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Diagnosing Market Power in Chile´s Electricity Industry.

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Abstract

Chile's electricity market is modeled as a Cournot duopoly with a competitive fringe. Due to the importance of hydro-storage resources (62% of total generation in 2000) particular care was given to the hydro scheduling issue. The model was estimated over a 1-month planning horizon using real cost and load data for April 2000. I found that the largest producer would be able to get markups that ranged from 66% to 76% (72% in average) when price elasticity was –1/3. In addition hydro resources are inefficiently allocated as production is shifted from high demand periods to low demand periods. Final equilibrium is sensitive to the value of the price elasticity of demand. Four different measures that could be implemented to reduce the potential for market power were analyzed: the divestiture of all or a fraction of Firm 1's hydro capacity, the divestiture of all of its thermal plants and the role of contracts. Results indicated that since Firm 1 exercises its market power mainly through its hydro resources, the divestiture of the thermal plants would have a negligible effect in the degree of market power that is exercised, although total output and price are closer to the competitive equilibrium. The divestiture of hydro plants, although an effective measure in terms of reducing distortions, would probably be difficult to implement. Requiring producers to sign contracts in advance proved to be successful in reducing incentives to manipulate prices by the firms; in addition, I found that the more contracted is the firm, hydro scheduling is more efficient, meaning that more hydro production is allocated to periods of high demand and less to periods of low demand.

I. Introduction

Chile was the first country that reformed and de-regulated its power industry. The power sector reform, implemented in the early 80's, was one element of a more general economic policy approach that intended to reduce market interventions only to those industries where the private sector was not able to take appropriate investment, production and/or consumption decisions. In particular, the regulatory authority decided that, since at that time, the generation segment was not a natural monopoly, the appropriate approach was to allow electric companies to compete. A different approach was implemented in the transmission and distribution segments, which continued being regulated because of their natural monopoly characteristics. This economic policy was complemented by a huge privatization effort, where most of the electric companies were re-organized and then sold to the private sector.[1]

Two decades have passed since the restructuring of the industry took place. It is fair to say that in general terms, the reforms have had a positive effect: installed capacity increased and both efficiency and quality of service and supply indices have exhibited a positive trend. However, in the past years warning signs have appeared that call for new changes. In particular, in 1998-99 there was a draught that lead to a huge supply crisis and private companies have been reluctant to increase their installed capacity in spite of the signs of future shortages. Currently, both Chilean regulatory authorities and private companies are analyzing the convenience of moving one step further in the de-regulation process of the electricity sector and stop fixing the nodal price. The price would no longer be set up by the authorities, as it is done right now, but they would be set by a spot market through a power exchange. Even though the new system would prevent some of the current flaws in regulation, it may also be dangerous. In particular the high degree of concentration in the generation segment has raised concerns regarding the appropriateness of a system like this one.

In this paper I analyze whether the high concentration in the generation sector will translate into anti-competitive behavior.[2] I model Chile's electricity market as a Cournot duopoly with a competitive fringe. Particular care is given to the modeling of hydro resources, which are not only important because of its large share in total installed capacity and in total generation (61% and 62% respectively in 2000), but because of its impact on the incentives firms face when competing. As it will be analyzed in the paper, having hydro resources as a source of electric generation, means that firms do not take static production decisions at each moment in time, but that firms have to take account that more water used today, means less water is available for tomorrow: the model becomes dynamic rather than static. I found that in a power exchange system there is plenty of room for market power abuses, in particular from Endesa, the largest firm. For instance, it is able to markup an average of 72% (when price elasticity is –1/3). In addition, hydro resources are inefficiently allocated; in particular, the producer constrains hydro production in periods when demands is high, while increases it in periods of low

[1] For more information on the privatization process, see Luders and Hachette (1991).
[2] See Borenstein et al (2000) for an analysis of why concentration indices are not a sufficient indicator of market power.

demand. In addition, the importance of hydro resources determines that Gener, although being a large firm in terms of installed capacity, has almost nothing strategic to do with its thermal plants (it doesn't own hydro-storage resources), particularly in periods of high demand.

I also qualitatively and quantitatively analyze the impact of four different measures that could be implemented to mitigate or reduce market power: mandatory contracting practices, full and partial divestiture of Endesa's hydro capacity and full divestiture of Endesa's thermal plants. Each of these measures resulted in a market equilibrium that was closer to the competitive equilibrium but they differ in their real feasibility. In particular, it seems difficult to force Endesa to dispose of the asset where its market power relies. In addition, the existence of contracting practices seems to be a more balanced measure in terms of altering the relative importance of each firm in this industry and the relative market power that each firm can exercise.

The paper is organized as follows: in the first chapter I review the main findings of the literature that are related to this topic. In Chapter II, I briefly describe the main characteristics of the Chilean power industry. In the fourth Chapter I analyze the model that will be used to estimate market power. Results are reported in Chapter V. In chapter VI I report results from four different versions of the main model that incorporate, each, a different measure that may be used to mitigate market power. The final chapter concludes and gives directions for further research.

II. Empirical literature Review

This paper is related to two areas of research: the modeling of electricity markets in order to (ex-ante) simulate strategic behavior after the industry has been deregulated and to the analysis of the strategic use of hydro resources as a way to exercise market power.

Three types of model have been used to simulate the strategic behavior of electricity firms. In the supply function equilibrium (SFE) approach, used by Green and Newbery (1992) and Halseth (1998) based on the work by Klemperer and Meyer (1989), the producers bid a supply function that relates quantity supplied to the market price. In a general case, the duopoly supply lies between the competitive and Cournot equilibrium; the range of feasible equilibria is reduced when uncertainty is added to the model.

Green and Newbery (1992) modeled the England and Wales electricity market as being made up by symmetric duopolists who submitted smooth supply schedules. They looked for the Nash-equilibrium of the spot market as a single shot game. They found that generators were able to earn extremely large profits, while creating a large deadweight loss.[3] They estimated the impact of restructuring the industry, modeling it as a quintopoly. In this case, the equilibrium price was significantly lower and the deadweight loss was reduced. In order to take account of the effect of potential entry, they estimated the model several years into the future, adjusting the incumbents' marginal cost functions

[3] Wolfram (1999) found that prices in the British market had been much lower than what Green and Newbery (1992) predicted.

and allowing for additional capacity. Entrants were assumed to build CCGT plants and to behave as price takers. They concluded that even though prices were lower, entry was excessive.[4]

Halseth (1998) used the SFE approach to analyze the potential for market power in the Nordic market. In his model, the supply function is restricted to be linear, with a constant markup over marginal cost. This markup is independent of the particular technology used by the producer but it varies between the different time periods. Asymmetry in production technologies is incorporated through the marginal cost function (each production level is associated to a specific marginal technology (hydro, nuclear or thermal). Due to the importance of hydro production in the Nordic market (it accounts for 50% of annual production), the hydro scheduling issue is explicitly modeled. In particular, annual hydro production is restricted to be less than the annual inflow and the water inflow that is stored between periods has to be within the reservoir capacity. He found that the potential for market power was less than expected due to the fringe's excess capacity. Only two of the six largest producers had incentives to reduce production.[5] Remaining producers did not have incentive to do so. In particular, he found that hydro producers were not interested in reducing its market supply. He argued that since all of its income came from hydro production (with a very low marginal cost), the price increase had to be very large in order to induce it not to use its generating capacity to the full.[6] It should be noted that all the results of this model are reported in annual terms. In particular, he found that hydro generating capacity was used to the full in the year. However, nothing is said regarding how it is allocated throughout the year. This is an important omission because it may be the case that hydro producers do not exercise market power by using less than its hydro capacity but through a strategy that distinguishes between periods of high demand from periods of low demand.

Auction theory has also been used to analyze strategic behavior in the electricity market. Von der Fehr and Harbord (1993) model the UK electricity spot market as a first price, sealed-bid, multiple unit private-value auction with a random number of units. In their model, generators simultaneously bid supply schedules (reflecting different prices for each individual plant), then demand is realized and the market price is given by the offer price of the marginal plant. They argue that producers face two opposing forces when bidding: by bidding a high price, the producer gets higher revenue but a lower probability of being dispatched. Equilibrium has different properties depending on the demand level. In particular, when demand is low, producers bid a price equal to the marginal cost of the least efficient generator and equilibrium is unique. When demand is high, there are multiple equilibria with the price being equal to the highest admissible price.[7] They remark that some of these equilibria may result in inefficient dispatching: when the high

[4] Von der Fehr and Harbord (1993) and Halseth (1998) criticize on theoretical grounds the Green and Newbery (1992) use of the SFE approach.

[5] This two producers are Vattenfall and IVO. The portfolio of the first one is split between hydro (42%), nuclear (48%) and conventional thermal plants (10%). IVO is mostly a thermal producer.

[6] Johnsen et al (1999) concluded from this result that market power can not be exercised in a market dominated by hydroelectric producers, to what they add, unless transmission constraint bind.

[7] Multiplicity of equilibria is given by the fact that both producers want to be the "low bidder" because the received price is the same but the producer is ranked first, and thus output is greater.

cost generator submits the lowest bid, it will be dispatched with its total capacity while the low cost generator will be dispatched for only a fraction of it. Finally they argue that their model is supported by the bidding behavior observed in the UK electricity industry from May 1990 to April 1991. In particular, they report that while bids were close to generation cost at the beginning of the period, they diverged thereafter, Even though contracts were in place in the first part of the analyzed period, they argue that contracting practice is not a plausible explanation to the observed bidding behavior because contracts started to expire after the change of pattern took place. The coincidence of the first period with the low demand season (warm weather) and the second with the high demand season (cold weather) make their model a more appropriate explanation. It should be noticed however that they analyzed a very short period and so in order to get a more conclusive support to their theory, I would like to see what happened in the next seasons so as to be able to separate the contract effect from the high/low demand effect.[8]

Finally a third approach that has been used in the literature is to model the electricity industry as a Cournot oligopoly where producers are assumed to bid fix quantities. Andersson and Bergman (1995) simulated market behavior of the Swedish electricity industry after deregulation took place. He assumed a constant elasticity demand function (with an elasticity of demand equal to 0.3 in the main case), constant marginal costs for hydro and nuclear power plants and a non-linear marginal cost function for conventional thermal units.. The analysis is restricted to prices and total output without mentioning how are markups. He gets that prices would increase and production would be constrained. In particular, he found that the Cournot price equilibrium was 36% higher than the current (base) case and 62% than the Bertrand equilibrium He also analyzed the impact of alternative market structures like splitting the largest company in 2 firms of the same size and a merge between the six smallest companies. In both cases equilibrium price is reduced below the base case. Finally he analyzed the impact of increased price responsiveness solving the model for a higher elasticity value (0.6). Since the hydro is modeled on an average basis, nothing is said regarding how resources are allocated within the year (for instance there is no differentiation between peak and off peak periods). In addition, nothing is said regarding how the portfolio of resources is used and how it compares to the base and Bertrand equilibrium cases. This is an important omission given the importance of hydro resources in the Swedish electricity market.

Borenstein and Bushnell (1999) and Bushnell (1998) modeled the California power industry as a Cournot triopoly with a competitive fringe.[9] Cournot producers face a residual demand where must run generation, the fringe's supply and hydro generation in the case of Borenstein and Bushnell (1999) are subtracted from total demand. Marginal cost functions were estimated using cost data at the plant level. A big difference between those articles is given by the treatment of hydro resources: Bushnell (1998) assumes that Cournot producers use them strategically while Borenstein and Bushnell (1999) assume that they are allocated competitively.[10] In other words, in Bushnell (1998)'s model, hydro

[8] Wolfram (1998) analyzes the bidding behavior in the UK and tests the theoretical predictions of the multi unit auction theory.
[9] Their market definitions are slightly different.
[10] In particular, they allocate hydro production over the period using a peak shaving technique.

producers are "allowed" to store water inflows from one period and use them in another one in order to manipulate prices. As a result, in his model the different periods are not independent and thus the maximization has to be solved simultaneously over the entire planning horizon, as opposed to Borenstein and Bushnell (1999)'s model where each period can be treated independently. Borenstein and Bushnell (1999) use a constant elasticity demand and run the model for a range of demand elasticity values (0.1, 0.4 and 1.0) and six different demand levels. They found that the potential for market power was greater when demand was high and the fringe's capacity was exhausted, making it impossible for the small producers to increase production. In lower demand hours, Cournot producers had less incentive to withhold production because the fringe had excess capacity. In addition they found that the more elastic was demand, the less was the incentive to exercise market power. Finally they analyzed the hydro scheduling issue by allocating hydro production across periods so as to equalize marginal revenue. They found that even though the resulting hydro allocation was very different from the one implied by the peak shaving approach, prices did not change much because as hydro production was moved out from one period, the resulting price increase induces the other large producers and the fringe to increase production. This result is against what Bushnell (1998) found.

Overall, the literature seems to agree in the following: more market power can be exercised when the fringe's capacity is exhausted, which usually occurs when demand is high. The exercise of market power results in high prices, reduced output and in an inefficient allocation (production costs are not minimized). Results are very sensitive to the elasticity of demand. In order to say something regarding the role of hydro resources in the exercise of market power, a formal study of the hydro scheduling issue is needed.

When the hydro scheduling issue is analyzed the general approach that is followed is always the same. There is a producer who maximizes intertemporal profits subject to certain constraints such as hydro generation being within a range determined by min and max flow constraints and by the availability of water. Then, an assumption is made regarding what sort of strategy producers may choose. Scott and Read (1996), Scott(1998) and Bushnell (1998) assumed Cournot producers. The main difference between their approaches is given by the method they chose to solve the optimization problem. While Scott and Read used a dual dynamic programming methodology (DDP), Bushnell solved by searching for the dual variables that satisfied the equilibrium conditions of the model. In particular, Scott and Read used DDP to optimize reservoir management for the New Zealand electricity market over a medium term planning horizon (1 year). They estimate a "water value surface" (WVS) that relates the optimal storage level at each period to the marginal value of water (MVW). The latter is interpreted as the marginal cost of generating at the hydro stations. The schedule of the system is determined by running each period a Cournot model in which the hydro plant is treated as a thermal plant using the WVS to determine the marginal cost of water (i.e. MVW), given the period and the storage level at that period. [11] The Scott and Read

[11] The water value surface consists on a set of curves, one for each period, which relates the storage level at that period to the marginal value of water. It is derived recursively. The storage level at the beginning of a certain period is calculating by adding to the end of period storage level a demand curve for release of

approach is rich in details as hydro allocation for the whole planning horizon is derived as a function of the MVW. However it is computationally intensive, especially when there is more than one producer who owns hydro-storage plants. It is also data demanding because information on water inflows is required on a very frequent basis. Since Bushnell wanted to model the Western US electricity market where the three largest producers had hydro-storage plants he adopted a dual method to solve the model, treating the marginal value of water multiplier and the shadow prices on the flow constraints as the decision variables. He derived an analytic solution by searching for values of the dual variables that satisfy the equilibrium conditions at every stage of the multi-period problem. In order to solve his model, he simplified it by assuming that demand and the marginal cost function were linear[12]. The planning horizon was assumed to be one month and the model was run for March, June and September. Bushnell (1998) found that firms could profit from shifting production from peak to off peak hours, i.e. from hours when the fringe was capacity constrained to when it was not. In particular, he estimated that hydro production was reduced by 10% (relative to perfect competition) during the peak hours, resulting in more than 100% price increase. Based on the estimated marginal water values for different months, he found that against what it was expected producers did not shift production from months of high demand to months of low demand. He argued "since the market is relatively competitive at least some of the time in each month, strategic firms do not need to reallocate across months in order to find hours in which extra output will have little impact on prices" (p.30)

III. Chilean Power sector

Electricity supply in Chile is provided through four non-interconnected electric systems: Interconnected System of Norte Grande (SING) in the north, Central Interconnected System (SIC) in the center and Aysen and Magallanes in the south of the country. Total installed capacity in 2000 amounted to 9713 MW, being the SIC the largest system in the country in terms of installed capacity and concentrate more than 90% of the country's population. Due to differences in resource availability, each system generates energy from different sources. While the north relies almost completely in thermal sources, the rest of the country also generates energy from hydroelectric sources and recently from natural gas. The most important source of energy in Chile is hydrological resources. They are concentrated in the central and southern part of the country, which explains why the SIC relies heavily on hydro generation. Fuel resources are not abundant: natural gas and a large fraction of the oil used are imported and Chilean coal is not of good quality. In what follows, all the analysis and estimations will refer to the SIC, the biggest Chilean system.

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water (DCR), which is a function of MVW, and subtracting the (expected) water inflows of the period. This is done recursively starting from the end of the planning horizon, resulting on a water value surface. The demand curve for release of water is calculated by running a one stage Cournot model for a representative range of MWVs holding all other inputs constant. The DCR is given by plotting hydro generation versus MWV.

[12] The slope of the demand function was assumed to be constant across periods and set at a level such that the elasticity of demand at the peak forecasted quantity was 0.1.

Gross generation in 2000 amounted to 29.577 GWh, 37% of which was hydro-reservoir generation, 38% thermal generation and 26% hydro-ROR generation. Maximum demand in the year 2000 amounted to 4576 MW (April). The generating sector is highly concentrated: 93% of total installed capacity and 90% of total generation is in hands of three economic groups (Endesa, Gener and Colbun) being Endesa the largest of them. (See Table 1). The Hirschmann-Herfindahl index is 3368. In order to simplify the reading of the paper, I will refer to these companies as "Firm 1" (Endesa), "Firm 2" (Gener), and "Firm 3"(Colbun). These three firms differ in terms of size, their generating plants portfolio and the associated marginal cost functions (See Figure 1). While Endesa relies mostly on hydro sources, Gener owns the majority of the thermal plants of the system.

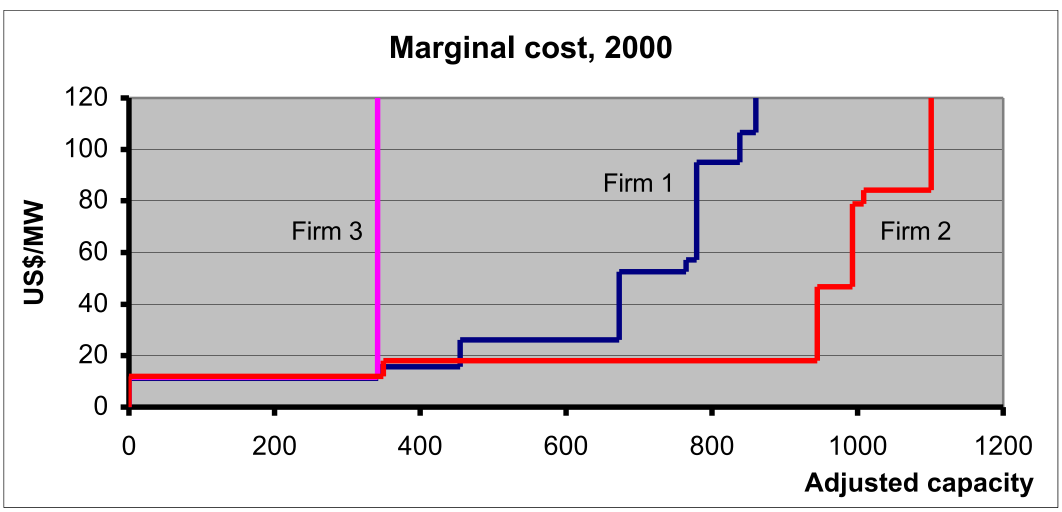
Table 1: Installed capacity in the SIC (December 2000), MW

Economic Group	Thermal	Hydro-ROR	Hydro-reservoir	Hydro	Total	% thermal	% hydro
Endesa (Firm 1)	939	238	2454	2693	3632	25.9%	74.1%
Gener (Firm 2)	1212	245	0	245	1457	83.2%	16.8%
Colbun (Firm 3)	370	0	697	697	1067	34.7%	65.3%
Other	61	403	0	403	463	13.1%	86.9%
Total	2581	886	3151	4037	6619	39.0%	61.0%

Source: CDEC-SIC

Firm 3 has the lowest marginal cost plant, but is also the smallest firm in terms of capacity. Firms 1 and 2 both own low and high marginal cost plants, being this feature more accentuated in the case of Firm 1.[13,14]

Figure 1



Generating companies are allowed to sell to three different customers: large consumers, distribution companies and other generating companies. Transfers of energy between

[13] Steps followed to estimate Marginal cost functions will be described later.

[14] In addition, there is an important degree of vertical integration in the SIC. In particular, Enersis, the owner of Endesa, is also the owner of two large distribution companies, Chilectra and Rio Maipo whose customers amount to 43% of the SIC.

gencos are made in what is called the “spot market” at a Short Run Marginal Cost (SRMC), which is calculated by the dispatcher, the “CDEC”, according to marginal cost information reported by the gencos themselves. The price at which they sell to large consumers is free, i.e. not regulated. The price charged to distribution companies for the energy that will be sold to small consumers (nodal price) is regulated and set every 6 months by the National Energy Commission (CNE), the regulatory agency. [15,16] Nodal The price has 2 components (capacity and energy) and is fixed at a level such that they represent an average marginal cost of producing energy. A particular feature of the Chilean pricing system is that the regulated (nodal) price is required to lie within a band of +/- 10% of the non-regulated price; this means that every time the regulated price is set, the regulator has to get information on the free price and make sure that that constraint is satisfied. An independent entity, called the CDEC, is in charge of the dispatch, of the operation of the system (short run, medium run and long run operation’s planning) including the calculation of SRMC, of guaranteeing open access to transmission lines and of other administrative tasks.[17] For a detailed analysis of the Chilean regulation, see Arellano (2001)

IV. Theoretical Model

I will estimate an ex-ante model much in the spirit of Green and Newbery (1992), Borenstein and Bushnell (1999) and Bushnell (1998) using real demand and cost data for the year 2000. The model that is analyzed in this Chapter will be referred to as the “hydro model”.

The industry is modeled as a Cournot duopoly (Firms 1 and 2) with a competitive fringe.[18] The use of a quantity strategy may be justified in theoretical and empirical grounds. Regarding the first one, both the Bertrand paradigm and the use of the Supply Function Equilibrium approach (SFE) seem not to be appropriate. According to the Bertrand paradigm, any firm would be able to capture all the market by charging a price slightly less than their competitors’. In a context where there are capacity constraints and increasing marginal cost, it is not true that a firm would be able to do that. First of all, capacity constraints preclude the increase of production to satisfy increased demand. In addition, it is not clear that the firm will be able to produce more and charge less. The SFE is, in some sense, less restrictive than the Cournot approach because producers can choose their strategy from a multidimensional space rather than from a one-dimensional (“quantity”) strategy space as in the Cournot approach. However in other aspects it is more restrictive. For instance, that approach is appropriate for markets where a single

[15] Small consumers are those whose connected capacity is less than 2 MW.
[16] Distribution companies do not have access to the spot market. In order to purchase energy they have to contract with the generating companies. They usually sign long-term contracts.
[17] The CDEC is made up by all the transmission companies and by the generating companies whose installed capacity is greater than 2% of the total installed capacity that the system had when the CDEC was established (61.148 MW in the case of the SIC). In addition, gencos whose installed capacity is greater than 9 MW are entitled to voluntarily make up the CDEC.
[18] I also estimated the model assuming that the third largest firm (Colbun, “Firm 3”) had some market power but it turned out that it always ended up behaving as a price taker. In other words, it wasn’t big enough to be able to use its resources strategically.

supply curve (and a single strategy) will be applied to different states of nature. According to what has been found in the literature, this is not likely to be the case in the power industry. Indeed, producers seem to behave less aggressive when demand is at its peak and more aggressive during off-peak periods. In addition, solving for the equilibrium requires well-behaved demand and cost functions. These "requirements" are clearly not satisfied in this model. First of all, the demand function faced by the producers is kinked and has flat regions as a consequence of the presence of the fringe. In addition, the marginal cost function is not smooth, but step wise due to capacity constraints. None of these elements (capacity constraints and the presence of the fringe) could be left aside of the model without altering the results.[19, 20] On the other hand, the emphasis of the model is on the hydro scheduling issue, which is a quantity problem. Secondly, the empirical literature provides many examples where the shutdown of plants, a quantity strategy, has been used by the firms when trying to control the market price. For instance, see Joskow (2001) for the case of California and Wolak and Patrick (1996) for the UK. [21]

The portfolio of generation sources is very important; in fact, it defines the *way* market power can be exercised. In general terms, the whole idea behind market power is to reduce output in order to increase market price. However, the decisions that producers can make are different depending on whether they are in a pure thermal / pure hydro or in a mixed electric system. In a pure thermal system, the only decision that can be taken is to whether switch on or off a plant and how much to produce at every moment in time; in this context, market power is exercised by reducing output when the other parties are capacity constrained, which usually correspond to periods of high demand. A system with hydro-reservoirs, on the other hand, allows producers to store water during some periods and release it in some others; in other words, they are able to "store" power and "throw it into the market" at their convenience. Hydro producers are entitled then to decide not only when to switch on or off their plants and how much to produce, but also to decide *when* they want to use their hydro resources over a certain period of time. This (dynamic) scheduling decision is not available to thermal producers[22]. In a pure hydro system producers exercise market power by exploiting differences in demand elasticities in

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[19] As it will be shown later, capacity constraints are an important element of the model.

[20] The model that I am estimating is deterministic. This could also be used as a reason against the use of the SFE approach. As Klemperer and Meyer (1989) say "without uncertainty, a firm knows its equilibrium residual demand with certainty and it therefore has a single profit-maximizing point, which it could achieve by choosing either a fixed price or a fixed quantity. It gains nothing from the ability to choose a more general supply function". (page 1244)

[21] Alternative assumptions that I could have used are a perfectly collusive or a perfectly competitively industry. The first one is discarded because it is not reasonable to assume that firms could (explicitly) collude due to antitrust regulation and due to the natural tendency to deviate from the collusive agreement. The second market assumption is discarded because it simply makes no sense to analyze the potential for market power abuses assuming that the market is perfectly competitive. In addition, the fact that firms can behave sometimes as perfect competitors does not mean that they will not try to manipulate the price at certain periods.

[22] Notice that even in a perfectly competitive market producers are able to do hydro scheduling. The difference is that while differences between on peak and off-peak hours are *reduced* when the market is competitive, they are *enlarged* when producers exercise market power.

different hours. In particular, they shift production from periods where demand elasticity is high to periods when it is low.[23]

It is important to keep in mind that not all sorts of hydro resources can be used strategically. In particular, since water from run of the river (ROR) sources can't be stored, it can't be used by producers to manipulate the price[24]. Only resources from hydro reservoirs can be used strategically. Hydro-ROR plants will be treated in the model as "must-run" (MR) units except for those ROR plants that are associated to a reservoir system upstream. These plants will be included as part of the reservoir complex. In the Chilean system, Firm 1 and the Fringe own hydro-reservoir plants. Firm 2 only has thermal plants. In particular, Firm 1 is the owner of the largest reservoir of the country, amounting to 78% of total (hydro-reservoir) capacity. Firm 2 is a purely thermal plant, concentrating the largest fraction of thermal resources in the SIC (47%). See Table 1 for more detailed information. In order to simplify the model as much as possible, each reservoir will not be modeled individually but I will aggregate them into a unique reservoir complex (one for Firm 1 and one for the Fringe).

Hydro scheduling strategy by Firm 1 will be a result of the model. However, since the Fringe also owns a medium size reservoir, it will be necessary to allocate its hydro production in a certain manner. In particular, I will use the Peak Shaving approach[25]. The basic idea is the following: when there are no flow constraints, producers schedule hydro generation so as to equalize the marginal profit that they earn from one more unit of production over the whole period in which the hydro plant is being used. If the market were perfectly competitive, prices would be equalized. If there were market power, then gencos would equalize marginal revenues over time. As long as demand level is a good indicator of the firm's marginal revenue, a peak shaving strategy would consist in allocating hydro production to the periods of higher demand.[26] In addition, producers also have to take account of minimum flow constraints, given by technical requirements and irrigation needs, and maximum flow constraints, given by capacity. As a result, hydro production by the fringe was distributed across periods allocating as much as possible (given min/max flow constraints) to every period in order to eliminate or reduce demand peaks.

Cournot producers face a residual demand given by:

$$D^R(P) = D(P) - S^f(P) - q^{MR} - q^{PS}_h$$

where $D(P)$ is market demand, $D^R(P)$ is residual market demand, $S^f(P)$ is the Fringe's (thermal) supply function (adjusted by transmission losses), q^{MR} is must-run units' generation and q^{PS}_h is the Fringe's hydro production from reservoirs distributed across periods according to a Peak shaving strategy.

[23] See Johnsen et al (1999), Bushnell (1998) and Halseth (1998).
[24] A generating company could always shut down the plant but since its marginal cost is low (almost zero) and it is known to be low, it would not be difficult to allege anticompetitive behavior. Unavailability due to maintenance reasons should not be credible for a long period…
[25] For more details, see Borenstein and Bushnell (1999).
[26] This is true when using either a linear or a constant price-elasticity demand.

Each firm's maximization problem is given by:

Firm 1's maximization problem:

$$\underset{q^{Th}_{1t},\, q^{h}_{1t}}{\text{Max}} \quad \Sigma_t \left(P_t (Q_t)\, q_{1t} \right) - C_1 (q^{Th}_{1t}) \qquad (1)$$

$$\text{s.t.} \qquad q^{h}_{1,\min} \leq q^{h}_{1t} \leq q^{h}_{1,\max} \quad \forall\, t \qquad (2)$$

$$q^{th}_{1,\min} \leq q^{th}_{1t} \leq q^{th}_{1,\max} \quad \forall\, t \qquad (3)$$

$$\Sigma_t\, q^{h}_{1t} \leq \quad q_1^{\sim h} \qquad (4)$$

Firm 2's maximization problem:

$$\underset{q^{Th}_{2t}}{\text{Max}}\ \Sigma_t \left(P_t (Q_t)\, q^{Th}_{2t} - C_2 (q^{Th}_{2t}) \right) \qquad (5)$$

$$\text{s.t.} \qquad q^{th}_{2,\min} \leq q^{th}_{2t} \leq q^{th}_{2,\max} \quad \forall\, t \qquad (6)$$

where

- $P_t(Q_t)$ is the inverse function of the *residual* demand,
- Q_t is total production by firm 1 and 2 in period t, ($Q_t = q_{1t} + q_{2t}$),
- q^{Th}_{it} is thermal production in period t by firm "i" (i=1,2),
- q^{h}_{1t} is hydro production by Firm 1 in period t,
- $q_{it} = q^{Th}_{it} + q^{h}_{it}$ is total production by Firm i in period t,
- $q^{h}_{1,\min}$ is minimum hydro production, per period, by Firm 1
- $q^{h}_{i,\max}$ is maximum hydro production, per period, by Firm 1
- $q^{Th}_{i,\min}$ is minimum thermal production, per period, by Firm i
- $q^{Th}_{i,\max}$ is maximum thermal production, per period, by Firm i
- $q^{\sim h}$ = available water in terms of energy.
- $C_i\, (q^{Th}_{it})$ = aggregate thermal total production cost. Marginal cost is a monotone increasing function on q^{Th}_{it}
- t is the time period within the planning horizon. The planning horizon of the model will be assumed to be a month, which will be divided in 6 sub-periods (t=1,2,..6) of equal length.

There are 2 important elements related to the incentive to use the hydro capacity that I would like to remark. First of all, notice that Firm 1 is not directly constrained to use all of its hydro capacity because of the "=" sign in constraint 4. This is important because one of the ways Firm 1 could use its market power is by not using what is available. At the same time, however, Firm 1's objective function gives a value of zero to the water left in the reservoir at the end of the planning horizon (a month). Implicitly this "forces" the producer to use all the water that is available in the period, thus reducing their market power. It is reasonable to think that the companies would prefer not to do this and to re-allocate water over a longer planning horizon. As it will be reported later, I found that Firm 1 reduces its hydro production (relative to the competitive equilibrium) in the periods of the month when demand is high and increases it when demand is low. I suspect that, if given the possibility of reallocating hydro production over months, something similar should be observed.[27] This behavior can't be observed in this version model[28]. Which effect is more important? It is difficult to know at this time. As long as constraint 4 is satisfied by equality, the second effect might dominate. In what follows, I will assume that constraints (3) and (6) are not binding.[29]

In order to solve, we construct the Lagrangean. Since Firm 2 doesn't have hydro (reservoir) plants, its optimization problem is static. Its Lagrangean is given by:

$$L = \Sigma_t [P_t (Q_t) q_{2t} - C_2 (q^{Th}_{2t})] \qquad (7)$$

From the FOC we get the well known result that marginal cost has to be equal to marginal revenue in every period.

$$C'_2 (q^{Th}_{2t}) = P_t(Q_t) + q_{2t} \times dP/dQ \qquad \forall t \qquad (8)$$

Firm 1's Lagrangean is given by:

$$L = \Sigma_t [P_t (Q_t) q_{1t} - C_1 (q^{Th}_{1t}) - \gamma_{1t} (q^h_{1t} - q^h_{1,min}) - \delta_{1t} (q^h_{1t} - q^h_{1,max})]$$

$$- \sigma_1 (\Sigma_t q^h_{1t} - q^{\sim h}) \qquad (9)$$

where σ_1, γ_{1t}, δ_{1t} are Lagrange multipliers. In particular, σ_1 indicates the marginal value of water (additional profit if an additional unit of water were available to generate). Note that σ_1 is constant over time. Finally, $\gamma_{1t} = 0$ and $\delta_{1t} = 0$.

From FOC:

$$C'_{1t} = P_t(Q_t) + q_{1t} \; dP/dQ \rightarrow MR_{1t} = MC_{1t} \; \forall t \qquad (10)$$

$$MR_{1t} = \gamma_{1t} + \delta_{1t} + \sigma_1 = \Omega_{1t} \qquad \forall t \qquad (11)$$

$$MC_{1t} = \gamma_{1t} + \delta_{1t} + \sigma_1 = \Omega_{1t} \qquad \forall t \qquad (12)$$

As a result, marginal revenue is equal to thermal marginal cost in every period, as expected. In addition, the thermal marginal cost (and marginal revenue) has to be equal to Ω_{1t} that can be interpreted as the marginal cost of water. This means that an extra unit of water will be generated until its cost is equal to the cost of the most expensive thermal plant in use. Finally notice that if minimum and maximum flow constraints are not binding (i.e. $\gamma_{it} = \delta_{it} = 0$), then $MC_{1t} = \sigma_1$ (constant) and Firm 1 will allocate hydro

[27] Based on estimations of the marginal value of water for different months, Bushnell (1998) concluded that this was not true for the Western US electricity market.
[28] In a companion paper I will report the results when the planning horizon is a year rather than a month.
[29] This is true for all the cases except when E=-0.1

storage resources in order to equate MC across periods. Firm 1 would peak shave marginal revenues rather than prices.

I would like to make some final remarks regarding the model that will be used to run the simulations. First of all, and as the reader has probably noticed, this is a completely deterministic model. In particular, hydrological resources, marginal costs and load levels are assumed to be known in advance by the agents. Certainty with respect to load curve and marginal cost should not be a real concern because both power industry's marginal cost functions and demand fluctuations are usually well known. Certainty with respect to hydrological inflows is clearly a more arbitrary assumption. In the context of my model, this should not be too problematic either because I am running the model assuming a planning horizon of only a month. The longer the planning horizon, the more uncertain are the hydro inflows, and the more important to incorporate it into the model. Secondly, the model lacks of dynamic competition elements. This omission is clearly important for this particular industry. In the context of a power exchange system, the producers interact on a very frequent basis providing optimal conditions to engage in (tacit) collusive practices. For instance, producers can easily learn their competitors' strategies, monitor their behavior and credibly threat in case of deviating from the "collusive" strategy. In this sense, the results of the model should be seen as a *lower* bound of market power. By the other hand, the model does not incorporate the effect of high prices on potential future entry or in consumption patterns, reason why market power could be *over*estimated. Transmission constraints were not taken into account, as neither were contracts in this version of the model.

V. Model estimation and Results

Supply side

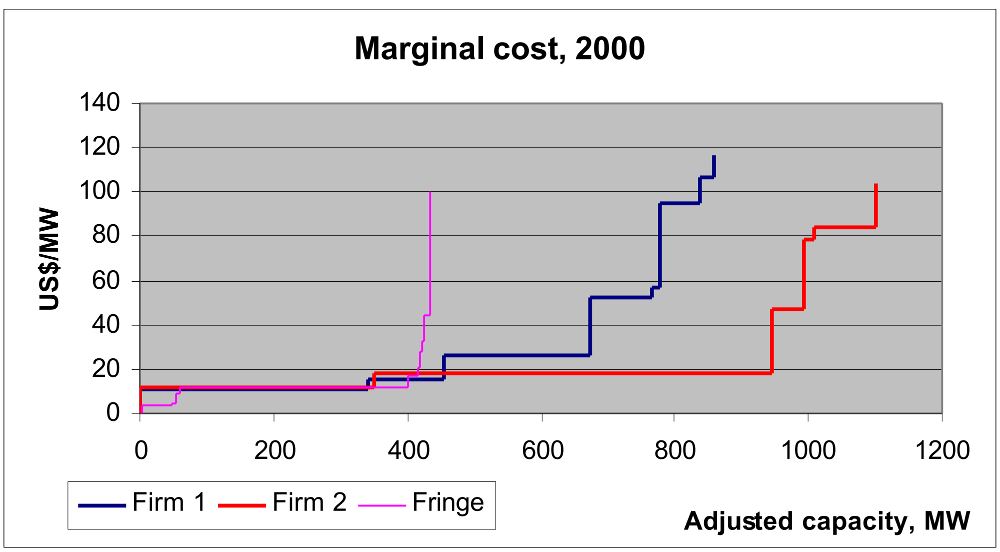
It was assumed that each plant had a constant marginal cost up to its expected capacity level.[30] Then an aggregated marginal cost function was calculated for each of the producers (Firm 1, Firm 2 and the Fringe). The constant marginal cost at the plant level (and at the plant "mouth") was calculated as the monthly average of the weekly marginal cost reported by the CDEC. This reported value does not incorporate any transmission loss. Since I plan to model the market behavior as if all transactions took place at the same (geographic) node, it is necessary to incorporate the fact that the MC of delivering energy at one node of the system is different from the MC of "producing" energy because a fraction of the energy that is generated in the plant is lost while it is being transmitted to the consumption node. In other words, the marginal cost of a KW produced by a plant located in node A and consumed at node B is "production MC^A" + "transmission charge". In order to incorporate this, I calculated for each plant a "system-equivalent marginal cost" as Production MC x Penalty factor (calculated by the CNE) [31].

[30] Start-up costs were not taken into account.
[31] Nodal Price Report, April 2000.

Each plant's capacity was adjusted for transmission losses, self-consumption and average availability[32]. I would like to mention that availability figures are high for international standards. This may be due to the way they are calculated: a plant is considered to be available if it doesn't go down when it is dispatched. However plants that are not dispatched but are available to are also considered being available. The issue here is that there is no certainty that those apparently available, non-dispatched plants would be effectively available if dispatched. In addition, availability data seems to include maintenance periods, which is a strategic variable. Unfortunately it was not possible to get separate data for scheduled and non-scheduled (non-expected) maintenance periods[33]. Related papers do not adjust for transmission losses that occur within the market but only for those that take place when energy is imported. I think this assumption is not appropriate for the Chilean case. The distance from North to South in the SIC is approximately 2300 kms. (about 1430 miles) and so transmission losses are likely to be important. In order to take them into account I adjusted capacity by the transmission loss factor. In other words, if maximum capacity is q, then the maximum delivered capacity is q*(1-l) where l is the loss factor. Finally since demand will be calculated as the *sales* of the system, auto-consumption must also be subtracted from total production. I used the last 5 years average for both the transmission loss and self-consumption factors (4.6% and 2% respectively).

Resulting marginal cost functions are reported below.

Figure 2



Notice that both Firms 1 and 2 own low and high marginal cost plants, being this feature more accentuated in the case of Firm 1.

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[32] As it was discussed in Borenstein et al (2000) the use of average availability may underestimate true expected capacity.

[33] If one believes on the average availability data, then the high average availability may mean that producers in the past have not used maintenance reasons as a way to manipulate the price.

Demand

As it was said before, Cournot producers face a residual demand given by:

$$D^R(P) = D(P) - S^f(P) - q^{MR} - q^{PS}_h$$

Where D(P) is market demand, $D^R(P)$ is residual market demand, $S^f(P)$ is the fringe supply's function (adjusted by transmission losses), q^{MR} is must-run units' generation and q^{PS}_h is the hydro production from reservoirs owned by the fringe that is distributed across periods according to a Peak shaving strategy.

a) *Market demand*: Demand is assumed to be linear $D(p_t) = A_t - BP_t$.[34] As a consequence, price elasticity increases as the level of production is reduced and the elasticity of demand at the price where the market clears is always higher when there is market power. I constructed a step function representation of April-2000's load curve with 6 discrete load levels (t=1 for the highest load level)[35]. The load level of each step was set equal to the average of the loads covered by those hours in the full load profile[36]. Each load level has an associated price given by the nodal price, which is the price paid by final consumers (see chapter III for more details on the Chilean regulation).[37] This price-quantity point will be used as the anchor points needed to parameterize demand.

Figure 3

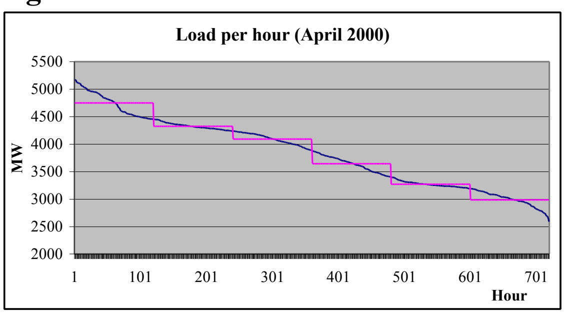
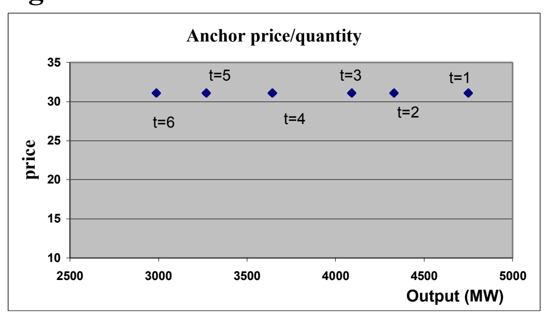


Figure 4



The empirical literature has emphasized the importance of price elasticity of demand in the results. In my model, demand elasticity will also turn out to be very important, as the Cournot results will be closer to the competitive results depending on its value; in addition hydro scheduling will be determined in part by demand elasticity. Estimates of the price elasticity of demand for electricity vary widely in the literature. As Dahl (1993) pointed out, the estimation of price elasticity is sensitive to the type of model used, to the estimation technique and to the data set used.[38] For instance, Wolak and Patrick (2001) in

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[34] A linear functional form is consistent with the peak shaving criteria that will be used later to allocate hydro generation: periods of high demand are also periods of high marginal revenue.

[35] I chose April because historically it has been the month where the highest demand of the year takes place.

[36] The observed load per hour was increased by 13% to take account of spinning reserves.

[37] Given the regulation, the nodal price is kept constant over a period of 6 months.

[38] Nesbakken (1999) suggested that since there is a lot of individual variation in energy used, estimates based on micro data were more reliable.

their study of large and medium sized industrial and commercial customers in the England and Wales market, got low estimates of short run price elasticity. In the water supply industry, which was the most price responsive industry analyzed, price elasticity estimates went from nearly zero (at peak) to -0.27. The steel tube industry was the least price responsive industry, with price elasticity estimates going from nearly zero to –0.007 (there is no indication of the demand level at which the upper estimate was observed). Garcia-Cerruti (2000) using panel (aggregate) data for selected California counties (1983-1997) estimated that short run price elasticity went from –0.132 to –0.172, while the range for the long run was from –0.17 to –0.19. On the other extreme, Nesbakken (1999) using micro data for residential energy consumption in Norway, estimated that the short run price elasticity ranged from –0.3 to –0.57.[39] In the particular case of Chile, Galetovic et al (2001) used a partial adjustment model to estimate the demand for electricity by commercial and residential users. Their estimates of short run (long run) price elasticity was –0.33 (-0.41) and -0.19 (-0.21) for residential and commercials users respectively.[40]

Because of the large variation in the price-elasticity estimates, I will follow the traditional approach of estimating and reporting the results of the model for different values of elasticity. In particular, the model will be estimated for 5 different values x = {-0.1, -1/3, -1/2, -2/3, -1.0}. In the main text of the paper I will only report results for –1/3 and – 2/3.[41] Remaining results will be reported in the Appendix. These values may appear to be high compared to some of the estimates reported. However it is not reasonable to assume that consumers will not react to the exercise of market power. In particular, we should expect them to learn, after a while, that the price is higher in certain periods than in others and to adjust their consumption behavior accordingly.[42]This change should mitigate the potential for market power. It is very difficult to explicitly incorporate this demand side reaction to market power into the model. An indirect way of doing it is to assume that the market is more price responsive than short run estimates of price elasticity indicate.

The price elasticity assumption was incorporated in the model through the slope parameter B, which was calculated such that the elasticity at the *peak* demand level was equal to "x". This implies that I will work with parallel demands ("same slope").[43] The

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[39] Dahl (1992) found no clear evidence that the developing world's energy demand were less price elastic than for the industrial world.

[40] As I mentioned before, the nodal price in Chile is fixed for a period of 6 months. During that period, it changes mostly according to he evolution of inflation. This means that the authors did not have much price variation over time. However, since the price that was used to estimate price elasticity was the final price, and since that price includes transmission and distribution charges that vary across consumers according to different parameters, they did have cross-section price variation..

[41] For comparison purposes, it may be useful to keep in mind the price elasticity values ("E") assumed by other authors. A constant elasticity of demand was assumed by Borenstein and Bushnell (1999), estimating the model for E=-0.1, 0.4 and 1.0 and by Andersson and Bergman (1995) who used E=0.3. A linear demand was assumed by Wolfram (1999) with E=-0.17 at the mean price and quantity and by Bushnell (1998) who assumed E=-0.1 at peak forecasted price/quantity point.

[42] See Wolak and Patrick (2001) and Herriges et al (1993) for estimations of elasticity of substitution within the day.

[43] I also ran the model assuming that the slope parameter B was such that the elasticity at every anchor point was equal to "x". This is referred to as the "different slope" approach. Results and magnitudes are very similar to the ones that I got with the "same slope approach" and they are reported in Appendix. I

intercept was calculated so as to fit anchor quantity and anchor price at each demand level (given the calculated slope B).[44] See Table 2 for demand parameters used assuming $x = -1/3$.

Table 2: Demand Estimation, April 2000, Elasticity = -1/3

Demand level	**# hours**	**Anchor quantity MW**	**Anchor price US$/MW**	**A**	**B**	**Elasticity at anchor point**
1	120	4749.7	31.1	6332.9	50.9	0.333
2	120	4329.6	31.1	5912.8	50.9	0.366
3	120	4091.1	31.1	5674.3	50.9	0.387
4	120	3643.3	31.1	5226.5	50.9	0.435
5	120	3270.8	31.1	4854.0	50.9	0.484
6	120	2988.5	31.1	4571.7	50.9	0.530

By assuming that demand is linear and the slope is constant across load levels, I am implicitly assuming that demand at peak hours is less elastic than demand at off peak hours (at a constant price). [45] Neither the linear demand assumption nor the anchor point choice had an influence on the results. Main conclusions (even order of magnitudes) were the same when running the simulation assuming that the slope was not constant.

b) *Fringe's supply:* In order to minimize the number of steps that the residual demand faced by Cournot producers have, I decided to use a linear approximation of the Fringe's supply function. This linear function is given by the following expression:

$$
\begin{array}{lll}
MC^{F} & = 3.66 & \text{for } 0 = Q^{F} = 54.9 \text{ MW} \\
 & = -114.60441 + 2.156038Q^{F} & \text{for } 54.9 = Q^{F} = 58.5 \text{ MW} \\
 & = 11.51217 & \text{for } 58.5 = Q^{F} = 399.9 \text{ MW} \\
 & = -333.526 + 0.8628848Q^{F} & \text{for } 399.9 = Q^{F} = 433.7 \text{ MW}
\end{array}
$$

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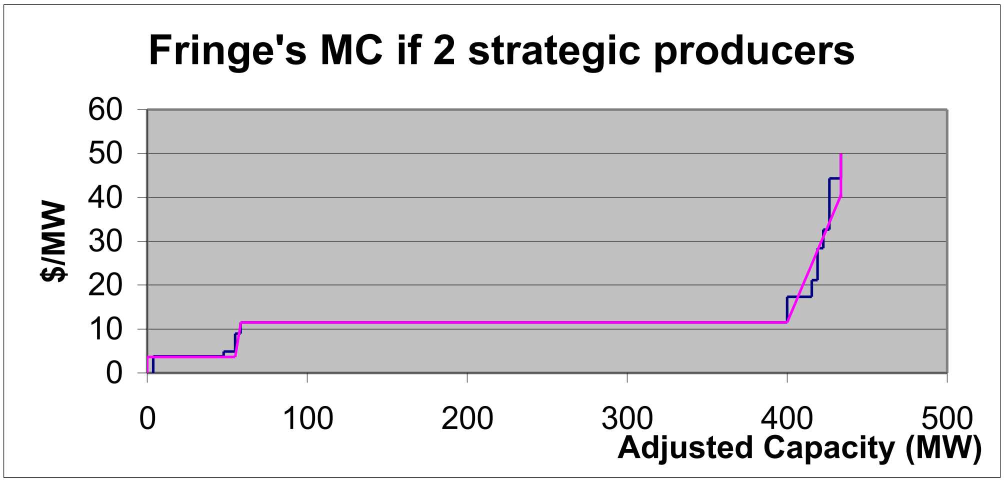
decided to report in the main paper the results for the same slope approach because when using the different slope approach, residual demands intersect on a certain (and relevant) price range making it more difficult to interpret results. Lerner indices are almost the same under both approaches.

[44] A similar approach was used by Bushnell (1998).

[45] Empirical evidence supports the assumption of price elasticity being a function of the output level as the linear functional form implies. However, evidence is not conclusive regarding whether demand at peak hours is more or less elastic than at off peak hours. Aigner et al (1994) estimated that demand for electricity in the winter was more elastic during peak periods while in the spring/autumn season it was the off peak demand the one that was more price responsive.

Figure 5



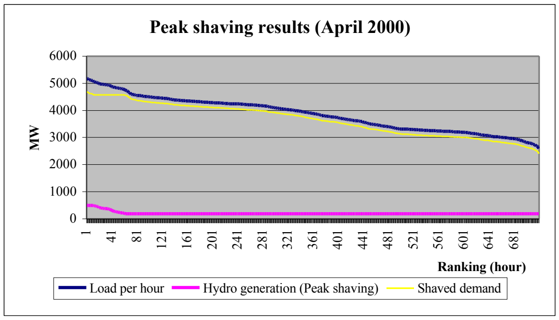
c) *Must run quantity:* The plants that have to be dispatched all the time (no matter the price) and thus cannot be used strategically by their owners were designated as "must run" plants. This includes two small co-generator thermal plants that produce electricity and steam and all the hydro-ROR plants that are not associated to any reservoir system. q^{MR} was calculated as the actual average generation per hour in the case of thermal plants, and as the average generation in a normal hydro year calculated according to the Energy Matrix provided by the CDEC in the case of hydro-ROR plants. [46]

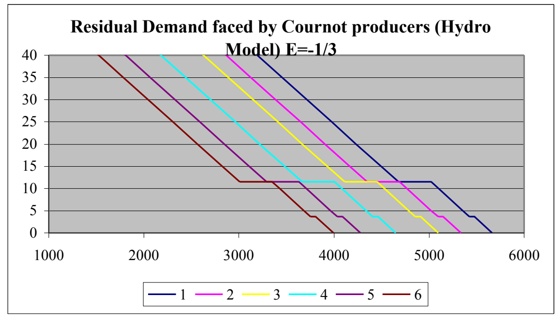
d) *Hydro-reservoir generation by the Fringe* ($q^{PS}{}_{h}$). In order to allocate the hydro-storage generation by the Fringe, I calculated, for each plant, the average generation per month (in this case April) in a normal hydrological year based on the Energy Matrix estimated by the CDEC. The monthly hydro generation calculated in this way is the total hydro production that was allocated each hour according to the peak shaving strategy described before. Minimum and maximum flow constraints were also taken into account. $q^{PS}{}_{h}$ used to estimate the model is the average hydro generation per hour allocated to each sub-period according to this approach.

   Since the Fringe owns relatively small hydro-storage plants, the amount of hydro production that can be allocated through a peak shaving approach is also small. Peaks are only slightly reduced and the shape of the "shaved load" curve remains mostly the same. (See Figure 6).

[46] Since Must Run plants' production was subtracted from total demand, the plants were also removed from the set of available units (in other words, they are not included in the aggregated marginal cost function).

Figure 6 **Figure 7**





e) *Residual demand*: See the following table for what was subtracted from market demand (April 2000) to get the demand faced by the Cournot producers.

Table 3: Data to calculate residual demand (MW)

Demand level	Hydro peak shaving	Thermal must run generation	Hydro ROR Must run generation	Total
1	274.6	14.2	380.3	669.1
2	183.8	14.2	380.3	578.2
3	183.8	14.2	380.3	578.2
4	183.8	14.2	380.3	578.2
5	183.8	14.2	380.3	578.2
6	183.8	14.2	380.3	578.2

The shape and position of residual demands faced by Cournot producers is explained by a combination of three elements: the anchor point, the fringe's supply for thermal production and the load curve shape that results after allocating fringe's hydro production through a peak shaving strategy and. (See Figure 7). [47]

Hydro data

Minimum hydro production per hour is given by technical requirements and by irrigation contracts. Maximum hydro production per hour is determined by technical requirements. Total April's available hydro production is 1118.1 GWh according to the Energy Matrix provided by the CDEC[48]. Since I divided total demand in 6 periods of constant demand, that quantity will have to be divided among 6 periods of 120 hours each. That means that $\Sigma\, q^h_t = 1118.1 / 120$, where "t' denotes each "representative" period and q^h_t denotes constant hydro production to be allocated to period t. Fringe's hydro production was allocated according to the Peak shaving strategy, as was explained before. Hydro scheduling by Firm 1 will be a result of the model.

[47] A similar pattern is observed when using the "different slope approach".

[48] Unfortunately, the CDEC does not have and estimation for the Laja system (the largest in the country). Because of that I used the observed average generation of that hydro system in April of a normal year.

Table 4

Firm	q^h_{min} (MW)	q^h_{max} (MW)	$q^{\sim h}$ (GWh month)	$q^{\sim h}$ (MWh / period)
Firm 1	743.7	2436.1	974.9	8123.8
Fringe	183.8	489.2	143.2	1193.3

Results

As a benchmark case, I calculated the competitive equilibrium. All the hydro-storage production (from both the fringe and Firm 1) was allocated according to the peak shaving strategy. (See Figure 8) Then I estimated a market demand for thermal generation, or "net demand", where must run and hydro generation were subtracted from total demand ($D(P) - q^{MR} - q^{PS}_h$). The competitive equilibrium was calculated as the quantity - price point where net demand and the aggregate marginal cost function intersect. Notice that the resulting Q is not the total quantity, but only the quantity that is produced by the Cournot producers and by the fringe, in other words, "thermal" production. Total output $= Q + q^{mr} + q^{ps}$. A chart, with a graphical equilibrium follows:

Figure 8

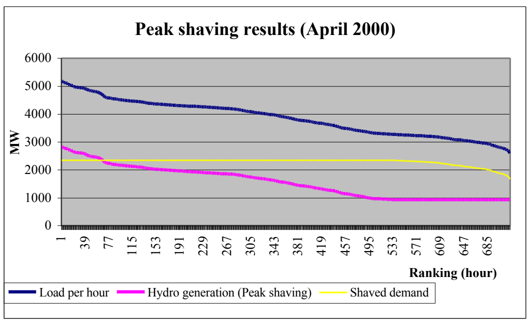
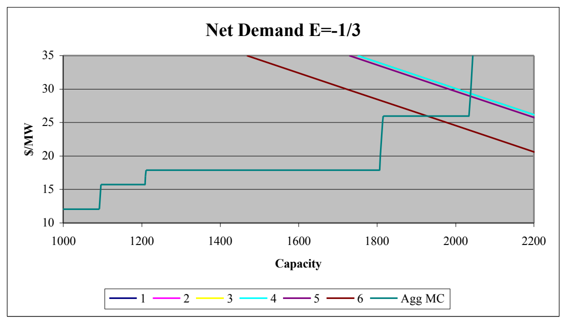


Figure 9



Resulting competitive equilibrium is reported below:

Table 5: Competitive results (E= -1/3)

t	qth1	qth2	QRth	qh1	qh2	QRh	QR	Qthfringe	Qtot	Price
1	673.1	944.4	1617.5	2133.1	0.0	2133.1	3750.6	420.5	4839.0	29.4
2	673.1	944.4	1617.5	1802.6	0.0	1802.6	3420.1	420.5	4418.9	29.4
3	673.1	944.4	1617.5	1564.1	0.0	1564.1	3181.6	420.5	4180.4	29.4
4	673.1	944.4	1617.5	1116.3	0.0	1116.3	2733.8	420.5	3732.6	29.4
5	673.1	944.4	1617.5	764.7	0.0	764.7	2382.2	420.1	3380.5	28.9
6	566.2	944.4	1510.6	743.7	0.0	743.7	2254.4	416.6	3249.3	26.0

Table 6: Competitive results (E= -2/3)

t	qth1	qth2	QRth	qh1	qh2	QRh	QR	Qthfringe	Qtot	Price
1	673.1	944.4	1617.5	2133.1	0.0	2133.1	3750.6	421.5	4840.0	30.2
2	673.1	944.4	1617.5	1802.6	0.0	1802.6	3420.1	421.5	4419.9	30.2
3	673.1	944.4	1617.5	1564.1	0.0	1564.1	3181.6	421.5	4181.4	30.2
4	673.1	944.4	1617.5	1116.3	0.0	1116.3	2733.8	421.5	3733.6	30.2
5	673.1	944.4	1617.5	764.7	0.0	764.7	2382.2	421.3	3381.7	30.0
6	673.1	944.4	1617.5	743.7	0.0	743.7	2361.2	418.4	3357.8	27.5

Observe that equilibrium is exactly the same for the first four periods (t=1 to 4) and almost the same for the fifth one. This is a consequence of net demand being the same in those periods, or, in other words, of hydro production being so large that its allocation across the month completely flattens demand in those periods, eliminating (reducing) the peaks[49]. See Figures 8 and 9 above.

Cournot equilibrium

I solved the model using GAMS. I started assuming that each firm produced at the average level observed in April 2000, and then solved for the Cournot equilibrium for Firm 2. Given the resulting production schedule, I solved for Firm 1 and used the resulting Cournot equilibrium as an input for Firm 2's maximization problem. I continued this iteration process until the model converged to a solution for each of the firms[50]**.** Results follow:

Table 7: Hydro model, Cournot Equilibrium (E=-1/3)

t	qth1	qth2	QRth	qh1	qh2	QRh	QR	Qthfringe	Qtot	Price
1	258.4	944.4	1202.8	1618.5	0.0	1618.5	2821.3	441.2	3931.3	47.2
2	258.4	944.4	1202.8	1453.7	0.0	1453.7	2656.5	437.5	3672.3	44.0
3	258.3	944.4	1202.7	1334.5	0.0	1334.5	2537.3	434.9	3550.4	41.7
4	0.0	944.4	944.4	1369.0	0.0	1369.0	2313.4	429.9	3321.5	37.4
5	0.0	867.7	867.7	1221.1	0.0	1221.1	2088.7	426.6	3093.6	34.6
6	0.0	773.6	773.6	1127.0	0.0	1127.0	1900.6	424.5	2903.3	32.8

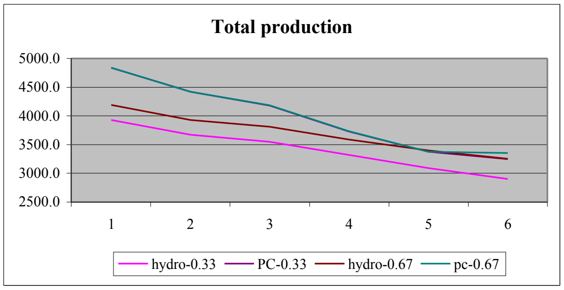
Table 8: Hydro model, Cournot Equilibrium (E=-2/3)

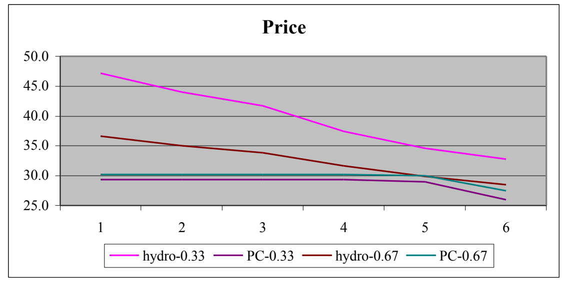
t	qth1	qth2	QRth	qh1	qh2	QRh	QR	Qthfringe	Qtot	Price
1	395.1	944.4	1339.5	1750.9	0.0	1750.9	3090.4	429.0	4188.1	36.6
2	395.1	944.4	1339.5	1586.0	0.0	1586.0	2925.6	427.1	3930.9	35.0
3	395.1	944.4	1339.5	1466.8	0.0	1466.8	2806.3	425.8	3810.3	33.9
4	342.7	944.4	1287.1	1295.4	0.0	1295.4	2582.4	423.2	3583.9	31.7
5	342.7	944.4	1287.1	1109.1	0.0	1109.1	2396.2	421.1	3395.6	29.9
6	395.0	944.4	1339.4	915.6	0.0	915.6	2255.0	419.6	3252.8	28.5

Total quantity is smaller than in the competitive model and prices are considerably higher, especially when demand is high. Notice that as demand falls, the Cournot equilibrium (price and production) converges monotonically to the competitive equilibrium. The exception is given by the last period when demand is at its lowest level which may be explained by Firm 2 increasingly constraining production as demand falls. The more elastic is demand, the larger is total production and the closer is hydro production to the competitive equilibrium.

[49] A similar result holds for the "different slope approach". The difference is that since the slope is different, net demands are not exactly the same in the first four periods but they are very close.
[50] Uniqueness of equilibrium was not investigated theoretically but empirically. In particular, the simulation was solved for different starting points. It always converged to the same equilibrium.

Figure 10 **Figure 11**





Firm 2 uses heavily its thermal capacity. Indeed, Firm 2 is "sort-of"capacity constrained when demand is high and thus can effectively exercise market power only in the last 2 periods, when demand is low. (See Figure 13) [51]. It is reasonable to think that when demand is high, Firm 1 is the one that really enjoys market power.

Firm 1 chooses to satisfy demand mainly through hydro production. In particular, it uses *all* the hydro production that is available but allocates it differently than in the competitive model. Firm 1 allocates relatively *less* water to high demand periods and relatively *more* water to the low demand periods (See Figure 10) [52]. This hydro allocation enlarges the difference between peak and off-peak periods rather than reducing it, as we observe in a competitive market. This effect is *smaller* the more elastic is demand. [53]. Firm 1's hydro scheduling strategy is consistent with what has been found in the literature. According to Johnsen et al (1999) "market power can not be exercised in markets dominated by hydroelectric producers unless there are transmission constraints". The hydro producer exploits differences in demand elasticity, reducing production when the constraint is binding (and demand is less elastic)[54]. My model results show that transmission constraints are not a necessary condition to the exercise of market power by hydro producers. Capacity constraints (supply constraints) will have the same effect. In other words if a hydro producer competes with a thermal producer, the first one may choose to restrict production when the thermal producer is capacity constrained, and to increase production the rest of the time. In this way, one could say that Firm 1 faced a less elastic demand when Firm 2 is capacity constrained. As a consequence, the shifting of hydro production is also the result of Firm 1 exploiting differences in price elasticity.

---

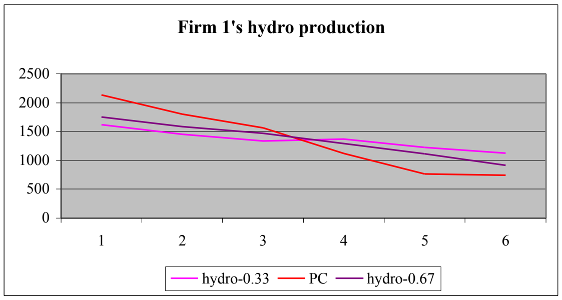
[51] By "sort-of" capacity constrained I mean the following: The big difference observed between the marginal cost of Firm 2's next available plant and the marginal plant at that demand level (almost $30) prevents Firm 2 from increasing production. By contrast, Firm 1 has a large capacity at a relatively low marginal cost. See Figure 2

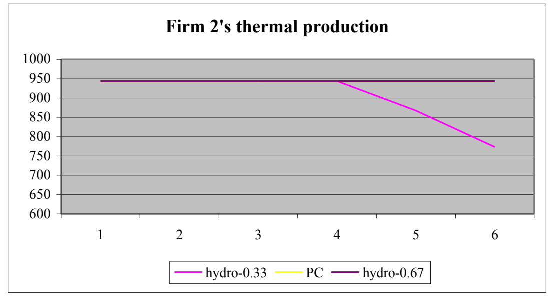
[52] This finding is consistent with Bushnell (1998)'s findings..

[53] It cannot be argued that the demand assumptions are driving the results. Even though I am implicitly imposing that peak demand is less elastic than off-peak demand (at a constant price) I am not imposing in any way how the water should be allocated across periods. This is just a result of the model.

[54] Notice that whether or not transmission constraints bind has an impact on the elasticity of the residual demand faced by the Cournot producers as imports/exports of energy take place (or not).

Figure 12 **Figure 13**





Firm 1's markups are decreasing as the demand it faces falls and they go from 66% to 76%, with a weighted average of 72% when demand elasticity is $-1/3$. The more elastic is demand, the smaller are the Lerner Indices, as expected. Firm 2's markups do not exhibit the same monotone pattern. In particular, the Lerner index is larger during the middle hours. [55]

Table 9: Lerner Indices

	E = -1/3		E= -2/3	
t	**Firm 1**	**Firm 2**	**Firm 1**	**Firm 2**
1	76%	38%	57%	25%
2	75%	41%	55%	26%
3	73%	43%	53%	27%
4	70%	48%	50%	29%
5	68%	48%	47%	31%
6	66%	45%	45%	32%

The Cournot equilibrium is not only inefficient because production falls short the competitive equilibrium production level but also because costs of production are not minimised. In particular, the fringe is running plants that are less efficient (higher marginal cost) than the ones that are being withheld by Firm 1.[56]

VI. Potential Mitigation Measures

According to the results that were reported in the previous Chapter, if a power exchange system were implemented in Chile, large generating companies, in particular Firm 1, would have plenty of room to exercise market power. Indeed, markups could be as high as 76% during peak hours (assuming price elasticity = -1/3).

[55] The Lerner index shows market power that is exercised. Since Firm 2 is "capacity constrained", it is probably not exercising market power. Consequently, Firm 2's Lerner index doesn't have an economic meaning during those periods.

[56] The possibility of inefficient dispatching was pointed out by Von der Fehr and Harbord (1993), Borenstein et al (2000) and Wolfram (1998).

Both the regulatory authority and public opinion have proposed some measures that would mitigate market power abusive practices. I would like to concentrate in four of them: full and partial divestiture of hydro storage generating capacity by Firm 1, full divestiture of its thermal capacity and contracting practices between producers and consumers (generating and distribution companies). Due to the importance of having a quantitative estimation of the real impact of these measures I estimated four different versions of the original model, each of them incorporating one of these mitigation measures.

1. Full Divestiture of hydro resources

Since a huge portion of Firm 1's market power was given by its property of hydro-storage plants, a policy that prevents the strategic use of those resources is required. This could be done by requiring Firm 1 to dispose of those plants.[57] Alternatively, we could think of a scenario where Firm 1 is entitled to bid only its thermal capacity while its hydro production would be scheduled by an independent agent such as the CDEC. Firm 1 would only be able to use strategically its thermal capacity. As a result, the industry would be made up by two large thermal producers (Firms 1 and 2) who play Cournot and by a price-taking fringe that owns a small fraction of thermal capacity but all the hydro capacity of the system. Installed capacity would be distributed among producers as follows:

Table 10: New distribution of Installed capacity in the SIC, MW

Economic Group	Thermal	Hydro-reservoir	Total
Endesa (Firm 1)	939	0	939
Gener (Firm 2)	1212	0	1212
Fringe	431	3151	3582
Total	2581	3151	5732

Hydro-ROR not included in the table.

Supply and demand side of the model is basically the same of the "hydro model". In particular, marginal cost functions are given by the same functions that were reported in Chapter IV**.** In what follows this model will be referred to as the "thermal model".

Cournot producers face, as in the hydro model, a residual demand of the following form:

$$D^R (P) = D(P) - S^f (P) - q^{MR} - q^{PS}_h$$

The only difference is that in this case all of the system's hydro production from reservoirs will be distributed across periods according to a peak shaving strategy.[58]

[57] Selling all the hydro storage plants to many different small producers is unrealistic because the operation of the hydro system under those circumstances would be too difficult.

[58] Hydro-ROR plants are still assumed to be must run plants.

Table 11: Data to calculate residual demand

Demand level	Hydro peak shaving	Thermal must run generation	Hydro ROR Must run generation	Total
1	2406.5	14.2	380.3	2801.0
2	1986.4	14.2	380.3	2380.9
3	1747.9	14.2	380.3	2142.4
4	1300.1	14.2	380.3	1694.6
5	948.5	14.2	380.3	1343.0
6	927.5	14.2	380.3	1322.0

The importance of hydro production is clearly observed in the following charts. Hydro generation is large enough to flatten demand over almost all the period. This means that shaved load curve (i.e. total demand – hydro generation) is almost constant during a large fraction of the month, eliminating the peaks. Because of the anchors that I used (same price and same slope) this result translates into same residual demands over the first four periods.[59]

Figure 14

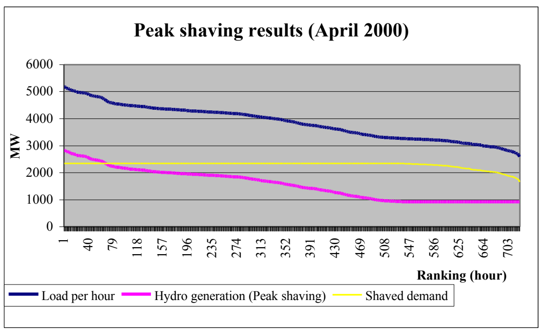
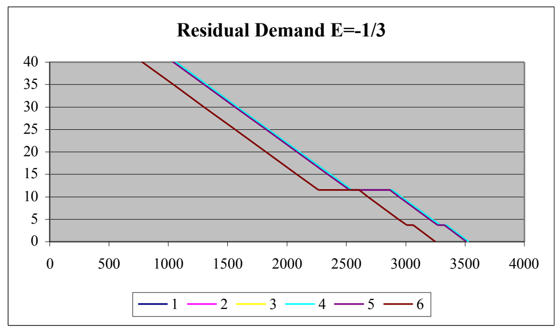


Figure 15



The model to be estimated is basically the same hydro model except that in this case Firm 1 does not have hydro resources to allocate across periods; this turns the problem into a completely static one. There are no interactions between one period and another; the producers treat each period as a different and independent market. Each firm's maximization problem is given by

Firm 1's maximization problem:

$$\max_{q^{Th}_{1\,t}} \quad \Sigma_t \left(P_t(Q_t)\, q_{1\,t} - C_1 (q^{Th}_{1\,t}) \right) \qquad (13)$$

$$\text{s.t.} \qquad q^{th}_{1,\,min} \leq q^{th}_{1\,t} \leq q^{th}_{1,\,max} \quad \forall\, t \qquad (14)$$

---

[59] When using the "different slope approach", residual demands are not exactly the same for the first 4 periods as they are in this case. They are however very close to each other. In addition, residual demands intersect around a price of \$31. As before, conclusions (and even magnitudes) drawn from the same slope approach are the same than one gets from the different slope approach. The main difference is that prices are not the same during the first four periods (because residual demand is not exactly the same) and that prices exhibit an inverted U shape pattern as demand falls, which is a result of residual demands intersecting over the relevant range, determining that $q^R_{i5} > q^R_{i4} > q^R_{i3} > q^R_{i2} > q^R_{i1}$, where q^R_{it} is residual demand faced by firm i in period t.

Firm 2's maximization problem:

$$\max_{q^{Th}_{2t}} \Sigma_t \left(P_t (Q_t)\, q^{Th}_{2\,t} - C_2 (q^{Th}_{2\,t}) \right) \qquad (15)$$

$$\text{s.t.} \qquad q^{th}_{2,\,min} \leq q^{th}_{1\,t} \leq q^{th}_{2,\,max} \quad \forall\, t \qquad (16)$$

As before, the planning horizon of the model will be assumed to be a month, which will be divided in 6 sub-periods (t=1,2,..6) of equal length. The Lagrangean is the same for both firms and given by[60]:

$$L = \Sigma_t \left[P_t (Q_t)\, q_{i\,t} - C_i (q^{Th}_{i\,t}) \right] \qquad (17)$$

Because of the inexistence of anything that links one period to another, solution of the problem involves 6 different and independent FOCs. As it was the case for Firm 2 in the hydro model described before, in equilibrium both firms' marginal cost has to be equal to their marginal revenue. FOC are

$$C'_i (q^{Th}_{it}) = P_t(Q_t) + q_{it} \times dP/dQ \qquad \forall\, t \qquad (18)$$

The model was estimated using GAMS. Results are reported in the following tables. As before, I will only report results for the case where price elasticity is –1/3. For comparison purposes, hydro model and competitive results will be reported again.

Table 12: Thermal model, Cournot equilibrium (E=-1/3)

t	qth1	qth2	QRth	qh1	qh2	QRh	QR	Qth fringe	Qtot	Price
1	457.7	877.5	1335.2	0.0	0.0	0.0	1335.2	426.8	4562.9	34.8
2	457.7	877.5	1335.2	0.0	0.0	0.0	1335.2	426.8	4142.8	34.8
3	457.7	877.5	1335.2	0.0	0.0	0.0	1335.2	426.8	3904.3	34.8
4	457.7	877.5	1335.2	0.0	0.0	0.0	1335.2	426.8	3456.5	34.8
5	454.6	868.6	1323.2	0.0	0.0	0.0	1323.2	426.6	3092.7	34.6
6	454.6	737.9	1192.5	0.0	0.0	0.0	1192.5	423.7	2938.2	32.1

Table 13: Hydro model, Cournot equilibrium (E=-1/3)

t	qth1	qth2	QRth	qh1	qh2	QRh	QR	Qth fringe	Qtot	Price
1	258.4	944.4	1202.8	1618.5	0.0	1618.5	2821.3	441.2	3931.3	47.2
2	258.4	944.4	1202.8	1453.7	0.0	1453.7	2656.5	437.5	3672.3	44.0
3	258.3	944.4	1202.7	1334.5	0.0	1334.5	2537.3	434.9	3550.4	41.7
4	0.0	944.4	944.4	1369.0	0.0	1369.0	2313.4	429.9	3321.5	37.4
5	0.0	867.7	867.7	1221.1	0.0	1221.1	2088.7	426.6	3093.6	34.6
6	0.0	773.6	773.6	1127.0	0.0	1127.0	1900.6	424.5	2903.3	32.8

[60] I assume that constraints 14 and 16 do not bind.

Table 14: Competitive results (E=-1/3)

t	qth1	qth2	QRth	qh1	qh2	QRh	QR	Qth fringe	Qtot	Price
1	673.1	944.4	1617.5	2133.1	0.0	2133.1	3750.6	420.5	4839.0	29.4
2	673.1	944.4	1617.5	1802.6	0.0	1802.6	3420.1	420.5	4418.9	29.4
3	673.1	944.4	1617.5	1564.1	0.0	1564.1	3181.6	420.5	4180.4	29.4
4	673.1	944.4	1617.5	1116.3	0.0	1116.3	2733.8	420.5	3732.6	29.4
5	673.1	944.4	1617.5	764.7	0.0	764.7	2382.2	420.1	3380.5	28.9
6	566.2	944.4	1510.6	743.7	0.0	743.7	2254.4	416.6	3249.3	26.0

Observe first what happens to the use of thermal capacity, the only resource that can be used strategically in this model. While Firm 1 *increases* the use of its capacity, Firm 2 *reduces* it. This means that while Firm 1's thermal production is closer to the competitive equilibrium than it was in the hydro model, Firm 2 is further from it. In a completely "thermal" game, it is Firm 2 and not Firm 1 the one that really enjoys market power. [61]

Figure 16[62]

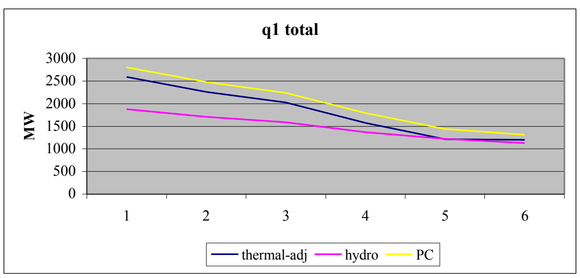


Figure 17

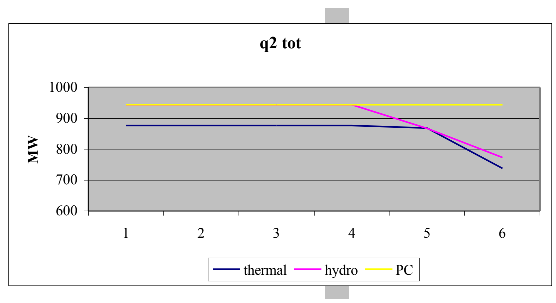


Figure 18

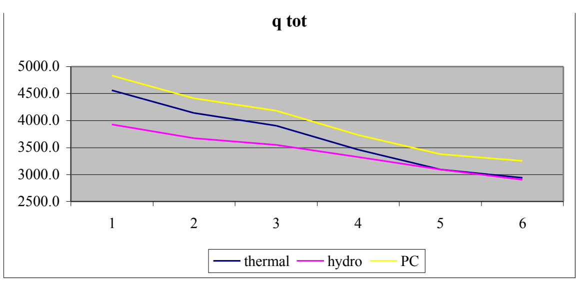
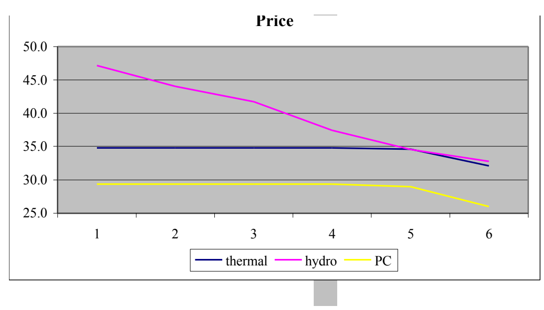


Figure 19



Observe that the results from the thermal and hydro models converge in the periods when demand is low. As it was expected, producers would charge a price that is in between the one that would be charged in a competitive and in the hydro model.

[61] Thermal quantities and prices are the same in the first four periods, a result expected given that residual demands were the same in those periods, after allocating hydro production through a peak shaving strategy.
[62] In the thermal case, I added the hydro generation produced from former Firm 1's hydro storage plants in order to be able to completely compare total quantities (q1 total (thermal adjusted) = q1th + q^{PS}_{h1})

Table 15: Lerner Indices

	Hydro model		Thermal model	
t	**Firm 1**	**Firm 2**	**Firm 1**	**Firm 2**
1	76.4%	38.4%	25.3%	48.5%
2	74.7%	41.2%	25.3%	48.5%
3	73.3%	43.5%	25.3%	48.5%
4	70.3%	48.5%	25.3%	48.5%
5	67.8%	48.2%	25.2%	48.2%
6	66.0%	45.3%	27.2%	44.2%

According to Table 15, requiring Firm 1 to dispose of its hydro plants effectively reduces market power. In fact, the industry reduces its average markup from 61.5% to 40.1%. Reduction in average markup is, however, not a generalized result. Indeed Firm 2 increases its average markup (from 44% to 48%) while Firm 1 reduces it (from 72% to 26%). It is interesting to notice that this change also entails a change in who is the one that effectively exercises market power in the power industry. In the hydro model, it was Firm 1 and in addition we got that in many cases Firm 2 was capacity constrained. In the thermal model, it is Firm 2 the one that enjoys more market power, while Firm 1 is even subject to some capacity constraints when demand is low.

The disposal of hydro-storage resources by Firm 1 has the effect of reducing the market power that it can exercise while transferring a part of it to Firm 2. Even though Firm 2 is able to exercise market power, the market equilibrium is closer to the competitive equilibrium.

While there may be economic reasons to implement this mitigation measure, in practice it may be difficult to. In particular, it is very unlikely that Firm 1 would be willing to dispose of its hydro plants because at the same time it would be giving up its market power. Someone might say that at the end it all depends on the price at which those plants are sold[63]. That is absolutely correct, however it s very easy to anticipate that the price at which Firm 1 would be willing to sell the plants will be higher than the price the small producers would be willing to pay for them. While Firm 1 will value its production at a "market power price", the small producers will value it at the competitive price. Under these circumstances, Firm 1 will be voluntarily willing to dispose of its hydro plants only if someone, the government for instance, makes up for the price difference. It is not clear whether the government would be willing to make such transference; if it does, it would be the price it is paying to get efficiency.

2. Partial divestiture of hydro plants: Divestiture of the "Laja" hydro-reservoir

Since requiring Firm 1 to dispose of all of its hydro-storage plants will probably prove too difficult to implement, an intermediate solution may be carried out. For instance, Firm 1 may be required to dispose of only one hydro-system, the Laja, which is the most

[63] It should be the same to be the owner of a milk cow than of the flow of milk it produces.

important in terms of inter-annual water regulation, but it would still be able to keep the remaining plants. [64] The new distribution of installed capacity, after Firm 1 has sold the Laja system is reported in the following table.

Table 16: New distribution of Installed capacity in the SIC, MW

Economic Group	Thermal	Hydro-reservoir	Total
Endesa (Firm 1)	939	1754	2693
Gener (Firm 2)	1212	0	1212
Fringe	431	1397	1828
Total	2581	3151	5732

Hydro-ROR not included in the table.

In order to analyze whether Firm 1 will retain a fraction of the market power it had in the hydro model, I estimated exactly the same hydro model that was described by equations 1-12, the only difference being the value of hydro parameters. This version of the model will be referred to as the "Laja model".

Hydro parameters are reported in the following table. Fringe's hydro production was allocated according to the Peak shaving strategy, as was explained before. Hydro scheduling by Firm 1 will be a result of the model.

Table 17

Firm	**q^h_{min} (MW)**	**q^h_{max} (MW)**	**$q^{\sim h}$ (GWh month)**
Firm 1	548.3	1628.5	470.7
Fringe	379.2	1296.8	647.3

The Fringe is able to allocate a total amount of hydro production that is in between the one it had in the hydro and thermal models. As a result, the peak shaving results in a shaved demand that still shows peaks but smaller than the ones observed in the hydro model. In fact, during the middle hours, shaved demand is almost constant. Consequently, residual demands faced by Cournot producers during those hours are almost the same. They are reported in the following charts:

Figure 20

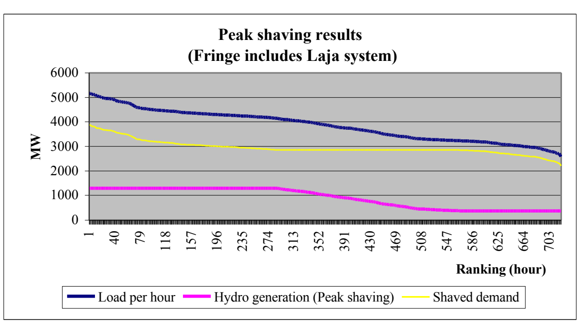
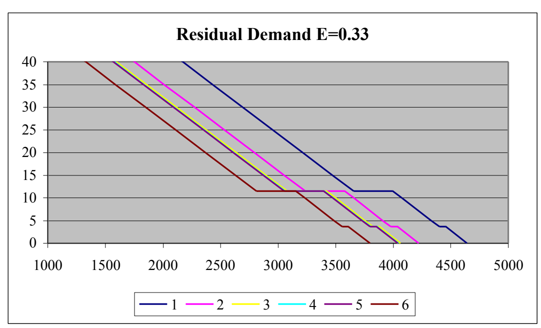


Figure 21



[64] One could still argue that there is going to be a difference in the price charged by Firm 1 and the one the small producers would be willing to pay, but it is reasonable to expect that the transfer the government would have to pay in order to make the sale of these plants real, would be smaller.

Table 18: "Laja" model, Cournot equilibrium (E=-1/3)

t	qth1	qth2	QRth	qh1	qh2	QRh	QR	Qthfringe	Qtot	Price
1	451.0	944.4	1395.3	793.7	0.0	793.7	2189.1	432.5	4312.8	39.7
2	355.2	930.3	1285.4	686.5	0.0	686.5	1971.9	428.0	4091.2	35.8
3	343.0	877.8	1220.8	646.2	0.0	646.2	1867.0	426.8	3904.0	34.8
4	350.4	871.8	1222.2	632.8	0.0	632.8	1855.0	426.7	3462.1	34.7
5	373.8	869.7	1243.5	607.3	0.0	607.3	1850.9	426.6	3091.6	34.6
6	344.6	789.1	1133.7	555.9	0.0	555.9	1689.6	424.9	2888.1	33.1

As it was expected, results are in between the thermal and the hydro model. The most interesting result is how each firm's relative position in the market changes with demand level. In the hydro model, we found that Firm 1 was the one that really enjoyed market power, while Firm 2 was in the thermal model. In this "in-between" model, both firms seem to enjoy market power, although who can really exercise it varies depending on the demand level. When demand is at its peak, Firm 1 is the one that really reduces its production; Firm 2 is "capacity constrained" and produces at the competitive level. Unlike that, in the middle hours, it is Firm 2 the one that enjoys market power; Firm 1's production closely resembles its production in the thermal model (when its market power was reduced).

Figure 22

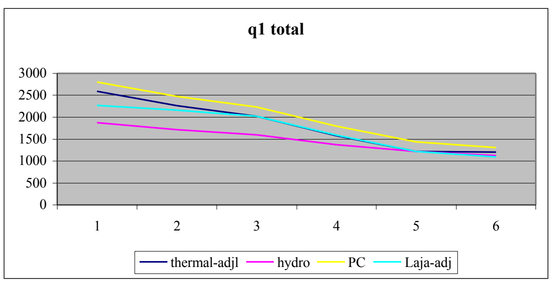


Figure 23

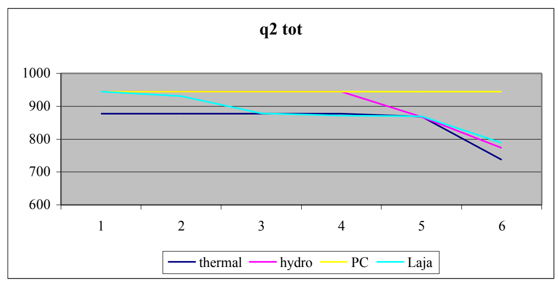


Figure 24

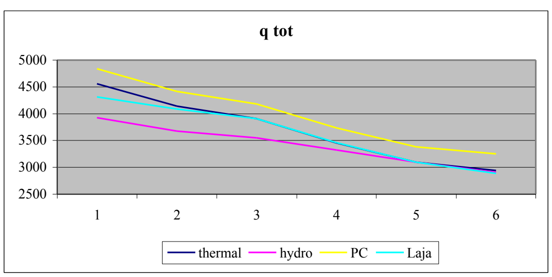


Figure 25

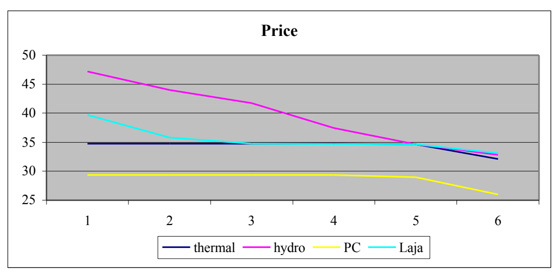


Table 19: Lerner Indices

	Hydro model		Laja Model		Thermal model	
t	Firm 1	Firm 2	Firm 1	Firm 2	Firm 1	Firm 2
1	76.4%	38.4%	60.2%	45.7%	25.3%	48.5%
2	74.7%	41.2%	55.9%	49.9%	25.3%	48.5%
3	73.3%	43.5%	54.6%	48.5%	25.3%	48.5%
4	70.3%	48.5%	54.5%	48.3%	25.3%	48.5%
5	67.8%	48.2%	54.4%	48.3%	25.2%	48.2%
6	66.0%	45.3%	52.3%	45.8%	27.2%	44.2%

Disposing of the Laja system by Firm 1 seems to help reducing market power, but it does not completely eliminate it. In fact, both Firms 1 and 2 have room to exercise market power at different demand levels. The main advantage that it has over the previous one is that it may be easier to implement, although there is no guarantee that it will be possible to implement it at all.

3. Full divestiture of thermal plants.

A third alternative of asset divestiture is given by Firm 1 being allowed to keep all of its hydro capacity but required to divest all of its thermal plants to many different small suppliers. Firm 1 would be a pure hydro producer and the Fringe, as a whole, would be the largest thermal producer, as it can be seen in the following table:

Table 20: New distribution of Installed capacity in the SIC, MW

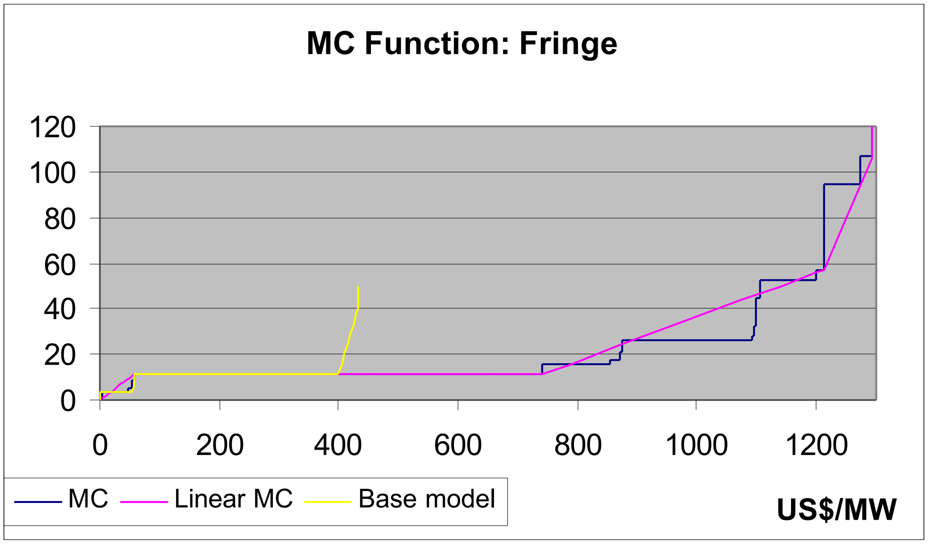
Economic Group	Thermal	Hydro-reservoir	Total
Endesa (Firm 1)	0	2454	939
Gener (Firm 2)	1212	0	1212
Fringe	1370	697	3582
Total	2581	3151	5732

Hydro-ROR not included in the table.

The transfer of the thermal capacity to the Fringe will result on Cournot producers facing *a smaller and more elastic residual demand*. The new Fringe's marginal cost function is reported in the following figure, along with the linear version of it that will be used to run the simulation[65]. The Fringe's marginal cost function used in the hydro model is also reported for comparison purposes. Notice that most of the plants that would be transferred are less efficient than the ones that the Fringe already had; in addition, remember that Firm 1's marginal cost function is above Firm 2's over almost all the range. (See Figure 1)

[65] Given that the linearizations are not exactly the same, results from the different models are not completely comparable.

Figure 26



The other elements of the model remain the same (Firm 2's marginal cost function, must run generation, hydro resources available and hydro generation by the fringe). The optimization problem is basically the same than in the hydro model. Differences are given by $q_{1t} = q_{1t}^{h}$ (because $q_{1t}^{th} = 0$) and by the omission of equation (3). Results from the simulation for the case where E = -1/3 are reported in the Table 21.

Table 21: Cournot equilibrium: Firm 1 owns only Hydro plants (E=-1/3)

t	qth1	qth2	QRth	qh1	qh2	QRh	QR	Qthfringe	Qtot	Price
1	0.0	944.4	944.4	1712.0	0.0	1712.0	2656.4	1026.3	4351.7	38.9
2	0.0	944.4	944.4	1547.3	0.0	1547.3	2491.7	998.5	4068.5	36.2
3	0.0	944.4	944.4	1428.1	0.0	1428.1	2372.5	978.4	3929.1	34.3
4	0.0	833.5	833.5	1259.6	0.0	1259.6	2093.1	950.0	3621.4	31.5
5	0.0	709.3	709.3	1135.5	0.0	1135.5	1844.8	929.1	3352.1	29.5
6	0.0	615.2	615.2	1041.4	0.0	1041.4	1656.6	913.3	3148.1	28.0

The most notable effect of forcing Firm 1 to sell all of its thermal capacity is a reduction in price and an increase in total output (comparable results for the hydro model are in Tables 7,8 and 9). This result may lead us to, mistakenly, conclude that Cournot producers exercise less market power. However, it should be noted that Firm 1 allocates its hydro resources in not only the same way that it did it before (less when demand is high, more when demand is low), but in similar amounts[66]. This should not come as a surprise since when it had a thermal portfolio, it decided to use only a minimum fraction of it (Firm 1 only used 27% of its thermal capacity when demand was high; it did not use it when demand was low)[67]. On the other hand, Firm 2's relative position in the market is strengthened. As a result, it constrains its production (relative to the competitive equilibrium and to the hydro model) in the intermediate and low demand levels (it is still

[66] In addition, the estimated marginal water value is almost the same in both models.

[67] Firm 1's marginal cost function is above Firm 2's marginal cost function over almost all the range.

capacity constrained when demand is high). Consistent with this is the fact that Lerner indices are slightly lower than the ones that I found in the base-hydro case.

Table 22: Lerner Indices (E = -1/3)

	Firm 1 with thermal plants		**Firm 1 without thermal plants**	
t	**Firm 1**	**Firm 2**	**Firm 1**	**Firm 2**
1	76%	38%	72%	40%
2	75%	41%	70%	43%
3	73%	43%	68%	45%
4	70%	48%	65%	43%
5	68%	48%	63%	39%
6	66%	45%	61%	36%

The increase in total output and the reduction in price is then a result of the fringe's increasing its production by a very large amount. In fact, former Firm 1's thermal plants produce very close to what they would in the competitive equilibrium. It is worth mentioning too that the allocation is still inefficient but less than in the hydro model.[68]

None of the alternatives of asset divestiture that have been analyzed here completely eliminate the incentives to exercise market power. It is necessary to look for a different mitigation measure.

4. Contracting practices

A final mitigation measure that I will analyze is the effect of contracting practices. In other words, generating companies will be entitled to sell to consumers a pre-arranged quantity at a pre-arranged price ("strike price"). In particular, I will assume that these contracts take the form of "two-way options", i.e. both parties deal with the spot market and the consumer is compensated for the difference between the spot price (P) and the strike price (W) if P>W (or vice versa). Contracts are private and are arranged outside the spot market; strike prices are not *directly* affected by the spot price in any given period.

I would like to remark at this point that I will not concentrate in the reasons why producers and consumers engage in contracting practices. I will just assume that because of a particular reason (or requirement) they do contract. [69]

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[68] In other words, Firm 2 could produce a fraction of what is being produced by the fringe at a lower marginal cost.

[69] There is an interesting literature regarding this issue. In particular some authors argue that even though it is true that given a large forward contract position, the generator would have less incentive to exercise market power, real and important issues should be why would they voluntarily give up to their market power position and sign these contracts. See for instance Harvey and Hogan (2000). They argue "The empirical evidence of the importance of contracting in mitigating market power relies on cases where the generators largely were forced to sign forward contracts (England and Wales, Australia). The theoretical models are interesting but ambiguous in their predictions… It is clear that generators will understand the incentives and will not be likely to volunteer for forward contracts at low prices that reduce their total profits". (pages 9-10) It is very likely that under the Chilean regulation, contracting practices will be mandatory. See Blais and Vila (1993) and Wolak (2000) for reasons why the generators competing in this market sell hedge contracts in large quantities.

The economic literature, both theoretical and empirical, has showed that the more contracted producers are, the less market power is exercised and the closer the outcome to a perfectly competitive (PC) market, in terms of prices and efficiency of output decisions,.[70] These results are explained by the change in producers' incentives that is observed when contracting practices are introduced. In particular, the more contracted a producer is, the more his profits are determined by the strike price as opposed to the spot market price. As a consequence, the firm has less incentive (or no incentive at all in the margin) to manipulate the spot price, as this would have little effect on its revenues. Indeed, for sufficiently high contract levels (when the firm is "over-contracted"[71]) profits are maximized at a price below its marginal cost.[72] Producers' incentive to raise the price is decreasing in the contracted quantity (See Newbery 1995). Wolak (2000) and Scott (1998) pointed out that what is really important for the final outcome is the overall level of contracting as opposed to the individual level of contracting.[73]

In order for contracting practices to mitigate market power, there must be some price responsiveness in demand. In other words, the more inelastic is demand, the less important is the contract level in producers' incentives to manipulate the price.

While the literature has extensively analyzed the impact that contracting practices on the "market equilibrium", the same has not happen with respect to their effect on hydro scheduling decisions. Scott (1998) shows that the higher the level of (total) contracting, the higher is total and hydro generation.[74] He also found a positive relationship between the total level of contracting and the marginal value of water. I would like to mention that this paper does not analyze the effect of contracts on the hydro *scheduling* issue explicitly. In particular, we know that the higher the level of overall contracting, the higher is hydro generation, but it is impossible to know how a particular firm allocates water across periods.[75] For instance, what does the firm do when it is over contracted in one period and under-contracted in the other one? My model will give an answer to this question.

In order to quantitatively analyze the effect of contracting practices, the following version of the model will be estimated:

---

[70] Harvey and Hogan (2000) point out that in a well designed competitive market, the existence of forward contracting opportunities should have no impact on the equilibrium expected prices in either the spot nor the forward market.

[71] A firm is over-contracted when the contracted quantity is more than what the firm can economically produce.

[72] Wolak (2000) uses a very simple framework to illustrate these effects.

[73] For more details on the impact of contracting practices see Wolak (2000), Allaz and Vila (1993), Newbery (1995) and Scott (1998).

[74] Over a certain level of contracting hydro generation is greater than in PC.

[75] It is impossible to know the answer to this question because of the way results are reported (hydro generation against total contracting level). However I think that the model does give an answer to the question posed but it wasn't reported.

Firm 1's maximization problem:

$$\max_{q^{Th}_{1t},\, q^{h}_{1t}} \; \Sigma_t \left(P_t(Q_t)(q_{1t} - k_{1t}) - C_1(q^{Th}_{1t}) \right) \qquad (19)$$

$$\text{s.t.} \quad q^{h}_{1,min} \leq q^{h}_{1t} \leq q^{h}_{1,max} \quad \forall t \qquad (2)$$

$$q^{th}_{1,min} \leq q^{th}_{1t} \leq q^{th}_{1,max} \quad \forall t \qquad (3)$$

$$\Sigma_t\, q^{h}_{1t} \leq q_1^{\sim h} \qquad (4)$$

Firm 2's maximization problem:

$$\max_{q^{Th}_{2t}} \; \Sigma_t \left(P_t(Q_t)(q^{Th}_{2t} - k_{2t}) - C_2(q^{Th}_{2t}) \right) \qquad (20)$$

$$\text{s.t.} \quad q^{th}_{2,min} \leq q^{th}_{2t} \leq q^{th}_{2,max} \quad \forall t \qquad (6)$$

where k_{it} is the quantity that was previously contracted outside the spot market. I omitted the "fixed revenue term" (strike price times contracted quantity, w x k) because it does not have any effect on the solution to the model. It will only affect the amount of revenues the firm gets.

When k = 0 (i.e. there are no contracts) the solution to the model is given by equations 8, and 10-12. When k > 0, equation 10 changes to

$$C'_{1t} = P_t(Q_t) + (q_{1t} - k_{1t})\, dP/dQ \rightarrow MR_{1t} = MC_{1t} \;\; \forall t \qquad (10')$$

We still get that the producer tries to equalize marginal revenue to marginal cost, but marginal revenue is not determined by the firm's total production, as before, but only by the level of production that is actually sold at the spot market. Notice that the smaller is this term, the closer is the marginal revenue to the price level, and thus the closer the "market power" equilibrium to the competitive equilibrium.[76] Equation 10' can be used to analyze the impact of being over (k>q) or under (k<q) contracted. When the producer is under-contracted, the market outcome will lie somewhere between the perfect competition and the no-contract equilibrium. When the producer is over-contracted (k>q), it is not a net seller in the market but a *net buyer*. In that case, the producer is no longer interested in driving prices up, but instead, it wants to drive prices *down* (and *below* marginal cost).

The competitive equilibrium will be the benchmark used to calculate the level of contracting at a certain time. In particular, when I say that the contracting level is x% I will mean that the contracted quantity (k) is given by x% of the load that the firm would

[76] When producers engage in contracting practices, market power in the spot market is measured by the excess of production over contracted quantity.

be expected to generate under perfect competition. This approach allows me to incorporate the fact that the contracted quantity is not constant across the month.[77]

The model was estimated using GAMS. Results for different contracting levels (0%, 50% and 100%) follow. Results will be reported for the case where price elasticity of demand is –1/3[78]. Note that when k=0 we go back to the original hydro model and that when the firms are "fully contracted" (contracting level = 100%) results are very close to the competitive equilibrium.

Table 23: Hydro model, Contracting level = 0% (E=-1/3)

t	K1	K2	qth1	qth2	QRth	qh1	qh2	QRh	QR	Qthfringe	Qtot	Price
1	0	0	258.4	944.4	1202.8	1618.5	0.0	1618.5	2821.3	441.2	3931.3	47.2
2	0	0	258.4	944.4	1202.8	1453.7	0.0	1453.7	2656.5	437.5	3672.3	44.0
3	0	0	258.3	944.4	1202.7	1334.5	0.0	1334.5	2537.3	434.9	3550.4	41.7
4	0	0	0.0	944.4	944.4	1369.0	0.0	1369.0	2313.4	429.9	3321.5	37.4
5	0	0	0.0	867.7	867.7	1221.1	0.0	1221.1	2088.7	426.6	3093.6	34.6
6	0	0	0.0	773.6	773.6	1127.0	0.0	1127.0	1900.6	424.5	2903.3	32.8

Table 24: Hydro model, Contracting level =50% (E=-1/3)

t	K1	K2	qth1	qth2	QRth	qh1	qh2	QRh	QR	Qthfringe	Qtot	Price
1	1403.1	472.2	454.6	944.4	1399.0	1967.6	0.0	1967.6	3366.5	429.1	4464.4	36.7
2	1237.8	472.2	454.6	944.4	1399.0	1720.1	0.0	1720.1	3119.1	427.2	4124.6	35.1
3	1118.6	472.2	454.6	944.4	1399.0	1541.3	0.0	1541.3	2940.2	425.9	3944.4	34.0
4	894.7	472.2	454.6	944.4	1399.0	1205.4	0.0	1205.4	2604.4	423.4	3606.1	31.8
5	718.9	472.2	454.6	944.4	1399.0	931.3	0.0	931.3	2330.2	421.2	3329.7	29.9
6	655.0	472.2	454.6	944.4	1399.0	758.2	0.0	758.2	2157.1	418.8	3154.2	27.8

Table 25: Contracting level =100% (E=-1/3)

t	K1	K2	qth1	qth2	QRth	qh1	qh2	QRh	QR	Qthfringe	Qtot	Price
1	2806.2	944.4	673.1	944.4	1617.5	2134.7	0.0	2134.7	3752.2	420.5	4841.4	29.3
2	2475.7	944.4	673.1	944.4	1617.5	1804.6	0.0	1804.6	3422.1	420.5	4420.9	29.3
3	2237.2	944.4	673.1	944.4	1617.5	1566.2	0.0	1566.2	3183.6	420.5	4182.4	29.3
4	1789.4	944.4	673.1	944.4	1617.5	1118.4	0.0	1118.4	2735.8	420.5	3734.6	29.3
5	1437.8	944.4	673.1	944.4	1617.5	756.3	0.0	756.3	2373.8	420.3	3372.3	29.1
6	1310.0	944.4	566.4	944.4	1510.8	743.6	0.0	743.6	2254.4	416.6	3249.2	26.0

Table 26: Competitive results (E=-1/3)

t	qth1	qth2	QRth	qh1	qh2	QRh	QR	Qthfringe	Qtot	Price
1	673.1	944.4	1617.5	2133.1	0.0	2133.1	3750.6	420.5	4839.0	29.4
2	673.1	944.4	1617.5	1802.6	0.0	1802.6	3420.1	420.5	4418.9	29.4
3	673.1	944.4	1617.5	1564.1	0.0	1564.1	3181.6	420.5	4180.4	29.4
4	673.1	944.4	1617.5	1116.3	0.0	1116.3	2733.8	420.5	3732.6	29.4
5	673.1	944.4	1617.5	764.7	0.0	764.7	2382.2	420.1	3380.5	28.9
6	566.2	944.4	1510.6	743.7	0.0	743.7	2254.4	416.6	3249.3	26.0

[77] Unfortunately I do not have good information regarding contracting practices in Chile. I only have data on the annual level of contracting but there is no additional information regarding how it is distributed across the year, if there is any particular relationship with capacity, etc.
[78] Conclusions are the same for the remaining cases.

Figure 27

Figure 28

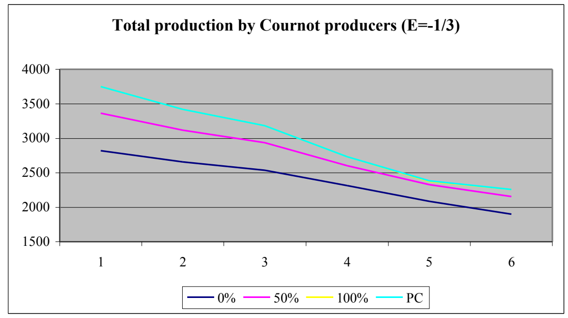

Figure 29

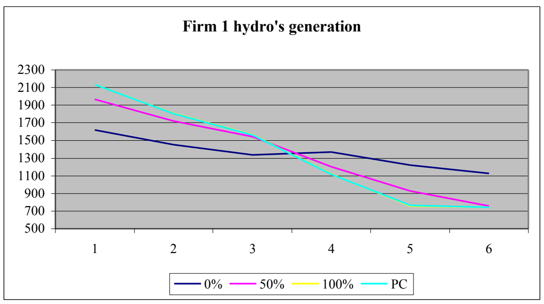

Figure 30

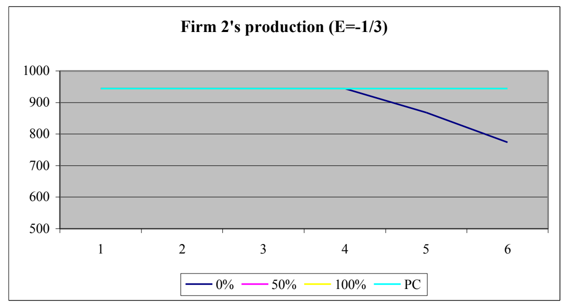

Figure 31

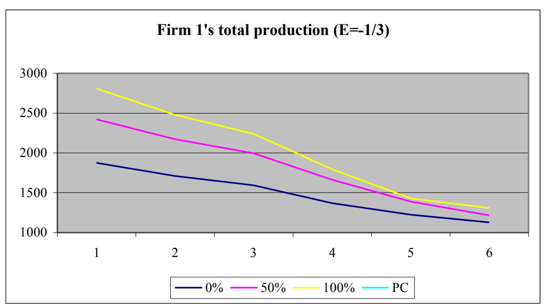

Table 27: Lerner Indices

	Contracting = 0%		Contracting = 50%		Contracting = 100%	
t	Firm 1	Firm 2	Firm 1	Firm 2	Firm 1	Firm 2
1	76.4%	38.4%	53.3%	24.7%	0%	0%
2	74.7%	41.2%	51.2%	25.8%	0%	0%
3	73.3%	43.5%	49.6%	26.7%	0%	0%
4	70.3%	48.5%	46.2%	28.5%	0%	0%
5	67.8%	48.2%	42.8%	30.3%	-1%	0%
6	66.0%	45.3%	38.5%	32.6%	0%	0%

As expected, the more contracted the firms are the lower are the prices, markups and the higher are quantities. In particular, when the firms are "fully contracted" the equilibrium is very close to the competitive equilibrium[79]. In addition, prices tend to be closer to marginal cost as the contracting level increases; indeed when Firm 1 is over-contracted (t=5 for a contracting level of 100%) price is lower than marginal cost as predicted by the theory.

Total production increases with the contracting level, as has also been found in the literature. There are two additional results that I would like to remark. First of all, notice that as the contracting level increases, Firm 2 loses all the market power that it had before. Remember that we found that Firm 2 could only exercise market power when demand was low, because in the other periods it was capacity constrained. However, when contracting practices are allowed (or forced) and they are sufficiently high, Firm 2 cannot exercise market power even in those low demand periods. Secondly, observe what happens to Firm 1's production. In addition to the fact that it produces more the more contracted it is (see Figure 31), there is an important change in the way hydro production is scheduled (see Figure 29). There may be two effects in place at the same time. By one side, I expect that the more contracted is the firm, the more efficient is its hydro scheduling. However, I also expected that when the firm was over-contracted, it would allocate more water to that period in order to drive the price down. What we observe is that as the contracting level increases, hydro scheduling is closer to the efficient (competitive) allocation. This means that there is not only a gain in terms of more production but also in how it is allocated (productive efficiency versus allocative efficiency). In addition, Firm 1 uses (relatively) more water when it is under-contracted (high demand periods) and less when it is over-contracted (when compared to the PC equilibrium). This implies that the contracting practices' "distortion reducing effect" dominates the second effect. It seems that Firm 1 increases total production at those times by relying as heavily as it can on its thermal plants; notice how closely is thermal production to the competitive equilibrium.

I would like to remark that my results differ from what was found by Scott (1998) regarding the impact of contracting practices on hydro production. He found a positive relationship between hydro production and the contracting level. According to my results, the higher is the contracting level, the closer is hydro scheduling to the optimal allocation, meaning that *more* is produced from hydro sources when demand is high and *less* is produced in low demand periods.

The more contracted the firm is, the higher is the marginal value of water, a result that is consistent with what Scott (1998) found for the electricity market in New Zealand. [80] The intuition behind this result is the following: the more contracted the firm is, the more it produces and given that the marginal cost function is increasing, the more costly it is to produce. In equilibrium the (total) marginal value of water has to be equal to thermal marginal cost, and thus the more the firm wants to produce, the more valuable is water.

[79] Notice that a contracting level of 100% does not mean that contracted quantity = production (k=q). How much the firm will produce at every period is an endogenous variable and thus difficult to predict with certainty at the time contracts are set.

[80] Recall from the theoretical model that it was given by $\Omega_{1t} = \sigma_1 + \gamma_{1t} + \delta_{1t}$.

Table 28: Marginal Value of water (W_1)

	Contracting Level		
t	0%	50%	100%
1	11.13	17.13	29.27
2	11.13	17.13	29.27
3	11.13	17.13	29.27
4	11.13	17.13	29.27
5	11.13	17.13	29.27
6	11.13	17.13	25.98

Do contracting practices help to mitigate market power? According to Table 27, the answer is yes. Firm 1's Lerner Indices are notably lower the more contracted the firm is.[81] Allowing the firms to engage in contracting practices (or requiring them to do it) entails the benefits of producing at levels closer to the competitive equilibrium and of increased productive and allocative efficiency.

VII. Conclusions

Currently Chilean authorities are evaluating the convenience of moving one step forward in the de-regulation process; in particular they are analyzing whether to stop regulating the nodal price. Concerns have been raised due to the high concentrations indices that the industry exhibits. In this paper the question of whether these high concentration indices would translate into anticompetitive behavior and market power abuses was addressed.

A model with 2 Cournot producers (Firms 1 and 2) and a competitive fringe was built. Both producers own thermal plants but only one of them (Firm 1) also owns hydro-storage plants. These plants turned out to be very important because they allowed the producer to store water (and power) and to allocate it over a certain planning horizon at its convenience. This alternative was not available to Firm 2.

The model was estimated over a 1-month planning horizon using real cost and load data for April 2000. I found that a power exchange system would give both producers, and particularly Firm 1, plenty of room to exercise market power. Indeed, it would be able to get markups that go from 66% to 76% (with a 72% average) if price elasticity of demand were –1/3. Firm 2 would be capacity constrained during the high demand periods and would be able to exercise market power only in the low-demand periods getting markups slightly above 45%. A very interesting result had to do with Firm 1's hydro scheduling decision: it allocated relative *less* water to high demand periods and relatively *more* water to low demand periods (compared to a perfectly competitive market). Unlike what we would observe in a perfectly competitive market, where hydro production is allocated so as to reduce differences between peak / off-peaks periods (and eliminate/reduce peaks as much as possible) a producer who enjoys market power schedules hydro production so as to enlarge the difference between those periods. This result is consistent with what has been found in the literature.

[81] Notice that the markup is *negative* for t=5, contracting = 100% indicating that the price is less than the marginal cost. This result is consistent with what we expected for periods when the firm is over-contracted.

Four different market power mitigation measures were analyzed: the divestiture of Firm 1's thermal portfolio, divestiture of all or a fraction of hydro-storage resources by Firm 1, and the introduction of contracting practices to the market. The first divestiture alternative showed us that Firm 1's market power relies on its hydro capacity; a change from a mixed thermal/hydro portfolio to a pure hydro portfolio does not have a big impact on Firm 1's incentives to exercise market power. The analysis of a divestiture of hydro plants was particularly useful to learn the importance of hydro-storage resources in the market power results. In particular, when Firm 1 was required to sell all of its hydro-storage facilities, it was Firm 2 the one that really enjoyed and exercised market power. In addition, average markup was clearly reduced and the equilibrium was closer to the PC outcome. In the intermediate case, when only the Laja system was sold to small producers, both Firms were able to effectively exercise market power but at different demand levels; while Firm 1 enjoyed (relatively) more market power when demand was high, Firm 2 enjoyed it when demand was low. Even though the divestiture of hydro plants proved useful to reduce market power and to bring the market equilibrium close to the competitive equilibrium, they will probably be very difficult to implement. By one side, it will be difficult to force Firm 1 to sell the assets where its market power lies (politically this may prove impossible). By other side, even if Firm 1 is willing to sell it, the price that it would charge would be too high to be attractive for small producers (without market power) to pay, probably requiring a large transfer from the government. The fourth mitigation measure that was analyzed was the introduction of contracting practices. In particular, I analyzed the market outcome if Firms 1 and 2 were allowed (or required) to sell certain quantities outside the spot market. I found that the more contracted the firms were, the closer was the market outcome to the PC equilibrium. In addition, there was an interesting effect in terms of hydro scheduling: unlike what had been found in a previous paper, the more contracted is the firm, hydro scheduling is more efficient, meaning that more water to periods of high demand and less water to periods of low demand

There are some elements of the model that should be kept in mind when analyzing its results. First of all, results in general, and the magnitude of distortions in particular, depend on the demand elasticity. The approach taken in this paper was to estimate the model assuming different parameters for the demand elasticity. As expected, the more elastic is demand, the less market power can be exercised by producers. Because of the importance of this parameter in the final result, more rigorous research in this topic is required for the Chilean case. Secondly, the model has no dynamic elements although a power exchange system is clearly a perfect scenario for repeated competition. It is reasonable to think that this omission results in my model underestimating market power. Finally, the model was estimated assuming a planning horizon that is rather short (a month). It would be interesting to see how the results of the model change when producers are allowed to allocate its hydro production over a longer planning horizon, say a year. I expect to find the same hydro scheduling pattern (relatively more water to periods of low demand, relatively less to high demand periods) but with a change in magnitudes.

In light of these results, Chilean authorities should be aware of the risks entailed in de-regulating prices. These risks take the form of high prices and markups, low production and an inefficient use of resources. If the de-regulation process is to be implemented, it should include some sort of market power mitigation measures like the ones that have been analyzed here: the disposal of hydro resources or the introduction of contracting practices. If I had to choose among these alternatives, I would choose the use of contracting practices as a way to mitigate market power. By one side, all of them bring the market equilibrium closer to the competitive equilibrium. However, requiring firms to contract seems to entail less intervention in the industry structure and in the firms' behavior. Firms would still be able to decide whom to contract with, at what price. Contracting practices could even be useful to fulfill other objectives of the Chilean reform, like the reduction of barriers to entry for new and small producers[82] and more transparent transactions between generating companies and distribution companies. Finally, unlike the disposal of hydro resources that mainly affected Firm 1, this mitigation measure is fair in terms of the impact that it has over the two firms, and thus will be probably easier to implement. An additional control mechanism that could be used and that has been pointed out by Wolfram (1999) is the regulatory threat. The basic idea is that a regulatory authority with real power to punish the companies in case they exercise market power (or too much market power) provides enough incentive for the firms to behave competitive (or closer to it).

Before the regulatory authorities decide to deregulate the price and include some sort of control mechanism to prevent market power abuses, there are two issues that I think should be addressed. First of all, any market power mitigation measure that is introduced attempts to control or influence the spot market's price.[83] The point is then why bother in reforming the price system and move towards a system where prices are market-set if at the end the authority wants to introduce additional controls that prevent the price from being really market based? The authority should introduce these control mechanism not as a way to continue regulating the price but to get the "market-based" price as close to the PC one as possible. This leads to a second point: if the current pricing system already sets the price at a level that is close to the PC level, is it really convenient moving forward to a system where prices are completely market based, even though that entails the risk of market power abuses? In order to answer this question, some previous questions should be addressed: is the current regulatory system pricing at levels that are really close to the competitive equilibrium? If yes, what additional benefits would have

[82] Depending on the characteristics of contracts (frequency, contracted amount relative to demand, etc.) they may increase or reduce barriers to entry to the industry. One of the possible amendments to the law that was analyzed in Chile was to require distribution companies to bid their contracts. These bids were supposed to take place 2 years before consumption take place. In this way, new IPPs can participate in the bid and analyze the convenience of entering the market and/or building new plants. In order to further reduce entry barriers it may be convenient to spread bids (in terms of volume traded) over a period of time; in this way small producers may be able to also enter the industry. The convenience of something like that requires a cost-benefit analysis because spreading the bids over the year may entail some undesirable costs (transaction costs for example). Newbery (1995) pointed out that contracting practices by IPPs increased contestability of the market.

[83] As Wolak (2000) pointed out: "if one is concerned about the exercise of market power in a restructured electricity market, then effective price regulation can be imposed by forcing a large enough quantity of hedge contracts on the newly privatized generator". Page 45

de-regulating prices? Some people mention that the system would gain in transparency. Until now critics have come on qualitative grounds but there are no quantitative estimations on how far or close current nodal prices are from the ones that would be set in a perfectly competitive market. Clearly more quantitative work is needed before implementing a power exchange system.

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APPENDIX - TABLES

1. Hydro Model, Same slope approach

A. Competitive Equilibrium (Same slope approach)

Table T1: Competitive equilibrium (E=-0.1)

t	qth1	qth2	QRth	qh1	qh2	QRh	QR	Qthfringe	qMR	qhPS	Qtot	Price
1	665.94	944.40	1610.34	2133.1	0	2133.1	3743.4	690.03	394.46	2406.49	4827.9	26.0
2	665.94	944.40	1610.34	1802.6	0	1802.6	3412.9	600.43	394.46	1986.36	4407.8	26.0
3	665.94	944.40	1610.34	1564.1	0	1564.1	3174.4	600.43	394.46	1747.87	4169.3	26.0
4	665.94	944.40	1610.34	1116.3	0	1116.3	2726.6	600.43	394.46	1300.08	3721.5	26.0
5	645.03	944.40	1589.43	764.7	0	764.7	2354.1	600.43	394.46	948.48	3349.0	26.0
6	454.60	944.40	1399.00	743.7	0	743.7	2142.7	595.43	394.46	927.52	3132.6	21.7

Table T1: Competitive equilibrium (E=-1/3)

t	qth1	qth2	QRth	qh1	qh2	QRh	QR	Qthfringe	qMR	qhPS	Qtot	Price
1	673.1	944.4	1617.5	2133.1	0.0	2133.1	3750.6	693.9	394.46	2406.49	4839.0	29.4
2	673.1	944.4	1617.5	1802.6	0.0	1802.6	3420.1	604.3	394.46	1986.36	4418.9	29.4
3	673.1	944.4	1617.5	1564.1	0.0	1564.1	3181.6	604.3	394.46	1747.87	4180.4	29.4
4	673.1	944.4	1617.5	1116.3	0.0	1116.3	2733.8	604.3	394.46	1300.08	3732.6	29.4
5	673.1	944.4	1617.5	764.7	0.0	764.7	2382.2	603.9	394.46	948.48	3380.5	28.9
6	566.2	944.4	1510.6	743.7	0.0	743.7	2254.4	600.4	394.46	927.52	3249.3	26.0

Table T1: Competitive equilibrium (E=-0.5)

t	qth1	qth2	QRth	qh1	qh2	QRh	QR	Qthfringe	qMR	qhPS	Qtot	Price
1	673.10	944.40	1617.50	2133.1	0	2133.1	3750.6	694.61	394.46	2406.49	4839.7	29.9
2	673.10	944.40	1617.50	1802.6	1	1803.6	3421.1	605.01	394.46	1986.36	4420.5	29.9
3	673.10	944.40	1617.50	1564.1	2	1566.1	3183.6	605.01	394.46	1747.87	4183.0	29.9
4	673.10	944.40	1617.50	1116.3	3	1119.3	2736.8	605.01	394.46	1300.08	3736.2	29.9
5	673.10	944.40	1617.50	764.7	4	768.7	2386.2	604.69	394.46	948.48	3385.3	29.7
6	673.10	944.40	1617.50	743.7	5	748.7	2366.2	600.79	394.46	927.52	3361.5	26.3

Table T1: Competitive equilibrium (E=-2/3)

t	qth1	qth2	QRth	qh1	qh2	QRh	QR	Qthfringe	qMR	qhPS	Qtot	Price
1	673.1	944.4	1617.5	2133.1	0.0	2133.1	3750.6	694.9	394.46	2406.49	4840.0	30.2
2	673.1	944.4	1617.5	1802.6	0.0	1802.6	3420.1	605.3	394.46	1986.36	4419.9	30.2
3	673.1	944.4	1617.5	1564.1	0.0	1564.1	3181.6	605.3	394.46	1747.87	4181.4	30.2
4	673.1	944.4	1617.5	1116.3	0.0	1116.3	2733.8	605.3	394.46	1300.08	3733.6	30.2
5	673.1	944.4	1617.5	764.7	0.0	764.7	2382.2	605.1	394.46	948.48	3381.7	30.0
6	673.1	944.4	1617.5	743.7	0.0	743.7	2361.2	602.2	394.46	927.52	3357.8	27.5

Table T1: Competitive equilibrium (E=-1.0)

t	qth1	qth2	QRth	qh1	qh2	QRh	QR	Qthfringe	qMR	qhPS	Qtot	Price
1	673.10	944.40	1617.50	2133.1	0	2133.1	3750.6	695.28	394.46	2406.49	4840.3	30.5
2	673.10	944.40	1617.50	1802.6	0	1802.6	3420.1	605.68	394.46	1986.36	4420.2	30.5
3	673.10	944.40	1617.50	1564.1	0	1564.1	3181.6	605.68	394.46	1747.87	4181.7	30.5
4	673.10	944.40	1617.50	1116.3	0	1116.3	2733.8	605.68	394.46	1300.08	3733.9	30.5
5	673.10	944.40	1617.50	764.7	0	764.7	2382.2	605.53	394.46	948.48	3382.2	30.4
6	673.10	944.40	1617.50	743.7	0	743.7	2361.2	603.56	394.46	927.52	3359.2	28.7

B. Cournot equilibrium (Same slope approach)

Table T1: Cournot equilibrium **(E=-0.1)**

t	qth1	qth2	QRth	qh1	qh2	QRh	QR	Qthfringe	qMR	qhPS	Qtot	Price
1	0.0	944.4	944.4	1612.5	0.0	1612.5	2556.9	500.3	394.46	274.6	3725.9	98.1
2	0.0	944.4	944.4	1447.7	0.0	1447.7	2392.1	488.6	394.46	183.8	3459.0	88.1
3	0.0	944.4	944.4	1328.4	0.0	1328.4	2272.8	480.2	394.46	183.8	3331.3	80.9
4	0.0	854.9	854.9	1149.3	0.0	1149.3	2004.2	467.6	394.46	183.8	3050.0	70.0
5	0.0	730.7	730.7	1025.1	0.0	1025.1	1755.8	458.8	394.46	183.8	2792.9	62.4
6	0.0	636.6	636.6	931.0	0.0	931.0	1567.7	452.2	394.46	183.8	2598.1	56.7

Table T1: Cournot equilibrium **(E=-1/3)**

t	qth1	qth2	QRth	qh1	qh2	QRh	QR	Qthfringe	qMR	qhPS	Qtot	Price
1	258.4	944.4	1202.8	1618.5	0.0	1618.5	2821.3	441.2	394.46	274.6	3931.3	47.2
2	258.4	944.4	1202.8	1453.7	0.0	1453.7	2656.5	437.5	394.46	183.8	3672.3	44.0
3	258.3	944.4	1202.7	1334.5	0.0	1334.5	2537.3	434.9	394.46	183.8	3550.4	41.7
4	0.0	944.4	944.4	1369.0	0.0	1369.0	2313.4	429.9	394.46	183.8	3321.5	37.4
5	0.0	867.7	867.7	1221.1	0.0	1221.1	2088.7	426.6	394.46	183.8	3093.6	34.6
6	0.0	773.6	773.6	1127.0	0.0	1127.0	1900.6	424.5	394.46	183.8	2903.3	32.8

Table T1: Cournot equilibrium **(E=-0.5)**

t	qth1	qth2	QRth	qh1	qh2	QRh	QR	Qthfringe	qMR	qhPS	Qtot	Price
1	341.7	944.4	1286.1	1760.0	0.0	1760.0	3046.1	431.7	394.46	274.6	4146.6	39.0
2	341.7	944.4	1286.1	1595.2	0.0	1595.2	2881.3	429.3	394.46	183.8	3888.9	36.9
3	341.7	944.4	1286.1	1476.0	0.0	1476.0	2762.1	427.5	394.46	183.8	3767.8	35.3
4	341.7	944.4	1286.1	1252.1	0.0	1252.1	2538.2	424.1	394.46	183.8	3540.6	32.4
5	341.7	941.5	1283.2	1067.3	0.0	1067.3	2350.5	421.4	394.46	183.8	3350.1	30.1
6	341.7	847.4	1189.1	973.2	0.0	973.2	2162.3	420.0	394.46	183.8	3160.5	28.9

Table T1: Cournot equilibrium **(E=-2/3)**

t	qth1	qth2	QRth	qh1	qh2	QRh	QR	Qthfringe	qMR	qhPS	Qtot	Price
1	395.1	944.4	1339.5	1750.9	0.0	1750.9	3090.4	429.0	394.46	274.6	4188.1	36.6
2	395.1	944.4	1339.5	1586.0	0.0	1586.0	2925.6	427.1	394.46	183.8	3930.9	35.0
3	395.1	944.4	1339.5	1466.8	0.0	1466.8	2806.3	425.8	394.46	183.8	3810.3	33.9
4	342.7	944.4	1287.1	1295.4	0.0	1295.4	2582.4	423.2	394.46	183.8	3583.9	31.7
5	342.7	944.4	1287.1	1109.1	0.0	1109.1	2396.2	421.1	394.46	183.8	3395.6	29.9
6	395.0	944.4	1339.4	915.6	0.0	915.6	2255.0	419.6	394.46	183.8	3252.8	28.5

Table T1: Cournot equilibrium **(E=-1.0)**

t	qth1	qth2	QRth	qh1	qh2	QRh	QR	Qthfringe	qMR	qhPS	Qtot	Price
1	454.6	944.4	1399.0	1768.4	0.0	1768.4	3167.3	426.3	394.46	274.6	4262.4	34.3
2	454.6	944.4	1399.0	1603.6	0.0	1603.6	3002.5	425.0	394.46	183.8	4005.8	33.2
3	454.6	944.4	1399.0	1484.3	0.0	1484.3	2883.3	424.1	394.46	183.8	3885.7	32.4
4	454.6	944.4	1399.0	1260.4	0.0	1260.4	2659.4	422.4	394.46	183.8	3660.1	31.0
5	454.6	944.4	1399.0	1074.2	0.0	1074.2	2473.1	421.0	394.46	183.8	3472.4	29.8
6	454.6	944.4	1399.0	933.0	0.0	933.0	2332.0	420.0	394.46	183.8	3330.2	28.9

Table T1: Lerner Indices

	E=-0.1		**E=-1/3**		**E=0.5**		**E= -2/3**		**E=-1.0**	
t	Firm 1	Firm 2	Firm 1	Firm 2	Firm 1	Firm 2	Firm 1	Firm 2	Firm 1	Firm 2
1	100%	59%	76%	38%	70%	31%	57%	25%	42%	18%
2	100%	65%	75%	41%	68%	33%	55%	26%	40%	18%
3	100%	71%	73%	43%	66%	34%	53%	27%	39%	19%
4	100%	74%	70%	48%	63%	38%	50%	29%	36%	20%
5	100%	71%	68%	48%	60%	40%	47%	31%	33%	21%
6	100%	68%	66%	45%	59%	38%	45%	32%	31%	21%

1. Hydro Model, Different slope approach

A. Competitive Equilibrium (Different slope approach)

Table T1: Competitive equilibrium (E=-0.1)

t	qth1	qth2	QRth	qh1	qh2	QRh	QR	Qthfringe	qMR	qhPS	Qtot	Price
1	665.94	944.40	1610.34	2133.1	0	2133.1	3743.4	690.0	394.46	2406.49	4827.9	25.98
2	659.02	944.40	1603.42	1802.6	0	1802.6	3406.0	600.4	394.46	1986.36	4400.9	25.98
3	655.09	944.40	1599.49	1564.1	0	1564.1	3163.6	600.4	394.46	1747.87	4158.5	25.98
4	647.72	944.40	1592.12	1116.3	0	1116.3	2708.4	600.4	394.46	1300.08	3703.3	25.98
5	620.67	944.40	1565.07	764.7	0	764.7	2329.7	600.4	394.46	948.48	3324.6	25.98
6	454.60	931.31	1385.91	743.7	0	743.7	2129.6	591.1	394.46	927.52	3115.2	17.92

Table T1: Competitive equilibrium (E=-1/3)

t	qth1	qth2	QRth	qh1	qh2	QRh	QR	Qthfringe	qMR	qhPS	Qtot	Price
1	673.1	944.4	1617.5	2133.1	0	2133.1	3750.6	693.9	394.46	2406.49	4839.0	29.4
2	673.1	944.4	1617.5	1802.6	0	1802.6	3420.1	604.1	394.46	1986.36	4418.7	29.2
3	673.1	944.4	1617.5	1564.1	0	1564.1	3181.6	604.0	394.46	1747.87	4180.0	29.1
4	673.1	944.4	1617.5	1116.3	0	1116.3	2733.8	603.7	394.46	1300.08	3732.0	28.8
5	673.1	944.4	1617.5	764.7	0	764.7	2382.2	602.8	394.46	948.48	3379.4	28.0
6	469.5	944.4	1413.9	743.7	0	743.7	2157.7	600.4	394.46	927.52	3152.6	26.0

Table T1: Competitive equilibrium (E=-0.5)

t	qth1	qth2	QRth	qh1	qh2	QRh	QR	Qthfringe	qMR	qhPS	Qtot	Price
1	673.10	944.40	1617.50	2133.1	0	2133.1	3750.6	694.6	394.46	2406.49	4839.7	29.93
2	673.10	944.40	1617.50	1802.6	0	1802.6	3420.1	604.9	394.46	1986.36	4419.4	29.81
3	673.10	944.40	1617.50	1564.1	0	1564.1	3181.6	604.8	394.46	1747.87	4180.8	29.74
4	673.10	944.40	1617.50	1116.3	0	1116.3	2733.8	604.6	394.46	1300.08	3732.8	29.58
5	673.10	944.40	1617.50	764.7	0	764.7	2382.2	604.0	394.46	948.48	3380.6	29.02
6	551.59	944.40	1495.99	743.7	0	743.7	2239.7	600.4	394.46	927.52	3234.6	25.98

Table T1: Competitive equilibrium (E=-2/3)

t	qth1	qth2	QRth	qh1	qh2	QRh	QR	Qthfringe	qMR	qhPS	Qtot	Price
1	673.1	944.4	1617.5	2133.1	0.0	2133.1	3750.6	694.9	394.46	2406.49	4840.0	30.2
2	673.1	944.4	1617.5	1802.6	0.0	1802.6	3420.1	605.2	394.46	1986.36	4419.8	30.1
3	673.1	944.4	1617.5	1564.1	0.0	1564.1	3181.6	605.2	394.46	1747.87	4181.2	30.1
4	673.1	944.4	1617.5	1116.3	0.0	1116.3	2733.8	605.0	394.46	1300.08	3733.3	30.0
5	673.1	944.4	1617.5	764.7	0.0	764.7	2382.2	604.5	394.46	948.48	3381.2	29.5
6	633.6	944.4	1578.0	743.7	0.0	743.7	2321.7	600.4	394.46	927.52	3316.6	26.0

Table T1: Competitive equilibrium (E=-1.0)

t	qth1	qth2	QRth	qh1	qh2	QRh	QR	Qthfringe	qMR	qhPS	Qtot	Price
1	673.10	944.40	1617.50	2133.1	0	2133.1	3750.6	695.3	394.46	2406.49	4840.3	30.51
2	673.10	944.40	1617.50	1802.6	0	1802.6	3420.1	605.6	394.46	1986.36	4420.1	30.45
3	673.10	944.40	1617.50	1564.1	0	1564.1	3181.6	605.6	394.46	1747.87	4181.6	30.42
4	673.10	944.40	1617.50	1116.3	0	1116.3	2733.8	605.5	394.46	1300.08	3733.7	30.33
5	673.10	944.40	1617.50	764.7	0	764.7	2382.2	605.1	394.46	948.48	3381.8	30.05
6	673.10	944.40	1617.50	743.7	0	743.7	2361.2	601.9	394.46	927.52	3357.6	27.26

B. Cournot equilibrium (Different slope approach)

Table T1: Cournot equilibrium **(E=-0.1)**

t	qth1	qth2	QRth	qh1	qh2	QRh	QR	Qthfringe	qMR	qhPS	Qtot	Price
1	0.0	944.4	944.4	1612.5	0.0	1612.5	2556.9	500.3	394.46	274.6	3725.9	98.1
2	0.0	944.4	944.4	1426.7	0.0	1426.7	2371.1	496.2	394.46	183.8	3445.5	94.6
3	0.0	944.4	944.4	1295.5	0.0	1295.5	2239.9	491.4	394.46	183.8	3309.6	90.5
4	0.0	860.5	860.5	1091.2	0.0	1091.2	1951.7	484.8	394.46	183.8	3014.7	84.8
5	0.0	738.2	738.2	947.4	0.0	947.4	1685.6	480.6	394.46	183.8	2744.5	81.2
6	0.0	645.6	645.6	838.5	0.0	838.5	1484.1	476.8	394.46	183.8	2539.1	77.9

Table T1: Cournot equilibrium **(E=-1/3)**

t	qth1	qth2	QRth	qh1	qh2	QRh	QR	Qthfringe	qMR	qhPS	Qtot	Price
1	77.7	944.4	1022.1	1799.2	0.0	1799.2	2821.3	441.2	394.46	274.6	3931.3	47.2
2	77.4	944.4	1021.8	1589.7	0.0	1589.7	2611.5	440.0	394.46	183.8	3629.8	46.2
3	76.4	944.4	1020.8	1446.0	0.0	1446.0	2466.8	438.6	394.46	183.8	3483.6	45.0
4	0.0	944.4	944.4	1250.6	0.0	1250.6	2194.9	435.5	394.46	183.8	3208.7	42.2
5	0.0	833.9	833.9	1079.7	0.0	1079.7	1913.6	434.0	394.46	183.8	2925.8	40.9
6	0.0	733.3	733.3	958.6	0.0	958.6	1691.9	432.9	394.46	183.8	2703.1	40.0

Table T1: Cournot equilibrium **(E=-0.5)**

t	qth1	qth2	QRth	qh1	qh2	QRh	QR	Qthfringe	qMR	qhPS	Qtot	Price
1	336.6	944.4	1281.0	1794.5	0.0	1794.5	3075.5	431.3	394.46	274.6	4175.5	38.6
2	336.5	944.4	1280.9	1562.3	0.0	1562.3	2843.2	430.5	394.46	183.8	3852.0	38.0
3	336.2	944.4	1280.6	1405.1	0.0	1405.1	2685.7	429.6	394.46	183.8	3693.5	37.1
4	115.6	944.4	1060.0	1329.9	0.0	1329.9	2389.9	427.5	394.46	183.8	3395.6	35.3
5	223.4	871.2	1094.6	1012.6	0.0	1012.6	2107.3	426.1	394.46	183.8	3111.6	34.1
6	82.3	767.5	849.7	1019.2	0.0	1019.2	1868.9	425.4	394.46	183.8	2872.6	33.5

Table T1: Cournot equilibrium **(E=-2/3)**

t	qth1	qth2	QRth	qh1	qh2	QRh	QR	Qthfringe	qMR	qhPS	Qtot	Price
1	341.7	944.4	1286.1	1933.1	0.0	1933.1	3219.2	427.5	394.46	274.6	4315.5	35.4
2	341.7	944.4	1286.1	1688.0	0.0	1688.0	2974.1	426.9	394.46	183.8	3979.3	34.9
3	341.7	944.4	1286.1	1523.2	0.0	1523.2	2809.3	426.2	394.46	183.8	3813.8	34.3
4	341.7	944.4	1286.1	1213.8	0.0	1213.8	2499.9	424.7	394.46	183.8	3502.8	32.9
5	341.7	944.4	1286.1	956.3	0.0	956.3	2242.4	423.0	394.46	183.8	3243.7	31.5
6	341.7	848.2	1190.0	809.3	0.0	809.3	1999.3	422.4	394.46	183.8	2999.9	30.9

Table T1: Cournot equilibrium **(E=-1.0)**

t	qth1	qth2	QRth	qh1	qh2	QRh	QR	Qthfringe	qMR	qhPS	Qtot	Price
1	454.6	944.4	1399.0	1969.7	0.0	1969.7	3368.6	424.8	394.46	274.6	4462.2	33.0
2	454.6	944.4	1399.0	1711.2	0.0	1711.2	3110.1	424.4	394.46	183.8	4112.8	32.7
3	454.6	944.4	1399.0	1538.7	0.0	1538.7	2937.7	423.9	394.46	183.8	3939.9	32.3
4	454.6	944.4	1399.0	1215.0	0.0	1215.0	2613.9	422.8	394.46	183.8	3615.1	31.3
5	454.6	944.4	1399.0	945.6	0.0	945.6	2344.6	421.8	394.46	183.8	3344.6	30.4
6	454.6	944.4	1399.0	743.6	0.0	743.6	2142.6	420.7	394.46	183.8	3141.6	29.5

Table T1: Lerner Indices

	E=-0.1		**E=-1/3**		**E=0.5**		**E= -2/3**		**E=-1.0**	
t	Firm 1	Firm 2	Firm 1	Firm 2	Firm 1	Firm 2	Firm 1	Firm 2	Firm 1	Firm 2
1	100%	59%	76%	38%	71%	32%	62%	26%	48%	19%
2	100%	66%	76%	43%	71%	35%	62%	29%	47%	21%
3	100%	73%	75%	47%	70%	38%	61%	31%	47%	22%
4	100%	79%	74%	56%	69%	45%	60%	36%	45%	25%
5	100%	78%	73%	56%	67%	48%	58%	42%	43%	29%
6	100%	77%	72%	55%	67%	47%	57%	42%	42%	33%