# Water and Power: Hydroelectric Resources in the Era of Competition in the Western US

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March 9, 1998

## 1 Introduction

The introduction of competitive reforms into the electricity industry, both in the United States and around the world, has inspired a new set of concerns about horizontal market power. The industry in the United States has traditionally been characterized by vertically integrated utilities with exclusive franchise arrangements that left those firms with seemingly dominant positions in the generation of electricity within their own service areas. The integration of utility service areas into larger, regional markets, along the with development of wholesale competition and independently owned generation has done much to undercut these dominant positions (see Joskow, 1997), but significant potential for localized market power remains.

Much of the remaining potential for horizontal market power in the US electricity industry stems from the limits of the regional integration experienced to date. While significant volumes of power are currently traded over long distances, transmission capacity in most regions is not sufficient to fully integrate local markets during high demand periods. This problem exists on both a local (e.g. San Francisco, New York City) and

*I am grateful to Severin Borenstein, Richard Green, Edward Kahn, Bart McGuire, and Tristram Scott for their comments and suggestions. I am also indebted to John Fazio of the Northwest Power Planning Council for both data and discussions, and to Chris Knittel, Wedad Elmaghraby, and Joyce Luh for excellent research assistance.

regional (e.g. California, New Jersey) level. Even in areas with significant independent and municipally owned generation capacity, large firms may still find it profitable to reduce output, exhaust the capacity of these competitors, and exploit their dominant position on the residual demand.[1]

The potential impact of transmission constraints is greatly exacerbated by the fact that electricity is, with some exceptions, not a storable product. The geographic scope of markets therefore can change seasonally and even hourly. Markets like northern California that appear to be very competitive during off peak hours still show the potential for significant market power during high demand periods (see Borenstein and Bushnell, 1997). The lack of storage also creates the potential for rather complex strategic manipulation of transmission constraints.[2]

Hydro electric generation is the primary, and most significant, exception to the conventional assumption that electricity cannot be stored. Utilities that control hydro resources can, subject to some constraints, 'move' energy between periods by adjusting the rates of releases from their reservoirs. Even in a regulated environment, this capability provides tremendous advantages. The ability to concentrate hydro generation on high demand hours allows utilities to 'shave' the peaks off of fluctuating demand, thereby reducing the need for investment in other forms of capacity. The relatively high level of operating flexibility provided by hydro plants also allows utilities to inexpensively follow demand fluctuations in real-time and to quickly respond to random supply or demand shocks.

The effects of hydro electric generation in a deregulated market are likely to be even more significant. In the hands of non-strategic firms, the storage capability of hydro power would, to some extent, allow those firms to merge the peak and off-peak markets that might otherwise be distinct due to transmission and other capacity constraints. Conversely, in the hands of a strategic firm, the ability to shift generation across time could produce a further separation of these geographically and temporally distinct markets.[3]

In this paper I attempt to quantify the extent of these advantages in the context of the electricity market in the western U.S. This market possesses many features that

[1]Von der Fehr and Harbord, 1993 argue that these considerations dominate the nature of competition in the United Kingdom. Wolak and Patrick, 1996, provide empirical evidence that supports this argument.

[2]Cardell, Hogan, and Hitt, 1997, demonstrate the potential for strategic firms to take advantage of 'loop flow' transmission externalities. Borenstein, Bushnell and Stoft, 1996, show that the interactions between strategic firms in a very simple network can be quite complex when transmission capacity is limited.

[3]The flexible operating characteristics of hydro plants could also give some firms advantages in providing some forms of ancillary services, such as load following and spinning reserve. Assesing the potential for market power in those markets is, however, beyond the scope of this paper.

make it an interesting test case for such an analysis. First, major portions of this market are moving rapidly towards unregulated competition in the generation sector. Secondly, although the market is very diverse and highly integrated, studies indicate that there is potential for regionalized market power. Third, there is a significant amount of hydro electric generation capacity in this region, most of it concentrated in the Pacific northwest and California. It is important to note that, while the share of hydro generation is significant, it does not hold the same kind of dominant share seen in markets such as Norway, New Zealand, or even Chile.[4] Therefore the interaction between hydro and thermal resources is much more complex in the western U.S.[5] than in those markets.

Lastly, a single firm controls a significant, if not dominant share of the hydro electric capacity in this market. This firm, however, is the U.S. government, manifested in the form of the Bonneville Power Administration (BPA). BPA is responsible for marketing the generation produced by federally owned dams along the Columbia river system. Interpreting the incentives of BPA in a deregulated electricity market is, to say the least, a complex task.

The model I develop here solves for a sub-game perfect equilibrium of a multi-period Cournot game between strategic producers. While there is an extensive literature on optimal hydro scheduling in the context of a regulated market, there has been very little work done on hydro scheduling in an unregulated, oligopoly environment. Scott and Read (1997) develop a dual dynamic programming approach to develop an optimal hydro schedule for a strategic firm that controls all the storage hydro capacity in a market with other Cournot producers that control thermal generation. In developing this model, I instead represent the equilibrium conditions analytically, and solve by searching for the dual variables that satisfy these conditions. This approach allows me to both represent multiple firms, each with storage hydro resources, and to introduce a new element, a price-taking fringe whose optimal hydro schedules sometimes operate at cross-purposes to those of the strategic players. This model also revisits the market examined in Borenstein and Bushnell (1997). That earlier paper solves for independent, single period Cournot equilbria in roughly the same market. I have had to simplify elements of both these earlier analyses in order to introduce the complexities of a multi-period model featuring multiple firms with hydro capacity.

The results indicate that the dominant firms often face an electricity marketplace that is bifurcated: an 'off-peak' market which is reasonably competitive, and an 'on-peak' market in which some firms posses significant market power. Additional output from the dominant firms in the off-peak hours has little impact on price, since such output is

[4]See Gilbert and Kahn (1996) for an overview of these and other international electricity markets.

[5]Throughout this paper, "western market" refers to those utilities included in the planning area of the Western Systems Coordinating Council (WSCC)

simply displacing fringe production. A reduction in output on peak, however, can result in significant price increases. Similar to firms that are able to price discriminate between markets, the dominant firms can therefore find it profitable to reduce output in peak hours and concentrate hydro output in the *off-peak* hours. This strategy constitutes a major change from current optimal scheduling practices.

## 2 Industry restructuring in the western US

The western U.S. has experienced a very active wholesale electricity market for over a decade, producing enough volume for the New York Mercantile Exchange to establish a electricity futures contract with delivery specified at two western locations. Even before the current proposals for deregulation, concerns over market power had been sufficient to prevent a proposed merger between Southern California Edison and San Diego Gas & Electric Co.[6] However, the forthcoming deregulation of the massive California electricity market, accounting for roughly 1/3 of the energy consumed in the WSCC, has generated a heightened level of interest in both the structure and competitive outlook of the western market.

While early discussions about electricity industry restructuring are under way in several States, it appears that, in the near future, California will be the only western state in the Union with large, privately owned, unregulated generation companies. Although firms such as PacifiCorp and Enron, through their purchase of Portland General Electric, clearly plan to be players in the California market, these firms also retain a degree of obligation to service their own native markets.

Primarily due to the factors outlined above, our earlier examination of market power in California treated firms in other states as price-taking fringe players that might export into California any power that is left over after serving their own native loads. Their ability to do this exporting was limited by transmission constraints into both northern and southern California. These transmission constraints often isolated California from other states in the desert southwest.

There was considerably less congestion on paths connecting Oregon and California. There were, however, limitations on the availability of competitive generation capacity in the Pacific northwest, particularly in the late summer and early winter months. In these months, hydro resources are at their lowest and demand in the northwest is at its highest. There was therefore little excess capacity available in the northwest for sale in California. Indeed, historically, this region is often buying power from California and the

[6] See Frankena & Owen (1994)

desert southwest during these months. Since we examined only the California market, our model did not reflect any impact of exports out of, rather than into, California.

This earlier study also took a simplified approach to modeling the production of hydro-electric energy. Since we treated hourly markets as independent of each-other, we had no means for optimizing the distribution of available energy *between* hours. We instead assumed that hydro releases would be scheduled using traditional methods, which were best approximated in our model through a peak-shaving heuristic, which assigns energy in such a way as to equalize, subject to flow constraints, the amount of demand that is left over after subtracting hydro generation. This peak shaving was performed on a regional basis. One potentially significant shortcoming of this approach, in the context of our regional model, was that it did not allow producers in the northwest to respond to higher on peak prices in California by shifting additional energy to the peak. In reality, producers in this region could, and often do, purchase energy from California off-peak, and sell their own power back into California on-peak.

In order to better account for such strategies, in this paper I combine the California market with that of the Pacific northwest. I take the boundaries of the northwest market to be those of the U.S. portion of the northwest region of the WSCC. This combined market is interconnected primarily with the remaining WSCC regions in the Rocky Mountain area, the desert southwest, and western Canada. Table 1 shows the states in the region that is modeled, and those whose exports into this market are also included.

| Region | States or Provinces in Region | Representation |
|---|---|---|
| California-northwest | CA, ID, MO, northern NV, OR, Utah, western WY, WA | Modeled region |
| Canada | Alberta, British Columbia | Exporter |
| Rocky Mt. | CO, ND, NB, eastern WY | Exporter |
| southwest | AZ, NM, southern NV | Exporter |

**Table 1: Regional Market Definitions**

As mentioned above, only California generation companies are assumed to be unregulated. Initially, I treat the two largest investor owned utilities, Southern California Edison (SCE), and Pacific Gas & Electric (PG&E), as strategic. Two other large California generators, San Diego Gas & Electric (SDG&E) and the Los Angeles Department of Water and Power (LADWP) are assumed to be fringe players, SDG&E because of its size (about 1/7 of the capacity of PG&E), and LADWP because of its large native demand. LADWP, unlike the investor owned utilities, will continue to be vertically integrated. PG&E and SCE have reached agreements to sell off most of their thermal generation capacity. While it is not known exactly when the transfer of ownership will occur, I also examine a case where the markets for thermal generation are operating perfectly competitively. In other words, all thermal capacity in California and the northwest is treated as owned by price-taking fringe firms.

The remaining strategic Cournot player in this model is the one additional institution that could be construed as having both significant incentive and ability to influence prices in an less regulated western electricity market, the Bonneville Power Administration.

## 2.1 Bonneville Power Administration

The Bonneville Power Administration (BPA) was formed in 1937 to market power from the newly constructed Bonneville Dam on the Columbia river. BPA's mandate has been to sell power from Federally owned water projects to a set of 'preference customers,' municipal utilities and rural electric cooperatives, at 'cost-based' rates. In addition, BPA sells considerable amounts of power to aluminum producers in the northwest and to investor owned utilities throughout the WSCC. It has been argued rather convincingly[7] that BPA in fact kept its preference rates well below its average costs. This led to economically inefficient demand growth, which in turned spawned several unfortunate nuclear generation construction projects.[8]

By the early 1990s, BPA had accumulated enormous debt obligations to the U.S. Treasury and faced increasing operating costs of its Hydro projects, partially due to increased requirements for salmon recovery. These factors have created enormous political pressure for BPA to increase its revenue. With a huge number of sales contracts set to expire in 2001, the Agency is currently rethinking its long-term marketing strategy. However, while almost everyone agrees that BPA needs to increase its revenue, each class of BPA customers seems to feel that this should be done at the expense of the other customer classes.

The analysis below assumes that BPA is constrained only by the *physical* limits of its resources. It therefore obviously understates the *political* constraints faced by the Agency. In particular, the minimum output levels of BPA resources are based upon stream-flow requirements and not upon some level of firm contractual obligations. While this may be a distortion of the political-economic environment in which BPA policies are set, it is nonetheless very instructive to examine what strategies would maximize BPA's revenues, and the impact of those strategies on the western electricity market.

[7] Costello and Haarmeyer provide an in-depth overview of the political and economic consequences of BPA policies.

[8] Only one of these plants is currently operating.

# 3 Strategic hydro scheduling

In this section, I describe a general model of a deregulated electricity market where some producers control significant hydro and thermal resources. I use the Cournot assumption and thereby represent the producers as competing in production quantities. While other equilibrium concepts, particularly that of 'supply-curve' competition,[9] have been applied to analysis of electricity markets, two factors lead me to adopt the Cournot assumption here. First, the focus of this paper is on the scheduling of hydro-electric resources, and hydro scheduling is, fundamentally, a quantity problem. Second, the capacity constraints of both fringe producers and transmission paths play a central role to equilibrium outcomes in the western U.S. electricity market. The supply curve framework is not well suited to markets where the competitive characteristics vary between the different time periods.[10]

Assume that we have $n$ Cournot producers who control both hydro and thermal generation resources. The framework also allows for small producers that act as price-taking fringe suppliers, although, for the moment, I assume that fringe producers do not control significant amounts of hydro capacity. I will use $q_i$ to denote the output quantities of firm $i$. Let $q_{it} = q_{it}^{Th} + q_{it}^{h}$ represent the total output of firm $i$ in time $t$. where $q_{it}^{Th}$ is the thermal output and $q_{it}^{h}$ the hydro output of firm $i$.

Each strategic producer $i = 1..n$ has a portfolio of thermal generation technologies with an associated aggregate production cost of $C_i(q_i^{Th})$ and marginal cost of $c_i(q_i^{Th})$. I assume that $c$ is a strictly monotone increasing function of $q^{Th}$.

I characterize the hydro systems of the strategic suppliers, with a reservoir of $\bar{q}_i^h$ units of available water[11], $q_{i,min}^h$ units of required minimum flow, and an instantaneous maximum flow of $q_{i,max}^h$. I assume that any inflows that occur the during the time periods modeled (say a week or a month) do not disrupt the aggregate hydro output decisions of each firm. In other words, the limits on the total reservoir capacity are not binding during this relatively short-term planning horizon, so that any unexpected inflows are added to storage.

Let $p_t(Q_t)$ represent the inverse demand function for the market at time $t$. Given the

[9]See Green and Newbery (1992), and Green (1996) for applications of this concept to electricity competition.

[10]This is due in part to the fact that, to date, supply curve models have relied upon the assumption that the slopes of the demand curves are constant across time periods.

[11]For simplicity, we measure units of water in terms of the energy that can be produced from it. We also assume that the production of electricity from a given unit of water is costless.

output of the other firms, firm $i$ has an optimal production problem defined as

$$Max_{q_{it}^h} \sum_t p_t(Q_t)q_{it} - C_i(q_{it}^{Th})$$

subject to the constraints

$$q_{i,min}^h \leq q_{it}^h \leq q_{i,max}^h$$
$$\sum_t q_{it}^h = \bar{q}_i^h$$
$$q_{it}^h, q_{it}^{Th} \geq 0.$$

where $q_{it} = q_{it}^{Th} + q_{it}^h$, and $Q_t = \sum_i q_{it}$, the total market output in that period. Note that this problem would be separable in $t$, except for the last constraint, which limits the total hydro production over the $T$ periods.

To characterize the optimal solutions, I assign Lagrange multipliers to each of these constraints. The multipliers of interest being $\gamma_{it}$ on the minimum flows, $\delta_{it}$ on the maximum flow limits, and $\sigma_i$ on the total available water to the strategic hydro producer. $\sigma$ is therefore this firm's *marginal value of water* in this model. This value represents the additional profit available to the hydro firm that would arise if an additional unit of water could be used for generation during the time frame of the optimization. The Langrange expression of firm $i$'s problem is

$$\mathcal{L} = Max_{q_{it}^{Th}, q_{it}^h} \sum_t \left[ p_t(Q_t)(q_{it}) - C(q_{it}^{Th}) - \gamma_{it}\left(q_t^h - q_{i,\min}^h\right) - \delta_{it}\left(q_t^h - q_{i,\max}^h\right)\right] - \sigma_i(\sum_t q_t^h - \bar{q}_i^h)$$

The optimal solution is characterized by the following first order conditions

$$\frac{\partial \mathcal{L}}{\partial q_{it}^{Th}} = p_t(Q_t) - c_i(q_{it}^{Th}) + \frac{dp}{dq}q_{it} = 0 \tag{1}$$

$$\frac{\partial \mathcal{L}}{\partial q_{it}^h} = p_t(Q_t) - (\gamma_{it} + \delta_{it} + \sigma_i) + \frac{dp}{dq}q_{it} = 0 \tag{2}$$

$$\gamma_{it}\left(q_{it}^h - q_{i,\min}^h\right) = 0 \quad \forall \quad t \tag{3}$$
$$\delta_{it}\left(q_{it}^h - q_{i,\max}^h\right) = 0 \quad \forall \quad t$$
$$\sigma_i(\sum_t q_{it}^h - \bar{q}_i^h) = 0$$

Combining 1 and 2 shows that $c_i(q_{it}^{Th}) = \gamma_{it} + \delta_{it} + \sigma_i$ for all $t$. Equalities 1 and 2 represent the condition that marginal revenue, $p_t(Q_t) + \frac{dp}{dq}q_t$, equals marginal cost, the traditional optimality condition for production. For firms with market power, this condition represents an important departure from the least-cost optimization case, where these marginal costs are usually set equal to a Lagrange multiplier on the constraint that demand must be met in every hour (the system Lambda value).

The economics behind these conditions become more transparent if we assume that there are no binding constraints on thermal capacity, or on minimum and maximum single period hydro output. This means that $\delta_{it} = \gamma_{it} = 0$ for all $i, t$. When applied to each of the $n$ firms, conditions 1 and 2 combine to produce $np_t(Q_t) + \frac{dp}{dq}Q_t = \sum_i c_i(q_{it}^{Th}) = \sum_i \sigma_i$. If we define $\epsilon < 0$ as the elasticity of demand, $\frac{\partial Q}{\partial p}\frac{p(Q)}{Q}$, we have

$$p_t(Q_t)\left(1 + \frac{1}{n\epsilon}\right) = \frac{\sum_i c_i(q_{it}^{Th})}{n} = \frac{\sum_i \sigma_i}{n} \tag{4}$$

which resembles the standard Cournot equilibrium condition that the mark-up of price over marginal cost is inversely proportional to the elasticity of demand and the number of firms.

## 3.1 Fringe producers with pondage hydro resources

The above analysis is easy to extend to markets where there are several small thermal producers acting as a price-taking fringe producers. The standard way of accounting for the production of the fringe is to subtract the cost curves of the fringe producers from the market demand curve. When the fringe has limited capacity, this means that the residual demand curve faced by the Cournot producers is far more elastic at lower quantity levels, when the fringe is marginal, than at higher quantity levels, when the fringe is operating at maximum capacity.

The inclusion of fringe firms becomes more complicated when those firms possess hydro resources with storage capacity. Since the quantity of hydro production can vary between hours it is no longer obvious how to 'subtract' such production from the demand curve. There is, however, a very intuitive interpretation of how competitive firms will choose to dispatch their hydro resources: these firms will allocate as much water as they can to the hours with the highest prices. In other words, the fringe will use their hydro resources to 'shave' prices across time periods. If the fringe possessed enough water, in the absence of binding flow constraints prices would be equalized across all time periods. When energy or flow constraints are binding, as is likely, the fringe is limited to reducing peak prices as much as these constraints allow.

### 3.1.1 Equilibrium conditions with fringe hydro production

Assume that, in addition to the Cournot firms, there is a set of firms that together act as a price-taking fringe. Their competitive behavior is reflected in the fact that their output levels are set so that the marginal 'costs' of their hydro production in each hour would equal the price in that hour. Recall that the cost of hydro in this model is equal to the relevant shadow prices on hydro production, $\sigma, \delta,$and $\gamma$. I use the subscript $f$ to distinguish the hydro output of these fringe firms. In equilibrium, the fringe firms would simply produce to a point where their marginal cost equals the market price,

$$p_t(Q_t) = \gamma_{ft} + \delta_{ft} + \sigma_f.$$

In hours where the hydro flow constraints do not bind for any firm, including the fringe, we have $p_t(Q_t) = \sigma_f$. We can then express the output of each firm in terms of their individual water values, $\sigma_i$, and the water value of the fringe. Let $\bar{\sigma}$ denote the vector of marginal water values $(\sigma_1, \ldots, \sigma_{n,}\sigma_f)$. From conditions 1 and 2, we know that

$$q_{it} = \left[c_{it}(q_{it}^{Th}) - p_t(Q_t)\right] \frac{dQ_t}{dp_t} = [\sigma_i - \sigma_f] \frac{dQ(\sigma_f)}{dp}$$

therefore the hydro releases of the Cournot firms in these periods would be

$$q_{it}^h(\bar{\sigma}) = q_{it} - q_{it}^{Th} = [\sigma_i - \sigma_f] \frac{dQ(\sigma_f)}{dp} - c_i^{-1}(\sigma_i) \tag{5}$$

and the hydro releases of the fringe firms would be

$$q_{ft}^h(\bar{\sigma}) = Q_t - \sum_{i=1}^{n} q_{it} = Q(\sigma_f) - \left[\sum_{i=1}^{n} \sigma_i - n\sigma_f\right] \frac{dQ(\sigma_f)}{dp}. \tag{6}$$

Note that in these hours, the hydro release of one Cournot firm does not depend upon the water value of the other Cournot firms, only on the water value of the fringe. The presence of a fringe that has enough flow capacity to discipline prices serves to flatten the market price over all hours in which the flow constraints of the fringe hydro capacity are not binding. The Cournot firms need only to react to that water value, which in turn equals the market price in those hours.

When a flow constraint on the hydro resources of any player is binding, as they are likely to be at least some of the time, we need to consider the shadow prices of the relevant flow constraints. Let $\Omega_{it} = \gamma_{it} + \delta_{it} + \sigma_i$. Remember that, for fringe firms, $p_t(Q_t) = \Omega_{ft}$. Conditions 5 and 6 then become

$$q^h_{it}(\overline{\Omega_t}) = q_{it} - q^{Th}_{it} = [\Omega_{it} - \Omega_{ft}]\,\frac{dQ(\Omega_{ft})}{dp} - c_i^{-1}(\Omega_{it}) \tag{7}$$

and

$$q^h_{ft}(\overline{\Omega_t}) = Q(\Omega_{ft}) - \left[\sum_i^n \Omega_{it} - n\Omega_{ft}\right]\frac{dQ(\Omega_{ft})}{dp}. \tag{8}$$

The evaluation of the hydro production would therefore entail finding the values of all non-zero $\gamma_{it}$ and $\delta_{it}$ equilibrium flow limit shadow prices. Methods for calculating these shadow prices in the context of a linear model are discussed in the following section.

## 3.2 Dual solution method

While conditions 1 and 2 characterize the multi-period equilibrium of this problem, it remains to derive what this equilbrium is. In doing so, I adopt a dual method that treats the marginal value of water multiplier, $\sigma$, and the shadow prices on the flow constraints, $\gamma$ and $\delta$, as the solution variables.

In their model of the New Zealand electricity market, Scott and Read (1997) utilize a dual-dynamic programming approach. For each period, one can derive, for a given time period, the optimal hydro-release for the strategic hydro firm as a function of its marginal value of water, $\sigma$. Scott and Read refer to these functions as *demand curves for release* of water. These curves would have as their upper and lower limits the minimum and maximum flow limits of the firm, respectively. Summing the optimal water releases for each period over all the periods gives a value for the total releases over the time horizon, as a function of $\sigma$. Inverting this latter function gives an expression for $\sigma$ as a function of the total reservoir available for spill over the time horizon.

Scott and Read modeled a duopoly market where one firm controls all the hydro resources with storage capability.[12] This was a representation of the conditions of the New Zealand electricity market at the time of their study. Thus it was only necessary for them to calculate a single, one dimensional, water release function in each period. They calculate this function numerically for a range of values of $\sigma$.

Once additional firms with hydro storage capacity are added, however, one must calculate many, multi-dimensional water release functions. This process becomes intractable for more than two firms. Since I need to represent at least 3 strategic firms, as well as a considerable number of fringe firms that all possess significant hydro storage capacity, I instead calculate the water release curves *analytically* for each time period.

[12] Scott (1996) describes how this approach could be extended to a model where Cournot duopolists control hydro resources.

Rather than solving for single period releases through backward iterations that explicitly constrain single period flows within their limits, I instead derive an analytic solution by searching for values of the dual variables that satisfy the equilibrium conditions at every stage of the multi-period problem. This has the advantage of allowing for a large number of both strategic and non-strategic firms. However, finding an analytic solution to a problem of this scope necessitates simplifying the representation of demand and of the firms' thermal production costs.

# 4 A linear demand model with 3 Cournot firms

I now derive the above equilibrium conditions in terms of a model of the Western U.S. I assume that there are 3 Cournot firms, BPA, PG&E, and SCE. BPA is considered to be a hydro-only firm, although it does posses a 1 GW nuclear unit that I consider to be must-run and that enters into BPA's profit calculations as an infra-marginal resource. In the derivation below, I will refer to PG&E, SCE, and BPA as firms 1,2, and 3 respectively. There is also a considerable amount of fringe capacity available. This capacity is aggregated into a single, price-taking fringe firm, whose production is denoted by the subscript $f$. The fringe thermal capacity is subtracted from the demand curve in each period, while fringe hydro production is allocated according to the 'price-taking quantity' firm approach described above.

I compute the Cournot equilibrium solution for a general linear demand function with linear marginal costs. Assume that $Q_t = a_t - b_t p_t$, or $p_t = \frac{a_t - Q_t}{b_t}$ and $c(q_i) = K + c_i q_i$. While the marginal cost curves of most electricity companies are not strictly linear, the marginal cost of the two large thermal producers, PG&E and SCE, are very close to linear for the range of production over which they make the bulk of their output decisions. The linear estimation is more of a problem when representing the competitive fringe. I discuss the implications of the the linearity assumption in more detail below.

In the following subsections, I derive the equilibrium conditions first of the thermal output of the Cournot firms, given the hydro output of all the firms in this market. These expressions of equilibrium thermal output can then be nested into the calculation of optimal hydro releases as a function of water values. In the presence of fringe hydro production, we can utilize the water value of the fringe to simplify this process.

## 4.1 Thermal output

If hydro production were at a known fixed level, $q_i^h, i = \{1, ..3, f\}$, the Cournot equilibrium thermal production of firm 1 could be characterized by

$$\frac{a - q_1 - Q}{b} = K + c_1 q_1^{Th}$$

$$q_1^{Th} = \frac{a - 2q_1^h - bK - q_2 - q_3 - q_f}{2 + bc_1}$$

substitution produces

$$q_1^{Th}\left(\frac{(2 + bc_1)(2 + bc_2) - 1}{(2 + bc_1)(2 + bc_2)}\right) = \frac{a - 2q_1^h - bK - q_2^h - \frac{a - 2q_2^h - q_1^h - bK - q_3 - q_f}{2 + bc_2} - q_3 - q_f}{2 + bc_1}$$

which can be solved to produce, for firm 1

$$q_1^{Th} = \frac{\left(a - 2q_1^h - q_2^h - q_3 - q_f - bK\right)(1 + bc_2) - q_1^h + q_2^h}{(2 + bc_1)(2 + bc_2) - 1} \tag{9}$$

## 4.2 Optimal hydro production

In this section, I derive the optimal water release for each Cournot firm $i$ as a function of its marginal value of water and that of the fringe. As above, I drop the subscript $t$ for ease of exposition. I also calculate the hydro output of the fringe assuming that they are scheduled through the 'price-taking quantity' approach. All other fringe resources are assumed to be subtracted from each period's demand curve. In this linear model, equation 5 becomes

$$q_{it}^h(\bar{\sigma}) = q_{it} - q_{it}^{Th} = -\left[\sigma_i - \sigma_f\right] b - \frac{\sigma_i - K}{c_i} \tag{10}$$

and, assuming no flow constraints bind, the demand for water for the fringe firms would be

$$q_{ft}^h(\bar{\sigma}) = Q_t(\sigma_f) - \sum_{i=1}^{3} q_{it} = a + b\left(\sum_{i=1}^{3} \sigma_i - 4\sigma_f\right). \tag{11}$$

When the flow constraints of the fringe hydro resources are binding, as they are likely to be at least some of the time, we need to consider the shadow prices of the relevant flow constraints. Let $\Omega_{it} = \gamma_{it} + \delta_{it} + \sigma_i$. Remember that, since these are fringe firms, $p_t(Q_t) = \Omega_{ft}$. Conditions 10 and 11 then become

$$q_{it}^h(\overline{\Omega}) = -\left[\Omega_i - \Omega_{ft}\right] b - \frac{\Omega_i - K}{c_i}$$

$$q_{ft}^h(\overline{\Omega}) = a + b\left(\sum_{i=1}^{3} \Omega_i - 4\Omega_{ft}\right).$$

The evaluation of the hydro production would therefore entail finding the values of all non-zero $\gamma_{ft}$ and $\delta_{ft}$ flow limit shadow prices. Methods for calculating these shadow prices in the context of a linear model are discussed below.

### 4.2.1 Calculating Shadow Prices

It is likely that the single period hydro production indicated by equations 10 and 11 will exceed one of the flow limits of at least one firm for some demand levels. When this happens, these equations no longer apply. In the linear model used here, one can calculate the shadow prices of any binding flow constraints by 'backing out' the value from the unconstrained flow levels.

When firm $i$ is the only firm reaching a flow limit in period $t$, firm $i$'s shadow price can be calculated as the adjustment that must be made to $\sigma_i$ to get that firm's optimal water release into the feasible region. If, for example, $q_{it}^h(\bar{\sigma}) < q_{i,\min}^h$ we would calculate $\gamma_{it}$ such that

$$q_{it}^h(\bar{\sigma}, \gamma_{it}) = -\left[\sigma_i + \gamma_{it} - \Omega_{ft}\right] b - \frac{\sigma_i + \gamma_{it} - K}{c_i} = q_{i,\min}^h$$

or

$$\gamma_{it}\left(1 + \frac{1}{c_i}\right) = -\left[\sigma_i - \Omega_{ft}\right] b - \frac{\sigma_i - K}{c_i} - q_{i,\min}^h. \tag{12}$$

Note that, since $q_{it}^h(\bar{\sigma}) < q_{i,\min}^h$, $\gamma_{it} \leq 0$. The value of water must appear to be lower in order for that firm to release more. Any adjustment to one firm's water value in a given period affects the output levels of all the other firms. Therefore, when more than one firm has reached a binding constraint we must calculate *all the relevant shadow prices simultaneously.* For a given time period, this would entail the addition of $2(n+1)$ shadow price variables and $2(n+1)$ constraints. The calculation of the shadow prices on the minimum flow constraints take the form

$$\gamma_{it} = \min\left[0, \frac{-\left[\sigma_i - \Omega_{ft}\right] b - \frac{\sigma_i - K}{c_i} - q_{i,\min}^h}{1 + \frac{1}{c_i}}\right].$$

for the strategic firms and

$$\gamma_{ft} = \min \left[ 0, \frac{a + b \left( \sum_{i=1}^{3} \Omega_{it} - 4\Omega_{ft} \right) - q^h_{f,\min}}{4} \right]$$

for the fringe firms. A similar logic applies to calculating the shadow prices on the maximum flow constraints.

# 5 The Western U.S. Market

The model described in the previous sections was implemented in the context of the Western U.S. electricity market. The length of the individual planning horizons that I examine is one month. This is highest frequency at which firm level hydro-electric production data are available. Equilibrium outcomes for each month can then be compared to examine the potential impact of the reallocation of water across months and seasons.

Our earlier study of the California market indicated very little transmission congestion between the Pacific northwest and California. Therefore, in this paper, I combine these two regions into a single, integrated market in order to examine the inter-regional impact of strategic hydro scheduling. By treating this region as an integrated market, however, I am unable to represent the impacts of transmission congestion and losses within this region. Imports into the California-northwest market are restricted by both the generation and transmission capacities avaliable in neighboring regions.

## 5.1 Suppliers

For the reasons given above, three firms, SCE, PG&E, and BPA were assumed to be strategic in this analysis. These three firms account for approximately 40% of the generation capacity in the California-northwest (CNW) region. All the remaining firms were treated as price-taking fringe producers. The thermal and hydro-electric generating capacity of each of these four sets of firms is given in table 2.[13]

[13]Hydro capacities are taken from EIA's 1996 Inventory of Power Plants. Thermal capacities are taken from the WSCC-MAPS dataset and are adjusted for forced outage rates.

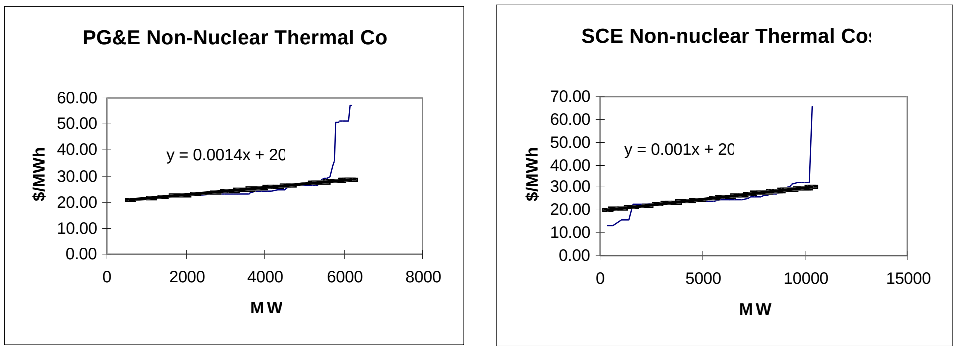


Figure 1: Thermal production costs of PG&E and SCE

| Firm | PG&E | SCE | BPA | Fringe | Total |
|---|---|---|---|---|---|
| Conventional Hydro Capacity (MW) | 2,676 | 932 | 20,212 | 19,240 | 43,060 |
| Pump-Storage Hydro Capacity (MW) | 1056 | 206 | 0 | 2,350 | 3,612 |
| Thermal Capacity (MW)* | 6,182 | 10,331 | 1,054 | 37,154 | 54,721 |

*adusted for forced outages

**Table 2: Generation Capacities**

*Thermal Generation Resources*

Thermal production costs were taken from the same data set that was used for our earlier market power study. The source was the dataset used by the WSCC for modeling their system using the MAPS production cost model. The data include heat-rates, variable operating and maintenance costs, and forced outage rates for each generating plant in the data set. I derate the generating capacity of the thermal units according to their forced outage rates, producing an 'expected' generating capacity.

When combined, the individual plant capacities and operating costs produce a stepwise cost function for each firm. However, the complexity of this hydro-thermal oligopoly model required me to use linear estimates of these step functions. The stepwise cost functions and the linear estimates that I used are presented for each set of firms in figure 1. Both SCE and PG&E have large regions of their cost curves that are nearly linear, and the bulk of their output decisions fell in this range. The marginal costs of the fringe, like those of the Cournot suppliers, rise sharply near their maximum capacity. For the demand levels that I examined, however, I find that most of the time the thermal output

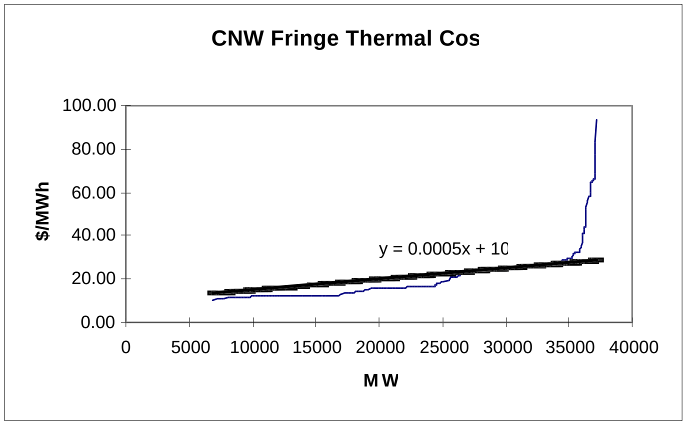


Figure 2: Thermal production cost of fringe firms

of the fringe is either at its maximum (with infinite marginal cost), or far enough down its aggregate supply function that a linear approximation to marginal costs is reasonable. The linear approximation will cause the most distortion in those hours in which the Cournot equilibrium price would fall on the sharply rising portion of the fringe's cost curve. Prices in such time periods should obviously be taken with a grain of salt, and further examination of these issues is warranted.

*Hydroelectric Generation Resources*

There are three key parameters that I used for representing the overall electricity producing capability of a hydro system. These parameters are the instantaneous minimum and maximum MW output of a system, and the amount of energy, in the form of water in the reservoir, that is available for electricity production during the time horizon of the game. The available energy plays a central role since, in the Pacific northwest, the capacity constraint is often not binding.

The maximum generation capacity of each hydro plant in the region taken from the Energy Information Administration's (EIA) *Inventory of Power Plants*[14] The energy available for production during the month of September is based upon historic production levels, taken from EIA's *Electric Power Monthly.* I used a three year average of monthly hydro-electric production levels from 1993 through 1995. The hydro generation characteristics of each set of firms is given in Table 3.

[14] Both PG&E and SCE have contracted for additional hydro energy from various sources. To the extent that these contracts allow the purchaser some discretion over the dispatch of these resources, the figures given above will understate the hydro resources controlled by these firms.

| Firm | | PG&E | SCE | BPA | Fringe |
|---|---|---|---|---|---|
| March | Min Flow (MW) | 1351 | 258 | 2737 | 2605 |
| | Hydro Energy (GWh) | 1220 | 471 | 7089 | 6901 |
| June | Min Flow (MW) | 1656 | 469 | 9773 | 3484 |
| | Hydro Energy (GWh) | 1204 | 588 | 8516 | 8761 |
| Sept. | Min Flow (MW) | 1351 | 258 | 2737 | 2605 |
| | Hydro Energy (GWh) | 1032 | 474 | 4097 | 4612 |

**Table 3: Hydro Generation Parameters**

Estimating the minimum energy production levels, however, is a more complicated task. Most of the minimum production limits are based upon minimum water flows that are imposed for a variety of reasons such as irrigation needs, reservoir management, and the maintenance of salmon habitat. These needs are a source of major contention between the various interest groups in the region, and may very well be subject to change in the coming years.

One element of the controversy involving salmon runs in the Pacific northwest has been the need to increase water flows during the spring run-off season. If the reservoirs were managed solely to minimize electricity production costs, they would, in general, be filled up as much as possible in the spring in order to produce electricity during the winter peak months. The salmon's need for increased springtime flows has created a tension between these two utilizations of the Columbia river system. Additional minimum flow constraints have in recent years been imposed during the spring months. Flow constraints during the month of September, however, have been relatively unaffected by that aspect of the water resources conflict.

Flow constraints are measured in units of cubic feet per second (CFS), for use in this model these flows need to be translated in minimum power production levels. The amount of power produced at a dam per unit of flow depends upon the head height of the reservoir, which determines the distance the water falls and thus the energy released. The MW production is represented by the H/F ratio which gives the MW/KCFS. For this analysis, I used the average H/F ratio for the dam sites for which I had data for, which were BPA plants in the Columbia river system. I did not have access to satisfactory data on the flow limits of non-Federal hydro resources in the northwest region. Instead, I multiplied the ratio of BPA's minimum over its maximum capacity by the fringe capacity in the CNW region to estimate the minimum flows of the fringe in the months of March and September. In June, the flow constraints on BPA's resources are extremely large, amounting to nearly half its maximum output. This is due to special fish habitat considerations on the Columbia river system. However, most of the hydro resources of the fringe lie outside of this region. Therfore the fringe's June minimum flows are estimated by applying an

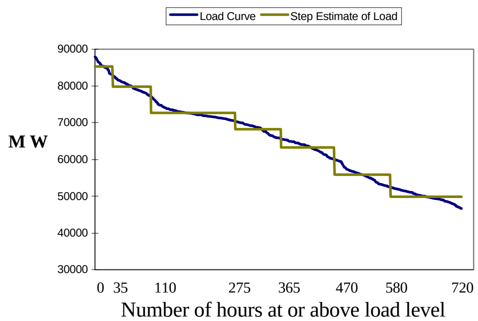


Figure 3: September 2001 CNW Load Duration Curve

increase over their March minimums that is consistent with the increases of PG&E and SCE. The minimum flows for SCE and PGE come from the dataset used by Kahn, et al., (1997) in their simulation of the WSCC system.

However, the H/F ratio is not an entirely exogenous variable. Firms can control the amount of power they release, even if they are constrained on the amount of water that must be flowing in particular systems. Therefore, the minimum flows should be viewed as estimates only. For this reason, sensitivity analysis on this parameter would also be very useful. The shadow prices on these flow constraints that are discussed below give some indication of the impact of relaxing these bounds.

## 5.2 Demand

Starting with detailed hour-by-hour load profiles,[15] I constructed a step function representation of the monthly load-duration curve with seven discrete load levels. The steps had varying durations and the demand level of each step was set equal to the average of the demands covered by those hours in the full load duration curve. The demand levels are specified in the first two columns of Table 4. In calculating the Cournot equilbria, demand was increased by 6% to reflect the capacity to be allocated to reserve margins.[16]

[15]The load profiles were taken from 1993 EEI load data for each State in the WSCC, these were added together to produce "regional" load-duration curves. These curves were then scaled by the ratio of the September peak demands in 1993 and forecast for 2001.

[16]The WSCC requires a 7% reserve margin on all demand met by thermal capacity and a 5% margin on demand met by hydro capacity, see WSCC (1995).

| Hour | # of hours in LDC | March | | June | | September | |
|---|---|---|---|---|---|---|---|
| | | Demand | Imports | Demand | Imports | Demand | Imports |
| Peak | 35 | 73,926 | 9687 | 79,147 | 7429 | 85,238 | 3464 |
| 2 | 75 | 71,384 | 9267 | 74,662 | 8119 | 79,815 | 4044 |
| 3 | 165 | 69,127 | 7560 | 69,370 | 7347 | 72,680 | 4650 |
| 4 | 90 | 65,825 | 8265 | 64,418 | 7169 | 68,255 | 4708 |
| 5 | 105 | 60,985 | 9197 | 59,418 | 7667 | 63,251 | 6281 |
| 6 | 110 | 55,717 | 10,646 | 52,526 | 9285 | 55,844 | 8586 |
| 7 | 140/164 | 50,196 | 12339 | 46,734 | 11,072 | 49,888 | 10,830 |

**Table 4: Load Duration Curve and Regional Imports**

For each of these forecast demand levels, I specified a linear demand curve such that the elasticity of demand at the forecast quantity, price point was equal to .1. The forecast price, applied to all hours, was 7.7 ¢/kWh. This was a weighted average of the CEC's forecast price for California and the 1995 regional price for the Pacific northwest.[17] Out of this price, I estimated that 3.5 ¢/kWh would be allocated to transmission, distribution and other services besides electrical energy.[18]

## 5.3 Imports

In this analysis, I took a slightly more simplified approach to the modeling of imports than what was done in Borenstein and Bushnell. For the two U.S. regions adjacent to the CNW region, I constructed equivalent seven-step load duration curves for the month of September at forecast 2001 demand levels. Using the thermal generation data from the WSCC-MAPS data set, I calculated the excess capacity available after reserves. I assumed that all of this capacity would be economic and treated it as must take generation in the CNW region. This calculation likely overstates the level of imports in the off-peak hours, but the overall level of imports was a rather small share of total demand. The overestimate of off-peak imports will revise downward the potential for market power during these hours.

For the Canadian provinces, data are available on exports into the U.S. In September of 1996, for example, British Columbia exported nearly 2000 Average MWh[19] to the U.S.

[17]1995 regional price comes from EIA's 1995 Electric Sales and Revenues

[18]This figure is consistent with White (1996) who calculates that just over half of utilities' costs are allocated to the energy production function.

[19]An average MWh is the total energy exported in a month divided by the number of hours in the month

The transmission path linking British Columbia to Washington is rated at 2300 MW. I therefore distributed the BC export energy according to a peak shaving hueristic subject to the 2300 MW maximum. The province of Alberta reported no exports to the U.S. in September of 1996.[20]

# 6 Results

The first case examined treats BPA, SCE and PG&E as Cournot firms. The hydro resources of the rest of the western firms are scheduled according to the price shaving method described above, while the thermal cost curve of the fringe is subtracted from demand. This produced a demand curve that was kinked at the net thermal capacity of the fringe. However, the analytic functions given above are derived from first-order conditions, and the kinked demand curve may yield two points where those first order conditions are met: one in which the fringe is marginal and one in which the fringe is operating at maximum capacity. I therefore checked the profits of each firm to take the outcome that was profit maximizing for each Cournot firm. This profit calculation included the 'cost' of hydro generation, $q^h_{it} * \sigma_i$ to reflect the opportunity cost of using the water in that hour.

In September, the results show that fringe firms are marginal only at the lowest demand level. Prices are much lower at this level, yet significant BPA hydro production is allocated to these hours; nearly as much as is allocated to the peak hours (Table 5). More detailed output for the four sets of firms is given in tables 10-18.

| Demand Level | Peak | 2 | 3 | 4 | 5 | 6 | 7 |
|---|---|---|---|---|---|---|---|
| Cournot Price ($/MWh) | 95.61 | 95.61 | 95.61 | 95.61 | 88.97 | 59.75 | 23.79 |
| BPA Hydro Output (MW) | 7740 | 7180 | 6444 | 5988 | 4897 | 2737 | 6216 |
| Fringe Hydro Output (MW) | 18802 | 14393 | 8813 | 5506 | 2605 | 2605 | 2605 |

**Table 5: September results when BPA, SCE, and PG&E are Cournot firms**

## 6.1 Price Taking Thermal Generation

As mentioned above, SCE and PG&E have both agreed to divest nearly all of their non-nuclear thermal generation capacity. While it is not known at this time just what market organization will emerge, the structure modeled in the previous section no doubt overstates the eventual concentration of at least the California market. To examine the

[20]These figures are taken from the Alberta Dept. of Energy

impact of strategic hydro-scheduling in a less concentrated market. I examined two cases in which all generation resources outside of the BPA system were treated as price-taking fringe suppliers.

I aggregated all thermal resources in the CNW system into one cost curve with an expected capacity of 52000 MW.[21] The hydro resources of SCE and PG&E were also aggregated into the fringe's hydro resource mix.

In September, when BPA is the only strategic firm, its output decisions are even more extreme than the case with 3 Cournot firms. Of all the cases modeled, this one produced the most significant shifting of hydro to the two most off-peak demand levels (Table 6).

| Demand Level | Peak | 2 | 3 | 4 | 5 | 6 | 7 |
|---|---|---|---|---|---|---|---|
| Cournot Price ($/MWh) | 81.58 | 78.77 | 78.77 | 78.77 | 50.30 | 24.47 | 22.78 |
| BPA Hydro Output (MW) | 6132 | 5367 | 4793 | 4437 | 2737 | 10457 | 6086 |
| Fringe Hydro Output* (MW) | 23127 | 18162 | 11012 | 6750 | 4287 | 4287 | 4287 |

*Includes output of SCE and PG&E

**Table 6: September results when BPA is the only strategic firm**

The impact of BPA's unilateral output decisions on prices is also quite significant. When BPA is the only firm acting strategically, it is able to induce an 80% increase in prices over competitive levels (figure 5), as opposed to an approximately 112% increase in peak prices over competitive ones when BPA, SCE and PG&E are all Cournot firms.

The results for the months of March and June follow a similar pattern, but are not as dramatic as those for September, the month with the most severe potential for market power. In both of these springtime months, we again see the pattern of shifting hydro production from the high demand to the low demand hours when there are 3 Cournot firms. However, BPA's ability to unilaterally influence prices is considerably muted in comparison the September results. This is due to both the increased hydro energy available from all sources and, in June, an extremely high minimum flow constraint.

[21] The last 1667 MW of capacity is composed of very high-cost oil and gas generation whose costs were above the market prices of the simulation. Since these plants fell in a steeply rising section of the aggregate cost-curve, the linear estimate was applied only to the first 52000 MW of capacity.

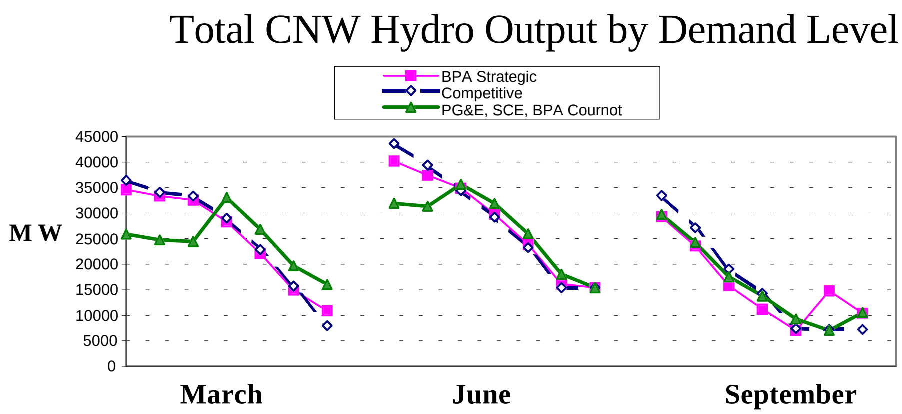


Figure 4: Hydro Production by Demand Level

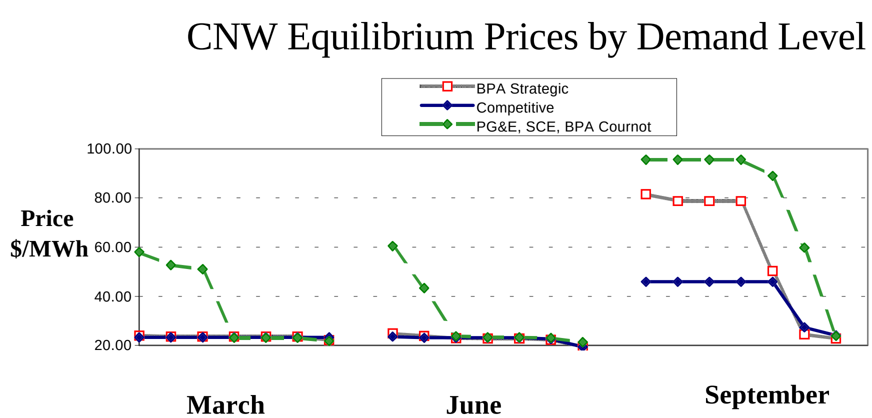


Figure 5: Equilibrium Prices by Demand Level

## 6.2 Water and Flow Values

The time-horizon of the equilibrium models discussed above has been 1 month. We can also develop some intuition for the potential price and revenue impacts of distributing hydro energy over a longer time horizon by examining the equilibrium water values resulting from these single month calculations. Since BPA often finds it profitable to shift water from hight to low demand *hours*, one might expect that it would also profit from reallocating energy from high to lower demand *months*.

In fact, as shown in Table 7, this is not the case. Water is most valuable in September, for all firms, no matter what the competitive outlook of the market is. This is largely due to the fact that the fringe has sufficient resources to be marginal in at least the off-peak hours in every month examined. Since the market is relatively competitive at least some of the time in each month, strategic firms do not need to reallocate across months in order to find hours in which their extra output will have little impact on prices.

| Firm | | BPA | Fringe |
|---|---|---|---|
| 3 Cournot firms | March | 15.60 | 23.04 |
| | June | 16.67 | 23.29 |
| | September | 20.28 | 95.61 |
| BPA strategic | March | 19.17 | 23.55 |
| | June | 17.81 | 22.81 |
| | September | 20.00 | 78.77 |
| Competitive | March | NA | 23.26 |
| | June | NA | 23.03 |
| | September | NA | 45.88 |

**Table 7: Equilibrium Marginal Water Values**

Tables 8 and 9 show the shadow price values on flows for the months of June and September, respectively, under the 3 Cournot firms scenario. It is important to remember that these values represent the *marginal* benefits to the individual producer of relaxing constraints given that the other producers do not change their output. Nevertheless, these values do provide useful insights into how each class of firm would benefit from either relaxing their flow constraints or releasing more energy.

From tables 8 and 9, one can see that both PG&E and SCE, with their relatively tight flow constraints, are at one of their flow limits most of the time. In part because both firms have broad thermal portfolios to draw upon, the value of relaxing these flow constraints is relatively small. In contrast, BPA seldom reaches one of its flow limits, but when these limits do bind, they have a large impact on BPA's profits.

This observation particularly applies to the month of June, where the extremely large minimum flow requirements prevent BPA from shifting as much water from the peak hours as it would like. As a result, BPA places an extremely high value on being able to reduce its minimum flow in these hours. Similarly, the fringe reaches its flow constraints much less frequently than either PG&E or SCE. However, the value to the fringe of relieving these constraints when they are binding can be extremely large. This is true of the maximum flow constraints in the peak hours of June, and of the minimum flow constraints in the off-peak hours of September.

These shadow price values can also be used to form crude estimates of the extent that pumped storage resources might be utilized and the value of such a utilization. Pumped storage is one way of relieving a firm's flow constraints, allowing, for example, a fringe firm to increase peak output and reduce its off-peak output. To estimate the value of reallocating hydro energy through pumped storage, take the difference between the minimum and maximum shadow values on flow constraints and compare it to that firm's value of water. Since roughly 40-50% of the energy is lost in the pumping-release cycle, the value of the shadow price differences should be 50% greater than the value of water if a firm were going to 'pump' some of its pondage hydro energy. BPA would clearly like to be pumping during the peak hours of June for releasing in any of the off-peak hours. However, the fringe, although it greatly values the ability to reallocate from an off-peak to a peak hour in September, places an even greater value on the water itself. Off course the fringe has thermal resources that it can call upon to generate power that would be 'pumped' during off-peak periods, so we would expect it to do so.

| Hour | Firm | PG&E | SCE | BPA | Fringe |
|---|---|---|---|---|---|
| | $\sigma$ | 22.87 | 21.55 | 16.67 | 23.29 |
| Peak | $\delta_{i1}, \gamma_{i1}*$ | 0.00 | 1.50 | -56.13 | 37.13 |
| 2 | $\delta_{i2}, \gamma_{i2}$ | -1.98 | 0.00 | -79.18 | 20.08 |
| 3 | $\delta_{i3}, \gamma_{i3}$ | -0.68 | 0.66 | 0.00 | 0.44 |
| 4 | $\delta_{i4}, \gamma_{i4}$ | -1.01 | 0.36 | 0.00 | 0.00 |
| 5 | $\delta_{i5}, \gamma_{i5}$ | -1.02 | 0.36 | 0.00 | 0.00 |
| 6 | $\delta_{i6}, \gamma_{i6}$ | -1.28 | 0.12 | 0.00 | -0.34 |
| 7 | $\delta_{i7}, \gamma_{i7}$ | -2.55 | -0.88 | -0.68 | -2.06 |

$^*\delta_{it} \geq 0, \gamma_{it} \geq 0$

**Table 8: June shadow prices with PG&E, SCE, and BPA Cournot**

| Hour | Firm | PG&E | SCE | BPA | Fringe |
|---|---|---|---|---|---|
| | $\sigma$ | 27.84 | 25.02 | 20.28 | 95.61 |
| Peak | $\delta_{i1}, \gamma_{i1}$ | 0.00 | 1.93 | 0.00 | 0.00 |
| 2 | $\delta_{i2}, \gamma_{i2}$ | 0.00 | 1.47 | 0.00 | 0.00 |
| 3 | $\delta_{i3}, \gamma_{i3}$ | -0.34 | 0.87 | 0.00 | 0.00 |
| 4 | $\delta_{i4}, \gamma_{i4}$ | -0.85 | 0.49 | 0.00 | 0.00 |
| 5 | $\delta_{i5}, \gamma_{i5}$ | -2.14 | 0.00 | 0.00 | -6.64 |
| 6 | $\delta_{i6}, \gamma_{i6}$ | -5.73 | -2.57 | -10.10 | -35.86 |
| 7 | $\delta_{i7}, \gamma_{i7}$ | -5.51 | -2.59 | 0.00 | -71.82 |

**Table 9: September shadow prices with PG&E, SCE, and BPA Cournot**

# 7 Conclusions

In the less-regulated electricity markets that will soon be operating in the western U.S., hydroelectric resources will clearly play a pivotal role. The Bonneville Power Administration, which controls vast hydroelectric capacity in this market, is a key producer. BPA's ability to shift large amounts of energy between off-peak and on-peak markets gives it a unique position from which to influence prices. BPA's strategic position in the western power market needs to be considered in any policy decisions regarding restructuring or, as some have proposed, privatizing the agency.

Of course BPA's ability to influence prices also depends upon the overall competitiveness of the market. In the relatively dry early fall, BPA's strategies have a greater effect on price in a *less* concentrated market. The price impact of strategic hydro-scheduling on the part of BPA was much greater when those strategies were superimposed on a perfectly competitive market for thermal generation than was the case when operated in a market with other large Cournot firms. In the spring, however, BPA could not unilaterally raise prices much more than 5% above competitive levels. When all three large firms act strategically in these months, they can have a large impact on equilibrium prices.

While strategic behavior can have a very large impact on the redistribution of water within a month, the implications of market power for the shifting of hydro-energy *between* months appear to be less dramatic. In all cases, both BPA and the fringe firms would prefer to be able to allocate more hydro energy to September from the springtime months. The differential between monthly water values was greater for BPA in the context of the more concentrated, 3 Cournot firm market, than when BPA alone acts strategically. This differential is even greater for the fringe, which greatly values additional hydro energy in the late fall when it is faced with a market with 3 Cournot firms.

In this paper, the limited production capacity of price taking firms is the primary driving force behind the 'bifurcation' of the electricity market into very competitive and less competitive hours. However, such divisions can also be created by such factors as local regulatory intervention, the mixed incentives of different firms, and, especially, transmission constraints. In addition, I do not consider here the potential impact of strategic behavior of investor owned utilities outside of California. All of these issues can have a significant effect on the degree of competition in the western power market and therefore merit further consideration.

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## March Individual hourly equilbrium outputs

| Demand Level | | 7 | 6 | 5 | 4 | 3 | 2 | Peak | Totals (GWh) |
|---|---|---|---|---|---|---|---|---|---|
| **Price ($/Mwh)** | | 21.77 | 23.04 | 23.04 | 23.04 | 51.03 | 52.71 | 57.93 | |
| **Mkt Quantity MW** | | 54626 | 60538 | 66261 | 71520 | 72458 | 74659 | 76789 | 49255 |
| **PGE** | *Fossil* (MW)* | 598 | 1199 | 1199 | 1199 | 1199 | 1199 | 1199 | 793 |
| | *Pondage hydro* | 1351 | 1673 | 1683 | 1692 | 1582 | 1838 | 2475 | 1220 |
| | *Total Quantity* | 1949 | 2871 | 2881 | 2890 | 2781 | 3036 | 3673 | 2013 |
| | *Marginal Cost* | 20.83 | 21.65 | 21.65 | 21.65 | 21.65 | 21.65 | 21.65 | |
| | *Marginal Revenue* | 20.83 | 21.65 | 21.65 | 21.65 | 21.65 | 21.65 | 21.65 | |
| **SCE** | *Fossil* (MW)* | 1089 | 1899 | 1899 | 1899 | 1899 | 2068 | 2646 | 1319 |
| | *Pondage hydro* | 358 | 541 | 550 | 557 | 862 | 932 | 932 | 471 |
| | *Total Quantity* | 1447 | 2441 | 2449 | 2457 | 2761 | 3000 | 3578 | 1790 |
| | *Marginal Cost* | 21.07 | 21.86 | 21.86 | 21.86 | 21.86 | 22.03 | 22.59 | |
| | *Marginal Revenue* | 21.07 | 21.86 | 21.86 | 21.86 | 21.86 | 22.03 | 22.59 | |
| **BPA** | *Nucelar (MW)* | 1054 | 1054 | 1054 | 1054 | 1054 | 1054 | 1054 | 784 |
| | *Pondage hydro* | 11697 | 14380 | 14433 | 14483 | 2737 | 2737 | 3232 | 7089 |
| | *Total Quantity* | 12751 | 15434 | 15487 | 15537 | 3791 | 3791 | 4286 | 7873 |
| | *Marginal Revenue* | 15.60 | 15.60 | 15.60 | 15.60 | 10.98 | 13.93 | 15.60 | |
| **Fringe** | *Pondage Hydro* | 2605 | 3073 | 10173 | 16297 | 19240 | 19240 | 19240 | 8591 |
| | *Imports* | 12339 | 10646 | 9197 | 8265 | 7560 | 9267 | 9687 | 7186 |
| | *Thermal* | 23535 | 26074 | 26074 | 26074 | 36325 | 36325 | 36325 | 21801 |
| | *Total Quantity (MW)* | 38479 | 39792 | 45444 | 50636 | 63125 | 64832 | 65252 | 37578 |

**Table 10: March, 3 Cournot Firms**

## March Individual hourly equilbrium outputs

| Demand Level | | 7 | 6 | 5 | 4 | 3 | 2 | Peak | Totals (GWh) |
|---|---|---|---|---|---|---|---|---|---|
| **Price ($/Mwh)** | | 22.14 | 23.55 | 23.55 | 23.55 | 23.55 | 23.55 | 23.97 | |
| **Mkt Quantity MW** | | 54601 | 60498 | 66218 | 71474 | 75059 | 77510 | 80228 | 50001 |
| **BPA** | *Nucelar (MW)* | 1054 | 1054 | 1054 | 1054 | 1054 | 1054 | 1054 | 784 |
| | *Pondage hydro* | 6578 | 10240 | 10272 | 10301 | 10320 | 10334 | 11438 | 7089 |
| | *Total Quantity* | 7632 | 11294 | 11326 | 11355 | 11374 | 11388 | 12492 | 7873 |
| | *Marginal Revenue* | 19.17 | 19.17 | 19.17 | 19.17 | 19.17 | 19.17 | 19.17 | |
| **Fringe** | *Pondage Hydro* | 4287 | 4684 | 11821 | 17980 | 22250 | 22980 | 23127 | 10282 |
| **with PG&E,** | *Imports* | 12339.1 | 10645.7 | 9197.24 | 8265.05 | 7559.81 | 9267 | 9686.82 | 7186 |
| **SCE** | *Thermal* | 30343 | 33875 | 33875 | 33875 | 33875 | 33875 | 34921 | 24660 |
| | *Total Quantity (MW)* | 46969 | 49204 | 54893 | 60119 | 63685 | 66122 | 67735 | 42128 |

**Table 11: March, Thermal Competition, BPA Strategic**

| Demand Level | | 7 | 6 | 5 | 4 | 3 | 2 | Peak | Totals (GWh) |
|---|---|---|---|---|---|---|---|---|---|
| **Price ($/Mwh)** | | 23.26 | 23.26 | 23.26 | 23.26 | 23.26 | 23.26 | 23.26 | |
| **Mkt Quantity MW** | | 54524 | 60521 | 66243 | 71500 | 75087 | 77538 | 80299 | 50005 |
| **CNW** | *Pondage Hydro* | 7981 | 15672 | 22842 | 29032 | 33324 | 34068 | 36410 | 17372 |
| **Region** | *Imports* | 12339 | 10646 | 9197 | 8265 | 7560 | 9267 | 9687 | 7186 |
| | *BPA Nuclear* | 1054 | 1054 | 1054 | 1054 | 1054 | 1054 | 1054 | 784 |
| | *Thermal* | 33149 | 33149 | 33149 | 33149 | 33149 | 33149 | 33149 | 24663 |
| | *Total Quantity (MW)* | 54524 | 60521 | 66243 | 71500 | 75087 | 77538 | 80299 | 50005 |

**Table 12: March, Perfect Competition**

## June Individual hourly equilbrium outputs

| **Demand Level** | | **7** | **6** | **5** | **4** | **3** | **2** | **Peak** |
|---|---|---|---|---|---|---|---|---|
| **Price ($/Mwh)** | | 21.23 | 22.95 | 23.29 | 23.29 | 23.74 | 43.38 | 60.42 |
| **Mkt Quantity MW** | | 50893 | 57077 | 64538 | 69968 | 75305 | 79042 | 81942 |
| **PGE** | *Fossil* (MW)* | 231 | 1155 | 1343 | 1345 | 1587 | 644 | 2081 |
| | *Pondage hydro* | 1656 | 1656 | 1656 | 1656 | 1656 | 1656 | 1990 |
| | *Total Quantity* | 1887 | 2811 | 2999 | 3001 | 3243 | 2300 | 4070 |
| | *Marginal Cost* | 20.32 | 21.59 | 21.85 | 21.86 | 22.19 | 20.89 | 22.87 |
| | *Marginal Revenue* | 20.32 | 21.59 | 21.85 | 21.86 | 22.19 | 20.89 | 22.87 |
| **SCE** | *Fossil* (MW)* | 687 | 1709 | 1949 | 1952 | 2259 | 1583 | 3118 |
| | *Pondage hydro* | 469 | 932 | 932 | 932 | 932 | 649 | 932 |
| | *Total Quantity* | 1156 | 2641 | 2881 | 2884 | 3191 | 2232 | 4050 |
| | *Marginal Cost* | 20.67 | 21.68 | 21.91 | 21.91 | 22.21 | 21.55 | 23.06 |
| | *Marginal Revenue* | 20.67 | 21.68 | 21.91 | 21.91 | 22.21 | 21.55 | 23.06 |
| **BPA** | *Nucelar (MW)* | 1054 | 1054 | 1054 | 1054 | 1054 | 1054 | 1054 |
| | *Pondage hydro* | 9773 | 11961 | 12735 | 12780 | 13755 | 9773 | 9773 |
| | *Total Quantity* | 10827 | 13015 | 13789 | 13834 | 14809 | 10827 | 10827 |
| | *Marginal Revenue* | 15.99 | 16.67 | 16.67 | 16.67 | 16.67 | -62.51 | -39.46 |
| **Fringe** | *Pondage Hydro* | 3484 | 3484 | 10616 | 16493 | 19240 | 19240 | 19240 |
| | *Imports* | 11072 | 9225 | 7667 | 7169 | 7347 | 8119 | 7429 |
| | *Thermal* | 22467 | 25900 | 26587 | 26587 | 27475 | 36325 | 36325 |
| | *Total Quantity (MW)* | 37023 | 38609 | 44870 | 50249 | 54062 | 63684 | 62994 |

**Table 13: June, 3 Cournot Firms**

## June Individual hourly equilbrium outputs

| Demand Level | | 7 | 6 | 5 | 4 | 3 | 2 | Peak | Totals (GWh) |
|---|---|---|---|---|---|---|---|---|---|
| **Price ($/Mwh)** | | 19.40 | 22.30 | 22.81 | 22.81 | 22.85 | 23.80 | 24.86 | |
| **Mkt Quantity MW** | | 51010 | 57123 | 64577 | 70011 | 75390 | 81044 | 85797 | 48027 |
| **BPA** | *Nucelar (MW)* | 1054 | 1054 | 1054 | 1054 | 1054 | 1054 | 1054 | 759 |
| | *Pondage hydro* | 9773 | 10491 | 11852 | 11886 | 12021 | 14529 | 17326 | 8516 |
| | *Total Quantity* | 10827 | 11545 | 12906 | 12940 | 13075 | 15583 | 18380 | 9275 |
| | *Marginal Revenue* | 15.18 | 17.81 | 17.81 | 17.81 | 17.81 | 17.81 | 17.81 | |
| **Fringe** | *Pondage Hydro* | 5609 | 5609 | 11984 | 17881 | 22848 | 22848 | 22848 | 10553 |
| **with PG&E,** | *Imports* | 11072 | 9225 | 7667 | 7169 | 7347 | 8119 | 7429 | 6096 |
| **SCE** | *Thermal* | 23503 | 30745 | 32021 | 32021 | 32119 | 34494 | 37139 | 22103 |
| | *Total Quantity (MW)* | 40183 | 45579 | 51672 | 57071 | 62314 | 65461 | 67417 | 38752 |

**Table 14: June, Thermal Competition, BPA Strategic**

| Demand Level | | 7 | 6 | 5 | 4 | 3 | 2 | Peak | Totals (GWh) |
|---|---|---|---|---|---|---|---|---|---|
| **Price ($/Mwh)** | | 19.40 | 22.58 | 23.03 | 23.03 | 23.03 | 23.03 | 23.53 | |
| **Mkt Quantity MW** | | 51010 | 57103 | 64559 | 69991 | 75372 | 81122 | 85941 | 48029 |
| **CNW** | *Pondage Hydro* | 15382 | 15382 | 23252 | 29182 | 34385 | 39363 | 43627 | 19066 |
| **Region** | *Imports* | 11072 | 9225 | 7667 | 7169 | 7347 | 8119 | 7429 | 6096 |
| | *BPA Nuclear* | 1054 | 1054 | 1054 | 1054 | 1054 | 1054 | 1054 | 759 |
| | *Thermal* | 23503 | 31443 | 32586 | 32586 | 32586 | 32586 | 33830 | 22108 |
| | *Total Quantity (MW)* | 51010 | 57103 | 64559 | 69991 | 75372 | 81122 | 85941 | 48029 |

**Table 15: June, Perfect Competition**

## September Individual hourly equilbrium outputs

| Demand Level | | 7 | 6 | 5 | 4 | 3 | 2 | Peak | Totals (GWh) |
|---|---|---|---|---|---|---|---|---|---|
| **Price ($/Mwh)** | | 23.79 | 59.75 | 88.97 | 95.61 | 95.61 | 95.61 | 95.61 | |
| **Mkt Quantity MW** | | 54152 | 57868 | 63011 | 67376 | 71744 | 78788 | 84141 | 47319 |
| **PGE** | *Fossil* (MW)* | 1684 | 1528 | 4130 | 5063 | 5429 | 5678 | 5678 | 2813 |
| | *Pondage hydro* | 1351 | 1351 | 1351 | 1351 | 1351 | 1730 | 2233 | 1032 |
| | *Total Quantity* | 3035 | 2879 | 5481 | 6414 | 6780 | 7408 | 7911 | 3845 |
| | *Marginal Cost* | 22.32 | 22.11 | 25.70 | 26.99 | 27.49 | 27.84 | 27.84 | |
| | *Marginal Revenue* | 22.32 | 22.11 | 25.70 | 26.99 | 27.49 | 27.84 | 27.84 | |
| **SCE** | *Fossil* (MW)* | 2472 | 2495 | 5118 | 5621 | 6008 | 6623 | 7084 | 3400 |
| | *Pondage hydro* | 358 | 358 | 422 | 932 | 932 | 932 | 932 | 474 |
| | *Total Quantity* | 2830 | 2853 | 5540 | 6553 | 6940 | 7555 | 8016 | 3874 |
| | *Marginal Cost* | 22.42 | 22.45 | 25.02 | 25.51 | 25.89 | 26.49 | 26.94 | |
| | *Marginal Revenue* | 22.42 | 22.45 | 25.02 | 25.51 | 25.89 | 26.49 | 26.94 | |
| **BPA** | *Nucelar (MW)* | 1054 | 1054 | 1054 | 1054 | 1054 | 1054 | 1054 | 759 |
| | *Pondage hydro* | 6216 | 2737 | 4897 | 5988 | 6444 | 7180 | 7740 | 4097 |
| | *Total Quantity* | 7270 | 3791 | 5951 | 7042 | 7498 | 8234 | 8794 | 4856 |
| | *Marginal Revenue* | 20.28 | 10.18 | 20.28 | 20.28 | 20.28 | 20.28 | 20.28 | |
| **Fringe** | *Pondage Hydro* | 2605 | 2605 | 2605 | 5506 | 8813 | 14393 | 18802 | 4612 |
| | *Imports* | 10830 | 8586 | 6281 | 4708 | 4560 | 4044 | 3464 | 4721 |
| | *Thermal* | 27582 | 37154 | 37154 | 37154 | 37154 | 37154 | 37154 | 25411 |
| | *Total Quantity (MW)* | 41017 | 48345 | 46040 | 47368 | 50527 | 55591 | 59420 | |

**Table 16: September, 3 Cournot Firms**

## September Individual hourly equilbrium outputs

| Demand Level | | 7 | 6 | 5 | 4 | 3 | 2 | Peak | Totals (GWh) |
|---|---|---|---|---|---|---|---|---|---|
| **Price ($/Mwh)** | | 25.26 | 27.64 | 29.63 | 30.97 | 24.20 | 27.61 | 64.18 | |
| **Mkt Quantity MW** | | 54052 | 60323 | 68152 | 73419 | 78852 | 86221 | 87810 | 50517 |
| **BPA** | *Nucelar (MW)* | 1056 | 1056 | 1056 | 1056 | 1056 | 1056 | 1056 | 760 |
| | *Pondage hydro* | 2737 | 5286 | 10452 | 13949 | 2737 | 2737 | 3496 | 4097 |
| | *Total Quantity* | 3793 | 6342 | 11508 | 15005 | 3793 | 3793 | 4552 | 4857 |
| | *Marginal Revenue* | 23.78 | 25.18 | 25.18 | 25.18 | -13.91 | -7.10 | 25.18 | |
| **Fringe** | *Pondage Hydro* | 1287 | 1287 | 1287 | 1287 | 16832 | 24717 | 26127 | 6118 |
| **with PG&E,** | *Imports* | 10830 | 8586 | 6281 | 4708 | 4560 | 4044 | 3464 | 4721 |
| **SCE** | *Thermal* | 38142 | 44108 | 49076 | 52418 | 53667 | 53667 | 53667 | 34821 |
| | *Total Quantity (MW)* | 50259 | 53981 | 56644 | 58413 | 75059 | 82428 | 83258 | 45660 |

**Table 17: September, Thermal Competition, BPA Strategic**

| Demand Level | | 7 | 6 | 5 | 4 | 3 | 2 | Peak | Totals (GWh) |
|---|---|---|---|---|---|---|---|---|---|
| **Price ($/Mwh)** | | 24.02 | 27.40 | 45.88 | 45.88 | 45.88 | 45.88 | 45.88 | |
| **Mkt Quantity MW** | | 54137 | 60342 | 66744 | 72025 | 76694 | 84224 | 89946 | 49826 |
| **CNW** | *Pondage Hydro* | 7205 | 7205 | 7409 | 14263 | 19080 | 27126 | 33428 | 10215 |
| **Region** | *Imports* | 10830 | 8586 | 6281 | 4708 | 4560 | 4044 | 3464 | 4721 |
| | *BPA Nuclear* | 1054 | 1054 | 1054 | 1054 | 1054 | 1054 | 1054 | 759 |
| | *Thermal* | 35048 | 43497 | 52000 | 52000 | 52000 | 52000 | 52000 | 34131 |
| | *Total Quantity (MW)* | 54137 | 60342 | 66744 | 72025 | 76694 | 84224 | 89946 | 49826 |

**Table 18: September, Perfect Competition**