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Forecasting the Chilean Short-Term Electricity Market Behavior under a New Proposed Regulation

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***Abstract*—This paper presents a study on the likely behavior of a daily electricity market proposed to operate in the Chilean system. The simulation has been carried out by using the tool VALORE, able to model oligopolistic behaviors. Conclusions on the desirable degree of long-term contracts are obtained. The theoretical basis of the simulation tool are also explained.**

Keywords: **Power system economics, Interconnected power systems, Power system planning.**

I. Introduction

Chile has been a pioneering country in the present trend towards electricity systems deregulation [1]. However, perceived deficiencies in the present regulatory framework have induced to the National Regulatory Commission (Comisión Nacional de la Energía, CNE), as september 2000, to propose a new one.

It was intended for most of the energy to be traded through long-term contracts. However, in order to address imbalances, a short-term (daily) market was also proposed, based on the introduction of a new power exchange system. Its existence has been cause of concern for several analysts, who are afraid of the possibility of anti-competitive behavior in this new market, mostly because of a possible excessive concentration level.

The main purpose of the study reported in this paper is to quantify the likely degree of price distortion to be expected in the new regulatory framework. Reference prices are the theoretical perfect competition ones, currently computed by the independent system operator (CDEC). The used simulation tool (VALORE) models the technical characteristics (maximum power, maximum energy, hydro topology, ...) and costs of the thermal and hydro equipment. It is also able to compute perfect competition and Cournot equilibria (widely considered to be the worst kind of non-collusive oligopolistic competition [3]), as function of the long-term agents contracts.

The paper is organized as follows. Section II is a brief description of relevant aspects of the new proposed regulation. Section III introduces the oligopolistic market model used in the study. Next section explains the simulation tool basis (Incidentally, we feel that the used approach has much better numerical properties than other Cournot equilibria computing algorithms reported in the literature. So, it is possible to study more complex and realistic power system models, as well as performing more simulations in a given time). Section V is the article core: after a brief description of the Chilean system, the performed simulations and their results are explained. In particular, it is quantitatively shown that if there are not significant entry barriers and the contracting level is high enough, small price distortion should be expected. This information can be useful from a regulatory point of view.

Finally, our conclusions are stated in the last section. The detailed structure of the simulation model is explained in the appendix.

II. Chilean new regulatory framework

The Chilean Regulatory National Commission (CNE) proposed in 2001 a new regulatory framework which was based on long-term contracts in a free market setting. As stated by the Commission itself [2]:

> *... being our position that supply and offer market conditions are better represented in medium and long term contracts, and that the agents and the whole market medium and long term decisions more closely approach the optimal resources allocation*[1].

Therefore, it was proposed that most of the energy to be traded through medium and long term bilateral contracts. The Electrical Act proposition [4] includes provisions which obliges to generation and distribution utilities to contract a significant part of the energy that they trade in medium and long term markets. Furthermore, it can

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[1] *... nuestra posición es que las condiciones de oferta y demanda del mercado se reflejan mejor en acuerdos (contratos) de mediano y largo plazo, y que la optimización en la asignación de recursos está mejor reflejada en las decisiones de mediano y largo plazo de los diversos agentes y del mercado globalmente.*

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be argued that there were enough economic incentives for the demand to seek to cover most of its forecasted needs in these markets.

It can be expected that the long-term market behavior approaches that of a perfect competition market. In fact, there are not significant entry barriers, either regulatory or physical ones (the lags involved in new equipment installation, particularly combined cycle plants and gas turbines, are no longer those of typical medium and long term contracts, being also amortization times much shorter than those of "traditional" power plants).

Actually, in the Chilean Central Interconnected System, electricity spot prices has been falling from 1997, mainly as consequence of the deregulating 1982 Electricty Act and the subsequent instalation of new combined cycle plants. Even more daramatically, in the Chilean North System, an investment glut has been cause of a total installed capacity of more than 3500 MW, being the peak demand 1350 MW. Almost all of the contracts in both cases has been long-term ones.

In any case, it remains the need to provide a mechanism to deal with the short-term fluctuations of the electricity demand over the long and medium term forecasts. So, it was proposed the creation of a daily market, where the energy balancing can be done in a day per day basis.

It is important to note that:

1. It should be expected that the energy traded in the diary market is going to be a fraction of the total system demand, as most of the energy has been traded by medium and long term contracts.
2. The prices of the medium and long term contracts are dealt in the corresponding markets, which are supposed to be contestable ones. So, prices in these markets are set by medium and long term conditions, and not by the daily market prices.

III. OLIGOPOLISTIC MARKET BEHAVIOR

The simulation tool tries to compute the market equilibrium, i.e., the set of generation outputs and demanded powers such that no agent has incentives to change his/her operation (in mathematical terms, the Nash equilibrium). It is assumed that each utility tries to maximize its profit.

In equilibrium, for each utility u, the additional cost of producing 1 additional MW-h (marginal cost MC_u) should be equal to the additional revenue earned by this additional MW-h (marginal revenue MR_u). So

$$MC_u = MR_u \tag{1}$$

(through all this section, temporal indices will be suppressed in order to keep a simple notation).

Marginal revenue has two components. Firstly, 1 additional MW-h earns the price daily market π. Secondly, because of the increased production, market prices diminishes an amount $\delta\pi_u$. This price fall impacts on all the energy which is being traded in the daily market, which is the difference between the total energy production P_u and the energy contracted in long term markets S_u. Therefore:

$$MR_u = \pi + (\delta\pi_u)(P_u - S_u) \tag{2}$$

(note that $\delta\pi_u \leq 0$, as an offer increase drives to a price fall).

On the other hand, the physical demand D depends on the market price π. Let us assume a linear dependence:

$$D = D_0 - \alpha_0 \pi \tag{3}$$

D_0 and α_0 are two parameters which define the demand curve. Although the demand curve is not linear, it is possible to estimate these parameters which define the demand curve linearitation in the neighborhood of the clearing point.

Furthermore, the physical demand-generation balance must be fulfilled:

$$D = \sum_u P_u \tag{4}$$

The two last equations jointly imply that:

$$D_0 - \alpha_0 \pi = \sum_u P_u \tag{5}$$

In order to close the model it is needed to provide some formula for $\delta\pi_u$. The study reported in this paper assumes the so-called *Cournot hypothesis*. Under this hypothesis, it is assumed that in the event that any utility changes its production, the remaining utilities keep their production constant. Therefore, if utility u increases its production by 1 MW-h, equation (5) implies that:

$$-\alpha_0 \delta\pi_u = 1 \tag{6}$$

So, $\delta\pi_u = -\frac{1}{\alpha_0}\ \forall u$.

Summarizing, the model solves the system:

$$\begin{aligned} MC_u &= MR_u \quad u = 1, \ldots, U && (7)\\ MR_u &= \pi - \frac{1}{\alpha_0}(P_u - S_u) \quad u = 1, \ldots, U && (8)\\ D &= \sum_u P_u && (9)\\ D &= D_0 - \alpha_0 \pi && (10) \end{aligned}$$

Several comments can be done:

1. Although time indices have been suppressed, these equations must be repeated for each period of the simulation time horizon.

2. Marginal cost MC_u computation requires the careful modeling of the utilities production means (thermal and hydro plants, reservoirs, etc.), taking into account the intertemporal constraints which limit its operation. This topic, and the way of solving the resulting equations, will be addressed in the next section.

3. The Cournot hypothesis [3] is very often assumed to quantify the limits to oligopolistic distortions, both in electrical [7, 8, 10] and other [3, 5, 6] markets studies. Actually, it should be expected that if any utility decreases its output, the remaining ones will increases theirs, which reduces the price variation [9, 11, 12]. Therefore, assuming that the demand behavior remains constant, Cournot prices distortion are a bound to more realistic prices distortions computed taking into account the utilities reactions.

4. In a perfect competition market, the marginal revenue MR_u equals the market price π, as it is assumed that no utility can significantly influence the clearing price. Formally, this is equivalent to set $\frac{1}{\alpha_0} = 0$ in equations (8).

IV. Oligopolistic market simulation basis

As in the previous section, temporal indices will be disregarded. However, the detailed model based upon the ideas introduced herein, which incorporates intertemporal links, is given in the appendix.

Marginal cost is the derivative of the cost function with respect to the generated power: $MC_u = \frac{dC_u}{dP_u}$. So, after eliminating MR_u, equations (7)-(10) can be written as:

$$\begin{aligned} \frac{dC_u}{dP_u} + \frac{1}{\alpha_0}(P_u - S_u) &= \pi;\ u = 1, \ldots, U && (11) \\ D &= \sum_u P_u && (12) \\ D &= D_0 - \alpha_0 \pi && (13) \end{aligned}$$

It is easy to check that these equations are the Karush-Kuhn-Tucker first order optimality conditions of the problem:

$$\begin{aligned} \min_{P_u, D} \quad & \textstyle\sum_u \left[C_u(P_u) + \frac{1}{2\alpha_0}(P_u - S_u)^2 \right] + \frac{1}{2\alpha_0}(D - D_0)^2 \\ \text{s.t.} \quad & \textstyle\sum_u P_u = D \qquad (14) \end{aligned}$$

being π the equality constraint multiplier. Intertemporal links can be introduced in a straightforward way, as shown in the appendix.

Centralized operation, which is theoretically equivalent to perfect market behavior, is the solution of the problem (assuming inelastic demand D_0):

$$\begin{aligned} \min_{P_u} \quad & \textstyle\sum_u C_u(P_u) \\ \text{s.t.} \quad & \textstyle\sum_u P_u = D_0 \qquad (15) \end{aligned}$$

Again, the price (which is equal to marginal cost) is the equality constraint multiplier.

V. Study case

A. Chilean system description

The most important electric system in Chile is the so called Sistema Interconectado Central (Central Interconnected System, SIC for short), which serves most of the population (about 93%) including the nation capital, Santiago. This is the system in which the reported study is focused.

In 2000, total installed SIC capacity was 6,653 MW, of which 60.58% was hydro and 39.42% thermal. Peak power was 4,516 MW and total generation 29,577 GWh. System growth has been very fast, of the order of 300 MW/year in the installed capacity for the last 15 years.

There are three main generating utilities in SIC: Endesa, Gener and Colbún; which own respectively about 57%, 21% and 15% of the total installed capacity.

Given the predominance of the hydraulic component, simulations must take into account intertemporal links related to the hydro operation. Most important system reservoir (Lago Laja) is hyperannual, with a cycle of about 2 years.

B. Parameters used in the study

1) Time representation: Simulation horizon was 4 years, divided in 52 periods of 4 weeks each one. Each period was divided in 2 subperiods (weekend and working-days), and each subperiod in 3 load levels (peak, off-peak 1 and off-peak 2).

2) Generation equipment technical data: The study has modeled all the significant thermal and hydro units. Thermal unit data include variable operation costs, maximum power and owner. Hydraulic unit data includes maximum power, reservoir capacities, hydro system topology (reservoirs and channels), energy coefficients (needed to relate the water volume to the energy is able to generate) and owner. There were also available realistic demand forecasts (they have been historically quite accurate).

3) Hydraulic inflows modeling: Three hydraulic inflows scenarios have been considered, which are based upon real inflows in the years 1998-1999 (dry), 1982-1983 (wet) and 1974-1975 (medium). In order to capture the long-term hydraulic system managing, simulations have a 4 years time horizon. First year has inflows corresponding to either the dry, wet o medium year; being the three last years inflows those of the medium year.

4) Long-term contracts modeling: Several long-term contracts scenarios were considered. The total amount of contracted power was set to a percentage (95%, 90%, 85%, 75% or 50%) of the total forecast system demand. For each scenario, each utility share in the total contracts volume was the same one than the real share on sold energy one corresponding to the year 2000 (Endesa 53.16%, Gener 24.68%, Colbún 16.10%).

5) Demand curve modeling: The demand response is modeled, for each period, by a line. Therefore, it can be defined by a point on the line an its slope. The point two coordinates are the demanded energy and its price. The energy demanded is the forecast demand, and its price the resulting of a centralized operation.

Three slopes scenarios were considered: 15, 30 and 45 (\$/MW-h)/GW. The medium slope implies a demand elasticity of about 0.14. These values are consistent with the ones reported in the literature [13, 8, 9]. In any case, the assumed demand curve is somewhat more inelastic that the reported ones.

C. Method

Firstly, a centralized operation under the medium hydraulic scenario serving the forecasted demand was done. This simulation yields, for each period, subperiod and load level, a price. The pair (demanded energy, price) is assumed to yield in the demand function. As the demand function slope is input data, the demand function can be computed.

Given this function, oligopolistic simulation are performed for each demand and hydraulic scenario. The centralized simulations (equivalent to perfect competition) for each scenario, are also done.

D. Results

Figure 1 show a typical prices output (peak, off-peak 1 and off-peak 2 prices in working and non-working days of each 4-weeks period) for a scenario. Productions of each plant are also computed.

The basic results can be summarized in figures 2 and 3. They show the relationship between the long-term contracts volume and the average price distortion. To quantify this one, the Cost-Price Margin (CPM) Index has been used. The CPM index is defined as:

$$\text{CPM Index} = \frac{\text{Market price} - \text{Centralized marginal cost}}{\text{Centralized marginal cost}}$$

Centralized marginal cost should be the market price in a perfect competition market. Therefore, the index should be 0 if the prices were those corresponding to a perfect market.

Actually, the cost and prices used in the CPM Index computation are averaged ones. The average was done

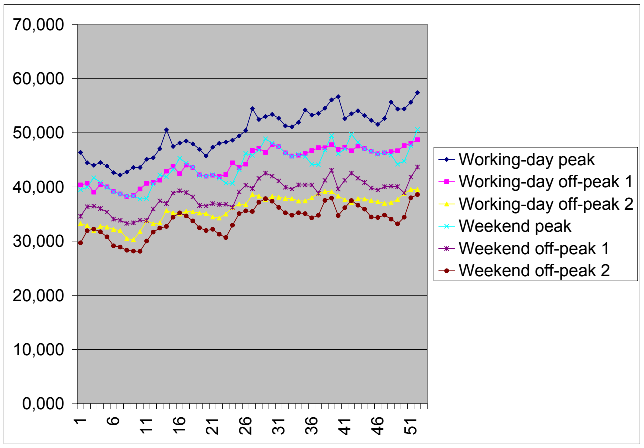

Fig. 1. Prices evolution (mills/kWh).

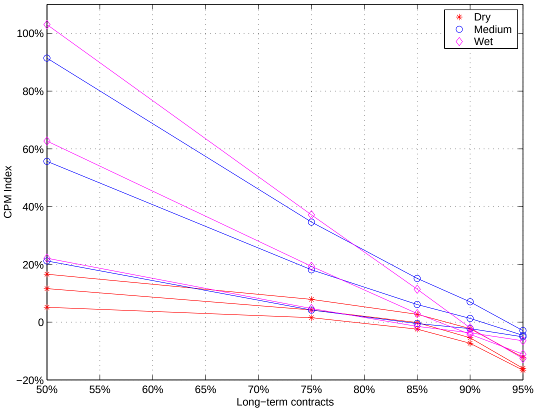

Fig. 2. Prices distortion.

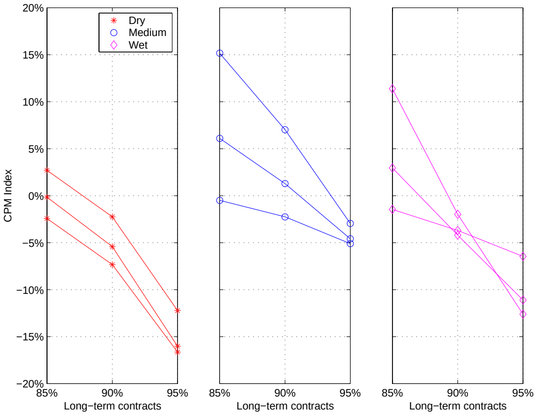

Fig. 3. Prices distortion. Detail.

with respect to the traded energy during the two first simulation years, in order to represent the short-term market prices distortion.

The curves represent the results for dry, medium and wet hydraulic scenarios. For each hydraulic scenarios, low, medium and high demand elasticity cases were studied. The low elasticity demand always corresponds to the highest price distortion when long-term contracts amount by 50% of the demand, whereas the high elasticity demand always corresponds to the lowest price distortion.

It can be observed that if the long-term contracting is high enough (higher than 85%) prices distortion are quite moderate, specially in the more likely situation of relatively higher elasticity. Note also that CPM Index can be negative, which means that market prices are lower that the perfect competition ones. That happens because some utilities are so heavily contracted that they are net energy short-term market buyers, and therefore have an interest in getting low prices.

VI. CONCLUSIONS

A method for the study of the short-term electricity market behavior has been introduced. The method is based in a simulation model able to cope with oligopolistic behavior, in order to study the possible range of price distortion. The method has been applied to quantify the behavior of a proposed short-term market in Chile.

It is shown that if long-term contracting is high enough (higher than 85% in our case), i.e., the short-term market is basically an adjustment market, prices distortion should be small. This conclusion highlights the importance of having competitive and well-regulated long-term markets. The authors think that this is particularly relevant in case of having concentrated markets, in order to bound anticompetitive behavior.

VII. APPENDIX: DETAILED DESCRIPTION OF THE SIMULATION MODEL

Simulation model solves problem (14) considering temporal links and detailed cost structure. Specifically, the optimization model structure is as follows:

A. Time representation

The model scope is divided in periods (weeks or months), denoted as p. Each period is divided in subperiods, denoted as s. A subperiod consists of several load levels, denoted as b. Each level of a subperiod and a period is characterized by its duration:

l_{psb} Duration of load level b of subperiod s and period p.

B. Decision variables

The power system consists of a group of thermal and hydro units owned by different utilities.

t_{jpsb} power generation of thermal unit j in level b of subperiod s and period p.

h_{mpsb} power generation of hydro unit m in level b of subperiod s and period p.

r_{mp} energy reservoir level of hydro unit m at the end of period p.

s_{mp} energy spillage of hydro unit m in period p.

D_{psb} demand in level b of subperiod s and period p.

D'_{psb} auxiliary variable equal to D^2_{psb}.

P'_{ipsb} auxiliary variable equal to P^2_{ipsb}. P_{ipsb} is generated power (pumping consumption excluded) of utility i in level b of subperiod s and period p.

Generated power, as will be shown later, is computed as a linear combination of decision variables.

C. Parameters

–Thermal units are supposed to have constant heat rate:

$\overline{t}_j$ maximum power generation of thermal unit j.

δ_j heat rate of thermal unit j.

q_j EFOR of thermal unit j.

m_{jp} Maintenance variable. Its value is 0 if thermal unit j is operative during period p and 1 if it is being maintained.

o_j Owner utility of thermal unit j.

–Hydro units are represented as a single group. Every hydro unit has an associated reservoir. Run-off-the-river production is considered separately for each utility.

$\overline{r}_{mp}, \underline{r}_{mp}$ maximum and minimum energy reservoir storage of hydro unit m at the end of period p.

f_{ipsb} Run-off-the-river hydro energy for utility i in level b of subperiod s and period p.

I_{mp} Hydro inflows (except run-off-the-river) of hydro unit m in period p.

r_{m0} initial energy reservoir level of hydro unit m at the beginning of period 1.

o_m owner utility of hydro unit m.

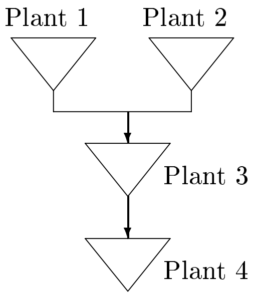

Fig. 4. Hydro system.

u_m maximum power for hydro unit m (run-off-the-river hydro energy is not included).

−A simplified representation of hydraulic system topology is considered, as shown in figure 4.

$\mathcal{E}_m$ hydro plants immediately upstream of hydro plant m.

ϵ_m performance of inflows into the downstream plant M

So, for the system in figure 4, $\mathcal{E}_{\text{Plant 3}} = \{\text{Plant 1}, \text{Plant 2}\}$.

−Demand has a linear relationship with price for each level, subperiod and period.

D^0_{psb} inelastic demand in level b of subperiod s and period p.

α_{0psb} demand slope in level b of subperiod s and period p.

−Contracted energies are given for each level, subperiod and period.

S_{ipsb} contracted energy by utility i in level b of subperiod s and period p.

−Generated power for utility i in level b, subperiod s and period p is computed as a linear combination of decision variables:

$$P_{ipsb} = \sum_{j|o_j=i} t_{jpsb} + \sum_{m|o_m=i} h_{mpsb} + f_{ipsb} \tag{16}$$

−Parameters for linear piecewise approximation of quadratic variables: each quadratic function is approximated with t segments.

D^X_{psbt} values of demand where $(D_{psb})^2$ is approximated. There are t values in level b, subperiod s and period p.

P^X_{ipsbt} values of power where $(P_{ipsb})^2$ is approximated. There are t values in level b, subperiod s and period p.

D. Constraints

−Decision variables bounds:

$$\begin{aligned} t_{jpsb} &\leq (1-q_j)(1-m_{jp})\,\overline{t}_j & (17)\\ h_{mpsb} &\leq u_m & (18)\\ \underline{r}_{mp} \leq r_{mp} &\leq \overline{r}_{mp} & (19) \end{aligned}$$

−Final level for each hydro unit (p^* is the last period).

$$r_{mp^*} = r_{m0} \tag{20}$$

−Power balance for each period, subperiod and level. The dual variable of each one of these constraints will be referred as π_{psb}.

$$\sum_j t_{jpsb} + \sum_m h_{mpsb} + \sum_i f_{ipsb} = D_{psb} \tag{21}$$

−Energy balance for each period and hydro unit.

$$\begin{aligned} r_{mp} - r_{m,p-1} = {} & -\sum_{sb} l_{psb} h_{mpsb} + I_{mp} - s_{mp} + \\ & \sum_{m' \in \mathcal{E}_m} \left(\sum_{sb} \epsilon_{m'} l_{psb} h_{m'psb} + s_{m'p} \right) \end{aligned} \tag{22}$$

−Piecewise approximation of quadratic values for demand. There is a constraint for each segment, period, subperiod and level.

$$D'_{psb} \geq -(D^X_{psbt})^2 + 2D^X_{psbt} D_{psb} \tag{23}$$

−Piecewise approximation of quadratic values for generated power. There is a constraint for each utility, segment, period, subperiod and level.

$$P'_{ipsb} \geq -(P^X_{ipsbt})^2 + 2P^X_{ipsbt} P_{ipsb} \tag{24}$$

E. Objective function

The objective function O.F. includes total system operation costs, additional quadratic costs and demand utility (see (14)):

$$\begin{aligned}\text{O.F.} \;=\; & \sum_{jpsb} \delta_j l_{psb} t_{jpsb} + \\ & \sum_{ipsb} \frac{l_{psb}}{\alpha_{0psb}} \left[\frac{P'_{ipsb}}{2} - P_{ipsb} S_{ipsb} \right] - \\ & \sum_{psb} \frac{l_{psb}}{\alpha_{0psb}} \left[D_{psb} D^0_{psb} - \frac{D'_{psb}}{2} \right] \end{aligned} \qquad (25)$$

F. Additional model results

−Price for each level, subperiod and period is directly obtained from demand:

$$\lambda_{psb} = \frac{D^0_{psb} - D_{psb}}{\alpha_{0psb}} \qquad (26)$$

−Operational profit for each utility in each level, subperiod and period is obtained as its incomes minus its costs,

$$B_{ipsb} = \sum_{psb} l_{psb} \left[\lambda_{psb} P_{ipsb} - \sum_{j|o_j = i} \delta_j t_{jpsb} \right] \qquad (27)$$

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IX. Biographies

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Rodrigo Quinteros received his B.Sc. in Electrical Engineering from Catholic University of Chile and he is candidate for M.Sc. at the same university. He has 7 years of commercial and regulatory experience in the Latin-America's generation and distribution markets working for important electric companies as Enersis (Endesa España) and AES gener (AES). His research interests include power systems economic dispatch, electric market regulation, pricing models and related topics.