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MARGINAL COST PRICING IN HYDRO-THERMAL POWER INDUSTRIES: IS A CAPACITY CHARGE ALWAYS NEEDED?

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Abstract

This paper explores marginal cost pricing in hydro-thermal power industries. As in standard peak-load pricing for all-thermal electric systems, pricing consists of an energy charge and a capacity charge. However, the marginal cost of hydro generation now includes the value of water, which is determined endogenously. In turn, the capacity charge equals the marginal cost of increasing capacity which depends on the costs of both technologies and on the plant factor of hydro plants relative to the system's load factor. Moreover, if the cost advantage of the hydro technology is sufficiently high, then the optimal total installed capacity is larger than the system's maximum demand and henceforth the optimal capacity charge equals zero.

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1 Introduction

In some industries, like postal services, transportation, communications and electricity, the product or service can not be stored. In such industries demand must be satisfied instantaneously, which requires an installed capacity capable of satisfying peak demand. In those cases, marginal cost pricing adopts a specific form: peak-load pricing (Steiner 1957 and Boiteux, 1961). However, peak-load pricing, as it is usually understood, does not necessarily apply to hydro-thermal power industries as water reservoirs serve to "store" energy although not electricity. This paper explores marginal cost pricing in hydro-thermal power industries.[1]

The standard peak-load pricing for a multiple linear-cost generating technologies power sector that faces an inelastic demand, consists of an energy charge and a capacity charge, where the latter applies only to peak-demand consumption. The instantaneous energy charge equals the per unit operating cost of the plant with the highest operating cost among those operating, while the capacity charge equals the per unit capacity cost of the peaking technology, i.e., the technology that has the lowest per unit investment cost but the highest per unit operating cost. Assuming that generating plants are dispatched in strict order of merit, peak-load pricing leads a decentralized system to the optimal operating solution. Moreover, under perfect competition the configuration of the generation portfolio is optimal. This basic model has been extended in many directions,[2] but to the best of our knowledge hydroelectric

[1] Nguyen (1967) analyzes peak-load pricing with the availability of storage facilities. He finds that when there are storage facilities, off-peak prices increase and peak prices decrease. In our model, water –an input of electricity generation– can be stored, but electricity in itself cannot.

[2] Crew et al. (1995) provide a thorough review of its properties and its different applications.

generation has never been modeled.

We consider a two-technology, hydro and thermal, power industry. These technologies differ in their operating and capacity costs, with thermal plants having a lower per unit capacity cost but a higher per unit operating cost. The crucial difference with previous studies is that hydro generation is constrained by both installed capacity and water storage. We assume that water storage capacity sets a cap on the plant factor of hydro plants (i.e the ratio between actual generation and the nominal generation capacity). For simplicity, we further assume that all hydroelectric plants have the same cap on their plant factor, and that it is less than one. Demand, which is assumed to be inelastic, is summarized in a continuously differentiable load curve

In the paper we focus on those cases in which the optimal generation portfolio always includes hydro plants. In this context, we arrive at the standard result that the energy charge equals the marginal cost of the most expensive technology being used, but now the marginal cost of hydro generation includes the endegenously determined value of water. In addition, the capacity charge equals the marginal cost of increasing capacity, but this no longer necessarily corresponds to the per unit capacity cost of the peaking technology. We show that the optimal composition of the generating portfolio not only depends on the costs of both technologies, as in the standard peak-load pricing model, but also on the plant factor of hydro plants relative to the system's load factor (the ratio of average consumption to maximum consumption). These variables also determine the peaking technology, as the thermal technology does not always play this role.

Two cases need to be distinguished. First, when the plant factor cap of hydro plants is less than the sytem's load factor, we show that the stored water constraint is always binding and that the shadow value of water is such that hydro becomes the peaking technology. The optimal capacity charge decreases as the capacity cost ratio of thermal and hydro technologies decreases, while the energy charge increases. Indeed, if the cost advantage of hydro technology is sufficiently high, then the optimal total installed capacity is larger than the system's maximum demand and hence the optimal capacity charge is zero.[3] Second, when

[3]Some authors argue that capacity payments are required to ensure adequate supply as a large fraction of the net revenues earned to compensate investors relies on very high spot market prices occurring few hours

the plant factor cap on hydro plants is higher than the sytem's load factor, we show that thermal is the peaking technology, i.e., thermal plants are used to peak shave the load curve. In addition, if the water supply restriction is not binding, marginal cost pricing results in the standard peak-load pricing. Otherwise, the marginal cost of hydro plants includes the shadow value of water, but it is still below that of thermal plants.

Thus, marginal cost pricing in a mixed hydro-thermal industry is not as simple as in traditional thermal peak-load pricing. Notwithstanding that, it retains its most important property: it leads a decentralized competitive system to the optimal solution. Finally we show that generators operating in a mixed hydro-thermal industry could generate rents by deviating from the welfare maximizing generation portfolio, extending a previous result by Arellano and Serra (2007) for thermal systems.

The use of peak load pricing is common among countries that have privatized their power systems but where full competition seems impractical at the outset. The popularity of peak load pricing is due to its highly desirable efficiency characteristics, as well as by its simple pricing rules that are easy to apply. Countries that have adopted some format of peak-load pricing include Chile, Peru and Panama, where 50% or more comes from hydro generation.[4] According to our results, the use of the overly simple rules of all-thermal standard peak-load pricing in those countries may be inappropriate.

The paper is organized as follows. The next section describes the model. The model is solved in section 3. The main results are summarized in section 4. Section 5 analyzes producers' incentives to exercise market power when marginal cost pricing is used. The final section concludes.

2 The Model

We model a hydro-thermal power industry, where subindex h denotes hydro technology, and subindex g denotes thermal technology. Both technologies have linear costs, with r_i

each year, and income volatility could deter new investment in long-lived generation capacity. However, Joskow (2006) dismisses capacity payments as a second best solution at best.

[4] In El Salvador a reform to introduce a pricing system that resembles peak load pricing is currently being discussed .

denoting the per unit capacity cost and c_i the per unit operating cost, $i = h, g$. In addition, we assume that $\Delta r = r_h - r_g \geq 0$ and $\Delta c = c_g - c_h \geq 0$.[5] A cap α on the plant factor of hydro plants is imposed to take into consideration that hydro generation is limited by water stored in reservoirs ($\alpha \leq 1$). Demand, which is assumed to be inelastic, is summarized in a continuously differentiable load curve q, where $q(t)$ denotes consumption at the t-th-highest consumption hour. Finally, we assume that plant startup costs can be neglected and that no operating failures occur. Given this set of assumptions, the problem of minimizing the total cost of the power system can be formalized as follows:

$$Min_{k_h,k_g,H,G} \quad \{r_h k_h + r_g k_g + c_h H + c_g G\} \tag{1}$$

$$\begin{aligned}
s.t \qquad k_h + k_g &\geq q^m && (2)\\
G + H &\geq \int_0^T q(t)dt && (3)\\
G &\leq k_g t(k_g) + \int_{t(k_g)}^T q(t)dt && (4)\\
H &\leq k_h t(k_h) + \int_{t(k_h)}^T q(t)dt && (5)\\
H &\leq \alpha T k_h && (6)
\end{aligned}$$

where q^m denotes maximum market demand, k_i the installed capacity of type i technology, G and H are the total production from thermal and hydro plants, respectively, T the number of hours in a year, and $t(\cdot)$ denotes the inverse of the load curve. Since the load curve $q(t)$ has a negative slope, $t' < 0$.

Constraints 2 and 3 guarantee that supply matches demand: while the "capacity constraint" (constraint 2) ensures that total installed capacity is enough to supply peak demand, the "energy constraint" (constraint 3) guarantees that there is enough generation to satisfy the entire load curve. Constraints 4 and 5 reflect the fact that both thermal and hydro total generation have an upper limit. Technology i plants can operate at maximum capacity only for $t(k_i)$ hours. After hour $t(k_i)$ generation is restricted by demand (See Figure 1). Finally, constraint 6 reflects the fact that hydro generation is limited by stored water.

[5] We focus only in the cases in which $r_i > 0$, $c_i > 0, \forall i$.

Let's denote the Lagrange multipliers as follows: λ for the capacity constraint (constraint 2), μ for the energy constraint (constraint 3), δ_g for the thermal generation constraint (constraint 4), δ_h for the hydro generation constraint (constraint 5) and δ_w for the stored water constraint (constraint 6). Hence, δ_w represents the shadow value of water. Then assuming that both types of plants are dispatched, the Kuhn-Tucker conditions are:

$$\begin{aligned} \mu &= c_g + \delta_g \\ \mu &= c_h + \delta_h + \delta_w \\ \lambda &= r_g - \delta_g t(k_g) \\ \lambda &= r_h - \delta_h t(k_h) - \alpha T\ \delta_w \end{aligned}$$

A simple inspection shows that constraints 4 and 5 can not be binding at the same time, and hence $\delta_g\ \delta_h = 0$. Furthermore, the technology for which this constraint is binding will be the baseload technology. Whether hydro or thermal is the peaking technology depends on the model parameters. When technology i is the baseload technology and plants are dispatched in order of merit, between hours $t(k_i)$ and T demand is met by technology i's plants only, since installed capacity renders this feasible. Between hours 0 and $t(k_i)$ peaking plants generate the demand unmet by baseload plants. Hence the generation of peaking technology plants equals $\int_{k_i}^{q^m} t(q)dq$, where i stands for the baseload technology. Furthermore, when the generation portfolio includes hydro plants, the system's total cost is minimized when hydro generation is maximized given constraints 5 and 6, thus at least either δ_w or δ_h must be positive. Therefore

$$\begin{aligned} \delta_g \delta_h &= 0 \\ \delta_h \delta_w &\neq 0 \end{aligned}$$

Peak-load pricing consists of a capacity charge (applied only to consumption at peak demand) and an energy charge. The capacity charge is equal to the marginal cost of increasing capacity, which, in the context of this model is given by λ. From constraint 3 , it follows that the cost of increasing energy supply is μ when peaking plants are being dispatched. If supply is increased in those hours in which only baseload plants are dispatched, the cost of increasing supply is reduced to $\mu - \delta_i$, as follows from constraints 3, 4 and 5, where i is the baseload technology. Thus the energy charge equals μ for $t < t(k_i)$, and $\mu - \delta_i$ when $t \geq t(k_i)$.

Hence the energy and capacity charges satisfy the conditions reported in Table 1.

Table 1 about here

Thus we obtain the traditional result in marginal cost pricing, namely that the energy charge equals the marginal cost of the most expensive technology being used. However, now the marginal cost of hydro generation also includes the value of water. The capacity charge equals the marginal cost of increasing capacity, i.e., λ. Nevertheless, the latter no longer necesarily corresponds to the per unit capacity cost of the peaking technology.

3 The Model Solution

We rely on the idiosincratic characteristics of the model to solve the cost minimization problem. The hydro generation constraint (constraint 5) is a concave function as its slope is given by $t(k_h)$ and $t' < 0$. On the other hand, the stored water constraint (constraint 6) is a linear function, with slope α. Hence there is a unique positive level of installed hydro capacity at which constraints 5 and 6 are both binding, denoted $\hat{k}_h$,[6] which satisfies the following equation:

$$\hat{k}_h = \frac{\int_{\hat{t}}^{T} q(t)dt}{\alpha T - \hat{t}} \qquad \text{where} \qquad \hat{t} = t(\hat{k}_h) \tag{7}$$

The solution to the model depends on how high the hydro plant factor cap (α) is relative to the system's load factor ($\frac{\bar{q}}{q^m}$), where $\bar{q}$ denotes average demand, i.e. $\bar{q} = \frac{1}{T}\int_0^T q(t)dt$.

3.1 Case I: Low Hydro Plant Factor Cap ($\alpha < \frac{\bar{q}}{q^m}$)

As shown by Figure 2, if $\alpha < \frac{\bar{q}}{q^m}$, then $\hat{k}_h > q^m$, and only the water stored constraint (constraint 6) is binding on the relevant range. Hence the hydro generation constraint (5) is

[6] $\hat{k}_h > 0$ because $t(k_h = 0) = T > \alpha T$. Both constraints also bind when $k_h = 0$.

not binding, which implies that $\delta_h = 0$. Substituting H and G in constraint 3 results in:

$$k_g t(k_g) + \int_{t(k_g)}^{T} q(t)dt + \alpha T k_h \geq T\bar{q} \tag{8}$$

Thus the "energy" constraint is a convex function with slope $-\alpha T \ / \ t(k_g)$.[7]

Let k_g^B denote the thermal capacity at which both the capacity constraint (constraint 2) and the energy constraint 8 are binding. As shown in Figure 3, this intersection exists and is unique. Let us define $r_h' = r_h - \alpha T \Delta c$, which may be seen as the net per unit capacity cost of the hydro technology (the capacity cost less the maximum reduction in energy costs). Then the optimal solution depends on the relative costs of the thermal and hydro capacities (r_g/r_h'), as reported in Table 2.

Table 2 about here

If $r_g/r_h' < 1$ (case I.1, point A in Figure 3) the optimal solution does not include hydro plants. When $r_g/r_h' = 1$ (case I.2, energy constraint A-B in Figure 3), which occurs with probability 0, the inclusion of hydro plants is optional as hydro and thermal generation are perfect substitutes for $k_h \leq q^m - k_g^B$. When $r_g/r_h' > 1$, (curve B-C in Figure 3), the optimal generation portfolio includes hydro plants. Since $\delta_g > 0$, hydro is the peaking technology. Hence, the marginal cost of hydro plants satisfies that $c_h + \delta_w > c_g$. Also note that the capacity charge is no longer r_g as in previous cases. In case I.3 (point B in Figure 3), both δ_w and δ_g are increasing in r_g/r_h', thus the capacity contraint $\lambda = r_g - \delta_g t(k_g)$ is decreasing in r_g/r_h'. Indeed, when $\frac{r_g}{r_h'} \geq \frac{t(k_g^B)}{\alpha T}$ (cases I.4 and I.5), the optimal capacity charge is zero, since the capacity constraint is no longer binding. Note that if $\alpha r_g \geq r_h'$ (case I.5, point C in Figure 3), then there is no thermal generation. Finally note that if $\Delta r = r_h - r_g \leq 0$, cases I.1 and I.2 can not occur.

3.2 Case II: High Hydro Plant Factor $(\alpha \geq \frac{\bar{q}}{q^m})$

As shown in Figure 4, when $\alpha > \frac{\bar{q}}{q^m}$, then $\hat{k}_h < q^m$ and each hydro constraint is binding in a different interval. The hydro generation constraint (constraint 5) is binding in the B-C

[7] In addition, when $k_g = 0$, then $k_h = \bar{q}/\alpha > q^m$ and $\partial k_g / \partial k_h = -\alpha$. On the other hand, when $k_h = 0$, then $k_g = q^m$ and $\partial k_g / \partial k_h = -\infty$.

segment of Figure 4, while the stored water constraint (constraint 6) is binding in the A-B segment. In addition, the thermal constraint is never binding (and therefore $\delta_g = 0$).[8] Then the solution to this problem depends again on the values of r_g/r'_h and α as shown in Table 3.

Table 3 about here

Several elements of this set of solutions are worth underscoring. First, when $r_g/r'_h > 1$ the optimal portfolio includes hydro plants and $k_h \geq \hat{k}_h$. [9] In addition, and as seen in Figure 4, the hydro capacity constraint (constraint 6) is binding, and therefore hydro is the baseload technology. In II.3, the stored water constraint is also binding and therefore water has a positive value ($\delta_w > 0$). This implies that the energy charge in those hours in which only hydro plants generate is $c_h + \delta_w < c_g$. The solution for II.4 coincides with the one obtained for the case in which the generation portfolio considers two thermal technologies.

Note that the higher is α, the closer may hydro production be to its full capacity, and therefore the more similar is hydro technology to thermal technology ($\partial\hat{k}_h/\partial\alpha < 0$). Finally observe that if $\Delta r = r_h - r_g \leq 0$, then generation is purely hydro as cases II.1 and II.2 can not occur.

4 Basic results

The most important results are summarized in the following propositions:

Proposition 1 *For $r_g/\ r'_h > 1$, the optimal generation portfolio includes hydro plants.*

[8] In the B-C segment, the thermal constraint can not be binding because the hydro generation constraint is binding, and both can not be binding at the same time. In the A-B segment, if the thermal generation constraint were binding, then it would be the baseload technology and therefore the hydro generation would be given by $\int_{k_g}^{q^m} t(q)dq$. This implies that the hydro generation capacity would be at least equal to $\alpha T(q^m - k_g)$. We have that $\alpha \geq \frac{\bar{q}}{q^m} = \frac{1}{Tq^m}\int_0^{q^m} t(q)dq \geq \frac{1}{T(q^m-k_g)}\int_{k_g}^{q^m} t(q)dq$. The latter inequality results from the fact that $\frac{\partial}{\partial k_g}\left(\frac{1}{T(q^m-k_g)}\int_{k_g}^{q^m} t(q)dq\right) = \frac{1}{T(q^m-k_g)^2}\left(\int_{k_g}^{q^m} t(q)dq - t(k_g)(q^m-k_g)\right)$, is negative because $t' < 0$.

[9] When $r_g/r'_h = 1$ (Case II.2), hydro and thermal technologies are perfect substitutes, and therefore hydro is optional. This case has probability 0.

When $r_g/\ r'_h < 1$, and therefore the capacity cost of thermal technology is lower than the net capacity cost of hydro technology, the optimal portfolio is purely thermal. When $r_g/\ r'_h = 1$, the inclusion of hydro capacity in the optimal portfolio is optional since hydro and thermal plants are perfect substitutes. These results are independent from α.

The condition for the system to be purely hydro depends on α. Indeed when $\alpha > \frac{\bar{q}}{q^m}$, the generation portfolio would be purely hydro if and only if $\Delta r = 0$. However when $\alpha < \frac{\bar{q}}{q^m}$, the cost advantage of hydro technology required for the system to be purely hydro is $r_g/\ r'_h \geq 1/\alpha$. In addition, in this case, installed capacity must be greater in order to ensure that energy demand will be met ($k_h = \bar{q}/\alpha > q^m$).

In the following, we will focus on the most interesting cases, i.e., those in which $r_g/\ r'_h > 1$, where the optimal solution includes hydro plants.

Proposition 2 *Thermal is the peaking technology when $\alpha \geq \frac{\bar{q}}{q^m}$, otherwise hydro is the peaking technology.*

For a given hydro plant factor cap, hydro is the baseload technology when the system's load factor is low and therefore peak demand is high relative to average demand.

Proposition 3 *When hydro is the peaking technology and $\frac{r_g}{r'_h} \geq \frac{t(k_g^B)}{\alpha T}$, the capacity constraint is not binding ($k_h + k_g > q^m$) and the optimal capacity charge equals zero; otherwise the capacity constraint is binding and the capacity charge is positive but less than r_g.*

When the cost advantage of hydro technology is sufficiently high, the optimal generating portfolio includes a large fraction of hydro capacity. Indeed, this installed capacity must be large enough to compensate for the fact that the hydro plant factor cap is relatively low.

Proposition 4 *The stored water constraint is always binding when hydro is the peaking technology. When thermal is the peaking technology, the water availability constraint is binding if and only iff $\frac{r_g}{r'_h} \leq 1 + \frac{\Delta c(\alpha T - \hat{t})}{r'_h}$.*

Proposition 5 *When the stored water constraint is binding, water has a positive value and therefore the marginal cost of hydro plants must include it. On the other hand, when the stored water constraint is not binding, marginal cost-pricing results in the traditional peak-load pricing.*

Therefore, pricing rules derived from the traditional peak-load pricing model for all-thermal power systems do not necessarily apply to industries whose generation portfolio include hydro plants.

5 Decentralized Solution

Next we analyze whether the pricing rules derived earlier lead a decentralized system to the optimal solution. We will consider a competitive system in which there is free entry to both types of technologies and a system in which producers may exercise market power. Hereafter we focus only on the cases in which $r_g/\ r'_h > 1$.[10] In the analysis we assume that hydro plants operators are aware of the shadow price of stored water δ_w and act accordingly.

5.1 Competitive Power Industry

In this section we show that assuming that an independent operator dispatches generating plants in strict order of merit, the derived pricing rules will lead a decentralized competitive system to the optimal solution.

If $\alpha < \frac{\bar{q}}{q^m}$, since $c_h + \delta_w > c_g$ when the price of energy is c_g, only thermal plants are willing to produce, whereas at price $c_h + \delta_w$, both types of plants are willing to produce. Moreover, under perfect competition the configuration of the generation portfolio is optimal and neither type of plants obtains rents. Since in this case, the stored water constraint is always binding and thermal is the baseload technology, hydro plants' profits (π_h) and thermal plants' profits (π_g) are given by the following expressions:

$$\pi_h = (\lambda - r_h + \alpha T\ \delta_w)k_h \tag{9}$$

$$\pi_g = [\lambda - r_g + (\delta_w - \Delta c)t(k_g)]\, k_g \tag{10}$$

It is easy to prove resorting to Table 2 that $\pi_h = \lambda + \alpha T\ \delta_w - r_h = 0$, for any value of $r_g/\ r'_h$. Therefore, the peaking plants (hydro plants) never obtain rents. Assuming free entry to the generation industry, thermal plants will enter up to the point when they have no profits either; which happens when k_g attains the value k_g^* in Table 2 .

[10] The results are also valid for the remaining cases.

The same results hold when $\alpha > \frac{\bar{q}}{q^m}$.[11] Indeed, since in this case $c_h + \delta_w < c_g$ when the price of energy is $c_h + \delta_w$, only hydro plants are willing to produce, whereas at price c_g, both types of plants are willing to produce. The composition of the generation portfolio is also optimal and neither type of plants obtains rents. In fact,

$$\pi_h = \left[\lambda - r_h + \Delta c t(k_h) + \frac{\delta_w}{k_h}\int_{t(k_h)}^{T} q(t)dt\right] k_h \tag{11}$$

$$\pi_g = (\lambda - r_g)k_g \tag{12}$$

Recalling Table 3, it becomes inmediately apparent that $\pi_g = 0$. Therefore, the peaking plants (thermal plants) never obtain rents. Assuming free entry to the generation industry, hydro plants will enter up to the point when they have no profits either; which happens when k_h attains the value k_h^* given in Table 3.

Proposition 6 *Competition leads a decentralized power industry subject to peak-load pricing to the welfare-maximizing solution. In addition, neither type of plants obtains rents.*

5.2 Market Power in the Power Industry

Next we show that generators operating in a mixed hydro-thermal industry could generate rents by deviating from the welfare maximizing generation portfolio.

5.2.1 Case I: Low Hydro Plant Factor Cap ($\alpha < \frac{\bar{q}}{q^m}$)

We have computed the capacity and energy charges assuming competition. However, the regulator may or may not adjust those charges as the generation portfolio deviates from its welfare maximizing mix. Since this is policy choice, we analyze both cases.

Unadjusted capacity and energy charges. Assuming that both the capacity and the energy charges are not adjusted when the generation portfolio differs from its welfare maximizing mix, differentiating π_g given in equation (10) results in:

[11] We assume that $\Delta r \geq 0$, otherwise there is no thermal generation.

$$\pi_g^{'}(k_g) = (\lambda + (\delta_w - \Delta c)t(k_g) - r_g) + k_g(\lambda^{'} + t(k_g)\delta_w^{'} + (\delta_w - \Delta c)t^{'}(k_g)).$$

Using the values for λ and δ_w reported in Table 2, and recalling that $t' < 0$, then $\pi_g^{'}(k_g^*) < 0$. Hence, there is a range in which reducing the share of thermal plants in the generation portfolio ($k_g < k_g^*$) increases profits. Also note that $\pi_g^{'}(0) = 0$. As function t was assumed to be continuously differentiable, it follows that function $\pi_g^{'}$ is continuous. Consequently there is at least one k_g satisfying the optimality condition. If we further assume that function t is strictly concave, then there is only one solution to $\pi_g^{'}(k_g) = 0$.

Adjusted capacity and energy charges. Prices remain unchanged when $r_g/\ r_h' > t(k_g^B)/\alpha T$ because in that case both prices *are* independent of k_g and a small reduction in the thermal capacity would keep the composition of the generation portfolio in the same "relevant range" (segment BC in Figure 3). This is no longer true if $1 < r_g/r_h' \leq t(k_g^B)/\alpha T$ (case I.3, point B in Figure 3). Indeed, if the producer underinvests in thermal capacity then $k_g < k_g^B$ (there is a shift from B to BC in figure) and prices are those in I.4 Table 2, then

$$\begin{aligned} \pi_h &= (\alpha T\ \delta_w - r_h)k_h = 0 \\ \pi_g &= \left[(\delta_w - \Delta c)t(k_g) - r_g\right]k_g = \left[\frac{t(k_g)}{\alpha T}r_h' - r_g\right]k_g > 0 \end{aligned}$$

The last inequality holds because $t(k_g^B)/\alpha T > r_g/r_h'$ and $t(k_g) > t(k_g^B)$. Hence generators can obtain rents by reducing the share of the baseload technology in the generation mix.

5.2.2 Case II: High Hydro Plant Factor ($\alpha \geq \frac{\bar{q}}{q^m}$)

In this case, hydro is the baseload technology and hydro and thermal profits are given by equations (11) and (12), respectively. We assume that $\Delta r \geq 0$, otherwise there is no thermal generation in the welfare maximizing generation portfolio.

Unadjusted capacity and energy charges. As shown in the previous section, $\pi_g = 0$. Differentiating equation (11) results in:

$$\pi_h^{'}(k_h) = -\Delta r + \Delta c\ t(k_h) + (\Delta c - \delta_w)t^{'}(k_h)$$

Therefore, if $\frac{r_g}{r_h^{'}} > 1 + \frac{\Delta c(\alpha T - \hat{t})}{r_h^{'}}$ (case II.4 in Table 3), then $t(k_h^*) = \frac{\Delta r}{\Delta c}$ and $\pi_h^{'}(k_h) = \Delta c\ t^{'}(k_h) < 0$. Therefore by reducing the hydro capacity k_h below the welfare-maximizing level k_h^*, hydro generators obtain profits.[12] On the other hand, when $1 < \frac{r_g}{r_h^{'}} < 1 + \frac{\Delta c(\alpha T - \hat{t})}{r_h^{'}}$ (case II.3 in Table 3) $\pi_h^{'}(k_h) < 0$ since $\hat{t} \leq \frac{\Delta r}{\Delta c}$.

Capacity and Energy charges are recalculated. Results do not change when $\frac{r_g}{r_h^{'}} > 1 + \frac{\Delta c(\alpha T - \hat{t})}{r_h^{'}}$ because capacity and energy charges are independent of k_h. Now if $1 < \frac{r_g}{r_h^{'}} < 1 + \frac{\Delta c(\alpha T - \hat{t})}{r_h^{'}}$(case II.3 in Table 3), then reducing investment in hydro plants compared to the competitive solution will lead to case II.2 in Table 3. Hence $\pi_g = 0$ and $\pi_h = (r_g - r_h + \alpha T \Delta c)k_h = (r_g - r_h^{'})k_h$. Since $r_g > r_h^{'}$, generators obtain rents by reducing the hydro generation capacity.

Proposition 7 *When prices are set according to peak load pricing, generators may exercise market power by under-investing in the baseload technology compared to the welfare maximizing mix.*

6 Conclusions

We show that, as in traditional peak-load pricing, the energy charge equals the marginal cost of the most expensive technology being used. However, when the stored water constraint is binding, the marginal cost of hydro plants must include the value of water. Moreover, the capacity charge is no longer always equal to the capacity cost of the technology with the lowest capacity cost. When the hydro plant factor cap is low, the optimal capacity charge decreases as the capacity cost ratio of thermal and hydro technologies decreases. Indeed, when the cost advantage of the hydro technology is sufficiently high, total installed capacity is larger than the system's maximum demand and the optimal capacity charge is zero.

These results suggest that countries that apply the standard all-thermal peak load pricing without taking into consideration that some of their plants are stored-hydro, may have an inefficient generation portfolio. Since these countries usually use optimization programs to dispatch their plants, it is likely that the value of water is included in the energy charge.

[12] Notice that this is the Arellano and Serra (2007) result for a purely thermal power industry.

However, the capacity charge is usually set to the marginal cost of increasing capacity in the entire system. Therefore, the policy implication of this paper is to revise the criteria used to set this charge since it may be optimal to charge a lower figure or to charge nothing at all.

In addition, it is shown that the derived pricing rules preserve the most important attributes that peak load pricing has in purely thermal industries. First, assuming that an independent operator dispatches generating plants in strict order of merit, peak-load pricing will lead a decentralized competitive system to the welfare maximizing solution. In addition, neither type of plants obtain rents. Second, it is shown that producers may exercise market power by increasing the share of peaking technology in their generating portfolios.

The results reported in this paper depend on a number of crucial assumptions. The first simplification we made is that demand is price-inelastic. In the traditional peak load pricing model, when this assumption is relaxed it may be optimal to apply a capacity charge to all consumption and not only to peak demand. Secondly, our model is fully deterministic. Perhaps the most restrictive part of this assumption is that hydrology is assumed to be predictable. In a future paper we intend to relax these assumptions.

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Table 1: Energy and Capacity Charges*

Baseload Technology	**C**apacity Charge	**Energy Charge** $t < t(k_i)$	**Energy Charge** $t \geq t(k_i)$
thermal ($k_i = k_g$)	$r_g - \delta_g t(k_g)$	$c_h + \delta_w$	c_g
hydro ($k_i = k_h$)	r_g	c_g	$c_h + \delta_w$

*Assumes the existence of both types of plant.

Table 2
Case I ($\alpha < \frac{\bar{q}}{q^m}$): Solutions

Case	r_g/r_h'	λ	δ_g	δ_w	k_h^*	k_g^*	Energy Charge
I.1	< 1	r_g	0	$\frac{\Delta r}{\alpha T}$	0	q^m	c_g
I.2	1	r_g	0	$\frac{\Delta r}{\alpha T}$	$q^m - k_g$	(k_g^B, q^m)	c_g
I.3	$1 < \frac{r_g}{r_h'} < \frac{t(k_g^B)}{\alpha T}$	$\frac{r_h' \, t(k_g^B) - \alpha T r_g}{t(k_g^B) - \alpha T}$	$\frac{r_g - r_h'}{t(k_g^B) - \alpha T}$	$\frac{\Delta c t(k_g^B) - \Delta r}{t(k_g^B) - \alpha T}$	$q^m - k_g^B$	k_g^B	$t < t(k_g^B) \, : \, c_h + \delta_w$ $t \geq t(k_g^B) \, : \, c_g$
I.4	$\frac{t(k_g^B)}{\alpha T} \leq \frac{r_g}{r_h'} < \frac{1}{\alpha}$	0	$\frac{r_h'}{\alpha T}$	$\frac{r_h}{\alpha T}$	$\frac{1}{\alpha T} \int_0^{t(k_g^*)} q(t) dt$	$t^{-1}(\alpha T \frac{r_g}{r_h'})$	$t < \alpha T \frac{r_g}{r_h'} \, : \, c_h + \delta_w$ $t \geq \alpha T \frac{r_g}{r_h'} \, : \, c_g$
I.5	$\geq \frac{1}{\alpha}$	0	$\leq \frac{r_g}{T}$	$\frac{r_h}{\alpha T}$	$\frac{\bar{q}}{\alpha}$	0	$c_h + \delta_w$

Table 3
Case II ($\alpha \geq \frac{\bar{q}}{q^m}$): Solutions

Case	r_g/r'_h	λ	δ_h	δ_w	k_h^*	k_g^*	Energy Charge
II.1	< 1	r_g	0	Δc	0	q^m	c_g
II.2	$= 1$	r_g	0	Δc	$< \hat{k}_h$	$q^m - k_h$	c_g
II.3	$1 < \frac{r_g}{r'_h} \leq 1 + \frac{\Delta c(\alpha T - \hat{t})}{r'_h}$	r_g	$\frac{r_g - r'_h}{\alpha T - \hat{t}}$	$\Delta c - \delta_h$	$\hat{k}_h$	$q^m - \hat{k}_h$	$t < \hat{t} : c_g$ $t \geq \hat{t} : c_h + \delta_w$
II.4	$> 1 + \frac{\Delta c(\alpha T - \hat{t})}{r'_h}$	r_g	Δc	0	$t^{-1}(\frac{\Delta r}{\Delta c})$	$q^m - k_h$	$t < \frac{\Delta r}{\Delta c} : c_g$ $t \geq \frac{\Delta r}{\Delta c} : c_h$

Figure 1

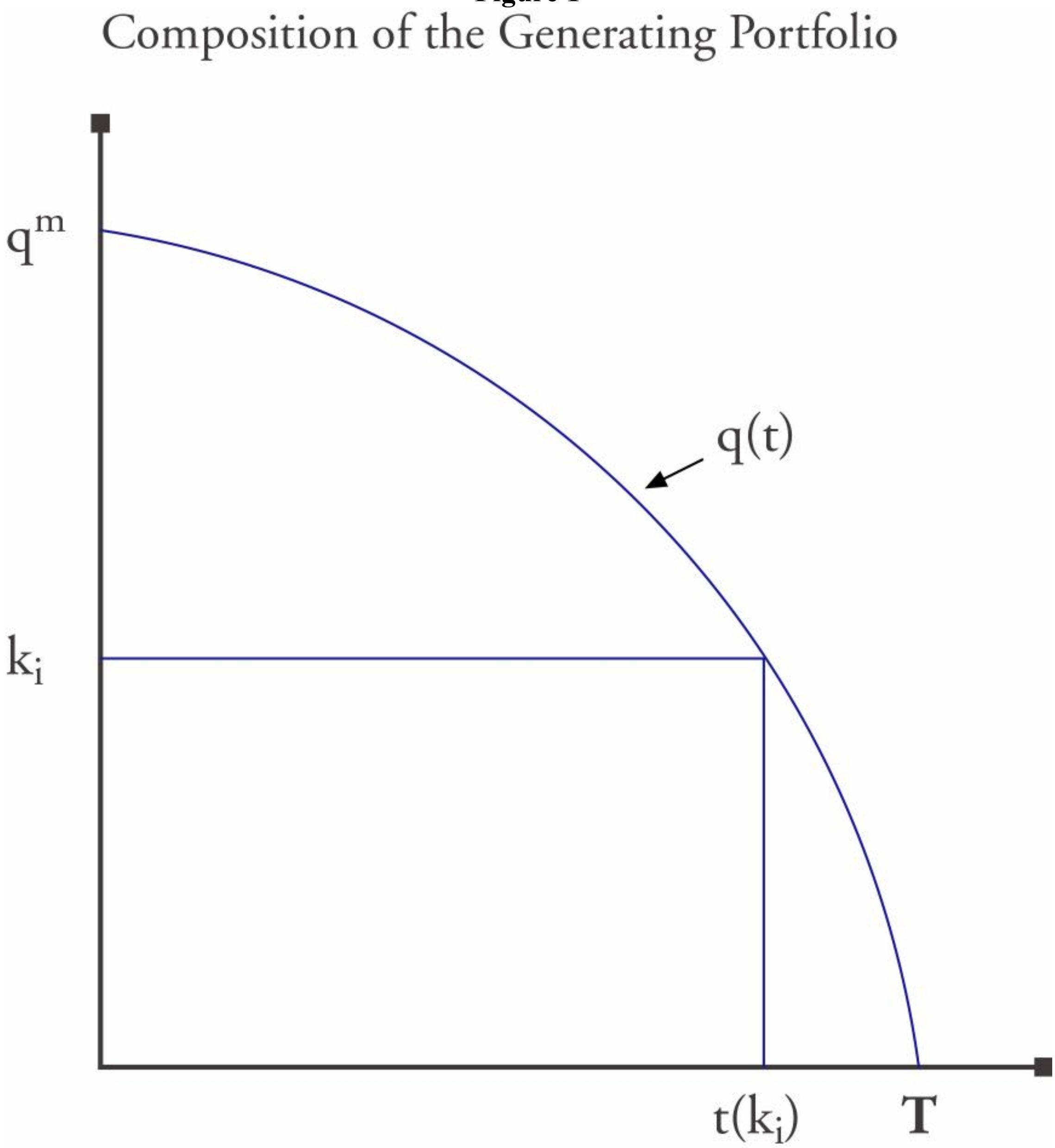


Figure 2

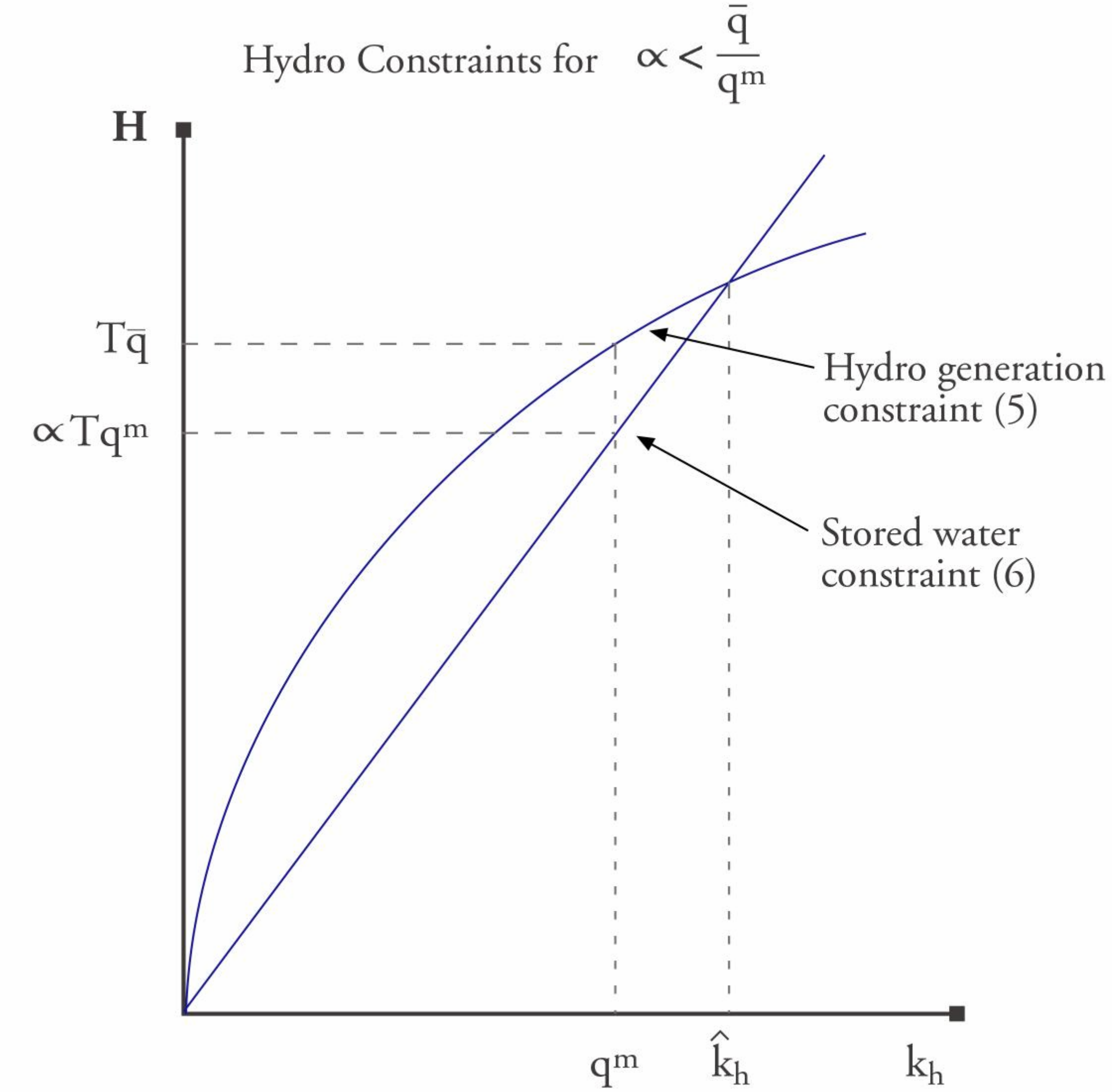

Hydro Constraints for $\propto < \frac{\bar{q}}{q^m}$
H
$T\bar{q}$
$\propto Tq^m$
Hydro generation constraint (5)
Stored water constraint (6)
q^m
$\hat{k}_h$
k_h

Figure 3

Hydro Constraints for $\propto < \frac{\bar{q}}{q^m}$

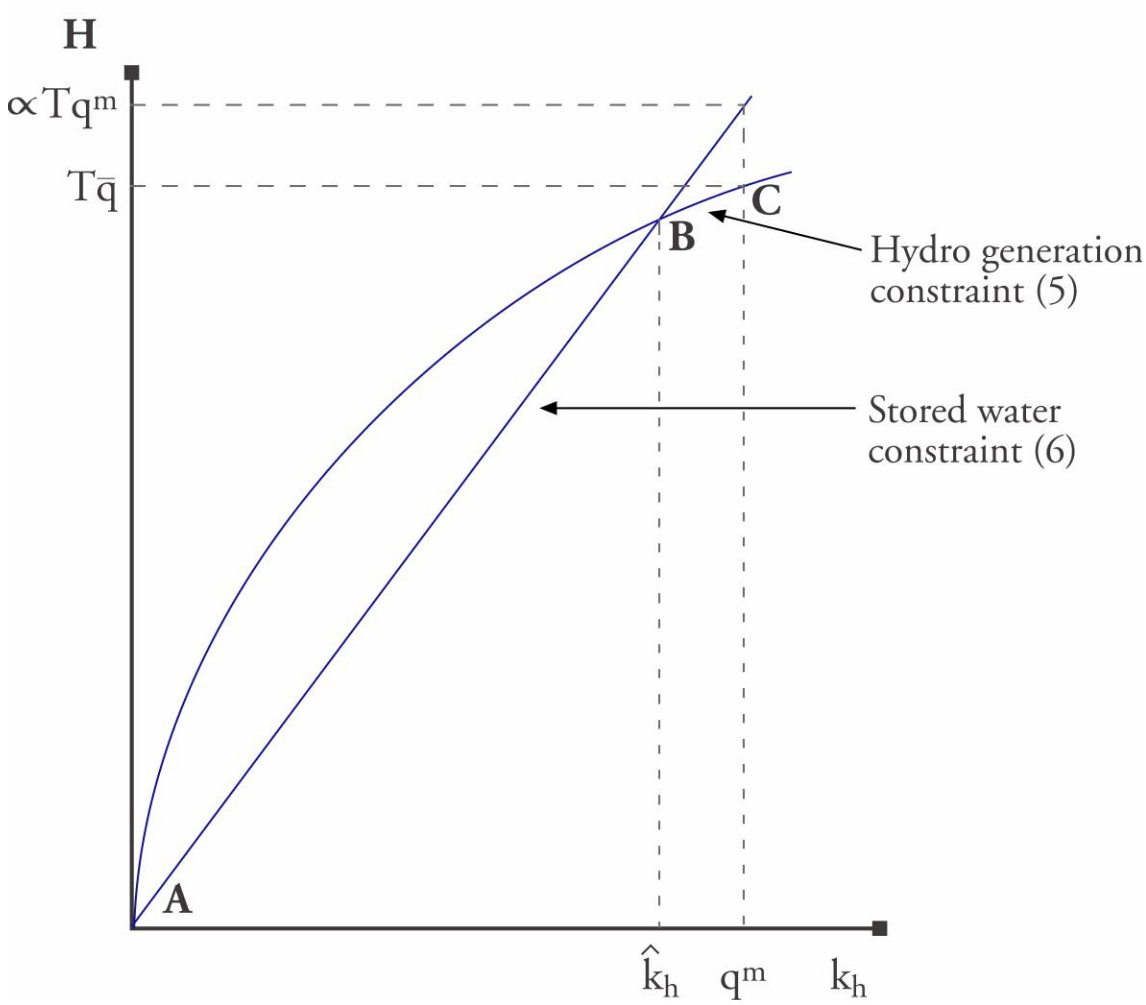
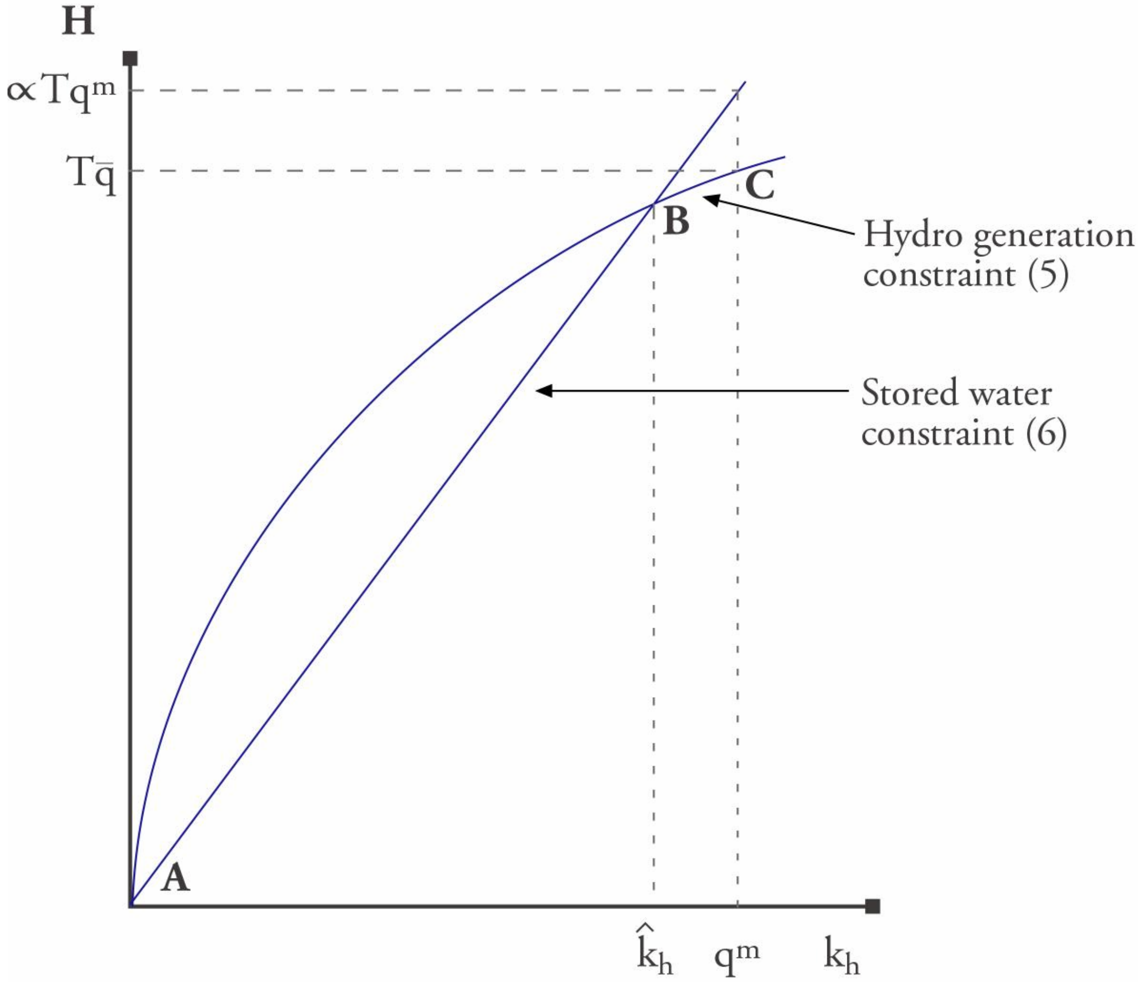


Figure 4

Hydro Constraints for $\propto > \frac{\bar{q}}{q^m}$



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