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INCENTIVES FOR EXPANSION OF ELECTRICITY SUPPLY AND CAPACITY RESERVES IN THE MEXICAN ELECTRICITY SECTOR

Abstract

We have constructed a model to analyze the incentives for expansion of electricity supply in the spot market and the capacity in the long run reserve market. With this model we also analyze the incentives for collusion in the spot market in order to get higher profits. We find that for the Mexican Electricity Sector, where it is likely to have big differences among plants in terms of technologies and costs, the best mechanism is to use the reserve market to cop with peaks in demand. On the other hand, the mechanism of merit order dispatch gives incentives to expand de capacity in the spot market and in the long run reserve market.

Resumen

Construimos un modelo para analizar los incentivos para expandir la oferta de electricidad en el mercado spot y la capacidad en el mercado de reservas de largo plazo. En este modelo también analizamos los incentivos para coludirse en el mercado spot para así obtener mayores ganancias. Nuestros resultados muestran que para el caso del Sector Eléctrico Mexicano, en donde es muy posible encontrar grandes diferencias en términos de tecnologías y costos, el mejor mecanismo para cuando se tienen picos en la demanda es utilizar un mercado de reserva. Además, el mecanismo de despacho de acuerdo al orden de mérito genera incentivos para expandir la capacidad en el mercado spot y en el mercado de reservas de largo plazo.

Introduction[*]

In this paper we analyze the incentives that might have the generation plants to expand the generation capacity in the spot market as well as the reserves in the long run. We analyze these two questions in the context of the proposal of the Mexican reform to restructure the electricity sector. We think of a system operator (SO) that coordinates real-time operations from an engineering technical scope as well as from an economic perspective. This SO offers economic dispatch service based on marginal-cost power pricing, and participation in the dispatch is voluntary. The pool service provides the means by which generation costs are minimized through merit-order bids that selects generators based on their generation price, and establishes as the market price the price-bid of the last dispatched generator. The SO operates a sequence of day-ahead and real-time operation as well as short-run reserves in a longer time framework.

Based on this context, we want to study the incentives for expanding electricity supply as well as capacity reserves in the forward market or, more generally, the supply of ancillary services. Finally, we also want to know if under this mechanism plants have incentives to collude in order to get higher profits.

We get clear answer for these questions for the Mexican case. Given the plants that are operating in Mexico and the available technologies for the new plants, we get the following results.

First, there are incentives to expand capacity in the sport market and in the long run reserves market. Second, the scheme that proposes to increase artificially the price in the peak period gives incentives to collude. These incentives are present because plants will get extra economic rents any time there is a peak in demand. That is, plants have incentives to cut supply in order to induce a peak in demand.

The paper is structured as follows. In Section I, we discuss the importance of the System Operator in the Electricity Market. In Section II, we present the model from which we get our results under different assumptions. In Section III, we analyze the mechanism that should be used when there are peaks in demand. In Section IV, we put these results in the context of the Mexican Electricity Industry by analyzing some information about costs for the Mexican generating pants. Finally in Section V, we state our conclusions and gives some hints for further work along these lines.

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I. The ISO and the Market for long-run capacity reserves

The forward market for reserves is characterized by substitutes in hierarchy of quality, as measured by response time. This makes very difficult the simultaneous clearing of the reserve markets. Moreover, the design of an optimal bidding procedure in the forward reserves market is not an easy task.[1] Additionally, reliability-must-run plants, which contract long-run capacity, have monopoly power because they are occasionally needed for local voltage support.[2]

According to Wilson (1999), the forward market for reserves is one of four markets that characterize the complete electricity market. The other three markets are the spot energy market, the forward energy market (or market of bilateral contracts), and the forward transmission market. These four markets have complex interactions that affect the analysis in this market. First, they complicate the analysis of the optimal incentives to expand capacity and energy supply (as discussed in the next Section). Second, they have an impact on the role of an independent system operator (ISO) in achieving this task.[3] Finally, they also affect the optimal behavior of a generator in the spot energy market (as discussed in Section III) and the forward market for capacity (as discussed in Section II).

There exist at least three structures for an ISO that have been designed in order to reach an equilibrium for these four markets. Each one of them determines the way expansion in energy supply and capacity is reached.[4] The first one is a decentralized ISO (as in California), the second is a centralized ISO (as in the

[1] Wilson (1999) argues that the design of a bidding procedure in the market of capacity reserves has to face that the price of a reserve is divided into a capacity fee and an energy fee. These two parts would usually be combined in a scoring rule and the winning bid would be the one with the lowest score. However, the typical score adds the value of capacity plus the value of energy through the use of the expected value of generated energy. These provides similar incentives to the Paasche weights because the bidder of energy might foresee that the ISO is over predicting the generated energy and therefore allocate all of its costs to the capacity fee. Wilson and Chao (1999) study the solution of this problem by assigning a zero weight to the energy bid and defining separated markets to increasing and decreasing offers of energy.

[2] When reserve margins are low, similar provisions apply to plants with unique capabilities to meet peak loads.

[3] The system operator is needed in the spot electricity market in order to coordinate real-time operations from an engineering technical scope as well as from an economic perspective. The ISO operates a sequence of day-ahead and real-time operations as well as short-run reserves in a longer time framework. Much longer time frameworks are possible with the use of bilateral physical or financial contracts usually based on contracts for differences with respect to the spot energy price. Mature electricity systems frequently show a pattern of 80% long-run bilateral contracts, 20% day-ahead contracts, and less than 10% of spot trading.

[4] The ISO has a natural monopoly over its functions. Several design issues arise regarding the ISO's organization and institutional characteristics such as governance, incentives, regulation, and economic objective function. Regarding congestion of transmission lines, Vogelsang believes that the objective function of an ISO should consider the minimization of difference in nodal prices and the maximization of total energy traded in the electricity system.

Pennsylvania-New Jersey–Maryland system),[5] and the third option is an integrated dispatch control and transmission operator or TRANSCO (as in United Kingdom).

A centralized ISO imitates vertically integrated functions through an overall optimization of operational decisions and long-term contracting among participants. This minimizes the costs of ensuring reliability and of coordinating generation, transmission and reserves. However, Wilson (1999) argues that centralization does not provide the right incentives for cost minimization since pool bids not always reflect actual costs (like in the UK electricity market). On the contrary, a tiny decentralized ISO would manage transmission and reserves with small intrusion into energy markets. A decentralized ISO provides more incentives for competitiveness but entails deficiencies in coordination, incomplete markets and mechanisms, and imperfect pricing. In a decentralized ISO, the pool dispatch function is ideally separated from other economic activities. Wilson believes that centralization is preferable under the presence of vigorous competition and adequate technical and economic optimization of an electricity industry, while decentralization is better when incentives for cost minimization and good scheduling decisions by each participant's pool are more important than coordination in electricity markets.

The system's stability can be maintained by the ISO through the management of the pre-arranged system of reserves. A continuous balance might be achieved using the submitted offers and several categories of short run-reserves including regulation capacity, operating reserves (spinning and non-spinning), replacement reserves and reliability-must-run. In a more long-term perspective, Wilson explains that a decentralized ISO should permit a sequential optimization of the spot market, the forward market for reserves, the forward market for transmission, and the forward markets for energy. A centralized system attempts a simultaneous optimization of all these four markets. Likewise, in a fully centralized system the ISO has full control of the real-time dispatch and reserve options are not voluntary while in decentralized systems participation in forward markets for reserves and in the spot market is voluntary. Reliability is therefore greater under a centralized system than under a decentralized system.

In a decentralized system with congestion of transmission lines, a decentralized ISO relieves congestion intervening in the energy markets by buying flows and counterflows in congested locations. The decentralized ISO implements this procedure with an access charge and a fix injection charge, and the use of increasing (incs) and decreasing (decs) offers of energy. In centralized systems the ISO reduces flows or produces counterflows by directing generators to reduce or expand their production according to a bidding procedure. Centralized systems normally use locational prices in order to obtain the energy price at certain node as the shadow price of injection in that node.

The TRANSCO approach is similar to a centralized ISO but with a dispatch controller that also owns the transmission network. Joskow (2000) hints that the

[5] Hybrid designs that allow for different degrees of centralization are also possible: central control of transmission and reserves by an ISO together with forward markets for energy.

decision between the two options is based mainly on institutional conditions. In the case of the United Kingdom, such conditions made possible the implementation of a TRANSCO. In the United States, however, it is difficult to impose a TRANSCO due to the property structure of the transmission network. In fact, Hogan believes that such a measure would end up with small regional TRANSCOs with compatibility problems among them.

In practice, several measures have been devised in order to solve provision of long-term reserves. For example, the 1999 Zedillo's proposal to reform the Mexican Electricity Sector proposes a rule that artificially increases the spot price of electricity as a function of generation congestion. This rule was taken from a similar measure implemented in the UK electricity market. The Mexican proposal presents a pricing mechanism that modifies the market-pricing rule during periods of high demand when reserve capacity margins are low. The market price is then defined as the weighted average of two factors: the price of the last accepted offer to generate (*LAO*) and the cost of failure (*CFALLA*). The weight is the loss of load probability (*LOLP*). The formula for the market price is then *market price* = $LAO * (1\text{-}LOLP) + CFALLA * LOLP$, where: $0 \leq LOLP \leq 1$.

The greater the surplus capacity (high reserve margin), the smaller is *LOLP* and the market price will be determined almost entirely by *LAO*. Generators would ideally add capacity when the expected sum of all these payments over all hours of the year was greater than the cost of installing new capacity. Additionally, the proposal foresees the use of another capacity payment to generators, the "*K* factor", to introduce additional incentives for new generation while the electricity becomes established. The "*K*" factor payment is charged to the distributors and thereby passed on to consumers. It is applied as an annual fixed payment to new generators per *KW* of available capacity. The size of the "*K*" factor payment would be decided by auction. The *CFALLA* and *K* terms are mechanisms that artificially increase the price of electricity and produce high rents.

Other countries, like Australia, have chosen not to interfere in the spot market but to create a regulated market for long-term capacity reserves. A market price is always used for spot transactions, and generation shortages are met in a "bypass" market by plants that supply electricity when reserve capacity margins are low. This last market consists of a small number of plants like those that are not normally dispatched due to their high marginal costs, or those that are able to supply both at non-peak and peak periods. This market is typically subject to incentive regulation.

The solution to the provision of long-run capacity reserves is a crucial issue that might determine the success or failure of a complete reform of an electricity sector as dramatically exemplified by the recent Californian experience. In this paper we try to contribute to the analysis of the complex market of ancillary services. Assuming a decentralized ISO, we study the profit-maximizing behavior of a generation plant both in the cases of a short-run spot market and in a long-run reserves market. This is the goal for the next Section.

II. Merit Order Model

In this Section, we analyze the profit-maximizing behavior of a generation plant in the electricity market. Any generation plant has three possibilities: (a) supplying for the short-run spot market, (b) supplying for the long-run reserve market, and (c) not supplying at all. Firstly, the generator might sell energy in the short-run market (or pool) or capacity in a long-run market for capacity reserves or not supplying at all. Secondly, if the generator decides to supply for the spot market, it might choose to sell energy in non-peak and peak periods.

The conditions that characterize the optimal behavior of the generator under these scenarios should hopefully provide the centralized ISO with key clues to evaluate the impacts of different pricing rules that seek to enhance supply of energy and capacity reserves. We will abstract from the forward markets of transmission and energy, so as to concentrate our analysis in the forward market for reserves.

We think in the following set up (See Graph 1). There exists a sequence of decisions that any generation plant (GP) must take. First, after the System Operator announces the expected demand for the following day, the GP must decide whether to enter the spot market, to enter the long-run reserve market, or not participate at all in the electricity market. Second, if it decides to participate in the spot market, it must decide to supply for the non-peak or for the peak period. Once any GP has made its decision, the market plays and decides the size of demand in any of the three markets: non-peak and peak periods in the spot market and the long-run reserve market. After this, any GP gets its payoff by computing its expected profits in these three markets. Finally, based on this information, each plant must decide in which market it will participate.

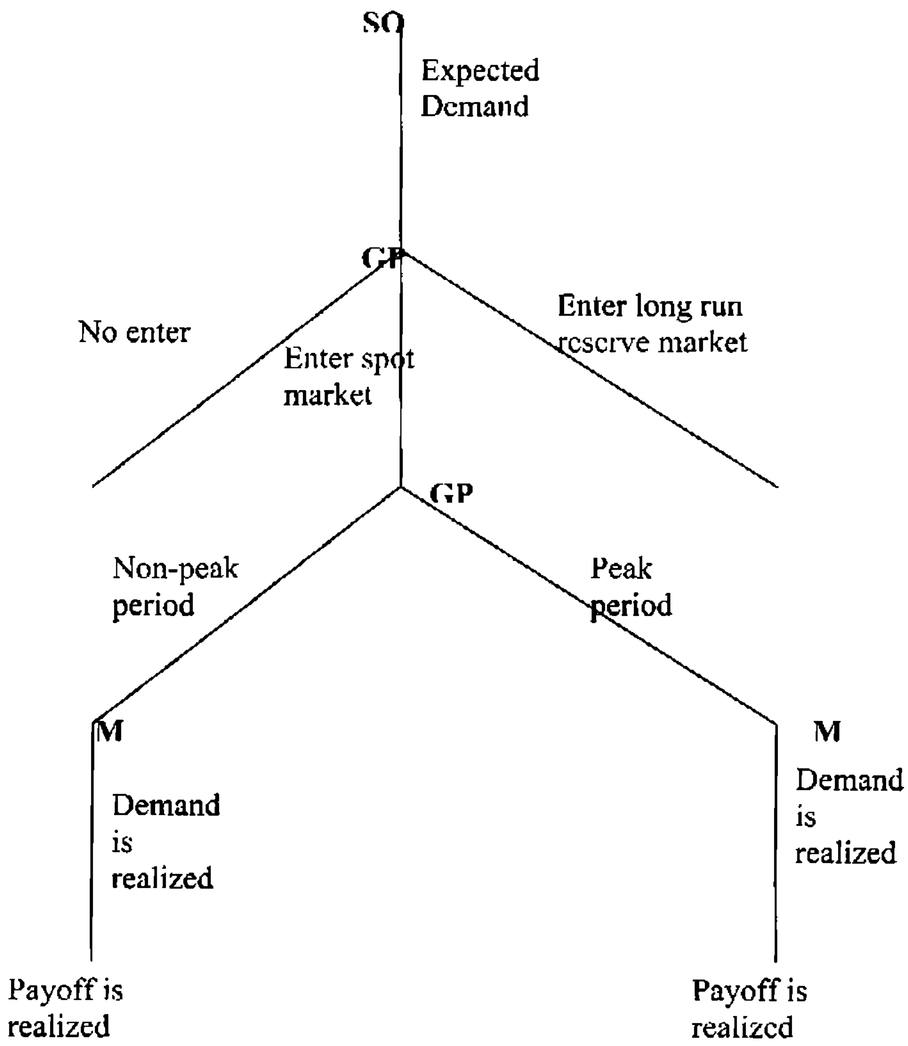
Therefore, we will think of this set up as a sequential game. We will be looking for an equilibrium of this game. In this case, the concept of solution will be the Perfect Subgame Nash Equilibrium. This is a configuration of plants in which no plant has incentives to move from one market to another.

Based on this model, we will study two questions. First, we want to know if this mechanism has the right structure to give incentives to expand the generation capacity in the spot market and in the long-run reserve market. Second, we want to explore if this mechanism creates incentives to collude in the spot market. In this Section we study the first ones. The last question is the task of the next Section.

Incentives for expansion of capacity

For now, we will analyze the strategic behavior of the generation plants in the short-run spot market. The only choice for them is to choose to generate electricity for the non-peak period or for the peak period. After solving for this model, we will allow plants to decide whether to generate for this market or to offer capacity for the long-run reserve market. In this context, all generators will make their decisions depending on the expected profits they would get in each market.

Graph 1. Sequence of Decisions



The Spot Market

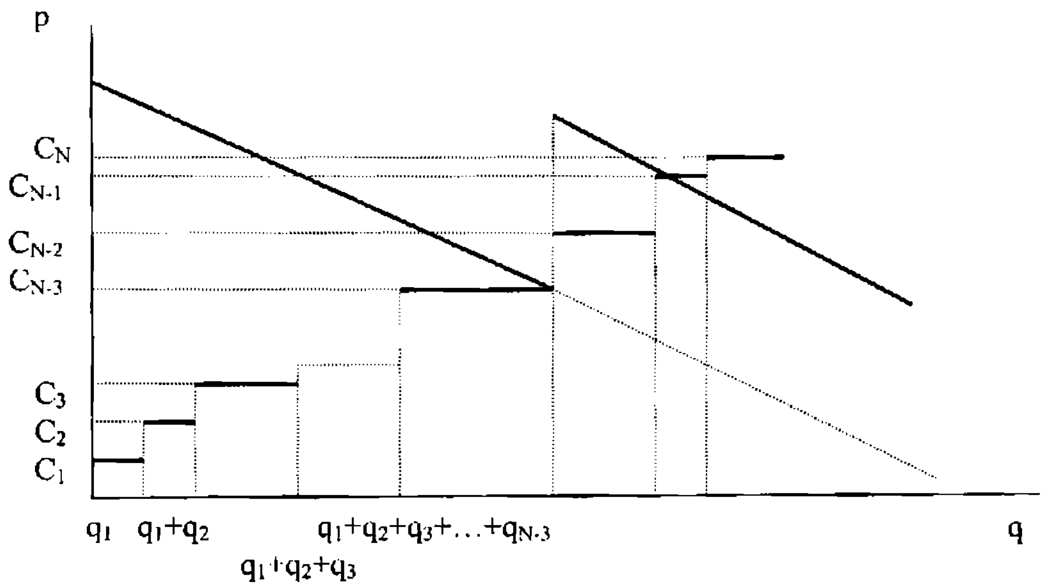
The spot market works as follows. Each generator decides voluntarily whether or not to participate in the market. Once it decides to participate, it chooses to supply for the non-peak or for the peak period. The system operator coordinates the market with operations in real-time and forecasting for a day in advance from an engineering technical scope as well as from an economic perspective. Based on the expected demand for the non-peak period, each participating generator makes a merit order bid based on its capacity and costs for the next day. Then, in the real-time market, the system operator ranks the bids and offers economic dispatch service based on marginal-cost power pricing. That is, generators are dispatched, according to their price bids, from the lowest one to the highest one until demand is satisfied. After that, the market price in the non-peak period is the price bid of the last dispatched generator. For the peak period, the system operator and the participating generators follow the same rules.[6]

Let us consider the following set up. There are N potential generators. Each generator $i = 1,2,\cdots,N$ has capacity of q_i and cost of $C_i(q_i)$.[7] Each generator makes a merit order bid based on q_i y C_i. Suppose that each generator makes a bid of c_i for each unit of capacity that it is willing to supply. That is, generator i offers each unit of capacity at cost c_i. Without loss of generality we suppose that $c_1 < c_2 < \cdots < c_N$. So, we have ordered plants according to their bids and name them accordingly. The generation capacities for these plants are $q_1, q_2, \cdots, q_N$ and these are the quantities they offer. We assume that if the generator decides to participate in the spot market, it offers all capacity in the non-peak or in the peak period. We do not allow plants to participate in both periods. Let $P = P(q)$ be the inverse demand function, which includes the peak load. We assume that this function is linear in both, the peak and non-peak periods. This inverse demand function has the shape shown in Graph 2. In this Graph we have ranked all generators according to their bids. The quantity supplied in the market is the sum of all the quantities supplied by each one of these plants. That is, the supply curve is upward sloping curve shown in this same Graph. Then, price and quantity are defined according to this graph following the rules described above. That is, this Graph shows a particular situation in the spot market. For example, in this case, the price in the non-peak period will be $p = C_{N-3}$ and the quantity supplied will be $Q = q_1 + q_2 + \cdots + q_{N-4} + q_{N-3}$.

[6] It is important to note that this mechanism minimizes generation costs in both periods.

[7] This cost includes the capacity fee and the energy fee.

Graph 2



From now on, we simplify this model. We assume that each plant has only one unit of capacity. This makes computation easier. In this context, we compute the market price for generation, the quantity supplied by the generators, the producer surplus and the consumer surplus. Based on this information, each firm will decide to supply for the non-peak period or for the peak period.

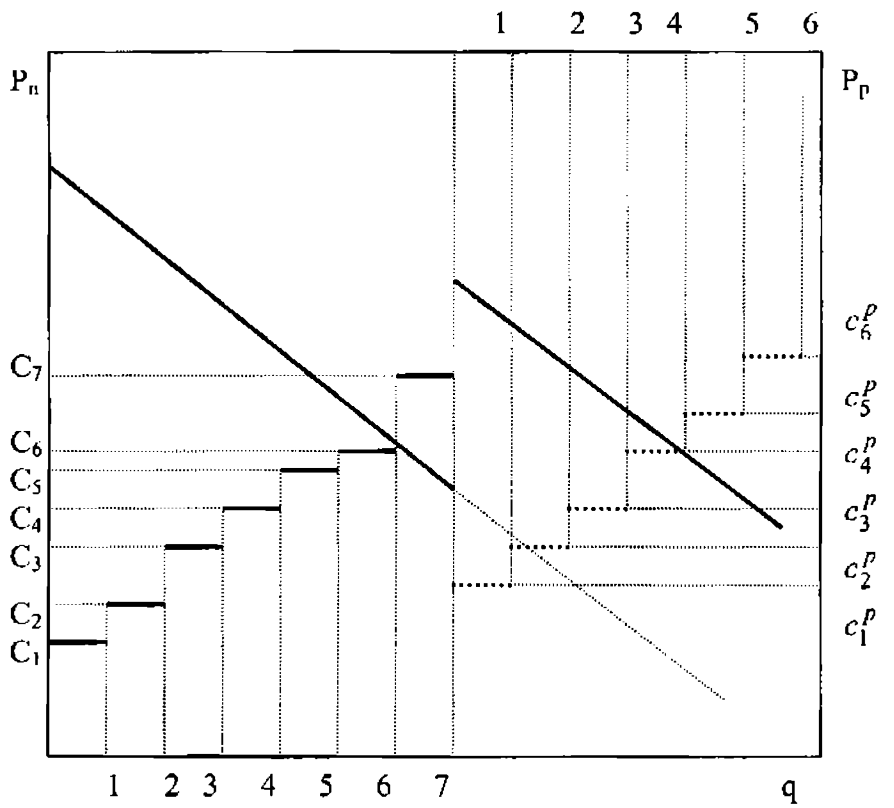
Thus, we have that $q_1 = q_2 = \cdots = q_N = 1$. From the total number of generators, there are N_{np} supplying in the non-peak period, N_p plants supplying for the peak period, and N_r supplying energy for the long run reserve market. This configuration satisfies with $N_{np} + N_p + N_r = N$. This situation is depicted in Graph 3. In this Graph we do not show the offers made by the N_r participating in the long run reserve market.

Given this demand function and the bids made by these generators, we get the following results.

For the non-peak period: price is $p_{np} = c_6$; quantity is $Q_{np} = \sum_{i=1}^{6} q_i = 6$; producer surplus is $PS_i^{np} = p - c_i = c_6 - c_i$ for $i = 1,2,\cdots,6$; and consumer surplus is $CS_{np} = \frac{1}{2}(6)[P(0) - c_6] = 3[P(0) - c_6]$.

For the peak period: price is $p_p = c_4^p$; quantity is $Q_p = \sum_{i=1}^{4} q_i = 4$; producer surplus is $PS_i^p = p - c_i = c_4^p - c_i$ for $i = 1,2,\cdots,4$; and consumer surplus: $CS_p = \frac{1}{2}(4)\left[P(7) - c_4^p\right] = 2\left[\bar{P}(7) - c_4^p\right]$

Graph 3



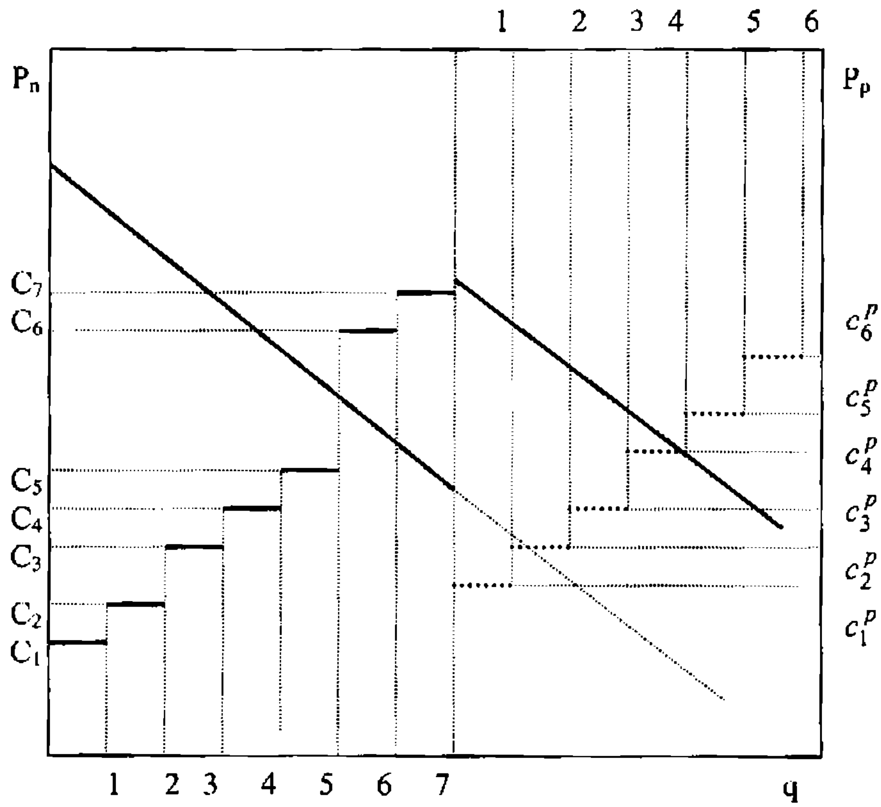
Let us analyze the behavior of plant 1 in this market. Its decision of offering for the non-peak or the peak period depends on the last plants dispatched in each period. In this particular case, plant 1 will get lower producer surplus by offering for the non-peak period since $PS_1^{np} = c_6 - c_1 < c_4^p - c_1 = PS_1^p$ because $c_6 < c_4^p$ and, as a consequence, we have that $p_{np} < p_p$. For the same arguments, all plants offering for the non-peak period have incentives to move to the peak period. However, it could also be that $p_{np} > p_p$. In this case, the incentives would be to move from the peak to the non-peak period. Thus, all plants will decide depending on the cost of the last plant being dispatched in each period. Therefore, the actual prices for the non-peak and the peak period depend on the configuration of plants choosing to serve each period.

Let c_m^{np} and c_m^{p} be the bids of the last plants dispatched in the non-peak and peak periods, respectively. Then, we have that $\frac{\partial PS_i^k}{\partial c_m^k} \geq 0$ for $k = np, p$. That is, the higher (lower) the bids of these plants, the higher (lower) the profits of all plants in that period. Therefore, the incentives to move from one period to the other will depend on the configuration of each set of generators. No plant will move if $c_m^{np} = c_m^{p}$.

Finally, an equilibrium in this market is a configuration of plants $\{N_{np}^*, N_p^*\}$ such that $c_m^{np} = c_m^{p}$. This gives a Nash Equilibrium in this market since no plant has incentives to move from one period to the other.

Now, we discuss some possible combinations of costs that could generate problems in this market. Think of the cost structure shown in Graph 4.

Graph 4



In this case, there exists excess demand in the non-peak period. The bid of the fifth plant is c_5, but at this price, there is more demand that cannot be satisfied since the next bid is c_6. On the other hand, at this price, $p = c_6$, demand is lower than 5 units. Therefore, in this case the merit order mechanism will generate some problems (excess demand at c_5 and excess supply at c_6) that must be fixed in some way. This calls for some type of regulation in the market to cop with these situations.

Therefore, we have a model where there is at least one generator that has incentives to move from one period to the other as long as $c_m^{np} \neq c_m^p$. That is, the only equilibrium where no plant has incentives to move is given by a configuration such that $c_m^{np} = c_m^p$. Moreover, it can be the case that there is not enough supply to satisfy demand in the non-peak period (as the example shown in Graph 4).

Now we proceed to analyze the long-run reserve market. In this case, we compute the expected profits of a generator that decides to offer capacity in this market. We then compare these profits with profits it would get in the short run spot market. Based on this, the generator will decide its strategy that maximizes its profits.

The long run reserve market

In this section we model the behavior of the generation plants that choose to supply electricity for the reserve market in the long run. This is an uncertain market, since it is unknown the size of demand at that particular point in time. All plants deciding to participate in this market have a probability of being dispatched. The bigger the capacity demanded in this market at that time, the higher the probability of being dispatched. Clearly, given the merit order mechanism, the generator with the lowest bid will be dispatched for sure. For the other plants, it will depend on the size of the actual demand at that moment in time.

In order to analyze this market, we construct a simple model that gives us some hints of what could happen. We assume that demand might be $d = 1,2,3,\cdots,M$ units of electricity. There exists a probability distribution over this demand. The lower the quantity demanded the higher the probability. Let P be a probability distribution over d given by $\{p_j\}_{j=1}^M$. So, p_j is the probability of having a demand of $d = d_j$ for $j = 1,2,3,\cdots,M$ where $p_1 > p_2 > \cdots > p_M$, $p_j > 0$ for $j = 1,2,3,\cdots,M$ and $\sum_{j=1}^{M} p_j = 1$,

Suppose that each plant, i, entering this market makes a bid. It will offer one unit of electricity at cost of c_i. As before, this cost is the sum of a capacity fee and an energy fee. Once all plants willing to supply for the long run reserve market make their offers, their are ranked according to their bids. Say we have N_r plants in the market. Then the ordering will be $c_1^r < c_2^r < \cdots < c_{N_r}^r$. Given this ordering, we compute the expected profits for entering this market.

Plant 1 will get c_1^r with probability p_1, $c_2^r - c_1^r$ with probability p_2, $c_3^r - c_1^r$ with probability p_3, and so on. That is, it will get an expected profit of $\Pi_1^{re} = \sum_{j=1}^{M} p_j \left(c_j^r - c_1^r\right) = \sum_{j=1}^{M} p_j c_j^r - c_1^r$.[8] Thus, plant i will get an expected profit of $\Pi_i^{re} = \sum_{j=i}^{M} p_j c_j^r - c_i^r$.

Therefore, according to this set up, we have the following results. First, we have $\frac{\partial \Pi_i^e}{\partial c_i^r} < 0$; that is, the lower the costs of plant i the higher the expected profits. Then, the less costly plants are the ones that are more likely to enter this market. Second, if we have a probability distribution $\overline{P}$ given by $\overline{p_j}$ where $\overline{p_1} > \overline{p_2} > \cdots > \overline{p_N}$, $p_j > 0$ for all $j = 1,2,3,\cdots,M$ and $\sum_{j=1}^{M} \overline{p_j} = 1$ that is stochastically dominated by the probability distribution P, then the expected profits for all generators will be higher under P than under P. Therefore, the higher the expected demand, the higher the expected profits in the long-run reserve market. In this case, more generators will be willing to supply capacity for this market. Third, $\frac{\partial \Pi_i^{re}}{\partial\left(c_j^r - c_i^r\right)} > 0$. That is, the bigger the difference between the i's bid and the bids of the other firms (which are more costly), the higher the expected profits of generator i. Therefore, the less costly generators with respect to all generators in the market, are the ones that are more likely to enter this market.

Finally, we compare these expected profits with the profits in the short-run spot market. Think of generator 1, the less costly one, for the case depicted in Graph 3 above.

In the non-peak period, it would get $c_6 - c_1$. In the peak period, it would get $c_4^p - c_1$. In the long run reserve market, it would get $\Pi_1^{re} = \sum_{j=1}^{M} p_j c_j^r - c_1$. Given that $c_6 < c_4^p$, it prefers the peak period than the non-peak period. However, if

[8] We should say at this point that we are assuming that all plants are risk neutral

$\sum_{j-1}^{M} p_j c_j^r > c_4^p$, this generator will prefer to supply capacity for the long-run reserve market. That is, if the expected cost of all plants in the long run reserve market is bigger than the price bid of the last dispatched generator in the peak period, then generator 1 would get higher profits in the long-run reserve market.

Finally, based on these profits, we see that there are incentives for building more capacity for two reasons. First, the new potential generators would use better technologies, which imply lower costs and higher expected profits for them. Second, given that demand is growing over time, the more costly plants will be likely to keep being dispatched even though more capacity is installed. The only case when these more costly plants are displaced form the market is when the growth rate of demand is lower than the growth rate of new capacity. In this case, there would be gains in consumer surplus, since the new generation is entering at lower cost and, therefore there would be lower generation prices.

Moreover, this new capacity would enter the non-peak period, the peak and the long run reserve market depending on the configuration of plants that are generating electricity at that moment in time. These new plants will get producer surplus that is strictly positive. It would be a matter of choice whether they enter the non-peak or the peak or the long run reserve. This decision would depend on the market prices that are expected to prevail in each period. However, it is important to note that generation prices could not decrease over time if the expansion in capacity grows at the same or lower rate than demand.

III. Structure of Incentives for Generation in the Spot Market

The 1999 proposal to restructure the Mexican electricity sector presents a pricing mechanism that artificially increases the price of electricity during periods of high demand. This policy is similar to policies implemented in other restructured electricity industries as in the UK. Although, this measure might generate investment incentives, it also promotes collusion in the generation market as can be empirically and theoretically shown.[9] The main reason is that the artificial increase of price ends up creating monopolistic rents that motivates the existence of a few number of generating plants.

We next formally see that other kinds of policies for generation enhancement can result in better outcomes. For example, in the Australian electricity market the use of a pool together with a "bypass" market to meet generation shortages has provided satisfactory results. The bypass market would normally consist of plants not normally dispatched in the pool, and those capable to supply both at non-peak and peak periods. We will show under what conditions this mechanism provides better social results than a policy of arbitrary manipulation of prices.

[9] The existence of a duopoly in the UK electricity market is a well-known market failure

In order to analyze this problem we assume that $N = 2$. We also allow these two firms to play a game where they can make use of their market power. That is, they can charge a price higher that marginal cost. This is a different set up from the one used in the above Section. However, it is simpler to analyze this problem and has the advantage that any gain in this context would be a lower bound in the context of the last Section because of there are more competition in that model. We model two mechanisms to cop with the peak in demand. The fist one that asks for an artificial increase in price is named the "British Model". The second one that deals with this situation by using a "bypass" market is named the "Australian" model.

The "British" Model

Let us first study a simple stylized version of the "British" model for enhancement of generation capacity. Assume that the inverse demand function at a peak period has the form:

$$P(Q) + \Delta P(Q) = a(1+k) - bQ(1+k) \tag{1}$$

where $P(Q)$ is the inverse demand function, Q is the amount of electricity generated, $a > 0$ and $b > 0$ are positive constants, and $k > 0$ is a factor added to the price of electricity during peak periods.[10] Since there are only two firms, firm 1 and firm 2, we have that $Q = q_1 + q_2$ (where q_1 and q_2 are the amounts of electricity generated by firm 1 and firm 2, respectively)

The cost functions are

$$c_i(q_i) = c_i q_i \qquad \text{for } i = 1,2 \tag{2}$$

where c_i is the marginal cost of power generation for firm $i = 1,2$. Suppose that $c_1 < c_2$. The profit maximization problem for firm $i = 1,2$ is then

$$\max_{q_i}\{\Pi_i\} = \max_{q_i}\{[a(1+k) - b(1+k)(q_i + q_j)]q_i - c_i q_i\} \tag{3}$$

The optimal quantities of a Cournot duopoly and the market price that solve problem (3) are

[10] k would therefore contain terms such as "*cfalla*" and "*k factor*".

$$q_i^* = \frac{a(1+k)+c_j-2c_i}{3b(1+k)} \qquad \text{for } i=1,2 \tag{4}$$

$$P^*(Q)+\Delta P^*(Q) = \frac{a(1+k)+(c_1+c_2)}{3} \tag{5}$$

Given these optimal values, profits for firm $i=1,2$ are

$$\Pi_i = \frac{[a(1+k)+c_j-2c_i]^2}{9b(1+k)} \tag{6}$$

Therefore, the net social benefit, equal to the sum of total profits plus total consumer surplus is

$$NSB = \Pi_1 + \Pi_2 + EC$$
$$= \frac{\{8a^2(1+k)^2-(c_1+c_2)[8a(1+k)+(c_1+c_2)]-36c_1c_2\}}{18b(1+k)} \tag{7}$$

Note that that this expression is mainly determined by the value of k (the term that artificially increases the price of electricity) and the marginal costs of each firm.

The "Australian" Model

Let us now formally analyze the "Australian" model in which excess demand is satisfied in a reserve or standby market. Now, firm 1 is a monopoly in the pool market, while firm 2 is also a monopoly operating in the reserve market. Firm 2 only takes care of excess demand.

Firm 1's inverse demand function is given by

$$\hat{p}(\hat{q}_1) = \hat{a} - \hat{b}\hat{q}_1 \tag{8}$$

and its cost function is

$$c(\hat{q}_1) = \hat{c}_1\hat{q}_1 \tag{9}$$

The profit maximization problem of firm 1 is then:

$$\max_{q_1} \{\hat{\Pi}_1\} = \max_{q_1}\{(\hat{a}-\hat{b}\hat{q}_1)\hat{q}_1 - \hat{c}_1\hat{q}_1\} \tag{10}$$

In this case, the equilibrium quantity and price are

$$\hat{q}_1 = \frac{\hat{a} - \hat{c}_1}{2\hat{b}} \tag{11}$$

$$\hat{p}^*(\hat{q}_1) = \frac{\hat{a} + \hat{c}_1}{2} \tag{12}$$

Then, profits are

$$\Pi_1 = \frac{(a - c_1)^2}{4b} \tag{13}$$

Firm 2 only operates to satisfy excess demand at peak periods. This firm faces an inverse demand function of the form:

$$\hat{p}(\hat{q}_2) + \Delta\hat{p}(\hat{q}_2) = \hat{a}(1+\hat{k}) - \hat{b}\hat{q}(1+k) \tag{14}$$

and its cost function is

$$\hat{c}(\hat{q}_2) = \hat{c}_2\hat{q}_2 \tag{15}$$

Firm 2's profit maximization problem is

$$\max_{q_2}\{\hat{\Pi}_2\} = \max_{q_2}\{[\hat{p}(\hat{q}_2) + \Delta\hat{p}(\hat{q}_2)]\hat{q}_2 - \hat{c}_2\hat{q}_2\} \tag{16}$$

In this case, the equilibrium quantity and price are

$$\hat{q}_2^* = \frac{\hat{a}(1+\hat{k}) - \hat{c}_2}{2\hat{b}(1+\hat{k})} \tag{17}$$

$$\hat{p}^*(\hat{q}_2) + \Delta\hat{p}^*(\hat{q}_2) = \frac{\hat{a}(1+\hat{k}) + \hat{c}_2}{2} \tag{18}$$

Then, profits are

$$\Pi_2 = \frac{[a(1+k) - c_2]^2}{4b(1+k)} \tag{19}$$

Hence, net social benefit in the "Australian" model is

$$NSB = \frac{3(1+k)(a-c_1)^2 + 3[a(1+k) - c_2]^2}{8b(1+k)} \tag{20}$$

Now, given that $c_1 \langle c_2$ (since the firms that operate in the pool are typically more efficient than the firms that operate in the reserve market), we get

$$\hat{q}_1^* = \frac{\hat{a} - \hat{c}_1}{2\hat{b}} \;\rangle\; \hat{q}_2^* = \frac{\hat{a}(1+\hat{k}) - \hat{c}_2}{2\hat{b}(1+\hat{k})} \tag{21}$$

and

$$\hat{p}^*(\hat{q}_1) = \frac{\hat{a} - \hat{c}_1}{2} \;\langle\; \hat{p}^*(\hat{q}_2) + \Delta\hat{p}^*(\hat{q}_2) = \frac{1}{2}\hat{a}(1+\hat{k}) + \frac{\hat{c}_2}{2} \tag{22}$$

Comparison of the "Australian" and "British" Models

Once we have obtained the equilibrium values for quantities, prices, profits, consumer surplus and net social benefits in both models, it is possible to compare under what conditions one policy is superior to the other. For this purpose we will assume that generators in Australia and the UK face the same cost and demand functions, that is

$\hat{a} = a$

$\hat{b} = b$

$\hat{q}_i = q_i, i = 1,2$

$\hat{c}_i = ci, i = 1,2$

We carry out the comparison both at the firm level and at the social level. Total profits under the "Australian" model are greater than total profits under the "British" model if

$$\frac{5}{18}c_1\left(\frac{a}{b}\right) - \frac{5}{18}c_2\left(\frac{a}{b}\right) + \frac{5}{9}\frac{c_1^2}{b(1+k)} - \frac{8}{9}\frac{c_1c_2}{b(1+k)} - \frac{11}{36}\frac{c_2^2}{b(1+k)} \;\rangle\; \frac{1}{4}\frac{a^2}{b} - \frac{5}{18}\frac{a^2(1+k)}{b} \tag{23}$$

while consumer surplus in the "Australian" model is greater than consumer surplus under the "British" model if

$$\frac{5}{18}\left(\frac{a}{b}\right)c_1 - \frac{5}{18}\frac{c_2}{(1+k)} + \frac{1}{(1+k)}\left[\frac{5}{9}c_1^2 - \frac{11}{36}c_2^2 + \frac{c_1}{4} - \frac{8}{9}c_2\right] \;\rangle\; \frac{1}{36}\frac{a^2(1+k)}{b} + \frac{a^2}{b} \tag{24}$$

Given that $c_1 \langle c_2$, it is evident from these equations that profits, consumer surplus and net social benefits are greater under the "Australian" model than under the English model the greater is the value of $(c_2 - c_1)$. That is, the "Australian" model provides better social and private outcomes for economies where the marginal cost difference between modern and old plants is large enough.

Moreover, both models can also be compared in terms of implied electricity prices. According to equation (22), the equilibrium reserve-market price in the

"Australian" model is greater than the corresponding spot price. However, what is the relation between the former price and the equilibrium price of the "British" model? It can be shown that

$$p^*(q_1+q_2)+\Delta p^*(q_1+q_2) > \hat{p}^*(\hat{q}_2)+\Delta\hat{p}^*(\hat{q}_2)$$

whenever the difference (c_2-c_1) is sufficiently large. That is, implementation of a bypass reserve market makes social sense in terms of prices only if there is a large efficiency gap between old and new generation plants. In such a case, the implementation of the "British" solution would only create an artificially high rent that could provide incentives for a development of oligopoly generation markets.

IV. Generation Plants in the Mexican Electricity Industry

The above results imply that the use of the "Australian" model in the Mexican electricity sector would make sense only if it can be technically proved that the cost difference between old hydroelectric plants and new thermoelectric plants is such that inequalities (23) and (24) are met. Tables 1 and 2 show the costs of production and the investment costs for different technologies for generation of electricity.

Table 1. Production costs for different generation plants

Type	*Production cost per MWh (dollars)*
Conventional thermoelectric	42.68
Combined cycle	26.54
Hydrocarbon	32.03
Hydroelectric	19.20

Table 2. Investment costs for different generation plants

Type	*Investment cost per MWh (millions of USD)*
Nucleoelectric	1,700
Hydroelectric	1,000
Combined Cycle	500-600
Turboelectric	637-6652

It can be observed that there exist significant differences between hydro generation plants and hydrocarbon generation plants in terms of investment and cost of production.

In Graph 5, we have information above the age of plants that are generating electricity in Mexico. We can see that there are some plants that have more than 100 years in operation. From this we can say that the costs for generation from these pants could be higher than the generation cost for more recent plants. Moreover, the new plants that would enter the market would have lower cost that these incumbent plants.

Graph 5. Age of Mexican Plants

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Therefore, given the information in Tables 1 and 2 and Graph 5, we conclude the following. First, there would be plans willing to enter the spot ant the long runs reserve markets, because they would get expected profits that are strictly positive. Second, the "Australian" model would produce better results for the Mexican Electricity Sector given these differences in technologies.

V. Conclusions

We have constructed a model to analyze the incentives for expansion of capacity in the spot market and in the long run reserve market. With this model we also analyze the incentives for collusion in the spot market in order to get higher profits. We find that for the Mexican Electricity Sector, where it is likely to have big differences among plants in terms of technologies and costs, the best mechanism is to use the reserve market to cop with peaks in demand. On the other hand, the mechanism of merit order dispatch gives incentives to expand de capacity in the spot market and in the long run reserve market.

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