consumers in Commission proceedings, pursuant to statute.) The Commission also has a Public Advisor who assists the public in participating in Commission proceedings, and a unit that is charged with informally resolving consumer complaints.[1]

After the tumult of the Roosevelt years and the end of World War II, the electric power industry enjoyed a period of steady growth, driven by both technological and efficiency advances that were reflected in lower prices. Between 1947 and 1973, the growth rate for the electric industry held steady at about 8% per year and there was little change in the industry structure. Peak electrical demand consumption grew at a relatively even rate. The industry began to promote increased electricity usage through advertising campaigns with such slogans as GE’s “Live Better Electrically” Campaign that began in 1956[2]. As the industry grew and prices continued to decline because of economy of scale, there was little need for state and Federal regulatory intervention and certainly no fears of shortage because of plentiful power supplies and fuel to operate them. Investor Owned Utilities (IOU’s) were the primary service providers for most Americans and their continued growth and low rates satisfied both consumers and investors. Municipal utilities, the original local utilities, began to consolidate and submit to state regulators.

The energy crisis of the 1970’s[3] is often symbolized by images of long lines at gas pumps all over the United States resulting from the 1973 Organization of the Petroleum Exporting Countries (OPEC) oil embargo. Oil, coal and natural gas shortages, was well as declining public confidence in the nuclear

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[1] California Public Utilities Commission web site at http://www.cpuc.ca.gov/static/aboutcpuc/puhistory.htm

[2] This campaign was started in 1956 by the General Electric Company and endorsed by power utilities and electrical manufacturers across the nation to produce public awareness and the desire for the usage of electricity. The theme was "Live Better Electrically" and it was a campaign to push the usage of electricity in the home and Ronald Reagan was the official spokesman. General electric produced a series of educational films about the history of electricity, its usage and what the future had in store for electricity in industry, health and general quality of life. One of the most ambitious aspects of the campaign was the certification of newly built homes called "Medallion Homes". To qualify as a Medallion Home" each house had to be completely electrified which included all electric appliances and electric heating. Each home that meet this qualification received a plaque or Medallion that could be mounted somewhere in the home, usually mounted on a garage wall or out in the front near the front doorway. From 1957 to 1970, some 1,000,000+ homes were certified as Medallion homes and today many of these homes can still be found with their Medallions still hanging proudly on some wall.

3 In October, 1973, panic gripped the United States. The crude oil-rich Middle-Eastern countries had cut off exports of petroleum to Western nations as punishment for their involvement in recent Arab-Israeli conflicts. Although the oil embargo would not ordinarily have made a tremendous impact on the U.S., panicking investors and oil companies caused a gigantic surge in oil prices. The situation, caused more by fear and irrationality than any firm economic basis, turned out to be one of the most memorable of the 1970s. Those who can remember the so-called "Mideast oil crisis" also remember long lines at the gas pump due to petroleum shortages and high gasoline prices.

power industry, contributed to rate increases for consumers throughout all the energy industries, including electricity.

The California Energy Commission was created in 1974 and headquartered in Sacramento as California's primary energy policy and planning agency. Initially called the Energy Resources Conservation and Development Commission, the Energy Commission was charged with forecasting future energy needs, promoting energy efficiency through appliance and building standards, and supporting renewable energy technologies.

In 1975 the California Warren-Alquist State Energy Resources Conservation and Development Act was based on a legislative finding that the rapid growth rate in the demand for electric energy was in part due to wasteful, uneconomic, inefficient, and unnecessary uses of power. A continuation of this trend was expected to cause serious depletion or irreversible commitment of energy and land and water resources and potential threats to the state's environmental quality. The California Legislature also found there was a pressing need to accelerate research and development of alternative sources of energy. This policy resulted in a situation where more than 20 agencies, ranging from the Barbers' Licensing Board to the State Architect, could adopt building standards and publish them under the separate titles of the California Code of Regulations.

In 1975, California changed its historical cost-of-service methodology of allocating costs to various customer classes and using the cheaper-by-the–dozen pricing of electricity. California created residential lifeline (later "baseline') electric rates, targeted to low-income households and low users of electricity – giving them very low, frozen rates. Residential customers who used more than baseline amounts of power monthly, based on geographic usage zones, would receive more-costly-by-the dozen pricing with very large users having multiples of the cost per unit of smaller users. This was one of the first programs in California that intentionally charged prices to encourage consumer response, not just collect for the cost of service.

Elected as U.S. President in 1976, President Jimmy Carter made energy concerns one of his top priorities. In attacking the demand side of the problem, he waged a public campaign focused on energy conservation to reduce the American public's high rates of consumption. In 1977 President Carter signed the Department of Energy Organization Act. The Act created the Department of Energy by consolidating organizational entities from a dozen departments and agencies. Under this legislation, the Federal Power Commission was replaced by the Federal Energy Regulatory Commission (FERC) as the federal agency that establishes and enforces wholesale electricity rates and interstate energy commerce. To combat the supply side, President Carter sought to cultivate the growth of new sources of energy, including nuclear power and renewable resources such as solar and wind. These two approaches were crystallized in the five-part National Energy Act, which Carter signed into law in 1978.

The Public Utility Regulatory Policies Act of 1978 (PURPA) was the piece of Carter's National Energy Act that affected the national electric power industry. It was designed to encourage efficient use of fossil fuels by allowing non-generators (known as Qualifying Facilities or QFs) to enter the wholesale power market.[4]

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[4] PURPA designated two main categories of QFs: *cogenerators*, which use a single fuel source to either sequentially or simultaneously produce electric energy as well as another form of energy, such as heat or steam; and *independent power producers*, which use renewable resources including solar, wind, biomass, geothermal and hydroelectric power as their primary energy source. Although intended to be an environmental statute, a primary effect of PURPA was to introduce competition into the electric generation sector of the electricity marketplace, thus challenging the utilities' claim that the electricity market encouraged a "natural monopoly." One feature of the PURPA legislation was to obligate regulated utilities to buy all of the power output of a QF at the utility's "full avoided cost" as long as the operating supply and thermal efficiency of the cogenerator met the minimum seasonal and annual average standards, respectively.

In 1978 to correct the problems and confusion resulting from the uncoordinated proliferation of conflicting, duplicate, and overlapping state regulations, California SB 331 (Robbins, Chapter 1152, Statutes of 1979), effective January 1, 1980, provided the Energy Commission with broader powers. As a result of SB 331, all proposed building regulations adopted by various state agencies were required to be reviewed and approved by the Energy Commission before the regulations had any force or effect. Further, the legislation called for all building standards to be removed from other titles of the California Code of Regulations and put into a single code — Title 24 — that the Energy Commission would be responsible for codifying and publishing. Title 24 provided an "energy budget" that would ultimately dictate building materials including window size and type, insulation levels, and other materials that could ensure efficient energy consumption within types of buildings.

In 1978 the California Public Utilities Commission approved interruptible electric programs of its regulated IOUs with the express goals to "…meet energy demands of our communities and keep rates lower." IOU tariffs provided about a 15% rate discount to large customers who signed agreements to interrupt a pre-agreed level of electric usage within 30 minutes of notice to their Remote Terminal Unit. Better rate discounts were offered to customers who involuntarily interrupted entirely when the IOU grid frequency sagged below 59.75 cycles per second. The interruptible programs were popular with large industrial customers who could interrupt their electric demand without damaging their products or disadvantaging their workers. Interruptions were initially plentiful as interruptible customers were considered to be the equivalent of electric generation – called upon when needed largely to *optimize the economy of the utility generation* and secondarily to instantaneously balance electric demand with supply.

Under the PURPA legislation, by the early–1980's many private companies quickly installed gas-fired cogeneration, largely financed indirectly by long term (up to 30-year) utility contracts, and generation resources swelled to over-supply growing consumer electric demands. The free–market mania of the 1980's and 1990's further challenged the notion of the electric power industry as a "natural monopoly." Many politicians and economists argued regulation had outlived its value, and the market should determine price and allocate resources. The telecommunications and transportation industries were deregulated, and the natural gas industry followed suit in the mid-80's and early-90's. Advocates for deregulating the electricity industry argued the implementation of PURPA had proved non-utility generators could produce power as inexpensively and effectively as the regulated utilities. Large industrial consumers searching for lower prices also chimed in and urged Federal regulators to pursue deregulation.

In 1992, Congress passed President Bush's Energy Policy Act (EPACT), which opened access to transmission networks to non-utility generators. EPACT further facilitated the development of a competitive market by creating another category of generators known as exempt wholesale generators (EWGs), which were exempted from regulations faced by the traditional utilities.[5]

In 1995 the push toward electricity deregulation at the Federal level led states with relatively high electricity rates, including California, to investigate and pursue deregulation of the state-regulated aspects of electricity service, and retail service in particular. In California the push was led by large industrial customers facing high electricity costs in an ailing economy. At that time electric interruptions occurred infrequently as there was robust generation and plentiful fuel to operate power plants. It was the delivered *cost of electricity* that large consumers surged against, at least those customers without the ability to accept interruptible electric service. These customers saw the immediate advantage of bypassing the IOU's "bundled service", renting utility wires, and buying electricity directly from market suppliers (Energy Service Providers or ESPs).

[5] To assist in the implementation of PURPA and EPACT, FERC issued Orders 888 and 889 in April 1996. The two Orders provided guidelines on how to open electricity transmission networks on a nondiscriminatory basis in interstate commerce.

The industrial customers were joined in the push for deregulation by merchant generators and marketers, who wanted to compete on equal footing with the IOU's and sell electricity and regulated services to selected profitable customers. The IOU's, who saw promising ventures in deregulated electricity markets for themselves, favored deregulation once their primary concern about recovery of investments stranded by the departure of their customers to competitors was satisfied.

In November 1996, the CPUC suspended any new IOU applicants for interruptible electric service, claiming that the potential for interruption and cost-benefit to other ratepayers for maintaining the program was minimal and no new customers should be allowed. At that point, it appeared that "firm" electric service would be common for all customers, especially with the advent of deregulated electric service that would offer the ability for all customers to purchase electricity directly from power vendors (ESPs) apart from any utility service. The concept of interruptible electric service seemed to have evolved past the ability of the utility to regulate.

In 1997, electric deregulation, or "restructuring," legislation was passed by the California Legislature. Assembly Bill 1890 (AB 1890) codified a series of deregulation proposals either undertaken or recommended by the California Public Utilities Commission (CPUC), whose work on deregulation had been inspired by the EPACT and subsequent FERC Policies. Chief among the CPUC proposals was "Direct Access" – the authorization of retail competition within the IOU service territories. AB 1890 ended the retail service monopoly of utilities and authorized retail customers to buy power directly from alternative providers, or ESPs, beginning April 1, 1998.

The essential bargain of AB 1890 was to authorize Direct Access and assure the IOU's could recover stranded investments, but the CPUC's implementing decisions took a series of further steps intended to facilitate competition and Direct Access in particular, which would prove disastrous. The CPUC imposed a form of "synthetic competition" to improve on the natural workings of commodity markets. These included compelling the IOU's to sell off power plants that generated the electricity needed to serve their own customers; requiring the IOU's to buy and sell their non-equity power through the Power Exchange (PX) controlled by the newly-formed California Independent System Operator (CA ISO); and retreating from long term planning and investment.[6]

AB 1890 contained a number of "side deals." These included a guaranteed 10% reduction in retail rates for small customers, a guaranteed level of funding for low-income and environmental purpose programs, and assistance for IOU employees whose jobs would be at risk. The final product was widely supported. At the time, deregulation champions heralded the bill as paving the way for more competitive, efficient, reliable, and affordable electricity service. Many would-be critics saw deregulation in California as inevitable and AB 1890 as the best possible bargain. Only IOUs were subject to AB 1890, but municipal utilities could participate if they wished; none did.

[6] Other elements of deregulation, such as the IOU's transfer of control of their transmission systems to the ISO to facilitate non-discriminatory access to competing suppliers, were addressed in AB 1890, but likely would have happened anyway pursuant to Federal policies, such as FERC's Order 888. The main contribution of AB 1890 in this area, which was to attempt to ensure accountability of the Independent System Operator to the State, met with limited success. The Power Exchange, as directed, conducted periodic "Dutch auctions" for power to meet utility needs and awarded the highest price bid to all the bidders that were accepted for a forecast block of electricity needs for a limited time period. Gaming (withholding power) led to high prices to utilities, which were passed along to consumers along with high profits to the new unregulated power plant owners. AB 1890 also ensured that all *consumers* would fund the stranded investment of utilities from deregulation, not just the direct customers of the utilities, spreading risk of liability broadly among all Californians.

The California Electricity Oversight Board (EOB) was formed by the California Legislature under AB 1890 to perform three functions: to oversee the Independent System Operator (ISO) and the Power Exchange (PX); to determine the composition and terms of service and to appoint the members of the governing boards of the ISO and PX; and to serve as an appeal board for majority decisions of the ISO governing board.

The California Independent System Operator (ISO) was formed in March 1998, charged with managing the flow of electricity along the long-distance, high-voltage power lines that make up the bulk of California's transmission system. The not-for-profit public-benefit corporation was opened in Folsom, California. The ISO assumed the responsibility when California opened its energy markets to competition and the state's investor-owned utilities turned their private transmission power lines over to the ISO to manage. The mission of the ISO was to safeguard the reliable delivery of electricity, facilitate markets and ensure equal access to a 12,500 circuit mile "electron highway." It turns out that reliable delivery of power delivery was not the challenge in a deregulated market in California, but rather the voluntary operation of electric generation to meet customer needs.

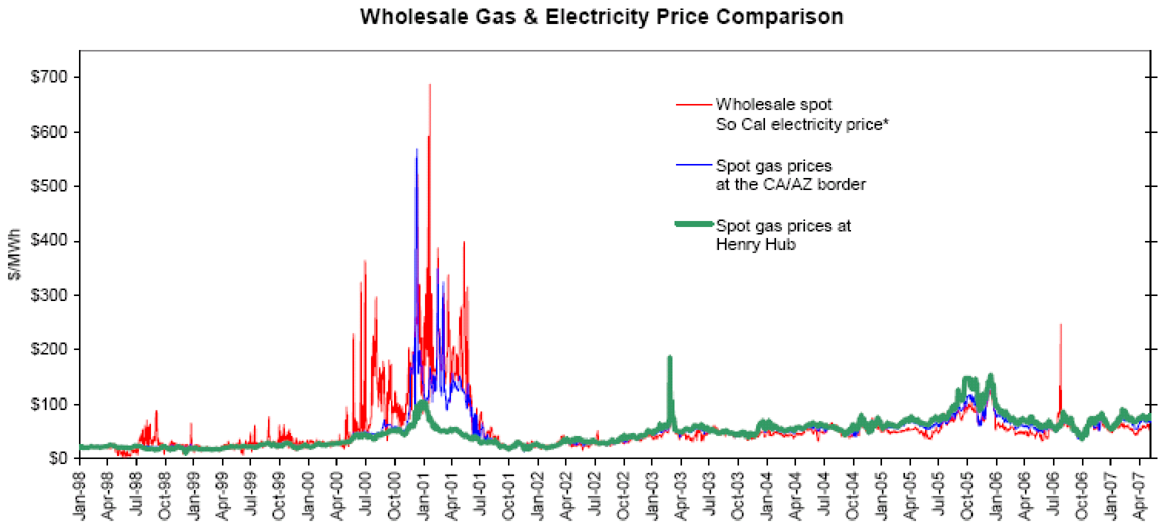
The first two years after implementation of AB 1890, the deregulation experiment appeared to be paying off well for IOU's and customers alike in California. Service remained reliable, few electric interruptions were called for customers that selected the rate option, wholesale prices remained below the frozen retail rates of December 1996, and the IOU's stranded cost recovery funding surged, due in large part to unexpectedly high prices fetched for the sale of power plants. All Direct Access service remained "firm" in its supply between ESPs and customers. Large utility *rate reductions* were anticipated once the AB 1890-required Competition Transition Charge (CTC) period to amortize "stranded investment" from deregulation was over, legislated for March 31, 2002.

Evidence of market power problems began to surface in 1999. Irregular but enormous price spikes in hourly and day-ahead purchased energy and ancillary services markets raised concerns among observers. The potential for market power abuse and increased prices was at the forefront of skepticism over Pacific Gas & Electric Company's (PG&E's) failed attempt to divest its entire hydroelectric system to an unregulated affiliate. The California Legislature's refusal to permit PG&E's proposed divestiture was the first major hiccup in the march toward deregulation. By 1999 few customers that could take advantage of deregulated service did so because of continued attractive retail "bundled service" rates, uncertainty about future market prices for wholesale electricity, and monthly-changing Competition Transition Charges (CTC) charges by utilities. At that time, "bundled service" rates were frozen, so aggregate monthly utility costs were subtracted from frozen rates to derive the monthly CTC, which could be positive or negative, leaving great financial risk to Direct Access customers who bought power at market prices plus "wires charges" and the CTC.

Then in mid-2000, unprecedented price spikes began to occur with growing regularity. In San Diego, where the rate freeze had ended with SDG&E amortization of claimed "stranded investment" costs to get to a deregulated market, San Diego Gas & Electric (SDG&E) customers were directly exposed to outrageous prices, exacerbated by the fact that SDG&E had to buy most all of its power from the open, competitive market. Within six months, the market was in disarray, rolling blackouts occurred during relatively low electricity demand to both traditional bundled utility customers and Direct Access customers, suppliers' demands for extraordinary prices were unchecked, high wholesale prices caused nearly all customers of the collapsing Direct Access market to return to IOU's frozen rates, the IOU's became financially unable to pay for electricity, and the State of California had to assume the IOU's power buying duties for their "net short" positions to provide credit support for purchases and "keep the lights on."

Please see the following daily electric and gas prices in Southern California (South Path-15 or SP-15) served by Southern California Edison (Edison) during the 2000-2001-2001 period, very similar to North Path 15, not experienced by California before or since.[7]

[7] Southern California Gas Company, Energy Markets Update, May 2007.



There were multiple electric interruptions during 2000-2001 for IOUs, largely diminishing the public appeal for deregulated electric service or respect for market participants. Rotating blackouts became the norm as power suppliers operated the power plants purchased from IOUs under AB 1890 to maximize their profits, with little apparent concern for the integrity of their public services.

To avoid a dysfunctional spot market that financially decimated the IOU's, threatened catastrophic rate increases, and threatened continued electric interruptions for all customers, the California Legislature passed emergency measure AB 1X [8] on February 1, 2001 to establish a structure to permit the California Department of Water Resources (CDWR) to buy needed electricity for IOU customers under long-term contracts and stabilize power prices and supply reliability of the electric market. To ensure the predictable revenue stream necessary for long term contracts, to promote the competitive issuance of ratepayer-backed revenue bonds, and to prevent cost-shifting from Direct Access to "bundled service" customers, the CPUC was directed to suspend Direct Access to prevent additional migration of IOU customers. After a seven month delay, the CPUC suspended Direct Access on September 20, 2001, other than to allow "normal load fluctuations" by existing Direct Access customers.

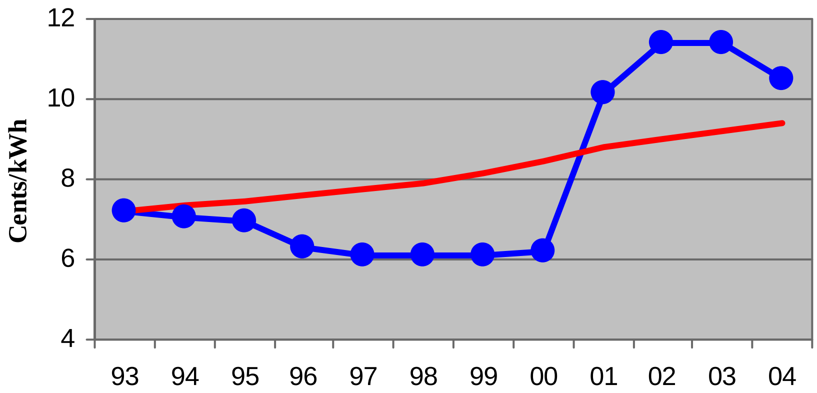
The market chaos in early-2001 caused the ISO to collapse the Electricity Oversight Board (EOB) and PX in January 2001 and focus on restoring integrity between power producers and power consumers, largely initiated with hearings about why generators were bidding to sell power to the ISO, but not performing once bids were accepted. The ISO retained its responsibility to call interruptions to regulated utility customers based on its control of dispatching (approving) power plants to operate, coordinating major grid switching and power flows in California, and coordinating the generation and switching with the Western Utility Coordinating Council that controls the major grids of the nine western states.[9] Regulated utilities retained their responsibility to build, own, and operate their electric grid system and equity generation as controlled by the ISO.

Between January and June 2001, the vast majority of customers previously served by Direct Access ESPs returned to IOU service, benefiting from retail rates which were lower and more stable than then-current market prices. As a result of the CDWR's errant purchase of electricity for expected levels of "bundled service" customers at multiples of historical market price for terms of 10-20 years, between July 1, 2001 and September 20, 2001, thousands of predominantly large industrial customers, who had just taken service from utilities at below-market rates, departed for Direct Access as market conditions improved. During the July 1 to September 20, 2001 period, Direct Access service increased from approximately 2% to approximately 13% of the total IOU load. (Direct Access

[8] Keely, Chapter 4, Statutes of 2001
[9] http://www.caiso.com/PowerCentral/

load now stands at approximately 12%.) Since 2001, the electricity rates set by the CPUC for the customers of the state's major IOU's have far exceeding the rates of in-state municipal utilities or any neighboring state, and firmly rank among the highest in the nation.

In January and again in March 2001, the CPUC increased rates for the customers of Edison and PG&E a combined average of 4 cents per kilowatt hour (KWh). High usage residential customers and the vast majority of business customers who were taking "bundled service" were hit especially hard. The rate increase marked the practical collapse of the rate freeze initiated in 1996 and transition cost recovery scheme created by AB 1890. As you can see from the chart below from PG&E for its E-20 (largest) electric customers, bundled rates (in blue) increased at an alarming level from 2000-2002 compared to the Consumer Price Index (in red).[10]



While CDWR claimed a share of the electricity rates for its ongoing operating costs and payments on bonds it issued to finance its high-cost power purchases in 2001, the IOU's have also been collecting an extra measure of rates that would have otherwise be dedicated to buying electricity, namely *above the costs incurred by the CDWR* since they stepped in to buy power for the financially ailing utilities.

The CPUC has maintained the level of rates imposed in 2001, instead of refunding the excess funds to customers or using them for ongoing procurement, and expanded their purposes to include restoring the financial health of Edison and PG&E. For example, in October 2001, the CPUC entered into a settlement of Federal litigation with Edison, permitting Edison to use $3.3 billion in excess rates under the Procurement Related Obligations Account (PROACT) to pay off procurement debts incurred in 2000. Since then, Edison has been applying an average of about $200 million per month in rates to pay these debts. A challenge to this settlement by The Utility Reform Network (TURN) and a filing by multiple parties in a request for a Writ of Review for action by the CPUC failed before the California Supreme Court. Four times the State of California, IOUs and the CPUC have approached the FERC to disallow contracts the CDWR entered into with power plant owners, without success. Partial renegotiations of deals between CDWR and power plant owners have occurred, but results have been nominal.

In April 2001 the CPUC issued a unanimous decision in D.02-11-026, applicable to both Edison and PG&E, lifting its prior restriction to the use of the 2001 rate increase and allowing the money to be used for "returning each utility to financial health." In the same month, Edison filed for approval from the CPUC to begin its Base Interruptible Program (BIP), among other programs intended to enhance Edison's ability to attract program participants and reduce its electric demand effectively during

[10] Making Rates in a Reformed Market, Tom Bottorff, Senior Vice President Customer Service and Revenue, Panel Discussion, California Manufacturers & Technology Association Energy Conference, South Lake Tahoe, July 29, 2004, Page 3.

periods of shortage.[11] Notably, Edison's vigor to establish a new interruptible electric service program came from its profound experience during the energy crisis whereby 54% of I-6 interruptible customers elected to return to "bundled utility", 22% increased their Firm Service level during the prior annual November "Open Season." Only 23% did not change their service, and a paltry 630 active I-6 accounts remained on interruptible electric service.[12]

In 2001, Senate Bill 1771 (Sher, Chapter 1018, Statutes of 2000) required that the California Energy Commission update California's inventory of greenhouse gas emissions in January 2002 and every five years there after. The inventory was used to develop policies affecting emissions of greenhouse gases and was to be updated more frequently than required by legislation. Under this statute, using market-based incentives, California plans to reduce carbon emissions to 1990 levels by the year 2020, a 25% reduction. By 2050, California plans to reduce emissions to 80 percent below 1990 levels.

California initiated a needed improvement to its electric grid operations as part of a process that began with a Federal Energy Regulatory Commission (FERC) Order in 2001.[13] California's program is called Market Redesign and Technology Upgrade (MRTU.) The program, beginning in April 2008, will improve economic dispatching of power, grid reliability, and technical operation of California's grid controlled by the California Independent System Operator (CAISO.)[14]

Senate Bill 1078 (SB 1078, Sher, Chapter 516, Statutes of 2002) established the California Renewables Portfolio Standard (RPS) program, which requires an annual increase in renewable generation by the utilities equivalent to at least 1 percent of sales, with an aggregate goal of 20 percent by 2017. The CPUC accelerated the goal, requiring the utilities to obtain 20 percent of their power from renewables sources by 2010 (Senate Bill 107 codified this goal in state law). Currently, the CPUC is considering ways to achieve 33 percent renewable energy by 2020. The RPS program requires the CPUC to work collaboratively with the Energy Commission to implement the RPS and assigns specific roles to each commission. Among other things, the California RPS program calls for the CPUC to "establish a methodology to determine the market price of electricity for terms corresponding to the length of contracts with renewable generators. The "market price" must reflect the long-term market price of electricity a utility would need to purchase to meet its capacity and energy needs from conventional fossil fuel resources instead of the renewable resources proposed under the RPS bidding process.[15]

In November 2002, the CPUC issued its decision that initiated a Direct Access Cost Recovery Surcharge of $.027 per kWh beginning January 1, 2003 for all Direct Access customers, excepting those that did not use any IOU power during the period February 1 through September 20, 2001. This measure, the final step in implementing AB 1X, was intended to fully compensate regulated utilities for cost imposed by the CDWR and to ensure abundant, well-financed energy was available to meet customer demands.[16]

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[11] "SCE Load Reduction Programs: Summer 2001 Experience and Lessons Learned," Mark Wallenrod, Manager, Pricing & Tariff Operations, ACEE Conference on Energy efficiency and Reliability, October 31, 2001.

[12] Ibid.

[13] Federal Energy Regulatory Commission Docket Nos. EL00-95, et. al of December 19, 2001

[14] California Independent System Operator, MRTU High-Level Timeline predicting a 4/01/08 Go Live Date.

[15] To date, the CPUC has addressed its responsibilities in implementing the RPS in R.01-10-024, Order Instituting Rulemaking to Establish Policies and Cost Recovery Mechanisms for Generation Procurement and Renewable Resource Development and R.04-04-026, Order Instituting Rulemaking that is specific to Renewables, which will be coordinated under a new broader procurement rulemaking, Order Instituting Rulemaking to Promote Policy and Program Coordination and Integration in Electric Utility Resource Planning, R.04-04-003, that succeeds R.01-10-024.

[16] CPUC Decision 02-11-022 of November 7, 2002.

On June 19, 2003, the CPUC in its Resource Adequacy Requirement (RAR) Decision[17] (1) directed that each Load Serving Entity (LSE) within the utility's service territory (i.e., IOU, Energy Service Provider (ESP) or Community Choice Aggregator) has an obligation to acquire sufficient reserves for its customer's load located; (2) adopted a reserve capacity margin for Load Serving Entities (LSEs: all IOUs and ESPs) of 15-17%; (3) directed the LSEs to meet this 15-17% reserve requirement by no later than January 1, 2008, through a gradual phase-in including the establishment of interim benchmarks to become effective in 2005; (4) established a requirement that utilities forward contract 90% of their summer (May through September) peaking needs (loads plus planning reserves) a year in advance; and (5) continued the 5% target limitation on utilities' reliance on the spot market (i.e., Day-Ahead, Hour-Ahead, and Real-Time energy) to meet their energy needs."

The CPUC accelerated the date of RAR implementation to be consistent with Governor Schwarzenegger's letter request and the CPUC responded as follows: "We therefore adopt June 1, 2006 as the date to achieve full implementation of the 15-17% PRM. We are mindful of the caution CAISO has raised about the feasibility of fully satisfying long-term resource adequacy requirements for this date. As discussed further below, in Phase 2 we direct parties to develop a package of reporting requirements and an initial filing date that reveals resources under the LSEs' control for 2006. We expect that the second year's filing requirements, i.e. September 2006 filings for summer 2007, may be enhanced to more fully reflect our long-term resource adequacy requirements."[18]

On June 24, 2004, the ISO Board of Directors approved two parallel programs for the MRTU Project: market improvements to assure grid reliability and more efficient use and cost effective use of resources, and technology upgrades to strengthen the entire CAISO computer backbone.[19] Here is a summary of the major grid improvements that begin April 1, 2008, likely to ensure better grid control, dispatching of generators, supply reliability, and market price stability:

<u>Market Redesign</u>

1. The CAISO will conduct a Day-Ahead Market that combines energy, ancillary services, and congestion management to better predict energy needs and ensure maximum operating economy of the grid. (The grid today is controlled an hour ahead.)
2. The grid control system will better predict how energy scheduled in the *day-ahead* of time will flow in real-time at up to 3,000 locations or "nodes."[20] (The CAISO now accepts *hour-ahead* power bids from suppliers in North Path and South Path 15.)
3. New market rules will prevent gaming as occurred in the 2000-2001 "energy crisis" namely with holding power from market gain. (Rules now are based on auditing during shortages.)
4. Local prices will be produced, showing the cost of producing and delivering costs, broadening market knowledge of risks and resources. (No data exists today.)

<u>Technology Upgrade</u>

1. Minimize maintenance of control systems and allow more cost-effective Future control changes
2. Minimize grid downtime and possibility for interruption, giving grid operators a better forecasting tool to spot potential bottlenecks on power before power flow real-time.

The California Energy Commission, pursuant to its new responsibility to develop a strategic transmission plan in its 2005 Energy Report proceeding, sought to establish a comprehensive

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[17] CPUC Decision 03-06-076 in R.01-10-024, Order Modifying Decisions 02-10-062 and 02-12-074 and Denying Rehearing; pursuant to Assembly Bill 57 and Senate Bill 1976 which became effective on September 24, 2002 and were codified as Public Utilities Code Section 454.4., pages 3, 11, 33 and 45.

[18] CPUC Decision 04-01-050 in R.01-10-024 of January 26, 2004.

[19] California ISO, Fast Facts, "The Basics: MRTU Programs", page 1

[20] California ISO, MRTU, Frequently Asked Questions, December 1, 2006, page 2.

statewide transmission planning process with the CPUC, ISO, other key state and federal agencies, local and regional planning agencies, investor-owned and municipal utilities, generation owners and developers, stakeholders and interest groups, and the public. This statewide planning process intended to: 1. Assess statewide transmission needs for reliability and economic projects as well as transmission to support Renewable Portfolio Standard (RPS) goals; 2. Examine non-wires alternatives to transmission (demand response, energy efficiency, generation, etc.); 3. Approve beneficial transmission infrastructure investments that can move into permitting; 4. Examine the right-of-way needs for future transmission projects, 5. Designate and conduct environmental reviews of needed corridors and allow utilities to set aside or bank necessary land for longer periods of time; 6. Assess transmission costs and benefits that recognize the 30-50 year useful life of transmission assets, 7. Incorporate methods (quantitative and qualitative) to assess the long-term strategic benefits of transmission, and 8. Use an appropriate social discount rate.[21]

On March 2, 2006, the CPUC opened a proceeding to develop rules and procedures for the California Solar Initiative (CSI) and to continue consideration of policies for the development of cost-effective, clean and reliable distributed generation (DG). On August 21, 2006, the Governor signed Senate Bill 1 (SB1), which directs the CPUC and the Energy Commission to implement the CSI program consistent with specific requirements and budget limits set forth in the legislation. The CPUC has a rulemaking in progress to reconcile its decisions with SB1, and it also continues to hold public workshops to continue designing program elements. Current incentives provide an upfront, capacity-based payment for a new system. The CSI incentive system will change in 2007 when it moves to performance-based payments.[22] In its August 24, 2006, decision, the CPUC shifted the program from volume-based to performance-based incentives and clarified many elements of the program's design and administration, acknowledging that the payback on solar investments could be 5-10 years, but punctuating the need for California to have diversified, renewable electric generation resources.

The California Global Warming Solutions Act of 2006 (Assembly Bill 32 (AB 32) - Nuñez & Pavley, Statutes of 2006, Chapter 488) requires that the California Air Resources Board (CARB) determine the statewide 1990 greenhouse gas (GHG) emissions level as a statewide aggregate emissions limit to be achieved by 2020. Under separate statutory authority, on January 1, 2007, ARB received responsibility for maintaining the Statewide GHG emissions inventory from the California Energy Commission.[23] AB 32 requires the CARB to develop regulations and market mechanisms that will ultimately reduce California's greenhouse gas emissions by 25 percent by 2020. Mandatory caps will begin in 2012 for significant sources and ratchet down to meet the 2020 goals.[24] In the interim, CARB will begin to measure the greenhouse gas emissions of the industries it determines as significant sources of greenhouse gas emissions. AB 32 also provides the Governor the ability to invoke a safety valve and suspend the emissions caps for up to one year in the case of an emergency or significant economic harm.

In 2007 the Energy Commission set up relatively strict laws which forbid the signing of energy supply contracts between utilities and coal-fired power plants under its regulatory power to approve power plants over 50 MW. This was a major initiative to stem greenhouse gas emissions by 2020.

Since the lofty prices for market electricity of the energy crisis of 2000-2001, market prices for Direct Access electricity have largely remained in the $60-80 per MWh range for term pricing and between $30-100 per MWh for day-ahead pricing, with average prices being between $10-20 per MWh higher than term prices. Institution of RAR, GHG, RPS, and imbalance costs for electric loads that do not fit the 15-minute supply profile are likely to swell by 2012, enhancing the opportunity for both capable

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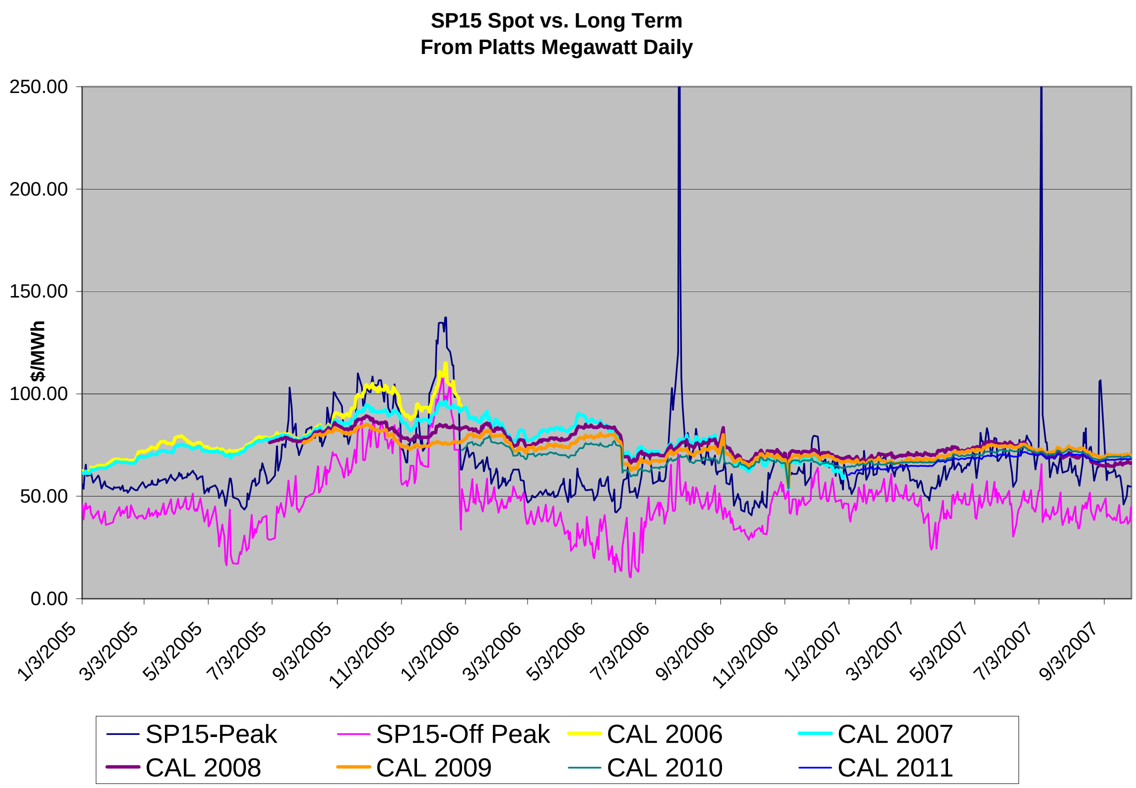
[21] California Energy Commission, 2004 Integrated Energy Policy Report Update, page xvii
[22] California Solar Initiative web site at http://www.gosolarcalifornia.ca.gov/csi/index.html
[23] State of California Web site at www.climatechange.ca.gov : policies : greenhouse gas inventory : index
[24] AB 32: Global Warming Solutions Act, A Fact Sheet of the Union of Concerned Scientists, Authors: Assembly Speaker Fabian Nuñez, Assembly Member Fran Pavley

power sellers and nimble buyers to take advantage of market arbitrage opportunities. Opportunities for power sellers who can offer RAR, renewable energy credits, and even Heat Rate products for savvy buyers will be to tailor economical supplies to customer needs via bilateral contracts. Opportunities for customers, including IOU's who are seeking to satisfy their net short positions to secure long term power arrangements, will be to buy long term, shaped supplies of power, including Heat Rate products, with pre-agreed margins. Customers seeking Green Credits or alternate fuel supplied power will likely need to shop vigorously to avoid doubling their cost of power, just to enjoy the rightful privilege of making the Green Credit or renewable generation supply claim. Please see the chart below of wholesale electricity prices since January 2005 in South Path 15, very similar to North Path 15, showing Peak and Off Peak (day-ahead or spot) power prices as well as one-year term prices.



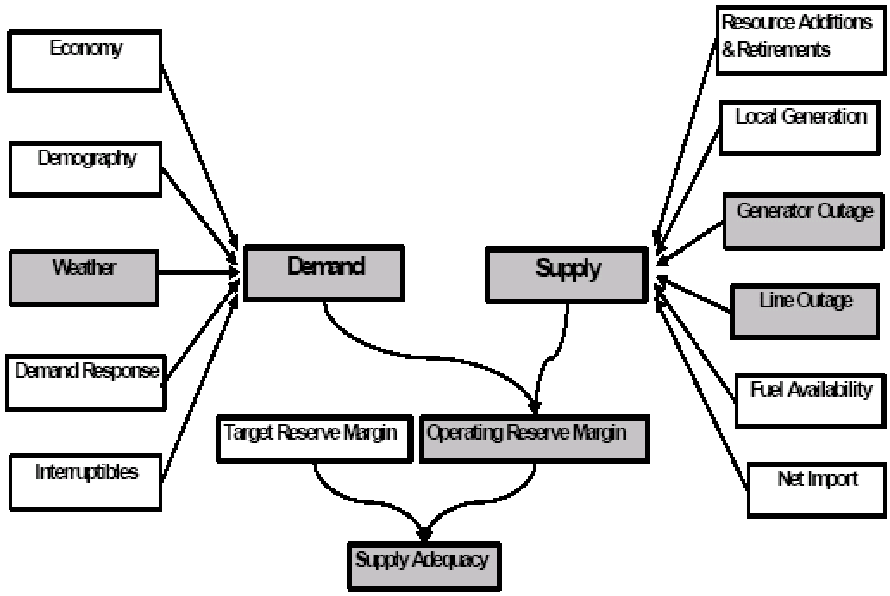
B. Outlook for Meeting Electric Generation Needs with Planned Resources

1. Power Plans Ahead

Looking forward to the outlook for electric supply and demand, we can see that excellent progress has been made in ensuring robust coverage and the timely addition of generating units to meet short term consumer demand. The model to balance demand with supply is show in the following chart entitled "Major Factors Affecting Supply Adequacy".[25]

[25] California Energy Commission, Summer 2007 Electricity Supply and Demand Outlook, May 2007, page 12.

Figure 2: Major Factors Affecting Supply Adequacy



Looking past the model above, what follows is the California Energy Commission's expectations for the Planning Reserve for the summer months of June through September 2007, comfortably above the any of the alert levels for an interruption this summer.[26]

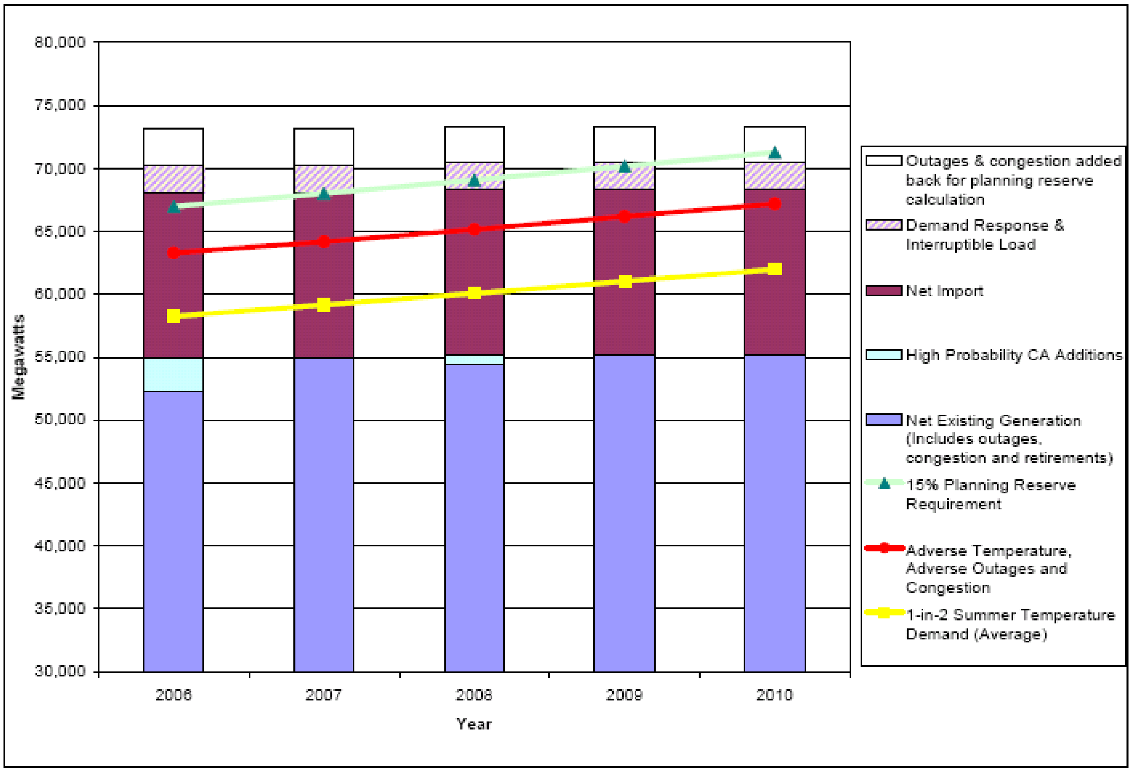
Table A-4: 2007 Detailed Monthly Electricity Outlook – California ISO Southern Region (SP26) (Megawatts)

Resource Adequacy Planning Conventions	June	July	August	September
1 Existing Generation	21,848	21,863	22,101	22,277
2 Retirements (Known)	0	0	0	0
3 High Probability CA Additions	15	238	176	0
4 Net Interchange	10,100	10,100	10,100	10,100
5 Total Net Generation	31,963	32,201	32,377	32,377
6 1-in-2 Summer Temperature Demand (Average)	26,044	27,612	28,050	28,375
7 Demand Response	202	202	202	202
8 Interruptible/Curtailable Programs	1,087	1,087	1,087	1,087
9 Planning Reserve	27.7%	21.3%	20.0%	18.6%

Looking even further out, the following chart shows the California Energy Commission's Five year Outlook with abundant electric resources to meet demands plus 15% planning reserve readily through 2009.[27] As you can see, by 2010, even after demand response programs and after the 15% planning reserve, in an adverse summer, California could experience electric service outages.

[26] Ibid, page 22.
[27] California Energy Commission Summer 2006 Electricity Supply and demand Outlook, April 2006

Figure 4-1: Five-Year Electricity Outlook - California Statewide



2. Renewable Portfolio Standards

All Load Serving Entities (LSEs, including IOUs and ESPs) are required by State Law to meet 20% renewable energy sources by 2010. While some LSE's are off to a slow start (as shown in the following Power Content Label chart), others are making remarkable strides to enhance their diversity of electric generation, away from traditional fossil fuel power plants.

Specifically, the new RPS program would require that a retail seller of electricity, including electrical corporations, community choice aggregators, and electric service providers, meet the minimum percentage of electricity generated by eligible renewable energy resources. If they fail to procure sufficient eligible renewable energy resources in a given year to meet an annual target, the electrical corporation would be required to procure additional eligible renewable resources in subsequent years to compensate for the shortfall.

The California PUC is required to adopt rules for establishing a process for determining market prices of electricity from renewable generators, a process for rank ordering and selection of least-cost and best-fit renewable resources to fulfill program obligations, flexible rules for compliance that permit sellers to apply excess procurement in one year to subsequent years, or inadequate procurement in one year to the following three years, and standard terms and conditions to be used by electrical corporations in contracting with renewable electricity generators.

SB 1078 requires the Energy Commission to certify eligible renewable energy resources, to design and implement an accounting system to verify compliance with the renewables portfolio standard by retail sellers, and to allocate and award supplemental energy payments to cover above-market costs of renewable energy.

Power Content Labels for CA LSEs - Projected for 2007

LSEs	APS ES	Constellation	Coral	Sempra	SC Edison
Eligible Renewal	21%	5%	5%	7%	16%
- Biomass and Waste	lt 1%	lt 1%	lt 1%	lt 1%	0.02
- Geothermal	20%	4%	4%	4%	9%
- Small Hydro	lt 1%	1%	lt 1%	3%	1%
- Solar	lt 1%	lt 1%	0%	lt 1%	1%
- Wind	lt 1%	lt 1%	lt 1%	lt 1%	3%
Coal	32%	38%	29%	38%	7%
Large Hydro	19%	24%	31%	23%	5%
Natural Gas	28%	33%	35%	32%	54%
Nuclear	lt 1%	0%	0%	lt 1%	17%
Other	lt 1%	0%	0%	lt 1%	1%
Total	100%	100%	100%	100%	100%

Of particular importance with the shortfall in meeting the 20% renewable portfolio standard by 2020 is Edison's admission that the capacity factor of renewable resources is profoundly less than conventional generation resources, exacerbating the capital cost to build and connect generation that can meet peak electric demands. Below is Edison's current filing with the CPUC.[28]

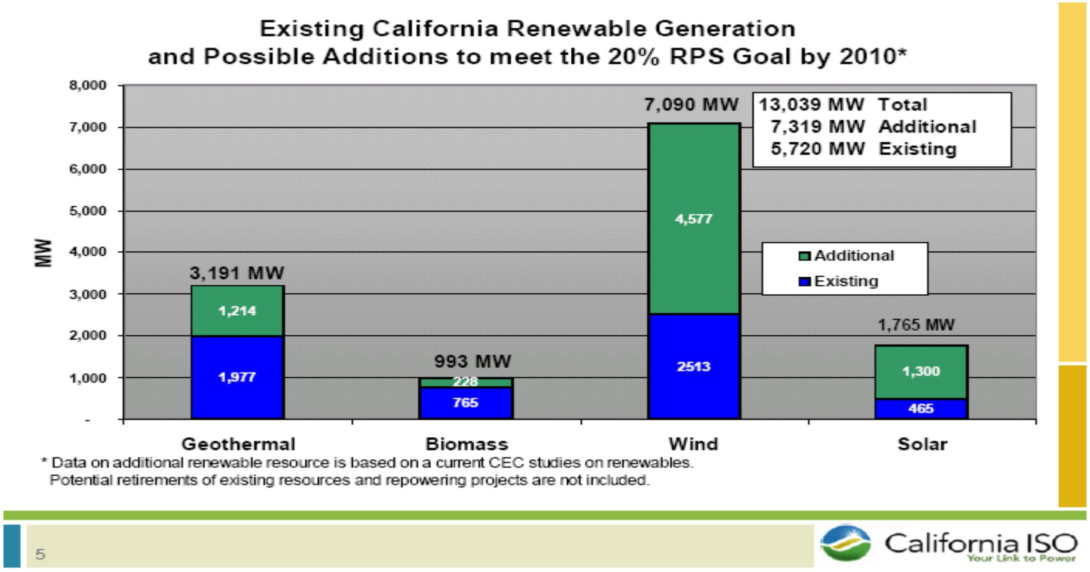
Table IV-12

Capacity Factors by Technology

Biomass	**81%**
Cogeneration	**84%**
Geothermal	**101%**
Small Hydro	**30%**
Solar	**20%**
Wind	**28%**

Please note the potential renewable generation resources chart following, largely from geothermal, offering a forecast that biomass may be the underutilized resource even though it has among the longest history in the wood products and forest industries as a waste disposal method.[29]

[28] Southern California Edison, Energy Resource Recovery Account (ERRA), 2008 Forecast of Operations, Public Version before the California Public Utilities Commission U 338-E, July 2007
[29] Cal ISO Integration of Wind Generation and Other Renewables in California, David Hawkins, Cal ISO, Energy Analysis Department, 2006



3. Resource Adequacy Requirements

The Resource Adequacy Requirement (RAR) applies to all IOUs and ESPs to identify 90% of the resources needed to meet summer (May through September) peak demands plus 15% planning reserve margin (approximately 103.5% of peak demand) by September 30th of the prior year. IOUs and ESPs are also required to demonstrate the procurement of resources equal to 115% of forecasted monthly peak loads by the first of the prior months. The scope and timing of data submittals by IOUs and ESPs beginning in 2006 intentionally provided additional capacity to the California grid. For both bundled and Direct Access, the LSE must procure 115% of the same-month-prior-year peak demand for RAR, even if business conditions change or are firmly not needed – opening a whole new market for power sellers and savvy buyers who may reach a term hedge agreement.

C. Electric Generation and Demand Ahead for California

1. Electric Demand Increases

Electric Demand Increases for three IOU's (PG&E, Southern California Edison, and SDG&E) are for approximately 2% growth per year in electric consumption but up to double that value in peak demand - exacerbating the problem of meeting peak electric demand during the hottest of summer seasons. It is likely that IOUs will continue to promote voluntary load reduction by customers to minimize peak demand growth, but IOUs run the risk that usage will decrease from conservation and demand peaks will continue - resulting in a revenue shortfall in a time of rising demands and costs. The CPUC has a well-established record of supporting the IOUs in time of financial crisis – seemingly independent of the regulatory compact for IOUs to bear the financial risk of regulatory programs in exchange for monopoly rights to serve franchise territories.

Imports of power from neighboring states and countries (principally Mexico) have the escalating risk that power imported may have to meet the same air quality and renewable portfolio standards as California electric generation, further straining California resources to meet growing customer demand if imports cannot be made.

Current levels of energy conservation to reduce electric demand over the years have included Title 24 energy-efficient building standards, demand response programs that have largely been voluntary, IOU-sponsored energy conservation programs that were initiated as early as the energy crisis of the mid-1970s, residential rates that are not cheaper-by-the-dozen, and the very magnitude of California IOU rates that are among the highest in the U.S. One possibility is that the energy consumer, absent remarkably higher rates, may not continue conserving at historical levels and IOUs and the energy market may be at risk for load swells from diminished conservation given that other costs for all consumers are rising at comparatively higher rates.

Electric demand increases are likely to come from developed geographic areas as communities expand. The inverse is true for renewable resources that are most likely to be developed far from current load centers – resulting in material capital costs for connections to the grid, especially for large scale resources.

Electric municipalities, regulated by the Federal Energy Regulatory Commission, are largely free from the CPUC's and California Legislature's control. Many have developed a "make all" versus "buy all" strategy following the energy crisis of 2000-2001 to avoid having any dependence on the IOU grid controlled by the ISO.[30] Instead of beefing up grid connections with LSEs to share resources, many of the electric municipalities have strengthened both their grid connections with the Western Area Power Administration and Northern and Southern California Power Associations and have installed peaking plants to minimize dependence on non-governmental entities. This isolation by the electric municipalities has forced the LSEs to be more independent and to meet their own load growth with limitations on the type of generation growth.

2. Electric Generation Resource Increases

Renewable portfolio standards mandate renewable electric generation resources that carry comparatively high capital costs (nearly double), high grid connection costs (two-ten times), low capacity factor (20-50%), and limited natural resource scale (limited by Mother Nature.). While long term operating costs of renewable resources may have some benefit, it is the near term reduction in greenhouse gas emissions (GHG) that are being sought, rather the electric generation economy, thus offering the prospect of higher energy costs ahead to pay for expensive generation resources.

Electric generation resources plus the 15% Resources Adequacy Requirement (RAR) for spare capacity need to be developed at a rapid rate to keep up with growing consumer demands, especially when kW demand is growing faster than kWh consumption. California's history of causing stranded and uneconomic investment has hardly encouraged robust investment, especially in an industry where remarkable changes have occurred in the past thirty years – including mandatory IOU divestiture of electric generation assets from AB 1890, forced efficiency of generating facilities, power plant approval by the Energy Commission, and dispatching and load control by the ISO.

The prospect of adding hydroelectric or nuclear electric generation resources in California, given the public preference for returning hydroelectric resources to the public domain and for shunning high-risk nuclear power, respectively. Coal-fired generation is getting the cold shoulder from environmental groups pushing RPS, and GHG, even though its fuel costs are almost half that of gas-fired electric generation. Adding gas-fired electric generation given the statutory requirement to return to 1990 emission levels will certainly curtail its development for much than peaking plants.

It is likely that the current opposites of energy choice by consumers (volume and type of generation) will run head first into electric generation development challenges of tougher power plant siting, financing, air quality regulations, and fuel requirements. I suspect that choice by consumers will not suffer, so additional generation will need to be built and operated – albeit at a higher costs and more environmentally friendly method than historical coal, oil, natural gas, and nuclear generation.

[30] Modesto Irrigation District has planned a 20-30% rate increase in 2008 to its largest customers as a result of its isolation program with the IOUs and the ISO.

3. Optimal Direct Access Electric Buying Strategies

The chronicle of regulatory and legislative actions presented in this White Paper have profoundly affected the power market in California, now offering multiple consequences for generation resource development, consumer load shapes, market prices, regulated utility conservation programs, air quality standards and attainment, renewable resource development, and the availability of energy. Following is a chart of the regulatory and legislative actions and market conditions discussed in this White Paper with methods to mitigate risks and optimize opportunities for buying power in California.

Leg/ Reg/Market Action	Intended Action	Affect	Mitigation/ Opportunity
CA Public Utilities Commission formation	Better service and lower prices	Focal point for environmental causes	Participation in critical issues
Interruptible service	Lower peaks, less cost	Small risk for savings	Participate if possible for operations
Baseline rates	Lower residential cost	Some deterrence fro usage	Minimize rate class subsidy via CPUC
PURPA	Promote cogeneration	Long term power investment	1/3 of IOU supply – critical viability
Title 24	Energy-efficient buildings	Reductions in KW and kWh	Code requirements – no options
AB 1890	Better service and lower prices	Staggering cost increases	Participation at CPUC
CAL ISO	Control ISO grid	Control of ISO and creation of trading hubs	Minimize ISO imbalances
Suspension Direct Access	Avoid rate class subsidy	Limitation of competition	Prepare for reversal 2008-9 and more competition
CTC charges	Compensate IOUs for stranded assets	Ongoing charges for delayed IOU funding of stranded dereg. assets	Amortization of IOU charges through 2015
GHG	Limit greenhouse gases from generation	Higher cost and uncertain technology	Hedge costs where timing is right
RPS	20% LSE renewable generation by 2010	Higher costs and limited generation	Buy renewable or hedge when the time is right
DA CRS	Compensate IOUs for mandatory power purchases	2.7 cents per kWh, diminishing by 2015	Participation at CPUC
RAR	Provide 15% spare generation	Higher operating costs, more peak generation	Hedge costs where timing is right
MRTU	Better grid control by ISO	2000 trading points in CA vs. NP and SP 15	Ensure ESP contract protects customer
Market fixed prices	Price certainty	Price premium, except periodic opportunities	Set targets and buy when the time is right
Market floating prices	Minimum credit, less balancing	Periodic price spikes	Base contract optimal as long as margin is fixed long term
Direct Access term	Flexible period	Optimal period offering	Long term fixed margin is optimal
CSI	Promotion of solar development	Mitigation of remarkable cost	Utilize if practical
Consultant	Market products	Market knowledge and risk assessment	Strategic planning optimal

I am fully prepared to support _____ program to minimize its electric operating costs and to ensure that critical legislative and regulatory actions and energy market conditions are identified early, critically analyzed, and utilized to ensure reliable, economical electric service with emphasis on long term, comprehensive cost savings.

Sincerely,