THE GEOGRAPHIC EXPANSE OF THE MARKET FOR WHOLESALE ELECTRICITY

Elizabeth M. Bailey*
Massachusetts Institute of Technology

ABSTRACT

This paper develops new techniques to assess the expanse of the geographic market under varying supply and demand conditions and applies these techniques to the current wholesale electricity market in the western United States. This paper finds that, by and large, the expanse of the geographic market extends across most of the western United States, but that conditions which create congestion along transmission lines, such as high hydroelectric flows in the Pacific Northwest, transmission line outages and deratings, and high demand for wholesale electricity, cause the expanse of the geographic market to narrow at certain times.

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1. Introduction

Spatial price relationships have been used widely in the literature as a means to infer the geographic expanse of the market, and more generally, market performance. A large number of goods have been the subject of previous studies of the geographic expanse of the market. For example, Horowitz (1981) examined the geographic expanse of the market for meat products sold for consumption in the eastern United States. Elzinga and Hogarty (1973) considered the geographic extent of the market for beer. Several markets including those for wholesale flour, wholesale unleaded gasoline, and residual fuel oil captured the attention of Stigler and Sherwin (1985) in their approach to estimating the geographic expanse of the market. Both Spiller and Huang (1986) and Spiller and Wood (1988) examined the geographic expanse of the market for wholesale gasoline in the northeastern United States. The geographic expanse of the market for agricultural products is especially well represented in the literature including studies of the market for California tomatoes, Canadian hogs, California and Florida celery, Nigerian food grain products, and rice in Bangladesh.[1]

Although each study examines the geographic expanse of the market for a different good using slightly different empirical methods, all these empirical approaches share several common features. First, transportation costs as well as all other characteristics of the good are treated as fixed over the time period of the data. Second, changes in the direction of flow of trade are usually ignored in the analysis, so that the expanse of the market is considered to be the same whether the good flows from region A to region B or whether the good flows from region B to region A. Third, the expanse of the market is treated as a pair-wise relationship (region A and region B are treated independently of any third region C), that is to say, any network characteristics of the good are ignored in the analysis. Fourth, with the exception of Spiller-Huang and Spiller-Wood, the empirical methodologies used do not provide results which shed light on how frequently the regions are in the same geographic market and how frequently the regions are not in the same geographic market. Moreover, none of the methodologies distinguish between the two very different reasons that a region could be "out of the market": economical reasons could keep a region "out of the market" (i.e. autarky) as well as inefficiency reasons (i.e. congestion). Taken together, these features of the methodologies provide only a very static description of the geographic expanse of the market.

The spatial dispersion of prices, however, is rarely static. First, transportation costs, as well as other characteristics of the good, change over time, and, as a result, the geographic expanse of the market changes over time as well. Second, the direction of flow of trade may change over time in response to changing marginal costs of production. As a result, the geographic expanse of the market may look very different when the good flows in a north to south direction than when the good flows in a south to north direction. Third, if trade occurs on a network, constraints to trade along one path will have implications for the expanse of the market elsewhere in the network. For these reasons, spatial price dispersion changes over time, and as a result, it is unlikely that the geographic expanse of the market for a particular good can be characterized once and for all as a single specific size. Rather, the geographic expanse of the market for a particular good is more appropriately though of as "wide" under some conditions, "narrow" under other conditions because trade between regions is not economical, and finally, in still other conditions, "narrow"

[1] Durham et. al. (1996), Faminow and Benson (1990) , Sexton et. al (1991), Delgado (1986), , and Ravallion

because congestion prevents economical trade from occurring. In sum, the geographic expanse of a market for a particular good is dynamic.

The wholesale[2] electricity market in the western United States is particularly well suited to a study of the dynamics of spatial price dispersion and, more particularly, how the geographic expanse of the market changes over time. First, electricity is a non-storable good. Second, the market must equilibrate instantaneously. Third, wholesale electricity trade occurs on large network of high voltage transmission lines that link the many regions together. As a result, shocks to supply and demand in one region are likely to have noticeable effects on wholesale prices in other regions. Finally, wholesale energy trade between vertically integrated utilities in the western U.S. has grown over time and has become increasingly more sophisticated. Initially, wholesale energy trade typically involved transactions between two physically interconnected utilities that utilized their own transmission capacity to consummate bilateral transactions. Until 1992, utilities were not obligated to supply "unbundled" transmission or wheeling service to others to support wholesale transactions, although some utilities provided such service voluntarily. When unbundled transmission service was not available, transactions involving trade over larger geographic areas often involved a series of "buy/sell" transactions involving three or more utilities. Over the last decade, unbundled transmission service, especially for short term transactions (daily and hourly) has become increasingly available in the western US as a result of voluntary multilateral agreements, requirements imposed on vertically integrated utilities by the Federal Energy Regulatory Commission (FERC) to file open access transmission tariffs as a

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(1986) respectively.

[2] Wholesale electricity transactions are purchases and sales of electricity by electric utilities to each other. Retail electricity transactions are sales to end-use residential, commercial, and industrial customers.

condition for approval of merger applications and application to sell wholesale electricity at market based rates, and most recently through the obligations created by FERC Order 888 (effective January 1 1997) which require all vertically integrated utilities to file open access transmission tariffs that meet certain criteria specified by FERC under authority provided by the Energy Policy Act of 1992. The availability of unbundled transmission service has increased opportunities for bilateral energy trade among utilities within the same region, but which are not necessarily directly interconnected. As a result, a study of the dynamics of spatial price dispersion can shed light on how well integrated the wholesale electricity market in the western US has become as a result of increased opportunities for bilateral energy trade.

A study of the dynamics of spatial price dispersion in the current wholesale electricity market can also go a long way toward informing the discussion of pricing behavior and performance in a restructured electricity industry. The United States electricity industry is presently being restructured in order to promote competition in the supply of generation services at wholesale and retail. [3] An important issue in restructuring the electricity industry is the significance of seller market power associated with the current ownership patterns of generation capacity.[4] One

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[3] On January 1st 1998, the three investor owned utilities in California will be restructured and retail customers will be permitted, for the first time, to buy power directly in the wholesale market or from competing brokers and marketers. Although the California restructuring project is by far the largest project to date, several other states have already instituted pilot programs which offer retail customers a choice of electricity suppliers. On August 1 1997, Rhode Island began offering large retail customers a choice of electricity suppliers. New Hampshire and Massachusetts have instituted pilot programs for smaller retail customers. The New Hampshire pilot program has been ongoing for about 12,000 customers since June 1996. Under the terms of the program, customers are free to purchase electricity from one of about 30 competitive power suppliers. The Massachusetts pilot program, "Choice: New England", began in July 1997. The Massachusetts program offers 4,727 residential and small business customers a choice of electricity suppliers.

[4] Wolfram (1995) finds some empirical evidence that generators exercise market power in the British electricity spot market. Joskow and Schmalensee (1983) find little support for the assumption that the generation market would be competitive at all times if the US electricity market were to be restructured. Borenstein and Bushnell

important input into a complete assessment of imperfect competition in a restructured electricity industry is the geographic expanse of the market for generation services. Because market conditions in the electricity industry are likely to change significantly in the next few years as the structure of the electricity sector changes dramatically, the present analysis can provide a useful benchmark against which to compare post-restructuring wholesale price relationships.

In this paper, three techniques are developed to assess how the geographic expanse of the market for wholesale electricity changes in response to shocks to supply and demand. The first technique identifies the particular supply and demand conditions that give rise to a "narrower" market. This paper finds that high hydroelectric flows in the Pacific Northwest, transmission line outages and deratings, and high demand for electricity are conditions likely to give rise to congestion along transmission lines. The second technique assesses whether transmission line congestion causes arbitrage constraints to become non-binding. This paper finds that transmission line congestion does cause arbitrage constraints to become non-binding. The third technique assesses how often arbitrage constraints do not bind, providing insight into how frequently the geographic expanse of the market narrows. This paper finds that between June 1995 and December 1996, arbitrage constraints bind prices in eighty percent of the daily observations, transmission congestion causes price separation in nineteen percent of the daily observations, and autarky prevails in the remaining one percent of the daily observations.

The remainder of the paper proceeds as follows: Section 2 introduces the market for pre-scheduled wholesale electricity in the western United States and illustrates the dynamic nature of

(1997) find empirical evidence that generators in the soon to be restructured California electricity industry will be the wholesale electricity market. Section 3 formalizes how the market for pre-scheduled wholesale electricity equilibrates. Section 4 describes the data. Section 5 presents the empirical investigation of how regional supply and demand conditions affect the arbitrage constraints between sub-regions of the western United States and cause the geographic market to widen or narrow. Section 6 provides conclusions.

2. Spatial Price Dispersion in the Western US Wholesale Electricity Market

The Western System Coordinating Council (WSCC), the electricity market that this paper focuses on, covers all of the contiguous US states west of the Rocky Mountains, two provinces in Western Canada (British Columbia and Alberta) and portions of Northern Mexico (See Figure 1). The electric power companies located in this large region operate as part of a single synchronized AC network, known as the Western Interconnection, whose physical operation and reliability is coordinated by the WSCC, a voluntary regional reliability council. It should not be of concern that the effect of electricity systems in locations east of the Rocky Mountains has essentially been ignored. It is not likely that supplies from the east and southeast could have a significant effect on prices in the WSCC since only small DC interconnections connect the WSCC with the Eastern Interconnection and the Texas Interconnection, the two other synchronized AC systems operating in the United States.

The WSCC region can be sub-divided into five smaller regions[5] - Northwest, Northern California, Southern California, Inland Southwest, and Central Rockies - which reflect the distinct

able to raise price above competitive levels.

[5] Northwest: Washington, Oregon, Idaho, and Montana. Northern California: The northern portion of the State above Midway, a juncture of transmission lines slightly north of Los Angeles. Southern California: The southern

geographic and climatic conditions in the WSCC.[6] By and large, the bulk of the electricity supplied to retail customers in the WSCC is supplied by vertically integrated electric utilities that serve retail loads in exclusive geographic areas using primarily own-generation, but because high voltage transmission link these five sub-regions together, utilities in the five regions are able to buy and sell electricity at wholesale under bilateral contracts that cover exchanges of energy for periods as short as an hour and as long as ten years. These wholesale electricity transactions allow vertically integrated utilities to trade on the margin with one another to reduce the utility's cost of meeting its own retail electricity demand. The majority of transactions for wholesale electricity in the WSCC are daily, pre-scheduled transactions.[7] Table 1 presents data from the WSCC on 1995[8] annual aggregate quantities of short-term imported (as opposed to self-generated) and exported electricity.

High voltage transmission lines link the five sub-regions of the WSCC together. Figure 2 illustrates the location and relative size, as measured by the maximum MW capacity of the

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portion of the State below Midway. Inland Southwest: Southern Nevada, Arizona, New Mexico, and Western Texas. Central Rockies: Northern Nevada, Utah and Colorado.

[6]Hydroelectric facilities constitute a significant part of the resources available to serve demand especially in the Pacific Northwest and Northern California. Electricity demand in the Pacific Northwest peaks in the chilly winter months, while Northern California electricity demand peaks during the warm summer months. Generating capacity in Southern California is predominantly nuclear and natural gas. Demand for electricity in Southern California peaks in the hot summer months. Coal-fired and nuclear are the largest contributors to generating capacity in the Inland Southwest. Like California, demand for electricity in the Inland Southwest peaks in the hot summer months. Generating capacity in the Central Rockies is predominantly coal-fired. Electricity demand peaks in the summer months as well. These five sub-regions correspond to the five major supply and demand areas in the WSCC. Electricity demand in these five regions is not perfectly correlated because of variations in weather conditions (temperature as well as precipitation) and time zone changes (the WSCC covers states located in the Pacific Time Zone as well as states located in the Mountain Time Zone).

[7] Pre-scheduled energy transactions are energy transactions that are scheduled a day-ahead of actual physical production.

[8] 1996 data are not available.

transmission line, of the major high voltage transmission lines in the WSCC. In the WSCC, there are competing transmission paths for most routes. For example, under most conditions, utilities can transport wholesale electricity from the Northwest into Southern California either by the DC Pacific Intertie, which directly connects the Northwest with Southern California, or by using a combination of the AC Pacific Intertie, which connects the Northwest with Northern California, plus the lines at Midway which connect Northern California to Southern California. Most transmission lines, including the three major lines (the AC Pacific Intertie, the DC Pacific Intertie, and the AC lines which connect Southern California with the Inland Southwest), are owned by several utilities each which has ownership shares of the line's transmission capacity. These entities own the transmission rights to the transmission line and have the right to use the capacity themselves or to sell the transmission rights to other utilities or third parties.

The capacity of a transmission line is limited. The maximum allowable rating of the line defines the maximum megawatts of electricity that the transmission line can transport and therefore the maximum amount of wholesale electricity trade that can occur between the sub-regions connected by that line. Figure 3a and 3b illustrate graphically the daily ratings of the southbound AC Pacific Intertie and of the southbound DC Pacific Intertie between June 23 1995 and May 9 1997. It is not uncommon for a transmission line's rating to be lowered below its maximum allowable rating, or "de-rated", on a one day basis either for planned or unplanned maintenance or because of an unexpected line outage. Moreover, it is not uncommon for the rating of a transmission line to remain below its maximum allowable rating for extended periods of time as long-term maintenance is performed or for reliability concerns. Figure 3a and 3b demonstrate that the rating of the AC line and the rating of the DC line are constantly in flux over this period. When the transmission line constraint binds, that is the demand for wholesale electricity trade exceeds the rating of the transmission line, the transmission line is said to be “congested”.

Figure 4a (4b) present the daily peak (off-peak)[9] period pre-scheduled wholesale prices in the five sub-regions of the WSCC from June 23 1995 to December 31 1996. Both Figure 4a and Figure 4b illustrate that wholesale electricity prices in the five sub-regions of the WSCC move more or less together, consistent with the hypothesis that the wholesale electricity market is a single market westward from the Rocky Mountains. Although the wholesale prices appear to move in tandem, Figure 4a and 4b also indicate that there is quite a bit of time of day (peak versus off-peak) and seasonal fluctuation in prices. These time of day and seasonal fluctuations in prices reflect changes in marginal costs due to available generation resources as well as changes in the quantity of electricity demanded by retail consumers. Figure 4a and 4b also illustrate an important attribute of electricity: electricity does not always flow in the same direction (e.g. from region A to region B). For example, in the WSCC during daytime hours in the Spring, wholesale energy typically flows from the Northwest into Northern and Southern California because of the abundant inexpensive hydroelectric resources available at that time in the Northwest ($P_{NW}>P_{NCA}$ and $P_{NW}>P_{SCA}$). In the late Fall and early winter though, utilities in California are more likely to be exporting electricity to the Northwest, especially at night when it is cold in the Northwest, in order to conserve scarce hydroelectric resources in the Northwest for use during peak hours

[9] Peak: daytime weekday hours (6:00am-9:59pm); Off-peak: nighttime hours (first six and last two hours of the day) and all hours on weekends and national holidays. Price for Saturday and Sunday are scheduled by control area operators as if they were the same day.

($P_{NW}<P_{NCA}$ and $P_{NW}<P_{SCA}$). Figure 5 presents examples of the geographic dispersion of wholesale electricity prices on typical days when electricity flows in different directions.

Although Figure 4a and Figure 4b illustrate that wholesale electricity prices in the five sub-regions of the WSCC move more or less together suggesting that the geographic market is quite wide much of the time, it is clear from Figure 4a and 4b that there are time when prices do not move together suggesting that under some conditions the geographic market may be much "narrower" than the entire expanse of the WSCC. For example, prices in the Northwest and the Inland Southwest seem to separate on September 7 1995.[10] Figure 6 highlights the wholesale electricity prices between September 6-8 1995 from Figure 4a. September 7 1995 was marked by unusually hot temperatures in the Inland Southwest. The high temperatures increased retail cooling loads and, as a result, increased demand for wholesale electricity imports in the Inland Southwest from the Northwest. The transmission lines into the Inland Southwest from the Northwest were filled to capacity and unable to accommodate the increased demand for wholesale electricity. As a result, utilities in the Inland Southwest were forced to rely on more expensive own generation resources causing the price for wholesale electricity to rise in the Inland Southwest. The demand

[10] In general, congestion causes the price difference between two regions to be greater than the regulated transmission price cap by only a few Mills. On occasion though, congestion can cause regional price differences to be well in excess of the regulated transmission price cap. For example, on August 5 1997, a day of record high retail electricity demand due to hot weather, a small plane clipped two 500 KV lines in Southern California Edison's system. The downed transmission lines created a cascade of unit outages in and around Southern California, and in addition, made it difficult, if not impossible, to import of power into Southern California. As a result, brown outs were reported all around the Los Angeles area. Prices for pre-scheduled power for August 7 1997 (scheduled on August 6 1997) rose by gargantuan amounts in all regions as Southern California and the Inland Southwest tried to cover loads by purchasing wholesale power from the Northwest and the Central Rockies. Prices in Southern California and the Inland Southwest peaked as high as 100Mills/KwH (up 55Mills/Kwh from the day before the disturbance) and 160Mills/Kwh (up 113Mills/Kwh from the day before the disturbance) respectively. Prices in the Northwest and Central Rockies were reported as high as 37Mills/Kwh (up 15.5Mills/Kwh from the day before the disturbance) and 60Mills/Kwh (up 31Mills/Kwh from the day before the disturbance).

shock had no effect on wholesale electricity prices in the Northwest because the transmission constraint prevented more energy from flowing from the Northwest into the Inland Southwest. As a result, wholesale electricity prices in the Northwest remain virtually unchanged. Because it was physically impossible for additional trade to occur between the Northwest and Inland Southwest even though it appears economical to engage in wholesale transactions, the Northwest and the Inland Southwest are properly conceptualized as a separate geographic market on September 7th. Just as quickly as pre-scheduled wholesale prices in the Inland Southwest rose sharply in response to the heat wave, pre-scheduled wholesale prices across the WSCC fell back to levels observed prior to the demand shock as the heat wave dissipated. The next section formalizes precisely how the pre-scheduled market for wholesale electricity equilibrates and in what sense the sub-regions of the WSCC are conceptualized as a "wide" or "narrow" geographic market.

3. Formalizing Wholesale Price Relationships

Although the nature of energy flows are complex, in general, electricity flows from low "autarky" price regions to high "autarky" price regions until the gains from trade are exhausted unless transmission constraints or local operating requirements prevent further economical trading opportunities. Assuming a competitive market for generation services[11] and transmission service[12]

[11] The current wholesale electricity market in the WSCC is relatively competitive. First, there are a large number of generation suppliers at all locations around the network. Under normal, uncongested periods, wholesale electricity customers can to turn to generation suppliers dispersed over a wide geographic area purchasing or selling electricity either within their control area, in directly connected control areas, or in more remote control areas. When congestion constrains the geographic expanse of the market, wholesale electricity customers are still able to turn to a large number of generation suppliers located within their control areas, including self generation. Second, the ability of sellers to raise price above competitive levels is constrained by the fact that most of the buyers of wholesale electricity are vertically integrated utilities which own their own generating capacity, and therefore have the opportunity to generate electricity themselves. Finally, sellers have little incentive to restrict

and no congestion on the transmission line connecting region A and region B, Figure 7a demonstrates graphically how the market for wholesale electricity equilibrates. Suppose the demand for retail electricity in region A and region B are Q_A and Q_B respectively. Without wholesale electricity trade, the marginal cost to generate Q_A units of electricity to fill retail demand in region A is $MC_{A,autarky}$ and the marginal cost to generate Q_B units of electricity to fill retail demand in region B is $MC_{B,autarky}$. Suppose it is the case that region A's "autarkic" marginal cost is greater than region B's "autarkic" marginal cost ($MC_{A,autarky} > MC_{B,autarky}$). If the difference between the "autarkic" wholesale electricity prices is less than the competitive price of transmission service from region B to region A, wholesale electricity trade is not economical and utilities fulfill their own retail electricity demand using only their own generation resources. Suppose, though, the difference in autarkic prices between the two regions is greater than the competitive price for transmission service to transport electricity from region B to region A. In this case, engaging in wholesale trade reduces the cost of meeting retail electricity demand in each region. When there is no congestion, utilities in each region engage in trade (of the amount X) until the gains from trade are exhausted region (region A gains area Π_A and region B gains area Π_B). The difference in the prevailing prices for wholesale electricity is the competitive price for

output in order to raise price because they can only make a profit by expanding output beyond what is required to supply their retail customers at regulated prices.

[12]The market for transmission rights in the WSCC is quite competitive. Most transmission lines, including the two major lines are owned by several utilities each which has ownership shares of the line's transmission capacity and can either use the line themselves or sell the rights to use the line to other utilities or third parties. In addition, there are competing transmission paths for most routes.

transmission service: P_A - P_B = T_{BA}.[13] In this case, the geographic expanse of the market for wholesale electricity encompasses both region A and region B.

Suppose the transmission line between region A and region B is not fully utilized at the equilibrium P_A and P_B. If there is an increase in demand for retail electricity in region A, the autarkic marginal cost in region A rises. Wholesale electricity imports from region B to region A increase to give a new equilibrium, P'_A, P'_B, and X' (see Figure 7b). If the marginal cost of transmission service is constant[14], then equilibrium wholesale prices in region A and region B increase by the same amount, P'_A - P'_B = T_{BA}. The price in region B responds to the demand shock in region A and the geographic expanse of the market for wholesale electricity continues to encompass both region A and region B.[15]

Now suppose at the equilibrium P_A, P_B, and X, the transmission line between region A and region B is just fully utilized. In this case, a demand shock in region A which increases prices in region A

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[13]This case corresponds to the framework which Schweppe et al (1988) have in mind in their proposition that the short run marginal costs of generating electricity at each node on the network are efficient locational spot prices, and the difference in the locational spot prices at any two nodes on the network is, subject to capacity constraints, the marginal cost of transmission between those two nodes.

[14]In the WSCC, a constant marginal cost of transmission service is a reasonable assumption because reliability, rather than thermal constraints, limit transfers along the major transmission paths in the WSCC. For this reason, the marginal cost of transmission service is relatively flat up to the rated limit.

[15]The analysis of the geographic expanse of the market becomes more complicated if the marginal cost of transmission service is upward sloping. If the marginal cost of transmission service is upward sloping, some of the price increase in region A will be due to an increase in the competitive price for transmission service and the rest will be due to an increase in the price for wholesale electricity in region B: P''_A - P''_B = T'_{BA}. The difference in the wholesale prices between the two regions will increase to reflect the increase in transmission prices (T'_{BA}> T_{BA}). Prices between the two regions will appear to be less closely related even though the geographic expanse of the market for wholesale electricity continues to encompasses both region A and region B in the sense that a demand shock in region A causes a price response in region B. This paper controls for the possibility that transaction costs may be different under different conditions by assessing price relationships separately under various sets of supply and demand conditions.

will have no effect on wholesale electricity prices in region B because the transmission constraint prevents more energy from flowing from region B into region A (Figure 7c).[16] The competitive price for transmission service, T_{BA}, will rise in order to allocate the scarce transmission capacity. The price for transmission service is in fact regulated by a price cap set by FERC. The maximum price a utility can charge for transmission service is defined by the average embedded cost of the utility's network.[17] As a result, when there is congestion, the price for transmission service can rise only as high as the regulated price cap. In the case of transmission congestion, each region is properly conceptualized as a separate geographic market.

4. The Data

Daily transaction price data for pre-scheduled, non-firm[18], wholesale energy traded during "peak" and "off-peak" periods in the five sub-regions of the WSCC for the period covering June 1995 to December 1996 form the basis of the empirical analysis. These data have been provided by Economic Insights, Inc., a firm which continuously surveys electricity market transactions in the WSCC and makes the information available (for a fee) to utilities and intermediaries engaged in energy trade in the WSCC. During the course of the day, the Economic Insights staff contacts by phone a subset of the over fifty different utilities, marketers, and power brokers that have agreed to exchange information with the staff. In the average week each source is contacted two or three

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[16] The price in region B cannot rise because generation services in region B are competitive.

[17] Averaging across all utilities in the WSCC, the regulated price cap for hourly, non-firm, point to point transmission service is 3.69Mills/Kwh with a standard deviation of 1.6Mills/Kwh. The lowest price cap set by FERC is 1.33Mills/Kwh (Idaho Power Company). The highest price cap set by FERC is 7.1Mills/Kwh (San Diego Gas and Electric).

[18] Firm service refers to non-interruptible service. Non-Firm service refers to service which may be interrupted.

times. To assure correct information has been relayed, the staff seeks confirmation from at least two sources before including the data in the survey. Specific transactions involving names of the parties involved, quantities, and prices are confidential. Prices reported by Economic Insights are transacted prices (as opposed to bid or offer prices), including the price of transmission when appropriate, as reported by the participants contacted that day for non-firm, pre-scheduled power. Prices for each sub-region[19] are broken into two categories: peak energy and off-peak energy. For each category two prices are reported: the high and the low.

The Economic Insights data have been transformed for the purposes of this paper. In this paper, a single day of price information consists of two price observations (peak and off-peak) for each of the five sub-regions. Whereas the Economic Insights data report a high and a low price for each sub-region in each period, this paper simply takes an average of the high and the low price to arrive at an average transaction price for each sub-region in each period. For example, if Economic Insights reports that in the peak period in the Northwest the low price was 10 Mills/Kwh and the high price was 13 Mills/Kwh, this paper would report the transaction price in the Northwest in the peak period to be 11.5 Mills/Kwh.

The data used for this paper cover the period June 23rd 1995 to December 31st 1996. Over this period, there are 474 days with price observations for the five sub-regions in the WSCC. Each non-holiday weekday has two observations for each sub-region: one peak and one off-peak. Each weekend and holiday weekday has two observations for each sub-region: two off-peak. In

[19] The wholesale prices reported by Economic Insights Inc. for each sub-region are in fact an average price throughout that entire sub-region. In practice the price of wholesale electricity varies even within each of the five sub-regions.

total, each sub-region has 948 price observations: 379 peak period observations and 569 off-peak period observations.

Supplemental data on daily supply and demand conditions thorough the WSCC are used to augment the price data. Information is available on daily maximum allowable capacities of transmission lines, unexpected transmission line outages, reports of transmission line congestion and congestion on the network, generating plant outages (unplanned, planned repairs, and economic outages), natural gas prices, contract coal prices, water flows at key locations in the Northwest, realized daily peak and off-peak demand for retail electricity. In addition, daily readings of maximum and minimum temperature, precipitation, and snow depth as well as 30 year norms for temperature, precipitation and snow depth are available for major cities across the WSCC.

For the bulk of the day ahead energy transactions that are analyzed there are no observable prices for transmission service that can be matched directly with the prices paid for energy. The empirical techniques developed below estimate the implicit price for transmission service. The regulated price cap for transmission service is used to check the accuracy of the estimation. Estimated prices for transmission service between two regions should not exceed the value of the regulated price cap if arbitrage constraints bind the two regions together. When there is congestion on the transmission line connecting two regions, the estimated difference in regional wholesale prices in these two regions should exceed the regulated price cap for transmission service.

5. Empirical Examination of the Expanse of the Market

A. The Effect of Regional Supply and Demand Conditions On Price Correlations

If two or more regions are bound together by arbitrage constraints, prices in the two regions should move together quite closely: Shocks to supply or demand in one region should be transmitted to all other integrated regions. If two or more regions are not bound together by arbitrage constraints, either autarky or congestion prevails, prices in the two regions will be less tightly related. In general, shocks to supply or demand which increase congestion on the network decrease the extent to which arbitrage constraints bind and therefore narrow the geographic expanse of the market. The effect that these shocks have on the extent to which arbitrage constraints bind and therefore the expanse of the geographic market should be reflected in the magnitude of the price correlations.

A methodology is developed in the spirit of the Stigler-Sherwin (1985) approach to explore how prevailing supply and demand conditions influence the expanse of the geographic market. Price correlations are generated from several categories of price observations and are regressed on the variables (X_k, k=1,2...K) which were used to divide the price data into the categories plus a set of dummy variables ($PAIR_n$, n=1,2...N) used to control for the particular market pair. The dependent variable is the price correlation for market pair n (e.g. Northwest and Northern California) for a particular set of price observations taken during times with factors $\{X_1=x_1, X_2=x_2, \ldots X_K=x_k\}$ present. The equation to be estimated takes the form:

$$\rho_i = \sum_{n=1}^{N} \alpha_n PAIR_{i,n} + \sum_{k=1}^{K} \beta_k X_{i,k} + \varepsilon_i$$

where ρ_i is the price correlation for observation i, $PAIR_{i,n}=1$ if the correlation is from market pair n and 0 otherwise and $X_{i,k}=1$ if the price correlation is generated from the set of price data observed in a period characterized by X_k being present and 0 otherwise. The coefficient on PAIR should be positive and larger for price correlations from regions which are closer together relative to regions which are further apart since regions closer together are likely to have lower transaction costs and therefore are more likely to be bound by arbitrage constraints. Price correlations generated from prices observed in times with factors which increase congestion present should be lower than price correlations generated from prices observed in times without congestion factors present. Consequently, the coefficient on X_k is expected to be negative if X_k increases congestion.

The standard Stigler-Sherwin test of market expanse needs to be carefully interpreted because price correlations fail to account for common supply and demand shocks that may lead prices to move together even when there are no arbitrage opportunities between the regions where the prices are observed.[20] The approach developed in this Section is not fraught with that difficulty. Factors that may lead prices in different regions to move together, for example, common inputs to generating units such as coal and natural gas, are common to all categories. The technique developed in this Section relies on the change in the level of the price correlation not the level of

[20] For example, two or more regions may exhibit high price correlations even when transmission lines connecting the regions are severed (clearly a case of market separation) if generating units across the regions rely on common

the price correlation to interpret how different supply and demand conditions affect the expanse of the geographic market.[21]

To apply this technique, I divide the set of 948 price observations into mutually exclusive and exhaustive categories based on several variables.[22] The variables are: Season (SPRING, SUMMER, FALL, WINTER), time of day (PEAK), reports that transmission lines from the Northwest in Northern California (NWNCAF) or from the Northwest in Southern California (NWSCAF) are full, a low transmission line rating on the Pacific Intertie (DERATING)[23], and a high hydroelectric flow at the Chief Joseph Dam in the Pacific Northwest (CJDAMH)[24]. For example, one category is the set of prices such that it was Spring (SPRING=1), transmission lines from the Northwest into Northern California were not full (NWNCAF=0) but lines into Southern California were full (NWSCAF=1), the rating of the Pacific Intertie was low (DERATING=1),

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inputs factors such as coal and natural gas. Changes in the common input prices would affect all regions similarly yielding a false positive result of market integration.

[21]The typical fix to correct for the effect of common supply or demand factors is to run price correlations for first or longer price differences. This technique was not used due to the nature of the price data: peak and off-peak observations are not necessarily consecutive. Price data from a non-holiday weekday consist of one peak and one off-peak observation. Price data from a weekend consist of two off-peak observations. The interruption of the non-holiday weekday with a holiday weekday (two off-peak price observations) further complicates the matter.

[22] Using too many variables to partition the data is problematic. In the limit, each category would have only one observation in it, too few to compute a price correlation.

[23] During the period that the data covers, June 23rd 1995 - December 31st 1996, the maximum allowable rating of the combined Pacific Intertie (AC line plus DC line) was 7900 megawatts (MW). This rating fluctuated over the time period from 7900MW to 2000MW. A low rating on the Pacific Intertie is designated to be a rating below 6000MW. The results in Table 3 are invariant to small changes around this cut-off.

[24] During the period that the data covers, June 23rd 1995 - December 31st 1996, hydroelectric flows along the Columbia river fluctuated between 43.7kcfs and 197.1kcfs. A high river flow is designated to be a flow above 150.0kcfs. The results in Table 3 are invariant to small changes around this cut-off.

and hydroelectric flows along the Columbia river were high (CJDAMH=1). These variables generate a total of 128[25] mutually exclusive and exhaustive categories.

Each of these variables can be associated with transmission line congestion and therefore can have an effect on the expanse of the geographic market for wholesale electricity in the WSCC. First, since the Spring season is typically a time of high demand by Southern California and the Inland Southwest utilities for the cheap hydroelectric energy generated in the Pacific Northwest, demand for transmission capacity in the North to South direction is also high. As a result congestion tends to arise in a North to South direction during the Spring months. Second, peak periods are generally a time of high wholesale electricity demand and therefore high demand for transmission. As a result, congestion tends to arise in peak periods. Third, explicit reports that transmission lines are full suggests that transmission lines are likely to be congested. Fourth, when transmission line ratings are below their standard rated capacity, the line can carry less electricity between geographic regions. Consequently, transmission line congestion is more likely to arise. Fifth, when hydroelectric flows along the Columbia River in the Northwest are high, transmission lines from the Northwest region sometimes become congested in a southbound direction because the limited capacity of the transmission lines cannot accommodate all of the demand for the cheap hydroelectric power located in the Northwest.[26]

Price correlations are generated for each of the 128 categories of price observations. Eliminating the diagonal price correlations (those which equal one invariantly, i.e. the correlation between the

[25] 128=4*2*2*2*2*2 (4 seasons times 2 states for each of the other 5 categories).

Northwest and the Northwest), each category generates 10 price correlations. Price correlations generated from observations in categories with less than 2 observations -- 88 categories, of which 86 contained zero observations -- were eliminated. A total of 400[27] price correlations remain.

The equation estimated by Ordinary Least Squares is:

$$\rho_i = \sum_{n=1}^{10} \alpha_n PAIR_{i,n} + \beta_1 PEAK_i + \beta_2 SPRING_i + \beta_3 SUMMER_i + \beta_4 WINTER_i + \beta_5 NWNCAF_i$$
$$+ \beta_6 NWSCAF_i + \beta_7 DERATING_i + \beta_8 CJDAMH_i + \varepsilon_i$$

where ρ_i is the price correlation for observation i, $PAIR_{i,n}=1$ if the price correlation is for market pair n, PEAK=1 if the price correlation is generated from peak period price observations, SPRING=1 if the price correlation is generated from spring price observations, SUMMER=1 if the price correlation is generated from summer price observations, WINTER=1 if the price correlation is generated from winter price observations, NWNCAF=1 the price correlation is generated from price observations taken during a time when the line connecting the Northwest to Northern California was reported full, NWSCAF=1 if the price correlation is generated from price observations taken during a time when the line connecting the Northwest to Southern California was reported full, DERATING=1 if the price correlation comes from price observations taken during a period when the cumulative rating of the southbound Pacific Intertie was low, and CJDAMH=1 if the price correlation is generated from price observations taken from a period when the flows at the Chief Joseph dam were high.

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[26] The correlation between "spring" and "high hydroelectric flows" is 0.26.

Table 2 presents the parameter estimates from the regression. Because heteroscedasticity is introduced when the correlation coefficients are formed from different numbers of price observations, White corrected standard errors are reported. The price correlations for the ten market pairs under normal, uncongested conditions are relatively high, ranging from .76 for the Northwest-Southwest market pair to .94 for the Northern California-Southern California market pair. All market pair correlations under “normal”, uncongested times are statistically distinguishable from zero at the 1% level. Price correlations are higher for regions nearer in distance and lower for regions further apart, consistent with the hypothesis that regions which are nearer in distance are bound by arbitrage constraints more often (because transmission costs are lower) than regions which are located further apart. In addition, parameter estimates are consistent with the hypothesis that regional supply and demand factors which increase the level of congestion on the network decrease the extent to which the five regions in the WSCC are integrated. First, price correlations are lower in the Spring months, consistent with the hypothesis that regions are less tightly linked during the spring flush. As expected, price correlations are lower during peak periods, consistent with the hypothesis that utilization of the transmission grid affects the extent to which regions are integrated. All variables which explicitly indicate congestion on the network have the correct sign, though only one, congestion along the transmission line from the Northwest into the Southwest, is statistically significant. A low capacity rating on the southbound Pacific Intertie lowers price correlations as expected and is statistically significant. Finally, high water flows in the Northwest decrease price correlations, though the coefficient is not precisely estimated.

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[27] 128*10-88*10=400

These results suggest that under normal, uncongested periods, prices in the five sub-regions in the WSCC are closely related, but that regional supply and demand conditions which give rise to congestion on the network cause prices to be less closely linked to one another. This latter result should be interpreted as implying that the relevant geographic market is more likely to narrow when these supply and demand conditions prevail. As with the standard price correlation test for the geographic expanse of the market, this methodology does not provide concrete guidance for which levels of price correlations are high enough to definitively consider a set of regions integrated. The next section provides a more precise method to assess the expanse of the geographic market by examining the effect of congestion on arbitrage constraints.

B. The Effect of Congestion on Arbitrage Constraints

In this Section, an empirical method is developed which assesses whether arbitrage constraints are binding and how transmission line congestion affects these arbitrage constraints. The interpretation of this technique is straightforward. If arbitrage constraints bind the wholesale prices in two regions together, the two regions are said to be in the same market. If arbitrage constraints do not bind the wholesale prices in the two regions together, the regions are said to be in different markets. The larger number of regions whose prices are all bound together by binding arbitrage constraints, the wider the expanse of the geographic market.

This approach estimates a variation of an arbitrage equation: $P_A = \beta_0 + \beta_1 P_B + \varepsilon$, where the flow of trade is from region B to region A and P_A and P_B are the prices in region A and B respectively. While the approach is similar in spirit to Horowitz (1981), this method incorporates known physical constraints to trades, changes in the transportation cost due to seasonal variation, losses during transportation, and attention to the direction of flow of trade thereby extending the Horowitz methodology.

A further extension of Horowitz and subsequent literature based on this technique is to recognize the contemporaneous correlation of disturbances across regions in a network. In the WSCC, disturbances in the arbitrage equations include factors that are common to all of the regions, such as FERC announcements about merger approvals or denials as well as changes in the skills and technologies available to the regional electricity control operators. In addition, there are likely other omitted variables, such as unplanned generation plant outages and unplanned transmission line outages, that are common to all regions which cause the disturbances across equations to be correlated. Given the correlation of disturbances among regions in a network, the arbitrage equations are estimated jointly by seemingly unrelated regression (SUR) techniques.[28]

Another natural extension would seem to be to instrument for the price in region B since P_B and ε should be correlated: A positive shock to the price in region A should increases the demand for electricity purchased from region B thus raising the price in region B. This relationship though is exactly what a binding arbitrage equation implies and therefore what the arbitrage equation is testing: that shocks to one region are fully incorporated into the prices in the other

[28]Horowitz (1981) and variations on this approach in the literature use OLS to examine price relationships between pairs of prices.

region. For this reason, there are no instruments available if the arbitrage equation binds. Every factor correlated with P_B is also correlated with ε.[29]

The form of the arbitrage constraint for each market pair in a particular flow pattern (i.e. electricity flows from region 1 into region 2 and from region 1 into region 3) is:

$$P_A = \beta_0 + \beta_1 PEAK + \beta_2 P_B + \sum_{j=1}^{J} \gamma_j CONGESTION_j + \varepsilon$$

where regions A and B compose the market pair (region A is the buyer, region B is the seller), the dependent variable, P_A, is the price on date t in region A, PEAK =1 if the observation comes from a peak period, P_B is the price on date t in region B, and $CONGESTION_j$=1 if there is a report of congestion on transmission line j on date t. Each flow pattern yields an M equation SUR model, where M is the number of market pairs in the flow pattern. Each m=1,2...M arbitrage equation to be estimated for a particular flow pattern has N observations. Stacking the M arbitrage equations gives a total of M*N observations used to estimate the system.

Expectations of the parameter estimates are straightforward. Electricity, like other goods which are transported for trade, experiences some degree of loss during transportation. For high voltage transfer of electricity, these "line losses" are typically 5% of electricity purchased. Assuming an 5% line loss, this means for every one MW of electricity that region A purchases from region B

[29]If P_B and ε are positively correlated, which they will be if the price for transmission service is a constant and arbitrage constraints bind, then parameter estimates from OLS (and SUR) are biased toward zero. Later sections

only .95 MW arrive in region A. Therefore, for region A to receive 1 MW of electricity from region B it must purchase 1.053 (100/95) MW of electricity from region B. Consequently, if arbitrage constraints are binding between region A and region B, $\hat{\beta}_2$ is expected to be greater than 1 and about 1.053 assuming a line loss of 5%. Because line losses increase as the transmission distance increases, regions located closer together are expected to have a slightly lower coefficient on $\hat{\beta}_2$ while regions located further apart are expected to have a coefficient slightly greater than 1.053. If autarky prevails between the two regions, no relation is expected between the two prices and therefore $\hat{\beta}_2 = 0$ is expected.

If arbitrage constraints are binding, $\hat{\beta}_0 = T > 0$ is expected, where T is the transmission price in an off-peak period. The price of transmission service should increase in high electricity demand periods (the peak period) compared to low electricity demand periods (the off-peak period) *ceteris paribus*. As a result, PEAK should enter positively. The price of transmission should increase as the distance between region A and region B increases. Looking across market pairs, it is expected that transportation costs in both peak and off-peak periods are smaller for regions located closer together than for regions located further apart. Since the transmission price for wholesale electricity is regulated by FERC, it is expected that both $\hat{\beta}_0$ and $\hat{\beta}_0 + \hat{\beta}_1$ are no greater than the regulated price cap on transmission service.

Congestion is expected to enter positively when the congestion is on the line directly connecting the two regions in the market pair because congestion increases the marginal cost of transmission

find some evidence toward this end. Estimates of the mean price for transmission service in the next Section are along that line. Because the cap on the price of transmission set by FERC prevents the price of transmission from rising as high as the price for transmission service which would cause the arbitrage constraint to bind, it is expected that $\hat{\beta}_0 + \hat{\beta}_1 + \gamma_j$ is greater than or equal to the regulated price cap. Line congestion has different effects depending on the line constrained and the market pair in question. In general, the constraint on the line is expected to have a positive effect on the price difference for market pairs located near a congested transmission line. For regions far from the congested transmission line, the constraint is expected to have a smaller positive effect, or no effect at all.

This technique is applied to the set of prices such that electricity flows from the Northwest into Southern California, from Northern California into Southern California, and from Southern California into the Inland Southwest. This pattern is observed most frequently in the data, thirty percent of the 948 sets of price observations follow this pattern, and is most commonly observed in the peak periods of Spring and Summer months.

There are four arbitrage equations to be estimated: Northwest $\rightarrow$ Northern California, Northwest $\rightarrow$ Southern California, Northern California $\rightarrow$ Southern California, and Southern California $\rightarrow$ Inland SW. The supplemental data indicate that congestion occurs on the lines from the Northwest into Northern California (NWNCAF), on the line from the Northwest into Southern California (NWSCAF), on the line from Northern California into Southern California (NCASCAF), and on the line from Southern California into the Southwest (SCASWF). For each market pair, the arbitrage equation estimated is:

slightly larger than estimates of the mean price for transmission service in the present Section.

$$P_A = \beta_0 + \beta_1 PEAK + \beta_2 P_B + \gamma_1 NWNCAF + \gamma_2 NWSCAF + \gamma_3 NCASCAF + \gamma_4 SCASWF + \varepsilon$$

Each of the four (there are four market pairs) arbitrage equations contains 322 observations; a total of 1288 observations are used to estimate the SUR equation.[30] Table 4 presents the generalized regression parameter estimates.

Coefficient estimates presented in Table 3 strongly suggest that the prices in the sub-regions of the WSCC are bound together by arbitrage constraints, but that congestion gives rises to price separation. Coefficient estimates for $\hat{\beta}_2$ are as expected for all market pairs: Slightly greater than 1 assuming a reasonable amount of line loss. Table 4 illustrates that line loss increases as the transmission distance increases (2.06% for Northern California to Southern California - the nearest pair - and up to 7.5% for transmission from the Northwest into Southern California - the furthest pair). Estimated prices for off-peak transmission service are positive, significant, and less than the regulated price cap. Comparing across pairs of regions, off-peak prices for transmission service increase with distance from 0.431 Mills/KW from Northern California to Southern California up to 1.045 Mills/KW from the Northwest to Southern California. In addition, the estimated price of transmission service from the Northwest to Northern California plus the estimated price of transmission service from the Northern California to Southern California equals the estimated price of transmission service from the Northwest to Southern California. For three

[30] 322 of the 948 sets of price observations follow this directional electricity flow. Since there are 4 arbitrage equations to be estimated, each with 322 observations, when the 4 arbitrage equations are stacked to form the SUR system equation, there are a total of 322*4=1288 observations used in the estimation.

pairs, the estimated increase in the price for transmission service in a peak period compared to an off-peak period is positive as expected although only precisely estimated for the Southern California-Southwest pair. For one pair, Northern California-Southern California, the estimated difference in transmission price in a peak period compared to an off-peak period is negative, but it is imprecisely estimated.

Coefficients on congestion variables are generally positive and significant. For the Northwest-Northern California market pair, congestion on the transmission line directly connecting the regions (NWNCAF), causes a significant positive increase in the price difference by .83 Mills/Kwh. Parameter estimates for congestion on the two near transmission lines are not significant. The positive and significant coefficient on the SCASWF variable captures the fact that when there is high demand for imported wholesale electricity in the Southwest, the increased demand for wholesale electricity increases the demand for wholesale electricity generated in the Northwest. Because the capacity of the transmission line from the Northwest into Northern California, one transmission route from the Northwest into the Southwest, is limited, the market pair Northwest-Northern California exhibits price separation.

For the Northwest-Southern California market pair, parameter estimates for congestion along direct and far transmission lines are not significant. Congestion on the near line (SCASWF) causes an increase in the price difference between the price in the Northwest and Southern California. The positive and significant coefficient on the SCASWF variable again captures the fact that when there is high demand for imported wholesale electricity in the Southwest, the increased demand for wholesale electricity increases the demand for wholesale electricity generated in the Northwest. The limited capacity of the transmission line from the Northwest into Southern California, another transmission route from the Northwest into the Southwest, causes the market pair Northwest-Southern California to exhibit price separation.

Parameter estimates in the Northern California-Southern California market pair indicate that congestion on the near transmission line (NWSCAF) causes an increase in the price difference between the price in Southern California and the price in Northern California. Congestion on the near transmission line (NWNCAF) and on the direct transmission line (NCASCA) cause a decrease in the price difference between Northern California and Southern California. This narrowing of the price difference when there is congestion along the transmission line connecting the Northwest to Northern California and the transmission line connecting Northern California to Southern California may be explained by energy flowing back up through Midway, the transmission juncture which divides California into a “Northern” and “Southern” half, from Sylmar, the terminus of the DC line connecting the Northwest with Southern California. This feature causes the price in Southern California to fall relative to the price in Northern California thereby narrowing the price difference between Southern California and Northern California. Variables which indicate a report of congestion on the transmission grid are not precisely estimated in the Southern California - Inland Southwest market pair.

The results in this Section indicate that arbitrage constraints are binding across the WSCC under normal, uncongested conditions, but that congestion causes arbitrage constraints not to bind. In the next Section an empirical technique is developed to assess how frequently arbitrage constraints bind throughout the WSCC and how frequently prices in some regions become separated from prices in other regions.

C. How Frequently Do Arbitrage Constraints Bind?

Although results from the previous two Sections suggest that arbitrage constraints do bind and that congestion does cause price separation, these two Sections did not provide insight into how frequently congestion occurs nor how frequently wholesale prices in the WSCC are linked by arbitrage constraints. How frequently wholesale prices in the WSCC are linked by arbitrage constraints provides insight into how often the geographic expanse of the market is significantly smaller than the entire expanse of the WSCC. The method developed in this Section finds that arbitrage constraints bind prices across the WSCC 80% of the time, 19% of the time congestion arises which leads to price separations, and 1% of the time autarky prevails and the price difference between the regions is less than the price for transmission service.

The technique developed is similar to that proposed by Spiller-Huang (1986) and Spiller-Wood (1988), but expands on their method because this technique allows for three rather than two possible regimes: autarky, arbitrage, and congestion. Spiller-Huang and Spiller-Wood consider only autarky and arbitrage. The technique developed also allows for transaction costs and the probabilities of the three states - arbitrage, autarky, and congestion - to be different under different prevailing supply and demand conditions.

i. Technique

Consider two regions: A and B. In period t, if both regions fill retail electricity demand using only own generating capacity, the price for wholesale electricity in each region is the autarky price: $P_t^{A,Autarky}$ and $P_t^{B,Autarky}$. Assume $P_t^{A,Autarky} > P_t^{B,Autarky}$. Denote the price for transmission service from region B to region A in period t as T_t, where $T_t = T + \varepsilon_t$ and $\varepsilon_t \sim N(0, \sigma_\varepsilon^2)$. There are three mutually exclusive and exhaustive possibilities for the relationship between the prevailing prices in region A, P_t^A, and region B, P_t^B:

(1) Autarky

If the autarkic prices differ by less than T_t, then the price for wholesale electricity which prevails in region A, P_t^A and in region B, P_t^B, are the autarkic prices: $P_t^A = P_t^{A,Autarky}$ and $P_t^B = P_t^{B,Autarky}$:

$$P_t^A - P_t^B - T < \varepsilon_t . \qquad \text{(eq. 1)}$$

(2) Arbitrage

If the autarkic prices differ by more than T_t and there is no transmission line congestion, then the prevailing prices for wholesale electricity satisfy:

$$P_t^A - P_t^B - T = \varepsilon_t . \qquad \text{(eq. 2)}$$

(3) Congestion

If the autarkic prices differ by more than T_t and there is transmission line congestion, then the prevailing prices for wholesale electricity satisfy:

$$P_t^A - P_t^B - T > \varepsilon_t . \qquad \text{(eq. 3)}$$

The probability of observing each regime - autarky, arbitrage and congestion - is a constant: $\lambda^{Autarky}$, $\lambda^{Arbitrage} (= 1 - \lambda^{Autarky} - \lambda^{Congestion})$, and $\lambda^{Congestion}$ respectively.

Define v_t to be a positive random variable. Then the three mutually exclusive and exhaustive possibilities for the relationship between the prevailing prices in region A and region B are in fact a switching regressions system where,

$$P_t^A - P_t^B - T = \varepsilon_t - v_t \qquad \text{(eq. 4)}$$

occurs with probability $\lambda^{Autarky}$ (corresponding to the autarky regime);

$$P_t^A - P_t^B - T = \varepsilon_t \qquad \text{(eq. 5)}$$

occurs with probability $1 - \lambda^{Autarky} - \lambda^{Congestion}$ (corresponding to the arbitrage regime); and

$$P_t^A - P_t^B - T = \varepsilon_t + v_t \qquad \text{(eq. 6)}$$

occurs with probability $\lambda^{Congestion}$ (corresponding to the congestion regime).

In this paper, the positive error component is assumed to be distributed independently of ε_t, with a truncated (from below at zero) Normal distribution, $N(0,\sigma_v^2)$. Denote

$$\theta = \{T, \sigma_\varepsilon, \sigma_v, \lambda^{Autarky}, \lambda^{Congestion}\}$$

as the parameter vector. The likelihood function for the N observations is given by:

$$L = \prod_{t=1}^{N} \left\{ \lambda^{Autarky} * f_t^{Autarky} + (1 - \lambda^{Autarky} - \lambda^{Congestion}) * f_t^{Arbitrage} + \lambda^{Congestion} * f_t^{Congestion} \right\}$$

where $f_t^{Autarky}$, $f_t^{Arbitrage}$, and $f_t^{Congestion}$ are the density functions of (eq. 4), (eq. 5), and (eq. 6) respectively. Appendix 1 derives the form of the density functions. The maximum likelihood estimates are obtained by maximizing the logarithm of the likelihood function with respect to θ.

ii. Estimation and Interpretation

As with the previous methodologies, it is important to apply this technique taking account of the flow of electricity and prevailing supply and demand conditions. This technique is applied to the Northwest and Southern California regions with electricity flowing in a southbound direction (from the Northwest into Southern California). Price data matching this flow criterion are partitioned into two categories: peak period observations and off-peak period observations.[31] Figure 8 presents a histogram of the price differences for the Southern California - Northwest pair when electricity moves in the southbound direction.

Parameter estimates are expected to differ between peak period observations and off-peak period observations. First, the mean price for transmission service is expected to be different under different prevailing supply and demand conditions. In particular, the mean price for transmission service, T, is expected to be higher in peak periods compared to off-peak periods ($T_{Peak} > T_{Off-Peak}$) since the demand for transmission service is higher in peak periods than in off-peak periods. Second, the probability of the three regimes are expected to be different under different prevailing supply and demand conditions. The congestion regime is expected to prevail more frequently in peak periods than in off-peak periods because high demand for electricity (peak period) increases utilization of the grid, and thus increases the likelihood of congestion occurring ($\lambda_{Peak}^{Congestion} > \lambda_{Off-Peak}^{Congestion}$). The autarky regime is expected to prevail more frequently in off-peak periods than in peak periods because minimum load conditions arise in off-peak periods ($\lambda_{Peak}^{Autarky} < \lambda_{Off-Peak}^{Autarky}$). Finally, the arbitrage regime is expected to prevail more frequently in off-peak periods than in peak periods because the transmission grid is not fully loaded in off-peak periods ($\lambda_{Peak}^{Arbitrage} < \lambda_{Off-Peak}^{Arbitrage}$).

[31] There are not sufficient data to partition the observations more finely than peak and off-peak. Maximum likelihood techniques depends on a relatively large number of observations for estimation to proceed reliably.

Table 4a presents the parameter estimates obtained from maximum likelihood estimation using peak period observations. All of the parameter estimates are of the expected sign and reasonable magnitude. All but one parameter estimate, the probability of observing the autarky regime, are statistically distinguishable from zero at the 5% level. The estimated mean price for transmission service between Southern California and the Northwest, T, is 1.99 Mills/Kwh, which agrees with the estimated price for transmission service in Table 3. The probabilities of the three regimes in peak periods are reasonable and agree with both anecdotal evidence[32] from the WSCC as well as with the flavor of the earlier sections in this paper: 1% of the time autarky prevails, efficient arbitrage prevails 80% of the time, and 19% of the time congestion prevents efficient arbitrage.

Table 4b presents the parameter estimates obtained from maximum likelihood estimation using off-peak period observations. All of the coefficients are of the correct sign and reasonable magnitude, but only three parameter estimates are statistically distinguishable from zero at the 5% level. The estimated mean price for transmission service between Southern California and the Northwest, T, is 1.66 Mills/Kwh and agrees with the estimated price for transmission service in Table 3. The probabilities of the three regimes occurring in off-peak periods are reasonable: 9% of the time autarky prevails, efficient arbitrage prevails 83% of the time, and 8% of the time congestion prevents efficient arbitrage. Neither the probability of autarky nor the probability of congestion are statistically distinguishable from zero at the 5% level, implying that efficient arbitrage prevails 100% of the time in off-peak periods.

[32]See Lehr and VanVactor (1997) and McCullough (1996).

Estimates of the level of the probabilities for the three regimes compared across peak and off-peak periods are as expected. First, results indicate that efficient arbitrage is more likely to occur in off-peak periods compared to peak periods, $\lambda_{Arbitrage}^{Peak} = 80\% < 83\% = \lambda_{Arbitrage}^{Off-Peak}$. Second, results indicate that price separation is more likely to occur due to congestion in peak periods compared to off-peak periods, $\lambda_{Congestion}^{Peak} = 19\% > 8\% = \lambda_{Congestion}^{Off-Peak}$. Third, results indicate that autarky is more likely to occur in off-peak periods than in peak periods, $\lambda_{Autarky}^{Peak} = 1\% < 9\% = \lambda_{Autarky}^{Off-Peak}$. Finally, comparing parameter estimates of the mean price for transmission service between peak and off-peak observations, the estimated mean price for transmission service is lower in off-peak periods compared to peak periods, which agrees with both expectations as well as with estimates from Table 3.

While the previous two Sections indicate that congestion occurs on transmission lines in the WSCC and that congestion causes regions to exhibit price separation, these Sections did not provide evidence of how frequently arbitrage occurs nor how frequently prices in the WSCC regions become separated. The technique developed in this Section demonstrates that for the Northwest-Southern California market pair, arbitrage constraints bind approximately four-fifths of the observations. These results indicate that, by and large, the geographic expanse of the wholesale electricity market extends across the WSCC so that under normal uncongested conditions, wholesale electric customers are able to turn to generation suppliers dispersed over a wide geographic area, allowing them to purchase or sell electricity either within their control areas, in directly connected control areas, or in more remote control areas. On the other hand, in nineteen percent of the observations, price separation occurs. In these times, the geographic expanse of the market narrows and the effective number of competing firms falls.

6. Conclusion and Implications

This paper explored spatial dispersion of prices and the geographic expanse of a market in a dynamic setting. Spatial price relationships can be used as a means to infer the geographic expanse of the market, and more generally, market performance. In particular, the larger the geographic market, the more competitors, and therefore the less likely firms will be able to exercise market power. This paper suggests that the geographic expanse of the market for wholesale electricity is quite wide under most conditions and in most time periods, but that imperfect competition may arise as a result of transmission line congestion. Although a "narrow" geographic market may be more conducive to market power than a "wide" geographic market, a smaller geographic market does not immediately imply that market power problems will necessarily arise in these times. A smaller geographic market may still have enough competitors in generation services to alleviate market power concerns.

The behavior of the current wholesale electricity market can also go a long way toward informing the discussion of pricing behavior and performance in a restructured electricity industry. One important input into a complete assessment of imperfect competition in a restructured electricity industry is the geographic expanse of the market for generation services. This paper suggests that the geographic expanse of the market for retail electricity in a restructured electricity market is likely to be quite wide, and therefore relatively competitive, under most conditions and in most time periods, but that transmission line congestion can cause the geographic expanse of the market to narrow giving rise to imperfect competition. Finally, the techniques developed in this paper can readily be applied to data once a restructured electricity market emerges. Because market conditions in the electricity industry are likely to change significantly in the next few years as the structure of the electricity sector changes dramatically, the present analysis will be a useful benchmark against which to compare post-restructuring wholesale price relationships.

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APPENDIX 1

The density functions $f_t^{Autarky}$, $f_t^{Arbitrage}$, and $f_t^{Congestion}$ are derived as follows. Denote ϕ and Φ as the standard Normal density and cumulative distribution functions respectively. The error term in the Autarky and Congestion equations is a composite error term, composed of one term distributed as a Normal ($\varepsilon_t \sim N(0,\sigma_\varepsilon^2)$) and one term distributed as a truncated Normal ($v_t \sim N(0,\sigma_v^2)$ with $v_t>0$).

The density function for the autarky regime is given by:

$$\varepsilon_t - v_t = P_t^A - P_t^B - T$$

$$f_t^{Autarky} = f(\varepsilon_t - v_t) = \left(\frac{2}{\sqrt{\sigma_\varepsilon^2 + \sigma_v^2}}\right) * \phi\left(\frac{P_t^A - P_t^B - T}{\sqrt{\sigma_\varepsilon^2 + \sigma_v^2}}\right) * \left[1 - \Phi\left(\frac{(P_t^A - P_t^B - T)(\frac{\sigma_v}{\sigma_\varepsilon})}{\sqrt{\sigma_\varepsilon^2 + \sigma_v^2}}\right)\right]$$

The density function for the arbitrage regime is given by:

$$\varepsilon_t = P_t^A - P_t^B - T$$

$$f_t^{Arbitrage} = f(\varepsilon_t) = \left(\frac{1}{\sigma_v}\right) * \phi\left(\frac{P_t^A - P_t^B - T}{\sigma_v}\right)$$

The density function for the congestion regime is given by:

$$\varepsilon_t + v_t = P_t^A - P_t^B - T$$

$$f_t^{Congestion} = f(\varepsilon_t + v_t) = \left(\frac{2}{\sqrt{\sigma_\varepsilon^2 + \sigma_v^2}}\right) * \phi\left(\frac{P_t^A - P_t^B - T}{\sqrt{\sigma_\varepsilon^2 + \sigma_v^2}}\right) * \left[1 - \Phi\left(\frac{-(P_t^A - P_t^B - T)(\frac{\sigma_v}{\sigma_\varepsilon})}{\sqrt{\sigma_\varepsilon^2 + \sigma_v^2}}\right)\right]$$

FIGURE 1
The WSCC Region

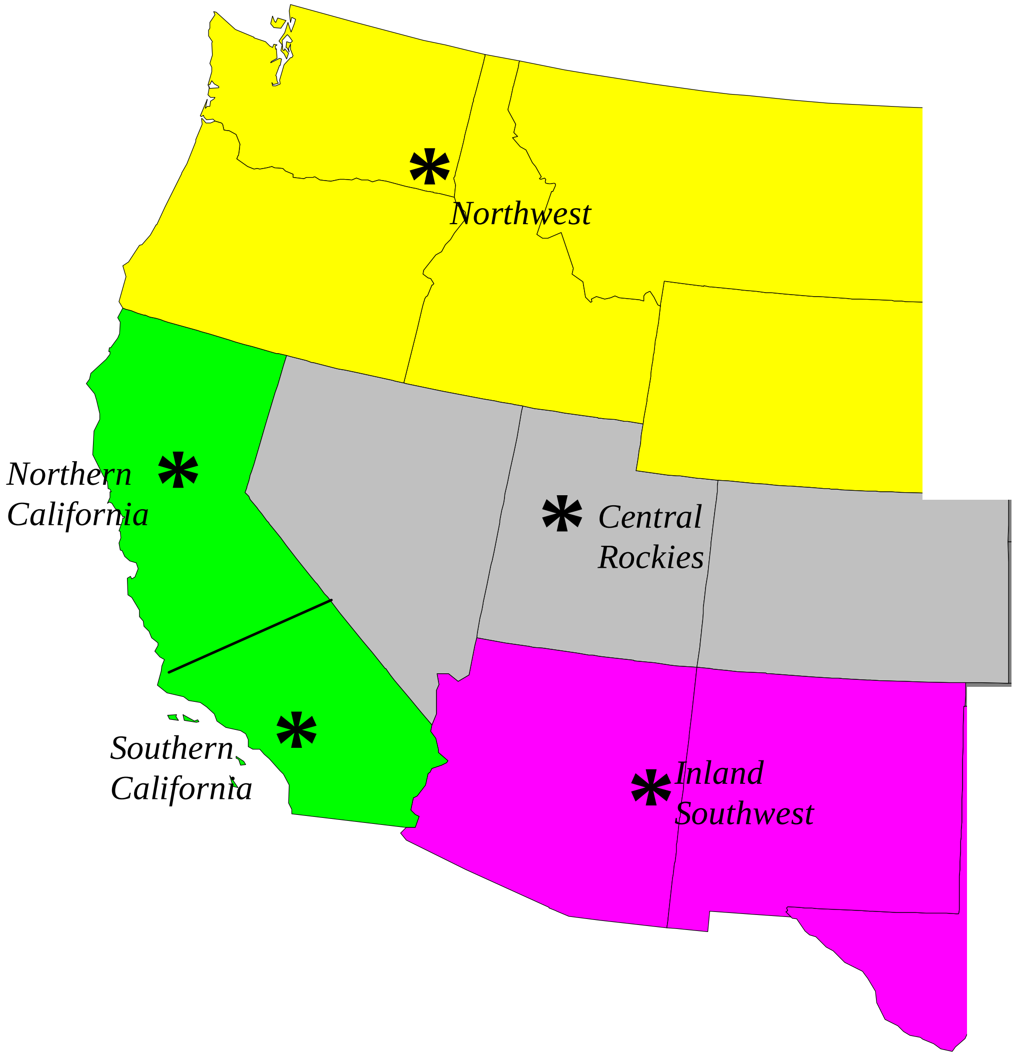


FIGURE 2
Major Transmission Paths in the WSCC

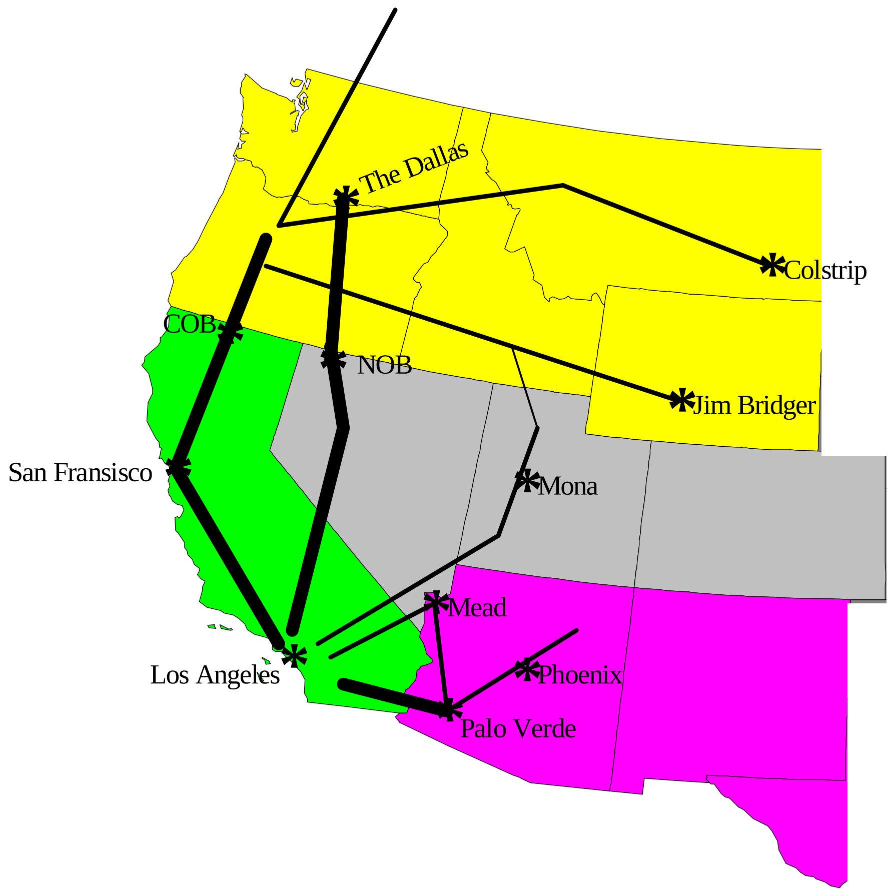


FIGURE 3a
Rating of the Southbound AC Pacific Intertie
June 23 1995 - May 9 1997

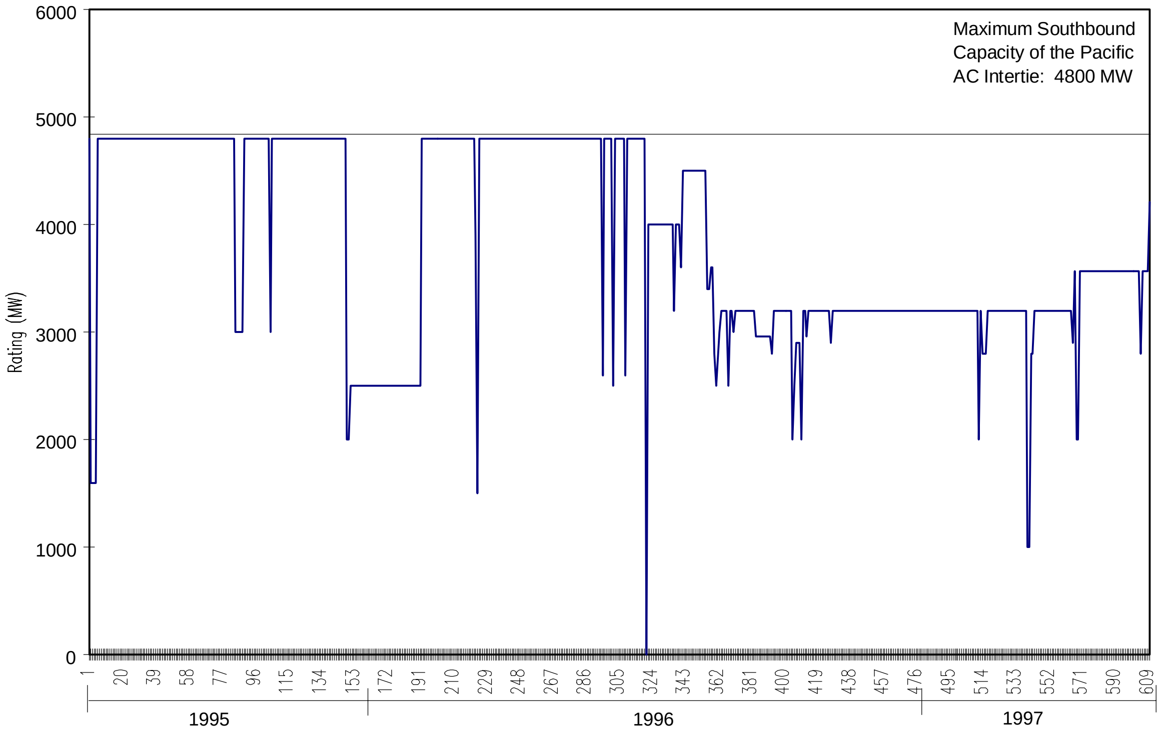


FIGURE 3b
Rating of the Southbound DC Pacific Intertie
June 23 1995 - May 9 1997

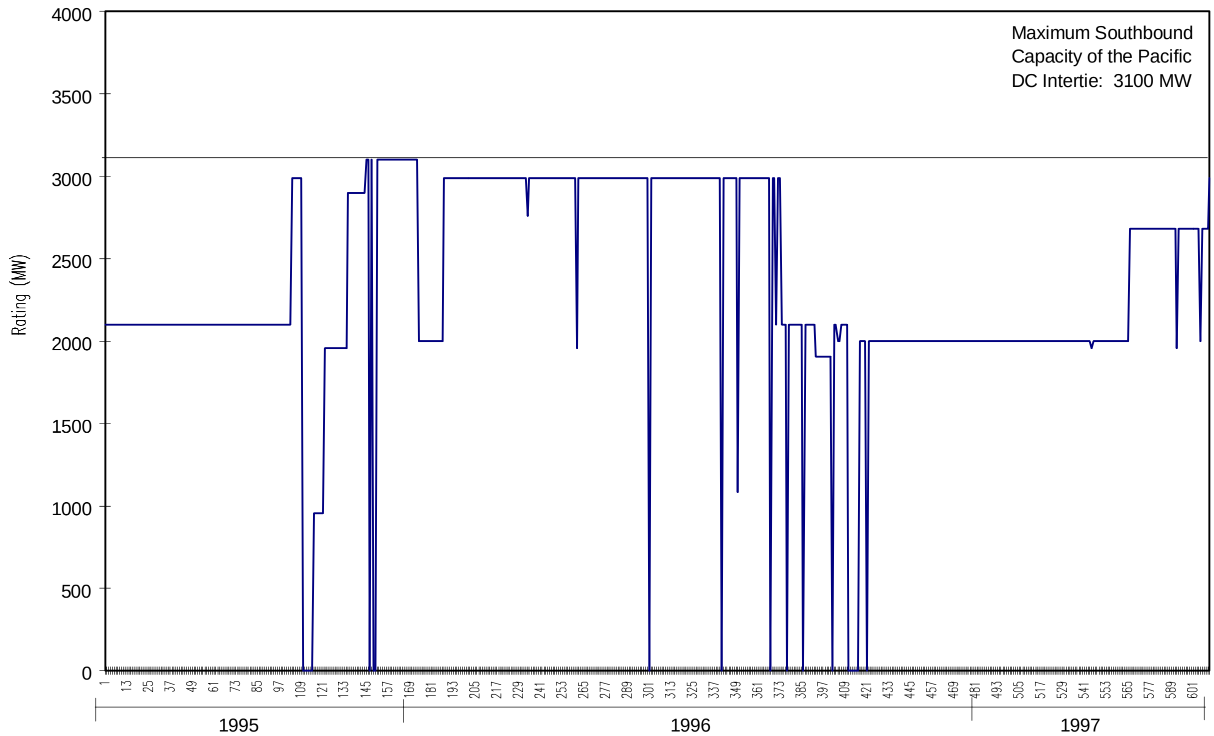


FIGURE 4a
Peak Pre-Scheduled Wholesale Electricity Movements in the WSCC
JUNE 23 1995 - DECEMBER 31 1996

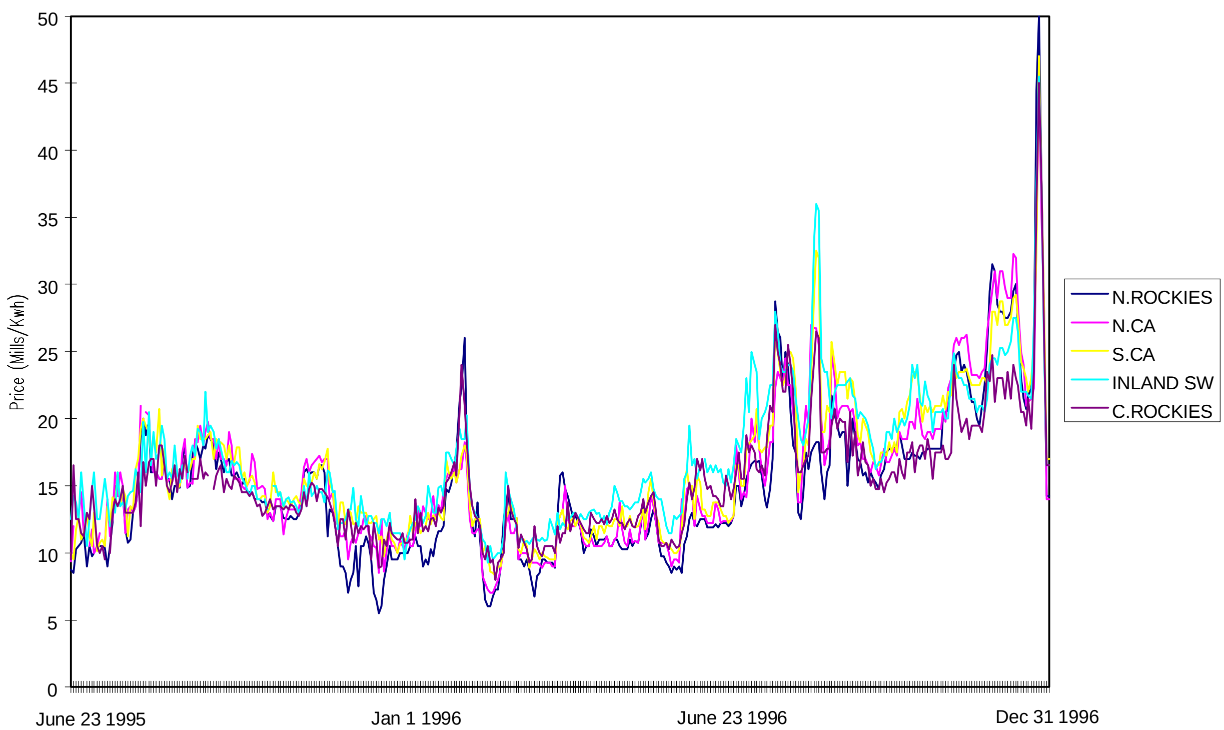
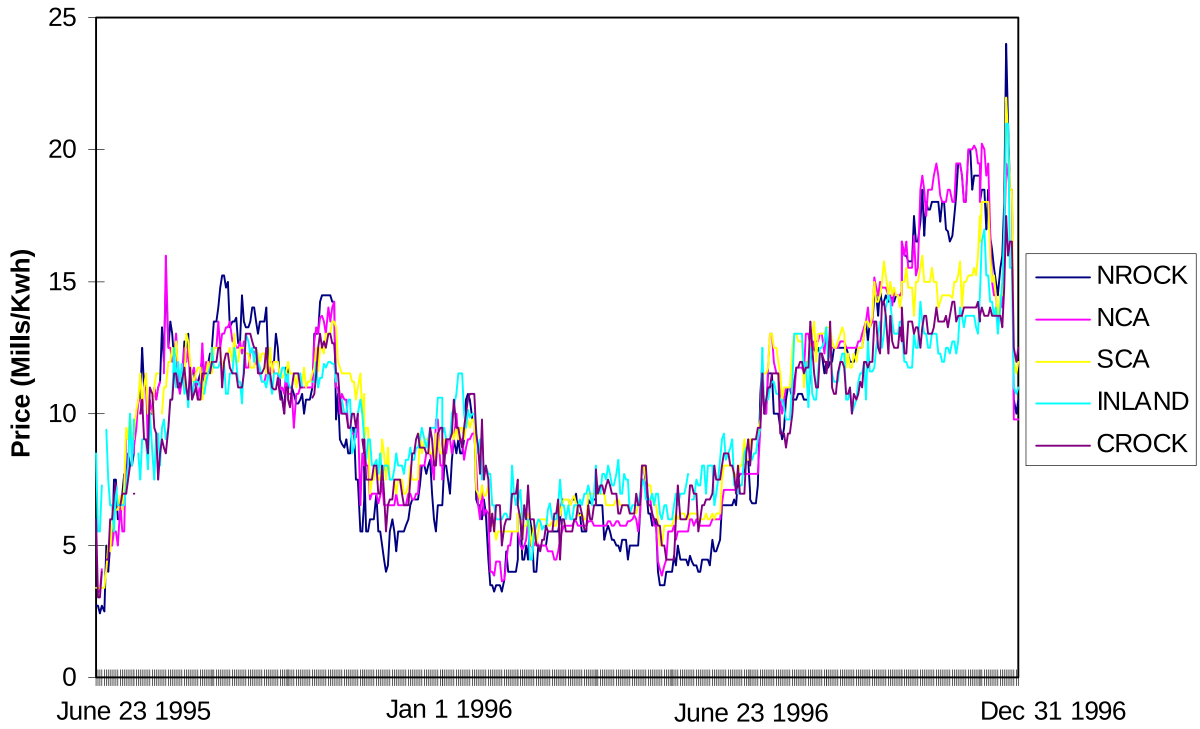


FIGURE 4B
Off-Peak Pre-Scheduled Wholesale Electricity Movements in the WSCC
June 23 1995 - December 31 1996



25
20
15
10
5
0
Price (Mills/Kwh)
June 23 1995
Jan 1 1996
June 23 1996
Dec 31 1996
NROCK
NCA
SCA
INLAND
CROCK

FIGURE 5
Wholesale Electricity Prices (Mills/Kwh) Under Typical Electricity Flows

Figure 4a

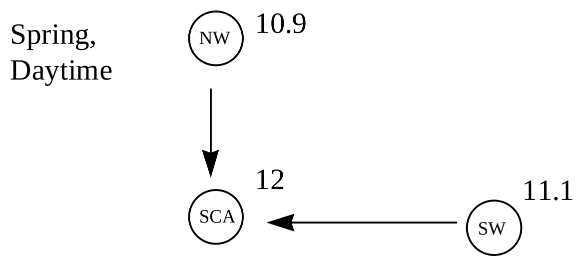


Figure 4b

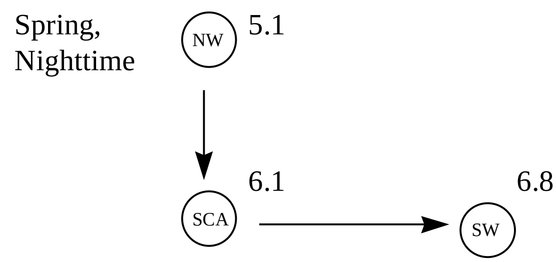


Figure 4c

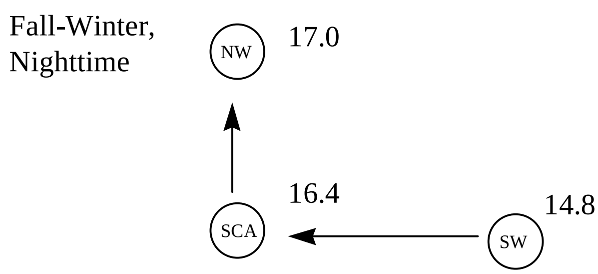


FIGURE 6
Price Relationships: Heat Wave in Southwest

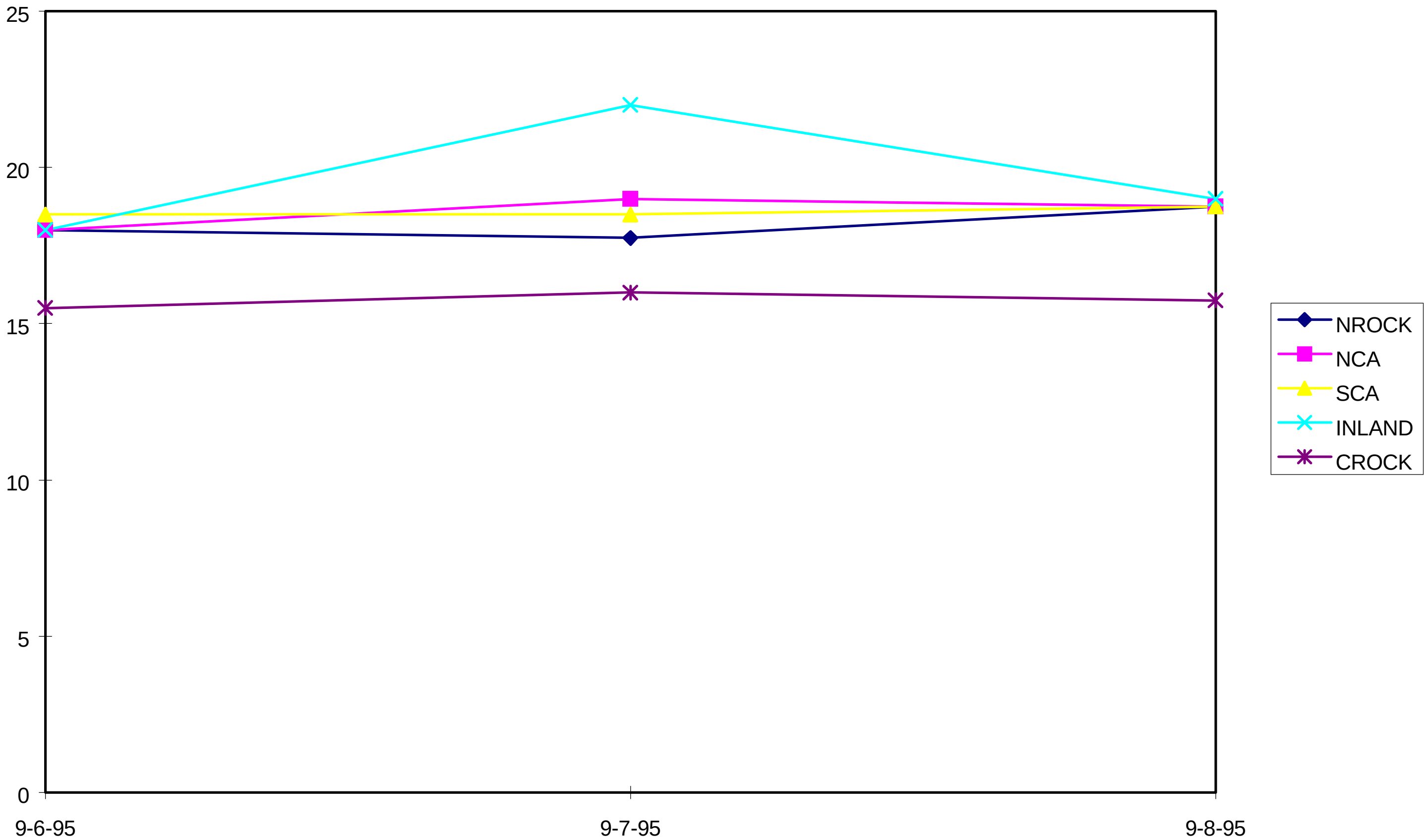
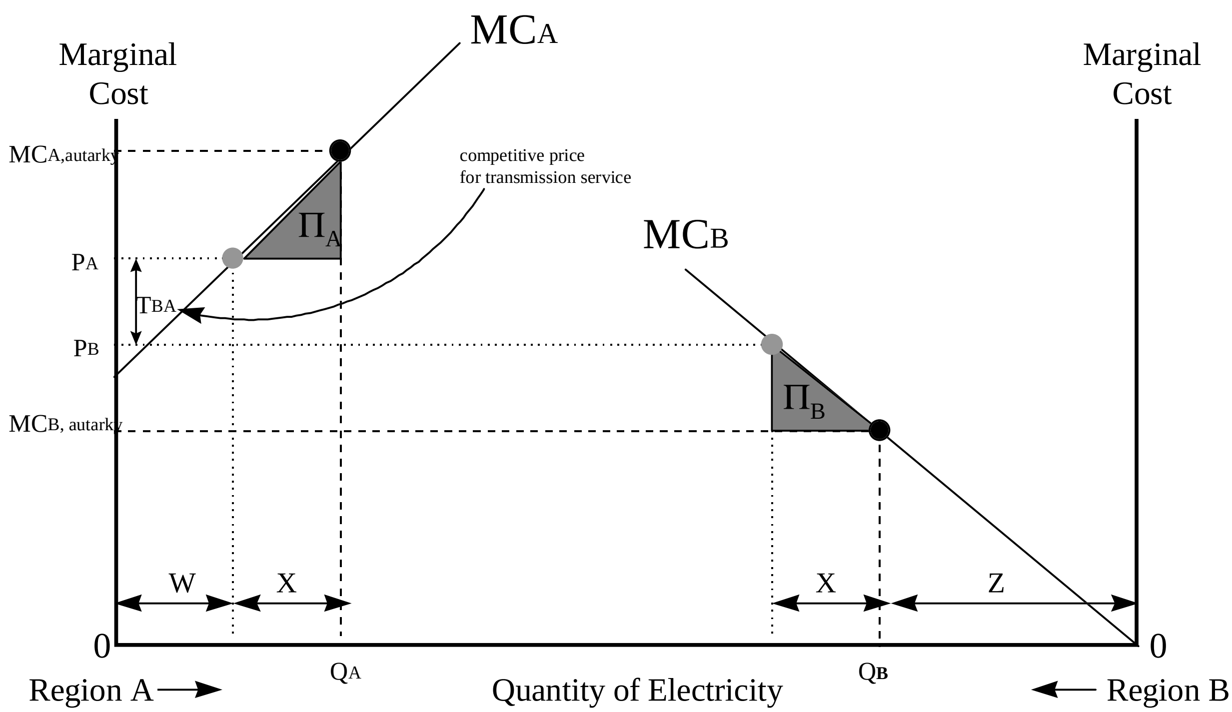
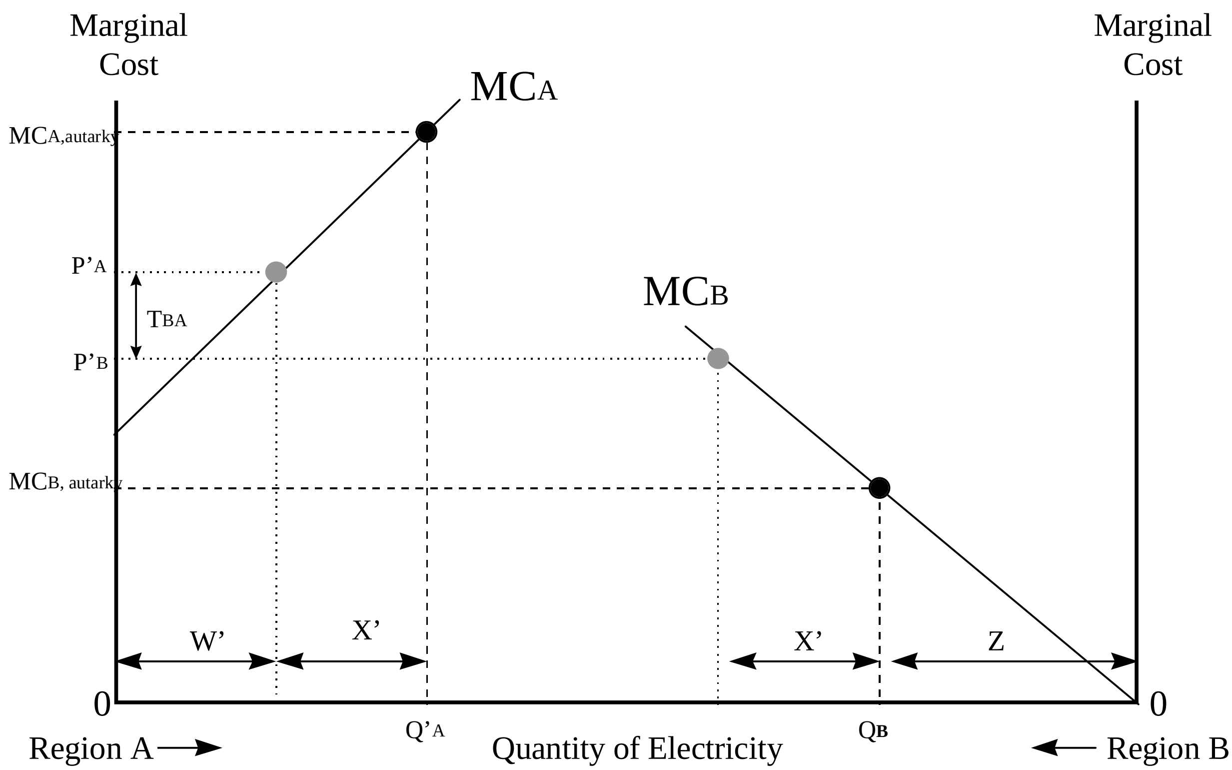


FIGURE 7a
Wholesale Electricity Trade
Competitive Generation and Competitive Transmission Service.
No Constraints to Trade



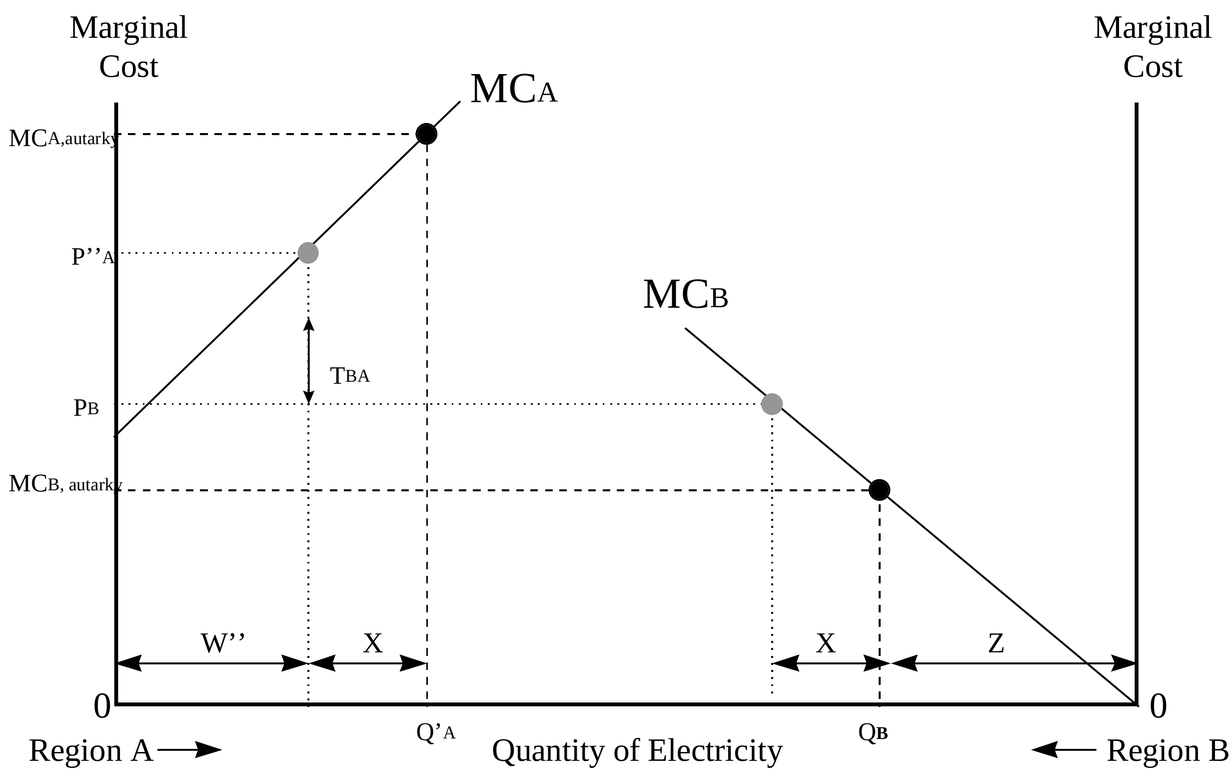
Q_A	retail electricity demand in region A
Q_B	retail electricity demand in region B
W	quantity of electricity generated by Utility A to fulfill retail demand in region A
Z	quantity of electricity generated by Utility B to fulfill retail demand in region B
X	quantity of electricity sold by Utility B to Utility A
Π_A	gain from wholesale trade in region A
Π_B	gain from wholesale trade in region B

FIGURE 7b
Wholesale Electricity Trade: Increase Demand in Region A
Competitive Generation and Competitive Transmission Service.
No Constraints to Trade



Q'_A	retail electricity demand in region A
Q_B	retail electricity demand in region B
W’	quantity of electricity generated by Utility A to fulfill retail demand in region A
Z	quantity of electricity generated by Utility B to fulfill retail demand in region B
X’	quantity of electricity sold by Utility B to Utility A

FIGURE 7c
Wholesale Electricity Trade: Increase Demand in Region A
Competitive Generation and Competitive Transmission Service.
Constraint to Trade

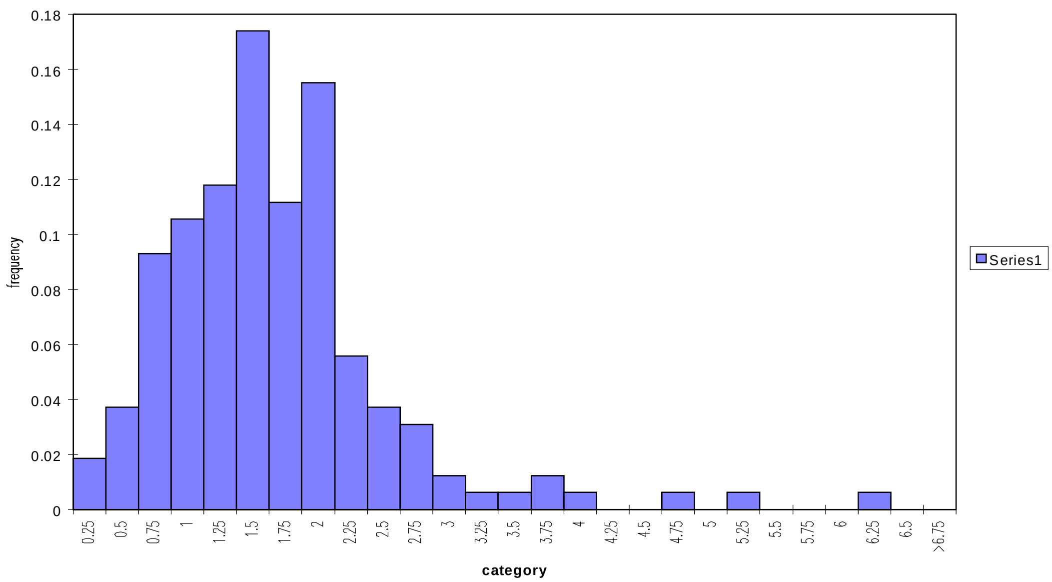


Q'_A retail electricity demand in region A
Q_B retail electricity demand in region B

W'' quantity of electricity generated by Utility A to fulfill retail demand in region A
Z quantity of electricity generated by Utility B to fulfill retail demand in region B
X quantity of electricity sold by Utility B to Utility A

FIGURE 8
Price Difference = P_{SCA}-P_{NW}

Frequency of Price Difference: Off-Peak



Frequency of Price Difference: Peak

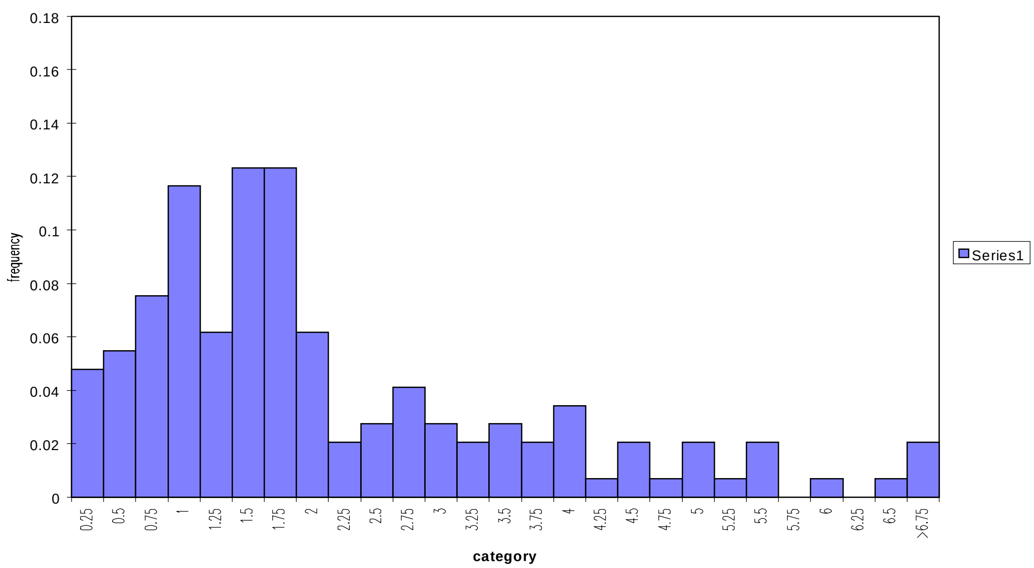


TABLE 1
Sources of Non-Firm Imported Energy, 1995

GWhs Purchased from Region*

	Pacific Northwest	Northern California	Southern California	Inland Southwest	Central Rockies	Canada/ Mexico	Power Marketer	All Regions
Pacific Northwest	51,554	3,341	1,664	714	1,108	2,875	4,862	66,118
Northern California	1,323	8,676	880	114	396	296	310	11,995
Southern California	4,529	1,740	1,028	2,265	1,416	413	1,335	12,726
Inland Southwest	1,074	165	312	1,534	225	0	689	3,999
Central Rockies	1,567	1,292	219	1,050	3,216	85	4,361	11,790

*Data was obtained from Energy Information Agency, *Wholesale Electric (Bulk Power) Trade Data*. Purchases from Qualifying Facilities have been excluded.

TABLE 2
The Effect of Regional Supply and Demand Conditions: OLS Parameter Estimates

$$\rho_i = \sum_{n=1}^{10} \alpha_n PAIR_{i,n} + \beta_1 PEAK_i + \beta_2 SPRING_i + \beta_3 SUMMER_i + \beta_4 WINTER_i + \beta_5 NWNCAF_i + \beta_6 NWSCAF_i + \beta_7 CJDAMH_i + \beta_8 RATINGL_i + \varepsilon_i$$

Parameter	**Coefficient**	**White Corrected Standard Error**
Market Pair:		
NW, NCA	0.925***	0.045
NW, SCA	0.900***	0.043
NW, SW	0.763***	0.055
NW, CR	0.835***	0.050
NCA, SCA	0.937***	0.043
NCA, SW	0.791***	0.058
NCA, CR	0.856***	0.050
SCA, SW	0.795***	0.063
SCA, CR	0.853***	0.051
SW, CR	0.846***	0.056
SPRING	-0.074	0.061
SUMMER	0.106***	0.038
WINTER	0.087**	0.040
PEAK	-0.066***	0.021
NWNCAF	-0.064	0.043
NWSCAF	-0.051*	0.030
DERATING	-0.042*	0.022
CJDAMH	-0.014	0.022

N=400; R^2=.93
***significant at 1%**significant at 5%,*significant at the 10% level.

TABLE 3

Estimating the Effect of Congestion on Arbitrage Constraints: SUR Parameter Estimates

(standard errors in parentheses)

$$P_B = \beta_0 + \beta_1 PEAK + \beta_2 P_B + \gamma_1 NWNCAF + \gamma_2 NWSCAF + \gamma_3 NCASCAF + \gamma_4 SCASWF + \varepsilon$$

	NW->NCA P_{NCA}	**NW->SCA** P_{SCA}	**NCA->SCA** P_{SCA}	**SCA->SW** P_{SW}
P_{NW}	1.058*** (0.021)	___	___	___
P_{NW}	___	1.081*** (0.021)	___	___
P_{NCA}	___	___	1.021*** (0.003)	___
P_{SCA}	___	___	___	1.044*** (0.015)
$T_{NW\text{->}NCA}$	0.602*** (0.180)	___	___	___
$T_{NW\text{->}SCA}$	___	1.045*** (0.195)	___	___
$T_{NCA\text{->}SCA}$	___	___	0.431*** (0.097)	___
$T_{SCA\text{->}SW}$	___	___	___	0.731*** (0.159)
PEAK	0.184 (0.186)	0.025 (0.210)	-0.161 (0.132)	0.335** (0.155)
NWNCAF	0.833*** (0.235)	0.339 (0.280)	-0.512** (0.208)	0.172 (0.202)
NWSCAF	-0.306 (0.280)	0.318 (0.333)	0.630*** (0.246)	-0.227 (0.239)
NCASCAF	1.019* (0.604)	-0.495 (0.719)	-1.536*** (0.534)	-0.108 (0.517)
SCASWF	2.650*** (0.647)	3.116*** (0.770)	0.409 (0.571)	0.197 (0.561)
	N=322 R^2=.93	N=322 R^2=.91	N=322 R^2=.95	N=322 R^2=.96

***significant at 1%, **significant at 5%, *significant at 10%

TABLE 4a
Frequency Arbitrage Constraints Bind: MLE Parameter Estimates
Electricity flows from the Northwest into Southern California, Peak

Parameter	Estimate	Standard Error
T	1.993***	0.569
σ_e	1.531***	0.518
σ_v	1.711***	0.296
$\lambda^{Autarky}$	0.011	0.596
$\lambda^{Congestion}$	0.198**	0.106

N=146.
***significant at 1%, **significant at 5%, *significant at 10%

TABLE 4b
Frequency Arbitrage Constraints Bind: MLE Parameter Estimates
Electricity flows from the Northwest into Southern California, Off-Peak

Parameter	Estimate	Standard Error
T	1.668***	0.548
σ_e	0.741***	0.239
σ_v	0.490***	0.167
$\lambda^{Autarky}$	0.094	1.635
$\lambda^{Congestion}$	0.084	0.352

N=161.
***significant at 1%, **significant at 5%, *significant at 10%