Capacity payments in a cost-based wholesale electricity market: the case of Chile

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***Abstract*—This paper compares the long-run generator revenues implications of a capacity payment mechanism relative to an energy-only market mechanism for the Chilean wholesale electricity supply industry. The advantage of studying this question for the Chilean industry is that the system dispatch and short-term energy prices are determined from a cost-based market. This allows us to run the market with and without a capacity payment mechanism. Our counterfactual energy-only market outcomes are computed with the shortage cost of energy set to achieve the same discount present value of aggregate revenues for generation unit owners as under the capacity payment mechanism. We compute the distribution of annual revenues across generation technologies for the combined capacity payment and energy market and the energy-only market. Although revenue volatility for generation units increases significantly for the energy-only market relative to the combined capacity payment and energy market, this is completely explained by increased energy price variability. There is no significant change in the mean and variance of monthly generation unit-level output across the two market designs. This increased price volatility provides strong incentives for generation unit owners and retailers to sign fixed-price forward contracts to hedge this price volatility and finance new generation investments and for final consumers paying according to dynamic pricing plans to reduce their demand during high-priced periods, both of which enhance market efficiency and system reliability.**

***Index Terms*—Capacity payments, Energy-only market, Power generation planning, Power system economics.**

I. Introduction

Restructuring of the electricity supply industries around the world has led to an ongoing debate over which market design is more like to maintain the long-term financial viability of the industry at least cost to electricity consumers. One important dimension of this debate is the existence of a capacity payment mechanism that establishes a per mega-watt (MW) daily payment to generation unit owners in addition to the income from the energy market.

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Many Latin American countries have opted for a capacity payment mechanism with capped prices in the short-term energy market, whereas restructured industries in other parts of the world, such as Australia, New Zealand, and Singapore, do not have a capacity payment mechanisms and instead rely on periods of high short-term energy prices to provide the appropriate signals for suppliers and retailer to sign the long-term contracts necessary to finance new investments in generation capacity.

There has been considerable debate over the relative merits of these two approaches to electricity market design but surprisingly little systematic study of this issue.[1] We compare of the performance of these two approaches within the context of the Chilean wholesale electricity market. Simulating market outcomes under each market design for the same set of system conditions is relatively straightforward because Chile operates a short-term energy market based on generation unit supply offers computed by the system operator using the technical characteristics of generation units, information on current and future water levels, and the evolution of demand. Consequently, we do not have to address the question of how generation units would change their offers to supply energy under capped short-term energy market with a capacity payment versus an energy-only market with scarcity pricing.

We perform 19-year simulations of the actual operation of the Chilean Central Interconnected System (SIC) between 1989 and 2008 for each market design.. We compute the present value of expected energy and capacity payment revenues for each generation unit and the system as a whole. We then eliminate the capacity payment mechanism and adjust the shortage cost parameter in the model used to operate the SIC and to compute energy prices that produce the same discounted present value of expected revenues from energy sales only.

Under the current combination capacity and energy market design, we find that the allocation of capacity payments across different technologies is relatively constant and represents roughly 19% of a generation unit's total revenue. Under the energy-only market design, the average market-clearing energy price increases from \$67/MWh to \$82/MWh, a 23% increase relative to a market with capacity payments, and the highest observed price increases from \$493/MWh to \$2,350/MWh, roughly a fivefold increase relative to the current market design.[2]

[1]Recent discussions about market design and the impact of capacity payments have been had in California [4], Colombia [14] and England [8].

[2] All the values in April, 2008 US dollars.

The absence of a capacity payment mechanism increases dramatically generation unit-level revenue volatility. However, this increase in revenue volatility is completely explained by the increase in wholesale price volatility. For all technologies, the standard deviation of the average monthly output of the generation unit under the energy-only market is not appreciably different from that same magnitude under the current combined capacity payment and energy market. Because monthly generation unit level output levels are no less predictable under the energy-only market design, the primary revenue risk that must be managed is wholesale price risk. This risk is easily hedged using a fixed-price, fixed-quantity of energy forward contract, where the supplier can lock in a fixed price for their expected pattern of output over the term of the contract.

This hedging arrangement provides a stable revenue stream for the generation unit owner for the vast majority of its actual output. The energy-only market design also has number of market efficiency benefits relative to the current combined capacity payment and energy market. Besides providing strong incentives for generation unit owners and retailers to sign fixed-price forward contracts, the risk of high-priced hours provides generation unit owners with a strong financial incentive to keep their units in working order, because an outage during a high-priced period can be extremely expensive for the generation unit owner. High priced-periods also provide strong incentives for final consumers to reduce their demand and shift it to the low-priced periods.

Consequently, the combination of an energy-only market with high-levels of fixed-price forward contracting for the generation unit owner's expected output can significantly improve wholesale market efficiency because of the high-powered incentives it provides for suppliers and final consumers to take actions to benefit system reliability and limit wholesale prices.

The remainder the paper proceeds as follows. In section 2 we briefly describe the SIC, the Chilean restructuring process and the mechanisms used to determine generation unit owner revenues under the existing market design. In section 3 we explain the mechanism for allocating capacity payments among generation units in Chile. In section 4 we present the methodology used in this study. In section 5 we report the results of the simulations and in section 6 we conclude. The appendix describes the sources of inputs to our simulation exercise.

II. The Chilean electricity market and Generator Revenue determination

A. A brief description of SIC

The SIC serves around 93% of Chile's population and represents 71.8% of its total installed capacity. As of 2008, the SIC's installed capacity has the following fuel mix: hydroelectricity (55.1%), natural gas (27.3%), coal (9.7%), diesel (7.4%) and others (0.4%). Hydroelectricity exposes the SIC to major hydrological risk because more than 50% of its energy is generated in hydroelectric units which, except for Laja reservoir, do not have inter-year storage capacity and thus depend on each year's hydrology. [3]

In an average hydrological year, hydroelectric generation supplies around 58% of the energy. However, in a very dry year, little more than 27% of the energy produced is supplied by hydroelectric units. This means that water is not a secure supply source because its availability it not constant or at least predictable from year to year and it therefore requires backup from thermal power plants.

B. Wholesale Market Overview

The Chilean electricity market was radically restructured during the 1980s as part of sweeping market-oriented reforms introduced in Chile during the 1970s and 1980s. As Bernstein [3] notes, the 1982 Electricity Law functionally separated the provision of electricity into three distinct segments, generation, transmission and distribution. The law also introduced the cost-based dispatch model for pricing energy, benchmark regulation in distribution, and long-term contracts between generators and distributors at regulated prices.[4] This was followed in the late 1980s with a massive privatization of state-owned electricity utilities. This regulatory framework has remained fundamentally unchanged since 1982, with specific changes introduced during the last couple of years to improve the regulation of transmission, strengthen the conflict resolution mechanisms and substitute competitive auctions for explicit regulation to set retail residential energy prices. [5,6]

The core of the current wholesale pricing mechanism is the so-called spot market. The Economic Load Dispatch Center (CDEC by its Spanish acronym) centrally dispatches generation units to minimize the expected discounted present value of actual production costs (including the expected cost of future shortage periods) to meet demand each hour of the day. The system price is the running cost of the most expensive unit required to meet system load every half hour. Dispatch is mandatory and completely independent of any financial contract obligations a supplier might have. Because all retailers must purchase financial contracts for 100% of their demand from generation unit owners, each hour a given generator is either a net supplier to the system or a net buyer. Net buyers pay net suppliers the system price. This situation avoids market power in the generation side. The spot market has an energy price cap set by the National Energy Regulatory Commission or NEC each six months, which it is equivalent to the shortage cost, or the Value of load lost (VOLL).

In addition, each generation unit is receives a monthly capacity payment based on its annual availability. The price of capacity is determined based on the capital cost of a peaking generation unit which, in the case of Chile, is a diesel turbine

To sum up, in the total revenues received by a power plant come from its energy and capacity sales, given by

$$E \cdot mgc + \widehat{c} \cdot pc,$$

[3] See [11] for a detailed description of the Chilean system..

[4] See [1], [3], [5] and [13].

[5] A description of the Chilean system pricing can be found in See [7], [5], and [14].

[6] For a discussion of the electricity law enacted in 1982 and updated in 2007, see [10].

with E the energy generated by the plant; mcg , the system price; $\widehat{c}$, the power plant´s firm capacity and pc the system capacity price.

III. Allocation of Capacity payments

Each year the capacity mechanism remunerates only as many MW as is required to meet the system's peak load (call it $\overline{D}$), which equals the average of the 52 largest hourly loads during the Winter season, between May and September.[7] Thus, the total system-wide capacity revenue equals

$$CP = p_c \times \overline{D}.$$

Of course, the system's nominal capacity exceeds the year's peak load. Thus, CP must be prorated among existing plants. In general, nominal capacity has followed demand growth, but with a relatively large margin of about 30% to 40% higher than peak load, $\overline{D}$. In this section, we first describe the procedure to prorate CP across generation units and then present descriptive statistics on capacity payments in Chile between 1989 and 2007.

A. *Firm capacity allocation*

Let n_i be the nominal capacity of unit *i*. In general, the sum of the installed capacity of all units exceeds system peak, so that $\sum_i n_i > \overline{D}$. Consequently, nominal capacity must be adjusted to prorate the available capacity revenue, $p_c \cdot \overline{D}$. This is done in three steps.

1. Each unit's nominal capacity is adjusted to reflect its historic availability. This is called a unit's *initial capacity*. Call this magnitude $\widehat{n}_i$. The initial capacity of thermal unit is the average amount of available capacity from the unit since it entered the system. For run-of-river hydro units it is the available capacity during a dry year. Finally, for reservoir hydro units, it is the capacity that the reservoir can provide during the peak hour during a dry year.
2. Initial capacity is further adjusted to determine *preliminary firm capacity*, call it c_i . Preliminary firm capacity approximates the power (instantaneous energy) that unit *i* can provide with high probability during the system peak. To obtain it, the empirical distribution of each unit's availability is obtained from historical data. This information is used to obtain a joint probability distribution of aggregate power availability with and without unit *i*. Then, for the system's loss-of load probability during the peak hour, available capacity with probability 0.99 and higher is computed with and without unit *i*. The difference is c_i . Steps 1 and 2 imply that for each unit *i* one can define an adjustment factor

$$\alpha_i \equiv \frac{c_i}{n_i}.$$

3. In general $\sum_i c_i > \overline{D}$. Hence, a factor

$$\beta \equiv \frac{\overline{D}}{\sum_i c_i}$$

is calculated. *Firm capacity* of unit i defined as

$$\widehat{c}_i \equiv \beta c_i .$$

[7]The winter season was chosen because the system's peak demand occurs then. and, moreover, the hydrology at that time of the year is very volatile. In contrast, between October and March, the runoff from snow melt ensures a stable flow of water. This is the main reason why firm energy sufficiency is assessed only during the Winter.

B. *The regulated capacity price*

The capacity price equals the cost of investing in a diesel-fired turbine meant to run during the system peak. This cost equals the sum of I_t , the cost of the turbine, and I_l , the cost of the transmission line needed to connect it to the high-voltage grid. Both are converted to a yearly equivalent figure assuming an 18-year recovery period, a system reserve margin, η and a 10% real discount rate.[8] Thus

$$p_c = (1+\eta)\frac{1}{R}(I_t + I_l)$$

with

$$R \equiv \left[\int_0^{18} e^{-0.1 \cdot t} dt\right]^{-1}$$

This price is fixed in US dollars and converted to nominal Chilean Pesos indexed for inflation.

C. *Capacity payments*

In terms of the above notation, unit i's capacity payment revenue is equal tost,

$$p_c \cdot \widehat{c}_i = p_c \cdot \beta \cdot \alpha_i \cdot n_i \tag{3.1}$$

is unit's i capacity revenue.

D. *Capacity Payments in Chile, 1989-2007*

Figure 1 shows the capacity price between 1989 and 2007 in April, 2008 US dollars. The capacity price has moved between $US 6 and $US 10/kW/month.

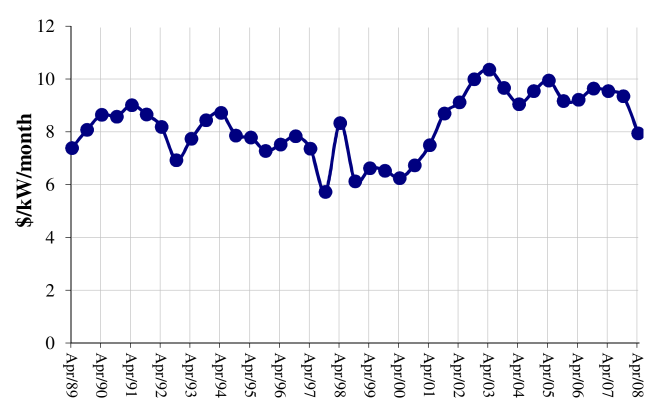

Figure 1. Capacity price at Quillota Node (in April 2008 US$).

[8]In 1989 the reserve margin was fixed at 10% , but it was increased to 15% in 1990; reduced to 6.27% in October 1997; and increased yet again to 11.76% in October 2001.

Figure 2 shows the evolution of total nominal capacity in the SIG, total firm capacity derived from the capacity payment mechanism, and the system's maximum load. Maximum load has grown from 2,270 MW in 1989 to 6,313 MW in 2007. The reserve margin (nominal capacity over maximum load) is regularly quite large. Indeed, it can be seen from Table 1 that it has never fallen below 20%. It reached 62% in 1999 and has averaged 41% over the sample period.

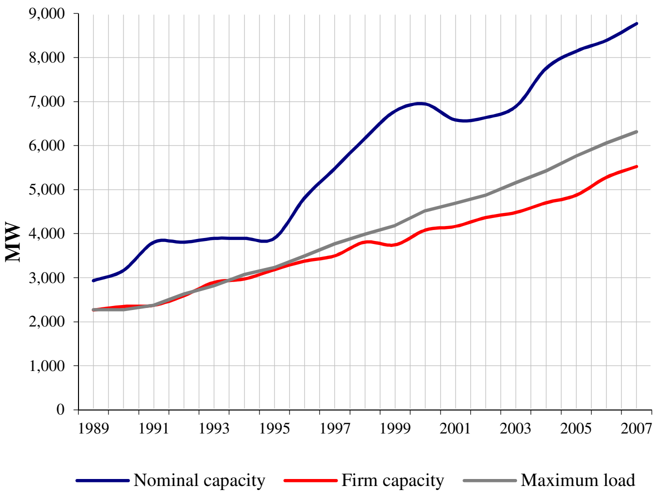

Figure 2. Nominal and Firm capacity and maximum SIC load, 1989-2007.

Figure 3 shows the capacity payment shares of generation technologies over time. The four technologies are: (1) run-of-river hydro, (2) the Laja lake hydro, (3) other reservoir hydro units, and (4) thermal generation units. In the late 1990s, there was a marked shift in capacity payments towards fossil generation, mainly because of the arrival of Argentine natural gas.

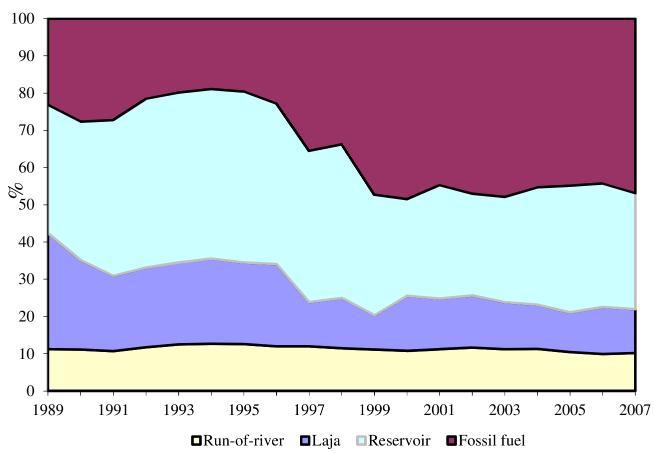

Figure 3. Capacity payment shares by technology between1989-2007.

IV. Methodology

We simulated the operation of Chile's Central Interconnected System (SIC) between April 1990 and March 2008 for the current combined capacity and energy market design and for an energy only market.

In both cases, the system is dispatched to minimize the expected discounted present value of total operating costs. [9] To do this we use the OMSIC model, which it was used by the CDEC to schedule the SIC operation up to 2005.

A. The optimization model

The OMSIC model is based on stochastic dynamic programming techniques. The focus of the dynamic optimization problem is the use of the Laja reservoir. When full, it holds enough water to generate about 7,000 GWh, roughly one-seventh of annual energy demand in the SIC. Because the annual capacity of the generation units that run with Laja water is 2,500 GWh/year, energy can be stored for several years. Generation from other reservoirs with weekly or monthly re-charge is modeled as run-of-river with monthly energy availabilities obtained from information provided by CDEC.

The model trades off the benefit of using water today and displacing thermal generation, against the cost of not having water in the future and thus having to use thermal generation or ration customers and pay the shortage cost per MWh of the energy shortfall. The model's state variable is the current level of the Laja reservoir. The probability distribution of future hydrologies is modeled with 61 years of past monthly hydrologies (hence, there are 61 January hydrologies, 61 February hydrologies and so on, and 61x12 monthly hydrologies in total). Each of the 61 hydrologies is assumed to be an equally likely for any year during the simulation period. The model solution yields the amount of Laja water that is used during each month and the shadow price of the remaining water. This shadow price is the system marginal cost or wholesale market spot price. Under normal conditions, the opportunity cost of water equals the operating cost of the most expensive thermal unit dispatched. If the model optimally predicts a shortage, the opportunity cost of water equals the shortage cost.[10]

B. Simulations

The OMSIC model is run for 19 hydrological years. A run consists of 12-year look-ahead, month-by-month dynamic optimization problem that minimizes the expected generation and outage cost of serving the exogenous sequence of actual energy demands. For example, the run for year y = 2001-02 is a 12-year look-ahead month-by-month dynamic optimization problem that starts in April 2001 and ends in March 2013 and minimizes the operation and outage cost of supplying the exogenous sequence of loads for that year. Each run begins with the level of the Laja reservoir at the beginning of the first hydrological year of that run. In each run, new power plants are entered into the optimization problem at the actual date that they began operation.

Each run comprises 5,000 simulations of the model with a randomly sampled sequence of monthly hydrologies. We only use the results of the first year of each 12-year run. Thus, for the y = 2001-02 12-year run we only use the results for April

[9] See [6] for more information about the cost- based power plant dispatch in Chile.

[10] For more information about the OMSIC model and the optimization process, see [6].

2001 to March 2002. Therefore, we have 19 years of output, each from a different run of the model.

Total energy demand in each month of the simulation is divided into five demand blocks, b = 1,2,..,5, which approximate the system's actual monthly load curve (see Figure 7). Specifically, let t = 1,2,..12 and y = 1990-91, 1991-92,..,2007-08. Then

$$E(b,t,y)$$

is the amount of energy demanded during block b in month t in year y. We use actual energy demand from 1990-91 to 2007-08. Because our 12-year optimizations go beyond 2007-08, we use NEC's April 2008 load projection for 2008-09 through 2018-19.

C. *Power plants and generation*

We index units present during part or all of the period with i = 1,2..,m . We let

$$I_i(t,y)=\begin{cases} 1 & \text{if unit } i \text{ is operational in month } t \text{ of year } y; \\ 0 & \text{if unit } i \text{ is not operational in month } t \text{ of year } y. \end{cases}$$

Hence

$$m(t,y)^{o}\sum_{i=1}^{m} I_i(b,t,y)$$

is the number of units which are operational in month t of year y. Furthermore we denote by $E^i(b,t,y)$ the amount of energy produced by unit i. Note that $E^i(b,t,y)>0$ only if $I_i(b,t,y)=1$. Between 1989-90 and 2007-08 we simulate with the generation units that were actually in the system at each point in time. For 2008-07 and beyond we use the new entry sequence that was calculated by NEC in April 2008.

D. *Simulation outputs*

All 5,000 simulations of year y to (y+12) are run starting with the actual initial level of the Laja reservoir in April of year y. The output of each simulation k = 1,2,..5,000 is as follows. For each demand block b of month t of year y we obtain:

(i) the energy spot price or system marginal cost,

$$mc(b,t,y;k);$$

(ii) the vector

$$\left[E^i(b,t,y;k)\right]_{i=1}^{m}$$

and the energy outage

$$E^o(b,t,y;k)$$

which satisfies the equation

$$\sum_{i=1}^{m} E^i(b,t,y;k)+E^o(b,t,y;k)\equiv E(b,t,y),$$

and minimizes the expected discounted sum of generation and outage costs.

E. *Generator energy revenues*

From the output of the simulations we compute the following magnitudes:

(i) For year y and each unit i such that $I^i(t,y)=1$, energy revenue in the kth simulation in run y,

$$RE_i(y;k)=\sum_{t=1}^{12}\sum_{b=1}^{5} mc(b,t,y;k)\cdot E^i(b,t,y;k).$$

(ii) For each unit i such that $I^i(t,y)=1$, the expected energy revenue during run's y initial year y,

$$\overline{RE}_i(y)=\frac{1}{5{,}000}\sum_{k=1}^{5{,}000} RE_i(y;k), \tag{4.1}$$

with standard deviation

$$\sigma_i(y)=\sqrt{\frac{1}{5{,}000}\sum_{k=1}^{5{,}000}\left[RE_i(y;k)-\overline{RE}_i(y)\right]^2},$$

and coefficient of variation

$$CV_i(y)=\frac{\sigma_i(y)}{\overline{RE}_i(y)}. \tag{4.2}$$

(iii) For year y, total value of lost load (VOLL) in the kth simulation of run y, viz.

$$VOLL(y;k)=\sum_{t=1}^{12}\sum_{b=1}^{5} oc\cdot E^o(b,t,y;k),$$

With oc = \$492.60/MWh in the base simulation.

(iv) For year y, the expected total outage cost in run y, viz.

$$\overline{VOLL}(y)=\frac{1}{5{,}000}\sum_{k=1}^{5{,}000} VOLL(y;k) \tag{4.3}$$

with standard deviation

$$\sigma_{VOLL}(y)=\sqrt{\frac{1}{5{,}000}\sum_{k=1}^{5{,}000}\left[VOLL(y;k)-\overline{VOLL}(y)\right]^2},$$

and coefficient of variation

$$CV_{VOLL}(y)=\frac{\sigma_{VOLL}(y)}{\overline{VOLL}(y)}. \tag{4.4}$$

(v) For year y and the kth simulation of run y, total energy revenue,

$$RE(y;k)=\sum_{i=1}^{m} RE_i(y;k).$$

(vi) For year y total expected energy revenue, viz.

$$\overline{RE}(y)=\frac{1}{5{,}000}\sum_{k=1}^{5{,}000} RE(y;k)$$

F. *Generator capacity revenues*

Capacity revenues do not depend on the hydrology. To estimate them we calculated firm capacity $\hat{c}_i(y)$ for each year y between 1989 and 2007 for each unit i. We valued each MW of firm capacity at p_c = \$8.365/kW-month. Capacity revenues for unit i in year y is

$$RC_i(y)=p_c\cdot\hat{c}_i(y)\cdot I_i(y)$$

and total capacity revenues are

$$RC(y)=\sum_{i=1}^{m} RC_i(y).$$

From these magnitudes, we can also compute

$$CV_i^T(y) = \frac{\sigma_i(y)}{\overline{RE}_i(y) + RC_i(y)}, \qquad (4.5)$$

the coefficient of variation of total revenues.

G. *Equivalent Energy-Only Market Outcomes*

To compute the energy-only market outcomes that have the same discounted expected total energy revenues as our combined capacity and energy market runs, we take the 19 years of expected revenues with an outage cost oc_0 = \$492.60/MWh and compute

$$\sum_{y=1}^{19} \frac{\overline{RE}(y;oc_0) + RC(y)}{(1+r)^y},$$

the present value of total expected revenues.

Next we redo the simulations for the 19 years and find an outage cost $\widehat{oc}_0$ such that

$$\sum_{y=1}^{19} \frac{\overline{RE}(y;oc_0) + RC(y)}{(1+r)^y} = \sum_{y=1}^{19} \frac{\overline{RE}(y;\widehat{oc}_0)}{(1+r)^y}. \qquad (4.6)$$

That is, $\widehat{oc}_0$ is the outage cost that yields energy-only expected revenues that have the same expected discounted present value as energy and capacity revenues with outage oc_0.

V. Results

Table 1 shows that for the current market design, capacity payments are 19% of the total revenues. Although the means of annual expected revenue differ slightly, reflecting differences across the 19 years when revenues are earned under the two market designs, the standard deviation of the revenues increases dramatically from 36% of mean expected revenues for the current market design to 99% of mean expected revenues for the energy only market. The average market price increases from \$67/MWh to \$82/MWh, a 23% increase. The peak price increases from \$493/MWh with capacity payments, to \$ 2,350/MWh under the energy-only market. In both cases the LOLP is similar, which is obvious, since the supply offers remains the same across the two simulations.

To see the effect of the higher outage cost parameter on the market prices, Figure 4 compares monthly average energy prices with capacity payments (dark line) and without capacity payments (light line). The figure shows that average energy prices are much higher without capacity payments. The reason is occurs because the shortage cost is much higher under the energy-only market so more expensive thermal units are run more frequently during low water conditions, relative to the current market design.

Next, Figure 5 shows monthly deficit probabilities--the fraction of simulations such that the model returns a deficit greater than 1% of the system's load. Again, the base case is the dark line, and the light line shows results with no capacity payments. The figure shows that deficit probabilities do not differ much across the two market designs and, if anything, they are slightly smaller for the energy-only market. This should not be surprising, because with a higher outage cost the reservoir water is used more conservatively, which leads to smaller deficit probabilities. In both cases, deficit probabilities are computed with the same generation units; in future work we plan to endogenize generation unit entry decisions, which in turn will impact deficit probabilities.

TABLE 1
Revenues, Market Prices and LOLP

	With capacity payments		Without capacity payments	
Energy revenues (million \$)	11,480	81%	14,248	100%
Capacity revenues (million \$)	2,685	19%	-----	-----
Total revenues (million \$)	**14,165**	**100%**	**14,248**	**100%**
Standard deviation (million \$)	5,077	36%	14,054	99%
Average market price 1989-2007 (\$/MWh)	66.7		82.1	
Standard deviation (\$/MWh)	37.9		50.3	
Peak market price (\$/MWh)	493		2350	
Average LOLP 1989-2007	0.44%		0.46%	

Note: Revenues are reported in present value@10% in the year 1989.

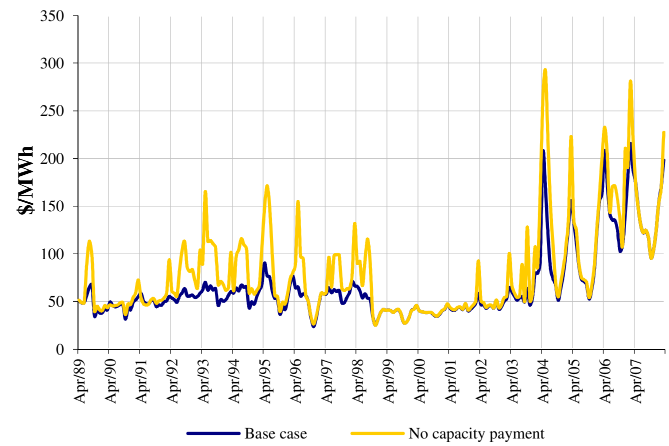

Figure 4. Monthly average energy prices, April 1989 through March 2008.

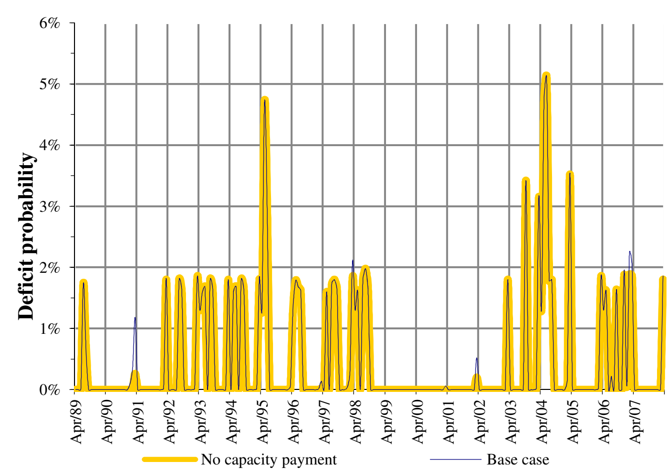

Figure. 5. Monthly deficit probability April 1989 through March 2008.

A. Explaining Increase in Revenue Volatility

We now explore the factors underlying the difference in revenue volatility in Table 1 between the combined capacity and energy market and the energy-only market. Figure 6 presents monthly mean generation by technology for the two market designs. Figure 7 presents the monthly standard deviation of energy production by technology for the two market designs. There is very little difference in both mean generation by technology and the standard deviation of generation by technology. Consistent with the higher shortage cost under the energy-only market, thermal generation units—natural gas-fired and coal-fired—have slightly higher mean generation and a slightly higher standard deviation of generation under the energy-only market design.

The energy-only market design makes slightly less intensive use of the Laja reservoir in a less irregular manner, because the standard deviation of generation from it is also lower under the energy-only market design. Based on the results in these two figures, it is difficult to argue that an energy-only market design would yield a lower level of system reliability. A case could even be made that the higher shortage cost under the energy-only market increases system reliability.

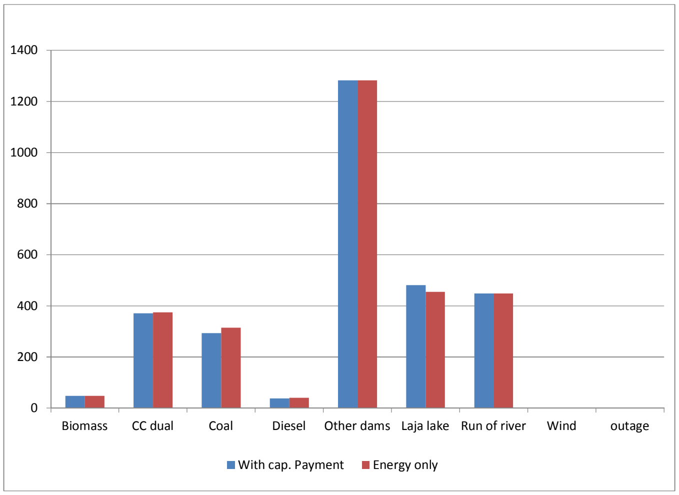

Figure 6: Mean of Monthly Generation by Technology

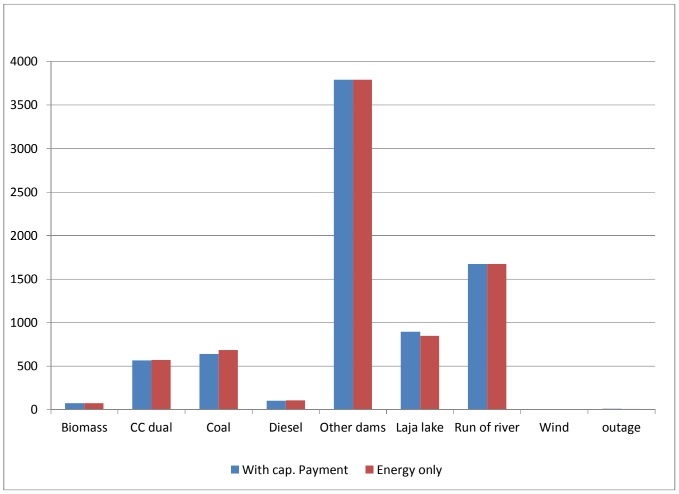

Figure 7: Standard Deviation of Monthly Generation by Technology

Figure 8 plots the mean monthly prices under the two market designs. Particularly during the winter months, mean prices for the energy-only market are significantly higher than those for the capacity and energy market design.

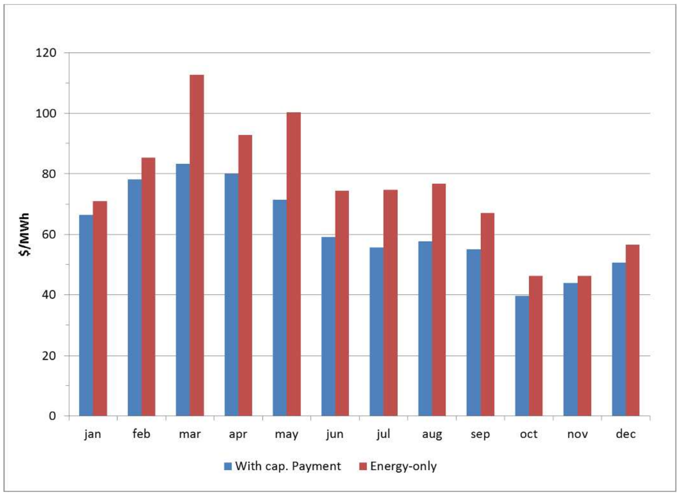

Figure 8: Mean Monthly Prices in $US per MWh

Figure 9 plots the standard deviation of monthly prices for the two market design. For all months of the year, the standard deviation of the market price for the energy-only market is substantially higher, almost two to three times higher, than for the combined capacity and energy market. Taken together, Figures 7 to 10 demonstrate that all of the revenue volatility in the energy-only market is due to price volatility. However, this price volatility has a number of market efficiency benefits.

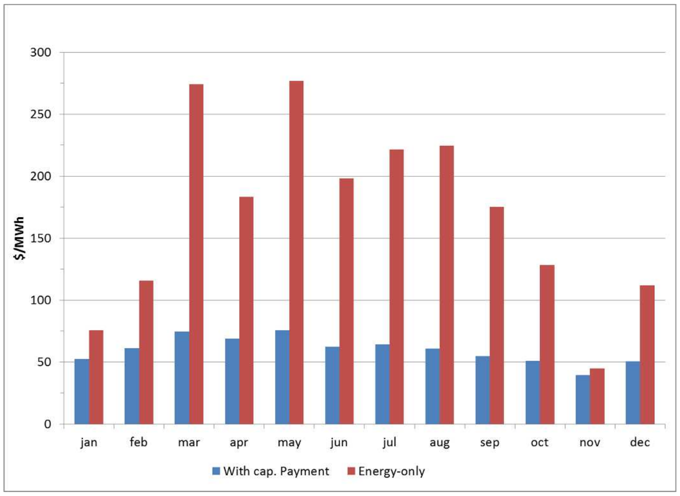

Figure 9: Standard Deviation of Monthly Prices in $US per MWh

First, volatile short-term market prices provide strong incentives for both sides of the market to enter into fixed price forward contracts to hedge this revenue risk. Electricity retailers want to hedge against the risk of high short-term prices, whereas generation unit owners want to hedge against sustained periods of low prices. These divergent incentives for signing fixed-price forward contracts are the source of the gains from trade signing these contracts.

Second, the high shortage cost in the energy-only market provides strong incentives for generation unit owners to keep their units available to produce energy during potential scarcity periods. The generation unit owner faces a potentially high opportunity cost of producing energy if it is unable to produce during low water periods. Moreover, if this generation unit owner has fixed-price forward contract obligations, buying energy out of the short-term market to replace the energy the unit owner is unable to provide can be extremely expensive.

Third, the periods of high and low energy prices under an energy-only market design provides strong incentives for final consumers with interval meters to reduce their demand during high-priced periods and shift this demand to low-priced periods. More active participation of final consumers in the wholesale market makes it more likely that the same number of consumers can be served with less generation capacity, which raises the prospect of consumers paying lower average wholesale energy prices under an energy-only versus a combination capacity and energy market design.

Taken together these results suggest than an energy-only market has the potential to improve system reliability and benefit consumers with lower average electricity bills relative to a combination capacity and energy market design.

VI. Conclusions

In this work we simulated the operation of the SIC with two different market designs. First, we simulated the operation under the existing market design with a capacity payment mechanism and an energy market with a low shortage cost that caps energy prices. In the second case, we assumed an energy-only market and we calculated the shortage cost so that the expected discounted present value of total revenue is the same as under the existing market design.

Although revenue volatility for generation units increases significantly for the energy-only market relative to the combined capacity payment and energy market, this is completely explained by increased energy price variability. There is no significant change in the mean and variance of hourly generation unit-level output across the two market designs. This increased price volatility provides strong incentives for generation unit owners and retailers to sign fixed-price forward contracts to hedge this price volatility and finance new generation investments and final consumers paying according to dynamic pricing plans to reduce their demand during high-priced periods, both of which enhance market efficiency and system reliability.

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