Assessing the Integration of Electricity Markets using Principal Component Analysis: Network and Market Structure Effects*

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Abstract

The major difficulties in assessing market power in electricity wholesale spot markets mean that great weight should be placed upon assessing market outcomes against the fundamental determinants of supply, demand and competition. In this spirit we study whether the New Zealand market has been a national market or a set of local markets since its inception in 1996. Electricity markets generally have loop flows that require simultaneous assessment of prices at all nodes, thereby limiting the informativeness of pair-wise nodal comparisons. We introduce principal component analysis to this application and show that it is a natural tool for the qualitative and quantitative assessment of the presence of local markets. We find that increased competition induced some separation into local markets that was eliminated by transmission enhancement and the introduction of generation downstream from the constrained circuits. For most of the period New Zealand has had one national market.

JEL Classification code: D4, L1, L4

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1 Introduction

Detecting the exercise of market power in electricity markets is even more difficult than detecting it in markets for more conventional goods because of such features as the volatility of electricity prices and fuel supplies.[1] This makes it especially important to develop techniques that can detect situations in which exercising market power is possible, so that the occurrence of such situations can be minimized. In this paper we describe one such technique and demonstrate it in the context of the New Zealand Electricity Market (NZEM). Our approach assesses the number and nature of the factors driving prices across the market and provides valuable information on where market power problems are likely to arise.

The NZEM is a pool market with locational marginal-loss pricing determined by a uniform price auction.[2] In pool-based systems, generators' output is pooled and then used to meet demand with a centrally-coordinated dispatch process controlled by the market operator. Under locational marginal-loss pricing regimes, each node has its own price, which equals the marginal cost of supplying electricity to that node. Ideally, there will be no outages or transmission constraints, so that the system operator is able to call on all generators when implementing the dispatch schedule; that is, the market is 'integrated'. In this case, prices at all nodes will be driven largely by market-wide factors, such as total demand and the market-wide supply schedule. In contrast, if the market is segmented into two or more parts, the dispatcher must select generators from within each segment to meet demand in each segment. This creates inter-segment variation in prices, although intra-segment variation will continue to be determined only by transmission losses. Prices within each segment should still be driven by a single factor.

Market segmentation makes it easier for firms to exercise market power because it reduces competition and thus renders it easier for them to influence market prices through their choice of supply schedules. When prices are set using a uniform price auction, offering generation at prices in excess of marginal cost leads to one of three possible outcomes in a situation of imperfect competition. First, if the market-clearing price exceeds the firm's offer price, the market clearing price is the same as it would have been had the firm offered in at its marginal cost. Second, if the

[1]An indication of just some of the difficulties involved can be found from recent papers investigating the causes of the crisis in the Southern Californian electricity market in 2000–2001 (Borenstein et al., 2002; Bushnell, 2005; Bushnell et al., 2004; Joskow and Kahn, 2002). However, these papers do not adequately address issues arising from price and fuel supply volatility (Counsell et al., 2006).

[2]Many other electricity markets (notably, the PJM market in the US) use locational marginal-loss pricing. However, alternative pricing regimes have been adopted by, for example, Nordpool and the UK market.

offer price is set so high that the plant in question is not dispatched, the market-clearing price will be higher than it would have been had the firm offered in at its marginal cost (unless the marginal cost itself was greater than the market-clearing price), so all of the firm's inframarginal plants will benefit from the higher market-clearing price. Third, if the dispatch process leads to the firm having the marginal generator (that is, the uniform price auction yields a price equal to the firm's offer price), the firm raises the market-clearing price, so that all of its generating plants that are dispatched benefit. Thus, knowing *ex ante* that it owns the marginal generator confers market power on a firm — its offer price can influence the distribution of market prices — which can be exploited by offering some generation at prices higher than marginal cost.[3] This will be relatively unlikely in an integrated market, since then any single firm competes with all other firms. However, when the market is segmented, there will be fewer competitors in each segment, and accordingly a greater probability of influencing the marginal generator.

Attempts to detect the exercise of market power in electricity markets usually involve so-called strategic offering and direct analysis, which compare actual price and supply outcomes with the theoretical ideal of a perfectly competitive electricity market. Strategic offering analysis examines the offer strategies of individual generators against the counterfactual of a (perfectly) competitive market, looking for evidence that the generators have attempted to influence the market (Joskow and Kahn, 2002; Wolfram, 1998). Direct analysis is similar, but it uses the entire market rather than individual generating firms (Borenstein et al., 2002; Joskow and Kahn, 2002). Some authors supplement direct analysis by also comparing actual prices to those resulting from an oligopoly counterfactual — typically a Cournot equilibrium (Bushnell, 2005; Bushnell et al., 2004; Wolfram, 1999). It is apparent from all these studies that the construction of the supply curve is critical to conclusions reached. They adopt an 'engineering' approach in order to construct the 'perfectly competitive market' supply curve and thereby ignore important characteristics of electricity markets such as uncertain future input and output prices and resource availability. These features can mean that the marginal cost of generating electricity includes a sizeable opportunity cost, which derives from the value of the option to delay generation that is destroyed when generation occurs. As Counsell et al. (2006) demonstrate, this option value can be many times larger than the direct marginal cost of generation. Since there is no established model for quantifying the option value, estimation of the price-cost margin in electricity markets where option values are likely to be large is currently infeasible.[4] It remains possible, however, to assess the performance of the market against the fundamental determinants of supply and demand. This paper contributes to this purpose.[5]

Our approach is to assess the extent to which the electricity market breaks into segments.

[3]Market power in the spot market applies only to power transacted in that market. The extent of market power is typically substantially reduced by hedge contracts, which may be long-term or as short as a day ahead.

[4]Such markets include those dominated by hydroelectric generation, but generation from stored gas also involves option values.

[5]Cicchetti et al. (2004) study the role of market fundamentals in the 2000–2001 electricity crisis in California.

If this is rare, market power will be relatively difficult to attain; in contrast, if segmentation is frequent and predictable, some firms may have substantial ability to raise prices by offering generation at prices greater than marginal cost at frequent predictable times. We use principal component analysis to determine the number of factors driving prices across the market and, when we detect segmentation, we use the composition of these principal components to identify the ways in which the market breaks up. This approach provides more informative analysis of the correlation structure of prices than a simple pairwise calculation of correlation coefficients.[6]

Other authors have attempted to identify the geographical extent of deregulated electricity markets, but these studies typically involve pairwise assessments of market integration.[7] For example, Bailey (1998a, 1998b), de Vany and Walls (1999), and Woo et al. (1997) investigate the integration of electricity markets in the western US.[8] Using daily peak and off-peak price data from five regions of the Western System Coordinating Council (WSCC) during the period June 1995–December 1996, Bailey finds that pairwise correlations of prices at different nodes are generally high and that they are highest when known congestion conditions are absent. De Vany and Walls also use daily peak and off-peak prices. They find them to be integrated of order 1 and that, during the period 1994–1996, prices at the overwhelming majority of regional market-pairs are cointegrated. Woo et al. restrict their attention to one of the five regions, the Pacific Northwest, of the WSCC. Using daily data on the peak period (6 a.m.–10 p.m.) for 1996, they find that four submarkets in this region are integrated, inter-submarket price differences quickly disappear and are generally smaller than posted transmission tariffs, and prices in different submarkets are highly positively correlated.[9] An alternative approach, which has been adopted by several authors, is to estimate the cost of transporting electricity between pairs of markets — market power will be relatively unimportant when these costs are low, since then individual firms are exposed to a greater number of potential competitors. For example, Bailey (1998a, 1998b) estimates that inter-region price differences across five regions of the WSCC exceed a (stochastic) measure of transmission costs just 19% and 8% of the time during the peak and

[6]Our approach is essentially looking at the geographical and intertemporal extent of economic markets. The most popular test for economic market composition involves examining the correlation between prices at different locations, with a high correlation indicating the two locations are in the same economic market (Stigler and Sherwin, 1985).

[7]The principal limitation of focussing on pairwise relationships is the ensuing difficulty in capturing network effects, which are very important in a pool market. For example in a pairwise analysis of a three node network, nodes A and B are treated independently of node C, whereas the network interactions that occur in an electricity pool market can be both strong and complex. Indeed, a single constraint can create congestion that can change the price in a different way at every location in a network (Cardell et al., 1997).

[8]Park et al. (2006) analyze price dynamics among 11 markets that cover three regions of the US. However, there is limited transmission between these regions and the markets are quite distinct, with different operators and market structures. Their study is quite different from ours, both in the technique used and in our focus on a single market which, as there is a single operator setting all prices, should be integrated except when there is substantial congestion.

[9]Woo et al. find that electricity prices are stationary, but nevertheless proceed with cointegration tests.

off-peak periods, respectively. Kleit (2001) applies a similar approach using daily peak prices at four trading hubs in the Western US.

Compared with this literature, our approach offers insights in two dimensions. First, by using principal component analysis we extend the pairwise analysis of traditional studies and investigate situations with more than two regional markets. Second, by analyzing prices in each half-hour trading period separately we are able to draw a finer picture of market integration across time. Our approach thus reveals more information about both the geographical and temporal extent of any market segmentation.

We demonstrate our approach in the context of the NZEM, which has been operating since 1996 and is therefore one of the oldest functioning pool markets in the world. Evans and Meade (2005, Chapter 5) provide a detailed account of the evolution of the NZEM throughout this period. Significant events for our study include the split of the Electricity Corporation of New Zealand (ECNZ) into three competing state-owned firms at the beginning of 1999, which increased the number of large generating firms operating in the NZEM from two to four; the opening of the Otahuhu B generation facility in January 2000, which relieved congestion in the north of the North Island; and droughts in 2001 and 2003, which had a significant impact on supply, as the majority of generation capacity in New Zealand is hydroelectric. We find that the New Zealand electricity market was one market in 1997–1998 and 2001–2004 inclusive, but that in 1999 and 2000 there was some market separation (although the quantitative effect of this was small). We consider that the competition produced by the change from a duopoly to four generators at the beginning of 1999 so altered network electrical energy flows that some segmentation occurred. Since the end of 2000, when a generation plant was placed downstream of the constrained region and the transmission constraint was relaxed by network enhancement, the market has been integrated.[10] This result indicates the importance of adequate transmission network capacity for competitive electricity spot markets.

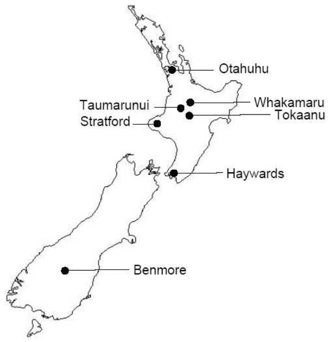
We describe our data in the next section and report the results of a preliminary assessment of market integration in Section 3. We describe how we use principal component analysis to give a more detailed view of market integration in Section 4. The results of this analysis are presented and discussed in Section 5, while Section 6 contains some concluding remarks.

2 Data

This paper examines the spot prices at seven nodes (Otahuhu, Whakamaru, Taumarunui, Stratford, Tokaanu, Haywards, and Benmore) in the NZEM for the period from November 1, 1996 to April 30, 2005. These nodes, which are shown in Figure 1, were chosen to make our sample representative of the market as a whole. The large hydroelectric generators in the south of the

[10]The network enhancement entailed splitting the bus at the Tokaanu node with the effect that electrical flows made more use of an alternative to the Tokaanu-Whakamaru circuits.

Figure 1: New Zealand Electricity Market



Notes. The map shows the location of the seven nodes analyzed in this study. They are Otahuhu (OTA), Whakamaru (WKM), Taumarunui (TMN), Tokaanu (TKU), Stratford (SFD), Haywards (HAY), and Benmore (BEN).

South Island and the high-demand metropolitan regions in the North Island[11] are separated by several potential congestion points, including the 'Cook Strait Cable', a bipole HVDC line that connects the Benmore substation in the South Island to the Haywards substation in the North Island. This cable is the only way to transfer electricity between the islands. Another constraint, which has been congested at times, arises at the Tokaanu-Whakamaru circuits in the middle of the North Island.

The long time series of half-hourly electricity spot prices for each node is separated into 48 series, each one comprising daily observations for a different half-hourly trading period.[12] By treating electricity delivered in different trading periods as separate commodities we are able to identify which periods are more vulnerable to market segmentation, giving a better understanding of the dynamics of market integration and performance. The prices at the seven nodes we analyze are stationary.

The existence of day-of-the-week and seasonal trends means that, even if the NZEM is segmented, prices at different nodes will be highly correlated. To prevent these predictable patterns contaminating our study, we filter such influences out of our price series using regressions of the form

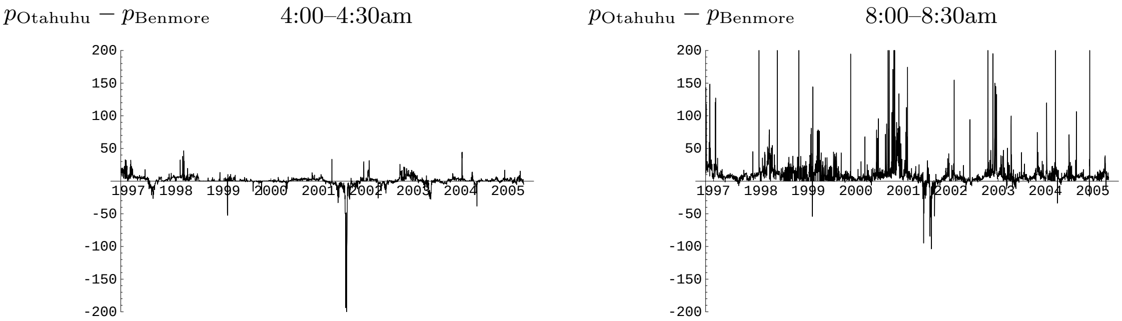
$$p_{i,t}^n = \sum_{j=1}^{6} \gamma_{i,j}^n d_{j,t} + \sum_{k=1}^{102} \delta_{i,k}^n m_{k,t} + u_{i,t}^n, \quad u_{i,t}^n \sim N(0, \psi_{n,i}^2), \tag{1}$$

where $p_{i,t}^n$ is the price at node n in trading period i on day t, $d_{j,t}$ is a dummy variable that takes

[11] 39% of total generation capacity is located in the South Island and 65% of demand is located in the North Island. (Source: www.nzelectricity.co.nz)

[12] Guthrie and Videbeck (2004) model the dynamics of spot prices in the NZEM by treating electricity sold in different trading periods as distinct commodities. They find that prices in different trading periods can behave quite differently from one another.

Figure 2: Price difference between Benmore and Otahuhu (selected periods)



Notes. The two graphs plot the difference between the (unfiltered) prices at the Otahuhu and Benmore nodes for two trading periods (4:00–4:30am in the left graph and 8:00–8:30am in the right graph). The sample spans the period November 1996–April 2005.

the value 1 on day j and 0 otherwise (Wednesday is day 1, Thursday day 2, and so on), and $m_{k,t}$ is a dummy variable that takes the value 1 in month k and 0 otherwise (November 1996 is month 1, April 2005 is month 102). Equation (1) is estimated for each node separately and the resulting 'filtered prices', the residuals $\hat{u}^n_{i,t}$, are used in our subsequent analysis.

3 A first look at the data

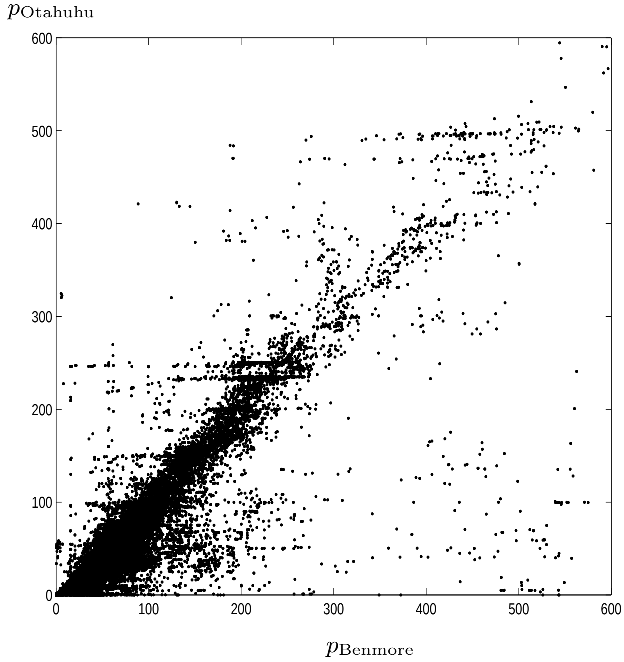
The shape of the NZEM evident from Figure 1 means that if the market segments, nodes at opposite ends of NZ will usually lie in different markets.[13] Therefore, in this section for descriptive purposes we focus on the Otahuhu and Benmore nodes. These two nodes are separated by both of the known regions of congestion, so that if either region is indeed congested, we would expect prices at these two nodes to diverge. We also focus on two trading periods, reflecting peak and off-peak behavior.

During our full sample period the average prices at Benmore and Otahuhu nodes are \$30.62 and \$31.33 respectively during the trading period beginning at 4:00am, and \$50.07 and \$62.74 during the trading period beginning at 8:00am. The two graphs in Figure 2 plot the difference between the prices at the Otahuhu and Benmore nodes for these two trading periods (4:00–4:30am in the left graph and 8:00–8:30am in the right graph) over the eight and a half years of our sample. With the exception of 16 days during the drought year (2001) when it exceeded \$50, the price difference is small in the off-peak period. However, Otahuhu prices are often substantially higher than Benmore prices in the morning-peak period.[14] The magnitude and variability of

[13]However, the existence of a loop in the North Island creates the possibility of other segmentations, which require consideration of more nodes as in the following sections of the paper.

[14]Some differences among the prices at different nodes may be predictable, as a consequence of predictable differences in losses. Such differences are not relevant to the assessment of one spot market, although they may signal opportunities for grid and generation investment.

Figure 3: Prices at Benmore and Otahuhu



Notes. The graph shows a simple scatter plot of the (unfiltered) prices at Benmore (horizontal axis) and Otahuhu (vertical axis), with the prices in all 48 trading periods combined. The sample spans the period November 1996–April 2005.

the price difference in the peak period suggest that the market may not be integrated at peak periods at times during the year.

The typical approach in testing for market integration is to measure the correlation between prices at the two locations. Over our full sample period, the correlation coefficient is 0.843. Figure 3 shows a simple scatter plot of the prices at Benmore (horizontal axis) and Otahuhu (vertical axis), with the prices in all 48 trading periods combined. The dispersion in the figure indicates that the market is not always integrated. However, grouping prices from all trading periods together like this may lose useful information, especially if (as suggested by Figure 2) the market only breaks up in some trading periods. To investigate this possibility, Table 1 reports the correlation coefficients for prices at Benmore and Otahuhu for each half-hour trading period, measured over the full sample period. They range from a maximum of 0.958 for the 6:00am trading period to a minimum of 0.633 for the noon trading period. The coefficients reported in Table 1 suggest that the market is much more likely to break up during some trading periods than others, which motivates our decision to analyze the trading periods separately.

This preliminary look at the data suggests that the NZEM may be prone to segmentation and that the extent of segmentation varies across the day. If we are to obtain a better idea of where this segmentation occurs, we need to consider all seven nodes in our sample, not just the nodes at either end of the network. This is the focus of the remainder of the paper.

Table 1: Correlation coefficients for prices at Benmore and Otahuhu

Period	Corr.	Period	Corr.	Period	Corr.	Period	Corr.
midnight	0.915	6 : 00	0.958	noon	0.860	18 : 00	0.808
0 : 30	0.944	6 : 30	0.956	12 : 30	0.633	18 : 30	0.892
1 : 00	0.943	7 : 00	0.955	13 : 00	0.824	19 : 00	0.950
1 : 30	0.935	7 : 30	0.906	13 : 30	0.833	19 : 30	0.940
2 : 00	0.932	8 : 00	0.862	14 : 00	0.832	20 : 00	0.939
2 : 30	0.935	8 : 30	0.910	14 : 30	0.810	20 : 30	0.749
3 : 00	0.935	9 : 00	0.896	15 : 00	0.790	21 : 00	0.918
3 : 30	0.935	9 : 30	0.834	15 : 30	0.655	21 : 30	0.867
4 : 00	0.931	10 : 00	0.725	16 : 00	0.758	22 : 00	0.838
4 : 30	0.945	10 : 30	0.920	16 : 30	0.794	22 : 30	0.916
5 : 00	0.941	11 : 00	0.685	17 : 00	0.794	23 : 00	0.927
5 : 30	0.946	11 : 30	0.886	17 : 30	0.746	23 : 30	0.906

Notes. The entries in the table give the correlation coefficients between the raw prices at the Benmore and Otahuhu nodes for the trading period starting at the indicated time. The sample spans the period November 1996–April 2005.

4 Sub-markets and principal component analysis

The nature of a pool market with nodal pricing means that the prices at different nodes in the same pool will move together if the market is integrated; prices at different nodes will differ only according to the extent of (marginal) transmission losses. Therefore, if the market is integrated, price movements at all nodes in that market may be explained by a single factor. In contrast, if the market is segmented into two parts, prices across the market may be explained by two factors, with each factor explaining prices in a separate segment. Prices within each segment are explained by a single factor, but as the values of the two factors diverge, so will the prices in different segments. Equivalently, prices across the market could be explained by two (different) factors that operate in both segments: the first factor explains the general price level, while the second factor determines the extent of the price differences between the two sub-markets. In this section we describe how principal component analysis can be used to uncover this structure.[15]

The main outputs of principal component analysis are linear combinations of the prices at the individual nodes (the so-called 'principal components') that explain as much of the variation in prices across the market as possible. For example, the first principal component is the linear combination of the prices at the individual nodes with the largest variance, subject to the constraint that the squares of the coefficients sum to 1. The second principal component is the linear combination of the prices at the individual nodes with the largest variance, subject to the constraints that (i) it is uncorrelated with the first principal component and (ii) the squares of the coefficients sum to 1. For a particular trading period (i, in this case) we can write the value

[15]For a very complete exposition of principal component analysis see Jolliffe (2002).

of the mth principal component (or factor) on day t as

$$f_{i,t}^m = x_{m1}\hat{u}_{i,t}^1 + \dots \ + x_{mN}\hat{u}_{i,t}^N, \quad m = 1, \dots, N,$$

where N is the number of nodes in the market and $\hat{u}_{i,t}^n$ denotes the price at node n. The coefficients x_{mn} are known as the 'loadings' on the principal component. It turns out that each vector $(x_{m1}, \dots, x_{m7})$ is an eigenvector of the price covariance matrix and that the matrix of eigenvectors is orthonormal. Thus, we can equivalently write the price at node n on day t as

$$\hat{u}_{i,t}^n = x_{1n}f_{i,t}^1 + \dots \ + x_{Nn}f_{i,t}^N, \quad n = 1, \dots, N.$$

The price at each node is thus a linear combination of the N principal components (or factors). The eigenvalues corresponding to the principal components are ordered from largest to smallest. For our purposes, we will therefore write the price as a linear combination of the first two principal components and a residual term; that is,

$$\hat{u}_{i,t}^n = x_{1n}f_{i,t}^1 + x_{2n}f_{i,t}^2 + \varepsilon_{i,t}^n. \tag{2}$$

For our data, the elements of the vector $(x_{11}, \dots, x_{1N})$ corresponding to the first principal component are all positive and of similar magnitude. The first principal component $(f_{i,t}^1)$ therefore offers a measure of the market-wide price — from equation (2), an increase in the value of the first principal component will lead to a higher price at each node. In contrast, the vector $(x_{21}, \dots, x_{2N})$ corresponding to the second principal component is a mix of positive and negative elements, so that the second principal component $(f_{i,t}^2)$ represents the spread in prices across the market — from equation (2), an increase in the value of the second principal component will lead to higher prices at some nodes and lower prices at others. The loadings on the second principal component therefore give useful information about where segmentation tends to occur. For example, suppose the NZEM breaks into two due to the HVDC link between the North and South Islands becoming constrained. Then, compared to what would have happened if the market had remained integrated, prices in one part of the NZEM (typically the North Island) will be high and prices in the other part will be low. The overall level of prices will continue to be determined primarily by the first factor, but a second factor will determine the extent of separation. We should find that nodes in one segment will have positive loadings on the second principal component (so that positive values of the principal component are associated with relatively high prices in that segment), while nodes in the other segment will have negative loadings (so that positive values of the principal component are associated with relatively low prices in that segment).

The mix of negative and positive signs of the coefficients of the second principal component are only of interest in this respect if the contribution of the second principal component is important. If variation in $f_{i,t}^2$ is significant, the second principal component will be important in explaining the (co)variance of prices; otherwise the second principal component will not explain (much) price variation and there will be a one-factor market. In this case, the first principal component can be viewed as determining the base level of prices collectively across all nodes of one market. Where the second principal component has relatively significant variation, there will be market separation given by the wedge between markets arising from the negative and positive coefficients on the second principal component. In this case nodes will fall into two markets. This argument can be extended to allow the approach to describe a situation where there are more than two markets among the nodes.

The eigenvalues of the covariance matrix reveal a great deal of useful information about market integration. We denote the eigenvalues by λ_i for $i = 1, \ldots, N$, and order them so that $\lambda_i \geq \lambda_{i+1}$. The sum of the eigenvalues of the covariance matrix equals the sum of the variances of the prices at each node. The largest eigenvalue divided by the sum of all eigenvalues equals the weighted average of the R^2s obtained by regressing the prices at each node on the first principal component, where each individual R^2 is weighted by the variance of prices at that node relative to the total variance across all nodes. If this measure, which we denote by

$$\Lambda_1 \equiv \frac{\lambda_1}{\lambda_1 + \ldots + \lambda_N},$$

is high, a single factor explains much of the variation in prices across the market, so that market segmentation is relatively unimportant. If it is low, more than one factor is needed to explain the variations in prices across the market, so that segmentation is a more important issue.[16] Similarly, the sum of the two largest eigenvalues divided by the sum of all eigenvalues equals the weighted average of the R^2s obtained by regressing the prices at each node on the first *two* principal components, with the same weights as before. We denote this measure by

$$\Lambda_2 \equiv \frac{\lambda_1 + \lambda_2}{\lambda_1 + \ldots + \lambda_N}.$$

Thus, we proceed by extracting the first two principal components from prices in each trading period. If the market is integrated, a single factor will explain most of the variation across prices in the network and the second factor will explain little; if the market is prone to segmentation, the second factor will play a bigger role. In either case, we expect the loadings on the first factor to all have the same sign and be of similar magnitude. If the market breaks up, the loadings on the second factor tell us where this occurs. We discuss the results of this procedure in the next section.

5 Results

We start by considering the case of a single trading period during November 1996–April 2005 in detail. We choose period 17 (8:00–8:30am) as it is representative of a peak period, and summarize our results in Table 2. The second and third columns of Table 2 show the variance

[16] There may be no significant factor explanation, in which case prices across nodes are independent.

Table 2: Analysis of prices in trading period 17 (08:00–08:30)

			Loadings		Reg'n on PC_1		Reg'n on PC_1, PC_2	
Node	Variance	Std dev	PC_1	PC_2	R^2	Std error	R^2	Std error
OTA	2352	48.50	0.444	0.302	0.960	9.76	0.974	7.83
WKM	1977	44.47	0.407	0.243	0.958	9.16	0.969	7.88
TMN	2002	44.75	0.395	0.411	0.892	14.73	0.923	12.43
SFD	1550	39.38	0.366	−0.002	0.985	4.77	0.985	4.77
TKU	1623	40.28	0.359	−0.334	0.906	12.37	0.931	10.57
HAY	1664	40.79	0.377	−0.196	0.977	6.14	0.986	4.85
BEN	1160	34.05	0.276	−0.729	0.753	16.94	0.922	9.50
Total	12328							
Weighted average					0.927		0.957	

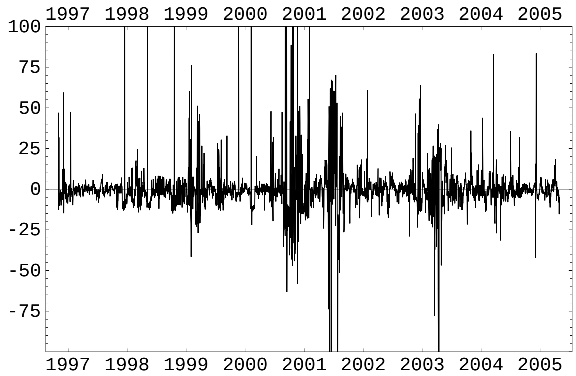
Notes. The analysis uses filtered prices during the period November 1996–April 2005. The nodes are labelled as in Figure 1.

and standard deviation of (filtered) prices at each of the seven nodes listed in the first column, measured over the full eight and a half year sample. The nodes are ordered, approximately, from north to south. The next two columns give the loadings for the first two principal components. As expected, the first principal component weights all nodes approximately equally, and so provides a measure of the overall level of prices across the NZEM. However, the loadings on the second principal component are negative for the four southern-most nodes and positive for the remaining nodes. This principal component thus measures the extent to which prices in the southern part of the market deviate from those in the north. The next two columns of Table 2 summarize the results from regressing the price at each node on the first principal component. For all but the southern-most node, the R^2 is greater than 0.89. The weighted average of the R^2s is 0.927, where R^2 at an individual node is weighted according to the variance of prices at that node (as discussed in Section 4). When the second principal component is added to the regressions, all R^2s increase to 0.92 and above and the weighted average rises to 0.957.

Figure 4 plots the path of the second principal component for trading period 17 during November 1996–April 2005. The value of the second principal component on any given day equals the linear combination of the prices at the seven nodes on that day, where the coefficients of the prices are given in Table 2. The graph shows that the extent and frequency of segmentation varies over time, a subject we discuss in further detail below.

Much of the information in Table 2 is summarized by the eigenvalues of the covariance matrix for (filtered) prices at these nodes in trading period 17. The second column of Table 3 shows these eigenvalues, in decreasing order. Consistent with our discussion in Section 4, comparison with Table 2 shows that the sum of the eigenvalues equals the sum of the variances of the prices at each node. Moreover, when expressed as a proportion of this total, the largest eigenvalue equals the weighted average of the R^2s obtained when regressing the prices at each node on the

Figure 4: Second principal component in trading period 17 (08:00–08:30)



Notes. The graph plots the second principal component in trading period 17. The sample spans the period November 1996–April 2005.

Table 3: Analysis of market-wide prices in trading period 17 (08:00–08:30)

k	λ_k	$\frac{\lambda_k}{\sum \lambda_j}$	Cumulative
1	11432	0.927	0.927
2	370	0.030	0.957
3	240	0.020	0.977
4	229	0.019	0.995
5	30	0.002	0.998
6	15	0.001	0.999
7	11	0.001	1.000
Total	12328	1.000	

Notes. The analysis uses filtered prices during the period November 1996–April 2005.

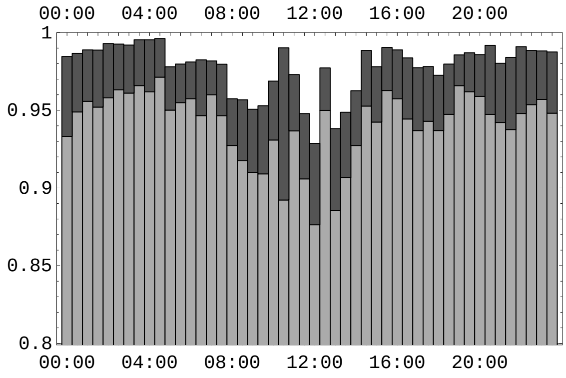
first principal component. Similarly, the sum of the two largest eigenvalues, when expressed as a proportion of the total, equals the weighted average of the R^2s obtained when regressing the prices at each node on the first two principal components.

Therefore, in what follows we report the average proportion of the variance explained by principal components 1 and 2, respectively, and the loadings on the second principal component.[17] The first two quantities indicate the degree of integration of the market, while inspection of the loadings provides information on where any segmentation typically occurs.

We now apply this analysis to all 48 trading periods. Figure 5 plots our integration measure as a function of the trading period. The height of each light gray bar shows the proportion of the variance in prices across the seven nodes that is explained by the first principal component in the indicated trading period. The height of each dark gray bar shows the additional proportion

[17]The latter is just the eigenvector corresponding to the second largest eigenvalue, normalized so that the squares of the elements sum to 1.

Figure 5: Proportion of variance explained by the first two principal components (1996–2005)

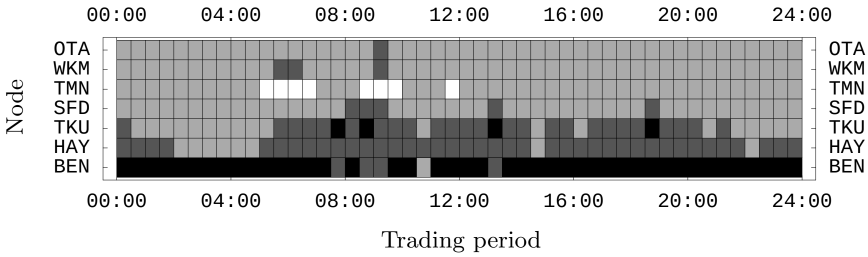


Notes. The height of each light gray bar shows the proportion of the variance in prices across the seven nodes that is explained by the first principal component in the indicated trading period. The height of each dark gray bar shows the additional proportion of the variance that is explained by the second principal component. The analysis uses filtered prices during the period November 1996–April 2005.

of the variance that is explained by the second principal component. Figure 5 shows that the extent of market integration varies over the course of the day, with the first principal component explaining at least 95% of the variation in (filtered) prices across the NZEM before 8:00am and a similar level after 3:00pm. However, this falls to approximately 90% during the middle of the day. The figure also shows that the first two principal components explain more than 98% of the variation in prices before 8:00am and after 3:00pm. Between these hours, the first two principal components explain approximately 95% of the variation in prices. These results suggest that any NZEM vulnerability to segmentation is more likely to occur between the morning and evening peaks, not during the peaks themselves.

Figure 6 provides information on where the NZEM segments. The graph represents a matrix, with each column corresponding to a separate trading period and each row corresponding to the indicated node. The shading of each cell indicates the loading of the corresponding node on the second principal component. Loadings are shaded black if in the interval $[-1.0, -0.5)$, dark gray if in the interval $[-0.5, 0.0)$, light gray if in the interval $[0.0, 0.5)$, and are otherwise white. Between the hours of 2:00–5:00am, the Benmore node seems to break off from the rest of the NZEM, suggesting that the market segments at the Cook Strait Cable. At other times of the day, the three southernmost nodes seem to be in a distinct sub-market, suggesting that congestion in the middle of the North Island is more important than congestion at the Cook Strait Cable. The white cells corresponding to the Taumarunui node either side of the morning peak periods suggest that prices at this node behave quite differently from prices over the remainder of the NZEM during these periods, providing further evidence that the most important congestion is

Figure 6: Loadings on the second principal component (1996–2005)



Notes. The graph represents a matrix, with each column corresponding to a separate trading period and each row corresponding to the indicated node. The shading of each cell indicates the loading of the corresponding node on the second principal component. Loadings are shaded black if in the interval $[-1.0, -0.5)$, dark gray if in the interval $[-0.5, 0.0)$, light gray if in the interval $[0.0, 0.5)$, and are otherwise white. The analysis uses filtered prices during the period November 1996–April 2005.

occurring in this part of the market and not at the inter-island HVDC link.

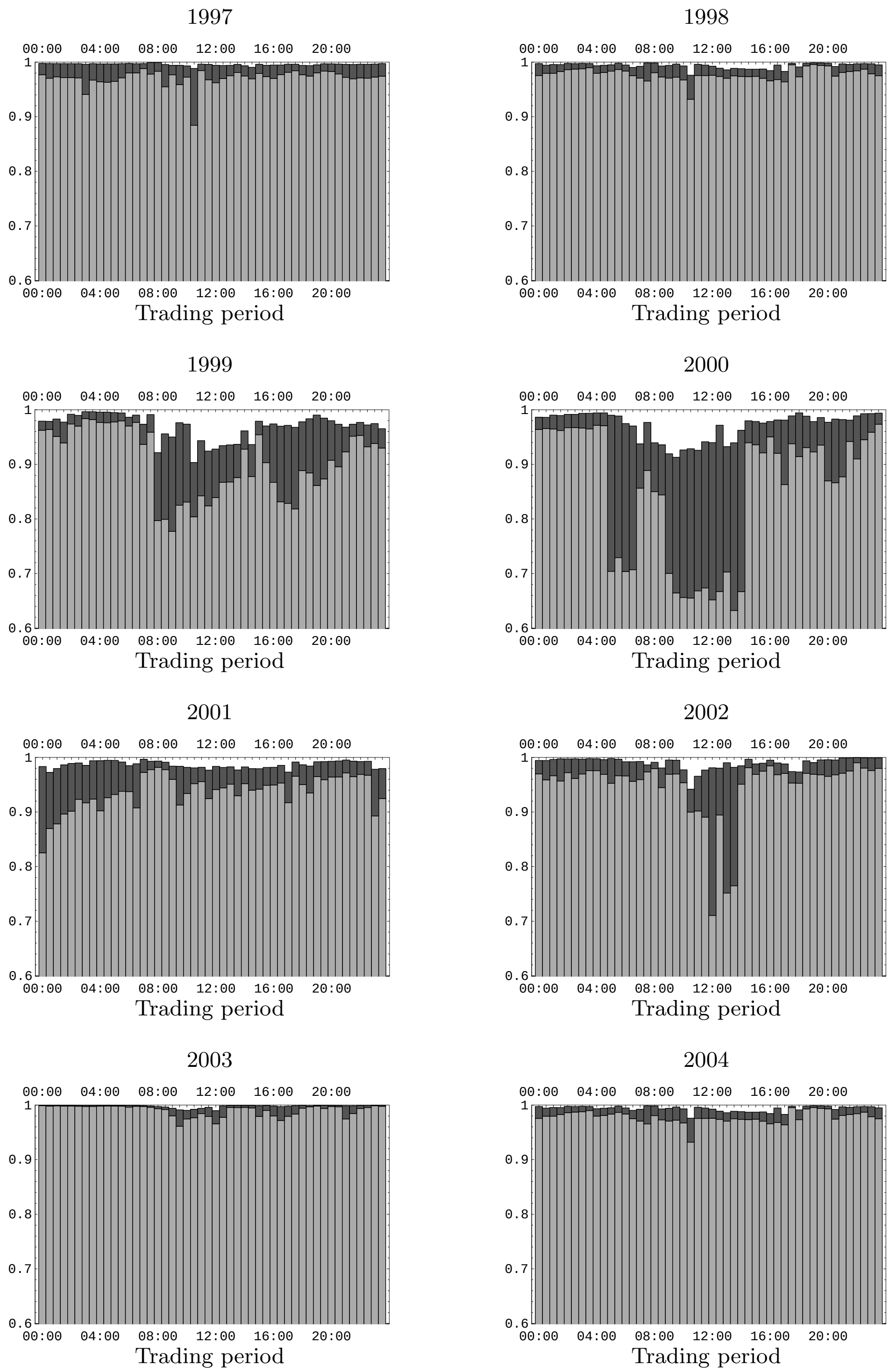
Since there is no set level of the proportion of variance explained by the first principal component that can be used to determine whether the market is integrated or not, the best approach is to use the outputs of principal component analysis for comparative purposes. For example, if the first principal component explains an especially high proportion of price variance at some times of day, then the market can be said to be relatively integrated (and market power relatively weak) at those times. Similarly, if the proportion of price variance explained by the first principal component is high during certain months, this again suggests that the market is relatively integrated during these times.

Because we have detected some market breakup we explore links between market structure and performance. In 1998 the existing generation duopoly was transformed to four competing companies that commenced business on April 1, 1999.[18] In January 2000 the Otahuhu B power station was commissioned north of the Whakamaru constraint, but it suffered a sustained outage that meant it did not operate consistently until the end of January 2001.[19] Figure 7 plots our integration measure as a function of the trading period for each complete calendar year in our sample. As in Figure 5, the height of each light gray bar shows the proportion of the variance in prices across the seven nodes that is explained by the first principal component in the indicated trading period. The height of each dark gray bar shows the additional proportion of the variance that is explained by the second principal component. The most notable feature

[18]The change involved splitting a large state-owned generator into three generators, removing a prohibition on vertical integration of generation and retail, and separating distribution firms into retail companies and companies with lines only. A fifth merchant generator-retailer also became established in 1999. Since 1999 all the major generators have also been involved in retail.

[19]Otahuhu B is a combined-cycle plant that produced approximately ten percent of New Zealand's electricity demand at the time it was introduced.

Figure 7: Proportion of variance explained by the first two principal components for each calendar year



Notes. The height of each light gray bar shows the proportion of the variance in prices across the seven nodes that is explained by the first principal component in the indicated trading period. The height of each dark gray bar shows the additional proportion of the variance that is explained by the second principal component. The analysis uses filtered prices for the indicated calendar year.

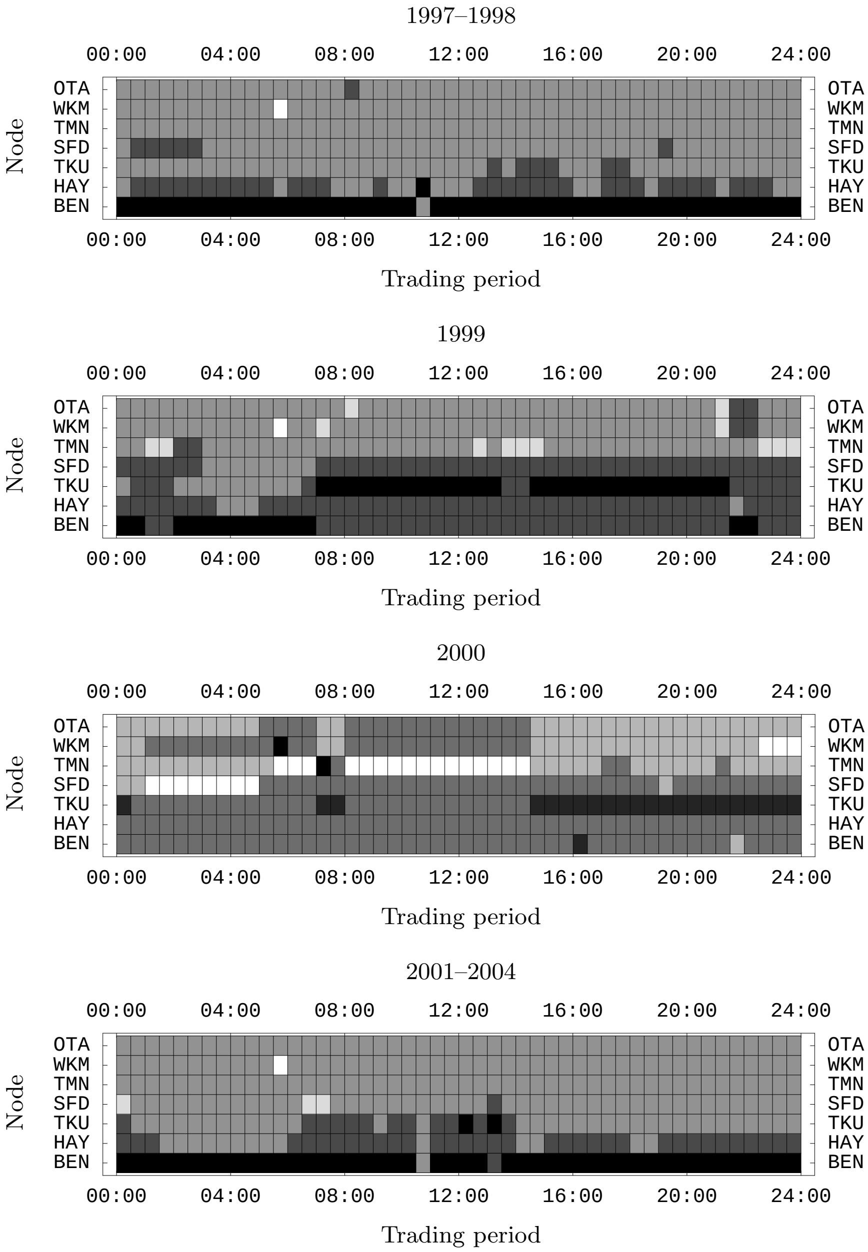
of the eight graphs is that the NZEM was much more prone to segmentation in 1999 and 2000, with the market breaking up during the periods 5:00–7:00am and 9:00am–2:30pm, than in other years. There is evidence that the market was breaking up into at least three segments during the latter period. Inspection of the other graphs suggests that the NZEM is more integrated after Otahuhu B entered service and the network was strengthened: during this period the first principal component alone explains a great deal of the variation in prices throughout the day. Of course, factors other than the appearance of the new power plant and expansion of network capacity may be explaining the greater integration. However, the 2001–2004 periods include two high-price episodes — the dry years of 2001 and 2003 — which we would expect to have imposed greater pressure on the transmission constraints as the generally northward flow of electricity was reversed for considerable periods of time. Nevertheless, the 2001–2004 period exhibits the characteristics of one market. The significance of the 1999–2000 market separation is a matter of judgement. Both factors explain almost all of the variation in prices during this period, but in certain non-peak periods, particularly in 2000, the second factor contributes more than 30 percent to the explanation of price variation.[20] We have no information about the effect of this separation on market participant behavior. However, it may well have affected decisions such as the location of hedge agreements, especially had the 2000 segmentation persisted.

Figure 8 provides more detail on segmentation in the NZEM. The top graph corresponds to the period (1997–1998) before competition in the NZEM was materially enhanced, the middle graphs relate to 1999 and 2000, and the bottom graph to the period 2001–2004. Interpretation of the cells represented by the graphs is as for Figure 6. Here, as in Figure 7, the behavior before competition and after the introduction of Otahuhu B and transmission expansion is similar. In contrast to the duopoly period of 1997–1998, in 1999 and 2000 the three northernmost nodes (Otahuhu, Whakamaru, and Taumarunui) were prone to separate from the rest of the NZEM during the daytime and early evening; overnight segmentation typically occurred nearer the inter-island HVDC link. However, the introduction of Otahuhu B and transmission expansion appear to have relieved congestion in the middle of the North Island because, as the bottom graph shows, segmentation in the period beginning in 2001 tends to involve only the two southernmost nodes separating from the rest of the market.

The period 1999–2000 is quite distinctive. Recall from Figure 7 that the NZEM was especially prone to break up into two or three parts during this period. The middle graphs in Figure 8 suggest that this involved the Stratford (overnight) or Taumarunui (daytime) node separating from the rest of the market. The results in Figure 7 strongly indicate that in only 1999 and 2000 has there been other than one market. This conclusion is supported by Figure 8, which demonstrates the location of the market segmentation. Together they suggest that the advent

[20] As Figure 7 reveals, the constraint seems to bind in the morning and middle of the day: outside peak hours. This is concordant with generators with storage — hydro, gas or coal — reducing their generation in off peak times to an extent that northbound electricity induced the Tokaanu-Whakamaru constraint to bind. Absent the constraint, this management of storage may have been efficient (see Counsell et al., 2006).

Figure 8: Loadings on second principal component



Notes. The graph represents a matrix, with each column corresponding to a separate trading period and each row corresponding to the indicated node. The shading of each cell indicates the loading of the corresponding node on the second principal component. Loadings are shaded black if in the interval $[-1.0, -0.5)$, dark gray if in the interval $[-0.5, 0.0)$, light gray if in the interval $[0.0, 0.5)$, and are otherwise white. The analysis uses filtered prices during 1997–1998 in the top graph, 1999 in the next graph, 2000 in the next graph, and 2001–2004 in the bottom graph.

of a sharp increase in competition induced market separation hitherto not present, and that this was removed by the appearance of additional generation downstream of the constraint and some expansion of network capacity in the critical area of the transmission grid.[21]

6 Conclusion

This paper has used principal component analysis to examine the degree of market integration in the New Zealand spot wholesale market for the years 1997–2004 inclusive. Our approach is different from previous analyses in that we use principal component analysis, which provides a natural way to model the base level of prices and relative prices that may vary across the nodes of the market. The base factor and, by definition, different other factors provide a way of exploring and describing market segmentation in an interconnected pool.

We find that there was some regular separation in the market in 1999 and 2000 around a constraint in the center of the North Island and that, particularly in 2000, it had some significant effect. At 1 April 1999 a generator duopoly was replaced by four generator-retailer firms, and for two years competition among them seemed to result in a constraint that had not previously been present. The constraint was relaxed somewhat by a transmission enhancement at the end of 2000 and at the same time a new combined cycle gas generation plant downstream of the constraint commenced reliable operation. From this date the separation was virtually eliminated and the spot market returned to its 'one-market' status. It maintained this status even in two dry-year high-price episodes when electricity often flowed opposite to its normal direction. These findings suggest that increased generator-retailer competition may well require grid and generator-locational investments to enable the maintenance of a competitive wholesale spot market.

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[21]The segmentation in 1999 and 2000 depicted in Figure 8 is in accord with transmission network experiences of the period. The relatively high prices during this period at Tokaanu and Stratford occurred at the same time as relatively low prices to the south of these nodes. Indeed, on 57 occasions during this period the constraint pressure was sufficient to produce a spring-washer effect (Read and Ring, 1995) in which prices to the south of the constraint were so low — to back off generation — that they became negative. At the same time, prices to the north of the constraint were very high to encourage demand reductions.

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