# An Empirical Analysis of a Dominant Firm's Market Power in a Restructured Electricity Market, A Case Study of Colorado

by

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## Overview of the Study and Its Findings

Many states in the U.S. are currently considering, or have already decided upon, plans to implement some form of competition in the provision of electricity. "Electric restructuring" is a term commonly used in reference to these efforts to create a competitive market for the generation of electricity, while the transmission and distribution of electricity remain regulated monopolies. In general, state restructuring plans are designed to offer customers a choice regarding the source of their electricity, stimulate the marketing of innovative products, and reduce the price of electricity for consumers. For most consumers, a key issue is price. Whether restructuring plans will result in lower generation prices depends, in large part, on how quickly effective competition develops among firms that sell electricity in the restructured market. Economic theory suggests that effective competition will compel generation firms to price their output at the marginal cost of generation.[1]

When effective competition doesn't exist, a firm or group of firms has market power and can profitably set price above marginal cost. The existence of excessive market power would significantly erode the economic benefits of electric restructuring. Essentially, the degree of market power firms can exercise reflects whether electric restructuring has produced truly competitive markets or competition in name only.

This analysis focuses on horizontal market power, as opposed to vertical market power. Horizontal market power accrues to firms that control a large market share. Vertical market power, in contrast, comes from economies of scope of which a vertically integrated company can take advantage. One means of mitigating vertical market power is through functional

[1] Marginal cost includes all variable costs associated with power generation, such as fuel costs and variable operations and maintenance (O & M) costs. "Marginal" is used because, at any hour, the plant with the highest variable costs supplying power to a particular market will set the price of generation.

unbundling, where a formerly integrated firm separates its generation, transmission, and distribution operations. Another means is the creation of an Independent System Operator, who ensures that all firms have fair access to the transmission grid and dispatches the region's generation in a non-discriminatory manner.

Defining the potential for horizontal market power in the generation of electricity is a complex task. There are different types of generation, and each type has unique operating constraints. The characteristics of the transmission grid for a particular region affect the markets that firms may enter. The relative location of demand, generation, and transmission paths create bottlenecks on the grid that can prevent firms from entering certain markets.

A number of studies have attempted to quantify the potential for market power in places that have been in the forefront of electric restructuring, such as the United Kingdom and California. These studies analyzed a restructured market where a few large firms might have the ability to exercise market power (Newbery, 1995, and Borenstein and Bushnell, 1997 are examples). However, many states have one large firm that currently provides electric service to most of its customers. In fact, there are thirty-two states where one firm currently owns more than 40% of the generation capacity. In twenty of these states, one firm owns more than 50% of the generation capacity.[2] It seems intuitively obvious that market power would be a greater concern where one firm controls most of the existing generation, yet this issue has not been extensively analyzed.

This paper develops a measure of the ability of a dominant firm to exercise market power in a restructured generation market and applies that measure to a particular state considering

[2] The 32 states are Alabama, 57%, Arizona, 42%, Arkansas, 79%, Colorado, 51%, Connecticut, 40%, Delaware, 90%, Florida, 43%, Georgia, 85%, Hawaii, 72%, Idaho, 48%, Illinois, 67%, Maine, 57%, Maryland, 49%, Michigan, 48%, Minnesota, 71%, Missouri, 46%, Montana, 60%, Nebraska, 47%, New Hampshire, 46%, New Jersey, 74%, New Mexico, 41%, North Carolina, 54%, Oklahoma, 47%, Oregon, 66%, Rhode Island, 96%, South Carolina, 44%,

restructuring. It is a “short-run” analysis, in that it attempts to measure the amount of market power that would exist immediately after restructuring is implemented, given the existing firms, their generation, and the existing transmission capacity. Economic theory suggests that effective competition will prevail in the “long-run.” However, it is difficult to determine when exactly the “long run” might arrive. The United Kingdom restructured its electricity industry in 1991 and, despite almost yearly re-intervention by government agencies to increase competition, a significant degree of market power is still exercised by the two largest generation firms (Newbery and Pollitt 1997, 2).

The intent of this analysis is not to predict how a dominant firm might behave in a restructured market. The behavior of these firms will be the result of a number of decisions the firm’s executives make in developing the firm’s overall business strategy. Rather, the goal is to provide state policy makers an example of how to measure market power that considers the many nuances pertinent to generation markets, and a means to compare policy options for mitigating market power.

Any detailed analysis of market power must consider the specific characteristics of a region’s demand for electricity, transmission network, and generation. In this analysis, Colorado serves as a case study. It is the author’s hope that this study will provide insights and a methodology appropriate for other states faced with a similar market structure.

Public Service Company of Colorado (PSCo) owns 75% of the generation in eastern Colorado, where most of the region’s population, and, therefore, electricity demand, is concentrated. Transmission presents significant constraints into this “load pocket.” Furthermore, under the restructuring plans that have been introduced before the legislature, the state’s Rural

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South Dakota, 58%, Tennessee, 97%, Utah, 53%, Vermont, 50%, Virginia, 83%, Wyoming, 66% (EIA 1997a, Table 20)

Electrical Cooperatives (RECs) and municipal power companies would have the choice of whether to participate in the competitive retail electric market. Most RECs and municipals would probably choose to remain monopolies in their current service territories. Competition under electric restructuring would take place only in the service territories of the state's two investor-owned utilities, PSCo and WestPlains Energy.

The analysis focuses on market power PSCo could exercise in eastern Colorado during 2002-2005. The analysis initially uses a simulation model to compute the market outcome that would occur if perfect competition existed. Then, PSCo's ability to exercise market power is analyzed. To summarize, the model assumes that when there is insufficient uncommitted fringe generation at a given level of demand to mitigate PSCo's market power, then PSCo can apply a profit-maximizing markup over its marginal cost. The portion of the year over which the markup can be applied and the average amount of this markup serve as measures of market power.

The results of the analysis show that, given current and currently forecast market conditions, PSCo has the ability to set prices above marginal cost up to 93% of the year during 2002-2005. The price elasticity of demand for Colorado's electricity consumers, which represents their ability to reduce their demand in response to a price increase, greatly affects the amount of the markup PSCo could apply. Since price elasticity of demand varies by customer class, if PSCo can segregate the market, there is potential for PSCo to charge different rates to different customer classes (price discriminate).

The study investigates three scenarios under which PSCo's market power might be mitigated. Relaxing transmission constraints into eastern Colorado has almost no effect on PSCo's market power, as long as entry over the grid is restricted to firms within the Rocky Mountain Power Area (RMPA, which includes all of Colorado and Wyoming east of the

Continental Divide). The entry of 1,000 MW of fringe generation into the restructured eastern Colorado market, either over the grid or through the construction of new generation in eastern Colorado, reduces the amount of the year over which a markup could be applied from the base case estimate of 93% to 72%. Divestiture of generation resources appears to affect PSCo's market power the most. If PSCo agrees to divest 50% of its generation, markups can be applied only 37% of the year.

This study represents only a first effort toward a potentially more detailed analysis. As other policy options are developed that might mitigate PSCo's market power, these can each be analyzed in turn. Further sensitivity analysis can be conducted over the alternative scenarios (a range of values for levels of entry and divestiture, for instance). Additionally, the current model is limited to a detailed analysis of only the RMPA. Entry from other regions (the Northwest Power Pool or Arizona-New Mexico) is modeled only in an aggregate manner. Existing contracts for power exchanges between regions are modeled, and the potential entry of up to 1,000 MW of generation from the NWPP or Arizona-New Mexico are part of the study. However, the dynamic interactions that might take place between regions under electric restructuring are beyond the scope of this analysis. A multi-area model of the entire western grid might reveal additional insights.

These results should not be interpreted as a condemnation of electric restructuring. The study merely points out that in states where a regulated electric utility controls a large share of generation capacity, state policy makers are presented with a special challenge in creating effective competition. Policy makers have options to mitigate market power, including divestiture of generation, measures to encourage the entry of new firms, the imposition of price caps, and a continued role for regulators as a watchdog to protect consumers.

## The Herfindahl-Hirschmann Index

The most common measure of market power is the Herfindahl-Hirschmann Index (HHI), which is a standard used by the U.S. Department of Justice in antitrust litigation (Werden 1996, 20). The HHI is the sum of the squared market shares for each firm competing in a given market.

$$HHI = \sum_{i=1}^{n} (market\ share_i)^2 \text{ where i = firms } 1, \ldots, \text{n} \qquad \text{(equation 1)}$$

In a market with 100 firms, where each firm has 1% of the market, the HHI = $\sum_{\mathrm{i}=1}^{100} (1)^2 = 100.$ In contrast, a monopoly market where one firm controls the entire market would have an HHI = $100^2 = 10{,}000.$ A moderately competitive market with five equally sized firms would have an HHI = $\sum_{i=1}^{5} 20^2 = 2{,}000$. While the HHI is not a direct measure of a firm's ability to exercise market power, markets with a high HHI are more likely to experience problems with market power.

In his testimony before the Federal Energy Regulatory Commission (FERC), Paul Joskow from MIT (1995) recommends that a market power analysis begin by defining the relevant market, identifying suppliers and their associated capacity, and then use the HHI as a screen for market power. If the HHI for a market were below some threshold level, such as 2,500, the market would be presumed to be competitive. Persuasive evidence of market power abuse would be required to merit further investigation once a market met this standard (Joskow 1995, 29).

The HHI may have value as a screening tool for measuring market power in generation markets, but it also has shortcomings. The dimensions of an electricity market change considerably as a function of transmission constraints. Congestion on the transmission grid can isolate markets. Once these constraints are relaxed, firms over a wide area may compete, limited only by their increased costs due to transmission charges and power losses. Thus, the HHI is a static measure of a very dynamic situation.

Furthermore, the HHI measures only one of aspect of market power. The ability of firms to charge prices in excess of marginal cost (MC) is also related to the price elasticity of customer demand (|ε|). The price elasticity of demand is a measure of a consumer's ability to reduce consumption of a particular product in response to a price increase; it is the percent a representative consumer would reduce demand for a good when faced with a 1% increase in price.

$$|e| = \frac{\%\ \Delta \text{ quantity demanded}}{\%\ \Delta \text{ price}} \qquad \text{(equation 2)}$$

When the price elasticity of demand is inelastic, as it is in generation markets, |ε| < 1. This means that when a generation firm increases its price by 1%, consumers reduce demand, but the reduction is less than 1%. Therefore, the firm can increase its total revenue by increasing price.

In a market with "*n*" identical firms, it can be shown that the percent markup of price over marginal cost is as shown.

$$\frac{P - MC}{P} = \frac{1}{n \bullet |e|} = \frac{.001 * HHI}{|e|} \qquad \text{(equation 3)}$$

This equation highlights the fact that price responsive demand plays an important role in an analysis of market power (Borenstein, Bushnell, Kahn, and Stoft 1996, 11). In a market with a demand elasticity of |0.2| and 10 equally sized firms, equation 3 indicates that market price would be twice marginal cost. As demand elasticity increases to |1.0|, firms realize little additional profit if they increase price.

There is another problem related to defining the relevant market that the HHI fails to consider. The HHI calculates market shares simply on the basis of generation ownership. For fringe firms, it may be more appropriate to consider the quantity of excess generation they have available once they've served their native customers. Colorado, like many states considering restructuring, gives RECs and municipals the choice of whether to participate. If these firms do not open their own service territories up to competition, restructuring plans usually prohibit them from selling their excess generation in the competitive market. However, RECs, at least in Colorado, own no generation. Tri-State Generation and Transmission, Inc., which is jointly owned by RECs in Colorado, Wyoming, and Nebraska, supplies the RECs. Most of Colorado's municipal power companies, likewise, own little or no generation. They receive their power from the Western Area Power Authority (WAPA), a federal power agency. It seems doubtful that Colorado could impose provisions of its electric restructuring plan on extra-jurisdictional (out-of-state) corporations, or a federal power agency to prohibit them from selling their excess generation in a restructured market. Similarly, firms owning generation in neighboring states that have not restructured electricity will continue to serve their native customers. However, it seems reasonable to assume that these out-of-state firms would sell any excess power they can produce, once they've served their native customers. These firms could sell generation directly to customers in the restructured market or the generation could be sold wholesale to power marketers, who resell it to customers in the restructured market. Even Colorado municipal power companies that own generation (integrated firms) might be able to sell excess power to interstate power marketers who could resell that power in Colorado's restructured market.

For these reasons, provisions of any restructuring plan that attempt to exclude generation firms from the restructured market might be difficult to enforce. Given the hurdles in the way of creating effective competition in generation markets, it might also seem to be a questionable policy for a state to aggressively pursue measures that limit competition. For the purposes of this analysis, the quantity of generation significant for mitigating PSCo's market power from any generation and transmission cooperative, integrated municipal power company, or federal power agency is that generation which is uncommitted once these firms serve their native load.

The HHI for the eastern Colorado generation market is approximately 5,000 when transmission is congested, which reflects PSCo's ownership or control through contracts of 75% of the eastern Colorado generation. If the relevant market is the entire RMPA, the HHI is 3,000. In either case, the HHI suggests a strong possibility that the market power PSCo could exercise in a restructured Colorado electricity market might be a concern.

## Conceptual Framework

This analysis will develop a more detailed measure of market power that provides state policy makers a better picture of how a dominant firm might exercise market power and a means to compare policy measures that might be employed to mitigate market power. The general framework of the measure presumes that there is an hourly generation spot market, where all firms that want to sell power bid the price and quantity of their generation (the supply curve) against consumer demand for that hour (the demand curve). The time period studied is 2002-2005. This time period was selected because it is feasible to implement electric restructuring in Colorado by 2002, and the four year time span provides an opportunity to analyze the effects of load growth, contract expiration, and planned construction of new generation.

If the market is competitive, firms and consumers will be "price-takers." Consumer demand reflects the marginal price consumers are willing to pay for a quantity of goods sold in the market place (figure 1). Market supply, in generation markets, can be thought of as a "step" function. Each step represents the variable production cost (marginal cost) and generation capacity at a particular plant. The plant at the competitive price-quantity equilibrium is just covering its variable costs. Plants with lower variable costs are earning revenue in excess of their variable costs, which pays some portion of their fixed costs and provides a return on capital invested. Market price reaches equilibrium at the intersection of consumer demand and generation supply ($P_c$ and $Q_c$). Competitive prices are expected to be lower than prices under regulation because they reflect only the marginal (variable) costs of supplying a product at a given level of demand. Regulated prices, in contrast, are based on average total costs. Regulated prices give utilities an opportunity to recover all of their fixed and variable costs, as well as earn a return on investment for the firm's shareholders.

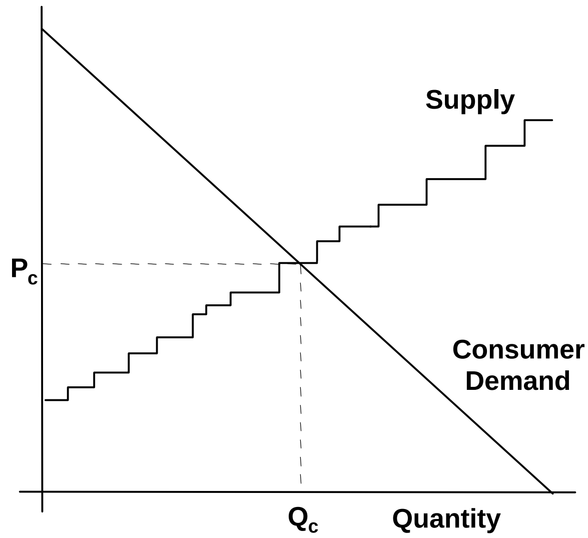


Figure 1. Competitive market equilibrium

When a dominant firm exercises market power, it acts as a "price maker." Dominant firms control such a large share of a market's generation that they are able to set the market price at a level above marginal cost. In addition to controlling a large share of the market, two other conditions help the dominant firm exercise market power, price elasticity of demand that is "inelastic" and inelastic supply of the fringe firms. When demand is "inelastic," consumers cannot readily reduce their quantity demanded in response to a price increase[3]. This is a

[3] The elasticity of demand (ε) for electricity is typically modeled as being between |0.1| (very inelastic) and |0.9| (less inelastic).

particular problem in electricity markets. Given the current state of technology, most customers cannot easily substitute another commodity for the electricity they need. Only the largest customers can economically operate their own generation.

The other condition required for the dominant firm to exercise market power is that the supply of smaller fringe firms is inelastic; there is a capacity constraint on fringe generation. Fringe capacity constraints arise because transmission paths into an area are constrained and because the fringe capacity that exists in a given area, once transmission constraints bind, has a fixed upper bound on output. This problem is exacerbated in generation markets because of the time required to construct new generation, which is twelve to twenty months by some estimates (PSCo 1997, 3). Furthermore, in the RMPA, new generation construction will probably remain limited for some time due to the excess generation already in the region. The Western Systems Coordinating Council (WSCC) forecasts that the RMPA will maintain a generation reserve margin in excess of 30% at least through 2005, which is well in excess of the 15% reserve margin required for reliability (RDI 1997, Table R-1a). Firms with capital to invest in the construction of new generation would probably be drawn first to other areas of the United States that have lower reserve margins, where new plants would be required to run most of the year.

Economic theory provides an explanation of how a dominant firm exercises market power to maximize profits. The dominant firm calculates the equilibrium that would occur under perfect competition (figure 2). The overall market supply can be broken down into the dominant firm's own supply curve, and the supply of all of its competitors, the competitive fringe. This model assumes that firms in the competitive fringe are price takers; they will accept whatever price the dominant firm sets.[4] The dominant firm subtracts the supply curve of the fringe firms

[4] If any firms in the competitive fringe firms also attempted to exercise market power, price markups would be even higher.

from market demand to determine residual demand. Residual demand is the amount of demand "left over" when fringe supply is exhausted at a particular price and quantity. From the residual demand curve, the dominant firm calculates its marginal revenue curve. Marginal revenue is the amount of revenue the firm earns if it chooses to produce an additional unit of output. The intersection of the dominant firm's marginal revenue curve and supply curve determines the profit-maximizing quantity that the dominant firm will supply to the market ($q_{\text{Dominant firm}}$). Tracing up from this quantity, the residual demand curve, at $q_{\text{Dominant firm}}$, determines the optimal market price for the dominant firm ($P_M$). At this price, the overall market demand curve determines how much electricity consumers will purchase ($Q_{\text{Market}}$). The difference between the market quantity demanded ($Q_{\text{Market}}$) and the quantity that the dominant firm will supply ($q_{\text{Dominant firm}}$) will be made up by the competitive fringe ($q_{\text{fringe}}$).

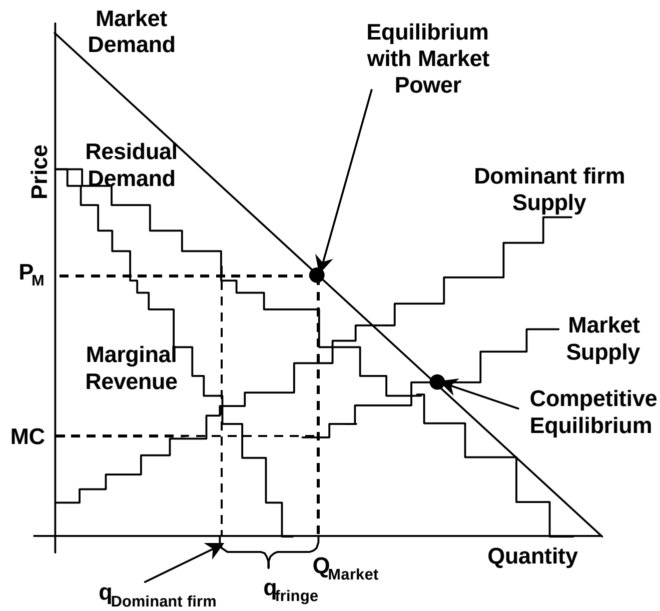


Figure 2. Dominant firm markup.

Therefore, the dominant firm uses its market power to restrict the quantity it supplies to the marketplace and increase price above marginal cost. The profit maximizing strategy for the dominant firm can be calculated mathematically. If the dominant firm is maximizing profits, it calculates the difference between price and marginal cost at a given level of demand as shown.

$$\text{Price markup} = \frac{P - MC_{\text{Dominant firm}}}{P} = \frac{1}{|e|} \bullet \frac{q_{\text{Dominant firm}}}{Q_{\text{Market}}} \qquad \text{(equation 4)}$$

Equation 4 shows that the markup of market price over marginal cost is affected by two factors. The first is the inverse elasticity of demand, $\frac{1}{|e|}$ suggesting that, if the dominant firm is able to price discriminate, different customer classes might face different price markups. The second factor is the dominant firm's market share, $\frac{q_{\text{Dominant firm}}}{Q}$. The larger the market share of the dominant firm, the greater the markup of price over marginal cost.

The percent of a year that a dominant firm can apply a price markup and the average price markup that the dominant firm is able to impose provide simple, aggregate measures of the market power the dominant firm can exercise. Calculation of the average markups is shown.

$$\text{Average markup} = \sum_i (t_i \bullet \text{Price markup}_i) \qquad \text{(equation 5)}$$

where $t_i$ is the percent of a year that a particular markup can be applied and $\sum_i (t_i) = 1$ for the year in question. When there is no price markup, prices are competitive. The extent that different restructuring options can mitigate market power can be compared on the basis of the percent of the year price markups can be applied and the average price markup over marginal cost that these options produce.

In developing restructuring options, it might be appropriate to ask whether it is necessary that prices always reflect marginal costs. There are, in fact, some good reasons why prices sometimes diverge from marginal generation costs. For a certain portion of the year, approximately 20% in Colorado, peaking plants are required to operate to meet power demands. These are generally small plants that have lower capital costs for construction, but higher operating costs. The benefit of these plants is that they can be quickly brought on-line to satisfy short-term, peak-power demand, typically during cold periods of the winter and hot periods of the summer. When these plants operate, they must recover their fixed costs, provide a return to investors, and cover their operating costs. Unless all costs are recovered during the brief times when these plants operate, peaking plants are not economic investments. The benefit peaking plants provide, as part of the overall generation portfolio, would be lost if generation prices were always set at marginal cost.

Furthermore, it might be appropriate, from an overall societal perspective, that consumers have some motivation to reduce their energy demand during peak periods. Higher electricity prices during peak periods could provide that motivation. This could reduce the need for additional peaking plants, and permit society's resources to be invested elsewhere. This study will not attempt to define the portion of the year that it might be appropriate for prices to diverge from marginal generation costs, because this a question for state policy makers.

While the calculated price markups represent the profit-maximizing strategy for a dominant firm, it is doubtful that these markups would really appear in the marketplace. A profit-maximizing strategy would result in such high prices that it would invite an unwanted backlash from consumers and state policy makers. The ill will that such a strategy would produce between the firm and its customers could strengthen the presence of the dominant firm's competitors. State policy makers might implement measures to mitigate the firm's market power. A profit-maximizing strategy would probably not be in the firm's best interest in the long run. Rather, the calculation of these markups is a tool for policy makers that provides them information on what level of competition exists in restructured generation markets.

The Colorado Electricity Market

The three most significant factors that affect a generation firm's ability to exercise market power in a particular area are ownership of generation, the location and concentration of demand, and the capacity and number of transmission paths. Generation factors important to Colorado's market have already been mentioned; PSCo controls 75% of eastern Colorado's generation and 45% of RMPA generation. Much of PSCo's generation is coal-fired, which, because it is close to coal fields, is very inexpensive. The other major source of generation is the Western Area Power Administration's hydroelectric dams. Together, these assets provide Colorado's electric customers rates below the national average.[5] Because of its low cost generation and high reserve margins, the RMPA is a net exporter of its low cost power to the rest of the Western Interconnect.

Demand for electricity is closely correlated to population density. In Colorado, population is concentrated in eastern Colorado along the "Front Range" of the Rocky Mountains where the cities of Greeley, Fort Collins, Boulder, Denver, Colorado Springs, and Pueblo are located. 73% of the RMPA's electrical demand is in eastern Colorado. However, there is a not enough generation physically located in eastern Colorado to service demand the entire year. This shortfall of generation must be made up through imports from western Colorado and Wyoming into eastern Colorado to meet demand.

Limited transmission paths into eastern Colorado also play a major role in an analysis of market power in the region. Colorado is at the eastern edge of the Western Interconnect (figure 3). There are no transmission paths directly linking Colorado to the Eastern Interconnect. Limited DC interties to the Eastern Interconnect exist in Nebraska at Sidney and Stegall, but

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[5] In 1996, Colorado's rates average for all retail customers averaged 6.1¢/kWh vs. a U.S. average of 6.9¢/kWh (EIA 1996a, 36).

these are north of the TOT 3 transmission path, which links Wyoming and eastern Colorado. There are also no transmission paths linking Colorado to the south. The only southern transmission path is through Four Corners, which is west of the TOT 5 transmission path, which links western Colorado and eastern Colorado.

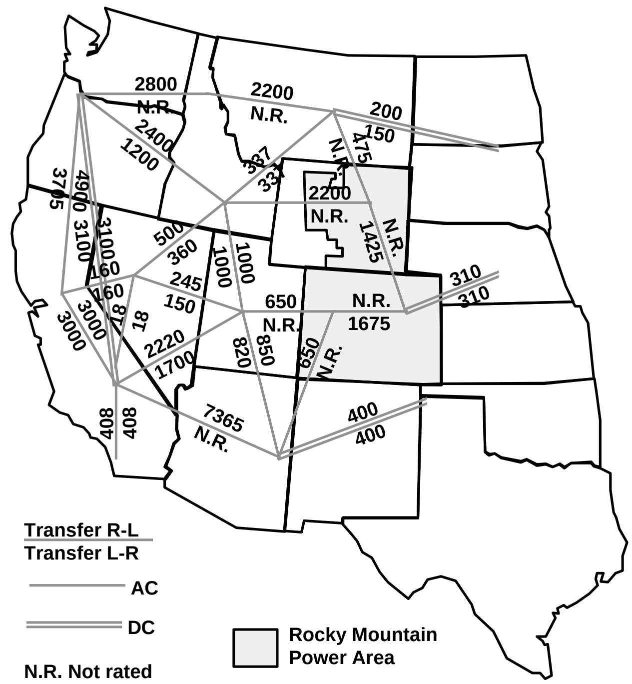


Figure 3. The Western Interconnect.

The TOT 3 and 5 transmission paths are constrained approximately 15% of the year. The transmission capability of TOT 3 from Wyoming into eastern Colorado varies depending upon a number of operating conditions that may occur, but has an upper limit of approximately 1425 megawatts (MW) (WSCC 1997a, 64-65). TOT 5 capacity from western Colorado into eastern Colorado is affected by the amount of power flowing over TOT 3, but has an upper bound of 1675 MW. The limits on these transmission paths occur because of the capabilities of equipment along the paths and thermal limits on the lines; if the lines carry too much power they can overheat, sag onto the ground, and short out the transmission grid.[6] Figure 4 provides a more detailed picture of these constraints. TOT 3 conceptually runs east west along the Wyoming-Colorado border, while TOT 5 runs north south along the Continental Divide.

[6] TOT is a commonly used term referring to the TOTal flow of power that can occur over a transmission path. The path is not one line, but, in fact, a number of lines owned by many different companies. A property of electricity is that it cannot be directed down single lines that are connected to the electrical grid. The power will flow according to the laws of physics. Therefore, firms jointly perform engineering studies on the lines that connect different regions, determine the maximum transmission capacity of these lines under various operating conditions, and then allocate ownership of that transmission capacity to the firms that own the individual lines.

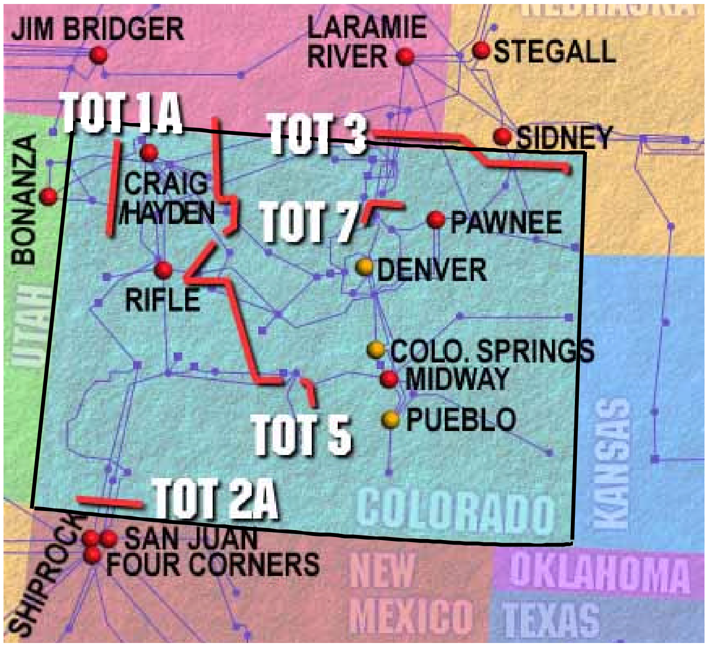


Figure 4. RMPA transmission constraints.

The net effect of all of these factors is that the most likely region for PSCo to exercise market power is eastern Colorado. PSCo's share of the generation market in eastern Colorado is quite large. The limited supply of fringe generation in eastern Colorado and the limitations on transmission make existing supply very inelastic. If PSCo does exercise market power, fringe firms have a limited ability to respond unless there is a large amount of new generation constructed by fringe firms.

## Methodology

The approach that will be used to analyze the potential for PSCo's market power in a restructured Colorado generation market has three steps. The first step is to estimate the market outcome in eastern Colorado, western Colorado, and Wyoming with a utility production cost model, Elfin, assuming that perfect competition exists. Elfin's output is exported to a spreadsheet model in the second step to determine when PSCo can exercise market power, calculate price markups, and analyze power flows among the regions. Step 2 produces the base case scenario (Scenario 1), which attempts to capture all of the factors of the current and currently forecasted factors that affect the RMPA electricity market. The third step analyzes three alternative scenarios (Scenarios 2-4) under which PSCo's market power might be mitigated.

Step 1. The Elfin model is used to estimate a competitive equilibrium in the eastern Colorado, western Colorado, and Wyoming markets, using only the generation native to each region. Elfin is an electric utility financial and production cost model developed by the Environmental Defense Fund (EDF). Numerous utilities, government agencies, and public interest groups in the United States and internationally, have used this software over the past two decades for policy analysis (EDF 1996, 1).

Interactions with regions outside the RMPA are incorporated by adjustments to demand within the RMPA. Firm power contracts and exchanges between the RMPA and the Northwest Power Pool (NWPP), Mid-America Power Pool (MAPP), and Southwest Power Pool (SPP), as projected by the WSCC, are treated as part of Wyoming's demand. Firm power contracts and exchanges between the RMPA and the Arizona-New Mexico and California-Nevada portions of the WSCC, as projected by the WSCC, are considered part of western Colorado's demand.

To calculate the competitive market equilibrium, Elfin requires an hourly load curve, representing the hour-by-hour demand for electricity, for each region. This data is obtained from the 1996 FERC Form 714s (hourly load data) submitted by the six RMPA control centers: Black Hills Power, WAPA, Platte River Power Authority, PSCo, Colorado Springs Municipal Utilities, and WestPlains Energy. The hourly load from each control area is added together to get the overall RMPA hourly load curve. Figure 5 reflects the load for each hour of 1996 from 1 AM, January 1st through midnight on December 31st (8,784 periods, since 1996 is a leap year). Elfin then scales demand for each year of the simulation using two parameters, net energy demand in gigawatt hours (GWh) and peak hourly demand (MW). Forecasts for these values were obtained from the WSCC (1997b). Elfin also requires detailed data on each generation resource. This data includes generation type (baseload, load-following, hydroelectric, pumped storage), capacity, number of units, heat rate, fixed and variable costs, outage rates, and other factors. Contracts are modeled by assigning a share of a particular generation resource to a company, or as a separate generation resource. Some of these parameters are varied for particular months of the year, for instance, to account for the monthly variations in hydroelectric capacity. Other parameters are varied by year, to account for such factors as expansions in capacity, retirements, and contract expiration. Data for each generator is obtained from utility FERC Form 1 submissions, Integrated Resource Plans, and a commercially available database from Resource Data International (RDI).

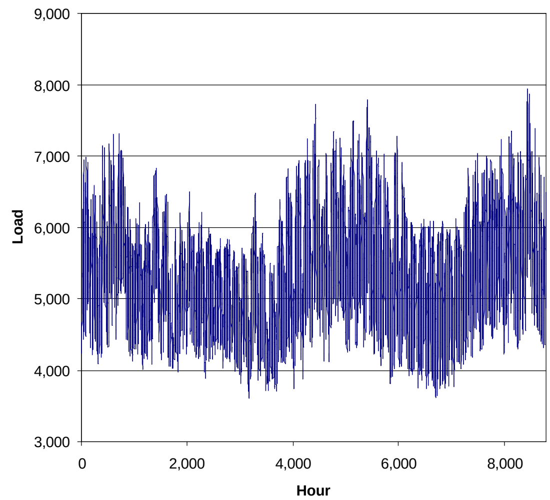


Figure 5. 1996 RMPA hourly load curve.

Elfin then calculates the optimal (least cost) generation set for each area on an hour-by-hour basis. It dispatches generation to service demand in order of increasing cost, subject to the engineering constraints unique to each type of generation. Using Elfin to model this process incorporates many of the nuances that affect the dispatch of generation such as reserve requirements, outage rates, limitations on the use of hydroelectric generation, and the load-following constraints of baseload plants.

Step 2. Elfin provides several elements of data from the competitive equilibrium that are key to Step 2: the economic dispatch order, the time that each individual plant is the marginal producer, and an estimate of market prices that would exist under perfect competition. In Step 2, this data is exported to a spreadsheet to determine when PSCo can exercise market power, calculate price markups, and analyze power flows among the regions. This analysis is performed over what is commonly called a load duration curve (figure 6). In a load duration curve, hourly load data is sorted from largest load (peak demand) to smallest load over a given period of time, in this case, a year. The economic dispatch order tells how to array plants against the load duration curve (figure 7). The time marginal for each plant tells what portion of a year each plant is marginal along the load duration curve. During the time each plant is marginal, PSCo's market share is calculated. To incorporate the effect of competition PSCo would experience if it attempted to exert market power, the uncommitted

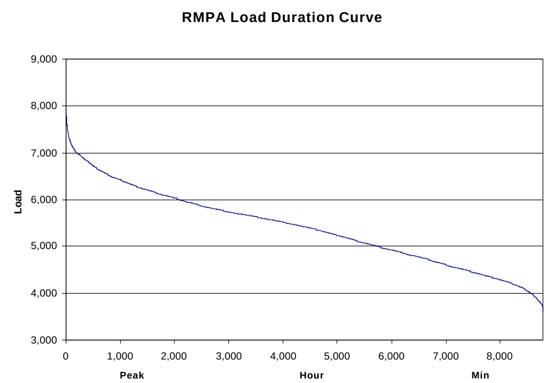


Figure 6. RMPA load duration curve.

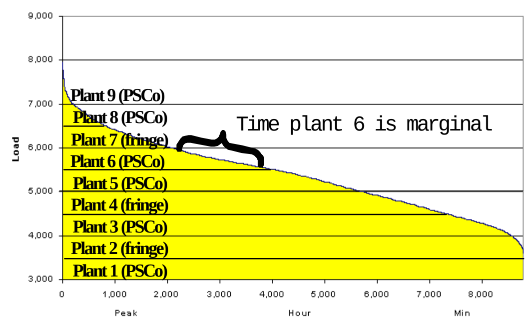


Figure 7. Use of economic dispatch order and time marginal.

fringe generation ($q_{f\_E.Co}$) is also identified at each point along the load duration curve (figure 8).

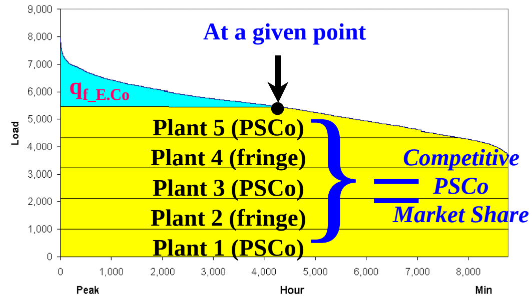


Figure 8. PSCo's competitive market share and the uncommitted fringe.

To include the effect of imports from western Colorado and Wyoming, the quantity of fringe generation that is not committed to serve native load in these regions ($q_{f\_W.Co}$, $q_{f\_Wyo}$) is identified at the same point along the load duration curves for these regions. If PSCo attempts to exercise market power, uncommitted fringe generation in western Colorado and Wyoming is available to enter the eastern Colorado market up to the level permitted by transmission constraints (figure 9). When

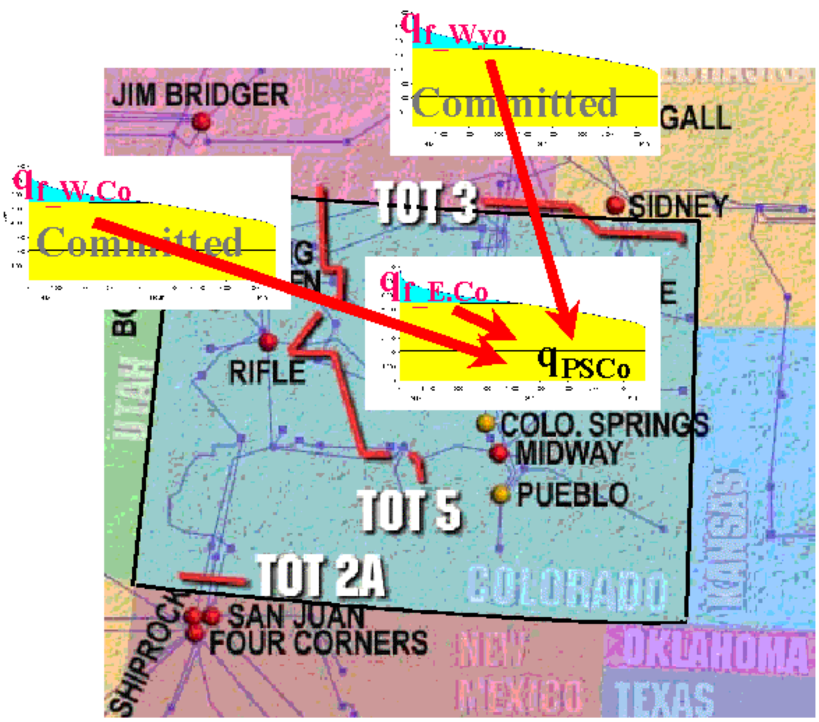


Figure 9. Identification of uncommitted fringe generation in eastern Colorado, western Colorado, and Wyoming.

all uncommitted fringe generation is identified, PSCo's market share if it attempted to exercise market power is calculated as shown.

$$\text{PSCo Adj. Market Share} = \frac{q_{PSCo} - q_{f\_E.Co} - q_{f\_W.Co} - q_{f\_Wyo}}{Q_{Market}} \qquad \text{(equation 6)}$$

In equation 6, $q_{PSCo}$ is the quantity PSCo would supply if the market were competitive. The terms, $q_{f\_E.Co}$, $q_{f\_W.Co}$ and $q_{f\_Wyo}$, are the quantities of uncommitted fringe generation in each region. PSCo's adjusted market share (equation 6, the quantity PSCo supplies when exercising market power) can then be used in equation 4 to calculate PSCo's markup over marginal cost. These calculations are performed over the entire load duration curve.

The base case scenario (Scenario 1) attempts to capture all of the current and currently forecasted factors that affect the RMPA electricity market. These factors include current and planned generation, forecasted load growth, contracts, joint ownership agreements, transmission constraints, and interactions with other regions. The significant assumptions related to this scenario are shown.

1. Elasticity of demand is linear. Market outcomes are calculated for the following elasticities: $|0.9|$, $|0.7|$, $|0.4|$ and $|0.1|$. These values were selected because the same values were used in Borenstein and Bushell's study (1997). The EIA (1997, 24) uses a narrower range of elasticities from |0.15| to |0.5|.

2. Spinning reserve requirement: 7%.

3. Competition occurs in the service territories of Colorado's IOUs: PSCo and WestPlains Energy.

4. PSCo does not renew contracts for independent producers as they expire; after contract expiration these plants become part of the competitive fringe.

5. Fringe generation serves its native load first; uncommitted fringe generation competes for PSCo's market share.

6. All fringe generation within the RMPA competes for PSCo's market share (5,000 MW, 2002-2005, of which 1,700-1,900 is physically located in eastern Colorado-exact quantities vary by year).

7. Due to declining reserve margins in the rest of the WSCC, and competition in other states with higher generation prices, no generation outside the RMPA competes for PSCo's market share.

8. The shape of the hourly load curve for eastern Colorado, western Colorado, and Wyoming is the same.

<u>Step 3.</u> In this step, alternative scenarios are modeled to calculate the effect of various conditions on PSCo's market power. As these policies cause the parameters of the model to change, Steps 1 and 2 are repeated under the new conditions so that the duration and amount of price markups can again be estimated. The following scenarios are considered:

<u>Scenario 2.</u> Assume that transmission constraints (TOTs 3 and 5) do not affect the flow of power within the RMPA. A detailed cost-benefit analysis of increasing transmission to this level is beyond the scope of this study. The intent here is merely to provide an estimate of how PSCo's market power in eastern Colorado might be affected when RMPA transmission constraints are relaxed.

<u>Scenario 3.</u> Assume that 1,000 MW of fringe generation enters the eastern Colorado market, either over the transmission grid from beyond the boundaries of the RMPA or through new generation construction in eastern Colorado. While

entry is not normally modeled in a short-run economic analysis, the intent of this scenario is to explore the effect of entry by fringe firms on PSCo's market power. These plants are assumed to operate with the cost characteristics of PSCo's Fort St. Vrain plant, a modern gas turbine facility.

<u>Scenario 4.</u> Assume that, as part of an agreement to implement electric restructuring, PSCo agrees to voluntarily divest 50% of its generation. PSCo might be motivated to do this in return for the opportunity to compete for unregulated profits or to receive compensation for stranded investments, if they exist. Divested plants are assumed to become part of the competitive fringe. This implies that one company is unable to purchase all plants divested by PSCo. To implement divestiture, this scenario assumes that PSCo sells a 50% interest in each of its generation resources. While admittedly, this is not the approach that would necessarily be implemented, calculating divestiture in this way avoids complications that could arise if PSCo sold off only baseload generation, or peaking generation, or particular plants that, because of their location on the grid, were in a "must-run" status. The 50% level of divestiture was chosen because California's IOUs agreed to divest 50% of their fossil plants. Additionally, this level of divestiture reduces PSCo's share of eastern Colorado generation to 37.5%, which is close to Joskow's (1995, 8) threshold of 35% market share, where a dominant firm begins to exercise market power.

As part of each scenario, the effect of making the demand for generation more price responsive is considered. PSCo's markup at each of the price elasticities indicated is compared ($|0.1|$, $|0.4|$, $|0.7|$, and $|0.9|$). These calculations provide an indication of the effect of improving demand elasticity. Possible policy measures to improve the price elasticity of demand include encouraging the presence of load aggregators, or requirements that utilities provide detailed, time-of-day price information on electric bills. Whether or not these measures would actually increase demand elasticity is an empirical issue.

Overall, the methodology is, admittedly, somewhat clumsy in the way it calculates PSCo's market share when the firm exercises market power. The approach described requires that the uncommitted capacity of the fringe be completely exhausted before PSCo is able to apply a price markup. A mathematically more-precise calculation of the market share may reveal that PSCo could maximize profits in eastern Colorado's market by restricting its output somewhat less, and, in doing so, permit the firm to exercise market power a greater portion of the year. In general, though, PSCo's market share is so large that, for most price elasticities of demand, the methodology described does, in fact, maximize profits. The calculated markups are so large that the market price is set at a level higher than any generation resource in the RMPA. This strategy would also have an advantage for PSCo in that the quantity of generation PSCo withholds from the eastern Colorado market could be sold elsewhere on the grid, either wholesale or in other restructured markets, such as California, and these sales further enhance PSCo's profits. This methodology also presents a conservative measure of market power. If PSCo were to restrict output somewhat less so it could exercise market power a greater portion of the year, or if fringe firms, over time, learned that they could also restrict supply and act like dominant firms, the problem of market power would only become worse.

A more serious problem of the methodology is the assumption that the overall load curve for the RMPA is the same as the load curve for the areas within the RMPA (eastern Colorado, western Colorado, and Wyoming). A correlation analysis was performed on the FERC Form

714s (hourly load data) for the six control areas of the RMPA to test this assumption. For the five areas that included large urban centers in their load, the correlations were approximately 90%. However, the WAPA control center's correlation with the other five areas was approximately 40%, although the correlation was still positive. To analyze this problem further, the hourly load curves for each control area were plotted and compared. All areas had a morning peak and an evening peak. The major difference was that in the five areas that served urban centers, the morning peak was sustained throughout the day and then demand reached a higher evening peak. In WAPA's control area, demand declined after the morning peak. Demand then ramped up quickly for an evening peak was approximately the same as the morning peak.

The discrepancy in hourly load introduces some error into this model. A true multi-area model that permits control centers to interact on an hourly basis may reveal additional insights into the problem of market power. However, given the small portion of demand represented by WAPA's control area (approximately 20%), the fact that most of this generation is committed to serve its native load, and the fact that load correlation for all regions is positive anyway, the results of the analysis might not change greatly.

## Findings and Analysis

Overall, the results of this model show that PSCo can exercise a large degree of market power in a restructured Colorado electricity market. In the base case scenario, PSCo can apply a markup over marginal cost greater than 93% of the year, each year from 2002 through 2005 (figure 10). The average markups customers would face are a function of the price elasticity of

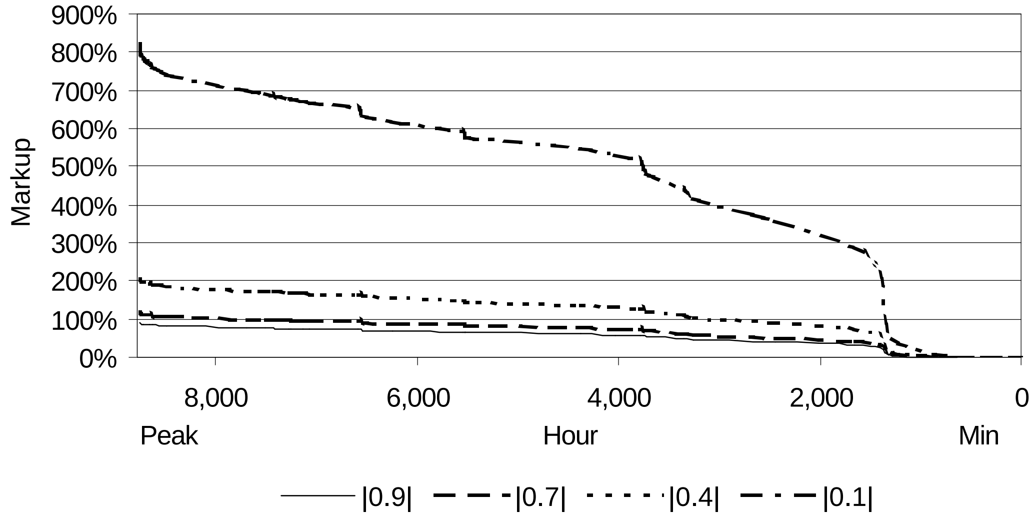


Figure 10. Markups PSCo can apply over marginal cost given a range of price elasticities of demand in 2002, base case scenario.

demand. Average markups for 2002 vary from 53% to 478% as the price elasticity of demand is decreased from |0.9| to |0.1|. It would be unlikely that PSCo would actually apply the full markup in any case. As mentioned earlier, price gouging of this magnitude would probably invite re-regulation, encourage customers to seek other suppliers and reduce or shift load, and encourage other firms to construct new generation in eastern Colorado. Rather, it is more likely that PSCo would attempt to select a lower level of profits that satisfies its shareholders, does not incur the wrath of Colorado consumers, and does not invite entry by new firms.

The results suggest that competition will not force prices to marginal cost for a significant portion of the year. Studies that purport to calculate the economic benefits of electric restructuring rely on price forecasts. These studies must consider the possibility that prices will be above marginal cost and include some type of sensitivity analysis for price. Any *ex ante* estimation of stranded costs also makes assumptions regarding prices. Currently, RDI (1997, SC-2) and Moody's Investor Services (McGraw-Hill Energy and Business Newsletters 1997, 14), using models that assume prices under electric restructuring will be at marginal cost, predict that PSCo has negative, or no stranded generation costs. If price, as this study suggests, exceeds marginal cost, PSCo's generation will be even more valuable than RDI and Moody's currently estimate.

Another result suggested by this model is that if a utility is able to segregate the market by customer class, price markups could vary substantially among customer classes. Specifically, customers with a |0.1| price elasticity of demand face a price markup nine times higher than customers with a |0.9| price elasticity of demand. Restructuring legislation should carefully consider the market institutions the plan implements. Policy makers should carefully design market structures that treat each customer class fairly. A common pool that all firms and customers bid into for short-term energy sales would be one option. The pool would set the price for all customers, regardless of class. For long-term needs, large industrial customers have an advantage over residential customers in negotiating deals because of the size of their loads. Nevertheless, if the restructured market encourages the presence of load aggregators, who represent many small customers, this might prove to be one effective means of leveling the playing field.

In terms of mitigation strategies, relaxing transmission constraints within the RMPA (Scenario 2) does not seem to affect the portion of the year over which PSCo can exercise a markup, or the amount of markups that are applied. The reason why this occurs is that there is simply not enough uncommitted fringe generation in western Colorado and Wyoming, during the periods when PSCo can apply a price markup, to make the transmission constraints an issue. It appears that the transmission constraints would become important only if firms beyond the RMPA (in Arizona-New Mexico, or the Northwest Power Pool) attempted to compete with

PSCo in eastern Colorado. Whether firms would be motivated or capable of doing this is questionable. Certainly, if PSCo attempted to apply its maximum markup, and eastern Colorado generation prices were inordinately high, firms from other regions would want to sell their excess generation in eastern Colorado. However, there are other states on the western grid that already have higher energy prices, such as California. California also has a large head start on electric restructuring, relative to other states. It is conceivable that much of the western grid's excess generation could be already committed to customers in California by the time Colorado implements electric restructuring. The significant investment that would be required to increase the transmission capability of TOTs 3 and 5 appears risky in light of these uncertainties.

The entry of 1,000 MW of new fringe generation (Scenario 3) appears to have a limited, negative effect upon PSCo's ability to exercise market power. Over the period 2002-2005, the time of year over which PSCo could apply a price markup falls from in excess of 93% to in excess of 74%. The amount of the price markups that can be applied is similarly reduced. Furthermore, if some entry occurs, the threat of even more entry in the long run becomes more credible. In accordance with Baumol's (1982, 5) theory of contestable markets, the threat of competition could be a disciplining influence on PSCo's pricing strategy.

On the other hand, between 1990 and 1995 in the UK, the generation market share of the two largest firms declined from 74% to 54% because of entry by new firms and generation retirements. The two large firms continued to exert market power keeping prices well above marginal cost during this period (Wolak and Patrick 1997, 7). Given PSCo's large market share and the length of time required to construct new generation, it might take a very long time for entry to put much of a dent in PSCo's ability to exercise market power. Additionally, firms constructing new generation have the option of building in the market with the greatest profit potential. Whether firms would choose to build generation in eastern Colorado, where reserve margins are expected to remain above 15% through 2006 (WSCC 1997a, 38), instead of California or some other market with a greater population density, lower reserve margins, and already higher energy prices is a serious concern.

PSCo divestiture of 50% of its generation (Scenario 4) appears to offer the greatest reduction in the portion of the year markups can be applied, as well as the amount of the markups. PSCo can apply a markup over marginal cost 47% of the year or less during 2002-2005. The average markup is approximately one-eighth of the markup of the base case. Divestiture of generation, either voluntarily or mandated, might have appeared to be a pipe dream only a few years ago. However, it has become somewhat common as part of the implementation of restructuring plans. The Montana Power Company (MPC) recently announced that it would divest 100% of its generation as part of the state's electric restructuring. The three largest California utilities agreed to divest 50% of their fossil generation as part of that state's electric restructuring. Some New England utilities are also divesting portions of their generation as part of state restructuring plans. Of course, to increase competition, the generation of the dominant firm cannot be divested entirely to another firm. The divestiture plan must somehow ensure that the divested generation becomes part of the competitive fringe.

When the outcome of each scenario is compared, the similarities and differences become obvious (table 1 and figure 11). There is almost no difference in the extent and duration of price markups that can be applied in the base case and when RMPA transmission constraints are relaxed. The entry of 1,000 MW of fringe generation reduces the extent and duration of markups. The divestiture of 50% of its generation appears to be most effective means to reduce PSCo's ability to apply a markup over marginal cost. PSCo can apply a markup over only a small portion of the year. The amount of markup is approximately one-eighth the base case.

Table 1. Summary of Data.

| | | 2002 | 2003 | 2004 | 2005 |
|---|---|---|---|---|---|
| **Scenario 1. Base Case** | | | | | |
| | PSCo's competitive market share | 87% | 87% | 85% | 85% |
| | PSCo's market share with price markup | 53% | 54% | 50% | 51% |
| | % of year PSCo can apply a price markup | 93% | 95% | 94% | 96% |
| Markup | $\lvert\varepsilon\rvert = 0.9$ | 53% | 55% | 50% | 53% |
| Markup | $\lvert\varepsilon\rvert = 0.7$ | 68% | 71% | 65% | 68% |
| Markup | $\lvert\varepsilon\rvert = 0.4$ | 120% | 125% | 113% | 119% |
| Markup | $\lvert\varepsilon\rvert = 0.1$ | 478% | 498% | 452% | 474% |
| **Scenario 2. Unconstrained RMPA transmission** | | | | | |
| | PSCo's competitive market share | 87% | 87% | 85% | 85% |
| | PSCo's market share with price markup | 53% | 54% | 50% | 51% |
| | % of year PSCo can apply a price markup | 93% | 95% | 94% | 91% |
| Markup | $\lvert\varepsilon\rvert = 0.9$ | 53% | 55% | 50% | 52% |
| Markup | $\lvert\varepsilon\rvert = 0.7$ | 68% | 71% | 65% | 67% |
| Markup | $\lvert\varepsilon\rvert = 0.4$ | 120% | 124% | 113% | 117% |
| Markup | $\lvert\varepsilon\rvert = 0.1$ | 478% | 498% | 452% | 468% |
| **Scenario 3. Entry of 1,000 MW generation** | | | | | |
| | PSCo's competitive market share | 88% | 87% | 85% | 85% |
| | PSCo's market share with price markup | 47% | 45% | 43% | 42% |
| | % of year PSCo can apply a price markup | 78% | 74% | 77% | 79% |
| Markup | $\lvert\varepsilon\rvert = 0.9$ | 31% | 35% | 27% | 28% |
| Markup | $\lvert\varepsilon\rvert = 0.7$ | 39% | 45% | 34% | 36% |
| Markup | $\lvert\varepsilon\rvert = 0.4$ | 69% | 79% | 60% | 63% |
| Markup | $\lvert\varepsilon\rvert = 0.1$ | 276% | 314% | 240% | 252% |
| **Scenario 4. 50% divestiture** | | | | | |
| | PSCo's competitive market share | 44% | 44% | 42% | 43% |
| | PSCo's market share with price markup | 33% | 30% | 29% | 29% |
| | % of year PSCo can apply a price markup | 37% | 47% | 44% | 45% |
| Markup | $\lvert\varepsilon\rvert = 0.9$ | 6% | 7% | 6% | 7% |
| Markup | $\lvert\varepsilon\rvert = 0.7$ | 8% | 10% | 8% | 9% |
| Markup | $\lvert\varepsilon\rvert = 0.4$ | 14% | 17% | 14% | 15% |
| Markup | $\lvert\varepsilon\rvert = 0.1$ | 56% | 67% | 56% | 61% |

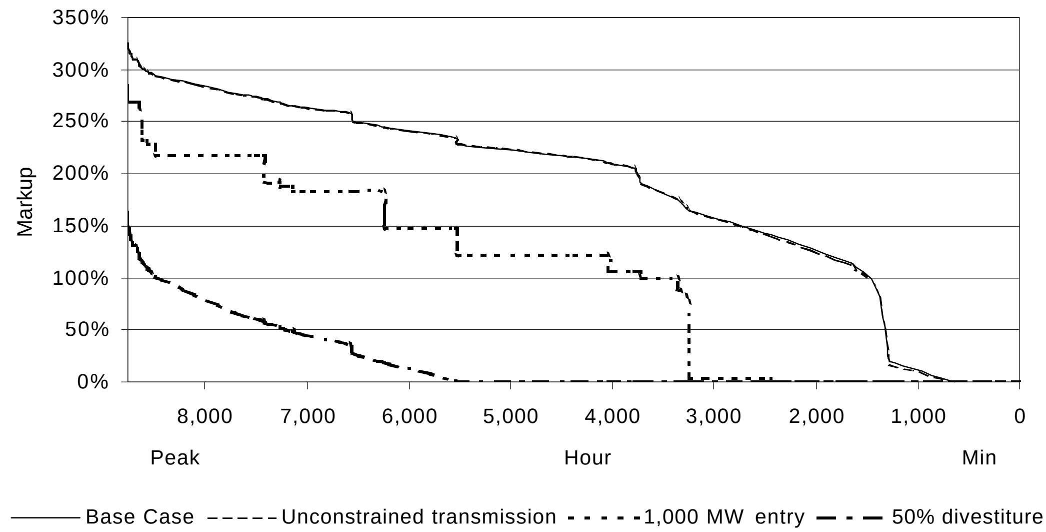


Figure 11. Comparison of markups PSCo can apply over marginal cost to various customer classes in 2002 in each scenario, elasticity = |0.4|.

## Policy Implications and Issues for Future Analysis

This study represents an initial effort at quantifying the effects of the market power of a dominant firm in a restructured electricity market. Although the analysis is tied to the specifics of Colorado's electricity market, its framework may have value to the other 31 states where one firm controls a significant portion of the state's generation. The economic paradigm of a dominant firm that acts as a "price maker," and a competitive fringe that are "price takers," would be suitable when one firm controls a large market share, and all other firms are so small that they can be considered part of the competitive fringe. If there are multiple firms, each with a large share of the market, a Cournot model may be more appropriate. The Cournot model is detailed in analyses by Newbery (1995), Borenstein and Bushnell (1997), Klemperer and Meyer (1989), and others.

What size market share must a dominant firm own to cause concern? There is no clear rule. As part of his screens for market power, Joskow (1995, 8) sets a threshold market share of

35% for the dominant firm. However, in generation markets, defining the relevant market as a basis to estimate market share is not an easy task. One could begin by analyzing the transmission network relevant to a particular area. If transmission into a particular area is frequently constrained, one could then analyze the market shares of firms within that particular geographic area, together with the market shares of firms outside that area, that compete up to the level of transmission constraints. During periods where transmission paths aren't constrained, it may be more germane to consider the entry capability of firms over a wider geographic area. For all fringe firms, capacity by itself might not necessarily be important. Instead, it might be more appropriate to consider the excess capacity firms own, once their native load is served.

In the case of Colorado, the analysis was simplified by the fact that eastern Colorado, which would comprise most of Colorado's restructured electricity market, sits at the eastern edge of the Western Interconnect. The only two paths into this region are from western Colorado and Wyoming and these are frequently constrained. Beyond western Colorado and Wyoming, little power flows from the rest of the WSCC into eastern Colorado. The role of the Northwest Power Pool and Arizona-New Mexico regions could, therefore, be assumed to be very limited. The declining reserve margins in these regions reinforce this assumption. Transmission analysis becomes much more complicated as the number of transmission paths increase.

The more important conclusion that can be drawn from this analysis is that there is no guarantee that electric restructuring would force prices to marginal cost in a state with a dominant firm. This outcome, in itself, is significant for any *ex ante* calculation of the benefits of electric restructuring or stranded costs. Estimates of electric restructuring benefits or stranded costs should incorporate a sensitivity analysis that portrays a range of markups over marginal cost.

Furthermore, states developing electric restructuring plans where one firm controls a large share of the market might want to carefully consider how to mitigate the firm's market power. Policy makers should consider measures that ensure fairness in the marketplace, reduce the dominant firm's market share, and increase the price elasticity of demand of consumers. It is probably not necessary to attempt to completely eliminate the dominant firm's market power. Policy makers instead may be comfortable with the assurance that competitive pricing will prevail "most" of the time (and these policy makers must determine what level of "most" they are comfortable with).

In terms of appropriate market structures to mitigate market power, there are numerous policy options, including Poolcos, Independent System Operators, transmission pricing schemes, and market aggregators. An adequate description of each of these options is beyond the scope of this analysis. Policy makers might choose to develop state restructuring plans that employ these measures singly or in combination to mitigate market power.

Reducing the dominant firm's market share would be implemented most easily if the company simply voluntarily agreed to divest a portion of its generation in return for the opportunity to compete for unregulated profits or for favorable consideration of its estimate of stranded costs. If a voluntary agreement between the state and the firm cannot be reached, the task of reducing the dominant firm's market share is much more difficult. The restructuring plan could include measures to make it easier for new generation firms to enter the market, but these measures may conflict with the need to hold entrants to high standards that promote reliability. Power marketers can also play a role in increasing competition by buying excess power anywhere on the grid and reselling it. The restructuring plan may include provisions for how power marketers enter the market and what standards, if any, they are held to. While increasing transmission capacity is another option, the time, capital investment, and uncertainty associated with the availability of excess generation elsewhere on the grid may make this option a risky proposition.

Measures to increase elasticity of demand are touted by economists as an effective means of mitigating market power, but their acceptance by customers, particularly small customers, has not been demonstrated. Relatively few loads in a regulated environment are interruptible. It was only during the oil shocks of the 1970s that small customers made any large-scale efforts at conservation of electricity, or substitution to alternatives, such as solar energy. Real-time metering and pricing of electricity has already been incorporated in some state restructuring plans. The implicit assumption of real-time pricing is that if customers see how their electric rates vary with overall demand, they may be more inclined to reduce consumption during peak periods.

As stated earlier, this analysis represents only an initial effort at quantifying a dominant firm’s market power. The analysis has already admitted its shortcomings in the way the shape of the load curve is assumed to be the same for the entire RMPA, when this is clearly not true. There are other ways the analysis can be refined and improved.

A new version of Elfin currently being beta-tested enables the modeling of up to ten markets simultaneously. The six control areas of the RMPA could then be modeled, each with its own load curve and resident generation. The Northwest Power Pool, Arizona-New Mexico, and Eastern Interconnect, via the DC ties, could be modeled as separate markets. This might result in a simulation that has higher fidelity to reality.

The modeling of other scenarios might also reveal additional insights. A complex, and dynamic problem might be to model how the dominant firm can withhold a certain quantity of generation from a restructured market, driving up price and encouraging entry by the competitive fringe, while the dominant firm exports its excess generation to other restructured markets. This analysis would require a detailed study of the available transmission capacity over which power would move to these distant markets.

Additional scenarios will be appropriate for analysis as state policy makers develop specific market structures. For instance, would a restructured state market be part of a larger, regional Independent System Operator? Would the market include long-term bi-lateral contracts as well as a short-term commodity market (Poolco)? What are the pricing effects of social benefits charges and stranded cost recovery? Each of these issues will require the development of additional scenarios for analysis. These issues could keep consultants and academics employed for many years.

A final concern relates to the availability of data to do modeling of this nature. Performing a study such as this requires a tremendous amount of detailed data on generation, demand, and transmission capacity. While there are undoubtedly data errors in the model regarding the costs and characteristics of individual plants, in general, these values could be verified through several different sources. A significant concern is that, as electric restructuring progresses, it will become increasingly difficult to obtain this data. The ability of policy makers to do this type of analysis in the future could be severely compromised. Maintaining the ability of policy makers to conduct analyses in the public's interest while protecting the confidentiality of firms will be a serious issue as restructuring progresses.

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