On the Efficiency of the Argentinean Electricity Wholesale Market

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May 30, 2002

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[1] University of Chicago, Department of Economics. 1126 E.59th St., Chicago, IL 60637. E-mail: p-ferreira@uchicago.edu. Preliminary version. I thank several individuals who were of immense help in the data gathering process: Iván and Pablo Werning, Laura Giumelli, Ernesto Badaraco, José María Liberti, Tomás Serebrisky and especially Claudio Calvagna and Sabino Mastrangelo, from Cammesa. I also thank Rigoberto Arabeña, Carlos Romero, and again Ernesto Badaraco, Laura Giumelli and Sabino Mastrangelo for helpful discussions and explanations on the functioning of the Argentinean Electricity Market. Finally, I thank Professor Lester Telser's attention and guidance throughout the meetings of the Applied Price Theory Workshop at the University of Chicago, and Juan Santaló, Luis Henrique Braido, Ali Hortacsu, Wouter Dessein and Kevin Tsui for helpful discussions. Financial support from CNPq, Brazil, is gratefully acknowledged. All remaining errors are my own.

Abstract

This paper discusses two key aspects regarding the efficiency of the Argentinean Electricity Market. Using hourly data on prices, marginal costs, and operational status of generators, it will be argued that, unlike the former British and Californian electricity spot markets, this market is not subject to the conventional forms of exercise of market power by generators. We then use Chao's (1983) model of optimal configuation of electricity supply to evaluate the social desirability of the change in the supply pattern of the Argentinean electricity industry, which took place throughout the last ten years.

1 Introduction

During the last decade several countries undertook serious efforts in order to restructure their electricity markets. Governments recognized that their vertically integrated power companies - frequently responsible for generation, transmission and distribution of electricity - lacked the correct economic incentives in order to generate electricity on an efficient basis. With the divestiture and/or privatization of the utilities, the focus of the restructuring efforts turned to the establishment of competitive environments for the operation of electricity generators.

Argentina was one of the first countries to conduct a major restructuring of its electricity sector. Most of the state-owned generation, transmission and distribution assets were privatized between March, 1992 and June, 1994. In addition, a cost-based price determination system for the market was set up at that time. Thermal generators would submit, every six months, bids for the price at which they are willing to supply electricity. A central dispatcher would then order the generators with respect to their bids, lowest to highest, and determine, at each hour, the spot price of the system, roughly equal to the bid of the marginal plant - the last one to be dispatched to satisfy demand. The bids cannot exceed 115% of the actual fuel costs incurred by the generators in their fuel purchases, and can be adjusted within the 6-month period in which they are valid only when fuel prices fluctuate more than a certain amount. The price determination mechanism of the Argentinean Electricity Market is the major aspect in which the system differs from those implemented elsewhere, notably in Britain and in California, where prices were determined by free supply price and quantity bids submitted, everyday, by generators, for every half hourly (Britain) or hourly (California) period of the next day[1].

The experiences of Britain and California with electricity spot markets have failed, for various and distinct reasons. The British Electricity Pool operated between April, 1990, and March, 2001. Shutdown

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[1] Other still operational electricity competitive market places exist in Scandinavia, New Zealand, and Victoria, Australia. In all these markets the price determination mechanism is based on bids not necessarily tied to generation costs, therefore resembling the British model in opposition to the Argentinean.

of the pool was a consequence of two major forces - the influence of the coal industry lobby and exercise of market power by the major generators. Utilization of coal for electricity generation purposes in England decreased 50% between 1990 and 1999 due to increasing reliance of generators on natural -gas fired plants. In its justification for redesigning the system, in 1997[2], the British Government argued that the pool had been discriminating against British coal as a fuel. The other major cause of the shutdown of the pool was the failure of the regulators in mitigating the various forms of exercise of market power by the two largest generation companies, *PowerGen* and *National Power*, which led to observance of consistently high pool prices. The market power issues in the British Pool were addressed, among others, by Wolfram (1999), who reported pool price to marginal cost gaps to be inconsistent with competition, and by Wolak and Patrick (2001), who provided evidence on the capacity withdrawal scheme used by the two largest generators, which involved the withdrawal of more efficient units at peak times, in order to shift industry supply to the left and ensure a higher clearance price for the market.

The Californian Market operated during a much shorter period of time, between April 1998 and the Spring of 2001, time at which the system collapsed, after declaration of bankruptcy of the state's largest utility, Pacific Gas & Electric, and the state government decided to take over electricity purchases, paying prices ten times as high as they had been one year before. Soaring natural gas prices, excessive requirements for entry in the generation business, absence of a contract market, and, to a smaller extent, market power issues similar to those observed in Britain, were the major causes of the California disaster, which has been analyzed in a number of papers: Borenstein, Bushnell and Wolak (2002), Puller (2001), Joskow and Kahn (2001), Borenstein (2002), Joskow (2001).

Contrary to the cases of Britain and California, the Argentinean experience in competitive electricity marketplaces has not failed. Wholesale prices decreased by 50% between 1992 and 2001, and total installed generation capacity increased by almost 70% in the same period - most of the entry was of large, efficient combined cycle thermal generators. Large private investments were undertaken also in distribution and

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[2] See for example Green (1998).

transmission, and the country's developed electricity generation system represented an important alternative source of power for Argentina's neighbor, Brazil, during its electricity crisis in 2001[3].

This paper will make two claims regarding the efficiency of the Argentinean Electricity System:

a) market power is not observed, even though the market is relatively concentrated;

b) market rules induced entry in such a way that the heterogeneity pattern of generation units with regard to thermal efficiency is now close to the one predicted by a standard planner problem. This means that the price signals being sent by the market are producing an optimal configuration of supply.

To demonstrate the absence of market power, we will analyze the only period in the short history of the Argentinean Electricity Market in which one could suspect of occurrence of such a practice - in the last months of year 2000, level and volatility of market prices raised above historical levels. In principle, one could think that high prices could be the result, for example, of capacity withdrawal by generators, just as Wolak and Patrick argued in the case of Britain. Using hourly data on the operational status of generators, we will show that this is not the case in this episode in Argentina.

To evaluate the efficiency of the supply configuration, we will use Chao's (1983) model. A central planner decides the optimal amount of each generation technology to be constructed, given the probability that demand will reach a certain level. Technologies differ in two dimensions: variable (fuel) costs, and fixed, capital costs. Base load generators have lower variable (fuel) costs (they are thermodynamically more efficient), but are capital intensive, and therefore should be constructed only when its expected dispatch rate is large enough. Peak load generators have higher fuel costs (are thermodynamically less efficient), but are also cheaper to build, and therefore need a smaller dispatch rate to justify their installation. Optimal proportion between the two technologies occur when expected savings on fuel equal extra capital expenditures. We will show that the present configuration of the Argentinean electricity supply approaches the one predicted by such social optimal condition.

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[3] During the second half of 2001, Brazil faced a severe electricity supply shortage due to extremely low rainfall. About 95% of electricity produced in Brazil comes from hydro-powered generators. Power imports from Argentina helped alleviate the effects of the shortage.

The remain of the paper is organized in four sections. Section 2 describes the Argentinean Electricity Market and discusses its structure, as background for section 3, which analyzes the market power issues. Section 4 analyzes the optimal technology configuration issue, and section 5 concludes.

2 The Argentinean Electricity Market

Argentina, like most countries in South America, has undergone substantial changes in its economy in the past ten years. In the macroeconomic arena, the convertibility plan, launched in 1991, brought monetary stability: by 1994, inflation and interest rates had dropped to industrial country levels. The country has enjoyed an average growth of GDP of 4,8% between 1991 and 1999. The improvement in the macroeconomic performance becomes more clear when the recent figures are contrasted with the economic indicators of the late 80's, a period in which Argentina suffered reductions on its GDP for three consecutive years and experienced the chaos brought by hyperinflation[4].

At the micro level, the infrastructure of the country suffered a major transformation. The Law of State Reform (Law 23.696), published on August 1989, set the basis of the privatization program to be conducted by the government during the upcoming years. This law specified which state-owned companies would be subject to privatization, and determined the rules and restrictions which applied to foreign capital participation in the process.

Law 24.065, published in 1991, set the basis for the reform of the electricity sector and introduced dramatic changes in industry structure. The vertically integrated, state-owned utilities were divested into three main businesses: generation, transportation and distribution. According to the law, generation was considered to

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[4] During the last months of 2001, the macroeconomic performance of the country deteriorated significantly. Strong fiscal indiscipline of central and provincial governments during the whole convertibility period (1990-2001) ultimately led to the collapse of the exchange rate rate regime in the first days of 2002, soon after the resignation of President Fernando de la Rúa, in December, 2001. The country subsequently defaulted on its debt, submerged in a deep financial system crisis and is now facing an extremely severe recession. The market developments that we describe are, however, unnafected by the recent deterioration of the macroeconomic scene, since the period which we analyze precedes such facts.

be a competitive activity, and therefore the state would impose virtually no regulation (neither price, nor entry-related) in this business (apart from an authorization for exploration of natural resources, in the case of hydro generators). Transportation and distribution, on the other hand, were considered activities of "public interest". Tariffs in these two sectors would be regulated by the state, and the distribution companies would have the responsibility of meeting total demand in their operating areas, and would be subject to penalties in case of failure. Entry in these businesses would also be severely regulated. The regulatory role in the distribution and transportation businesses was assigned by law to ENRE - *Ente Nacional Regulador de la Electricidad*, who would approve the tariffs, grant concessions, and establish penalties.

The establishment of *Mercado Eléctrico Mayorista* (MEM), a marketplace for wholesale electricity transactions, in august 1992, changed the whole nature of competition in the generation business. Generators, distributors and large consumers - but not transmission firms - are allowed to negotiate electricity in the MEM. They are the so-called MEM agents. Despite the lack of agent status, transmission companies are very important in ensuring competition in generation - they must allow generators to hook up their electricity on a non-discriminatory basis. ENRE is entitled to enforce this practice.

The design of the system represents an attempt to satisfy the demand, at each moment, using the most efficient combination of generators. The optimal dispatch of the plants is under responsibility of Cammesa, an organization in which all classes of MEM agents have equal stakes at (the government holds a 20% share of it). The competition induced by MEM and the relatively few regulations to which electricity generation was submitted determined a substantial increase in generation capacity: according to Cammesa, total nominal installed capacity of the system added up to 13,260 MW in 1992. By the end of 2001, it had reached 22,300 MW, that is, a capacity increase of over 68% in a period of nine years - an average growth of 6% per year. According to FIEL (1999), an Argentinean think tank, total investment in the electricity sector in the period 1992-97 amounted to US$ 6,4 billion, of which US$ 1,4 billion represented investment in new thermal capacity, US$ 2,2 billion in new hydro capacity, US$ 0,5 billion in transmission, and US$ 2,3 billion stand for investments in distribution. Approximately 93% of the electricity produced in Argentina is negotiated in MEM, being the rest negotiated at the Patagonian system (MEM-SP - 6%) and at other small isolated systems (remaining 1%).

Table 1 details the evolution of total installed generation capacity in the Argentinean Electrical Sector (MEM only) since its reform, in 1992. Note that thermal generators are divided in three categories: TV (*turbovapor*, or steam turbine), TG (*turbogas*, or gas turbine) and CC (combined cycle). These three types of generators differ significantly in the way they produce electricity. Steam turbine generators have a boiler where heat from fuel combustion boils water to produce steam, used to rotate the turbine which powers the generator. Gas turbine generators work under the same principle of aircraft jet engines - a mixture of compressed air and fuel is ignited, and the resulting combustion gas rotates the turbine. Combined cycle generators use the exhaustion emissions of gas turbines to boil water and rotate an additional steam turbine, yielding substantial fuel savings in comparison to the two previous, "open-cycle" processes. On the other hand, combined-cycle plants have higher installation costs.

As mentioned in the introduction, in contrast with most other regions which established competitive marketplaces for electricity, Argentina has opted for a system based on cost declaration rather than on price bidding. Every six months (in July and December), the thermal and nuclear generators submit their variable costs of operation valid for the upcoming season - the July declaration is valid for the summer season, which lasts from November to April, and the December declaration is valid for the winter season, which lasts from May to October. To avoid excessive distortions, the generators are allowed, up to an extent, to adjust their cost declarations monthly to account for variations on fuel prices . All generators, including the hydro plants, also declare their total power capacity available for delivery. Hydro generators also declare the value of water stored on their reservoirs.

Cammesa - the dispatcher, based on its demand forecast models, determines the marginal plant for each hour of operation, everyday. The marginal plant cost declaration then determines the hourly energy price. The minimization of total cost of meeting the demand is subject to the restrictions on transmission capacity, also taking into account the transmission losses between the source and destination of the energy. When the transmission restrictions are binding, local prices on the system - disconnected from the Buenos Aires price - may develop. Start-up costs of generators and several other technical characteristics of the plants are also reported to Cammesa and are considered in the optimal dispatch process.

There are two basic forms of negotiation of electricity in MEM - the spot market and the contract market. Generators can sign contracts with distributors or large customers, in which schedules of delivery, power levels and prices may be freely negotiated between the parts. The amount of electricity negotiated under contracts has grown since the establishment of MEM: in 1992, it represented only 20% of the total amount. By 1995 it had reached 50%. In 2000 the total amount of electricity negotiated under contracts started to decrease again, due to the fact that some large contracts which dated back to the privatization days, included by the government in the privatization package in order to turn key generator assets into more attractive investment opportunities, began to expire, and were not renewed. In that year, electricity negotiated under contracts reached 45% of the total, and in 2001 it dropped to 38%.

Electricity not negotiated under contracts is commercialized in the spot market - that is, at the price determined by the marginal firm of the system at each hour of operation - the system marginal price. On valley hours and weekends, this price - adjusted by the proper generator nodal factors[5] - represents the bulk of the compensation to the generators negotiating their power in the spot market. The actual price received by the generators for their service during business days, in non-valley hours (from 6 a.m. to 11 p.m.) is actually larger due to the so–called capacity charge - a US$ 10 / MWh fee which is added to the cost of the marginal turbine, designed to help generators cover fixed costs. Generators are also paid for provision of ancillary services to the system[6], and there's an additional capacity charge to thermal generators which is based on the difference between total dispatch of the generator on the given year and the simulated dispatch

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[5] Nodal factors arise because of transmission restrictions. In case of congestion, generators located on the "exporter" branch of the network actually "see" a lower price than that of the market - they have smaller than one nodal factors. Inversely, generators located on the "import" branch of the network have their price adjusted by a higher than one nodal factor.

[6] For example, some generators are responsible for provision and maintenance of the frequency of the system in their areas of operation.

that would occur on an extra dry year. Peak load generators are rarely dispatched on wet years, but may be required to produce more power in case of low rainfall conditions. The amount of the charge is again of US$ 10 / MWh , and these payments are netted out of the regular capacity charges to which the generator is entitled.

Table 2 details the evolution of the mean prices in these two markets. Note that, on average, electricity is traded at a significantly higher price at the contract market than at the spot market[7].

It is important to note that even though the electricity itself may be negotiated at either the spot price or at some contract price, all the dispatch occurs on a least-cost declaration basis. That is, the dispatcher activates the most efficient generators that will be capable of meeting the demand at each hour, regardless of the existence of contracts. Therefore, if a generator that has, by contract, an obligation of delivering electricity to a customer is not dispatched at a certain hour, it must then use the spot market to buy electricity in order to fulfill its obligation.

Fuel cost declarations are subject to verification and cannot exceed 115% of a "reference" price established by Cammesa - generators must submit to the dispatcher, on a regular basis, their actual contracts of fuel purchasing. For plants which operate with natural gas, the reference prices are local, that is, they depend on where the plant is located. Cammesa uses as reference prices the ones established by ENARGÁS, the natural gas industry regulatory body, on a quarterly basis. For plants which operate with fuel oil or gas oil, the reference price is based on monthly quotes of these commodities in the New York market. The reference price for mineral coal is the observed in San Nicolas, the location of the single plant which operates with this fuel. The great majority of the thermal generated electricity comes from combustion of natural gas (during the winter, some plants switch to utilization of heavier fuels, because residential consumers have priority on natural gas using for heating purposes). In 2001, 93% of total thermal electricity was generated by combustion of natural gas (92% in 2000, 88% in 1999 and 86% in 1998).

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[7] Again this is a consequence of the contracts established at privatizations times, which were designed to be attractive to generators.

2.1 Market Structure

Despite the facts that both the number of generator business units and total installed capacity have increased substantially since privatization and deregulation, in 1992, (see table 1 and graph 1) it cannot be said, looking only at standard horizontal concentration measures, that the structure of the Argentinean Market resulted competitive. Three major energy business groups entered the Argentinean market at the time of the privatization. These groups were *Endesa*, a Spanish group with heavy presence in the European power markets; *AES*, a major American electricity operator; and *Gener*, one of the most important Chilean economic groups. These groups have taken over, respectively, *Central Costanera*, *Central San Nicolás* and *Central Puerto*, the largest business units in which *SEGBA* (*Servicios Electricos del Gran Buenos Aires*, the former integrated utility which was responsible for electricity supply of the Buenos Aires area) was divested. A total of 19 generation business units were privatized between 1992 and 1994. *Endesa*, *Gener* and *AES* also acquired the control of some of these other business units, and other important business groups have acquired smaller generators. The state retained the two nuclear units of Atucha and Embalse, and three large hydroelectric plants - two of them are Binational ventures, *Yacireta* with Paraguay and *Salto Grande* with Uruguay.

Table 3[8] depicts the structure of the market in the end of year 2000. The share of the four and two largest groups (excluding the government), considering total supply, respectively of 49% and 36%, shows that this market could be considered moderately concentrated in the end of 2000. Concentration increased dramatically in the very last days of 2000[9], when *AES* Corporation acquired the assets of *Gener*. *AES Gener* became the most important private business group in the Argentinean market. After this merger and the conclusion of the new plants *AES Parana* and *Dock Sud*, the market share of the two largest groups evolved to 49%, and of the four largest groups, to 58% (see table 4). This structure is quite comparable,

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[8] Between parenthesis, in the group column, the original nationality of the controlling group is indicated. In the business unit column, the parenthesis refers to the region of the country where plant is located, as follows: GBA - Gran Buenos Aires, BAS - Provincia de Buenos Aires, NOA - Northwest, NEA - Northeast, COM - Comahue (Southwest), CUYO (West).

[9] The merger was announced on Dec 28th, 2000.

to, say, the Californian electricity industry structure in 1999, when Pacific Gas & Electric and Southern California Edison together had a 43% share of installed capacity[10] (C4 was 63%). It remains, however, distant from the British duopoly benchmark - PowerGen and National Power had, together, 85% of total installed capacity of the British market at the time of deregulation, in 1990.

It should be said that several of the business units listed on tables 3 and 4 have multiple shareholders. Also, some of the controlling business groups also hold stakes at business units controlled by other groups. Besides, business units enjoy considerable management independence. It was not until 2000 that *Endesa*, for instance, decided to centralize some management activities of the several units it controls in *Central Costanera*. Therefore the concentration indexes are only indicative of the actual concentration the market is subject to.

3 Market Power Issues in the Argentinean Electricity Generation Industry

The simple fact that the price determination mechanism in the Argentinean electricity system is cost-based, rather than free-bid based, by itself prevents, to a large extent, the occurrence of generator market power in its most natural form, that is, coordination among generators leading to bid prices - and consequently system prices - substantially above variable costs of production. This is one of the problems which caused, for example, the shutdown of the British Electricity Pool. As already pointed out, in the Argentinean system, generators are not free to choose their bids - they cannot exceed 115% of their actual fuel costs, which are to be reported Cammesa. Bids are valid for six months and cannot be changed unless unexpected fluctuations on fuel prices occur, in what case Cammesa may agree on generators changing their bids.

It turns out that bids are, on average, substantially lower than reference prices of natural gas - See table[11]

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[10] See Borenstein et alli (2002).

[11] I focus on natural gas bids since this fuel has been responsible for more than 90% of thermal electricity generation in recent years.

6. That is, generators seem to not take advantage even of the 15% margin they are permitted above fuel costs. There are at least four reasons why this phenomenon occurs: First, bids stay active for a long period. This severely mitigates chances of success of any potential agreement generators may reach on boosting up bid prices together, for the incentive to break the agreement is greatly increased - being a sole high bidder might mean displacement of dispatch for six months, too long a time to be affordable for any player in this business. Second, actual natural gas transaction prices between generators and gas distribution utilities are not necessarily conducted at reference prices disclosed by ENARGAS. The reference prices are maximum prices to be followed on these transactions - therefore it may be the case that generators bid lower than reference prices because they may actually have reached better terms with the utilities[12]. A third reason why bids are smaller than reference prices is related to the nature of gas supply contracts: as pointed out by NERA (1998), they are usually take-or-pay contracts. In such contracts, generators pay for a certain fixed supply of natural gas, and they are charged for this amount whether they use it to produce electricity or not. This means that, once the contract is into play, generators' opportunity cost becomes the cost of disposing out of the unused gas - and not the price of the gas itself - because unused gas cannot be stored in reasonable quantities.

The last reason why bids tend to be smaller than gas prices is due to the structure of generator compensation. The capacity charge of US$ 10 / MWh is added to the price determined by the marginal turbine in a total of 85 non valley hourly periods during the week. That is, during 50% of the time (a week has 168 hours) generators have an extra incentive to be dispatched. Therefore they are willing to partially sacrifice their bids, as the capacity charge may more than compensate it. Between 1996 and 2000 difference between bids and reference prices has diminished, perhaps suggesting that one or more of these effects is becoming weaker.

Spot prices in any given hour are then to be picked among the span of (already depressed by the afore-

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[12] It is unfortunate that I did not have access to natural gas transaction prices between generators and gas utilities in order to further investigate this possibility.

mentioned affects) bids submitted by the generators every six months. Therefore we should in principle expect to see zero price to marginal cost differences in this market basically all the time. But this happens to be untrue. We have obtained hourly information on prices and on the identity of the marginal generators from Cammesa. Graph 2 (figures on table 5) plots the monthly average values of price to marginal cost gaps in percentage terms - (P-MC)/P - between January 1996 and October 2000. The graph also plots the proportion of periods in the month in which price is actually equal to marginal cost. It is very clear, as expected, that these series are negatively correlated.

So why is it the case that price is not equal to marginal cost in this market in all periods, and not only on the proportion indicated on graph 2? The basic reason for appearance of positive - and negative - differences between prices and marginal costs is because there are special circumstances under which price becomes disconnected to the variable costs of the marginal turbine. There are basically three different situations in which this disconnection takes place. The first circumstance arises in the event of approach of a considerable probability of system failure, due to large scale failures in the transmission grid, sudden loss of system load, or short circuits in important parts of the network. Sometimes these events are associated with adverse atmospheric conditions (tornados) or criminal (terrorist) actions. In this case, price is automatically raised to one of four fixed values, depending on the (increasing) likelihood of a failure: US$ 120, US$, 170, US$ 240, or US$ 1500 / MWh. Between 1996 and 2000, 98 such periods were observed (among 8760 * 5 = 43,800 possible - a proportion of 0,2 % only).

The second circumstance arises much more frequently than the first, and is responsible for the bulk of the proportion of the periods in which price differed from marginal cost, reported in graph 2. The fact is that, during peak hours, there is a price floor. This price floor is represented by the minimum variable costs of all steam turbine generators which were included, in peak hours, in the weekly pre-dispatch - a weekly program of the actual upcoming dispatch of the following week. Steam turbines can't be started quickly, and need a long waiting time - 12 hours on average - between shut-off and a new start. As more combined cycles became available in the market, steam turbines have been displaced to peak only utilization. Due to long start-up times they require, in case they are actually needed in the peak hour dispatch, they must be already spinning - even though they may stay disconnected of the system. And therefore system price should reflect this.

Finally, there were months in which average price to marginal cost difference was negative - December 1999, for instance. This is due to another "distortion" of the system, the so-called $forced\ generation$. This represents the third circumstance under which the spot price may depart from marginal cost. Sometimes the presence of a generator in the system is demanded by a specific consumer, or by technical reasons (maintenance of frequency, for example). In this cases the dispatcher commands their permanence on the system, but they are not entitled to market price compensation - they get their own variable costs instead. In case actual market price is lower than their variable costs, the difference can become negative. This distortion is relatively infrequent, but has been growing the past years.

On average, it can be said that the magnitude of these three effects is relatively low - average price to marginal cost gap in the 58-month period of graph 2 is only 4,5%. This is a fairly small figure when compared to the two–digit figures reported by Wolfram (1999) - 25% - and by Borenstein et alii (2002) - 35% - in their analysis of the British and Californian markets, respectively. It is true that when the regular capacity charge is accounted for, average mark-up in the period rises to 18% - but still - contrary to the aforementioned markets - the reasons why positive price to marginal cost differences arise are totally disconnected with occurrence of market power. Indeed one could hardly worry about market power issues given the sole piece of evidence of price to marginal cost differences.

During the year of 2000, however, market price volatility increased significantly. Market price annual standard deviation in 2000 was 3 to 4 four times larger than in all previous years (see table 7(a)). In table 7(b) it is possible to see that volatility increase was concentrated in the second half of the year, especially in October. Graph 3(a) plots average prices across the 24 hours of the day, for years 1998-2000. It is possible to see from this graph that volatility increase in 2000 was concentrated in peak hours - 7 p.m. to 11 p.m. More specifically, graphs 3(b) to 3(d) show us that the critical period was the final third of the year.

Complementing the information of table 7(b), graph 3(e) shows that October was the month in which prices reached the highest average levels on peak hours.

As argued previously, market rules in Argentina prevent, to a great extent, generators from bidding too much in excess of actual fuel costs, what eliminates one of firms' traditional weapons for the exercise of market power. Rules do not, however, explicitly prevent generators from using an alternative weapon - capacity withdrawal of more efficient units in order to shift industry supply to the left and induce a higher equilibrium price for supply and demand. Wolak and Patrick (2001), for instance, argue that this was generators's preferred weapon in their efforts to achieve higher profitability.

Therefore, in principle, a possible explanation for the events of the second half of 2000 would be withdrawal of capacity by generators. We will show that this was not the case. We will first dismiss this possibility, and then alternative explanations for the events will be discussed.

3.1 Why the Events of Late 2000 Were Not a Result of Capacity Withdrawal

Profitability of the withdrawal strategy requires that generators attempting it have two basic characteristics: first, generators must be large, in order to induce a large displacement of the supply curve to the left and raise the price significantly. Second, in order to maximize effectiveness of the withdrawal strategy, generators must have two different technologies at their disposal. Withdrawal of the most efficient generator, at the same time that the less efficient generator delivers power at maximum capacity increases the likelihood that the next machine to be called upon by the dispatcher has a larger variable cost declaration, inducing a higher clearance price for the market than the alternative strategy (withdrawal of the less efficient machines conjugated with more efficient machine at full delivery). That is, we should observe a reversed pattern in the utilization of the machines - heavier utilization of less efficient machines - if withdrawal of capacity is the reason for the price hikes in late 2000.

In Argentina, at the time of the events, in late 2000, there were only two generators which fulfilled these two requirements. They are *Central Costanera* and *Central Puerto*. Each of these two companies held slightly less than 2000 MW of installed capacity (*Costanera* had 851 MW in combined cycle capacity, and 1130 MW in steam turbine capacity; *Puerto* had 789 MW in combined cycle capacity and 980 MW in steam turbine capacity, including the *Nuevo Puerto* site), and represented together about 19% of the market installed capacity. They are both located in the *Buenos Aires* area, therefore are subject to relatively few transmission restrictions.

There is one further reason that turns *Puerto* and *Costanera* into agents specially tempted to take advantage of their size in order to increase profitability. Their old contracts with major Buenos Aires area electricity retailers *Edenor* and *Edesur* (priced at US$ 38 / MWh), which had been effective since privatization times, expired on May, 2000 (*Puerto*) and March, 2000 (*Costanera*). Without the hedge provided by these contracts, dependence of profitability on spot prices increased significantly.

Table 8(a) summarizes the operational status of *Puerto* and *Costanera's* turbines[13] in the critical peak hours on the months of October, November and December 2000, for the periods in which each of the machines' nodal prices reached at least US$ 25 / MWh - far above their variable costs, which were on the vicinity of US$ 21 / MWh for the steam turbines and US$ 16 /MWh for the combined cycles. These were, therefore, periods in which all these units should have been delivering power.

The combined cycle (CC) of *Central Costanera*, for example, was delivering power in 76% of the 50 hourly critical periods it saw prices higher than US$ 25 / MWh. In all the other periods it was under programmed unavailability, that is, it was unavailable due to pre-scheduled maintenance reasons. Costanera's steam turbines, on the other hand, were producing (either at market prices, variable costs-forced generation, or in the process of starting up) during a proportion of periods which varies between 44 and 74%. During the majority of the other periods they were either with status of *forced unavailability* or *available*, but not producing. Forced unavailability means that the unit is unavailable for reasons other than programmed maintenance. Thermal turbines are subject to unexpected failed starts, and require maintenance sessions which are not always predictable. Therefore a status of forced unavailability does not necessarily mean

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[13] This information is provided by each generator to Cammesa, from whom we obtained this data.

that the unit is being deliberately withdrawn by the operator as an attempt to force prices up. A status of availability without production when prices are superior to US$ 25 would seem strange - as we said these prices are superior to their variable costs and therefore, if they were not unavailable for maintenance, they should have been in principle producing power. Cammesa is not a generator-only club (all classes of MEM agents have equal stakes at it), and therefore it is would be difficult to conceive that Cammesa were deliberately not calling units upon dispatch according to the least cost rule, in order, for instance, to benefit certain generators by forcing prices up. We then opt to consider that generator dispatch at periods under this status was, for a restriction of some reason, considered uneconomical.

For *Central Puerto′s* combined cycle the rate of production added to programmed unavailability is 77% during the 127 periods in which the unit 'saw' prices higher than US$ 25. It is true that some of Puerto's less efficient units delivered more power than the combined cycle. But the combined cycle was in a period of programmed maintenance, as can bee seen from the high proportion of scheduled maintenance periods in the corresponding column. This means that some of the forced unavailability periods might have been periods of extended maintenance, not scheduled ex-ante but which turned out necessary - this combined cycle unit had been in commercial operation for less than six months at that time. Moreover, some of the less efficient units had a higher forced unavailability rate than the combined cycle (TV #1 and Nuevo Puerto TV #1), which is inconsistent with the withdrawal scheme.

Table 8(b) is exactly equal to Table 8(a), but it reports periods in which nodal prices higher than US$ 50 / MWh were observed - if the firms are using withdrawal strategies, it must be the case that they show up in these very high priced periods. As can be seen from the table there were roughly 20-25 periods in which prices reached these levels, what represents about 1% of the time within the 3-month target. Proportion of programmed maintenance periods for both Puerto and Costanera combined cycles increases significantly when compared to the ones reported in the previous table, showing that in the most critical periods (the ones in which prices hiked to US$ 50 / MWh levels) these units were in programmed maintenance - they were not deliberately taken away from service. For capacity withdrawal to be responsible to those high prices we would need a disproportional amount of forced unavailability of these two combined cycles to have taken place - instead, regular maintenance stops seem to have contributed to the problem. Moreover, the less efficient units of the two generators have a significant amount of their power delivered, in those periods, under forced generation! This means they are NOT taking advantage of the high market prices during a significant part of the time they were observed.

Thus,we feel relatively comfortable to dismiss market power as a possible source of the high prices observed in the last months of 2000. We now discuss some other pieces of evidence which help explain the price hikes of late 2000.

We mentioned that, between January 1996 and December, 2000, 98 periods in which prices reflected high probabilities of system collapse were recorded. In October, 2000 - the month in which price to marginal cost gaps reached 30%, and average price levels reached US$ 80 / MWh in peak hours, 25 such periods (more than 25% of the total) were registered. Moreover, the single couple of periods in MEM's history in which price reached US$ 1500 / MWh - the level associated with the highest programmed probability range of failure - were registered in October. In December, 2000, 14 periods of high failure probability occurred. Both these months had a higher number of such periods than any of the years 1996 to 1999. As mentioned, these events are associated with sudden failures of generators, transformer stations or appearance of heavy transmission restrictions. Some atypical operation conditions can help explain why the occurrence of such stressful periods increased so much in these months.

First, in 2000, exports, mainly directed to Brazil and Uruguay, were at least 6 times as high as in previous years (see table 9), reaching 6% of total electricity production - in previous years they never exceeded 1%. They were concentrated in the last months of the year, in particular in August and December. Exports tend to increase price levels, because part of the supply becomes unavailable to the domestic market.

Second, throughout all the year of 2000, and, most importantly, in the last third of the year, the nuclear, $all-time\ base\ load$ plants of *Atucha* and *Embalse* delivered power at reduced times due to general maintenance requirements. Total utilization of the plants in 2000 was 65% only (it's usually in the 75-85% range).

Between September and December the utilization of the plants were, respectively, 46%, 34%, 58% and 19%. These units have total installed capacity of 1005 MW (about 5% of system capacity in 2000), and, as they are supposed to operate most of the time, their absence requires the dispatch of other units as base load, and of older, less efficient and less reliable units as peak machines. Both *Cammesa* and *Central Costanera* recognize, in their 2000 annual reports, that this was one of the reasons which most contributed to the price hikes of late 2000.

Third, the occurrence of several periods of disconnection between price and marginal cost due to high likelihood of system failure in 2000 was reflected in the severity index of the system in 2000. This index is the ratio between non-supplied electricity and total annual demand. In 2000 this index reached a record of $22{,}66*10^{-5}$. In previous years the index had been $13{,}38*10^{-5}$ (1997), $3{,}17*10^{-5}$ (1998), and $10{,}85*10^{-5}$ (1999).

We do not intend to offer a complete explanation of why price standard deviation increased so much in the second half of 2000. It seems that operational problems, unavailability of base load generators, and increase of exports all had contributed to it. Our basic objective was to dismiss market power as one of possible explanations for the late 2000 events.

4 The Optimal Pattern of Electricity Supply

We reported substantial entry in the Argentinean electricity market during the years which followed deregulation. If entry occurred, it is likely that it seemed profitable for potential entrants. An important empirical question lies in the evaluation of the desirability of the entry that occurred, from the social point of view.

From the overall efficiency viewpoint, a generator should be built if expected benefits derived from its utilization at least equal its total costs. Production of thermal electricity demands two major inputs: capital and fuel. If a certain thermal electricity production technology is superior to all others both from the fixed and variable cost point of view, then there is no trade-off for an hypothetical central planner when deciding the optimal capacities of each technology to be installed. However, electricity production technologies do exhibit variation in these two dimensions. Hydroelectric power technology, for instance, is extremely capital intensive, but its variable costs of operation are basically restricted to maintenance costs, since it uses no fuel. Nuclear power plants are also very capital intensive, and have relatively low fuel costs. On conventional thermal generation, as already mentioned, gas turbine technology is less capital intensive but also requires more fuel to generate the same amount of electricity than a combined cycle plant of the same size.

Chao (1983) develops a simple, static model which formalizes this intuitive trade-off faced by a central planner of the electricity sector. We will reproduce his derivation and discuss the optimality condition which determines the optimal proportion of technologies to be installed. We will then use this condition and several pieces of data to evaluate the efficiency of the Argentinean Electricity Market with respect to its supply structure.

4.1 Chao's Model

Chao considers a single pricing period of length θ. Power demand in this period, D, is assumed to be a continuous function of price, P, time, t, and a measurable function of the outcome of a random event, $\xi \in \Omega$ (the sample set). This stochastic demand is represented by $\tilde{D}(P)$. Expected energy demand is then $\tilde{D}_e(P)$ $= \theta E\{\tilde{D}(P)|\xi\}$, where $E\{\}$ is the expectancy operator.

Gross benefit of electricity consumption is denoted by $U(q,\xi)$, or simply $U(q)$, where q stands for electricity demand. This represents the total consumer surplus plus electricity bills, for the residential sector, or gross output, for the industrial sector.

Production costs - Chao assumes that there are n technologies with capacity cost k_i and operating cost c_i, for $i = 1, ..., n$, respectively. Technologies are ranked in ascending order by operating cost. If Y_i is the installed capacity of technology i, then the total capacity cost is $\sum_{i=1}^{n} k_i Y_i$.

Supposing that individual generating units are subject to random failures, then available capacity would be a random variable, to be denoted by $\tilde{Y}_i$.Relationship between installed capacity Y_i and available capacity

$\tilde{Y}_i$ can be written as

$$\tilde{Y}_i(Y_i) = \int_0^{Y_i} \tilde{y}_i(z) dz_i. \tag{1}$$

where$\tilde{y}_i(z)$ is a random variable distributed between 0 and 1 with mean a_i. That is, capacity of technology i consists of a continuum of generating units, each of them with the same availability factor a_i.

System operation is based on pre specified dispatch order of technologies from 1 to n. This is actually the basic method through which Cammesa, for instance, determines the dispatch order of thermal turbines in the Argentinean Electricity System. Capacity configuration $Z_i \in \Re^n$ is defined in this order, as follows:

$$Z_i = (Y_1, ..., Y_i, 0, ...0) \text{ for } i = 1, ..., n \text{ and } Z_0 = (0, ..., 0). \tag{2}$$

Correspondingly, total available capacity of technologies $1, ..., i$ is denoted by

$$\tilde{Z}_i = \sum_{j=1}^{i} \tilde{Y}_j. \tag{3}$$

Power supply cannot exceed total capacity. Therefore power actually supplied by technologies $1, ..., i$ is given by

$$\tilde{Q}(P, Z_i) = \min\{\tilde{D}(P), \tilde{Z}_i\} \text{ for } i = 1, ..., n. \tag{4}$$

Therefore the expected amount of energy supplied by technology i is given by

$$\theta E\{\tilde{Q}(P, Z_i) - \tilde{Q}(P, Z_{i-1})\}. \tag{5}$$

Then total expected operating cost can be written

$$\sum_{i=1}^{n} \theta C_i E\{\tilde{Q}(P, Z_i) - \tilde{Q}(P, Z_{i-1})\}. \tag{6}$$

Outage Costs - Since generating units may be unavailable, and demand is random, it is possible, for some realizations of the shock ξ, that demand cannot be met. Actual magnitude of the outage costs depends on the specific rationing scheme used during the shortage period. Chao uses a constant marginal outage cost specification, the simplest and most convenient functional form:

$$\tilde{S}(x, y) = b(x - y) \text{ for } x \leq y. \tag{7}$$

where x is supply , y is energy demand and b is a constant. Outage cost is very important to determination of the optimal capacity level, as it will become clear.

The objective of the central planner is to maximize expected social welfare W, by choosing electricity price P and capacity levels $Y_1, ..., Y_n$:

Maximize W = gross benefit - capacity cost - operating cost - outage cost

$$= E\{\tilde{U}((\tilde{D}_e(P))\} - \sum_{i=1}^{n} k_i Y_i - \sum_{i=1}^{n} \theta C_i E\{\tilde{Q}(P, Z_i) - \tilde{Q}(P, Z_{i-1})\} - \theta b E\{\tilde{D}(P) - \tilde{Q}(P, Z_n)\} \tag{8}$$

4.1.1 Optimal Capacities

Optimal capacities can be determined by differentiating[14] social welfare with respect to the capacities $Y_1, ..., Y_n$.To differentiate W in (11) is necessary to find the derivatives of $E\{\tilde{Q}(P, Z_i)\}$.By differentiating (4) it turns out that

$$\frac{\partial \tilde{Q}(P, Z_i)}{\partial Y_j} = \begin{cases} \tilde{y}_j \text{ if } \tilde{D}(P) > \tilde{Z}_i \text{ and } j \leq i; \\ 0 \text{ if } \tilde{D}(P) < \tilde{Z}_i \text{ or } \quad j > i. \end{cases} \tag{9}$$

Assuming the random variables $\tilde{y}_i$, for $i = 1, ..., n$ to be bounded integrable, the order of differentiation and expectation can be interchanged to obtain

$$\frac{\partial E\{\tilde{Q}(P, Z_i)\}}{\partial Y_j} = \begin{cases} E\{\tilde{y}_i | \tilde{D}(P) > \tilde{Z}_i\} \Pr\{\tilde{D}(P) > \tilde{Z}_i\} & \text{if } j \leq i \\ 0 & \text{if } j > i. \end{cases} \tag{10}$$

Since $\tilde{y}_i$ is independent of $\tilde{D}(P)$ and $\tilde{Z}_i$, the above conditional expectation can be written as unconditional:

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[14] This procedure assumes capacity levels for all technologies to be positive. Refer to Chao's paper for a justification of this assumption.

$$\frac{\partial E\{\tilde{Q}(P,Z_i)\}}{\partial Y_j} = \begin{cases} a_j \Pr\{\tilde{D}(P) > \tilde{Z}_i\} \text{ if } j \leq i \\ 0 \qquad\qquad\qquad\quad \text{if } j > i. \end{cases} \tag{11}$$

Using (11) it is possible to find the optimality conditions equalling the derivatives of W with respect to $Y_1, ..., Y_n$ to zero:

$$\frac{\partial W}{\partial Y_i} = 0 = -k_i + a_i \sum_{j=i}^{n-1} \theta(C_{j+1} - C_j) \Pr\{\tilde{D}(P) > \tilde{Z}_j\} + a_i \theta(b - C_n) \Pr\{\tilde{D}(P) > \tilde{Z}_n\} \text{ for } i = 1, ..., n. \tag{12}$$

Rewriting (12) for $i = n$,

$$\Pr\{\tilde{D}(P) > \tilde{Z}_n\} = \frac{k_n/a_n}{\theta(b - C_n)}. \tag{13}$$

Substituting (13) into (12) and repeating this backward substitution operation, we obtain

$$\Pr\{\tilde{D}(P) > \tilde{Z}_i\} = \frac{(k_i/a_i) - (k_{i+1}/a_{i+1})}{\theta(C_{i+1} - C_i)} \text{ for } i = 1..., n-1. \tag{14}$$

This is the marginal condition that yields the optimal proportion between technologies i and $i+1$, for $i = 1, ..., n-1$. Imagine that an $effective$ unit of technology $i+1$ (that is, a unit controlled for technology availability) is substituted by one of technology i. Multiplying both sides of equation (14) by $\theta(C_{i+1} - C_i)$, we get

$$\theta(C_{i+1} - C_i) \Pr\{\tilde{D}(P) > \tilde{Z}_i\} = k_i/a_i - k_{i+1}/a_{i+1} \tag{15}$$

The left hand side are the expected savings on operating costs resulting from such substitution, and the right hand side represent the extra capital costs incurred. Optimal mix between two given technologies will occur when expected fuel savings coming from substitution of one effective unit of technology $i+1$ by one of technology i exactly equal the extra capital costs involved.

4.2 Evaluating the Optimality of the Argentinean Electricity Supply

Chao's model gives us a simple, but effective, theoretical framework to evaluate one important aspect of market efficiency - structure of supply. The convenience of the above first order condition is that it enables one to draw conclusions regarding the adequacy of the price scheme in providing firms the correct incentives to invest, without having to discuss and evaluate the details of the price mechanism by itself - as discussed before, the structure of compensation to generators is not simple, it includes two capacity charges and other fees apart from the basic energy cost.

It is important at this moment to look back at table 1 and graph 1 to examine the supply profile of the Argentinean electricity industry. There has been some entry of hydro generators. Most of the difference between the hydro capacity in 1992 and 2001 refers to the progressive entry into operation of the various generating units of *Yacireta* and *Piedra del Aguila* hydro plants. *Yacireta* was a joint entrepreneurship effort of the Argentinean and Paraguayan governments. Its first units were delivered in 1994, and the last groups began operation in 1998. With final installed capacity of 1700 MW, it is the largest generator of the Argentinean system. The first units of *Piedra del Aguila* hydro plant were delivered in May 1993, some months before the plant was privatized. Final capacity amounts to 1400 MW. In nuclear power capacity no change was observed, and some exit of older, steam turbines took place.

The biggest action has obviously been on gas turbine and combined cycle generators. At first glance it looks like entry of gas turbines in 1992-97 was followed by scrapping of the same kind of technology during 1998-2001. This is misleading. The apparent exit of gas turbine units can be explained by the way combined cycle plants are constructed. For technical reasons, the most common configuration for combined cycle plants involve two gas and one steam turbines. The gas turbines are usually installed before, enabling the generator to operate in open cycle while the additional steam turbine is being constructed. Most of the gas turbine "exit" during 1998-2001, therefore, actually refers to completion of combined cycles. Sometimes the steam turbine addition takes several years, sometimes it never takes place. For example, one of the first combined cycles of the system, *Capex′s* plant *Agua del Cajón*, began open cycle operation in 1993, and only in 1999 was completed. Also *Gener* planned *Loma de Lata* plant, built in 1993-94, to ultimately operate as a combined cycle, but it was never completed and today the plant still operates as an open, gas turbine cycle.

Table 10 details major combined cycle additions to the market since deregulation (some information is missing, in particular regarding beginning of construction). It is apparent that construction of the first combined cycles began right after deregulation took place (MEM was established in August 1992, but privatizations were held between 1992 and 1994, as mentioned). Some of the plants operated during little or no time as an open cycle, like *Puerto*, *Dock Sud* and *AES Parana*. In others, however, the last units were completed years after the first ones - see the cases of *Genelba*, *Buenos Aires*, *Tucumán* and the already mentioned *Agua del Cajón*. Summing total additions of combined cycles in the period 1992-2001 with the final capacities of the two large hydro plants mentioned, we arrive at 8800 MW (5700+1700+1400), which is roughly equal to the 9000 MW total capacity addition in the same period (from table 1). That is, apart from completion of two governmental projects, entry in the period consisted basically of combined cycles.

Nuclear and hydro plants are usually the first to be dispatched. Hydro plants have very low, almost zero variable costs, and nuclear plants, have relatively low fuel costs. Therefore, in almost any electricity system in which they are present - Argentina is no exception here - nuclear and hydro plants represent the bulk of base load generation. In the cost-based Argentinean market, the thermal plants are then progressively called upon dispatch based on their relative efficiency. The incumbent steam and gas turbines which were active on the Argentinean market in 1992 had thermal efficiencies in the 2900 - 4500 Kcal/MWh range. Modern combined cycles which began to be constructed right after deregulation are much more efficient, working on the 1400-1600 Kcal/MWh range. A 1500 kcal/MWh combined cycle requires roughly half the fuel a 3000 Kcal/MWh generator needs to deliver the same amount of power. Therefore, upon their completion, combined cycle generators were incorporated into the base load group generators, displacing older steam and gas turbines to the peak load group and leading to scrapping of the oldest ones.

According to equation (15), social desirability of the displacement which took place would depend on fuel prices, variability of demand, availability of plants, and capital costs.

Our strategy to evaluate equation (15) will be the following: We will adjust each type of installed base load generation - nuclear, hydro and combined cycle - to its availability, therefore evaluating an effective baseload capacity availability. This will be the $\tilde{Z}_1$ for each year. That is, technology 1 will add hydro, nuclear and combined cycle effective capacities. I have hourly data on system load for the years 1997-2000 - therefore we can estimate the term $\Pr\{\tilde{D}(P) > \tilde{Z}_i\}$ using the number of periods (hours) in which load exceeded effective baseload capacity. That is,

$$\Pr\{\tilde{D}(P) > \tilde{Z}_i\} = \frac{\text{Number of hours in which load} > \text{Effective Baseload Capacity}}{8760}$$

Technology 2, $\tilde{Z}_2$,will be represented by modern gas turbines, which are the state of the art, peak load, alternative to combined cycle. As the exercise will be conducted for every year, parameter θ is equal to the number of hours in a year, 8760.

Availabilities - Hydro electricity production in Argentina is usually far below the nominal capacity of hydro plants. Between 1997 and 2000 total hydro production fluctuated around 35-40% of maximum which could be generated with total installed capacity (table 11), except for years 1996 and 1999 which were extra dry years[15]. Nuclear plant utilization is much higher, but recently dropped from the 80-85% range due to increased maintenance periods, especially in 2000. For these two types of plants we will use Table 6 availabilities for purposes of calculating effective baseload capacity. Combined cycles are designed to operate almost on a permanent basis. Their availability rates vary in the 85-95% range. The exercise will be in principle conducted with a 85% assumption for availability of combined cycles.

Savings on fuel costs - We are evaluating the social desirability of the massive combined cycle entry which took place in Argentina following deregulation. That is, we want to check whether, given the pattern of demand variability, fuel and capital costs, and effective baseload capacity, if the amount of entry as combined cycle was efficient. We will take hydro entry as given, and compare the two sides of the equation for combined and open cycle technology. We will use natural gas reference prices of ENARGAS in the Buenos Aires area as fuel prices. To estimate the difference on variable costs, we will suppose a 1500 Kcal/MWh combined cycle against a 2200 Kcal/MWh gas turbine - this is the average efficiency of the modern open cycle turbines which constituted the first units of the today completed combined cycles. As the results on table 8 show,

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[15] Hydro utilization is base on end of year installed capacity. Therefore it represents a lower bound on the actual utilization rate, because some units were actually incorporated throughout the year.

these hypotheses yield savings around US$ 7 per MWh generated.

Physical Capital Costs - Combined cycle construction costs depend substantially on whether the plant was built on a new, empty site or took advantage of refurbished, previously installed older equipment. Table 13 summarizes the available information on combined cycles constructed in Argentina in the analyzed period. *Buenos Aires*, *Puerto and Costanera* combined cycles all were erected on or near sites where the companies held older generation facilities. For instance, one of the turbines of *Central Buenos Aires* is a refurbished generator of SEGBA, part of the assets purchased by *Endesa* at the time of privatization. On the other hand, *AES Parana* and *Termoandes*[16] were completely new plants, and made little or no use of refurbished equipment. It shows up on their costs per installed MW, on the US$ 500-800 range, far higher than the US$ 300 range of the other generators. Therefore we will use US$ 600 / MW as the basic price for new combined cycles. As we will analyze the 1997-2001 period, and since the construction of these last two, new plants were initiated at that time, this will be our capital cost benchmark for the period[17]. Note that capital costs are plugged into equation (15) in annualized form.

For the capital costs of open cycles we will use the benchmark value reported by General Electric (2001) for state of the art GE gas turbines in the period 1998-99, which is around US$ 330 / MW . This value is reasonably consistent with the most recent open cycle additions on the Argentinean market, also reported on table 8. Thermal availability of gas turbines will be considered slightly lower than that of combined cycles (75% instead of 85%), because gas turbines, which operate on a intermittent basis, are usually required to be started a higher number of times per year than combined cycles, what demands more periods of maintenance.

Interest Rates – Cost of Capital- We were able to obtain cost of capital information for two of the combined cycle projects, those of Puerto and Costanera, projects which had their implementation started

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[16] Geographically located in the Argentinean province of Salta, but disconnected from the Argentinean electricity network, Termoandes' production is directed exclusively to the Chilean market. It was included in the table as a benchmark comparison for capital costs.

[17] Conversations with industry experts confirmed that US$ 600 / MW is still (2002) a good estimate of capacity costs for new combined cycle generators. Barreiro and Cortiñas (2000) use the value US$ 580 / MW in a combined cycle project evaluation for Brazil.

in 1996. The loans were taken from various international financial institutions, at costs in the range 7.0-7.5 per year, as shown in table 7. The right hand side of equation (15) is obviously very sensitive to the interest rate used - therefore we present results using interest rates of 7, 10 and 15% per year.

4.3 Results

Table 12(a) shows our basic results for evaluation of equation (15). Note that for 2000 we used 0,75 for nuclear availability instead of the actual 0,65 in the year, as this is more compatible with regular maintenance hours for the two nuclear plants. As we do not have the hourly load data for 2001, we used the 2000 load distribution shifted by the (small) change in overall production between the two years - in 2000 total electricity production amounted to 79,960 GWh, and in 2001, to 81,300 GWh.

It is clear that with the initial configuration of the demand and the inefficiency of the incumbent steam and gas turbines there was a large space to be preempted by new, efficient combined cycles. Demand pattern of 1997 was such that baseload generators could not be solely responsible for demand satisfaction even at valley hours - minimum load registered was 4661 MW, and effective baseload capacity amounted to 4508 MW. That is, the social benefits of addition of an extra unit of baseload / combined cycle capacity would be immense, because on average that extra unit would be required to operate all 8760 hours of the year. Actually, expected savings on fuel when upgrading a modern 2200 KCal / MWh gas turbine unit to a 1500 KCal / MWh combined cycle , given 1997 natural gas prices, would amount to almost US$ 66,000 / MW / year[18]. This value is larger than the extra costs of capital a combined cycle represents when compared to a simple gas turbine - as can be seen at the bottom of table 12(a), this extra cost is in the range of US$ 17,000 to 29,000 per MW per year, depending on the discount rate chosen (capacity life was fixed at 30 years, a standard procedure for this type of equipment). That is, in 1997 the "signal" sent by equation (15) is clearly one for heavy entry of new combined cycles.

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[18] Note that actual fuel savings would be more than the double of this value if comparison is made to the incumbent, old steam and gas turbines, wtih, say, efficiency of 3000 KCal / MWh. We are establishing modern gas turbines as the basic alternative, though.

The machines were on their way. In 1998 and 1999 as we know more combined cycles started commercial operation, and baseload capacity surpassed minimum demand by a small amount. The equation was still heavily unbalanced, though, suggesting the combined cycles which were being constructed would be more than welcome from the overall efficiency point of view. In 2000 probability that hourly demand exceeds effective baseload capacity reaches 0,75, and in 2001, it dramatically drops to 0,315. In 2001 we can see that the two sides of the equation are of equal magnitude, suggesting that the correct amount of combined cycle generation had been built already. Of course the comparison is very sensible to the discount rate used, but it is clear that expected savings on fuel would at best surpass extra capital costs by a small amount from 2002 on.

An important qualification should be made, though. The model is static, and the calculations reveal the ex-post probability of usage of one additional combined cycle unit on a give year. Investments in generation should obviously take into account future demand growth - if it is expected, for instance, that demand growth will increase in the near future, it would be optimal to have extra baseload capacity, which at present demand levels would be considered idle.

Also, it is interesting to point that some of the plants which were constructed barely faced the trade off between fixed and variable costs discussed - taking advantage of parts of incumbent installations and making usage of refurbished equipment, several combined cycle plants had installation costs below those of new gas turbines (table 7).

On table 12(b) we evaluate a slightly different version of equation (15). Instead of performing an yearly evaluation of both capital and fuel costs, we compare the full (not annualized) difference in capital costs with the discounted sum of yearly proceedings from fuel savings. That is, we evaluate

$$\sum_{t=0}^{29}(\frac{1}{1+d})^t\theta(C_{i+1,t}-C_{i,t})\Pr\{\tilde{D}(P)>\tilde{Z}_{i,t}\}=K_i/a_i-K_{i+1}/a_{i+1} \tag{16}$$

where $C_{i,t}$ is the variable cost of technology i at each time period t, $Z_{i,t}$ is the effective capacity in time period t, and K_i represent unit capital costs (not annualized), and d is the discount rate. We use different hypotheses with regard to the discount rate (the top half of Table 12(b) refers to simulations using a 10% discount rate, the bottom half, to a use of 15% rate), natural gas prices, and dispatch rates. For gas prices we suppose three scenarios, all beginning with US$ 90/dam^3 in 1997: prices decreasing 5% per year, constant prices, and prices increasing 5% per year. For the dispatch rates we also consider three possibilities: always 75%, always 50%, and 100% for three years, 75% for one year, and 50% from then on. This pattern is similar to the actual path followed by combined cycle estimated dispatch rate between 1997 and 2001.

At 10% discount rate, only at the most adverse scenario (decreasing gas prices and 50% dispatch) fuel savings proceedings from combined cycle installation are smaller than the extra capital costs they imply. Of course at 15% the benefits are considerably smaller and equation becomes more balanced. But we believe 10% is a closer approximation of the opportunity cost of capital for Argentinean corporations at that time than 15% - see the 7-7,5% p.y. loans they were able to contract.

There is one more calculation we should perform in order to show that entry of combined cycles was actually the most efficient solution. We must compare these units' costs with the old, steam turbine incumbents avoidable costs. We adopt a very conservative approach, assuming these much older machines have the same availability rate of the new combined cycles (0,85). We assume a difference on thermal efficiency of 1000 KCal / MWh between steam turbines and combined cycles (Cammesa reports suggest that 2500 KCal / MWh was the average heat conversion rate of thermal units in 1992, and combined cycles, as already mentioned, have efficiencies around 1500 KCal / MWh). The first two parts of Table 12(c) show this comparison (evaluation of equation (16) with K_{i+1} set to zero, since these units were incumbents) for 10% and 15% discount rates, assuming incumbents have also the same 30-year life as the entrants. The same sets of hypotheses of the previous exercise regarding gas prices and dispatch rates are used. Last part of Table 12(c) show results when the much more realistic hypothesis of a shorter (15 years) life for the incumbents is assumed (10% discount rate only). This last set of hypotheses represent what we believe to be the most realistic assumptions. At average dispatch rates (0,75) and constant gas prices the new investment is clearly justified.

Overall, our results show that the private, decentralized entry of combined cycles which was observed in the Argentinean electricity market between 1997 and 2001 was very consistent with the investment decisions which would be taken by a central planner responsible for choosing the supply pattern, if we assume, for instance, that the hydroelectricity potential of the country is exhausted, or it that remaining hydro generator possible additions would be unfeasible due to excessive capital or electricity transportation costs.

5 Conclusion

We have analyzed two essential aspects regarding the efficiency of the Argentinean Electricity Market. We have seen that it is relatively insulated from market power, even though its concentration measures are comparable to markets where market power has proven to be a problem - Britain and California, for instance. We have also shown that price signals sent to the generators induced entry of efficient, modern combined cycle technology, and as a result the pattern of electricity supply approaches the one predicted by a standard, central planner problem, in which the planner is faced with a trade off between variable and fixed costs.

The natural question which arises from such conclusions is very clear: what are the design and theoretical features of the Argentinean System that drives its superior performance in comparison with other markets? It seems obvious that the freeze-on-bids system coupled with fixed capacity charge plays a prominent role in such result. A proper address of this issue should receive high priority in the electricity markets research agenda.

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Table 1 - Installed Capacity by Type of Generation (MW)

Year	cc	tv	tg	Nuclear	Hydro	Total	Number of Generators
1992	144	4777	1620	1005	5721	13267	13
1993	144	4777	1680	1005	6384	13990	22
1994	144	4777	2211	1005	7309	15446	27
1995	144	4777	2777	1005	7629	16332	33
1996	144	4777	3033	1005	8230	17189	38
1997	402	4777	3272	1005	8748	18204	40
1998	1514	4777	3208	1005	8670	19174	40
1999	2365	4515	2698	1005	8926	19509	40
2000	4229	4515	2032	1005	8926	20707	39
2001	5856	4515	2039	1005	8926	22341	40

Source: Cammesa

Note: Between 1992 and 1997 the proportion CC / TV / TG is estimated

Table 2 – Evolution of Annual Prices on MEM

Year	Monomic Price	Contracts Price*
1992	48,8	N/A
1993	35,7	38,7
1994	31,8	37,9
1995	29,7	35,9
1996	28,6	35
1997	25,3	33
1998	24,4	31,5
1999	26,1	31,4
2000	27,6	
2001	23,2	

Source: Cammesa

* mean of representative months during the year

Table 3 - Structure of the Argentinean Electricity Supply Market in Dec 2000

Group	Business Unit	Installed Capacity in Dec 2000				
		tg/tv	cc	hyd	nuc	total
Rep. Argentina	E.B. Yacireta (NEA)			1710		**4410**
	Salto Grande			945		
	Nucleoelectrica Arg.			750	1005	
Endesa (Spain)	CT Costanera (GBA)	1131	851			**3696**
	CT Buenos Aires (GBA)		322			
	El Chocon (COM)			1320		
	CT Dock Sud (GBA)	72				
Gener (Chile)	CT Puerto (GBA)	589	789			**3543**
	CT Nuevo Puerto (GBA)	390				
	CT Loma de la Lata (COM)	375				
	CH P. del Aguila (COM)			*1400*		
AES Corp. (US)	CT San Nicolas (BAS)	650				**1888**
	CT Dique (GBA)	55				
	H.T. San Juan (CUYO)	30		42		
	H.R. Juramento (NOA)			111		
	H. Alicura (COM)			1000		
CMS / Duke (US)	C. Mendoza	134	374			**1054**
	HC Colorados			450		
	Alto Valle (COM)	16	80			
Pecom (Arg.)	Genelba (GBA)		674			**929**
	Pichi Picun Leufu (COM)			255		
PlusPetrol (Arg.)	Tucuman(NOA)		447			**600**
	S.M. de Tucuman (NOA)(2)	113				
	Ave Fenix (NOA)	40				
Capex (US/Arg)	Agua del Cajon (COM)		628			**628**
IPC (UK) / Camuzzi (ITA)	CT Piedrabuena (3) (BAS)	620				**620**
EdF (France)	Hidisa (CUYO)			388		**605**
	Hinisa (CUYO)			217		
FATLyF / IATE (Arg.)	CT NOA	184				**465**
	CT NEA	148				
	CT LITORAL	70				
	CT Filo Morado	63				
APUAYE/ NECON / CHEDIAK (Arg.)	H. Tucuman (NOA)			52		**69**
	H. Rio Hondo (NOA)			17		
Other						
CT Guemes (NOA)		261				**261**
CT Sorrento (LIT)		212				**212**
ARCOR (centro)			64			**64**
CT Gen Roca (COM)		124				**124**
Local (Provincial) Gov.						
ESEBA (BAS)		413				**413**
Casa de Piedra (COM)				60		**60**
GECOR (Centro)		289				**289**
EPEC (Centro)		235		164		**399**
Total		**6214**	**4229**	**8881**		**20329**
Total Private						**14758**
C4	over total private supply	**69%**		over total supply		**49%**
C2		**49%**				**36%**

Table 4 - Structure of the Argentinean Electricity Supply Market in Dec 2001

Group	Business Unit	Installed Capacity in Dec 2001				
		tg/tv	**cc**	**hyd**	**nuc**	**total**
Rep. Argentina	E.B. Yacireta (NEA)			1710		**4410**
	Salto Grande			945		
	Nucleoelectrica Arg.			750	1005	
AES Gener (US)	CT Puerto (GBA)	589	789			**6276**
	CT Nuevo Puerto (GBA)	390				
	CT Loma de la Lata (COM)	375				
	CH P. del Aguila (COM)			*1400*		
	CT San Nicolas (BAS)	650				
	CT Dique (GBA)	55				
	H.T. San Juan (CUYO)	30		42		
	H.R. Juramento (NOA)			111		
	H. Alicura (COM)			1000		
	AES Parana (GBA)		845			
Endesa (Spain)	CT Costanera (GBA)	1131	851			**4469**
	CT Buenos Aires (GBA)		322			
	El Chocon (COM)			1320		
	CT Dock Sud (GBA)	72	773			
CMS / Duke (US)	C. Mendoza	134	374			**1054**
	HC Colorados			450		
	Alto Valle (COM)	16	80			
Pecom (Arg.)	Genelba (GBA)		674			**929**
	Pichi Picun Leufu (COM)			255		
PlusPetrol (Arg.)	Tucuman(NOA)		447			**600**
	S.M. de Tucuman (NOA)(2)	113				
	Ave Fenix (NOA)	40				
Capex (US/Arg)	Agua del Cajon (COM)		628			**628**
IPC (UK) / Camuzzi (ITA)	CT Piedrabuena (3) (BAS)	620				**620**
EdF (France)	Hidisa (CUYO)			388		**605**
	Hinisa (CUYO)			217		
FATLyF / IATE	CT NOA	184				**465**
(Arg.)	CT NEA	148				
	CT LITORAL	70				
	CT Filo Morado	63				
APUAYE/ NECON /	H. Tucuman (NOA)			52		**69**
CHEDIAK (Arg.)	H. Rio Hondo (NOA)			17		
Other						
CT Guemes (NOA)		261				**261**
CT Sorrento (LIT)		212				**212**
ARCOR (centro)			64			**64**
CT Gen Roca (COM)		124				**124**
Local (Provincial) Gov.						
ESEBA (BAS)		413				**413**
Casa de Piedra (COM)				60		**60**
GECOR (Centro)		289				**289**
EPEC (Centro)		235		164		**399**
Total		**6214**	**5847**	**8881**		**21947**
Total Private						**16376**
C4	over total private supply	**78%**		over total supply		**58%**
C2		**66%**				**49%**

Table 5 - Monthly Price to Marginal Cost Gaps - Lerner Index

	Average	Std Dev		Average	Std Dev
Jan-96	0,0137	0,0138	Jan-98	0,0949	0,1631
Fev-96	0,0170	0,0297	Fev-98	0,0354	0,0371
Mar-96	0,0183	0,0176	Mar-98	0,0491	0,0635
Abr-96	0,0287	0,0489	Abr-98	0,0408	0,0547
Mai-96	0,0180	0,0247	Mai-98	0,0643	0,0746
Jun-96	0,0354	0,0827	Jun-98	0,0512	0,1018
Jul-96	0,0544	0,0803	Jul-98	0,0466	0,0814
Ago-96	0,0246	0,0355	Ago-98	0,0330	0,0529
Set-96	0,0121	0,0288	Set-98	0,0499	0,0824
Out-96	0,0291	0,0538	Out-98	0,0491	0,0982
Nov-96	0,0152	0,0280	Nov-98	0,0459	0,0774
Dez-96	0,0076	0,0122	Dez-98	0,0213	0,0539

	Average	Std Dev		Average	Std Dev
Jan-97	0,0193	0,0286	Jan-99	0,0783	0,0207
Fev-97	0,0105	0,0230	Fev-99	0,0337	0,0701
Mar-97	0,0064	0,0158	Mar-99	0,0152	0,0400
Abr-97	0,0161	0,0436	Abr-99	0,0339	0,0638
Mai-97	0,0221	0,0453	Mai-99	0,0196	0,0328
Jun-97	0,0203	0,0376	Jun-99	0,0390	0,0727
Jul-97	0,0529	0,0732	Jul-99	0,0267	0,0481
Ago-97	0,0425	0,0945	Ago-99	0,0203	0,0336
Set-97	0,0934	0,0155	Set-99	0,0602	0,0932
Out-97	0,0402	0,0490	Out-99	0,1052	0,1174
Nov-97	0,0829	0,0970	Nov-99	0,0970	0,1073
Dez-97	0,1650	0,1685	Dez-99	-0,0444	0,4549

	Average	Std Dev
Jan-00	-0,0846	0,5564
Fev-00	0,0246	0,0375
Mar-00	0,0197	0,0298
Abr-00	0,0184	0,0342
Mai-00	0,0579	0,1040
Jun-00	0,1014	0,1305
Jul-00	0,1267	0,1856
Ago-00	0,0879	0,0860
Set-00	0,0754	0,1208
Out-00	0,2972	0,1785

Table 6 - Bids and Reference Prices of Natural Gas (in US$ / MWh)

	Bid		Reference Price		Difference	
	Average	Std Dev	Average	Std Dev	Average	Std Dev
1996	22,34	10,02	26,45	7,80	-4,11	3,78
1997	22,42	10,72	25,93	7,97	-3,52	4,18
1998	22,46	11,94	25,44	8,06	-2,98	5,33
1999	21,30	11,25	23,97	7,73	-2,67	4,91
2000	22,22	12,09	24,50	8,15	-2,28	5,34

Note: Prices and bids transformed from US$ / dam^3 to US$ / MWh based on natural gas heat power of 8400 Kcal/dam^3 and on each unit's specific heat consumption on Kcal / MWh

Table 7(a) - Summary Statistics of Argentinean Electricity Price and Load data

year	Market Price			Total Hourly Generation		
	average (US$/MWh)	Std Dev	# obs	average (MWh)	Std Dev	# obs
1992	41.86	16.80	3672	-		
1993	32.08	10.51	8760	-		
1994	25.60	9.43	8760	-		
1995	22.04	9.09	8760	-		
1996	20.56	9.54	8784	6925	1231	8712
1997	16.57	5.99	8760	7557	1217	8760
1998	16.16	5.37	8760	7928	1302	8760
1999	18.15	8.12	8760	8354	1356	8760
2000	18.68	27.08	8784	9139	1580	8784

Table 7(b) - Market Price Throughout year 2000

Month	Average (US$/MWh)	Stdev
jan	16,81	1,83
fev	17,62	3,03
mar	15,37	2,58
abr	15,64	2,75
mai	17,39	9,10
jun	24,58	15,14
jul	25,45	24,79
ago	21,50	12,26
set	20,34	19,50
out	19,30	80,60
nov	10,82	11,17
dez	19,17	20,35

Table 8(a) - Large Generator Operational Summary - Oct-Dec 2000

(a) Central Costanera

Operational Status - Number of Periods Facing Nodal Price > US$ 25 / MWh between 7 and 11 pm

		Producing						Not Producing				Total	
Turbines	Capacity (MW)	Market Prices	Local Prices	Forced Generation	Start-up	Limited Transport.	*Subtotal*	Programmed Unavail.	Forced Unavail.	Available	*Subtotal*	%	# per.
CC	851	76%	0%	0%	0%	0%	76%	24%	0%	0%	24%	100	50
TV #1	185	27%	0%	18%	4%	0%	48%	5%	21%	25%	52%	100	56
TV #2	185	26%	0%	20%	19%	0%	65%	0%	0%	35%	35%	100	54
TV #3	185	34%	0%	20%	14%	0%	68%	0%	0%	32%	32%	100	56
TV #4	185	23%	0%	20%	20%	0%	63%	0%	2%	36%	38%	100	56
TV #5	185	40%	0%	18%	16%	0%	74%	0%	0%	26%	26%	100	50
TV #6	185	12%	0%	4%	28%	0%	44%	0%	16%	40%	56%	100	50

(b) Central Puerto

Operational Status - Number of Periods Facing Nodal Price > US$ 25 / MWh between 7 and 11 pm

		Producing						Not Producing				Total	
Turbines		Market Prices	Local Prices	Forced Generation	Start-up	Limited Transport.	*Subtotal*	Programmed Unavail.	Forced Unavail.	Available	*Subtotal*	%	# per.
CC	789	24%	40%	2%	0%	2%	68%	9%	22%	1%	32%	100%	127
TV #1	195	19%	0%	16%	4%	0%	39%	4%	53%	4%	61%	100%	128
TV #2	195	22%	3%	52%	7%	0%	84%	1%	0%	15%	16%	100%	121
TV #3	195	32%	2%	56%	3%	0%	93%	7%	0%	0%	7%	100%	123
N.Puerto TV #1	125	0%	0%	0%	2%	0%	2%	0%	30%	69%	98%	100%	127
N.Puerto TV #2	125	37%	36%	19%	5%	0%	97%	0%	1%	2%	3%	100%	127
N.Puerto TV #3	125	23%	24%	20%	2%	0%	68%	13%	11%	9%	32%	100%	127

Table 8(b) - Large Generator Operational Summary - Oct-Dec 2000

(a) Central Costanera

Operational Status - Number of Periods Facing Nodal Price > US$ 50 / MWh between 7 and 11 pm

		Producing						Not Producing				Total	
Turbines	Capacity (MW)	Market Prices	Local Prices	Forced Generation	Start-up	Limited Transport.	*Subtotal*	Programmed Unavail.	Forced Unavail.	Available	*Subtotal*	%	# per.
CC	851	57%	0%	0%	0%	0%	57%	43%	0%	0%	43%	100%	21
TV #1	185	26%	0%	32%	0%	0%	58%	0%	37%	5%	42%	100%	19
TV #2	185	32%	0%	42%	11%	0%	84%	0%	0%	16%	16%	100%	19
TV #3	185	37%	0%	37%	16%	0%	89%	0%	0%	11%	11%	100%	19
TV #4	185	15%	0%	35%	35%	0%	85%	0%	0%	15%	15%	100%	20
TV #5	185	41%	0%	32%	18%	0%	91%	0%	0%	9%	9%	100%	22
TV #6	185	10%	0%	5%	55%	0%	70%	0%	15%	15%	30%	100%	20

(b) Central Puerto

Operational Status - Number of Periods Facing Nodal Price > US$ 50 / MWh between 7 and 11 pm

		Producing						Not Producing				Total	
Turbines		Market Prices	Local Prices	Forced Generation	Start-up	Limited Transport.	*Subtotal*	Programmed Unavail.	Forced Unavail.	Available	*Subtotal*	%	# per.
CC	789	18%	14%	9%	0%	0%	41%	18%	41%	0%	59%	100%	22
TV #1	195	8%	0%	52%	16%	0%	76%	0%	24%	0%	24%	100%	25
TV #2	195	23%	12%	54%	12%	0%	100%	0%	0%	0%	0%	100%	26
TV #3	195	39%	13%	39%	0%	0%	91%	9%	0%	0%	9%	100%	23
N.Puerto TV #1	125	0%	0%	0%	0%	0%	0%	0%	55%	45%	100%	100%	22
N.Puerto TV #2	125	45%	18%	36%	0%	0%	100%	0%	0%	0%	0%	100%	22
N.Puerto TV #3	125	18%	14%	14%	0%	0%	45%	18%	27%	9%	55%	100%	22

Table 9 - Argentina Electricity Exports (GWh)

year	GWh	Year 2000	GWh
1992	12	Jan	285
1993	14	Fev	279
1994	15	Mar	315
1995	190	Abr	160
1996	311	Mai	142
1997	273	Jun	432
1998	78	Jul	723
1999	712	Ago	874
2000	4713	Set	327
		Out	71
		Nov	256
		Dez	849
			4713

Source: Cammesa

Table 10 - Major Combined Cycle Additions in the Argentinean Market 1992-2001

		Approximate Dates			
	Final Capacity (MW)	Beginning of Construction	Operation of First Unit	Operation of Last Unit	Commercial Oper. as CC
CT Buenos Aires	322	Jul 1994	Nov 1995	Feb 1997	Jul 1997
Genelba	674	1995	Apr 1997	Jul 1998	Late 1998
CT Luján de Cuyo	374			Mar 1998	Late 1998
Agua del Cajón	628	1993	Nov 1993	Oct 1999	Jan 2000
CT Tucuman	447		Nov 1996	Jul 1999	Feb 2000
CC Costanera	851	Nov 1996	1998	Jan 1999	March 2000
CC Puerto	789	1996	Ago 1999	Oct 1999	May 2000
CC Dock Sud	773	1997	May 2000	May 2000	Early 2001
AES Parana	845	Sept 1997	Sept 2001	Sept 2001	Nov 2001
Total	5703				

Sources: Cammesa, various financial and market reports, Energy Secretariat

Table 11 - Utilization Rates of Hydro and Nuclear Plants with Respect to Maximum Capacity, 1995-2001

Year	Hydro				Nuclear			
	Inst. Cap (MW)	Max. Ger. (GWh)	Actual Ger. (GWh)	Util. (%)	Inst. Cap (MW)	Max. Ger. (GWh)	Actual Ger. (GWh)	Util. (%)
1995	7629	66830	22582	0,34	1005	8804	7066	0,80
1996	8230	72095	19574	0,27	1005	8804	7459	0,85
1997	8748	76632	28789	0,38	1005	8804	7445	0,85
1998	8670	75949	28927	0,38	1005	8804	6928	0,79
1999	8926	78192	24859	0,32	1005	8804	6586	0,75
2000	8926	78192	31269	0,40	1005	8804	5731	0,65
2001	8926	78192	38056	0,49	1005	8804	6541	0,74

Source: Cammesa, Energy Secretariat

Table 12 (a) - Estimation of Social Optimal Mix of Generators Condition

	1997		1998		1999		2000		2001*	
	MW	utilization	MW	utilization	MW	utilization	MW	utilization	MW	utilization
Hydro	8748	0,38	8670	0,38	8926	0,32	8926	0,40	8926	0,49
Nuclear	1005	0,85	1005	0,79	1005	0,75	1005	0,75	1005	0,74
Cc	402	0,85	1514	0,85	2365	0,85	4229	0,85	5856	0,85
total nominal baseload cap. (MW)	10155		11189		12296		14160		15787	
"effective" baseload capacity (MW)	4508		5380		5600		7918		10095	
tg/tv capacity	8049		7985		7213		6547		6554	
Minimum load (MW)	4661		4714		5193		4854		4935	
maximum load (MW)	11058		11717		12131		14167		14061	
average load (MW)	7557		7928		8354		9139		9292	
Standard deviation (MW)	1217		1302		1356		1580		1606	
# periods of dem < effective baseload capacity	0		24		25		2192		6002	
Prob (Demand > effective baseload capacity)	1		0,997		0,997		0,750		0,315	
Difference in fuel cost (US$ / MWh)	7,5		7,4		6,7		7,2		6,9	
LHS (US$ savings on fuel / MW / year)	**65919**		**64646**		**58160**		**47399**		**18892**	
Base Hypothesis										
Kcost CC (1000 US$ / MW)	600									
Kcost TG (1000 US$ / MW)	330									
Availability CC	0,85									
Availability TG	0,75									
RHS - US$ extra capital cost / MW / year										
at 7% , 30 years	**17309**									
at 10%, 30 years	**22081**									
at 15% , 30 years	**29880**									

Natural gas prices (US$/dam3)	
1997	90,3
1998	88,8
1999	79,9
2000	86,6
2001	82,2

* for 2001, demand information and (periods of demand < baseload capacity) were estimated based on the 2000 load distribution.

Table 12(b) - New Combined Cycle X New Gas Turbine
Sensitivity Analysis

Sum of Discounted Fuel Savings, 30 years @ 10%, US$ per MW of installed capacity

Hypotheses **Dispatch Rate**	**Gas Price Path** start at $ 90 decreases 5% p.y.	 constant at $ 90	 start at $ 90 grows 5% p.y.
100% for 3 years, 0,75 for 1 year and then 0,5	334239	442844	652122
always 0,75	356905	510962	815547
always 0,5	237936	340642	543698
Extra Capital Exp. CC @ US$ 600000 / MW and availability 0,85 TG @ US$ 330000 / MW and availability 0,85			317647

Sum of Discounted Fuel Savings, 30 years @ 15%, US$ per MW of installed capacity

Hypotheses **Dispatch Rate**	**Gas Price Path** start at $ 90 decreases 5% p.y.	 constant at $ 90	 start at $ 90 grows 5% p.y.
100% for 3 years, 0,75 for 1 year then 0,5	279939	345100	455847
always 0,75	282413	372069	529673
always 0,5	188275	248046	353116
Extra Capital Exp. CC @ US$ 600000 / MW and availability 0,85 TG @ US$ 330000 / MW and availability 0,85			317647

Table 12 (c) New Combined Cycles X Avoidable costs of Incumbent Steam Turbines

Difference in Thermal Eff. considered: 1000 Kcal/MWh

Sum of Discounted Fuel Savings, 30 years @ 10%, US$ per MW of installed capacity

Hypotheses		Gas Price Path	
Dispatch Rate	start at $ 90 decreases 5% p.y.	constant at $ 90	start at $ 90 grows 5% p.y.
100% for 3 years, 0,75 for 1 year then 0,5	477485	632634	931603
always 0,75	509864	729946	1165068
always 0,5	339909	486630	776712
Capital Exp. CC @ US$ 600000 / MW and availability 0,85			706000

Sum of Discounted Fuel Savings, 30 years @ 15%, US$ per MW of installed capacity

Hypotheses		Gas Price Path	
Dispatch Rate	start at $ 90 decreases 5% p.y.	constant at $ 90	start at $ 90 grows 5% p.y.
100% for 3 years, 0,75 for 1 year then 0,5	399912	493000	651209
always 0,75	403446	531527	756677
always 0,5	268964	354351	504451
Capital Exp. (RHS) CC @ US$ 600000 / MW and availability 0,85			706000

Sum of Discounted Fuel Savings, 30 years @ 10%, US$ per MW of installed capacity
Incumbents with a remaining life of 15 years

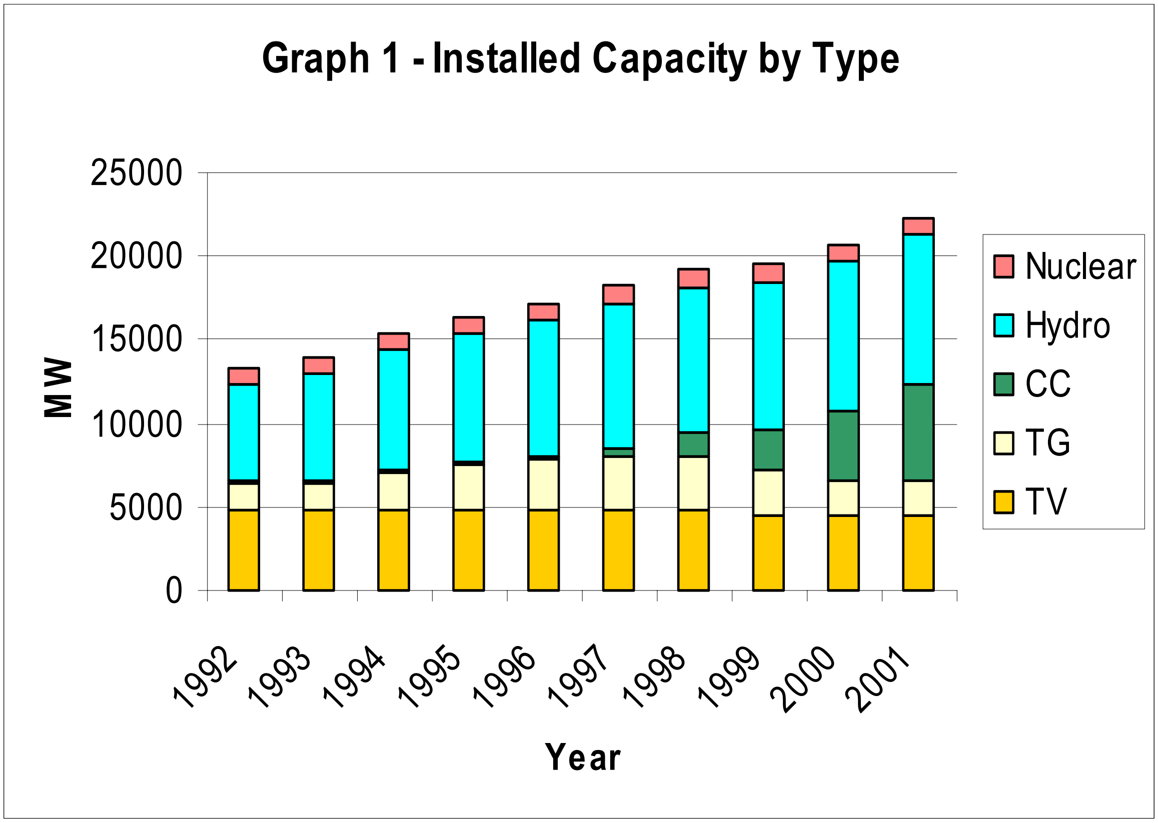
Hypotheses		Gas Price Path	
Dispatch Rate	start at $ 90 decreases 5% p.y.	constant at $ 90	start at $ 90 grows 5% p.y.
100% for 3 years, 0,75 for 1 year then 0,5	528387	773625	1318756
always 0,75	586218	941932	1745797
always 0,5	390812	627621	1163865
Capital Exp. CC @ US$ 600000 / MW and availability 0,85			706000

Table 13 - Recent Investments in Combined and Open Cycle Plants in Argentina

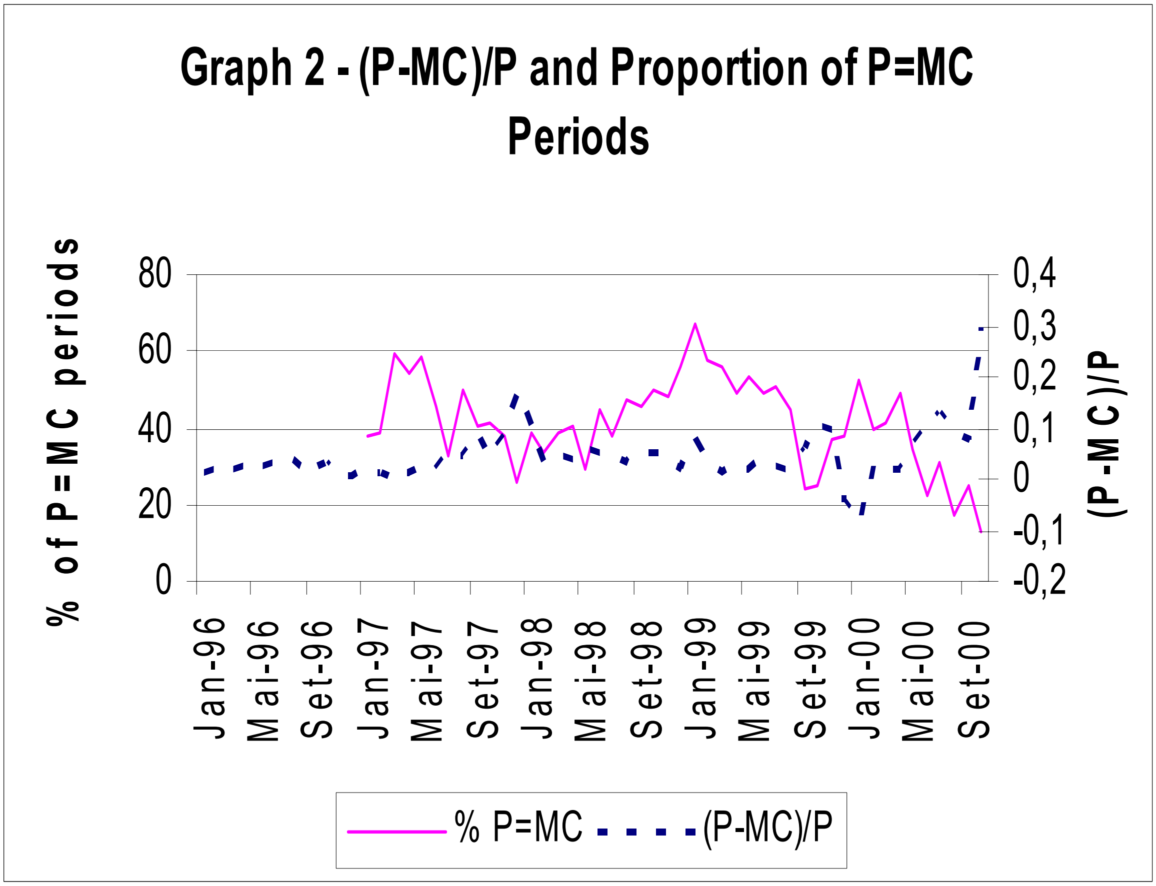
Plant	Date of start of comm. Operation	MW	Total Cost (US$ M)	1000 US$ per MW	financing interest rate	remarks
Agua del Cajon	Jan 2000	628				
AES Parana	Nov 2001	826	448	542		**whole new plant**
CC Dock Sud	Jan 2001	773	330	428		
CC Costanera	March 2000	851	270	317	7,42% fixed	
CC Puerto	May 2000	789	240	304	LIBOR + 0,05 / 2,25 % p.y. (swaped for 7,1% p.y. fixed)	
CC Tucuman	Feb 2000	447				
CC Buenos Aires	July 1997	320	100	312		used former SEGBA steam turbine
Termoandes*	March 2000	633	494	780		**whole new plant**
Open Cycle additions						
CT Loma de Lata	1994	375	146	362		Open Cycle
CT Ave Fenix	sched Apr 2002	+ 118	50	424		Open Cycle
GE 1999 - 2000 state of art gas turbine benchmark from GE report to US Dept of Energy, May 2001 "Next Generation Gas Turbine Systems Study"				314 to 346		

* Located in Argentinean territory but disconnected from the system, Termoandes' production is directed exclusively to the Chilean market

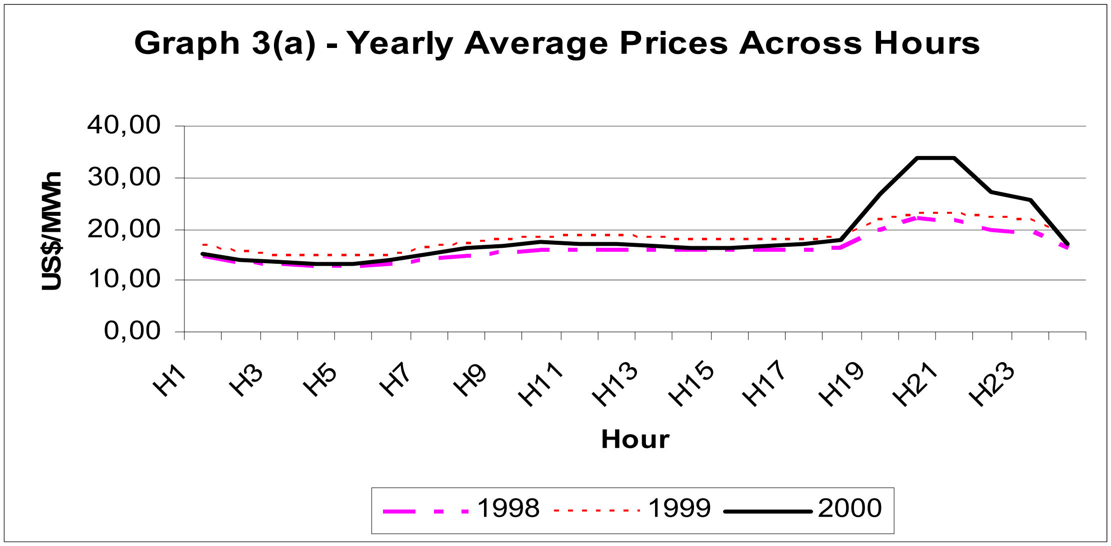
Sources: Company, market and financial institutions reports



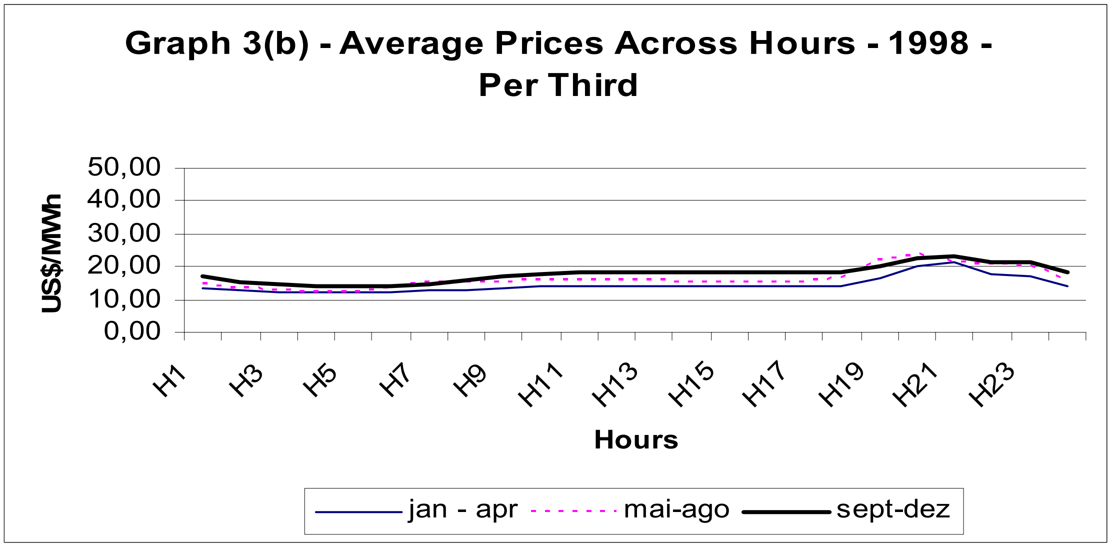
Graph 1 - Installed Capacity by Type



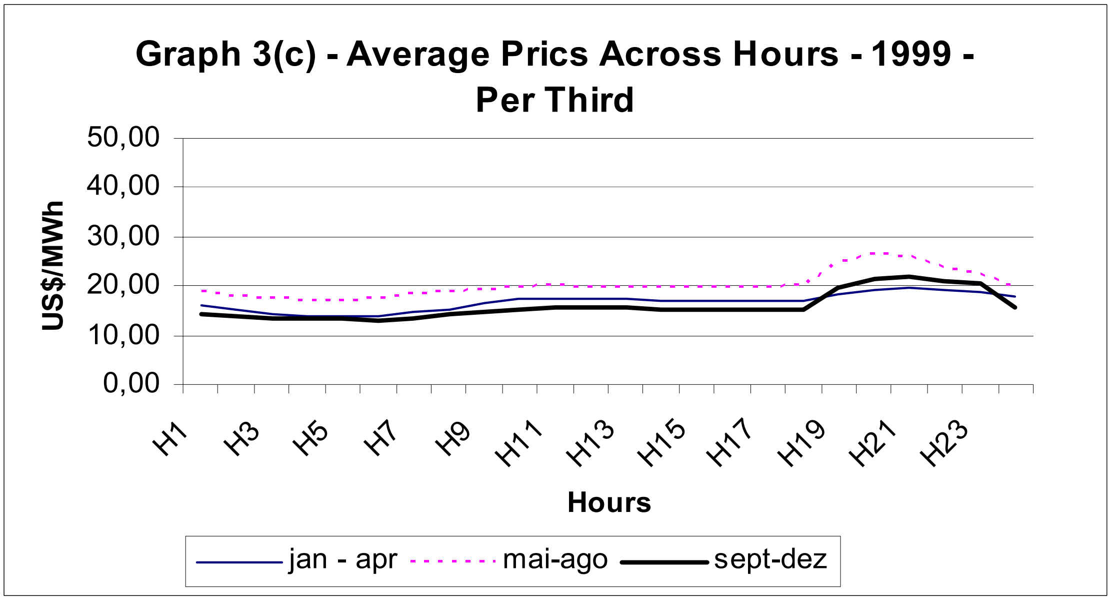
Graph 2 - (P-MC)/P and Proportion of P=MC Periods



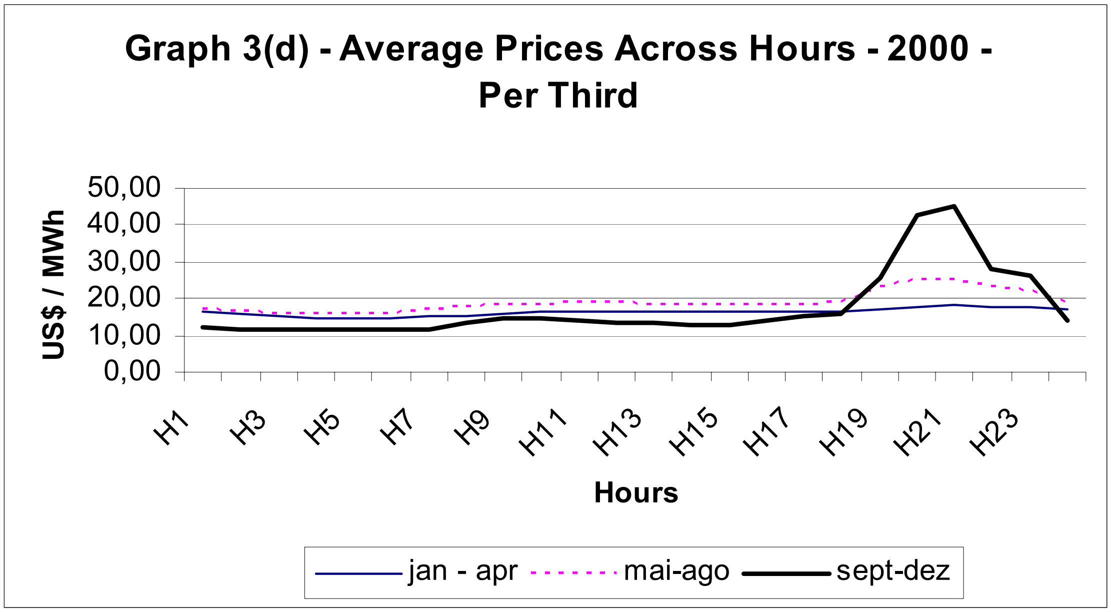
Graph 3(a) - Yearly Average Prices Across Hours



Graph 3(b) - Average Prices Across Hours - 1998 - Per Third



Graph 3(c) - Average Prics Across Hours - 1999 - Per Third


Graph 3(d) - Average Prices Across Hours - 2000 - Per Third

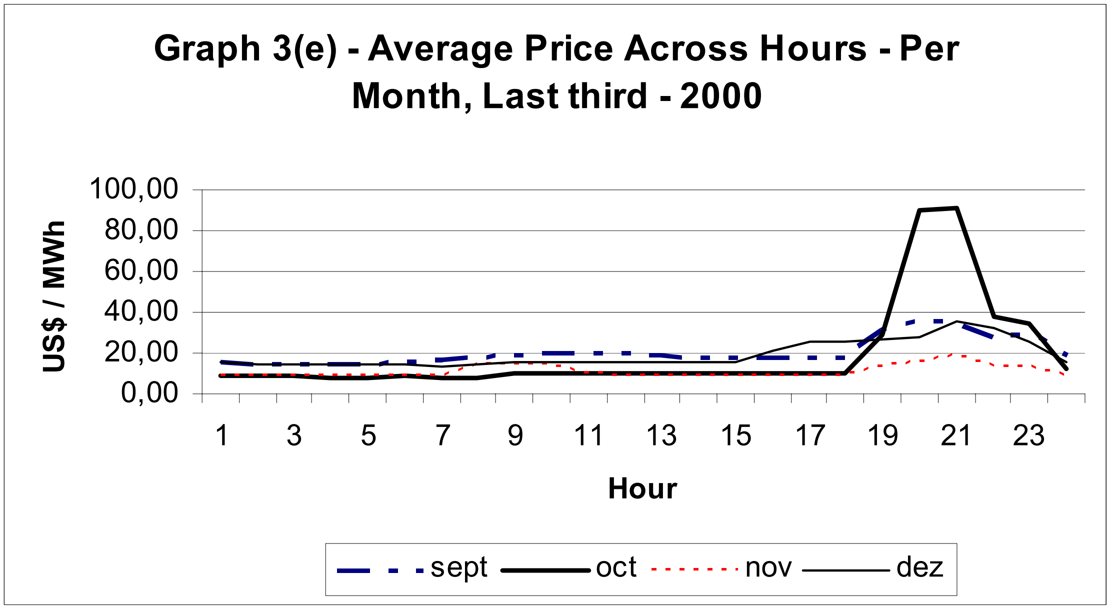

Graph 3(e) - Average Price Across Hours - Per Month, Last third - 2000

Figure 1 – Capacity Withdrawal Logic