Competitive Ancillary Service Procurement in California

Sixth Symposium on Energy Innovation: Energy Innovation and the Liberalized Market
Technical University Graz, Austria, 1-2 February 2000

Chris Marnay, Afzal S. Siddiqui, and Mark Khavkin

Environmental Energy Technologies Division
Ernest Orlando Lawrence Berkeley National Laboratory
University of California
Berkeley CA 94720 0001

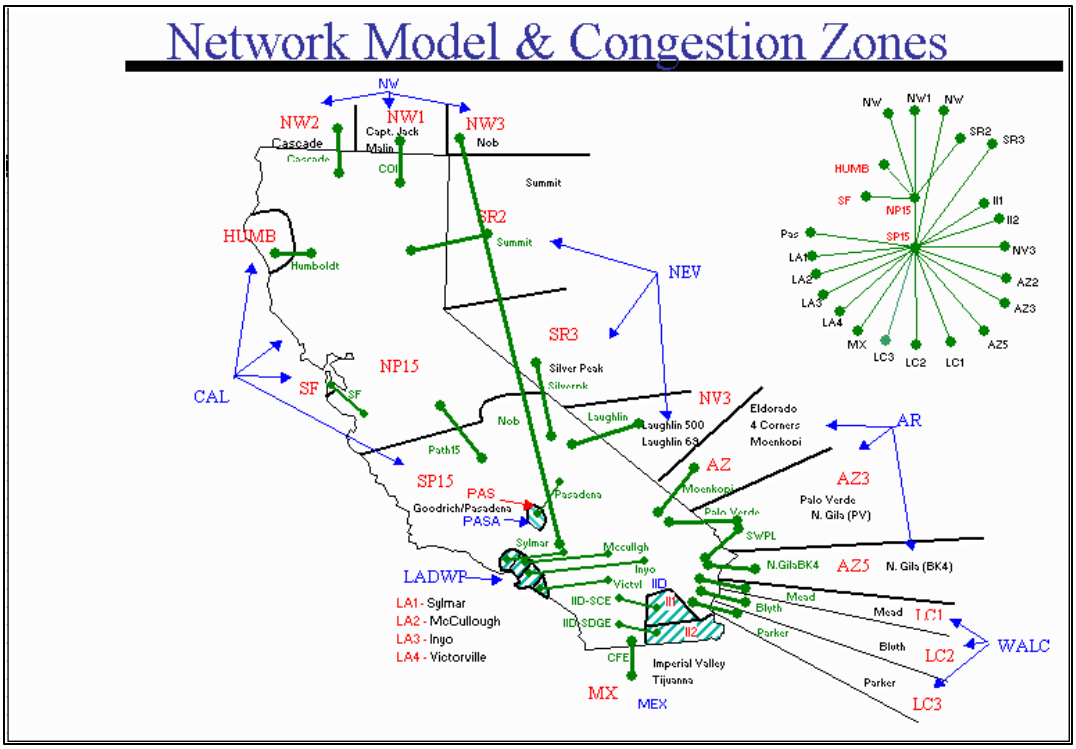
Chris Marnay
Staff Scientist
Phone: +1 (510) 486-7028
Fax: +1 (510) 486-6996
Email: C_Mamay@lbl.gov

Afzal S. Siddiqui
Graduate Student Research Assistant
Phone: +1 (510) 495-2874
Email: ASSiddiqui@lbl.gov

Mark Khavkin
Student Research Assistant
Phone: +1 (510) 495-2843
Email: M_Khavkin@lbl.gov

1. Introduction

Within California, more than 1300 generators produce electricity using a sum of approximately 54 GW of capacity, and total 1997 electricity consumption was 254 TWh (including self-generation). California's major interties and its congestion zones are shown in Figure 1. California is a major electricity importer and has numerous transmission interconnections with adjacent states as Of the 20% of electricity use that the state imported in 1997, 48% came from the Northwest and 52% from Southwest interconnections (CEC 1998).



Zone Abbreviation Legend

AZ2	Eldorado	AZ3	Palo	AZ5	North Gate (BK4)	HUMB	Humboldt
II1	SCE	II2	SDG&E	LA1	Sylnar	LA2	McCullough
LA3	Inyo	LA4	Victorville	LC1	Mead	LC2	Blyth
LC3	Parker	MX	CFE	NP15	North Path 15	NV3	Laughlin
NW1	Captain Jack	NW2	Cascade	NW3	NOB	Pas	Goodrich/Pasadena
SF	San Francisco	SP15	South Path 15	SR2	Summit	SR3	Silver Peak

Figure 1 California Network Model (Source: California Power Exchange)

In late 1996, the California state legislature approved legislation that, beginning 31 March 1998, fundamentally reorganized the state's electricity industry and introduced retail competition for the electricity consumers of the three major prior utilities. These three large private, investor-owned utilities (IOUs), Pacific Gas and Electric Company (PG&E), Southern California Edison (SCE), and San Diego Gas and Electric Company (SDG&E) were, historically, responsible for matching their own load and resources to maintain frequency and to match scheduled and actual flows at interconnection points. Therefore, each utility acted as a *control area* managing the coordinated operation of its own entire generation, transmission, and distribution systems as well as some of the assets of publicly owned utilities. The IOUs were responsible for all economic and technical functions, such as security analysis, economic dispatch, unit commitment, etc. The system was also characterized by significant assets owned and operated by publicly owned utilities, notably the significant transmission capacity of Los Angeles Department of Water and Power and the Sacramento Municipal Utility District, significant non-utility generating capacity, and numerous distribution networks.

In August 1996, the passage of Assembly Bill 1890 (AB-1890) provided the legal basis for competition among electric service providers in California. In brief, AB-1890:

- calls for the establishment of the Power Exchange (PX) and the Independent System Operator (CAISO) as independent, public benefit, non-profit market institutions to be overseen by a five-member Electricity Oversight Board, as well as by Federal regulation through the Federal Energy Regulatory Commission (FERC);
- requires California's utilities (both IOUs and publicly owned) to commit control of their transmission facilities to CAISO, that is, owners of transmission assets maintain ownership of them, but CAISO now operates them as part of the overall the state system;
- allows for direct, bilateral electricity trading;
- calls for a transition to retail competition beginning 1 January 1998 and will be completed no later than 31 March 2002;
- calls for additional requirements concerning stranded cost recovery, rate reduction, divestiture of generation assets, etc.

The roles and relationship between the market participants on both the wholesale and retail sides of the new California electricity market are illustrated in Figure 2.

The primary purpose of the California PX is to provide an efficient, short-term, competitive wholesale spot energy market. The PX is one of a potentially unlimited number of Scheduling Coordinators (SC) authorized to communicate balanced schedules and other information to CAISO, which conducts the real-time dispatch. PG&E, SCE, and SDG&E, are functionally separated into generation, transmission, and distribution activities. Distribution remains a regulated business and the three utility distribution companies (UDC's or discos) together distribute about 80% of the electricity sold in California, must buy and sell electricity through the PX during a transitional period of stranded cost recovery. The PX determines the price of electricity on an hourly basis for the Day-Ahead and Hour-Ahead markets, according to the demand and supply bids submitted. AB-1890 and the subsequent implementation of restructuring provided incentives for the IOU's to divest their in-state thermal (virtually all quite old natural gas fired plant) generating assets and create a fully competitive market. These provisions have worked well and almost all thermal generating capacity in the state has now passed into the hands of about seven

major owners. The IOU's still operate the nuclear and coal stations, however, and PG&E remains by far the largest owner of hydro generation in the state. Divestiture of this hydro capacity has proven to be a contentious process and remains undecided.

CAISO is charged with ensuring open access and maintaining the reliability of the transmission grid. CAISO (1) coordinates day-ahead and hour-ahead schedules from all SCs, (2) buys and provides AS as required, (3) controls the dispatch of generation accepted to procure AS, and (4) performs real-time balancing of load and generation in the Imbalance Energy Market (More and Anderson 1997).

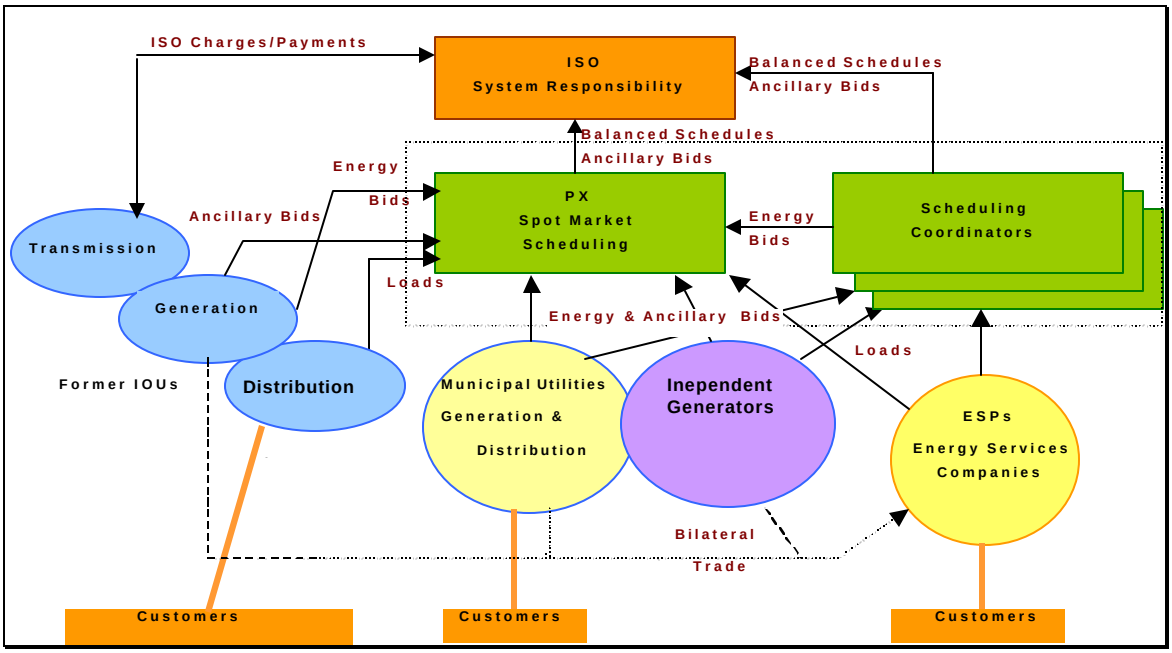


Figure 2 California Market Structure

CAISO directly acquires AS and imbalance energy needed to rectify submitted schedule inaccuracies using quite different procedures. The AS procured daily through competitive mechanisms are:

- **Regulation service** the use of generation equipped with governors and automatic-generation control to maintain minute-to-minute generation/load balance within the control area to meet NERC[1] control-performance standards
- **Spinning reserve** the provision of generating capacity, usually with governors and automatic-generation control, that is synchronized to the grid and is unloaded that can respond immediately to correct for generation/load imbalances caused by generation and transmission outages and that is fully available within 10 minutes
- **Non-spinning reserve** similar to spinning reserve, except that the generating capacity is not required to be synchronized to the grid
- **Replacement reserve** the use of generation to compensate for the transmission-system losses from generators to loads

Each Scheduling Coordinator is assigned a share of the total AS requirement. This obligation is determined *pro rata*, based on the contribution of its metered demand to the total requirement of each particular AS. The obligation was originally based on scheduled demand (see Section 5.1 for details). For instance, each SC must provide the percentage of its metered demand that will be used for regulation service, where CAISO determines the percentage. Each SC may choose to self-provide all, or a portion of its obligation in each zone. To the extent that a SC self-provides, CAISO correspondingly reduces the quantity of AS it procures. Suppliers' bid prices and quantities for each type of service are made in Day-Ahead and Hour-Ahead markets. Two other vital AS, reactive power supplied locally for voltage support and black-start generation capability, are acquired by specific contracts.

Provisions were also made in the AB-1890 to maintain public purpose programs, through the imposition of a per kWh tax on electricity delivered by the discos. The revenues from this tax are subdivided into several programs to support energy efficiency investments, and renewable generation.

2. Operation of Ancillary Services Markets

Under ideal competitive conditions (i.e., no market participant has market power) and assuming sufficient supply resources, the following conditions should hold:

- Prices in all AS markets should equilibrate so that suppliers would expect to earn almost the same variable profits (market revenues less variable costs) regardless of the market they choose to bid their generating capacity
- Prices in regulation and spinning reserve markets should be related to day-ahead and real-time energy prices
- Prices in the non-spin and replacement reserve markets should be lower than the prices of regulation and spin reserve markets because the former services do not require the generator to be running during the hour for which capacity is made available

In practice, however, prices in the AS markets have not conformed to the theory, especially during the 1998 calendar year. The early months of operation saw little correlation between AS and energy prices, and the price of spinning reserve often

[1] North American Electric Reliability Council

exceeded that of regulation and even energy. For example, the price of regulation reserve (the AS with the greatest volume and monetary value of trading) was below energy prices but did not correlate with them (with correlation coefficients of 0.12 for PX day-ahead prices and 0.001 for real-time prices). Thus, it appears that the trajectory of these prices did not reflect actual or opportunity generation costs. In addition, important price fluctuations from one week to another were observed without any clear explanation. The existence of a long period with almost zero and negative prices can explained by REPA payments[2] (see CAISO 1998b). After the suspension of REPA, regulation capacity prices have adopted a pattern more closely correlated to energy prices. Indeed, from , it can be seen from Figure 3 that the price of regulation has stabilized since market reforms such as the granting of market-based rates for all participants were introduced in November 1998[3]. Furthermore, the caps instituted by the CAISO for AS market prices on 24 July 1998 (initially set at $500/MW, then lowered to $250/MWh) have been raised to $750/MWh during the summer of 1999. This indicates greater confidence in the competitive viability of the AS markets.

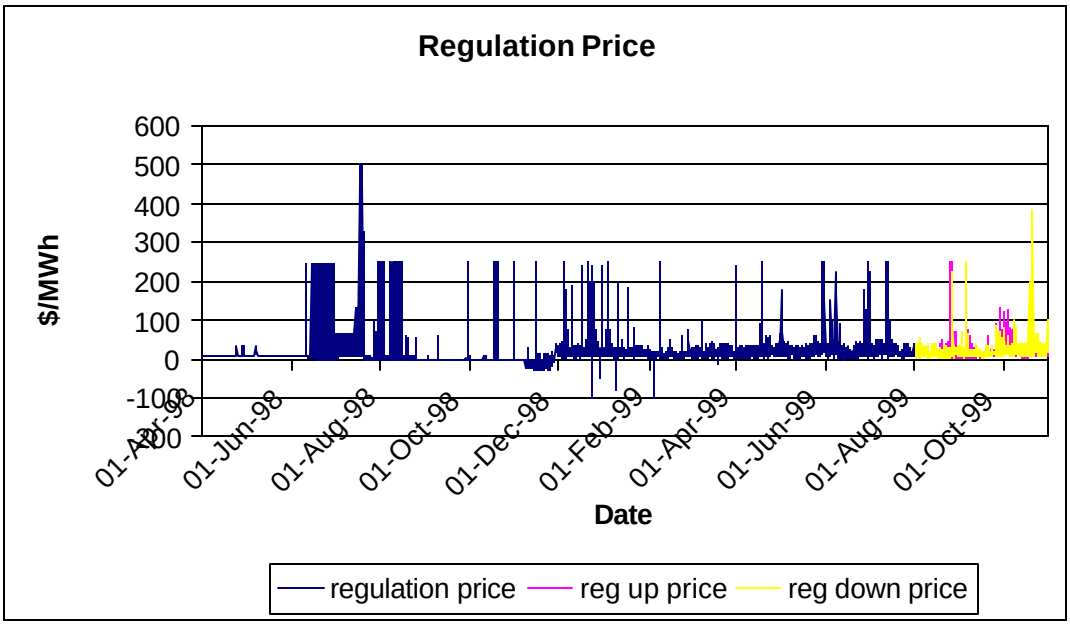


Figure 3 Regulation Reserve Prices (Source: CAISO)

The stabilization of AS prices can best be seen from the distribution of prices. Here, a preliminary analysis attempts to determine the approximate distribution of the AS prices and the AS expenditures at various price levels. For convenience, the prices were divided into ranges, and for each AS, a cost distribution and price frequency chart was constructed to show the price ranges in which AS expenditures were greatest. Examples of this can be seen for the regulation reserve ancillary service for August 1998 and March 1999 (see Figure 4 and Figure 5). From Figure 4, it can be

[2] Regulation Energy Payment Adjustment (REPA) was an amount paid to generators to encourage bidding in the regulation reserve market. It was the greater of the PX energy price and $20/MWh.

[3] In September 1999, the CAISO began to operate separate markets for the procurement of *upward* and *downward* regulation: the former is used to increase generation to respond to real-time contingencies, whereas the latter is for decreasing generation in such situations.

observed that almost 90% of the cost of procuring regulation reserves occurs over only a 5% range of the prices. After some market reforms, however, one can see from Figure 5 that the distribution of expenditures is more equitable, with nearly all expenditures occurring over the most frequent price range.

By contrast, few such problems persisted in the energy markets: a high correlation, i.e., approximately 0.95, between average prices in the PX day-ahead energy market and in CAISO real-time energy market (hourly ex-post prices) exists and is also evident from Figure 6 and Figure 7.

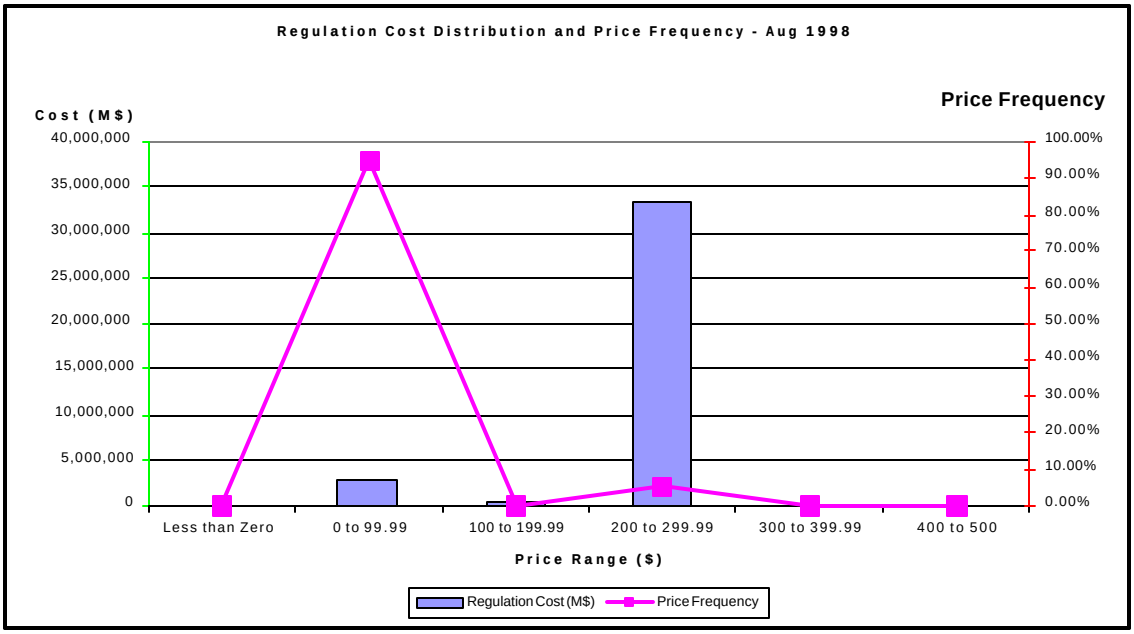


Figure 4 Regulation Cost Distribution and Price Frequency - August 1998

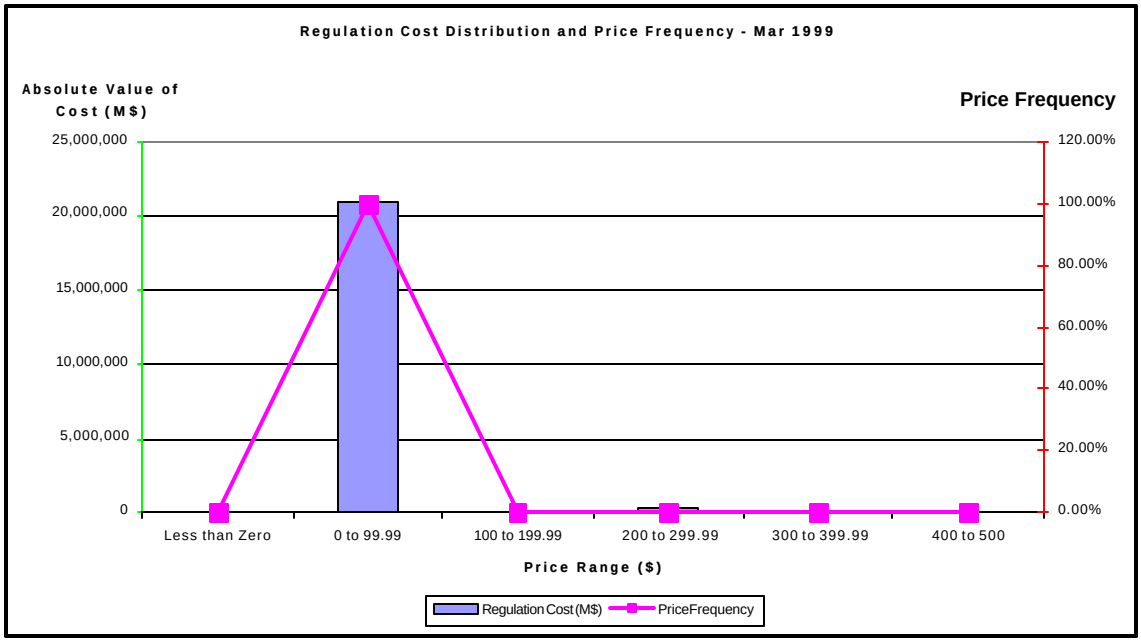


Figure 5 Regulation Cost Distribution and Price Frequency - March 1999

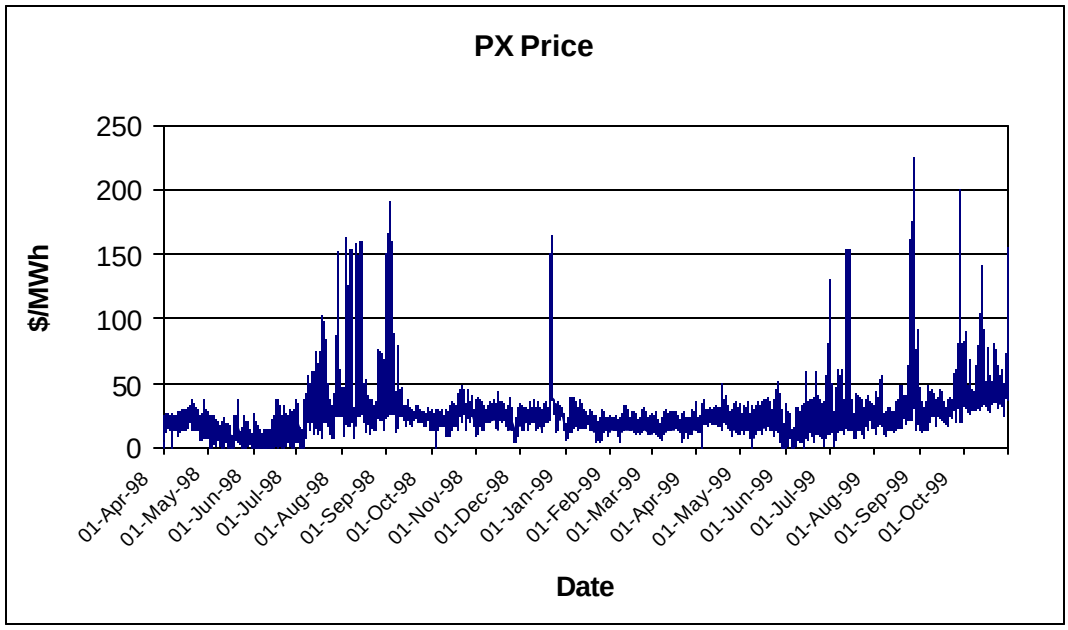


Figure 6 PX Day-Ahead Price (Source: California Power Exchange)

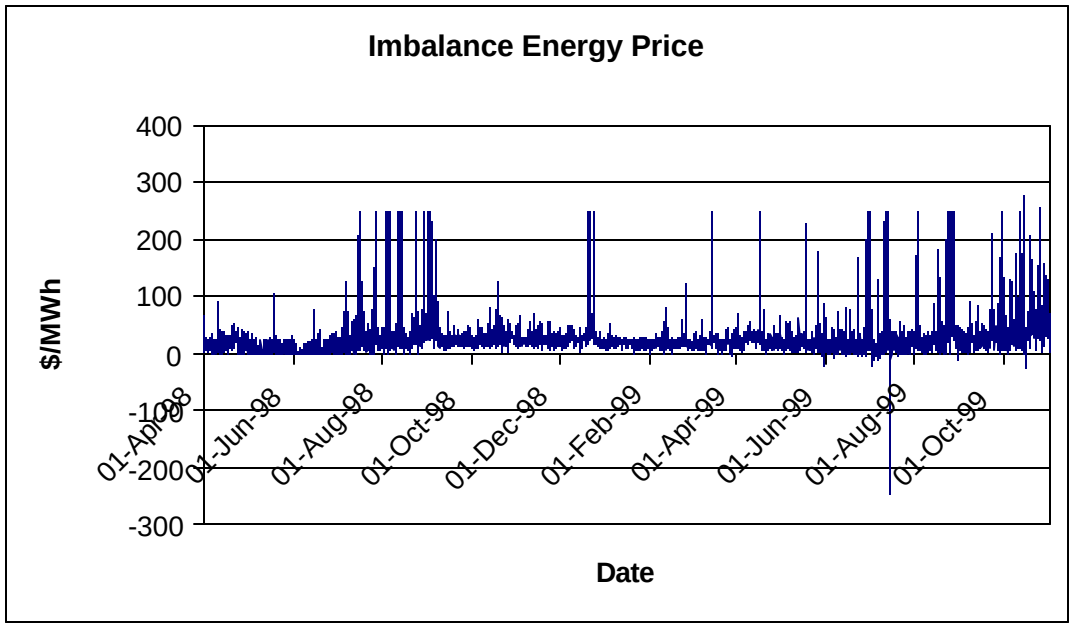


Figure 7 Imbalance Energy Price (Source: CAISO)

3. Operation of Ancillary Services Markets

The AB-1890 legislation that established the California markets also contained provisions for the support of public purpose programs during the transitional period. Note that no provisions are in place to continue the tax or A tax of approximately 0.3-0.4 ¢/kWh was imposed, and the revenues divided among several accounts as shown in Figure 8. The governance of the programs varies considerably, but the Renewables Technologies Fund of 540 M$ over the four year transition is administered by the California Energy Commission. California was the leading U.S. state in renewable generation from several sources, most notably geothermal, wind, and solar, before restructuring. Figure 9 shows total generation of the major *eligible renewables* in 1998, that is ones eligible to receive subsidies. Note that, in total, these sources have provided 10-11% of total in-state generation in recent years, and that only in-state generators can receive subsidies. Because of their significant contribution and the dominance of California in some technologies, there was a lively debate over the correct form of renewable subsidies in the restructured market.

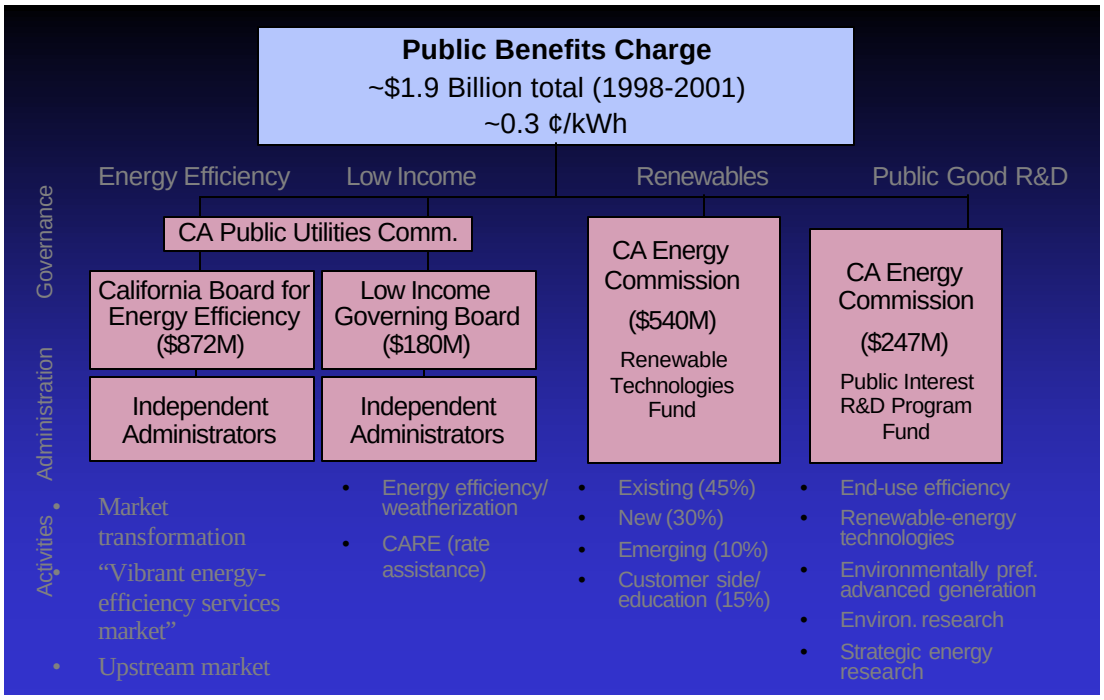


Figure 8 California Public-Purpose Programs

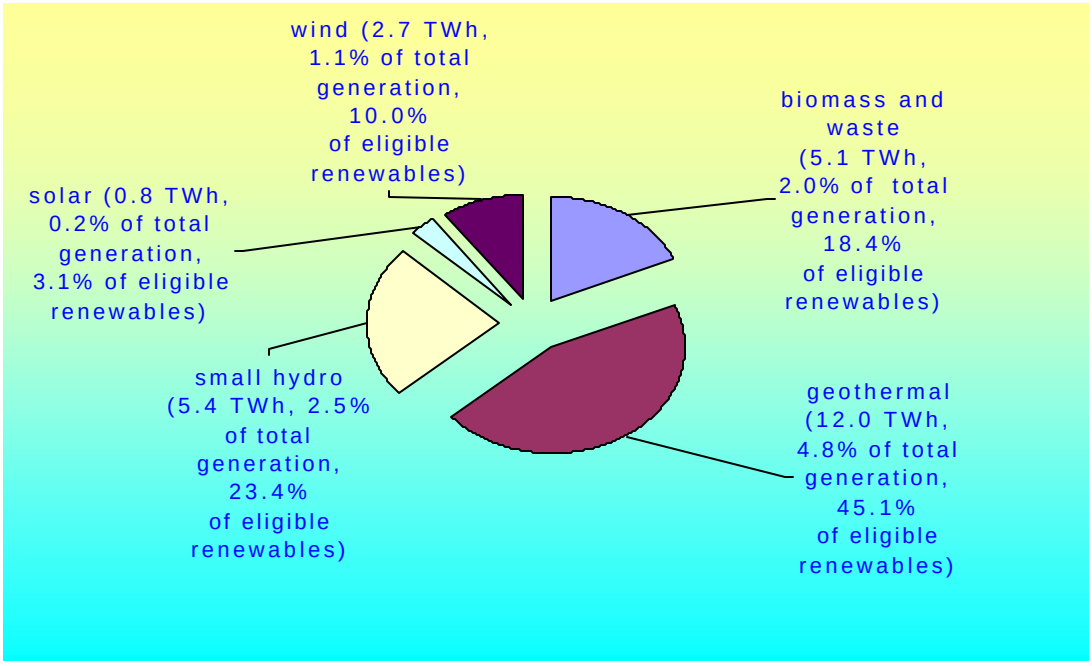


Figure 9 Eligible Renewable Generation

The fund is subdivided into four categories, for existing generators, new generators, emerging technologies, and customer side/education. The share going to existing generators is by far the largest, 45%. This fund is distributed to generators who were in production prior to 1998 in the form of a direct energy (i.e. per kWh) subsidy that varies by technology and is related to the market (PX) energy price, but for most

technologies the subsidy is capped at 1 ¢/kWh, and it has varied considerably with the PX price. The fund is subdivided into 4 categories, for existing generators, new generators, emerging technologies, and customer side/education. The share going to existing generators is by far the largest, 45%. This fund is distributed to generators who were in production prior to 1998 in the form of a direct energy (i.e. per kWh) subsidy that varies by technology and is related to the market (PX) energy price. For most technologies the subsidy is capped at 1 ¢/kWh, but biomass can receive up to 1.5 ¢/kWh. Because it depends on the PX price and generation, the subsidy has varied considerably. For example, the geothermal subsidy fell to zero for the two months of November and December, 1998, while the biomass subsidy has been at 1.5 ¢/kWh almost continuously. The distribution of funds from the new account is innovative. The money is divided among the winners of an auction in which bidding renewable generators bid the level of subsidy they require to make their projects viable. Those developers asking for the smallest subsidies win the auction. Figure 10 shows the winning technologies. This auction approach resulted in a surprisingly broad range of technologies being funded and was quite successful overall.

The emerging fund is given in the form of grants, much more along the lines of traditional support to renewable technology development. The customer fund is used in part to deliver a direct subsidy to marketers. That is, if a retail provider of electricity other than the disco provides eligible electricity to a residential customer, the marketer, in addition to the generator, receives a subsidy of approximately 1.5 ¢/kWh. This provision has provided a strong incentive for retailers trying to compete with discos to sell eligible power, even though its wholesale price tends to be slightly above non-eligible generation. For this reason, the few (about 2%) residential customers who have switched from their local disco to alternative retailers have overwhelmingly chosen to purchase green power products.

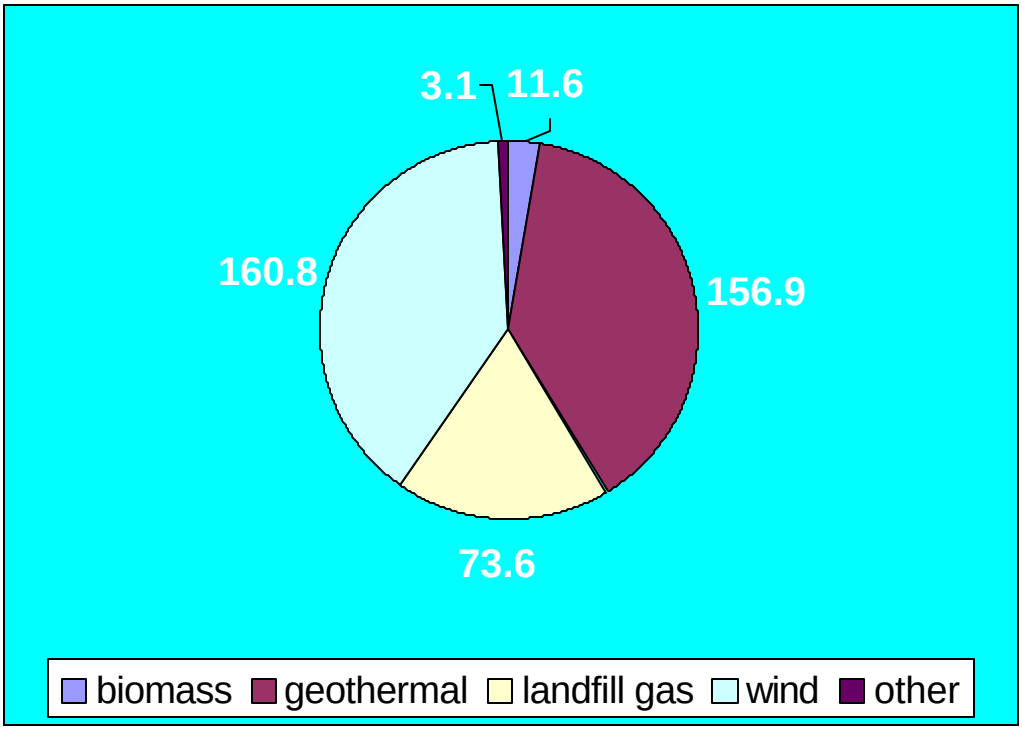


Figure 10 New Renewable Technology Auction Results By Capacity

4. Conclusion

California has undertaken a major restructuring of its electricity utility sector. Most electricity is now sold in open markets operated by the PX and other entities. Bilateral contracting among some market participants is also permitted. A group of independent generating companies bids into these markets together with out of state resources. In addition to these markets, CAISO operates markets for both imbalance energy and AS, a quite unusual feature of the California system. These markets were initially quite chaotic and were rife with market power problems. However, various reforms have now created a system that functions well. During the restructuring process, special provisions were made to protect public purpose programs, including renewable generation.