THE STRATEGIC COST OF HYDROELECTRIC RESOURCES

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ABSTRACT

Abstract: In liberalized hydro-dominated power supply systems, the way managers use the knowledge they have about water levels in order to make production decisions impacts both their market power potential and the market outcomes. Assuming that the corresponding risk can be priced, we develop a dynamic hydro-dominated oligopolistic modeling framework to discuss the strategic cost of hydroelectric resources, in the context of the short-term marginal opportunity cost of storable electricity. As our contribution over previous approaches we construct a criterion embodying in a single number the strategic cost of hydropower production decisions. This criterion is built through the use of an indifference (risk-neutral) argument regarding the expected profits associated to a particular production strategy. Our result enables us to define regulatory policies to mitigate the market power potential of oligopolistic hydro-dominated producers**,** and to define socially optimum water allocation policies. We use data from the Colombian power market to run an informal check of the plausibility of our findings.

1. INTRODUCTION

It seems well established wisdom that the rationale of oligopolistic power producers is driven by price risk exposition and by changes in the slope of the residual load they serve (Hansen, 2009). These two overarching causes are nevertheless composed of more specific ones. In the case of hydro-dominated power systems, it is important to clarify how managers use the knowledge they have about water levels in order to make production decisions. In this work we assume that this is an important contributor to price risk in the system. There may be several channels through which this problem can be approached. In particular, in this paper we construct a criterion that embodies in a single number the strategic cost of hydropower production decisions. To our knowledge, previous work on the economics of deregulated hydro-thermal power supply systems has not dealt with the specific computation of the strategic cost of hydroelectric resources. Here we develop a dynamic hydro-dominated, oligopolistic framework and use it to discuss the rationale that underlies electricity markets, within the context of the short-term marginal opportunity cost of storable hydroelectric resources. We explicitly build this framework in terms of market and the short-term weather expectations, as well as the market power potential.

Decades ago, the industry focused mainly in estimating water costs, but since then the main object of concern has evolved, following changes in regulation (Pereira, 1989; Wolfgang et al., 2009). By the 1950's hydro-thermal systems grew complex and the integrated/centralized state owned model –worldwide adopted– was facing a resource allocation problem: To maximize the expected utilities subject to uncertainties, e.g. water inflows, electricity demands, transmission constraints, among others. There were trade-offs between hydro and thermal generation costs to be optimized in short-term planning horizons and in this pure resource management problem investment costs played no relevant role. Hence, water and electricity shadow prices as well as reservoir and turbine efficiency rates became the object of attention.

In the late 1980's water allocation strategies were further enhanced exploiting computational developments. The initial emphasis in shadow prices yielded to interest in marginal hydroelectricity production costs from Stochastic Dual Dynamic Programming formulations. Nowadays, Brazil follows a centrally operated model using an improved SDDP formulation and there is a Scandinavian reciprocal model,[2] though it is not used for scheduling purposes.

Technological changes in the early 1990's quickened the liberalization pace within the industry. The capital intensity of the industry led to concentrated markets, which motivated market power assessments by the regulators, specifically in hydro-dominated systems, where the problem has been further exacerbated. Producers engaged in setting up bidding strategies in pool-based markets, while market regulators sough to create competitive environments.

Afterwards, the technological differences became a deep concern, due to issues of their complementarities as well as the reliability of power supply systems without a centralized coordination. The situation got worse with the emergence of intermittent renewable resources hard to forecast. In fact, the coordination of these new resources will become a harder task to undertake if expected technological changes like smart-grids become part of the market environment, leading thus to their participation in the system of distributed generation.

Two decades after the liberalization trend started, the relative benefits of competition and coordination in power supply systems are still questioned. Due to market architectures that are unbundled and competitive, the concept of integrated water cost is being replaced by one of short-term marginal cost (Ambec & Doucet, 2003; Wolfgang, 2009).Water costs are benchmarked to the price of the fuels powering its thermal competitors as shadow prices; the short-term water opportunity costs incorporate this information, as well as the uncertainty of demand and water inflows, into the price-bid structure and the shape of the load individually served by producers[3] (Hansen, 2009). Therefore, the cost of water is no longer viewed as a variable production cost, declared to a centrally managed system, but rather as a cost of the strategic resource to be internally assessed.

In this paper we argue that in a price-bid structure the opportunity cost of the hydroelectric resources is also priced. This cost depends on the market power potential and on local market architecture customizations.

In Section 2, we present a brief literature review on the subject. Then, the proposed model is described in Section 3. In Section 4 we derive an explicit expression for the strategic cost of hydroelectric resources in competitive power markets following an indifferent strategy argument. In Section 5 we show evidence that supports the existence of the priced opportunity cost using market data from the Colombian power market. In Section 6 we discuss some implications of the concept of strategic cost for the socially optimal outcome. Finally, we draw some conclusions and propose some ideas regarding further work.

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[2] It is a power-market model, the EMPS1 (EFI's Multi-area Power-market Simulator).

[3] As it is also explained in Hansen (2009), the demand faced by a firm with market power does not depend solely on consumer demand, but also on the supply of its competitors which further depends on production technologies and other constraints such as bottlenecks in the transmission network.

2. LITERATURE REVIEW

The precise and proper estimation of water opportunity costs in deregulated markets would favor the achievement of efficient market prices, competitive strategies and water management policies as well. Nevertheless, most of the contributions regarding the economics of hydro-thermal and hydro-dominated power markets are not framed within this context[4] and usually lack an analytical and explicit interpretation of the strategic cost of the hydroelectric resources.

Crampes and Moreaux developed a simplified dynamic model where hydro and thermal resources compete (Crampes & Moraux, 2001). Their formulation describes in analytical and geometrical ways optimal resource allocation policies and market price levels under alternative market architecture assumptions. The economic rationality of the model is supported on the shadow prices of the scarce resource (water balance constraint). In fact, the authors state the value of water arises from its scarcity as compared to the needs in successive time periods.

The approaches developed afterwards successfully overcame the static nature of the models describing the economics of hydropower markets and incorporated the intrinsic dynamism of the hydro technologies into the modeling framework. These contributions still lacked the means to explicitly model the water opportunity costs in deregulated markets; however, most of them point out the relevance of this concept.

Ambec and Doucet developed a dynamic model to quantify the impact on welfare before and after the introduction of competition (Ambec & Doucet, 2003). Their formulation falls short of describing the strategic value of water, but they underscore its close interrelationship with the power market architecture. As they explain, welfare losses induced by biased water management policies may be counteracted by both institutional settings.[5] Moreover, they specify the suitability of either scheme depends upon the topology of the system.

Førsund (2006) follows an approach close to that developed by Crampes and Moreaux (2001). The author assesses the market power potential of hydro-dominated monopolists supported on demand functions perfectly known by the producer and engages in deriving outcomes after considering different alternatives e.g. inter-regional trade, reservoir constraints, a competitive thermal fringe. As it is stated by Førsund, the relevant variable to measure the existence of market power from hydropower producers is the opportunity cost of water; however, it is only highlighted as an important though not directly observable variable. The author associates the water value with the shadow price of a resource constraint as it is done in (Crampes & Moraux, 2001). However, the strategic value of water is not explicitly summarized in a single variable.

Hansen discusses how the costs structure of the marginal supply, as well as inflow uncertainties, influence the behavior of firms with market power (Hansen, 2009). This article presents an approach to how the qualitative and quantitative features of market power in hydro-dominated markets depend on the characteristics of the residual demand faced by individual firms. However, there is no explicit construction of a valuation formula for the cost of using the water use of the resource may have significant, short-term consequences.

[4] The idea of a water market parallel to the power market to properly price the resource in hydro-dominated systems have been suggested as a remedy (Ambec & Doucet, 2003). However, it remains an unpopular idea in a very reluctant institutional environment.

[5] A centralized monopoly would minimize the effects of suboptimal water allocation policies, whereas a competitive market environment would minimize the potential for market power.

Garcia, Campos-Nañez, & Reitzes (2005) (see also Garcia, Reitzes, & Stacchetti, 2001) came close to the idea of incorporating what they call the "strategic value" of water into price-bidding strategies of an infinite-horizon oligopoly model. They built upon an indifference price approach where the producer is indifferent between producing power with its water resources and holding onto those resources for the future. Their findings, despite symmetrical assumptions, characterize a Markov Perfect Equilibrium and give valuable insights for regulatory policy in hydro-dominated systems. They rely on a still general (stream of payoffs) functional form to describe the strategic value of water. It depends upon the states of own and competing water reservoirs after following a particular strategy.

3. THE MODEL

We propose a three-date, two-period model. At the beginning of the first period ($\tau = 1$) the agents learn what the state of nature (the weather) will be during the period. The states could be either rain or no-rain. This knowledge, together with any other ancillary information about competitors, is enough for the oligopoly to choose its bid for the period. The future state of nature (time period starting at $\tau = 2$) is nevertheless uncertain, with the states of rain and no-rain having objective probabilities $1 - q$ and q, respectively. Such probabilities are common knowledge, since all agents in this market have access to the same data. From this fact they may agree, for instance, on defining q as the relative frequency of dry days in a moving window historic sample.

Power supply is represented by an oligopoly of large producers holding a portfolio of hydro (h) and thermal (t) power generation assets. In this model the oligopoly is assumed to be hydro-dominated. There may be also other competitors, of comparatively smaller scale and diversified power production assets.

It is assumed that there is a wholesale day-ahead spot market where producers individually bid their resources to meet an inelastic system load. The oligopoly supplies a residual load share assuming that the strategy followed by its competitors is perfectly known. This load share is assumed to be constant: $D_\tau = D$, for all τ.

The final sale spot price is found once a uniform-price auction is cleared, at the end of each period. The prices are directly affected by the strategy followed by the oligopolistic power producers, i.e., their choice of technological production share. Once the prices are known, delivery is assumed to be immediate.

The oligopoly may produce an amount q_τ^h of hydroelectricity with corresponding subjectively assessed strategic cost of opportunity v_τ^h. This cost accounts for the value of the forgone opportunity of using the storable resource once released, and will be affected by market customizations (in this case a pool-based spot market), by the expectations about inflow realizations, competitors' behavior, and the market power exerted after following the particular strategy q_τ^h. By "market power", we understand the ability of the power producer to effect the distribution of the final sale price.

Consider an oligopolistic player that owns a water reservoir with maximum storage capacity $\bar{\delta}$, which is currently holding an amount of hydroelectricity $\delta_\tau \leq \bar{\delta}$. By convention, this is the amount of energy equivalent to the water level in the reservoir at the beginning of time interval τ. Uncertain water inflows during previous periods of time ($a_{\tau-1}$) produce a cumulative distribution function $F[\delta_\tau]$ such that

$1 - F(\bar{\delta}) = 0$. During the time interval τ there may also be spillovers s_τ, that can be calculated from the balance equation

$$s_\tau = max\{0, \delta_\tau + a_\tau - \bar{\delta}\} \quad (1)$$

Hydroelectricity production is constrained either by the maximum turbine output capacity β, or by the amount of water δ_τ. Hence, the decision about the actual production of hydropower will take place at the end of interval τ. The amount produced is given by

$$q_\tau^h = w_\tau \cdot min\{\delta_\tau, \beta\} \quad (2)$$

Where $w_\tau \in [0,1]$ corresponds to the manager's production decision at τ. Therefore, the water/energy balance at the beginning of interval $\tau + 1$ will be,

$$\delta_{\tau+1} = \delta_\tau + a_\tau - s_\tau - q_\tau^h \quad (3)$$

The oligopoly may also produce an amount

$$q_\tau^t \leq min\{\alpha, D - q_\tau^h\} \quad (4)$$

of thermal electricity with corresponding variable production cost v_τ^t. Assuming that producers enter into fuel supply forward contracts, this cost is assumed to be certain in the short run.[6] Parameter α is the maximum thermal electricity production given the installed capacity. Let β represent the maximum hydropower production capacity. Then, the hydro-dominance of the oligopoly means that $\beta > \alpha$. For the remainder of this paper the relation $D \leq \alpha + \beta$ is assumed to hold.

Any deficit in supply is given by $\xi_\tau = max\{0, D - q_\tau^h - q_\tau^t\}$. This, as well as any production overhang, has to be bought or sold at spot prices. Note that, since we assume that any deficit is bought and sold at the same spot price, there is no net financial effect from this operation.

The design of a strategy starts with the monopolistic producer bidding its resources at the beginning of time interval τ expecting a market realization price p_τ. Nevertheless, on delivery the actual market outcome p_τ^* may be different. His oligopoly market power resides in the fact that he can narrow the dispersion of the p_τ^* distribution about his expected price, which may be computed from some previously determined procedure; for instance, a procedure that uses as its input information about weather related probabilities and a chosen set of historic prices. The use of conditional sets of historic weather registries of the number of dry and wet days produces something of an "objective" binomial probability distribution, about which al agents may construct a common belief. This procedure avoids in large measure some of the more troubling assumptions made in the rational expectations frame.

The (risk-neutral) utility of the particular strategy will be the two-period total profit associated to a fully speculative ($v_\tau^h = 0$) strategy w_τ. We shall work, for the sake of specificity, with the case when water power acts as marginalizer in the power bid, that is, in the initial move thermal power is always at its maximum, and we will limit ourselves to the case when $\delta_\tau \geq \beta$. Under those conditions, the total income for the two periods may be written as follows:

$$\Pi = \Pi_\tau + \Pi_{\tau+1} = [w_\tau \beta p_\tau^* + \alpha(p_\tau^* - v_\tau^t)] + [q_{\tau+1}^h p_{\tau+1}^* + q_{\tau+1}^t (p_{\tau+1}^* - v_{\tau+1}^t)] \quad (5)$$

[6] It might of course be subjected to uncertainties different from the rain and no-rain scenarios, such as fluctuations in the international price of crude oil.

In this model, any profits come only from the electricity trade in the spot market. For the sake of simplicity, no bilateral contract market is considered and the discount rate for all cash flows is set at zero. The power producers are assumed to be short-term utility maximizers, therefore the set of optimal strategies excludes cases with zero total power production for any single period. The underlying rationale for any strategy in which the oligopoly would rather produce less than its target demand is because it believes that, by doing so, its market power will bring about a higher realization price and higher revenue.

Let's consider two benchmark strategies, *A* and *B*, that correspond to the extreme strategies $w_\tau^A = 1$ and $w_\tau^B = 0$. Given that the state of nature in period $\tau + 1$ is still unknown, strategy *A* may be deemed a gambler's strategy. On the other hand, *B* could be characterized as one of excess of prudence. In either case, the first move does not fully condition the decisions to be made for the second.

Even in the absence of any conscious effort, a strategy judged to be "prudent" can be decomposed into one that is risk-neutral minus an implied cost of use of the resource. Strategy *B* will turn out to be dominant, as long as $\Pi^B \geq \Pi^A$. The application of (5) to this condition yields the inequality:

$$p_\tau^{*B} \geq \left[1 + \frac{\beta}{\alpha}\right] p_\tau^{*A} + \frac{1}{\alpha}\{Q_{\tau+1}^A p_{\tau+1}^{*A} - Q_{\tau+1}^B p_{\tau+1}^{*B} + (q_{\tau+1}^{tB} - q_{\tau+1}^{tA}) v_{\tau+1}^t\} \qquad (6)$$

Where variables with capital letters represent total power production. The notation in (6) is used not only to label each strategy, but most important, to convey the notion that each strategy builds a different cumulative distribution for future prices p^*.

Inequality (6) corresponds to a linear constraint of the form $p_\tau^{*B} \geq m \cdot p_\tau^{*A} + b$, which is shown in Figure 1. The shaded area demarks the $\Pi^B > \Pi^A$ feasibility set. Depending on the market architecture, the depicted plane may be bounded by price caps.

From (6), it can be seen that the slope m will always be positive and will be defined by the hydro to thermal power production ratio. On the other hand, the intercept b may take either positive or negative values depending upon the net profit difference between strategies *A* and *B* at $\tau + 1$. This intercept will take positive values whenever the strategy *A* overcomes strategy *B* at $\tau + 1$.

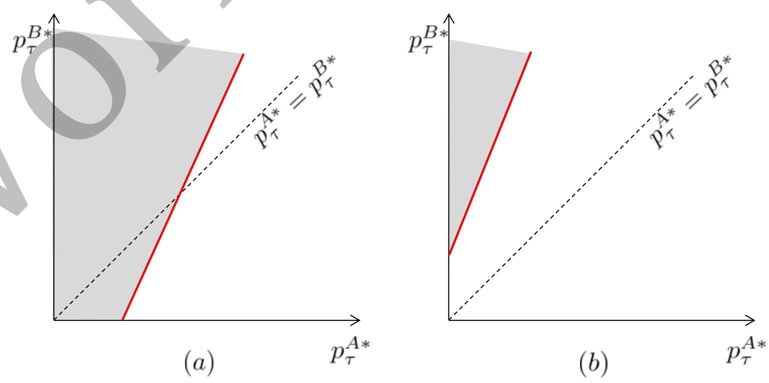

Figure 1. $\Pi^B > \Pi^A$ feasibility set.

The two graphs in Figure 1 show the feasibility sets for $b < 0$ and $b > 0$, respectively. The line $p_\tau^{A*} = p_\tau^{B*}$ corresponds to the case when the producer has no oligopoly power and therefore the market is not influenced by its individual actions. This line serves as a reference for the relative positions in each case. When $b < 0$, the $\Pi^B > \Pi^A$ feasibility zone extends even to points where the oligopolistic producer may afford market prices below the competitive benchmark.

4. THE STRATEGIC COST OF HYDROELECTRIC RESOURCES

We proceed next to derive a simplified expression for the strategic cost of the hydroelectric resources v_τ^h, in the way an oligopolistic hydro-dominated power producer could perceive it. To achieve this end, we rely upon an indifference strategy argument. That is, a risk-neutral strategy for an oligopolistic power producer in terms of the expected profit minus an internally assigned cost. This is the short-term certainty equivalent cost of the hydroelectric resources.

Consider now a strategy $w_\tau \in (0,1)$, which is midway between the previously defined benchmarks *A* and *B*. To determine v_τ^h, we equate the profit of this strategy w_τ when no hydroelectric production costs are perceived, as it was previously defined in (5), to the profit derived in the case when $v_\tau^h > 0$.

Let $\Pi^N(w_\tau)$ be the expected utility from a strategy such as the one described by equation (5). The expectation is to be taken over the distribution of $p_{\tau+1}^*$ resulting from assuming a world where there are no strategic costs to the use of water. This expectation is represented by the operator $E_0[\cdot]$. Let $\Pi^C(w_\tau)$ be the expected utility, corresponding to the same production decision w_τ, but assuming that there is an implied cost v_τ^h to the resource. This expectation is represented by the operator $E_>[\cdot]$. The assumption here is that the resulting distribution of final prices, when agents act as if there were no strategic costs to the use water, is not necessarily the same as the one that would result from some or all agents acting as if the use of the resource implied such costs. Notice that for the latter to be the case it is not necessary that the agents are themselves aware of their actions as being driven by the explicit knowledge of a valued cost.

These expected utilities are then computed over different distribution functions. For instance, if the monopoly makes production decisions as if there were no implied costs in the use of the hydroelectric resource, it follows that:

$$\Pi^N(w_\tau) = (w_\tau\beta + \alpha)p_\tau^* - \alpha v_\tau^t + E_0[Q_{\tau+1}p_{\tau+1}] - E_0[q_{\tau+1}^t]v_{\tau+1}^t \tag{7}$$

where $Q_{\tau+1} = q_{\tau+1}^h + q_{\tau+1}^t$. Note that the value given in (7) must be seen as a sort of certainty equivalent. This statement is to be understood in the following sense: under the “business as usual” assumption of zero cost of water, agents responses within the limited competition left are adjusted – given all they know about other agents plus their own private information – so that the overall result is a known lottery (distribution), such as $E_0[\cdot]$. The introduction of a cost of water exposes all players to a different – perhaps lesser known – lottery $E_>[\cdot]$. Since this cost would presumably arise from pure strategic behavior, agents will not be willing to assign a price to it larger than that which will produce the same utility as the certainty equivalent.

All expectation operators $E[\cdot]$ are the composition of two types of distributions: the discrete distribution associated with the future states of no rain or rain, and the continuous conditional distribution on each of these two states. The general formula is then:

$$E[x] \equiv q\overline{E}[x] + (1-q)\underline{E}[x] \tag{8}$$

Where $\overline{E}$ is defined over a distribution conditional on the no-rain state. $\underline{E}$ is conditional on the alternative state of rain.

The implied costs of the hydroelectric resources are then defined to be the set $\{v_\tau^h\}$ that would make the monopolist indifferent between the two types of expectations:

$$\Pi^N(w_\tau) = \Pi^C(w_\tau) \tag{9}$$

From (7) – (9) it can be shown that v_τ^h satisfies the following recurrence formula:

$$w_\tau \beta v_\tau^h = \{\{E_>[Q_{\tau+1}p_{\tau+1}] - E_0[Q_{\tau+1}p_{\tau+1}]\} + \{E_0[q_{\tau+1}^t]v_{\tau+1}^t - E_>[q_{\tau+1}^t]v_{\tau+1}^t\}\} - E_>[q_{\tau+1}^h]v_{\tau+1}^h \tag{10}$$

Notice first the mean reverting character of this recurrence formula. The left-hand-side of the equation is the strategic cost of water of the hydropower production decision[7] at the beginning of period τ. On the right-hand-side, the last term counterbalances the effects of the decision made; if the initial decision implied a tight use of the resource, i.e., a high implied strategic cost, then it is expected that in the following period there will be an important release of the resource, which would make for a negligible, or even negative, associated cost.

The influence on (10) of the storage-flow formulas given by equations (1) through (4) is not at first glance obvious. Nevertheless, straightforward applications of (10) in idealized situations show that if the producer has considerable water regulation capacity[8], reservoir levels are not too relevant for his strategic valuation of the hydroelectric resource. On the other hand, a run-of-the-river producer will be affected by the water inflows and the reservoir levels after following a specific production strategy.

To further clarify the meaning of equation (10), it is useful to rewrite it thus:

$$w_\tau \beta v_\tau^h = E_>[Q_{\tau+1}p_{\tau+1} - q_{\tau+1}^t v_{\tau+1}^t - q_{\tau+1}^h v_{\tau+1}^h] - E_0[Q_{\tau+1}p_{\tau+1} - q_{\tau+1}^t v_{\tau+1}^t] \tag{11}$$

In this rearrangement, the first and second terms of the right-hand-side may be read as expected revenue net of production costs for each case. Notice that under $E_0[\cdot]$, the presumed cost of the hydroelectric resource is zero. The difference between these two quantities represents a "margin" (which could be either positive or negative), that will result from the particular production decision, but under different assumptions about the cost of water. Assume that this margin is positive. Then it could happen that the cost of use of the resource in the following period will also be positive. Several successive periods with positive costs of the resource may be characterized as a situation of crisis management. The intuition that conveys this formula becomes then immediate: under conditions of scarcity, the producer estimates that constantly acting as if the water had an intrinsic cost of use will bring in higher expected net revenue. There is then agreement between (11) and common wisdom: in hydro-dominated markets, the strategic cost of the hydroelectric resources will take high positive values during dry hydrological seasons, and low values during wet periods.[9] The degree of uncertainty in the weather forecast will impact the

[7] That is meant to be a part of some strategy.

[8] We refer to the water regulation capacity of a hydroelectricity power producer as the ability to shift water from one time period to the other. It depends upon both its water storage capacity and its turbine output capacity. Henceforth it will be associated to the ratio $\overline{\delta}/\beta$.

[9] This might not be the case when there is a smaller competitor counteracting the actions of the oligopolistic producer, as it was demonstrated in Garcia, Campos-Nañez, & Reitzes (2005). In this case, the strategic value of water may be positive

perceived value of the resource today. Taking clues from this general intuition, in the next section we proceed to check what the recurrence relation (10) can tell, using data from the Colombian power market.

5. EVIDENCE FROM THE COLOMBIAN POWER MARKET

In this section, we use the historic data from the Colombian power market as a laboratory to display graphical evidence of the relevance of equation (10). We begin by developing a proxy approach supported on backward induction, as dictated by relation (10), to estimate a proxy for the strategic cost of hydroelectric resources in Colombia. Then, we present graphical results evidencing hydro-dominated oligopolistic behavior within the market environment.

Before 1995, the electricity in Colombia was supplied following a vertically integrated architecture. A centralized state owned enterprise minimized variable costs of production declared by power producers. The economic inefficiencies of that scheme opened the door to the deregulation trend then sweeping the international power markets.[10] This reform was aimed at overcoming the following market inefficiencies: *(i)* the misleading power generation costs declared by power producers (mostly hydro); *(ii)* two major national blackouts in 1983 and between 1992 and 1993 due to inefficient water management policies from the central coordinator; and finally, *(iii)* the public finance constraints threatening the capacity headroom of the overall system. Hence, the previous centralized scheme was transformed into an unbundled/decentralized architecture, and the injection of private capital was allowed across most levels of the supply chain. The reform set a competitive market environment for wholesale power producers, which was further extended to power retailers. Power transmission and distribution remained regulated as natural monopolies given their network economies.

From its origin, a neutral regulatory policy regarding the technological preferences of the system has driven the capacity expansion of the national interconnected system; however, the large hydrologic resources within the national territory have favored a state of hydro-dominated power generation. This particular feature has exposed the power supply system to abnormal dry events like the ENSO.[11] This hydro-dominated feature of the park, combined with the capital structure of the power generation business, lead to an oligopolistic market structure in Colombia. Recent estimations of the Herfindahl-Hirschman Index[12] calculated as the market share of the (monthly) aggregated power generation in Colombia, show the index usually takes values between 1500 and 1600. However, it may oscillate between 1200 during extreme dry events and 1800 during abnormally wet seasons. This evidences not only a concentrated power generation market but also an increased market power potential whenever there is excess of hydroelectricity supply.

Nowadays, four submarkets compose the Colombian electricity market: the day-ahead market, the bilateral (tailor-made and OTC) contract market, the ancillary services market, and finally, the capacity adequacy market, updated in December 2006. This last market was originally an administrated mechanism remunerating the installed capacity of power producers. That mechanism proved to entail

and high, even when there is excess of hydroelectric supply, depending upon the water discharge policy followed by the part counteracting the oligopoly.

[10] See (Alzate, Cadena, Benavides, & Castro, 2011) for further details.

[11] ENSO is the acronym for El Niño-Southern Oscillation.

[12] It is a widely accepted indicator of market concentration taking into account the relative size and distribution of companies in a market. See http://www.justice.gov/atr/public/testimony/hhi.htm

some perverse incentives; therefore it was replaced by a market based mechanism that remunerates instead Firm Energy Obligations (FEOs).[13]

To estimate the strategic cost of hydroelectric resources in Colombia, we rely upon expression (10) and follow a backward induction proxy approach. We begin at a point where the hydrologic scenario guarantees excess of hydroelectric supply. We then proceed to take this point as the reference level, i.e. $v^h = 0$. The chosen point lies within the severest time interval of the most recent La Niña event, in December 2010. Then, the series followed by v^h was estimated by backwardly replacing the remaining terms in (10) with their corresponding proxies.

In expression (10) we use the hydroelectric production of the aggregated market as a proxy for $w_\tau \beta$; while for $E_>[Q_{\tau+1} p_{\tau+1}]$ it is used the expected revenue earned after the strategy actually followed by the aggregated market. That is, under the assumption that hydroelectric power producers in Colombia behave as an oligopoly that effectively perceive a strategic cost for the storable resource.

The proxy used for $E_0[Q_{\tau+1} p_{\tau+1}]$ is harder to estimate. We used the average revenue in the last event when it was perceived excess of hydroelectric supply by producers. The decision as to when to declare an "excess" of hydro power supply is somewhat arbitrary, but inspection of the empirical cumulative probability distribution of the hydroelectric production share indicates this threshold should be at about 85% of the system load (see Figures A.1 and A.2 on the Appendix). Similar approaches were followed to derive the proxy for the terms $E_>[q^t_{\tau+1}]$ and $E_0[q^t_{\tau+1}]$. In the first case, it is used the expected production associated to the thermoelectric production after the strategy actually followed by the aggregated market. In the other case, the inspection of the empirical probability distribution of the thermal production share (see Figure A.3 on Appendix), suggests the thermoelectric threshold should be 20%.

The result of the procedure just described is presented in Figure 2.[14] It displays the evolution of electricity spot prices in Colombia (continuous black line) and the impact the last ENSO event[15] had on them. In the same graph it is also plotted the competitive expectation for the spot price, i.e. $E[p] = (1-q)\underline{p} + q\overline{p}$ (dotted line). For this calculation, rain and no-rain probabilities were previously estimated according to the anomalies of the daily inflows to the market aggregated reservoir (see Figure A.4 in the Appendix). The parameter $\underline{p}$ is the lower price in the last running month, and $\overline{p}$ is the upper price bid for the same period.[16]

[13] See Alzate, Cadena, Benavides, & Castro (2011) for further details.
[14] The trajectories sketched in Figure 2 correspond to weekly moving average values in order to avoid unnecessary noise.
[15] Simultaneously to the ENSO event, frequent and heavy regulatory interventions altered the normal trajectory of the market signal throughout this time interval. See (Alzate, Cadena, Benavides, & Castro, 2011) for further details.
[16] To avoid misleading results due to abnormal oil prices throughout the 2008 oil crisis it was rather used the maximum price bid registered along the former month instead of the scarcity price which carried with this anomaly due to its indexation to international fuel oil prices.

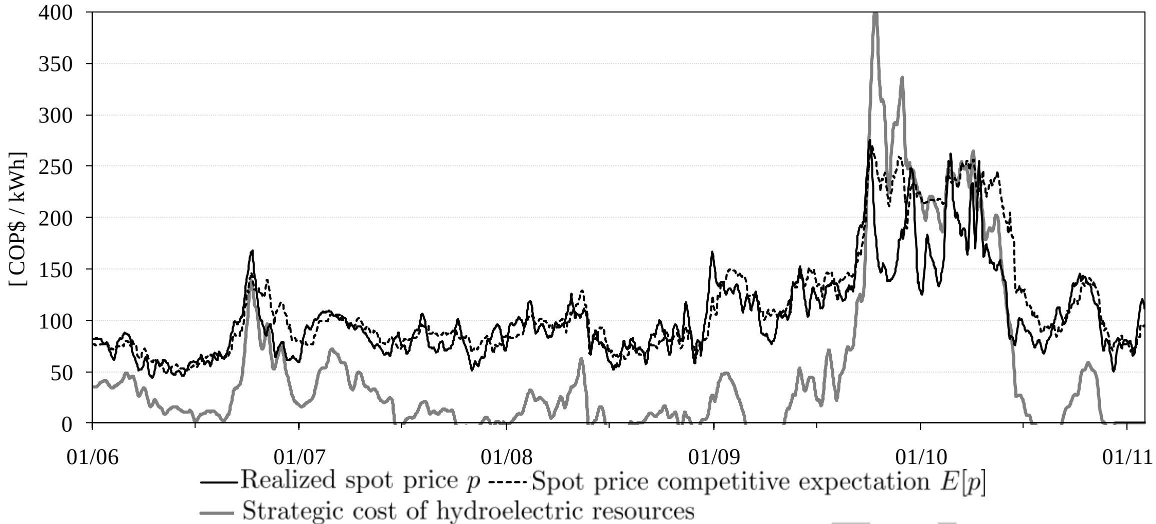

Figure 2. Proxy for the strategic cost of hydroelectric resources in Colombia.

As it can be observed from Figure 2, the expectation $E[p]$ using the empirical set of values for *q* follows rather well the graph of actual prices.

It is also depicted in Figure 2 the proxy for the strategic cost of hydroelectric resources in Colombia. Starting from $v^h = 0$ in December 2010, its value was backwardly induced as explained above. Notice the way its value significantly increases along extreme dry events as it was the case along the ENSO 09-10 event. This is direct evidence of the strategic use of water during this period; otherwise, under normal or even excessive hydrologic conditions, the variable takes low or even negative values.

Now, to reveal the hydro-dominated oligopolistic behavior within the Colombian power market environment consider the following. The daily load profile in Colombia is mainly driven by the residential sector; it presents its peak profile between the hours 18 and 20. The electricity demands during this time period tend to be relatively inelastic in the short-term, compared to off-peak periods. The upper graph in Figure 3 sketches the median, lower and upper quartiles for the variable. In the same fashion, the hydroelectric production from two anonymous generators A and B are depicted in the middle and lower graphs. These power plants belong to different owners holding significant shares of installed capacity in the Colombian power generation park. Even when producer B holds about half the installed power capacity of producer A, its water regulation capacity ratio is about a hundred times greater than that of producer A.

As it can be observed in Figure 3, producer B tends to shift the storable hydroelectric resources according to its strategic water valuation from relatively inelastic demand periods to relatively elastic ones. On the contrary, given its technological features, it is not profitable for the run-of-the-river producer A, to follow the same strategy. This evidences hydro-dominated oligopolistic power producers in the Colombian power market tend to shift the storable hydroelectric resource according to its strategic water valuation from relatively inelastic demand periods to relatively elastic ones.

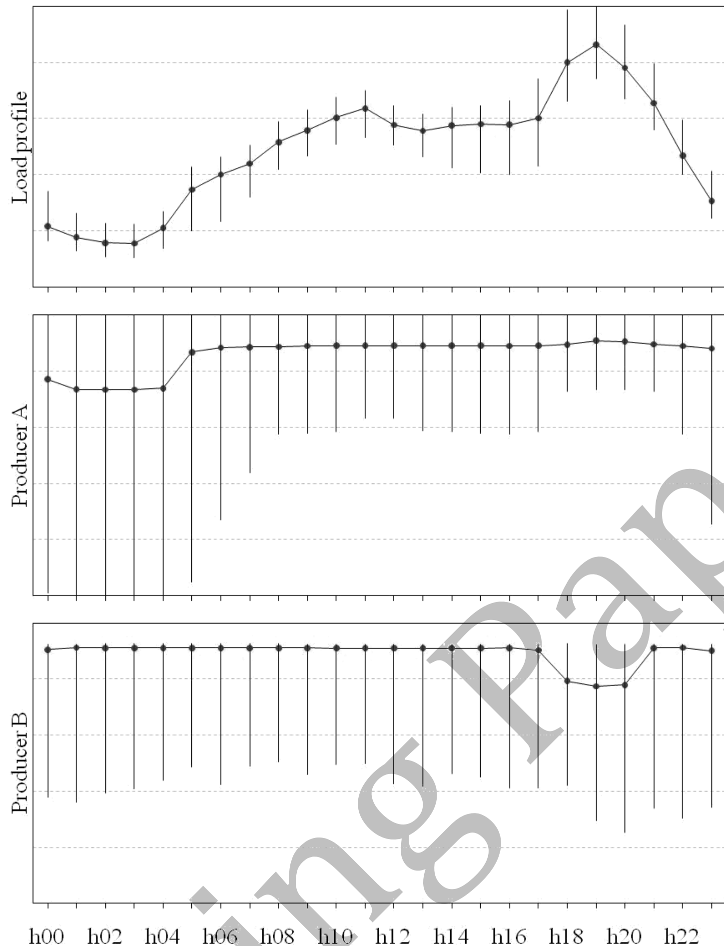

Figure 3. Evidence of hydro-dominated oligopolistic behavior within the Colombian power market.

6. CONCLUSIONS AND FURTHER WORK

Deregulation of the hydro-thermal power markets substituted the concept of short-term marginal opportunity costs of water for the earlier of variable cost of producing hydroelectricity. In this paper we attempt to construct an explicit expression for such marginal short-term opportunity costs, which spring from the strategic behavior of hydropower producing agents, in the aggregate. Our contribution differs from previous work, in the attempt we make to construct a criterion embodying in a single number the strategic cost of hydropower production decisions. This criterion relies upon an indifference (and risk-neutral) argument regarding the expected profits associated to a particular production strategy. The plausibility of this construction is then assessed using the Colombian power market as a working bench on which to verify our results.

The resulting expression involves market and weather expectations, and absorbs all agents best responses through the careful definition of conditional cumulative distributions hydropower supply, which we take as those actually given by market conditions. This enabled us to discuss some features of the rationale behind electricity markets. After the worldwide liberalization trend, the risk born by producers in hydro-dominated power supply systems is directly affected by the time-variable cost of using the storable hydroelectric resources. Once this strategic cost is made explicit, it sheds some new light on the way managers use the knowledge they have about present and future water levels, in order to make production decisions that impact their market power potential and the market outcomes. Seeking to contribute in this dimension, we develop a dynamic hydro-dominated oligopolistic modeling framework to discuss the economic rationality of power systems by way of the strategic cost of hydroelectric resources. That is, within the context of the short-term marginal opportunity cost of storable electricity. Beyond devising an explicit formula, an important part of our results is to provide a "proof of existence" by construction.

We believe we provide that proof in section 5, were we apply the model in section 4 to data from the Colombian power market. These results readily reproduce the common intuition that in hydro-dominated markets, the strategic cost of the hydroelectric resources takes high (positive) values during dry hydrological seasons, and turns to low (and even negative) values during wet periods.

On the regulatory front, the explicit expression found for the strategic cost of hydroelectric resources enables both power producers and power market regulators to better define water management policies. On one side, private producers could manage higher profits from an enhanced and custom made water discharge policy. On the other, regulators would be empowered with an objective tool to set suitable regulatory interventions aimed at mitigating market power potential from oligopolistic hydro-dominated producers.

Our findings indicate oligopolistic producers tend to further exacerbate market outcomes bidding spikier prices according to the hydrologic scenarios when the price risk exposition is low, and contrarily, muffling either positive or negative market spikes whenever this risk exposition is significant. On the other hand, our findings indicate oligopolistic power producers tend to shift the storable hydroelectric resources according to its strategic water valuation from relatively inelastic demand periods to relatively elastic ones. The data from the Colombian power market was successfully used as a test bed to evidence both outcomes.

Hence, and from a regulatory perspective aimed to control the market power potential from hydro-dominated oligopolistic power producers, the following can be suggested. First, bounds to the electricity served through bilateral contracts must be introduced. This measure will seek to avoid biased price bids and thus misleading market signals. This would also promote auto-regulatory behavior. Second, considering the current technological trend of positioning the demand side as an active market participant, the elasticity of the load individually served by oligopolistic producers might be affected using demand response programs (e.g. disconnecting consumers). This would set incentives for the producers to behave competitively.

These interventions may improve the allocation of hydroelectric resources through time and would harmonize positively with the pro-competitive technological changes currently taking place (e.g. smart grids) to further exploit the advantages of market places. They would also prevent from going back to the centrally administrated institutional settings with a unique public firm allocating the resource.

Our work might be further developed in different directions. For instance, the expression for the strategic cost of hydroelectric resources is suited for dynamic programming applications. Moreover, the impact associated to inflow and demand uncertainty might be further studied writing the expression (10) in terms that more explicitly include the water reservoir balance equations and the water regulation capacity of the plants. In this paper, these two aspects do not show in the application of (10) made in section 5, due to the fact that our approach follows the general outline of the "representative agent" model.

Finally, the strategic cost of hydroelectric resources is dynamic and involves multiple time scales like that of the hydrologic seasons, the time resolution of the market where electricity is traded as well as that of the elasticity of load to be served. This value is thus affected by the time resolution and by its transition throughout overlapping time scales. This could be the object of further research.

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APPENDIX A

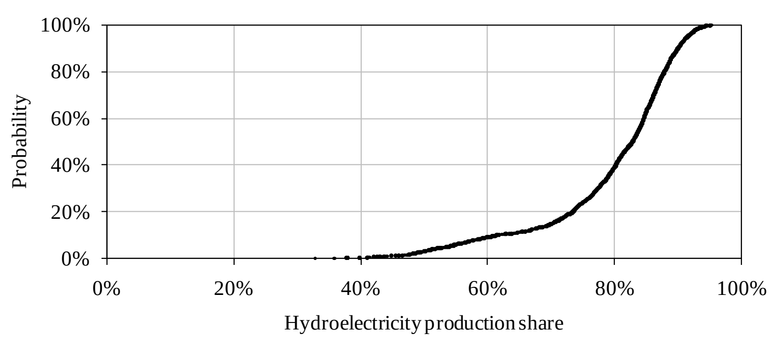

Figure A.1. Empirical cumulative probability distribution for the hydroelectricity production share in Colombia. Time interval: January 2006 – January 2011.

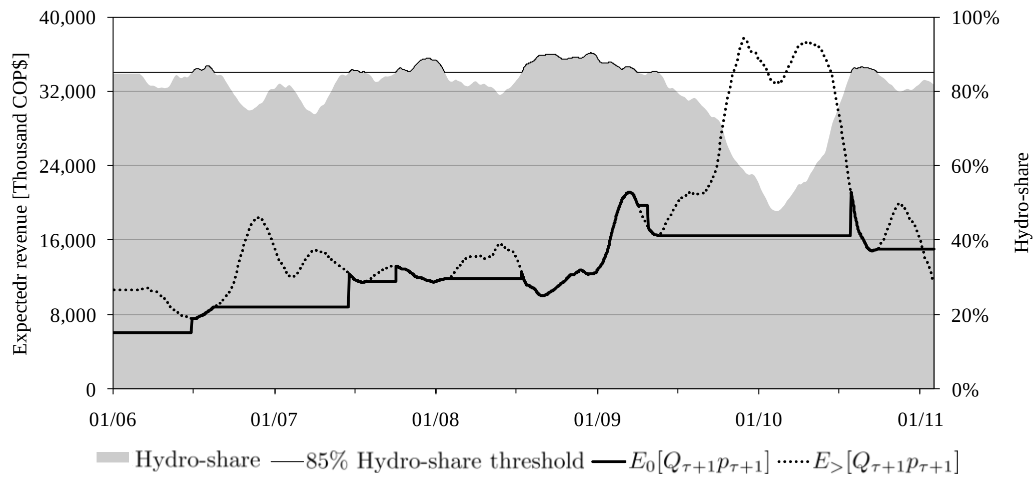

Figure A.2. Proxies for $E_>[Q_{\tau+1}p_{\tau+1}]$ and $E_0[Q_{\tau+1}p_{\tau+1}]$.

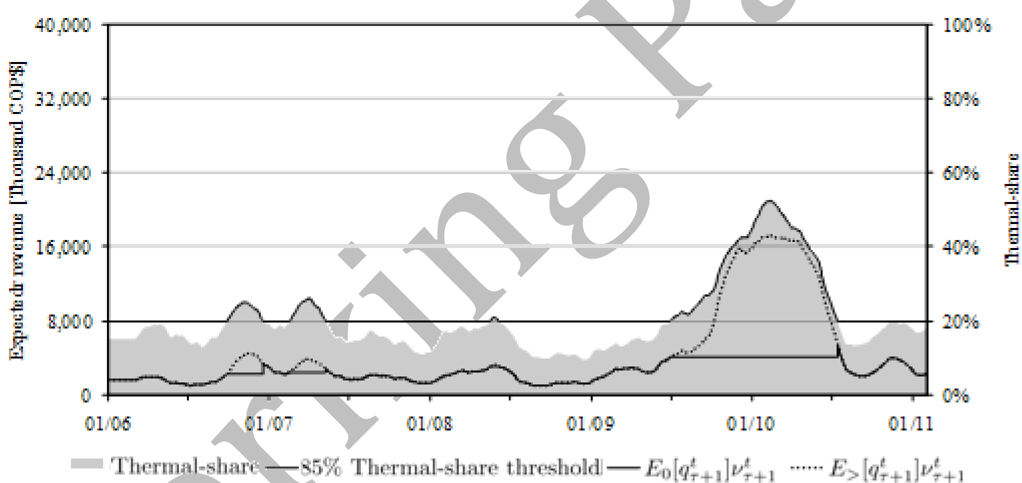

Figure A.3. Proxies for $E_>[q^t_{\tau+1}]\nu^t_{\tau+1}$ and $E_0[q^t_{\tau+1}]\nu^t_{\tau+1}$.

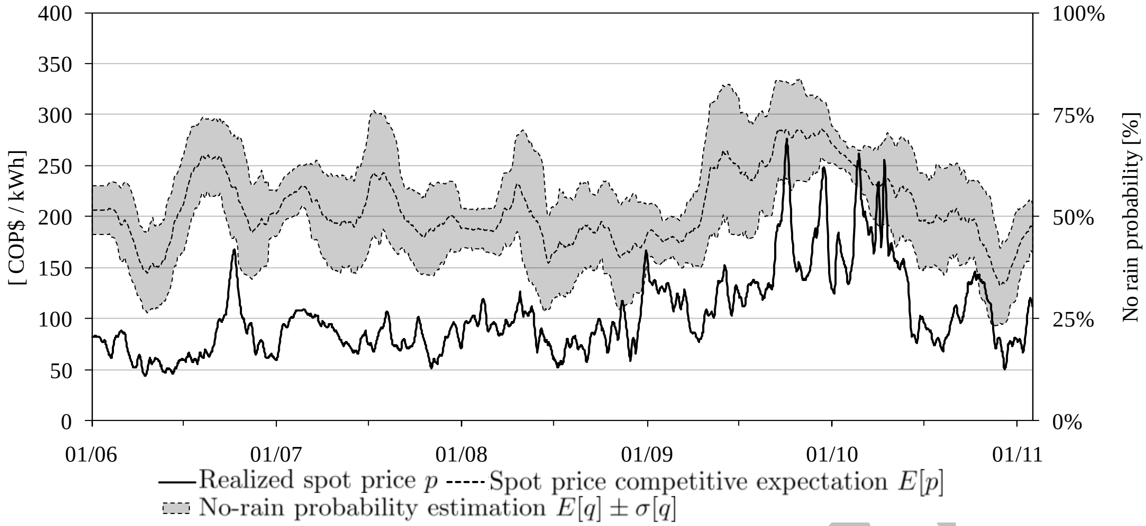

Figure A.4. No-rain probability expectation and associated standard deviation estimation for Colombia.