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Impact of electricity deregulation in the state of California

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ABSTRACT

The electric industry started as a natural monopoly and was regulated to protect the customers from high prices. Electricity deregulation was expected to reduce prices by introducing competitive markets. Every country or state implementing deregulation has gone through a unique experience. In this paper, the impact of electricity deregulation in the state of California is addressed by first examining historical retail prices, and second by developing a model to estimate the grid marginal costs using historical data. Results show that, although some customers pay lower rates today, the average customer does not pay a lower rate due to deregulation. Moreover, the results of the modeling show that the wholesale prices realized were higher than the marginal cost associated with the grid. Impacts of improved grid management are discussed along with transmission investments, market operator start-up and operation costs, energy and environmental goals, advances in technology on electricity prices, and the impact of deregulation on these factors.

1. Introduction

The purpose of the current analysis is to examine the impacts of electricity deregulation or restructuring in the state of California 20 years after the 1996 Federal Energy Regulatory Commission (FERC) issued Order 888 better known as the "Open Access" rule. In the same year, the California Public Utilities Commission (CPUC) passed Assembly Bill 1890, known as the Electric Utility Industry Restructuring Act that provided legislative guidance for electricity restructuring in the state of California. Debate on whether or not deregulation has helped or hurt the electricity industry, electricity prices, and ultimately customers continues (Apt, 2005; Borenstein and Bushnell, 2015; Joskow, 2008; Klitgaard and Reddy, 2000; Slocum, 2007). However, very few (Blumsack et al., 2008; Jahangir, 2011; Joskow and Kahn, 2002; Kwoka, 2008) provide quantitative analysis for their position on the success of electricity deregulation. Even fewer studies investigate the impacts of electricity deregulation after the passage of sufficient time to reasonably assess the results while the majority of the studies has focused on analyzing the 2000–2001 energy crisis in California and market power exercised by some entities (Borenstein et al., 2000; Joskow and Kahn, 2002; Joskow, 2001).

In the wholesale market, the spot price or market clearing price (MCP) is the price of the most expensive generators that is serving the demand. In an economic dispatch strategy, this will be the last generators that gets cleared in the market. Another way to explain the MCP is that it is the price that all suppliers operate at or below this price, and all the market participants get paid the same MCP. The bids that participants place are not only the cost of generation, but also include market participation fees and costs, and other costs associated with selling electricity such as Firm (or Financial) Transmission Rights.

The retail price of electricity consists of several components including electricity generation (energy), transmission (including, e.g., Transmission Access Charge and California Independent System Operator (CAISO) Grid Management Cost), distribution, and other fees such as the Competition Transition Charge which is associated with the cost of electricity restructuring. Overall the price of electricity depends on a variety of factors including generation mix and fuel prices (Borenstein and Bushnell, 2015), status of the transmission and distribution systems and investments in these systems, transmission congestion, electricity demand (which is itself a function of season, weather, and economic indicators), various rate structures and/or market regulations (e.g., market competitiveness and market power), and energy and environmental regulations.

In this study, a model has been developed that uses historical data for the state of California to determine the expected grid marginal cost of electricity and assess how close the actual wholesale prices of electricity have been to the anticipated wholesale prices calculated based on the grid marginal costs. This price-cost gap can indicate how

Abbreviations: CAISO, California Independent System Operator; CEC, California Energy Commission; COG, Cost of Generation; CPUC, California Public Utilities Commission; EIA, Energy Information Administration; FERC, Federal Energy Regulatory Commission; ISO, Independent System Operator; MC, Marginal Cost; sCOG, Simple Cost of Generation; WECC, Western Electricity Coordinating Council

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competitive the market has been and if deregulation has helped reduce prices. Other factors affecting prices including energy and environmental policies, and transmission and distribution system upgrade investments are also discussed briefly in this paper.

2. Background

The first investor owned utility was established by Edison Illuminating Company in 1882 on Pearl Street in New York and served around 60 customers in lower Manhattan. The electricity industry started as a natural monopoly when it made economic sense for a single company to operate the generation, transmission, and distribution of electricity. As the number of customers grew, so did the size of power plants as economies of scale were achieved. Soon, companies realized the value of sharing reserves and three utilities began to share their generating units and profits. In 1927, the first power pool was established in PJM[1] which operated the units for these utilities. To protect the customers from extremely high and unreasonable prices, the Federal Power Commission (FPC) started regulating the electricity industry and, by the end of 1930s, almost all aspects of the industry were regulated and the industry evolved into a vertically integrated monopoly.

In 1978, the Public Utilities Regulatory Policies Act (PURPA) provided the first step towards a competitive market. As the support for open access to transmission grew in the mid 1990s, FERC, on April 24, 1996, issued the Open Access rule (order 888) which required all transmission line owners, to provide nondiscriminatory service to others seeking such services. Moreover, this order ensures that all potential suppliers of electricity, from small suppliers to big utilities, have equal access to the market and market tools in order to compete in a fair environment. Order 889 established Open Access Same-Time Information System (OASIS) for showing available transmission capacity and reserving capacity to all entities. The transmission system was no longer limited to those who owned transmission assets and became available to everyone to compete in the market. After the open access and OASIS orders, FERC approved PJM as the nation's first fully functioning Independent System Operator (ISO)[2] in 1997. In the areas where an ISO is established, the ISO coordinates, controls, and monitors the operation of the electrical power system, within a single U.S. State, or encompassing multiple states (such as PJM[3]).

In 1996, the CPUC passed legislation to provide guidelines for electricity restructuring and, after two years in April 1998, the electricity market started operation in the state of California. The market in California was originally designed to include an *unbundled* market where an independent entity, the system operator, was responsible for ensuring the reliability of the grid and another entity, the market operator, settled supply and demand bids (Chow et al., 2005). In the original design, the day-ahead market, the California Power Exchange (CalPX), was also a separate entity and independent from the ISO. This configuration, one of the more complicated market designs, was not based on a serious analysis or practical experience (Joskow, 2001).

During the California Energy Crisis in May 2000, the electricity wholesale prices increased 800% and one of the state's investor owned utilities went bankrupt and another came close to bankruptcy. In 2001, CalPX went out of business as a result of the crisis and the state was left without a day-ahead energy market from 2001 to 2009. During this period, the market participants (known as scheduling coordinators in CAISO) had to enter the day-ahead scheduling process with balanced schedules. In April 2009, the Market Redesign and Technology Upgrade (MRTU) was implemented in which a day-ahead energy market was added to the CAISO along with other changes to improve congestion management, and dispatch of resources (Isemonger, 2009).

As mentioned before, the majority of the research in this area has been focused on the energy crisis and the shortcomings of the system designed and events that led to the crisis (Joskow and Kahn, 2002; Joskow, 2001; Wolak, 2000). In this study, the impact of deregulation in the state of California is assessed across the decade following the energy crisis.

3. Methodology

In Section 4.1, historical data from the Energy Information Administration (EIA) and California Energy Commission (CEC) are used to compare retail prices before and after electricity deregulation in the state of California to determine whether a pattern can be observed in prices. Retail prices in regulated and deregulated states are also compared and analyzed in the same section to examine the difference between the trends of retail prices.

To further assess the impact of deregulation, grid marginal cost estimates based on historical data inputs were developed to compare with the actual historical spot market prices after deregulation. In a competitive market, the spot market price should approach the grid marginal cost. This was undertaken to investigate the manner by which spot market prices compared with marginal costs of the grid. An ideal approach is to have hourly production of individual generators across the state, some appropriately estimated financial information for each generator (e.g., interest rate, debt term, debt/equity ratio, lifetime, capital cost, etc.), and detailed information on all other costs and fess (e.g. transmission cost, market participation fees, etc.), estimate the actual cost of generation associated with each generating unit, and from that estimate the grid marginal cost at each hour. Unfortunately such detailed data only exist for 2000–2001 during the energy crisis. Instead, a methodology is developed, which uses available data associated with grid mix, contribution of various types of natural gas units, demand profile, and transmission and distribution costs, along with a set of reasonable assumptions and inputs from the literature.

This methodology for grid marginal cost estimation was developed based on the assumption that the spot market price would be driven by natural gas units. This assumption is based on two observations. First, historically, the primary source for electricity generation in the state of California has been natural gas. As a result, the electricity prices were expected to be sensitive to the price of natural gas as depicted in Fig. 1, which shows the electricity spot market price in California (starting in April 2008–2013) versus the natural gas prices from the same timeframe (Energy Information Administration, 2016). At first, it appears that the two are not correlated; however, after separating the data associated with 2000–2001 energy crisis, it is evident that a strong correaltion exists between the wholesale electricity prices and the natural gas prices. The correaltion coefficient matrix for these two datasets is $R = \begin{bmatrix} 1 & 0.8288 \\ 0.8288 & 1 \end{bmatrix}$. The justification for removing the data associated with the energy crisis is based on the unusually (i.e., not business as usual) high electricity prices during this timeframe that (1) resulted from a variety of reasons studied extensively by others, and (2) had little to do with natural gas prices and more with the lack of sufficient generation and exercise of market power by several entities (Borenstein et al., 2000; Joskow and Kahn, 2002).

Second, historical cost of generation and prices from non-natural gas fired generating units derived from various sources (Bolinger and Wiser, 2011; California Energy Commission, 2010; Chung et al., 2015; Feldman et al., 2015; GTM Research, 2016; U.S. Department of Energy, 2009; Wiser, 2013; Wiser and Bolinger, 2008; Wiser et al., 2012) were compared with the estimated cost of generation for natural gas units based on the methodology described in this paper, which confirmed that the natural gas units were the most expensive units in

[1] Pennsylvania-New Jersey-Maryland

[2] An ISO is an organization formed at the direction or recommendation of the FERC

[3] PJM coordinates the movement of wholesale electricity in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia

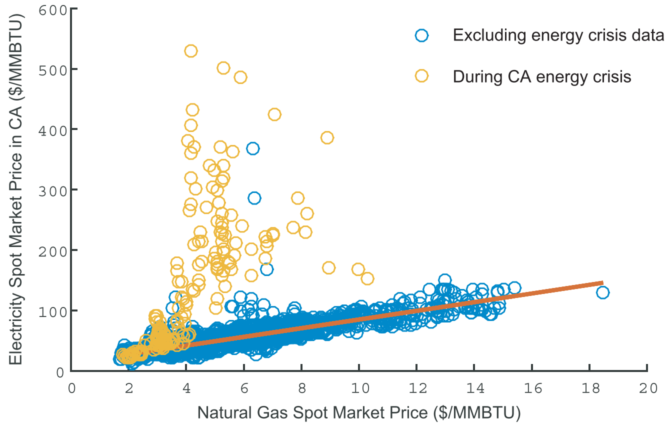

Fig. 1. Correlation between electricity spot market prices in CA and natural gas spot market prices associated with April 2008-December 2013 (the coefficient of determination R2=0.6869).

determining the grid marginal cost.

With this assumption, it is necessary to determine contribution of natural gas units to the grid mix at each hour, and from that (1) determine the contribution of load-following and peaking natural gas units, (2) determine the capacity factors associated with each, and finally (3) calculate the cost of the marginal unit using estimated capacity factor and heat rate.

The summary of the methodology for estimating the grid marginal cost including input data used and some of the more important assumptions are shown in Fig. 2. The methodology is divided into two timeframes due to availability of required data before and after a specific date. The detailed approach in determining the marginal cost is provided in the following sections.

3.1. Generation mix estimation

To estimate the cost of generation associated with the natural gas units and consequently the marginal cost of the grid, two methods were used due to availability of detailed data for only some years. From April 20, 2010, CAISO has recorded and released a daily "renewables watch" which includes the hourly generation of renewable resources (solar, wind, small hydro, biomass, and geothermal) along with hourly thermal, hydro, and nuclear generation, and imports (California ISO, 2016). In Fig. 3, the grid mix and renewable mix for a representative day in January 2012 are shown (derived from available data).

For dates prior to April 20, 2010, a representative day profile is calculated for each month using the data released by the CAISO (California ISO, 2010). Nuclear, small hydro, biopower (biomass and biogas are added together for simplicity), geothermal, and imports are assumed to have constant profiles (baseloading). Typical profiles then are used for solar, wind, and large hydro (Jamaly et al., 2012). Using the annual average grid mix available, electricity demand, and the daily normalized profiles of resources, the amount of electricity generated by each generation type is calculated. The remaining amount of electricity required to satisfy the entire load is then assumed to come from thermal natural gas units. As a result, the grid mix and renewable mix for a representative day of each month are determined. The generation mix will be used as described for these two timeframes in the rest of this section to determine the grid marginal cost. To summarize, for the method associated with dates after April 2010, the grid marginal cost calculated has a temporal resolution of one hour, and for the method associated with dates prior to April 2010, the marginal cost calculated has a temporal resolution of one month (although the representative day has a resolution of hourly to properly compare a monthly resolution) . This is a result of the temporal resolution of data available during these two timeframes.

3.2. Cost of generation – natural gas units

In this study, a simple Cost of Generation (sCOG) is used for analysis as shown in Eq. (1) to calculate the COG associated with natural gas units (National Renewable Energy Laboratory, 2013). In this equation O & M stands for operation and maintenance, and 8760 is the number of hours in one year. The resulting *sCoG* has the unit of $/kWh.

The capital recovery factor (*CRF*) is calculated based on the discount rate (d_r) during the analysis period n which is usually the same as the project life- the expected life of the generating unit and is shown in Eq. (2).

$$sCOG=\frac{Capital\ Cost \times CRF + Fixed\ O\,\&\,M}{8760 \quad \times Capacity\ Factor}+Fuel\ Cost\times Heat\ Rate \tag{1}$$

$$CRF=\frac{d_r\,(1+d_r)^n}{(1+d_r)^n-1} \tag{2}$$

Capital cost and fixed O & M are derived from multiple Annual Energy Outlook reports by the EIA (Energy Information Administration, 2015a). The discount rate is set to 8.76% (Klein, 2010). Wholesale natural gas prices associated with California commodity natural gas prices are derived from publicly available data (California Energy Commission, 2015a; Energy Information Administration, 2015b). Recorded annual average heat rates and capacity factors are available along with the annual grid mix (California Energy Commission, 2015b; 2015c; Energy Information Administration, 2015c; Nyberg, 2013; U.S. Department of Energy, 2009) as shown in Table 1 for natural gas generating units.

To determine the sCOG of the natural gas units, it is assumed that they are in two categories: load-following and peaking units. It is further assumed that the peaking units only come online at times of high electricity demand. The output of these peaking units is constrained such that the resulting contribution of peaking units among natural gas units matches those shown in Table 1. The ramping rate of load following units and peaking units is also used when determining the output of these units. Peaking units have a spinning ramp rate of 8% per minute and a quick start ramping rate of 22.5% per minute where load following units have a spinning ramp rate of 5% per minute (Black and Veatch, 2012). It is further included that, when peaking units are online, the load-following units carry as much of the load as their ramping constraints allow.

The capacity factor of the load-following units is assumed to follow their cumulative output and the daily mean of these values matches the values shown in Table 1. The capacity factor of the peaking units is assumed to be proportional to the inverse of the ramping rate. This means that, if the load increases sharply, peaking units with low capacity factors will result in higher sCOG associated with these units. To calculate the sCOG, both capacity factor and heat rate are required. The capacity factor has already been established and the heat rate is calculated using Table 1 and the changes in capacity factor as shown in Lew (Lew, 2012).

3.3. Grid marginal cost estimation

In previous section, the sCOG of the natural gas units (which is the highest COG among all generators) for each hour is estimated. To estimate the grid marginal cost, it is necessary to account for other costs (such as transmission rights) and fees associated with market participation that are not captured in sCOG calculations. Thus, the grid marginal cost (MC) at each time step is calculated using Eq. (3) where the coefficients a_k and b_k account for fixed and variable charges associated with market participation, and transmission and distribution costs. *mCOG* is the *maximum* sCOG observed during the analysis for each day or month. Use of *mCOG* allows for more conservative grid marginal cost estimates.

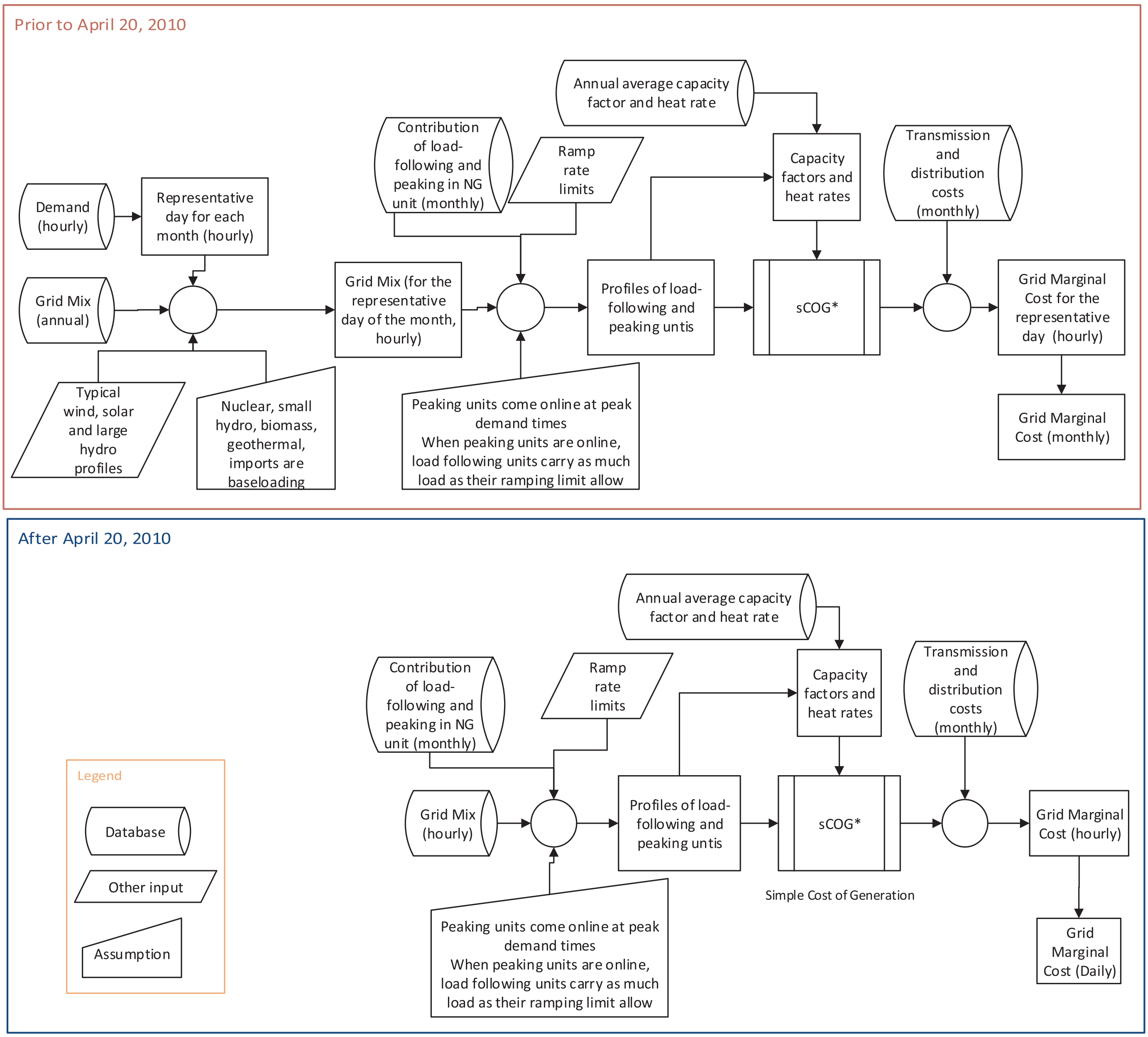

Fig. 2. Summary of methodology for estimating the grid marginal cost.

$$MC_{est,k}=a_k\times mCOG_k+b_k \tag{3}$$

It is assumed that the ratios $\frac{a_i}{a_j}$ and $\frac{b_i}{b_j}$ associated with the grid marginal costs of any two timesteps are proportional to the changes in cost of transmission and distribution (which can be found in EIA Annual Energy Outlooks (Energy Information Administration, 2015a)) and the inflation rate as show in Eq. (4). In this equation, TDI is transmission/distribution index which is derived from costs of transmission and distribution data (Energy Information Administration, 2015a).

$$\frac{a_i}{a_j}=\frac{TDI_i}{TDI_j}\,and\,\frac{b_i}{b_j}=\frac{TDI_i}{TDI_j} \tag{4}$$

If the coefficients are known at one point i, then they can be calculated for all points (such as k) using Eq. (4) since $\frac{a_i}{a_k}=\frac{b_i}{b_k}=\frac{TDI_i}{TDI_k}$ as well. To achieve this, it is assumed that the grid marginal cost (MC) is equal to the actual spot market price at two points i and j as shown in Eq. (5) and (6). The $SpotPrice_{hist}$ is the historical market spot price in these equations. The methodology for calculating the grid marginal cost consists of first solving for the four unknown coefficients (a_i, b_i, a_j, b_j) in the four equations (Eq. (4–6)) for "all" the i, j pairs of time steps in the available data. Having a_i, and bi, coefficients for all other points are calculated, and the grid marginal cost for each time step can then be calculated by Eq. (3).

$$SpotPrice_{hist,i}=a_i\times mCOG_i+b_i \tag{5}$$

$$SpotPrice_{hist,j}=a_j\times mCOG_j+b_j \tag{6}$$

Since there are several calculations of MC at each time step for every i and j time step pair chosen in Eq. (5) and (6), there are many different sets of MC calculations for the time period. An example of these calculations for one set of i and j is provided in Fig. 4.

For the dates after April 2010, the mean of these values across one day (daily grid marginal cost) is calculated and compared to actual daily spot market prices. Note that this is because hourly spot market price data are not available. For dates prior to April 2010, the mean of marginal cost over the representative day is used as the monthly grid marginal cost and will be compared to average spot market price for the

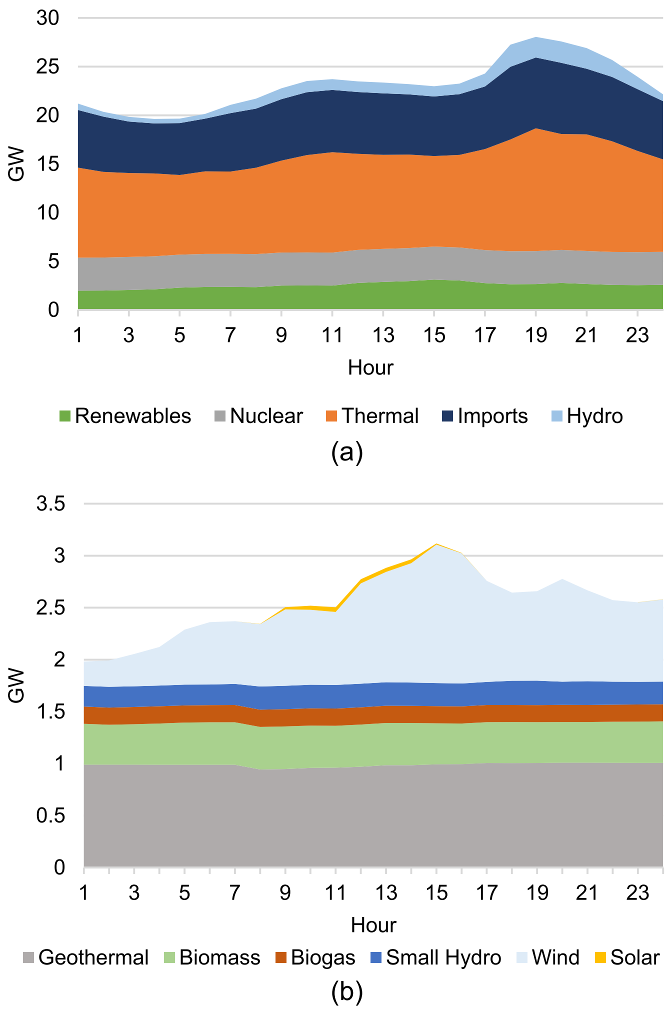

Fig. 3. (a) Grid mix, (b) renewable mix for representative day January 2012 in California.

month.

4. Results and discussion

4.1. Retail prices

Average retail price of electricity for the state of California for all sectors is shown in Fig. 5. Two different sources, EIA (Energy Information Administration, 2015c) and CEC (California Energy Commission, 2016), are used in this figure. Although the numbers are slightly different from one another, the trends during the time of interest are similar. As previously mentioned, the Electric Utility Industry Restructuring Act was passed in 1996 and the spot market began operation in 1998. From Fig. 5, it is evident that the retail prices were reduced slightly between 1998 and 1999 and increased significantly in 2000–2001 during California energy crisis. And today the prices are slightly lower than those observed in 1980s and early 1990s. Whether this overall reduction has been due to deregulation or not, requires more analysis. It must be noted that the retail prices started to decrease in 1991 before deregulation and further reduction in prices agrees with the trend before the deregulation. And thus the reduction in prices in the short time between restructuring and the energy crisis cannot be directly linked to deregulation.

To further show that the impact of electricity deregulation in the state of California on the retail prices is not as clear as previously anticipated by others (Klitgaard and Reddy, 2000; U.S. Department of Energy, 2002) , Fig. 6 shows the retail price of electricity by sector for Investor Owned Utilities (IOU) and Municipalities. From this figure, it is apparent that some customers pay lower rates today compared to 1997–1998 (before the deregulation), but the trends in the prices cannot be explained only by deregulation. It must be mentioned that, since electricity is still regulated when delivered to the end-user, the retail prices do not reflect the wholesale prices, and when they do, it is with a significant timelag due to the regulatory process. This will result in the electricity demand being very inelastic and not responsive to the spot market prices, and this in return will cause reduced competition in the market (Joskow, 2001) especially when the demand is high as was seen during the energy crisis (Borenstein et al., 2000).

In order to get a clearer picture of the changes in retail prices, the average retail prices in regulated states are shown along with the average retail prices in deregulated states and US average prices in Fig. 7 (Energy Inforamtion Administration, 2010; Energy Information Administration, 2015c). States that have “suspended” deregulation according to the EIA such as California and Arizona, are included in the deregulated states.

It is evident from this figure that the prices seen by the consumers follow the same trends in the regulated and deregulated states. The rate of increase in the deregulated states are higher than that of regulated states in 1999–2001 and 2004–2008, and the prices in deregulated states decreased from 2008 to 2012 on average. The higher rate of increase in prices and reduction in prices both coincide with the natural gas prices reduction from 2008 on. It should be noted that some of the deregulated states (such as Arizona and Ohio) during the time shown,

Table 1
Sample of Grid Inputs. State of California historical grid mix and other information associated with gas-fired units (Nyberg, 2013).

		2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Total Natural Gas	Percent	56.36	48.65	47.43	51.45	46.61	48.75	54.87	57.69	55.41	52.67	44.31
	Heat Rate	9997	9645	9080	8726	8393	8111	7890	7972	7858	7596	7855
Percent	Combined Cycle	3.40	15.27	28.63	36.27	42.15	50.85	55.96	58.87	61.54	63.82	57.81
In Total Natural Gas	Aging	61.75	38.75	26.86	23.01	16.76	14.91	12.80	11.78	9.04	5.42	5.93
	Peaker	1.55	1.03	1.14	1.24	1.17	1.03	1.09	1.29	1.38	1.19	1.73
	Cogeneration	32.54	44.21	41.89	37.66	37.91	32.01	28.93	27.06	27.36	28.68	32.93
	Other	0.75	0.75	1.48	1.82	2.01	1.21	1.21	1.00	0.68	0.88	1.61
Heat Rate (Btu/kWh)	Combined Cycle	7844	7379	7310	7223	7302	7261	7213	7217	7224	7195	7303
	Aging	10036	10474	10822	10859	10703	10673	10409	11327	11590	11268	11989
	Peaker	12556	10957	11311	11149	11155	10956	10972	10586	10761	10802	10705
	Other	11273	11182	9998	10041	10393	9825	9749	9553	9710	9737	9378
Capacity Factor	Aging	42.7	21.7	15.6	15.2	10.6	10.6	10.3	10.2	7.5	4.2	4.1
(Percent)	Cogeneration	67.8	72.3	69.5	70.9	65.9	62.5	64.1	63.3	61.1	59.6	59.3
	Combined Cycle	24.6	42.7	46.8	56.0	45.5	52.4	60.8	59.5	53.0	48.6	36.8
	Other	7.3	5.8	9.8	13.8	16.8	11.2	15.3	16.8	10.8	11.2	15.7
	Peaker	9.3	3.4	3.2	3.7	3.4	3.3	3.4	3.8	3.5	2.7	3.3
	Grand Total	42.8	31.4	29.1	31.7	28.2	30.2	33.2	33.7	30.5	27.9	23.8

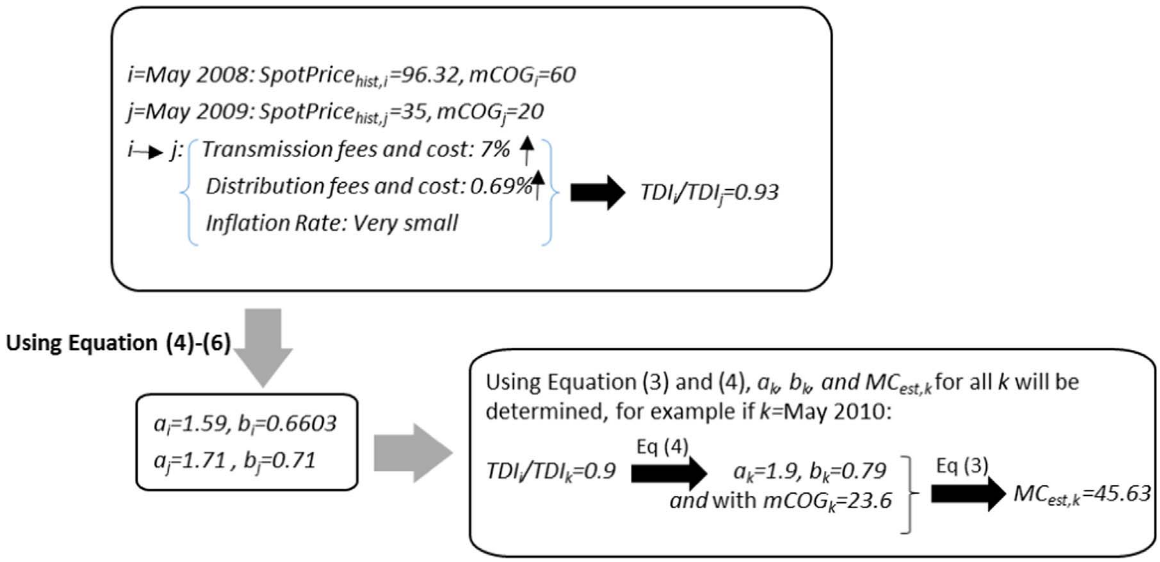

Fig. 4. An example of grid marginal cost calculations.

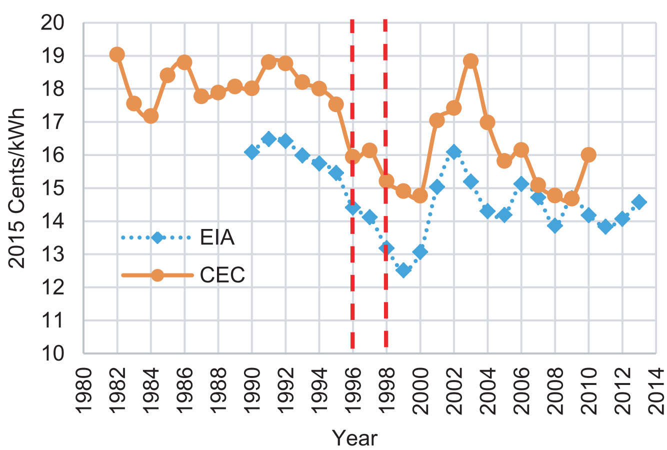

Fig. 5. Average electricity retail price for CA (California Energy Commission, 2016; Energy Information Administration, 2015c).

have imposed rate freezes, cuts or caps on retail prices that prevented higher increases in rates in these states.

Overall, the trends in electricity rates are very similar in regulated and deregulated states and it is difficult to see the impact of deregulation on retail prices. However, it must be noted that electricity prices in regulated states follow a more "predictable" increase in prices whereas the prices in a deregulated market seem be more volatile and more influenced by changes in fuel prices and other financial indicators.

4.2. Wholesale prices

It was previously discussed that the price of natural gas has a significant impact on the wholesale electricity prices in the state of California where natural gas is the primary source for both the majority of the electricity generated and the marginal generator dispatched. The spot prices associated with the California natural gas for electric power along with the electricity spot market prices in California are shown in Fig. 8. The electricity spot market from April 1998 to February 2001 are prices associated with the CalPX (Joskow, 2001). The prices between 2001 and March/31/2009 are mean of day ahead (DA) market for SP15- which is one of the three zones in the CAISO territory located in Southern California (Energy Information Administration, 2016). Prices after April 01, 2009 and after the MRTU are day ahead mean Locational Marginal Prices (LMP) shown for both SP15 and NP15

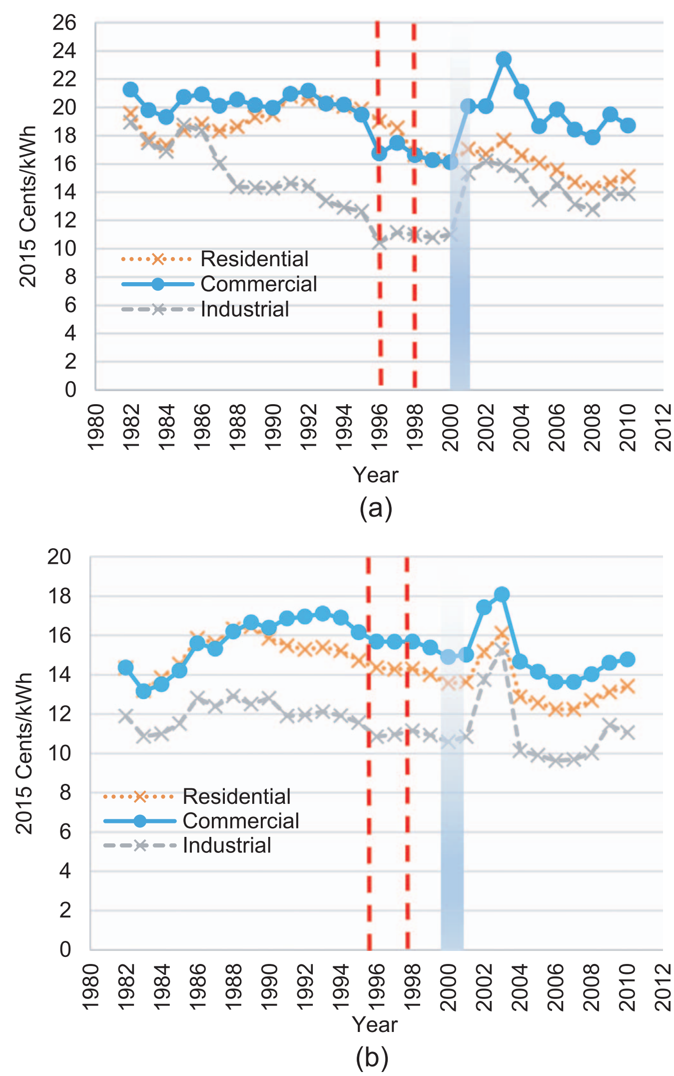

Fig. 6. Average retail electricity prices by sector (California Energy Commission, 2016) for (a) IOUs, (b) Municipals.

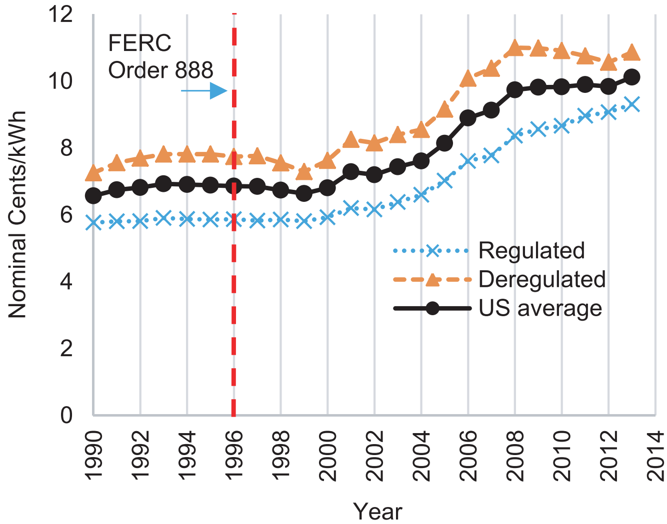

Fig. 7. Average electricity retail prices in regulated and deregulated prices (Energy Information Administration, 2015c).

(another zone in CAISO in northern California) hubs in California. As can be seen from Fig. 8, the wholesale electricity market price follows the price of natural gas and is especially sensitive to natural gas prices when the natural gas prices are high and on the rise. However, a reduction in natural gas prices does not translate directly into a reduction in electricity market prices. A potential reason is that even with cheaper fuel prices, the electricity providers in the market are able to keep their bids high due to the inelasticity of electricity demand (the retail market is still regulated and demand response is not significant enough to impact prices).

4.3. Grid marginal cost vs price

The model developed to estimate the expected grid marginal cost based on historical grid data and natural gas prices, is described in Section 3. As previously mentioned, the methodology is used to develop a representative day profile with grid mix for each month prior to April 2010. The results are shown for Jan 2008 in Fig. 9 (note that detailed data such as those shown in Fig. 3 are not available for this date). For dates after April 2010, daily grid mix data (Fig. 3) are available to use directly.

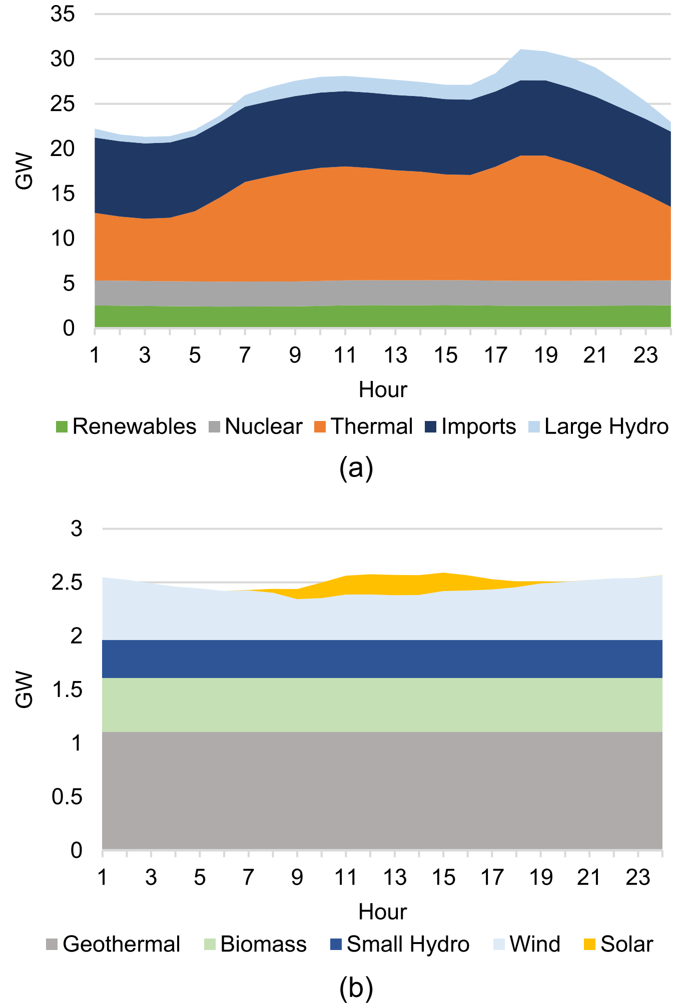

Fig. 9. Model result: average (a) grid mix, (b) renewable mix for January 2008 in California.

After developing grid mix profiles, the contribution of load-following and peaking units to serving the electricity demand are determined. The results are shown in Fig. 10 for one day in Jan 2012, and representative days in Jan 2008 and Aug 2008 in order to depict both

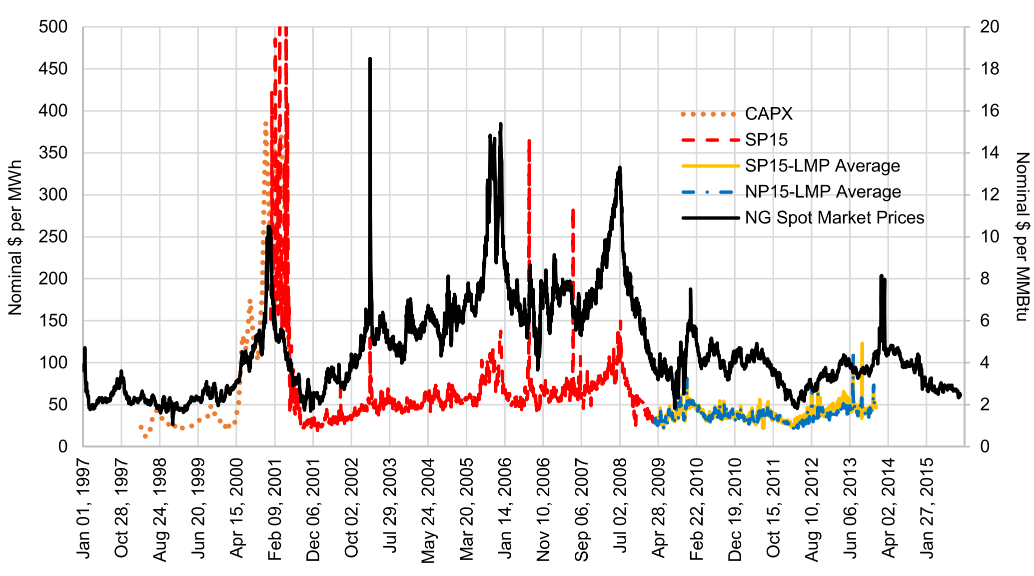

Fig. 8. California natural gas spot market prices for electric power along with California electricity spot market prices after deregulation (Energy Information Administration, 2016).

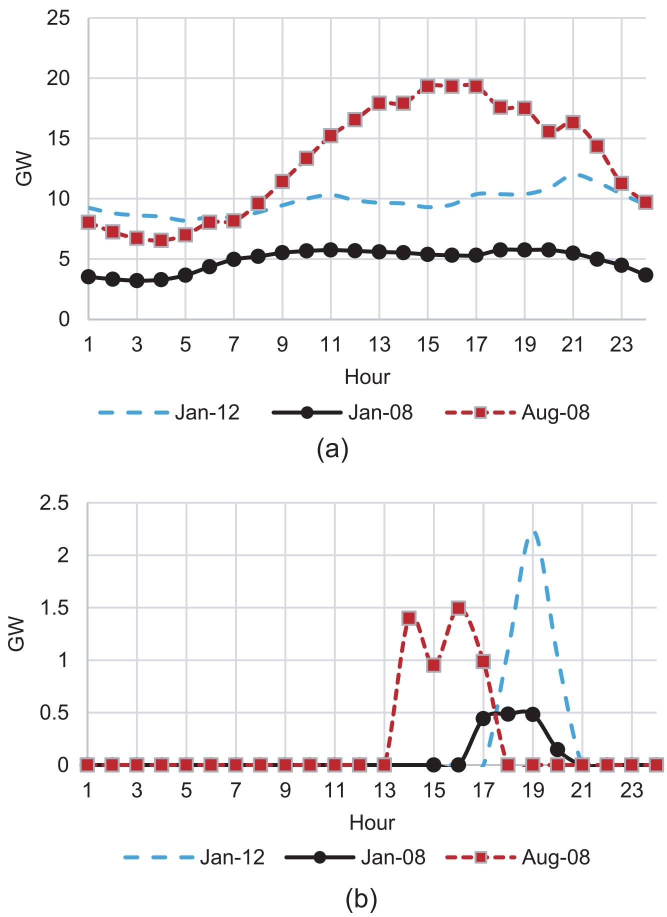

Fig. 10. Model results for natural gas units: (a) load-following, and (b) peaking units.

summer and winter conditions.

As mentioned in Section 3.3, this methodology results in multiple sets of grid marginal cost calculation for each time step. The results including all the sets are shown in Fig. 11. The lowest (I: min) and highest (II: Max) grid marginal costs calculated, are compared to actual spot market prices in Fig. 12.

It must be noted that in Fig. 12, the energy crisis timeframe was skipped since the prices and trends do not represent "business as usual" practices as previously discussed.

As can be inferred from Fig. 12, the electricity wholesale prices are higher than the grid marginal cost in the majority of instances. While the maximum grid marginal cost calculated (II: Max) results in the highest prices among the estimated sets, the expected wholesale prices are still lower than the actual prices in the majority of instances. For

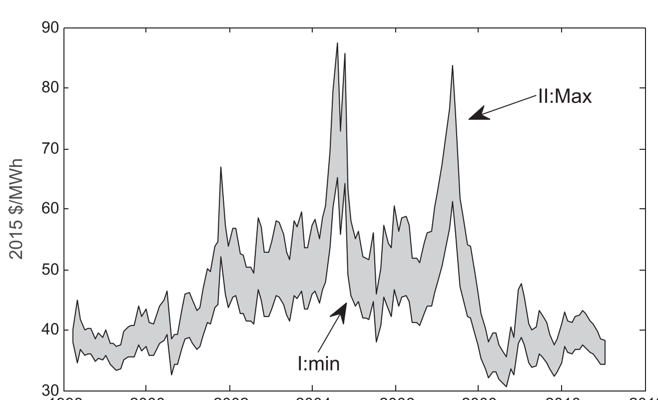

Fig. 11. Estimated grid marginal cost.

the maximum estimated grid marginal cost, during the time studied (1998–2013), market prices are on average 12% higher than the estimated grid marginal cost where in the lowest estimated grid marginal cost (I: min), this gap increases to 27.9%. The difference between the market price and the estimated grid marginal cost is shown in Fig. 13 in the form of two histograms associated with minimum and maximum estimated grid marginal costs.

Starting in 2009 and going forward, however, prices occurred that were lower than the grid marginal cost modeled. This might be due to the fact that, after implementation of the MRTU (April 2009), the CAISO became capable of running a more efficient and optimized market since they switched to nodal modeling and included a full network model in the market clearing process. As mentioned in the background, California did not have a day-ahead energy market between 2001 and 2009 after CalPX went out of business. In the absence of a day-ahead energy market, the market participants had to enter the day-ahead scheduling with balanced schedules. This requirement constrained the high efficiencies that are inherent in a bidding environment (Isemonger, 2009) and might explain why the market did not meet expectations during this period between the energy crisis and MRTU with actual prices remaining higher than grid marginal costs (outcome of the modeling).

Overall, during the 1998–2013 timeframe studied, in the majority of the instances, the modeled grid marginal costs are lower than the actual historical price after deregulation (Fig. 13), and the price reductions that occurred were mostly due to reductions in natural gas prices as well as reduction in cost of renewable resources (used as inputs) and improvements in the efficiency and heat rates of generating units (see Table 1).

4.4. Related considerations

Deregulation has probably impacted other aspects and sectors of the electric industry. In this section possible impacts of deregulation are discussed, as well as other factors (including costs) that need to be taken into account when analyzing the success of deregulation.

4.4.1. Increased efficiency

One argument for electricity deregulation is that it will result in increased efficiency of the grid. Competition introduced by implementing the market can result in increased investment in more efficient units and power plants because these units are more competitive in the market. While this is true, an increase in the efficiency of the grid might be due to a variety of reasons other than competition introduced by deregulation, for example:

1) Retirement and replacement of aging and old units with newer units that are more efficient due to advancement in technology. It is evident from Table 1 that aging units have been replaced mostly by new combined cycle and cogeneration generating facilities. Older gas turbines have also been replaced by new ones. New systems have higher efficiencies due to advancements in material and metallurgical sciences, as well as turbine and compressor efficiencies (Chase, 2001; Hata et al., 2011; Hunt, 2011; Lebedev and Kostennikov, 2008; Unger and Herzog, 1998). In a regulated or deregulated environment, generating units retire after 30–40 years depending on the technology. It is difficult to determine if some units were retired and replaced earlier than their life span by more efficient units due to competition brought on by deregulation.
2) Environmental rules and policies (pioneered by the Clean Air Act) that limit the emissions from power plants and generating units, as well as local air quality and emission controls. The state of California has stringent energy and environmental policies such as SB 1368 that limits long-term investment in baseload generation unless they meet specific emission requirements, AB32 California Global Warming Solutions Act (California Air Resources Board,

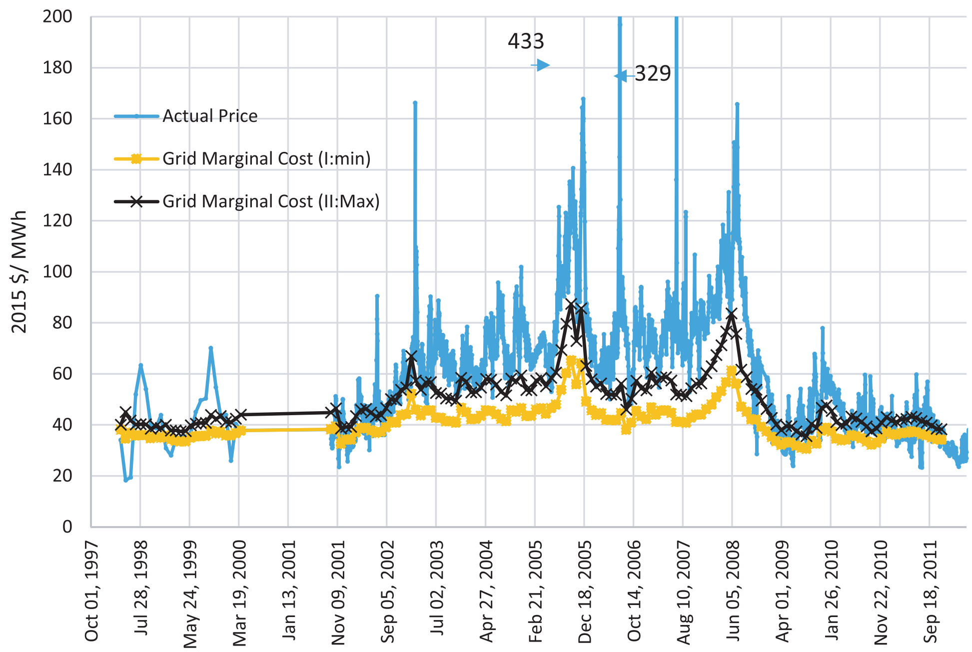

Fig. 12. Comparing estimated grid marginal cost with actual price.

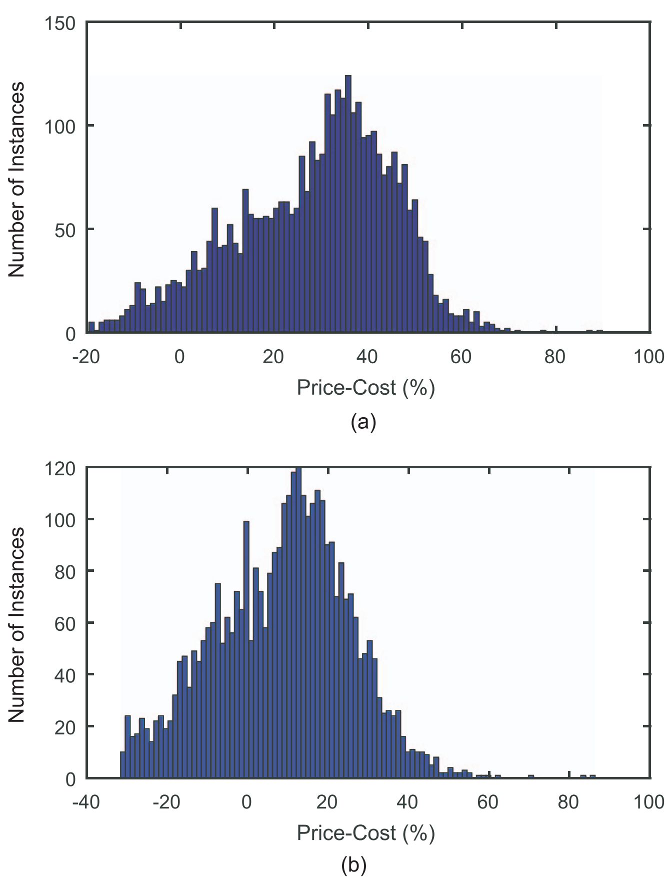

Fig. 13. Histogram for marginal cost-price difference in percent for (a) min, and (b) Max results.

2006), and Regulation XIII by South Coast Air Quality Management District (South Coast Air Quality Management District, 2014).

3) Improved management of the available resources in an optimal manner can also result in increased grid efficiency. This is mainly due to the policies and practices implemented by the ISO to dispatch resources. However, an independent entity managing the grid (grid operator) in a regulated system could also achieve increased efficiency. Better grid management can further be facilitated by data collection throughout the grid (SCADA) in parallel with advancements in data management, computational capability, and mathematical modeling and communication systems. All these advancements enable the ISO to develop a more accurate network model and enable an improved dispatch schedule. This can be seen from Fig. 8 where the spot market prices decrease after implementation of MRTU in April 2009 by CAISO focusing on improvement of dispatch of resources and better system and congestion management.

Overall, while it is difficult to determine which factors contributed to the increased efficiency of the grid, historical data suggest that retiring and replacing old units with newer technologies had the bigger impact. Moreover, even without deregulation of electricity, environmental policies would have directed investments towards more efficient units with lower emission factors.

4.4.2. Transmission and distribution

It was anticipated that electricity deregulation would increase investments in transmission and distribution systems through a competitive electricity market. As a matter of fact, investment in the transmission and distribution systems has grown between 1997 and 2012 in the United States and is still on the rise (Edison Electric Institute, 2013, 2015; Energy Inforamtion Administration, 2014; Federal Energy Regulatory Commission, 2012). This increase in investment also applies to Western Electricity Coordinating Council (WECC) and especially to the southern California region.

However, there are other plausible factors which have contributed to the increased investment in transmission and distribution system:

1) System reliability. The importance of grid reliability has increased significantly in recent years especially after the 2003 outage in northeast of U.S. (Energy Inforamtion Administration, 2014) that resulted in billions of dollars in losses. Furthermore, FERC regulates the interstate transmission commerce and oversees the reliability standards of the system and encourages a robust transmission system.
2) Energy and environmental laws and regulation. As mentioned in

the previous section, there are multiple laws and regulations -such as Renewable Portfolio Standard (California Public Utilities Commission, 2002)- in place that encourage/mandate the increase in renewables penetration, and thus transmission is required to connect these resources (centralized renewable resources) to the grid and ultimately customers. An example of this is the Tehachapi Renewable Transmission Project (Edison Electric Institute, 2015) in southern California which is being built to connect more than 4 GW of generation (mostly renewable and mostly wind) to the grid.

3) Grid modernization. Moving toward a future smart grid, requires substantial upgrades and investments both in transmission and distribution systems.

4.4.3. ISO start-up and operation costs

There are substantial costs associated with developing, establishing and managing an ISO or Regional Transmissions Operator (RTO), and operating electricity markets. In the state of California, the investor-owned utility (PG & E) went bankrupt and another utility (SCE) came close to bankruptcy during the energy crisis when the wholesale prices were extremely high and the retail prices were fixed. The state rescued these IOUs through fundraising via bonds, thereby burdening the tax-payers and rate payers for the flaws in market design and market power exerted by several entities.

FERC analysis showed that the RTO/ISO impact on the customer bill should be less than 0.5% and the average RTO requires an investment of $38-$117 million dollars and annual revenue requirement of $35-$78 million dollars (Federal Energy Regulatory Commission, 2004). It is estimated that the start-up cost associated with the CAISO was $300 million dollars (Lutzenhiser, 2004) and the CAISO 2015 budget provides for a revenue requirement of $198.5 million (CAISO, 2015) showing an increase of 0.6% a year since 2007. These costs are ultimately allocated to the ratepayers through various charges on their electricity bill such as the Grid Management Charge (GMC) in the state of California. While these costs might not amount to much in the entire industry, they need to be taken into account in the assessment of impacts of deregulation on electricity prices.

4.4.4. Impact on the future of the grid

The future of the electricity grid is being shaped by the need to address air quality and climate change goals, higher efficiency, and higher grid reliability and resiliency especially in case of unforeseen occurrences such as natural disasters. Some renewable resources can be competitive in a market (such as wind) especially when the natural gas prices are on the rise. Other technologies such as solar PVs and fuel cells are not currently competitive with conventional generation in a market. As a result, laws and regulations are put in place to encourage investment in low to non-carbon technologies. Various states also provide incentives and tax breaks to encourage these technologies or treat them somehow differently in the market.

It can be argued that deregulation has complicated reaching environmental goals especially in states such as California with ambitious goals. On the other hand, using more expensive generating units will ultimately affect the ratepayers and impact competition in the market. One solution to this issue has been identified as cap and trade, and carbon tax which has been implemented in more than 20 countries around the globe and in the state of California. With cap and trade, both cost of generation and emission factors will impact dispatch order in the market. However, still the ratepayer are most likely to incur the added cost.

5. Conclusions and policy implications

It is difficult to determine what the grid would have looked like today without deregulation or multiple rules, policies, and regulations that went into effect since the onset of deregulation in the state of California. In this paper, fuel prices, energy and environmental regulations and technological advancements in various areas were discussed as major factors in shaping the electric grid characteristics and, ultimately, prices under deregulation. The following are the conclusions of this research:

- Although some customers today pay electricity rates that are lower compared to the years before deregulation, by studying the retail prices before and after deregulation there is no clear trend to demonstrate that the recent reductions in retail prices in some sectors are associated with deregulation.
- The overall grid marginal costs estimated using the model developed are on average lower than actual reported wholesale prices suggesting that deregulation did not result in sufficient competition to lower prices. This is consistent with previous studies that electricity market competiveness is depressed especially when the demand is high.
- The main reason for reduced prices in the state of California is the declining natural gas prices, reduced cost of renewable generation, and improvements in the heat rates of new generating units.
- Deregulation may have resulted in increased grid efficiency; however, environmental regulations, better grid management, and replacing aging units with improved technologies are the more likely reasons associated with the increased efficiency.
- It is difficult to quantify the impacts of electricity deregulation, separate its impacts from other changes, and determine whether or not electricity restructuring has been successful or not. The proponents of deregulation relate the positive changes to deregulation and market operations while the opponents ignore the positive changes.

Deregulation has been relatively successful in Pennsylvania, England and New Zealand (Blumsack et al., 2008; Considine and Kleit, 2002; Joskow, 2008). When making the decision whether or not deregulate a regulated vertically integrated electricity system, it is necessary to acknowledge that electricity is inherently different from other commodities that are being traded in open markets. In the absence of energy storage, supply and demand must match at all times, and the electricity demand is rigid and does not respond to market prices because of (1) existing regulations and (2) end-users either not seeing the market prices in real-time or are not significantly affected by these prices. Experience in deregulating electricity in various areas suggest that markets go through revisions and upgrades from their original design where some were almost successful and some failed in preventing participants in exercising market power (such as California resulting in the energy crisis). As a result, gradual and small changes in the operation of the grid may be a more effective approach to grid management and restructuring. This is consistent with the current practice in the United States where no state is currently planning to deregulate or re-regulate electricity. However, changes in the operation of the market or gird management are still required to ensure that the energy and environmental goals are met. As a result, the ISOs need to constantly evolve to keep up with the economic as well as technological changes.

Whether deregulating the electricity sector completely (down to the retail customer) will help or not is also in doubt. In 1998, at the beginning of California deregulation, customers had the choice to choose an Energy Service Provider (ESP) or keep their service with the utility. Very few chose the ESP option. With the smart grid technologies being deployed throughout the grid, customers have access to the real-time price of electricity; however, if and the extent that customers will change their behavior is also not clear. Before implementing changes in the electricity industry, a plan must be devised to prevent, at a minimum, the problems that other ISOs or countries have faced. Some countries have already introduced retail or distribution markets and NYISO is discussing implementing one. Whether these markets will help unleash the full potential of deregulation remains to be seen.

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