AN ASSESSMENT OF THE PERFORMANCE OF THE NEW ZEALAND WHOLESALE ELECTRICITY MARKET

by

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[Confidential material in this report is contained in square brackets]

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EXECUTIVE SUMMARY

i. The purpose of this report is to provide a detailed assessment for the Commerce Commission of the ability and incentive of the four largest electricity suppliers in New Zealand to exercise unilateral market power and to quantify the market power rents in the wholesale market that have resulted from the exercise of unilateral market power.

ii. It is important to emphasize that a supplier exercising all available unilateral market power subject to obeying the market rules is equivalent to that supplier taking all legal actions to maximize the profits it earns participating in the wholesale market. Moreover, a firm's management has a fiduciary responsibility to its shareholders to take all legal actions to maximize the profits it earns from participating in the wholesale market. Consequently, a firm is only serving its fiduciary responsibility to its shareholders when it exercises all available unilateral market power subject to obeying the wholesale market rules.

iii. Although three of the major participants in the New Zealand wholesale electricity market are owned by the Crown, their principal objective, as set out in the State-Owned Enterprises Act 1986, is to be "as profitable and efficient as comparable businesses that are not owned by the Crown". That is, the directors of the State-owned firms also have a legal obligation to ensure that they are exercising all available unilateral market power.

iv. Electricity possesses virtually all of the product characteristics that enhance the ability of a supplier to exercise unilateral market power. Supply must equal demand at every instant in time and at each location in the transmission network. It is very costly to store electricity and its production is subject to extreme capacity constraints in the sense that it is impossible to produce more than a pre-specified amount of energy from a generation unit in an hour. Delivery of the electricity must take place through a transmission network with a finite capacity. The pricing of wholesale electricity to final consumers makes the half-hourly wholesale demand extremely inelastic, if not perfectly inelastic with respect to changes in half-hourly wholesale prices. Finally, in most wholesale markets the vast majority of generation facilities are owned by a relatively small number of firms.

v. There is evidence from virtually every wholesale electricity market operating around the world consistent with some or all of the suppliers having the ability to exercise unilateral market power and raise prices significantly above levels that would be predicted by perfectly competitive behavior for sustained periods of time under certain system conditions. The experiences of many of these wholesale electricity markets are also directly relevant to New Zealand because several features of the New Zealand market are similar to features of the wholesale electricity markets in countries where the ability or incentive to exercise of unilateral market power has been identified and substantial wholesale price increases have been documented as a result of the exercise of unilateral market power.

vi. The analysis presented in this report emphasizes that a significant dependence on hydroelectric generation resources can significantly enhance the ability of suppliers in a wholesale electricity market to exercise unilateral market power for a sustained period of time. That is because once low water levels arise, they tend to persist until enough precipitation occurs to restore normal water levels, which can often take more than six months, depending on the rate at which water is used to produce electricity during that time period.

vii. The fact that large suppliers in the international wholesale electricity markets have been found to have the ability and incentive to exercise unilateral market power makes it likely that four suppliers that control more than 85 percent of the installed generation capacity in New Zealand have both the ability and incentive to exercise substantial unilateral market power under certain system conditions. The dependence of the New Zealand market on electricity from hydroelectric resources also makes it likely that when these four suppliers have the ability and incentive to exercise substantial unilateral market power, they are able to do so for a long enough period of time to achieve significant wealth transfers from consumers to producers of electricity.

viii. This report provides three main lines of evidence consistent with the view that the four large suppliers in the New Zealand electricity market have both the ability and incentive to exercise unilateral market power, and that this exercise of unilateral market power has resulted in substantial wealth transfers from consumers to producers during several sustained periods of time between January 1, 2001 to June 30, 2007.

ix. The first line of evidence uses insights from a model of expected profit-maximizing offer behavior by a supplier in a wholesale electricity market to derive half-hourly, firm-level indexes of the ability and incentive of a supplier to exercise unilateral market power. For each of the four firms, these firm-level indexes of the ability to exercise unilateral market are found to closely track the behavior of the quantity-weighted average of the half-hourly nodal prices over the period January 1, 2001 to June 30, 2007. Specifically, higher values of each of these indexes of the half-hourly, firm-level ability to exercise unilateral market power are associated with higher values of the quantity-weighted average of the half-hourly nodal prices.

x. This analysis is repeated for a half-hourly index of the firm-level incentive to exercise unilateral market power. Higher values of each of these half-hourly firm-level indexes of the incentive to exercise unilateral market power are associated with higher values of the quantity-weighted average of the half-hourly nodal prices.

xi. The time periods with high values of the quantity-weighted average of the half-hourly nodal prices are also associated with low values of hydro storage levels in New Zealand. Detailed analyses of the three periods of high prices in Winter 2001, Autumn 2003, and Summer 2006 reveal that the higher values of the average of four firm-level indexes of the ability and incentive to exercise unilateral market power provide a far better explanation for movements in the quantity-weighted average of half-hourly wholesale prices during these periods than movements in water storage levels.

xii. Evidence that this increasing relationship between the half-hourly firm-level ability to exercise unilateral market power and half-hourly market prices is the result of the unilateral profit-maximizing actions of the four large suppliers is then presented. For each supplier, a linear regression is estimated relating its half-hourly offer price—the highest offer price at which it sells output at during that half-hour—on factors that completely account for daily changes in input fossil fuel costs and daily water levels, and half-hourly changes in operating conditions throughout the day, on that supplier's half-hourly, firm-level index of its ability to exercise unilateral market power.

xiii. For all four suppliers, larger values of its half-hourly, firm-level ability to exercise unilateral market power are found to predict higher values of the offer price. This result implies that after controlling for differences in input fossil fuel prices and water levels across days of the sample and operating conditions throughout the day, higher values of the firm-level index of the ability to exercise unilateral market power are associated with higher offer prices. This evidence is consistent with the statement that after controlling for input cost differences across each day in the sample and half-hours within the day, when each of these four suppliers faces less competition from other suppliers, it submits a higher offer price into the wholesale market.

xiv. This analysis is repeated for the half-hourly, firm-level incentive to exercise unilateral market power and qualitatively similar results are obtained. The major difference between the two sets of results is that the predicted increase in the offer price for a one unit change in the half-hourly index of the firm-level incentive to exercise unilateral market is much larger than the predicted increase in the firm's offer price from a one unit change in its half-hourly, firm-level index of the ability to exercise unilateral market power. This result is consistent with the fact that having a substantial ability to exercise unilateral market power is only a necessary condition to exercise unilateral market power. A firm must also have a strong incentive to exploit this ability to exercise unilateral market power in order to do so.

xv. Several alternative half-hourly indexes of the ability and incentive of a firm to exercise unilateral market power are then introduced. These measures are based on the concept of a pivotal supplier. A supplier is pivotal during a given half-hour in the wholesale electricity market if some of its offers to supply energy must be taken or there will be insufficient energy available to meet the market demand.

xvi. The half-hourly offer price regression analysis described above is repeated for several measures of the half-hourly ability to exercise unilateral market power based on the pivotal supplier concept. These results find that after controlling for daily changes in input fossil fuel prices and half-hourly operating conditions throughout the day, higher half-hourly, firm-level indexes of the ability to exercise unilateral market power are associated with higher values of the half-hourly offer price for each of the four large suppliers.

xvii. These regression results are repeated for half-hourly firm-level indexes of the incentive to exercise unilateral market power based on the net pivotal supplier concept. These results also find a positive association between the half-hourly, firm-level index of the incentive to exercise unilateral market and that firm's half-hourly offer price for the three suppliers that are net pivotal a non-trivial fraction of the half-hours during the sample period.

xviii. The final piece of evidence in favor of suppliers exercising unilateral market power is a test of the null hypothesis that fossil fuel generation unit owners behave as if they have no ability to exercise unilateral market power. If the unit owner behaved in this manner it would submit offer curves for these generation units that depend only on their input fossil fuel costs and other variable operating costs. The amount of water available to the hydroelectric suppliers should not impact the marginal cost of fossil fuel generation units. To test this null hypothesis, the half-hourly offer price of each fossil fuel generation unit is regressed on the daily water level and factors that control for input fossil fuel price changes and other factors that could change the unit's variable cost across half-hours of our sample period. For all fossil fuel suppliers, lower water levels predict substantially higher half-hourly offer prices. This result provides strong evidence against the hypothesis that fossil fuel generation unit owners behave as if they had no ability or incentive to exercise unilateral market power.

xix. The second major line of evidence quantifies the cost of the exercise of unilateral market power by constructing counterfactual half-hourly market prices for the period January 1, 2001 to June 30, 2007 that do not reflect the exercise of unilateral market power. These competitive benchmark prices are constructed to be an upper bound on the half-hourly market prices that would result if no supplier had the ability to exercise unilateral market power.

xx. Four approaches are taken to computing these competitive benchmark prices. These approaches differ in terms of how hydroelectric suppliers are assumed to behave under the competitive benchmark and the degree of spatial granularity in the process used to compute the competitive benchmark prices.

xxi. The first approach used to compute the counterfactual competitive benchmark prices assumes that the hydroelectric suppliers continue to produce the same amount of energy during each half-hour of the sample period as they actually did. Fossil fuel generation units are assumed to behave as if they had no ability to exercise unilateral market power and submit offer curves consistent with this assumption, based on an upper bound on their marginal cost of producing electricity from each generation unit they own.

xxii. The only difference between this competitive benchmark price and the actual market price is that fossil fuel generation unit owners are assumed to behave as if they had no ability to exercise unilateral market power in the price offers but not the quantity offers that they submit, and hydroelectric suppliers produce the same amount of electricity they actually produced during each half-hour of the sample period. This approach to computing the competitive benchmark price yields a slack upper bound on the true competitive benchmark price.

xxiii. The second approach used to compute the competitive benchmark price allows hydroelectric suppliers to exercise more unilateral market power in the computation of the competitive benchmark price than the first approach. The hydroelectric supplier's actual offer curve is used in the competitive benchmark pricing calculation with each of its offer prices capped at the highest competitive offer price of fossil fuel generation units in New Zealand. The aggregate competitive benchmark offer curve is now composed of this slack upper bound on the competitive benchmark offer curve for each hydroelectric generation unit, and the competitive benchmark offer curves of the fossil-fuel generation units. Each half-hour, this price is computed by finding the price at the intersection of the aggregate competitive benchmark offer curve with the aggregate demand for electricity during that half-hour.

xxiv. For both of these approaches to constructing the competitive benchmark offer curves for hydroelectric and fossil fuel suppliers, a version of the nodal pricing software using the network model supplied by Transpower New Zealand Limited (Transpower) is implemented to compute counterfactual competitive benchmark nodal prices. Comparisons of the half-hourly, quantity-weighted average of actual nodal prices with the quantity-weighted average of half-hourly nodal prices computed using this nodal-pricing software using the actual offers submitted to the wholesale market each half-hour finds very small differences between the actual quantity-weighted average price and the quantity-weighted average of the nodal prices that result from using actual offers submitted to the wholesale market for that half-hour.

xxv. Comparing the behavior of the quantity-weighted average of the competitive benchmark half-hourly nodal prices computed using the nodal-pricing software to the corresponding half-hourly competitive benchmark prices computed using the simplified single-zone approach does not yield quantitatively different conclusions about the cost of the exercise of unilateral market power for both approaches to computing the competitive benchmark offer curves. Because of the computational simplicity of the single zone approach, the empirical analysis focuses on these results.

xxvi. Three major conclusions emerge from this segment of the empirical analysis. First, for the majority of the half-hours from January 1, 2001 to June 30, 2007, the average difference between actual prices and both sets of competitive benchmark prices is very small. Second, for the majority of years of our sample period, the average difference between actual prices and both sets of competitive benchmark prices is small. Third, there are at least three sustained periods of between three to six months in duration during our sample period when the average difference between actual prices and competitive benchmark prices is extremely large.

xxvii. These periods coincide with the periods when each of the four large suppliers has very large firm-level indexes of the ability to exercise unilateral market power and several of the firms have sizeable firm-level indexes of the incentive to exercise unilateral market power. During these periods, the average half-hourly value of system-wide market power rents—the difference between the actual price and the competitive benchmark price times the total system demand—are very large. Because these periods generally persist for more than three months, the total market power rents over each of these periods are economically significant. This section also presents suggestive evidence that these wholesale prices that resulted from the exercise of unilateral market power in the wholesale market were passed-through to electricity consumers in higher retail prices with a time lag.

xxviii. The third major line of evidence explores the extent to which the observed values of half-hourly market power rents are the direct result of the increased half-hourly ability and incentive of the four large suppliers to exercise unilateral market power. Three measures of half-hourly market power rents are constructed, one on a system-wide basis and two for just the four largest firms. Each of these measures of half-hourly market power rents are then regressed on factors that account for daily changes in water levels and fossil fuel prices, half-hourly changes in system conditions, the half-hourly value of total system generation, and the average of the four firm-level indexes of the half-hourly ability to exercise unilateral market power.

xxix. Higher values of the average of the four half-hourly indexes of the firm-level ability to exercise unilateral market power are found to predict higher values of each of the three measures of half-hourly market power rents. This result is consistent with the statement that when the average ability of the four large suppliers to exercise unilateral market power is larger, each measure of market power rents is larger.

xxx. This same analysis is repeated for the four half-hourly, firm-level indexes of the incentive to exercise unilateral market power. In this case, higher values of each firm-level index of the incentive of the supplier to exercise unilateral market power is found to predict higher values of each half-hourly measure of market power rents. Specifically, after controlling for daily changes in water levels and fossil fuel prices and changes in half-hourly system conditions, higher values of each half-hourly index of the firm-level incentive to exercise unilateral market power are associated with higher values of each half-hourly measure of market power rents. Consequently, even after controlling for the half-hourly values of the other three indexes of the incentive of the other suppliers to exercise unilateral market power, a higher value of this index for each of the four large suppliers predicts larger values of each of the three half-hourly values of market power rents.

xxxi. Taken together these three major lines of empirical evidence are consistent with the following three statements. During certain time intervals between January 1, 2001 and June 30, 2007, the four large suppliers in the New Zealand wholesale electricity market had a substantial ability and incentive to exercise unilateral market power. This ability and incentive to exercise unilateral market power can give rise to sustained periods of market prices that deviate significantly from competitive benchmark pricing, which can lead to large wealth transfers from consumers to producers of electricity. The half-hour periods when each of these suppliers has a greater ability or incentive to exercise unilateral market power are associated with the half-hour periods when each of the three measures of market power rents (and the magnitude of wealth transfers from consumers to producers) are larger.

xxxii. Appendix 1 discusses mechanisms that have been used in other countries around the world to limit the ability and incentive of large suppliers to exercise unilateral power. These mechanisms take the form of structural, behavioral, or explicit regulatory remedies.

xxxiii. Appendix 2 summarizes the market structure, rules, operating protocols, and regulatory structure governing the operation of the New Zealand electricity supply industry as of December 2006. A history of the electricity supply industry and evolution of the re-structuring process in New Zealand is presented. A detailed description of the wholesale market and a typical operating day in the wholesale market is provided. An analysis of market outcomes—prices, consumption, and generation—from the New Zealand electricity supply industry from 1997 to the end of 2005 is given. These results motivate a discussion of those features of the New Zealand market rules, market structure and regulatory oversight process that may be degrading system reliability and market efficiency as of December 2006.

SECTION 1

INTRODUCTION

1.1 The potential for the exercise of unilateral market power in wholesale electricity markets

1. Firms serving their fiduciary responsibility to maximize the returns earned by their shareholders can be expected to undertake all unilateral profit-maximizing actions given the actions of their competitors. A firm that undertakes all unilateral profit-maximizing actions given the actions of its competitors is by definition exercising all available unilateral market power. Consequently, a firm has a fiduciary responsibility to its shareholders to exercise all available unilateral market power. Competition law typically does not prohibit firms from exercising all available unilateral market power. That is because for most products, the market outcomes that result from all firms serving their fiduciary responsibility to their shareholders do not differ substantially for sustained periods of time from the market outcomes predicted by perfectly competitive behavior.

2. For these goods, the number and relative sizes of firms in the industry, the structure of demand for the product, the magnitude of the barriers to new entry into the industry, and the time lag between the decision to enter and the time production is first possible is sufficiently short so that even though all firms are exercising all available unilateral market power, market outcomes do not differ substantially from those predicted by perfect competition. The past two decades of international experience with electricity industry re-structuring has provided ample evidence that wholesale electricity is not one of these markets.

3. It is difficult to conceive of an industry more susceptible to the exercise of unilateral market power than electricity. Unlike other product markets, coordinated actions among suppliers or the concentration of productive capacity in the hands of a few firms is unnecessary for electricity suppliers to raise prices substantially above perfectly competitive levels. A number of wholesale electricity markets with Herfindahl-Hirschman- Indexes (HHIs) that would not raise market power concerns if they were from other industries have been found to be subject to severe market power problems. In addition, for all of these market power episodes, the relevant competition authorities have not found evidence of coordinated actions among suppliers to raise prices in violation of competition law.

4. Electricity possesses virtually all of the product characteristics that enhance the ability of a supplier to exercise unilateral market power. Supply must equal demand at every instant in time and at each location in the transmission network. It is very costly to store electricity. Its production is subject to extreme capacity constraints in the sense that it is impossible to produce more than a pre-specified amount of energy from a generation unit during an hour. Delivery of the product consumed must take place through a transmission network with finite capacity to transfer electricity across locations in the network. Historically, the pricing of wholesale electricity to final consumers makes the half-hourly wholesale demand extremely inelastic, if not perfectly inelastic, because few

final consumers pay retail prices that vary with half-hourly wholesale prices. The technology of electricity production historically favored large generation facilities, and in most wholesale markets the vast majority of these facilities are owned by a relatively small number of firms. Generation capacity ownership also tends to be concentrated in small geographic areas within these wholesale markets. All of these factors also make wholesale electricity markets substantially less competitive the shorter the time lag is between the date when the sale of energy is negotiated and the date delivery of the electricity occurs.

5. All of these features of wholesale electricity markets imply that even when a small number of suppliers have the ability and incentive to exercise unilateral market power in the short-term wholesale market, their unilateral actions can produce market outcomes that differ substantially from those predicted by perfectly competitive behavior for sustained periods of time. There is evidence from virtually every wholesale electricity market operating around the world consistent with some or all of the suppliers having the ability to exercise unilateral market power and raise prices significantly above levels that would be predicted by perfectly competitive behavior for sustained periods of time under certain system conditions.

6. Borenstein, Bushnell, and Wolak (2002)[1], Joskow and Kahn (2002)[2], and Wolak (2003)[3] present evidence that the large fossil fuel suppliers in the California electricity market exercised substantial unilateral market power during the period June 2000 to October 2000. Mansur (2001)[4] presents evidence that suppliers in the PJM electricity market[5] exercised unilateral market power during the first summer of market-based bidding in the PJM market. Hortascu and Puller (2008)[6] present evidence in support of the hypothesis that suppliers in the Texas wholesale electricity market exercise unilateral market power. Bushnell and Saravia (2002)[7] present evidence consistent with the view that suppliers in

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[1] Borenstein, Severin, Bushnell, James and Wolak, Frank A. (2002) "Measuring Market Inefficiencies in California's Restructured Wholesale Electricity Market," American Economic Review, December, 1367-1405.

[2] Joskow, Paul L. and Kahn, Edward. "A Quantitative Analysis of Pricing Behavior In California's Wholesale Electricity Market During Summer 2000." Energy Journal, 2002, 23(4), pp. 1–35.

[3] Wolak, Frank A. (2003) "Measuring Unilateral Market Power in Wholesale Electricity Markets: The California Market 1998 to 2000," American Economic Review, May 2003, 425-430.

[4] Mansur, Erin T. (2001) "Pricing Behavior in the Initial Summer of the Restructured PJM Wholesale Electricity Market," POWER Working Paper Number 083, available from http://www.ucei.berkeley.edu/ucei/PDF/pwp083.pdf

[5] PJM Interconnection is a regional transmission organization (RTO) that currently coordinates the movement of wholesale electricity in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia.

[6] Hortascu, Ali and Puller, Steven L. (2008) "Understanding Strategic Bidding in Multi-Unit Auctions: A Case Study of the Texas Electricity Spot Market. The RAND Journal of Economics, April, 86-114.

[7] Bushnell, James and Saravia, Celeste (2002) "An Empirical Assessment of the Competitiveness of the New England Electricity Market," May, Center for the Study of Energy Markets Working Paper Number CSEMWP - 101, available from http://www.ucei.berkeley.edu/pubs-csemwp.html.

the New England wholesale electricity market exercise unilateral market power. Sweeting (2007)[8], Wolfram (1999)[9], and Wolak and Patrick (1997)[10], all present evidence that the large suppliers in the England and Wales electricity pool exercised substantial unilateral market power. Garcia-Diaz and Marin (2003)[11], Kuhn and Machado (2004)[12], and Fabra and Toro (2005)[13] all present evidence that large suppliers in the Spanish electricity market exercise market power. Brennan and Melanie (1998)[14] present evidence that several large suppliers in the Australian electricity market have a substantial ability to exercise unilateral market power, and Gans and Wolak (2007)[15] present evidence that several large suppliers in the Australian electricity market have the ability and incentive to exercise unilateral market power. Garcia and Arbelaez (2002)[16] and Stachetti (1999)[17] present evidence that large suppliers in the Colombian electricity market have a substantial ability to exercise unilateral market power. Arellano (2002)[18] presents evidence that large suppliers in the Chilean electricity market have the ability to exercise unilateral market power. Halseth (1999)[19] presents evidence that the large

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[8] Sweeting, Andrew T., "Market Power in the England and Wales Wholesale Electricity Market 1995-2000," Economic Journal, Vol. 117, No. 520, pp. 654-685, April 2007.

[9] Wolfram, Catherine D. (1999) "Measuring Duopoly Power in the British Electricity Spot Market," The American Economic Review, Vol. 89, No. 4 (Sep., 1999), pp. 805-826.

[10] Wolak, Frank A. and Patrick, Robert H. (1997) "The Impact of Market Rules and Market Structure on the Price Determination Process in the England and Wales Electricity Market," February.

[11] Garcia-Diaz, Anton, and Marin, Pedro L. (2003) "Strategic bidding in electricity pools with short-lived bids: an application to the Spanish market," International Journal of Industrial Organization, Volume 21, Issue 2, February, Pages 201-222.

[12] Kuhn, Kai-Uwe and Machado, Matilde Pinto, (2004) "Bilateral Market Power and Vertical Integration in the Spanish Electricity Spot Market (September). CEPR Discussion Paper No. 4590. Available at SSRN: http://ssrn.com/abstract=608249.

[13] Fabra, Natalia and Toro, Juan (2005) "Price Wars and Collusion in the Spanish Electricity Market," International Journal of Industrial Organization, Volume 23, Issues 3-4, April, Pages 155-181.

[14] Brennan, Donna, and Melanie, Jane (1998) "Market Power in the Australian Power Market," Energy Economics, Volume 20, Issue 2, April, 121-133.

[15] Gans, Joshua S. and Wolak, Frank A. (2007) "A Comparison of Ex Ante versus Ex Post Vertical Market Power: Evidence from the Electricity Supply Industry," available at http://www.stanford.edu/~wolak.

[16] Garcia, Alfredo and Abelaez, Luis E. (2002) "Market Power Analysis for the Colombian Electricity Market," Energy Economics, Volume 24, Issue 3, May, 217-229.

[17] Stacchetti, Ennio (1999) "Auction Design for the Colombian Electricity Market, No 62, Documentos de Trabajo from Centro de Economía Aplicada, Universidad de Chile, available from http://econpapers.repec.org/paper/edjceauch/62.htm.

[18] Arellano, Soledad (2002) "Diagnosing Market Power in Chile's Electricity Industry," available from http://ideas.repec.org/p/ioe/doctra/214.html.

[19] Halseth, Arve (1999) "Market Power in the Nordic Electricity Market," Utilities Policy, Volume 7, Issue 4, February, 259-268.

suppliers in the Nordic electricity market have the ability to exercise unilateral market power. Johnsen, Verma, and Wolfram (1999)[20] present evidence supporting the view that suppliers in the Norwegian electricity market exercise unilateral market power. Kauppi and Liski (2008)[21] develop a hydro storage model and calibrate it to the Nordic electricity market and find that a market structure where a significant portion of the storage capacity is managed strategically provides a significantly better fit to actual Nordic market outcomes relative to a model that assumes no firms have the ability to exercise unilateral market power.

7. The fact that firms in these wholesale electricity markets have the ability and incentive to exercise unilateral market power, and as a result, have raised wholesale electricity prices substantially by doing so, is hardly surprising given their fiduciary responsibility to their shareholders to maximize profits and therefore exercise all available unilateral market power. The experiences of many of these wholesale electricity markets are also directly relevant to New Zealand because several features of the New Zealand market are similar to features of the wholesale electricity markets in countries where the ability or incentive to exercise unilateral market power has been identified and substantial wholesale price increases have been documented as a result of the exercise of unilateral market power.

8. For example, a large share of energy comes from hydroelectric generation units in Colombia, Chile, Norway, and Spain. An energy-only market exists in the United Kingdom, California, ERCOT, and the Nordic countries. There is a substantial amount of vertical integration between retailing and generation in the United Kingdom, Spain, the Nordic countries, and throughout the United States. A number of the dimensions along which the New Zealand market differs from these other wholesale markets only increase the likelihood that suppliers in New Zealand have the ability and incentive to exercise unilateral market power. These include the substantial dependence on hydroelectric energy, the high concentration of generation unit ownership in a small number of firms, the high degree of vertical integration with no formal retail price regulation, the physical isolation of the transmission network from other electricity markets, the lack of integration into the international market for liquefied natural gas, and a limited market for fixed-price forward contracts. All of these factors increase the likelihood, relative to other wholesale electricity markets around the world, that there are periods when the large suppliers in New Zealand have both the ability and incentive to exercise substantial unilateral market power.

9. The analysis presented in this report emphasizes that a significant dependence of an electricity supply industry on hydroelectric generation resources (as is the case in New Zealand) can significantly enhance the ability of suppliers in a wholesale electricity market to exercise unilateral market power for a sustained period of time. That is because

[20] Johnsen, Tor A.; Shashi Kant Verma, Shashi K.; and Wolfram, Catherine, "Zonal Pricing and Demand-Side Bidding in the Norwegian Electricity Market," POWER Working Paper PWP-063, University of California Energy Institute, available from http://www.ucei.berkeley.edu/ucei/PDF/pwp063.pdf

[21] Kauppi, Olli and Liski, Matti (2008) "An empirical model of imperfect dynamic competition and application to hydroelectricity storage," Helsinki Center of Economic Research, Discussion paper number 232, September, available at http://ethesis.helsinki.fi/julkaisut/eri/hecer/disc/232/anempiri.pdf.

once low water levels arise, they tend to persist until enough precipitation occurs to restore normal water levels, which can take more than six months, depending on the rate at which water is used to produce electricity during that time period. Therefore, when water levels are low, all market participants will face less competition for their output. Each hydroelectric supplier is less willing to submit offer prices below those of other suppliers, because it has less water available to sell as electricity. This logic implies that there will be less energy made available in the wholesale market to compete with each large supplier at almost every price level relative to the case when water levels are higher. Consequently, until sufficient precipitation occurs to restore normal water levels, all suppliers will have a greater unilateral ability to exercise market power. In contrast, when water levels are high, hydroelectric suppliers are typically more aggressive competitors in the wholesale market. Each supplier faces substantially more competition to sell electricity because all of the hydroelectric energy suppliers have much more water that they would like to sell as electricity, which implies that they must submit lower offer prices if they expect to sell all of it as electricity without spilling any of it.

10. The fact that large suppliers in the international wholesale electricity markets described above have been found to have the ability and incentive to exercise unilateral market power makes it likely that four suppliers controlling more than 85 percent of the installed generation capacity in New Zealand have both the ability and incentive to exercise substantial unilateral market power under certain system conditions. The dependence of the New Zealand market on electricity from hydroelectric resources makes it even more likely that when these four suppliers have the ability and incentive to exercise substantial unilateral market power, they are able to do so for a long enough period of time to achieve significant wealth transfers from consumers to producers of electricity.

1.2 Purpose of report

11. This report provides three lines of evidence consistent with the view that the four large suppliers in the New Zealand electricity market have both the ability and incentive to exercise unilateral market power, and that this exercise of unilateral market power has resulted in substantial wealth transfers from consumers to producers during several sustained periods of time from January 1, 2001 to June 30, 2007.

12. The first major line of evidence uses insights from a model of expected profit-maximizing offer behavior in a wholesale electricity market to derive half-hourly, firm-level indexes of the ability and incentive of a supplier to exercise unilateral market power. Each of these firm-level indexes of the ability to exercise unilateral market are found to closely track the behavior of the quantity-weighted average of the half-hourly nodal prices over the period January 1, 2001 to June 30, 2007. Specifically, higher values of each of these indexes of the half-hourly, firm-level ability to exercise unilateral market power are associated with higher values of the quantity-weighted average of the half-hourly nodal prices. This analysis is repeated for a half-hourly index of the firm-level incentive to exercise unilateral market power. Higher values of each of these half-hourly firm-level indexes of the incentive to exercise unilateral market power are associated with higher values of the quantity-weighted average of the half-hourly nodal prices.

13. The time periods with high values of the quantity-weighted average of the half-hourly nodal prices are also associated with low values of hydro storage levels in New Zealand. Detailed analyses of the three periods of high prices in Winter 2001, Autumn 2003, and Summer 2006 reveal that the higher values of the average of four firm-level indexes of the ability and incentive to exercise unilateral market power provide a far better explanation for movements in the quantity-weighted average of half-hourly wholesale prices during these periods than movements in water storage levels.

14. Evidence that this positive relationship between the half-hourly firm-level ability to exercise unilateral market power and half-hourly market prices is the result of the unilateral profit-maximizing actions of the four large suppliers is then presented. A linear regression is estimated for each supplier that relates its half-hourly offer price—the highest offer price at which it sells output at during that half-hour—on factors that completely account for daily changes in input fossil fuel prices and daily water levels, and half-hourly changes in operating conditions throughout the day, on that supplier's half-hourly, firm-level index of its ability to exercise unilateral market power. For all four suppliers, larger values of its half-hourly, firm-level ability to exercise unilateral market power predict higher values of the offer price. Specifically, after controlling for differences in input fossil fuel prices and water levels across days of the sample and operating conditions throughout the day, higher values of the firm-level index of the ability to exercise unilateral market power are associated with higher offer prices. This evidence is consistent with the statement that after controlling for input cost differences across each day in the sample and half-hours within the day, when each of these four suppliers faces less competition from other suppliers, it submits a higher offer price into the wholesale market.

15. This analysis is repeated for the half-hourly, firm-level incentive to exercise unilateral market power and qualitatively similar results are obtained. The major difference between the two sets of results is that the predicted increase in the firm's offer price for a one unit change in the half-hourly index of the firm-level incentive to exercise unilateral market is much larger than the predicted increase in the firm's offer price from a one unit change in its half-hourly, firm-level index of the ability to exercise unilateral market power. This result is consistent with the fact that having a substantial ability to exercise unilateral market power is only a necessary condition to exercise unilateral market power. A firm must have a strong incentive to exploit this ability to exercise unilateral market power in order to do so.

16. Several alternative half-hourly indexes of the ability and incentive of a firm to exercise unilateral market power are then introduced. These measures are based on the concept of a pivotal supplier. A supplier is pivotal during a given half-hour in the wholesale electricity market if some of its offers to supply energy must be taken or there will be insufficient energy available to meet the market demand. For example, if there are five firms in a wholesale market and each is willing to supply at most 100 MWh of energy, and the demand for energy is 450 MWh, then each supplier is pivotal. The market demand of 450 MWh cannot be met without each supplier providing at least 50 MWh, assuming that all other suppliers provide 100 MWh.

17. The half-hourly offer price regression analysis described above is repeated for several measures of the half-hourly ability to exercise unilateral market power based on the pivotal supplier concept. These results find that after controlling for daily changes in input fossil fuel prices and half-hourly operating conditions throughout the day, higher half-hourly, firm-level indexes of the ability to exercise unilateral market power are associated with higher values of the half-hourly offer price for each of the four large suppliers. These regression results are repeated for half-hourly firm-level indexes of the incentive to exercise unilateral market power based on the net pivotal supplier concept. These results also find a positive association between the half-hourly, firm-level index of the incentive to exercise unilateral market and the firm's half-hourly offer price for the three suppliers that are net pivotal a non-trivial fraction of the half-hours during the sample period.

18. The final piece of evidence presented in support of the view that higher market prices are the direct result of greater firm-level abilities and incentives to exercise unilateral market power is a test of the hypothesis that fossil fuel generation unit owners behave as if they have no ability to exercise unilateral market power. Specifically, if a fossil fuel generation unit owner believes that it has no ability to exercise unilateral market power, it would submit an offer curve into the wholesale electricity market that depends only on its input fossil fuel costs and other variable operating costs. The amount of water available to the hydroelectric suppliers does not impact the marginal cost of fossil fuel generation units, so daily water levels should not predict changes in the offer prices of a fossil fuel generation unit owner, if it behaves as if it has no ability to exercise unilateral market power.

19. To test this hypothesis, the half-hourly offer price of each fossil fuel generation unit is regressed on the daily water level and factors that control for input fossil fuel price changes and other factors that could change the unit's variable cost across half-hours of our sample period. For all fossil fuel suppliers, lower water levels predict substantially higher half-hourly offer prices. This result provides strong evidence against the hypothesis that fossil fuel generation unit owners behave as if they had no ability or incentive to exercise unilateral market power. In addition, the fact that lower water levels predict higher offer prices for each of the fossil fuel generation units is consistent with the owners of these units exercising more unilateral market power when they face less competition from hydroelectric generation units, because the owners of hydroelectric units must be less aggressive competitors when they have less water available to sell as electricity.

20. The major second line of evidence quantifies the cost of the exercise of unilateral market power by constructing counterfactual half-hourly market prices for the period January 1, 2001 to June 30, 2007 that do not reflect the exercise of unilateral market power. These competitive benchmark market prices are constructed to be an upper bound on the half-hourly market prices that would result if no supplier had the ability to exercise unilateral market power. Several approaches are taken to computing these competitive benchmark prices. These approaches differ in terms of how hydroelectric suppliers are assumed to behave under the counterfactual competitive benchmark and the degree of spatial granularity in the process used to compute the competitive benchmark prices.

21. The first approach used to compute the counterfactual competitive benchmark prices assumes that the hydroelectric suppliers continue to produce the same amount of energy during each half-hour of the sample period as they actually did. Fossil fuel generation units are assumed to behave as if they had no ability to exercise unilateral market power and submit offer curves consistent with this assumption, based on an upper bound on their marginal cost of producing electricity from each of the generation units they own. Hydroelectric suppliers are assumed to behave as price-takers for the amount of output they actually supplied during each half-hour. The competitive benchmark price is equal to the price at the intersection of the aggregate competitive offer curve of fossil fuel suppliers with actual level of demand minus the amount of energy supplied by all of the hydroelectric suppliers.

22. It is important to emphasize that the only difference between this competitive benchmark price and the actual market price, is that fossil fuel generation unit owners are assumed to behave as if they had no ability to exercise unilateral market power in the price offers but not the quantity offers that they submit, and hydroelectric suppliers produce the same amount of electricity they actually produced during each half-hour of the sample period. This approach to computing the competitive benchmark price yields a slack upper bound on the true competitive benchmark price, because it assumes that any market power exercised by the fossil fuel and hydroelectric suppliers by withholding capacity from the wholesale market persists under competitive benchmark pricing. Specifically, only the actual amount of capacity made available to the wholesale market during that half-hour from each fossil fuel unit is used to set the competitive benchmark price, instead of the nameplate capacity of each fossil fuel generation unit.

23. A further source of upward bias in this competitive benchmark price is that only the actual amount of energy provided by the hydroelectric supplier during each half-hour is assumed to be produced during that half-hour. A hydroelectric supplier exercising unilateral market power can be expected to withhold water during hours when it faces less competition, and sell more water during hours when it faces more competition. Re-allocating the production of electricity from hydroelectric generation units from low ability-to-exercise-market-power and low-priced half-hours to high ability-to-exercise-market-power and high-priced half-hours in the computation of the competitive benchmark prices would further reduce their average value.

24. The second approach to computing the competitive benchmark price allows the hydroelectric suppliers to exercise more unilateral market power in the computation of the competitive benchmark price than the first approach. The hydroelectric supplier's actual offer curve is used in the competitive benchmark pricing calculation with each offer price capped at the highest competitive offer price of fossil fuel generation units in New Zealand. The aggregate competitive benchmark offer curve is now composed of this slack upper bound on the competitive benchmark offer curve for each hydroelectric generation unit, and the competitive benchmark offer curves of the fossil-fuel generation units. The price at the intersection of the aggregate competitive benchmark offer curve with the aggregate demand for electricity during that half-hour defines this second competitive benchmark price.

25. This conservative cap on the offer prices of the hydroelectric suppliers in the competitive benchmark offer curve is derived from the fact that hydroelectric suppliers can produce electricity at a very low incurred variable cost, so that the most significant cost to hydroelectric suppliers from producing electricity during the current half-hour is the opportunity cost of what that water could be sold for in a later half-hour period. During most half-hours of the year, the production of additional hydroelectric energy displaces production from fossil fuel generation units, so that the competitive benchmark opportunity cost of producing electricity during that half-hour is the competitive offer price of the highest-priced fossil fuel unit operating during that half-hour. During the half-hours when only hydroelectric units are operating, the competitive benchmark opportunity cost of water should be less than the competitive offer price of all fossil fuel units.

26. This logic implies that an expected profit-maximizing hydroelectric supplier with no ability to exercise unilateral market power, operating in a market where no supplier has the ability to exercise unilateral market power and there is no scarcity of fossil fuel generation capacity, would not submit an offer price above the highest competitive offer price of all fossil fuel suppliers. During many half-hours of the year it would be expected profit-maximizing for hydroelectric suppliers to submit offer prices below the highest competitive offer price. This approach to computing competitive benchmark prices yields an even more slack upper bound on the true competitive benchmark price than the first approach, because it allows hydroelectric suppliers to exercise unilateral market power with their offer prices up to the highest fossil fuel competitive benchmark offer price and uses the half-hourly generation capacity offers they submit to the wholesale market rather than the nameplate capacity of the generation unit.

27. For both of these approaches to constructing the competitive benchmark offer curves for hydroelectric and fossil fuel suppliers, a version of the nodal-pricing software using the network model supplied by Transpower is implemented to compute counterfactual competitive benchmark nodal prices. Comparisons of the half-hourly, quantity-weighted average of actual nodal prices with the quantity-weighted average of half-hourly, nodal prices computed using this nodal-pricing software using the actual offers submitted to the wholesale market each half-hour finds very small differences between the actual quantity-weighted average price and the quantity-weighted average of the nodal prices that result from using actual offers submitted to the wholesale market for that half-hour. This result provides confirmatory evidence that our nodal pricing software accurately reflects the actual nodal-pricing mechanism used in the short-term wholesale market.

28. Comparing the behavior of the quantity-weighted average of the competitive benchmark half-hourly nodal prices computed using the nodal-pricing software to the corresponding half-hourly competitive benchmark prices computed using the simplified single-zone approach does not yield quantitatively different conclusions about the cost of the exercise of unilateral market power for both approaches to computing competitive benchmark offer curves for our sample period. Because of the computational simplicity of the single-pricing zone approach, the empirical analysis focuses on these results.

29. Three major conclusions emerge from this phase of the empirical analysis. First, for the majority of the half-hours from January 1, 2001 to June 30, 2007, the average difference

between actual prices and both sets of competitive benchmark prices is very small. Second, for the majority of years of our sample period, the average difference between actual prices and both sets of competitive benchmark prices is small. Third, there are at least three sustained periods of between three to six months in duration during our sample period when the average difference between actual prices and competitive benchmark prices is extremely large. These periods coincide with the periods when each of the four large suppliers has very large firm-level indexes of the ability to exercise unilateral market power and several of the firms have sizeable firm-level indexes of the incentive to exercise unilateral market power. During these periods, the average half-hourly value of system-wide market power rents—the difference between the actual price and the competitive benchmark price times the total system demand—are very large. Because these periods generally persist for more than three months, the total market power rents over each of these periods are economically significant. This section also presents suggestive evidence that the prices that resulted from the exercise of unilateral market power in the wholesale market were passed-through to electricity consumers in higher retail prices with a time lag.

30. The third major line of evidence explores the extent to which the observed values of half-hourly market power rents are the direct result of the increased half-hourly ability and incentive of the four large suppliers to exercise unilateral market power. Three measures of half-hourly market power rents are constructed, one on a system-wide basis and two for just the four largest firms. Each of these measures of half-hourly market power rents are then regressed on factors that account for daily changes in water levels and fossil fuel prices, half-hourly changes in system conditions, the half-hourly value of total system generation, and the average of the four firm-level indexes of the half-hourly ability to exercise unilateral market power. Higher values of the average of the four half-hourly indexes of the firm-level ability to exercise unilateral market power are found to predict higher values of each of the three measures of half-hourly market power rents. This result is consistent with the statement that when the average ability of the four suppliers to exercise unilateral market power is larger, each measure of market power rents is larger.

31. This same analysis is repeated for each of the four firm-level indexes of the half-hourly incentive to exercise unilateral market power. In this case, higher values of each firm-level index of the incentive of the supplier to exercise unilateral market power is found to predict higher values of each half-hourly measure of market power rents. Specifically, after controlling for daily changes in water levels and fossil fuel prices and changes in half-hourly system conditions, higher levels of each firm-level index of the half-hourly incentive to exercise unilateral market power are associated with higher values of each half-hourly measure of market power rents. Consequently, even after controlling for the half-hourly values of the three indexes of the incentive of the other suppliers to exercise unilateral market power, a higher value of this index for each of the four large suppliers predicts larger values of each of the three half-hourly values of market power rents.

32. Taken together these three lines of empirical evidence are consistent with the following three statements. During certain time intervals between January 1, 2001 and June 30, 2007, the four large suppliers in the New Zealand wholesale electricity market had a substantial ability and incentive to exercise unilateral market power. This ability and

incentive to exercise unilateral market power can give rise to sustained periods of market prices that deviate significantly from competitive benchmark pricing, which can lead to large wealth transfers from consumers to producers of electricity. The half-hour periods when each of these suppliers has a greater ability or incentive to exercise unilateral market power are associated with the half-hour periods when each of the three measures of market power rents (and the magnitude of wealth transfers from consumers to producers) are larger.

1.3 Outline of the remainder of the report

33. The remainder of this report proceeds as follows. Section 2 presents a number of summary statistics on behavior in the New Zealand wholesale electricity market. This section summarizes several important features of the behavior of market outcomes from 2000 to 2007, and various aspects of the market rules governing the wholesale market. Section 3 presents the theory of expected profit-maximizing offer behavior with and without fixed-price forward market obligations that forms the basis for the firm-level measures of the ability and incentive to exercise unilateral market power used throughout the remainder of the report.

34. Section 4 presents the results of the first line of empirical work demonstrating the increasing relationship between the firm-level measures of the ability and incentive to exercise unilateral market power and market prices. This section then presents empirical results demonstrating an increasing relationship between firm-level offer prices and the index of the supplier's ability to exercise unilateral market power. This section also presents empirical results demonstrating an increasing relationship between firm-level offer prices and the index of that supplier's incentive to exercise unilateral market power. Section 4 also contains the analysis of the relationship between offer prices and measures of the firm-level ability to exercise unilateral market power based on the pivotal supplier concept, and the analysis of the relationship between offer prices and measures of the firm-level incentive to exercise unilateral market power based on the net pivotal supplier concept. This section closes with the empirical examination of the hypothesis that fossil fuel generation unit owners behave as if they have no ability to exercise unilateral market power.

35. Section 5 presents a discussion of the economic theory underlying the computation of the competitive benchmark price. This section emphasizes that the competitive benchmark price does not provide a measure of the long-term financial viability of the industry. It demonstrates that a comparison of competitive benchmark prices with actual prices is a measure of the performance of the wholesale market relative to a wholesale market where no suppliers have the ability to exercise unilateral market power. This section describes the details underlying the two approaches to computing the competitive benchmark offer curves for hydroelectric suppliers, and the two approaches to accounting for the spatial granularity in the computation of the competitive benchmark prices. This section then presents the results of applying each of these approaches to computing competitive benchmark prices. Various summary statistics comparing these competitive benchmark prices with actual prices, and various measures of the magnitude of market power rents, are presented.

36. Section 6 contains the analysis of the relationship between the three measures of market power rents and the four firm-level indexes of the ability to exercise unilateral market power and the three measures of market power rents and four firm-level indexes of the incentive to exercise unilateral market power. Computation of each measure of market power rents is first presented. Then the results of empirical analysis are presented and discussed.

37. Section 7 summarizes the results of the empirical analysis.

38. Appendix 1 relates the results presented in this report to those from other wholesale electricity markets operating around the world. The major theme of this discussion is that other jurisdictions have learned from the lessons of other hydro-electric dominated markets operating in California, Colombia, Spain, and the Nordic countries, and have acknowledged that the exercise of unilateral market power in a hydro-dominated electricity market can result in substantial wealth transfer from consumers to producers. As a consequence, regulators in these jurisdictions have put in place both ex ante and ex post regulatory safeguards to prevent these harmful market outcomes from occurring. Versions of these safeguards that could be implemented in New Zealand are discussed.

39. Appendix 2 contains a preliminary report on the New Zealand wholesale electricity supply industry completed in December of 2006. This report summarizes the market structure, rules, operating protocols, and regulatory structure governing the operation of the New Zealand electricity supply industry. A history of the electricity supply industry and evolution of the re-structuring process in New Zealand is presented. A detailed description of the wholesale market and a typical operating day in the wholesale market is provided. An analysis of market outcomes—prices, consumption, and generation—from the New Zealand electricity supply industry from 1997 to the end of 2005 is given. These results motivate a discussion of those features of the New Zealand market rules, market structure and regulatory oversight process that may be degrading system reliability and market efficiency as of December of 2006.

SECTION 2

DESCRIPTIVE ANALYSIS OF NEW ZEALAND MARKET OUTCOMES

2.1 Introduction

40. This section presents descriptive statistics on several aspects of the New Zealand wholesale electricity market from 2001 to 2007 in order to provide the necessary background for the analyses presented in Sections 3 to 6. Detailed background on the wholesale market rules and the timing of events in a typical day in the New Zealand electricity market is provided in Appendix 2.

41. Section 2.2 presents a description of the characteristics of electricity that enhance the ability of suppliers to exercise unilateral market. Section 2.3 presents a description of the fleet of generation units in New Zealand. Section 2.4 characterizes the pattern of load and generation throughout New Zealand. Section 2.5 summarizes the behavior of half-

hourly prices during the sample period. Information on water levels and the relationship between water levels and market outcomes are presented in Section 2.6.

42. Section 2.7 summarizes the behavior of the retail load obligations and forward contract purchases and sales of each of the four large suppliers, namely Meridian Energy Limited (Meridian), Contact Energy Limited (Contact or Contact Energy), Genesis Power Limited (Genesis) and Mighty River Power Limited (Mighty River Power). To the extent possible given the available data, these retail load obligations are then broken down into those with retail prices that vary with the half-hourly wholesale price and those with retail prices that do not vary with half-hourly wholesale prices. Section 2.8 summarizes the behavior of the electricity production mix by input energy source and fossil fuel prices over the sample period. Section, 2.9 describes the several rounds of advance scheduling, pricing, and dispatch (SPD) model runs that precede the final price-setting process in the wholesale market.

2.2 Characteristics of electricity that enhance the ability of suppliers to exercise unilateral market power

43. It is difficult to conceive of an industry more susceptible to the exercise of unilateral market power than wholesale electricity, as it possesses virtually all of the product characteristics that enhance the ability of suppliers to exercise unilateral market power. These characteristics include:

- Non-storability: supply must equal demand at every instant in time and each location in the transmission network and it is very costly to store electricity once it has been produced.
- Capacity constraints: production is subject to extreme capacity constraints in the sense that it is impossible to produce more than a pre-specified amount of energy from a generation unit in an hour.[22]
- Finite network capacity: delivery of electricity must take place through a transmission network with finite capacity. When a transmission line is congested additional electricity cannot be sent across it without endangering the reliability of the transmission network. Finite transmission capacity can also limit the number of independent suppliers that are able to compete to supply electricity at a given location in the network.
- Inelastic demand: in almost all industries, consumers observe the market price and then decide whether or not to purchase a product. The reaction of consumers to higher prices (i.e., their decision to decrease the amount they purchase) limits the incentive of suppliers to exercise unilateral market power. Historically, the pricing of electricity to final consumers makes the half-hourly wholesale electricity demand extremely inelastic, if not perfectly inelastic, with respect to

[22] For example, a generation unit with a nameplate capacity of 100 MW can typically produce only slightly more than 100 MWh of energy in an hour.

the wholesale price. The small number of existing meters capable of recording a customer's half-hourly electricity consumption in virtually all electricity supply industries around the world, make it impossible to charge these customers for anything but their consumption between two consecutive meter readings, which is typically one or two months in duration.

- Long time lag between entry and production: the technology of electricity production historically favored large generation facilities, and in most wholesale markets the vast majority of these generation units are owned by a relatively small number of firms, as is the case in New Zealand. The time lag between the decision to construct a large fossil-fuel generation facility and when it begins production is approximately 2 years. For a sizeable hydroelectric facility this time lag can easily be twice as long.

- Geographical concentration: generation capacity ownership also tends to be concentrated in small geographic areas. In New Zealand, only one of the four large firms owns dispatchable generation units in both the North and South Islands, although Meridian owns the Te Apiti wind farm in the North Island.

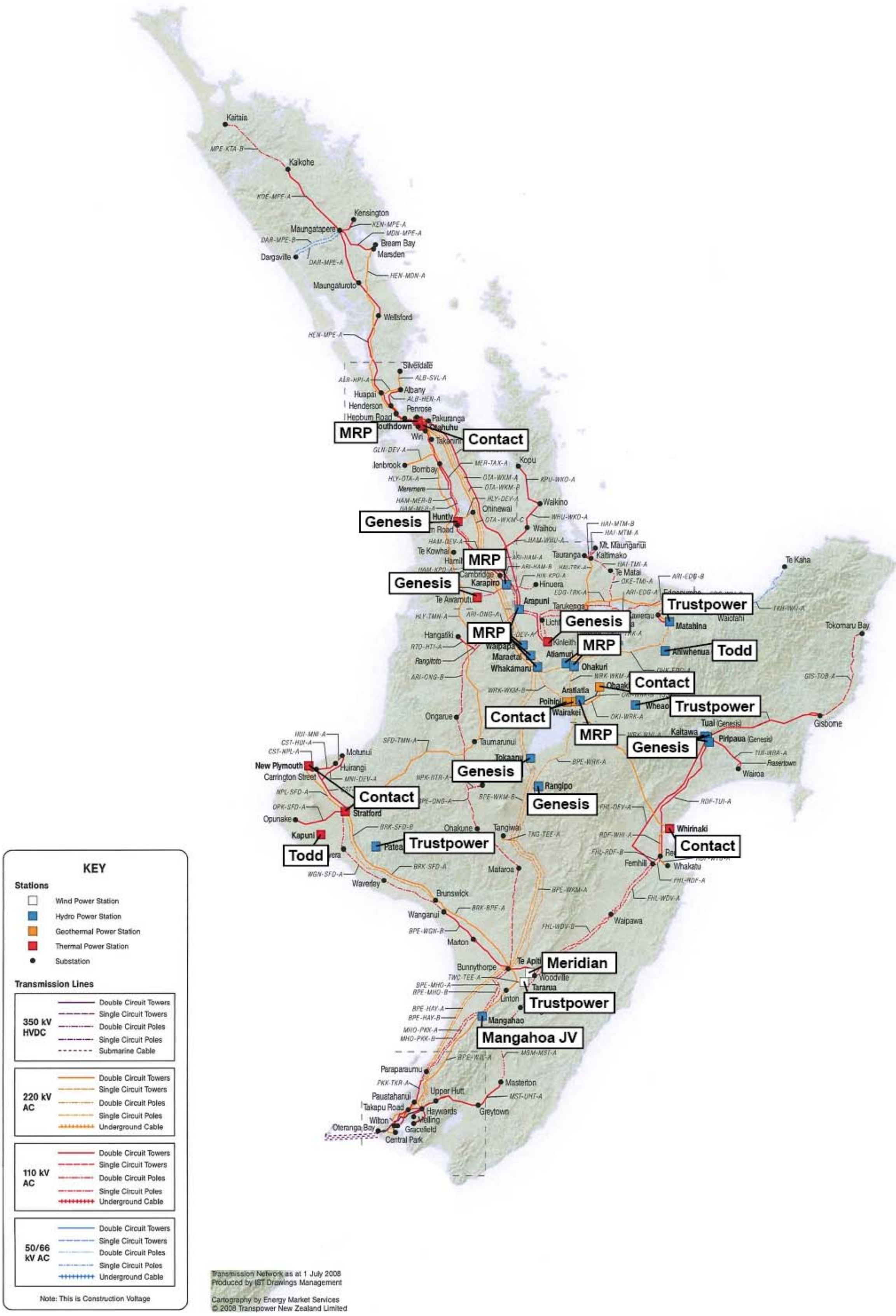
44. All of these factors also make wholesale electricity markets substantially less competitive the shorter the time lag is between the date the sale of electricity is negotiated and the date that delivery of that electricity occurs. For example, the number of independent suppliers able to construct and begin production in two years at a given location in the transmission network is significantly larger than the number of independent suppliers able to sell electricity one year in advance, and still larger than the amount of independent suppliers able to sell electricity one month in advance of delivery, and even larger than the amount of independent suppliers able sell electricity one day in advance of delivery.

45. New entrants cannot compete to sell electricity a month or day in advance--only existing generation units capable of starting up at this time horizon to delivery can compete in the short-term market. By this logic, the least competitive market for energy is the real-time market for energy, because only those generation units turned on with unloaded generation capacity and available transmission capacity can sell electricity at this time horizon to delivery.

2.3 Physical characteristics of generation fleet

46. The following maps (Figures 2.1 and 2.2) and tables (Table 2.1 and 2.2) show the location, generation fuel type, and capacity of generation assets in New Zealand.

Figure 2.1: North Island Generation locations and type



Source: Commerce Commission, amended from Transpower website, 2009

At http://www.Transpower.co.nz/f1010,2139700/2139700_transmission-map-ni.pdf

Table 2.1: North Island generation stations – ownership and type				
Owners/ Operators	**Fuel type**	**Plant Name**	**Commissioned**	**Total Capacity [MW]**
Contact Energy				
	Geothermal	Ohaaki	1989	50
	Gas	Otahuhu B CCGT	2000	380
	Geothermal	Poihipi	1997	55
	Gas	Taranaki CCGT	1998	360
	Geothermal	Wairakei	1958	162
	Geothermal	Wairakei Binary	2005	14
Genesis Energy				
	Gas	Huntly e3p CCGT (Unit 5)	2007	385
	Gas	Huntly P40 OCGT (Unit 6)	2004	50
	Coal/Gas	Huntly Steam Turbines (Units 1-4)	1987	1000
	Hydro	Kaitawa	1947	37
	Hydro	Piripaua	1942	44
	Hydro	Rangipo	1983	120
	Gas	Te Awamutu Cogen Gas Turbine	1995	54
	Hydro	Tokaanu	1973	240
	Hydro	Tuai	1929	60
	Gas/Wood/Coal	Kinleith Cogen Steam Turbine	1998	40
Meridian Energy				
	Wind	Te Apiti	2004	91
Mighty River Power				
	Hydro	Arapuni	1946	188
	Hydro	Aratiatia	1964	90
	Hydro	Atiamuri	1962	86
	Hydro	Karapiro	1948	96
	Geothermal	Kawerau	2008	100
	Hydro	Maraetai	1954/1971	360
	Hydro	Ohakuri	1962	112
	Gas	Southdown Cogen CCGT	1997/2007	170
	Hydro	Waipapa	1961	58
	Hydro	Whakamaru	1956	100
TrustPower				
	Hydro	Kaimai x 4	1972-1981	42
	Hydro	Matahina	1967	76
	Hydro	Patea	1984	31
	Wind	Tararua Wind Farm	1999-2007	161
	Hydro	Wheao x 2	1984	26
Others				
Alinta	Waste Heat	Glenbrook Cogen	1987/1997	112
Bay of Plenty (Todd Energy)	Hydro	Aniwhenua	1981	25
Bay of Plenty (Todd Energy)	Gas	Edgecumbe Co-Gen	1996	10
Mangahao Joint Venture	Hydro	Mangahao	1925	38
Tuaropaki Power Company	Geothermal	Mokai	2000/2005/2007	112
Vector/BOP (Todd Energy)	Gas	Kapuni Co-Gen CCGT	1998	23
NZ Govt (Contact Energy)	Diesel	Whirinaki*	2004	155

** The Whirinaki station is owned by the Government and operated by Contact. Its offer strategy is controlled by the Electricity Commission and Electricity Governance Rules.*

Source: MED Energy Data File 2008

Figure 2.2: South Island Generation locations and type

Source: Commerce Commission, amended from Transpower website, 2009

At http://www.Transpower.co.nz/f1010,2139700/2139700_transmission-map-ni.pdf

Table 2.2: South Island generation stations – ownership and type				
Owners/ Operators	**Fuel type**	**Plant Name**	**Commissioned**	**Total Capacity [MW]**
Contact Energy				
	Hydro	Clyde	1992	432
	Hydro	Roxburgh	1956	320
Meridian Energy				
	Hydro	Aviemore	1968	220
	Hydro	Benmore	1966	540
	Hydro	Manapouri	1971/2002/2008	728
	Hydro	Ohau A	1979	264
	Hydro	Ohau B	1980	212
	Hydro	Ohau C	1985	212
	Hydro	Tekapo A	1951	25
	Hydro	Tekapo B	1977	160
	Hydro	Waitaki	1936	105
Trust Power				
	Hydro	Argyle x 2	1983	11
	Hydro	Cobb	1956	32
	Hydro	Coleridge	1914	45
	Hydro	Waipori x 4	1903/1955	84

Source: MED Energy Data File 2008

2.4 Loads and generation in the New Zealand market

47. This subsection first summarizes the behavior of load over time and across regions of the country. How this load is served is then presented by describing the behavior of the generation produced and load served by each of the four large suppliers and TrustPower Limited (Trustpower) over the sample period. The behavior of the market shares of the major suppliers and retailers over the sample period are then described. Finally, the geographic distribution of generation and load for each of the large suppliers is characterized.

2.4.1. Behavior of loads in the New Zealand Electricity Market

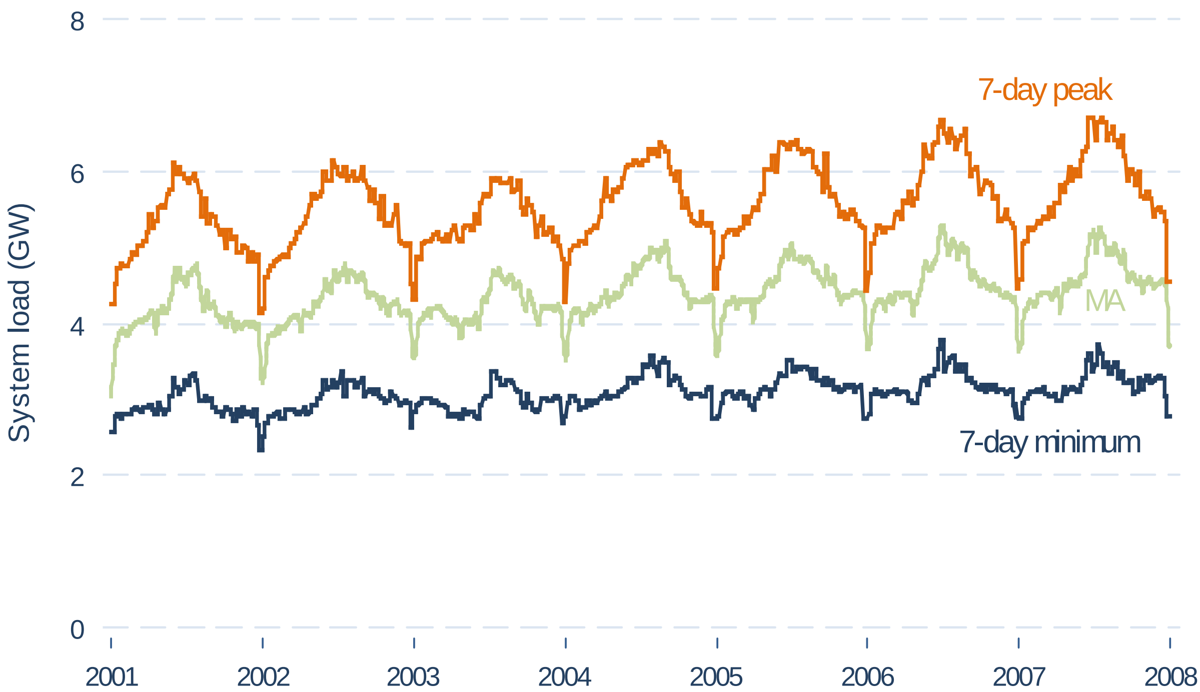
2.4.1.1 Pattern of system load

48. "Load" is the consumption of electricity by end-users. Because a very limited number of electricity users have half-hourly meters recording their consumption, assumptions are needed in order to estimate half-hourly system load for the analysis. We define the load at a node in the high-voltage transmission network (a Grid Exit Point, or GXP) as the sum of withdrawals from the transmission network at the GXP, plus the electricity produced by embedded generators connected to that GXP. Note that this overestimates the end-user load because it does not adjust for distribution network losses. However, these losses are likely to be fairly constant and a small fraction of system load. Both the GXP withdrawals and plant-level generation data are provided in the Electricity Commission's Centralised Data Set. System load is defined as the sum of loads at all GXPs.

49. Figure 2.3 shows the growth in system load from 2001 to 2007. The peak load (orange line) in 2001 was 6.10 GW, which increased to 6.72 GW in 2007, an annual rate of increase of 1.6%. The mean load over all half-hours in the year was 4.13 GW in 2001, increasing to 4.57 GW in 2007, a 1.7% annual increase. The green line in Figure 2.3 shows a seven-day moving average of the system load. The blue line shows the minimum system load each week.

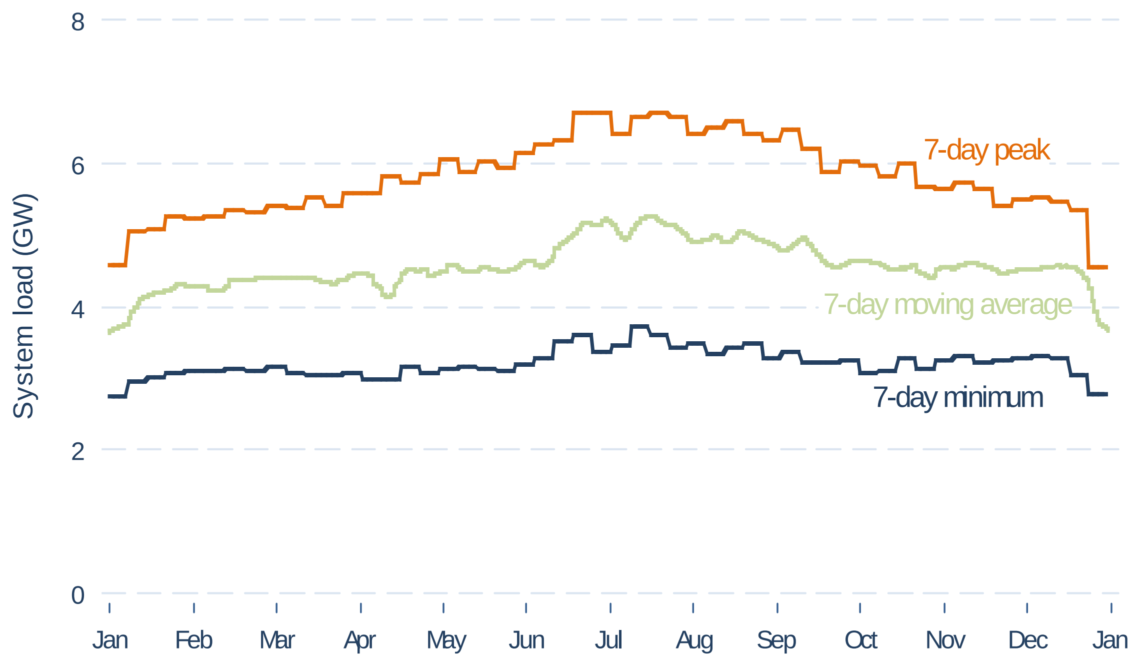
50. Figure 2.4 shows an enlarged version of Figure 2.3 for 2007. This highlights the very gradual increase in system load from the end of summer through autumn (February to May), followed by a 500MW jump in system load for winter. System load declines slowly from mid-winter (July) through to December. There is a sharp decline of about 750 MW in system load for the two-week Christmas holiday period.

Figure 2.3: Peak, minimum, and 7-day moving average system load, 2001-07



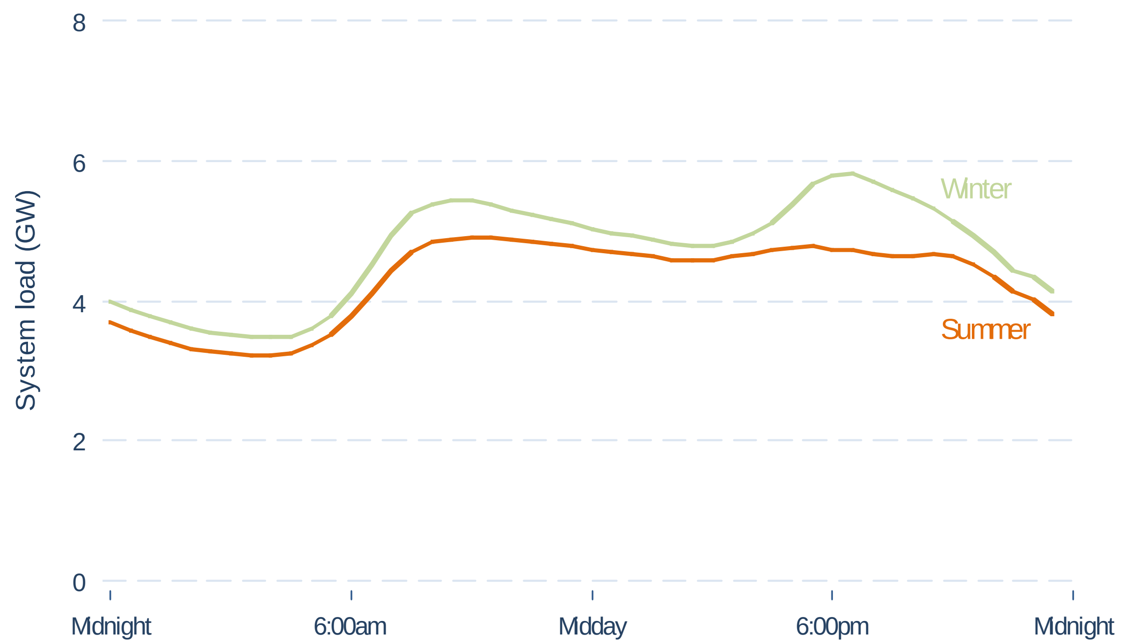
Source: Centralised Data Set

Figure 2.4: Peak, minimum, and 7-day moving average system load, 2007



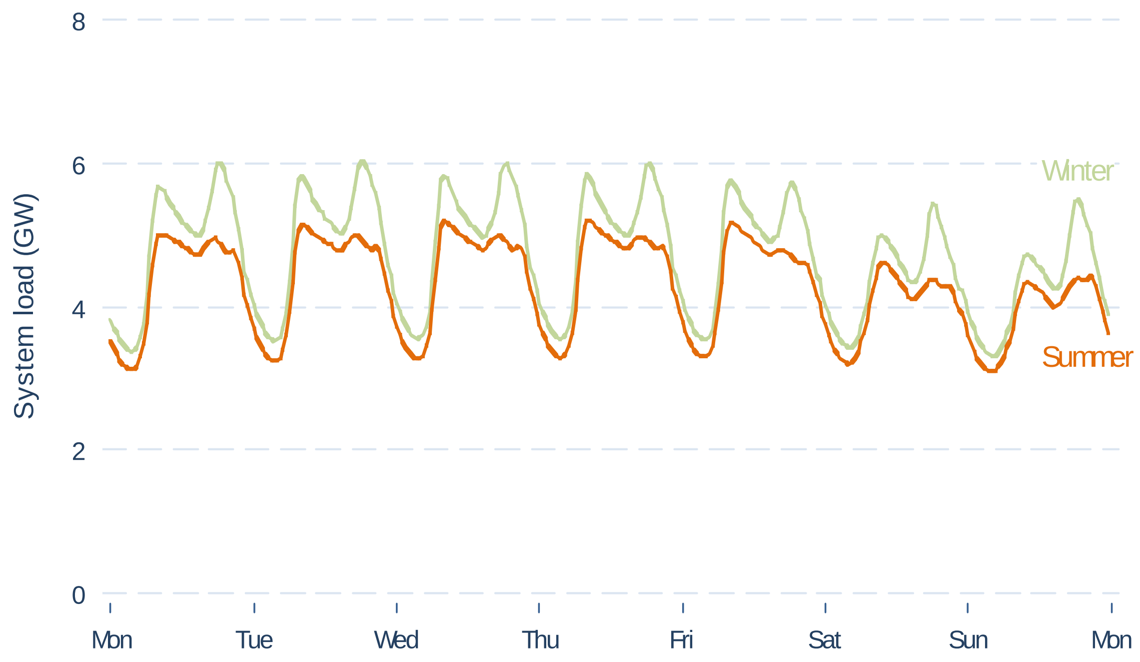
Source: Centralised Data Set

Figure 2.5: Intraday mean system load, summer and winter, 2004-07



Source: Centralised Data Set

Figure 2.6: Intra-week mean system load, summer and winter, 2004-07



Source: Centralised Data Set

51. Figure 2.5 shows the typical pattern of load during the day, in both summer (orange) and winter (green) months. Each point on the curve is the sample mean of a half-hourly load over all days from January 1, 2004 to June 30, 2007. Here summer is defined as October to March, and winter as April to September. For every half-hour of the day, mean load during winter is higher than the mean summer load in that half-hour. However, the difference is greatest in the evening period from 5:00pm through to about 8:30pm. Part of this is due to the shorter daylight hours during winter and the additional requirement for lighting in the early evening. The difference may also reflect the use of electric space heating during winter when people arrive home from work. The load shape during summer is much flatter overall, with the characteristic morning and evening peaks barely visible.

52. Figure 2.6 shows the typical load pattern over the week, again for both summer and winter. As expected, load drops slightly over the weekend. Interestingly, the evening peak is much higher than the morning peak during winter weekends; the two peaks are similar in magnitude during the week in winter.

2.4.1.2 Geographical distribution of load

53. The map in Figure 2.7 shows the distribution of mean load by GXP, calculated over all half-hours from 2004 to 2007[23]. Larger circles correspond to GXPs with higher average

[23] Note that the location of each circle corresponds to the geographic center of the region served by that GXP, not the location of the substation. This is because there can be multiple GXPs at the same location. The region served by each GXP was identified using data from the ICP Registry.

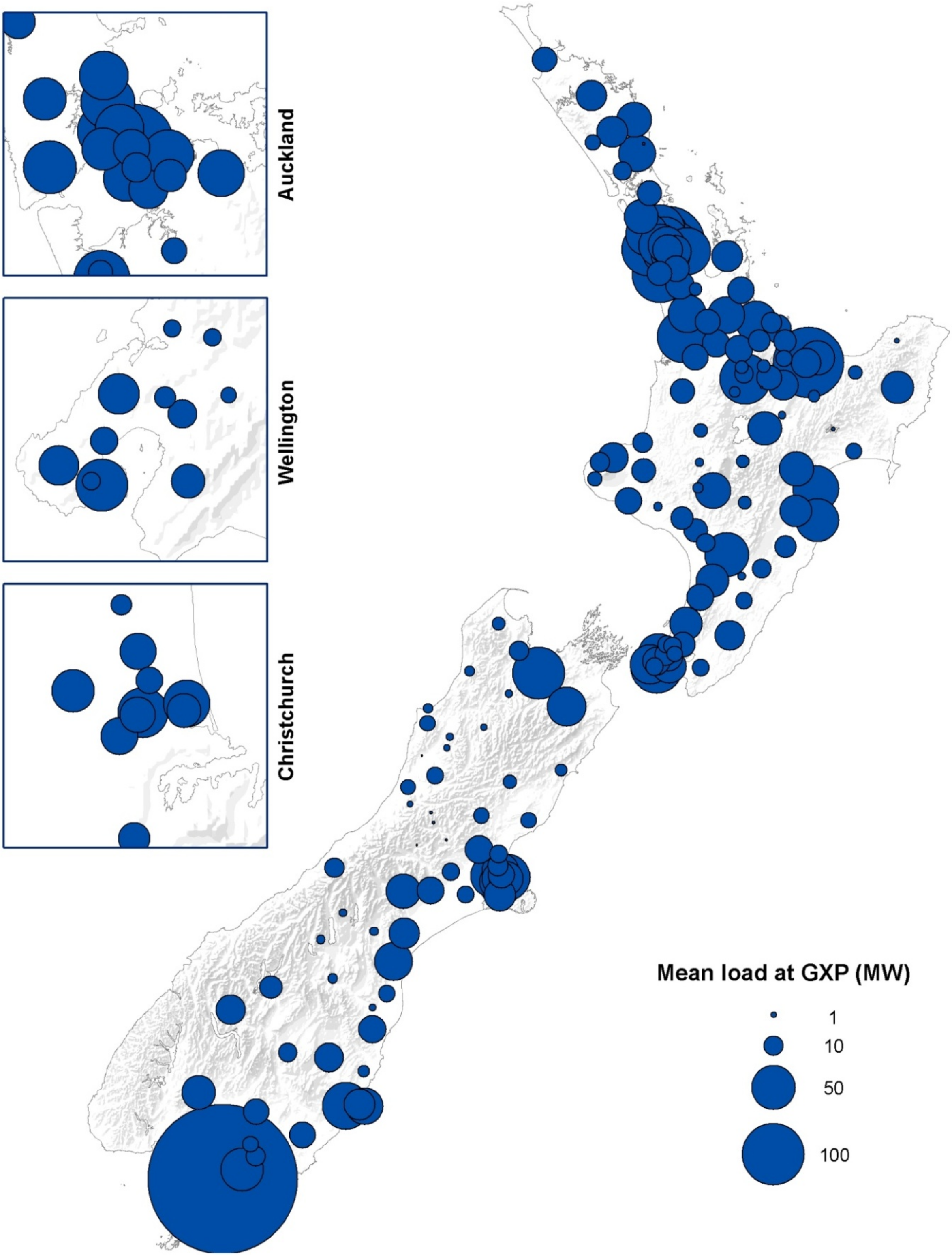
load. Apart from Wellington, load in the North Island is concentrated in a belt that runs from the Bay of Plenty through to Auckland, reflecting the presence of major industrial users and the large population in that region. South Island load is dominated by the Tiwai Point Aluminium Smelter in the far south of the island.

54. There are important changes in the distribution of load in New Zealand, both within each day and also over the course of the year. Figure 2.8 shows the average ratio of the minimum load each day to the maximum load each day, over the four-year period 2004 to 2007. For example, a value of 0.50 would mean that, on average, the minimum load at the GXP is half the maximum load at that GXP for that day. In general, the North Island shows a greater difference between the peaks and troughs each day than the South Island. Rural areas show less difference between the peaks and troughs than urban areas. One potential explanation for this pattern could be a greater use of electric water heating and night-storage space heating in the South Island, both of which would smooth the load shape. In addition, compared to people in rural areas, urban residents are more likely to leave their houses unoccupied during the day and return at about the same time each evening, creating the surge in demand at around 6:00pm.

55. Figure 2.9 shows the ratio of summer load to winter load for 2004 to 2007. Blue-colored regions have higher loads in winter, whereas red-colored regions have higher loads in summer. Almost all urban areas have higher loads during winter, although there is less difference for the centers of Auckland and Wellington than for the suburbs. In contrast, many rural areas (particularly in the South Island) have much higher loads during summer than in winter. This pattern corresponds to those areas with large amounts of irrigation during summer (the Canterbury Plains) as well as major dairying regions (such as the Waikato, Taranaki, parts of Northland, and Southland).

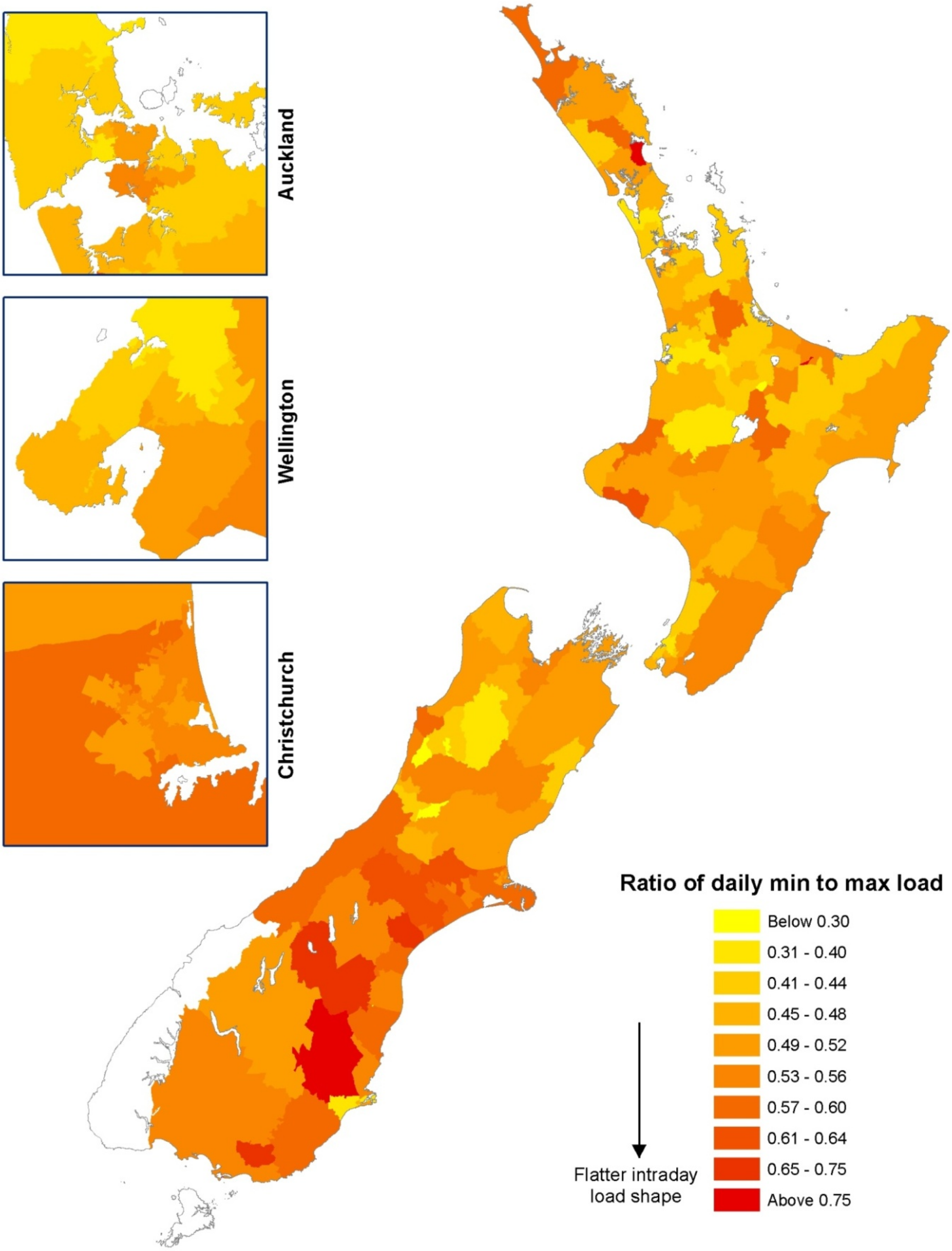
56. Figure 2.10 shows the load shifts between winter and summer in absolute rather than relative terms. The red circles correspond to regions with higher load during summer, and the blue circles regions with higher load during winter. The size of the circle corresponds to the difference between mean summer and winter loads, in MW. This map further demonstrates the shift of load from rural to urban areas during winter, and the extremely large additional load for irrigation during summer on the Canterbury Plains.

Figure 2.7: Mean load at each GXP, 2004-07



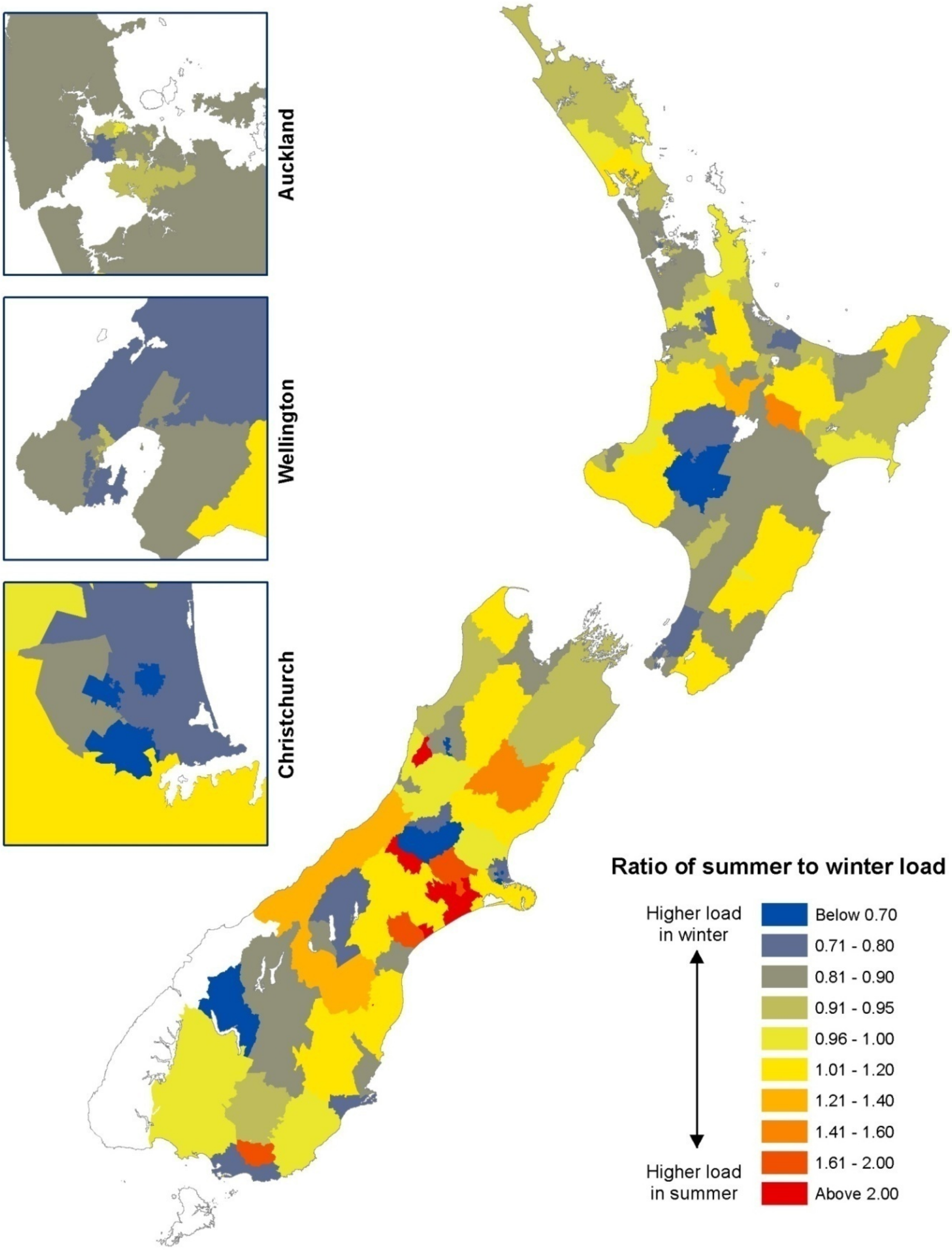
Source: Centralised Data Set

Figure 2.8: Mean ratio of daily minimum to peak load at each GXP, 2004-07



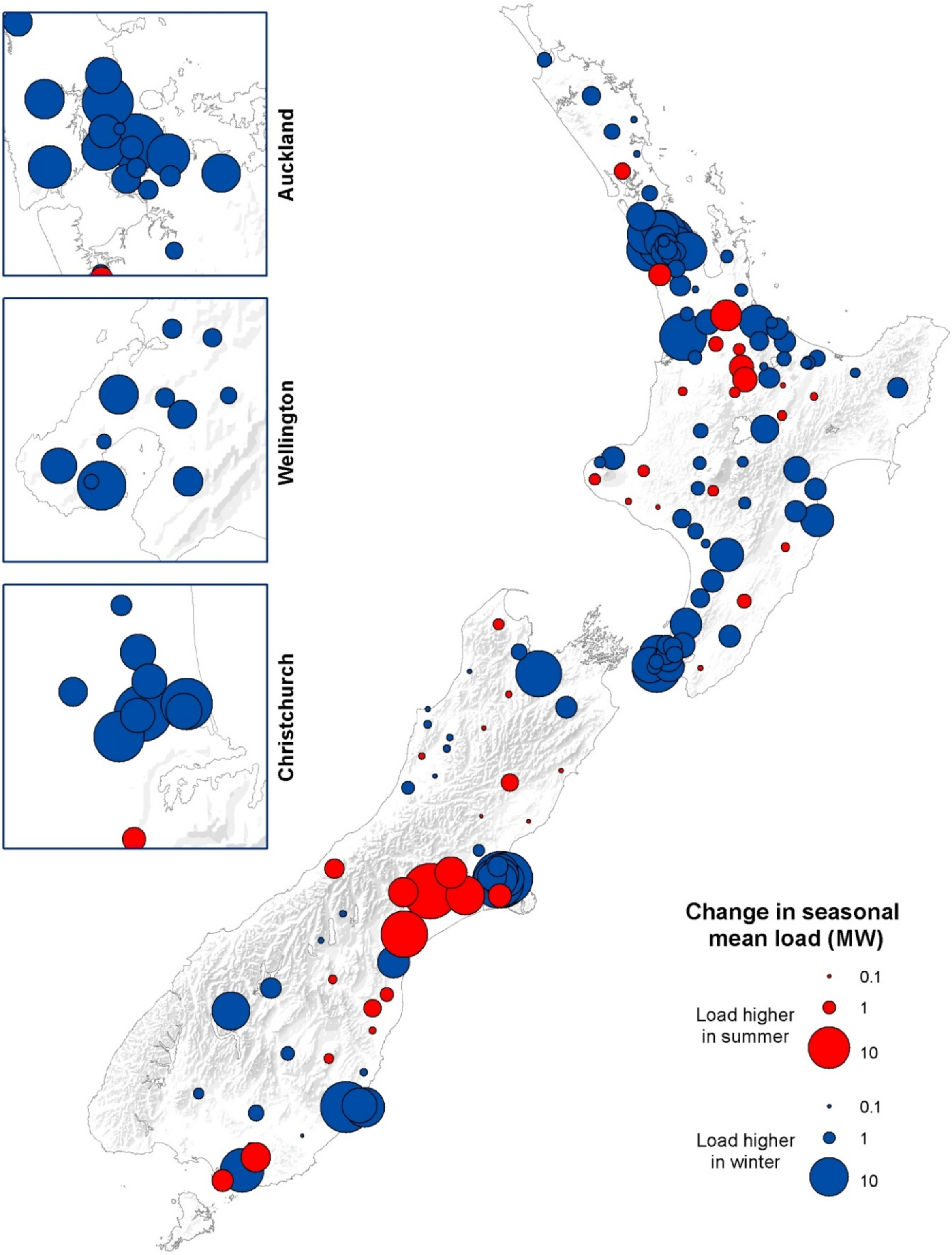
Source: Centralised Data Set

Figure 2.9: Seasonal change in load at each GXP, 2004-07



Source: Centralised Data Set

Figure 2.10: Seasonal change in load at each GXP, 2004-07



Source: Centralised Data Set

57. The combination of these geographical trends in load behavior is captured by Figure 2.11, which shows the correlation between the load at each GXP and the overall system load, for all half-hours from 2004 to 2007. The redder areas exhibit higher correlation with the system load. Much of Canterbury, as well as parts of Southland and Westland, show a negative correlation between their loads and the system load. This is caused by higher load during summer, when the system load is lowest. The rest of the South Island is generally less correlated with system load than the North Island. Auckland and Wellington have the highest correlation with the system load, although the centers of these cities are less correlated than the suburbs.

2.4.2. Behavior of Load and Generation by Supplier

58. Figure 2.12 shows the one-week moving average of generation and load for Contact Energy, from January 2001 to June 2007 (for load) and December 2007 (for generation). The one-week moving average of variable x_t in period t is defined as:

$$MA(x_t) = \frac{1}{336} \sum_{s=t-335}^{t} x_s$$

This quantity is first defined in period 48 on January 7, 2001.

59. The figure shows that Contact's annual load obligations increased by 380MW, or nearly 70%, between 2001 and 2003. This increase was the result of a large expansion in Contact's retail customers in networks where Contact was not the incumbent retailer. Between January 1, 2001 and December 31, 2002, Contact added approximately 108,000 ICPs in networks where it was not the incumbent retailer. This was more than the expansion by every other retailer combined (excluding the acquisitions of incumbent positions). In addition, Contact added a major industrial customer on a variable-price contract, which was responsible for the jump in load in May 2002.

60. As a result of these load increases, Contact's generation and load were approximately balanced during the second half of 2002. In March 2003, Contact acquired the Taranaki Combined Cycle (TCC) plant from NGC. Since then Contact's generation has exceeded its load obligations by about 300MW on average.

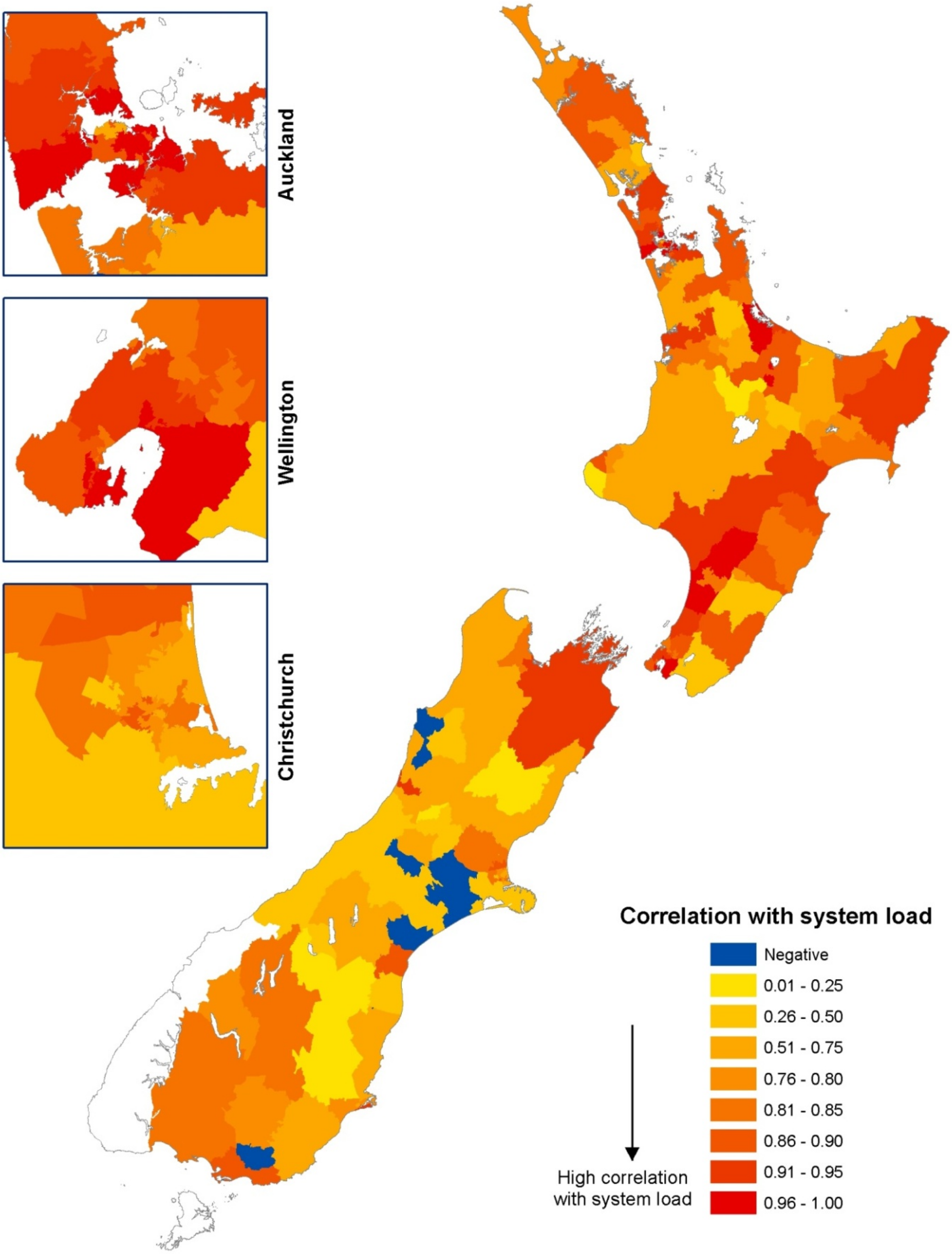
61. Figure 2.13 shows the one-week moving average of generation and load for Genesis Energy. The jump in October 2001 was due to the acquisition of NGC's retail customer base in the North Island. To a greater extent than the other generators, there is a strong seasonality in Genesis' generation that tracks the seasonality in Genesis' (and total) load. The difference in generation between mid-summer and mid-winter is about 400MW.

62. Figure 2.14 shows the one-week moving average of generation and load for Meridian Energy. The 200MW jump in Meridian's load in 2001 was the result of its acquisition of NGC's retail customers in the South Island. Meridian's weekly average generation varies by up to 800MW between periods with dry and wet hydrological conditions.

63. Figure 2.15 shows the one-week moving average of generation and load for Mighty River Power. Mighty River Power's load decreased by almost 200MW between 2001 and 2002, as a result of the loss of retail customers in its incumbent network area (Vector) as

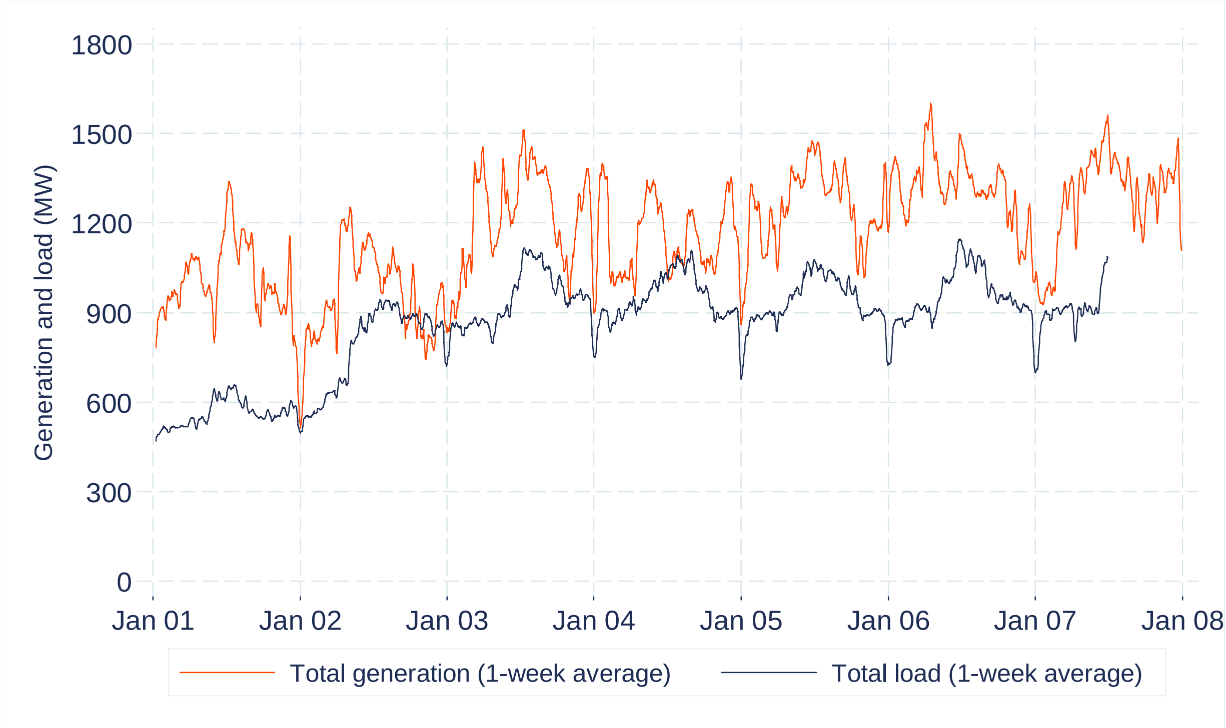
well as the loss of customers in non-incumbent networks. Since 2003 there has been a gradual increase in Mighty River Power's load. While its average generation has remained close to 600MW for the entire sample period, there is a lot of week-to-week volatility in Mighty River Power's generation quantity. The correlation between the average weekly generation and the previous average weekly generation is 0.83, which is the lowest of the four major generators.

Figure 2.11: Correlation of GXP loads with system load, 2004-07



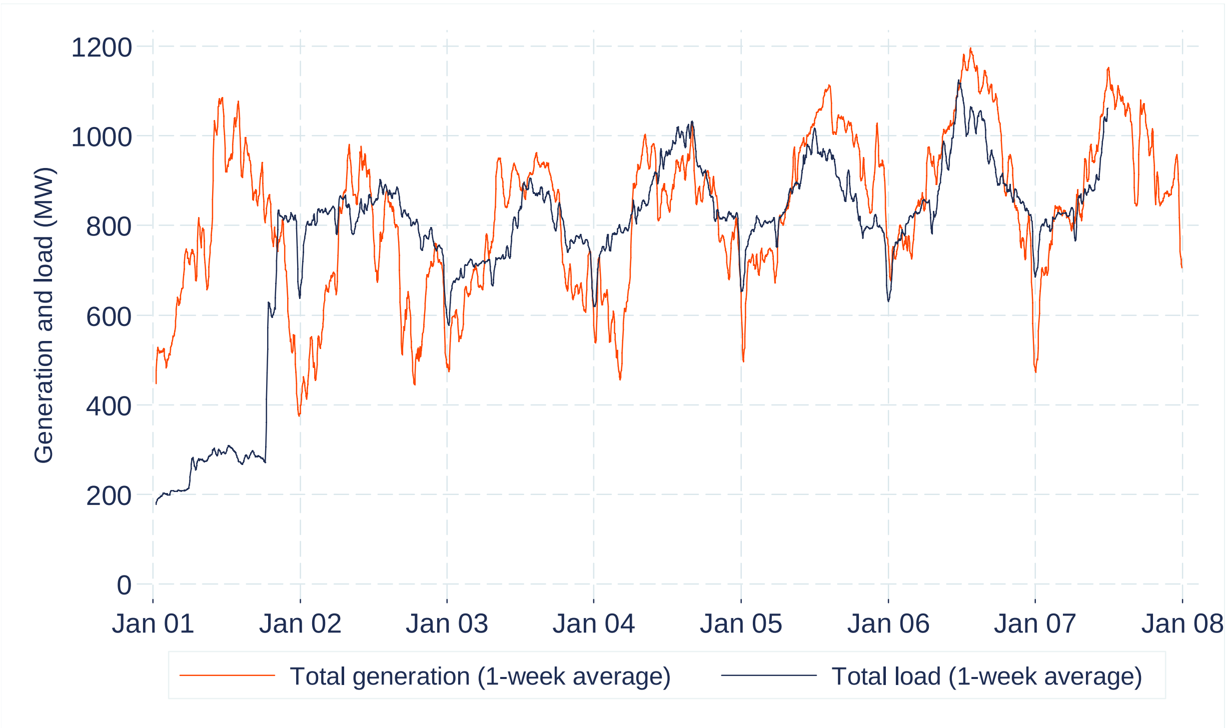
Source: Centralised Data Set

Figure 2.12: Generation and load, 1-week moving average, Contact



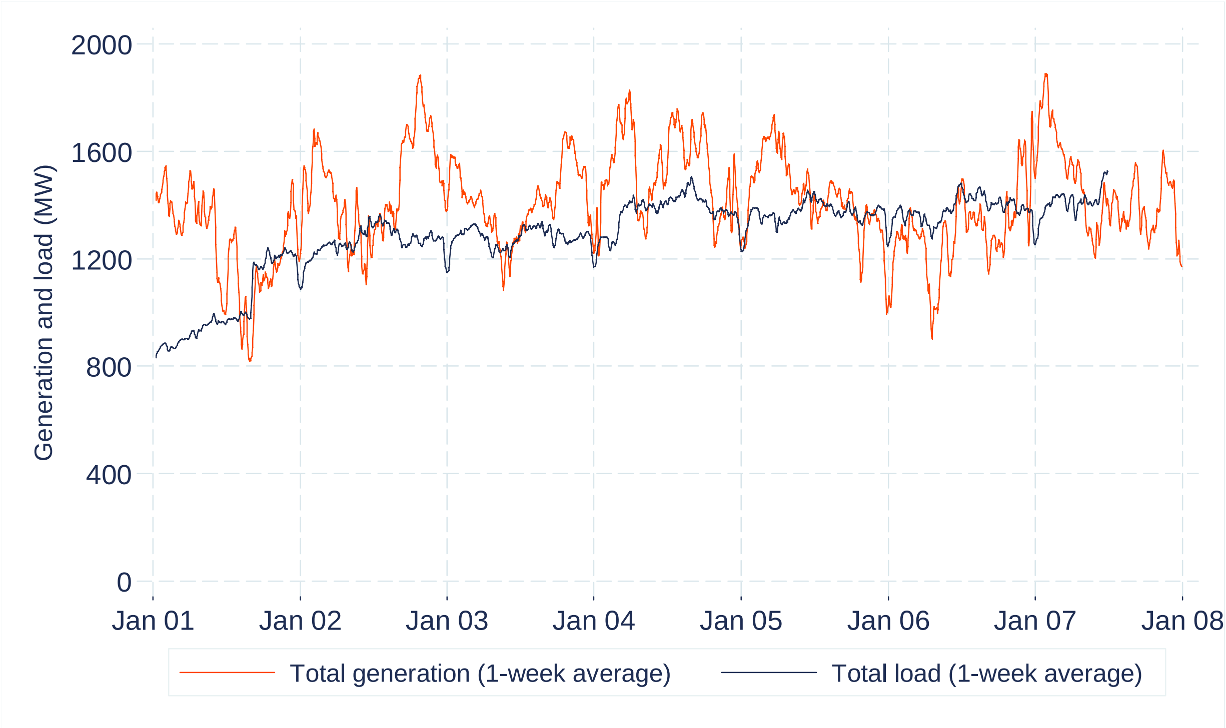
Source: Centralised Data Set (generation), EMS firm-level settlement data (load)

Figure 2.13: Generation and load, 1-week moving average, Genesis Energy



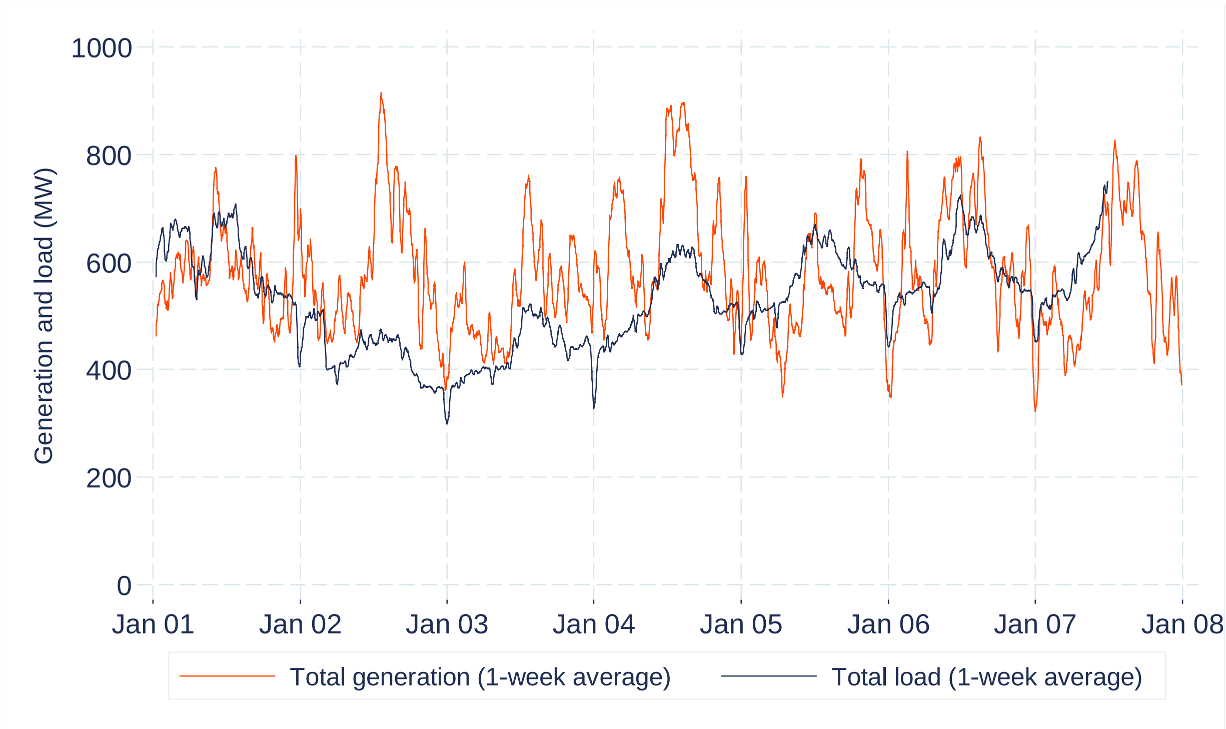
Source: Centralised Data Set (generation), EMS firm-level settlement data (load)

Figure 2.14: Generation and load, 1-week moving average, Meridian Energy



Source: Centralised Data Set (generation), EMS firm-level settlement data (load)

Figure 2.15: Generation and load, 1-week moving average, Mighty River Power



Source: Centralised Data Set (generation), EMS firm-level settlement data (load)

64. Figure 2.16 shows the one-week moving average of generation and load for TrustPower. Average load fell by 29% between 2002 and 2006, as TrustPower shed more than 40,000 ICP's in networks where it was not the incumbent retailer. Over the same period TrustPower increased its average generation by 23%. This was the result of the acquisition of the Cobb power station from NGC and the expansion of capacity at the Tararua wind farm.

65. Figure 2.17 shows the annual market shares in generation in the North Island from 2001 to 2007. Genesis and Contact are the largest generators in the North Island, each with about a third of total generation. Mighty River Power is in third place with just over a 20% market share. Mighty River Power's share of generation has declined since 2001 as the result of acquisitions and capacity expansions by Contact and Genesis. In 2001 and 2002, NGC was the fourth largest generator in the North Island, until it sold its TCC plant to Contact in March 2003.

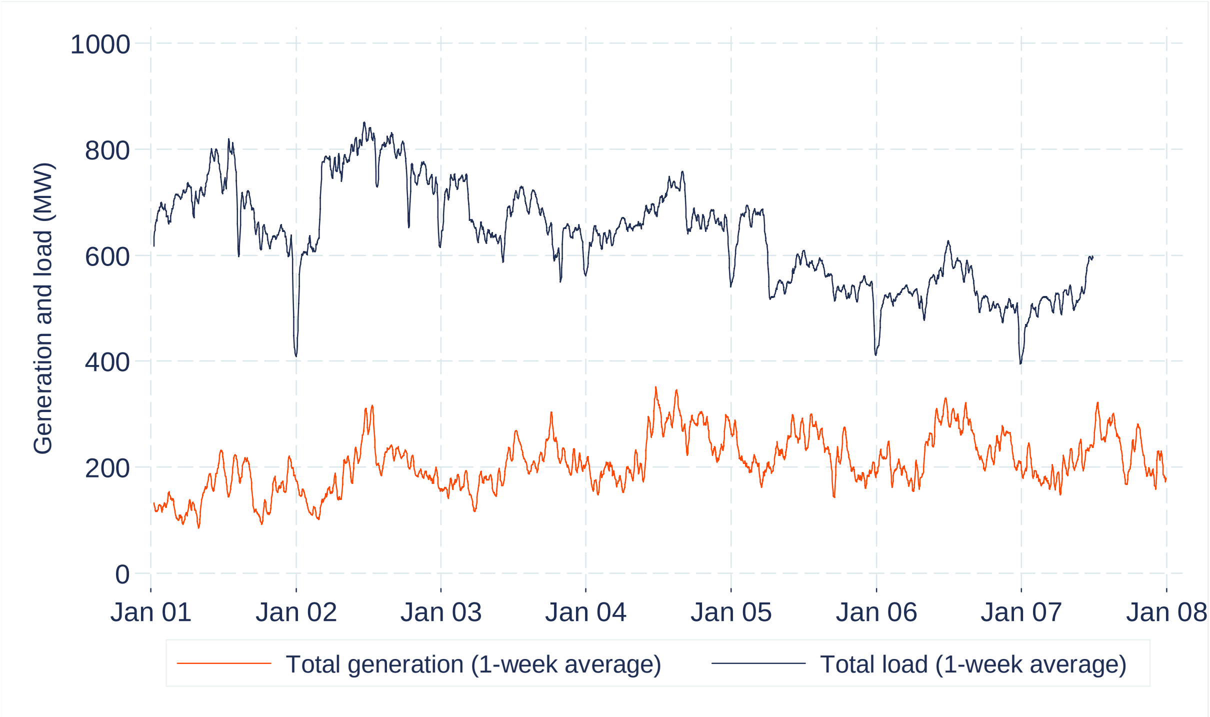
66. Figure 2.18 shows the annual market shares in generation in the South Island over the same seven-year period. Meridian, with its Waitaki River scheme and the Manapouri hydro station, is by far the largest generator in the South Island, with a market share of nearly 75%. Contact is the second-largest generator with a market share just above 20%.

67. Figure 2.19 shows the combined market shares in generation for both islands. Meridian and Contact are the largest generators overall, with Contact's share equaling Meridian's in 2006. The third largest generator is Genesis, with a market share of about 20%. Mighty River Power has a market share of about 12%, and finally TrustPower has a market share of about 5%.

68. Figure 2.20 shows the annual market shares for load in the North Island from 2001 to June 2007, where the last year is only for the first six months of 2007. Genesis is the largest North Island retailer with a market share of about 30% as the result of its acquisition of NGC's customer base in 2001. Mighty River Power and Contact are the second and third largest retailers, followed by Meridian and TrustPower. All five major retailers have a market share in the North Island that exceeds 10%, and the Herfindahl-Hirschman Index for the North Island retail market is 1,970.

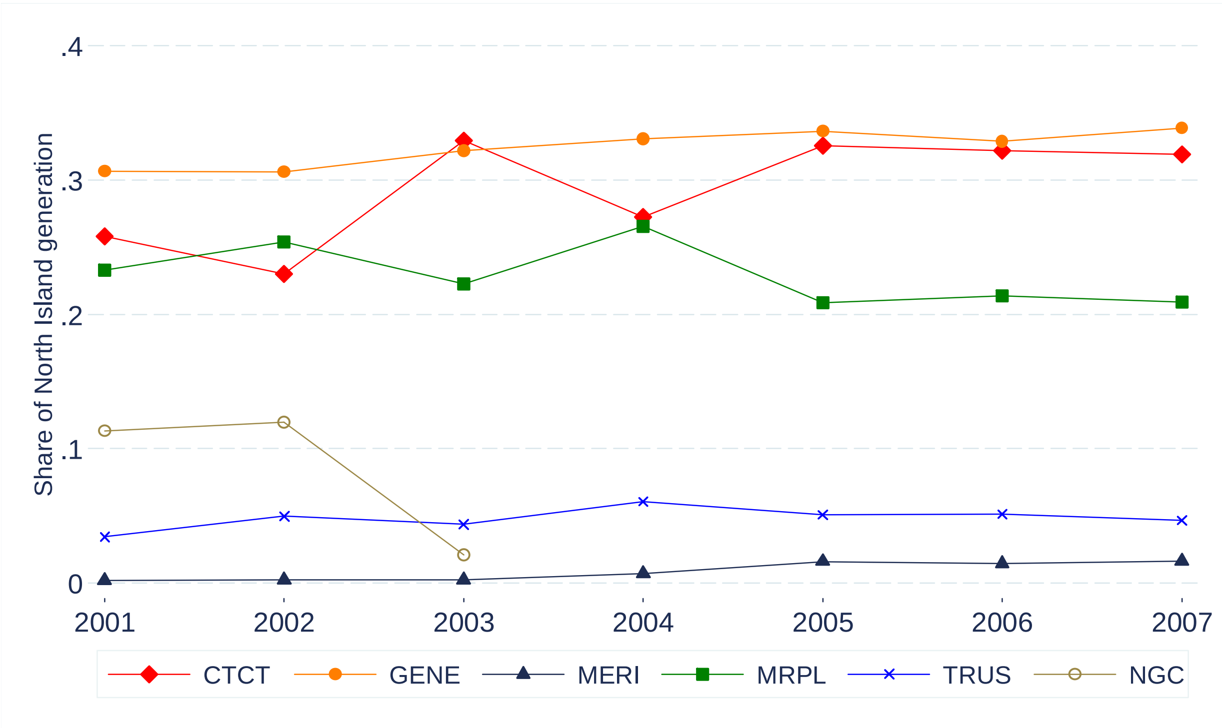
69. Figure 2.21 shows the annual market shares for load in the South Island from 2001 to June 2007. As it is for generation, Meridian is by far the largest retailer in the South Island, with a market share of more than 60%, followed by Contact with a market share of about 25%. However, it is important to note that more than half of Meridian's retail load in the South Island is its supply to the Tiwai Point Aluminium Smelter. Excluding the aluminum smelter load, Meridian has a market share close to that of Contact. TrustPower is the only other retailer with a significant presence in the South Island. The Herfindahl-Hirschman Index for the South Island retail market is 4,615 including the aluminum smelter load, or 3,500 excluding the aluminum smelter load.

Figure 2.16: Generation and load, 1-week moving average, TrustPower



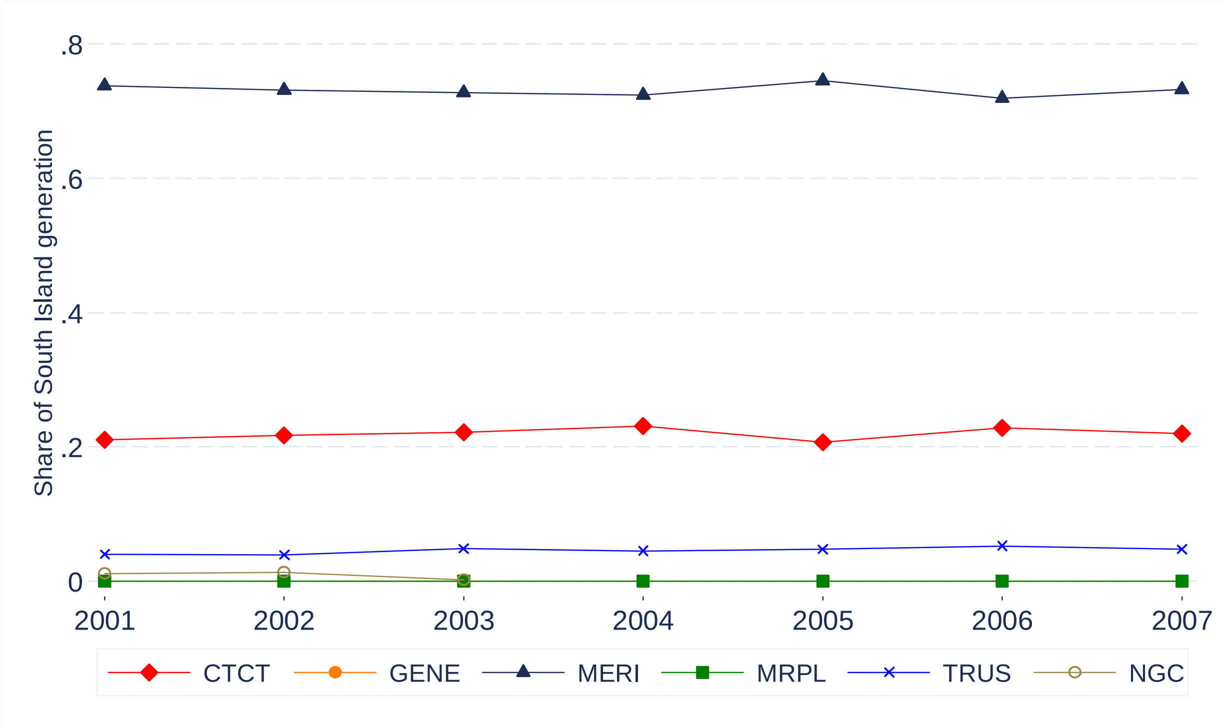
Source: Centralised Data Set (generation), EMS firm-level settlement data (load)

Figure 2.17: Annual market shares in generation, North Island, 2001–07



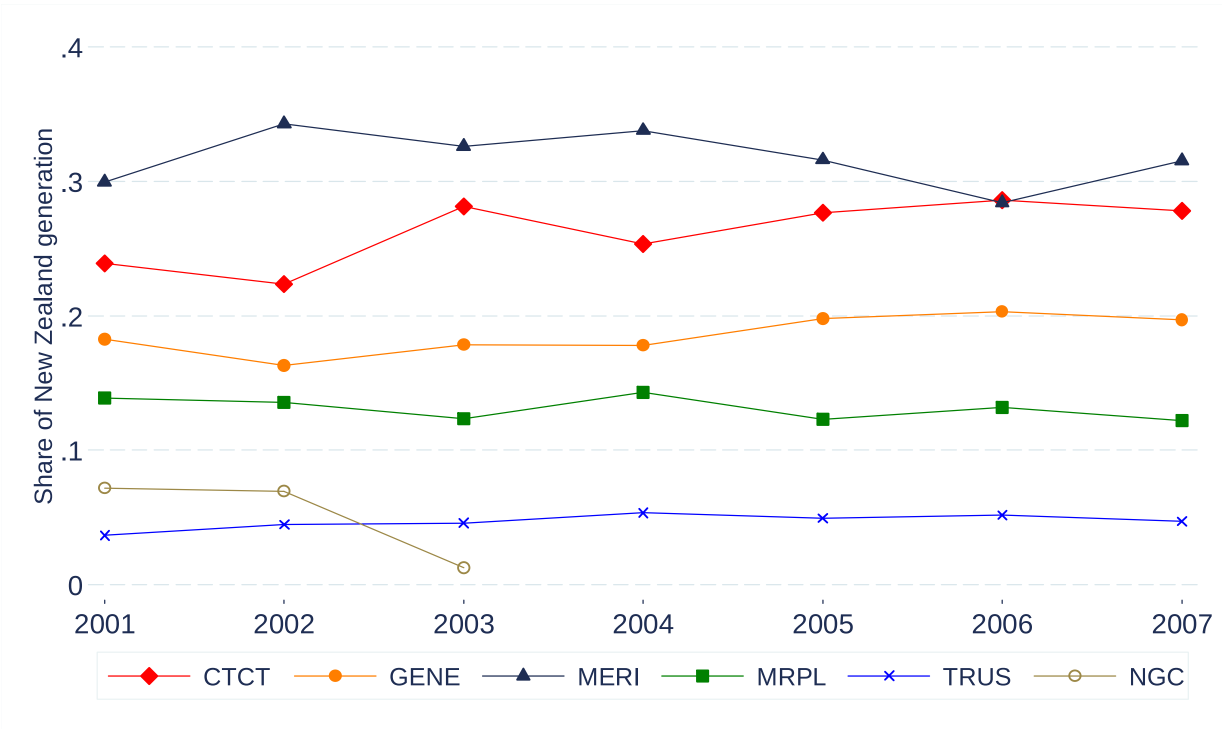
Source: Centralised Data Set

Figure 2.18: Annual market shares in generation, South Island, 2001–07



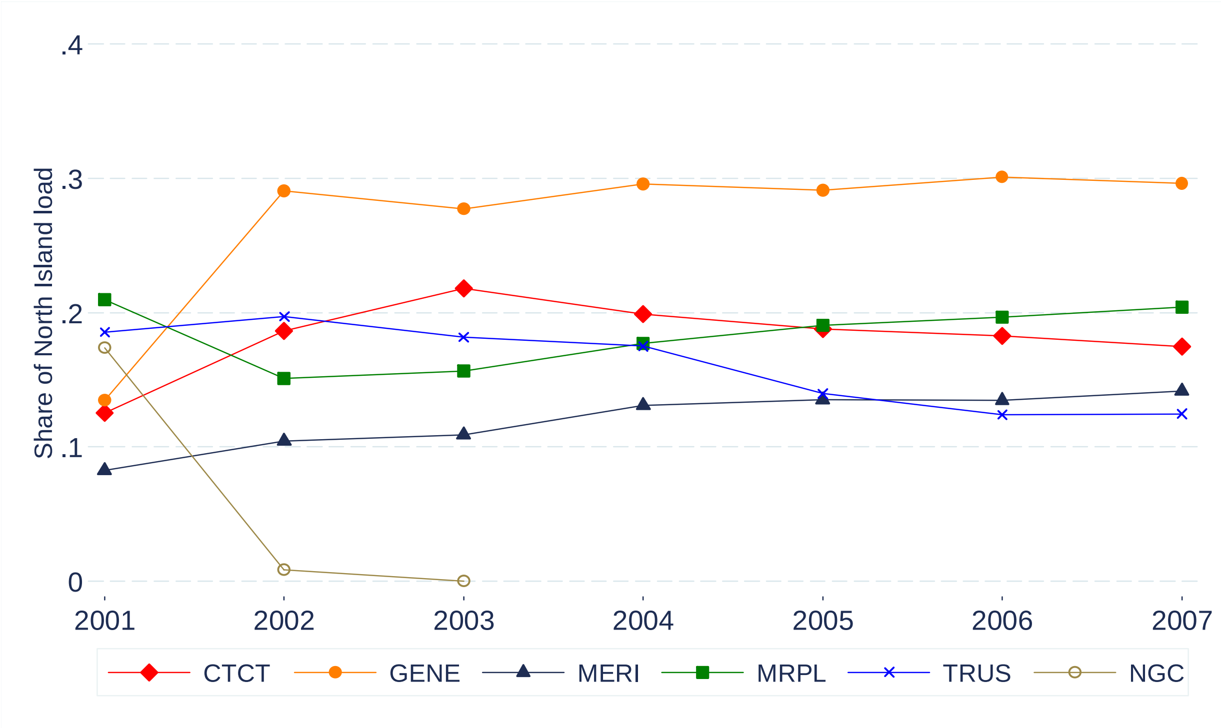
Source: Centralised Data Set

Figure 2.19: Annual market shares in generation, New Zealand, 2001–07



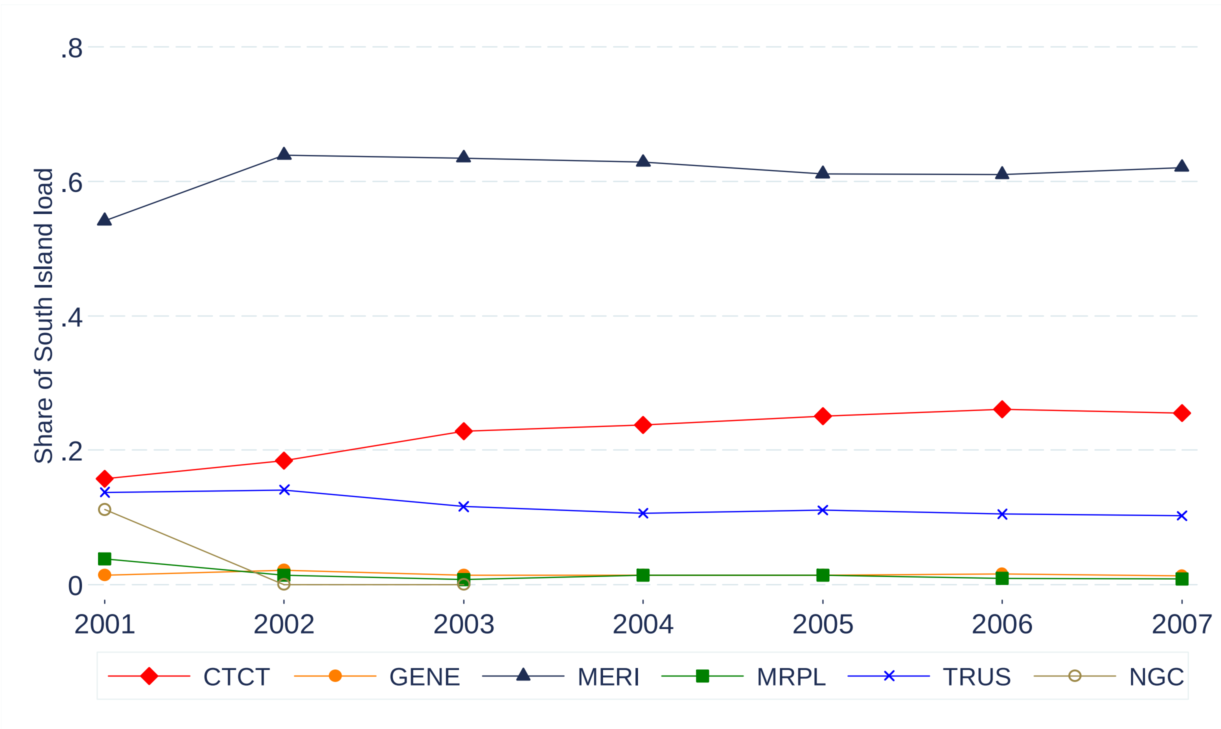
Source: Centralised Data Set

Figure 2.20: Annual market shares in load, North Island, 2001–07



Source: EMS firm-level settlement data

Figure 2.21: Annual market shares in load, South Island, 2001–07



Source: EMS firm-level settlement data

70. Figure 2.22 shows the combined market shares for load in both islands. Meridian is the largest retailer overall, with a market share of more than 30%. Contact and Genesis are the second and third largest retailers respectively, with market shares of about 20% each. If supply to the aluminum smelter were excluded, Meridian would be the third largest retailer behind Contact and Genesis. Mighty River Power and TrustPower are the fourth and fifth largest retailers. The relative market share of TrustPower has declined substantially since 2001, when it had a larger retail load than Genesis, Contact and Mighty River Power. The Herfindahl-Hirschman Index for total New Zealand load has increased from 1,629 to 2,114 between 2001 and 2007.

71. Figure 2.23 shows the location of generation and load for Contact Energy, using average quantities at each GXP between July 2004 and June 2007. This three-year period shows the current geographical distribution of generation and load, following the acquisitions and divestments of generation assets and retail customers in 2001 and 2003, as discussed above. Of the four largest gentailers, Contact is the only one with major generation assets in both islands. As a retailer, Contact has the most even geographical spread of load.

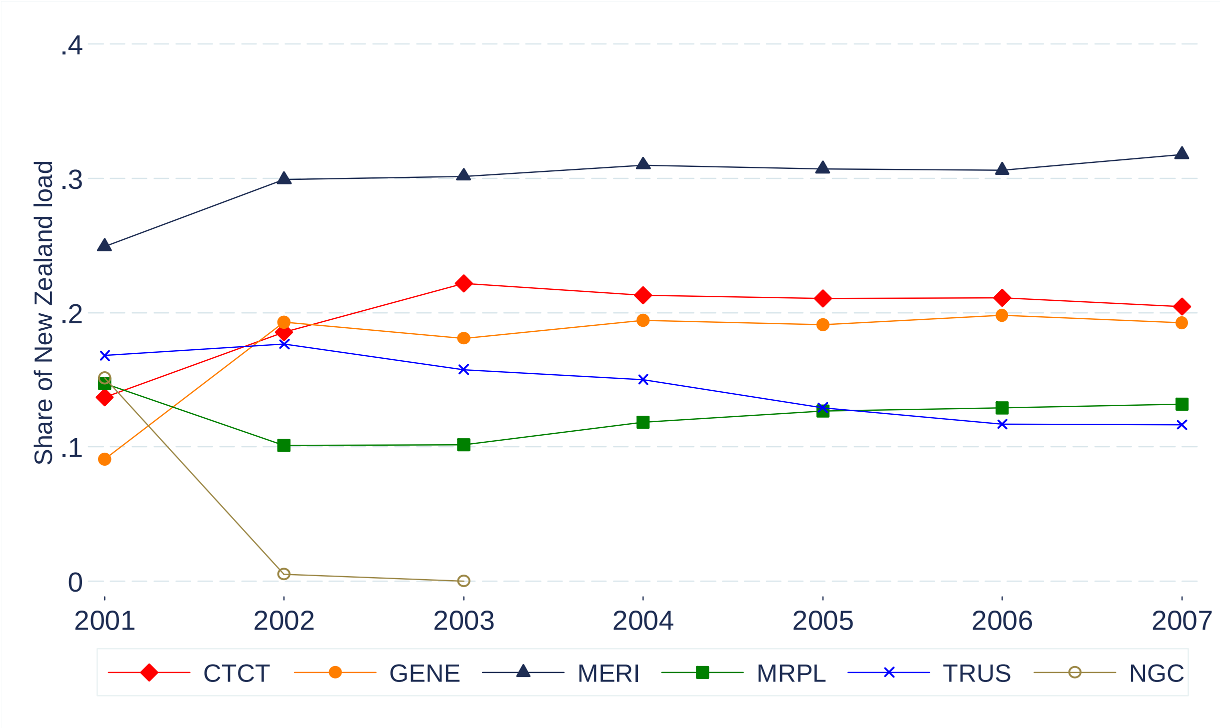
72. Figure 2.24 shows the location of generation and load for Genesis Energy, from July 2004 to June 2007. By far its largest generation asset is the Huntly power station. Genesis also has smaller generation plants in the central North Island. Virtually all of Genesis' load is located in the North Island. It has no generation and almost no load in the South Island.

73. Figure 2.25 shows the location of generation and load for Meridian Energy, from July 2004 to June 2007. The largest generation plant is the Manapouri hydro station in the south-west of the South Island, which has an average output similar to the average load at the nearby Tiwai aluminum smelter. Most of Meridian's generation is from plants located along the Waitaki River in the South Island. Its only generation asset in the North Island is the Te Apiti wind farm. Nonetheless, Meridian has large load obligations in the North Island, including the incumbent retailer position in three North Island networks.

74. Figure 2.26 shows the location of generation and load for Mighty River Power, from July 2004 to June 2007. Practically all generation and load is located in the northern North Island, with generation assets along the Waikato River and in Auckland, and most load in Waikato and in Auckland, where Mighty River Power is the incumbent retailer for the Vector network.

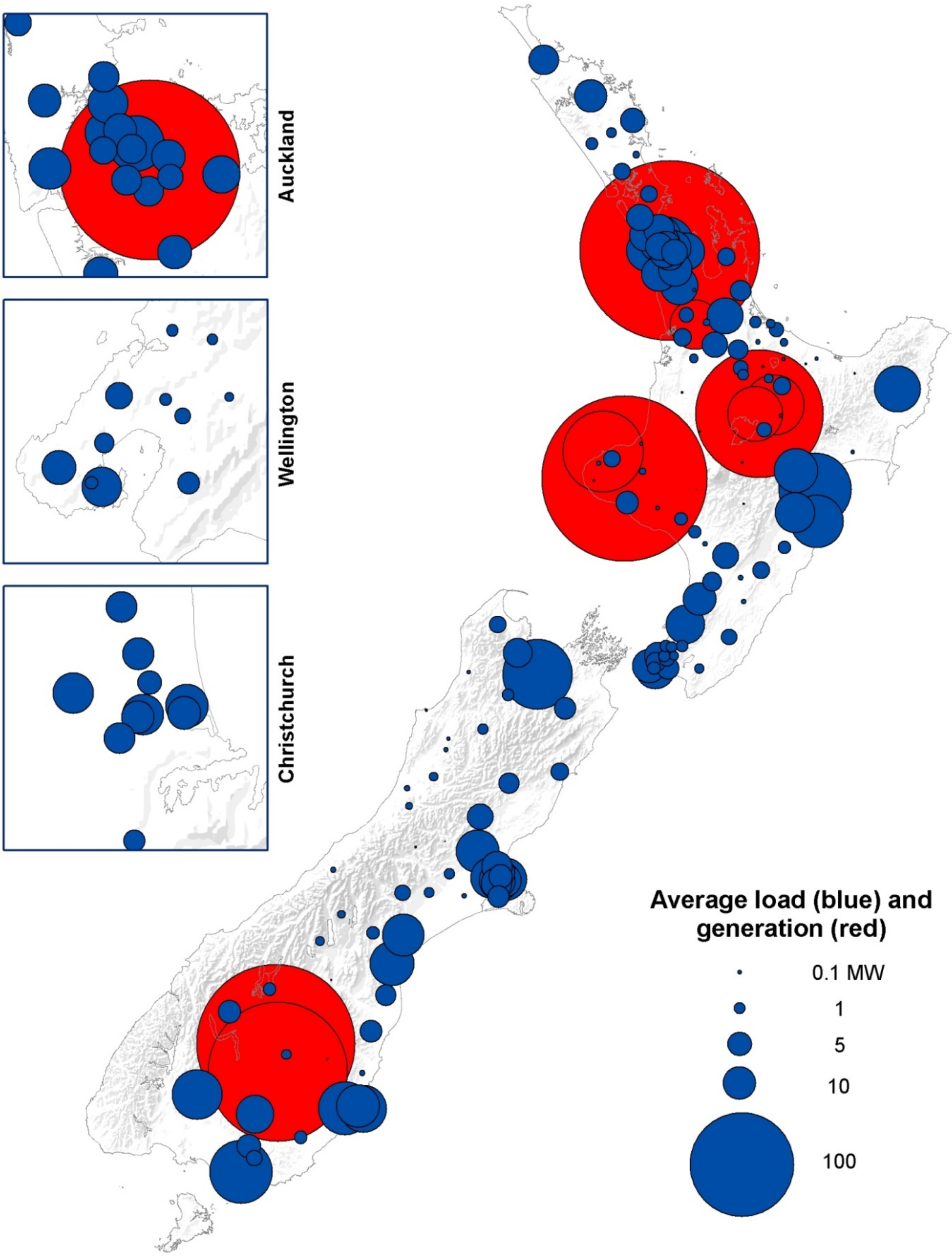
75. Figure 2.27 shows the location of generation and load for TrustPower, from July 2004 to June 2007. TrustPower has a large number of relatively small generation assets, spread throughout both the North and South Islands. TrustPower has retail customers in both islands, although the majority of its load is concentrated in the region around Tauranga and Rotorua in the North Island.

Figure 2.22: Annual market shares in load, New Zealand, 2001–07



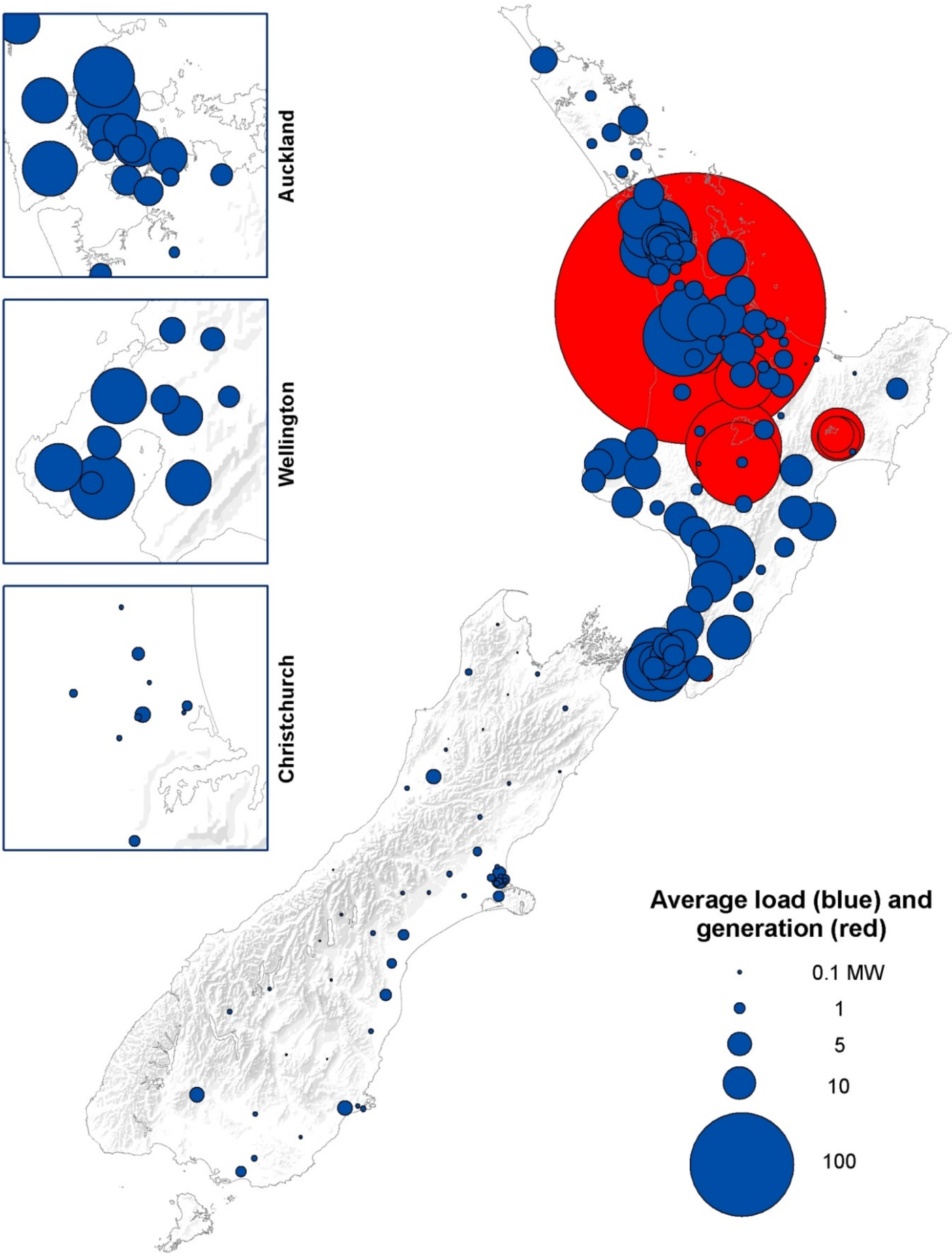
Source: EMS firm-level settlement data

Figure 2.23: Location of generation and load, Contact, 2004–07



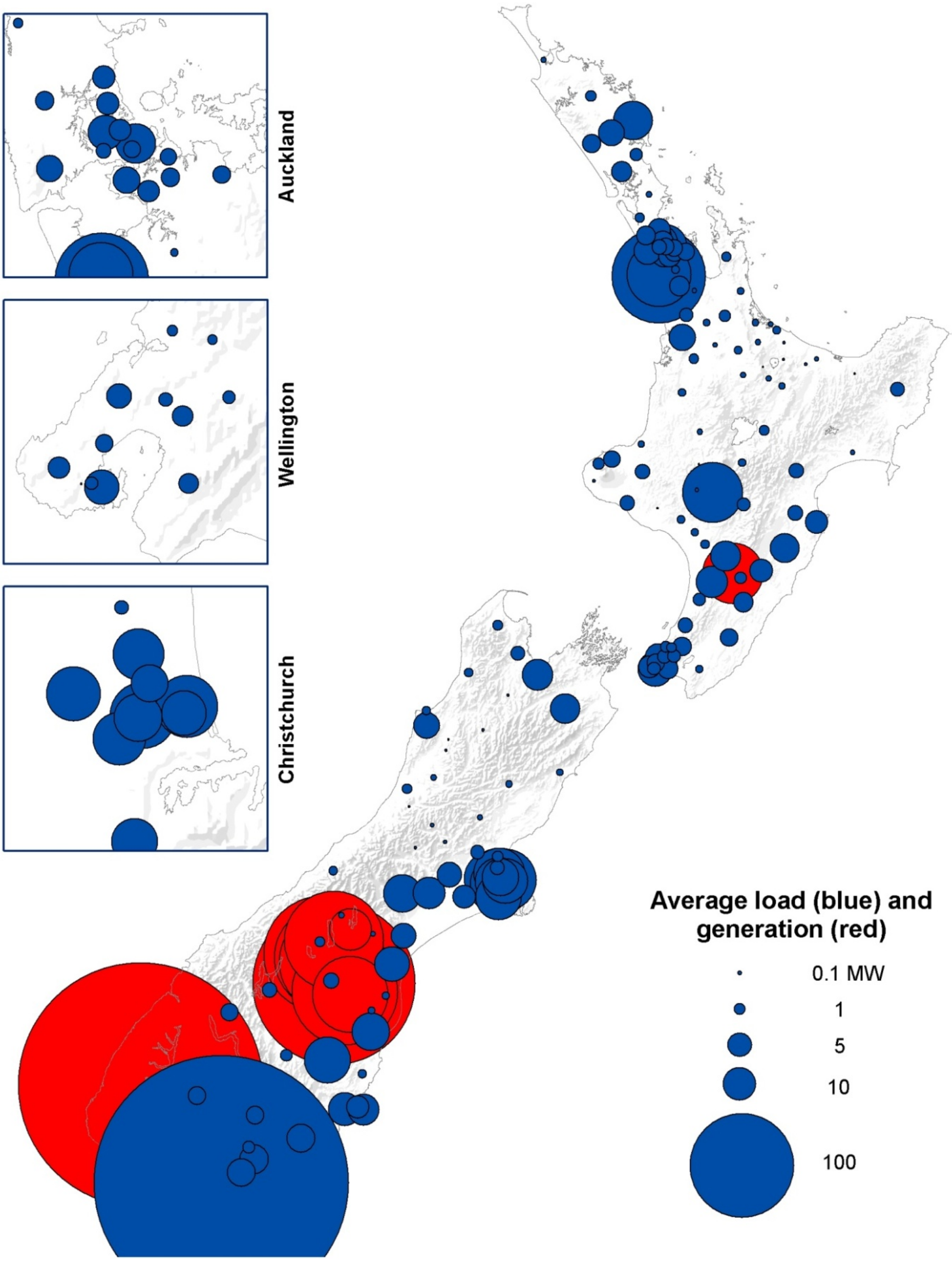
Source: Centralised Data Set (generation), EMS firm-level settlement data (load)

Figure 2.24: Location of generation and load, Genesis Energy, 2004–07



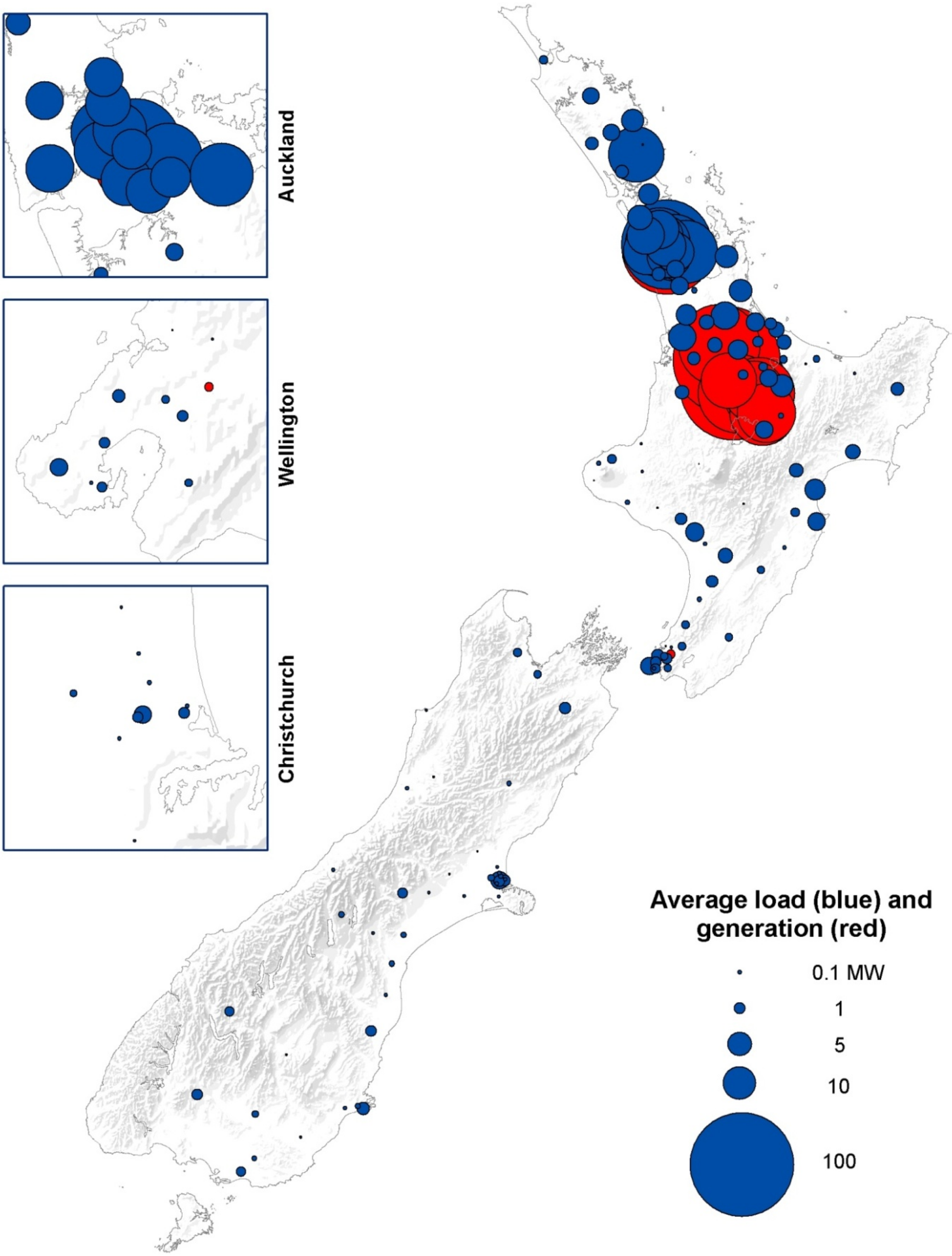
Source: Centralised Data Set (generation), EMS firm-level settlement data (load)

Figure 2.25: Location of generation and load, Meridian Energy, 2004–07



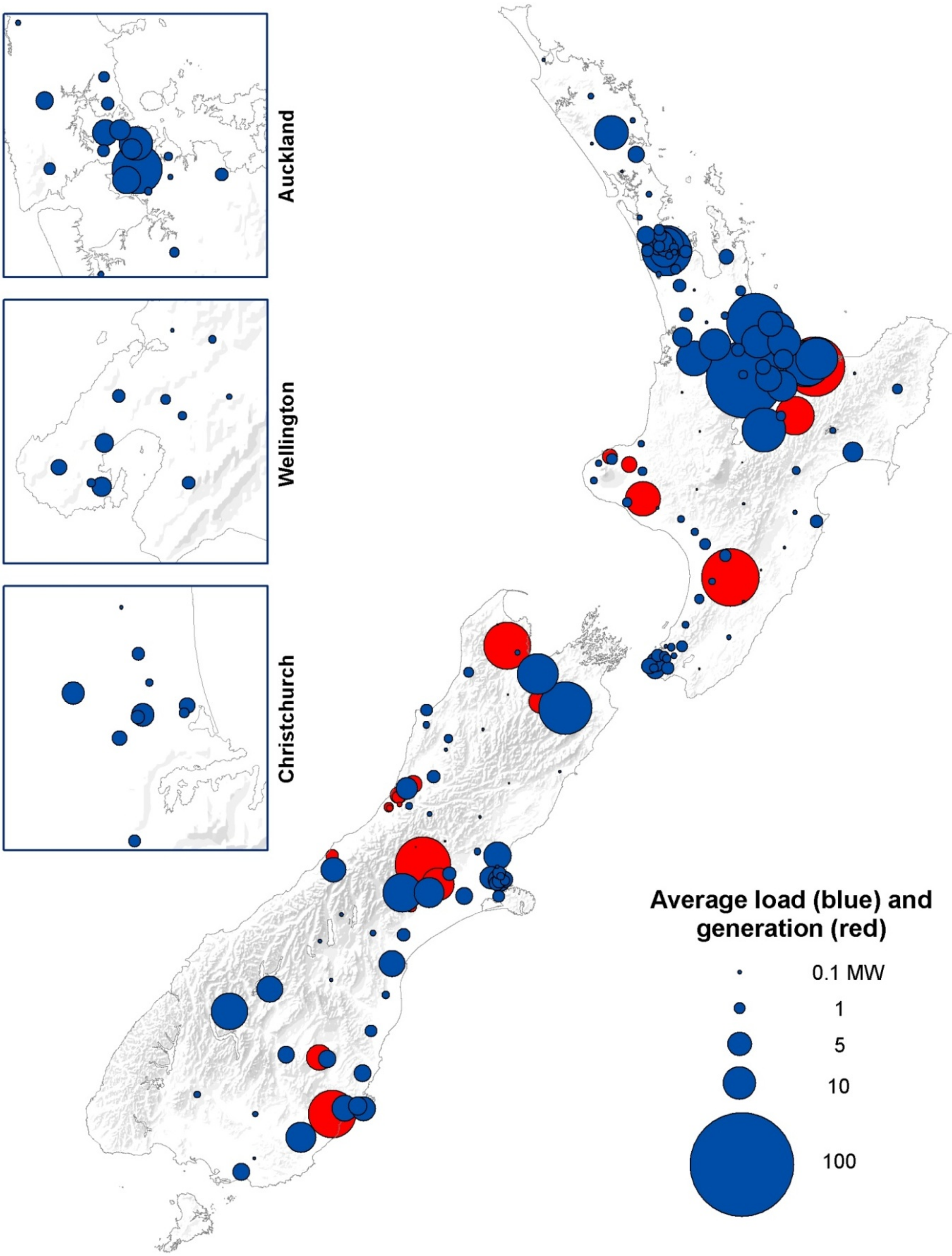
Source: Centralised Data Set (generation), EMS firm-level settlement data (load)

Figure 2.26: Location of generation and load, Mighty River Power, 2004–07



Source: Centralised Data Set (generation), EMS firm-level settlement data (load)

Figure 2.27: Location of generation and load, TrustPower, 2004–07



Source: Centralised Data Set (generation), EMS firm-level settlement data (load)

2.5 Behavior of Market Prices

76. This subsection summarizes the behavior of half-hourly nodal prices from the New Zealand Electricity Market from January 1, 2001 to December 31, 2007. A number of conclusions emerge from this analysis. First, price volatility, measured a number of ways, has shown a steady decrease over the sample period. Second, average prices have tended to increase over the sample period, particularly during the off-peak periods of the day. Third, the amount of predictable variation in prices throughout the day has also declined over the sample period.

2.5.1. Overall price trends

77. In the New Zealand wholesale electricity market, prices are reported at about 245 nodes each half-hour, providing 11,760 price observations in a single day. In order to analyze overall trends in market behavior it is helpful to aggregate this large quantity of data. One common approach is to consider prices at only a limited number of nodes, usually, Haywards and Benmore. An alternative is to take a weighted average of the prices at every node, where the weights are based on either the generation or the load at that node in each half-hour. For example, in calculating an average generation price, a greater weight would be placed on the nodal price at Huntly than on the nodal price at Tuai. The formula for calculating the weighted-average price is:

$$p_{avg} = \frac{\sum_{t=1}^{T}\sum_{n=1}^{N} p_{tn}q_{tn}}{\sum_{t=1}^{T}\sum_{n=1}^{N} q_{tn}}$$

where p_{tn} is the price at node n in period t, and q_{tn} is the quantity (either generation or load) at node n in period t. Generally, N is about 245. We sum over all nodes with reported prices. T might be 1 (the average price in a given half-hour), 48 (the average price over a given day), or even 17,520 (the average price over an entire year). Note that summing over multiple half-hours effectively places greater weight on those periods with higher generation or load. That is, the “load shape” factor is built into the formula and does not need to be applied as a separate adjustment.

78. The volume-weighted average price has a useful interpretation for the analysis of market performance. Using generation volumes as the weights, this price gives the average revenue for the period over all generators in the market. Using load volumes as the weights, the price gives the average wholesale cost over the period for all retailers in the market. The difference between these two prices gives a measure of difference between the average price that loads pay and the average price that generation unit owners receive. The half-hourly merchandising surplus in a nodal-pricing market such as New Zealand is defined as the difference between total payments made by loads and total revenues received by generation unit owners in that half-hour. These two magnitudes can differ both because generation unit owners inject more energy than loads withdraw during the half-hour because of losses in the transmission network, and because loads typically pay higher nodal prices than generation unit owners receive because of where generation units are located relative to the major load centers.

79. Figure 2.28 shows the behavior of the daily generation volume-weighted average price from 2001 to 2007. Since there are often large fluctuations in this price from day to day, the graph shows a three-month moving average of the daily price in order to smooth out this short-term noise and focus on the overall trend. The most striking features of the graph are the periods of extremely high prices in 2001, 2003 and 2006. Although prices in 2001 and 2003 reached higher peaks than in 2006, they remained at these high levels for a shorter period of time and then returned to below $50/MWh. In contrast, in 2005 and 2006 the average price remained well above $50/MWh for almost two years.

80. The effect of this price trend on average generator revenues is shown in Figure 2.29. This figure shows the volume-weighted average price over an entire year, for 2001 to 2007. The highest prices occurred in 2001 and 2003: $84 and $82/MWh respectively. However, in 2005 and 2006, prices were only slightly lower: $74 and $78/MWh respectively. This shows that the dramatic price spikes in 2001 and 2003 had only marginally greater impact on total generator revenues than the prolonged period of high prices in 2005 and 2006. Prices in 2007 fell back to an average of $52/MWh, about $17/MWh above the low prices of 2002 and 2004.

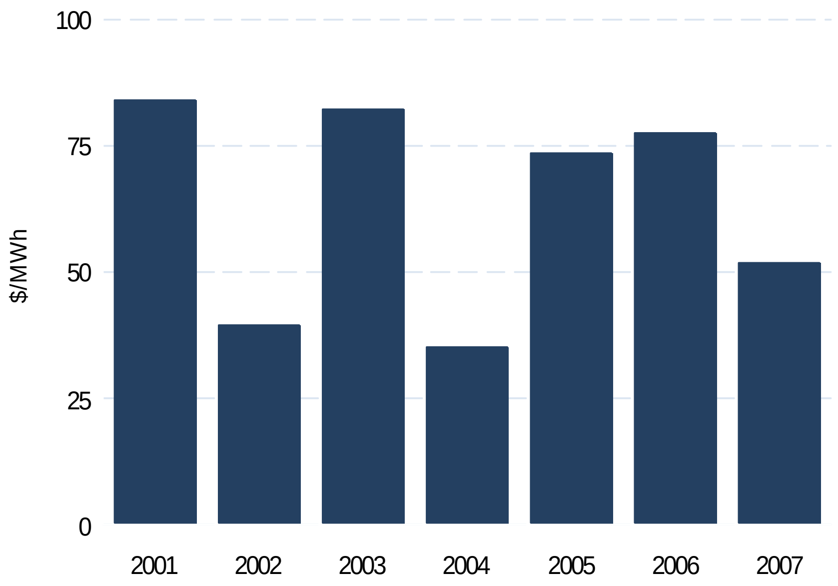
81. Figure 2.30 and Figure 2.31 provide further information on the behavior of prices over the seven year period. The first graph shows the proportion of half-hours in the year for which the volume-weighted average price fell below $50/MWh (the entire bar) and $25/MWh (the orange part of the bar). In 2005 and 2006, prices fell below $50/MWh in less than a quarter of all periods. In contrast, in the "high price" year of 2001, prices were below $50/MWh half of the time, and even below $25/MWh in 10% of the half-hours.

82. Figure 2.31 shows the proportion of half-hours in the year for which the average price was more than $100/MWh (the entire bar) and $200/MWh (the orange part of the bar). The proportion of half hours with prices above $100 were roughly the same in 2001, 2002 and 2006, although 2001 had a much greater number of periods with prices above $200/MWh. Comparing the two graphs we see that the higher average price for 2007 compared to 2002 and 2004 is a result of fewer low-price periods, particularly periods with prices below $25/MWh, rather than more high-price periods (since the proportion of these is similar in the three years).

Figure 2.28: Three-month rolling average daily wholesale price, 2001-07

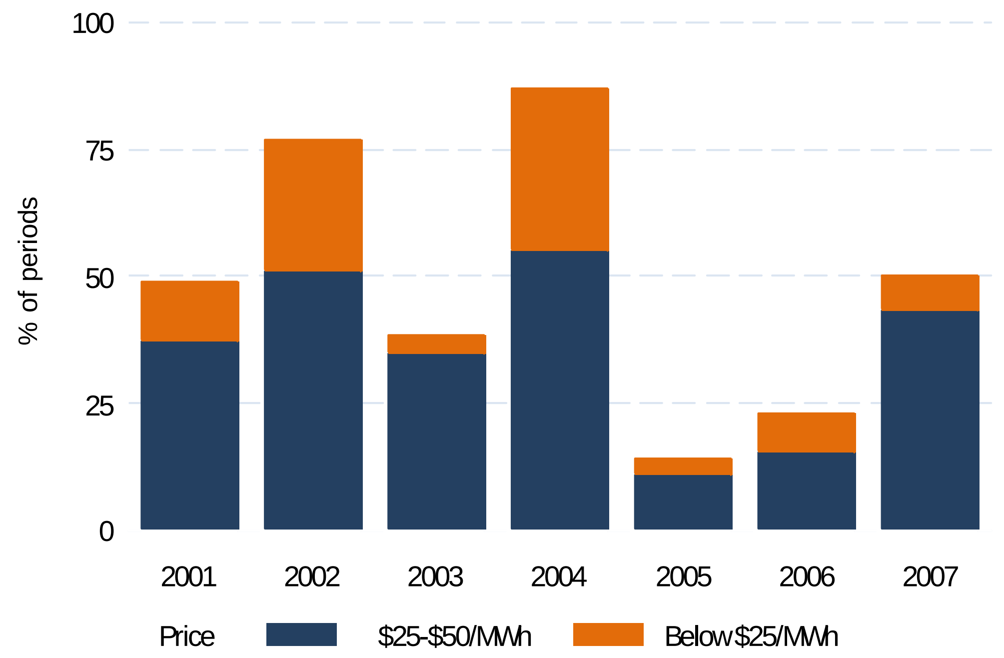
Source: Centralised Data Set

Figure 2.29: Annual generation volume-weighted average price, 2001-07



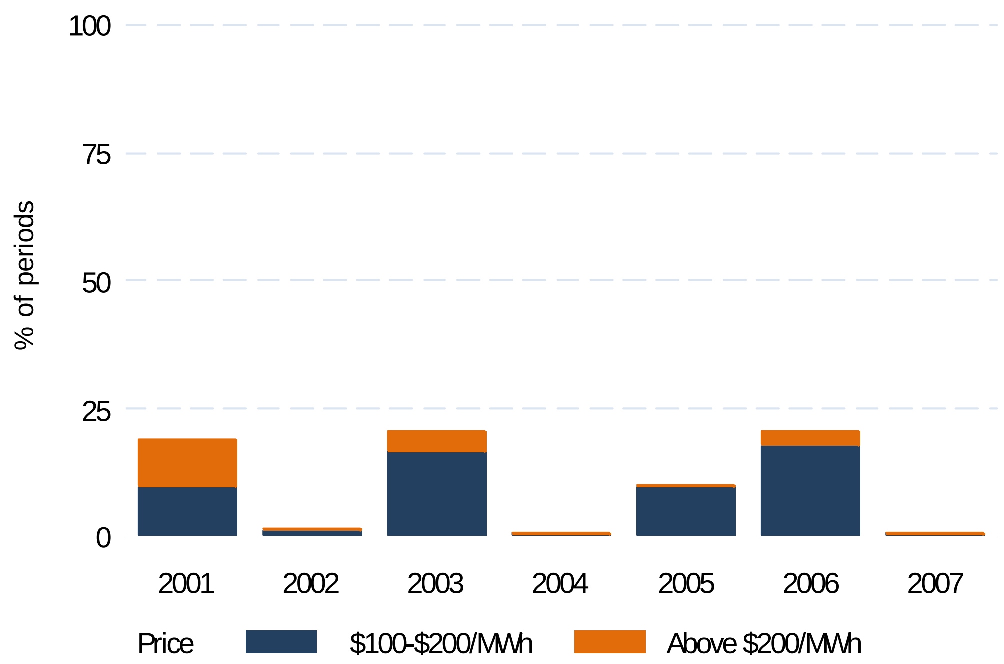
Source: Centralised Data Set

Figure 2.30: Proportion of half-hour periods with low prices, 2001-07



Source: Centralised Data Set

Figure 2.31: Proportion of half-hour periods with high prices, 2001-07



Source: Centralised Data Set

2.5.2. Intra-day Price Behavior

83. The analysis of average prices in the previous section compressed the wholesale electricity prices along two dimensions: over time and across nodes. It is useful to abstract from the overall price trend and examine the pattern of prices along each of these dimensions separately. This section analyzes the pattern of prices within a day; the following section analyzes the pattern of prices across nodes.

84. Wholesale prices can vary considerably over the 48 half-hours of a day. There are two reasons for this variation. First, as discussed in Wolak (2006)[24] electricity demand in New Zealand varies by an almost one to two ratio, from its early morning low to its early evening peak. This daily pattern of demand variation is predictable and extremely consistent over long periods of time. Second, generators vary the quantity of generation that they offer, and the price at which they offer that generation, in different half-hours of the day. This might be the result of technical constraints on their generation units or it may be due to strategic considerations.

85. The scatter diagram in Figure 2.32 shows the period in which the highest and the lowest price occurred in each day, for every weekday from 2001 to 2007, with the points from each year stacked on top of each other. This provides a graphical snapshot of the highest and lowest-priced periods, and how these change during the year. From late March until the end of September, the highest-priced period is usually in the early evening. The exact timing shifts from 6:30pm back to 5:30pm then returns to 6:30pm, tracking the change in sunset time over winter. In the summer months it is much less common for the highest-priced period to be in the evening. The morning period starting at 7:30am is also a common time for the highest price in the day, except in late December and January. Throughout the entire year the most common time for the lowest price to occur is in the early morning, around 4:00am.

86. Figure 2.33 summarizes this picture by counting the number of times at which each half-hour has either the highest price in the day or the lowest price in the day (again for weekdays only). Here we see that the half-hour beginning 7:30am has the highest price for the day in 25% of weekdays between 2001 and 2007. The one-and-a-half hours from 5:30pm to 7:00pm has the highest price in about 30% of weekdays. The lowest price occurs between 3:30am and 5:00am on about 40% of all weekdays. Interestingly, the lowest price also occurs in the last half-hour of the day for about 15% of weekdays.

87. How large are the differences between the highest and lowest prices each day? Figure 2.34 shows the 3-month rolling average of the difference in the maximum and minimum price, as a percentage of the maximum price. For example, if the maximum price were \$80/MWh and the minimum were \$60/MWh, the difference would be 20/80 = 25%. For most of 2001 to 2005, the difference between the minimum and maximum price each day averaged between 50% and 75% (so, for example, if the maximum price in the day were

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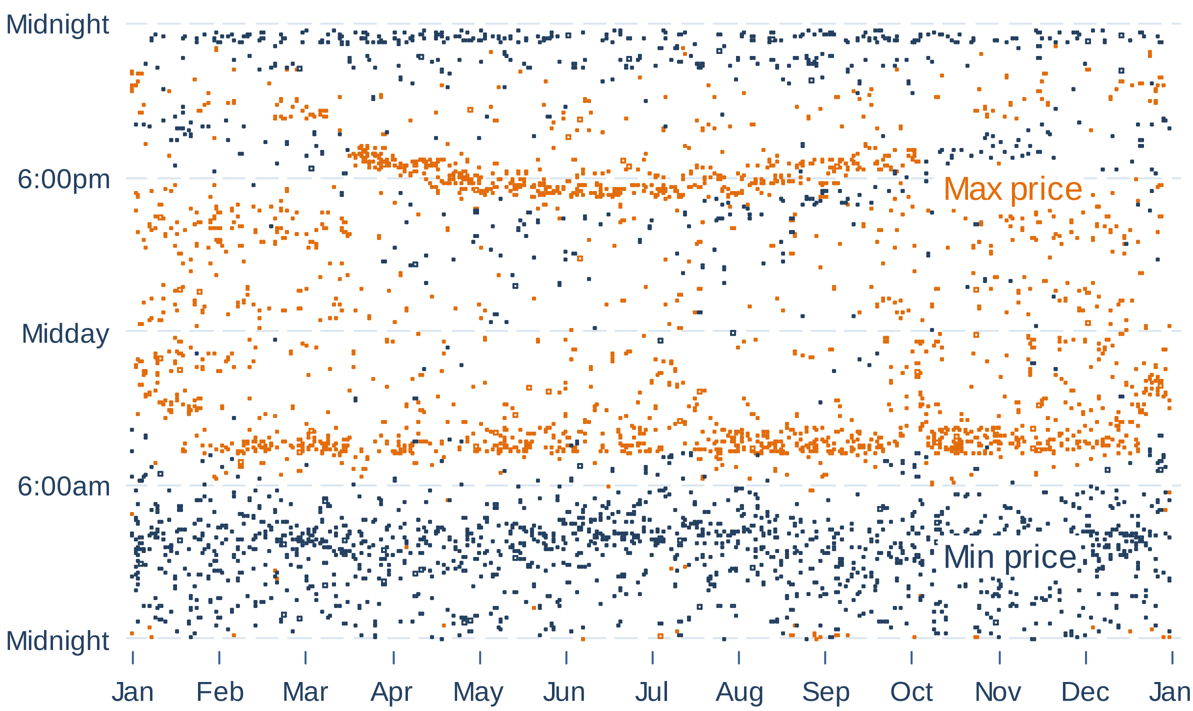
[24] Wolak, F.A. (2006) "Preliminary Report on the Design and Performance of the New Zealand Electricity Market," attached as Appendix 2.

$80 then the minimum price would be $20-$40). Since 2005 there appears to have been a reduction in the difference between the minimum and maximum prices each day.

88. A comparison of the intraday minimum and maximum only considers two prices each day. It is useful to incorporate information on the behavior of all prices during the day to judge whether this variation is due to a few extreme price outliers or a more disperse spread of prices between the minimum and maximum. Figure 2.35 shows one measure of this intra-day price variation: the standard deviation of prices within each day, again plotted as a 90-day moving average. The two spikes in 2001 and 2003 are driven by the extremely high prices in Winter 2001 and Autumn 2003 (because the standard deviation does not normalize for the mean price being at a much higher level). The vertical spike in mid-2006, and the sharp drop three months later when it falls out of the moving average window, were the result of the grid emergency on 19 June 2006 when the average price in period 36 was $8,829/MWh.[25]

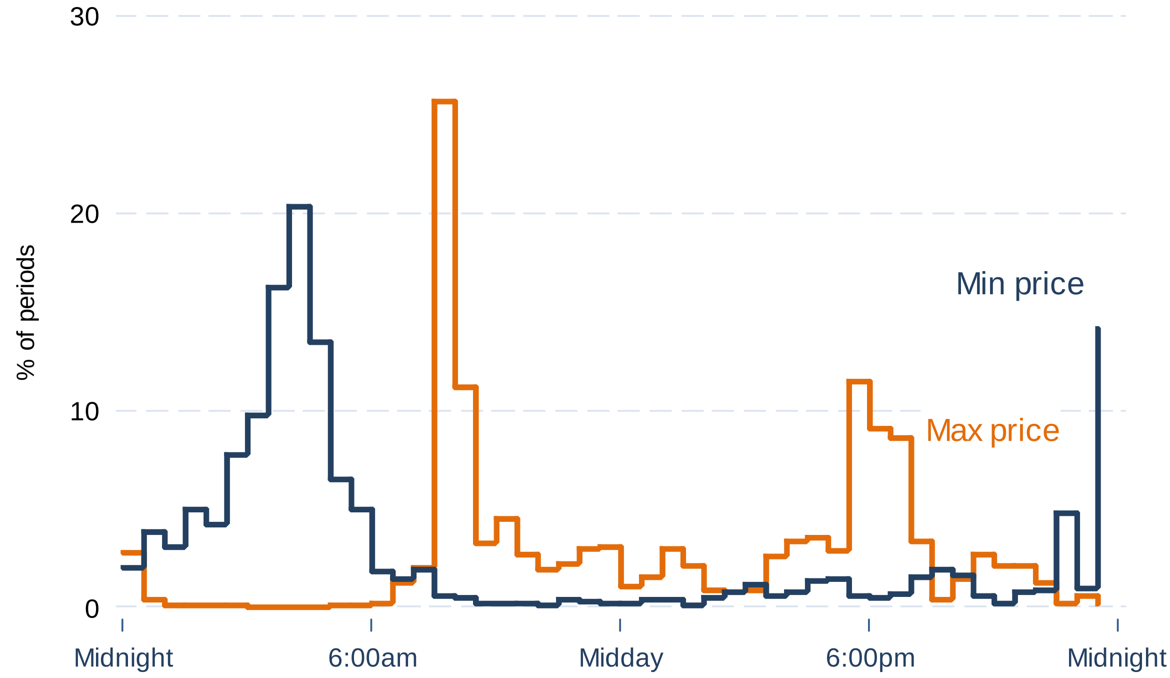
Figure 2.32: Time-of-day of max and min prices, by day-of-year, weekdays 2001-07



Source: Centralised Data Set

[25] Electricity Commission, Discussion Paper on Issues Arising from 19 June 2006 Grid Emergency, August 2006, pp3-4

Figure 2.33: Time-of-day when max and min prices occur, weekdays 2001-07



Source: Centralised Data Set

Figure 2.34: Difference between max and min prices, 90-day rolling average, 2001-07

Source: Centralised Data Set

Figure 2.35: Standard deviation of intra-day prices, 90-day rolling average, 2001-07

Source: Centralised Data Set

89. It is often useful to normalize the standard deviation in order to compare the variation in prices across different dates when there are large differences in the mean price. The normalized standard deviation (called the coefficient of variation), shown in Figure 2.36, is the standard deviation divided by the mean price for each day. This measure shows the same general reduction in intraday price deviation between 2001 and 2007 that was seen by comparing only the minimum and maximum prices each day.

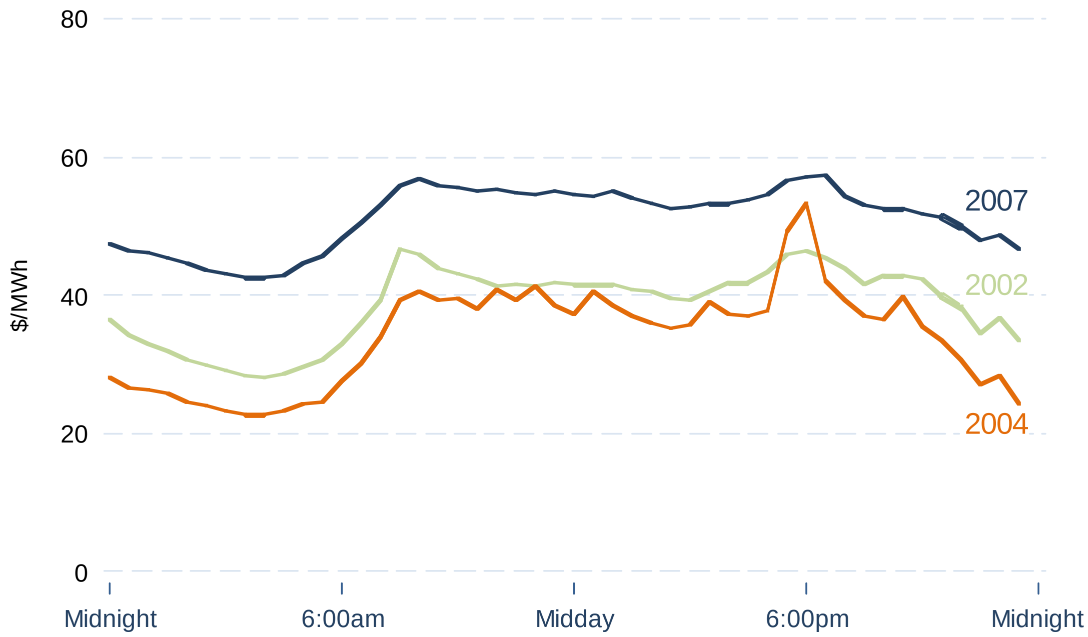
90. Another way to examine the pattern of intraday prices is to consider the (weighted) mean price over all days in the year, for each half-hour of the day. Figure 2.37 shows the pattern of prices during the day for the "low-price" years of 2002, 2004 and 2007. The absolute value of the difference between the minimum and maximum priced half-hours is the same or greater in the earlier two years as in 2007, even though in 2007 the overall level of the prices is higher. Therefore in relative terms the intraday price gap is even greater in 2002 and 2004. This exactly mirrors what was seen in Figure 2.36.

91. Figure 2.38 shows the same type of graph for the recent "high-price" years 2003, 2005 and 2006. The picture for 2006 is somewhat distorted by the 19 June grid emergency, which resulted in the spike in the average price for the period starting at 5:30pm (period 36). The thinner blue line shows the average prices for 2006 excluding this extreme event. Apart from this event, the prices for 2006 showed greater variation between the early morning low and the morning and evening peaks than the "low-price" years. Indeed, much of the difference between the overall average price in 2003 and 2006 appears to be a result of higher peak prices in 2003, since the off-peak prices are remarkably similar in all three years.

Figure 2.36: Coefficient of variation of intra-day prices, 90-day rolling average, 2001-07

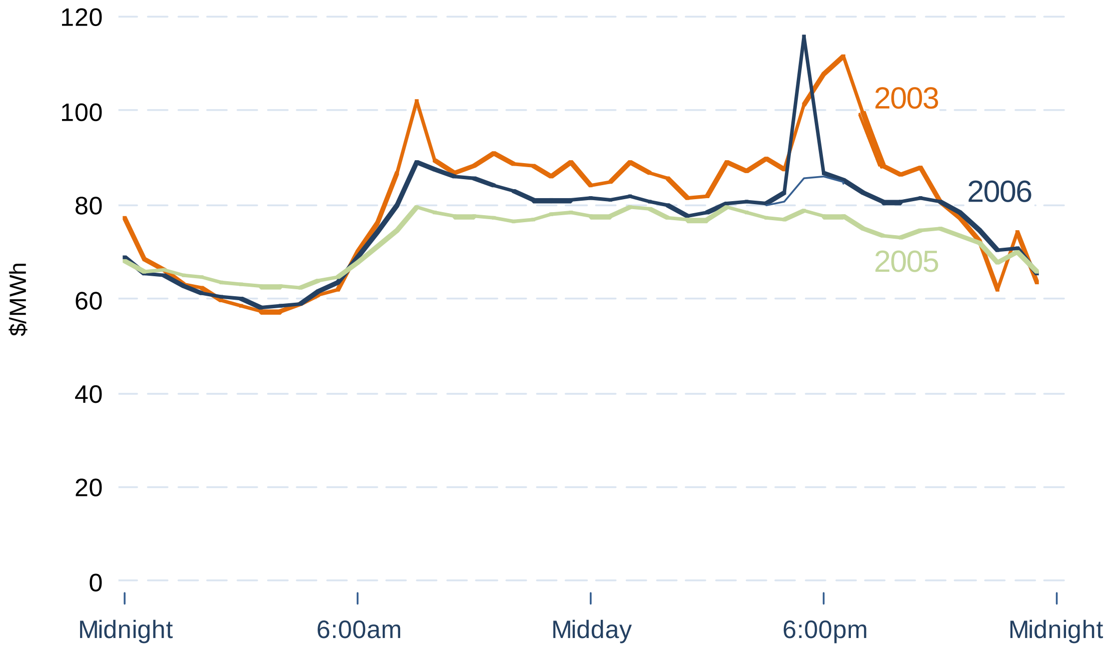
Source: Centralised Data Set

Figure 2.37: Intraday variation in generation weighted-average prices, low-priced years



Source: Centralised Data Set

Figure 2.38: Intraday variation in generation weighted-average prices, high-priced years



Source: Centralised Data Set

2.6 Water levels and market outcomes

92. This section summarizes the pattern of hydro storage levels from 2001 to 2007 from a variety of perspectives. The major result from this analysis is that there is a strong inverse relationship between water storage levels and market prices.

93. Figure 2.39 shows raw aggregate hydro storage data. The lowest point over the 2001-07 period was in winter 2001. The data source for 2001-05 was a six-hourly data extract from Comit Hydro. For 2006-07, the storage graphs from the Comit Free-to-Air website were digitized to produce the data for this time period.

94. Figure 2.40 presents the mean hydro storage level for each day of the year, over the seven year period, 2001 to 2007. We then calculated the difference between the actual daily storage level and the mean storage level for that day over the seven year period. These differences are plotted for the seven years in Figure 2.40. Periods falling below the red line have below-average storage, and periods above the red line have above-average storage.

95. For Figure 2.41, the storage levels from Figure 2.40 were smoothed using a 30-day moving average. The daily generation volume-weighted average price is also smoothed using a 30-day moving average. This smoothing helps to identify the broad trends over time by getting rid of the day-to-day fluctuations. The smoothed storage level deviations are shown as the blue line on top; the smoothed prices are shown in the red line below. Note that the three periods with the lowest storage levels correspond to the three periods with the highest prices. Also, periods with above-average storage generally have the lowest prices.

96. This relationship between storage levels and prices is shown again in Figure 2.42. Each blue dot represents the average price and the storage level for one day. The red line is a locally weighted regression of prices on storage levels (using a tricube weighting function and a bandwidth of 0.5).

97. Table 2.3 shows the same information as in Figure 2.42, dividing the sample period into six blocks based on the storage level deviations, and calculating the mean and standard deviation of price across all the days in each block. Note that these are the same six blocks that are shown on the vertical axis of Figure 2.40 and the horizontal axis of Figure 2.42.

Table 2.3: Relationship between system price and storage level deviations, 2001-07

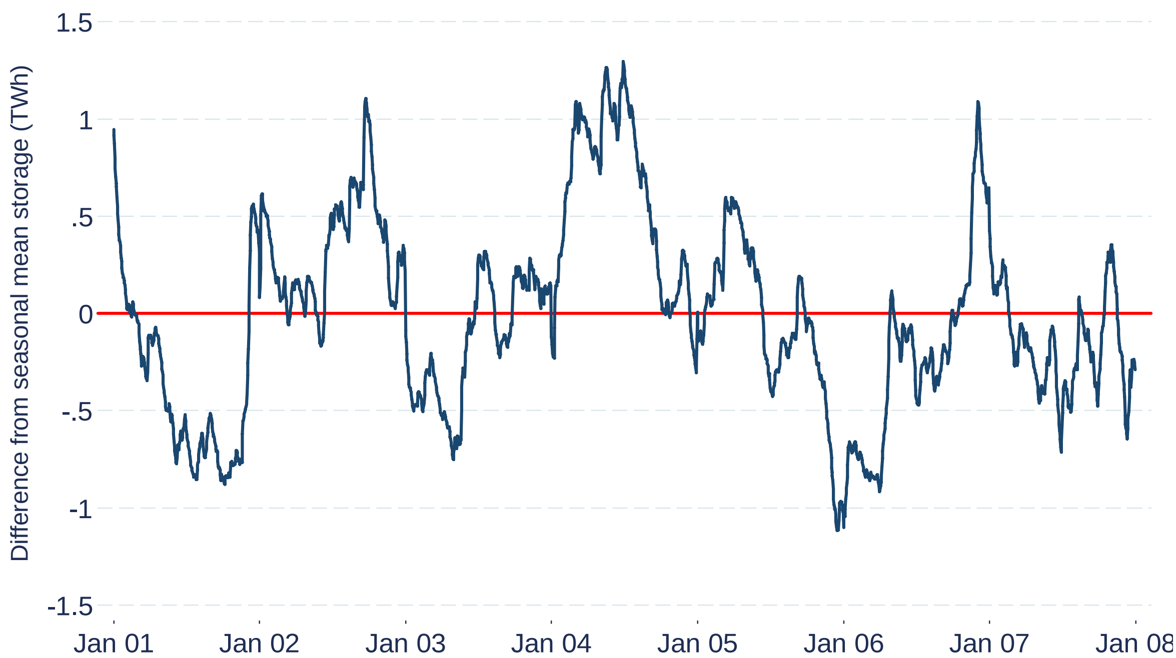
Deviation from seasonal storage level	Number of days	Mean price ($/MWh)	Standard deviation of price
1.0 TWh or more below mean	19	$112.09	$34.22
1.0 – 0.5 TWh below mean	399	$121.21	$68.09
Less than 0.5 TWh below mean	900	$65.93	$29.39
Less than 0.5 TWh above mean	810	$45.66	$19.32
0.5 – 1.0 TWh above mean	323	$31.67	$18.94
1.0 TWh or more above mean	104	$27.88	$13.91

Source: COMIT Hydro (M-co) and Centralised Data Set

Figure 2.39: Daily hydro storage levels, 2001-07

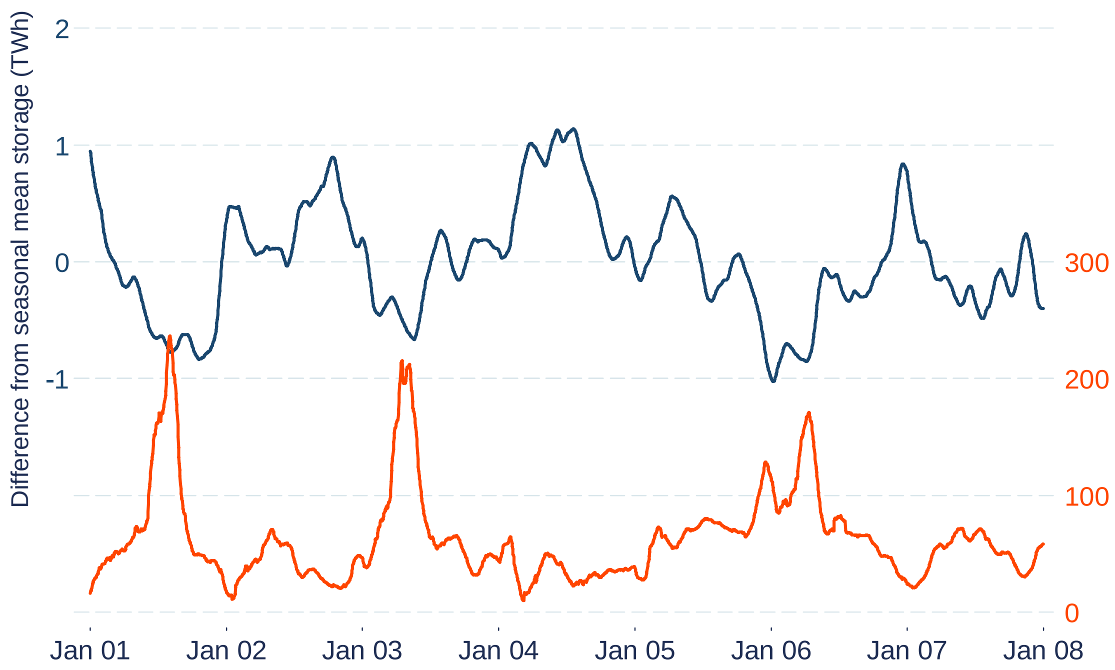
Source: COMIT Hydro (M-co)

Figure 2.40: Hydro storage deviations from seasonal mean, 2001-07



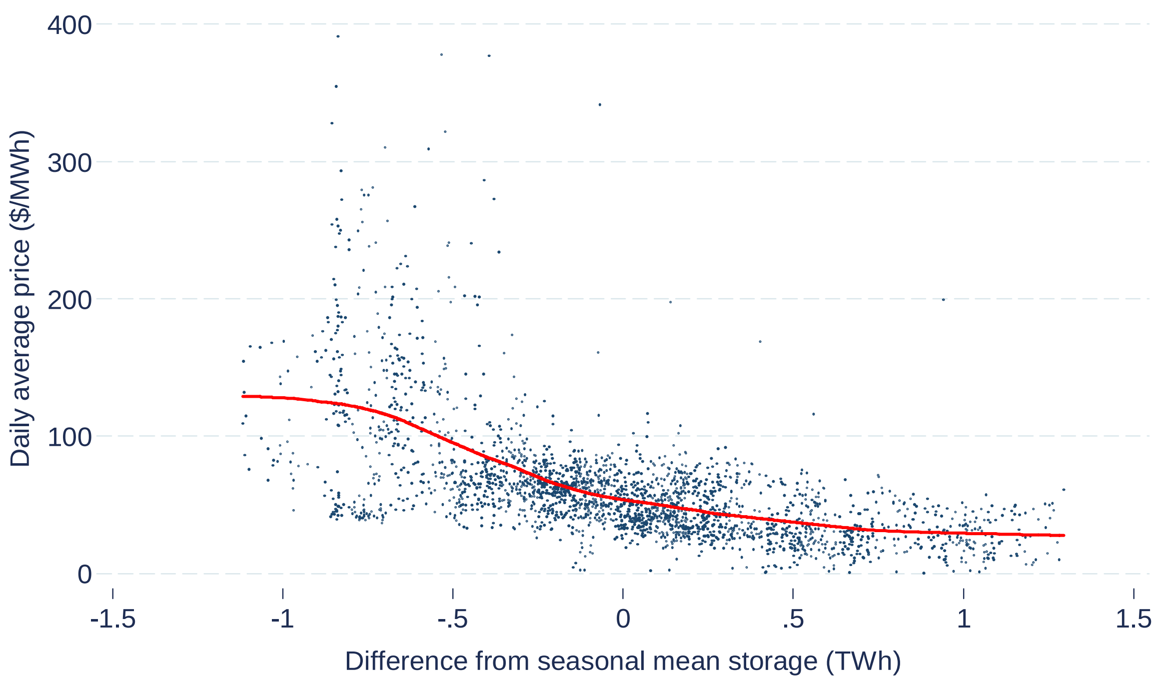
Source: COMIT Hydro (M-co)

Figure 2.41: Storage level deviations and system prices, 30-day moving averages, 2001-07



Source: COMIT Hydro (M-co) and Centralised Data Set

Figure 2.42: Relationship between system price and storage level deviations, 2001-07



Source: COMIT Hydro (M-co) and Centralised Data Set. Locally weighted regression with bandwidth = 0.5.

2.7 Forward contract and fixed-price and variable-price retail load obligations

98. This subsection presents information on the fixed-price and variable-price retail load obligations, and the fixed-price financial contract sales and purchases by each of the four large suppliers and TrustPower during the years 2001 to 2004. Two major conclusions emerge from this descriptive analysis. First, the vast majority of final consumers served by each of the four large suppliers pays for their electricity consumption according to a retail price that does not vary with the half-hourly wholesale price. Second, for each of the four large suppliers, the net quantity of its fixed-price forward financial contracts sold annually is a very small fraction of its fixed-price retail load obligations, although the quantity of fixed-price forward financial contracts bought or sold by of these suppliers does vary significantly over the sample period.

99. Figure 2.43(a) plots, in order from left to right, for Contact Energy for 2001: (1) annual generation in terawatt-hours (TWh) sold in the short-term market, (2) total annual quantity of forward contract purchases, (3) total annual quantity of forward contract sales, (4) total annual amount of energy sold to final consumers, (5) total annual amount of energy sold to final consumers at a retail price that varies with the half-hourly wholesale price, and (6) the net position of the supplier in the short-term market. As the figure demonstrates, the net position of suppliers, (6), is equal to (1) + (2) – (3) – (4) + (5), the supplier's total generation minus its net fixed-price financial contract sales (total sales minus total purchases) minus its fixed-price total retail load obligation (the difference between its total retail load obligations and amount that are sold at a price that varies with the half-hourly wholesale price). Contract and variable price load data is only available for the four large suppliers and TrustPower for the period January 2001 to July 2005, so the annual net position calculation is not possible for the full year of 2005 data or for subsequent years. Figures 2.43(b) to 2.43(d) repeat this same calculation for 2002, 2003, and 2004.

100. Figure 2.43 demonstrates that [

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101. Figure 2.44 repeats the same calculations presented in Figure 2.43 for Genesis Energy. Genesis Energy [

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102. Figure 2.45 presents the computation of the annual net position for Meridian Energy for 2001 to 2004. [

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103. Figure 2.46 presents the computation of the annual net position for Mighty River Power for 2000 to 2004. Mighty River Power [

].

104. TrustPower [

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105. Although all of the four large suppliers are net long in the short-term market every year from 2001 through 2005, there are time periods when each of the suppliers has total forward market obligations that exceed their generation sales in the short-term market. Figures 2.48 to 2.52 graph the monthly net position of each supplier from January 2001 for as long as the forward contract data is available. These values are graphed as vertical bars. The blue line on each graph is the total generation minus total retail load for each month. The difference between these two graphs is the supplier's net sales in the fixed-price forward financial contract market minus its retail sales at prices that vary with half-hourly wholesale prices.

106. For Contact [

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107. Figures 2.52 to 2.58 produce these same graphs for Contact, Meridian Energy and TrustPower separately for the North Island and South Island. [

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108. Figure 2.59 shows each large supplier's mean net position including contracts. Figure 2.60 shows each large supplier's mean net position excluding contracts, and Figure 2.61 shows the South Island's share of total generation and load.

[Redacted

Figure 2.43: Annual net position calculation for Contact, 2001–04

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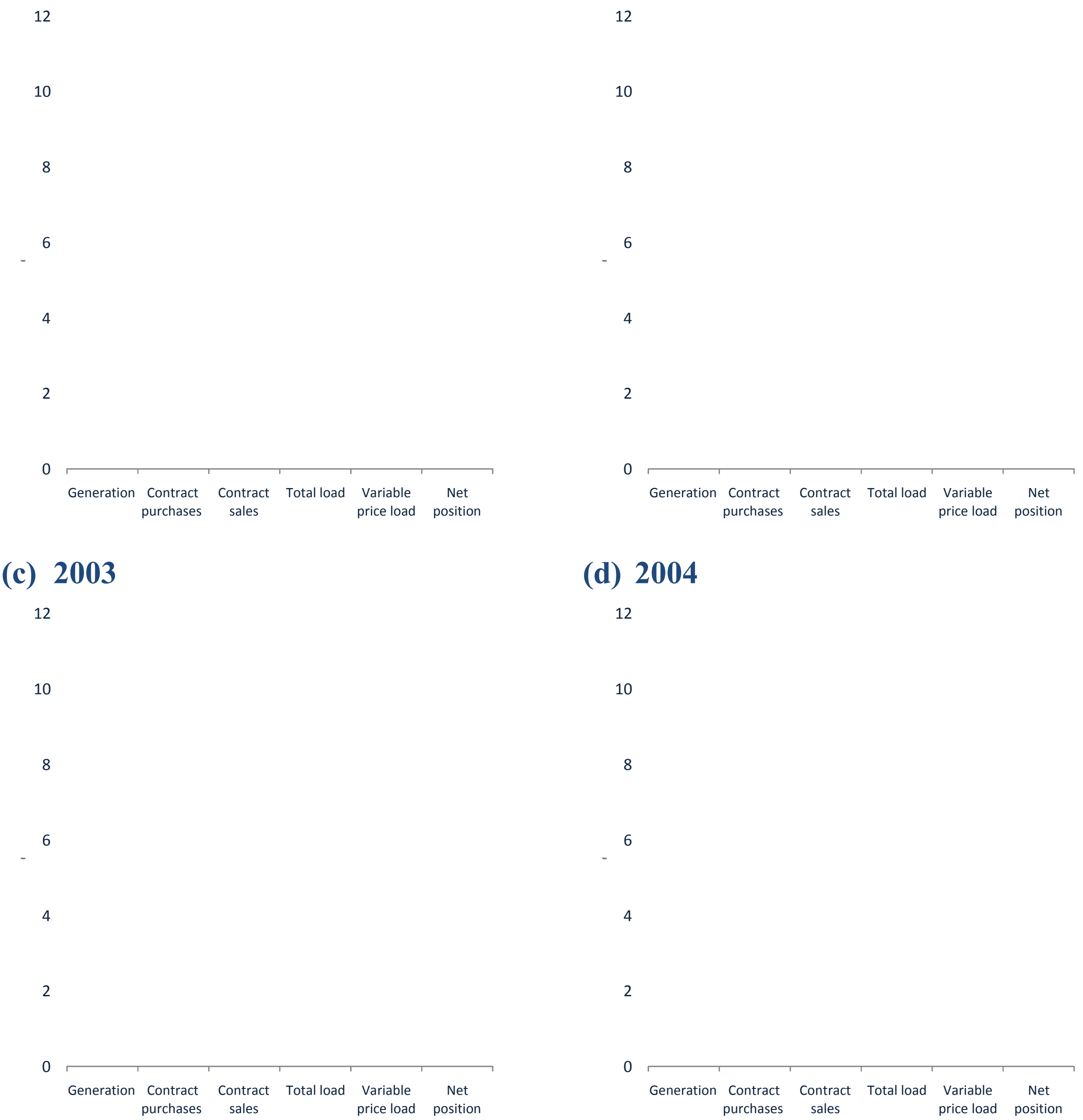
Source: Contact Energy (contracts and variable price load), Centralised Data Set (generation), EMS (load)

[Redacted

Figure 2.44: Annual net position calculation for Genesis Energy, 2001–04

(a) 2001 (b) 2002

(c) 2003 (d) 2004



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Source: Genesis Energy (contracts and variable price load), Centralised Data Set (generation), EMS (load)

[Redacted

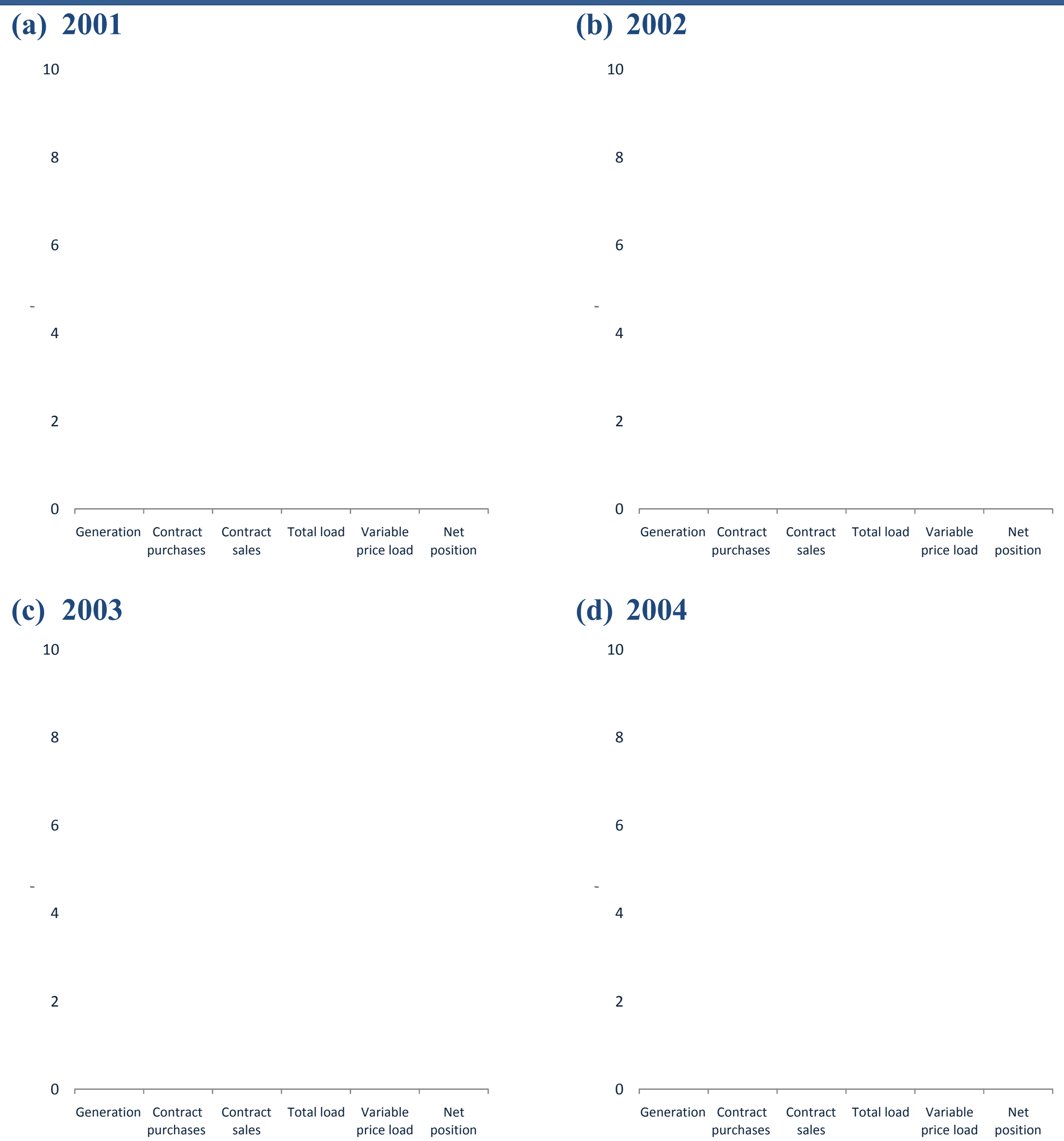
Figure 2.45: Annual net position calculation for Meridian Energy, 2001–04

]

Source: Meridian Energy (contracts and variable price load), Centralised Data Set (generation), EMS (load)

[Redacted

Figure 2.46: Annual net position calculation for Mighty River Power, 2001–04



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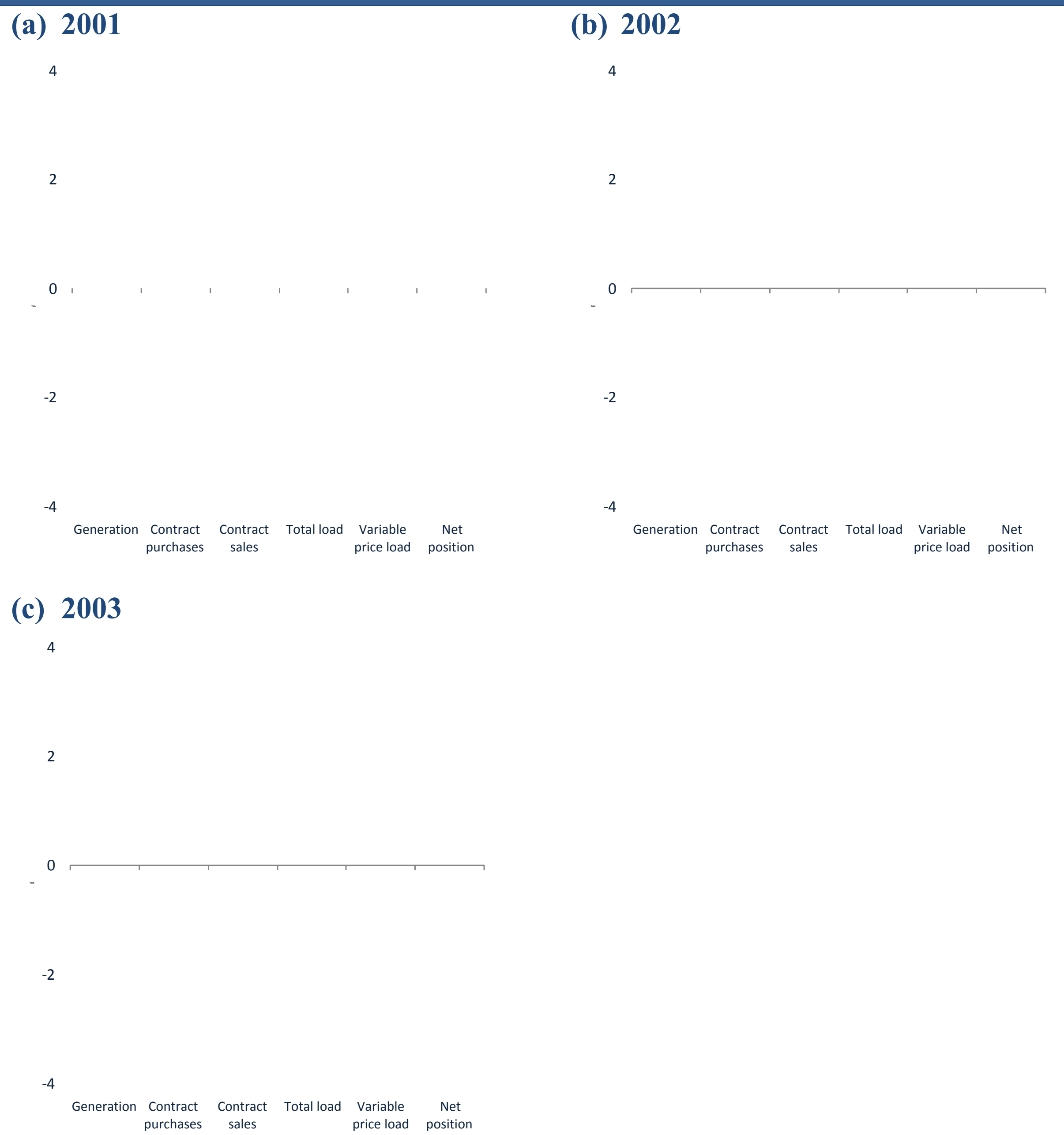
Source: Mighty River Power (contracts and variable price load), Centralised Data Set (generation), EMS (load)

[Redacted

Figure 2.47: Annual net position calculation for TrustPower, 2001–03



]

Source: TrustPower (contracts and variable price load), Centralised Data Set (generation), EMS (load)

[Redacted

Figure 2.48: Monthly net position for Contact, New Zealand, 2001–07

Source: Contact Energy (contracts and variable price load), Centralised Data Set (generation), EMS (load)

Figure 2.49: Monthly net position for Genesis Energy, New Zealand, 2001–07

Source: Genesis Energy (contracts and variable price load), Centralised Data Set (generation), EMS (load)

Figure 2.50: Monthly net position for Meridian Energy, New Zealand, 2001–07

Source: Meridian Energy (contracts and variable price load), Centralised Data Set (generation), EMS (load)

Figure 2.51: Monthly net position for Mighty River Power, New Zealand, 2001–07

Source: Mighty River Power (contracts and variable price load), Centralised Data Set (generation), EMS (load)

Figure 2.52: Monthly net position for TrustPower, New Zealand, 2001–07

Source: TrustPower (contracts and variable price load), Centralised Data Set (generation), EMS (load)

Figure 2.53: Monthly net position for Contact, North Island, 2001–07

Source: Contact Energy (contracts and variable price load), Centralised Data Set (generation), EMS (load)

Figure 2.54: Monthly net position for Contact, South Island, 2001–07

Source: Contact Energy (contracts and variable price load), Centralised Data Set (generation), EMS (load)

Figure 2.55: Monthly net position for Meridian Energy, North Island, 2001–07

Source: Meridian Energy (contracts and variable price load), Centralised Data Set (generation), EMS (load)

Figure 2.56: Monthly net position for Meridian Energy, South Island, 2001–07

Source: Meridian Energy (contracts and variable price load), Centralised Data Set (generation), EMS (load)

Figure 2.57: Monthly net position for TrustPower, North Island, 2001–07

Source: TrustPower (contracts and variable price load), Centralised Data Set (generation), EMS (load)

Figure 2.58: Monthly net position for TrustPower, South Island, 2001–07

Source: TrustPower (contracts and variable price load), Centralised Data Set (generation), EMS (load)

Figure 2.59: Half-hourly mean net position, including contracts, Jan 2001 – Jul 2005

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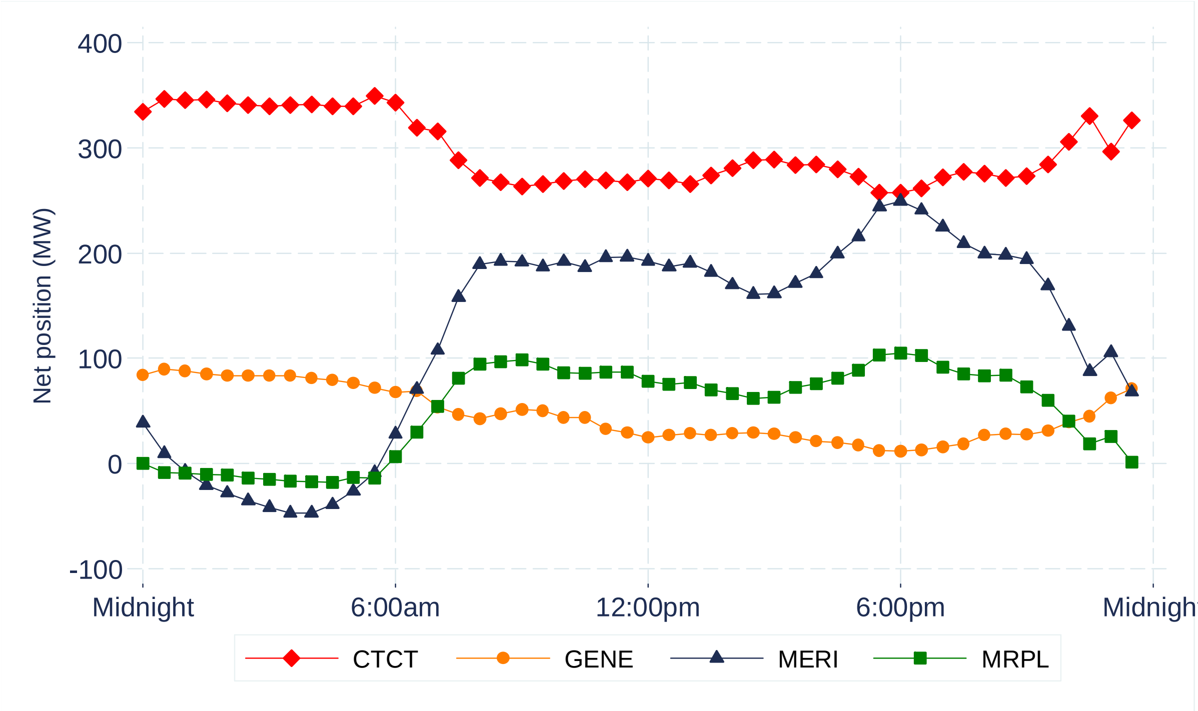
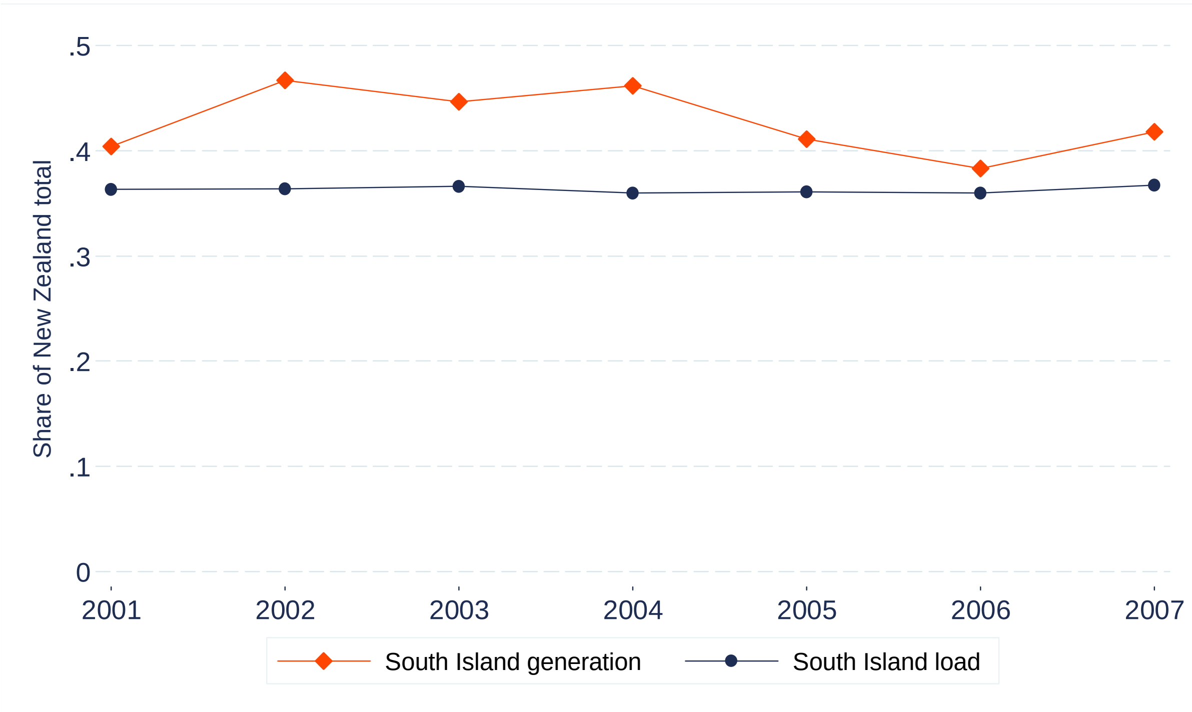
Source: Individual firms (contracts and variable price load), Centralised Data Set (generation), EMS (load)

Figure 2.60: Half-hourly mean net position, excluding contracts, Jan 2001 – Jun 2007



Source: Centralised Data Set (generation), EMS (load)

Figure 2.61: South Island share of New Zealand generation and load, 2001–07



Source: Centralised Data Set (generation), EMS (load)

2.8 Input energy mix of generation and behavior of input fossil-fuel prices

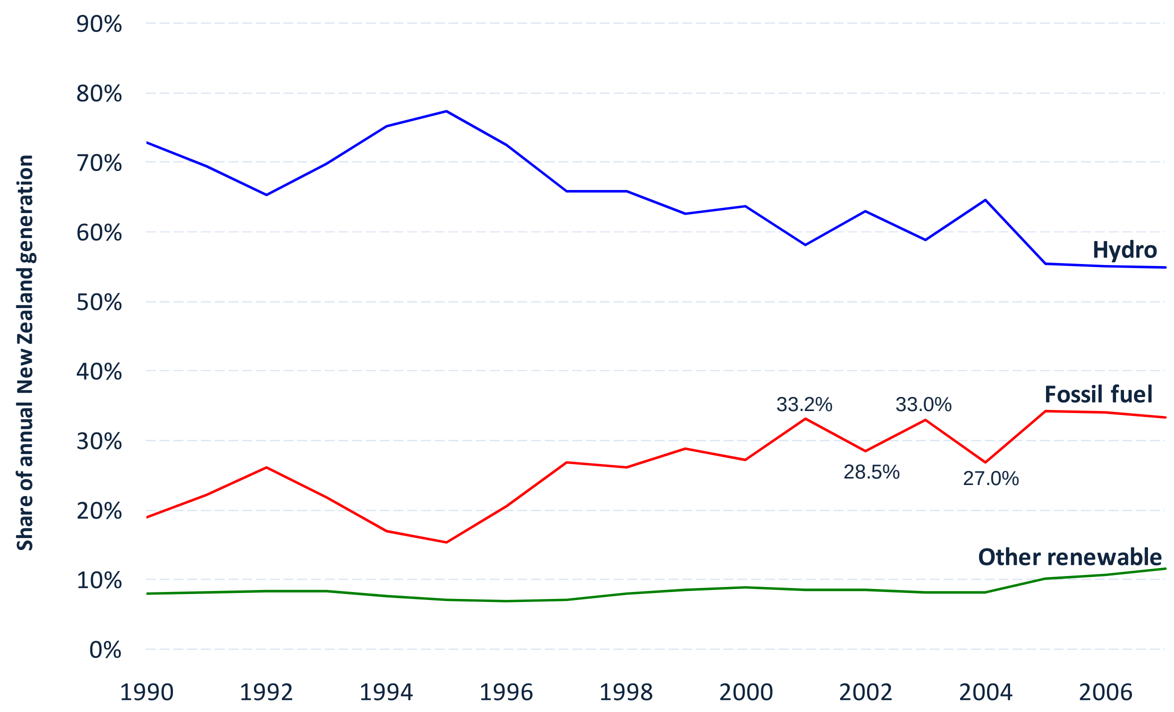
109. This subsection characterizes the behavior of the input energy mix of New Zealand electricity generation over the sample period. This information is first provided in terms of the share of the total generation in New Zealand, and then in terms of the quantity of energy produced by each input energy source. The time series behavior of the prices of input fossil fuels used by the two fossil fuel generation unit owners is then presented.

110. Figure 2.62 shows the proportion of total New Zealand generation from each of three major fuel types: hydro, fossil fuel and other renewable (mainly geothermal and wind). Figure 2.63 shows the annual generation in TWh from these fuel types over the same period. The share of hydro in total generation has fallen from more than 70% for most of the early 1990s to less than 60% after 2005. As shown in Figure 2.63, this is because total hydro generation has stayed relatively constant since 1992, when the last major hydroelectric project (at Clyde) was completed. All subsequent load growth has been met by increases in fossil fuel generation and, to a lesser extent, from other renewables apart from hydro. The graphs also show that there can be economically significant shifts in fuel shares between hydro and fossil fuel (approximately five percent of total generation) between years with dry hydrological conditions, such as 2001 and 2003, and years with wet hydrological conditions, such as 2002 and 2004.

111. Figure 2.64 shows the monthly average fossil fuel price in dollars per gigajoule (GJ) for generation by Contact and Genesis Energy. [

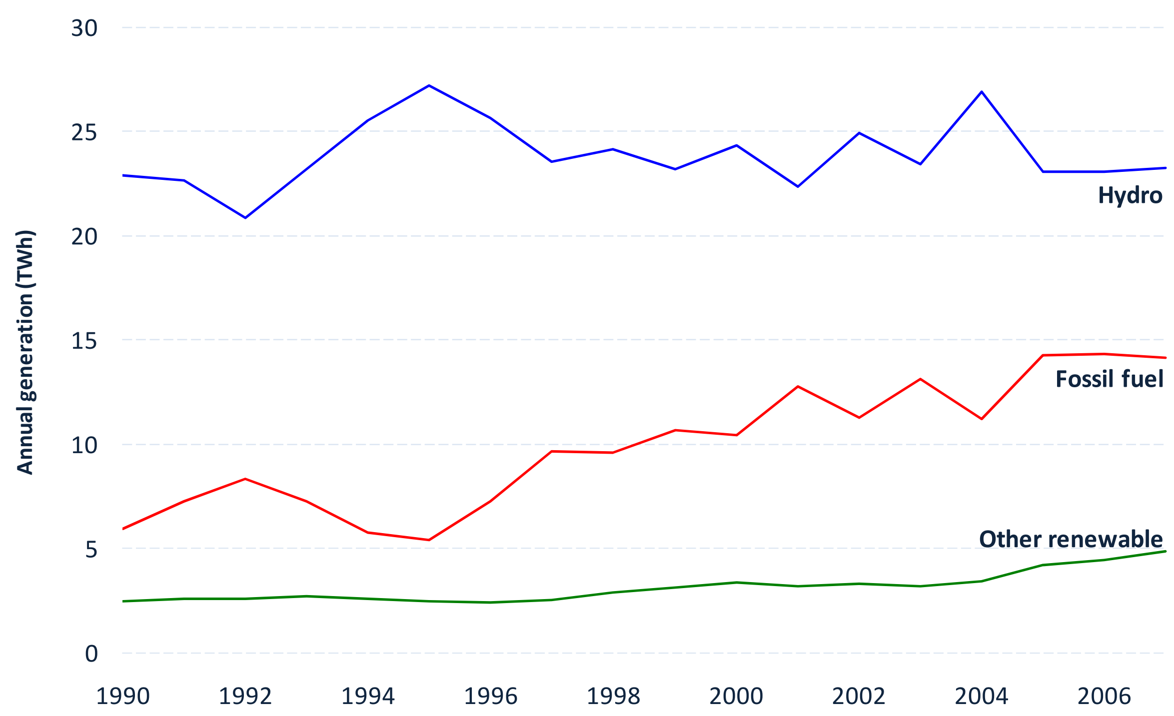
] The data on the graph for Contact for 2006 and 2007 is based on Contact's six-monthly public reports, which provide an average fuel price for the period, including gas transmission costs. In comparison, there is a significant amount of uncertainty in the fuel prices for Genesis after July 2005, as a result of its weaker reporting requirements and its unobserved fuel mix. Gas price estimates for Genesis are based on discounted industrial gas prices from the Energy Data File, with the fuel mix and coal prices chosen to match the total annual fuel cost reported by Genesis each year.

Figure 2.62: Fuel type share of annual New Zealand generation, 1990–2007



Source: MED Energy Data File

Figure 2.63: Annual generation by fuel type, 1990–2007



Source: MED Energy Data File

[Redacted

Figure 2.64: Fossil fuel price series, Contact and Genesis Energy, 2001–07

] **Source:** Contact Energy, Genesis Energy, MED Energy Data File

2.9 Timing of market operations

112. One final feature of the New Zealand electricity market that is important to emphasize is the number of times that the market Scheduling, Pricing and Dispatch (SPD) software that sets nodal prices for each half-hour period is run in advance of the actual final nodal price-setting process. The SPD software takes as input the supply offers and demand bids submitted by market participants, and computes nodal prices and dispatch and withdrawal levels, as well as operating reserves and operating reserves prices. For each advance run of the SPD model, market participants submit supply offers and demand bids, and using the transmission network model submitted by Transpower, nodal prices, dispatch and withdrawal levels, and operating reserves and operating reserves prices are computed. Only the subset of this information relevant to each market participant is provided to that market participant.

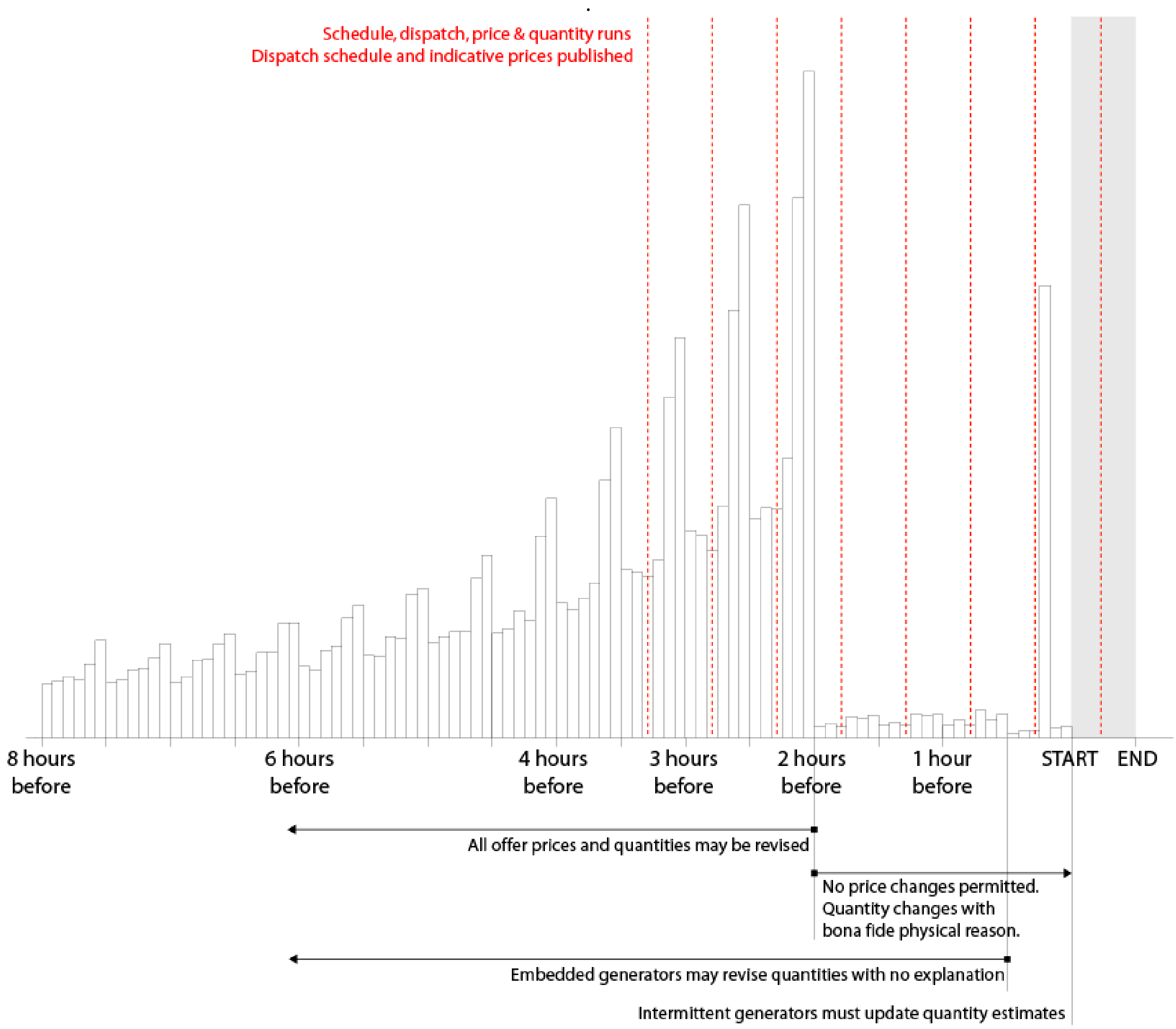
113. Each round of this process provides each market participant with feedback about the likely impact its willingness-to-supply offers have on the amount of energy it sells and the nodal prices that it will ultimately face, without any financial consequences, because dispatch quantities and nodal prices from these advance runs are not financially binding and are for informational purposes only. Depending on the amount of time before actual system operation, different aspects of the offer curves submitted by suppliers in earlier runs of the SPD model can be changed in subsequent runs of the model.

114. Figure 2.65 illustrates the process leading up to actual system operation, and the final run of the SPD model following the real-time system operation. Typically, there are eight

in-advance SPD runs for a given half-hour period. The first of these is about three-and-a-half hours before the half-hour period, and the last is about ten minutes into the period. As shown in Figure 2.65, firms are able to revise their offer prices and quantities, without limitation, before the fourth SPD run.

115. On the diagram, the red dotted lines indicate the time of each SPD run. The grey shaded area is the half-hour in question. The light grey bars show the distribution of new offer curves submitted to Transpower summed over all generation units for each five-minute interval for January 2005. The height of each bar is the number of new offers submitted during that five minute interval in advance of actual system operation for all half-hour intervals during January 2005. As can be seen, there are a significant number of revisions to the generation offers during all five-minute intervals between the publication of the results from the first SDPQ run and the close of offer submissions just before the fourth SPD run.

Figure 2.65: Timing of SDP runs and submission of final offers for January 2005



Source: Schedule of Dispatch Prices and Quantities offer data (Transpower)

SECTION 3

THE UNILATERAL MARKET POWER PROBLEM IN WHOLESALE ELECTRICITY MARKETS

3.1 Introduction

116. This section first describes the mechanisms that expected profit-maximizing suppliers use to exercise unilateral market power in a bid-based wholesale electricity market. This theoretical framework is used to derive indexes of the ability and incentive of a supplier to exercise unilateral market power using data on the offer curves of all suppliers, market demand, and market-clearing prices and quantities for all market participants.

117. In a market-based pricing regime, sellers and buyers may be able to influence the price they are paid or pay through the amount of output they are willing to supply or the amount of output they are willing to purchase. Market participants have an incentive to take actions to impact the price they are paid or receive when these actions lead to prices that are more favorable to their objectives. Market participants that take these actions unilaterally are said to be exercising unilateral market power.

118. A market participant is said to possess unilateral market power if it has the ability to take unilateral actions to influence the market price and to profit from the resulting price change. Because the demand-side of most electricity markets is composed of many small buyers (residential, industrial and commercial consumers) and the supply side is typically composed of a small number of large sellers, the primary market power concern in wholesale electricity markets is from suppliers taking actions to raise market prices. The New Zealand wholesale electricity market has four large suppliers whose unilateral behavior could significantly impact market outcomes under certain system conditions. In other words, these four suppliers may have the ability and incentive to exercise unilateral market power in the wholesale electricity market.

119. Before continuing this section, it is important to re-emphasize a point made in Section 1 that a supplier exercising all available unilateral market power subject to obeying the market rules is equivalent to that supplier taking all legal actions to maximize the profits it earns from participating in the wholesale market. Moreover, a firm's management has a fiduciary responsibility to its shareholders to take all legal actions to maximize the profits it earns from participating in the wholesale market. Consequently, a firm is only serving its fiduciary responsibility to its shareholders when it exercises all available unilateral market power subject to obeying the wholesale market rules. Although three of the major participants in the New Zealand wholesale electricity market are owned by the Crown, their principal objective, as set out in the State-Owned Enterprises Act 1986, is to be "as profitable and efficient as comparable businesses that are not owned by the Crown". That is, the directors of the State-owned firms also have a legal obligation to ensure that they are exercising all available unilateral market power. As discussed in Wolak (2007), there are a number of ways to modify the market structure, market rules, and the form of the regulatory process to limit the ability and incentive of suppliers to

exercise unilateral market power.[26] Thus, the role of regulatory oversight of the electricity supply industry is to institute market rules that ensure the conditions necessary for vigorous competition exist and limit the economic harm associated with the exercise of unilateral market power when they do not exist. To properly design and implement market rules that serve these purposes, policymakers must first understand why wholesale electricity markets are so susceptible to the exercise of unilateral market power and how suppliers actually exercise unilateral market power. This section provides the theoretical foundation for the indexes of the ability and incentive to exercise unilateral market power used throughout the remainder of this report.

120. The next section introduces the analytical framework for measuring the ability of a supplier to exercise unilateral market power. This section introduces the concept of a supplier's residual demand curve that can be constructed for each pricing period using the market demand and offer curves of all other suppliers besides the one under consideration. The inverse elasticity of this residual demand indicates the percentage change in the market clearing price a supplier can 'cause' by a certain percentage reduction in the quantity offered into the market. The impact of congestion, in particular of the HVDC linking the North and South Islands is discussed, and the adaptation of the residual demand analysis to account for this constraint is explained.

121. Section 3.3 extends the analysis presented in Section 3.2 (deriving an index of the ability of a supplier to exercise unilateral market power) to take into account a supplier's fixed-price forward market obligations to construct a measure of its incentive to exercise unilateral market power. First, the net fixed-price forward market obligations output of a supplier is defined. This measure and the index of the supplier's ability to exercise unilateral market power are then combined to construct an index of the supplier's incentive to exercise unilateral market power.

122. Section 3.4 presents alternative indexes of the ability and incentive of a supplier to exercise unilateral market power based on the concepts of a pivotal supplier and net pivotal supplier. This section first defines these two concepts using the residual demand framework and then discusses when these measures are most informative about the ability and incentive of a supplier to exercise unilateral market power. Section 3.5 concludes with a discussion the determinants of the length of time a supplier has the ability and incentive to exercise unilateral market power

3.2 Measuring the ability to exercise unilateral market power

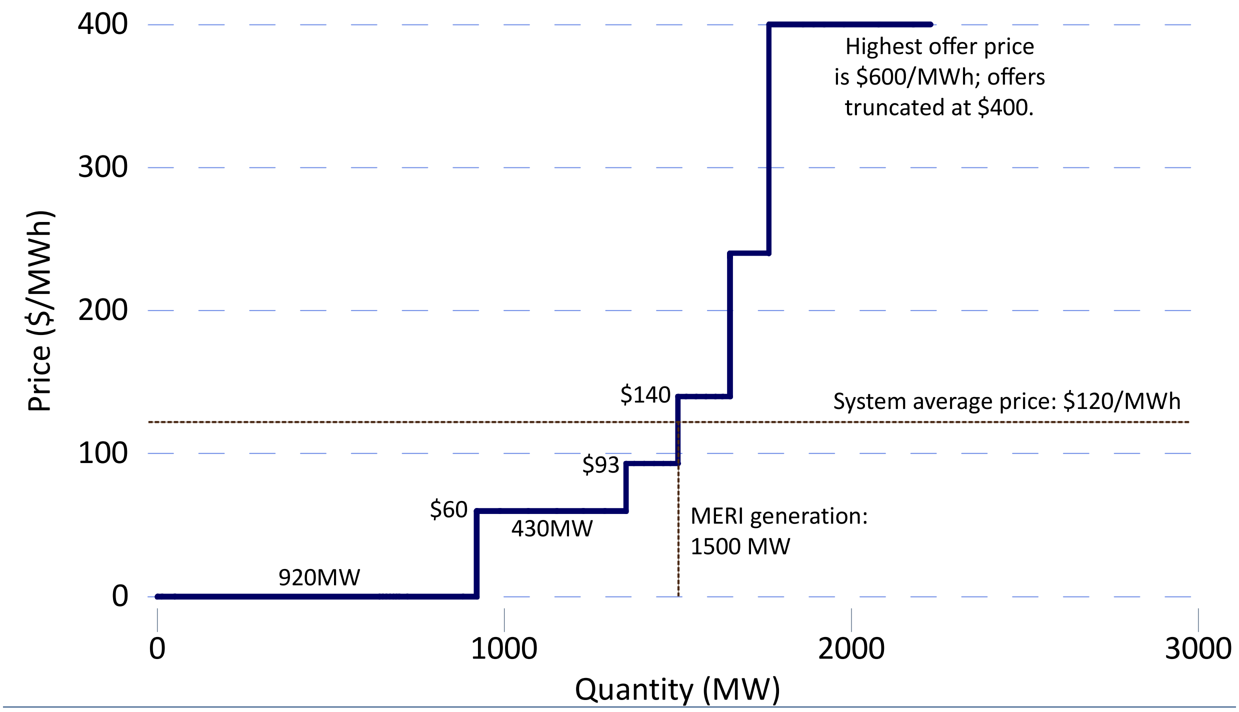
123. A supplier participates in a short-term wholesale electricity market by submitting for each pricing period an "offer curve", which is composed of a series of offer steps. The length of the step specifies an incremental quantity of energy to be supplied and the height of the step is the price at which the supplier is willing to sell that quantity. For the case of the New Zealand wholesale electricity market, Figures 3.1 and 3.2 show the final

[26] Wolak, F.A. (2007) "Regulating Competition in Wholesale Electricity Supply," forthcoming in N. Rose ed., Economic Regulation and Its Reform: What Have We Learned?, University of Chicago Press, available at http://www.stanford.edu/~wolak.

offer curves submitted by Meridian Energy and Genesis Energy for Period 36 on 18 February 2006. For the lowest-priced offer step, Meridian Energy is willing to supply 920 MW at $0.03/MWh and if the market price increases to $60/MWh, it is willing to supply an additional 430 MW, and so on. As the offer price increases, the supplier's cumulative willingness to sell electricity increases along with the offer price, from 920MW at $0.03/MWh to 1,350MW at $60/MWh (= 920MW at $0.03/MWh + 430 MW at $60/MWh). This increasing relationship between the offer price and the supplier's cumulative willingness to sell yields the upward sloping offer curves for each supplier shown in Figures 3.1 and 3.2. Let $S_k(p)$ denote the offer curve of supplier k. At each price, p, this function gives the total quantity of energy that supplier k is willing to sell.

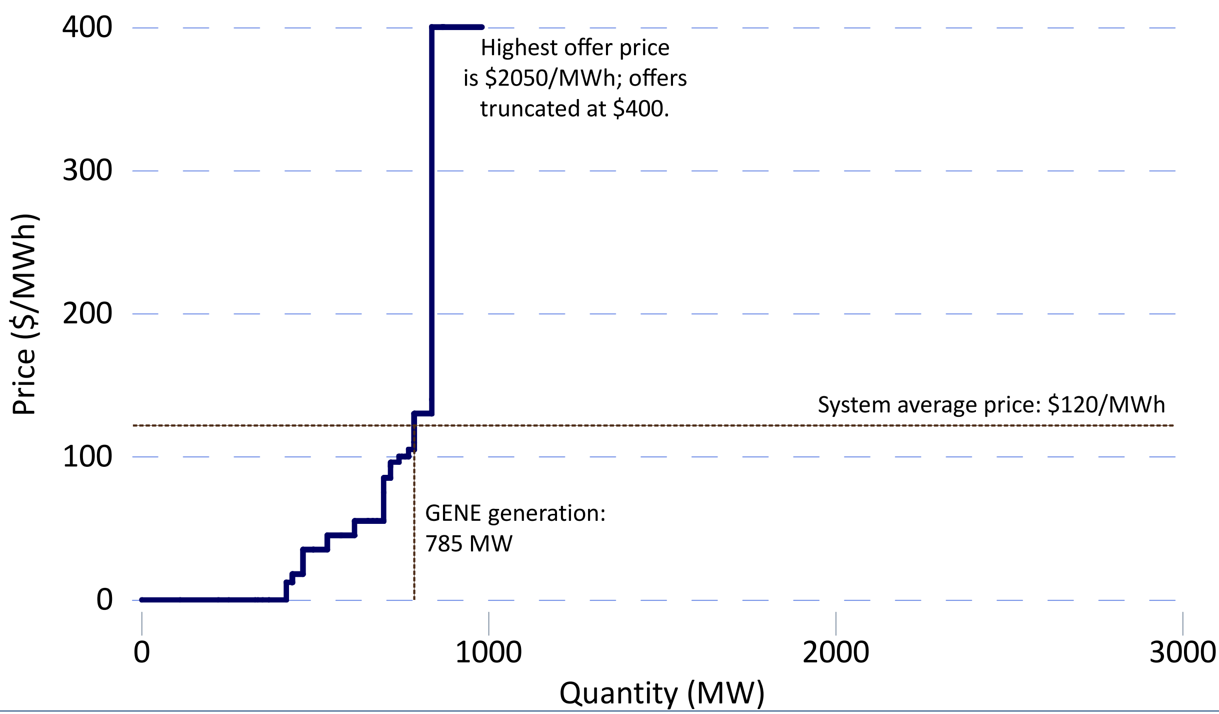
124. The offer curves from each supplier can be used to construct the aggregate offer curve for any set of suppliers. This is done by calculating the cumulative quantity that the set of suppliers are willing to sell across the relevant range of prices. Let $S_{123}(p)$ equal the aggregate offer curve for firms 1, 2, and 3. In terms of the individual offer curves, $S_{123}(p) = S_1(p) + S_2(p) + S_3(p)$, which means that $S_{123}(p)$ at price p is equal to the total amount of energy that firms 1,2, and 3 are willing to supply at price p. Figure 3.3 shows the aggregate offer curve for Meridian Energy and Genesis Energy for the firm-level offer curves shown in Figures 3.1 and 3.2. At a price of $200/MWh, for example, Meridian is willing to supply a total of 1650 MW and Genesis is willing to supply 835 MW. Therefore, the aggregate offer of both firms at a price of $200/MWh is 2485 MW. This procedure can be used to construct the aggregate offer curve for any collection of suppliers.

Figure 3.1: Offer curve for Meridian Energy on 18 Feb 2006, period 36



Source: Calculations based on data from Centralised Data Set and Energy Market Services.

Figure 3.2: Offer curve for Genesis Energy on 18 Feb 2006, period 36



Source: Calculations based on data from Centralised Data Set and Energy Market Services.

125. Given the offer curves of all generation units in New Zealand, the price each generation unit receives for its output and each buyer pays for its withdrawals is

determined by minimizing the as-offered cost of serving demand plus transmission losses at all locations in the country. The as-offered cost for each generation unit is equal to the offer price times the offer quantity for each quantity increment or partial quantity increment accepted to provide energy, summed over all offer price levels for that generation unit. The total as-offered cost of serving load in New Zealand is the as-offered cost for each generation unit summed over all units in the country. The total of all offer quantities accepted by the market operator (M-co) to produce energy is equal to the total demand at locations in the transmission network plus total transmission losses. The market price at each location in the transmission network is equal to the increase in the minimized value of the total as-offered cost of serving system demand at all locations in New Zealand as a result of an additional 1 MWh of load at that location.

126. These market-clearing prices or nodal prices differ across locations in the transmission network because of transmission losses and transmission congestion. For locations far from generation units, more energy must be injected by distant generation units in order to withdraw an additional 1 MWh from this location because of greater line losses in transferring the electricity from the point of injection to the point of withdrawal. In contrast, for locations close to generation units, the nodal price is lower because the electricity withdrawn at that location does not travel as far. Congestion in the transmission network arises when the amount of electricity that suppliers on one side of a transmission link would like to inject leads to implied flows on the transmission link that exceed its capacity. In these circumstances, prices on one side of the link must be lowered to reduce the flows on the transmission line to its capacity and prices on the other side of the link must be increased to ensure that there is sufficient local generation to serve demand given the actual flows of the transmission link into the area.

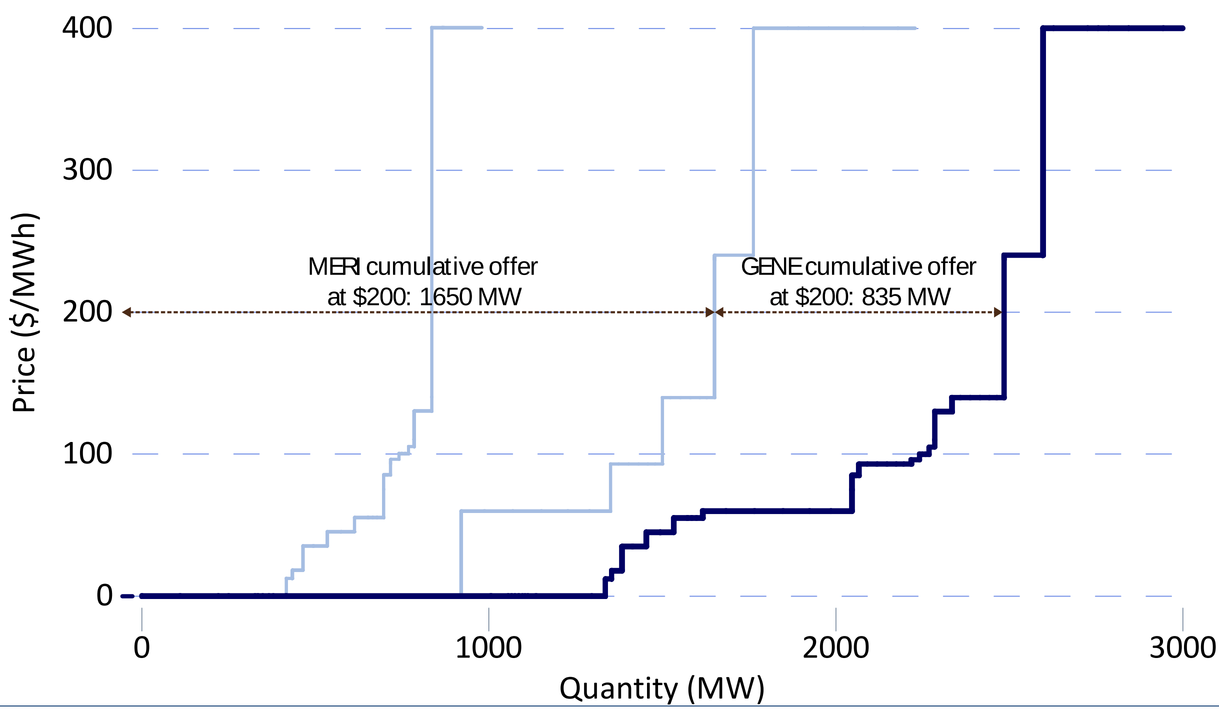
127. As noted in Wolak (2006), the frequency of transmission congestion in the New Zealand wholesale market, as measured by the number of half-hours with price differences between locations that are greater than can be explained by line losses, is low.[27] Line losses also tend to produce persistent price differences across locations in New Zealand because generation-rich nodes (those with low loss factors) and generation-poor nodes (those with high loss factors) within each island tend to remain so regardless of the level of demand throughout New Zealand.

128. Consequently, during the periods when no transmission constraints are binding, the price at each location in New Zealand is reasonably well-approximated by simply taking the aggregate willingness-to-supply curve across all locations in New Zealand and solving for the price where this curve intersects the total demand in New Zealand. Define $S(p)$ as the aggregate willingness-to-supply curve for a half-hour. It is equal to $S_1(p) + S_2(p) + \ldots + S_K(p)$, where K is the total number of suppliers in New Zealand. Let $QD = QD_1 + QD_2 + \ldots + QD_M$, where QD_m is the demand at node m and M is the total number of nodes in New Zealand. This no-congestion market-clearing price is the solution in p, to the equation $S(p) = QD$. An example of this process is shown in

[27] Wolak, F.A. (2006) "Preliminary Report on the Design and Performance of the New Zealand Electricity Market," attached as Appendix 2.

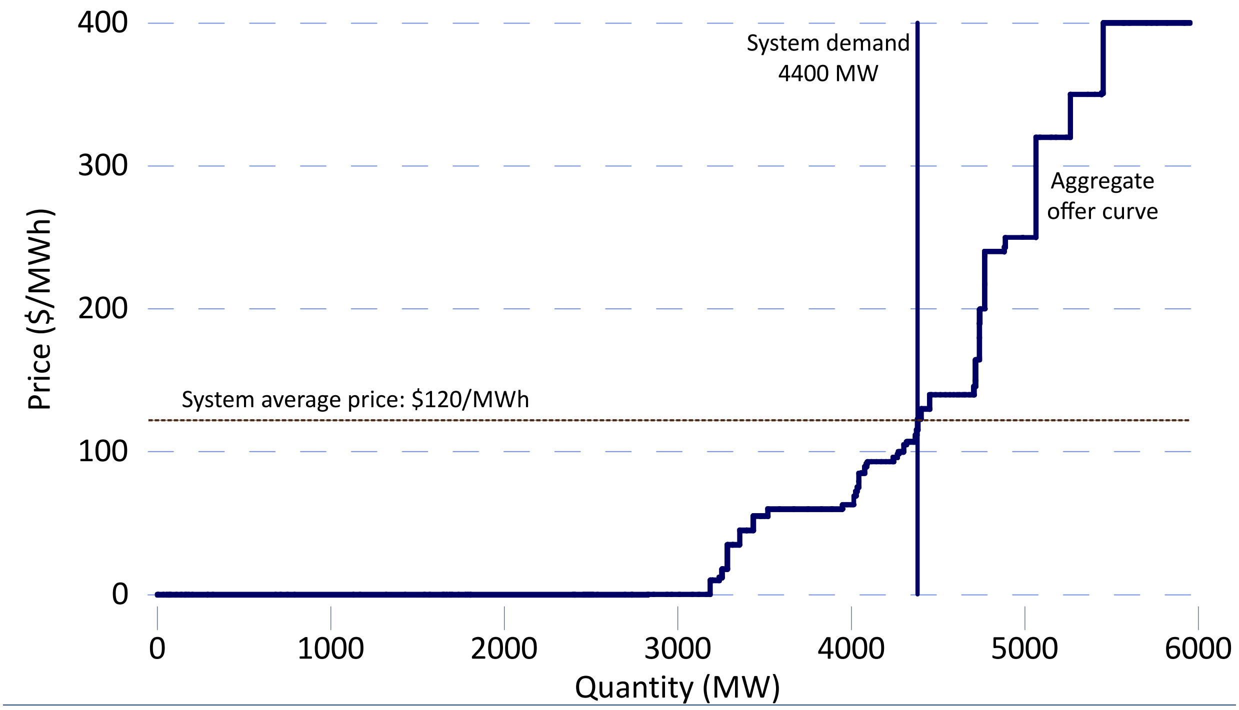
Figure 3.4 for Period 36 on 18 February 2006. In the period, the total market demand is 4400 MW and based on the aggregated offer curve for all the suppliers, the market price has to be at least $120/MWh for there to be enough supply offers to meet this demand.

Figure 3.3: Combined offer curve for Meridian and Genesis on 18 Feb 2006, period 36



Source: Calculations based on data from Centralised Data Set and Energy Market Services

Figure 3.4: Aggregate offer curve for all generators on 18 Feb 2006, period 36



Source: Calculations based on data from Centralised Data Set and Energy Market Services

3.2.1 Construction of aggregate offer curves and residual demand curves

129. This description of the price-setting process in the New Zealand market allows a graphical description of how suppliers exercise unilateral market power in a bid-based wholesale market, which motivates our measure of the ability of a supplier to exercise unilateral market power. As we discuss below, the basic intuition and insights provided by this single-price, graphical analysis carry over to the case of the nodal price-setting process used in the New Zealand market. To analyze the bidding behavior of an individual supplier using this graphical framework, the above mechanism can be reformulated in terms of the supplier's own offer curve, the offers of other suppliers and the total market demand. Specifically, the price setting equation $S(p) = QD$ can be re-written as:

$$S_1(p) + S_2(p) + \dots + S_K(p) = QD,$$

which is the total of all individual supply quantities equals total market demand, where each supply quantity depends upon the market price p. Suppose that we are interested in measuring the ability of just one supplier, supplier j, to exercise unilateral market power. This price-setting equation can be re-written as:

$$S_j(p) = QD - \left(S_1(p) + \dots + S_{j-1}(p) + S_{j+1}(p) + \dots + S_K(p)\right) = QD - SO_j(p)$$

where $SO_j(p)$ is the aggregate willingness-to-supply curve of all firms except supplier j, and so $QD - SO_j(p)$ represents total market demand less supply by all firms except supplier j. Define $DR_j(p) = QD - SO_j(p)$ as the residual demand curve facing supplier j at price p. This is market demand quantity less the willingness to supply curves of all other firms is maximum demand that can be provided by supplier j at each possible price.

130. Figure 3.5 provides a graphical version of the above calculation of the residual demand for Meridian Energy in Period 36 on 18 February 2006. The total market demand is 4,400MW and the total quantity offered by all suppliers other than Meridian is 3,350MW at \$300 and 2,560MW at \$50. Therefore, Meridian's residual demand at \$300 is 1,050MW (the market demand of 4,400MW minus 3,350MW of supply by other suppliers at that price). Its residual demand at \$50 is 1,840MW (the market demand of 4,400MW minus 2,560MW of supply by other suppliers at that price). Figure 3.6 shows the residual demand curve resulting from performing this calculation for all possible prices for Meridian in this half-hour period.

131. Figure 3.7 combines Meridian's residual demand curve from Figure 3.6 with Meridian's offer curve from Figure 3.1. Because this is a half-hour period with no transmission congestion, nodal prices differ across locations in New Zealand only because of line losses.[28] If p_m is price at node m and q_m is the amount of energy injected at node m, the quantity-weighted average nodal price is the sum of the product of the nodal price and nodal quantity of energy injected over all M locations in New Zealand divided by sum of the nodal injections at all locations in New Zealand during that half-hour. Mathematically, this quantity weighted average price p_{avg}, is equal to:

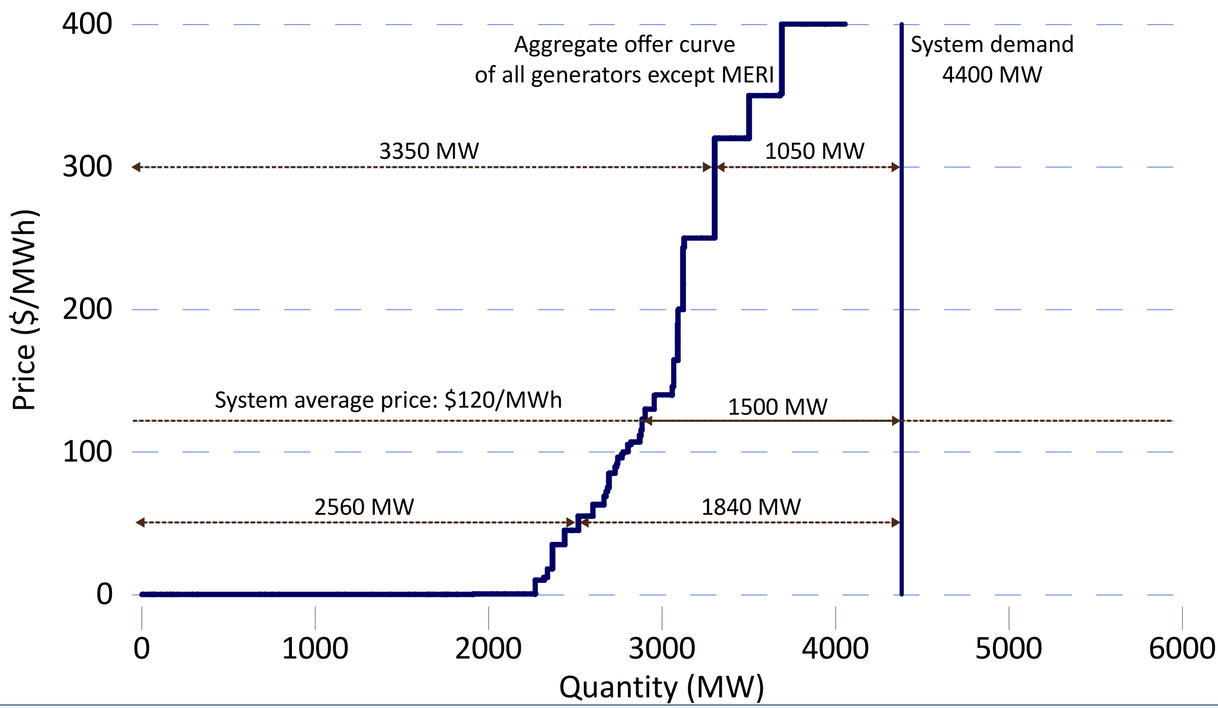
$$p_{avg} = \frac{\sum_{m=1}^{M} p_m q_m}{\sum_{m=1}^{M} q_m}$$

Applying this process to all of the nodal prices for Period 36 on 18 February 2006 yields a quantity-weighted average price of \$121.79/MWh.

132. To make the simplified model of the price-setting process described above consistent with the actual nodal price-setting process, we make shift the residual demand so that the actual quantity-weighted average price is the price at which Meridian's offer curve crosses its residual demand curve. We also shift Meridian's offer curve so that the quantity on Meridian's offer curve at this price is equal to the actual average amount of energy that Meridian produces during this half-hour period. For this half-hour, \$120/MWh is the quantity-weighted average price and Meridian's actual average output during the half hour is 1,500 MW.

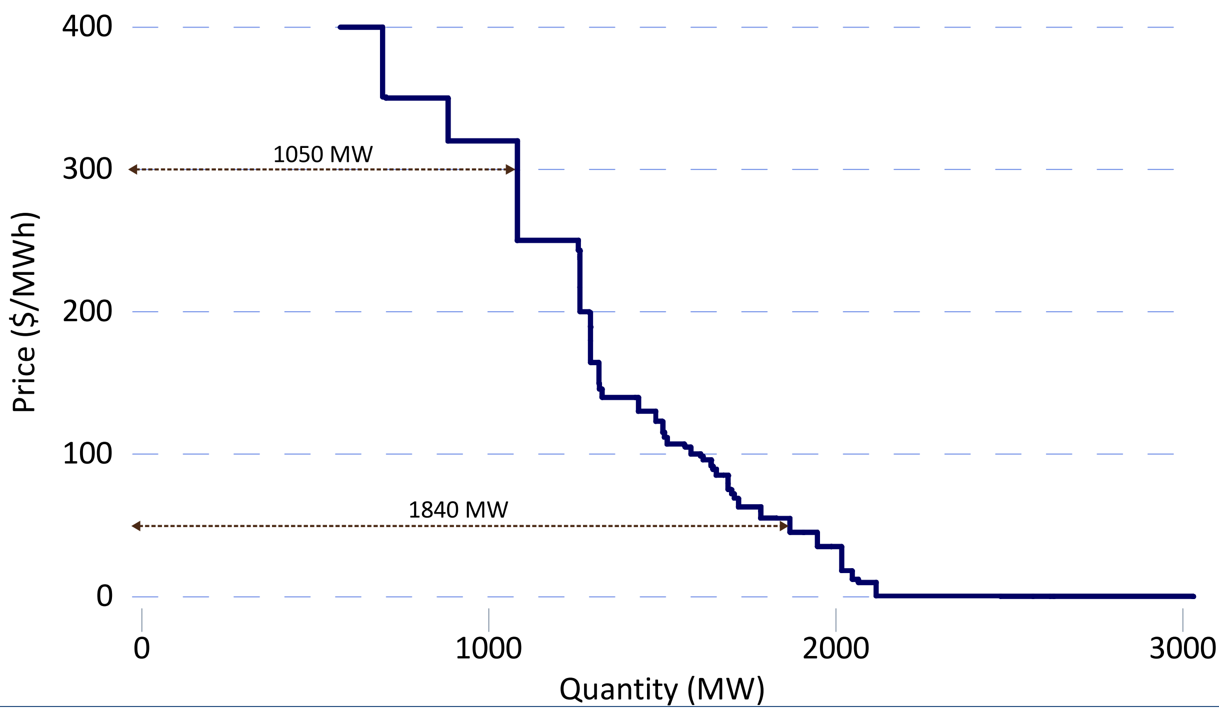
[28] The lowest price in this period was \$112/MWh at Tuai in the North Island, and the highest price was \$154/MWh at Kaikoura in the South Island. However, prices at major generation nodes were close to \$120/MWh: Manapouri \$119/MWh, Stratford \$120/MWh, Benmore \$121/MWh and Huntly \$124/MWh.

Figure 3.5: Calculation of residual demand for Meridian on 18 Feb 2006, period 36



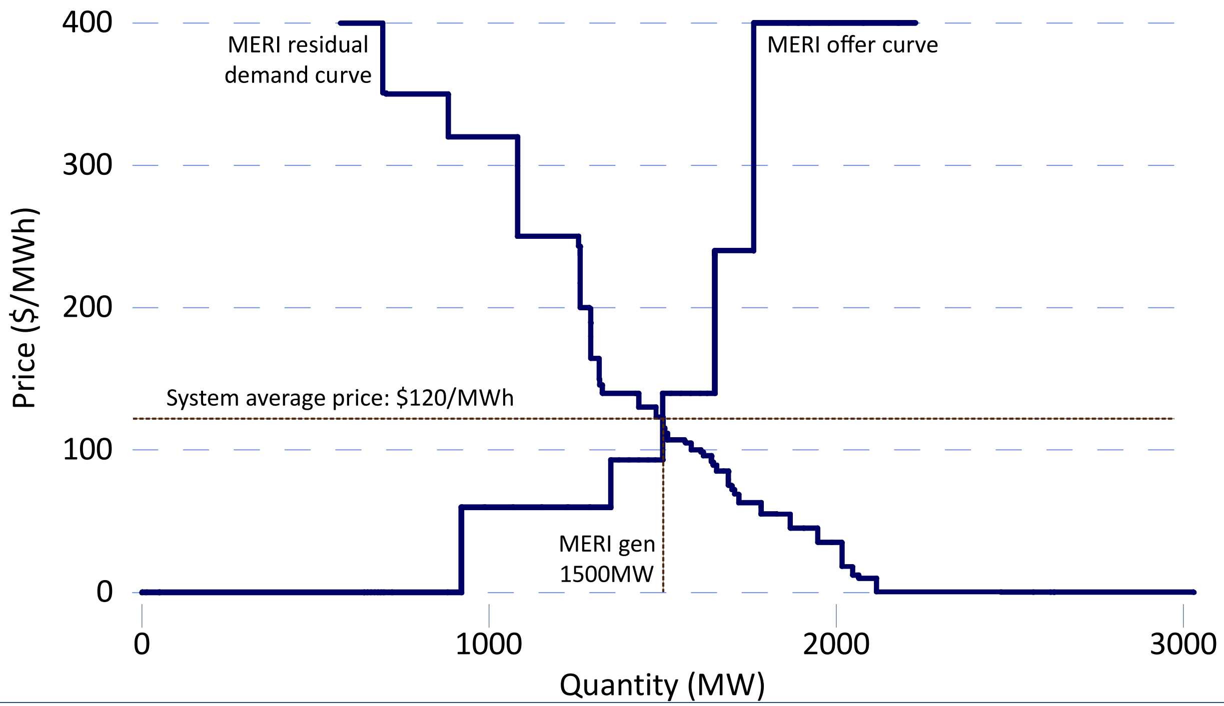
Source: Calculations based on data from Centralised Data Set and Energy Market Services.

Figure 3.6: Residual demand for Meridian on 18 Feb 2006, period 36



Source: Calculations based on data from Centralised Data Set and Energy Market Services.

Figure 3.7: Residual demand and offer curve for Meridian on 18 Feb 2006, period 36



Source: Calculations based on data from Centralised Data Set and Energy Market Services.

3.2.2 *The inverse elasticity of residual demand curve as a measure of ability to exercise unilateral market power*

133. The residual demand curve that a supplier faces summarizes its ability to change the market price by submitting a different offer curve while keeping offer curves of other suppliers and the market demand unchanged. The firm can choose to produce any price and generation quantity along its residual demand curve. For example, Figure 3.8 shows the residual demand curve for Meridian in Period 36 on 18 February 2006. The realized price was $120/MWh and the quantity supplied by Meridian was 1,500MW, which gives Meridian generation revenues of $90,000 in the half-hour. However, if Meridian had increased the price of the generation offers that it submitted for this period, it could have increased the market price to $250/MWh, with a reduction in its quantity supplied to 1,270MW, which would give it a generation revenue of $158,750 even though it supplies less to the market.

134. As shown in Figure 3.8, Meridian could have increased the market price by 108% with a reduction in its quantity supplied by 15%. The inverse elasticity of the residual demand curve at price p is defined as the ratio of percentage change in the price along the supplier's residual demand curve that results from it selling a certain pre-specified percentage less output. In this case, the inverse elasticity is 108/15 = 7.2.

135. Higher values of the inverse elasticity mean that the supplier has greater ability to change the market price through its unilateral actions. If the inverse elasticity is greater than 1 (the residual demand curve is "inelastic") then a given percentage reduction in the quantity supplied (e.g., 15% reduction in the above example) creates a greater percentage

increase in the market price (e.g., 108% increase in the above example). Because the revenue a supplier receives is equal to price it sells at, multiplied by the quantity that it produces, such a relationship between the quantity reduction and price increase would lead to higher revenue for the supplier. Conversely, an inverse elasticity less than 1 ("elastic" residual demand) corresponds to the case where a given percentage reduction in the quantity supplied creates a smaller percentage increase in the market price, and consequently lower revenue for the supplier.

136. Because offer curves in the New Zealand market are step functions, residual demand curves are also step functions. Therefore, the value of the inverse elasticity typically depends on the percentage reduction in the quantity supplied. Returning to Figure 3.8, a 15% percent reduction in the amount that Meridian supplies implies a 108% increase in the corresponding price on Meridian's residual demand curve, or an inverse elasticity of 7.2. Mathematically, the inverse residual demand elasticity for a 10 percent quantity reduction is equal to:

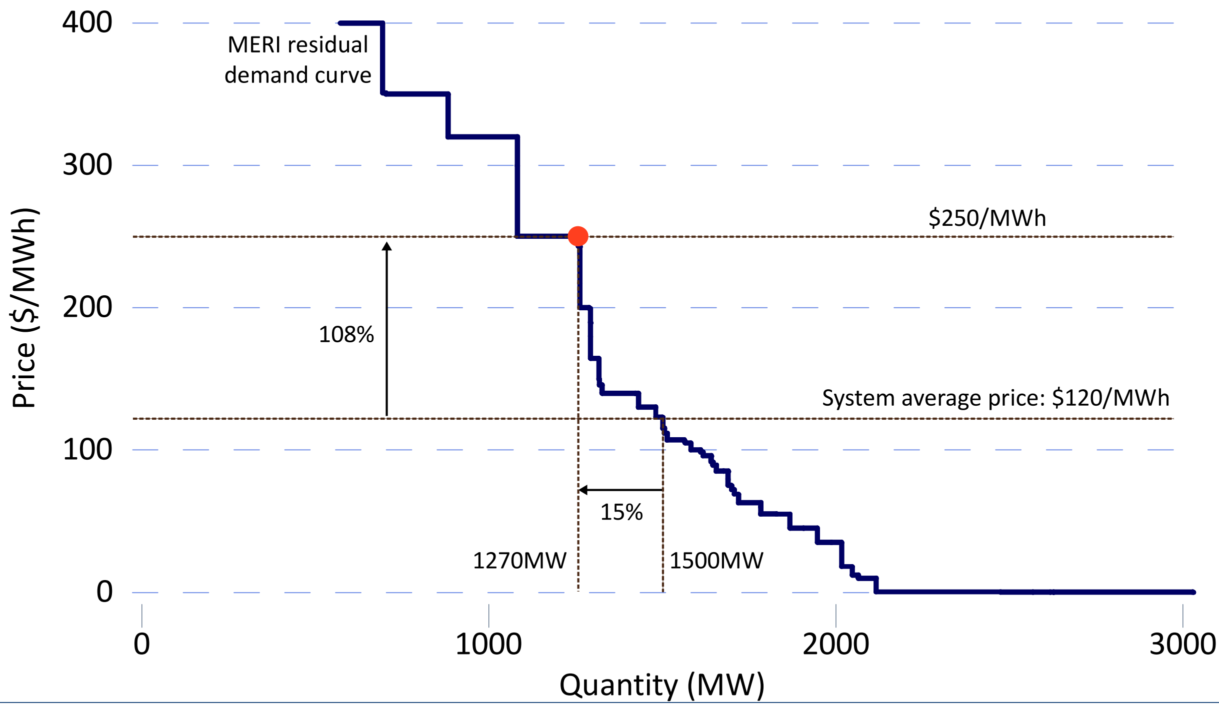
$$1/\varepsilon = \frac{(p^* - p_{avg})/p_{avg}}{0.10}$$

where p^* solves the equation $0.9q_j = DR_j(p^*)$. It is the price on the supplier's residual demand curve associated with at 10 percent quantity reduction relative to the market clearing quantity sold by firm j of q_j. This inverse elasticity measures how much supplier j could increase the price it is paid by reducing the amount of output it is willing to sell given the offers of its competitors.

137. This inverse elasticity is a key determinant of how far above its marginal cost (in percentage terms) a profit-maximizing supplier would like its offer curve to intersect with its residual demand curve. Specifically, the larger the value of the inverse of the elasticity of the residual demand curve, the greater is the percentage a profit-maximizing supplier would like the market price to be above its marginal cost. As noted above, a supplier's residual demand curve gives the set of feasible price/quantity pairs that it can choose from to maximize its profits. Firms in imperfectly competitive markets often speak of "pricing to take what competition gives them" or "pricing at what the market will bear." This can be interpreted simply as the firm pricing along its residual demand curve. In this sense, a supplier's residual demand curve shows the trade-off between a higher system price and lower generation quantity for the supplier.

138. Simplifying to the case of a linear residual demand curve and continuous marginal cost curve allows a straightforward illustration of this relationship. Assume for the moment that the supplier knows the offers of its competitors and the level of market demand, which completely determine its residual demand curve. The effect of this trade-off on the firm's revenue is shown by the marginal revenue curve, labeled MR_1 in Figure 3.9. The marginal revenue curve shows the total revenue change associated with each additional unit of quantity supplied. The marginal revenue curve is steeper than, and lies below, the residual demand curves because each additional unit sold by the firm requires it to accept a lower price, not just for this additional unit, but on all units sold, because of the market-clearing price determination process described above.

Figure 3.8: Residual demand and the calculation of inverse elasticity



Source: Calculations based on data from Centralised Data Set and Energy Market Services.

139. The supplier maximizes profits by producing at the output level where the marginal revenue associated with selling an additional MWh equals marginal cost associated with producing an additional unit. Producing one unit m*ore than* this quantity will lower the firm's profits, because the revenue received from supplying the additional unit is less than the cost of producing it. Likewise, if the firm produces one unit less than this quantity, then it is giving up profits, because the potential revenue from supplying that unit is greater than its cost of production. For the residual demand curve DR_1 and marginal cost curve MC in Figure 3.9, a profit-maximizing firm will supply the quantity $Q_{1,}$ the output level at the point of intersection of the marginal cost and marginal revenue curves. Note that the system price will be P_1, the intersection of quantity Q_1 with the residual demand curve. Note that this price exceeds the firm's marginal cost of supplying Q_1. The firm's profits are given by the area left of Q_1, below P_1 and above the marginal cost curve.

140. Figure 3.10 repeats the process of computing the profit-maximizing level of output for a flatter residual demand curve, DR_2, and the same marginal cost curve as in Figure 3.9. A profit-maximizing supplier will produce the quantity Q_2 at a price of P_2. Note that difference between P_2 and the firm's marginal cost is smaller than in Figure 3.9, which is a result of the flatter or more elastic residual demand curve in Figure 3.10.

141. The case is of a perfectly elastic residual demand curve, DR_3, is shown in Figure 3.11. This residual demand curve is the result of a flat aggregate offer curve of all other suppliers besides supplier j, which implies that there many other firms willing to supply the entire market at the price P_3 in Figure 3.11. For this residual demand curve, the marginal revenue curve MR_3 coincides with the residual demand curve, because

producing an additional unit of output has no effect on the market price, which implies that the additional revenue received from selling one more unit of output is equal to that price for all output levels. For the reasons discussed above, a profit-maximizing firm will produce at the point where marginal revenue is equal to marginal cost, but for this residual demand curve the marginal revenue curve is equal to the market price. This result implies that the firm will produce at the point of intersection of its marginal cost curve with its residual demand curve, which is the output level Q_3 and price P_3 in Figure 3.11. This residual demand curve is equivalent to the firm receiving a bid for as much output as it would like to produce at a fixed price of P_3. If the firm is offered a price of P_3, then if it would like to maximize the profits it earns from selling at this price, it will produce up to the point when its marginal cost is equal to P_3.

142. This example demonstrates the very important point that if a supplier faces a sufficiently elastic residual demand curve, typically because there is large number of independent suppliers competing to sell energy, then it is unilaterally profit-maximizing for this supplier to produce at the point where the market price is equal to its marginal cost. The firm accomplishes this market outcome by submitting an offer curve that is equal to its marginal cost curve, because the intersection of this offer curve with its residual demand curve produces the desired price/quantity pair.

143. The examples in Figures 3.9 and 3.10 demonstrate that when a profit-maximizing supplier faces a downward sloping residual demand curve, the firm will find it unilaterally profit-maximizing to produce at an output level that is below the output level at the point of intersection of its marginal cost curve with its residual demand curve. In Figure 3.9, the firm would optimally only offer only Q_1 into the market, even though the price P_1 greatly exceeds its marginal cost at that level of production. The firm accomplishes this by submitting an offer curve that lies above its marginal cost curve, giving an offer price for that level of output above the marginal cost of producing that output. Figures 3.9 and 3.10 suggest that the percentage by which the supplier's profit-maximizing offer price that intersects the supplier's residual demand curve exceeds the supplier's marginal cost is greater the larger is the inverse elasticity of the residual demand curve. This is an important implication of expected profit-maximizing behavior that will be explored in subsequent sections of this report.

Figure 3.9: Profit-maximizing choice of price and quantity

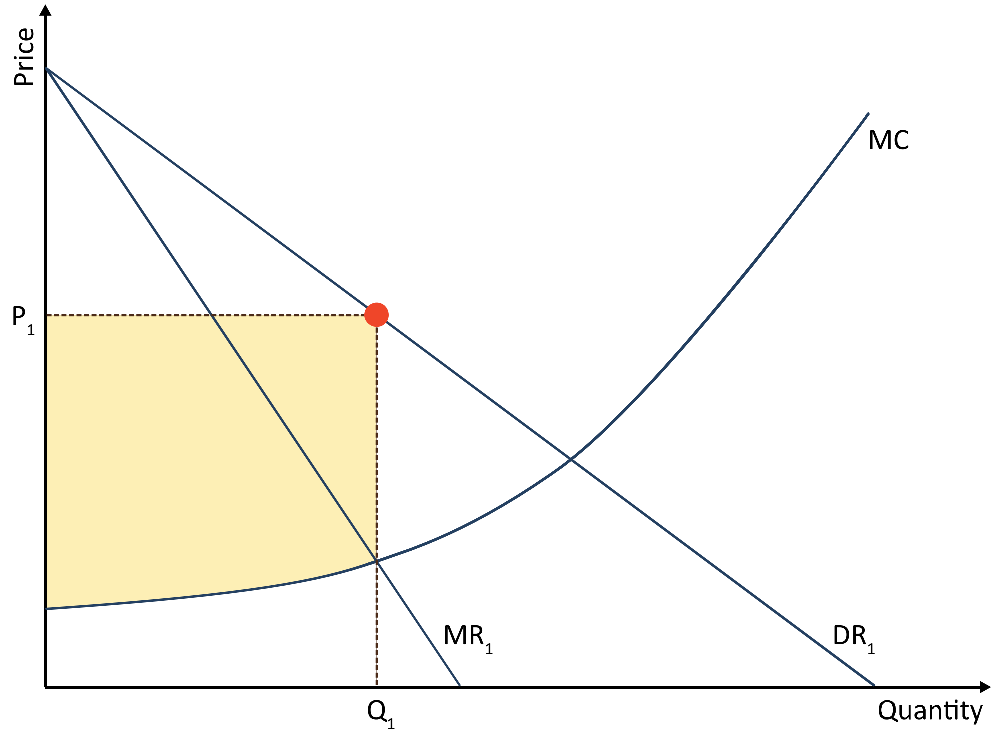


Figure 3.10: Profit-maximizing price and quantity with elastic residual demand

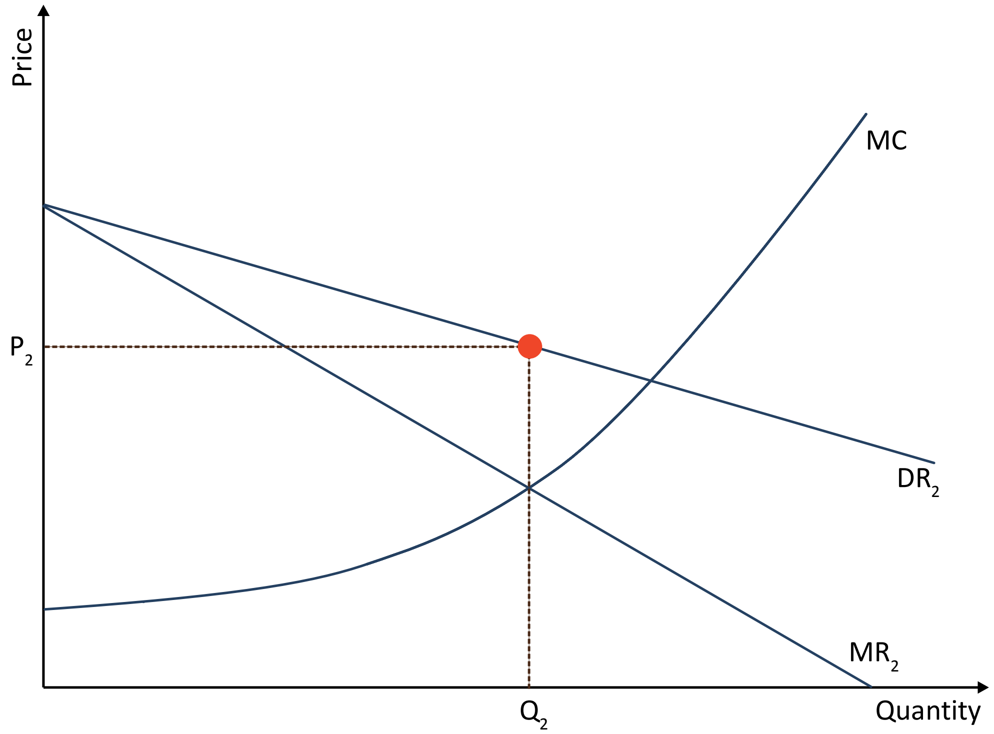
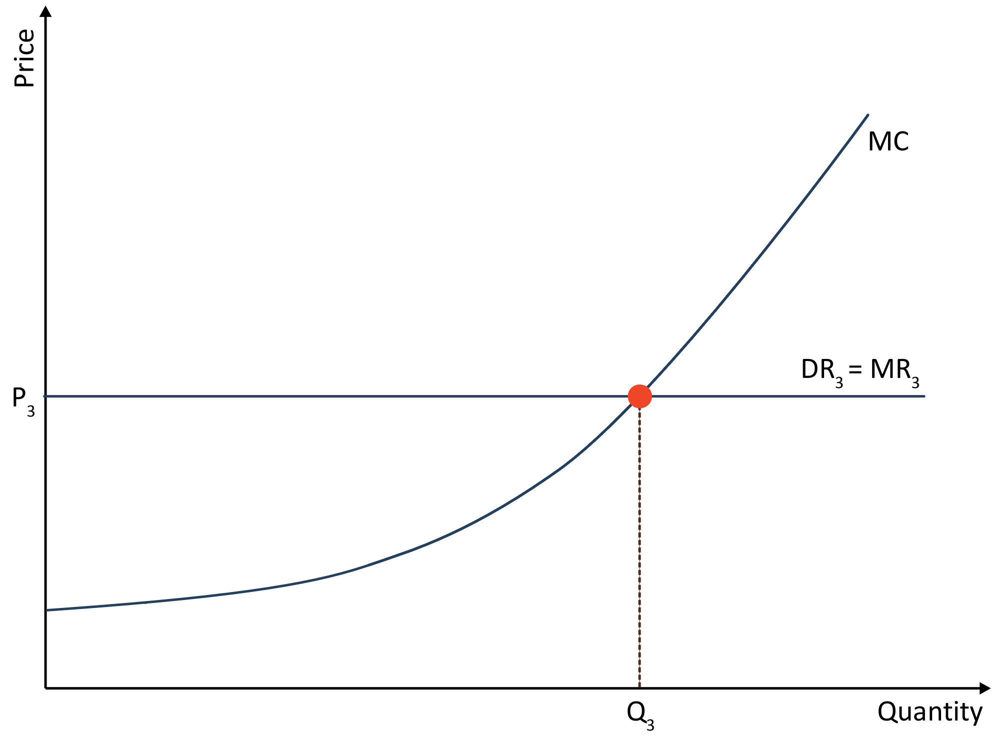


Figure 3.11: Profit-maximizing price and quantity with perfect elastic residual demand



3.2.3 *Transmission congestion and the computation of the residual demand curve*

144. The above discussion of the computation of the residual demand curve that a supplier faces assumes a single wholesale market in which the offers of a supplier in any part of the country are available to meet the demand in any other part of the country. From the nodal price analysis in Section 2, such an assumption of a single integrated market is reasonable for most half-hours of the year. However, in some half-hours this assumption fails, usually as a result of a transmission outage, or extreme system conditions that cause transmission capacity limits to be reached.

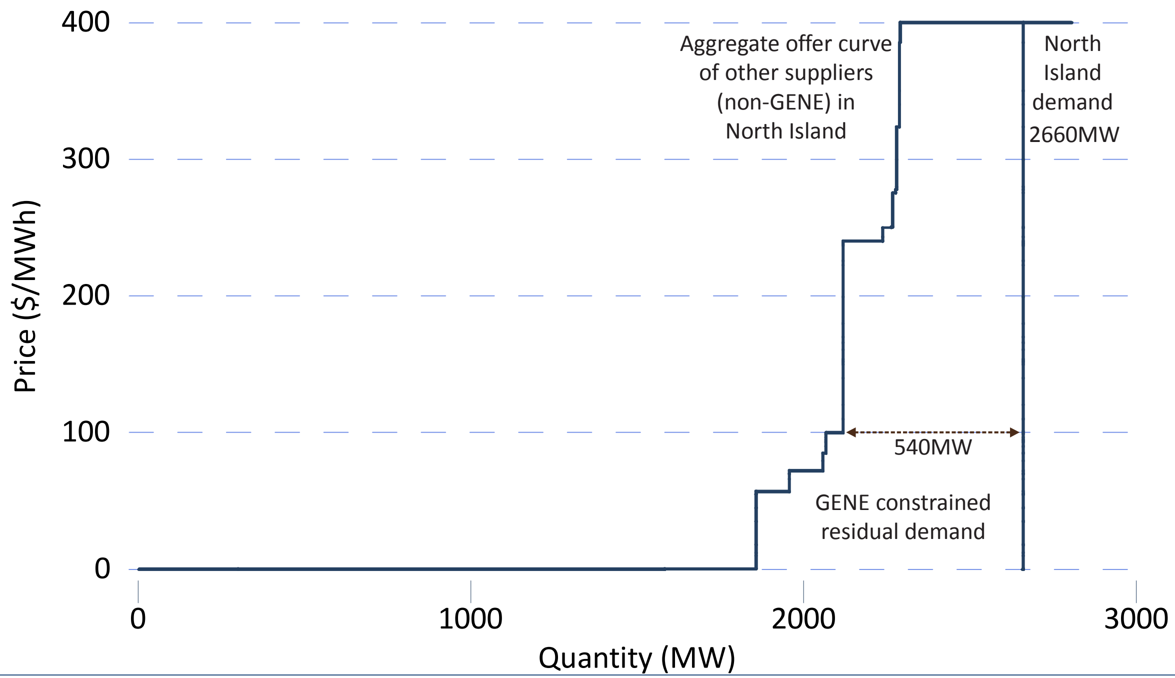
145. It is possible to modify the residual demand calculation to account for the transmission capacity and the potential for the market to "separate" across locations in the transmission network if these capacity limits are reached. We now explain the computation of the residual demand faced by a supplier taking into account the principal transmission link in the New Zealand wholesale market: the HVDC link between the North and South Islands. This link has two distinct effects on the residual demand calculation. First, the market demand faced by an individual supplier is the market demand in the supplier's own island, plus the portion of the demand in the other island that can be supplied given the inter-island capacity limit. Second, the relevant offers from competing suppliers, used to calculate the aggregate offer curve of other generators, are those offers from generators in the supplier's own island, plus the portion of the offers from generators in the other island that can be sent to the supplier's island given the inter-island capacity limit. Note that the relevant capacity constraints for these two effects are in opposite directions, one North-to-South and the other South-to-North.

146. As an example of this computation, consider period 36 on 26 February 2006. In this period the North Island demand was 2,660MW and the South Island demand was 1,610MW, so the total market demand was 4,370MW. Moreover, the HVDC link between the two islands had suffered a complete outage on this date, so the capacity for both North-to-South and South-to-North transfers was zero. Therefore, for any possible price, a supplier in one island was unable to meet the excess demand in the other island. Figure 3.12 shows the aggregate offer curve for other suppliers competing with Genesis in the North Island. Because generation unit owners in the South Island are unable to supply this market, all competition faced by Genesis has to come from generation units located in the North Island. Similarly, because Genesis cannot supply to the South Island, the total demand it faces is the North Island demand alone. The transmission-constrained residual demand for Genesis is obtained by subtracting from the North Island total demand the aggregate offer curve for other suppliers in the North Island. For instance, at a price of $100/MWh, the aggregate offer of other suppliers is 2,120MW; therefore, the transmission-constrained residual demand is 540MW (2,660MW less 2,120MW).

147. Figure 3.13 combines Genesis' transmission-constrained residual demand curve from Figure 3.12 with Genesis' offer curve. The two curves cross at approximately $70/MWh, which is the quantity-weighted average nodal price in the North Island during this period. The quantity at which the two curves cross is the amount of energy that the Genesis supplied in that period, 800MW. Figure 3.14 shows the corresponding situation for Meridian in the South Island. Meridian supplied approximately 1,140MW and the South Island average price was approximately $159/MWh.

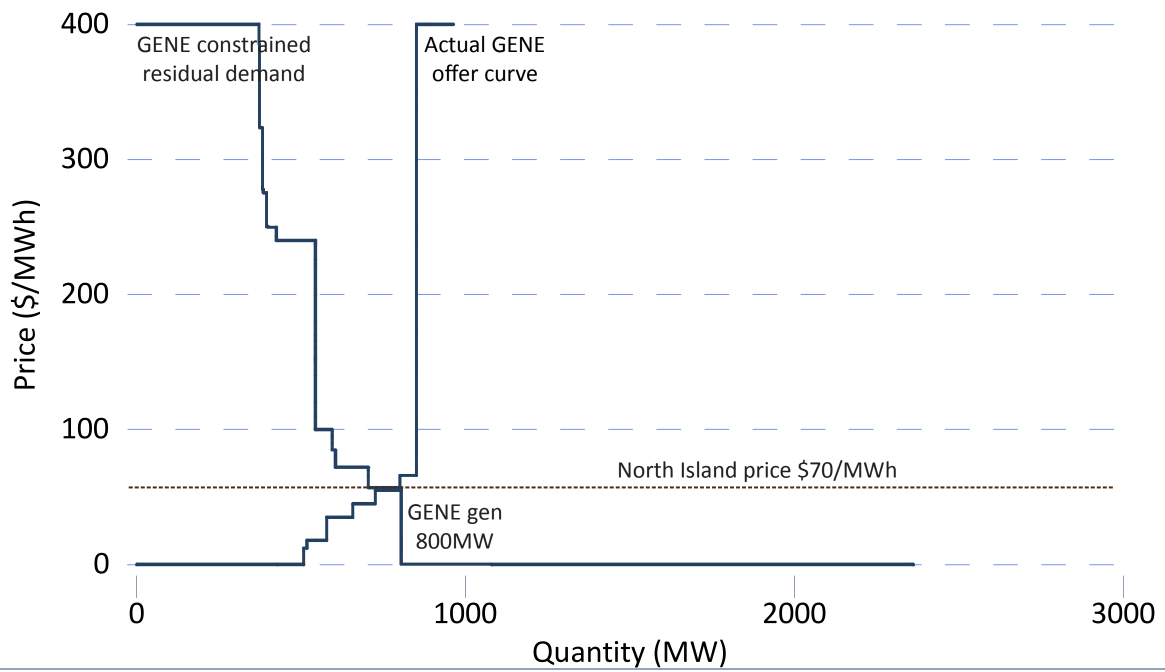
148. It is possible to estimate what the equilibrium price would have occurred if transmission constraints were absent in this half-hour. In this thought experiment, the offers submitted by all suppliers are assumed to be identical to their actual offers and the impact of transmission losses between the two islands is ignored in the pricing process. Figure 3.15 shows the unconstrained residual demand curve for Genesis and the actual offer curve. The point at which the two curves cross is the counterfactual equilibrium. Without transmission constraints, the price would have been $99/MWh (vs. actual $70/MWh) and Genesis would have supplied 850MW (vs. actual 800/MWh). Figure 3.16 shows the corresponding counterfactual situation in the South Island. The price would have been the same as in the North Island, $99/MWh (vs. actual $159/MWh) and Meridian would have supplied 1,010MW (vs. actual 1,140/MWh). Notice how transmission constraints prevented firms in the North Island from meeting excess demand in the South Island at prices between $70/MWh and $159/MWh.

Figure 3.12: Calculation of constrained residual demand, GENE, 26 Feb 2006, period 36



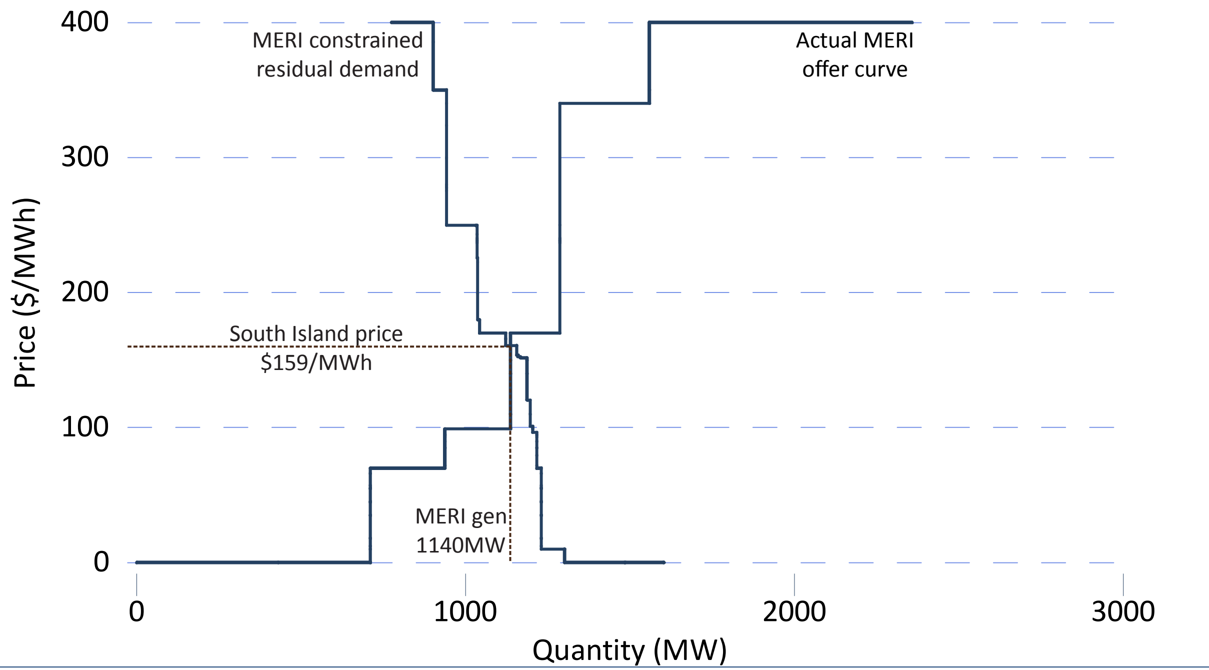
Source: Calculations based on data from Centralised Data Set and Energy Market Services; HVDC data from Transpower.

Figure 3.13: Constrained residual demand and offers for GENE, 26 Feb 2006, period 36



Source: Calculations based on data from Centralised Data Set and Energy Market Services; HVDC data from Transpower.

Figure 3.14: Constrained residual demand and offers for MERI, 26 Feb 2006, period 36



Source: Calculations based on data from Centralised Data Set and Energy Market Services; HVDC data from Transpower.

149. The above example assumed that the offer behavior of all firms is the same with or without transmission constraints. However, this assumption is unlikely to be valid. Note that the transmission-constrained residual demand curve is steeper than the unconstrained residual demand curve. As discussed in Section 3.2 this steeper (or more inelastic) residual demand means that generators have greater ability to increase the market price (at least for the portion of the market that they supply) by reducing their generation offers or increasing their offer prices.

150. For the general case of a non-zero transmission capacity between the North and South Island, the two-zone transmission-constrained residual demand curve for the North and South Island is defined as follows. Consider supplier j located in the South Island. To construct its residual demand curve define QD^S as the demand in the South Island and QD^N as the demand in the North Island, and $T_{N\to S}$ is the available transmission capacity from North to the South Island and $T_{S\to N}$ is the available transmission capacity from the South to the North Island. Let $SO_j^N(p)$ equal the aggregate willingness-to-supply curve of all North Island firms besides firm j and $SO_j^S(p)$ equal the aggregate willingness-to-supply curve of all South Island firms besides firm j. In terms of this notation the residual demand curve facing supplier j in the South Island is equal to:

$$DR_j^S(p) = (1+\tau_S)QD^S - SO_j^S(p) + \max\{T_{N\to S}, \min[(1+\tau_N)QD^N - SO_j^N(p), T_{S\to N}]\}$$

where τ_S is the average transmission loss factor for load in the South Island, τ_N is the average transmission loss factor for load in the North Island, $\max(x,y)$ is a function that gives maximum of x and y and $\min(x,y)$ is a function that gives the minimum of x and y.

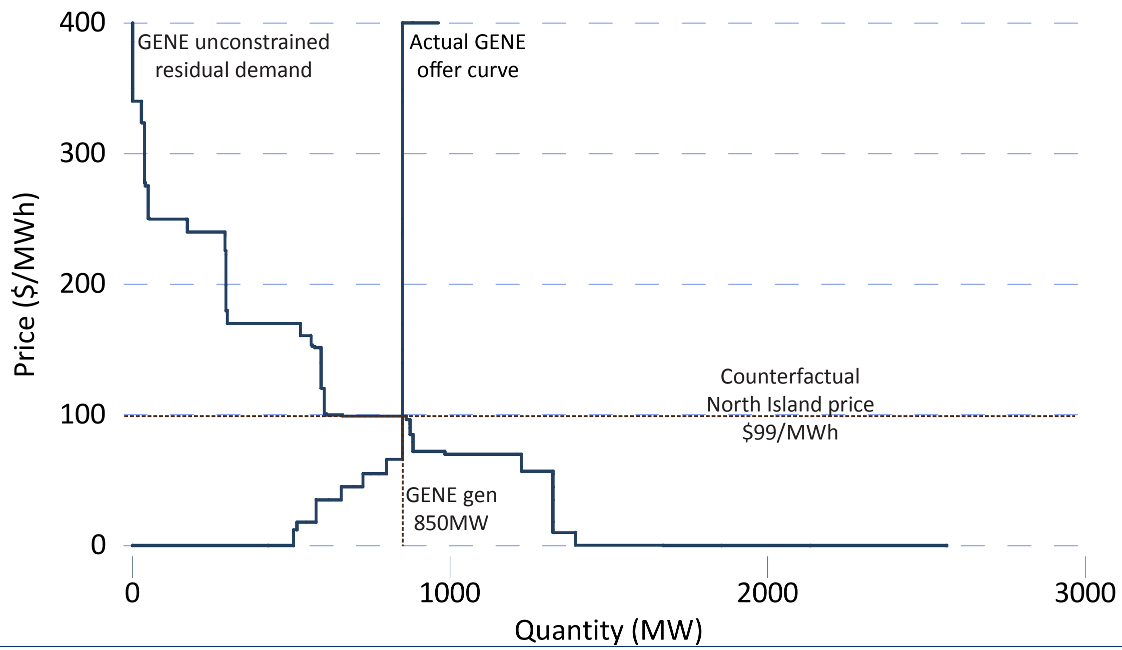
151. Following this same logic for a North Island supplier, the residual demand curve for supplier j in the North Island is equal to

$$DR_j^N(p) = (1+\tau_N)QD^N - SO_j^N(p) + \max\{T_{S\to N}, \min[(1+\tau_S)QD^S - SO_j^S(p), T_{N\to S}]\}.$$

152. Meridian, Genesis, and Mighty River Power have all of their dispatchable generation units in one of the two Islands.[29] Consequently, for each of these firms it is necessary to perform this calculation only for the island in which their units are located. In contrast, Contact owns generation units in both the North and South Island so it is necessary to compute a residual demand curve for Contact for each Island, particularly during periods where this is likely to be transmission congestion between the two islands.

153. These transmission-constrained residual demand curves can be used to compute inverse elasticities using the procedure described above to obtain location-specific measures of the ability of suppliers to exercise unilateral market power.

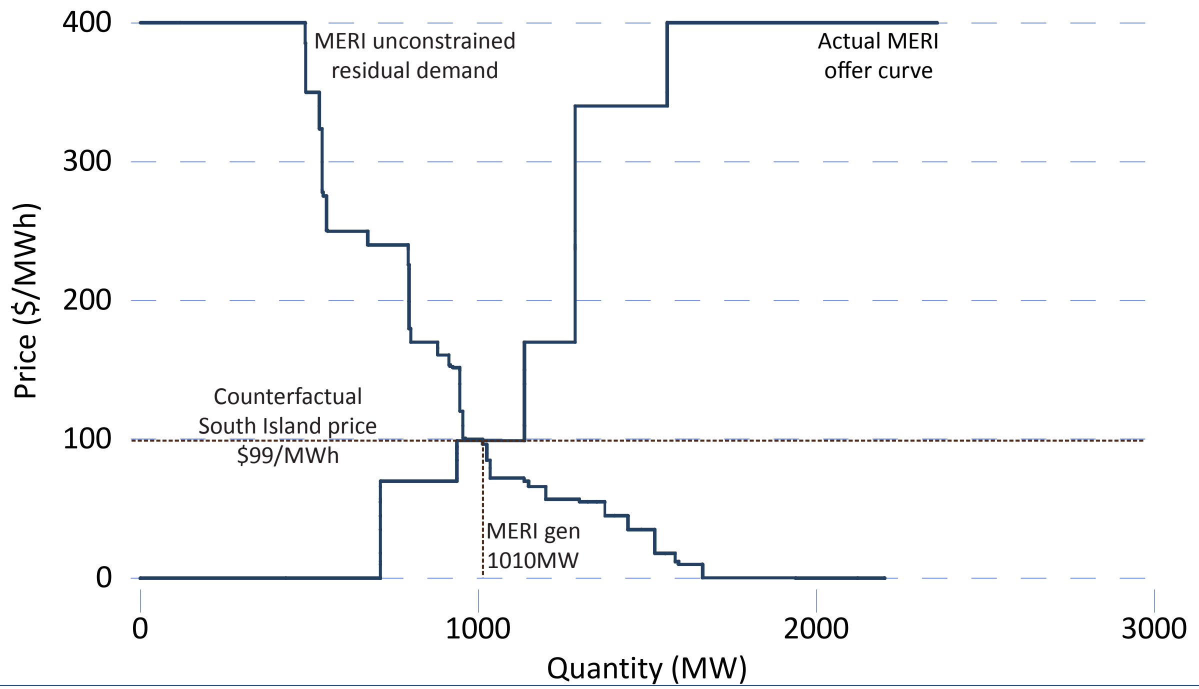
Figure 3.15: Counterfactual unconstrained residual demand for GENE



Source: Calculations based on data from Centralised Data Set and Energy Market Services; HVDC data from Transpower.

[29] As shown in Table 2.1, Meridian owns the Te Apiti wind units in the North Island.

Figure 3.16: Counterfactual unconstrained residual demand for MERI



Source: Calculations based on data from Centralised Data Set and Energy Market Services; HVDC data from Transpower.

3.2.4 A simplified model of expected profit-maximizing offer behavior

154. All of the examples presented thus far have assumed the supplier's residual demand curve is known when that supplier computes its profit-maximizing output level. Because a supplier's residual demand curve is composed of the willingness-to-supply offers of its competitors and the New Zealand market rules require all suppliers to submit their offers at the same time, this assumption is not in fact true. However, the economic justification for using the inverse elasticity of a supplier's residual demand curve as a measure of its ability to exercise unilateral market power carries over to the case that suppliers do not observe the actual residual demand curve they face at the time they submit their offers to the wholesale market.

155. Although a supplier does not know with complete certainty the market demand and the willingness-to-supply offers of other suppliers when it submits its offers for the pricing period, several features of the New Zealand market imply that each supplier has a very good idea of the distribution of realizations of the residual demand curves that it might face. The characteristics of each generation unit owned by the supplier's competitors and the market rules can significantly constrain the set of offer curves a supplier can submit. The New Zealand market rules specify a maximum number of quantity and price steps each generation unit owner can submit in its offer curve. The maximum value of the sum of these quantity steps must be less than the declared capacity of the generation unit. Each supplier submits offer curves for 48 half-hour periods each day and the behavior of half-hourly system demands throughout each weekday are very similar to other weekdays within at least the same month and the behavior of half-hourly

system demands for weekend days are very similar to other weekend days within at least the same month. Therefore, each supplier can learn the distribution of residual demand curves it will face from these residual demand realizations.

156. The half-hourly offer curves of all suppliers are made available to market participants two weeks after actual market outcomes are determined so residual demand curves are observable with a two-week lag.[30] In addition, as discussed in Section 2, for each day the market operates, there are number of advance runs of the actual market that are not financially binding where suppliers submit offers and learn how much they sell and the values of nodal prices throughout the New Zealand network. Producers are able to change their willingness-to-supply functions up to two hours before the trading period without explanation, which further aids the process of learning the distribution of residual demand curves that a supplier faces. There is also likely to be very little uncertainty in total system demand at the time suppliers submit their final willingness-to-supply offers.

157. These pre-market pricing and scheduling runs are designed to give market participants ample preparation for real-time system conditions, but these advance runs also provide each supplier with valuable information about the distribution of residual demand curves they will face in the actual price-setting process. All of these factors imply that suppliers have a very good idea of the distribution of residual demand curves that they will face. For each of these residual demand curve realizations, the supplier can find the ex post profit-maximizing market price and output quantity pair, given its marginal cost curve, following the process described above. This is the market price and output quantity pair that an expected profit-maximizing the supplier would like to achieve for this residual demand curve realization.

158. Figure 3.17 illustrates the construction of an expected profit-maximizing willingness to supply curve using this process for the case of two possible residual demand curve realizations, DR_1 and DR_2. Because these residual demand curves are assumed to be continuously differentiable function, the following procedure can be applied. For each residual demand curve realization, intersect the marginal cost curve with the marginal revenue curve associated with that residual demand curve realization. For example, for DR_1 the marginal revenue curve for this residual demand curve (not shown on the figure) intersects the marginal cost curve at the quantity Q_1. The output price associated with this output level on DR_1 is P_1. Repeating this process for DR_2 yields profit-maximizing price and quantity pair (P_2, Q_2). Note that because both residual demand curves are very steeply sloped, there is a substantial difference between the market price and the marginal cost at each output level. If these two residual demand realizations were the only ones faced by the supplier, it would submit an offer curve that passes through both of these points, because regardless of the residual demand realization, the offer curve would cross the realized residual demand curve at an ex post expected profit-maximizing level of output. The straight line connecting the points (P_1, Q_1) and (P_2, Q_2) is one such expected profit-maximizing offer curve.

[30] Electricity Governance Rules, February 2, 2009, Part G Trading Arrangements, Section 7.1, p. 24.

159. To illustrate the impact of more elastic residual demand curves on the offer curves submitted by an expected profit-maximizing supplier, Figure 3.18 repeats the construction of an expected profit-maximizing offer curve for the case of two more elastic residual demand realizations, DR_3 and DR_4. The line connecting the points (P_3, Q_3) and (P_4, Q_4), which is an expected profit-maximizing offer curve for these two residual demand realizations, is much closer to the supplier's marginal cost curve. Specifically, for each residual demand realization, the price associated with the profit-maximizing level of output for that residual demand curve realization is closer to the marginal cost of producing that level of output than it was in Figure 3.17. This outcome occurs because each residual demand realization is much more elastic at the two output levels than the two residual demand realizations in Figure 3.17.

160. Figure 3.19 considers the case of two infinitely elastic residual demand curve realizations. DR_5 and DR_6, meaning that for both realizations the supplier faces sufficient competition that the entire market can be satisfied at a fixed price by the remaining suppliers. By the logic described above, the supplier will find it unilaterally profit-maximizing to produce at the intersection of each residual demand curve realization with its marginal cost curve. In this case, the supplier's expected profit-maximizing offer curve, the line connecting the profit-maximizing output levels for each residual demand curve realization, is equal to the supplier's marginal cost curve. This result illustrates the very important point that if a supplier faces sufficient competition for all possible residual demand curve realizations, then it will find it unilaterally expected profit-maximizing to submit an offer curve equal to its marginal cost curve.

161. The examples in Figures 3.17 to 3.19 utilize linear residual demand curves. However, the same process can be followed to compute an expected profit-maximizing offer curve for the case of step function residual demand curves. Figure 3.20 shows how this would be done for the more realistic case of step function residual demand curves with two possible residual demand realizations. For each residual demand curve realization, the supplier would compute the profit-maximizing level of output and market price for the marginal cost curve given in Figure 3.20. For DR_1 this is the point (P_1, Q_1) and for DR_2 this is the point (P_2, Q_2). If these two residual demand curve realizations were the only possible residual demands that the supplier could face, then any step function offer curve that passes through these two points (for the example, the one given in Figure 3.20) would be an expected profit-maximizing offer curve.

Figure 3.17: Derivation of offer curve (steep residual demands)

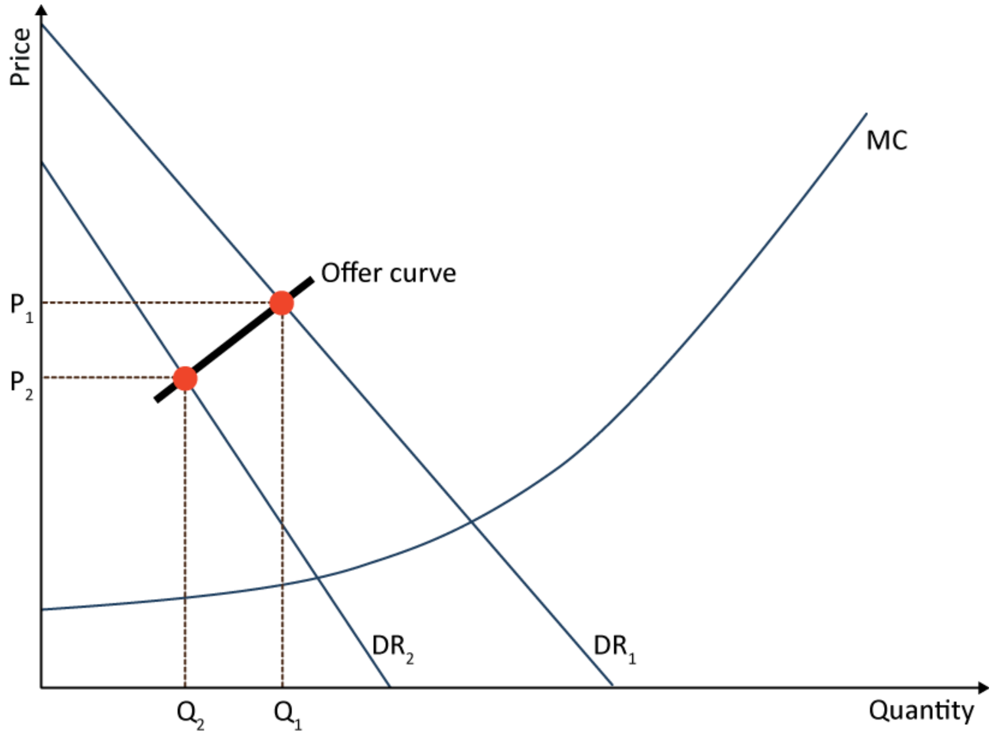


Figure 3.18: Derivation of offer curve (flatter residual demands)

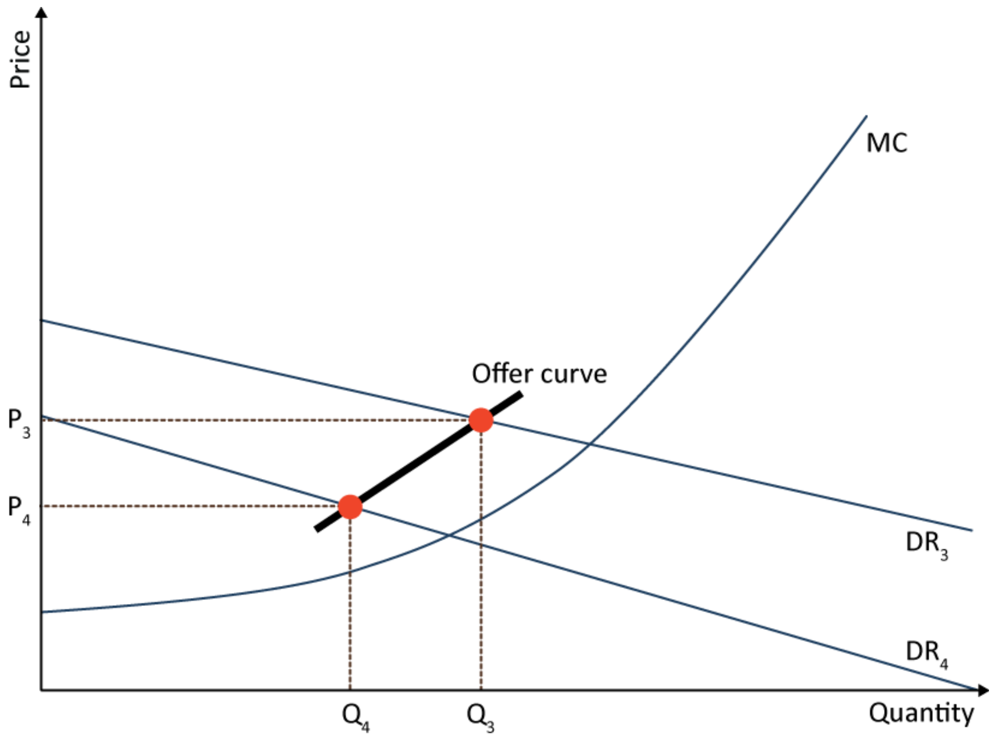
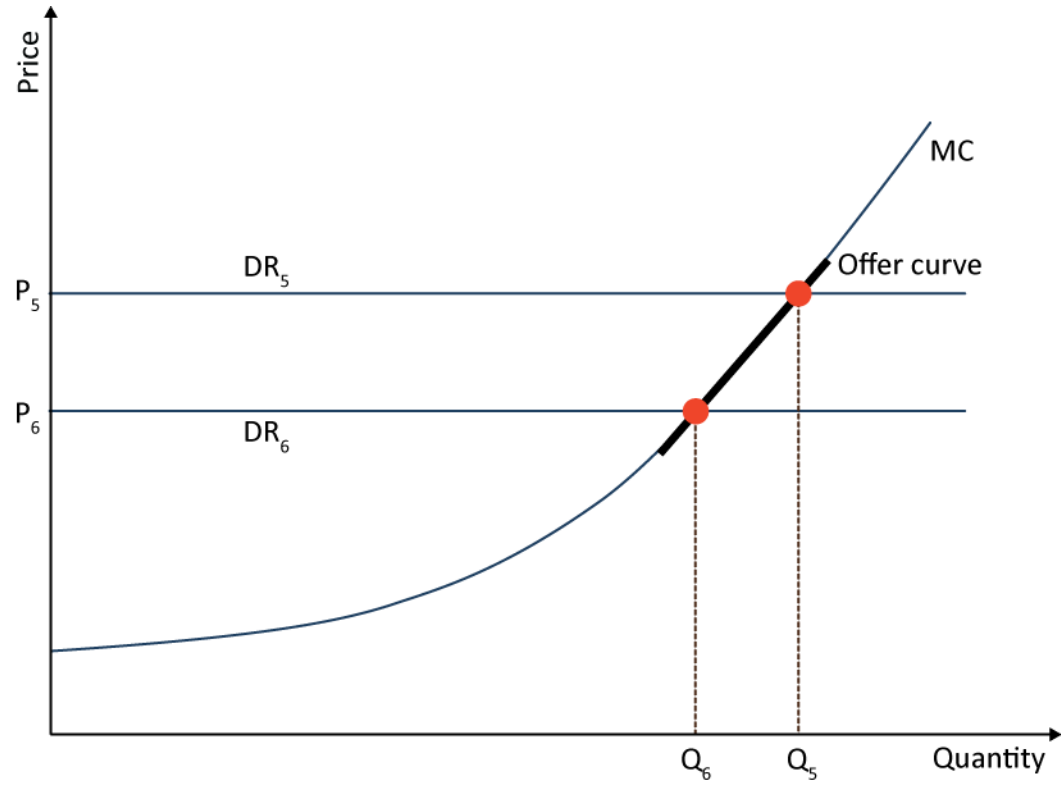


Figure 3.19: Derivation of offer curve (perfectly elastic residual demands)



162. However, computing the expected profit-maximizing offer curve for a supplier is generally more complex than passing an offer curve through the set of all possible ex post expected profit-maximizing price and output quantity pairs. This is because the market rules can prevent a supplier from achieving the ex post profit-maximizing market price and output quantity pair for all possible residual demand realizations. Specifically, unless all of these ex post profit-maximizing price and quantity pairs lie along a willingness-to-supply curve for the supplier that the market rules allow it to submit, it is not possible for the supplier to submit a willingness to supply curve that always crosses the realized residual demand curve at an ex post profit-maximizing price and quantity pair for that residual demand curve realization. Figure 3.21 provides an example of this phenomenon. This figure adds a third residual demand curve to Figure 3.20 and computes the ex post profit-maximizing price and quantity pair for DR_3. This price quantity pair is denoted by the point (P_3, Q_3). Note that this point lies above and to the left of the point (P_2, Q_2). This makes it impossible for the supplier to submit a non-decreasing step function offer curve that passes through the three ex post profit-maximizing price and output quantity pairs. In this case, the supplier must know the probability of each residual demand curve realization in order to choose the parameters of its expected profit-maximizing willingness to supply curve. Figure 3.21 demonstrates that the expected profit-maximizing residual demand curve need not pass through any of these three points. The form of the expected profit-maximizing willingness-to-supply curve depends on the shape of each residual demand curve realization and the probability that it occurs.

163. The general case of computing the expected profit-maximizing willingness-to-supply curve illustrates that this curve may not pass through the ex post profit-maximizing price and output quantity pair for any residual demand curve realization. As shown in Wolak (2003a)[31] and Wolak (2007)[32], the supplier chooses the price levels and quantity increment that determine its offer curve to maximize its expected profits over the distribution of residual demand curve realizations that it faces. Nevertheless, the inverse elasticity of the realized residual demand curve at the actual market-clearing price still provides a measure of the ability of a supplier to exercise unilateral market power. Specifically, this inverse elasticity quantifies the percentage increase in the market-clearing price that would have occurred if the supplier had reduced the amount of output it sold by a pre-specified percentage. This interpretation of the inverse elasticity of the residual demand curve does not rely on the assumption that the realized output level and market-clearing price maximize the supplier's ex post profits.

164. If each realization of the residual demand curve did cross the supplier's offer curve at this ex post profit-maximizing point, then for every market-clearing price and quantity pair the difference between the market price and the supplier's marginal cost at its current output level divided by the market price would equal the inverse of the elasticity of the residual demand curve. As emphasized in Wolak (2003b)[33] and Wolak (2007)[34], expected profit-maximizing offer behavior does not imply that every point of intersection of the supplier's offer curve with its residual demand curve yields the ex post profit-maximizing price and output quantity pair for the supplier for that residual demand curve realization. Therefore, there is no deterministic relationship between the difference between the market-clearing price and the firm's marginal cost of production at its actual output level divided by the market-clearing price and the value of the inverse elasticity of the residual demand curve. An additional implication of this result is that the inverse of the elasticity of residual demand curve need not be less than one, which would be required if it had to equal the market price minus marginal cost divided by the market price.

[31] Frank A Wolak (2003a) "Measuring Unilateral Market Power in Wholesale Electricity Markets: The California Market 1998 to 2000", American Economic Review, May 2003, 425-430.

[32] Frank A Wolak (2007) "Quantifying the Supply-Side Benefits from Forward Contracting in Wholesale Electricity Markets", Journal of Applied Econometrics, volume 22, 2007, 1179-1209.

[33] Frank A Wolak (2003b) "Diagnosing the California Electricity Crisis," The Electricity Journal, August/September, 11-37.

[34] Frank A Wolak (2007) "Quantifying the Supply-Side Benefits from Forward Contracting in Wholesale Electricity Markets", Journal of Applied Econometrics, volume 22, 2007, 1179-1209.

Figure 3.20: Impact of Step Functions on Optimal Offer Curve

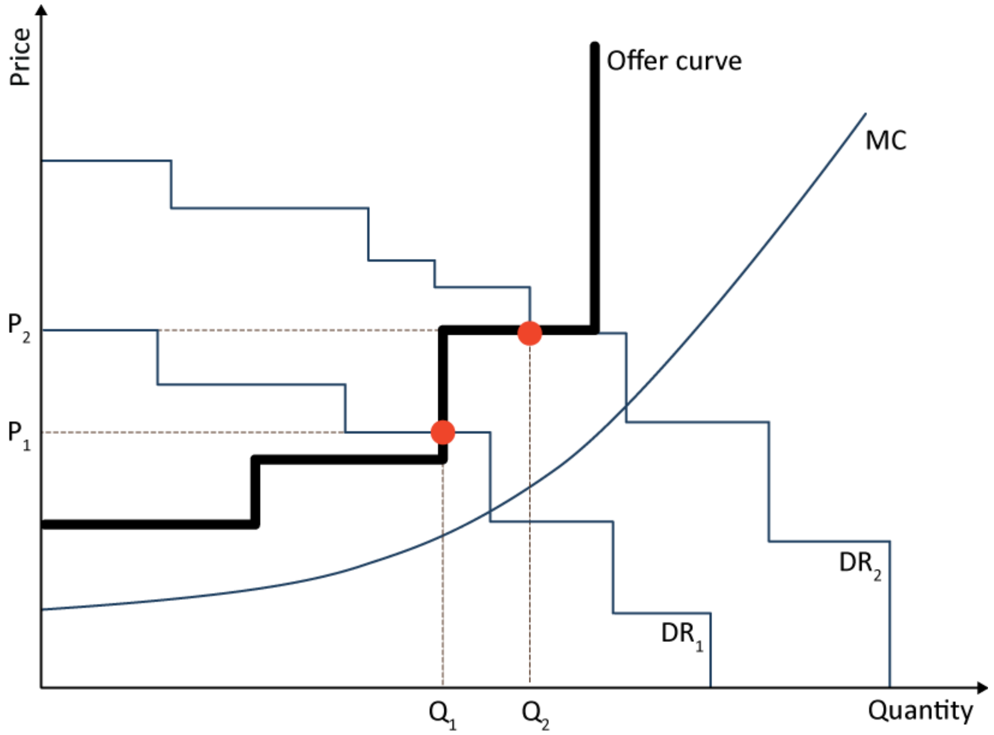
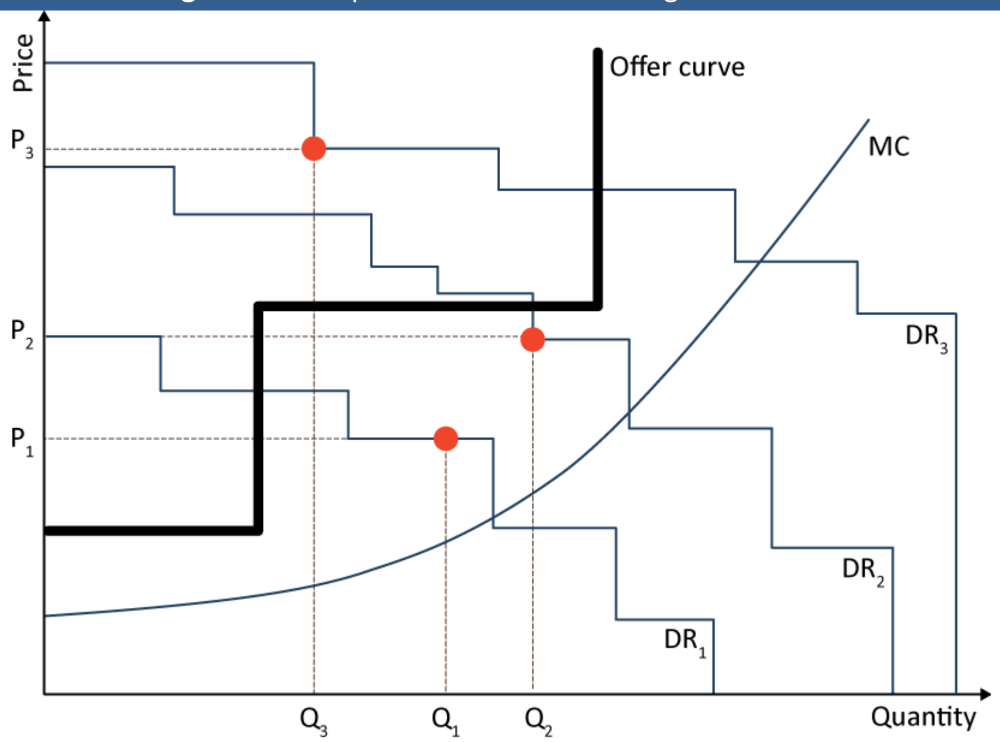


Figure 3.21: Expected Profit-Maximizing Offer Curve



3.3 Measuring the incentive to exercise unilateral market power

165. The above discussion of expected profit-maximizing offer behavior assumes the supplier only earns revenues from selling energy in the wholesale market. However, the five largest suppliers in the New Zealand market are all vertically integrated. They not only sell energy in the wholesale electricity market, but they also sell electricity to final consumers at retail prices that do not vary with hourly prices in the wholesale market. These fixed-price retail load obligations function very much like fixed-price forward financial contract obligations, because the vertically-integrated supplier has essentially made a commitment to provide its fixed-price retail load obligation at a pre-determined wholesale price. For example, in Period 36 on 18 February 2006, Contact Energy had retail load obligations of 865 MW at various fixed prices. That means that Contact Energy was obliged to supply 865 MW retail load at those prices regardless of actual wholesale price. This implies that Contact Energy had a strong financial incentive to purchase the 865 MW at the lowest price possible.

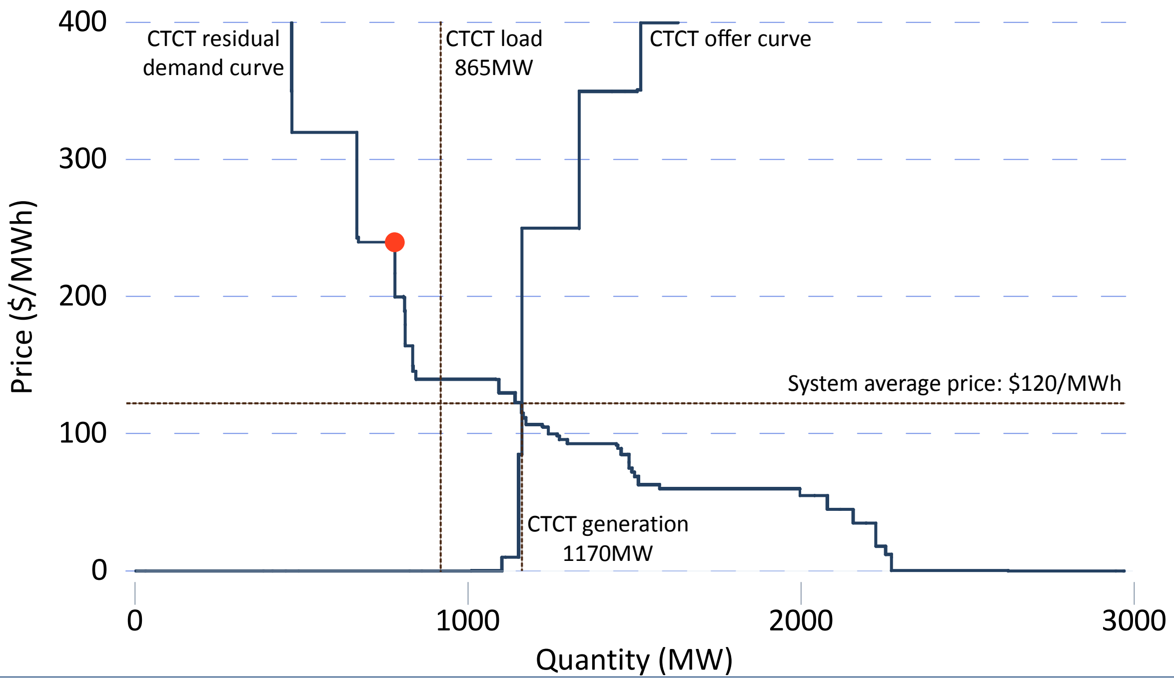
166. Figure 3.22 shows the offer curve and residual demand curve for Contact in that period. By increasing the price at which it offered in its generation, Contact could have moved to the point on its residual demand curve shown by the red dot. This would have increased the market price by 100% (from $120 to $240/MWh) and reduced the quantity supplied by Contact by 35% (from 1,170 MW to 765 MW). As a result, Contact's generation revenue in this half-hour would have increased from $70,200 to $91,800. However, Contact's net revenue from transactions in the wholesale market would have decreased substantially. At the actual prices and quantities, Contact sold 1,170 MW and bought 865 MW from the wholesale market, at the market price of $120/MWh. Therefore, its net position was 305MW, the difference between 1,170 MW and 865 MW, so Contact's net revenue would have been $18,300 (305MW at $120/MWh for one half-hour). At the higher price, Contact would have sold 765MW while still buying 865MW from the wholesale market, now at the higher market price of $240/MWh. Contact's net position would have been -100MW, and its net revenue -$12,000 (-100MW at $240/MWh for one half-hour). This example demonstrates the importance of the supplier's fixed-price load obligations in considering its incentive to increase the market price.

167. In general, because a supplier with fixed-price load obligations has to serve the load at a fixed retail price no matter what the actual wholesale price is, a wholesale market price increase has two opposite effects on the supplier's profits: (1) it increases the supplier's profits from selling energy in the wholesale market; and (2) it decreases the suppliers' profits by raising the supplier's cost of serving its retail demand. Consequently, whether and to what degree a price increase is beneficial to a vertically-integrated supplier depends on whether and to what degree the profit increase from supply more than offsets the increase in cost of serving retail demand covered by the supplier's fixed-price forward market obligations. If the profit reduction due to the cost increase in (2) exceeds that profit gain in (1), a supplier would lose profits from a market price increase. In that case, the supplier would not want to exercise unilateral market power to increase the market price. So, for a supplier, the comparison between its profit gain and loss from a price

increase depends on the difference between the supplier's sales in the short-term market and its fixed-price forward market obligations.

168. For example, suppose that a supplier's supply to the market is 2,000 MW while its fixed-price forward market obligation is 1,500 MW. In that case, a $1 increase in market price would increase the supplier's profits from its generation sales by $2,000 while increasing the cost of its load obligation by $1,500, implying a net gain of $500 (or $1 times the 500 MW difference between the supplier's supply of 2,000 MW and forward market obligations of 1,500 MW). In that case, the supplier has an incentive to increase market price through its unilateral actions because it is profitable to do so. However, if the supplier has a significantly larger fixed-price forward market obligation of 2,500 MW, then the $1 increase in market price would imply a net loss of $500 (or $1 times the -500 MW difference between its supply and fixed-price forward market obligations) as the supplier's profits gain from its generation sales ($2,000) is less than the increase in its cost to serve the fixed-price forward market obligation ($2,500).

Figure 3.22: Effect of fixed-price obligations for Contact Energy, 18 Feb 2006, period 36



Source: Calculations based on data from Centralised Data Set and Energy Market Services.

169. To understand the incentives to exercise unilateral market power of a supplier with fixed-price retail load obligations or fixed-price forward market obligations, first define the following notation. Let P_R equal the retail price at which the firm is selling Q_R MWh of retail electricity. Let $DR(p)$ equal the firm's residual demand curve for sales in the short-term market and p the market price. For simplicity, assume that c is the constant marginal cost of producing electricity and τ is the average cost of retailing, transmitting, and distributing wholesale electricity to final customers. The vertically-integrated suppliers in New Zealand also participate in the market for fixed-price long-term contract

obligations. Let P_C equal the quantity-weighted average price of fixed-price forward contract obligations held by the vertically-integrated firm and Q_C equal the net (sales minus purchases) quantity of fixed-price forward contract obligations. The firm's variable profits (profits excluding fixed costs) from selling into the short-term wholesale market given these forward market commitments is equal to

$$\Pi(p) = (P_R - p)Q_R + DR(p)(p - c) - (p - P_C)Q_C - \tau Q_R$$

The first term is the profits from retail sales. The second term is the profits from wholesale electricity sales in the short-term market. The third term is the profits or losses from fixed-price forward contract obligations, and the final term is the cost of distributing retail electricity.

170. This expression for the firm's variable profits from participating in the short-term market can be re-written as:

$$\Pi(p) = (P_R - \tau - c)Q_R + (P_C - c)Q_C + \big(DR(p) - (Q_R + Q_C)\big)(p - c).$$

The first and second terms are profits from retailing assuming Q_R cost c \$/MWh to produce, and the second term is the profit from sales of fixed-price forward contracts assuming Q_C is produced at c \$/MWh. The third term is the only one that depends on the short-term market price. The first and second terms only depend on variables that the supplier cannot influence at the time they are offering to sell in the short-term market.

171. This form of the firm's profit function shows that the values of Q_R and Q_C, the firm's retail load obligation and net fixed-price forward contract obligations influence its incentive to exercise unilateral market power. Even though the supplier may face a very inelastic residual demand curve, it would have little incentive to reduce the output it sells to raise prices above its marginal cost if the amount it sells in the short-term market, $DR(p)$, is less than the sum of its fixed-price forward market obligations, $Q_R + Q_C$. Under these circumstances, the vertically-integrated supplier is a net buyer from the short-term market. It has obligations for purchases of $Q_R + Q_C$ from the short-term market and it only sells $DR(p)$. As a net buyer, the supplier would like the price to be as low as possible. When $DR(p)$ exceeds $Q_R + Q_C$, the vertically-integrated supplier is a net seller in the wholesale market and as such would like to raise the price at which it sells its net output in the short-term market.

172. The difference between a firm's sales in the short-term market and its fixed-price retail load and forward contract obligations is its residual demand net of its forward market obligations. In terms of the above notation, this net residual demand curve is equal to $DR_F(p) = DR(p) - (Q_R + Q_C)$. Depending on whether a supplier's net residual demand is positive ("net long") or negative ("net short"), the supplier has an incentive to either increase or decrease the market price through its unilateral actions. If a supplier is net long (i.e., has a positive net residual demand), it will benefit from a higher market price because it is making net sales into the short-term market. Consequently, the larger a supplier's net residual demand, the greater is the supplier's gain from a market price increase. Conversely, the more a supplier is net short (i.e., a negative net residual

demand), the greater is the supplier's incentive to decrease market price because it is a net buyer from the short-term market.

173. In terms of this net residual demand function, the firm's profit function becomes:

$$\Pi(p) = DR_F(p)(p - c) + F, \text{ where } F = (P_R - \tau - c)Q_R + (P_C - c)Q_C.$$

The first two terms in the profit function written above are collected into the term F because all of the variables comprising of these terms are not affected by the supplier's offers into the short-term wholesale market and are known before the supplier submits these offers. This expression for the vertically integrated supplier's profit function takes the same form as a non-vertically integrated supplier with the net residual demand curve in place of the supplier's residual demand curve.

174. To determine the firm's profit-maximizing price and quantity pair we can solve for the value of p that maximizes the above expression. We can also follow a slightly more involved version of the graphical approach shown in Section 3.2. Figure 3.23 shows the original residual demand curve shifted to the left by the amount of the supplier's fixed-price forward market obligations, $Q_R + Q_C$. Figure 3.23 also graphs the supplier's marginal revenue curve for sales in excess of its fixed-price forward market obligations. Because the firm's production decision must still take account of its forward market position, Figure 3.24 shifts the marginal revenue curve of the net residual demand curve right by the amount of the fixed-price contract obligations. The firm produces at the point where this marginal revenue curve including fixed-price forward market obligations intersects the marginal cost curve, the output level Q_4 in Figure 3.24. The short-term market price is determined by the supplier's original residual demand curve at this level of production, the price P_4 in Figure 3.24.

175. Figure 3.25 demonstrates the impact of fixed-price forward market obligations on the supplier's expected profit-maximizing price and output quantity pair. For the residual demand curve given in Figure 3.25, a supplier without any forward market obligations would find it optimal to produce at the price and output quantity pair (P_1, Q_1) that was derived in Figure 3.9. A supplier with the level of fixed-price forward market obligations shown in Figure 3.23 and facing this same residual demand curve would find it unilaterally profit-maximizing to produce at the price and output quantity pair (P_4, Q_4). As shown in Figure 3.25, a firm with fixed-price forward market obligations facing the same residual demand curve finds it unilaterally profit-maximizing to sell more output in the short-term market at a lower price, $Q_4 > Q_1$ and $P_4 < P_1$.

176. There is even a level of fixed-price forward market obligations that would cause a supplier facing a steep residual demand curve to find it unilaterally profit-maximizing to produce at the point of intersection of its marginal cost curve with its residual demand curve. Specifically, if $Q_R + Q_C$ is chosen to equal $DR(c)$, the value of output at the point of intersection of the residual demand curve with the supplier's marginal cost curve, the supplier will find it unilaterally profit-maximizing to produce at $DR(c)$, regardless of the slope or inverse elasticity of the residual demand curve. In other words, a supplier that possesses a substantial ability to exercise unilateral market power, as measured by the

inverse elasticity of its residual demand curve, has no incentive to do so because of the level of its fixed-price forward market obligations.

177. The relationship in Figure 3.25 carries over to the case of constructing expected profit-maximizing offer curves with fixed-price forward market obligations. Figure 3.26 repeats the computation of the expected profit-maximizing offer curve for the same two residual demand curve realizations for the case of no fixed-price forward market obligations and positive fixed-price forward market obligations. For the case of positive forward market obligations, the expected profit-maximizing offer curve is much closer to the firm's marginal cost curve than the expected profit-maximizing offer curve derived assuming the firm has no fixed-price forward market obligations. This is a general result on the impact of fixed-price forward market obligations on the expected profit-maximizing offer curve of a supplier. The higher the level of fixed-price forward market obligations relative to the supplier's actual short-term market sales, the closer is the expected profit-maximizing offer curve to the supplier's marginal cost curve.

178. Because fixed-price forward market obligations alter the incentive of a supplier to exercise unilateral market power, the net residual demand curve can be used to construct a measure of the incentive, as distinct from the ability, of a supplier to exercise unilateral market power. This measure is the inverse elasticity of the net residual demand curve. In terms of $DR_F(p)$ this inverse elasticity is defined as:

$$1/\varepsilon^F = -\frac{DR_F(p)}{p} \times \frac{1}{DR_F'(p)},$$

which is also equal to the percentage change in the market-clearing price as a result of a one percent change in the net residual demand of the supplier.

179. The inverse elasticity of the net residual demand curve is related to inverse elasticity of the residual demand curve by the following equation:

$$1/\varepsilon^F = -\frac{DR(p) - (Q_R + Q_C)}{DR(p)} \times (1/\varepsilon).$$

The inverse elasticity of the residual demand curve times the exposure of the supplier to the short-term market is equal to the inverse elasticity of the net residual demand curve. Note that in spite of the fact that the inverse elasticity of the residual demand curve is always positive, the inverse elasticity of the net residual demand curve can be negative or zero. Zero occurs if the supplier's short-term market sales equals its fixed-price forward market obligations, $DR(p) = Q_R + Q_C$. A negative inverse elasticity occurs if the supplier's short-term market sales are less than its fixed-price forward market obligations, $DR(p) < Q_R + Q_C$.

Figure 3.23: Profit-maximization with fixed-price contracts, part I

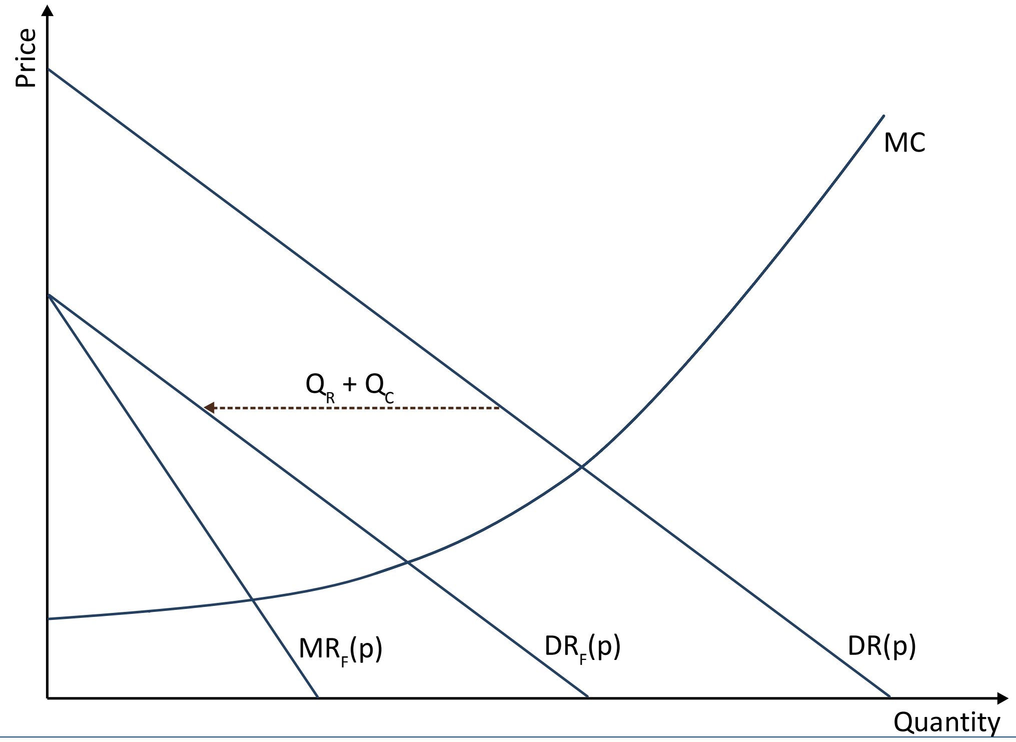


Figure 3.24: Profit-maximization with fixed-price contracts, part II

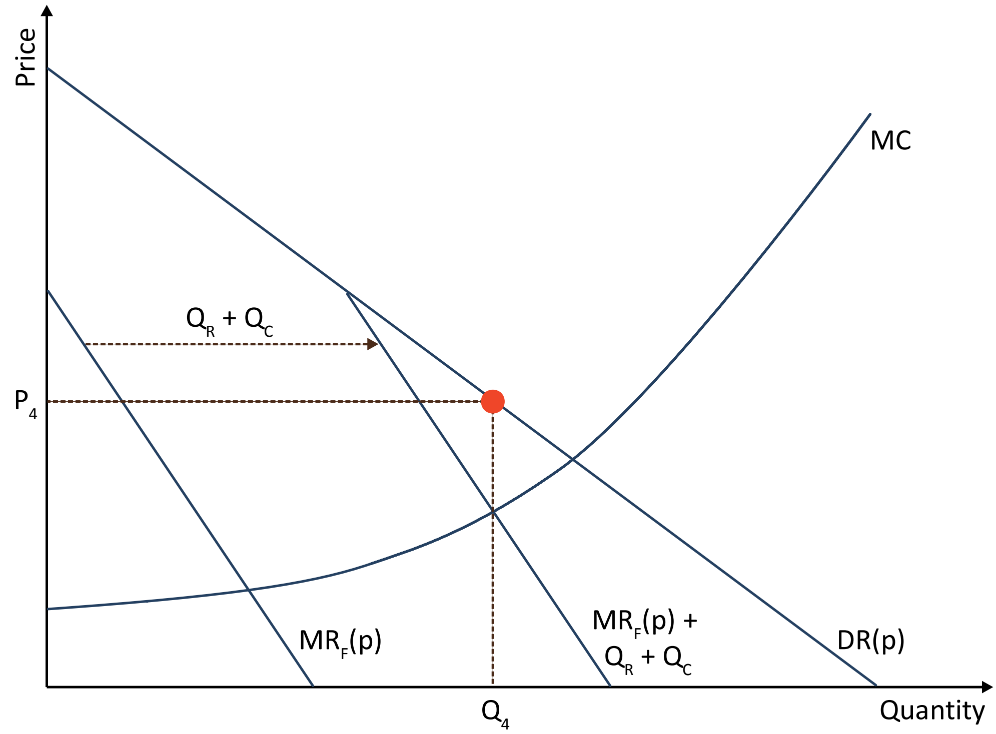


Figure 3.25: Price and quantity with and without fixed-price contracts

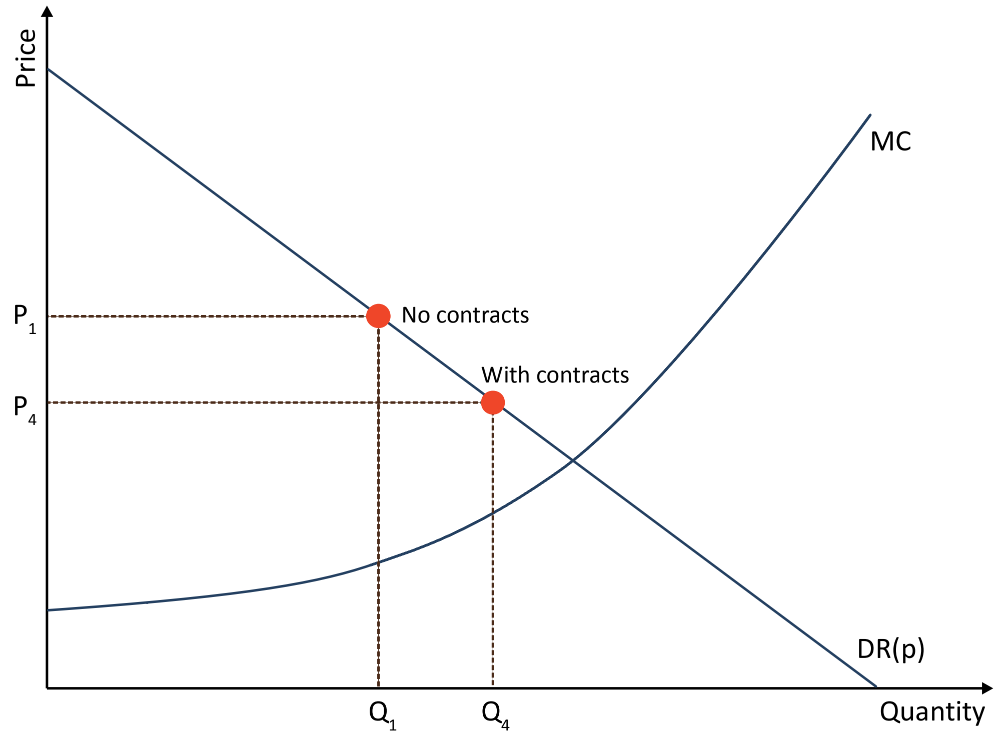
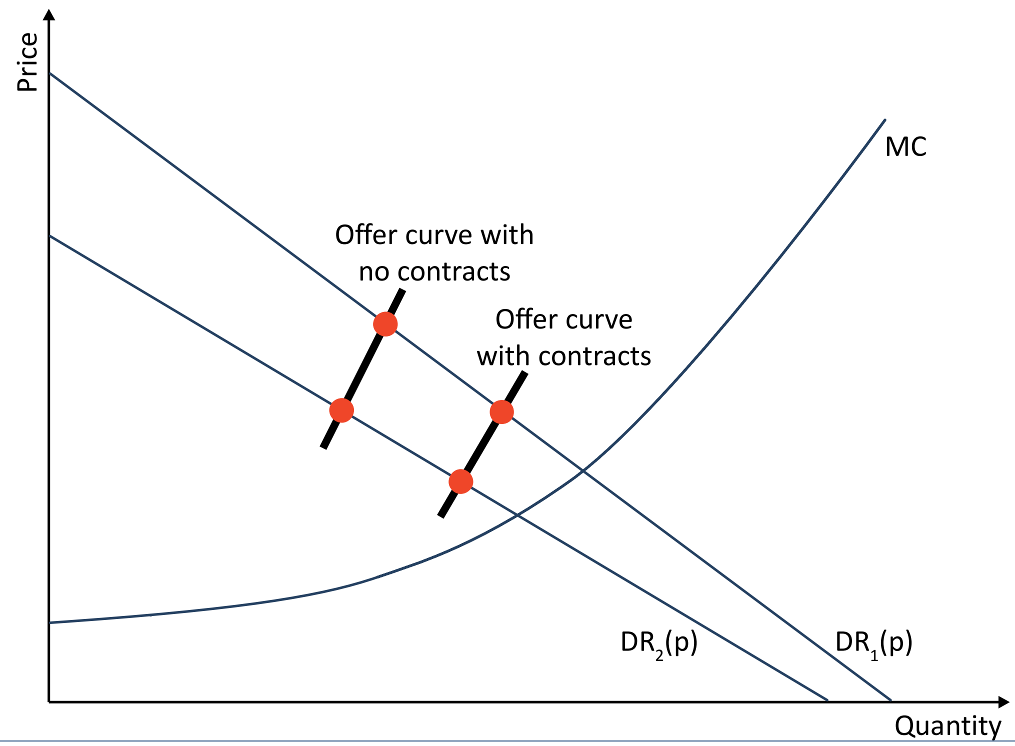


Figure 3.26: Derivation of offer curves with and without fixed-price contracts



180. The same caveats apply to the use of the inverse elasticity of the net residual demand curve when it is applied to step function residual demand curves such as those that exist in the New Zealand wholesale electricity market. Specifically, the researcher must choose the percentage change in the supplier's net position and then compute the implied change in the market price from the residual demand curve. The most straightforward way to compute values of the two inverse elasticities that are internally consistent is first to compute the inverse elasticity of the residual demand curve and then use the above relationship that relates this magnitude to the inverse elasticity of the net residual demand curve.

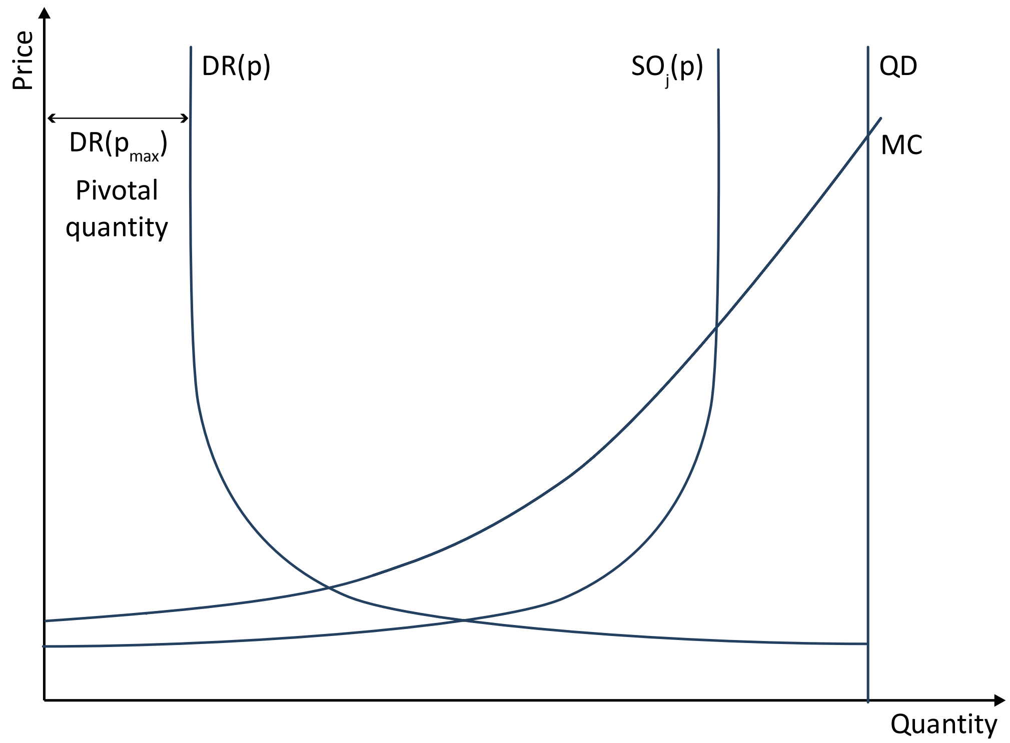
181. For the same reasons as described above for the case of the inverse elasticity of the residual demand curve, expected profit-maximizing offer behavior with fixed-price forward market obligations does not imply a deterministic relationship between the inverse elasticity of the net residual demand curve and the difference of the market price and the marginal cost of the supplier's highest cost generation unit operating in that period divided by the market price. Nevertheless, the inverse elasticity of the net residual demand curve still provides a valid index of the incentive of supplier to exercise unilateral market power because it measures the percent increase in the market-clearing price that would result from a one-percent change in the supplier's net position.

3.4 Pivotal supplier and net pivotal supplier measures of the ability and incentive to exercise unilateral market power

182. The residual demand curve and net residual demand curve can be used to derive additional measures of the ability and incentive of a supplier to exercise unilateral market power. In contrast to measures derived using the inverse elasticity, these measures typically depend on the behavior of the residual demand curve and net residual demand curve at prices significantly higher than the market-clearing price. As a consequence, these measures capture a more extreme ability and incentive to exercise unilateral market power.

183. Figure 3.27 shows the construction of a residual demand curve for the case in which the aggregate willingness-to-supply curve of all other suppliers reaches its capacity before system demand is met. As shown in the figure, this yields a residual demand facing the supplier that is positive for all possible prices. Because the real-time demand for electricity is perfectly inelastic and the production of electricity is subject to capacity constraints, it is possible for the residual demand curve facing a supplier to become perfectly inelastic at some positive output level. A supplier that faces a residual demand curve that is positive for all possible positive prices is said to be a pivotal because some of its supply is necessary to serve the market demand regardless of the offer price.

Figure 3.27: Definition of Pivotal Supplier and Pivotal Quantity



184. The output level at which the supplier's residual demand curve becomes perfectly inelastic is called the pivotal quantity and it is shown in Figure 3.27 as the quantity associated with the vertical portion of the residual demand curve. Mathematically, a supplier is pivotal if $DR(p_{max}) > 0$ where p_{max} is the highest possible price that could occur in the market. The quantity $DR(p_{max})$ is called the pivotal quantity. If a supplier is pivotal, this means that regardless of the offer price it submits, at least the pivotal quantity must be accepted from the supplier. A pivotal supplier has the ability to set the market price as high as it would like if it is willing to sell only the pivotal quantity.

185. Although a pivotal supplier clearly has a substantial ability to exercise unilateral market, it may not have an incentive to do so because of its fixed-price forward market obligations. In particular, if the supplier's fixed-price forward market obligations exceed its pivotal quantity, $DR(p_{max})$, then the supplier would have no incentive to exploit the fact that it is pivotal for the reason that it is a net buyer of energy at output levels equal to or below its pivotal quantity.

186. The net residual demand curve can be used to determine whether a pivotal supplier would have an incentive to exploit the fact that it is pivotal. Specifically, if a supplier is net pivotal, then clearly it has such an incentive. A supplier is said to be net pivotal if $DR_F(p_{max}) > 0$. The quantity $DR_F(p_{max})$ is called the net pivotal quantity. By definition of the net residual demand function, if a supplier is net pivotal and it has positive fixed-price forward market obligations, then the supplier is also pivotal. This

means that regardless of the offer price it submits, at least $DR(p_{max})$, the pivotal quantity (not the net pivotal quantity) of energy must be accepted from the supplier. Different from a pivotal supplier, a net pivotal supplier has very strong incentive to exercise unilateral market power the larger is the net pivotal quantity because it earns the short-term price on its net sales at the market-clearing price, $DR_F(p)$.

187. To summarize, a supplier can be pivotal and therefore have a significant ability to raise short-term prices. However, this supplier has little incentive to exploit its pivotal status if its fixed-price forward market obligations exceed its pivotal quantity, i.e., it is not net pivotal. Conversely, if a supplier is net pivotal, then it is also pivotal and has both a substantial incentive and ability to exercise unilateral market power. This incentive to exercise unilateral market power is greater the larger is the supplier's net pivotal quantity.

188. It is important to emphasize that a supplier cannot determine whether it is pivotal until the level of demand is realized and all supply offers of its competitors are known. Because the market rules require all suppliers to submit their offers at the same time, and the market demand is not known when these offers are submitted, no supplier knows with certainty if it is pivotal when it submits its offers. However, the same factors described above that help a supplier learn the distribution of residual demand curves that it will face also help the supplier predict when it might be pivotal. For example, an unexpectedly high level of demand or a large generation or transmission outage can create system conditions when one or more suppliers is pivotal.

189. Figures 3.28 to 3.30 depict an example of the trade-off that a supplier faces in deciding whether to submit offers into the short-term market to exploit the fact that it is pivotal. These figures consider the case of two residual demand curve realizations. For the low residual demand curve realization, $DR_L(p)$, the supplier is not pivotal. For the high residual demand curve realization, $DR_H(p)$, the supplier is pivotal. Let $0 < \theta < 1$ denote the probability of the high residual demand realization and $1 - \theta$ the probability of a low residual demand realization. Figure 3.28 draws $S_1(p)$, the expected profit-maximizing offer curve, for these two residual demand realizations assuming that the firm does not exploit the fact that it is pivotal for $DR_H(p_{max})$.

Figure 3.28: Offer curve determination with pivotal residual demand, Part I

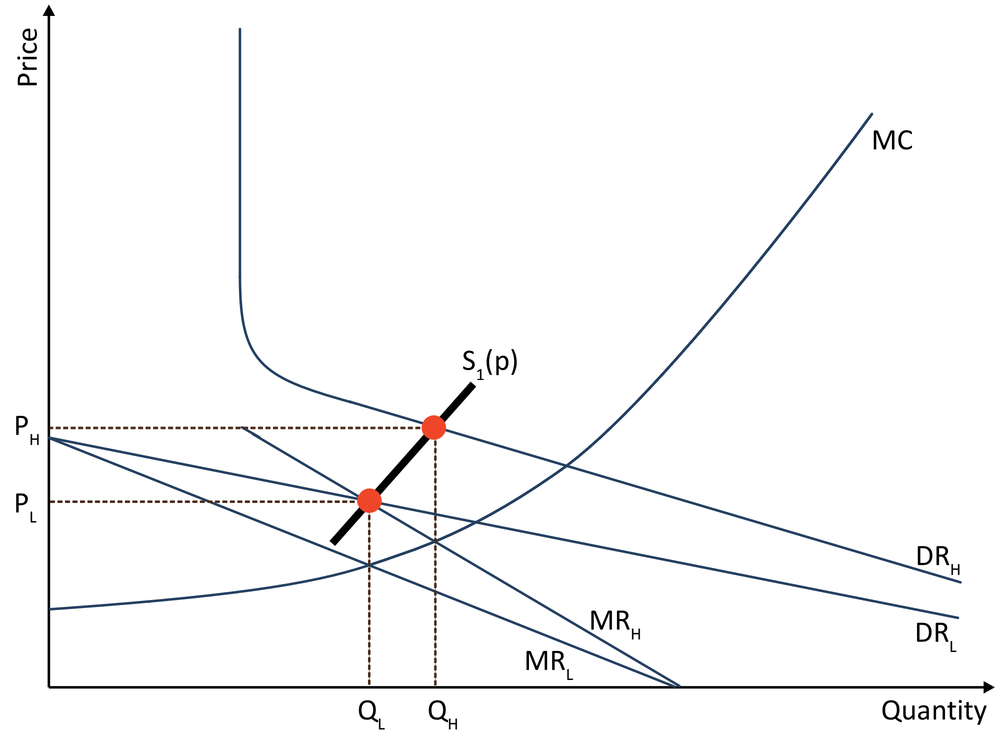


Figure 3.29: Offer curve determination with pivotal residual demand, Part II

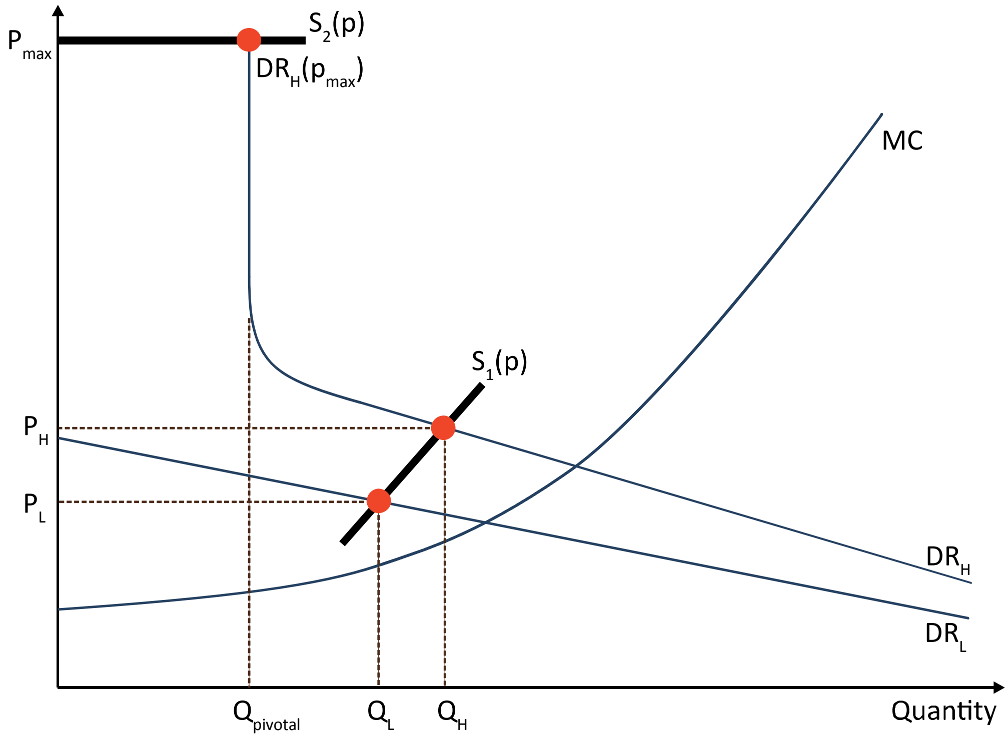
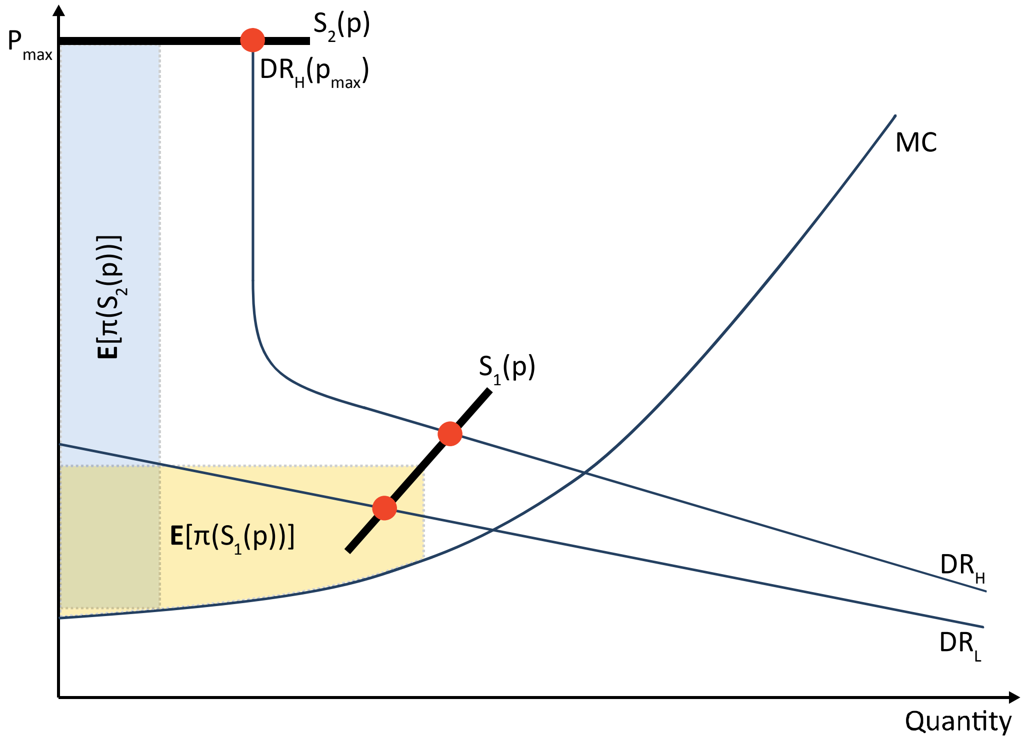


Figure 3.30: Offer curve determination with pivotal residual demand, Part III



190. However, if the probability of the high residual demand curve realization is sufficiently high, then it may be expected profit-maximizing for the supplier to exploit the fact that it is pivotal by submitting the willingness-to-supply curve $S_2(p)$, shown in Figure 3.29, that crosses its residual demand curve at the point $DR_H(p_{max})$. By doing so, the supplier forgoes the ability to sell any output if the low residual demand curve realization occurs. This may be expected profit-maximizing if the probability of being pivotal times the profits the supplier earns from selling $DR_H(p_{max})$ at p_{max} exceeds the expected profits from submitting the willingness-to-supply curve $S_1(p)$ in Figure 3.28 and selling $DR_H(p_H)$ in the high demand state and $DR_L(p_L)$ in the low demand state. Let $C(q)$ denote the variable cost of producing output level q. An expected profit-maximizing supplier will decide to exploit the fact it is pivotal and submit an offer curve that sets p_{max} in the high residual demand realization if the following inequality holds:

$$\theta\left(DR_H(p_{max})p_{max} - C\big(DR_H(p_{max})\big)\right)$$
$$> \theta\left(DR_H(p_H)p_H - C\big(DR_H(p_H)\big)\right) + (1-\theta)\left(DR_L(p_L)p_L - C\big(DR_L(p_L)\big)\right)$$

meaning that the expected profits of selling in the high demand states at p_{max} and selling zero in the low demand state exceeds the expected profits from selling at p_H in the high demand state and p_L in the low demand state. This inequality illustrates several points about the likelihood a supplier will exploit its pivotal status. The higher the values of p_{max}, the supplier's pivotal quantity, and probability the supplier is pivotal, the greater is the likelihood that the supplier will submit an offer curve that exploits the fact that it is pivotal.

191. Figure 3.30 shows an example of when the supplier is likely to find it expected profit-maximizing to submit $S_2(p)$ instead of $S_1(p)$. The long thin vertical gray shaded area, the expected profit from submitting $S_2(p)$, labeled $E(\pi(S_2(p)))$, is larger than the light brown horizontal shaded area, the expected profit from submitting $S_1(p)$, labeled $E(\pi(S_1(p)))$.

192. Factoring in the impact of fixed-price forward market obligations complicates the analysis slightly, although the basic insight about the determinants of when a supplier will exploit the fact that it is net pivotal remains. The supplier compares the expected profits from selling at p_{max} during high residual demand curve realizations when it is net pivotal, to the expected profit from submitting the expected profit-maximizing offer curve that does not exploit the fact that it is net pivotal. If the supplier assesses that the former expected profits are higher, then it will submit an offer curve that exploits the fact that it is net pivotal.

193. This logic suggests that when a supplier believes that the probability of being net pivotal is high, it will significantly increase its offer prices. The empirical validity of this prediction will be explored in the next section.

3.5 Determinants of the duration of the exercise of unilateral market power in wholesale electricity markets

194. One outstanding question from the above discussion is: what determines the length of time a supplier has the ability and incentive to exercise unilateral market power? There are many factors that limit the ability and incentive of suppliers to exercise unilateral market power. The resulting high prices can stimulate: (1) generation unit owners to supply more energy from existing generation units, (2) retail consumers to reduce their demand for electricity, and (3) new entrants and existing participants to build new generation capacity. All of these responses have their strengths and weaknesses in dealing with the problem of unilateral market power in the short-term market.

195. If there are a number of existing generation units off-line, then a high short-term price can cause their owners to bring these units back on-line and offer them into the short-term market, which increases the elasticity of the residual demand curve that all suppliers face. For example, Contact Energy brought one of the units of its New Plymouth plant back on-line during a period of high prices in the winter of 2008, after having decommissioned the plant at the end of the previous year. However, if all existing generation units are on-line and operating, then the limited increase in the output that is possible from these generation units is unlikely to limit the ability of existing suppliers to exercise unilateral market power.

196. If final consumers reduce their demand for electricity then this could significantly shift in the residual demand curves that all suppliers face, which limits the ability and incentive of suppliers to exercise unilateral market power. This reduction in demand may be the result of conservation campaigns, payments to industrial users to reduce their consumption, or emergency measures such as cuts to water heating. However, if the demand for electricity is still high despite the best efforts of consumers to reduce their

consumption, the supplier will still have a significant ability and incentive to exercise unilateral market power. Even at this high level of demand, if a significant fraction of final electricity demand is willing to alter its consumption in response to expectations about the ultimate half-hourly wholesale price, this can significantly flatten the residual demand curve that all suppliers face and significantly limit their ability to exercise unilateral market power.

197. In the absence of a final demand for electricity that responds to the half-hourly wholesale price of electricity, the ultimate limiting factor for the exercise of unilateral market is new entry. High prices that reflect the exercise of unilateral market power may provide a signal to new entrants that it would be profitable to construct additional generation capacity. However, the entrant must determine whether these high prices are the result of the exercise of unilateral market power that would no longer be possible if they entered, or if these prices indicate a true need for additional generation capacity.

198. If these high prices are the result of insufficient competition among existing suppliers, rather than any lack of sufficient generation capacity to meet demand, then a new entrant selling only in the short-term market may not risk entry because it may expect that after it enters and begins operation, market prices will fall to a level that does not allow it to recover its costs. In contrast, if the high prices are a valid signal of the need for additional generation capacity to meet demand, then a new entrant selling into the short-term market can be more confident that the prices it will sell its output at are sufficient to recover its production costs.

199. The problem of a new entrant being deterred by the possible fall in short-term prices after it enters can be addressed by this entrant signing a fixed-price long-term contract with a retailer or large consumers to guarantee its revenue stream. In a market with retailers that own less generation capacity than their retail load obligations, if these retailers are being subject to the exercise of unilateral market power in short-term wholesale market purchases, they should be willing to sign such a fixed-price forward contract with a new entrant at a price below the current short-term price that reflects the exercise of unilateral market power.

200. It is important to emphasize that the ability of new entry to discipline the exercise of market power is limited by the fact that in virtually all electricity markets around the world it takes at least two years to site, permit, construct and bring on-line a sizable new fossil fuel generation unit. In many markets, it can take even longer. Therefore, by the above logic, the maximum time that existing suppliers can exercise unilateral market power is limited by the length of time that it takes significant new entry to occur. Consequently, in markets where there are many generation options for new entrants, and the time lag between conception and operation is very short, the length of time a supplier can exercise unilateral market power is very short. However, in a market such as New Zealand where suppliers have limited generation technology options because of, for example, the recent (and now reversed) moratorium on the construction of fossil fuel facilities and the long time lag between conception and operation of large hydroelectric facilities, the exercise of unilateral market power can persist for a much longer time.

201. During a period of significant unilateral market power in the short-term market, retail customers could limit the incentive of suppliers to exercise such market power by increasing their purchases of fixed-price forward market obligations from the suppliers that are long in the short-term market. By the logic described in Section 3.3, these suppliers would then find it expected profit-maximizing to submit offer curves closer to their marginal cost curves and therefore set short-term prices closer to the marginal cost of the highest cost unit operating during that half-hour period. However, these forward market purchases would not come without a cost because the suppliers selling them know that they would be giving up the opportunity to exercise substantial unilateral market power in the short-term market, and would therefore only be willing to do so if the forward market price compensated them for the short-term power they expected to be able to exercise over the duration of the fixed-price long-term contract.

202. An example from the winter of 2001 in the California electricity market is instructive. As documented in both BBW (2002)[35] and Wolak (2003a)[36], suppliers to the short-term market in California exercised substantial unilateral market power during the summer of 2000. This continued into the autumn of 2000 until the late spring of 2001. Consequently, during the winter of 2001 when the state of California attempted to purchase fixed-price forward contracts starting "deliveries" in the summer of 2001, existing suppliers knew that they did not face significant competition from new suppliers for energy until the summer of 2003. In the late winter and early spring of 2001, existing suppliers knew that substantial unilateral market power was likely to be exercised during the summer of 2001 because water levels in California during summer depend on snowpack levels in the early spring, and these were known to be extremely low at the time.

203. The combination of known low water levels for the summer of 2001 and little competition from new sources of supply to California meant that existing suppliers knew as of the late winter and early spring of 2001 that they could expect to sell their energy at prices that reflected the exercise of substantial unilateral market power in the short-term market during the summer of 2001. As Wolak (2003b)[37] notes, quotes for summer 2001 electricity in California during the late winter of 2001 were in the US$300/MWh range.

204. This price represented suppliers' expectations of average short-term energy prices during the summer of 2001 as of the late winter and early spring of 2001. For the same reason that an expected profit-maximizing supplier that has the prospect of selling energy in the real-time market at US$100/MWh is unwilling to offer supply into the day-ahead market at anything less than US$100/MWh, a supplier that expects to sell power in the short-term market for an average price during the summer of 2001 of US$300/MWh is

[35] Borenstein, Bushnell & Wolak (2002) "Measuring Market Inefficiencies in California's Restructured Wholesale Electricity Market", American Economic Review, 92 (2002), pp. 1376-1405.

[36] Frank A Wolak (2003a) "Measuring Unilateral Market Power in Wholesale Electricity Markets: The California Market 1998 to 2000", American Economic Review, May 2003, 425-430.

[37] Frank A Wolak (2003b) "Diagnosing the California Electricity Crisis", The Electricity Journal, August/September, 11-37.

unwilling to sell a fixed-price forward contract for energy during the summer of 2001 at less than US$300/MWh. Consequently, at time horizons shorter than those necessary to allow a substantial amount of new entrants to compete to supply fixed-price forward contracts, existing suppliers are able to capture the market power they expect to be exercised in the short-term market in the fixed-price forward contracts they sell for that time period.

205. Similar logic applies to the prices offered by suppliers during the late winter of 2001 for fixed-price forward contracts to provide energy during the summer of 2002. At this time horizon to delivery there was less certainty about hydrological conditions in California and the Pacific Northwest. This fact meant there were more potential sources of supply to compete to provide electricity at that time horizon to delivery. However, it was still not possible to site, construct, and bring on line a substantial amount of new generation capacity in California between the spring of 2001 and the summer of 2002. For these reasons, existing suppliers still expected, as of the spring of 2001, that a significant amount of unilateral market power would be exercised in the short-term market during the summer of 2002. Thus, as Wolak (2003b)[38] notes, the price of summer 2002 energy in California at this time was in the neighborhood of US$150/MWh.

206. Because it was possible to site, construct, and bring on line a substantial amount of new generation capacity to supply electricity to California between the spring of 2001 and the summer of 2003, suppliers did not expect during the spring of 2001 that a significant amount of unilateral market power would be exercised in the short-term market during the summer of 2003. For this reason, it was possible to purchase summer of 2003 electricity in California for approximately US$45/MWh. For the same reasons, electricity to be "delivered" during the summers beyond 2003 sold for approximately the same price.

207. The above discussion provides a stark illustration of the choices facing final consumers when system conditions arise, exogenously or through the actions of some market participants, to allow suppliers to exercise substantial unilateral market power in the short-term market. These customers either pay prices that reflect the exercise of unilateral market power on the short-term market, or purchase fixed-price forward contract obligations (that subsequently reduce the ability and incentive of suppliers to exercise unilateral market power) at prices that reflect the market power that these suppliers expect to give up by selling these fixed-price forward market obligations. In short, the suppliers can either pay for the market power in the short-term market or pay for this market power on an "installment plan" in the fixed-price forward contracts they sign.

208. This logic also demonstrates that retailers and final consumers can avoid paying prices that reflect expectations about the amount of unilateral market power that will be exercised in the short-term market by purchasing fixed-price long-term contracts far enough in advance of delivery to allow new entrants to compete to sell this energy. At this time horizon to delivery, customers can be reasonably assured of paying a price that

[38] *ibid.*

does not reflect the exercise of unilateral market power. With the amount of advance notice needed for new entrants to site, permit, construct and bring on line a new generation unit, retailers and large consumers would be assured of being able to purchase fixed-price forward contracts at prices that reflect substantial competition between potential new suppliers and existing suppliers of electricity. In this way, market participants could take the appropriate precautions against the prospect of extremely high short-term prices at some future date, without having to pay forward contract prices that reflect the unilateral market power suppliers expect to be exercised in the short-term market during the delivery horizon.

209. Market participants that signed fixed-price long-term forward contracts during the winter and spring of 2001 in California were not so fortunate. As noted in Wolak (2003b)[39], these market participants had to pay for the market power that suppliers expected to be exercised during the summers of 2001 and 2002 in the prices that they paid for fixed-price forward contracts of up to ten years in duration. By agreeing to a much higher price than US$45/MWh during all years of the contract, these purchasers were able to obtain a fixed-price for the entire duration of the eight to ten-year contract that was significantly less than the forward price of electricity in California during the summers of 2001 and 2002. In this way, entities that signed long-term contracts during the winter and spring of 2001 paid for the market power that suppliers expected to be exercised in the short-term market during the summers of 2001 and 2002 on the installment plan by agreeing to pay prices significantly above US$45/MWh for all years of the contract.

210. It is important to emphasize that the forward contract prices that an existing supplier to the California market was willing to sell energy for during the summers of 2001 and 2002 did not reflect just the market power that that supplier alone expected to exercise in the short-term market, but the amount that each existing supplier expected would result from the combination of the independent actions of all existing suppliers to exercise their unilateral market power. Specifically, the amount of unilateral market power priced into the forward contracts that each supplier was willing to sell reflected the total (across all suppliers) amount of unilateral market power that each supplier expected to be exercised in the short-term market during that time period.

211. This logic suggests an extremely important role for public policy to ensure that independent retailers and large customers are not subject to substantial market power in their forward market purchases. The administrative and legal process to site, permit, construct and bring on line new generation units should be as transparent as possible, involve as many generation technologies as possible, and require the minimum amount of time possible. Any deviations from these minimums could result in independent retailers and larger customers paying higher prices in both the long-term and short-term energy markets because of the market power that suppliers expect to be able to exercise. For example, if suppliers know that there are no viable large generation technologies that can enter and produce electricity within at least five years, then buyers of fixed-price forward contracts negotiated for delivery less than five years in advance will pay for the market

[39] *ibid.*

power that existing suppliers expect to be exercised in the short-term market during this time period. Consequently, the more technologies that are allowed to compete to supply energy and the shorter the time lag between conception of a new facility and production from this facility, the less likely independent retailers and larger consumers will have to pay for the exercise of unilateral market power for the fixed-price forward contracts they negotiate one to two years in advance of delivery.

212. The discussion of the California experience illustrates an important difference between hydroelectric-dominated markets and fossil-fuel dominated markets in the duration of the exercise of significant unilateral market power. Because few, if any, electricity markets in the industrialized world have insufficient capacity to meet demand, with a few exceptions the periods when suppliers have the ability to exercise significant unilateral market power in fossil-fuel dominated systems are typically of short duration. That is because in most instances retailers and large consumers have purchased significant fixed-price forward contracts far enough in advance of delivery or policymakers have implemented "vesting contracts" at the start of the wholesale market regime to ensure that large suppliers have substantial fixed-price forward market obligations to final consumers. The periods of market power in a fossil-fuel dominated market typically arise when demand is unexpectedly high or certain generation or transmission facilities are temporarily unable to operate because of an outage. This often leaves one or more suppliers with a much greater exposure to the short-term market and they are able to increase their offer prices into the short-term market and still be accepted to supply energy as a result of the reduced competition due to the generation or transmission outage. However, once demand falls or the generation unit or transmission line comes back on line, these suppliers face greater competition and no longer have as great of an ability or incentive to raise prices in the short-term market.

213. The case of a hydroelectric-dominated system is much different because once an energy shortfall occurs it is typically for the entire seasonal or annual hydro cycle. Consequently, once low hydro conditions arise, fossil-fuel suppliers now face less competition for their output because the hydroelectric suppliers are attempting to save their water by submitting steeper willingness to supply curves, which leaves fossil fuel suppliers with steeper residual demand curves. These residual demand curves unilaterally cause fossil fuel suppliers to submit higher offer prices for the same level of output because they have a greater ability and incentive to exercise unilateral market power. This implies that hydroelectric suppliers now face more inelastic residual demand curves and have a greater ability to exercise unilateral market power. Even hydro-electric suppliers with no ability to exercise unilateral market power must submit a higher offer price in response to the higher offer prices by the fossil fuel suppliers, if they do not want to use their water to produce electricity. This leads to even higher prices and steeper residual demand curves faced by the fossil fuel suppliers, which further enhances their ability and incentive to exercise unilateral market power in the short-term market.

214. System conditions that allow the exercise of unilateral market power can persist for a sustained period of time because, different from the case of a fossil fuel-dominated system, the cause of the reduction in available energy cannot be repaired and brought back on line. The amount of energy available to produce electricity is lower because the

rate of water inflows is reduced relative to normal levels. There is little that can be done to correct this problem except hope that it rains or snows. This logic emphasizes the need for extremely high levels of fixed-price forward contract obligations signed far in advance of delivery in wholesale markets dominated by the production of hydroelectric energy, because once a unilateral market power problem arises in the short-term market because of the reduced availability of energy, there are few mechanisms available to market participants to address this problem in the short term besides reducing the demand for electricity. Only a sustained period of water inflows greater than water use can correct the problem, and there is little anyone can do to increase these water inflows.

215. The distinction between hydro-dominated systems and fossil-fuel dominated systems also has implications for new entry decisions. In a hydro-dominated system with adequate generation capacity to serve demand, a potential new entrant considering whether to construct a fossil-fuel unit or other dispatchable unit (that does not use hydroelectric energy) in response to a period of high prices due to the sustained exercise of unilateral market power, must factor in the likelihood that when the unit comes on line water levels may be normal or high, which would imply wholesale prices that do not allow the entrant to recover its costs. For a fossil-fuel dominated system, a potential entrant is less worried that there will be a substantial amount of low-variable-cost energy available to compete with its unit and drive energy prices below the level necessary to recover its costs when the unit begins operation, particularly if the new entrant is a combined cycle natural gas-fired (CCGT) generation with a low variable cost of production, and the remaining units in the fossil-fuel dominated system are conventional steam turbine units. Thus, the need for an active market for fixed-price forward market obligations negotiated farther in advance of the time horizon necessary to bring on line a substantial amount of new generation capacity is much greater in a hydroelectric-dominated market.

216. This logic can also be understood from a pure risk-management perspective. The risk of a supply shortfall due to insufficient water inflows is far greater than the risk of a supply shortfall in fossil fuel-dominated system. Additional fossil fuels can typically be purchased at a higher price, so preventing a supply shortfall in a fossil fuel-dominated system with adequate generation capacity is just a matter of the fuel price. In a hydroelectric-dominated system with adequate generation capacity, additional water cannot be purchased at any price. Therefore, one way to insure against the circumstance of a true shortage of electricity due to insufficient water or an artificial shortage due to the exercise of unilateral market power because water levels are lower than usual (but not too low that the annual electricity demand cannot be met), is for independent retailers and large consumers to sign a high level of fixed-price forward market obligations relative to their final demand.

217. If hydroelectric suppliers have a high level of fixed-price forward market obligations beyond the level of energy they expect to produce from their own units with a high degree of confidence, then they will have an incentive to manage this risk of a true supply shortfall by signing hedging arrangements with new and existing owners of fossil-fuel or other dispatchable generation units that do not rely on hydroelectric energy to ensure that demand can be met for all rates of water inflow. If independent retailers and large

consumers sign fixed-price forward market obligations far in advance of delivery then there will be adequate time for the necessary fossil-fuel and dispatchable units to be constructed to ensure that a future true or artificial supply shortfall does not occur.

218. As the above logic should make clear, it is no surprise that virtually all of the sustained periods of the exercise of unilateral market power in wholesale electricity markets have occurred in markets dominated by hydroelectric energy. The seasonal, stochastic, and uncontrollable rate of water inflows implies that once the circumstances arise that allow suppliers to exercise substantial unilateral market power, these conditions are difficult to reverse. Unless there are very high levels of fixed-price forward contract coverage of final demand, consumers can experience substantial harm from this exercise of unilateral market power. Moreover, unless they have high levels of fixed-price forward market obligations, suppliers have a strong incentive to exercise this unilateral market power when these system conditions arise.

219. The prospect of future low electricity prices because water levels increase at a future date can significantly dull the incentive for new entry in response to prices that reflect the exercise of substantial unilateral market power. This underscores the substantially greater need for high levels of fixed-price forward contract coverage of final demand signed farther in advance of delivery than the time horizon necessary to build and bring on line new generation capacity. Consequently, particularly in hydroelectric-dominated systems, it may make sense for policy-makers to intervene to ensure that there are high levels of fixed-price forward contract coverage of final demand to ensure that sustained periods of true or artificial scarcity due to the exercise of unilateral market power do not arise during periods when water levels are lower than normal.

SECTION 4

EMPIRICAL EVIDENCE ON THE ABILITY AND INCENTIVE TO EXERCISE UNILATERAL MARKET POWER

4.1 Introduction

220. This section uses supplier offers, water reservoir levels, and market outcomes to demonstrate that each of the four large wholesale electricity suppliers in New Zealand behave in a manner consistent with maximizing their expected profits. As noted in Section 3, a supplier has a fiduciary responsibility to its shareholders to take all legal actions to maximize its expected profits, which is equivalent to that supplier taking all legal actions to exercise all available unilateral market power. The empirical results in this section demonstrate that although prices in the wholesale electricity market depend on supply and demand conditions, actual supply conditions depend on the offer curves submitted by market participants to the wholesale market. These offer curves are a direct result of the unilateral expected profit-maximizing actions of suppliers given factors that they are unable to control such as the level of demand at all locations in the New Zealand, amount of water inflows to hydroelectric generation units and the price of input fossil fuels and other inputs consumed to produce electricity. Therefore, the ability and

incentive of large suppliers to exercise unilateral market power are important determinants of the supply conditions that determine short-term wholesale prices, even after the impact of exogenous factors such as daily water availability and fossil fuel prices have been taken into account.

221. This section presents three lines of empirical evidence to demonstrate that the half-hourly aggregate willingness-to-supply curve in the short-term wholesale market is the result of the unilateral expected profit-maximizing actions of market participants:

- First, summary statistics are presented on the behavior of half-hourly measures of both the ability and incentive to exercise unilateral market power for each of the four large suppliers. These half-hourly measures of the ability and incentive to exercise unilateral market power are shown to be highly positively correlated with the value of the quantity-weighted average half-hourly market-clearing price. These ability and incentive measures are also shown to track market prices much more closely than daily water storage levels, particularly during the periods of high wholesale prices in 2001, 2003, and 2006.

- The second line of empirical analysis presents evidence that the observed positive correlation between the average half-hourly firm-level ability to exercise unilateral market power and half-hourly market prices and positive correlation between the average half-hourly firm-level incentive to exercise unilateral market power are the direct result of market participant behavior. Expected profit-maximizing offer behavior implies that a supplier's half-hourly offer price—the price at which it is willing to a pre-specified amount of energy in the short-term wholesale market—should be positively correlated with both its ability and incentive to exercise unilateral market power during that half-hour. Econometric analysis is then used to quantify the empirical relationship between the half-hourly offer price of each supplier and the half-hourly value of an index of that supplier's unilateral ability to exercise unilateral market power, after controlling for other factors impacting half-hourly market outcomes such as daily water levels and daily input fossil fuel prices. Further econometric analysis examines the empirical relationship between the half-hourly offer price of each supplier and the half-hourly value of an index of that supplier's unilateral incentive to exercise unilateral market power. We find that when each of the four suppliers has a greater ability or greater incentive to exercise unilateral market power, they submit substantially higher half-hourly offer prices for a pre-specified quantity of energy. We perform these two analyses for a variety of other half-hourly measures of the ability and incentive of a supplier to exercise unilateral market power and find the same positive relationship between supplier's half-hourly offer price and its half-hourly ability and incentive to exercise unilateral market power after controlling for the impact of daily water levels and input fossil fuel prices.

- The third line of empirical evidence tests whether offer behavior of thermal generation unit owners is consistent with the hypothesis that they have no ability exercise unilateral market power. This is found not to be the case. The econometric evidence presented demonstrates that the offer behavior of the large suppliers that own fossil fuel generation units is inconsistent with the expected profit-maximizing offer behavior of a supplier that has no ability to exercise unilateral market power.

222. Taken together, these three lines of empirical inquiry provide strong evidence that the behavior of the aggregate willingness to supply curve is the result of the exercise of unilateral market power by at least the four large suppliers. Market prices are highly positively correlated with higher values of the ability and incentive of these suppliers to exercise unilateral market power. These unilateral incentive and ability measures follow fluctuations in market prices more closely than water storage levels. Each of the four large suppliers submits a higher offer price when it has a higher ability to exercise unilateral market power, after controlling for the impact of daily water levels and input fossil fuel prices. Each supplier also submits higher offer prices when it has a higher unilateral incentive to exercise market power, after controlling for the impact of daily water levels and input fossil fuel prices. Finally, the suppliers that own fossil fuel generation units do not submit offer curves for these units into the short-term market in a manner consistent with expected profit-maximizing behavior by a supplier with no ability to exercise unilateral market power.

4.2 Market outcomes and the ability and incentive to exercise unilateral market power

223. Section 3 derived measures of the unilateral ability and incentive of a supplier to exercise market power that can be computed on a system-wide basis, or separately for the North and South Islands, using the half-hourly level of demand and the willingness-to-supply curves of all market participants. In this section, we derive modifications of these measures that the theory of expected profit-maximizing offer behavior derived in Section 3 implies should be linearly related to the half-hourly market-clearing price. The measures of ability and incentive are shown to be highly positively correlated with the value of the quantity-weighted average half-hourly market-clearing price.

4.2.1 Ability to exercise unilateral market power

224. As shown in Section 3.2, the form of the residual demand curve that a supplier faces determines its ability to exercise unilateral market power. The inverse of the elasticity of the residual demand curve evaluated at the market-clearing price is one measure of the ability of a supplier to exercise unilateral market power. This inverse elasticity measures the percent change in the market-clearing price that would result from the supplier producing one percent less output than it actually produced during that half-hour period.

225. Under the simplified model of expected profit-maximizing offer behavior described in Figures 3.17 and 3.18, this inverse elasticity measure can be directly related to the market-clearing price minus the opportunity cost of the highest cost unit owned by that supplier operating during that half-hour period divided by the market-clearing price. Because of this nonlinear relationship between this measure of the ability to exercise unilateral market power and the market-clearing price and the opportunity cost of the

highest cost generation unit owned by that supplier operating during that hour period, we focus our analysis on an alternative measure of the ability to exercise unilateral market power that our simplified model of expected profit-maximizing behavior implies should be linearly related to the market price and the supplier's marginal cost.

4.2.1.1 Derivation of the inverse elasticity and the inverse semi-elasticity

226. The inverse elasticity measures are derived using market data. Box 1 presents the derivation of the inverse elasticity of residual demand, which measures the percent change in the market-clearing price that would result from the supplier producing one percent less output than it actually produced during that half-hour period. Box 1 also presents the derivation of η_i, the inverse semi-elasticity of the residual demand curve, which gives the \$/MWh increase in the market-clearing price associated with a one percent reduction in the amount of output sold by the supplier. Box 1 also shows that the simplified model of expected profit-maximizing offer behavior implies that higher market-clearing prices should be linearly related to higher values of the inverse semi-elasticity.

Box 1: Derivation of η_i, the inverse semi-elasticity of the residual demand curve, which shows the \$/MWh increase in the market-clearing price associated with a one percent reduction in the amount output sold by the supplier.

The logic underlying the construction of the expected profit-maximizing offer curve in Figure 3.17 implies that the point (P_1, Q_1) is the ex post profit-maximizing price/quantity pair for the firm for the residual demand realization $DR_1(p)$ and the point (P_2, Q_2) is ex post profit-maximizing price/quantity pair for the firm for the residual demand realization $DR_2(p)$. The first-order conditions for ex post profit-maximization for these two residual demand realizations are:

$$\frac{P_1 - C_1}{P_1} = -1/\varepsilon_1 \quad \text{and} \quad \frac{P_2 - C_2}{P_2} = -1/\varepsilon_2 \tag{1}$$

where C_i $(i = 1, 2)$ is the marginal cost for supplier i at output level Q_i $(i = 1, 2)$ and $-1/\varepsilon_i$ $(i = 1, 2)$ is the inverse of the elasticity of the residual demand curve for that residual demand realization. Recall that the inverse elasticity is defined in terms of the residual demand curve as:

$$-1/\varepsilon_i = \frac{DR_i(P_i)}{P_i} \times \frac{1}{DR_i'(P_i)} \tag{2}$$

where $DR_i'(P_i)$ is the slope of residual demand curve i evaluated at price P_i, and $DR_i(P_i)$ is the value of residual demand curve evaluated at price P_i. Note that equations given in (1) imply a nonlinear relationship between the market price and inverse elasticity because the market price appears in both the numerator and denominator of the left-hand side of each equation. However, using the definition of the inverse elasticity in equation (2), the two equations in (1) can be rearranged to equal:

$$P_i = C_i - \frac{DR_i(P_i)}{DR_i'(P_i)} \quad , i = 1, 2 \tag{3}$$

Equation (3) implies that the market-clearing price is equal to the marginal cost of the highest cost unit owned by that supplier operating during that half-hour plus the level of the residual demand curve divided by the absolute value of the slope of the residual demand curve.

Define η_i $(i = 1, 2)$, the inverse semi-elasticity of the residual demand curve i, as:

$$\eta_i = -\frac{1}{100}\frac{DR_i(P_i)}{DR_i'(P_i)} \tag{4}$$

This magnitude gives the \$/MWh increase in the market-clearing price associated with a one percent reduction in the amount output sold by the supplier. In terms of this notation, equation (3) becomes

$$P_i = C_i + 100\eta_i \quad , i = 1, 2 \tag{5}$$

which implies that the market-clearing price is a linear function of the inverse semi-elasticity, η_i, after controlling for the opportunity cost of the highest cost unit operating during that half-hour owned by the supplier.

227. As discussed in Section 3, because offer curves in the New Zealand wholesale market are step functions, residual demand curve realizations do not strictly satisfy the assumptions implied by the simplified model of expected profit-maximizing offer behavior presented there, so that equation (5) in Box 5 will not hold with equality. However, the general model of expected profit-maximizing offer behavior described in Section 3 implies that when a supplier has a greater ability to exercise unilateral market

power, as measured by the size of η_i, the \$/MWh price increase that results from reducing the amount it sells in the wholesale market by one percent is likely to be higher.

228. Computing the slope of the residual demand curve at the market-clearing price for a step-function residual demand curve requires choosing the output change used to compute the finite-difference approximation to the slope. These output changes should be large enough to ensure that enough price steps on the residual demand curve are crossed so that a non-zero slope is obtained, but not too large that the implied output change is judged as implausible for the supplier to implement. We also want to choose a procedure for selecting the output changes to ensure that the value of slope obtained is not sensitive to the size of the output changes used to compute it.

229. Box 2 presents the details of the process used to compute the slope of the residual demand curve for one supplier for one half-hour period.

Box 2: The process used to compute the slope of the residual demand curve for a supplier for one half-hour period

Figure 4.1 shows the residual demand curve for Genesis on February 2, 2006 in period 35. Suppose that Q^* = 901 MW is the output sold by Genesis at the market-clearing price for this half-hour period of P^*= \$145/MWh. We want to approximate the slope of the residual demand curve in the vicinity of (P^*, Q^*). Consider a 10% price change window on either side of P^*. Look for the closest steps on the residual demand curve to (P^*, Q^*) that lie outside this 10% price window. The closest point below P^* that has price less than 0.9 times P^* is (\$129, 969). Call this point (P_1, Q_1). Above P^* the closest point with price greater than 1.1 times P^* is (\$164, 871). Call this point (P_2, Q_2). The slope of the residual demand curve $DR(P^*)$ at (P^*, Q^*) according to this procedure is given by the formula:

$$DR'(P^*) = \frac{Q_1 - Q_2}{P_1 - P_2} = \frac{969 - 871}{129 - 164} = -2.81 \qquad (6)$$

Using price and quantity values that lie outside a given percentage price change window is superior to using a pre-specified change in price or quantity (such as a fixed +/- 10% change), because using a pre-specified price or quantity change can produce large jumps in the resulting value of the slope depending on the exact values of the step function crossed.

The resulting inverse semi-elasticity at (P^*, Q^*) for this residual demand curve gives the \$/MWh price increase from a 1% reduction in output and is equal to:

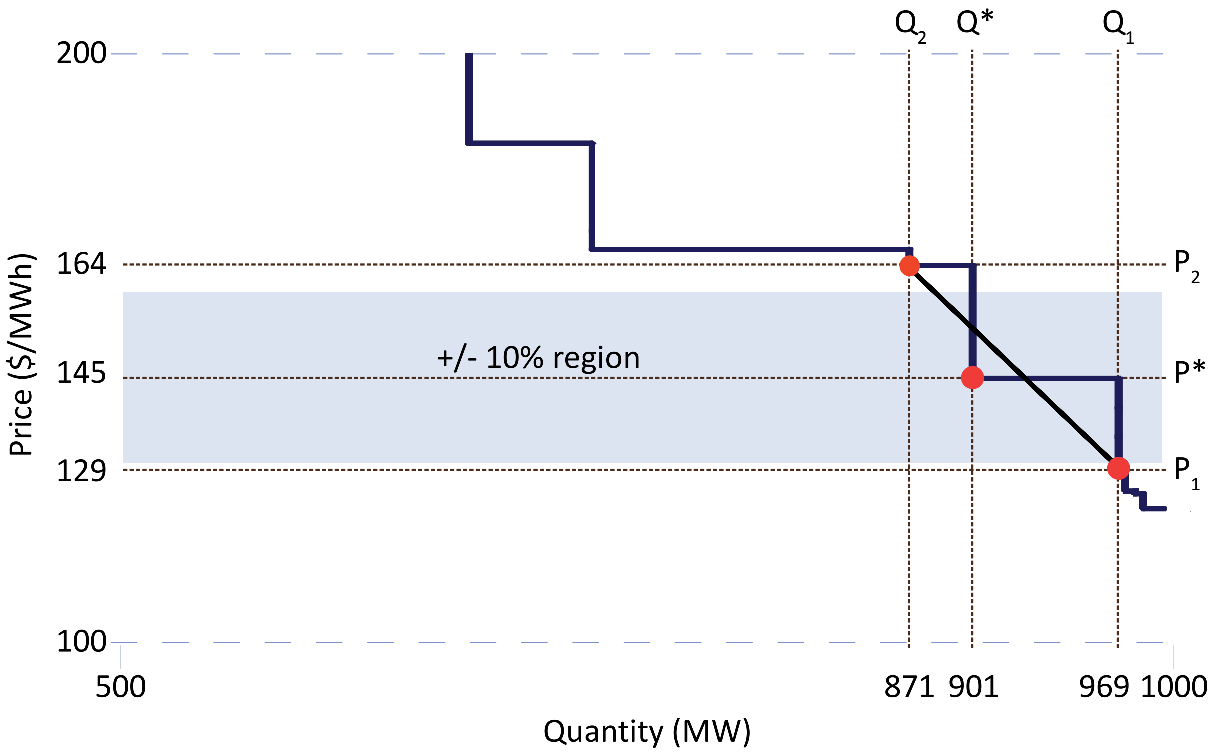
$$\eta = -\frac{1}{100}\frac{DR(P^*)}{DR'(P^*)} = -\frac{1}{100}\frac{Q^*}{DR'(P^*)} = -\frac{1}{100}\frac{901}{-2.81} = 3.21 \qquad (7)$$

This semi-elasticity quantifies the ability of Genesis to raise prices during this half-hour period by reducing its output by 1%. This magnitude implies that if Genesis reduces its output by 1% relative to Q^* = 901 MW, the increase in the market price would be approximately \$3.21/MWh. Figure 4.2 shows the same calculation for Genesis in the half-hour period exactly one year later. Here $(-1/100)(Q^*/DR'(P^*))$ = 0.29. That is, a 1% reduction in output would produce an increase in the market price of approximately \$0.29/MWh, a significantly lower price increase from the same 1% output reduction. Note that this inverse semi-elasticity is significantly lower, despite the fact that Genesis is producing more than 100 MW more output during this half-hourly period than in the same period during 2006. These two figures demonstrate the usefulness of the inverse semi-elasticity as measure of the ability of a supplier to exercise unilateral market power because high and low values of this measure can occur for both high and low output levels for the supplier.

230. To demonstrate the robustness of our inverse semi-elasticity estimates to the price change window used for the calculation, Table 4.1 compares the results from calculating the inverse semi-elasticity for the four large suppliers in each half-hour from January 1, 2001 to June 30, 2007, using four different values for the price change window: 1%, 5%, 10% and 15%.

231. For each supplier, the overall mean value of the semi-elasticity is shown for each price window. This is the mean value of η_i, which shows the mean \$/MWh increase in the market-clearing price associated with a one percent reduction in the amount output sold by the supplier. For example, using a price window of +/-15% the mean inverse semi-elasticity for Contact is 1.27, compared to a mean inverse semi-elasticity of 1.21 using a price window of +/-1%. The table also shows the Pearson correlation coefficients between the half-hourly inverse semi-elasticities calculated for different price windows. These show that there is high correlation (in all cases greater than 0.80) between the values calculated for different price windows. This provides strong empirical evidence that our inverse semi-elasticities are not sensitive to the choice of the price window used to compute them. For the remainder of this chapter all results are shown based on the inverse semi-elasticities calculated with a 10 percent price window.

Figure 4.1: Elasticity Calculation for Genesis, 2 February 2006, period 35

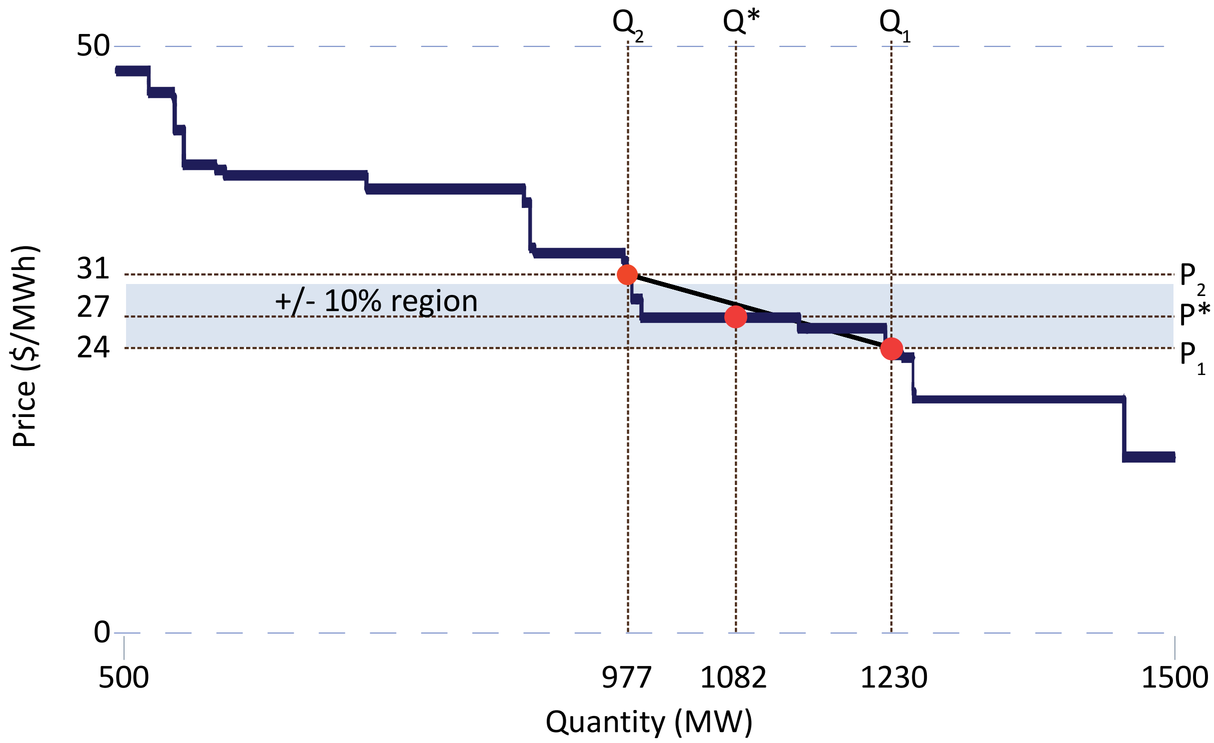


Source: Calculations based on offer data from Centralised Data Set and EMS, and dispatch data from M-Co.

4.2.1.2 Comparison of inverse semi-elasticities of the four largest suppliers

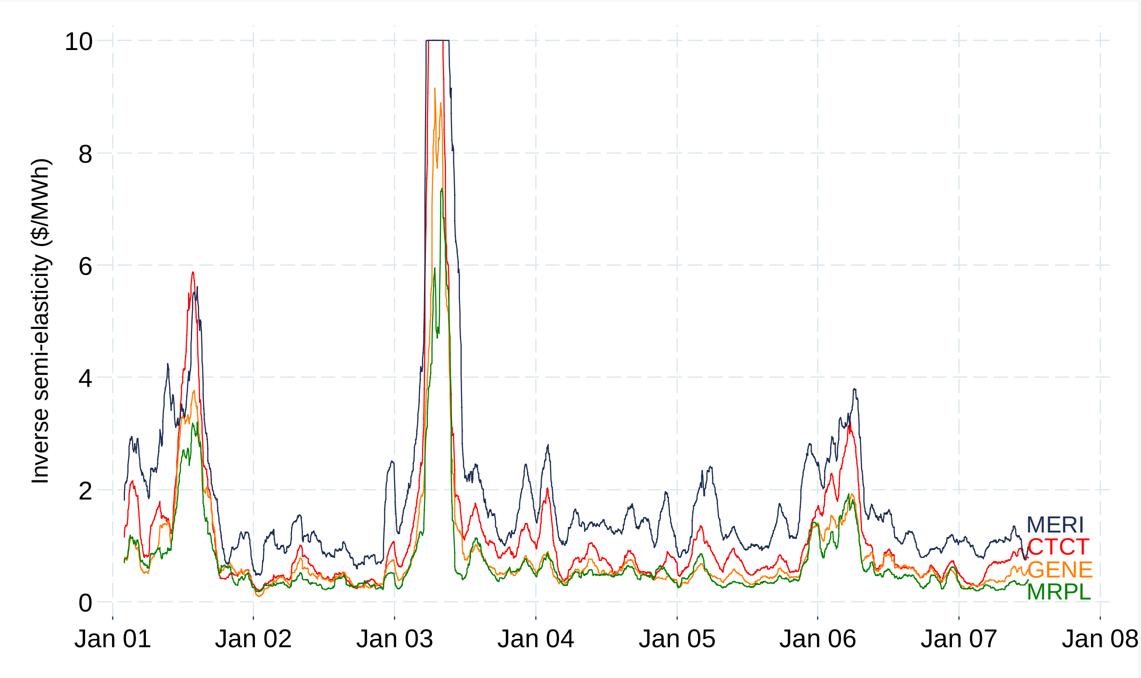
232. To compare time series behavior of the inverse semi-elasticities across firms, Figure 4.3 plots the 30-day moving average or smoothed values of the half-hourly inverse semi-elasticities for the four largest firms from January 1, 2001 to June 30, 2007. These moving averages follow a very similar pattern across the four firms and certain suppliers have persistently larger values than other suppliers. Although ten is the maximum value of the smoothed average inverse semi-elasticities displayed in this figure, the values for Meridian peak at close to 20 during early 2003, and the peak values for Contact for this time period also exceed 10. Over the entire sample period, Meridian's smoothed inverse semi-elasticities tend to be the highest, followed by Contact, then by Genesis, and finally by Mighty River Power.

Figure 4.2: Elasticity Calculation for Genesis, 2 February 2007, period 35



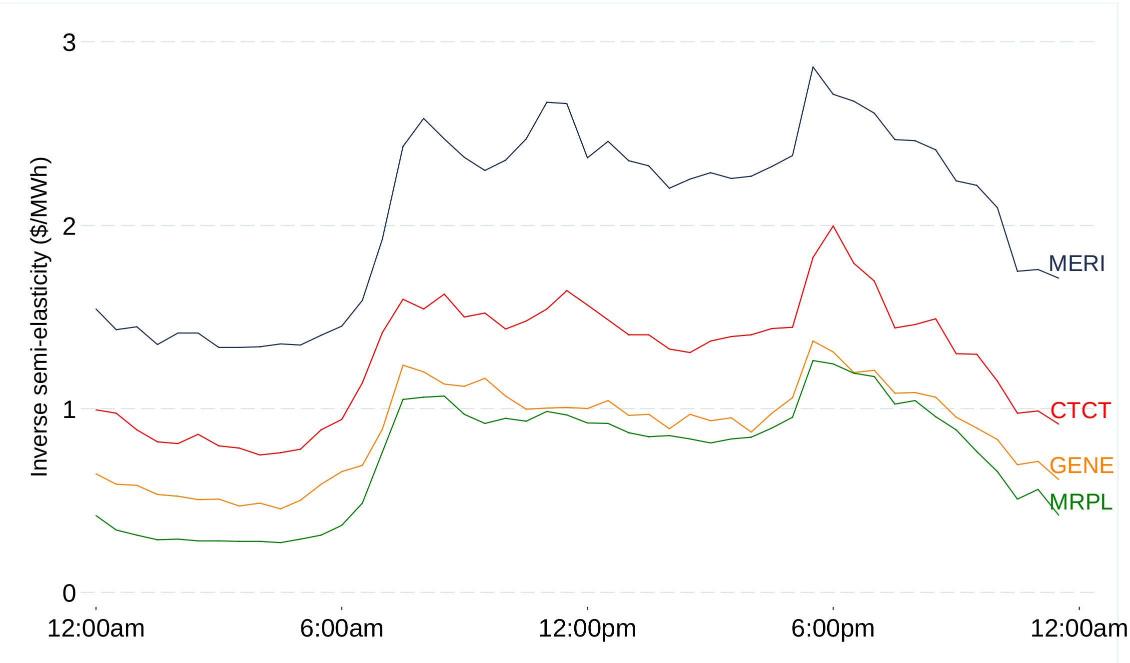
Source: Calculations based on offer data from Centralised Data Set and EMS, and dispatch data from M-Co.

Figure 4.3: Half-hourly inverse semi-elasticities by firm, 30-day rolling average



Source: Calculations based on offer data from Centralised Data Set and EMS, and dispatch data from M-Co.

Figure 4.4: Half-hourly mean inverse semi-elasticities by firm, 2001–07



Source: Calculations based on offer data from Centralised Data Set and EMS, and dispatch data from M-Co.

Table 4.1: Correlation between semi-elasticity results for different price windows

	Contact				Genesis			
Price window	15%	10%	5%	1%	15%	10%	5%	1%
15%	1.00				1.00			
10%	0.95	1.00			0.96	1.00		
5%	0.90	0.95	1.00		0.92	0.96	1.00	
1%	0.84	0.90	0.94	1.00	0.82	0.85	0.90	1.00
Mean semi-elasticity	1.27	1.28	1.25	1.21	0.88	0.88	0.86	0.83

	Meridian				Mighty River			
Price window	15%	10%	5%	1%	15%	10%	5%	1%
15%	1.00				1.00			
10%	0.96	1.00			0.97	1.00		
5%	0.88	0.92	1.00		0.91	0.94	1.00	
1%	0.81	0.85	0.93	1.00	0.85	0.88	0.94	1.00
Mean semi-elasticity	2.05	2.07	2.07	1.99	0.73	0.74	0.75	0.74

Source: Calculations based on offer data from Centralised Data Set and EMS, and dispatch data from M-Co.

233. To provide a clear picture of the magnitude of persistent differences across the four suppliers in this index of the ability to exercise unilateral market power, Figure 4.4 presents, $\eta_{ih}(mean)$, the sample mean of the half-hourly values of η_{ihd}, the semi-elasticity for supplier i during half-hour h of day d.[40] Meridian has the highest value of $\eta_{ih}(mean)$ for all half-hours and Mighty River Power the lowest for all half-hours. Genesis is slightly higher than Mighty River Power for all half-hours and the values for Contact Energy are roughly midway between the values for Genesis and Meridian. This ordering is consistent with the ordering of the market shares of electricity sold in the short-term market over the sample period shown in Section 2.

234. It is important to emphasize that these inverse semi-elasticities only depend on the generation quantity of the supplier and the slope of the residual demand curve faced by each supplier, which in turn depends of the level of system demand and the offers of all suppliers but the one under consideration. For example, the inverse semi-elasticity for Meridian for a given half-hour depends only on its half-hourly generation, the half-hourly offer curves of all other suppliers besides Meridian, and the level of system demand during that half-hour, but it measures the $/MWh increase in the half-hourly market price that would result from Meridian supplying 1% less output during that half-hour.

[40] Each point on the graph in Figure 4.4 for supplier i is equal to $\eta_{ih}(mean) = \frac{1}{D}\sum_{d=1}^{D} \eta_{ihd}$, where D is the total number of days in the sample period of January 1, 2001 to June 30, 2007.

4.2.1.3 The relationship between market-clearing prices and the ability of the four large suppliers to exercise unilateral market power

235. To demonstrate the close relationship between half-hourly market-clearing prices and the half-hourly ability of the four large suppliers to exercise unilateral market power (as measured by the inverse semi-elasticity of their residual demand curves), Figure 4.5 plots the 30-day moving average or smoothed value of $p_{hd}(avg)$, the quantity-weighted average of the nodal prices for half hour h of day d, and a 30-day moving average or smoothed value of the half-hourly un-weighted average of, $\eta_{hd}(firm)$, the half-hourly mean of the values of η_{ihd} for Genesis, Contact, Meridian, and Mighty River Power.[41]

236. Figure 4.5 shows that the time series pattern of the 30-day moving average of $p_{hd}(avg)$ closely tracks the 30-day moving average of $\eta_{hd}(firm)$. During periods when the smoothed value of the index of the average ability of the four suppliers to exercise unilateral market power is high, the smoothed value of the quantity-weighted average of the half-hourly nodal prices is also very high. Specifically, during mid-2001, early 2003, and early 2006 the smoothed index of the ability of suppliers to exercise unilateral market power is high and the smoothed value of the average of the hour-hourly nodal prices is high. Conversely, during periods when the smoothed index of the ability of these suppliers to exercise unilateral market power is low, the smoothed value of the average of the half-hourly nodal prices is significantly lower. This occurs during 2002, 2004, and 2005.

237. Figure 4.6 plots that the sample half-hourly means of $\eta_{hd}(firm)$[42], and the sample half-hourly means of the quantity-weighted average nodal prices[43], for our sample period. The average pattern throughout the day of the average half-hourly market-wide ability of the four suppliers to exercise unilateral market power very closely tracks the average half-hourly pattern of the quantity-weighted average of the nodal prices throughout the day. Figure 4.6 clearly demonstrates that over our sample period from January 1, 2001 to June 30, 2007, a greater average half-hourly ability of each supplier to exercise unilateral market power is coincident with a higher average half-hourly quantity-weighted average of the nodal prices.

4.2.2 Incentive to exercise unilateral market power

238. Even if a supplier possesses a substantial ability to exercise unilateral market power, it may not submit willingness-to-supply curves that reflect this ability if it has no incentive

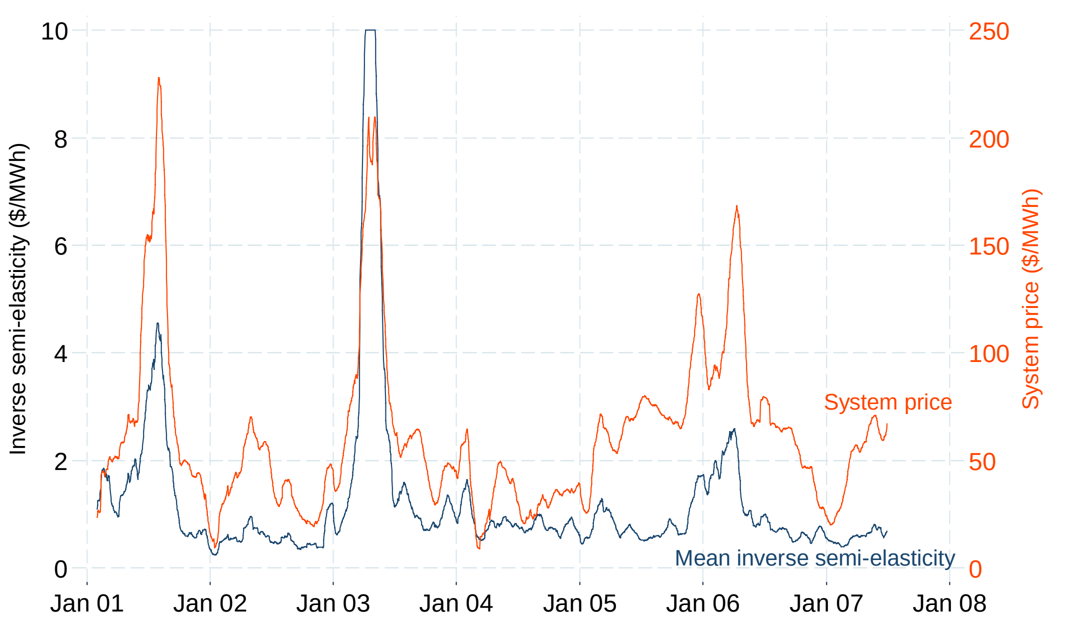
[41] Define p_{hdm} as the price at node m during half-hour h of day d, and q_{hdm} as the total amount of energy injected at node m during half-hour h and day d. The quantity-weighted average of the nodal prices for half-hour h of day d is $p_{hd}(avg) = \frac{\sum_{m=1}^{M} p_{hdm} q_{hdm}}{\sum_{m=1}^{M} q_{hdm}}$. The average of the half-hourly values of the four values η_{ihd} is equal to $\eta_{hd}(firm) = \frac{1}{4}\sum_{i=1}^{4} \eta_{ihd}$.

[42] The sample half-hourly means of $\eta_{hd}(firm)$ is equal to $\frac{1}{D}\sum_{d=1}^{D} \eta_{hd}(firm)$

[43] The sample half-hourly means of the quantity-weighted average nodal prices is equal to $\frac{1}{D}\sum_{d=1}^{D} p_{hd}(avg)$

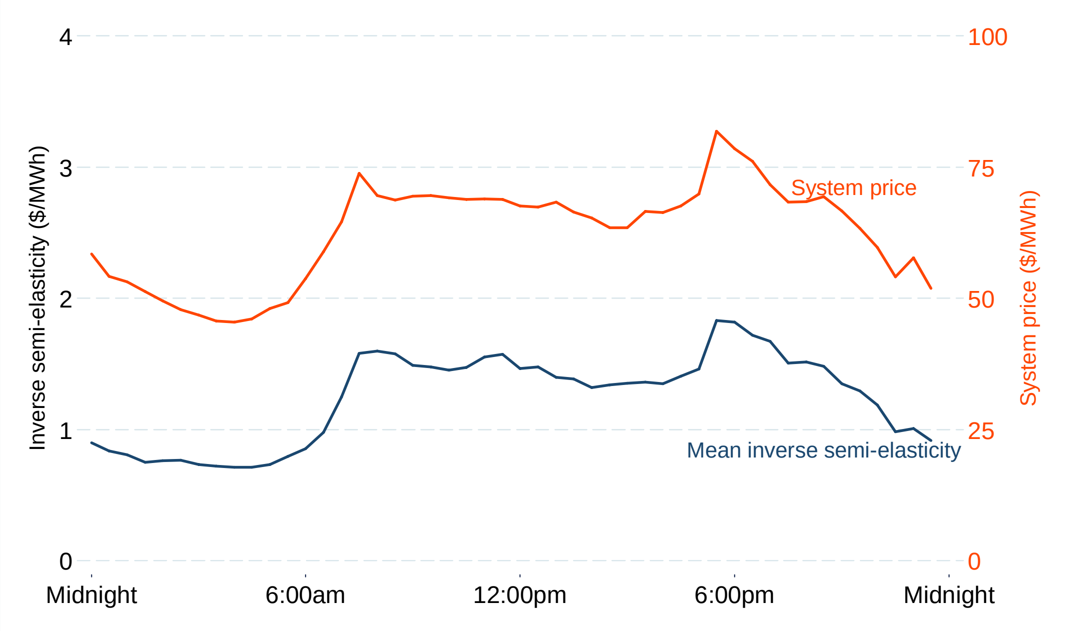
to exercise unilateral market power. As shown in Section 3.3, a supplier may have a substantial ability to exercise unilateral market power, but if its fixed-price forward market obligations are approximately equal to its sales in the short-term wholesale market, it may have little incentive to do so. This logic suggests that half-hourly measures of the unilateral incentive of each supplier to exercise unilateral market power should be correlated with both market-clearing prices and the level of offer prices that each supplier submits.

Figure 4.5: Mean inverse semi-elasticities and system price, 30-day rolling average



Source: Calculations based on offer and generation data from Centralised Data Set and EMS, price data from Centralised Data Set, and dispatch data from M-Co.

Figure 4.6: Half-hourly mean inverse semi-elasticities and system price, 2001–07



Source: Calculations based on offer and generation data from Centralised Data Set and EMS, price data from Centralised Data Set, and dispatch data from M-Co.

4.2.2.1 Derivation of the inverse elasticity and the inverse semi-elasticity of the net-of-fixed-price-forward-market-obligations residual demand curve

239. Inverse semi-elasticities for the net-of-forward market obligations residual demand curves can be computed from these inverse semi-elasticities to obtain measures of the incentive (as opposed to ability) of individual suppliers to exercise unilateral market power. Under the simplified model of expected profit-maximizing offer behavior described in Section 3, the inverse semi-elasticities of the net-of-forward obligations residual demand curve can be directly related to the market-clearing price and the marginal cost of the highest cost unit owned by that supplier operating during that half-hour period. Box 3 presents the derivation of the inverse elasticity of net-of-forward market obligations residual demand curve. Box 3 also presents the derivation of η_i^C, the inverse semi-elasticity of the net-of-forward market obligations residual demand curve, which gives the $/MWh increase in the market-clearing price associated with a one percent reduction in the amount output sold by the supplier.

240. Box 3 defines η_i^C in terms of the net of fixed-price forward market obligations residual demand curve and demonstrates that it is equal to the inverse semi-elasticity of the residual demand multiplied by the supplier's exposure to short-term prices. This value of η_i^C gives the $/MWh increase in the market-clearing price associated with a one percent reduction in the net position of the supplier (the difference between its short-term market sales and its fixed-price forward market obligations).

Box 3: Derivation of η_i^C, the inverse semi-elasticity of the net-of-fixed-price-forward-market-obligations residual demand curve.

The logic underlying the construction of the expected profit-maximizing offer curve with forward market obligations drawn in Figure 3.26 implies that the point of intersection between the offer curve and each residual demand realization is an ex post profit-maximizing price/quantity pair for the firm for each residual demand realization given the forward market obligations of the supplier, Q_C. For the two residual demand curve realizations in Figure 3.26, the first-order conditions for ex post profit-maximization for these two residual demand realizations are:

$$\frac{P_1 - C_1}{P_1} = -1/\varepsilon_1^C \quad \text{and} \quad \frac{P_2 - C_2}{P_2} = -1/\varepsilon_2^C \tag{8}$$

where C_i $(i = 1, 2)$ is the marginal cost for supplier i at the output level Q_i $(i = 1, 2)$ and $-1/\varepsilon_i^C$ $(i = 1, 2)$ is the inverse elasticity of the net-of-forward market obligations residual demand curve for that residual demand realization.

Recall from Section 3 that the inverse elasticity of the net-of-forward market obligations residual demand curve at price P_i and forward market obligation Q_C is equal to:

$$-1/\varepsilon_i^C = \frac{DR_i(P_i) - Q_C}{P_i} \times \frac{1}{DR_i'(P_i)} = (-1/\varepsilon_i)\frac{DR_i(P_i) - Q_C}{DR_i(P_i)}, \qquad i = 1,2 \tag{9}$$

The first equality defines this inverse elasticity and the second demonstrates that it is equal to the inverse elasticity of the residual demand curve multiplied by the firm's exposure to short-term market prices. This exposure is measured by difference between the supplier's short-term market sales, $DR_i(P_i)$, and its forward market obligations, Q_C, divided by its short-term market sales.

Using this definition of the inverse elasticity net-of-forward market obligations, the two equations in (8) can be rearranged to equal:

$$P_i = C_i - \frac{DR_i(P_i) - Q_C}{DR_i'(P_i)}, \quad i = 1, 2 \tag{10}$$

Equation (10) implies that if an expected profit-maximizing supplier has fixed-price forward market obligations, the market-clearing price is equal to the marginal cost of the highest cost generation unit operating during that half-hour owned by the supplier plus the value of the net-of-forward market obligations residual demand curve, $DR_i^C(P_i) = DR_i(P_i) - Q_C$, divided by the slope of this residual demand curve.

Define η_i^C $(i = 1, 2)$, the net inverse semi-elasticity of the net-of-forward market obligations residual demand curve i, as:

$$\eta_i^C = -\frac{1}{100}\frac{DR_i^C(P_i)}{DR_i^{C\prime}(P_i)} = \eta_i \times \frac{DR_i(P_i) - Q_C}{DR_i(P_i)} \tag{11}$$

The first equality defines η_i^C in terms of the net of fixed-price forward market obligations residual demand curve. The second equality demonstrates that it is equal to the inverse semi-elasticity of the residual demand multiplied by the supplier's exposure to short-term prices. This value of η_i^C gives the \$/MWh increase in the market-clearing price associated with a one percent reduction in the net position of the supplier (the difference between its short-term market sales and its fixed-price forward market obligations). In terms of this notation, equation (10) becomes

$$P_i = C_i + 100\eta_i^C, \quad i = 1, 2 \tag{12}$$

This equation demonstrates that the simplified model of expected profit-maximizing offer behavior with fixed-price forward market obligations implies that higher offer prices and higher market-clearing prices are linearly related to higher values of the inverse semi-elasticity of the net-of-fixed-price forward market obligations residual demand curve, after controlling for the opportunity cost of the highest cost generation unit in that supplier's portfolio of generation units operating during that half-hour period, C_i in equation (12).

241. To compute the half-hourly value of the inverse semi-elasticity of the net-of-forward market obligations residual demand curve for each of the four largest suppliers, we use the second equality in equation (11), which computes it by multiplying the inverse semi-elasticity of the residual demand curve by that supplier's exposure to short-term wholesale prices at the market-clearing price P^*, $DR(P^*) - Q_C$, divided by the supplier's short-term market sales, $DR(P^*)$. This approach to computing η_i^C ensures that the same estimate of the slope of the step-function residual demand curve is used to compute both η_i and η_i^C.

242. As discussed in Section 3, the assumptions required for the validity of the simplified model of expected profit-maximizing offer behavior with fixed-price forward market obligations do not hold because suppliers submit non-decreasing step functions rather than increasing continuous functions as their willingness-to-supply curves. It is important to emphasize that even if the assumptions necessary for the strict validity of the simplified model of expected profit-maximizing offer behavior do not hold, η_i^C is still a valid measure of the half-hourly incentive of a supplier to exercise unilateral market power. It equals the $/MWh increase in the market-clearing price that results from the net position being reduced by 1% relative to the supplier's actual net position during that half-hour. As shown in equation (11), this measure depends on the half-hourly offer curves of all other suppliers, the supplier's short-term market sales, and net quantity of its fixed-price forward market obligations.

4.2.2.2 Comparison of behavior of net inverse semi-elasticities for the four large suppliers

243. Figure 4.7 graphs the 30-day moving average or smoothed values of the net inverse semi-elasticities over the sample period of January 1, 2001 to June 30, 2007 computed as described above. For the value of Q_C in equation (11), we use the half-hourly value of the retail load obligation of that supplier. As noted in Section 2, there is a small, but sometimes important, fixed-price forward contract market in New Zealand. However, we only have data on fixed-price forward contract obligations and commitments of the four major suppliers for the periods January 1, 2001 to July 31, 2005. As also shown in Section 2, a very small fraction of the total retail load served by each of the large suppliers is sold at a price that varies with the half-hourly wholesale price. The half-hourly quantity of variable price retail loads is only available for the period January 1, 2001 to July 31, 2005 for two of the four large firms. Consequently, total retail load served is the only half-hourly data available for all four suppliers that can serve as a proxy for their fixed-price forward market obligations.

244. Figure 4.8 plots the 30-day moving average of $\eta_{hd}^C(firm)$, the half-hourly unweighted average of the four values η_{ihd}^C for Genesis, Contact, Meridian, and Mighty River Power.[44] To assess the impact of including our best estimates of the net fixed-price forward contract position of each of the suppliers on our net inverse semi-elasticity

[44] The 30-day moving average of the half-hourly values of the unweighted average of the four values η_{ihd}^C for Genesis, Contact, Meridian, and Mighty River Power equals $\eta_{hd}^C(firm) = \sum_{i=1}^{4} \eta_{ihd}^C$.

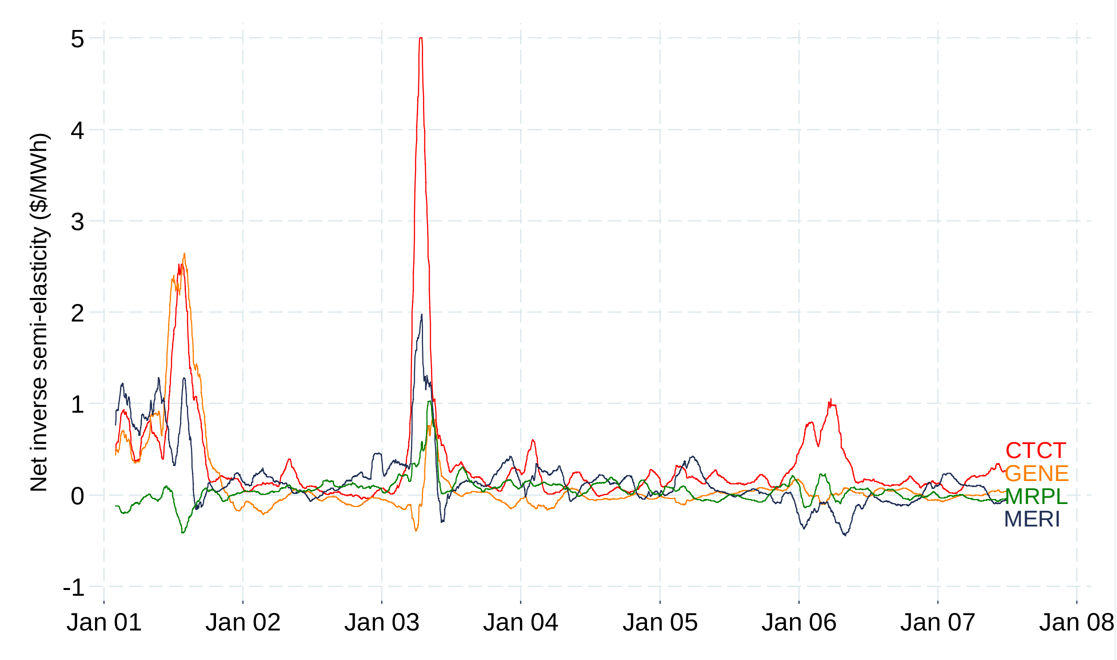
estimates, Figure 4.8 also plots the 30-day moving average of $\eta_{hd}^{C}(firm)$ over the shorter sample period, January 1, 2001 to July 31, 2005, with the value of Q_C equal to the sum of the supplier's fixed-price retail load obligation and its net position in the fixed-price forward contract market.

245. We estimate a supplier's net position in the fixed-price forward market obligations as follows. Suppose that $QF_h(sold)$ equals the fixed-price forward contracts sold by that supplier and $QF_h(bought)$ equals the fixed-price forward contracts bought by that supplier to clear during the half-hour period h. The supplier's net position in fixed-price forward contracts during half-hour period, NPF_h, is equal to $QF_h(sold) - QF_h(bought)$. The value of Q_C used to compute the net inverse semi-elasticities for the January 1, 2001 to July 31, 2005 time period shown in Figure 4.8 is equal to the sum of that supplier's half-hourly retail load obligation and the value of its net position in fixed-price forward contracts, NPF_h. Consistent with the discussion of Section 2, which showed that during most time periods, the net holdings of fixed-price forward contract obligations by the four large suppliers is very small relative to their retail load obligations, these two measures of the average unilateral incentive of the four suppliers to exercise unilateral market power follow a very similar pattern over the period January 1, 2001 to July 31, 2005.

246. Figure 4.7 demonstrates the mitigating influence of fixed-price forward contracts on the ability of the four suppliers to exercise unilateral market power. All of the inverse semi-elasticities of the residual demand curve are reduced significantly in absolute value as a result of multiplying them by the half-hourly value of the net exposure of the supplier to short-term prices, $(DR_i(P_i) - Q_C)/DR_i(P_i)$. This net exposure can be negative if the supplier sells less in the short-term market than its fixed-price forward market obligations, Q_C. This explains why some of the smoothed values of η_i^C are negative for certain suppliers during portions of the sample period. The supplier that is most often net long is Contact, which was net long in 93% of the half-hour periods of our sample. As shown in Figure 4.7, Contact maintained a significant incentive to raise prices during mid-2001, early 2003, and early 2006.

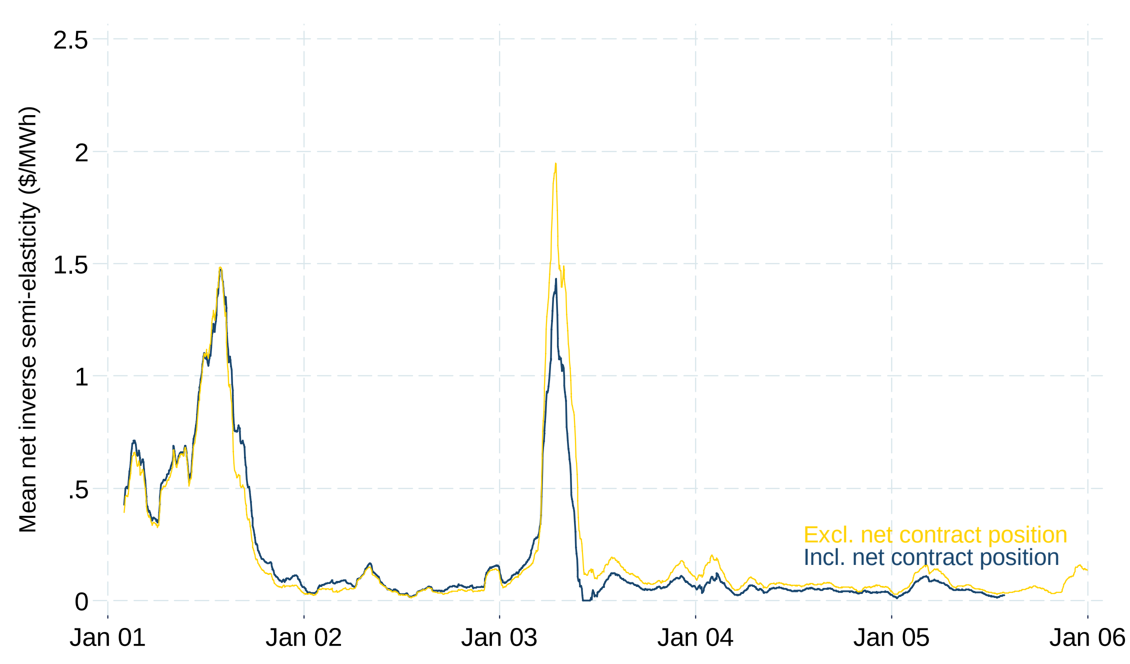
247. Figure 4.7 also helps to explain the slightly longer period of higher prices that prevailed during mid-2001 versus early 2003. During mid-2001 three of the four suppliers in this analysis had a significant incentive to raise market prices as measured by the value of η_i^C, the inverse semi-elasticity of the net-of-forward market obligations residual demand curve. Only Mighty River Power was net short relative to its forward market obligations during a portion of the mid-2001 period. The largest retailer at the time, NGC, was also net short relative to its retail load obligations in 2001.

Figure 4.7: Half-hourly net inverse semi-elasticities by firm, 30-day rolling average



Source: Calculations based on offer and generation data from Centralised Data Set and EMS, firm-level settlement data from EMS, and dispatch data from M-Co.

Figure 4.8: Mean net inverse semi-elasticities with and without forward contracts



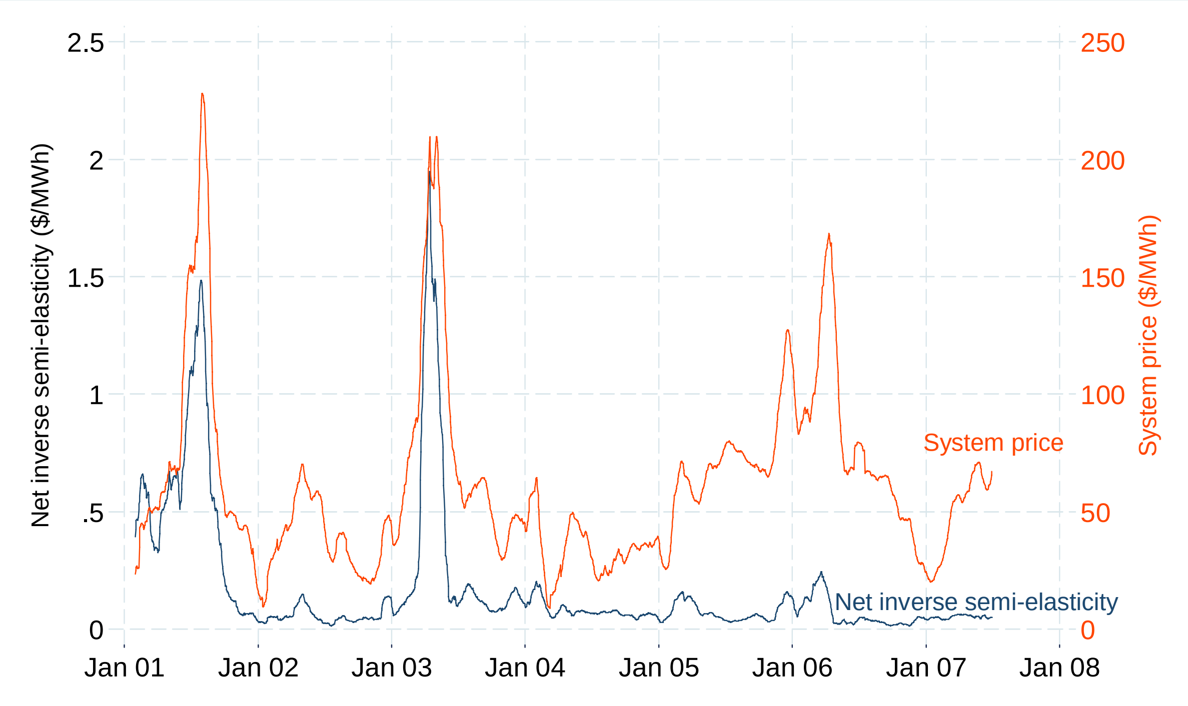
Source: Calculations based on offer and generation data from Centralised Data Set and EMS, firm-level settlement data from EMS, dispatch data from M-Co, and contract data from individual firms.

248. As shown in Figure 4.3, all four suppliers had more than double the ability to exercise unilateral market power in early 2003 relative to mid-2001, as measured by smoothed half-hourly semi-elasticities during the two time periods. Only Contact translated this larger ability into a large incentive to raise short-term prices as measured by the value of η_i^C. Following their acquisition of NGC's retail customer base, both Meridian and Genesis had a greatly reduced incentive to raise short-term prices during early 2003 relative to ability to raise market price during this time period as measured by the values of η_i and η_i^C that prevailed for these two suppliers. For example, the average values of η_i^C for Genesis during early 2003 were less than half of what they were during mid-2001. Consequently, one explanation for the slightly longer period of higher prices that prevailed during mid-2001 is the fact that a larger number of suppliers had a significant incentive to exercise unilateral market power during mid-2001, versus early 2003, when only a single supplier, Contact, had a substantial incentive to exercise unilateral market power.

4.2.2.3 The relationship between market-clearing prices and the incentive of the four large suppliers to exercise unilateral market power

249. Figure 4.9 plots the 30-day moving average of the half-hourly values of the quantity-weighted average of the nodal prices and a 30-day moving average of the half-hourly values of mean net inverse semi-elasticities. Figure 4.9 shows that the time series pattern of $p_{hd}(avg)$, the quantity-weighted average of the nodal prices for half-hour h of day d, closely tracks the time series pattern of the mean of net inverse semi-elasticities. During the half-hour periods when this average index of the incentive of these suppliers to exercise unilateral market power is larger, the quantity-weighted average of the nodal prices is high. Specifically, during mid-2001, early 2003, and early 2006 the average index of the incentive of suppliers to exercise unilateral market power is high and the quantity-weighted average nodal price is high. Conversely, during periods when the average index of the incentives of these suppliers to exercise unilateral market power is close to zero, the smoothed quantity-weighted average of the nodal prices is significantly lower. This occurs during 2002, 2004, and 2005. As we show in Section 5 and 6, during the half-hour periods when the unilateral incentive of these suppliers to exercise market power is very small in absolute value, market prices reflect little exercise of market power, and during the periods when the average firm-level incentive to exercise market power is large in absolute value, market prices reflect the exercise of significant unilateral market power.

Figure 4.9: Mean net inverse semi-elasticities and system price, 30-day rolling average



Source: Calculations based on offer and generation data from Centralised Data Set and EMS, price data from Centralised Data Set, firm-level settlement data from EMS, and dispatch data from M-Co.

4.2.2.4 Market prices, the average firm-level ability and incentive to exercise unilateral market power, and water levels

250. To assess the extent to which the relationship in Figure 4.5 (between the firm-level mean inverse semi-elasticities and the quantity-weighted average nodal prices) and the relationship in Figure 4.9 (between between the firm-level mean net inverse semi-elasticities and the quantity-weighted average nodal prices) is due to variations in water storage levels rather than variation in the ability and incentive of the four large suppliers to exercise unilateral market, Figures 4.10 and 4.11 present plots of the 30-day moving average of the mean inverse semi-elasticities and water storage levels (Figure 4.10) and the mean net inverse semi-elasticities and water storage levels (Figure 4.11). These figures show that water storage levels are falling during the 2001, 2003 and 2006 periods when the inverse elasticities and inverse semi-elasticities are high and increasing, so low water storage levels appear to be a contributing factor to higher market prices during these time periods. However, as is demonstrated in the empirical analysis of firm-level offer price behavior presented below, not all price increases during these periods can be attributed to a higher opportunity cost of water caused by low water storage levels.

251. To understand the relative contribution of water levels versus the ability and incentive to exercise unilateral market on the behavior of prices during each of the three periods of high prices in Winter 2001, Autumn 2003 and Summer 2006, the following higher resolution analysis is performed for each time period. Looking at these time intervals with a higher resolution can help to determine the relative contribution of hydro storage

levels versus the ability and incentive of the four large suppliers to exercise unilateral market power to changes in the level of market prices during each of these time periods.

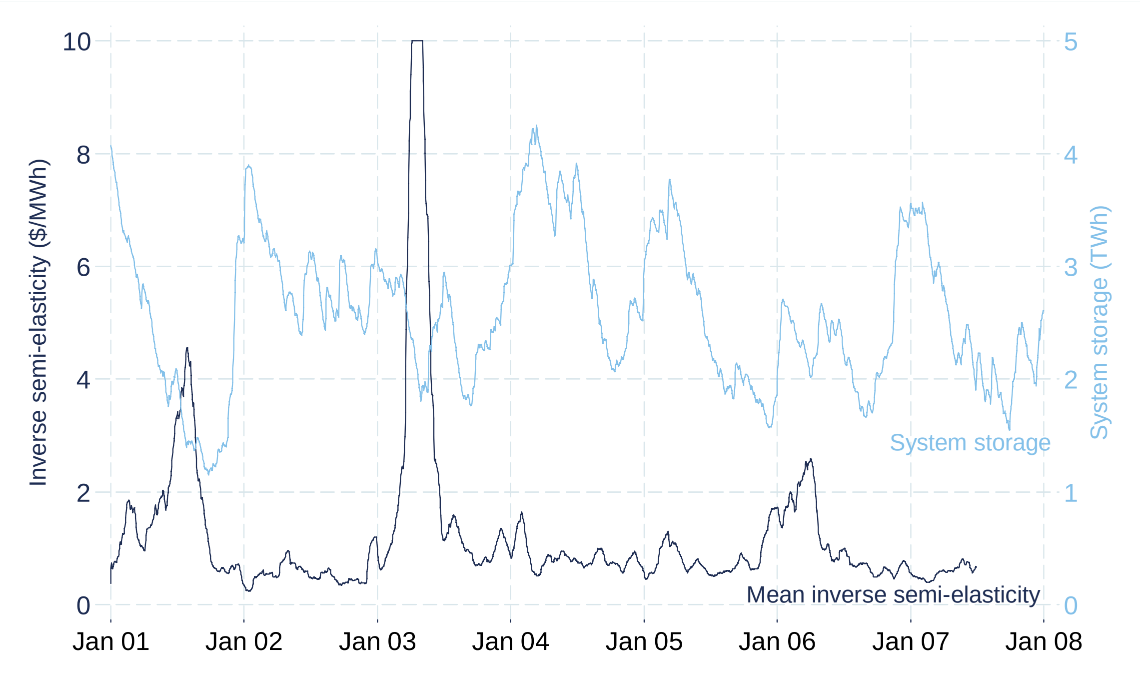
252. To show the three series—market prices, water storage levels, and the average firm-level ability or incentive to exercise unilateral market power—on the same graph, we first normalize them to an index in which 100 is the mean of each series for the entire sample period from January 1, 2001 to June 30, 2007. For example, if the mean of the quantity-weighted average of the half-hourly nodal prices over all half-hours in the sample is \$60/MWh, then this price index will have a value of 50 in periods when the price is \$30/MWh and 200 in periods when the price is \$120/MWh. Similarly, values of the hydro storage index below 100 correspond to days when the storage level is below the average for the whole sample. The same process applies to the firm-level mean of the half-hourly inverse semi-elasticities and inverse net semi-elasticities. When the value of the index is equal 200, the value of the firm-level mean index of the ability or incentive to exercise unilateral market power is equal to twice its sample mean. Each of the three series is smoothed with a weekly (seven-day) moving average. For the variables measured on a half-hourly basis each smoothed value is an average of 336 (= 7 x 48) values. For the daily water storage levels, each smoothed value is an average of 7 values.

253. Figure 4.12 plots these three variables for the Winter 2001 time period with a natural logarithm scale (log scale) for the vertical axis because of the large amount of variation in prices over this time period. The mean of the firm-level inverse semi-elasticities and system average prices closely track each other over this time period. On the other hand, the hydro storage level shows a downward trend over this time period which is inconsistent with the prices first rising and then falling, as is also the case for the mean firm-level inverse semi-elasticities. Figure 4.13 plots these three variables for the Autumn 2003 time period using the same log scale for the vertical axis. Once again, the mean firm-level inverse semi-elasticities and system average prices closely track each other over this time period. The values of the hydro storage levels are roughly constant over this period, which is inconsistent with the rise and fall of prices during this period. Figure 4.14 repeats this same plot for the Summer 2006 period. Once again fluctuations in the half-hourly mean inverse semi-elasticities appear to track movements in the system prices, whereas water levels are roughly flat throughout the period after a slight increase at the start of the period. The evidence in Figures 4.12 to 4.14 suggests that even after controlling for the impact of water storage levels, the half-hourly value of the mean firm-level ability to exercise unilateral market power is an important predictor of the level of half-hourly prices during these three high-priced periods.

254. Figures 4.15 to 4.17 repeat the plots in Figures 4.12 to Figure 4.14 for the mean firm-level net inverse semi-elasticities. Because the mean firm-level net inverse semi-elasticities can be negative, without some transformation to make of them positive, our indexing procedure would not have the same meaning for the three variables plotted in the figures. Negative values of the index would only be possible for one variable. Adding 1 to each of the firm-level half-hourly net inverse semi-elasticities is sufficient to make all of the transformed (by adding 1) mean firm-level net inverse semi-elasticities greater than zero. The normalized index for these transformed (by adding 1) mean firm-level net inverse semi-elasticities is computed in same manner as described above. The sample

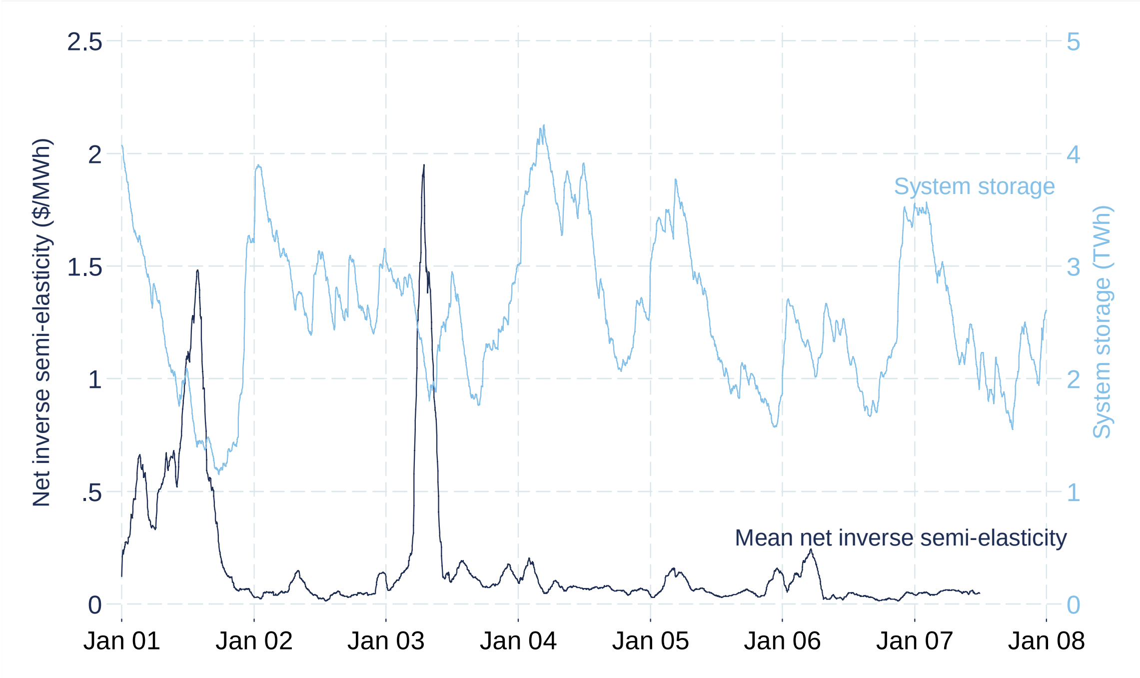
mean of this variable is computed and each half-hourly observation is divided by this magnitude and multiplied by 100. Figure 4.15 finds that the index of the average firm-level incentive to exercise unilateral market power closely tracks the quantity-weighted average of half-hourly nodal prices over Winter 2001. A similar conclusion holds for Autumn 2003, as shown in Figure 4.16. Finally, Figure 4.17 finds that higher values of the average index of the firm-level level incentive to exercise unilateral market power are associated with higher values of system prices during Summer 2006, although the relationship between the average of firm-level indexes of the incentive to exercise unilateral market power and system price is not as clear as it is for the two earlier periods. In contrast, except for the start of this time period, hydro storage levels and system prices appear to be largely unrelated. The results in Figures 4.15 to 4.17 suggests that even after controlling for the impact of water storage levels, values of the mean firm-level incentive to exercise unilateral market power is an important predictor of the level of prices during these three high-priced periods.

Figure 4.10: Hydro storage and mean inverse semi-elasticities, 30-day moving average



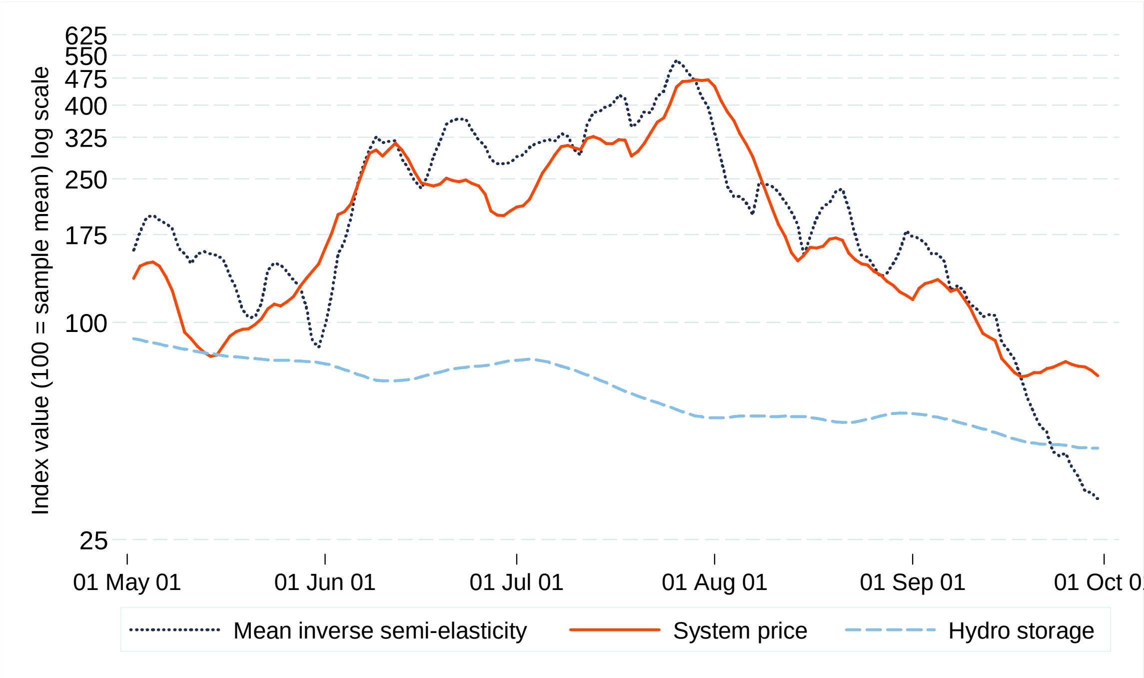
Source: Calculations based on offer data from Centralised Data Set and EMS, dispatch data from M-Co, and COMIT Hydro (M-co).

Figure 4.11: Hydro storage and mean net inverse semi-elasticities, 30-day moving average



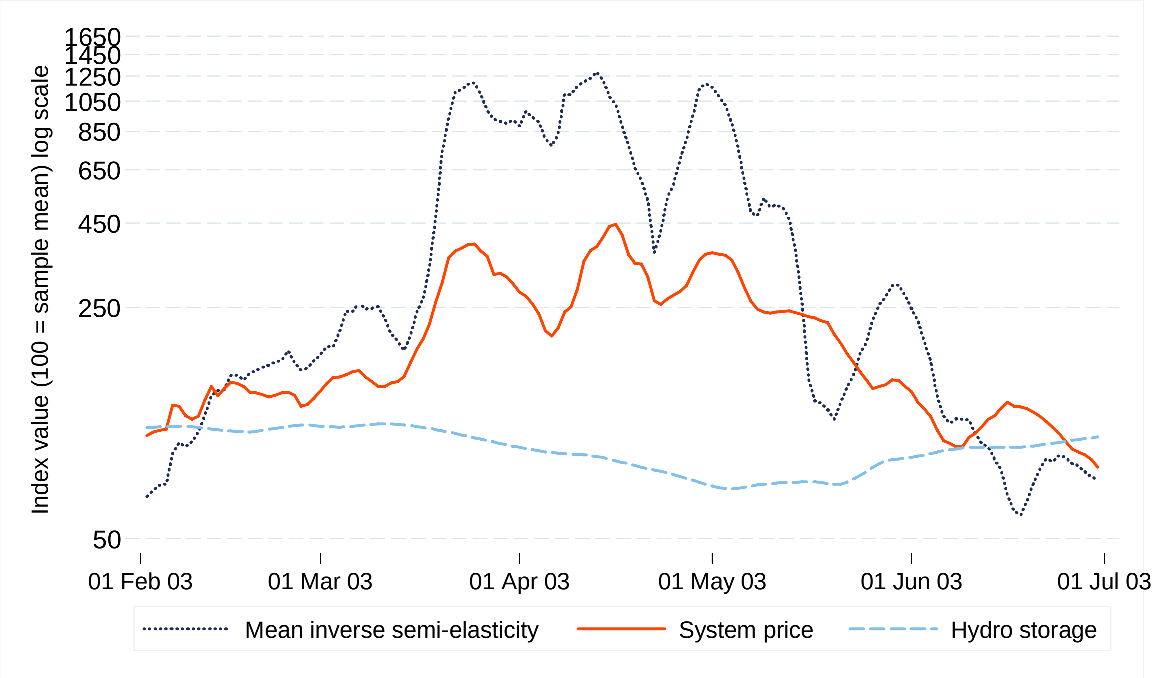
Source: Calculations based on offer data from Centralised Data Set and EMS, dispatch data from M-Co, firm-level settlement data from EMS, and COMIT Hydro (M-co).

Figure 4.12: Price, mean inverse semi-elasticity and hydro storage, Winter 2001



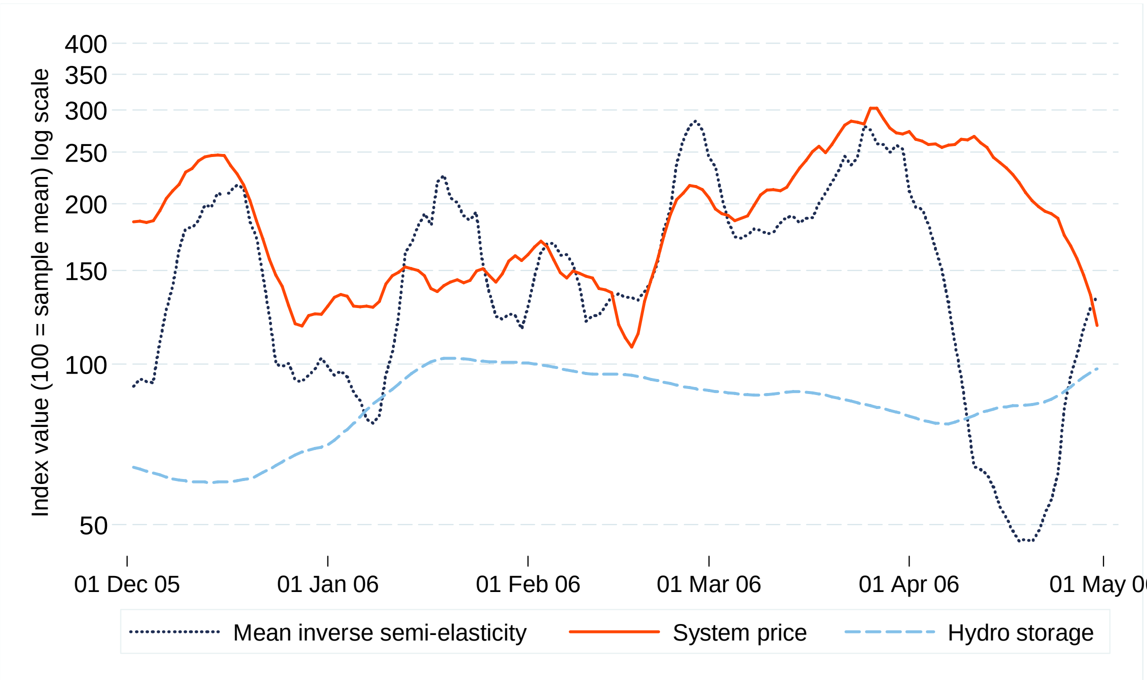
Source: Calculations based on offer and generation data from Centralised Data Set and EMS, price data from Centralised Data Set, dispatch data from M-Co, and COMIT Hydro (M-co). Graph shows 7-day moving average.

Figure 4.13: Price, mean inverse semi-elasticity and hydro storage, Autumn 2003



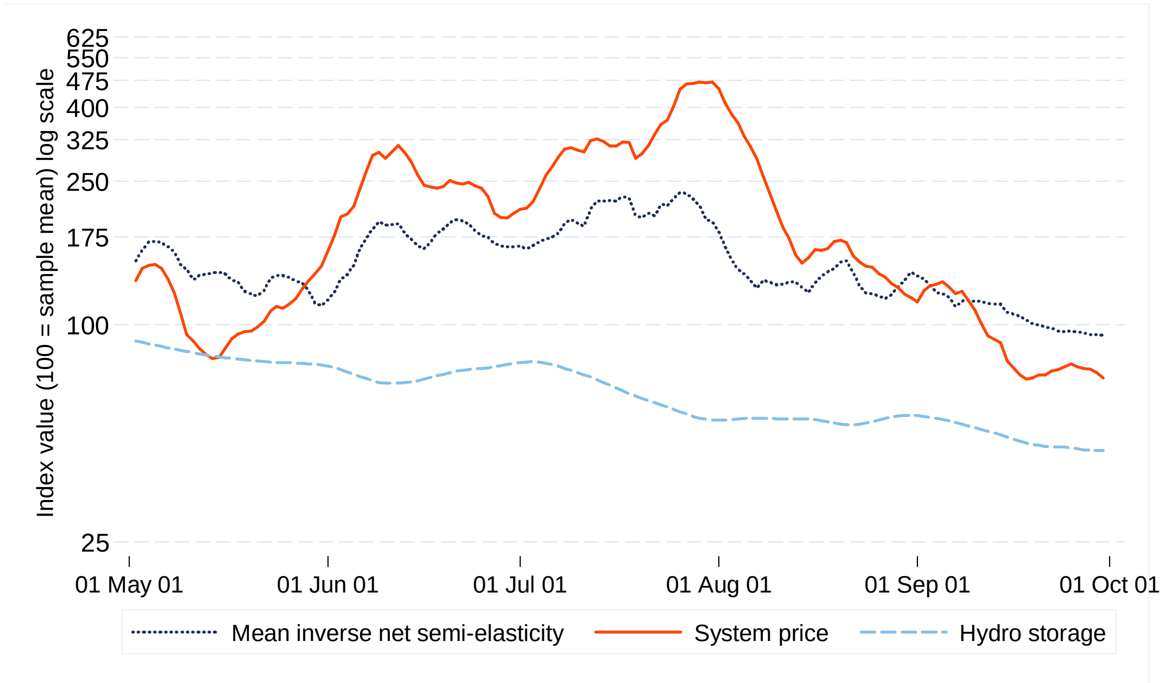
Source: Calculations based on offer and generation data from Centralised Data Set and EMS, price data from Centralised Data Set, dispatch data from M-Co, and COMIT Hydro (M-co). Graph shows 7-day moving average.

Figure 4.14: Price, mean inverse semi-elasticity and hydro storage, Summer 2006



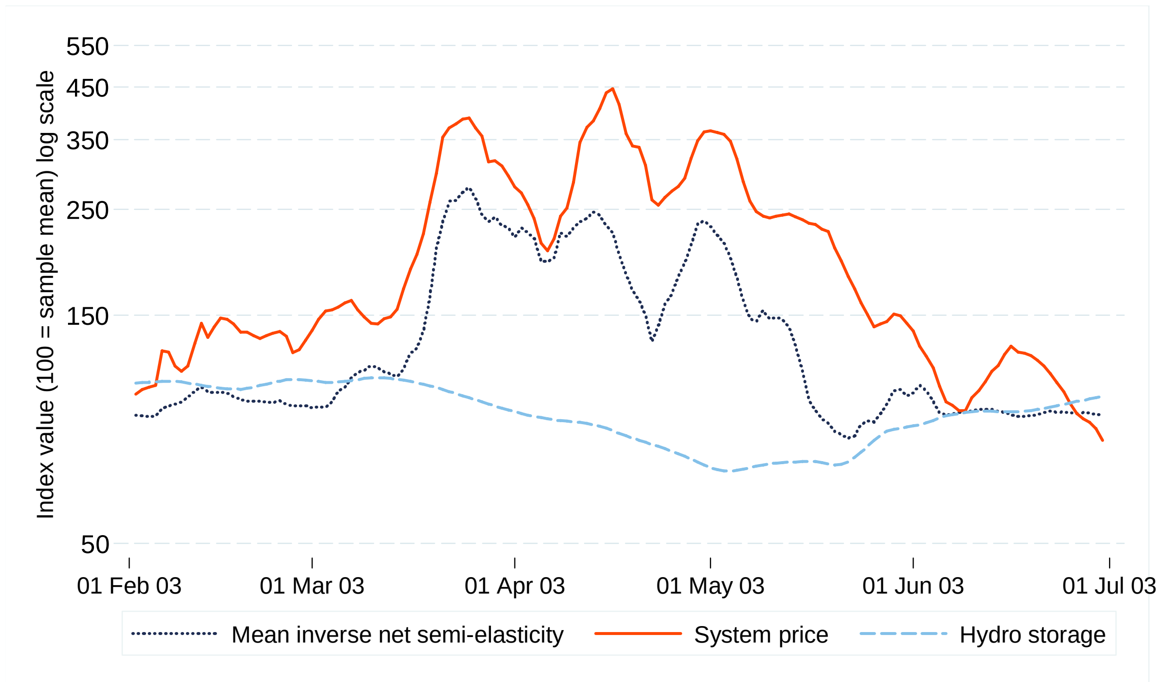
Source: Calculations based on offer and generation data from Centralised Data Set and EMS, price data from Centralised Data Set, dispatch data from M-Co, and COMIT Hydro (M-co). Graph shows 7-day moving average.

Figure 4.15: Price, mean net inverse semi-elasticity and hydro storage, Winter 2001



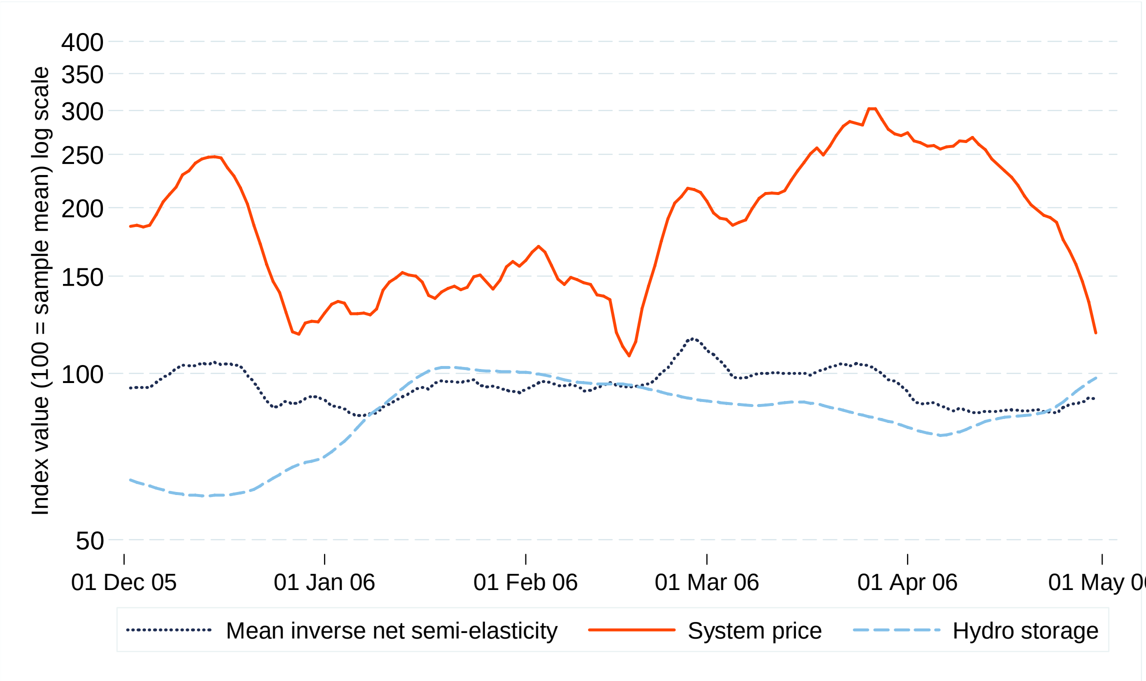
Source: Calculations based on offer and generation data from Centralised Data Set and EMS, price data from Centralised Data Set, firm-level settlement data from EMS, dispatch data from M-Co, and COMIT Hydro (M-co). Graph shows 7-day moving average.

Figure 4.16: Price, mean net inverse semi-elasticity and hydro storage, Autumn 2003



Source: Calculations based on offer and generation data from Centralised Data Set and EMS, price data from Centralised Data Set, firm-level settlement data from EMS, dispatch data from M-Co, and COMIT Hydro (M-co). Graph shows 7-day moving average.

Figure 4.17: Price, mean net inverse semi-elasticity and hydro storage, Summer 2006



Source: Calculations based on offer and generation data from Centralised Data Set and EMS, price data from Centralised Data Set, firm-level settlement data from EMS, dispatch data from M-Co, and COMIT Hydro (M-co). Graph shows 7-day moving average.

4.2.3 Conclusion on market outcomes and unilateral ability and incentive to exercise market power

255. This section has shown that both the ability and incentive of all four of these suppliers to exercise unilateral market power are positively correlated with market-clearing prices and that this correlation cannot be explained only by changes in hydro storage levels. The ability to exercise unilateral market power is clearly a necessary condition for a supplier to exercise unilateral market power because a supplier must face a downward-sloping residual demand curve to be able to raise market prices by withholding its output. However, even a supplier with a substantial ability to exercise unilateral market power may not exploit this ability unless it has an incentive to do so. As noted above, the difference between a supplier's short-term market sales and its fixed-price forward market obligations determines the supplier's incentive to exercise unilateral market power.

256. A risk-neutral supplier can be expected to take on fixed-price forward market obligations to the extent that it can sell energy at higher prices as forward contract obligations or retail load obligations than it expects to be able to sell this energy in the short-term market. If buyers of electricity are risk-averse, then they can be expected to be willing to pay more for a fixed-price forward market commitment for their electricity needs than the expected short-term market price. If suppliers are risk-averse, they will also be willing to sell forward market obligations at the same or lower prices than they expect to sell in the short-term market.

257. Regardless of a supplier's risk preferences, if it has a significant ability to exercise unilateral market power then it is unlikely to enter into sufficient fixed-price forward market obligations to eliminate completely its incentive to exercise unilateral market power. However, in a hydroelectric-energy-dominated system, risk-averse suppliers can be expected to sign sufficient fixed-price forward market obligations in advance of delivery to ensure that they will earn enough revenues selling wholesale electricity to cover their costs even during a year when there is plenty of hydroelectric energy available from a number of suppliers and short-term wholesale prices are low as a result.

258. Suppliers that also own significant amount of fossil fuel generation units face a different incentive (from those that primarily own hydroelectric energy units) to hedge their short-term price risk because when there are low water conditions in the system, these suppliers know that their fossil units will be needed to supply additional energy. Consequently, these suppliers can be expected to sign enough fixed-price forward market obligations to allow them recover their total operating costs in low water years, but not so many fixed-price forward market obligations so as to eliminate their incentive to exercise unilateral market power if their fossil fuel units are needed to operate at a high level during a low water year.

259. This difference in the short-term hedging strategy of suppliers with mostly hydroelectric units and those with significant fossil fuel units is consistent with the observed relationship between market prices and the observed incentive of suppliers to exercise unilateral market power. Note that even though Meridian, which has the largest capacity share and owns only hydroelectric capacity and a small wind facility, has by far the largest ability to exercise unilateral market power as measured by the inverse semi-elasticities shown in Figures 4.3 and 4.4. These figures also show that Contact, which has a significant amount of fossil fuel-fired generation capacity, is a distant second in terms of its ability to exercise unilateral market power. However, in terms of its incentive to exercise unilateral market power, Figure 4.7 shows that Contact is substantially higher than the other three suppliers during the three periods shown in Figure 4.9 when market prices were high.

4.3 Offer behavior and ability and incentive to exercise market power—two approaches

260. The previous section has demonstrated that the ability and incentive to exercise unilateral market power is very highly correlated with the level of market prices. This section explores the extent to which this relationship is due to suppliers exercising unilateral market power by raising their offer prices during periods when they have an increased ability and incentive to exercise market power. As discussed in Section 3 and demonstrated rigorously in Box 1 and Box 3 in Section 4.2, the theory of expected profit-maximizing offer behavior implies that suppliers exercising all available unilateral market power will submit higher offer prices for the same level of output when they have a greater ability and incentive to exercise unilateral market power. This section provides empirical confirmation for this implication of expected profit-maximizing behavior.

261. We find that after controlling for differences across days of the sample and half-hours of the day or half-hours of the day during each month of our sample period in an individual supplier's opportunity cost of producing electricity from their generation units, higher values of three different indexes of a supplier's ability to exercise unilateral market power are associated with higher offer prices for the quantity of energy dispatched during that half-hour period by that supplier. A similar statement holds for three analogous indexes of the supplier's unilateral incentive to exercise market power. After controlling for differences in the opportunity cost of the highest cost unit owned by that supplier operating in half-hour periods over time, higher values of each index of the incentive to exercise unilateral market power are associated with higher offer prices for the quantity of energy dispatched during that half-hour period by that supplier.

262. The absolute values of the coefficient estimates for the relationship between the firm-level offer price and firm-level incentive of a supplier to exercise unilateral market power are uniformly larger higher for all market participants than the corresponding coefficients estimates for the relationship between the firm-level offer price and firm-level ability to exercise unilateral market power measure. This outcome is consistent with the discussion in Section 3 that the incentive to exercise unilateral market power is the key determinant of a supplier's offer price if it has significant fixed-price forward market obligations, as is the case for all of four large suppliers under consideration.

263. We then examine whether a supplier being is pivotal or net pivotal, as described in section 3.4, is associated with that supplier submitting a higher offer price. We find that when a supplier is a pivotal its offer prices are higher by economically significant magnitudes. Similar results hold for being net pivotal for the three suppliers that are net pivotal beyond a trivial fraction of the half-hours of our sample period.

4.3.1 Approach 1: Offer behavior and ability and incentive to exercise unilateral market power

264. This section presents our analysis of the half-hourly relationship between a supplier's offer price and an index of its ability or its incentive to exercise unilateral market power, after controlling for daily fossil fuel prices and water storage levels.

4.3.1.1 Approach

265. In order to describe our empirical analysis a definition of a supplier's half-hourly offer price is required. Figure 4.18 presents the actual offer curve for Meridian on February 10, 2006 for half-hour period 16. The actual amount of energy sold by Meridian during that hour is 1,508 MW. The offer price along Meridian's willingness-to-supply curve for that half-hour period is found by extending a vertical line up from the horizontal axis at 1,508 MW until it intersects Meridian's willingness-to-supply curve. In this case, the offer price for the actual quantity sold by Meridian is equal to \$145/MWh, which is the offer step directly above the quantity level 1508 MW. In general, the offer price for output level Q^* for supplier k during half-hour period h is computed as the solution to the following equation in P, $Q^* = S_{hk}(P)$, where $S_{hk}(P)$ is supplier k's willingness-to-supply curve during half-hour period h.

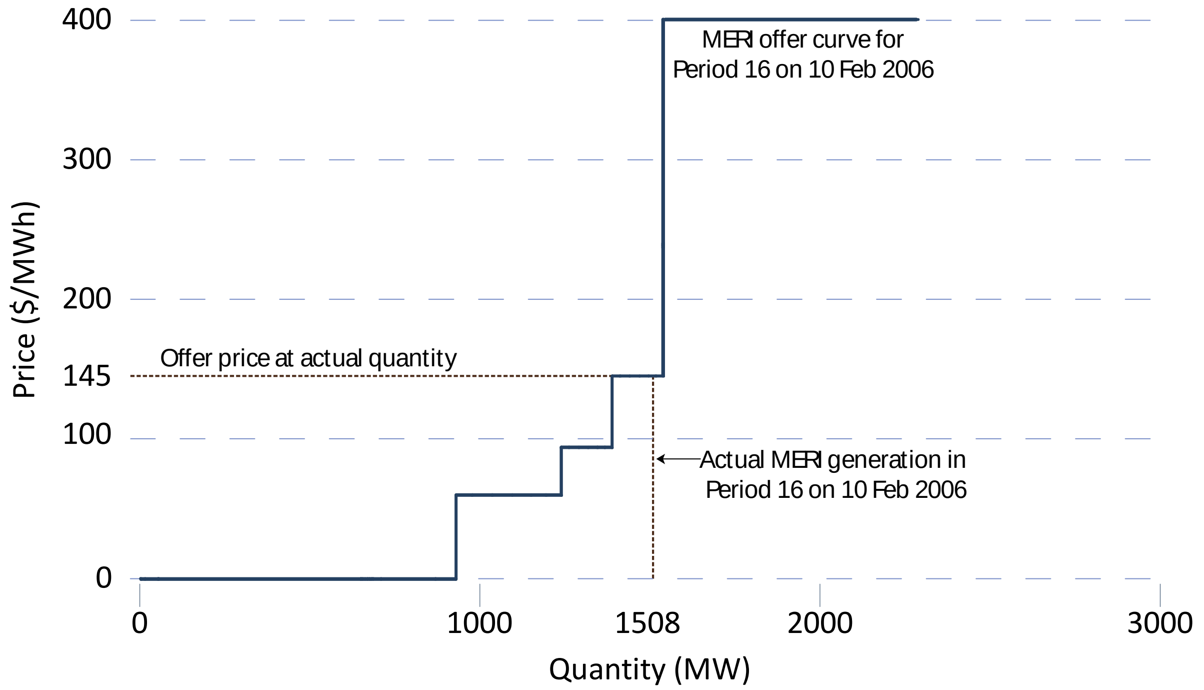
266. As equation (5) in Box 1 and equation (12) in Box 3 in Section 4.2 demonstrate, the simplified model of expected profit-maximizing offer behavior by a supplier facing a distribution of downward sloping residual demand curves implies that, after controlling for the opportunity cost of the highest cost generation unit operating during that half-hour period (the term C_i in these two equations), a supplier's offer price at the quantity of energy that it sells in the short-term market should be an increasing function of the value of the inverse semi-elasticity, if the supplier has no fixed-price forward market obligations, and increasing in the net inverse semi-elasticity if the supplier has fixed-price forward market obligations.

267. Although the conditions necessary for the strict validity of the simplified model of expected profit-maximizing offer behavior outlined in Section 3 do not hold for the New Zealand market, we still expect that when a supplier has a greater unilateral ability or incentive to exercise unilateral market power, after controlling for its opportunity cost of selling energy from its highest cost generation unit operating during that half hour, the offer price it sets for the amount of energy that it sells in the short-term market should be higher.

268. Let $P_{jhdm}(actual)$ equal the offer price at the actual level of output sold by supplier j during half-hour h of day d during month of sample m, η_{jhdm} the inverse semi-elasticity of supplier j's residual demand curve during half-hour h of day d during month of sample m and η^C_{jhdm} the inverse net semi-elasticity of supplier j's net-of-forward-market-obligation residual demand curve during half-hour h of day d during month of sample m. We take two approaches to controlling for differences across half-hours during our sample period in the variable cost of the highest cost generation unit owned by that supplier operating during that half-hour period. The first approach assumes that this variable cost can be different for each supplier for every day during our sample period and each half-hour during the day. The following regressions are estimated for each supplier j:

$$P_{jhdm}(offer) = \alpha_{dm} + \tau_h + \beta_j \times \eta_{jhdm} + \varepsilon_{jhdm}, \text{ and}$$
$$P_{jhdm}(offer) = \gamma_{dm} + \mu_h + \delta_j \times \eta^C_{jhdm} + \nu_{jhdm} \tag{13}$$

Figure 4.18: Example showing calculation of offer prices



Source: Offer and generation data from Centralised Data Set.

where the α_{dm} and the γ_{dm} are day-of-the-month fixed effects for month m and the τ_h and μ_h are half-hour-of-the-day fixed effects. The ε_{jhdm} and ν_{jhdm} are mean zero and constant variance regression errors. These fixed effects completely account for the impact of daily changes in fossil fuel prices and water levels during our sample period on the variable cost of the highest cost generation unit owned by supplier j that is operating during each half-hour period in the day. The half-hourly fixed-effects account for differences across half-hours of the day in this variable cost. Data on input fossil fuel prices and water levels is available at most on a daily basis. Because the α_{dm} and γ_{dm} can differ each day of the month of each month during our sample period, they are exactly collinear with daily input fossil fuel prices and daily water levels. Consequently, these day-of-the month fixed-effects for each month of the sample completely control for any differences across days of the sample in input fossil fuel prices and water levels. This strategy for controlling for variable cost changes across half-hours of the sample implies more than 2,400 possible variable cost values over the sample period for each supplier. Multiplying this figure by four implies more than 9,600 possible variable costs of the highest cost generation unit operating during a half-hour that could set the market-clearing price during our sample.

269. Our second strategy for controlling for the opportunity cost of producing electricity from the highest variable cost unit operating during half-hour period-of-the-day h during month of the sample m for supplier j uses different half-hour-of-the-day fixed-effects for each month of the sample period. The two equations estimated are:

$$P_{jhdm}(offer) = \alpha_{hmj} + \beta_j \times \eta_{jhdm} + \varepsilon_{jhdm}, \text{ and}$$
$$P_{jhdm}(offer) = \gamma_{hmj} + \delta_j \times \eta^C_{jhdm} + \nu_{jhdm} \quad (14)$$

where α_{hmj} and γ_{hmj} are half-hour-of-the-day for each month-of-the-sample fixed-effects to control for the differences in the opportunity cost of producing electricity from the highest variable cost unit operating during half-hour period-of-the-day h during month-of-the-sample m for supplier j. The ε_{jhdm} and ν_{jhdm} are once again mean zero and constant variance regression errors. Because there are 48 half-hour periods in the day and 78 months during our sample period from January 1, 2001 to June 30, 2007, there are 48 x 78 = 3,744 values of the α_{hmj} and the same number of values of the γ_{hmj} for each supplier j. These fixed-effects imply that the variable cost of producing electricity from the highest cost generation unit operating during half-hour 12 in month 3 of the sample period can be different from this same variable cost during all other months of the sample period. Moreover, the variable cost of producing electricity from the highest cost generation unit operating during half-hour 12 in month 3 can differ from the variable cost of producing electricity in any other half-hour of any other month of the sample period, including month 3.

270. These fixed-effects allow for a substantial amount of variability in the time path of the variable cost of the highest cost unit operating in the North and South Island of New Zealand during each half-hour of our sample period. There are 3,744 fixed effects for each supplier to account for differences in the variable cost of the highest cost unit in their portfolio operating during each half-hour of the sample period. Multiplying this figure by 4 implies 14,976 different possible variable costs of the highest cost unit operating owned by the four large suppliers that could set prices during our sample period.

271. The fixed-effects in model (13) and model (14) should be more than sufficient to account for differences in the variable cost of the highest cost generation unit operating during each half-hour of the sample period in portfolio of generation units owned by each of the four large suppliers. The opportunity cost of producing electricity from hydroelectric generation units should not differ significantly across half-hours of the day or days of the month in a hydroelectric dominated system. The opportunity cost of water depends on current water storage levels and the distribution of future water inflows and outflows. New information about these variables arrives daily, but the best estimates of future inflows and outflows changes slowly, as do water storage levels. Our day-of-sample fixed effects are likely to be more than sufficient to account for changes in the opportunity cost of water over our sample period.

272. The variable cost of producing electricity from individual fossil fuel generation units is unlikely to change significantly during individual months of our sample period, which implies that fixed-effects that allow these half-hourly variable costs to change each month of the sample period should provide for far more fluctuations in the marginal cost of the highest cost unit producing electricity during each half-hour of our sample period than is likely to be necessary to capture the amount of variability that actually exists in these marginal costs. Regressions of model (14) including the value of the relevant daily fossil fuel price and daily water levels to account for daily changes in the variable cost of

operating fossil fuel generation units and daily changes in the opportunity cost of water did not quantitatively change any of our results. This outcome is not surprising given the high level of agreement between our estimates of β_j and δ_j using day-of-the-month fixed effects for each month of the sample and half-hour-of-the-day fixed-effects and different half-hour-of-the-day fixed effects for each month of the sample period.

4.3.1.2 Results of assessment of offer behavior and ability to exercise unilateral market power

273. Table 4.2 presents the estimated values of β_j (the coefficient associated with the ability measure) and δ_j (the coefficient associated with the incentive measure) and the estimated standard errors for each of the four suppliers using the day-of-month for each month of the sample and half-hour-of-the-day fixed-effects. Table 4.3 presents estimates of the same parameter values for the half-hour-of-the-day fixed effects for each month of the sample period models. The values of β_j and δ_j, the coefficients associated with the ability and incentive measures respectively, are positive, precisely estimated and economically meaningful for all regressions. Focusing on the day-of-sample and half-hour-of-the-day fixed-effects model, holding all other factors constant, if the residual demand curve faced by Contact has an inverse semi-elasticity that is one unit higher, the offer price associated with the amount of output that it sells in the short-term market is predicted to be \$1.41/MWh higher, because of the greater ability Contact has to exercise market power implied by the inverse semi-elasticity of its residual demand curve.

274. Table 4.4 computes the half-hourly sample mean and standard deviation of η_{jhdm} (the ability measure) for each h. For each supplier, a row of the table is the sample mean and sample standard deviation across all days and months of our sample period of the value η_{jhdm} for that half-hour of the day. This table can be used to demonstrate the economic significance of our estimates of β_j (the coefficient associated with the ability measure). For example, for Contact for half-hour 37, the standard deviation of η_{jhdm} is equal to 6.811. This implies that holding opportunity cost of water and the price of the input fossil fuel constant, a one standard deviation change in the value η_{jhdm} for half-hour 37 implies a \$9.60/MWh higher offer price and a two standard deviation change a \$19.20/MWh higher offer price according to the parameter estimates in Table 4.2. For Meridian, the mean and variance of the inverse semi-elasticities over the sample period are even higher. The value of β_j for Meridian implies that a one standard deviation change in the value of the inverse semi-elasticity of its residual demand curve during half-hour 24, holding all other factors constant, implies an offer price increase of approximately \$4.50/MWh. Changes of this size in the value of its inverse semi-elasticity for half-hour 24 for Meridian across days during our sample period are not unusual.

Table 4.2: Dependent variable = offer price at dispatch quantity for supplier *j*

	Contact	Genesis	Meridian	Mighty River
β_j	1.41	0.56	0.46	3.81
(s.e.)	(.031)	(.040)	(.017)	(.062)
R^2	0.457	0.446	0.695	0.490
δ_j	4.31	4.02	5.08	21.63
(s.e.)	(.101)	(.146)	(.108)	(.335)
R^2	0.456	0.449	0.699	0.491

Source: Calculations based on offer data from Centralised Data Set and EMS, firm-level settlement data from EMS, and dispatch data from M-Co.

Note: Day-of-sample and half-hour fixed effects are included in all regressions.

Table 4.3: Dependent variable = offer price at dispatch quantity for supplier *j*

	Contact	Genesis	Meridian	Mighty River
β_j	1.16	0.73	0.67	4.54
(s.e.)	(.029)	(.040)	(.020)	(.064)
R^2	0.473	0.386	0.521	0.415
δ_j	3.38	3.39	7.27	22.86
(s.e.)	(.092)	(.154)	(.129)	(.354)
R^2	0.472	0.387	0.530	0.410

Source: Calculations based on offer data from Centralised Data Set and EMS, firm-level settlement data from EMS, and dispatch data from M-Co.

Note: Month-of-sample interacted with half-hour fixed effects are included in all regressions.

Table 4.4: Half-hourly summary statistics for η_i - the ability measure - by firm

Half-hour	Contact		Genesis		Meridian		Mighty River	
	Mean	Std. dev.	Mean	Std. dev.	Mean	Std. dev.	Mean	Std. dev.
1	0.993	2.420	0.644	2.079	1.541	2.636	0.416	0.913
2	0.975	2.807	0.587	1.276	1.429	2.530	0.339	0.640
3	0.888	2.035	0.584	1.416	1.447	2.410	0.310	0.608
4	0.822	1.483	0.533	0.921	1.351	2.166	0.287	0.585
5	0.813	1.511	0.526	1.054	1.412	2.474	0.289	0.659
6	0.860	1.991	0.505	0.962	1.409	2.594	0.281	0.613
7	0.800	2.455	0.509	1.620	1.333	2.322	0.279	0.643
8	0.789	1.468	0.472	0.799	1.333	2.318	0.278	0.621
9	0.748	1.218	0.486	0.965	1.333	2.491	0.275	0.588
10	0.761	1.422	0.456	0.687	1.348	2.354	0.269	0.546
11	0.780	1.634	0.501	1.107	1.342	2.285	0.288	0.642
12	0.882	2.444	0.587	1.993	1.393	2.723	0.311	0.698
13	0.939	2.496	0.654	1.669	1.445	2.627	0.364	0.699
14	1.137	3.897	0.688	1.210	1.584	3.191	0.485	1.028
15	1.409	5.288	0.882	2.197	1.917	4.402	0.760	2.667
16	1.589	4.039	1.229	6.171	2.418	6.425	1.045	3.220
17	1.537	3.994	1.194	5.489	2.570	7.223	1.057	4.789
18	1.622	4.799	1.134	3.108	2.463	6.399	1.066	4.715
19	1.501	4.333	1.120	4.086	2.372	5.881	0.968	2.636
20	1.526	4.469	1.161	4.631	2.300	5.690	0.926	2.268
21	1.442	3.706	1.068	3.243	2.364	6.734	0.958	2.774
22	1.487	4.349	0.997	2.816	2.479	6.608	0.942	2.420
23	1.549	4.374	1.004	2.491	2.677	9.769	0.988	2.709
24	1.647	5.656	1.008	2.480	2.668	9.224	0.970	2.493
25	1.562	5.810	0.999	3.021	2.366	6.058	0.924	2.770
26	1.486	4.647	1.043	4.225	2.458	6.747	0.920	2.844
27	1.408	3.411	0.962	3.524	2.348	5.341	0.872	2.338
28	1.402	3.847	0.967	3.707	2.319	6.026	0.851	2.302
29	1.322	3.034	0.890	2.019	2.198	5.043	0.852	2.471
30	1.305	3.477	0.965	3.881	2.247	6.291	0.834	2.532
31	1.366	4.191	0.933	3.261	2.293	6.303	0.817	2.341
32	1.394	3.937	0.951	3.088	2.254	5.510	0.839	2.179
33	1.402	3.845	0.877	1.713	2.263	4.978	0.850	2.437
34	1.437	4.428	0.974	3.242	2.318	5.427	0.896	2.420
35	1.445	3.843	1.057	2.809	2.375	4.528	0.954	2.619
36	1.823	4.874	1.364	4.375	2.853	6.571	1.257	4.240
37	1.989	6.811	1.301	4.435	2.712	5.981	1.241	3.660
38	1.784	5.458	1.191	2.690	2.672	5.361	1.186	3.423
39	1.687	5.058	1.203	3.762	2.599	6.263	1.168	3.888
40	1.435	3.618	1.079	2.861	2.454	6.112	1.023	3.723
41	1.452	4.059	1.082	3.108	2.448	6.388	1.042	4.053
42	1.482	4.036	1.060	2.568	2.402	5.690	0.954	2.524
43	1.298	3.253	0.954	2.347	2.242	4.855	0.884	2.194
44	1.298	4.765	0.894	3.299	2.218	5.787	0.768	2.229
45	1.148	2.636	0.831	2.304	2.093	4.885	0.656	1.630
46	0.977	1.843	0.694	1.501	1.747	2.897	0.511	0.988
47	0.990	1.962	0.715	2.311	1.758	3.442	0.562	1.765
48	0.917	2.047	0.613	1.365	1.705	4.103	0.419	1.073

Source: Calculations based on offer data from Centralised Data Set and EMS, and dispatch data from M-Co.

275. For Mighty River Power the value of β is significantly higher than it is for all of the other suppliers, on the order of \$3.81/MWh. However, as shown in Table 4.4 the mean value of the inverse semi-elasticity is the lowest of all of the suppliers and the variance is also the smallest. Nevertheless, the magnitude of β for Mighty River Power implies that even for one standard deviation changes in the value of its inverse semi-elasticity, economically significant changes in Mighty River Power's offer price are predicted to occur because of its increased ability to exercise unilateral market power.

4.3.1.3 Results of assessment of offer behavior and incentive to exercise unilateral market power

276. The values of δ (the coefficient associated with η^C_{jhdm}, the inverse semi-elasticity of the net of forward market obligations residual demand curve) are substantially larger in absolute value than the corresponding value of β (the coefficient associated with η_{jhdm}) for all suppliers. The value of δ for Contact implies that if the value of the inverse semi-elasticity of the net forward market obligations residual demand curve for Contact increases by one unit, then Contact's offer price for the amount it sells in the short-term market is predicted to increase by \$4.31 because of the substantially greater incentive Contact has to exercise unilateral market power. Table 4.5 lists the half-hourly sample means and standard deviations of η^C_{jhdm}, the net inverse semi-elasticity (the incentive measure), for each supplier. This table demonstrates that a one unit change in the value of η^C_{jhdm} is a fairly frequent occurrence for Contact. For several half-hours of the day, a 3 unit change in η^C_{jhdm} is less than a two standard deviation change. For example, during half-hour 37, a two standard deviation change in the value of η^C_{jhdm} implies a more than \$20/MWh increase in Contact's offer price.

277. It is important to emphasize that different from the case of the inverse semi-elasticity of the residual demand curve, which can only be positive, the inverse semi-elasticity of the net of forward market obligations residual demand curve can be negative if the supplier's fixed-price forward market obligations exceed the amount of energy that it sells in the short-term market. As shown in Figure 4.7, this was frequently the case for Meridian as well as for Genesis and Mighty River Power during the sample period. The results in Table 4.2 for Meridian imply that, keeping all other factors constant, if a negative value of η^C_{jhdm} for Meridian becomes larger in absolute value by one unit, Meridian's offer price is predicted to be \$5.08/MWh lower because of its greater incentive to exercise unilateral market power by driving the price down. As shown in Table 4.5, a one unit change in η^C_{jhdm} is less than a one standard deviation change for many half-hours of the day.

278. The results in Table 4.2 also imply that, keeping the opportunity cost of water and the price of the input fossil fuel constant, if the value of the inverse semi-elasticity of the net-of-forward-market-obligations residual demand curve facing Meridian increases by one unit, the offer price for the amount of energy it sold in the short-term market is \$5.08/MWh higher because of the greater incentive Meridian has to exercise unilateral market power.

279. Thus, once fixed-price forward contract obligations are introduced into a wholesale market, suppliers with the ability to exercise unilateral market power can do so either by increasing or decreasing prices. A supplier with a substantial ability to exercise unilateral market power that is net short relative to its forward market obligations, meaning that it has more fixed-price forward market obligations than the amount of energy it sold in the short-term market, has an incentive to exercise market power by driving down the wholesale price, which reduces the cost of closing out its net short position through purchases from the short-term market. The results shown in Table 4.2 confirm this logic for all suppliers, although it is rarely the case that Contact is net short relative to its fixed-price forward market obligations. Alternatively, when a supplier is long relative to its fixed-price forward market obligations, meaning that its sales in the short-term market exceed its fixed-price forward market obligations, a higher value of the η^C_{jhdm} implies that it will raise its offer price because it has an incentive to use its ability to exercise market power to raise the market-clearing price.

280. The estimate for δ_j for Mighty River Power is by far the largest of the five values reported in Table 4.2. However, as shown in Table 4.5 the standard deviations of the inverse elasticity of the net of fixed-price forward market obligations for Mighty River Power are very small in absolute value relative to the values derived for the other four suppliers. Nevertheless, even multiplying the estimate of δ_j for Meridian by a one standard deviation change in the value of its inverse elasticity yields predicted offer price changes of over \$10/MWh for many half-hours of the day. Because the η^C_{jhdm} for Mighty River Power takes on both positive and negative values during the sample period, there are times when Mighty River Power submits a substantially lower offer price, all other factors held constant, because it has an incentive to use its ability to influence market prices to lower the market-clearing price because its short-term market sales are less than its forward market obligations. Alternatively, when it is long relative to its forward market position, a higher value of the η^C_{jhdm} for Mighty River Power implies that it will raise its offer price because Mighty River Power has an incentive to use its ability to exercise market power to raise the market-clearing price.

281. It is important to emphasize that the goal of our modeling effort is to determine whether higher offer prices are systematically associated with higher values of η_{jhdm} and η^C_{jhdm}, the ability and incentive measures respectively, and whether the magnitude of this relationship is economically significant. The results of our modeling effort presented in Tables 4.2 and 4.3 provides confirmation of a positive and economically significant relationship between a supplier's half-hourly offer price and the half-hourly values of η_{jhdm} and η^C_{jhdm}. The magnitude of this relationship is substantially larger for the measure of the incentive to exercise unilateral market power relative to the measure of the ability to exercise unilateral market. This result is consistent with the logic in Section 3 that a supplier with the ability to exercise unilateral market power must also have the incentive to do so in order to find it expected profit-maximizing to submit offer prices to exploit it.

Table 4.5: Half-hourly summary statistics for η_i^C – the incentive measure - by firm

Half-hour	Contact		Genesis		Meridian		Mighty River	
	Mean	Std. dev.	Mean	Std. dev.	Mean	Std. dev.	Mean	Std. dev.
1	0.346	1.020	0.143	0.632	0.029	0.356	-0.029	0.290
2	0.354	1.086	0.142	0.518	-0.010	0.415	-0.033	0.242
3	0.333	0.822	0.145	0.586	-0.033	0.348	-0.028	0.222
4	0.315	0.676	0.132	0.459	-0.055	0.345	-0.022	0.189
5	0.314	0.667	0.130	0.577	-0.061	0.410	-0.022	0.194
6	0.346	1.004	0.125	0.508	-0.062	0.431	-0.028	0.189
7	0.311	1.020	0.126	0.981	-0.077	0.401	-0.023	0.206
8	0.308	0.638	0.099	0.266	-0.084	0.406	-0.028	0.209
9	0.290	0.519	0.099	0.308	-0.087	0.414	-0.026	0.163
10	0.295	0.604	0.093	0.274	-0.083	0.401	-0.024	0.173
11	0.298	0.706	0.101	0.569	-0.066	0.359	-0.019	0.177
12	0.332	0.961	0.111	0.761	-0.044	0.364	-0.030	0.191
13	0.333	0.962	0.131	0.856	0.010	0.379	-0.010	0.188
14	0.358	1.281	0.112	0.468	0.045	0.445	0.006	0.213
15	0.401	1.516	0.127	0.623	0.100	0.594	0.050	0.416
16	0.410	1.341	0.180	1.151	0.236	0.834	0.117	0.652
17	0.366	1.196	0.132	0.980	0.293	1.036	0.115	0.556
18	0.386	1.527	0.137	0.822	0.299	1.033	0.122	0.584
19	0.347	1.168	0.130	0.737	0.276	0.910	0.110	0.446
20	0.357	1.273	0.119	0.672	0.259	0.778	0.100	0.413
21	0.347	1.085	0.121	0.677	0.272	0.821	0.094	0.440
22	0.370	1.537	0.129	0.716	0.274	1.003	0.092	0.366
23	0.385	1.255	0.102	0.686	0.311	1.087	0.097	0.427
24	0.418	1.803	0.092	0.796	0.324	1.187	0.085	0.412
25	0.381	1.543	0.113	0.914	0.295	1.038	0.078	0.568
26	0.362	1.143	0.110	0.940	0.306	1.147	0.070	0.502
27	0.343	0.956	0.104	0.871	0.303	1.121	0.071	0.378
28	0.359	1.199	0.106	0.895	0.272	0.938	0.061	0.423
29	0.354	0.984	0.107	0.793	0.245	0.769	0.052	0.379
30	0.356	1.168	0.099	0.927	0.243	0.992	0.039	0.390
31	0.377	1.427	0.105	0.838	0.242	0.957	0.040	0.335
32	0.361	1.119	0.097	0.856	0.269	0.976	0.051	0.312
33	0.372	1.193	0.094	0.705	0.265	0.912	0.057	0.294
34	0.359	1.229	0.077	0.640	0.311	1.002	0.071	0.364
35	0.349	1.113	0.109	1.019	0.324	0.734	0.095	0.479
36	0.421	1.415	0.170	1.381	0.454	1.466	0.155	0.842
37	0.479	2.335	0.142	1.304	0.417	1.067	0.165	0.760
38	0.413	1.495	0.145	1.089	0.392	0.947	0.152	0.793
39	0.395	1.329	0.140	1.226	0.350	1.056	0.145	0.777
40	0.351	1.074	0.135	1.198	0.296	1.031	0.113	0.580
41	0.355	1.198	0.116	0.989	0.300	0.990	0.112	0.653
42	0.366	1.208	0.117	0.904	0.293	0.960	0.082	0.482
43	0.335	1.003	0.109	0.795	0.278	0.805	0.068	0.361
44	0.363	1.612	0.086	0.574	0.228	0.764	0.048	0.380
45	0.350	0.954	0.135	1.378	0.185	0.753	0.008	0.296
46	0.318	0.715	0.120	0.836	0.091	0.549	-0.017	0.265
47	0.291	0.716	0.125	1.001	0.115	0.496	0.008	0.448
48	0.304	0.875	0.127	0.686	0.068	0.574	-0.040	0.568

Source: Calculations based on offer data from Centralised Data Set and EMS, firm-level settlement data from EMS, and dispatch data from M-Co.

282. Table 4.2 and 4.3 also report the R^2 for each of these regressions. There are many reasons to expect that the R^2 of these regressions to be substantially less than one. First, as noted above, economic theory does not imply an exact relationship between the supplier's offer price and the values of η_{jhdm} and η^C_{jhdm}. There are many idiosyncratic reasons that a supplier's offer prices may vary across half-hours of the sample period. Our analysis is concerned with determining whether there is systematic, increasing, economically significant, predictive relationship between offer prices and the values of the two inverse semi-elasticities, after controlling for variable cost differences across half-hours of our sample period. This modeling strategy is clearly not designed to maximize the R^2 of the regression, but to obtain precise estimates of the parameters of economic interest in models (13) and (14).

4.3.2 *Approach 2: Offer behavior and indexes of the ability and incentive to exercise market power based on whether the supplier is pivotal and net pivotal*

283. This section presents an analysis of the relationship between a supplier's offer price and indexes of the ability and incentive to exercise market power, based on whether the supplier is pivotal and net pivotal as defined in Section 3.

4.3.2.1 Approach

284. Although there is no simple relationship between a supplier's offer price and its status as a pivotal supplier or net pivotal supplier that can be derived from the assumption of expected profit-maximizing offer behavior, periods when a supplier expects it is pivotal or net pivotal are likely to cause it to raise its offer price, particularly for the pivotal quantity of energy. In fact, a number of the market power mitigation mechanisms in United States wholesale markets are based on this supposition. The short-term market operator takes the offers and bids of all market participants and determines whether a supplier is pivotal or a set of suppliers are jointly pivotal. If this is the case, then the offers of this supplier or this set of suppliers are mitigated to some reference offer level that is based on that supplier's marginal cost of production. Our analysis examines whether being pivotal or net pivotal predicts higher offer prices by the supplier after controlling for the opportunity cost of water and input fossil fuel prices.

285. Recall from Section 3 that supplier j is pivotal during half-hour h of day d of month m if its residual demand is positive for all finite prices. Define the indicator variable Piv_{jhdm} to equal 1 if supplier j is pivotal during half-hour h of day d of month m, and zero otherwise. A related measure of the ability of supplier to exercise unilateral market power is the pivotal quantity of energy for supplier j, which is the maximum of zero and the residual demand of supplier j evaluated at a price that is higher than the highest observed offer price during that half-hour price, p_{max}. If $DR_{jhdm}(p_{max})$ is the value of the residual demand curve at p_{max} for supplier j during half-hour h of day d of month m, then the value of the pivotal quantity $PQuant_{jhdm}$ equals $\max(0, DR_{jhdm}(p_{max}))$. Note that when supplier j is not pivotal the value of the pivotal quantity is zero, and that when the supplier is pivotal the value of $PQuant_{jhdm}$ equals $DR_{jhdm}(p_{max})$.

286. The analogous measure of the incentive of a supplier to exercise unilateral market power is the indicator variable for whether a supplier is net pivotal, meaning that the pivotal quantity for that supplier exceeds its fixed-price forward market obligation. If QC_{jhdm} is supplier j's fixed-price forward market obligation in half-hour period h of day d and month m, then if $DR_{jhdm}(p_{max})$ is greater than QC_{jhdm}, the supplier is deemed to be net pivotal. Define the indicator variable $NPiv_{jhdm}$ to equal 1 if supplier j is net pivotal during half-hour h of day d of month m, and zero otherwise. The second measure of the incentive to exercise unilateral market power is net pivotal quantity, which is defined as the maximum of zero and the difference between the pivotal quantity and the supplier's fixed-price forward market obligation. Define $NPQuant_{jhdm}$, the net pivotal quantity for supplier j during half-hour h of day d of month m as $\max(0, DR_{jhdm}(p_{max}) - QC_{jhdm})$. If supplier j is not net pivotal then the value of $NPQuant_{jhdm}$ is equal to zero and if the supplier is net pivotal then $NPQuant_{jhdm} = DR_{jhdm}(p_{max}) - QC_{jhdm}$.

4.3.2.2 Finding of pivotal and net pivotal supplier assessments

287. Table 4.6 presents summary statistics on pivotal indicator and net pivotal indicator variables for each year of our sample period from January 1, 2001 to June 30, 2007. Meridian has by far the highest pivotal and net pivotal frequency. For all but 2001, it was pivotal in more than 50 percent of the half-hour periods of the year. Next is Contact with annual pivotal frequencies that range from 10 to 20 percent. Genesis' annual pivotal frequency ranges from slightly more than 3 percent to slightly more than 10 percent. Mighty River Power has the lowest annual pivotal frequency of the four suppliers. It is important to note that one supplier being pivotal or net pivotal during a half-hour period does not preclude other suppliers from being pivotal or net pivotal during this same half-hour period. Typically, when one large supplier is pivotal or net pivotal, other suppliers are as well.

288. Table 4.6 shows that for all suppliers but Meridian, being net pivotal is an extremely rare event. For all but 2001 for Meridian, the net pivotal percentage never exceeds one percent. For most of the years of the sample, the remaining suppliers are never net pivotal during any half-hour of the year. Contact and Genesis are net pivotal only in 2001 and Contact's net pivotal frequency is less than one-tenth that of Genesis. Therefore, we would not recommend putting much weight on the net pivotal regression results for Contact because it is net pivotal for such a small number of half-hours during the sample period.

4.3.2.3 Results of assessment of offer behavior and ability to exercise unilateral market power based on pivotal measures

289. Table 4.7 presents linear regressions of the offer price at the supplier's dispatched quantity of energy on these two indicators of the ability of the supplier to exercise unilateral market power and the two indicators of the incentive of the supplier to exercise unilateral market power. All of these regressions include day-of-month for each month of the sample and half-hour-of-the-day fixed-effects similar to the regressions presented in

Table 4.2. Table 4.8 presents linear regressions of the half-hourly offer price on half-hourly values of these same four variables with half-hour-of-the-day fixed-effects for each month of the sample similar to the regressions presented in Table 4.3. For all suppliers and all measures (except for the net pivotal dummy and net pivotal quantity for Contact in Table 4.7), we find that a higher ability and incentive to exercise unilateral market power as measured by respectively, the pivotal indicator variable and pivotal quantity and net pivotal indicator and net pivotal quantity, predict higher offer prices for the supplier's dispatched quantity of energy.

290. Although the point estimates for Contact in Table 4.7 for the net pivotal dummy and net pivotal quantity coefficients are negative, they are not statistically different from zero, which is to be expected given the near-zero frequency that Contact is net pivotal during our sample period. Although the net pivotal dummy and net pivotal quantity parameter estimates for Contact in Table 4.8 are both positive, they not statistically different from zero, which provides further evidence that the near-zero frequency that Contact is net pivotal during our sample period makes it impossible to estimate these coefficients with any degree of precision.

Table 4.6: Summary statistics for pivotal variables

	Contact	Genesis	Meridian	Mighty River
Gross pivotal				
2001	13.8%	4.7%	49.1%	2.7%
2002	12.9%	10.4%	61.2%	5.2%
2003	17.6%	4.6%	52.9%	1.4%
2004	20.2%	10.2%	60.9%	5.4%
2005	17.0%	3.4%	53.5%	1.2%
2006	16.6%	6.1%	52.4%	1.7%
2007	13.2%	4.1%	51.2%	0.6%
Net pivotal				
2001	0.02%	0.43%	2.25%	-
2002	-	-	0.67%	0.02%
2003	-	-	0.13%	0.02%
2004	-	-	0.48%	-
2005	-	-	0.07%	-
2006	-	-	0.06%	-
2007	-	-	-	-

Source: Calculations based on offer data from Centralised Data Set and EMS, firm-level settlement data from EMS, and dispatch data from M-Co.

Table 4.7: Dependent variable = offer price at dispatch quantity for supplier j

Regression on:	Contact	Genesis	Meridian	Mighty River
(a) Pivotal dummy (0/1)	11.40	10.22	12.45	16.07
(s.e.)	(.331)	(.491)	(.267)	(.903)
R^2	0.453	0.447	0.699	0.474
(b) Pivotal quantity (MW)	0.033	0.034	0.020	0.086
(s.e.)	(.0010)	(.0018)	(.0004)	(.0049)
R^2	0.452	0.447	0.702	0.474
(c) Net pivotal dummy (0/1)	-16.62	67.58	10.62	220.4
(s.e.)	(15.92)	(4.02)	(1.09)	(16.03)
R^2	0.447	0.447	0.694	0.473
(d) Net pivotal quantity (MW)	-0.093	0.511	0.078	1.642
(s.e.)	(.312)	(.032)	(.007)	(.133)
R^2	0.447	0.446	0.694	0.473

Source: Calculations based on offer data from Centralised Data Set and EMS, firm-level settlement data from EMS, and dispatch data from M-Co.

Note: Day-of-sample and half-hour fixed effects are included in all regressions.

Table 4.8: Dependent variable = offer price at dispatch quantity for supplier j

Regression on:	Contact	Genesis	Meridian	Mighty River
(a) Pivotal dummy (0/1)	14.33	13.68	17.37	24.34
(s.e.)	(.322)	(.544)	(.310)	(.993)
R^2	0.475	0.388	0.530	0.391
(b) Pivotal quantity (MW)	0.047	0.048	0.030	0.135
(s.e.)	(.0011)	(.0020)	(.0004)	(.0055)
R^2	0.474	0.387	0.540	0.391
(c) Net pivotal dummy (0/1)	5.76	70.35	19.37	259.7
(s.e.)	(15.68)	(4.32)	(1.36)	(17.13)
R^2	0.465	0.386	0.518	0.389
(d) Net pivotal quantity (MW)	0.350	0.585	0.122	1.937
(s.e.)	(.307)	(.035)	(.008)	(.143)
R^2	0.465	0.386	0.518	0.389

Source: Calculations based on offer data from Centralised Data Set and EMS, firm-level settlement data from EMS, and dispatch data from M-Co.

Note: Month-of-sample interacted with half-hour fixed effects are included in all regressions.

291. The estimates in Table 4.7 imply that keeping daily water levels and input fossil fuel prices constant, if Meridian is pivotal then the offer price for its dispatched quantity is predicted to be $12.45 higher. For Contact this corresponding figure is $11.40. According to Table 4.7, Genesis being pivotal is predicted to increase its offer price by $10.22. For all suppliers the coefficient on the pivotal quantity is also positive and precisely estimated. For example, a 50 MW pivotal quantity for Meridian implies a roughly $1.00 higher offer price. For Contact this same pivotal quantity of energy implies a $1.65 higher offer price.

292. For the net pivotal indicator, the predicted offer price increases are much larger for two of the four firms and the predicted increase in the offer price for a net pivotal quantity change is an order of magnitude larger for two of these firms. For Genesis, being net pivotal predicts a $67.58 increase in its offer price and for Mighty River Power being net pivotal implies a $220.40 increase in its offer price. For Meridian, a 20 MW net pivotal quantity predicts a $1.56 higher offer price and for Genesis a 20 MW net pivotal quantity predicts a $10.22 higher offer price. These net pivotal results should be interpreted with caution for all suppliers but Meridian because of the very small number of net pivotal events during the sample period for the remaining suppliers. Despite the very infrequent occurrence of being net pivotal for Genesis and Mighty River Power, different from Contact, these regressions yield precise estimates that imply these suppliers adjust their price offers upward by economically meaningful magnitudes when they are net pivotal, and increasingly so the larger is their net pivotal quantity.

293. These regression results and the results presented in Table 4.2 and 4.3 are consistent with the view that the higher market prices that occur when the four large suppliers have a greater unilateral ability or incentive to exercise market power are due to the fact that these suppliers submit higher offer prices in order to raise market prices. In addition, when these suppliers have a substantial ability to exercise market power and have an incentive to exercise market power by lowering their offer price, they also do so. Taken together, the empirical evidence presented in this section is consistent with the existence of a causal link between the unilateral ability and incentive of suppliers to exercise market power and the offer prices they submit for the quantity of energy they sell in the short-term market. Higher or lower offer prices produce higher or lower market-clearing prices that are consistent with the half-hourly measures of the incentive of the suppliers to exercise unilateral market power.

4.4 Do thermal suppliers behave as if they have no ability to exercise unilateral market power?

294. The final piece of evidence in favor of the view that the four large suppliers exercise all available unilateral market power is a test of the null hypothesis that fossil fuel suppliers behave as if they had no ability or incentive to exercise unilateral market power.

295. As discussed in Section 3, a supplier that has no ability or incentive to exercise unilateral market power can be expected to submit an offer curve equal to its aggregate marginal cost curve for supplying electricity. The complication with implementing this test for hydroelectric suppliers is that estimating their no-market-power opportunity cost

of supplying energy is a massively complex computational problem. However, for fossil fuel suppliers we know that the opportunity cost of producing electricity from their generation units depends on the price of the input fossil fuel, the heat rate of the generation unit and the variable operating and maintenance cost of the generation unit. Consequently, as demonstrated in Section 3, a fossil fuel supplier with no ability to exercise unilateral market power will submit an offer price for each fossil generation unit equal to the unit's variable cost.

4.4.1 Approach

296. Our test of the null hypothesis that no supplier has the ability to exercise unilateral market power is based on the simple insight that offer prices of fossil fuel generation unit owners with no ability to exercise unilateral market power should not be predicted by any other factors besides those that impact the variable cost of the generation unit. In particular, if fossil fuel suppliers do not have any ability to exercise unilateral market power, the offer price for the amount of energy they sell into the short-term market should not be impacted by the system hydro storage level. In contrast, if higher offer prices are associated with lower water levels, then this result is consistent with a supplier that has the ability to exercise unilateral market power taking advantage of this fact to raise their offer prices and market-clearing prices in response to the incentives that it faces.

297. To investigate this null hypothesis we regress the offer price for the quantity of energy sold from each fossil fuel generation unit during each half-hour period of the sample when the unit was available to supply energy on a number of factors that control for the variable cost of producing electricity from this generation unit at different levels of output, and the daily level hydro storage in Terawatt-hours (TWh), as shown in Box 4.

Box 4: Testing the null hypothesis that thermal suppliers behave as if they have no ability to exercise unilateral market power.

Let $P_{khdm}(offer)$ equal the offer price of the energy sold in the short-term market from fossil fuel generation unit k during half-hour h of day d and month m. Let $Hydro_{dm}$ equal the amount of hydroelectric energy in storage on day d of month m. Let $QINC_{ikdhm}$ equal a set of $I(k)$ dummy variables each of which equals 1 if the dispatch quantity from fossil fuel generation unit k during half-hour h of day d in month m lies in the 10 MW quantity increment i. For each generation unit we take the maximum and minimum output observed during the sample period and divide this range into 10 MW increments. For example, if 250 MW is the lowest output level and 360 MW is highest output level, then $I(k)$ equals 11, meaning that there are 11 possible 10 MW bins that the supplier could produce in during the sample period. These quantity bins are chosen to account for the fact that the heat rate of fossil fuel units can be different for different output levels. Define YR_{zdhm} as an indicator variable that equals one if half-hour h of day d and month of sample m is in year z, where z=2001,2002,…2007. Define MTH_{wdhm} as an indicator variable that equals 1 if half-hour h of day d and month-of-sample m is in month-of-the-year w=1,2,3…,12. We estimate the following regression for each fossil fuel unit:

$$P_{khdm}(offer) = \sum_{i=1}^{I(k)} \alpha_{ik}\, QINC_{ikdhm} + \sum_{z=2001}^{2007} \gamma_{zk}\, YR_{zkdhm} + \sum_{i=1}^{I(k)} \sum_{z=2002}^{2007} \theta_{izk}\, YR_{zkdhm} * QINC_{ikdhm} + \sum_{i=1}^{12} \delta_{ik}\, MTH_{wkdhm} + \beta_k Hydro_{dm} + \varepsilon_{khdem} \qquad (15)$$

This linear regression controls for differences in the variable cost of fossil fuel units across the 10 MW quantity increments of output levels for the unit (the first summation), across each year of the sample (the second and third summations), and within the months of the year (the fourth summation) in order to assess whether the level of hydroelectric storage provides incremental explanatory power, beyond these variables that control for differences in the generation unit's variable cost of production, in predicting the offer price.

4.4.2 Results

298. Table 4.9 presents the results of estimating (15) for the Huntly Unit 1, Huntly Unit 2, Huntly Unit 3, Huntly Unit 4 owned by Genesis, and the New Plymouth (all units combined), Taranaki CC, and Otahuhu B units owned by Contact. In all cases, the estimated value of β_k, the coefficient associated with the value of system hydro storage for unit k, is found to be negative and very precisely estimated. The null hypothesis that β_k is equal to zero is overwhelmingly rejected for all seven generation units, which provides strong evidence against the null hypothesis that the owners of these fossil fuel units behave as if they had no ability to exercise unilateral market power.

299. The implied change in offer behavior from these generation units as a result of changes in the water level are also economically meaningful. For example, if the value of system hydro storage decreases by 1 TWh, then the offer price for the Huntly Unit 2 is predicted to increase by \$24.31 and by \$24.12 for the Huntly Unit 4. The predicted increases in the offer prices for a 1 TWh reduction in the value of system hydro storage for Huntly Unit 1 and Huntly Unit 3 are roughly half these values. New Plymouth and

Taranaki CC have predicted offer price increases for a 1 TWh reduction in system hydro storage of $17.40 and $19.61, respectively.

300. These parameter estimates are inconsistent with the hypothesis that these fossil fuel generation unit owners have no ability to exercise unilateral market power. However, the signs and magnitudes of the estimated values of the β_k are consistent with the hypothesis that the owners of these generation units have a significant ability to exercise unilateral market power and that this ability to exercise unilateral market power increases with decreases in the level of system hydro storage. These results are also consistent with the results presented in the previous section which showed that the offer price for the quantity of energy sold in the short-term market by each of the four suppliers is increasing in that supplier's ability and incentive to exercise unilateral market power.

Table 4.9: Dependent variable = offer price at dispatch quantity for plant/unit k

	Huntly Unit 1	Huntly Unit 2	Huntly Unit 3	Huntly Unit 4
β_k	-8.05	-24.31	-11.01	-24.12
(s.e.)	(.674)	(.377)	(.459)	(.335)

	New Plymouth	Otahuhu B	Taranaki CC
β_k	-17.40	-2.34	-19.61
(s.e.)	(.457)	(.135)	(.340)

Source: Calculations based on offer data from Centralised Data Set and EMS, dispatch data from M-Co, and hydro storage data from COMIT Hydro (M-co).

Note: 10MW quantity bin fixed effects for each year of sample, as well as month-of-year fixed effects, are included in all regressions. Results for the Taranaki Combined Cycle plant are for the period of Contact ownership (since March 2003).

4.5 Conclusion

301. Section 4 presented evidence that the half-hourly aggregate willingness-to-supply curve in the short-term wholesale market is the result of the unilateral expected profit-maximizing actions of at least the four large suppliers.

302. Summary statistics on the half-hourly measures of both the unilateral ability and incentive to exercise unilateral market power for each of the four large suppliers are shown to be positively correlated with the value of the quantity-weighted average of the half-hourly nodal prices. Evidence from the three periods of high prices in the Winter 2001, Autumn 2003 and Summer 2006 was presented to demonstrate that this positive correlation could not be explained by changes in water storage levels.

303. The second line of empirical evidence demonstrates that increases in a supplier's half-hourly ability and incentive to exercise unilateral market predicts a higher values of its

half-hourly offer price for the quantity of energy sold during that half-hour in the short-term wholesale market, even after controlling for differences across days of the sample and half-hours of the day in the opportunity of water, input fossil fuel prices, and other input costs that vary across days or half-hours during the sample period. These results imply that when each of the four suppliers had a greater ability or greater incentive to exercise unilateral market power, they submit substantially higher half-hourly offer prices into the wholesale market.

304. Analyses of the half-hourly relationship between offer prices and half-hourly measures of the firm-level the ability and incentive to exercise unilateral market power are performed for a variety of other half-hourly measures of the ability and incentive of a supplier to exercise unilateral market power based on the concepts of a pivotal and net pivotal supply. An increasing relationship between supplier's half-hourly offer price and its half-hourly ability and incentive to exercise unilateral market power was found.

305. The final piece of evidence tested whether the offer behavior by owners of thermal generation units is consistent with the null hypothesis that they have no ability to exercise unilateral market power. This is found not to be the case. In particular, the offer behavior of the large suppliers that own fossil fuel generation units is inconsistent with the expected profit-maximizing offer behavior of a supplier that does not have the ability to exercise unilateral market power and is consistent with the behavior of a supplier that has the ability to exercise unilateral market power.

SECTION 5

QUANTIFYING THE IMPACT OF THE EXERCISE OF UNILATERAL MARKET POWER

5.1 Introduction

306. This section quantifies the market power rents or wholesale market cost of suppliers exercising unilateral market power in the short-term market over the period January 1, 2001 to June 30, 2007. Market power rents are defined on a half-hourly basis as the difference between the actual market price, P_A, and the counterfactual market price that would result if no supplier had the ability to exercise unilateral market power, P_C, times the actual market demand, Q_A. As discussed in Section 3, a generator with no ability to exercise unilateral market power (i.e. facing a distribution of a perfectly elastic residual demand curves) will submit an offer curve equal to its marginal cost of producing electricity. It follows that if no generator possesses the ability to exercise unilateral market power, as would be the case in a perfectly competitive market, then the aggregate willingness-to-supply curve would equal the aggregate short-run marginal cost curve of the industry. Therefore, the competitive benchmark price, P_C, is the price at the intersection of this perfectly competitive supply curve with the market demand.

307. Section 5.2 presents a brief overview of the competitive benchmark pricing analysis and challenges associated with computing this price in a hydroelectric energy-dominated industry. Section 5.3 explains the use of the short-run marginal cost curve for the

industry to compute the competitive price benchmark. This section emphasizes that the competitive benchmark pricing analysis provides a measure of the performance of the wholesale market, but does not measure the long-term financial viability of the industry. This section also compares the role of short-run marginal cost relative to long-run marginal cost in determining a firm's expected profit-maximizing operating, pricing and investment behavior.

308. Section 5.4 presents the various methodologies used to compute the no-market-power competitive benchmark price (P_C). These methodologies differ along two dimensions. The first dimension is how the counterfactual aggregate willingness-to-supply curve is constructed. The goal of all of these approaches is to estimate the supplier's offer curve under the assumption that it does not have the ability to exercise unilateral market power. As discussed below, constructing this no-market power offer curve is straightforward for the case of fossil-fuel generation unit owners. However, constructing a no-market power offer curve for hydroelectric generation unit owners is a considerably more complex task. Fortunately, there are several relatively straightforward methodologies that yield a slack upper bound on a hydroelectric generation unit owner's no-market-power willingness to offer curve. Two of these approaches are used to compute upper bounds on the no-market power counterfactual offer curves for hydroelectric suppliers.

309. The second dimension along which these methodologies differ is what locational pricing mechanism is used to construct the counterfactual market-clearing prices from the no-market power generation unit-level willingness-to-supply curves. The first method uses a single pricing zone for the entire New Zealand market. The second method attempts to replicate the nodal-pricing algorithm used to compute locational prices in New Zealand market. This substantially more computationally intensive method produces a counterfactual no-market-power price at each node in the New Zealand market. We find that these two approaches to estimating cost of the exercise of unilateral market power produce very similar results.

310. All of these methodologies are designed to compute upward biased estimates of the counterfactual no-market power wholesale market prices which imply downward biased estimates of the cost of the exercise of unilateral market power. Some of the methods rely on more conservative assumptions than others, but all find the same sustained periods when economically significant market power rents exist, as measured by the difference between actual price and competitive benchmark price times total system demand, $(P_A - P_C)Q_A$, summed over all hours during this time period.

311. The empirical results presented in Section 5.5 allow three major conclusions:

- First, for the majority of the half-hours from January 1, 2001 to June 30, 2007, the average difference between actual prices and both sets of competitive benchmark prices is very small.

- Second, for the majority of years of our sample period, the average difference between actual prices and both sets of competitive benchmark prices is small.

- Third, there are at least three sustained periods of between three to six months in duration during our sample when the average difference between actual prices and competitive benchmark prices is extremely large. These periods coincide with the periods when each of the four large suppliers has very large firm-level indexes of the ability to exercise unilateral market power and several of the firms have sizeable firm-level indexes of the incentive to exercise unilateral market power. During these periods, the average half-hourly value of system-wide market power rents--the difference between the actual price and the competitive benchmark price times the total system demand--are very large. Because these periods generally persist for more than three months, the total market power rents over each of these periods are economically significant.

312. The existence of these sustained periods of significant market power rents is consistent with the discussion of Section 3.5 concerning the exercise of unilateral market power in hydroelectric-dominated electricity supply industries. Also consistent with the discussion in Section 3.5, periods with low water storage levels are associated with high market power rents and normal and high water storage levels are associated with low market power rents.

313. We emphasize that the market power rents presented in Section 5.5 are measured at the wholesale market level. The extent to which these higher wholesale prices are passed on to a vertically-integrated supplier’s own retail customers, or indirectly to other retail customers, is not addressed in Section 5.5. The majority of retail customers pay for their electricity according to fixed retail prices, so wholesale price increases cannot be passed through to these customers until their retail prices increase. However, most of these retail contracts allow the retailer to change the customer’s price at its discretion, typically with some advance notice. Therefore, pass-through of wholesale prices increases to these customers could occur with a lag. Immediate pass of wholesale prices could only occur for the small proportion of customers whose retail price is linked to the half-hourly wholesale price. In Section 5.6, we present evidence that suggests that suppliers have been able to pass-through these wholesale price increases in higher retail prices with a time lag.

5.2 An overview of the competitive benchmark analysis

314. This section presents a simplified overview of the computation of the competitive benchmark price.

315. Figure 5.1 provides a stylized graphic description of the single-pricing-zone version of competitive benchmark analysis for one half-hour period. The upper line is the actual aggregate willingness-to-supply curve, $S_A(p)$ - an aggregate of the actual offer curves of all suppliers. The actual level of demand, Q_A, is graphed as a vertical line and the intersection of this line with the actual aggregate willingness-to-supply curve, $S_A(p)$, yields the point (P_A, Q_A), the actual market-clearing price and quantity pair.

316. The lower line is the competitive benchmark aggregate willingness-to-supply curve, $S_C(p)$, representing the aggregate marginal cost curves of all generator units in the

wholesale market. The intersection of the competitive benchmark aggregate willingness-to-supply curve, $S_C(p)$, and the actual level of demand, Q_A, is the market price that would result if no supplier had the ability to exercise unilateral market power, P_C. Note that this competitive benchmark price is also equal to the marginal cost of the highest cost generation unit necessary to meet demand.

317. Multiplying the actual price by the actual level of demand, $P_A \times Q_A$, gives the total generation revenues earned by all suppliers in the New Zealand wholesale market in that half-hour period. This is represented by the entire shaded region in Figure 5.2. This figure shows how these total generation revenues can be divided into three distinct magnitudes. The market power rents that result from suppliers in the New Zealand wholesale market exercising unilateral market power is defined as the difference between the actual market price, P_A, and the competitive benchmark price, P_C, times the actual market demand, Q_A. The region under the counterfactual aggregate willingness-to-supply curve $S_C(p)$, is the total variable cost of supplying the electricity dispatched. The area above the counterfactual aggregate willingness-to-supply curve $S_C(p)$ and below P_C, is the competitive market rents earned by generators during the period.

318. In a uniform price auction where no firms have the ability to exercise unilateral market power, the market-clearing price is paid to all energy produced. This means that all but the highest marginal cost generation unit needed to meet demand receives a price above its marginal cost. The competitive market rents contribute to the recovery of the supplier's fixed costs and provide incentives for entry and exit in markets where no suppliers have the ability to exercise unilateral market power. Moreover, in New Zealand, the vast majority of energy is provided from sources with a marginal cost of zero or close to zero such as hydro, geothermal and wind. All of the four large firms have one or more of these generation sources in their portfolio of units. As a result, it is probable that under the competitive benchmark counterfactual, every firm receives competitive rents substantially in excess of their total variable costs.

319. Fossil fuel generators exercise unilateral market power by withholding generation capacity from the market at any price, or increasing the offer prices on the increments of generation capacity offered into the market. Hydroelectric generation unit owners also use these same two mechanisms to exercise unilateral market power.

320. A hydroelectric supplier exercises unilateral market power by allocating its water to produce and sell electricity over half-hour periods to maximize expected profits. A hydroelectric supplier with the ability to exercise unilateral market power accomplishes this by using less water during periods when the supplier faces a less elastic residual demand curves relative to what it would use under these same system conditions if it did not possess the ability to exercise unilateral market power. If these suppliers face constraints on the amount of water they can store, they will also use more water during periods when they face a more elastic residual demand curves relative to the amount they would use under these same system conditions if they did not possess the ability to exercise unilateral market power. Producing more energy during the half-hours that the supplier faces a more elastic residual demand curves has significantly less impact on lowering the market-clearing price than would be the case if hydroelectric suppliers

produced more during half-hours when they face less elastic residual demand curves. By withholding water from the half-hours when they face inelastic residual demand curves and selling some or all of this water during half-hours when they face elastic residual demand curves, hydroelectric suppliers with the ability to exercise unilateral market power are able to increase the average price they are paid for all the energy they produce. Bushnell (2003) presents a dynamic model of the Western United States wholesale electricity market where hydroelectric suppliers exercise unilateral market power in this manner.[45]

5.3 Short-run costs, long-run costs and competitive benchmark prices

321. This section discusses the role of short-run cost curves and long-run cost curves in the pricing and operating decisions of generation unit owners in a bid-based wholesale electricity market, such as the one that exists in New Zealand. The short-run marginal cost curve is shown to be the basis for pricing and operating decisions of suppliers in a generic industry and in a bid-based wholesale electricity market. The long-run marginal cost curve is shown to be irrelevant to both the pricing and operating decisions of suppliers in a generic industry and in a bid-based wholesale electricity market. Short-run marginal cost is then shown to play a major role in the investment decisions of new entrants in a wholesale electricity market, whereas long-run marginal cost is largely irrelevant to these decisions. The introduction of uncertainty into the analysis of these decisions does not change the basic conclusion that short-run marginal costs are an important factor in new generation unit investment decisions.

5.3.1 The definition of short-run marginal cost and its role in computing competitive benchmark prices

322. The short-run marginal cost of production for a generation unit owner includes costs that vary with the actual quantity of electricity produced, such as input fuel and variable operating and maintenance costs. Annual fixed operating and maintenance costs that do not vary with the half-hourly output of the generation unit are not part of short-run marginal cost. For the same reason, other annual fixed-costs or the cost of constructing the generation unit are not components of the short-run marginal cost of producing electricity.

323. As demonstrated by the simplified model of expected profit-maximizing offer behavior in Section 3, when constructing its offer curve into the wholesale market during a given half hour, an expected profit-maximizing supplier finds the points of intersection between its short-run marginal cost curve and the marginal revenue curve associated with each possible residual demand curve realization that it expects to face. Capital costs and other fixed costs do not play a role in computing this expected profit-maximizing offer curve.

[45] Bushnell, James B. (2003) “A Mixed Complementarity Model of Hydro-Thermal Electricity Competition in the Western U.S." *Operations Research*. Vol. 51, No. 1: 81-93. January/February 2003.

324. A firm that does not have the ability to exercise unilateral market power and therefore cannot influence the market price through its unilateral actions is called a price-taker. As shown in Section 3, a firm will behave as a price taker if it expects to face perfectly elastic residual demand curves. Typically, a supplier faces an infinitely elastic residual demand curve because there is large number of independent suppliers competing to sell the product at the same price. In this case, it is unilaterally profit-maximizing for this supplier to produce at the point where this price is equal to its marginal cost.

In a bid-based wholesale electricity market, an expected profit-maximizing supplier with no ability to exercise unilateral market power will submit an offer curve that is equal to its marginal cost curve, because the intersection of this offer curve with every possible infinitely elastic residual demand curve produces the desired price/quantity pair for each residual demand curve realization. If all suppliers have no ability to exercise unilateral market power, then the aggregate willingness-to-supply curve is the aggregate short-run marginal cost curve for the industry and the competitive benchmark price is the marginal cost of the highest cost unit needed to meet demand during that half-hour. In the case of wholesale electricity in New Zealand, the market sets a potentially different equilibrium price each half hour of the day. As is the case with any short-run equilibrium, this competitive benchmark price could be above or below the price that is necessary to finance investment in new generation capacity, or needed to maintain the long-term financial viability of the industry.

Figure 5.1: Measurement of the Cost of Unilateral Market Power, Part I

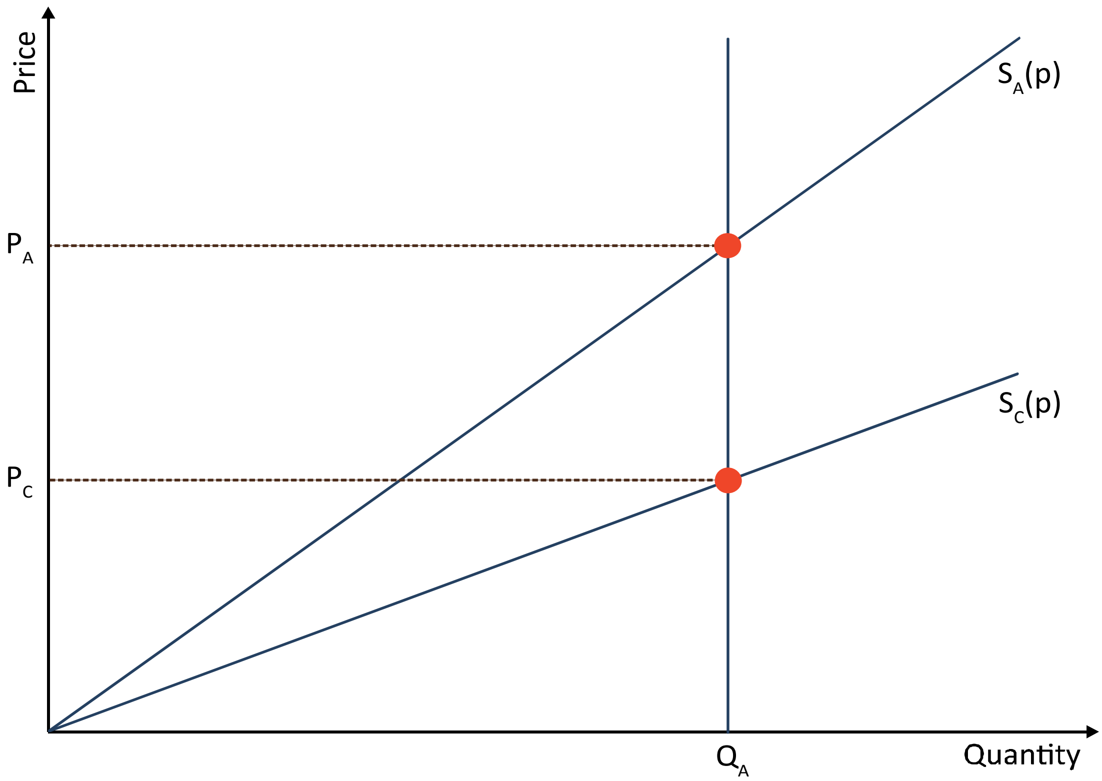
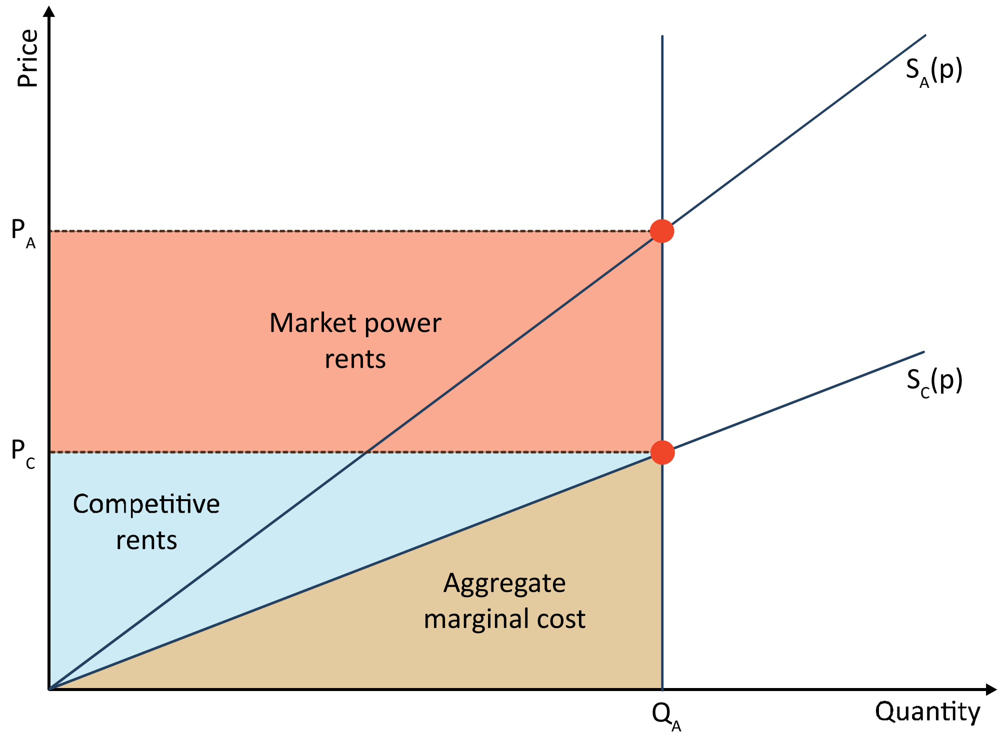


Figure 5.2: Measurement of the Cost of Unilateral Market Power, Part II



325. It is important to emphasize that the competitive benchmark price is not a measure of the profitability of individual generation units. Specifically, selling electricity at the competitive benchmark price could earn certain units large variable profits that far exceed the opportunity cost of funds invested in the project, and earn other units variable profits that are insufficient to recover the going-forward fixed costs necessary to continue operation. In addition, competitive benchmark prices provide no guarantee that unit owners will earn as much profits as they or their shareholders would like. The true test of whether a generation unit owner is earning sufficient revenues to recover the opportunity cost of funds invested is whether they are willing to remain in business and willing to sign long-term supply arrangements with other market participants and retail customers.

326. Subject to data availability, the competitive benchmark price can be computed for any industry. It is the short-run equilibrium price under the assumption that no supplier has the ability to exercise unilateral market power, because expected profit-maximizing firms base their output choice on the short-run marginal cost of production, given the amount fixed of inputs each firm has. For example, a profit-maximizing firm in a perfectly competitive industry produces at the point that the market price is equal to its short-run marginal cost of production for its current the level of fixed costs. The revenues to cover the firm's fixed costs come from selling units of output with short-run marginal costs below the market-clearing price. As explained below, in industries that require significant up-front fixed costs to produce output, expected profit-maximizing firms base their day-to-day production decisions on their short-run marginal cost curve. The up-front capital costs and other fixed costs should not impact these decisions by expected profit-maximizing firms. Consequently, a supplier's long-run average cost and long-run

marginal cost are not relevant to these day-to-day expected profit-maximizing operating and pricing decisions.

5.3.2 *The role of long-run costs and short-run costs in determining supplier behavior in a wholesale electricity market*

327. The long-run cost function of a firm assumes that for each level of output the firm produces its output in a least-cost manner under the assumption that all factors of production are variable. Specifically, for each level of output, Q, the firm is assumed to be able to choose the amount of all inputs—capital, labor, materials, input fossil fuels and other factors of production—to minimize its total cost of producing output level Q. The long run average cost at output level Q is the value of this long-run cost divided by the output level Q. The long-run marginal cost is the change in the firm's long-run cost associated with a one unit change in its output from output level Q. The reason that the firm's long-run marginal cost is not relevant to its day-to-day operating or pricing decisions is precisely because the firm cannot adjust all factors of production on a day-to-day basis.

328. In the case of wholesale electricity, a generation unit owner cannot adjust its capital stock on a day-to-day basis. It can only adjust the amount of output it sells by changing the amount of input fossil fuel and other variable factors of production it consumes to produce electricity in the generation units that it owns. Specifically, the actual cost of producing an additional unit of output (at each feasible level of output) is given by the firm's marginal cost curve for the fixed inputs it has, which is equal to its short-run marginal cost curve. The long-run marginal cost is not the relevant marginal cost for day-to-day pricing or operating decisions, because by definition the firm cannot produce along this marginal cost curve on a day-to-day or half-hourly basis. This distinction between the use of the short-run marginal cost curve versus the long-run marginal cost curve in the day-to-day operating and pricing decisions of a firm is not unique to wholesale electricity. It is the fundamental concept in the economic analysis of firm behavior in any industry.

329. To illustrate this point for a generic industry, Figure 5.3 shows a hypothetical long-run average cost of producing output for a supplier, a long-run marginal cost curve for that supplier, and three different short-run average and marginal cost curves for the supplier that intersect the supplier's long-run average cost at different points corresponding to different levels of the supplier's capital stock (the input to production that is fixed in the short run). For the case of an electricity supplier, each short-run cost curve represents a different level of installed generation capacity, which is fixed in the short-run. By the logic described in Section 3, if this firm faces sufficient competition, then it will offer to sell its output along this short-run marginal cost curve.

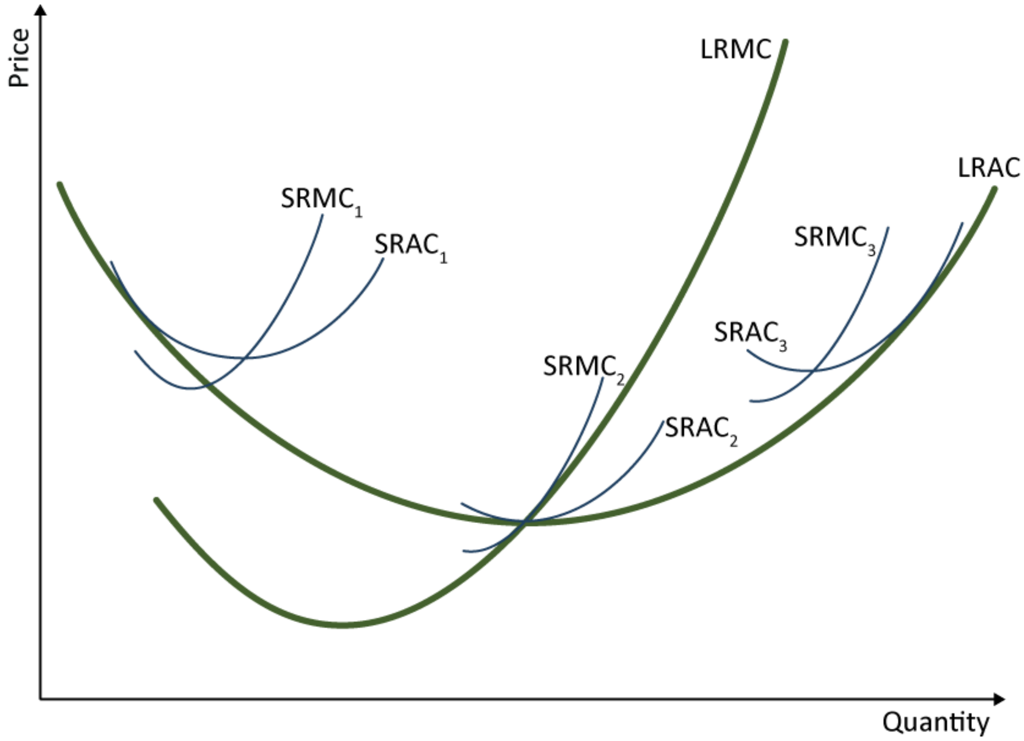
330. Figure 5.4 focuses on the case of one short-run marginal cost (SRMC) curve and short-run average cost curve. If SRMC in Figure 5.4 is the short-run marginal cost curve for the existing mix and amount of generation capacity owned by a supplier, then the price at the point of intersection of this short-run marginal cost curve with the residual demand curve that the supplier faces each half-hour equals the market-clearing price in a wholesale market where this supplier does not have the ability to exercise unilateral

market power. Depending on the residual demand curve realization, the short-run marginal cost curve, SRMC, can intersect the residual demand curve at a price that is above or below the firm's short-run and long-run average cost associated with that level of output. The above logic for pricing and operating behavior also applies to a generic industry with the cost functions given in Figure 5.4. A firm with no ability to exercise unilateral market power will find it profit-maximizing to produce at the output level given by the intersection of its SRMC curve with its residual demand curve.

331. Although the firm might earn a higher level of profits if it could produce at a point along its long-run marginal cost curve, this is physically impossible because by definition the firm cannot change its fixed inputs on a day-to-day basis. For example, in wholesale electricity, for a given half-hourly residual demand curve realization, the firm might be able to earn higher profits if it owned a different mix of generation capacity, but it cannot site, construct, and bring on line the necessary generation units between half-hours of the day, days of the week, or even months of the year. The firm cannot reduce its fixed costs if a half-hourly residual demand curve realization implies that it would be able to earn higher profits with less generation capacity.

332. For all half-hourly residual demand curve realizations within the day the supplier cannot alter the mix of generation capacity that it owns. The relevant marginal cost curve for the purpose of measuring how its production costs increase and decrease within half-hour periods of the day is its short-run marginal cost curve for the mix of generation capacity that it owns. Therefore, the supplier's short-run marginal cost curve is the relevant cost curve for determining how it will offer its generation units into the wholesale market and it will chose to operate these generation units.

Figure 5.3: Long-Run and Short-Run Marginal and Average Cost Functions



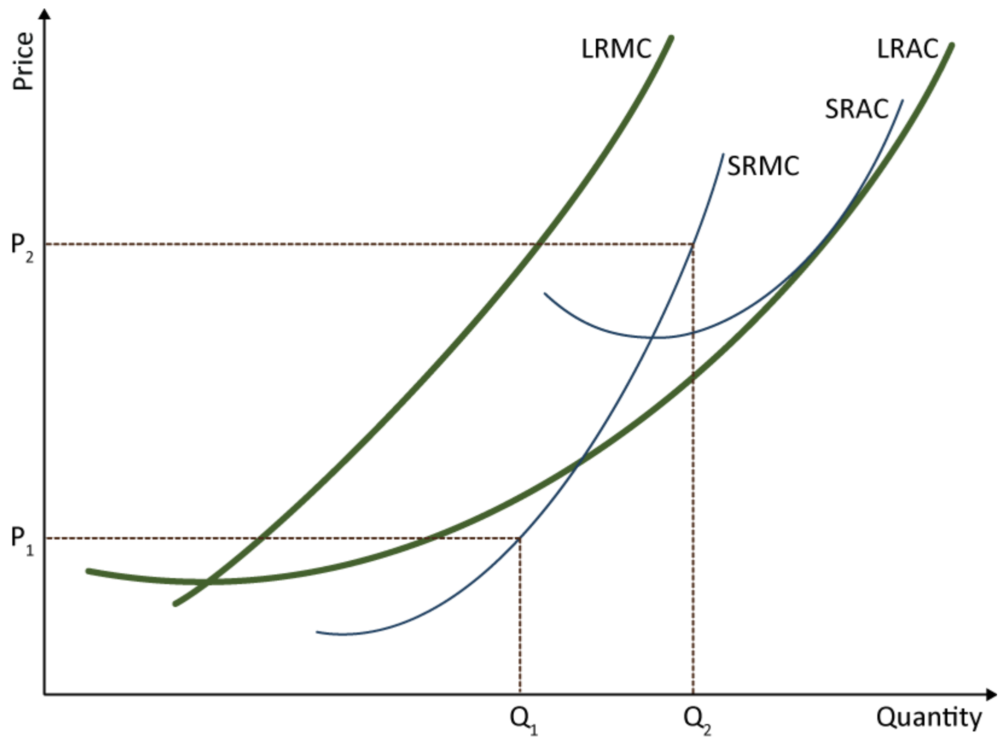
333. If all firms in the industry face sufficient competition, then all of them will submit as their willingness to supply curve, the short-run marginal cost curve that is relevant for their existing capital stock, which implies that the aggregate no-market power supply curve for a generic industry will equal the aggregate short-run marginal cost curve for the industry given its existing capital stock. In the case of the electricity supply industry, the aggregate no-market power offer curve is equal to the aggregate short-run marginal cost curve for the industry given the existing mix and amount of generation capacity owned by each supplier. As a result, the competitive benchmark price for the case of a single, system-wide price equals the short-run marginal cost of production for the highest cost supplier required to meet the system demand in that half-hour period. As Figures 5.3 and 5.4 illustrate, the competitive benchmark prices may be greater or less than the long-run marginal cost, long-run average cost or short-run average cost of any supplier.

334. For the case of wholesale electricity, if the average market price over a sustained period of time is below the short-run average cost of some generation units, then these generation units are likely to be shut down in order to limit the owner's losses. Conversely, if market prices are expected to remain at or above the long-run average cost of constructing a new generation facility for a long enough time for a supplier to recover the total cost of constructing and operating the generation facility, then this new generation capacity is likely to be built.

335. For example, if the price in the wholesale market was set at P_2 in Figure 5.4, new entry could be profitable despite the fact that no suppliers are exercising unilateral market power. At the output level Q_2, the long-run average cost for this supplier is below the short-run market-clearing price. If this supplier expected that market-clearing prices

would average P_2 for a sustained period of time then it might be willing to invest in new generation capacity, for the reasons discussed below.

Figure 5.4: Competitive Benchmark Pricing and Average Costs



336. If suppliers expected market prices to equal P_1 for a sustained period of time, then it is likely that this supplier and other suppliers would be forced to shut down some of their generation units. In this case, the market-clearing price, P_1, is below the long-run average cost of supplying electricity for this firm. As is the case with any market where no supplier has the ability to exercise unilateral market power, there is no guarantee that all suppliers will earn revenues at market-clearing prices that are greater than their long-run average costs. For the case of wholesale electricity markets, there is no guarantee that all generation units will earn sufficient revenues to recover their short-run or long-run average costs. As noted in Section 3, one way for a supplier to reduce the likelihood of an extended period of prices below its average cost of production is to sign an agreement to sell a fixed amount of output each half-hour over an extended period of time in a long-term fixed-price forward market obligation.

337. Nevertheless, it is always possible that a firm selling in a market where it has no ability to exercise unilateral market power will make *negative* profits. This happens if the firm's short-run marginal cost is below its short-run average cost at the market-clearing price. Moreover, as Figure 5.4 demonstrates, in a market where no suppliers are able to exercise unilateral market power it is possible for the market-clearing price to be below the long-run average cost of production for some suppliers as well.

5.3.3 *Short-run costs, long-run costs, wholesale prices and the determinants of new generation unit investments*

338. In wholesale electricity markets and other markets where large fixed costs must be incurred to produce a unit of output and the vast majority of these fixed costs are sunk, the long-run marginal cost of production in the current period is not directly relevant to the decision of a firm to built new generation capacity. Once a generation facility has been built on a site, it has no other uses that have as much value as producing electricity, so the owner must expect to earn sufficient revenues in excess of variable costs over the life of the project to cover these up-front costs. Expectations about the future pattern of short-term prices, short-run marginal costs, annual fixed costs and up-front fixed costs all determine when new investment in generation capacity will occur.

339. To understand the determinants of investment in new generation capacity without fixed-price forward contracts, consider the following stylized but representative example. Suppose that F is the fixed cost of constructing a 150 MW generation unit. To fix ideas, assume a world with no uncertainty about future input prices and wholesale electricity prices, a finite life for the project of T periods, and no time lag between the decision to construct the unit and when it is able to produce electricity. A profit-maximizing supplier will construct this generation unit if the following equation is satisfied:

$$\sum_{t=1}^{T} \frac{(p_t - c_t)q_t}{(1+r)^t} - F > 0 \qquad (1)$$

where p_t is the market price in period t, q_t is the amount of output produced in period t, c_t is the short-run marginal cost of producing electricity in period t, and r is the real interest rate for riskless projects. For simplicity, assume the marginal cost of production in each time period is the same for all levels of output and there are no annual fixed costs.

340. Because generation units come in discrete sizes, such as a 150 MW unit, the new entrant is comparing the discounted present value of the variable profits, $(p_t - c_t)q_t$, for $t = 1, 2, \dots, T$ periods to the fixed cost it must pay up front to construct the facility. This means if the new generation unit has a short-run marginal cost less than the price paid for its output, then positive variable profits are earned in that period. If the present value of the variable profits over the life of the project is greater than the up-front cost of the project, then a profit-maximizing supplier will build it.

341. Note that this decision rule for new generation investment does not involve the long-run marginal cost of producing one more unit of output in the current period. The substantial up-front costs, the long life of the project, and the fact that most of these up-front costs are sunk imply that the construction decision depends on the future values of short-run marginal costs and wholesale electricity prices. Another factor that plays an important role in the decision of the supplier to invest is the delay between the up-front payment and the time until output is first produced. For example, it typically takes more than 18 months to 2 years from the date that the decision to construct a new generation unit is made until the date that the unit is able to produce electricity.

342. Suppose that it takes k periods to construct a plant. This implies that equation (1) becomes:

$$\sum_{t=1+k}^{T+k} \frac{(p_t - c_t)q_t}{(1+r)^t} - F(k) > 0 \tag{2}$$

where $F(k)$ is the discounted present value of fixed construction costs over the k periods that construction takes place. This equation implies that the investment will be undertaken if the discounted present value at period $t = 0$ of variable profits from operating a plant that comes on line in period k exceeds the period $t = 0$ discounted present value of the up-front fixed costs.

343. The time path of future prices also impacts the construction decision. Suppose that price equals the marginal cost of the generation unit for the first K periods and then price is substantially larger than the marginal cost for the remaining $T - K$ periods. Mathematically, this means $p_s = c_s$, for $s = 1, \dots, K$, but $p_s \gg c_s$, for $s = K + 1, \dots, T$, and so much so that the inequality in (2) is satisfied. In other words, the new entrant expects to earn zero variable profits for K periods, but the variable profits in periods $K + 1$ to T are so large that the investment decision makes economic sense.

5.3.4 Uncertainty and the importance of fixed-price forward contract obligations in financing new generation capacity investments

344. The above discussion raises an issue that becomes more important when uncertainty is factored into the entry decision. A strategy that delays the investment, and instead gathers more information, may have a larger expected discounted present value of variable profits (revenues in excess of variable costs) than investing in the current period. For example, if a profit-maximizing new entrant knew that it would earn negative variable profits for K periods, it would not invest to produce in those periods, and instead would delay this decision to begin production in period $K + 1$ when variable profits first turn positive. For this reason, there are instances when the long-run marginal cost of new generation is larger or smaller than the current market price, yet generation unit owners are constructing new capacity. This occurs because of their expectations about future short-term prices, short-run marginal costs and annual fixed costs. Alternatively, the entrant may have signed fixed-price forward contracts for energy that guarantee the prices the owner receives in future periods when the unit is operating. This fixed-price forward contract typically guarantees the unit owner a fixed revenue stream for a fixed quantity of output each half-hour period for finite period of time.

345. Adding uncertainty into this analysis does not complicate the basic insight described above, that the decision to invest in new capacity depends on the future time path of short-term prices and variable input costs relative to the up-front construction costs and other non-volume-variable costs. This decision rule follows from the fact that once the fixed cost of constructing the generation unit has been incurred, the vast majority of these costs cannot be recovered unless the unit produces electricity. Assuming that both future short-term electricity prices and input prices are uncertain, if the firm maximizes expected profits, it will construction the new generation unit if the expected discounted present

value of the revenues it earns from building the generation unit discounted at the appropriate risk-adjusted rate of interest, r_r, is greater than the expected discounted present value of the up-front construction costs discounted at that same risk-adjusted rate of interest. Mathematically, the decision rule becomes:

$$\sum_{t=1+k}^{T+k} \frac{E[(p_t - c_t)q_t]}{(1+r_r)^t} - E(F(k,r_r)) > 0, \tag{3}$$

where E(x) denotes the expected value of the random variable x given the information available to the firm at the time the investment decision is made and $F(k,r_r)$ is the realized discounted present value of construction costs discounted at the risk-adjusted rate r_r.

346. Expression (3) illustrates the risk-mitigation benefits to a supplier from signing a fixed-price forward contract obligation or committing to supply retail load at a fixed-price for a sustained period of time. Suppose that p_t^f is the fixed forward price of energy in period t that a supplier commits to receive for the contracted level of output in period t, q_t^f, in a fixed-price forward contract. Under these conditions the supplier's revenue stream from fulfilling this fixed-price forward contract obligation and selling the excess energy it produces or purchasing the deficit it is unable to produce from the short-term market yields the following payment stream for the owner of the new generation unit:

$$\sum_{t=1+k}^{T+k} \frac{[(p_t^f - c_t)q_t^f]}{(1+r_s)^t} + \sum_{t=1+k}^{T+k} \frac{E[(p_t - c_t)(q_t - q_t^f)]}{(1+r_r)^t} - E(F(k,r_r)) > 0. \tag{4}$$

347. The first term is a fixed payment that the new entrant will receive for selling the fixed-price forward contract for T periods into the future. The only risk associated with this payment stream is that associated with whether or not the counterparty to the contract will make the payments, so it is discounted at a lower rate than the second term, which implies $r_s < r_r$. The second term is the time path of payments that the supplier will receive or costs that it will incur for producing more energy than its contract quantity or less energy than its contract quality during time period t. This term is stochastic because both the amount sold in the short-term market, q_t, and the short-term market price, p_t, are both uncertain. Note that a supplier can mitigate or completely eliminate this exposure to short-term electricity prices by making the absolute value of the difference between the amount it produces, q_t, and its forward market obligation, q_t^f, as small as possible.

348. Expression (4) underscores the importance of fixed-price forward contract obligations for financing new generation capacity investments, particularly if suppliers are risk averse. A fixed-price forward contract signed at the time construction of the new plant begins for a quantity of energy close to what the plant expects to produce over its lifetime or for a substantial portion of its lifetime, provides the new entrant with a very reliable revenue stream that should lower the average price necessary to cause this supplier to construct a new generation unit. Because the revenue stream earned by the supplier under a fixed-price and quantity forward contract is less risky than the revenue stream the supplier would earn from only selling in the short-term market, the quantity-weighted average price over the life of the forward contract can be less than the expected quantity-weighted average short-term market price and still cause even an expected profit-

maximizing supplier to invest in the generation unit. Specifically, the following equality can hold, even if equation (4) holds:

$$\sum_{t=1+k}^{T+k} \frac{p_t^f q_t}{\sum_{t=1+k}^{T+k} q_t} - \sum_{t=1+k}^{T+k} \frac{E(p_t) q_t}{\sum_{t=1+k}^{T+k} q_t} < 0, \tag{5}$$

where the first term is the quantity-weighted average forward contract price weighted by the supplier's actual output and the second term is the quantity-weighted average expected short-term price weighted by the supplier's actual output.

349. Expression (5) demonstrates that suppliers should have a strong incentive to sign fixed-price forward contracts when they are considering constructing a new generation unit. Moreover, as the discussion of Section 3 demonstrates, with high levels of fixed-price forward contract obligations relative to their actual output levels, suppliers have little incentive to exercise unilateral market power in the short-term market. With very little incentive to exercise unilateral market power in the short-term market, by the logic of Section 3, suppliers will submit offer curves very close to the short-run marginal cost curve associated with the existing amount and mix of generation capacity that they own.

350. If all suppliers have high levels of fixed-price forward contract obligations relative to their expected sales in the short-term market, then all suppliers will submit offer curves very close to their short-run marginal cost curve and the aggregate industry willingness-to-supply curve will equal the aggregate marginal cost curve. If the aggregate industry willingness-to-supply curve is equal to the aggregate marginal cost curve, then short-term market prices will be very close the competitive benchmark price. Finally, depending on the level of demand and total amount of generation capacity, these competitive benchmark prices can be above or below both the short-run and long-run average cost of producing electricity for each supplier.

5.3.5 Factors impacting estimated competitive benchmark prices

351. The logic described above implies that a major determinant of the magnitude of the difference between the actual price and competitive benchmark price in a market where there are a few suppliers that own a substantial fraction of the available generation capacity (such as New Zealand) is the extent of fixed-price forward contract obligations and fixed-price retail load obligations of these suppliers relative to the expected level of output of these generation unit owners. If there are no suppliers with substantial net long positions in the short-term market, then even large suppliers with a substantial ability to exercise unilateral market power are likely to have little incentive to exercise it in the short-term market.

352. Another determinant of the level of the competitive benchmark price is the amount of hydro-electric energy available, because with less water stored or lower expected water inflows, fossil-fuel generation units must be run more frequently and more expensive fossil-fuel units must be run more frequently, which implies higher average wholesale market prices. However, it is important to emphasize the point made in Section 3 that a fossil fuel generation unit owner with no ability to exercise unilateral market power will

submit offer curves equal to its marginal cost of producing electricity, regardless of how much water is available to produce electricity or the level of expected water inflows.

5.4 Constructing the no-market-power aggregate willingness to supply curve

353. This section explains the methodologies used to estimate the no-market power hydroelectric generation supply curve. The methodology used to estimate the short-run marginal cost curve for fossil fuel generation units is also presented. We use two conservative approaches to calculating upper bounds on the no-market power hydroelectric supply curve. This implies two sets of prices for our single-pricing zone competitive benchmark pricing approach.

354. Because the transmission network configuration in New Zealand and the use of nodal-pricing may impact the competitive benchmark price estimate we construct a model to replicate the nodal price-setting process in the New Zealand market. We then input offer curves from the two approaches to computing the no-market power hydroelectric capacity supply curves and our no-market power fossil generation supply curve to this nodal pricing model to compute two sets of competitive benchmark nodal prices.

5.4.1 Estimating the marginal cost of fossil fuel generation units

355. For the case of fossil fuel-based units, the process of constructing an estimate of the generation unit's marginal cost is relatively straightforward, as is discussed in Borenstein, Bushnell and Wolak (2002).[46] If the analyst has the heat rate of the generation unit (the rate at which the heat energy of the input fuel is converted to electricity) and the price of the input fossil fuel, then the marginal fuel cost is constructed as the product of these two magnitudes. For example, if the heat rate of a coal-fired unit is 10 gigajoules (GJ) per MWh and the price of coal is $2.50 per GJ, then the marginal fuel cost of the unit is $25 per MWh (= 10 GJ/MWh x $2.50/GJ). The other component of the marginal cost of the generation unit is the variable operating and maintenance cost, which is typically in the range of $5/MWh. The marginal cost of a fossil fuel generation unit is the marginal fuel cost plus the variable operating and maintenance cost. The no-market power willingness-to-supply curve for a supplier's portfolio of fossil fuel units is equal to the aggregate marginal cost curve for all of those generation units constructed as described above.

356. As discussed in Section 2.8, monthly input fuel price and usage data were collected from each of the large fossil fuel generation unit owners for period January 1, 2001 to July 31, 2005. For the period August 1, 2005 to June 30, 2007, fossil fuel price data was compiled from public reports by the generation unit owners of their input fuel costs, combined with aggregate quarterly data from the Energy Data File produced by the Ministry of Economic Development. Average heat rates for each fossil fuel unit were calculated by dividing total fuel usage for each unit over the period January 1, 2001 to July 31, 2005 by the total generation for that unit over this period. These heat rates are assumed to be constant over time and for different output levels from the same unit. This

[46] Borenstein, Bushnell & Wolak, 2002, "Measuring Market Inefficiencies in California's Restructured Wholesale Electricity Market", American Economic Review, 92 (2002), pp. 1376-1405.

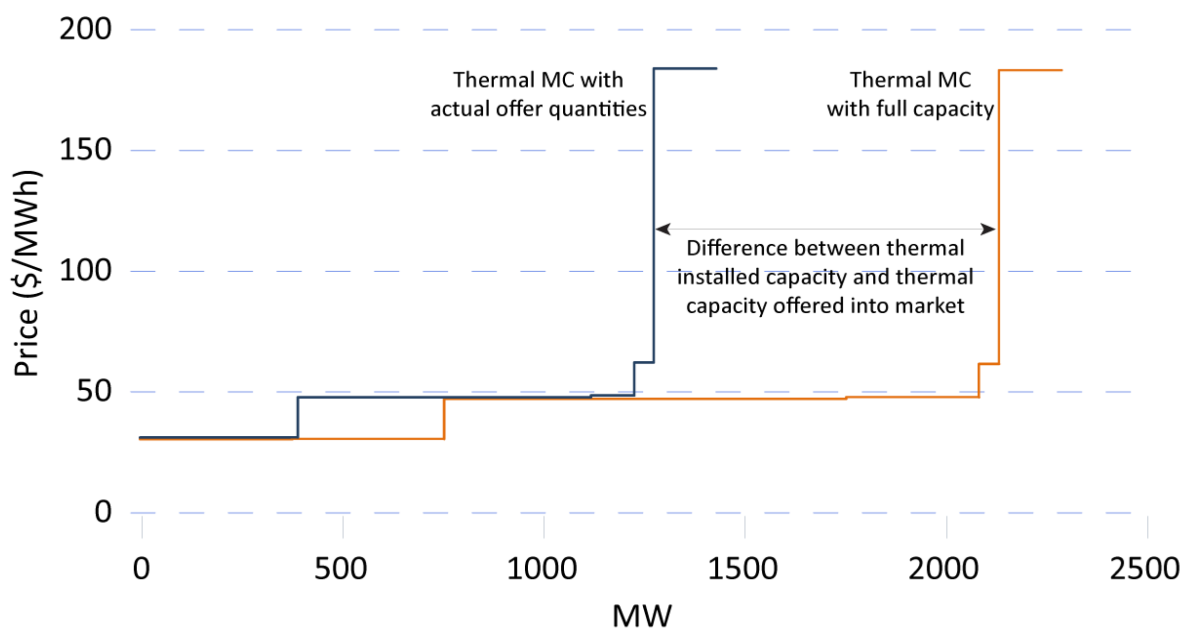
is a simplifying assumption, because, in practice, heat rates can vary across the maintenance cycle of the generation unit and by its level of output. This assumption is likely to have little material effect on competitive benchmark pricing results, because the average heat rate will be too high in some periods and too low in others, and for the most part these errors will tend to cancel out when summed across periods to produce the summary statistics on market power rents that we report below.

357. Rather than attempt to compute unit-specific variable operating and maintenance costs, an upper bound on the plausible range of variable operating and maintenance costs based on an international comparison of operating and maintenance costs was used. A value of $4.00/MWh was used for combined cycle gas turbines and $6.50/MWh for combustion turbines and steam plants. Reasonable changes in these magnitudes do not materially impact our market power rent calculations.

358. Figure 5.5 plots the aggregate marginal cost curve for fossil fuel generation units for a half-hour period in July 2005, assuming all suppliers make all of their generation capacity available to the market. Suppliers typically make available only a portion of their generation capacity because of planned or forced outages, or because they find it unilaterally expected profit-maximizing to withhold generation capacity from the short-term market. To demonstrate this behavior, Figure 5.5 also plots the aggregate marginal cost curve for fossil fuel generation with the length of each step equal to the capacity of the unit offered into the short-term market during period 20 on July 2, 2005.

359. That is, if a generation unit is offered into the short-term market the height of each step is the same, but the length of each step is often shorter than the maximum capacity of the generation unit. The Whirinaki Reserve Generation unit is included in both offer curves, despite the fact that this unit is owned by the New Zealand government and its offer behavior is managed by the Electricity Commission and Electricity Governance Rules.

Figure 5.5: Installed and Offered Thermal Capacity for 2 July 2005, Period 20



Source: Calculations based on offer data from Centralised Data Set and EMS, fuel price and usage data from Contact Energy, Genesis Energy and MED, and publicly reported generation capacity from plant owners and MED.

5.4.2 Two approaches computing no-market power willingness-to-supply curve for hydroelectric generation

360. Computing the no-market power willingness-to-supply curve for hydroelectric facilities is complicated by the fact that there is no explicit cost of using water to produce electricity, similar to the fuel cost for fossil fuel generation units. The owner of a hydroelectric unit has the option to use stored water to produce electricity during any hour of the day, week, month or year, subject to the technical operating constraints of their generation unit. A supplier with a finite amount of water behind the dam that has no ability to exercise unilateral market power can be expected to find it profit-maximizing to sell this water during the highest priced half-hours of the year.

361. For example, if the supplier has 100 half-hours of water that it can use to produce energy at the capacity of its generation unit during each of these half-hours, and the supplier is able to sell this water during any half-hour of the year because of its ability to store water, then it is expected profit-maximizing for a supplier with no ability to exercise unilateral market power to sell its water in the 100 highest-priced half-hours of the year. The supplier would accomplish this by offering to sell energy during all hours of the year at an offer price equal to its estimate of the lowest price that will occur during the 100th highest-priced half-hour period of the year. For this supplier, the opportunity cost of water is the market price that will occur during the 100th highest-priced half-hour period of the year. In a market where no suppliers have the ability to exercise unilateral market power, this opportunity cost would be equal to the marginal cost of the highest cost fossil fuel unit operating during the 100th highest-priced half-hour of period of the year.

362. This offer price strategy is expected profit-maximizing for a hydroelectric supplier with no ability to exercise unilateral market power only if that supplier has sufficient storage capacity to hold all of the water it receives throughout the year and use it only during the 100 highest priced half-hours of the year. For example, suppose that the owner of a 100 MW unit is only able to store 1,000 MWh of energy behind the dam, but inflows arrive at a rate of 100 MWh per day. These inflows imply that over the course of the year, the generation unit owner can produce 36,500 MWh = 365 days x 100 MWh per day. Based on the nameplate capacity of the generation unit, the supplier could produce its maximum output during the 365 highest priced hours of year. However, if these 365 highest-priced hours are too close together, the unit owner will be unable produce its maximum output during all of these hours because it will run out of water. Specifically, if there are more than 10 of these highest-priced hours in a day, the unit owner cannot sell its maximum output during all of these hours because it cannot store enough water to do so. In addition, if the amount of time between these highest-priced hours is greater than 10 days, the generation unit owner must use some stored water to produce electricity or spill water without producing electricity.

363. Consequently, an expected profit-maximizing generation unit owner with no ability to exercise unilateral market power will have to sell at a price lower than the price during 365th highest-priced hour of the year or spill water over the dam and produce no electricity and receive no revenues for this water. The existence of these dynamic operating constraints greatly complicates the process of computing the opportunity cost of water for a hydroelectric generation unit owner with no ability to exercise unilateral market power.

364. Computing the no market power offer price for a hydroelectric supplier would involve, at a minimum, solving a stochastic dynamic programming problem to schedule all hydroelectric units in New Zealand assuming that all fossil fuel suppliers submit their no-market power willingness-to-supply curve. This model would dispatch the hydroelectric generation units to minimize the expected discounted present value of the fossil fuel generation costs and the operating costs of all other generation units associated with serving load into the distant future, assuming a stochastic process for the distribution of future water inflows in each water basin, a stochastic process for the distribution of future demand at all locations in New Zealand, and a cost of deficit parameter to value the cost of a water supply shortfall. As discussed in Wolak (2008)[47], a similar process is used to dispatch the hydroelectric system in the Brazilian electricity supply industry. Constructing such a model would be an extremely complex task that is fraught with substantial uncertainties, and as the experience of Brazil described in Wolak (2008)[48] illustrates, the resulting competitive benchmark prices are likely to be extremely sensitive to assumptions about the future distribution of water inflows and load growth as well as a number of other modeling assumptions.

[47] Wolak, F.A. (2008) "Options for Short-Term Price Determination in the Brazilian Wholesale Electricity Market: Report Prepared for Cámara de Comercialização de Energia Eléctrica (CEEE), available at http://www.stanford.edu/~wolak.

[48] Ibid.

5.4.2 Counterfactual 1 approach to computing single pricing-zone competitive benchmark prices

365. The first approach to computing the single pricing-zone competitive benchmark prices assumes that the hydroelectric supplier does not re-allocate hydroelectric production across half-hours under the no-market-power assumption. The simplifying assumption that hydroelectric suppliers continue to produce the same amount of energy in each half-hour period under competitive benchmark pricing is likely to lead to higher quantity-weighted average competitive benchmark prices than the competitive benchmark price computed as the solution of a stochastic dynamic program.

366. This upward bias in the competitive benchmark price occurs because this assumption implies less hydroelectric energy is produced during periods where higher marginal cost fossil fuel units operate and the aggregate fossil fuel marginal cost curve is steeper, and more hydroelectric energy is produced during periods when lower marginal cost fossil fuel units operate and the aggregate fossil fuel marginal cost curve is flatter. Consequently, this assumption for computing the competitive benchmark prices is conservative in terms of yielding average competitive benchmark prices that are likely to be too high. The Appendix of Borenstein, Bushnell and Wolak (2002) rigorously demonstrates that the simplifying assumption that hydroelectric suppliers do not re-allocate water will yield a higher system-load weighted average competitive benchmark price than would be the case if this competitive benchmark price was computed from the solution to the optimal hydroelectric generation scheduling problem described above.[49]

367. To further bias our results against finding a competitive benchmark price that is too low and market power rents that are too high, we estimate the no-market-power fossil fuel offer curve using the actual capacity offered into wholesale market by each hydroelectric generation unit during that half-hour, rather than the nameplate capacity of the generation unit. This assumption implies that all capacity withholding to exercise unilateral market power in actual market outcomes by fossil fuel generation unit owners is included in the no-market-power fossil fuel offer curve. Only the offer prices associated with each actual offer quantity are reset to their marginal cost. Figure 5.5 illustrates how more supply is available at every price level if nameplate capacity is used instead of the unit's actual quantity offers.

368. The construction of the Counterfactual 1 competitive benchmark price for this no-market power aggregate offer curve for thermal suppliers is shown in Figure 5.6. The no-market power thermal offer curve is the non-decreasing step function drawn from left to right. Each step of the no-market power aggregate thermal offer curve has height equal to the marginal cost of that generation unit and length equal to the actual capacity the supplier offered into the market from that generation unit during that half hour. As discussed above, the length of each step is typically significantly less than the nameplate

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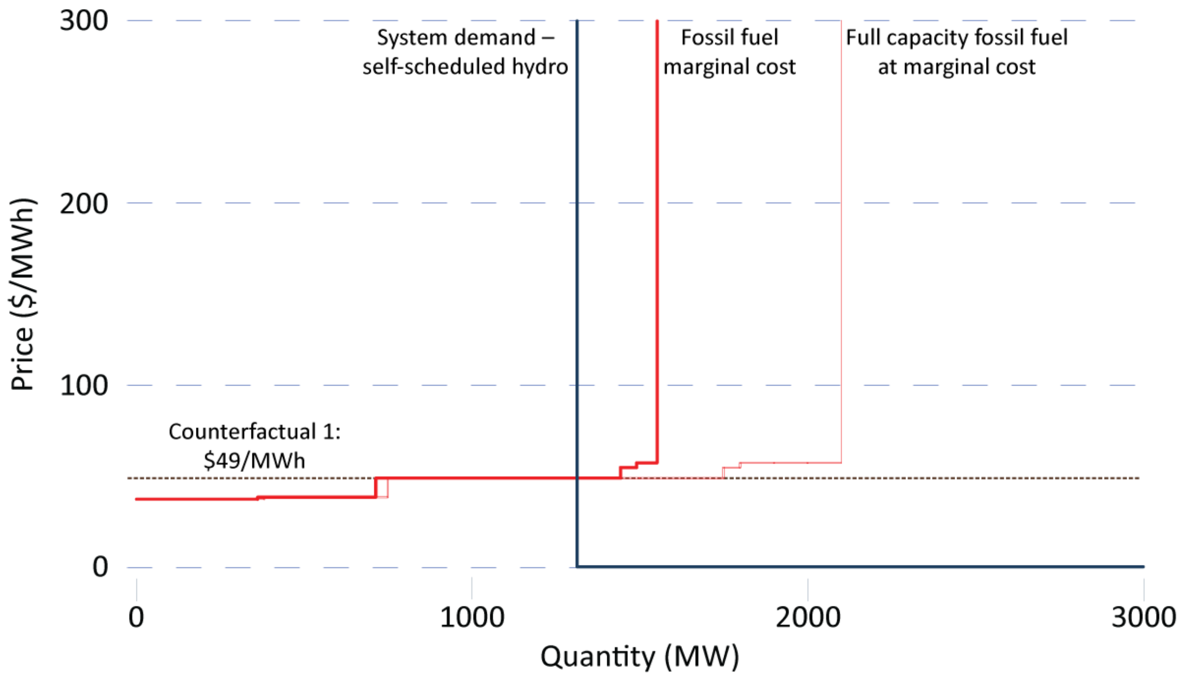
[49] Borenstein, Bushnell & Wolak, 2002, "Measuring Market Inefficiencies in California's Restructured Wholesale Electricity Market", American Economic Review, 92 (2002), pp. 1376-1405.

capacity of the respective generation unit. The price where the no-market power thermal offer curve that uses actual quantity offers intersects the market demand for that half-hour less the amount of hydroelectric energy supplied during that half-hour determines the first upper bound on the true competitive benchmark price.

369. To demonstrate the difference between using the actual quantity offers rather than the maximum nameplate capacity of the fossil fuel unit to compute the no-market power fossil fuel offer curve, Figure 5.6 also plots the aggregate marginal cost curve for all fossil fuel units in New Zealand assuming their nameplate capacity is offered into the market at the marginal cost of the generation unit.

Figure 5.6: Construction of No-Market-Power Counterfactual 1



5.4.3 Counterfactual 2 approach to computing single pricing-zone competitive benchmark prices

370. Our second approach to computing an upper bound on the competitive benchmark price recognizes that if a hydroelectric supplier produces one more MWh of electricity when a fossil fuel generation unit is operating, it is reducing the total cost of supplying electricity in that half-hour by the marginal cost of the highest cost fossil fuel generation unit operating during that half-hour. Unless all fossil fuel generation units in New Zealand operate at their maximum capacity during a half-hour period of an annual hydro cycle, which is a necessary but not sufficient condition for a period of true scarcity of fossil fuel generation capacity, the opportunity cost of water should never exceed the highest marginal cost fossil fuel generation unit in the New Zealand system. Consequently, the Counterfactual 2 approach to computing the competitive benchmark price uses the actual hydroelectric quantity increments for each half-hour, but caps the offer prices associated with each quantity increment at the marginal cost of the highest cost fossil fuel unit in New Zealand at that time. The offer price associated with each

offer quantity is the minimum of the actual offer price and the marginal cost of the highest cost fossil fuel unit.

371. A period of true scarcity of fossil fuel generation capacity would exist if there was a half-hour period during the period January 1, 2001 to December 31, 2007 when all fossil fuel units were operating at their maximum capacity. The event that all fossil fuel units in New Zealand were operating at their maximum capacity does not appear to have occurred during our sample period. Generation units can and periodically do operate beyond their nameplate capacity. So the yearly maximum half-hourly generation from a fossil fuel generation unit may exceed its nameplate capacity by more than 10 percent. Define the maximum capacity for a generation unit for 2001 as the maximum half-hourly generation quantity over all 17,520 half-hours in the year. For subsequent years, we allow this maximum capacity value to increase if the generation quantity in any half-hour is greater than the previous observed capacity.

372. If the maximum capacity of each fossil fuel generation unit is measured in this manner, there are no half-hour periods during the period January 1, 2001 to December 31, 2007 when all fossil fuel units in New Zealand were simultaneously operating at close to maximum capacity. The highest system-wide half-hourly fossil fuel capacity utilization rate—the ratio of total half-hourly generation to the total of the maximum available generation unit capacity for that year—is 95 percent in 2001. Table 5.1 presents the percentiles of annual half-hourly fossil fuel capacity utilization rate distributions for 2001 to 2007 for this measure of generation capacity. By this measure of maximum annual capacity, there are few half-hour periods with a fossil fuel capacity utilization rate above 90%, and these all occur in 2001. Figure 5.7 plots the maximum fossil fuel capacity for each day in the sample period (the red line) and the maximum half-hourly generation from fossil fuel units for that day (the blue dots). At no point during the sample period does maximum daily half-hourly generation come close to the maximum fossil fuel capacity

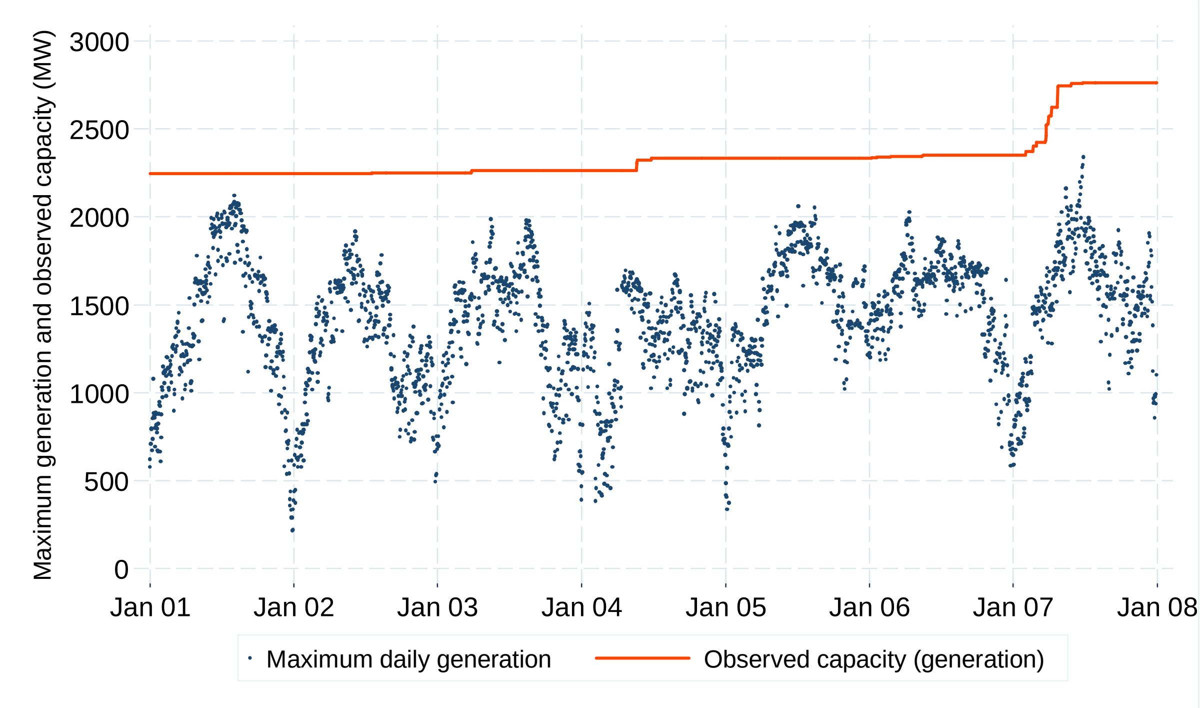
373. A more conservative measure of the maximum generation capacity from a fossil fuel generation unit is based on the maximum half-hourly offer quantity from the generation unit owner over all 17,520 half-hours in the year. For subsequent years, we allow this maximum capacity value to ratchet up if the offer quantity in any half-hour is greater than the previous observed quantity. If the maximum capacity of each fossil fuel generation unit is measured in this manner, then actual generation does not exceed maximum generation capacity in any half-hour periods during the sample period. Table 5.2 presents the percentiles of annual half-hourly fossil fuel capacity utilization rate distributions for 2001 to 2007 for this measure of generation capacity. The maximum half-hourly capacity utilization rate is 97.6%, which occurs in 2001. Figure 5.8 plots the maximum fossil fuel capacity for each day in the sample period (the blue does) and the maximum half-hourly generation from fossil fuel units for that day (the red line). Even for this conservative measure of the maximum available fossil fuel capacity, at no point during the period January 1, 2001 to December 31, 2007 (besides July 2001) does the maximum daily half-hourly generation come close to maximum fossil fuel capacity.

Table 5.1: Capacity utilization (generation) at fossil fuel plants, 2001–07

Year	Percentiles of the distribution of capacity utilization						
	Min	1st	25th	Median	75th	99th	Max
2001	2.3%	8.2%	43.6%	55.5%	69.1%	89.8%	94.4%
2002	9.8%	15.4%	33.8%	45.6%	58.3%	79.6%	85.4%
2003	10.6%	18.5%	39.3%	52.3%	63.9%	82.2%	87.8%
2004	9.1%	14.9%	32.8%	42.6%	53.4%	71.1%	74.8%
2005	10.4%	14.7%	47.9%	58.2%	68.7%	83.4%	88.4%
2006	14.3%	19.7%	51.4%	60.6%	68.0%	80.0%	86.4%
2007	12.3%	19.5%	42.0%	50.6%	58.0%	75.2%	84.7%

Source: Calculations based on generation data from Centralised Data Set and EMS.

Figure 5.7: Maximum daily generation and observed capacity (gen) for fossil fuel plants



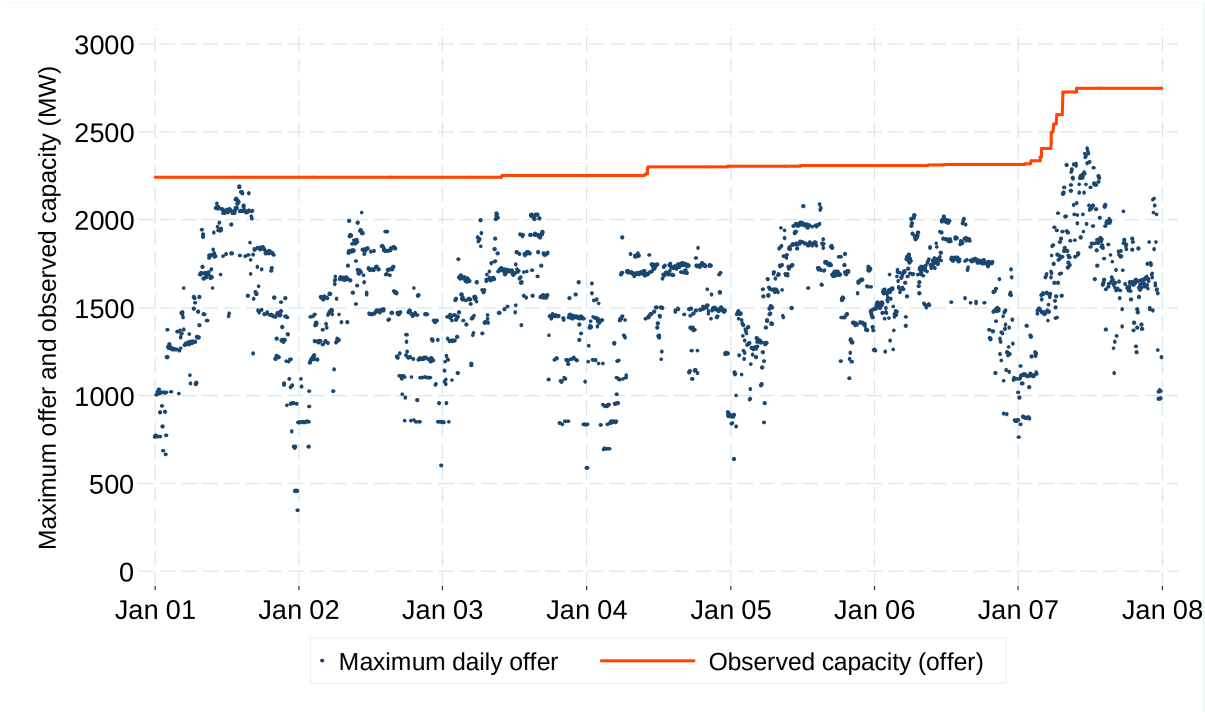
Source: Calculations based on generation data from Centralised Data Set and EMS.

Table 5.2: Capacity utilization (offer) at fossil fuel plants, 2001–07

Year	Percentiles of the distribution of capacity utilization						
	Min	1st	25th	Median	75th	99th	Max
2001	4.6%	15.6%	54.3%	64.7%	80.2%	94.2%	97.6%
2002	22.3%	26.8%	49.0%	58.4%	70.5%	86.1%	91.0%
2003	12.5%	33.9%	53.9%	65.1%	75.3%	89.9%	90.7%
2004	24.9%	26.1%	51.4%	63.0%	73.4%	79.3%	84.4%
2005	24.5%	32.4%	55.6%	67.9%	75.4%	85.6%	90.6%
2006	26.6%	36.6%	62.3%	70.6%	75.9%	86.2%	87.8%
2007	28.4%	35.1%	51.0%	59.2%	66.5%	84.8%	87.6%

Source: Calculations based on offer data from Centralised Data Set and EMS.

Figure 5.8: Maximum daily offer and observed capacity (offer) for fossil fuel plants

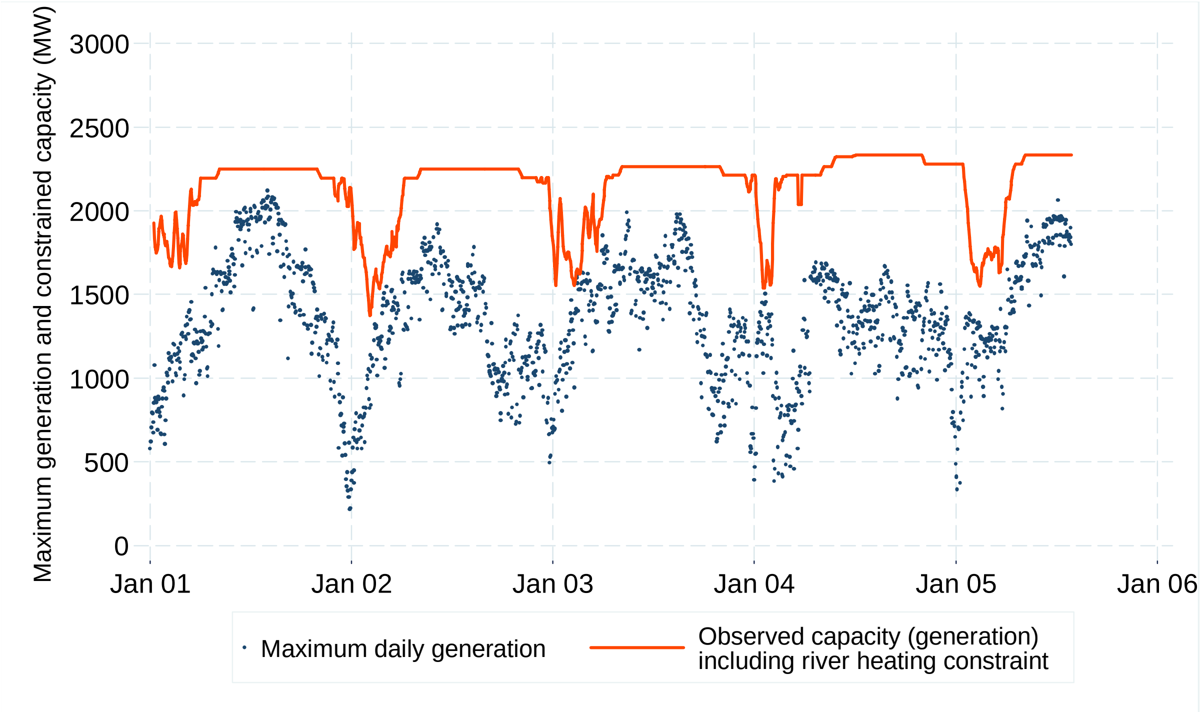


Source: Calculations based on offer data from Centralised Data Set and EMS.

374. The Huntly generation units sometimes face environmental river heating constraints on the amount of capacity that these units can make available to the wholesale market. Information on these constraints was provided for the period January 1, 2001 to July 31, 2005. Figure 5.9 repeats the information in Figure 5.7 taking into account the constraints on the maximum capacity that the Huntly units can make available each day due to these river heating constraints. Table 5.3 repeats the calculations in Table 5.1 taking into account these constraints on the maximum daily available generation capacity. The maximum daily generation never meets the maximum daily available generation capacity

accounting for these heating constraints at any time during this time period, and in most cases the difference is significant.

Figure 5.9: Maximum daily generation and observed capacity (gen) including river heating



Source: Calculations based on generation data from Centralised Data Set and EMS, and Huntly river heating constraint data from Genesis Energy.

Note: Constrained capacity including river heating is calculated as the seven-day moving average of the minimum daily capacity.

Table 5.3: Capacity utilization (generation) including river heating constraints, 2001–05

Year	Percentiles of the distribution of capacity utilization						
	Min	1st	25th	Median	75th	99th	Max
2001	2.3%	8.4%	45.8%	57.6%	69.3%	89.8%	94.4%
2002	11.3%	16.1%	35.6%	48.0%	61.2%	79.6%	85.4%
2003	10.9%	18.6%	41.0%	54.2%	65.9%	82.3%	87.8%
2004	9.3%	15.2%	33.2%	43.6%	55.1%	72.1%	78.9%
2005	10.7%	15.0%	51.5%	58.9%	69.0%	83.4%	88.4%

Source: Calculations based on generation data from Centralised Data Set and EMS, and Huntly river heating constraint data from Genesis Energy.

375. The results in Figures 5.7 to 5.9 and Table 5.1 to 5.3 imply that the opportunity cost of water should not exceed the highest variable cost fossil fuel generation unit in the New Zealand system at anytime during our sample period because true scarcity conditions for fossil fuel generation capacity did not arise. This insight yields our second and most conservative estimate of the no-market power opportunity cost of water for hydroelectric

suppliers—the marginal cost of the highest cost fossil fuel generation unit in the New Zealand system.

376. This approach implies a no-market power hydroelectric willingness-to-supply curve where all offer prices are capped at the marginal cost of the highest cost fossil fuel generation unit in the New Zealand system. This approach yields an extremely slack upper bound on the true no-market power willingness-to-supply curve for a hydroelectric supplier with no ability to exercise unilateral market power because it implies that the supplier would produce at the level of output associated with this opportunity cost of water only when the highest marginal fossil fuel unit in New Zealand was also producing. For the purposes of computing the highest marginal cost fossil fuel unit in New Zealand that caps all hydroelectric offer prices, we exclude the Whirinaki generation unit from consideration because of its status as a government-owned reserve generation unit and the special conditions under which it is offered into the wholesale market. Nevertheless, we include it in the no-market power fossil fuel supply curve to allow for the fact that it might be needed to meet system demand and therefore set the competitive benchmark price.

377. The construction of this no-market power aggregate offer curve for hydroelectric suppliers is shown in Figure 5.10. The no-market power aggregate hydroelectric offer curve is the non-decreasing step function drawn from right to left. The length of each step is equal to the actual MW offered into the market from that generation unit and the height of each step is the minimum of the actual offer price for that generation unit and the variable cost of the highest cost fossil unit in New Zealand. Use of the actual hydroelectric capacity quantity offer instead of the unit's nameplate capacity is extremely conservative against finding a low competitive benchmark price because the hydroelectric unit owners routinely submit total quantity offers for each generation unit significantly less than the nameplate capacity of the unit.

378. The point of intersection of this no-market power aggregate hydroelectric offer curve with the no-market power thermal offer curve is the counterfactual market price. To demonstrate that this approach also yields an upper bound on the competitive benchmark price, Figure 5.10 also plots the aggregate marginal cost curve for all fossil fuel units in New Zealand assuming their nameplate capacity is offered into the market at the marginal cost of the generation unit.

379. We emphasize that both of the approaches to computing competitive benchmark prices use a slack upper bound on the no-market power thermal offer curve because they do not eliminate the withholding of generation capacity from the market in constructing the no-market power thermal offer curve. The full capacity offer curves in Figures 5.6 and 5.10 demonstrate the extent to which this capacity withholding takes place for a representative half-hour period during our sample. Both approaches also do not eliminate the withholding of hydroelectric generation capacity from the no-market power hydro offer curve. For Counterfactual 1 we use the amount of hydroelectric energy actually supplied during that half-hour as the hydroelectric offer curve. For Counterfactual 2, each step of the offer curve uses the actual hydroelectric quantity offers for that half-hour period rather than the nameplate capacity of the generation unit.

380. Consequently, both approaches to computing the competitive benchmark price allow suppliers to continue to exercise unilateral market power through the quantity of generation capacity they withhold from the market in computing the no-market power offer curve. These curves assume that the thermal and fossil fuel suppliers only offer the amount of capacity from each generation unit that they actually offered in. Only the offer prices associated with these quantities are changed relative to the actual thermal and hydroelectric offer curves. These are extremely conservative assumptions against a finding that actual prices are significantly above competitive benchmark prices.

381. For both Counterfactual 1 and Counterfactual 2, we compute the value of the competitive benchmark price for all half-hours in our sample period. For the reasons, discussed above, both of these approaches conservative yield upper bounds on the no-market power price for that half-hour. The difference between the actual market price and this competitive benchmark price is the per MWh cost of suppliers exercising unilateral market power. Multiplying this difference by the total demand for electricity yields an estimate of the total market rents in the wholesale market.

5.4.3 Two approaches to computing competitive benchmark nodal prices

382. To address the concern that the single zone competitive benchmark pricing approach described above may be inappropriate for the New Zealand market, we also modified this procedure by computing competitive benchmark nodal prices using the full network model for the New Zealand market obtained from Transpower. This procedure is extremely computationally intensive, because it requires solving a large-scale linear programming problem for each half-hour period. It also has much more demanding data requirements, since solving the model requires knowledge of the transmission network configuration and net withdrawals at each node on the network in every half-hour. This approach produces a counterfactual no-market-power price at each node in the New Zealand market.

383. At first we planned to compute these counterfactual nodal prices for our entire sample period for each approach, but the close agreement between the cost of market power from the single zone and nodal pricing approaches for a number of randomly chosen subsets of the sample period combined with the substantial amount of computer time necessary to solve these problems for each half-hour period caused us to abandon computing these counterfactual prices for the entire sample period. The close agreement between the single zone and nodal pricing approaches is not surprising given the very low frequency of transmission congestion in the New Zealand market during our sample period. As noted in Wolak (2006)[50], transmission congestion in the New Zealand market is infrequent, with most locational price differences due to the fact that transmission losses are priced.

[50]Wolak, F.A. (2006) "Preliminary Report on the Design and Performance of the New Zealand Electricity Market," attached as Appendix 2.

5.4.3.1 Nodal-pricing analogue to Counterfactual 1

384. To compute the fixed-hydroelectric production competitive benchmark nodal prices, we assume that all hydroelectric units continue to produce at their actual level output at their location in the transmission network in the counterfactual market outcome and use actual offer quantity at an offer price equal to the unit's the marginal cost for each fossil-fuel generation unit its location in the transmission network. With these location specific offer curves, we solve for the nodal prices by minimizing the as-offered costs of serving actual nodal demand. This solution assumes that the fossil-fuel generation unit owner makes the same amount of capacity available under the competitive benchmark pricing solution as was actually made available, so that supplier is assumed to continue to exercise market power by withholding quantity under the no-market power generation unit-level fossil fuel willingness-to-supply curves.

385. The only difference between the actual offer curve submitted and the competitive benchmark offer curve is the offer price of the generation unit. This is set equal to the generation unit's marginal cost. This process yields the nodal-pricing analogue to the Counterfactual 1 competitive benchmark prices and is very conservative against finding low competitive benchmark nodal prices because quantity-withholding from both hydroelectric and fossil fuel suppliers persists under the no-market power solution.

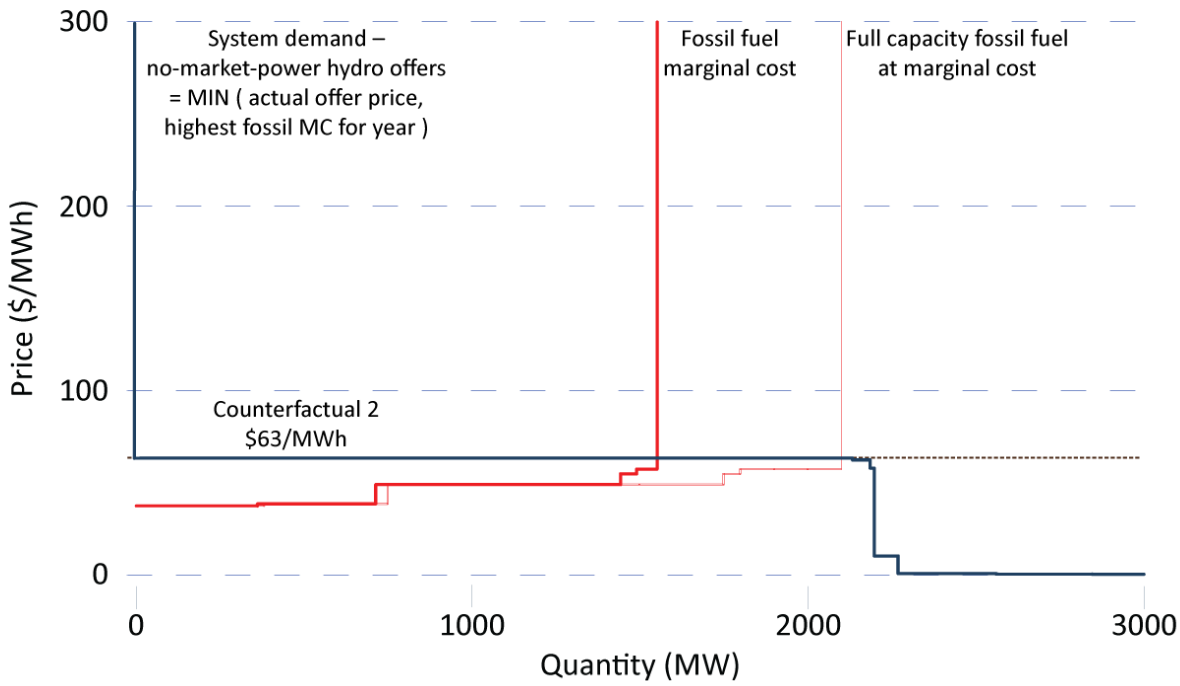
5.4.3.2 Nodal-pricing analogue to Counterfactual 2

386. To compute the nodal-pricing analogue to the Counterfactual 2 competitive benchmark price, the actual hydroelectric offer quantity submitted by each generation unit is used. The associated offer price for each offer quantity is equal to minimum of the actual offer price and the marginal cost of the highest cost fossil fuel unit in New Zealand, regardless of whether that unit offered to sell in the New Zealand market during that half-hour period. Using these no-market power hydroelectric generation unit-level offer curves and the no-market power offer curve for each fossil-fuel generation unit, we minimize the as-offered costs of serving actual nodal demand.

5.4.3.3 Procedures to validate nodal-pricing models

387. To quantify the accuracy of our nodal pricing algorithm for replicating actual market prices, we also perform a number of simulation exercises. First, we compare the behavior of the quantity-weighted average of all half-hourly nodal prices to the behavior of half-hourly single-pricing zone prices computed using the actual offer submitted during that half-hour and the demand during that half-hour. We also compute estimates of actual nodal prices by using the actual offers of all suppliers during that half-hour and minimize the as-offered costs of meeting actual nodal demands. The nodal prices computed by using the actual offers in our nodal-pricing model are compared to actual nodal prices and the quantity-weighted average of these nodal prices are also compared to the quantity-weighted average of actual nodal prices.

Figure 5.10: Construction of No-Market-Power Counterfactual 2



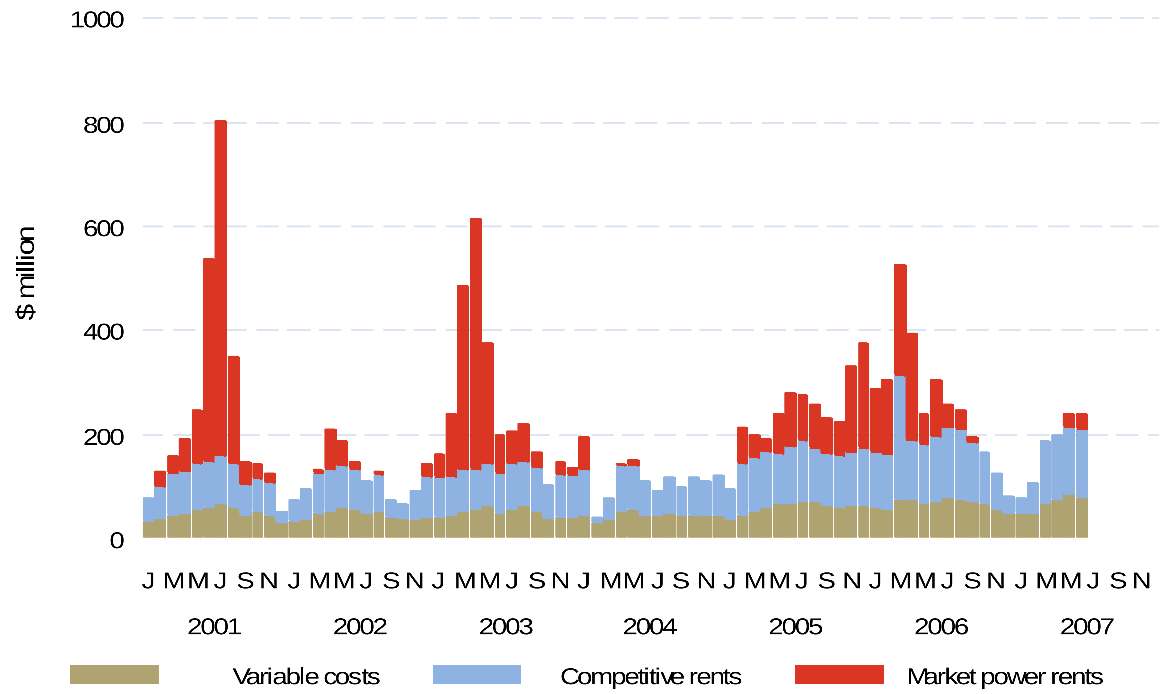
5.5 Estimates of the wholesale market cost of market power

388. Using the competitive benchmark prices, actual prices, and the marginal cost of each generation unit we can compute a decomposition of total wholesale market revenues during each half-hour. This magnitude is equal the nodal price times the quantity of energy injected at that node summed over all nodes in the system or the nodal quantity-weighted average price times the total amount of energy produced during that half-hour period. This magnitude can be decomposed into three parts: (1) market power rents equal to the difference between the actual price and competitive benchmark price times the total amount of energy produced, (2) competitive market rents equal to the difference between the competitive benchmark price times that total quantity of energy produced minus the total cost of producing that energy, and (3) the total cost of producing that energy. As noted earlier, because the nodal and single zone competitive benchmarks are very similar in most hours, we find that the market power rents under the two methods are very similar for most hours.

5.5.1 Single-pricing zone Market power rents

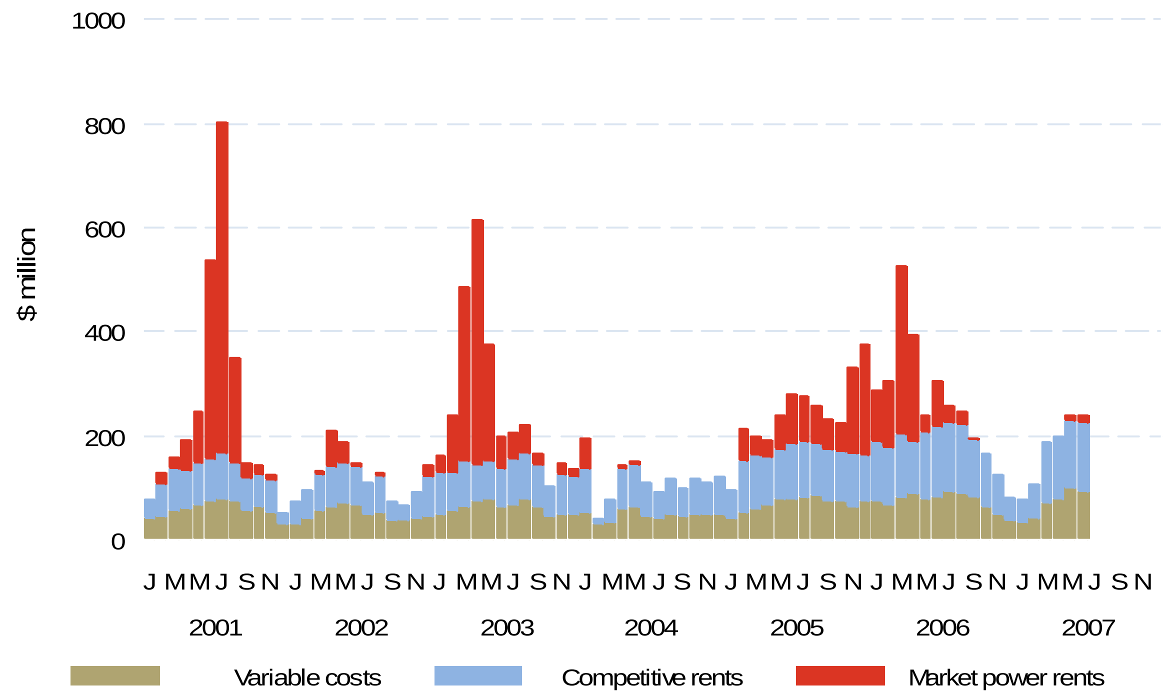
389. Figure 5.11 computes this decomposition of actual wholesale market revenues on a monthly basis for the single zone and the fixed-hydro production (Counterfactual 1) competitive benchmark price for each year in our sample from 2001 to the first half of 2007. For each monthly bar, the first box is the total variable cost of producing that electricity assuming that hydroelectric energy has an actual variable operating cost equal to $5.00/MWh. The next box gives the competitive market rents. The third box is the market power rents for that month. The sum of these three magnitudes is equal to the wholesale market revenues for that month.

Figure 5.11: Decomposition of Wholesale Market Revenues, Counterfactual 1



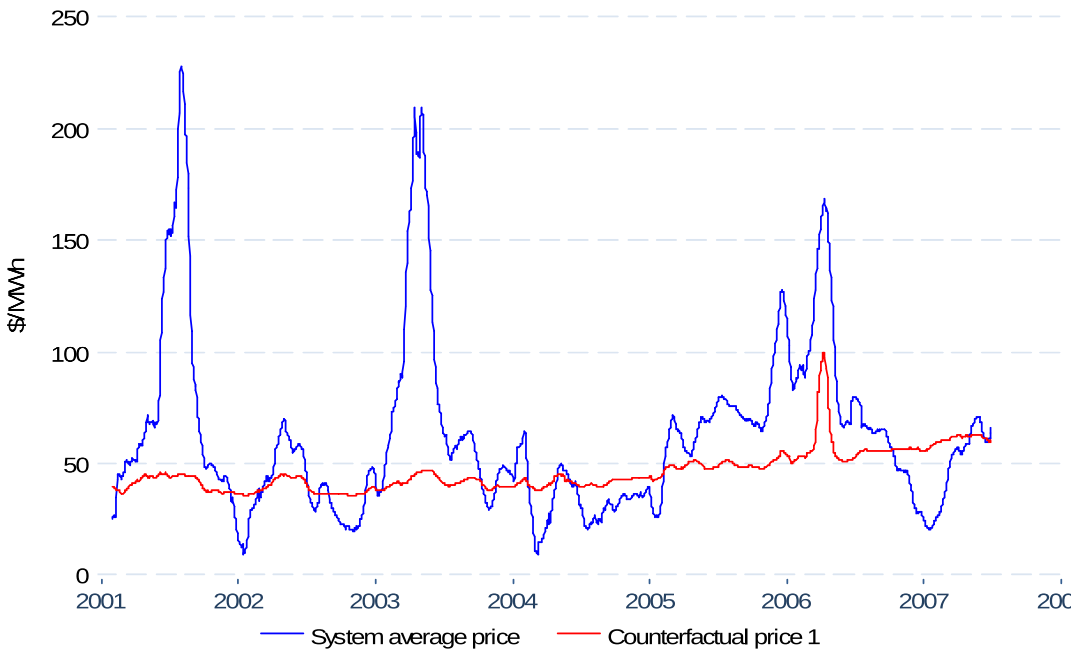
Source: Calculations as described in text using offer data from Centralised Data Set and EMS, dispatch data from M-Co, and fuel price and usage data from Contact Energy, Genesis Energy and MED.

Figure 5.12: Decomposition of Wholesale Market Revenues, Counterfactual 2



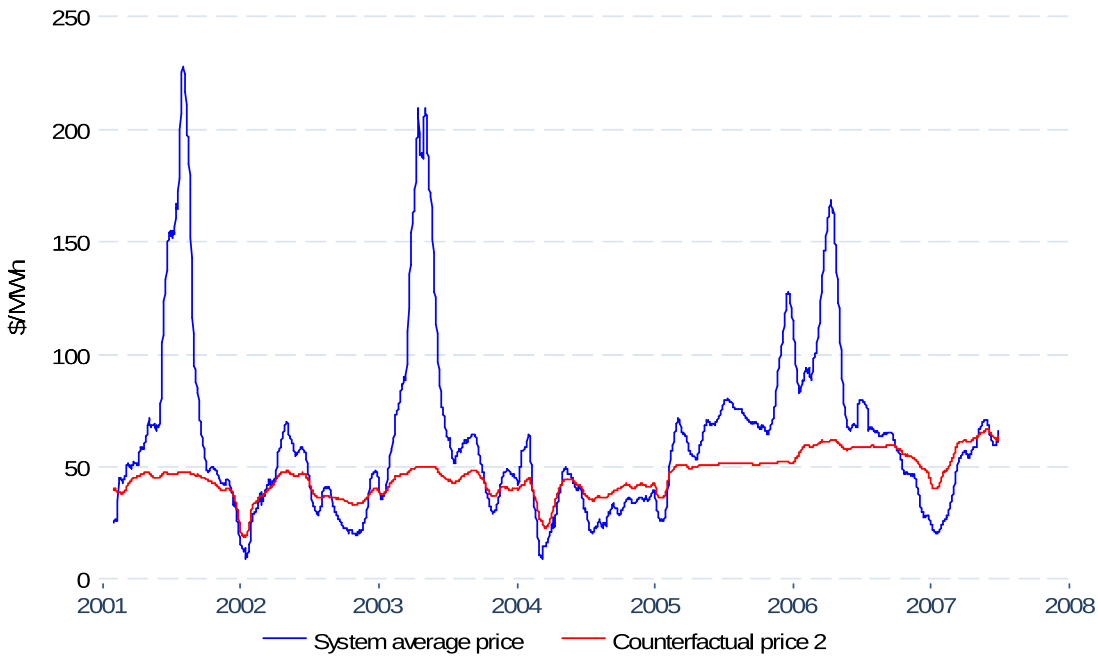
Source: Calculations as described in text using offer data from Centralised Data Set and EMS, dispatch data from M-Co, and fuel price and usage data from Contact Energy, Genesis Energy and MED.

Figure 5.13: Counterfactual 1 and System Average Prices, 30-day Moving Average



Source: Calculations as described in text using offer and generation data from Centralised Data Set and EMS, price data from Centralised Data Set, dispatch data from M-Co, and fuel price and usage data from Contact Energy, Genesis Energy and MED.

Figure 5.14: Counterfactual 2 and System Average Prices, 30-day Moving Average



Source: Calculations as described in text using offer and generation data from Centralised Data Set and EMS, price data from Centralised Data Set, dispatch data from M-Co, and fuel price and usage data from Contact Energy, Genesis Energy and MED.

390. Figure 5.12 repeats this same decomposition for the single zone version of the Counterfactual 2 approach to computing the competitive benchmark price. Figure 5.13 plots the 30-day moving average of the quantity-weighted average actual nodal prices and the 30-day moving average of the Counterfactual 1 competitive benchmark prices. Figure 5.14 plots the same 30-day moving average of actual prices and the 30-day moving average of the Counterfactual 2 competitive benchmark prices. The time series patterns of the two competitive benchmark prices are very similar. These prices fluctuate much less than actual market prices, particularly during mid-2001 and early 2003, when actual prices are often more than $100/MWh more than the competitive benchmark prices.

391. Table 5.4 provides annual summaries of the extent of market power rents for each year from 2001 through the first half of 2007. These results yield three sets of conclusions. First, substantial market power rents are earned during several years of the sample period. Between 45% and 50% of total wholesale market revenues in 2001 and 2003 appear to be the result of the exercise of unilateral market power. The second conclusion is that in several years there were virtually no market power rents earned by suppliers. In 2002, market power rents are estimated to be equal to approximately 2% of total wholesale market revenues. In 2004 and the first half of 2007 the market power rents are estimated to negative, which provides empirical evidence that our two methodologies for estimating the competitive benchmark price yields a very slack upper bound on the true competitive benchmark price. The two remaining years of the sample have intermediate levels of market power rents. During 2005 and 2006 roughly 20% to 30% of total wholesale market revenues are estimated to be market power rents.

392. Figure 5.11 and 5.12 illustrate that the large market power rents typically come during only a portion of the year, during high demand periods and low water periods. As discussed in Section 3 and demonstrated in Section 4, these are the two sets of system conditions when the unilateral ability and incentive to exercise market power are greatest. Consequently, it is not surprising that substantially larger market power rents are realized during these periods.

5.5.2 *Nodal-pricing market power rents*

393. To demonstrate the quality of the single zone model of New Zealand for capturing the time series variation in the quantity-weighted average of nodal prices in New Zealand, Figure 5.15 plots the 30-day moving average the quantity-weighted average of the actual nodal prices for each half-hour during the sample and the 30-day moving average of the prices obtained from solving for the single-pricing zone market price using our algorithm and the actual offers of hydro and fossil fuel suppliers and actual demand for each half-hour. This graph demonstrates that with a few exceptions our single zone pricing algorithm is able to reproduce the quantity-weighted average of actual nodal prices from the actual offers submitted and actual nodal demand level because for virtually all half-hours during the sample period from January 1, 2001 to June 30, 2007 these two lines are virtually identical.

394. Figure 5.16 plots the smoothed density of the half-hourly difference between the estimated actual single-pricing zone price computed as described above and the quantity-

weighted average of actual nodal prices. This density is symmetrically distributed over zero and most of the probability mass is concentrated in the -$5/MWh to +$5/MWh range, which implies that there are no systematic biases in our single zone approach to computing counterfactual competitive benchmark prices.

395. To demonstrate the close agreement between the market power rents from our single zone approach and the nodal-pricing approach, Figure 5.17 plots the half-hourly difference between the single-pricing zone Counterfactual 1 price and the quantity-weighted average Counterfactual 1 nodal prices from a random sample of half-hours over our sample period. Virtually all of the half-hourly price differences are clustered around zero throughout the sample period, with values above and below zero equally likely to occur.

396. There is an even greater agreement between the single-pricing zone Counterfactual 2 prices and the Counterfactual 2 nodal-pricing results. Figure 5.18 plots the half-hourly difference between the single-pricing zone Counterfactual 2 prices and the quantity-weighted average Counterfactual 2 nodal prices from a random sample of half-hours during the sample period. For the Counterfactual 2 approach, there are far fewer extreme values and a greater concentration of the half-hourly differences around zero.

397. A final piece of evidence consistent with the conclusion that the single zone and nodal pricing approaches to computing competitive benchmark prices yields virtually identical estimates of the market power rents is the close agreement between actual nodal prices and nodal prices computed using our nodal pricing model with actual supplier offers and actual demand. Figure 5.19 computes the difference between the quantity-weighted average of the nodal prices computed using actual offers and nodal demands and the quantity-weighted average of the actual nodal prices for a smaller random sample of half-hours from January 1, 2001 to June 30, 2007. These differences are also clustered around zero for all years of the sample, with only a few larger differences in both the positive and negative direction.

398. The nodal-pricing competitive benchmark prices also allow us to examine the extent to which the exercise of unilateral market power has increased the cost of transmission congestion in the New Zealand market. Specifically, we can compare the actual cost of congestion in New Zealand to the cost of congestion under the nodal pricing competitive benchmark. The usual way to measure aggregate congestion is the difference between the total amount paid by loads minus the total amount paid to generation unit owners. This difference is called the merchandising surplus. In this case of New Zealand this magnitude measures both line losses and congestion.

399. To see why this is case, consider the case in which there are no losses in the transmission network, so that the total amount that suppliers inject is equal to the total amount that consumers withdraw. Therefore, the only reason that consumers pay more is because they withdraw more at nodes with higher prices because of transmission congestion than generation unit owners inject. For example, assume a two-node network with a total demand of 100 MWh at one node and 90 MWh of transmission capacity between the two nodes. The prices are $70/MWh at the node where all but 10 MWh of

energy is produced and \$100/MWh at the node where this 10 MWh is produced. In this case consumers pay a total of \$10,000 = 100 MWh x \$100/MWh, and producers receive \$7,300 = \$100/MWh x 10 MWh + \$70/MWh x 90 MWh. So the merchandising surplus is \$2,700, which is also equal to the flow on the transmission line times the difference prices between the two locations, 90 MWh x \$30/MWh. When losses are accounted for, the problem becomes slightly more complex because generation unit owners inject more energy than consumers withdraw.

400. Figure 5.20 graphs the smoothed density of the half-hourly merchandising surplus as a percent of total half-hourly generation revenues for actual market outcomes. Figure 5.20 also plots the smoothed density of the half-hourly merchandising surplus as percent of total half-hourly generation revenues for the random sample of our Counterfactual 2 nodal pricing competitive benchmark pricing market outcomes. The close agreement between these two smooth densities demonstrates that the exercise market power did not lead to a significant increase in the magnitude of congestion relative to total wholesale market revenues.

401. This result is consistent with the fact that transmission congestion in New Zealand is infrequent during our sample period. These results imply that market power appears to be primarily a system-wide problem, although there are rare instances when prices do increase substantially at specific locations in the transmission network. The transmission network in New Zealand appears to be sufficiently robust so that suppliers are unable to exercise unilateral market power by causing transmission congestion and raising local prices with any degree of persistence. However, this result does not rule out the fact that periodically suppliers are able to raise local prices substantially because of transmission constraints or generation unit outages.

Table 5.4: Annual decomposition of wholesale market revenues

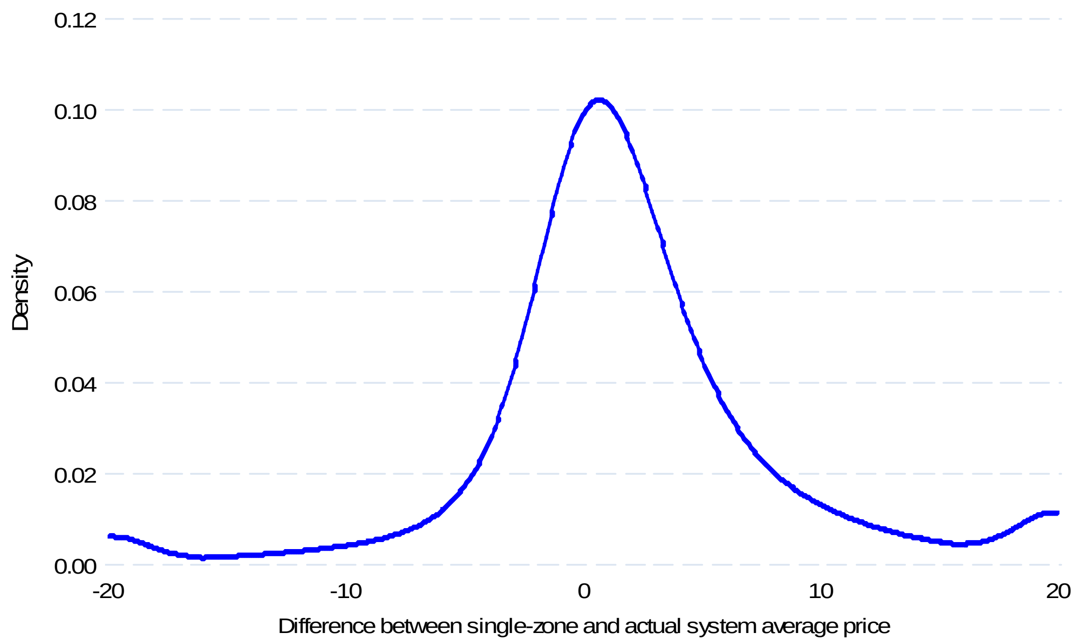
Year	Wholesale revenues	Variable costs $ million	Variable costs % of total	Competitive rents $ million	Competitive rents % of total	Market power rents $ million	Market power rents % of total
Counterfactual 1							
2001	2956.9	562.7	19.0%	906.9	30.7%	1487.4	50.3%
2002	1457.9	528.2	36.2%	900.9	61.8%	28.7	2.0%
2003	3052.9	581.8	19.1%	975.6	32.0%	1495.5	49.0%
2004	1371.1	516.8	37.7%	1117.7	81.5%	-263.4	-19.2%
2005	2904.2	697.9	24.0%	1255.7	43.2%	950.7	32.7%
2006	3118.7	780.4	25.0%	1570.7	50.4%	767.7	24.6%
1H 2007	1049.5	395.6	37.7%	784.4	74.7%	-130.5	-12.4%
Counterfactual 2							
2001	2956.9	675.6	22.8%	849.7	28.7%	1431.6	48.4%
2002	1457.9	574.6	39.4%	858.5	58.9%	24.8	1.7%
2003	3052.9	713.5	23.4%	956.7	31.3%	1382.7	45.3%
2004	1371.1	549.5	40.1%	983.5	71.7%	-161.9	-11.8%
2005	2904.2	813.7	28.0%	1171.6	40.3%	919.0	31.6%
2006	3118.7	865.9	27.8%	1442.9	46.3%	810.0	26.0%
1H 2007	1049.5	410.3	39.1%	744.4	70.9%	-105.2	-10.0%

Source: Calculations as described in text using offer and generation data from Centralised Data Set and EMS, price data from Centralised Data Set, dispatch data from M-Co, and fuel price and usage data from Contact Energy, Genesis Energy and MED.

Figure 5.15: Single-Zone and Actual System Prices, 30-day Moving Average, 2001–07

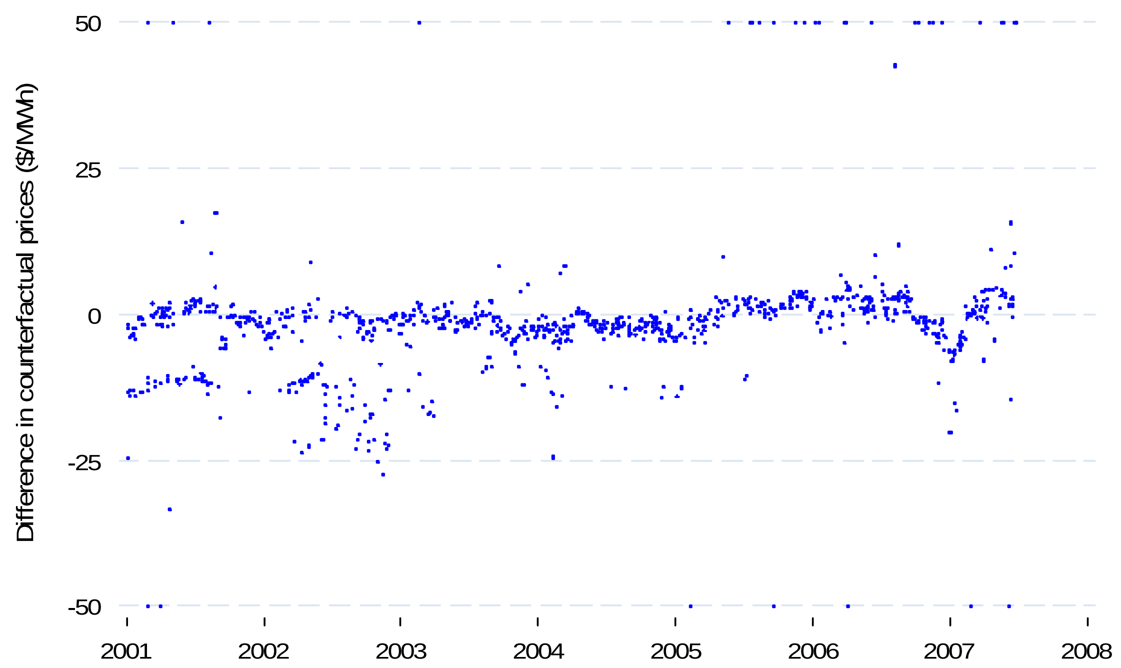
Source: Calculations as described in text using offer and generation data from Centralised Data Set and EMS, price data from Centralised Data Set, and dispatch data from M-Co.

Figure 5.16: Distribution of Differences Between Single Zone and Actual Average Price



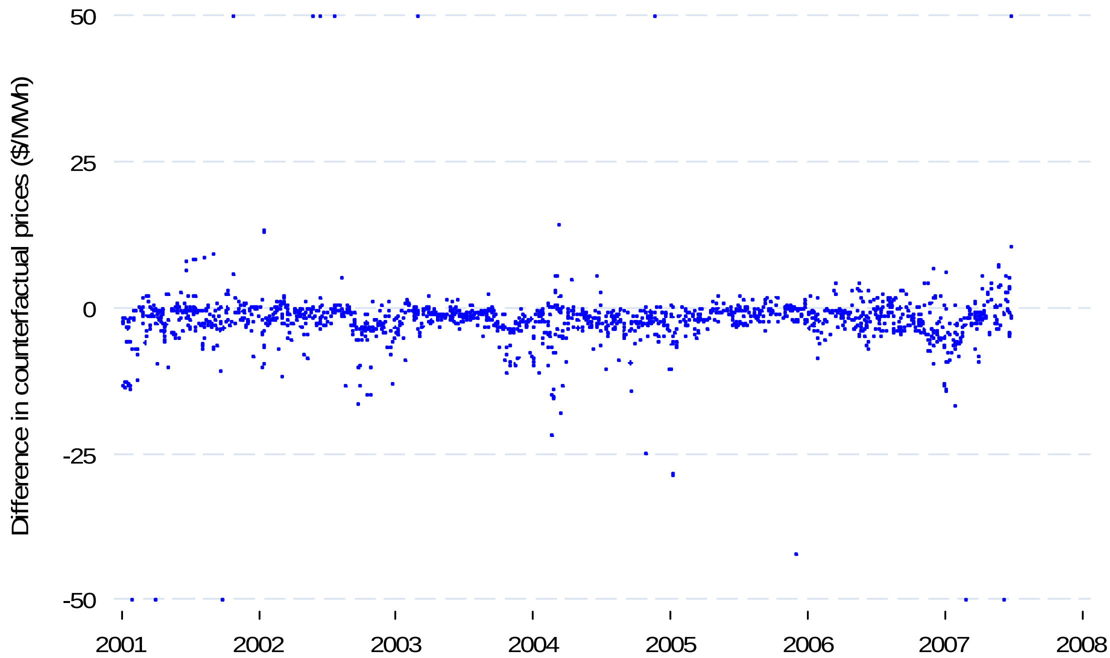
Source: Calculations as described in text using offer and generation data from Centralised Data Set and EMS, price data from Centralised Data Set, and dispatch data from M-Co.

Figure 5.17: Single-zone minus Network Model Prices, Counterfactual 1
Random Sample of Half-Hours from 2001 to 2007



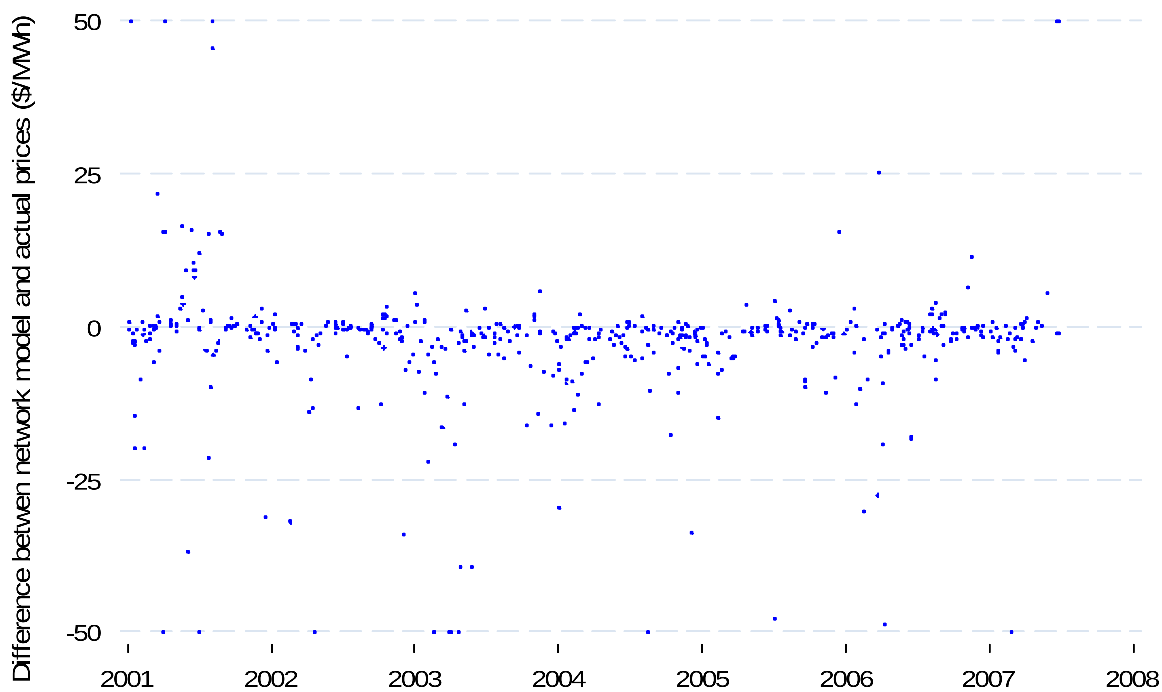
Source: Calculations as described in text using offer and generation data from Centralised Data Set and EMS, dispatch data from M-Co, fuel price and usage data from Contact Energy, Genesis Energy and MED, and network model data from Transpower.

Figure 5.18: Single-Zone minus Network Model Prices, Counterfactual 2
Random Sample of Half-Hours from 2001 to 2007



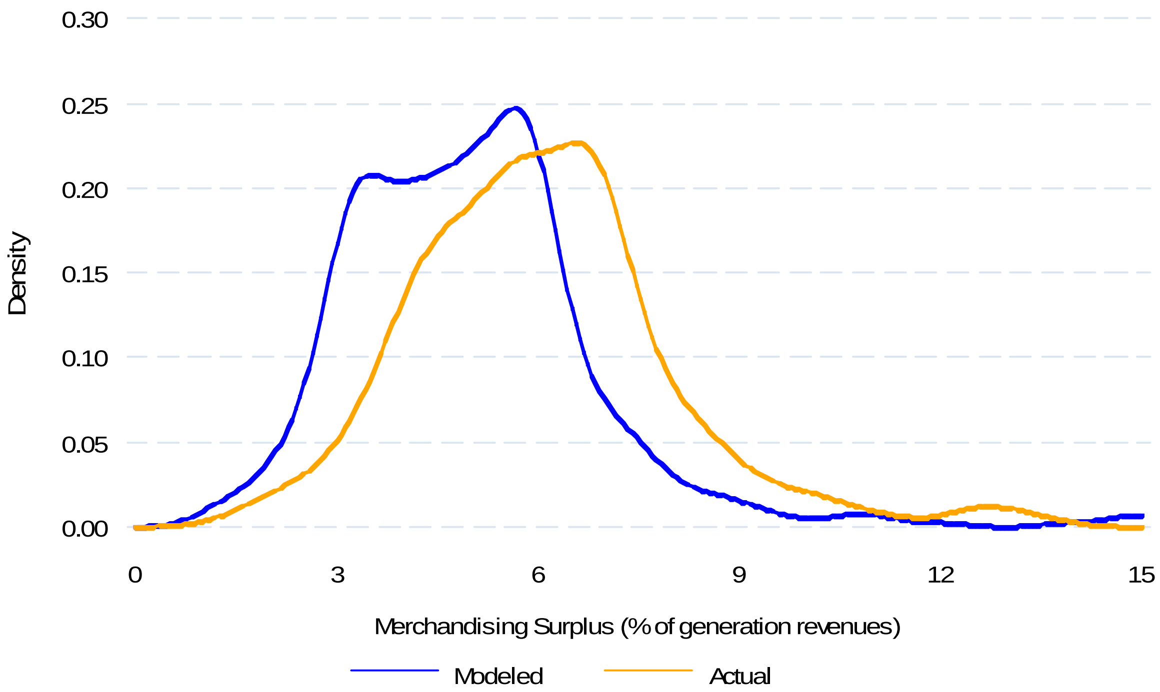
Source: Calculations as described in text using offer data from Centralised Data Set and EMS, dispatch data from M-Co, fuel price and usage data from Contact Energy, Genesis Energy and MED, and network model data from Transpower.

Figure 5.19: Difference Between Network Model and Actual Prices
Random Sample of Half-Hours from 2001 to 2007



Source: Calculations as described in text using offer and generation data from Centralised Data Set and EMS, price data from Centralised Data Set, dispatch data from M-Co, and network model data from Transpower.

Figure 5.20: Merchandising Surplus Computed from Actual Nodal Prices and Network Model Prices, Counterfactual 2, Random Sample



Source: Calculations as described in text using offer and generation data from Centralised Data Set and EMS, price data from Centralised Data Set, dispatch data from M-Co, and fuel price and usage data from Contact Energy, Genesis Energy and MED, and network model data from Transpower.

5.6 Evidence of pass-through of wholesale prices into retail prices

402. The market power rents presented in Table 5.4 are calculated at the wholesale level, but the four large suppliers in New Zealand all have substantial retail load obligations sold at prices that do not vary with half-hourly wholesale prices. Although generation unit owners sell all of their output at the short-term price to the Clearing Manager and retailers buy all of their load from the Clearing Manager at the short-term price, vertical integration implies that any purchase of retail energy by the supplier up to the half-hourly of its generation units is purchased and sold at the same price. Consequently, these suppliers only sell the energy they produce each half-hour in excess of their half-hourly retail load obligation plus their net fixed-price forward contract obligations at the half-hourly wholesale price. They must also buy any shortfall between their half-hourly production and their retail load obligation plus their net fixed-price forward market obligations at the half-hourly wholesale price. Each supplier sells the energy it produces to serve its half-hourly retail load obligation at an implicit wholesale price equal to the difference between its average retail price minus its average cost of retailing, transmitting, and distributing electricity. However, as noted at the start of this section, the supplier can increase the retail price it charges to most of its customers with limited advance notice at its own discretion in order to recover the higher wholesale price in future half-hour periods.

403. The analysis in this section presents suggestive evidence on extent to which this has occurred. Specifically, did suppliers manage to recover the higher wholesale prices that occurred during the periods of high market power rents through higher retail prices in future periods? The data presented in this section suggests that suppliers did in fact manage to recover these higher wholesale prices fully through subsequent retail price increases.

404. The next subsection outlines the process we use to compute an estimate of the implicit wholesale price in retail price. The second subsection characterizes the behavior of average retail prices and average line charges over our sample period. This information is also presented by different classes of final consumers. The third subsection presents a comparison of the behavior of average wholesale prices and the implicit wholesale price in the average retail price over our sample period.

5.6.1 Computing wholesale price implicit in retail price

405. Consider the following stylized expression for the half-hourly variable profits for a vertically-integrated supplier.

$$\Pi(p) = (P_R - p)Q_R + DR(p)(p - c) - \tau Q_R$$

where P_R is the retail price at which the firm is selling Q_R MWh of retail electricity. Let $DR(p)$ equal the firm's residual demand curve for sales in the wholesale market and p the wholesale market price. For simplicity, assume that c is the constant marginal cost of producing electricity and τ is the average cost of retailing, transmitting, and distributing wholesale electricity to final customers. For simplicity, I ignore the impact of fixed-price long-term contract obligations because of the extremely small quantity of contracts held by each of the four suppliers relative to their retail load obligation documented in Section 2.

406. This expression can be re-arranged to yield the expression given below:

$$\begin{aligned}\Pi(p) &= (P_R - \tau - c)Q_R + (DR(p) - Q_R)(p - c) \\ &= \left(\mathrm{P_W^I} - \mathrm{c}\right)Q_R + (DR(p) - Q_R)(p - c), \text{where } \mathrm{P_W^I} = (P_R - \tau).\end{aligned}$$

This expression demonstrates that the retailer sells its retail load obligation, Q_R, at a price of P_W^I and its net long position, $(DR(p) - Q_R)$, at the wholesale price, p. Consequently, if the value of P_W^I eventually equals or exceeds the wholesale price, p, then pass-through is complete.

5.6.1 Time series behavior of retail prices and distribution charges

407. Figures 5.21, 5.22 and 5.23 show long-run trends in retail electricity prices based on three data sources compiled by the Ministry of Economic Development. Figure 5.21 shows residential prices from the Quarterly Survey of Domestic Electricity Prices (QSDEP). This survey calculates the electricity price for a consumer on a typical pricing plan, with an annual consumption of 8000 kWh. The top line in the graph shows the price charged by the incumbent retailer in each distribution area, averaged across all distribution areas. The second line shows the price charged by the cheapest retailer in

each distribution area, again averaged across all areas. The line at the bottom of the graph shows the average line and transmission charge component of the total retail price.

408. Figure 5.21 demonstrates that increases in the regulated component of electricity prices—line and transmission charges—comprise only a small part of the total increase in prices since the start of retail competition in 1999. Line and transmission charges increased from 6.7 cents/kWh in 1999 to 8.5 cents/kWh in 2009, an average annual rate of increase of 2.6%, or almost zero in real terms. Over the same period, energy and retailing charges for the incumbent retailer more than doubled, from 7.3 cents/kWh in 1999 to 14.7 cents/kWh in 2009. This represented an average annual rate of increase of 7.6%. As a result, the share of line and transmission charges in the total retail price fell from 48% in 1999 to 37% in 2009. The difference between the average price for the incumbent retailer and the cheapest available price from any competing retailer has remained between 0.6 and 1.7 cents/kWh over the whole sample period.

409. Figure 5.22 shows prices for residential and commercial users from the Annual Residential and Commercial Electricity Price Survey. This is an annual survey since 1984 of the list prices charged by the incumbent retailer in each network area, for six categories of customer: small, medium and large residential, and small, medium and large commercial. The figure shows the mean price across all network areas for large residential and medium commercial customers, which are both calculated based on a consumption of 1,500 kWh/month. Goods and Services Tax is excluded from the residential prices for comparability with the commercial prices.

410. The figure shows that list prices for residential customers have stayed below list prices for commercial users with the same level of consumption, over the whole sample period. However, the gap between residential and commercial prices has narrowed, from more than 4 cents/kWh in 1998 to 1 cent/kWh in 2008. Most of the elimination of this gap took place in the 1990s: the gap was just 1.4 cents/kWh by 1999.

411. Finally, Figure 5.23 shows electricity prices for the three major sectors of the economy calculated as average revenue (that is, annual electricity revenue from that sector divided by annual electricity consumption in that sector), rather than based on published list prices for each retailer. The graph shows a remarkably different picture of prices in the commercial sector to that shown in Figure 5.22, even though the pattern of residential prices is very similar in both figures. For commercial users, the prices in the two figures match closely for the first ten years and then start to diverge after 1992. Based on average revenue (as shown in Figure 5.23), commercial prices increased by only 2.4 cents/kWh between 1992 and 2007. Based on list prices for the incumbent retailer (as shown in Figure 5.22), commercial prices increased by 7.2 cents/kWh between 1992 and 2007.

412. One possible interpretation of these results is that there is a lot of "off-schedule" competition for commercial and industrial users, so that the incumbent retailer's published price schedules are increasingly meaningless as a guide to commercial prices in each region. Large commercial and industrial users have greater bargaining power to be able to negotiate and lock in low rates on non-standard plan types. As a result, they have a

greater ability to benefit from retail competition than residential users. In the international context, many jurisdictions have recognized this inherent difference between residential and commercial users in the ability to compete in the retail electricity market, and have maintained regulated rates for small customers while allowing full, unregulated retail competition only for large customers.

5.6.3. Evidence on extent of pass-through of wholesale prices into retail prices

413. Figure 5.24 compares the behavior of our estimate of P_W^I to the behavior of wholesale prices over the past decade. For our estimate of P_W^I, we compute the difference between the total average retail price for the incumbent retailers and the line and transmission component of the retail price, calculated from Figure 5.22. This difference represents the energy (including losses) and retailing component of the total retail price, so that strictly speaking it differs from the definition of P_W^I in Section 5.6.1, because it includes the average variable cost of retailing. However, the $/MWh variable cost of retailing is likely to be very small. Goods and Service Tax is excluded from this implicit wholesale price.

414. For comparison, Figure 5.24 also shows the one-year moving average of wholesale electricity prices, calculated as the weighted average price across all nodes in the New Zealand market, where the weights are the load volumes at each node. The wholesale prices are multiplied by 1.068, an estimate of the average distribution loss factor in New Zealand.[51] As such, the wholesale price series in Figure 5.28 represents the average cost of wholesale electricity delivered to end users. For most time periods, the estimate of P_W^I exceeds the one-year moving average of this wholesale price. Moreover, there are a number of sustained time periods when the estimate of P_W^I exceeds the one-year moving average of the wholesale price by as much as 6 cents/kWh. The ordering of the time series behavior of these two prices is consistent with the complete pass-through of wholesale prices into future retail price.

415. A more detailed study of the time lag between retail price increases and wholesale price increases and how the magnitude of this pass-through varies by classes of customers and retailers would allow a quantitative assessment of the magnitude of the pass-through of wholesale prices into retail prices. In particular, the significantly larger number of sustained periods when the difference between P_W^I and the one-year moving average of the wholesale price is large and positive relative to the two short periods that this difference is negative suggests more than a complete pass-through of wholesale prices into retail prices, meaning that market power rents exist at the retail level as well as the wholesale level.

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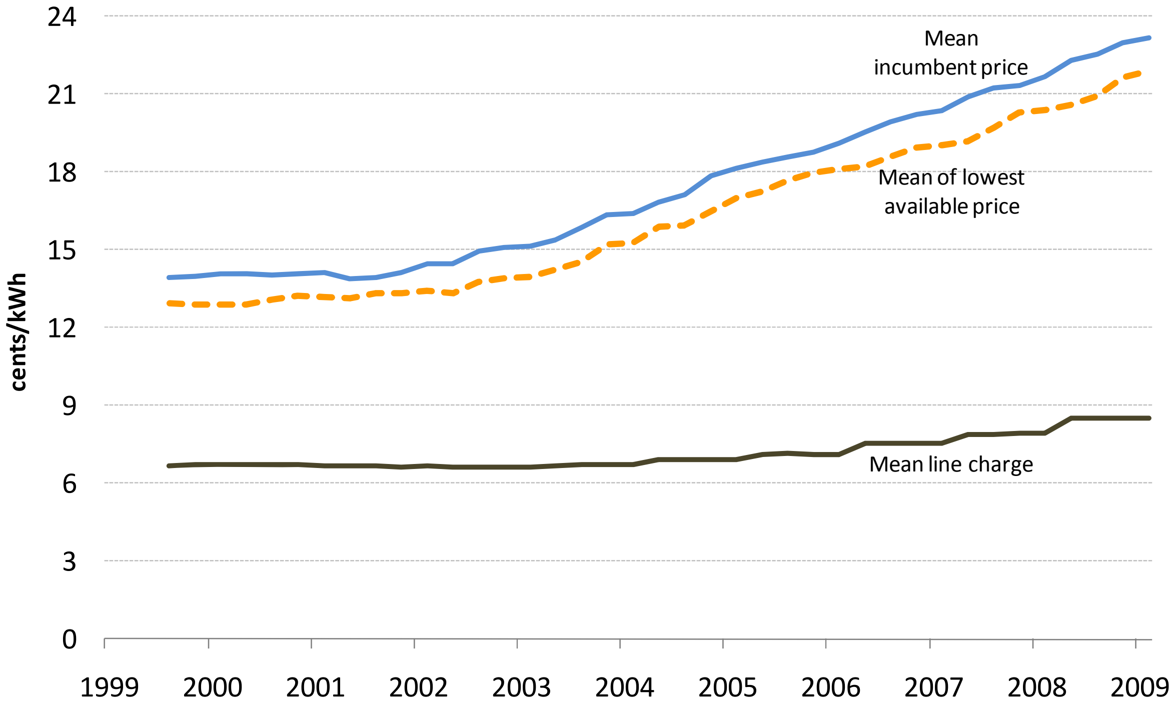
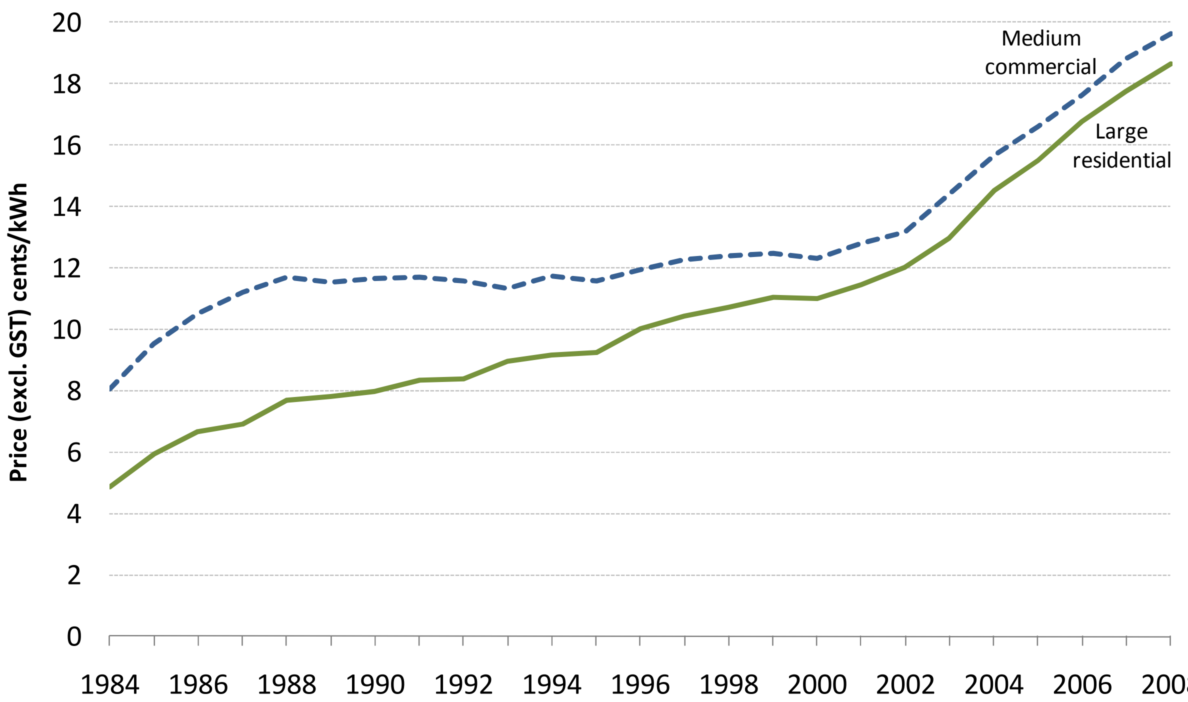
[51] Unweighted average of distribution loss factors from Electricity Commission Retail Model (Version 5). This figure is likely to be an upward biased estimate of the average loss per KWh distributed in the country because the higher volume distribution networks have lower average losses.

Figure 5.21: Residential prices and line charges for incumbent and lowest-priced competitor



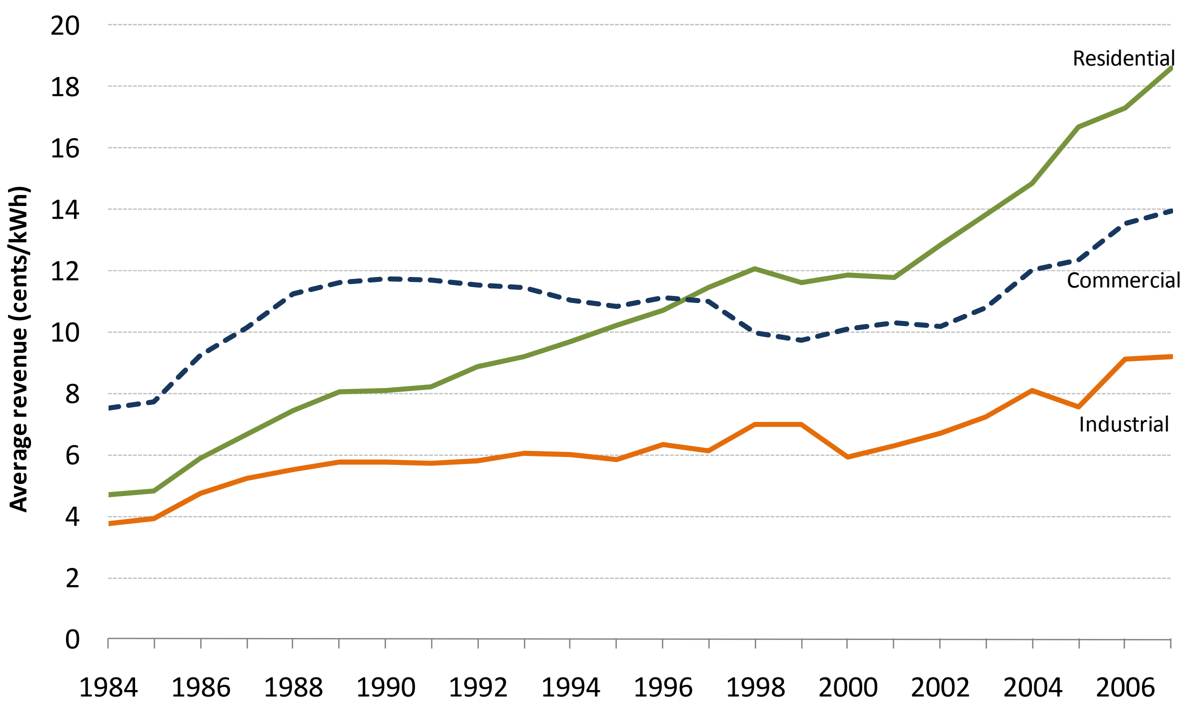
Source: Quarterly Survey of Domestic Electricity Prices (MED).

Figure 5.22: Residential and commercial prices, 1984–2008



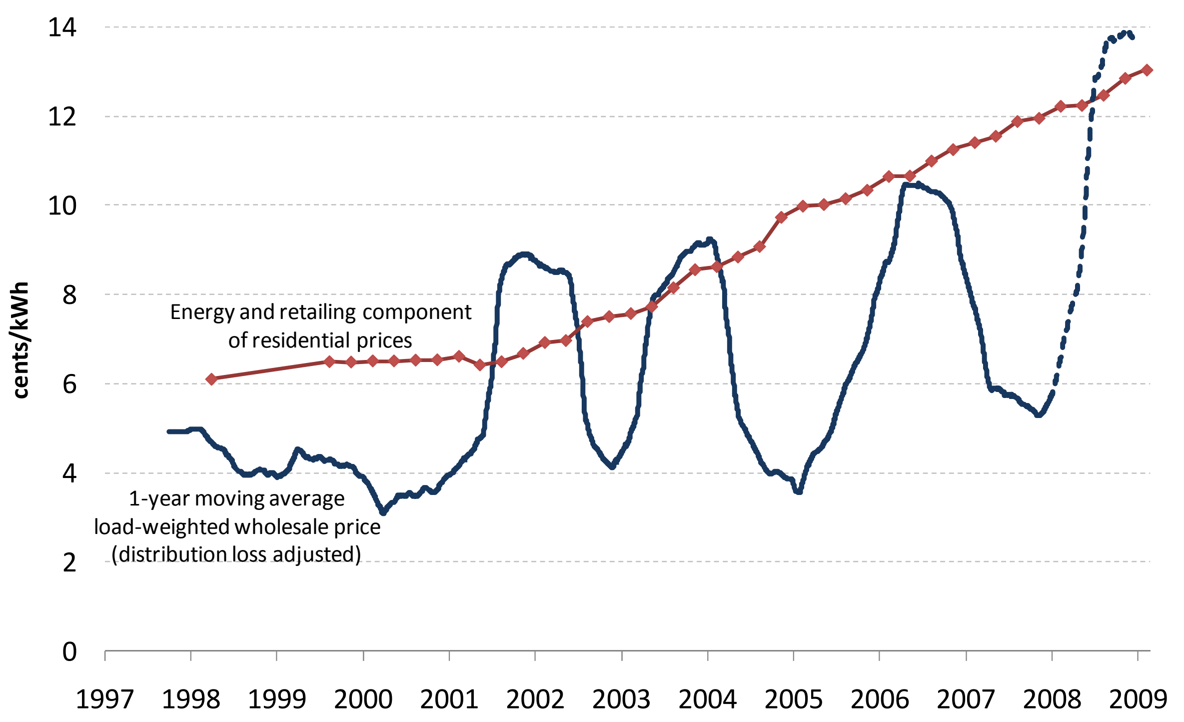
Source: Annual Residential and Commercial Electricity Price Survey (MED).

Figure 5.23: Average revenue by sector, 1984–2007



Source: Energy Data File (MED).

Figure 5.24: Wholesale prices and energy & retailing component of residential prices



Source: Quarterly Survey of Domestic Electricity Prices (MED) and Centralised Data Set.

5.7 Conclusion

416. This section quantified the market power rents or wholesale market cost of suppliers exercising unilateral market power in the short-term market over the period January 1, 2001 to June 30, 2007. First, a brief overview of the competitive benchmark pricing analysis and challenges associated with computing this price in a hydroelectric energy-dominated industry was presented. This was followed by a discussion of the role short-run marginal cost versus long-run marginal in determining a firm's expected profit-maximizing operating, pricing and investment behavior.

417. Four methodologies were presented to compute an upper bound on the no-market-power competitive benchmark price. These methodologies differed along two dimensions. The first dimension was how the counterfactual aggregate willingness-to-supply curve was constructed. Two methodologies that yield a slack upper bound on a hydroelectric generation unit owner's no-market-power willingness to offer curve and one methodology for the fossil fuel generation units were presented.

418. The second dimension along which these methodologies differed was what locational pricing mechanism was used to construct the counterfactual market-clearing prices from the no-market power generation unit-level willingness-to-supply curves. The first method used a single-pricing zone for the entire New Zealand market. The second method attempted to replicate the nodal-pricing algorithm used to compute locational prices in New Zealand market. The two approaches to estimating cost of the exercise of unilateral market power produced very similar results.

419. The empirical results presented in Section 5.5 allow three major conclusions:

- First, for the majority of the half-hours from January 1, 2001 to June 30, 2007, the average difference between actual prices and both sets of competitive benchmark prices is very small.
- Second, for the majority of years of our sample period, the average difference between actual prices and both sets of competitive benchmark prices is small.
- Third, there are at least three sustained periods of between three to six months in duration when the average difference between actual prices and competitive benchmark prices is extremely large. Because these periods generally persist for more than three months, the total market power rents over each of these periods are economically significant.

420. The extent to which these higher wholesale prices are passed on to a vertically-integrated supplier's own retail customers, or indirectly to other retail customers, is addressed in Section 5.6. The empirical evidence suggests that suppliers have been able to pass-through these wholesale price increases in higher retail prices with a time lag.

SECTION 6

LINKING THE ABILITY AND INCENTIVE TO EXERCISE MARKET POWER TO MARKET POWER RENTS

6.1 Introduction

421. This section links the analysis of the half-hourly relationship between the incentive or ability of the four large suppliers to exercise unilateral market power and the offer prices that they submit to the wholesale market presented in Section 4 to the magnitude of the half-hourly values of various measures of market power rents computed using the competitive benchmark pricing results from Section 5.

422. Section 4 found that for the same daily input fossil fuel prices and daily opportunity cost of water, each of the four large suppliers submits a higher offer price when it has a greater ability or incentive to exercise unilateral market power. This behavior by the four large suppliers implies that higher half-hourly quantity-weighted average nodal prices are associated with higher half-hourly values of the firm-level and average firm-level index of the ability and incentive of these four suppliers to exercise unilateral market power. The purpose of this section is to estimate the predictive relationship between the half-hourly firm-level ability or incentive of these four suppliers to exercise unilateral market power and three measure of half-hourly market power rents earned.

423. These measures are: (1) gross market power rents, (2) net market power rents, and (3) positive net market power rents. Each of the three half-hourly measures (computed using the competitive benchmark prices derived in Section 5) is increasing in the average (across the four firms) half-hourly values of the ability and incentive of the four large suppliers to exercise unilateral market power, after controlling for differences in fossil fuel prices, the opportunity cost of water, and the level of total system generation across days and half-hours during our sample period. These results imply that, holding input fossil fuel prices, the opportunity cost of water, and total system generation constant, higher market power rents occur during half-hours when these four suppliers face less competition (as measured by their average ability to exercise market power) and have a greater incentive to exploit their ability to exercise market power.

424. This same conclusion holds for each supplier individually for its incentive to exercise unilateral market power, and for three of the four suppliers for their ability to exercise unilateral market power. Specifically, for each supplier, given the half-hourly values of the indexes of the ability or the incentive of the remaining suppliers to exercise unilateral market power, and factors that control for input fossil fuel prices, the opportunity cost of water, and total system generation, higher values of each supplier's half-hourly incentive to exercise unilateral market power are associated with higher values of each of the half-hourly measures of total market power rents.

425. These results provide evidence for the existence of a causal link between half-hourly measures of the ability and incentive of these four suppliers to exercise unilateral market power and the half-hourly magnitude of market power rents. As discussed in Section 3,

the ability of a supplier to exercise unilateral market power depends on the extent of competition that supplier faces. The extent of competition a supplier faces in an imperfectly competitive market is quantified by the form of the residual demand curve it faces. As discussed in Sections 3 and 4, in a bid-based wholesale electricity market it is possible to compute this residual demand curve using the bids and offers submitted to the short-term market. The inverse semi-elasticity of a supplier's residual demand curve quantifies the extent of competition that a supplier faces for its output, with higher values denoting the fact that the supplier faces less competition (it has a greater ability to exercise market power) and lower values more competition (it has less ability to exercise market power).

426. As emphasized in Sections 3 and 4, a supplier must have an incentive to exploit any ability it has to exercise unilateral market power, or equivalently the supplier must have an incentive to exploit the reduced amount of competition that it faces. Therefore, the results presented in this section are consistent with the statement that during half-hours when these four suppliers face less competition and have a greater incentive to exploit this lessened amount of competition, half-hourly market power rents are higher, or equivalently the economic distortions in market outcomes from the perfectly competitive ideal are larger.

427. These empirical results and those from Sections 4 and 5 imply that although market prices, and therefore market power rents, are the result of the interaction of the half-hourly aggregate willingness-to-supply curves submitted by all suppliers with the level of aggregate demand, the half-hourly offer prices in these aggregate willingness-to-supply curves depend on the half-hourly ability and incentive of the four large suppliers to exercise unilateral market power as well as on the level of fossil fuel prices and the opportunity cost of water.

428. According to the results of Section 4, during half-hours when any of these suppliers has a greater incentive to exercise market power, they will submit higher offer prices which cause higher market-clearing prices. The results presented in this section demonstrate that these market-clearing prices also result in larger half-hourly market power rents for the entire market and for these four suppliers combined. Alternatively, the results in this section demonstrate that during half-hours when these four suppliers face less competition and have a greater incentive to exploit that fact, half-hourly market power rents for the market and for these four suppliers are higher.

6.2. Measures of market power rents

429. The three measures of half-hourly market power rents are constructed using the competitive benchmark pricing results from Section 5. Each measure quantifies a slightly different component of the cost of market power rents in the wholesale market outcomes. All of these measures quantify different dimensions of the extent to which short-term wholesale market revenues to suppliers differ from those they would receive if no supplier had the ability or incentive to exercise any unilateral market power.

6.2.1 Gross market power rents

430. The first half-hourly measure of market power rents is gross market power rents in half-hour h of day d of month-of-sample m, $GrossRents_{hdm}$. This variable is defined as the quantity-weighted average nodal price for half-hour h of day d during month-of-sample m, $p_{hdm}(avg)$, minus $p_{hdm}(comp)$, the competitive benchmark price for half-hour h of day d during month-of-sample m, multiplied by QT_{hdm}, the total system generation in half-hour h of day d during month-of-sample m produced by all suppliers in New Zealand. In terms of this notation:

$$GrossRents_{hdm} = \left(p_{hdm}(avg) - p_{hdm}(comp)\right)QT_{hdm} \quad (1)$$

431. The components of $GrossRents_{hdm}$ defined in terms of the half-hourly market outcome variables are:

$$p_{hdm}(avg) = \frac{\sum_{n=1}^{N} p_{hdmn} q_{hdmn}}{\sum_{n=1}^{N} q_{hdmn}} \quad (2)$$

where p_{hdmn} is the price at node n during half-hour h of day d during month-of-sample m, and q_{hdmn} equals the total amount of energy injected at node n during half-hour h of day d during month-of-sample m. The competitive benchmark price for half-hour h of day d during month-of-sample m, $p_{hdm}(comp)$, is computed as described in Section 5. This measure of market power rents does not account for the fact that suppliers have fixed-price forward market obligations. Nevertheless, it is still a valid measure of the total amount of market power exercised in the short-term market, because all energy produced in New Zealand is settled at the half-hourly nodal prices that make up $p_{hdm}(avg)$. Moreover, the evidence presented in Section 5.6 suggests that wholesale price increases are passed through into retail prices with lag.

432. As shown in Section 3, fixed-price retail load obligations and other fixed-price forward market obligations change the effective price at which suppliers sell some or all of their half-hourly production, and the half-hourly market power rents that a supplier receives from raising or lowering short-term market prices. For this reason, two measures of market power rents for the four large suppliers, which account for the presence of fixed-price forward market obligations, are also computed.

6.2.2 Net market power rents

433. The first half-hourly measure of wholesale market power rents that accounts for the presence of fixed-price forward market obligations is the net market power rents in half-hour h of day d of month-of-sample m, $NetRents_{hdm}$. If a supplier has fixed-price forward market obligations, then it earns or pays the short-term market price only on the difference between its short-term market sales and its fixed-price forward market obligations. The remainder of its production during that half-hour earns the implied average wholesale price implicit in its fixed-price forward market obligations for that half-hour. As noted in Sections 2 and 4, the major fixed-price forward market obligations of these four suppliers are their fixed-price retail load obligations.

434. Let QR_{jhdm} equal supplier j's total retail load obligations for half-hour h of day d of month-of-sample m, and q_{jhdmn} equal total half-hourly injections of energy by supplier j at node n during half-hour h of day d of month-of-sample m. Define NR_{jhdm} to equal the short-term power market rents net of supplier j's forward market obligations for half-hour h of day d of month-of-sample m. In terms of our notation,

$$NR_{jhdm} = \big(p_{hdm}(avg) - p_{hdm}(comp)\big)(QS_{jhdm} - QC_{jhdm}) \tag{3}$$

where $QS_{jhdm} = \sum_{n=1}^{N} q_{jhdmn}$ is the total amount of energy injected by supplier j during half-hour h and day d during month-of-sample m across all nodes. Note that depending on the signs of the two terms in equation (3), NR_{jhdm} can be positive or negative. The usual way that NR_{jhdm} becomes negative is if the supplier sells less in the short-term market than his retail load obligations, $\big(QS_{jhdm} - QR_{jhdm}\big) < 0$, or the quantity-weighted average of the nodal prices exceeds the competitive benchmark price, $\big(p_{hdm}(avg) - p_{hdm}(comp)\big) > 0$. In terms of the above notation,

$$NetRents_{hdm} = \sum_{j=1}^{4} NR_{jhdm}, \tag{4}$$

the net market power rents for half-hour h of day d of month-of-sample m is equal to the sum of the firm-level net rents across the four suppliers.

6.2.3 Positive net market power rents

435. The third measure of wholesale market power rents is called positive net market power rents, $PositiveNetRents_{hdm}$. This measure truncates the net market power rents for each supplier at zero and then sums the result across the four firms. The rationale for this measure stems from the assumptions that go into computing the half-hourly competitive benchmark prices described in Section 5. Specifically, as noted in Section 5, this calculation relies on assumptions that bias against a finding of market power rents, meaning that the true competitive benchmark price may be lower than the competitive benchmark price that we measure.

436. Although this bias will lower the magnitude of the net market power rents that we estimate, it can also change the sign of the estimate of these net market power rents when market prices are close to the true competitive benchmark. By computing the positive net market power rents we mitigate the impact of this bias on our measurement of firm-level net market power rents and the sum of these market power rents across the four suppliers. In terms of our notation, we have

$$PositiveNetRents_{hdm} = \sum_{j=1}^{4} \max(0, NR_{jhdm}) \tag{5}$$

so that the net positive rents are the maximum of zero and the net market power rents for each supplier summed across the four suppliers.

6.3 Econometric models relating market power rents to ability or incentive to exercise unilateral market power

437. Two variants of the same econometric model are estimated for each of the three measures of the half-hourly market power rents earned by the four suppliers. The econometric models differ along three dimensions:

- the first is whether the index of the *ability to exercise unilateral market power* for supplier j during half-hour h of day d of month-of-sample m, $\eta_{j,hdm}$, or the index of the *incentive to exercise unilateral market power* for supplier j during half-hour h of day d of month-of-sample m, $\eta_{j,hdm}^{C}$, is included in the regression;

- the second is whether all four half-hourly firm-level indexes of the ability or incentive of each supplier to exercise market power are included in the regression, or a single half-hourly average of these measures across the four firms is included; and

- the third is whether day-of-month for every month of the sample and half-hour of day fixed effects, or different half-hour-of-the-day fixed effects for every month of the sample, are included in the regression to control for differences in fossil fuel prices and the opportunity cost of water across half-hours, days and months during the sample period.

Finally, a quadratic term in the total system generation, QT_{hdm}, the sum of the total amount of energy produced during half-hour h of day d of month-of-sample m, is included in all regressions to control for the level of half-hourly system demand on the value of these half-hourly market power rents.

438. There are two sets of regressions presented in Table 6.1, corresponding to the two variants of the model. Let y_{hdm} equal one of the three measures of market power rents—Gross Rents, Net Rents or Positive Net Rents—during half-hour h of day d of month-of-sample m. The first column of the pair of columns for each of these three dependent variables estimates the following regression:

$$y_{hdm} = \lambda_{hm} + \beta_{CTCT} \times \eta_{CTCT,hdm} + \beta_{GENE} \times \eta_{GENE,hdm} + \beta_{MERI} \times \eta_{MERI,hdm} + \beta_{MRPL} \times \eta_{MRPL,hdm} + \delta_1 \times QT_{hdm} + \delta_2 \times (QT_{hdm})^2 + \varepsilon_{hdm} \quad (6)$$

where $\eta_{j,hdm}$ is the inverse semi-elasticity of the residual demand curve of supplier j during half-hour h of day d during month-of-sample m. The four letter abbreviations are defined as follows: $CTCT$, Contact; $GENE$, Genesis; $MERI$, Meridian; and $MRPL$, Mighty River Power. The parameters λ_{hm} are half-hour-of-the-day fixed effects for month-of-sample m. As discussed in Section 4, there are 3,744 different values of λ_{hm} to control for half-hourly differences in the half-hourly values of y_{hdm}.

439. The second column of the pair of columns for each of the three dependent variables estimates:

$$y_{hdm} = \alpha_{dm} + \tau_h + \beta_{CTCT} \times \eta_{CTCT,hdm} + \beta_{GENE} \times \eta_{GENE,hdm} + \beta_{MERI} \times \eta_{MERI,hdm}$$

$$+\beta_{MRPL} \times \eta_{MRPL,hdm} + \delta_1 \times QT_{hdm} + \delta_2 \times (QT_{hdm})^2 + \upsilon_{hdm} \quad (7)$$

where the α_{dm} are day-of-the-month d of month-of-sample m fixed effects and the τ_h are half-hour-of-the-day fixed effects. The ε_{jhdm} and ν_{jhdm} are mean zero and constant variance regression errors.

440. By the logic discussed in Section 4, the day-of-sample fixed effects in (7) completely account for the impact of daily changes in input fossil fuel prices and daily water levels during our sample period on values of the market power rent. These day-of-sample fixed effects account for variations in daily input fossil fuel prices and daily water levels. The half-hour fixed-effects in (7) account for differences across half-hours of the day in the level of market power rents. This strategy for controlling for differences in market power rents changes across half-hours of the sample implies more than 2,400 combinations of the α_{dm} and τ_h over our sample period.

441. Table 6.2 estimates the following two versions of equations (6) and (7). The first column of each pair of columns is:

$$y_{hdm} = \lambda_{hm} + \beta \times \eta_{hdm}(firm) + \delta_1 \times QT_{hdm} + \delta_2 \times (QT_{hdm})^2 + \varepsilon_{hdm} \quad (8)$$

where $\eta_{hdm}(firm) = \frac{1}{4}\sum_{j=1}^{4} \eta_{j,hdm}$ is the average of the half-hourly inverse semi-elasticities for the four suppliers during half-hour h of day d during month-of-sample m, and. The second column of each pair of columns is:

$$y_{hdm} = \alpha_{dm} + \tau_h + \beta \times \eta_{hdm}(firm) + \delta_1 \times QT_{hdm} + \delta_2 \times (QT_{hdm})^2 + \varepsilon_{hdm} \quad (9)$$

442. The only difference between regressions (8) and (9) and regressions (6) and (7) is that a single average of the half-hourly indexes of the ability of four suppliers to exercise unilateral market power is included in the regression, rather than the index for each supplier, as is the case for equations (6) and (7).

443. Table 6.3 repeats regressions (6) and (7) with the $\eta_{j,hdm}^{C}$, the four half-hourly indexes of the incentive of supplier j to exercise market power during half-hour h of day d during month-of-sample m in place of the four $\eta_{j,hdm}$. Table 6.4 repeats regressions (8) and (9) with $\eta_{hdm}^{C}(firm) = \frac{1}{4}\sum_{j=1}^{4} \eta_{j,hdm}^{C}$, the average of the indexes of the incentive of each of the four suppliers to exercise unilateral market power during half-hour h of day d during month-of-sample m in place of $\eta_{hdm}(firm)$.

6.4 Empirical results

444. This section discusses the estimation results in Tables 6.1 to 6.4. To construct the measures of market power rents, the Counterfactual 1 single-pricing zone approach to computing the competitive benchmark price described in Section 5 is used. Estimation results using the other single zone measures of the competitive benchmark price defined in Section 5 or a subsample of half-hours using the nodal-pricing approaches to computing the competitive benchmark prices yielded quantitatively similar results to those presented in Tables 6.1 to 6.4. This is not surprising given the similarity in the time

series pattern of half-hourly competitive benchmark prices across the approaches demonstrated in Section 5. Consequently, we only report regression results for market power rents based on the Counterfactual 1 single-zone approach to computing the competitive benchmark prices presented in Section 5.

445. Table 6.1 demonstrates that the half-hourly values of gross rents, net rents, and positive net rents are increasing in the half-hourly index of the ability of Contact, Meridian and Mighty River Power to exercise market power. Each of these coefficients is precisely estimated in the sense that each parameter estimate is large relative to its standard error. Although the point estimates of the coefficient on the half-hourly index of the ability of Genesis to exercise unilateral market power is negative for all of the regressions, none of these coefficient estimates are statistically different from zero.

446. The β_j coefficients in the first two columns in the table can be interpreted as the predicted increase in gross market power rents as a result of a one unit change in the half-hourly index of the ability of that supplier to exercise unilateral market power. Column (1) of the table implies that a one unit change in the index of Contact's half-hourly ability to exercise unilateral market power predicts a $6,578 increase in the half-hourly value of market power rents for the entire market. As shown in Table 4.4 of Section 4, changes in the index of Contact's half-hourly ability to exercise market power between 5 and 10 are within the 1 to 2 standard deviation range for most half-hours of the day. The coefficient estimate in the first column of Table 6.1 implies that these changes in the half-hourly ability of Contact to exercise unilateral market power will produce increases in the half-hourly value of total market power rents of between $33,000 and $66,000. The corresponding coefficient estimates for column (2) imply similar total market power rent increases from increases in the indexes of the ability of Contact, Meridian and Mighty River Power to exercise market power.

447. The coefficient estimates for net rents and net positive rents are smaller in absolute value, but positive and precisely estimated for Contact, Meridian, and Mighty River Power. The results in Column 2 for the net rents predicts that a one unit change in the half-hour ability of Meridian to exercise market power suggests a $111 increase in the net market power rents earned by Contact, Genesis, Meridian, and Mighty River Power. As shown in Section 4, changes in the index of the ability of Meridian to exercise unilateral market power in the range of 7 to 14 are in the 1 to 2 standard deviation range for a number of half-hour periods, which implies net market power rent increases for these four suppliers in the range of $750 to $1,500. The coefficient estimates for positive net rents are typically slightly larger in absolute value than the coefficient estimates for net rents, but these coefficient estimates yield the same prediction about the positive impact of changes in the half-hourly index of the ability of Contact, Meridian, and Mighty River Power to exercise unilateral market power on the positive net market power rents.

Table 6.1: Regressions for total market power rents on firm-level semi-elasticities

	Gross rents		Net rents		Positive net rents	
	(1)	(2)	(1)	(2)	(1)	(2)
CTCT semi-elasticity	6577.6	7501.4	562.1	774.5	606.8	788.7
	(263.72)	(266.41)	(17.33)	(18.76)	(20.98)	(22.12)
GENE semi-elasticity	-711.9	-232.5	-15.8	-18.9	-49.0	-52.1
	(317.37)	(319.95)	(20.85)	(22.53)	(25.25)	(26.56)
MERI semi-elasticity	3002.7	2283.5	177.9	110.9	252.3	184.7
	(180.11)	(183.46)	(11.84)	(12.92)	(14.33)	(15.23)
MRPL semi-elasticity	11103.0	11659.2	905.7	1094.1	926.4	1087.1
	(355.44)	(364.42)	(23.36)	(25.67)	(28.28)	(30.26)
Total generation (MW)	-45.1	66.6	-2.6	8.0	-6.4	4.5
	(16.88)	(15.27)	(1.11)	(1.08)	(1.34)	(1.27)
Total generation squared	0.0175	0.0066	0.0012	0.0002	0.0015	0.0005
	0.0018	0.0015	0.0001	0.0001	0.0002	0.0001
Month-of-sample x half-hour	Y		Y		Y	
Day-of-sample and half-hour		Y		Y		Y
Number of observations	113423	113423	113345	113345	113345	113345
R^2	0.443	0.464	0.690	0.658	0.615	0.597

Source: Calculations as described in text using offer and generation data from Centralised Data Set and EMS, firm-level settlement data from EMS, price data from Centralised Data Set, dispatch data from M-Co, and fuel price and usage data from Contact Energy, Genesis Energy and MED.

448. Table 6.2 presents the results of estimating regressions (8) and (9). Across all specifications, the parameter estimates indicate that higher values of the half-hourly average of the indexes of the ability of the four suppliers to exercise unilateral market power are associated with higher values of the three measures of half-hourly market power rents. The coefficient estimate for column (2) for gross rents implies that a one unit change in the average ability of the four suppliers to exercise market power yields a \$18,018 increase in gross market power rents. Column (2) for net rents implies that a one unit change in this same average index of the ability of the suppliers to exercise unilateral market power predicts a \$1,605 increase in the net market power rents to the four large suppliers. The net positive rents coefficients in columns (1) and (2) are slightly larger than the corresponding coefficients for the net rents coefficient. The results in Table 6.2 are consistent with the statement that higher levels of the average half-hourly ability of the four suppliers to exercise unilateral market power implies higher gross market power rents, higher net market power rents to the four suppliers, and higher positive net market power rents to the four suppliers during that half hour.

449. Table 6.3 presents the results of estimating equations (6) and (7) with the firm-level half-hourly indexes of the incentive to exercise unilateral market. For all four suppliers, all measures of market power rents, and both columns of results, the coefficient estimates on the firm-level indexes of the incentive of the supplier to exercise market power are positive and precisely estimated. Moreover, the point estimates of these magnitudes are

substantially larger than the corresponding point estimates for the index of the ability of each supplier to exercise market power. These results emphasize the point made in Section 3 that the ability to exercise unilateral market power is only a necessary condition for a supplier to exercise unilateral market power in the short-term market. If a supplier has sufficient fixed-price forward market obligations relative to its short-term market sales, then it has little incentive to exercise market power and is therefore unlikely to do so.

Table 6.2: Regressions for total market power rents on average semi-elasticity

	Gross rents		Net rents		Positive net rents	
	(1)	(2)	(1)	(2)	(1)	(2)
Mean semi-elasticity	17340.3	18017.8	1368.2	1604.9	1518.0	1702.6
	(297.66)	(313.37)	(19.6)	(22.17)	(23.69)	(26.06)
Total generation (MW)	-43.6	74.9	-2.5	8.9	-6.2	5.4
	(16.92)	(15.32)	(1.11)	(1.08)	(1.35)	(1.27)
Total generation squared	0.0176	0.0060	0.0012	0.0002	0.0015	0.0004
	0.0019	0.0015	0.0001	0.0001	0.0002	0.0001
Month-of-sample x half-hour	Y		Y		Y	
Day-of-sample and half-hour		Y		Y		Y
Number of observations	113426	113426	113348	113348	113348	113348
R^2	0.440	0.461	0.687	0.652	0.612	0.592

Source: Calculations as described in text using offer and generation data from Centralised Data Set and EMS, firm-level settlement data from EMS, price data from Centralised Data Set, dispatch data from M-Co, and fuel price and usage data from Contact Energy, Genesis Energy and MED.

450. The results in Table 6.3 demonstrate that when any of the four suppliers has a higher half-hourly incentive to exercise market power, the corresponding half-hourly value of gross market power rents are higher, and net market power rents and positive net market power rents earned by the four suppliers are higher, and substantially so. For example, taking the results in column (2) for net rents implies that a one unit higher index of the incentive of Genesis to exercise unilateral market power predicts \$4,386 higher net market power rents earned by the four suppliers. As shown in Section 4, a 1 to 2 unit change in the half-hourly incentive of Genesis to exercise market power is consistent with a 1 to 2 standard deviation change in this index for a number of half-hours of the day. The corresponding coefficient estimate for the half-hourly incentive of Meridian to exercise unilateral market power is \$3,188. The coefficient estimate in column (2) for net rents for Contact is \$1,993. However, Table 4.5 demonstrates that the standard deviation of the half-hourly index of the incentive of Contact to exercise market power is typically substantially larger than it is for either Meridian or Genesis during that same half hour of the day. The results in Table 4.5 are consistent with the statement that for half-hours when each supplier has a greater incentive to exercise market power, the market power rents as measured by gross rents, net rents and positive net rents are

substantially higher even after controlling for the total amount of energy produced in New Zealand during that half-hour period.

Table 6.3: Regressions for total market power rents on firm-level net semi-elasticities

	Gross rents		Net rents		Positive net rents	
	(1)	(2)	(1)	(2)	(1)	(2)
CTCT net semi-elasticity	15655.3	15554.7	1434.2	1993.0	1598.0	2040.5
	(713.97)	(764.16)	(46.61)	(52.83)	(56.88)	(62.93)
GENE net semi-elasticity	7203.8	17072.5	2886.4	4386.4	2331.9	3758.5
	(1019.73)	(1009.2)	(66.57)	(69.77)	(81.24)	(83.11)
MERI net semi-elasticity	32974.3	33560.1	2949.5	3188.2	3232.3	3562.0
	(1031.89)	(1055.39)	(67.37)	(72.96)	(82.21)	(86.92)
MRPL net semi-elasticity	73499.9	72904.9	5101.7	4996.8	5214.1	4907.8
	(1771.62)	(1773.39)	(115.66)	(122.6)	(141.14)	(146.05)
Total generation (MW)	-67.8	35.1	-3.8	4.9	-7.5	1.4
	(16.73)	(15.22)	(1.09)	(1.05)	(1.33)	(1.25)
Total generation squared	0.0191	0.0089	0.0013	0.0005	0.0016	0.0007
	0.0018	0.0015	0.0001	0.0001	0.0002	0.0001
Month-of-sample x half-hour	Y		Y		Y	
Day-of-sample and half-hour		Y		Y		Y
Number of observations	113345	113345	113345	113345	113345	113345
R^2	0.448	0.466	0.700	0.674	0.621	0.608

Source: Calculations as described in text using offer and generation data from Centralised Data Set and EMS, firm-level settlement data from EMS, price data from Centralised Data Set, dispatch data from M-Co, and fuel price and usage data from Contact Energy, Genesis Energy and MED.

451. The coefficient estimates in Table 6.3 have two important implications that follow from the fact that both gross and net market power rents for an individual supplier and the half-hourly firm-level index of the incentive of a supplier to exercise market power can be negative.

- First, controlling for the index of the half-hourly incentive of the other three suppliers to exercise unilateral market power, a higher value of the half-hourly index of the incentive of the other suppler to exercise unilateral market power predicts a higher value of all three measures of half-hourly market power rents.

- Second, controlling for the index of the half-hourly incentive of the other three suppliers to exercise unilateral market power, a larger (in absolute value) negative value of the half-hourly index of the incentive of any other suppler to exercise unilateral market power predicts a lower value of each of the three measures of half-hourly market power rents or larger (in absolute value) negative value market power rents or net market power rents.

The second implication emphasizes the pro-competitive effects of high levels of fixed-price forward market obligations on wholesale market outcomes. The offer price regression results in Section 4 demonstrated that a supplier with a substantial ability to exercise unilateral market power than is net short relative to its fixed-price forward market obligations (which is equivalent to it having a large (in absolute value) negative index of its half-hour incentive to exercise unilateral market power) is predicted to submit a substantially lower half-hourly offer price. The results in Table 6.3 are consistent with this action to reduce market prices (submitting a lower offer price) resulting in a reduced amount of all three measures of the half-hourly market power rents.

452. Table 6.4 presents the results of running the regressions presented in Table 6.2 for the half-hourly average of the firm-level indexes of the incentive to exercise market power. In all cases, the coefficient on the average firm-level index of the incentive to exercise market power is positive and precisely estimated for all measures of market power rents and both columns of results. These coefficient estimates imply sizeable increases in the half-hourly value of gross market power rents and net market power rents and positive net market power rents for the four large firms as a result of a one unit change in the average half-hourly index of the incentive to exercise unilateral market power. For example, column (2) for gross rents implies that a one unit change in the half-hourly average incentive to exercise unilateral market power suggests a $102,387 increase in gross rents. The estimates for the net rents and positive net rents are also large. For example, column (2) for net rents implies a one unit change in the average incentive to exercise market power suggests a $12,477 increase in the half-hourly value of net market power rents. For positive net rents the corresponding figure is $12,341. These numbers imply large and economically significant increases in all three measures of market power rents in response to increases in the half-hourly average of the firm-level incentive of each of the four suppliers to exercise unilateral market power that routinely occur during our sample period, even after controlling for total amount of energy produced in New Zealand during that half-hour period.

Table 6.4: Regressions for total market power rents on average net semi-elasticity

	Gross rents		Net rents		Positive net rents	
	(1)	(2)	(1)	(2)	(1)	(2)
Mean net semi-elasticity	92811.4	102386.8	9738.3	12476.9	9916.3	12340.6
	(1614.57)	(1646.97)	(105.32)	(113.83)	(128.3)	(135.33)
Total generation (MW)	-69.3	62.2	-3.9	5.7	-7.6	2.6
	(16.82)	(15.26)	(1.1)	(1.05)	(1.34)	(1.25)
Total generation squared	0.0201	0.0069	0.0013	0.0004	0.0016	0.0006
	0.0018	0.0015	0.0001	0.0001	0.0002	0.0001
Month-of-sample x half-hour	Y		Y		Y	
Day-of-sample and half-hour		Y		Y		Y
Number of observations	113348	113348	113348	113348	113348	113348
R^2	0.441	0.461	0.697	0.672	0.618	0.606

Source: Calculations as described in text using offer and generation data from Centralised Data Set and EMS, firm-level settlement data from EMS, price data from Centralised Data Set, dispatch data from M-Co, and fuel price and usage data from Contact Energy, Genesis Energy and MED.

453. Comparing the coefficient estimates in Table 6.3 to those in Table 6.4 provides further evidence on the pro-competitive effects of high levels of fixed-price forward market obligations on wholesale market outcomes and market prices. Note that coefficient estimates for the mean net semi-elasticity in each column in Table 6.4 is orders of magnitude larger than many of the coefficient estimates for any one of the four suppliers in the corresponding column of Table 6.3. For example, in column 2 of Table 6.4, a one unit change in the mean net semi-elasticity predicts a $102,387 increase in half-hourly gross market power rents. The coefficient estimate associated with the firm-level index of the incentive to exercise unilateral market power in column 2 of Table 6.3 for Contact, the firm with largest sample average index of the incentive to exercise unilateral market power over the sample period, is $15,555. These results imply that a one unit increase in Contact's unilateral incentive to exercise unilateral market power predicts an increase in gross market power results that is approximately 15% of the increase that is predicted by a one unit change in the average firm-level index of the ability to exercise unilateral market power.

454. Similar results hold for net market power rents. The coefficient on the half-hourly mean net semi-elasticity in column 2 of Table 6.4 is $12,477 and the coefficient estimate for Contact's firm-level net semi-elasticity for net market power rents in column 2 of Table 6.3 is $1,993. This result implies that a one unit change in Contact's half-hourly incentive to exercise unilateral market power predicts an increase in net rents that is 16% percent of predicted increase in net rents that results from a one unit increase in the half-hourly average of the firm-level indexes of the incentive to exercise unilateral market power.

455. The results in Tables 6.3 and 6.4 imply that with high levels of fixed-price forward market obligations for each of the four large suppliers, there are unlikely to be many half-hour periods when all four of these suppliers have a significant ability and incentive to exercise unilateral market power, conditions that are sufficient to achieve a large mean net semi-elasticity, the average firm-level incentive to exercise unilateral market power. If some firms are net short relative to their fixed-price forward market obligations, even if they have a substantial ability to exercise unilateral market power, the results in Section 4 imply that the firm will use this ability to reduce market prices (by submitting lower offer prices) and the regression results in Table 6.3 imply that these actions will reduce all three measures of half-hourly market power rents.

456. Consequently, high levels of fixed-price forward market obligations for all four suppliers increase the frequency of half-hour periods when at least one supplier with a substantial ability to exercise unilateral market power has an incentive to use this ability to lower rather than raise market prices. When all suppliers have a substantial ability to exercise unilateral market power and all are net long relative to their fixed-price forward market obligations, then all suppliers have a substantial incentive to exercise unilateral market power and the mean of the net semi-elasticities of the four suppliers is likely to be high. Under these circumstances, the results in Table 6.4 imply that even after controlling for the half-hourly value of total generation in New Zealand, all three measures of market power rents are high.

6.5 The exercise of unilateral market power and firm-level market power rents

457. In an imperfectly competitive market with all firms unilaterally maximizing their profits given the strategies of their competitors, or equivalently exercising all available unilateral market power, there is typically a non-monotone relationship between the ability or incentive of a supplier to exercise market power and the amount of market power rents that supplier earns. It is well-known that the supplier that benefits the most from the exercise of unilateral market power is typically the one that has the least ability and incentive to exercise unilateral market power. For example, a supplier with no ability to exercise market power that produces its maximum possible output at a price that reflects the exercise of substantial market power typically earns significant market power rents.

458. The supplier that has the greatest ability and incentive to exercise market power often does not earn the largest market power rents. This result occurs because a supplier exercising unilateral market power does so by selling less output than it is able to sell at a non-negative variable profit. For example, suppose that a supplier with a short-run marginal cost of $40/MWh producing 1,500 MWh at a market-clearing price of $60/MWh finds that by selling one more unit of output its total revenues increase by less than $40/MWh. This supplier would still earn positive profits if it sold this additional unit of output because its marginal cost is $40/MWh. However, by selling one more unit of output the supplier find that it increases its production costs by more than it increases its revenues, so it is unilaterally profit-maximizing for the supplier to continue to produce at 1,500 MWh. As emphasized in Section 3, this supplier foregoes profitable sales in order to increase the profits on the sales that it does make, given the strategies of its competitors.

459. The market power rents earned by a supplier exercising market power also depends on the actions of its competitors. For example, if competitors are exercising unilateral market power, then the market power rents earned by that firm by exercising unilateral market power are likely to be larger than if these competitors were behaving as if they had no ability to exercise unilateral market power. This non-monotonic relationship between the firm-level incentive and ability to exercise unilateral market power and the market power rents earned by that firm in a market where several suppliers have the ability and incentive to exercise unilateral market power explains why the dependent variable in our regression is always aggregate market power rents over a collection of firms, in our case the entire market or just the four largest suppliers.

460. Despite this theoretical non-monotonicity of the firm-level incentive to exercise market power and firm-level market power rents, we still find that all three measures of market power rents are increasing in each of the four suppliers' half-hourly incentive to exercise market power and in three of the four suppliers' half-hourly ability to exercise market power. These results clearly demonstrate that during the half-hours when each of the four suppliers has a greater incentive to raise its offer price, all three measures of market power rents are higher as a result of these actions, behavior that is consistent with each of these suppliers submitting half-hourly offer curves that fully exploit their ability and incentive exercise unilateral market power.

6.6 Conclusion

461. This section has demonstrated a direct link between the half-hourly firm-level ability and incentive of the four large suppliers to exercise unilateral market power and half-hourly market power rents earned even after controlling for the level of daily water levels, daily input fossil fuel prices, and the half-hourly value of total generation in New Zealand.

462. Each of the three half-hourly measures of market power rents (computed using the competitive benchmark prices derived in Section 5) is predicted to be higher during half hours with higher average (across the four firms) half-hourly values of the ability or the incentive of the four large suppliers to exercise unilateral market power, even after controlling for differences in fossil fuel prices, the opportunity cost of water, and the level of total system generation across days and half-hours during our sample period.

463. These results demonstrate that holding input fossil fuel prices, the opportunity cost of water, and total system generation constant, higher market power rents occur during half-hours when these four suppliers face less competition (as measured by their average ability to exercise market power) and have a greater incentive to exploit their ability to exercise market power. This same conclusion holds for each supplier individually for its half-hourly incentive to exercise market power (given the values of these indexes for the three other suppliers) and for three of the four suppliers for their ability to exercise unilateral market power.

464. The results in this section demonstrate that during half-hours when the four large suppliers face less competition and have a greater incentive to exploit that fact, half-hourly market power rents for the market and combined half-hourly market power rents for these four suppliers are higher.

SECTION 7

SUMMARY AND CONCLUSIONS

465. This report provided three main lines of evidence consistent with the view that the four large suppliers in the New Zealand electricity market have both the ability and incentive to exercise unilateral market power, and that this exercise of unilateral market power has resulted in substantial wealth transfers from consumers to producers during several sustained periods of time from January 1, 2001 to June 30, 2007.

466. Although prices in the wholesale electricity market depend on the half-hourly aggregate supply curve and the level of half-hourly demand, these supply curves depend on the offer curves submitted by all market participants to the wholesale market. The results presented in this report demonstrate these offer curves are the direct result of the unilateral expected profit-maximizing actions of suppliers given factors that they are unable to control such as the level of demand at all locations in New Zealand, the amount of water inflows to hydroelectric generation units, and the price of fossil fuels and other inputs consumed to produce electricity. The ability and incentive of large suppliers to exercise unilateral market power are important determinants of the supply conditions that

determine short-term wholesale prices (and eventually retail prices), even after the impact of factors such as daily water availability and fossil fuel prices have been taken into account.

467. The first line of empirical evidence in favor of this logic uses insights from a model of expected profit-maximizing offer behavior in a wholesale electricity market presented in Section 3 to derive half-hourly, firm-level indexes of the ability and incentive of a supplier to exercise unilateral market power. The half-hourly firm-level ability measure was derived from the residual demand curve that the supplier faces during that half-hour period and gives the approximate $/MWh price increase that would result from the supplier providing 1 percent less output during that half-hour period.

468. The analysis in Section 3 also demonstrates that an expected profit-maximizing supplier with a substantial ability to exercise unilateral market power may have little incentive to do so if the amount of energy it sells in the short-term market is approximately equal to the quantity of its fixed-price forward market obligations—typically in the form of fixed-price retail load obligations or fixed-price financial contracts. The half-hourly index of the incentive to exercise unilateral market power uses the model of expected profit-maximizing offer behavior to take into account the supplier's fixed-price forward market obligations. This index of the incentive to exercise unilateral market power during a half-hour period gives the approximate $/MWh price increase that would result from the supplier having 1 percent less exposure (positive or negative) to short-term market prices during that half-hour period. Therefore, this index of the incentive to exercise unilateral market power can be either positive or negative, depending on the sign of the difference between a supplier's short-term market sales and its fixed-price forward market obligations.

469. In Section 4, each of these firm-level indexes of the ability to exercise unilateral market were found to closely track the behavior of the quantity-weighted average of the half-hourly nodal prices over the period January 1, 2001 to June 30, 2007. Specifically, higher values of each of these indexes of the half-hourly, firm-level ability to exercise unilateral market power are associated with higher values of the quantity-weighted average of the half-hourly nodal prices. This analysis was repeated for a half-hourly index of the firm-level incentive to exercise unilateral market power. Higher values of each of these half-hourly firm-level indexes of the incentive to exercise unilateral market power was found to be associated with higher values of the quantity-weighted average of the half-hourly nodal prices.

470. The time periods with high values of the quantity-weighted average of the half-hourly nodal prices were also found to be associated with low values of hydro storage levels in New Zealand. Detailed analyses of the three periods of high prices in Winter 2001, Autumn 2003, and Summer 2006 revealed that the higher values of the average of four firm-level indexes of the ability and incentive to exercise unilateral market power provided a far better explanation for movements in the quantity-weighted average of half-hourly wholesale prices during these periods than movements in water storage levels.

471. Evidence that the increasing relationship between the half-hourly firm-level ability to exercise unilateral market power and half-hourly market prices is the result of the unilateral profit-maximizing actions of the four large suppliers was then presented. A linear regression is estimated for each supplier that relates its half-hourly offer price—the highest offer price at which it sells output at during that half-hour—on factors that completely account for daily changes in input fossil fuel costs and daily water levels, and half-hourly changes in operating conditions throughout the day, on that supplier's half-hourly, firm-level index of its ability to exercise unilateral market power.

472. For all four suppliers, larger values of its half-hourly, firm-level ability to exercise unilateral market power were found to predict higher values of the offer price. This evidence is consistent with the statement that after controlling for input cost differences across each day in the sample and half-hours within the day, when each of these four suppliers faces less competition from other suppliers, it submits a higher offer price into the wholesale market.

473. This analysis was repeated for the half-hourly, firm-level incentive to exercise unilateral market power and qualitatively similar results are obtained. The predicted increase in the offer price for a one unit change in the half-hourly index of the firm-level incentive to exercise unilateral market is much larger than the predicted increase in the firm's offer price from a one unit change in its half-hourly, firm-level index of the ability to exercise unilateral market power. This result is consistent with the fact that a firm must have an incentive to exploit any ability to exercise unilateral market power.

474. Several alternative half-hourly indexes of the ability and incentive of a firm to exercise unilateral market power are then introduced. These measures are based on the concept of a pivotal supplier. A supplier is pivotal during a given half-hour in the wholesale electricity market if some of its offers to supply energy must be taken or there will be insufficient energy available to meet the market demand.

475. The half-hourly offer price regression analysis described above was repeated for each of these measures of the half-hourly ability to exercise unilateral market power and found that after controlling for daily changes in input fossil fuel prices and half-hourly operating conditions throughout the day, higher half-hourly, firm-level indexes of the ability to exercise unilateral market power are associated with higher values of the half-hourly offer price for each of the four large suppliers.

476. These regressions were repeated for half-hourly firm-level indexes of the incentive to exercise unilateral market power based on the net pivotal supplier concept and found a positive association between the half-hourly, firm-level index of the incentive to exercise unilateral market and that firm's half-hourly offer price for the three suppliers that are net pivotal a non-trivial fraction of the half-hours during the sample period.

477. One implication of the null hypothesis that fossil fuel generation unit owners behave as if they have no ability to exercise unilateral market power is tested and rejected using the half-hourly offer prices of the fossil fuel generation unit owners. For all fossil fuel suppliers, lower daily water levels predict substantially higher half-hourly offer prices,

which is inconsistent with the hypothesis that fossil fuel generation unit owners behave as if they had no ability or incentive to exercise unilateral market power.

478. The second main line of evidence quantified the cost of the exercise of unilateral market power by constructing counterfactual half-hourly market prices for the period January 1, 2001 to June 30, 2007 that do not reflect the exercise of unilateral market power. These competitive benchmark market prices were constructed to be an upper bound on the half-hourly market prices that would result if no supplier had the ability to exercise unilateral market power.

479. Four approaches are taken to computing these competitive benchmark prices. These approaches differ in terms of how hydroelectric suppliers are assumed to behave under the counterfactual competitive benchmark and the degree of spatial granularity in the process used to compute the competitive benchmark prices.

480. The first approach used to compute the counterfactual competitive benchmark prices assumes that the hydroelectric suppliers continue to produce the same amount of energy during each half-hour of the sample period as they actually did. Fossil fuel generation units were assumed to behave as if they had no ability to exercise unilateral market power and submit offer prices consistent with this assumption, based on an upper bound on their marginal cost of producing electricity.

481. The second approach used to compute the competitive benchmark price allowed the hydroelectric suppliers to exercise more unilateral market power in the computation of the competitive benchmark price than the first approach. The hydroelectric supplier's actual offer curve was used in the competitive benchmark pricing calculation with each offer price capped at the highest competitive offer price of fossil fuel generation units in New Zealand.

482. For both of these approaches to constructing the competitive benchmark offer curves for hydroelectric and fossil fuel suppliers, a version of the nodal-pricing software using the network model supplied by Transpower was implemented to compute counterfactual competitive benchmark nodal prices.

483. Comparisons of the behavior of the quantity-weighted average of the competitive benchmark half-hourly nodal prices computed using the nodal-pricing software to the corresponding half-hourly competitive benchmark prices computed using the simplified single-zone approach does not yield quantitatively different conclusions about the cost of the exercise of unilateral market power for both approaches to computing competitive benchmark offer curves. Because of the computational simplicity of the single zone approach, the empirical analysis focuses on these results.

484. Three major conclusions emerged from this line of empirical analysis. First, for the majority of the half-hours from January 1, 2001 to June 30, 2007, the average difference between actual prices and both sets of competitive benchmark prices is very small. Second, for the majority of years of our sample period, the average difference between actual prices and both sets of competitive benchmark prices is small. Third, there are at least three sustained periods of between three to six months in duration during our sample

period when the average difference between actual prices and competitive benchmark prices is extremely large.

485. These periods coincide with the periods when each of the four large suppliers has very large firm-level indexes of the ability to exercise unilateral market power and several of the firms have sizeable firm-level indexes of the incentive to exercise unilateral market power. During these periods, the average half-hourly value of system-wide market power rents--the difference between the actual price and the competitive benchmark price times the total system demand--are very large. Because these periods generally persist for more than three months, the total market power rents over each of these periods are economically significant.

486. This section also presented suggestive evidence that these wholesale prices (that were the result of the exercise of unilateral market power in the wholesale market) were passed-through to electricity consumers in higher retail prices with a time lag.

487. The third line of evidence explored the extent to which the observed values of half-hourly market power rents were the direct result of the increased half-hourly ability and incentive of the four large suppliers to exercise unilateral market power. Three measures of half-hourly market power rents were constructed, one on a system-wide basis and two for just the four largest firms. Each of these measures of half-hourly market power rents were then regressed on factors that account for daily changes in water levels and fossil fuel prices, half-hourly changes in system conditions, the half-hourly value of total system generation, and the average of the four firm-level indexes of the half-hourly ability to exercise unilateral market power.

488. Higher values of the average of the four half-hourly indexes of the firm-level ability to exercise unilateral market power were found to predict higher values of each of the three measures of half-hourly market power rents. This result is consistent with the statement that when the average ability of the four suppliers to exercise unilateral market power is larger, each measure of market power rents is larger.

489. This same analysis is repeated for the four half-hourly firm-level indexes of the incentive to exercise unilateral market power. In this case, higher values of each firm-level index of the incentive of the supplier to exercise unilateral market power was found to predict unilaterally higher values of each half-hourly measure of market power rents. Specifically, after controlling for daily changes in water levels and fossil fuel prices and changes in half-hourly system conditions, higher levels of each half-hourly index of the firm-level incentive to exercise unilateral market power are associated with higher values of each half-hourly measure of market power rents, even after controlling for the half-hourly values of the three indexes of the incentive of the other suppliers to exercise unilateral market power.

490. Taken together these three lines of empirical evidence are consistent with the following three statements. During certain time intervals between January 1, 2001 and June 30, 2007, the four large suppliers in the New Zealand wholesale electricity market had a substantial ability and incentive to exercise unilateral market power. This ability and incentive to exercise unilateral market power can give rise to sustained periods of

market prices that deviate significantly from competitive benchmark pricing, which can lead to large wealth transfers from consumers to producers of electricity. The half-hour periods when each of these suppliers has a greater ability or incentive to exercise unilateral market power are associated with the half-hour periods when each of the three measures of market power rents (and the magnitude of wealth transfers from consumers to producers) are larger.

491. Although each of the four large suppliers has a statutory mandate to maximize the expected returns paid to its shareholders, which is equivalent to maximizing expected profits or exercising all available unilateral market power, there are structural and behavioral interventions that can improve the performance of the short-term market in the sense of reducing the average difference between actual prices and competitive benchmark prices. These are discussed in Appendix 1.

APPENDIX 1

OBSERVATIONS ON THE NEW ZEALAND GENERATION AND RETAIL MARKETS STRUCTURE AND REGULATORY CONDITIONS

A1.1 Introduction

A1.1. The analysis presented in Sections 3-6 of the main report provides strong empirical evidence that the half-hourly aggregate willingness-to-supply curves from January 1, 2001 to June 30, 2007 and the half-hourly prices that these offer curves produce are the direct result of the expected profit-maximizing actions of at least the four largest suppliers—Contact, Genesis, Mighty River Power and Meridian.

A1.2. Given the findings of the main report, this section provides observations on market power mitigation mechanisms used, or discussed, elsewhere in the world to limit the ability and incentive of suppliers to exercise unilateral market power in order to improve the performance of the short-term wholesale markets.

A1.2 Proactive regulation recognizes the need to adapt the market structure, market rules and the regulatory process to alter the ability and incentive of market participants to exercise unilateral market power

A1.3. The events described in Wolak (2007)[52] imply that a finding that large suppliers in a hydroelectric energy-dominated wholesale electricity market have the ability and incentive to exercise unilateral market power and this has resulted in significant market power rents for sustained periods of time is not unique to New Zealand. Virtually all electricity markets currently operating around the world have experienced periods when suppliers have been able to exercise substantial unilateral market power. Those markets that have best dealt with episodes when significant unilateral market power was exercised or had to potential to be exercised are those that have a proactive regulatory process that recognizes the need to adapt the market structure, market rules, and regulatory process to alter the ability and incentive of market participants to exercise unilateral market power.

A1.4. Although each of the four large suppliers in New Zealand has a statutory mandate to maximize the expected returns paid to its shareholders, which is equivalent to maximizing expected profits or exercising all available unilateral market power, there are regulatory interventions that can improve the performance of the short-term market in the sense of reducing the average difference between actual prices and competitive benchmark prices. As discussed in Wolak (2007), there are a number of

[52] Wolak, F.A. (2007) “Regulating Competition in Wholesale Electricity Supply,” forthcoming in N. Rose ed., Economic Regulation and Its Reform: What Have We Learned?, University of Chicago Press, available at http://www.stanford.edu/~wolak.

ways that have been discussed or implemented in other wholesale electricity markets around the world to modify the market structure, market rules, and the form of the regulatory process to limit the ability and incentive of suppliers to exercise unilateral market power. The role of regulatory oversight of the electricity supply industry is to institute market rules that ensure the conditions necessary for vigorous competition exist and limit the economic harm associated with the exercise of unilateral market power when they do not exist.

A1.5. This appendix provides observations on mechanisms that are used, or could be used, to improve the performance of the short-term market by limiting the ability and incentive of large suppliers to exercise unilateral market power. These mechanisms involve either changes to the market structure or changes to the market rules that alter the incentives that suppliers face.

A1.6. The goal of structural remedies is to increase the amount of competition faced by fossil fuel generation unit owners when water levels are below the levels necessary for the hydroelectric generation capacity to provide sufficient competition for the thermal generation units. Structural remedies include considering the balance of each generator's fossil and hydro generation assets, and the geographic spread of generation units. Regulatory remedies include a reliability insurance mechanism.

A1.7. Before describing these remedies, we first discuss the nature of the unilateral market power problem in short-term wholesale electricity markets in order to understand the tradeoffs that exist in formulating market structure and market rule changes that will improve wholesale market performance. We also discuss the vertically-integrated market structure that is relevant to any discussion of wholesale market power rents in the New Zealand context.

A1.3 Limiting unilateral market power in wholesale electricity markets

A1.8. As emphasized in Section 3 of the main report, a supplier serving its fiduciary responsibility to its shareholders to maximize the return on their investment in the firm should maximize profits and exercise all available unilateral market power. In a market where all suppliers face substantial competition, profit-maximizing firms will take many actions that ultimately benefit consumers. For example, privately-owned profit-maximizing firms facing substantial competition for their output should produce their output at minimum cost and set prices based on these minimum costs of production. A supplier facing substantial competition knows that if it does not produce in a least-cost manner, competitors that do so will be able to undercut this firm's prices and still remain profitable. Consequently, a firm facing substantial competition that does not produce in a least-cost manner will lose sales and eventually be forced to exit the industry because firms producing in a least-cost manner are able to earn profits and remain financially viable at prices lower than those that allow this firm to remain financially viable.

A1.9. By the logic of Section 3 of the main report, a supplier faces substantial competition for its output and therefore has no ability to exercise unilateral market power is equivalent to that supplier facing a perfectly elastic residual demand curve. A firm facing a perfectly elastic residual demand curve knows that it is unable to influence the market price through its unilateral actions. Consequently, the only way for this firm to maximize its profits is to produce in a least-cost manner. Moreover, if there are no barriers to entry into the industry, only those firms able to produce at least cost will remain financially viable and consumers will benefit from prices that reflect the production costs of the surviving firms.

A1.10. In contrast, a profit-maximizing firm that does not face substantial competition is very likely to take actions contrary to the interests of consumers to maximize the returns that its shareholders receive on their investment. As discussed in Section 3 of the main report, a supplier facing an upward-sloping residual demand curve maximizes profits by withholding output from the market in order to increase the price it is paid for output it sells. Although a profit-maximizing supplier still has an incentive to produce in a least cost-manner, it does not have an incentive to sell this output at the lowest possible price because it faces insufficient competition for its output to find it unilaterally profit-maximizing to do so.

A1.11. This logic suggests that market prices in excess of the competitive benchmark level should not be blamed on suppliers having a strong incentive to maximize profits and exercise all available unilateral market power. In fact, as noted above, firms have a fiduciary responsibility to maximize the returns paid to their shareholders. Moreover, if all suppliers face flat residual demand curves, they will find it in their unilateral interest to produce at minimum cost and set market prices equal to the competitive benchmark price. Therefore, the primary driver of the magnitude of the deviation of actual market prices from the competitive benchmark level is the lack of competition faced by suppliers in the short-term market.

A1.12. Remedies that ask suppliers not to exercise unilateral market power when they have the ability and incentive to do so, or subject them to political pressure or popular scorn for exercising market power under these circumstances, are likely to be ineffective and may even degrade system reliability and market efficiency. If suppliers have a fiduciary responsibility to their shareholders to maximize the return on their investment in the firm, then asking the firm not to exercise all available unilateral market power is equivalent to asking its managers not to serve their fiduciary responsibility to their shareholders. Managers will instead be asked to balance the risk of political pressure or popular scorn against the wrath of their shareholders for not maximizing the return on their investment. Therefore, remedies that tell suppliers not to exercise unilateral market power can create instances where the firm might not take actions that benefit shareholders and consumers for fear that these actions are deemed politically unacceptable and will subject the firm's management to public scorn.

A1.13. Any successful remedy for improving the performance of the short-term market must alter either the ability or incentive of suppliers to exercise unilateral market power. Changes in market structure can significantly impact the ability of individual suppliers to exercise unilateral market power by increasing the amount of competition each supplier faces. Changes in market rules can alter the incentives suppliers have to exercise unilateral market power.

A1.14. The following subsections present observations on and discussions of mechanisms to mitigate the ability and incentive of suppliers to exercise unilateral market power. The next subsection discusses possible structural remedies that change the ability of suppliers to exercise unilateral market power. The following section discusses market rule changes that alter the ability or incentive of suppliers to exercise market power. Section A1.8 discusses the role of public information disclosure in enhancing the competitiveness of wholesale market outcomes. Some combination of the remedies discussed below may achieve market outcomes closer to competitive benchmark pricing with the least political conflict and economic cost.

A1.4 Structural remedies

A1.15. The results in Sections 3 to 6 point to several structural remedies that should improve the performance of the short-term wholesale market. Particularly for the pre-2005 time period, the results demonstrate if water levels are sufficiently high, each of the four large suppliers faces enough competition to limit its ability and incentive to exercise market power, and so there is little difference between average actual market prices and average competitive benchmark prices over sustained periods of time at these water levels. In contrast, lower water levels are associated with significantly larger differences between average actual prices and average competitive benchmark prices, particularly during the middle of 2001 and beginning of 2003.

A1.16. One interpretation of these results is that when water is plentiful, the major hydroelectric suppliers would prefer to produce electricity from the water rather than allow it to spill and this leads to vigorous competition between the four large suppliers. For these water levels, the fossil fuel generation unit owners know that they must submit offer prices close to their marginal cost of production or risk being left out of the market by the hydroelectric generation units vigorously competing to sell their water as electricity. These two sets of incentives lead to willingness-to-supply curves for all suppliers that produce average market prices that differ very little from average competitive benchmark prices.

A1.17. When lower water levels occur, each hydroelectric supplier knows that it faces less competition from other hydroelectric suppliers. Higher offer prices by these suppliers will result in less lost sales to other hydroelectric suppliers, because all firms know that the other hydroelectric suppliers have less water available. The thermal generation unit owners also face less competition from the hydroelectric unit owners. The only discipline on the offer prices of the thermal generation unit owner comes from the offer prices of other thermal generation unit owners. However, there are only two major thermal generation unit owners--Contact and Genesis. Therefore, at lower water levels, market prices are effectively set by competition between these two firms, which is clearly insufficient to discipline the ability of each supplier to exercise market power.

A1.18. This logic points to market structure changes that create a larger number of independent fossil generation unit owners which would increase the extent of competition faced by each fossil fuel generator when lower water levels occur. Such a remedy could be accomplished in different ways, including:

- a limit could be placed on the construction of new fossil fuel generation units by firms with existing fossil fuel capacity that exceeds, for example, 20% of the total fossil-fuel capacity in the New Zealand market;
- one or both of the two other large suppliers, or a new entrant, could construct a sizeable fossil-fuel generation unit; and
- existing fossil fuel generators could be ordered to divest some of their fossil fuel generation capacity to one of the two firms that currently do not own significant fossil fuel generation capacity, or to a new entrant.

The goal of this change of market structure is to increase the amount of competition faced by fossil fuel generation unit owners when water levels are below the levels necessary for the hydroelectric generation capacity to provide sufficient competition for the thermal generation units. Some combination of these three structural solutions may also be relevant to market power mitigation discussions.

A1.19. The geographic distribution of generation owned by the four large suppliers suggests another dimension along which a structural remedy may increase the competitiveness of the short-term wholesale market. In particular, as noted in Sections 3 and 4 of the report, Contact is the only one of the four major suppliers that owns sizeable amounts of generation capacity in both the North and South Islands.[53] This fact implies that there is only one firm that can directly impact the difference between prices in the North and South Islands by how it offers its generation units. Because virtually all of the generation capacity in the South Island is hydroelectric, the market for electricity sales between the South and North Islands is also likely to be less competitive at lower water levels.

A1.20. This logic suggests another structural remedy. The ownership of generation capacity among the four large suppliers could be re-arranged so that each firm owns capacity in both the North and South Islands. This market structure will increase the competitiveness of the market for electricity sales across the two islands. This logic also points to additional competitive benefits associated with constructing new fossil fuel generation units in the South Island, instead of in the North Island. Doing so would also have the additional benefit of increasing the competition to supply electricity between the North and South Islands.

[53] As shown in Table 2.1 in the main report, Meridian owns the Ti Apiti wind facility in the North Island. Both the capacity (91 MW) and technology (wind) make it very unlikely that this facility could be used to exercise unilateral market power in the North Island.

A1.5 Behavioral remedies

A1.21. The potential remedies presented in this section address the incentive of the four large suppliers to exercise unilateral market power. All wholesale electricity markets around the world must deal with a reliability externality that arises because no single market participant or collection of market participants bears the full cost of electricity supply shortfalls. The wholesale market regime is designed to manage supply adequacy problems by raising short-term prices to a high enough level to cause consumers to reduce their demand to equal the available supply. If this is not possible because of regulatory intervention or political constraints then random curtailments or rationing will occur. This externality arises because customers that have purchased sufficient supplies of energy in advance of delivery will still be subject to this rationing because it is typically technically impossible to curtail supply to only a subset of consumers in a given geographic area. For example, unless the necessary technology has been installed in the distribution network, is impossible to turn off the electricity to one customer and not all other customers connected to the same distribution substation.

A1.22. If consumers recognize that they will not bear the full cost of failing to procure sufficient supplies in advance because randomized rationing (not higher short-term prices) is used to allocate the available supply, then customers will not procure sufficient energy in advance of delivery to prevent supply shortfalls from occurring. For example, if a customer knows that when a system-wide shortfall occurs, it will be curtailed with some probability along with other customers, then it has little incentive to make the potentially expensive advance purchases necessary to prevent this outcome from occurring because it does not capture the benefits of its prudent procurement strategy.

A1.23. The Reserve Energy Mechanism attempts to address this reliability externality. This mechanism holds generation capacity in reserve to operate in case a supply shortfall occurs. The Reserve Energy Mechanism allows the Electricity Commission to operate the Reserve Energy generation unit when there is a clear threat to electricity security. Although this mechanism charges customers for the cost of the Reserve Energy generation capacity, the mechanism does not address an important factor leading to these apparent supply shortfalls. As shown in Sections 5 and 6 of the main report, these events are extremely profitable for some of the four large suppliers. Consequently, in spite of the existence of the Reserve Energy Mechanism, high-priced periods claimed to be the result of supply shortfalls have continued to occur.

A1.24. The frequency of these high-priced periods due to apparent supply shortfalls can be reduced by making it unprofitable to the large suppliers for these events to occur. One way to accomplish this is to create a financial instrument that must be sold by all of the suppliers to all retail customers that provides average wholesale price insurance for each kWh of electricity they consume. Instead of paying for a Reserve Energy generation unit, all final consumers would be required to contribute a fixed amount each month to a Reliability Insurance Fund. In exchange for receiving this monthly insurance payment, their retailer would be required to provide a guarantee that the annual average wholesale price paid by the customer would not exceed a pre-specified level. For example, suppose that P_S is this pre-specified average annual wholesale price. If the actual annual average wholesale price a consumer pays exceeds P_S then the supplier would be required to pay the customer the difference between that price and P_S times that customer's total annual electricity consumption. These wholesale price insurance payments would be made at the end of each fiscal year.

A1.25. To understand the details of this proposal, consider the following example. Suppose that P_{avg} is the system-wide quantity-weighted average wholesale price over the previous fiscal year and q_{ann} is the annual electricity consumption of that customer over the same time period. Mathematically, P_{avg} is equal to:

$$P_{avg} = \frac{\sum_{m=1}^{12} \sum_{d=1}^{D(m)} \sum_{h=1}^{48} \sum_{n=1}^{N} p_{hdmn} q_{hdmn}}{\sum_{m=1}^{12} \sum_{d=1}^{D(m)} \sum_{h=1}^{48} \sum_{n=1}^{N} q_{hdmn}}$$

where p_{hdmn} is the price at node n during half-hour h of day d during month m and q_{hdmn} equals the total amount of energy injected at node n during half-hour h of day d during month-of-sample m, $D(m)$ is the number of days in month m, 12 is the number of months in the fiscal year and N is the number of nodes in the New Zealand network.

A1.26. In exchange for receiving the monthly reliability insurance payment for each of the previous 12 months, each retailer must pay to all of their customers the greater of zero and $(P_{avg} - P_S)q_{ann}$ where q_{ann} is the customer's annual electricity consumption. Each customer's annual reliability insurance payments guarantees that the annual average wholesale price paid by the customer is less than P_S. Mathematically, the retailer’s annual payment obligation to each of the customers it serves is equal to $\max(0, (P_{avg} - P_S)q_{ann})$.

A1.27. This reliability insurance policy only requires suppliers to make annual payments to its retail customers if the annual average wholesale price exceeds P_S. The price in any half-hour during the year can exceed P_S, as long as the prices in the other half-hours of the year, when combined with this price, yields a value of P_{avg} less than P_S. Consequently, this mechanism does not prevent the wholesale market from setting half-hourly nodal or system-wide prices high enough to operate the transmission network reliably.

A1.28. This is the advantage of the reliability insurance mechanism compared to a cap on half-hourly wholesale prices. As long as P_{avg} does not exceed P_S, suppliers can keep all of the reliability insurance payments paid by its customers each billing cycle. This mechanism only penalizes suppliers for sustained periods of extreme prices, an event over which they have control, through the offer prices they submit to the short-term market.

A1.29. Recall that the first set of competitive benchmark pricing results in Section 5 assumes that the hydroelectric suppliers produce their actual half-hourly output under the counterfactual competitive benchmark. The competitive benchmark prices are computed by finding the point of intersection between the no-market power fossil fuel willingness-to-supply function with the half-hourly demand for electricity that remains after the half-hourly output of all hydroelectric producers has been subtracted from this demand. In constructing the no-market power fossil fuel unit willingness-to-supply function, these generation unit owners are assumed to continue to offer same quantity of generation capacity they actually offered during each half-hour of the sample period. The only difference between the actual fossil fuel offer curves and the no-market power curve used in the competitive benchmark pricing run is that the offer prices for all of these units are reset to an upper bound on the marginal cost of producing electricity from the unit, constructed as defined in Section 5 of the report.

A1.30. These competitive benchmark pricing results demonstrate that the actual pattern of half-hourly demand from January 1, 2001 to June 30, 2007 could have been met at substantially lower average wholesale prices if the hydroelectric suppliers had provided the same energy they actually did during each half-hour of the sample and all fossil fuel suppliers had submitted same total quantity of generation capacity but at offer prices equal to an upper bound of the short-run marginal cost of producing electricity from that generation unit (constructed as described in Section 5 of the report), which is the expected profit-maximizing offer price for the generation unit owned by a firm that has no ability to exercise unilateral market power. However, as the results of Section 4 demonstrate, the four large suppliers recognized their unilateral ability to exercise market power and submitted higher offer prices when they had a greater incentive and ability to exercise it. Therefore, it is unrealistic to expect them not to take advantage of their ability to exercise market power given their fiduciary responsibility to maximize the returns earned by their shareholders.

A1.31. By providing a strong financial incentive for suppliers to keep the average annual wholesale price below P_S, the reliability insurance mechanism will also cause all suppliers to take actions to prevent periods of true supply shortfalls that can lead to extreme prices. For example, suppliers that receive the reliability insurance payment will have a strong incentive to build the necessary new fossil fuel generation capacity to prevent true energy shortfalls. These investments can be funded, at least in part, from the annual reliability payments that retail customers pay. Instead of having to decide how much Reserve Generation Energy is needed to prevent periods of extreme prices, the reliability insurance mechanism allows suppliers to determine the appropriate amount of new fossil fuel generation capacity needed to prevent periods of high wholesale prices that yield average annual prices above P_S. If they are correct, then all suppliers are able to keep all of the reliability insurance payments customers have made over the past year. If they are unsuccessful then all suppliers must pay the difference between P_{avg} and P_S for every kWh sold to retail consumers.

A1.32. Table A1.1 presents a summary of the history of fossil fuel generation capacity in New Zealand. The last two columns of the table demonstrate that the amount of major fossil fuel generation capacity in New Zealand in 1985 before re-structuring took place is only 57 MW less than amount that existed as of the end of 2008. This compares to an average annual increase in load of more than 650 GWh per year over the same period, which corresponds to a requirement for additional capacity of roughly 75 MW per year. As noted in Section 2, peak demand in New Zealand increased by more than 600 MW between 2001 and 2007. Section 2 also demonstrated that the share of annual generation coming from fossil fuel units has also steadily increased, despite this very small net increase in fossil fuel generation capacity. While there has been an expansion in wind and geothermal generation capacity, as well as fossil fuel cogeneration at industrial sites, these technologies are poorly suited to serve as reserve generation for periods of reduced water availability. Consequently, this very small net increase in major fossil fuel generation capacity in more than 20 years helps to explains why low water levels have allowed suppliers to substantially increase wholesale prices in Winter 2001, Autumn 2003, and Summer 2006.

A1.33. This small net increase in fossil fuel generation capacity throughout the wholesale market regime argues in favor of a regulatory invention such at the reliability insurance mechanism outlined in this section to provide additional financial incentives for suppliers to undertake new investment in fossil fuel generation capacity. Net additions to fossil fuel generation capacity by new or existing suppliers that do not currently own fossil fuel capacity will make it more difficult for suppliers to raise wholesale prices during periods of reduced water availability.

A1.34. The remaining complication associated with implementing this reliability insurance mechanism is setting the value of P_S. There are a number of approaches for setting this parameter. The value of P_S should be set sufficiently low to ensure that suppliers have a strong incentive to construct sufficient new fossil fuel generation capacity to maintain a reliable supply of electricity, but not too low to make the cost of providing this insurance prohibitively expensive. The process used to set P_S should not interfere with the ability of retailers to compete for customers. It should also provide strong incentives for suppliers to procure input fossil fuels in a least-cost manner and operate their generation units to minimize the cost of producing the wholesale electricity that they sell each half hour.

Table A1.1: History of major fossil fuel generation units in New Zealand

Plant name	Fuel	Opened	Closed	Capacity (MW)		
				As built	1985	2008
Meremere	Coal	1958	1991	210	115	-
Marsden A	Oil	1967	1996	240	231	-
Otahuhu A	Oil/gas	1970	1998	273	111	-
New Plymouth	Oil/gas	1974	2007	600	605	-
Stratford	Gas	1976	1999	220	218	-
Whirinaki (original)	Diesel	1978	2001	220	204	-
Marsden B	Oil	1979	1979	250	-	-
Huntly Units 1-4	Coal/gas	1983		1,000	1,000	1,000
Southdown	Gas	1997		118	-	170
Stratford CCGT	Gas	1998		357	-	377
Otahuhu B	Gas	1999		380	-	404
Whirinaki	Diesel	2004		155	-	155
Huntly P40	Gas	2005		50	-	50
Huntly e3p	Gas	2007		385	-	385
Total				**4,458**	**2,484**	**2,541**

Sources: Annual Report of the Ministry of Energy (1983); Martin, J., *People, Politics and Power Stations: Electric Power Generation in New Zealand 1880–1998*, Electricity Corporation of New Zealand, 1998; MED Energy Data File; newspaper archives from LexisNexis.

Note: Excludes small generation units and cogen plants.

A1.35. The competitive benchmark pricing mechanism could be applied on a prospective basis to compute P_S. Before the start of each fiscal year, an independent entity could apply this algorithm using estimates of input fossil fuel prices and generation unit heat rates for the coming year and a projected annual pattern of demand and half-hourly output levels from the hydroelectric generation units. To provide strong incentives for suppliers to procure their input fossil fuels in a minimum cost manner and operate their generation units in a cost-effective manner, international figures for input fossil prices and generation unit heat values and other variable costs could be used, instead of values collected from or submitted by market participants. For example, natural gas and coal prices could be taken from forward prices for delivery each month during the coming year from the New York Mercantile Exchange. These prices could then be adjusted for transportation costs and quality differences to the New Zealand market. Generation unit-level heat rates and variable operating and maintenance costs could be collected from comparable generation units and technologies used in other countries. The competitive benchmark pricing algorithm would then be run over the coming year using the half-hourly load values from the previous year increased by some expected load growth rate and different scenarios for half-hourly hydroelectric output throughout the year. For example, the algorithm could be run for the half-hourly pattern of hydroelectric output for the past five years. This would provide five values of the annual average prospective-competitive benchmark price, P_{comp}^{pro}.

A1.36. These five values of P_{comp}^{pro} would form the basis for computing P_S. For example, P_S could be computed as the average of these annual average competitive benchmark prices across the five hydrological conditions plus some damage control factor such as \$10/MWh to \$15/MWh. This means that if over the coming year, the value of P_{avg} exceeds the average of these five values of $P_{comp-pro}$ plus the damage control factor, the suppliers would have to make payments to retail consumers to ensure that they only pay P_S for their annual wholesale electricity consumption. Assuming an annual aggregate electricity consumption in New Zealand of roughly 40,000 GWh, the \$10/MWh to \$15/MWh damage control factors imply that if annual wholesale market revenues differ from the level that would exist under the average of the five prospective competitive benchmark prices by less than \$400 million (for the \$10/MWh factor) or \$600 million (for the \$15/MWh factor) per year, consumers, would not receive payments. This mechanism would allow ample opportunities for half-hourly prices to exceed P_S for sustained periods of time and still not trigger payments to consumers because there are over 17,000 half-hour periods within a given year.

A1.37. If suppliers are required to provide this maximum annual average wholesale price insurance for all kWh sold in New Zealand, they would have a very strong incentive to prevent sustained periods of extreme wholesale prices, because they, would have to make up the difference between P_{avg} and P_S for the entire amount of electricity that each of their customers consumed during the year. All suppliers would have a joint incentive to prevent periods of both true and artificial scarcity that lead to sustained periods of high wholesale prices.

A1.38. It is important to emphasize that it is very likely that if this reliability insurance mechanism is implemented these periods of supply shortfalls will no longer arise because it is no longer in the financial interest of large suppliers for these events to occur. They will have a strong incentive to make the needed investments in new fossil fuel generation units and support transmission upgrades and active demand-side participation to ensure that the sustained periods of extreme wholesale prices do not occur.

A1.39. If wholesale market outcomes similar to those in the Winter of 2001, Autumn of 2003, and Summer of 2006 do not occur, this does not mean that the customers should no longer have to purchase insurance against these extreme prices and that suppliers should no longer have to provide this insurance. For the same reason that a home or car owner does not believe that it was an imprudent expenditure to purchase insurance against damage to their home or car that did not payoff, an electricity consumer should not conclude that purchasing insurance against extreme prices was imprudent because these extreme prices did not occur.

A1.7 Conclusion

A1.40. One conclusion that could be drawn from the results of Sections 3 to 6 is that for the majority of our sample period, the wholesale market achieved market prices very close to the competitive benchmark prices, and the cost of taking action to address the ability and incentive of suppliers to exercise market power are too great to justify the expected cost savings. This logic fails to recognize the fact that these periodic sustained episodes of extreme wholesale prices are likely to continue into the distant future, particularly if there are no significant new investments in fossil fuel capacity by new or existing suppliers that do not currently own fossil fuel capacity. Applying any sort of discount rate to these future episodes of extreme prices, the expected discounted present value of costs to consumers into the distant future associated with these periods of extreme prices is very large. Consequently, it is important to recognize that, if suppliers retain their current ability and incentive to exercise unilateral market power, these sustained periods of extreme prices will continue to occur in New Zealand.

A1.41. Therefore, taking note of these methods for limiting the ability and incentive of suppliers to exercise unilateral market power should benefit consumers in both the short-term and into the distant future. The discounted present value of these benefits should be compared to the current economic and political cost of taking action. Considered from the perspective of balancing benefits into the distant future against current implementation costs, it is difficult to see how taking action now to fix these market performance problems does not have positive expected net benefits to New Zealand consumers and the New Zealand economy.

APPENDIX 2

Preliminary Report on the Design and Performance of the New Zealand Electricity Market

by

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Abstract

This report summarizes the market structure, rules, operating protocols, and regulatory structure governing the operation of the New Zealand electricity supply industry. A history of the electricity supply industry and evolution of the re-structuring process in New Zealand is presented. A detailed description of the wholesale market and a typical operating day in the wholesale market is provided. An analysis of market outcomes—prices, consumption, and generation—from the New Zealand electricity supply industry from 1997 to the end of 2005 is given. These results motivate a discussion of those features of the New Zealand market rules, market structure and regulatory oversight process that may be degrading system reliability and market efficiency. This report proposes directions for further study using data on actual market outcomes.

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1. Introduction

A common goal of electricity industry restructuring around the world is to provide the strongest possible incentives for a reliable supply of electricity at the lowest possible price to final consumers consistent with the long-term financial viability of the industry. This has led to the use of market mechanisms to set prices and determine production decisions where it is technologically feasible and competitive market outcomes are likely. Only those segments of the industry most efficiently supplied by a single firm remain regulated.

The prevailing view is that market mechanisms are technologically feasible to implement in electricity generation and retailing even for a country the size of New Zealand. Economies of scale in electricity generation are exhausted at levels of production significantly below the current level of industry output in New Zealand. If all market participants have equal access to the transmission network and all local distribution networks and can purchase electricity from the wholesale market under equivalent terms and conditions, then returns to scale in electricity retailing are unlikely to exist, which implies that market mechanisms are technologically feasible in electricity retailing.

In contrast, the technology of constructing and operating electricity transmission and distribution networks for a given geographic area favors least cost supply by a single firm, even after accounting for productive inefficiencies induced by regulating the provision of these services. These two segments of the electricity supply industry are thought to be natural monopolies over wide ranges of output and geographic areas. A large fraction of the total costs of providing these services for a given geographic area are fixed, which implies that these production technologies exhibit substantial economies of scale and scope for a given geographic area. As a consequence, the transmission and distribution sectors of the electricity supply industries in all countries continue to be regulated to varying degrees.

The New Zealand electricity supply industry has been re-structured according to this standard paradigm with a number of important exceptions. Both the wholesale electricity generation and electricity retailing sectors are open to competition. The transmission network and local distribution networks are currently regulated by the Commerce Commission. Transmission investment is also regulated by the Electricity Commission. Some generation assets have been privatized, but slightly more than 60% of installed capacity in New Zealand remains in the hands of State-Owned Enterprises (SOEs).

Although the use of market mechanisms to set wholesale and retail electricity prices is technologically feasible in New Zealand, there are number of factors that impact the extent to which market mechanisms result in least cost supply and wholesale and retail prices that only recover total production costs (including a return to capital). A major determinant of the performance of wholesale and retail electricity markets is the market structure and rules governing the operation of the industry. Neither the market structure nor the market rules are the direct result of independent actions by market participants, although the original New Zealand market design was formulated by market participants with limited involvement by the Government. Government actions aimed at improving the performance of the industry are a major determinant of the existing market structure and a motivation for a number of recent market rule changes. This is different from the experience of other goods or services where markets or exchanges for these products arise from the voluntary actions of buyers and sellers to form a self-regulating organization to facilitate mutually beneficial trades. All wholesale electricity markets that currently exist around the world are the outcome of a deliberate government policy to re-structure the industry. Despite its historically "light-handed" approach to regulation, the New Zealand electricity supply industry is no exception to this rule.

Consequently, both the market structure and market rules should be analyzed to determine if past decisions by the government and market participants along these dimensions are adversely impacting efficiency of wholesale and retail market outcomes. From the perspective of economic efficiency, the optimal price for both wholesale and retail electricity should mimic the market price in a competitive industry with many non-colluding firms and minimal barriers to entry. This price has several desirable properties. First, it gives firms the proper signals for the timing and magnitude of new investment expenditures. Second, because firms have no influence over this market price, it is profit-maximizing to produce their output at minimum cost.

There are a number of challenges associated with achieving economically efficient prices. The one receiving the greatest attention is unilateral market power, which I define as the ability of a firm to cause a significant increase in the market price and profit from this price increase through its unilateral actions. A major policy question is the extent to which past decisions in New Zealand about market rules and market structures enhance the ability of participants in the wholesale and retail markets to exercise unilateral market power.

Another important factor contributing to the performance of both the wholesale and retail markets in New Zealand is the structure of the regulatory process for transmission and distribution services, market operation, and other aspects of industry oversight. How transmission and distribution services are regulated or the market and transmission network are operated can impact the behavior of wholesale and retail market participants. Consequently, a second goal of this report is to describe key features of the regulatory process governing the transmission and distribution network and system and market operation. A number of features of the regulatory oversight process in the New Zealand electricity supply industry do not exist in other re-structured countries. These differences are noted and their potential impact on the efficiency of market outcomes and the incentives market participants have to exercise unilateral market power discussed.

The remainder of this report proceeds as follows. The next section provides a brief history of the re-structuring process in New Zealand. This discussion includes a description of the market rules and regulatory structure governing the operation of the industry. Section 3 provides a detailed description of the wholesale market and a typical operating day in the wholesale market. Section 4 presents an analysis of market outcomes from the New Zealand electricity supply industry from 1997 to the end of 2005. Section 5 uses these results to motivate a discussion of those features of the New Zealand market rules, market structure and regulatory oversight process that may be degrading system reliability and market efficiency. This section proposes directions for further study using data on actual market outcomes.

2. New Zealand Electricity Supply Industry

This section describes the evolution of the New Zealand electricity supply industry since the beginning of the 20th century to the start of the wholesale market in 1996. This is followed by a description of the major changes in the structure of the wholesale market from 1996 to the present time. The final part of this section provides an overview of the market rules and regulatory structure governing the industry.

2.1. The History of the New Zealand Electricity Supply Industry

Historically, the New Zealand electricity supply industry was dominated by a state-owned agency that operated the generation facilities and the bulk transmission network. The State Supply of Electricity Act of 1917 gave the government the exclusive right to acquire, construct and maintain generation units. The Electric Power Board Act of 1918 divided the country into separate electric power districts with each to be served by an electric power board. The Municipal Corporations Act of 1920 allowed local councils to purchase wholesale electricity and supply it to their citizens.

These local power boards or local authorities were collectively referred to as Electricity Supply Authorities (ESAs). ESAs initially purchased wholesale electricity from the Electricity Division of the Ministry of Energy of the New Zealand government, the entity responsible for owning and operating generation units and the transmission network. The ESAs had exclusive franchises to sell retail electricity within their geographic boundaries. This organizational structure continued largely unchanged until April 1, 1987, when the government entity responsible for owning and operating generation units and the transmission network was restructured as the Electricity Corporation of New Zealand (ECNZ) and became New Zealand's largest SOE. The government quickly removed restrictions on non-governmental-entity entry into generation and wholesaling of electricity. Largely because of perceived excess capacity in generation, little new entry took place.

The Electricity Act of 1992 removed the requirement for a license to sell retail electricity for a specific geographic area and began the process of allowing retail competition. By 1994, retail competition was allowed with the prices that local distribution companies charged for access to their networks by competitive retailers set through "light-handed regulation." Bertram and Twaddle (2005) argue that this "light-handed regulation" allowed the local distribution network owners to earn profits substantially in excess of those that would have been earned if a traditional cost-of-service regulatory pricing mechanism had been in place. I will discuss potential implications of this regulatory mechanism for market participant behavior and retail and wholesale market performance in Section 5.

The Energy Companies Act of 1992 required each ESA to incorporate and submit a transition plan to become an energy company (EC). The intention of the government appears to have been that the ESAs would be privatized, but the most common business model selected was a company/trust where shares of the trust were owned by the local community, usually the electricity consumers served by the EC. Of the 44 ECs established, 21 were owned by the community or consumer trusts and 10 were partially owned by a trust, 9 were owned by local councils, and one was formed as a cooperative, and three were investor-owned (Kalderimis, 2000, p. 260).

On the wholesale side, ECNZ was expected to earn a competitive rate of return on its assets despite being a SOE. Specifically, Section 4(1)(a) of the State-Owned Enterprise Act of 1986 states: "The principal objective of every State enterprise shall be to operate as a successful business and, to this end, to be as profitable and efficient as comparable businesses that are not owned by the Crown." However, there are a number of differences between the ownership and control structure of SOEs versus privately-owned and publicly traded corporations that can result in differences in the operation of these two types firms. Shirley and Walsh (2001) discuss these differences and the survey the empirical research comparing the performance of state-owned versus privately-owned firms.

In 1988, ECNZ restructured itself into a corporate group with four subsidiaries: Production; Marketing; Transpower; and the PowerDesignBuild Group. On July 1, 1994 the government converted Transpower to a separate SOE that owned and managed the national bulk transmission grid. This decision left ECNZ exclusively focused on generation and wholesale electricity sales. In February of 1996, Contact Energy, a SOE formed from ECNZ, began operation as wholesale electricity supplier in competition with ECNZ.[1]

In April of 1998, the Government stated its intention to implement further reforms of the electricity sector. The first reform was to split ECNZ into three independent SOEs. The second reform mandated separation of local distribution network ownership from electricity retailing. The first reform went into effect on April 1, 1999 when the three new SOEs began operations. They are: (1) Genesis Energy Limited (Genesis),which owns the Huntly (thermal) and Tongario (hydro) generating plants; (2) Meridian Energy Limited (Meridian) which owns the Waitaki (hydro) and Manapouri (hydro) generating plants; and (3) Mighty River Power Limited (MRP) which owns the Waikato (hydro) system of generation plants. The Electricity Industry Reform Act of 1998 sought full corporate separation of distribution networks from retailing by April 1, 1999 and full ownership separation by December 31, 2003.[2] This ownership separation ultimately took place much more rapidly than the Act required.

2.2. Structure of the New Zealand Wholesale Electricity Market

In October 1996, a wholesale electricity market was formed by the industry. This market was a contract between market participants--generation unit owners, retailers, and energy

[1] Ministry of Economic Development (2005) p. 9.
[2] Ministry of Economic Development (2005) p. 10.

traders--that specified how generation units were dispatched and wholesale prices were determined.

The New Zealand electricity system consists of two alternating current (AC) subsystems, for the North and South Islands, connected by an underwater High-Voltage Direct Current (HVDC) cable. According to the Transpower web-site, the maximum total power transfer capability is presently 1040 MW from south to north, the direction of flows for the vast majority of half-hour periods of the year, and approximately 600 MW from north to south. The actual transmission capacity used during each half-hour of the day fluctuates, varying from approximately 300 MW north to south, to over 800 MW south to north, depending on electricity market conditions. Hydroelectric energy availability in the south and north is the major determinant of the direction and level of energy flows

Table 1 provides a summary of energy production in New Zealand for the year period ending 31 March 2005 broken down by the North Island and South Island and for each of the five major producers and all other producers. More than 99% of the energy produced in the South Island comes from hydroelectric sources. There is sufficient generation capacity on the South Island to serve its annual electricity requirements, as well as export a substantial amount of energy to the North Island using the HVDC cable. Approximately 35% of the North Island supply comes from hydroelectric sources, with the remaining 65% split between natural gas-fired (22.5%), coal and oil-fired (17.4%), geothermal (11.6%), cogeneration (11.3%), wind (2%), and less than 1% from biogas facilities.

Annual electricity consumption for the entire country for the year ending March 2005 is approximately 36.9 Terawatt hours (TWh) per year, with 21.6% of this total coming from the commercial sector, 43.9% from the industrial sector, and 34.5% from the residential sector.[3] With approximately 4.1 million people dispersed throughout two electrically connected islands and a population density smaller than all but a few industrialized countries, transmission and distribution charges are likely to account for a larger fraction of the retail price of electricity in New Zealand compared to most industrialized countries.[4] Another important aspect of the New Zealand electricity industry is that much of the population resides in the northern part of North Island in the Auckland metropolitan area, whereas many of the major hydroelectric resources are in the southern part of the South Island.

Prior to the start of the wholesale market, the generation side of the industry was dominated by the state-owned ECNZ, which owned and operated more than 95% of total New Zealand electricity generating capacity. In June of 1995 the government made a number of announcements about the actions it would take before the start of the wholesale market for electricity. One of these was to split ECNZ into two competing SOEs. Contact Energy Limited (Contact) commenced operation with generating capacity formerly owned and operated by ECNZ that represented roughly 22% of total electricity production. The government also imposed a cap on new capacity construction by ECNZ until its generation market share fell below 45%. ECNZ was prohibited from owning any of the retail electricity companies and was required to offer a substantial fraction of its capacity in the form of "reasonably priced" forward financial contracts to electricity retailers.[5]

Both ECNZ and Contact were prohibited from entering electricity retailing until 1998. Contact was subsequently privatized in April 1999, although Transpower and ECNZ remained as

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[3] Table G.2, Energy Data File, Ministry of Economic Development, January 2006.

[4] See the New Zealand population clock at http://www.stats.govt.nz/populationclock.htm and for a list of countries by population density see http://en.wikipedia.org/wiki/List_of_countries_by_population_density.

[5] Ministry of Economic Development (April 2005), pp. 8-9.

SOEs. The sale of Contact was accomplished through 60 percent public share sale with the remainder of the company being sold to Edison Mission Energy Taupo Limited, a New Zealand subsidiary of the United States company Edison Mission Energy.[6]

Immediately following the start of the wholesale market, there were 38 electricity distribution companies, providing equal access distribution services and electricity supply to final customers and one electricity retailer providing electricity supply only (Wolak, 1999). The reduction in the number of distribution companies was primarily due to the continuing trend towards consolidation in the distribution sector which has been taking place since 1945, when there were 94 ESAs (Culy, Read and Wright, 1996). Transpower continued to own and operate the bulk transmission grid. In this capacity it was also responsible for the purchase of ancillary services.

The Electricity Market Company Ltd or EMCO which changed its name to The Marketplace Company and then shortened its name to M-co, was established in 1993 as a joint venture company by the electricity industry. M-co was charged with the design, implementation, and operation of the wholesale electricity market. On October 1, 1996, the wholesale market commenced operation with two large suppliers ECNZ and Contact, controlling the vast majority of generation capacity.

In response to a perceived lack of competition in both the wholesale and retail markets, the Government announced a series of reforms of the electricity supply industry in April of 1998. These reforms were designed to increase competition in the wholesale and retail segments of the industry and improve the effectiveness of the regulatory process for the monopoly segments of the industry. These reforms proposed splitting ECNZ into three SOEs. On April 1, 1999, ECNZ

[6]Ministry of Economic Development (April 2005), p. 11.

was separated into three SOEs: Genesis; Meridian; and MRP. The other reforms included strengthening of the information disclosure regulations and improvement of the quality of information published by the combined electricity retailing and distribution companies to enable more straightforward comparisons of their relative performance. The Government also threatened these companies with price control if it determined that they were not setting the best possible prices for consumers. The primary form of price regulation for the ESAs up to this point was information disclosure, as there was no explicit regulated retail price.

A controversial reform, announced in April 1998, was the ownership separation of the retailing and distribution businesses of the ESAs. Legislation implementing this reform was passed in July of 1998. This reform required the ESAs to choose whether they would like to remain as an electricity retailing or electricity distribution business. The option to continue to operate as combined distribution and retail supply companies was no longer available. This reform is unique to New Zealand. Although the need for retailing to be separate from distribution is widely acknowledged, most countries have chosen to deal with this through financial separation, rather than formal divestiture. Under financial separation the company either forms separate subsidiaries engaged in retailing and distribution services or undertakes an accounting separation of its distribution services business from its electricity retailing business. This approach saves on the transaction costs of explicitly selling one of the ESA's businesses, because it does not prohibit a parent company from owning both the regulated distribution network business and the unregulated electricity retailing business. This approach has been used in the United Kingdom, Australia, and throughout Latin America and the United States.

Virtually all of the ESAs chose to retain their distribution networks. One exception eventually became Trustpower Limited (Trustpower), a privately-owned electricity generation unit owner and electricity retailer, what is often referred to as a "gentailer." By April of 1999, this divestiture process was largely complete. At this time there were seven retailers and the majority of these were owned by the generation owners. This was down from approximately 35 retailers only a year earlier. However, it is important to emphasize that this reduction in the number of retailers may not have lessened the amount of competition faced by any of the remaining retailers, because a number of retailers did not compete for customers outside of their local areas. The seven retailers remaining after this consolidation all participated in larger markets and in most cases the national market.

The large generation unit owners (recall that ECNZ had been separated into three SOEs by this time) used these forced sales as an opportunity to purchase the retail customers of the ESAs. It seems reasonable to assume that the combination retailer and distribution-network-owning ESA would prefer to retain ownership of the monopoly network business instead of face stiff competition in electricity retailing from large national firms with substantial generation assets. These small retailers would need to purchase their wholesale electricity in long-term contracts from one of the large generation unit owners or from the short-term market. Neither of these options was determined to be particularly palatable to the ESAs, which explains why virtually all of them chose to retain their distribution assets.

Some observers have argued that the Government's vertical separation adversely impacted New Zealand consumers, particularly those supplied by the community-owned ESAs (Kalderimis, 2000). These companies typically operated their local distribution networks and supplied retail electricity to benefit their community. Although these ESAs did not have a strong incentive to supply retail electricity at least cost, they also did not have an incentive to charge whatever the market would bear. Although the separated local distribution company could continue to operate to benefit the community, the new electricity retailer had a strong incentive to charge final consumers a retail price of electricity that maximized its profits, rather than serve the interests of local consumers. Unless this retailer faced significant competition, this price could be higher than the price formerly charged by the ESA. There is considerable debate over the extent to which inefficiencies in wholesale electricity procurement and retailing by the ESAs led to higher prices than those that exist under the current regime with a regulated wires business and competitive supply from the large gentailers.

A number of implications of this vertical separation decision are undeniable. First, there are far fewer retailers than there were before the July1998 reform. However, it is also unclear whether less retailers implies that each remaining retailer faces less competition for the reasons discussed earlier. There is a substantial amount of vertical integration between electricity generation and electricity retailing. Currently, there are five large retailers in New Zealand. All but one, Trustpower owns substantially more generation capacity than its average retail load obligations. NERA Economic Consulting attempted to determine the net position of the five large gentailers as of late 2004 for various hydro scenarios (Shuttleworth and Sturm, 2004, p.3) A summary of this analysis is reproduced in Figure 1. In the median water availability year NERA determined that Meridian could produce slightly more than 12 TWh, but its retail load obligation was slightly more than 10 TWh. Contact could produce 14 TWh in a median water year, but its retail load obligation was slightly more than 7 TWh. Genesis Energy had a retail load obligation of slightly more than 8 TWh and its median water year energy production is approximately 1 TWh more. MRP had a retail load obligation of slightly more than 5 TWh and its median water year energy production is 0.5 TWh more. In contrast to these four net long gentailers, Trustpower had a median water year output of approximately 2 TWh, but it had a retail load obligation of close to 6 TWh.

More recent evidence suggests that the five large gentailers have segmented their customers geographically to better match their generation holdings (Murray and Stevenson, 2004, p.17). Because the New Zealand wholesale market uses nodal pricing and includes losses in these nodal prices, generation owners serving loads distant from their generation units may be required to pay wholesale prices significantly higher than what they receive for the energy they inject into the network to cover the withdrawals at the locations of the final consumers they supply. If generation unit owners located near these final consumers are able to exercise local market power and raise the nodal prices they receive, then the distant generation unit owner that serves these final consumers faces an additional source of locational price risk. A gentailer can limit this exposure to locational wholesale price differences by only serving customers located near its generation units.

This allocation of final consumers to the various gentailers is not *a priori* harmful to consumers. If gentailers serving final customers located far from their generation units initially charged a risk premium beyond the expected cost of these locational price differences, this reshuffling of customers can limit the total payments by final consumers for this risk premia on a system wide basis. However, if all gentailers initially charged the expected cost of these locational price differences to final consumers, there would be no efficiency gains from re-shuffling customers to the gentailer with nearby generation units because all customers pay the expected nodal price at the location that they withdraw energy from the transmission network.

Another potential market efficiency gain from allocating final consumers to the local gentailer is that it can reduce the incentive the local gentailer has to exercise local market power and raise the nodal prices its generation units are paid. If this gentailer signs a fixed-price retail supply contract with a final consumer its revenue stream from this customer does not depend on its actions in the wholesale market. Any increase in nodal prices at that customer's location increases the gentailer's wholesale cost to serve that customer. Although the gentailer's generation units are the major beneficiary of these nodal price increases, transmission losses between the customer's location and the gentailer's generation units make taking actions to raise locational prices unprofitable to the local gentailer. However, if the gentailer has customers paying retail prices that vary with spot wholesale prices, then raising prices paid the gentailer's generation units can be profitable because higher local wholesale prices translate directly into higher retail prices for these customers.

A market inefficiency associated with the geographic segmentation of customers is that it can lessen the extent of competition for retail customers if retailers do not compete as vigorously for customers outside of their local area. The supplier located nearest to a final consumer can therefore charge higher prices to final consumers. Which of these mechanisms dominates in terms of the net market efficiency consequences of geographic segmentation of final customers is an empirical question worthy of further study.

Currently, the installed capacity of the New Zealand market is approximately 8440 megawatts (MW). Table 2 provides detailed breakdown of generation units by ownership, installed capacity, and fuel type. Meridian owns 2583 MW in hydroelectric and wind capacity. Contact is the second largest generation owner with 2225 MW of gas-fired, geothermal and hydroelectric generation units. Genesis owns 1500 MW of capacity, including the combination gas and coal-fired Huntly Power station and a significant amount of hydroelectric capacity. MRP owns 1257 MW of a combination hydroelectric capacity, geothermal and natural gas-fired capacity. Trustpower owns 452 MW of hydroelectric and wind capacity. The remaining 433 MW of generation capacity is owned by a number of small firms, none of them owning more than 100 MW of capacity.

2.3. Regulatory Oversight in New Zealand Electricity Supply Industry

Until very recently, there was no explicit regulation (of the form that exists in most other industrialized countries) of the generation, transmission or distribution sectors, aside from monitoring by the New Zealand Ministry of Commerce (which became the Ministry of Economic Development in March of 2000) primarily as mandatory disclosure of annual financial information. As noted earlier, the New Zealand government had taken a "light-handed" approach to regulation of the industry. The Government's stated goal for this mandatory information disclosure approach to regulation was that self-regulation of monopolistic behavior would occur as a result of the transparency caused by the information disclosure (Bollard, 1997).

Several implicit forms of regulatory oversight exist that are unique to New Zealand. The Ministry of Commerce has the authority to exercise control over goods and services provided by firms with some degree of market power. Control can include price control, but this authority can expand to other aspects of the operation of the firm. SOEs are also required to prepare a Statement of Corporate Intent (SCI) and discuss it with their Shareholding Ministers. The SCIs provide a mechanism for the Government (through the Shareholding Ministers) to impact the pricing and other operating practices of SOEs. The SCI process is another reason that SOEs may pursue objectives different from those of privately-owned companies.

The New Zealand Electricity Market (NZEM) organizational structure allowed participants to form contractual arrangements among themselves, with all parties being free to pursue actions before the Courts or raise concerns with the Commerce Commission about potential violations of competition law. A Market Surveillance Committee (MSC) was established by NZEM to act as an independent monitor of the market. The NZEM rules allowed the MSC to recommend rule changes, cancel rule changes, investigate misconduct and breaches of market rules, and discipline market participants for undesirable behavior. The MSC could also impose fines on market participants for violations of the market rules or what it determined to be undesirable practices.

In response to potential power shortages and extremely high prices during the period June to September of 2001, the Minister of Energy implemented a review of the New Zealand electricity industry. This review concluded that the wholesale market would have worked better during this time period if many of the earlier reforms proposed in the December 2000 Government Policy Statement such as improved information disclosure, demand-side participation in the wholesale market, and improved methods for determining grid investment, had been fully implemented.[7] In January of 2002, the Electricity Complaints Commission (ECC) was established at the Government's request.[8] The member companies provide funding for the ECC, but it is independent of the industry. It was reformulated as the Electricity and Gas Complaints Commission because the gas sector was included effective April 1, 2005.

During March to June 2003, the Government forecast another dry year similar to June to September 2001 and implemented an electricity saving campaign. In April 2003, the Government announced that it was preparing to establish a governance board for the industry in case it failed to reach an agreement on a new self-governance structure. The Electricity Commission was established after the Electricity Governance Establishment Project (EGEP),

[7]Ministry of Economic Development (April 2005, p. 15).
[8]Ministry of Economic Development (April 2005, p. 15).
[10]Ministry of Economic Development (April 2005, p. 14).

which was established in October 2000, failed to put in place a single self-governance structure for the industry. The EGEP was established in response to the Government's request to bring together the three existing industry governance structures at the time to establish an Electricity Governance Board.[9] The Electricity Amendment Act of 2001 provided for the establishment of an Electricity Governance Board.

In October of 2004, the Government issued a policy statement on Electricity Governance covering the responsibilities and direction of the Electricity Commission. This Government Policy Statement (GPS) specified the priorities of the Electricity Commission.[10] Managing security of supply is a core priority of the Electricity Commission. The Electricity Commission has the authority to contract with generation unit owners for dry year reserve generation capacity and input fuel. The Electricity Commission's other priorities are facilitating investment in the New Zealand transmission network, improving hedge market transparency and liquidity, and facilitating demand-side participation in the wholesale market. Although the Electricity Commission has the authority to review and approve major new investments in the transmission network, it is unclear what actions it can take to improve hedge market efficiency and demand-side participation in the wholesale market. (Electricity Commission, 2005, p. 23). For example, in most industrialized-country wholesale electricity markets, the regulator is able to compel market participants to enter into forward financial contracts and implement a certain number of MWs of interruptible demand. The Commission does have $18 million to invest in electricity efficiency programs over three years (Electricity Commission, 2005, p. 17).

In June of 2004 the Government procured the Whirinaki Reserve Generation Plant as part of the Reserve Energy Mechanism. This is a 155 MW peaking unit that is only intended to run

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[10]See http://www.electricitycommission.govt.nz/aboutcommission

when there are low hydroelectric inflows or a major generation or transmission outage. It is owned by the New Zealand government and on April 1, 2005 the Electricity Commission was made responsible for determining when it will operate. The Electricity Commission has determined that the Whirinaki plant is sufficient for system security and has procured no additional reserve capacity under its mandate to maintain system security.

The final aspect of the regulatory mechanism is the setting of price thresholds for the transmission and distribution services providers. As a result of continuing consolidation in the distribution sector of the industry currently there are 27 lines companies that distribute electricity to final customers.[11] These distribution companies are owned by the 24 members of the Electricity Networks Association. The distribution companies are subject to a price path threshold and quality threshold set by the Commerce Commission. The current thresholds apply for five years for the distribution companies and expire on March 31, 2009. The threshold for Transpower can also be set for up to five years. To comply with the quality threshold, the distribution company must maintain a certain level of reliability of the local distribution network and demonstrate that they have met certain standards for service quality. The price path threshold takes the form of a price cap mechanism where the company's weighted average price (with constant weights for threshold period proportional to base year output levels) can increase at rate equal to the rate of change of the consumer price index (CPI) less some X-factor. Different from the standard price cap mechanism used in other industrialized countries, the regulated entities can breach this threshold, but they must justify these actions to Commerce Commission. If the Commerce Commission is not satisfied with a party's justification for its actions, it can exercise its authority to control the firm for up to five years.

[11]See http://www.electricity.org.nz/?page=aboutUs.

As discussed in Section 5, the structure of the regulatory process for transmission and distribution companies can have a substantial impact on the competitiveness of the wholesale market and the ability of market participants to exercise unilateral market power in the wholesale and retail segments of the industry. For this reason, it is important have clear understanding of how regulatory processes for these two segments of the industry operate and what the major sources of conflict between these companies and the regulator have been.

According to Bertram and Twaddle (2005), from 1994 to 2003, the distribution networks operated without an industry regulator, but subject to mandatory public information disclosure, including audited accounting cost and revenue information. These authors use the financial information disclosed annually by the distribution companies and the annual reports of these companies to compute estimates of average revenue less average cost differences over the period 1990 to 2002. They find that for all of the companies studied individually―United Networks Limited, Vector Limited, Powerco Limited, and Orion Limited, and for the remaining 27 companies aggregated, the difference between their measures of average revenues and average operating costs increased from 1998 to 2002.

Bertram and Twaddle (2005) also compare the time path of the book value of the fixed assets of these companies with their estimate of the rate base that would have been allowed under US regulatory procedures. The authors find that only $0.7 billion of the $3.6 billion increase in the industry's total book value over the period can be attributed to new net investment. They argue that the $2.9 billion difference is due to revaluations of these assets by the distribution companies based on the replacement cost of their distribution networks. Bertram and Twaddle (2005) then estimate the difference in total revenues earned under the light-handed regulatory scheme that allowed these asset revaluations and an estimate of the revenues these firms would have received under a US cost-of-service price-setting process that did not allow revaluation of the assets of these companies. They argue that this difference in revenues received by the distribution companies due to the existing regulatory process in New Zealand amounted to roughly $200 million per year, or a $2.6 billion lump sum transfer from electricity consumers to the distribution companies. In terms the difference between average revenue and average operating cost, the margin was roughly 1 cent/KWh in the early 1990s and rose to almost 3 cents/KWh in 2002. The authors conclude that the New Zealand approach to light-handed regulation of the distribution companies imposed substantial wealth transfers on New Zealand electricity consumers.

Recently the effectiveness and efficiency of the regulatory process for Transpower has been questioned. Transpower announced a 19% price increase in November 2005 to start on April 1, 2006 that it argues is necessary to fund new investment expenditures to upgrade the transmission network on the North Island. The point of debate is the necessity of 400 kV line between Whakamaru and Otahuhu to improve the reliability of supply to the Auckland and surrounding areas. The Electricity Commission has issued a list of alternatives to the Transpower proposal that involve delaying the project until at least 2017, instead of 2010 as Transpower proposes. Transpower argues that 400 kV line in 2010 is consistent with good utility practice and argues delaying until 2017 implies accepting a lower level of reliability of supply. The interim decision by the Electricity Commission on whether to move ahead with Transpower's proposal has been delayed until the end of April 2006 and the final decision has been delayed until the end of July. Transpower has announced that regardless of the Electricity Commission's decision, it will not submit an alternative plan that it does not believe to be consistent with good utility practice.

The Commerce Commission also had an ongoing investigation of the justification for Transpower's breech of its price threshold which first occurred in late 2004. In January of 2006 the Commerce Commission issued a Notice of Intention to Declare Control over Transpower as a result of this investigation.

2.4. Markets for Input Fuels

New Zealand is increasingly dependent on fossil fuels as inputs to electricity production. In 1945 hydroelectricity supplied 95% of total New Zealand demand and by 1996 this number had dropped to 75% (Culy, Read, and Wright, 1996, p. 319). As shown in Table 1, for the year ending March 2005, this figure has fallen further to 64%. Natural gas-fired plants supplied 12.4% and coal and oil together supplied 9.6% of all electricity produced in this same year.

2.4.1. Natural Gas

Natural gas is currently only produced in the Taranaki region in 11 gas fields. Production is dominated by the Maui field. For the calendar year 2004, gross gas production for New Zealand was 171.30 Petajoules (PJ) and 111.29 PJ, or 65% of total production, came from the Maui field (Ministry of Economic Development, 2006, p. 97). Next in line is the Kapuni field, which produced 27.79 PJ, or 16% of total production. New Zealand does not have any liquefied natural gas (LNG) import or export facilities, so all natural gas consumed in New Zealand must be produced in New Zealand. At present there are also no compressed natural gas (CNG) import facilities in New Zealand. This process is much less capital intensive than LNG importation and has roughly 15 % of the operating and maintenance costs. Therefore, it may be a more viable short-term option for additional natural gas supplies to New Zealand.[12]

[12] See http://en.wikipedia.org/wiki/LNG (Section heading LNG, LPG and CNG).

Electricity generation (including co-generation) accounted for 49% of New Zealand natural gas produced during the year ending September 2005 (Ministry of Economic Development, 2006, p. 94). Virtually all of the natural gas consumed to produce electricity is supplied under long-term contracts. There is little activity in the short-term market for natural gas in New Zealand.

The weighted average price of natural gas to the electricity, gas and water sectors has increased steadily from $4.50/GJ in the year ending September 2003 to $5.20/GJ for the year ending September 2005. Nevertheless, these prices are less than the delivered price of LNG in New Zealand (including the cost of a LNG terminal) from international sources which is estimated to be greater than $6.50/GJ. These prices for natural gas imply that oil would not be competitive with natural gas on a $/GJ basis unless the price of oil fell below $30 per barrel, which seems extremely unlikely. Futures contract prices from the New York Mercantile Exchange predict future spot prices greater than $US 65 per barrel out until December 2012, the last delivery date of futures contracts listed.[13] These futures prices suggest that oil is unlikely to be a significant competitor for natural gas as an input fuel for electricity production for the foreseeable future.

Given the small number of independent suppliers of natural gas, an active short-term market for natural gas seems unlikely to develop in New Zealand in the near term. Exploration and development of natural gas is typically the result of joint exploration for both oil and natural gas. Currently, there is a significant amount of development activity due to extremely high world oil prices. More new entrants into the New Zealand natural gas sector and including the

[13]See http://www.nymex.com/lsco_fut_csf.aspx?product=CL

availability of CNG and/or LNG import facilities would substantially increase the likelihood that an active short-term market for natural gas would develop.

2.4.2. Coal

A report commissioned by the Ministry of Commerce in 1994 estimated that New Zealand has 8.6 billion tones of economically recoverable reserves, of which 80% is lignite, 15% is sub-bituminous coal and 5% is bituminous coal (Ministry of Economic Development, 2006, p. 33). The vast majority of these coal reserves are located in the South Island. New Zealand exports slightly less than half of its domestic coal production. Solid Energy produces 85% of the coal produced in New Zealand, with remaining tonnage produced by a number of small private firms (Ministry of Economic Development, 2006, p. 33).

The demand for sub-bituminous coal has been driven by its use in electricity generation. Significant imports of coal to New Zealand first started in 2003, when the Huntly generation plant began to switch from natural gas to coal. Electricity generation accounted for 55.8 percent of domestic consumption for the year ending September 2005 (Ministry of Economic Development, 2006, p. 36). Coal use for electricity generation (excluding cogeneration) increased from 30 PJ for the year ending September 2003 to 50.4 PJ for the year ending September 2005 (Ministry of Economic Development, 2006, p. 36). The sub-bituminous coal resources used in the Waikato region (near the Huntly generation plant) are becoming increasingly expensive to access, which has led to increasing imports of sub-bituminous coal for electricity generation (Ministry of Economic Development, 2006, p. 36). From the year ending September 2003, until the year ending September 2005, total coal imports have risen from 11.93 PJ to 23.36 PJ, and the vast majority of these imports are sub-bituminous coal.

If New Zealand becomes increasingly dependent on imported sources of coal, the likelihood of a short-term market for coal in New Zealand increases because there is an active short-term international market for sub-bituminous coal used to produce electricity. However, a necessary condition for this to occur is more coal-fired generation capacity in New Zealand. Besides the Huntly generation plant, the only plant with the ability to burn coal at the present time (according to Table 2) is the 40 MW Kinleith facility jointly owned by Genesis and Carter Holt Harvey. The higher greenhouse gas emissions per MWh of electricity produced from coal-fired electricity production relative to natural gas-fired or oil-fired production argue against more sizable coal-fired generation units in New Zealand. Taken together this logic suggests that the market for sub-bituminous coal in New Zealand is unlikely to experience significant growth over the next decade.

3. Market Rules in New Zealand Electricity Market

On October 1, 1996, a wholesale electricity market in New Zealand commenced operation under the name New Zealand Electricity Market (NZEM). This market is an *ex post* spot market in the sense that the half-hourly prices that market participants settle on are set based on a dispatch of the system run after the half-hour that has just been completed. EMCO carried out most of the functions that market operators undertake in other wholesale electricity markets operating around the world. In particular, EMCO was the Market Administrator, Settlements Manager and Pricing Manager. Transpower performed Scheduling and Dispatch, the major functions of the system operator in other wholesale electricity markets operating around the world.

Participation in the NZEM was voluntary and the market rules were developed by market participants with no explicit regulatory oversight. Trading in the NZEM began October 1, 1996 and ended the last day of February 2004. There was no government legislation that formed the basis for the wholesale market and there was no government sanctioned regulator for the industry or market. In this sense, the NZEM was unique among all markets around the world. Changes in market rules were implemented by market participants according to procedures set out in the initial market rules. The market was self-monitoring in the sense that monitoring of compliance with the market rules was in the hands of the MSC. The MSC chair was elected by a simple majority of Market Participants and the MSC members by each of the four participant classes, which were: (1) generator, (2) purchaser, (3) trader, and (4) service provider.

Participation in the NZEM was voluntary in the sense that market participants could trade electricity bilaterally using the Metering and Reconciliation Information Agreement (MARIA). In 1996, when NZEM first started, approximately 7% of electricity was traded using MARIA (NZIER, 2005, p. 4). By March 2004 when NZEM ceased operation, approximately 30% of electricity was traded through MARIA (NZIER, 2005, p.4).

On 3 February of 2000 the Government announced a Ministerial inquiry into the performance of the NZEM chaired by the Honorable David Caygill.[14] This inquiry reported in June 2000 that it supported a continuation of the self-regulation approach, but recommended that if the industry failed to agree on the governance changes needed for the industry, then the Government should take action to achieve the desired outcome. The industry attempted to implement a new rulebook through an extensive stakeholder process. In April 2003, a referendum was held on the new rulebook, but it failed to receive the votes necessary to be

[14]Ministry of Economic Development (April 2005, p. 12)

implemented. This caused the Government to abandon self-regulation of the industry and market. It established the Electricity Commission in September of 2003. On March 1, 2004 the NZEM ceased to exist and operation of the wholesale market continued under the regulatory oversight of the Electricity Commission. Currently, the Electricity Governance Regulations (EGRs) govern the New Zealand electricity industry. The Minister of Energy provided the initial set of EGRs. For the wholesale market, the EGRs are very similar to the rules that existed in the NZEM. A major change concerns Part F, which covers the provision of transmission services.

3.1. Overview of Wholesale Market Operation

The New Zealand wholesale energy market employs a single settlement of nodal prices to compensate generation unit owners and charge loads. Single settlement means that each half-hour of the day there is a single price that is paid for all energy produced during that half hour. Nodal pricing means that a security constrained dispatch process using a network model for the New Zealand transmission network is used to set potentially different prices at each injection and withdrawal point. Both congestion and transmission losses are explicitly priced in the nodal-pricing dispatch computed at the end of each half-hour period. The price setting process co-optimizes the as-bid cost of energy, reserves and transmission losses, accounting for transmission losses, respecting transmission constraints and operating constraint (primarily ramping constraints) on generation units.

The HVDC cable between the North and South Islands and the level of line losses along this link is a major source of price differences in New Zealand. The Haywards is the North Island reference node and Benmore is the South Island reference node. The price at Benmore is typically significantly lower than the price at the Haywards node. More recently, there has been congestion and significant transmission losses from Haywards to the Auckland area. For example, the price at the Otahuhu node south of Auckland is typically higher than the price at the Haywards node. Section 4 documents the magnitude of these geographic price differences and how they have changed over time.

The spot market operates on a daily basis with generators submitting increasing offer step functions giving the amount of capacity they are willing to supply as a function of the price for all half-hours during the following day for each generating unit. Each generation unit can have a maximum of five price and quantity bands, and all individual generating unit offer functions must be increasing in the offer price. The total amount of capacity offered into market within a trading interval must be less than a reasonable estimate of the maximum amount that can be produced from the generation unit. Purchasers submit bid functions which are decreasing in the bid price and can contain up to ten price bands. The price and quantity bands associated with bids and offers cannot be changed less than two hours prior to the trading period. However, if a bona fide physical reason exists, the quantity bands can be changed less than two hours prior to the trading period. Under the NZEM, the Market Surveillance Committee was notified of these quantity revisions and ruled on whether the revised bid was due to a bona fide physical reason. Different from the former Electricity Pool in England and Wales and the current Australian National Electricity Market (NEM), both the price and quantity bands associated with the demand bids and supply offers can vary across half-hours of the day.

3.2. One Day in the New Zealand Electricity Market

This section describes a sample day in the operation of the New Zealand market. It starts with the four hour ahead pre-dispatch process and ends with the ex post pricing process that sets the final prices that generation unit owners and loads settle at. All of these dispatch runs use the Scheduling, Pricing and Dispatch (SPD) model developed and owned by Transpower. As the

Pricing Manager, M-co has a license to use the SPD. This model minimizes the as-bid costs of serving load and reserve requirements accounting for transmission losses and network constraints.

The first step in this process uses a model of the New Zealand transmission network submitted by Transpower by 1 pm for every half-hour of the day for the following day. This submission accounts for outages in the transmission network and differences in the winter versus summer rating of the various links of the transmission network. This information is first combined with the offer and bid functions to perform a prospective dispatch four hours before the actual trading period. The generation unit owners also submit ramp rates to M-co which are input into the SPD model. All of this information is used to produce a pre-dispatch schedule and forecast prices for the next two hours. This four-hour ahead prospective dispatch is run every two hours. Neither the schedules nor the prices produced from this prospective dispatch are financially binding. The output of this run of the SPD model is purely for informational purposes. This pre-dispatch process yields injections and withdrawals, reserves supplied, energy prices and reserve prices at all locations in the transmission network. Only the subset of this information relevant to the generation units owned by and loads served by that market participant are released to each market participant. Transpower also provides a system security analysis four times per day.

Two hours before the actual trading period Transpower is required to submit changes in the network configuration relative to what it submitted the day before. Transpower can update the network configuration information later than two hours prior to the trading period when it has a legitimate system reliability reason for making the change. Using the updated system conditions and updated offers submitted by generation unit owners, the market operates again, but this time it uses a load forecast prepared by Transpower for that half hour rather than the bids submitted by loads. This dispatch sets the schedule for the trading period and indicative prices using the SPD with the updated network configuration. These prices and schedules are once again not financially binding, although a generation unit owner can be penalized for being too far from its dispatch point at the start of the trading interval.

During each 5-minute period of each trading interval, the system operator, Transpower, issues dispatch instructions to minimize the total cost of the deviations necessary to meet demand during that 5-minute interval. This process produces 5-minute prices and dispatch instructions for that 5-minute interval. Once again these 5-minute prices are indicative only.

During the trading interval the system operator also determines the amount of reserves to be procured. If a generation unit owner or interruptible load has a valid contract with the system operator to provide reserve offers, then it is able to submit reserve offers by 1 pm for the following day. Each reserve offer consists of a maximum of three price and quantity pairs for each trading interval. The total quantity offered must be a reasonable estimate of the total reserves that the generation unit is able to provide at a grid exit point or injection point. There are two types of reserves procured in the New Zealand market: (1) fast reserves (available 6 seconds after an event if it is a generation unit and within 1 second of frequency falling to 49.2 Hz if it is an interruptible load), and (2) sustained reserves (available during the first 60 seconds). Fast reserves must be provided for at least 60 seconds and sustained reserves for at least 15 minutes. Generation unit owners can make offers for both energy and reserves from the same generation unit, because the SPD model chooses the least as-bid cost combination of reserves and generation. The same restrictions for changing offers into the energy market apply for offers into the reserves market. Consequently, the 4-hour-ahead market and the 2-hour ahead market each produce reserves levels taken for each generation unit.

At the start of each day, M-co also runs a must-run dispatch auction. This auction is necessitated by the fact that the minimum energy offer in the New Zealand market is equal to zero. Consequently, without this auction, it is possible that more units would offer zero than are needed to serve demand. The must-run dispatch auction allows suppliers to bid for the right to submit a zero offer into the energy market. There are two auctions each day. A night auction that covers the period 12 am to 8 am and a day auction covering the period 8 am to 12 am. This auction is on a system wide basis and these rights are transferable in the sense that each 1 MW offer into energy market at a price of zero must show a 1 MW right purchased in the must-run dispatch auction. The auction revenue is distributed to purchasers of electricity during the time block relevant to the auction revenues. For the day auction revenue, these are the hours of 8 am to 12 am. Bids into this auction may have up to five price and quantity pairs. The amount of rights sold by the system operator is based on 80% of lowest demand during any trading period during the respective time block during the same day of the previous year. Generation unit owners are informed of this supply quantity by 11 am the day before the auction. Pritchard (2002) analyzes the economic efficiency of this auction mechanism and argues that even under the assumption of price-taking behavior by suppliers in the must-run dispatch auction and the amount of must-run capacity exceeds the amount of must-run rights in the auction, the outcome may not allocate the rights to bid zero to the entities that derive the greatest value from owning this right.

Generation unit owners are paid for the energy they actually inject into the network during a given trading interval and loads are charged for the energy they actually withdraw from the network during the trading interval. At the conclusion of each trading interval, information on the characteristics of the transmission network at the start of the trading interval, the instantaneous MW utilization at the start of the trading interval for each generation unit is collected. Actual metered injections and withdrawals of energy during the trading interval at each grid injection or withdrawal point is collected. The final energy offers for each trading interval for each generation unit and the final reserve offers are also collected. The Pricing Manager, currently M-co, publishes final prices by running the SPD model using actual withdrawals during the half-hour period and the final offers for energy and reserved submitted. This is done by noon the day after the trading day if three conditions are met: (1) no infeasibilities arose in the mathematical program used to compute the prices, (2) the information on real-time injections and withdrawals is complete or has been reliably estimated, and (3) there are no known metering errors. If one or more of these conditions are not met at any node during any trading period during the day, a provisional pricing situation is said to exist. M-co must then attempt to resolve the discrepancy that led to the provisional prices as soon as possible. Once these discrepancies have been resolved, final half-hourly prices for energy and reserves are determined for the actual load served during the half hour period, given where each generation unit started that half-hour period, given the state of the transmission network and the offers for energy and reserves submitted by all generation unit owners.

Because the ex post pricing mechanism sets prices based on the actual load served at each location in the network, it is possible that some generation unit owners will not be asked to supply any energy despite the fact that the nodal price at their location is above their offer price. These generation unit owners do not receive any explicit constrained off payment, but this loss in revenue is computed on a monthly basis and made public. Generation unit owners can also have energy dispatched in real time that is offered at a higher price than the ex post nodal price at that location. These generation unit owners receive a constrained-on payment in addition to the nodal price at their location for all of the energy they supply within a trading interval. This constrained on payment is equal to the positive difference between their offer price and the nodal price at their location multiplied by the amount of energy taken from each offer step above the nodal price at that location. During each half hour, these constrained on payments are charged to market participants in proportion to their share of total load served during that trading interval. Aggregate constrained on amounts are calculated on a monthly basis and publicly reported.

Once the final prices have been determined, the reconciliation manager, currently Energy Market Services must determine which market participants sold what electricity where during each half-hour trading interval. A major role of the reconciliation manager is allocating metered half-hourly injections and withdrawals at each location in the network to various market participants. On the generation side, this is a relatively straightforward task, because there is typically one generation owner at each grid injection point and the energy produced by each generation unit is metered at least on a half-hourly basis.

For electricity retailers, this task is complicated by the fact that there can be multiple retailers withdrawing electricity from a single node in the network during a half-hour period but many of the loads served by each retailer have meters that are only read at monthly intervals. Consequently, the reconciliation manager must prepare what are referred to as deemed half-hourly consumption profiles for various customer classes to allocate the half-hourly metered withdrawals at each location in the network to specific market participants at various locations in the transmission network. The final output of this process is the assignment to each market participant of a payment obligation or revenue for every unit of energy injected or withdrawn from the transmission network.

The settlement process allocates these revenue and payment obligations to all market participants for each half-hour on a monthly basis. Load consuming market participants receive a refund each half-hour of their share of payments for transmission losses and congestion. Transmission losses imply that generation unit owners produce more electricity than loads ultimately consume and this is reflected in higher nodal prices at withdrawal points relative to injection points. Transmission congestion is managed by setting higher prices on the constrained side of the transmission link (typically close to major load centers) and lower prices on the unconstrained side of the transmission link (typically close to major generation areas). Both transmission congestion and line losses imply that the total amount of collections from loads during any half-hour period is greater than or equal to the total amount of payments made to generation unit owners. The settlement process pays this loss and constraint excess to Transpower on a half-hourly basis and Transpower currently refunds this to market participants in proportion to the total transmission charges they pay. Congestion charge rentals for the HVDC line are distributed to generation unit owners located in the South Island using this same formula. Transpower does not currently issue Financial Transmission Rights (FTRs), although there has been significant stakeholder and regulator comment on whether they should be issued.

4. Analysis of Market Outcomes Using Centralized Data Set

This section summarizes the performance of the wholesale market from 1997 to 2005 using price and quantity data from the Electricity Commission's Centralized Data Set (CDS). This section also describes some of the problems with CDS that have been uncovered in the process of undertaking this analysis.

Several insights emerge from the analysis of the behavior of nodal prices. First, there is significant price variation across years, primarily due to water availability. Second, there is a high degree of correlation between nodal prices both within and across the North and South Islands, although the correlations between pairs of prices within the same island are substantially larger than the correlations between pairs of price, across the two islands. Third, there are very rare extreme events that can produce enormous price differences both within and across nodes in the North and South Islands. These events produce very high prices which have the potential to impose significant transfers of wealth among market participants.

The analysis of the patterns of load through the New Zealand system shows steady load growth throughout the day from 2000-2004. The daily load shape in the North Island has more pronounced peaks than the daily load shape in the South Island, even after removing the load of the Tiwai Aluminum Smelter. Finally, there is tangible evidence that the energy conservation campaigns during August and September 2001 and April to June of 2003 resulted in significantly lower demand for electricity.

This analysis revealed a substantial amount of missing price, quantity demanded, and quantity supplied data from the CDS. For example, there were a large number of half-hourly quantity demanded observations with no corresponding price observation. There are a number of extreme nodal price observations equal to $100,000/MWh. The supply data from the CDS is missing a substantial number of generation units. In particular, all embedded generation units appear to have been removed from the CDS. A number of generation units are incorrectly labeled. For this reason, it is impossible to use the generation unit-level output data from the CDS to reproduce summary data on electricity production provided by the Ministry of Economic Development in the Energy Data File.

4.1. Nodal Price Correlation Analysis

This section computes correlation coefficients between nodal prices throughout New Zealand. This analysis demonstrates that the correlations between pairs of nodal prices within the same island are extremely high and the correlations between pairs of nodal prices across the North and South islands are slightly less, but still very close to one. In addition, a major reason for positive correlations less than one is a small number of extremely high prices during a small number of half-hour periods. This correlation analysis provides strong evidence that all nodal prices move together and that a single integrated wholesale market exists in New Zealand the vast majority of the half-hours of the year.

The Figure 3 is a map of New Zealand with the 11 major nodes (5 in the South Island and 6 in the North Island) that are used in the correlation analysis Half-hourly prices from these 11 nodes are published on the M-Co web site on a daily basis. Table 3A presents the half-hourly annual mean prices for each year from 1997 to 2005. The 2005 data is only through to the end of November 2005. Average prices fluctuate substantially across the years, ranging from \$29.50/MWh in 2000 to \$80.10/MWh in 2001 for the Benmore node and \$32.50/MWh in 2000 to \$82.90/MWh in 2003 at the Haywards node. The mean difference in annual prices across the 11 nodes is relatively small, although the range of annual mean prices across the 11 nodes appears to be increasing over time.

Excluding the two low water years in 2001 and 2003 and 1997 and 2005, the annual mean prices for each of the 11 nodes are in the range of \$29/MWh to \$35/MWh. Average prices in 2001 and 2003 are almost triple that amount, in the range of \$70/MWh to \$90/MWh. Table 3B contains the annual standard deviation of prices for each of the 11 nodes. With the exception of 2001 and 2003, the standard deviations of half-hourly prices are fairly stable across nodes and years. The annual standard deviations of half-hourly prices are approximately three times larger than values in other years during the sample period. The year with by far the least price volatility was 1997. During 1997, the market was a duopoly of two SOEs--ECNZ and Contact--which faced limited competition from other suppliers.

Table 3C contains the annual median half-hourly prices for these 11 nodes. The annual medians are typically smaller than the annual means. This is particularly the case for the low water years in 2001 and 2003, when the annual median prices for each of the 11 nodes are roughly equal to 2/3 of the annual mean price for the same node. Finally, Table 3D contains the annual maximum price at the 11 nodes. With the exception of the Haywards node in 2004, which had an annual maximum price of $12,019/MWh, these annual maximum prices are below the annual maximums in Australia (which has a $AU 10,000/MWh bid cap and has prices at this level during a few half-hour periods of the year) and in the range of the annual maximum prices in the eastern United States wholesale electricity markets (which have a bid cap of $US 1,000/MWh and have prices at this level a few hours of the year).

Tables 4A to 4I contain the annual correlations between half-hourly prices at these 11 nodes for 1997 to 2005. For most years, the prices at all nodes in the North and South Islands are highly correlated (in many cases with a correlation coefficient greater than 0.99). The exceptions are:

- The southern part of the South Island (INV and HWB) relative to the rest of the island, in 1999 and 2000
- The northern part of the South Island (ISL and STK) relative to the rest of the island, in 2003 and 2004
- The eastern part of the North Island (TUI) relative to the rest of the island, particularly in 2000 and 2002–2004.
- HAY in the southern North Island in 2004.

Prices between the North and South Islands are less correlated. However, in the two years with the highest prices (2001 and 2003), most of the correlation coefficients are greater than 0.9. Analysis of the scatter plots for several of these cases suggest that the low correlation coefficients are the result of a few extreme outliers.

Figures 4A to 4E contain scatter plots of several pairs of half-hourly prices to illustrate the point that the two prices are virtually collinear for the vast majority of half-hourly periods, but there are a small number of half-hours when this linear relationship is dramatically violated. For all of these plots, the vast majority of price pairs lie along a straight line, but there are a few observations which deviate from this line and a small number of these deviations are substantial. These scatter plots suggest that the lower correlations between nodes within each island are the result of isolated incidents of extreme price separation, whereas low correlations between the islands (i.e. BEN – HAY) are due to more frequent but less extreme differences in prices.

There are large year-to-year changes in the BEN – HAY correlation coefficient. For example, the correlation is 0.978 in 2001, 0.714 in 2002, 0.984 in 2003 and 0.169 in 2004. One method for examining these changes is to consider the monthly correlations between the prices. Figure 5A shows the BEN – HAY correlation coefficient for each month of data, from 1997 to October 2005. The figure also includes the mean BEN price for each month. It suggests that the BEN and HAY prices are less correlated during summer (the months around January) and, more generally, at other times when the price is low. Months with price spikes and high mean prices show a high correlation between BEN and HAY prices. This pattern can be seen more clearly in Figure 5B, which plots the monthly BEN – HAY correlation coefficients against the average BEN price for that month.

4.2. Half-Hourly Price Graphs for Benmore and Haywards Nodes

The results of the previous section demonstrate that the Benmore and Haywards nodal prices are representative of the behavior of prices at other nodes in the South Island and North Island, respectively. This section plots the mean, median and standard deviation of the 48 half-hourly prices throughout the day at these two nodes for all days of the year, the winter days only (from 1 April to the end of September) and summer days only (from 1 October of the previous year until the end of March).

This analysis demonstrates the existence of two distinct pricing regimes: (1) those for the normal water years of 2000, 2002, and 2004, and (2) those for the low water years of 2001 and 2003. The pattern throughout the day of the mean, median and standard deviation of half-hourly prices are similar for years within these two groups. However, the pattern of prices within the day for 2005 looks very much like that for a normal water year, but the average value throughout the day looks more like a low water year.

Figures 6A to 6I plot the mean, median, and standard deviation of the 48 half-hourly prices for the three sets of days each year from 2000 to 2005: (1) all days, (2) winter days, and (3) summer days. Consistent with the discussion of the previous section, the pattern of prices throughout the day for 2000, 2002, and 2004 are very similar. The daily pattern of mean and median prices for 2005 is very similar to these three years except that the half-hourly means for 2005 are uniformly higher during all hours of the day. One possible explanation for this difference is the higher fossil fuel prices in 2005 relative to 2004, 2002 and 2000 although data on the input fuel prices these suppliers pay is necessary to determine the extent to which this explanation is valid.

The pattern of half-hourly prices in 2001 and 2003 are very similar. The daily peaks in prices during these two years are far more pronounced than the daily peaks in the other years. An open question is the extent to which these more pronounced daily peaks in 2001 and 2003 are due to the exercise of unilateral market power of individual market participants. An analysis of market participant bidding behavior over the period 2000 to 2005 can shed light on this question.

The daily pattern of median half-hourly prices is flatter than the mean pattern of prices for all years. Median half-hourly prices in 2005 are higher than median half-hourly prices during all years in the sample, including 2001 and 2003 which have the highest annual average prices. Consistent with the results for the half-hourly means, the half-hourly standard deviations for all years but 2001 and 2003 are very similar. The pattern of the half-hourly standard deviations in 2001 and 2003 follow the same pattern as the half-hourly means, indicating that those half-hours during the day with highest average prices also have the most volatile prices.

A comparison of the results for the winter and summer days, shows that the winter months tend to have significantly higher mean and median half-hourly prices and standard deviations of half-hourly prices than do the summer months. The results for the Haywards nodes for all hours of the year are given in Figures 7A to 7C. These figures show the same pattern as the corresponding figures for the Benmore nodes. Results (not shown) for the winter and summer months for the Haywards nodes are qualitatively similar to the figures for the Benmore nodes. These results provide further credence to the perspective that during the vast majority of hours of the year, prices throughout New Zealand move together.

4.3. Half-Hourly Load Graphs

This section studies the behavior of loads throughout the day and across seasons of the year in the North and South Island and for the entire country from 2000 to 2005. The purpose of this section is to characterize the pattern of loads throughout the day for the North Island, South Island and entire country. This section also shows how load growth within the day has occurred across years in the sample and documents the impact of the conservation programs implemented in 2001 and 2003. In addition, I find that the loads during the early morning and late evening hours are substantially the most variable, despite the fact that the average loads during these hours of the day are only slightly higher than the average loads during other daylight hours.

Figure 8A shows the mean load for the entire country in each half-hour period, where the mean is taken over a whole year (January to December). No results are shown for 2005 because the data for December is missing. The load profile shows two peaks for each day: (1) in the morning before 9:00am and (2) in the early evening around 6:00pm. Although the average load has generally increased over time, the profile for 2001 is close to that for 2000, and 2003 close to that for 2002. One explanation for these results is the "power crises", higher prices and savings campaigns in 2001 and 2003.

Figures 8B, 8C and 8D divide the load in Figure 8A between the North Island, South Island and the Tiwai Aluminum Smelter. The Tiwai load is so large in comparison to the remainder of the South Island load (they are close to equal in the early morning) that the two are shown separately. The load in the North Island has more pronounced daily peaks than the load in the South Island, even after excluding load from the Tiwai Aluminum Smelter.

Figure 8E shows the standard deviation of the total New Zealand load, for each half-hour period, across the 365 days of the year. These results are consistent with the logic that the half-hour periods of the day with the highest average loads also have the most unpredictable loads.

Figures 8F and 8G show the summer load profiles for the North Island and South Island (excluding Tiwai). Figures 8H and 8I show the winter load profiles for the two islands. Here summer is taken as October of the previous year until the end of March, and winter as April until the end of September. For both islands, there is much less daytime variation in loads during the summer than during the winter, with the morning and evening peaks almost unidentifiable in summer. One interesting feature of the South Island load profiles is the spike at 11:00pm and the flatter portion from 7:00am to 8:00 am. This appears to be the result of appliances on separate meters that make use of cheaper night-rate electricity. These are primarily night-store heaters, which is why the effect is greatest in the South Island and in winter. In 2003, at least one retailer (Meridian) lengthened the night-rate until 9:00pm, which may be why the 11:00pm spike is smaller in 2004 and 2005.

Figure 8J shows the month-by-month mean load at one of the peak times (6:00pm). The seasonal trend in loads is very clear on this graph. It is also possible to identify the two “crisis” periods which had national savings campaigns that occurred in August and September 2001, and again from April to June 2003. For this reason, it is not surprising that the lower envelope of average 6:00 pm demand from April to June occurred in 2003 and the lower envelope of average 6:00 pm demand from August to September occurred in 2001. Figure 8K has another presentation of the change in intra-day loads over the year. For 2004 only, it shows the mean load profile for successive pairs of months (January and February, March and April, and so on). This graph shows the large increase in peak-time (particularly early evening) loads during winter, compared to a much smaller increase in the off-peak loads.

4.3. Issues with Centralized Data Set

This section discusses a number of issues with the half-hourly price, load data and supply data associated with versions of CDS starting in July 2005. I first discuss missing price and load data and the issue of extreme nodal price observations. Then I discuss the difficulties encountered with constructing a consistent generation output series using the CDS.

It is extremely difficult to determine precisely how much data is missing from the CDS because the number of nodes in the New Zealand network changes over the sample period. However, I do not have a dataset that documents the entry and exit of nodes over time so that a complete account of missing data can be performed. In addition, it is extremely difficult to distinguish a valid price from an invalid price observation. At best, only incomplete analyses of the amount of missing data can be performed using simple logical checks such as if a node has a positive injection or withdrawal of energy during a half-hour period it should have a price observation. The incomplete analysis I am able to perform is not encouraging about the quality and completeness of the CDS.

The correlation analyses are extremely sensitive to outlying price values. These extreme prices may be due to recording errors in the data set. Unfortunately, the frequency of incomplete data in the CDS makes it very difficult to determine whether these very large prices are caused by an unusual market situation or a recording error. Between 1997 and 2004 there are 297,156 quantity observations in the load data that have no corresponding price observation. However, for about a third of these, the observed quantity is zero. This leaves 163,167 non-zero quantity observations with no price observation. Nearly all of these observations appear to be the result of a single missing series of input data. There are 22 nodes with names starting with "M", and each node is missing 1,488 price observations in 1999 and 5,810 price observations in 2000. The only other load node with missing price data over the period is NI.Kawerau.Tasman.C113, which is missing 2,691 observations from 1997. Also, most nodes have quantity data for November 2005 but no price data.

The reverse case of missing data is where a node has price information but no quantity information. There are 16 nodes where this occurs over the 1997–2005 period, with a total of 310,876 half-hours that are missing. The number of missing half-hour observations, by node and year, is shown in Table 5A. Most of these nodes are in fairly isolated regions and the loads are probably very small (or even zero), so it is unlikely that this missing data will significantly affect the system-level load calculations. There are also nodes and half-hours in which both the load and price information is missing. However, it is often unclear whether the data exists but has not been incorporated into the data set, or if the node was not part of the network at that time.

The dataset also contains 110,398 half-hourly nodal price observations with the maximum price of $100,000/MWh. These do not appear to be market-clearing prices because generally the corresponding volume observation is 0. A total of 90 out of the (approximately) 235 nodes have at least one half-hour period with this price. However, just 16 nodes make up nearly 97% of these extreme price observations. The Table 5B shows these 16 nodes and the number of $100,000 price observations in each year. There are also a small number of observations with extreme negative prices. These include prices of $−100,000/MWh and $−9,999/MWh that do not appear to be market-clearing prices. The three load nodes with these extreme prices (less than $−9,000) are:

- NI.Kaponga (47 half-hour periods from 1999 to 2001);
- SI.Albury (7 half-hour periods in 2001); and
- SI.Ashburton.66KV (1 half-hour period in 2002).

There are also 9 generation nodes that have negative prices below - $9,000. For all of the analyses, the node half-hours with an (positive or negative) extreme price are set to "missing" and therefore excluded from the calculation. This has a very large impact on calculating the standard deviation across nodes.

The Table 5C shows summary statistics, by year, for the half-hourly standard deviation of prices across the load nodes. At the bottom of the table there is a count of the number of half-hour periods in each year for which the standard deviation falls within the various ranges. The years 2001, 2003 and 2004 had the most "extreme events" with standard deviations above $200. 2004 had 8 half-hour periods in which the standard deviation across nodes exceeded $1000. These figures provide further confirmation that price differences across nodes is infrequent, but when it occurs the resulting price differences can be substantial and economically meaningful in terms of the costs they impose on market participants.

There are a number issues associated with matching the identifiers in the "Gnash" database on the CDS CD-ROM with actual generation units names and locations. Some issues uncovered include (and this is not necessarily a comprehensive list):

- Trustpower's Patea hydro scheme (31MW) does not appear to be included.
- The Kapuni cogen plant (25MW) does not appear to be included.
- There are many code names that don't identify the type of generation. Here are examples of names and guess as to which unit or units they refer to
  - Gen.Silverstream: landfill methane plant operated by Mighty River Power
  - Gen.Edgecumbe: cogen plant at the Fonterra dairy factory
  - Gen.Hinemaia: Trustpower Hinemaiaia hydro scheme in the Bay of Plenty
  - Gen.Kurutau: King Country hydro station. It is unclear if this also includes output from Mokauiti, Wairere and Piriaka,
  - There are many others, most of which appear to be small hydro stations.
- Other code names appear to be misidentified:
  - Gen.Thermal.Kawerau.A, Kawerau.B, Kawerau.C are all said to belong to the Tasman Pulp & Paper factory. However, only the Kawerau.B input series appears

to relate to the mill. Kawerau.A and Kawerau.C may be for the Kawerau geothermal station (~6.3 MW). The output looks similar, and this station does not appear elsewhere.

- The Gen.Hydro.Hawera series: It is unclear if the 110KV.1 series could be the Patea hydro scheme owned by Trustpower. Also, the 110KV.2 series looks like the 69MW Fonterra cogen plant at Hawera (the input series has a "KIWI" code).

The CDS only contained generation data after 2000 and in many instances there is missing data. Table 6A shows all of the generation data series in the CDS that have data after 2000, with the range of the series, the number of days with actual data, and the number of days that are missing data. The nodes are sorted by the number of days of available data.

The generation nodes can be grouped into about four categories, based on the level of data availability. The group with the most data (continuous from October 2000) consists of a few small hydro stations, geothermal and cogen plants. The next group has data from May 2003 until November 2005. It contains many of the largest and most important generators, including all of the major hydro stations in the South Island and Contact's thermal units in the North Island. Huntly has data from about mid-2002. The third group contains further hydro, geothermal and cogen units, with data from 1 November 2004. The final group contains most of the small hydro and embedded generation. These have only two months of data available in the CDS. The Electricity Commission appears to be currently undergoing consultations regarding the addition of further generation data for these producers.

To determine the magnitude of these data issues, I attempted to duplicate information produced in the Ministry of Economic Development's Energy Data File. Table 6B shows the total generation from the CDS, by generator and fuel type, for the years to March 2004 and March 2005. The actual generation data, from the Ministry of Economic Development publication "Energy Data File", is included for comparison. For the year to March 2005, the production figures from the CDS are 93% of the total. The figures for Meridian, Contact and Genesis correspond to the Energy Data File values. The "missing generation" appears to be from Mighty River Power, Trustpower and other generators. This matches the series in the CDS that are known to be missing data: the Whakamaru and Atiamuri hydro stations of Mighty River Power, and many of the small generation units belonging to TrustPower and others. For the year to March 2004, the CDS figures are 84% of actual generation. For this period, Meridian and Contact also have CDS generation below the Energy Data File figures. This reflects the missing data for many of their major generating plants (including Clyde, Roxburgh, Manapouri, the Waitaki scheme and Stratford) before May 2003. This difference represents about a month of generation, which is the amount of data missing from the CDS for this period.

5. Potential Sources of Inefficiencies in Current Market Design

The previous section identified a number of directions for further inquiry into sources of potential wholesale market inefficiencies. This section first discusses these potential sources of market inefficiencies and proposes further empirical analyses to determine their underlying causes. It then describes features of the current New Zealand market that may be degrading the performance of the wholesale and retail markets and may also enhance the ability of market participants to take unilateral actions to raise the prices they are paid for producing energy, providing ancillary services or selling retail electricity. Directions for future research are suggested that may shed light on the magnitude of these potential market inefficiencies and the incentives for market participant behavior created by these inefficiencies.

5.1. Extreme Market Prices

The price correlation analysis of Section 4 found infrequent price spikes that lead to prices at scattered nodes throughout New Zealand that were vastly different from the quantity-weighted average price during that half-hour period. Very high half-hourly prices at certain nodes clearly benefit some suppliers. It is unclear whether these suppliers are able to take actions that allow them to cause these high prices or increase the likelihood of these high prices.

The pattern of extreme prices could be consistent with them being caused by events outside the control of any market participant, such as transmission line and generation unit outages or unexpected increases in demand at certain locations in the transmission network.

These high prices at certain nodes could also be consistent with them being caused (in part) by the unilateral actions of the suppliers that benefit from them. For example, these suppliers could notice that certain system conditions allow them to raise market prices significantly through their unilateral behavior, how much generation capacity they make available to the market and the prices at which they make this generation capacity available.

A detailed analysis of market participant offer behavior and how this offer behavior changes with system conditions can help to distinguish between these two possible explanations for extreme market prices. For example, if a supplier offers dramatically different supply curves—significantly higher offer prices and/or lower offer quantities—during these extreme system conditions relative to other system conditions, this would constitute strong evidence that these market prices are caused in part by that supplier's unilateral actions. This analysis can be undertaken with data on the half-hourly offers of generation unit owners, the availability of transmission network links, the availability of other generation units in the system, and the level of system demand.

Measures of the unilateral ability of a generation unit owner to raise market prices can be computed from half-hourly offers submitted by all other market participants, if a complete set of offer data is available for all market participants. (A partial collection this information exists in the CDS from the middle of 2004 to the present time.) These half-hourly magnitudes provide a quantitative measure of the percent increase in the market-clearing price each generation unit owner can cause by unilaterally reducing its output by a given percentage of what it actually produced during that half-hour. These measures can also be compared to similar measures computed for generation unit owners in other markets around the world. In addition, these measures can be compared over time and across generation unit owners to quantify how competitive conditions vary over time and across market participants.

5.2. Persistently Higher Prices in Calendar Year 2005

Section 4 demonstrated that prices in 2005 followed the same qualitative pattern within the day as all of the other years besides the two low water years of 2001 and 2003. However, both the mean and median half-hourly prices within the day in 2005 were closer to the levels set during 2001 and 2003. This raises the question of what is the underlying cause of the persistently higher prices throughout the day during 2005. One explanation is the significantly higher international oil prices in 2005 relative to previous years. However, little electricity in New Zealand is produced using oil and the most commonly used fossil fuel is natural gas, which trades in New Zealand below international LNG prices. This logic suggests that there may be factors besides input fuel cost increases that have led to higher electricity prices in 2005, although a definitive answer to this question requires information on the natural gas prices paid by electricity generation unit owners over the sample period. Another factor to investigate is whether one of the major suppliers had less fixed-price forward contracts or retail load commitments relative to their expected spot market sales of energy during 2005 which left them with a greater incentive to attempt to raise spot prices through their unilateral offer behavior.

An analysis of input fuel prices, supplier offer behavior, water availability, and the level half-hourly demands can help to determine whether strategic behavior by suppliers, input fuel costs or water availability is the cause of higher wholesale prices in 2005. Specifically, if the following facts were shown to be present it might constitute strong evidence that suppliers were able to raise prices in 2005 through their forward contracting levels and offer behavior into the wholesale market:

- input fuel prices and water availability have not changed significantly between 2004 and 2005;
- fixed-price forward contract obligations of the major suppliers are lower in 2005 relative to same period in 2004;
- retail load obligations of the major suppliers have fallen from their levels during the same period in 2004; and
- generation unit owners offered less energy at the same price in 2005 relative to 2004.

5.3. Vertical Integration

A major difference between the New Zealand market and a number of wholesale electricity markets around the world is the extent of vertical integration between electricity generation and retailing. At the start of both the England and Wales market and the Australian market, the former vertically integrated utility was separated into pure electricity generation unit owners and pure electricity retailers. In both of these markets, distribution was included with supply, meaning that the electricity retailers also owned and operated a local distribution network. In England and Wales there has been considerable merger activity in the retailing and distribution segment of the industry since the electricity Pool was formed in 1990. Until recently, there has been very little vertical integration between electricity generation unit owners and electricity retailers in Australia. In early 2004, AGL the largest retailer in Victoria acquired, Loy Yang the largest generation unit owner in Victoria.

Vertical integration between electricity generation unit owners and retailers is not *per se* harmful to the efficiency of either the wholesale or retail market. Vertical integration can benefit market efficiency to the extent that it reduces the incentive that generation unit owners have to raise the wholesale market price because the supplier has a fixed-price retail load obligation. Under these circumstances the supplier has no incentive to raise the short-term price of wholesale electricity until it sells more energy into the wholesale market than its retail load obligations. In markets where a regulator sets the fixed retail price at which a vertically-integrated firm is obligated to supply all retail demand, this mechanism can cause a supplier that owns a substantial amount of generation capacity to use these assets to increase the efficiency of the short-term market. This occurs if the vertically integrated firm's fixed-price retail load obligations set by the regulator are typically larger than the amount of energy it expects to supply from its generation units. This is the situation in all of the eastern US wholesale markets, where there is a substantial amount of vertical integration between generation and retailing. The retail price that these vertically-integrated firms must sell at is set by state level regulators for a substantial period of time, typically for several years. This creates strong incentives for the vertically integrated firms to use their substantial generation holding to increase the efficiency of the short-term market.

Bushnell, Mansur and Saravia (2005) provide strong evidence of these market efficiency benefits of vertical integration between generation ownership and retailing when the retail price is regulated or fixed for substantial period of time. They simulate the performance of the PJM and New England wholesale electricity markets with the high degree of vertical integration that actually exists in these two markets to counterfactual markets with no vertical integration. They also simulate the actual vertical integration and no-vertical integration market outcomes for the California market, which has relatively little vertical integration. They find that under the counterfactual no-vertical integration market outcome, the large suppliers in PJM and New England are able exercise substantial amounts of unilateral market power. In fact, the levels of market power exceed those that the authors compute for the no-vertical integration simulation of the California market. The authors take this as evidence that vertical integration has the potential to improve short-term wholesale market performance substantially.

If the retail price is unregulated, then vertical integration can reduce the efficiency of the wholesale market. In particular, because all suppliers use their own generation units to serve the vast majority of their retail load obligations, they have very little incentive to enter into long-term contracts for supply arrangements and little incentive to contribute to the liquidity of the short-term wholesale market. Both these factors can increase the cost of new entry into electricity retailing, because a new retailer must purchase wholesale energy to serve its load obligations either from long-term contract purchases or from the short-term market. These higher barriers to entry into retailing enhance the ability of the vertically integrated firms to degrade the efficiency of the wholesale and retail markets and ultimately result in higher retail prices of electricity.

By this logic, the lack of any regulatory oversight of retail electricity prices in New Zealand suggests that vertical integration between retailing and generation may be harmful to the efficiency of both the wholesale and retail markets in New Zealand. Determining the extent to which this is the case requires assessing the competitiveness of both the wholesale and retail segments of the electricity industry in New Zealand.

The efficiency of a market is typically measured by how closely the price paid for a product is to the marginal cost of the highest cost unit sold of that product. Consequently, a first-step in assessing the competitiveness of both the wholesale and retail segments of the industry is measurement of the extent to which the nodal prices each half-hour differ from the prices that would result if all suppliers submitted bids equal to their marginal cost of supplying electricity. Assessing the competitiveness of the retail market proceeds in a similar manner, by comparing actual retail prices to the retail prices that would exist if each retailer charged a price equal to the marginal cost of supplying the last unit of electricity consumed at that location in the transmission network. Computing these market efficiency measures requires extensive information on the generation unit owner's variable cost of supplying electricity and the retailer's variable cost of selling electricity.

5.4. Form of Regulatory Oversight

A second way in which the New Zealand market differs from other markets around the world is the extent of regulatory oversight of the industry. In the US and a number of other countries around the world, the transmission and distribution segments of the industry are very rigorously regulated using a cost-of-service approach. Under this mechanism, the regulated firm is only guaranteed the opportunity to earn a pre-specified rate of return on its investments if it operates in a prudent manner. Any perceived excess profits are typically refunded to consumers in the form of lower prices.

The typical cost-of-service regulatory process in the US sets a single output price or different prices for different customer classes. The regulated firm is then required to satisfy all demand from these customers at the regulated prices. For example, the price that all retailers pay to access the same distribution network is set by regulator. Similar logic applies to the price paid to access the transmission network. The fact that these regulated firms are prohibited setting differential prices or limiting the amount they sell to certain customers severely limits their ability to degrade the overall efficiency of the wholesale market. The regulatory process in New Zealand appears to leave several avenues for the distribution companies and Transpower to degrade overall market efficiency and enhance the ability of market participants to exercise unilateral market power.

The usual goal of monopoly regulation is to set a price that allows the regulated firm an opportunity to remain financially viable in the long-run. Allowing a regulated monopoly to earn more revenues than the minimal amount necessary to remain financially viable can involve significant transfers of wealth from consumers to producers and deadweight losses to consumers in the sense that there are sales that would have taken place if an economically efficient price had been set by the regulator, but did not take place because the price was set too high. Moreover, the incentives created by this regulatory process can impact the performance of the unregulated portions of the industry.

The evidence presented by Bertram and Twaddle (2005) suggests that distribution price regulation in New Zealand was overly generous to the firms being regulated, at least over the period 1994 to 2003. In addition, the pricing flexibility this regulatory mechanism grants to the distribution companies can enhance the ability of gentailers to raise the prices that final consumer pay for electricity. For example, a distribution company and a gentailer could fashion complex pricing arrangements for distribution services that make it more difficult for other gentailers to compete for final consumers in this geographic area.

A more detailed analysis of the incentives for firm behavior caused by the current regulatory oversight mechanism of the network providers is worthwhile, because regulated firms can increase their profits by responding strategically to the structure of the regulatory process. Averch and Johnson (1962) were the first to point out that the structure of the regulatory process can significantly impact the regulated firm's incentives for least cost production and therefore the efficiency of the regulated prices charged to consumers. In addition, the strategic response of competitive generation owners and retailers to the regulatory process governing the transmission and distribution segments of the industry can further degrade overall market efficiency.

The wholesale and retail markets in New Zealand also have significantly less regulatory oversight than wholesale markets in virtually all other parts of the world. In the US, there are bid caps on the offers for energy and ancillary services that suppliers can submit into the short-term market. For example, in the Eastern US markets, the maximum energy offer a supplier can submit is currently $1,000/MWh. All US markets also have local market power mitigation mechanisms that mitigate the offers of a generation unit owner in those instances where that generation unit owner is one of a small number of suppliers able to meet a local energy need. The mechanisms typically mitigate the offers of suppliers determined to possess substantial local market power because of their location in the transmission network to either an estimate of the generation unit's variable cost or a representative bid that was accepted to supply energy during system conditions when the generation unit did not possess substantial local market power. These local market power mitigation (LMPM) mechanisms are a part of all US markets and limit the extent of locational price differences and the accompanying market inefficiencies that are due to the exercise of local market power. Although it is clearly possible to that the vast majority of nodal price differences can be explained by transmission constraints and offer curves by electricity generation unit owners reflecting little or no exercise of local market power, this has not been the experience of United States wholesale markets that employ nodal pricing.

The infrequent price spikes at various nodes in the transmission network documented in Section 4 are consistent with the exercise of substantial local market power. An important lesson from the United States nodal-pricing markets is that certain system conditions in terms of the level and geographic distribution of demand, configuration of the transmission network and operating behavior other generation units are required for suppliers to be able to exercise substantial local market power. An important issue is whether these conditions arise during a sufficiently large fraction of the hours of the year to cause significant harm to market efficiency.

Further empirical analysis of market outcome data is necessary to determine whether local market power is the underlying cause of these price spikes. An LMPM mechanism is the regulatory response to these market outcomes in the US and a number of other wholesale markets around the world. In a nodal pricing market, an LMPM mechanism limits the frequency of extremely high locational prices due to the exercise of local market power, which can significantly reduce the volatility and improve informational value of short-term prices. New Zealand is the only nodal-pricing short-term market currently operating in the world that does not have a local market power mitigation mechanism.

Finally, there is a maximum retail price of electricity that suppliers can charge for each geographic area in all wholesale electricity markets in the US. These retail prices are set by the state regulator, typically for at least one year in duration. Competitive retailers are able to offer retail prices above or below these levels, but the incumbent supplier in a given geographic area must offer a tariff with this regulated price to all consumers. This maximum regulated price is implemented to protect unsophisticated electricity consumers. A number of observers have argued that these regulated retail prices have been set so low that they effectively eliminate all retail competition. However, if the incumbent supplier is able to remain financially viable at this price, then one might also question the need for retail competition, if the end result is higher prices for final consumers. A number of researchers have argued that without hourly pricing of electricity to final consumers, which is possible only if the customer has an interval meter, it is difficult to find any market efficiency advantages to allowing retail competition (Joskow, 2000).

None of these regulatory constraints on the wholesale and retail markets exist in New Zealand. Consequently, an important question is the extent to which their absence has significantly reduced the efficiency of the wholesale and retail markets in New Zealand.

5.5. Multi-Settlement Markets and Active Demand-Side Participation

As discussed in Section 3, the SPD model is run a number of times in advance of real-time system operation. However, the generation and load schedules that result are not financially binding. Only the price-setting run using the supplier's half-hourly output done immediately following the end of the half-hour period is financially binding. This run determines the prices each supplier will be paid for all of their output and loads will pay for all of their consumption during that half-hour period.

Although several of the nodal-pricing markets in the US started with similar single price-setting or settlement process, currently all of the nodal-pricing markets in the eastern US employ a multi-settlement price-setting mechanism with a financially binding day-ahead forward market schedules and prices and a real-time or imbalance market. These multi-settlement markets have the advantage that suppliers can submit multi-part bids for start-up, no-load and variable operating costs and generation units can be committed and dispatched on a day-ahead basis taking into account all of these costs. In addition, load-serving entities can submit financially binding demand bids, which enter into this day-ahead price setting process. The day-ahead forward market produces financially binding generation and load schedules and day-ahead prices based on the bids and offers submitted. For example a supplier intending to produce between 150 MWh and 200 MWh may offer 100 MWh in the day-ahead market and then bid to supply the additional 50 MWh to 100 MWh in the real-time market.

There are a number of market efficiency advantages to a multi-settlement mechanism. First, it is possible to allow the bids that loads submit to be used to set day-ahead prices. From a grid reliability perspective, there is no need for day-ahead load schedules to equal actual consumption the following day. Because loads have the flexibility to determine how much they will purchase from the day-ahead and real-time markets, day-ahead prices tend to be significantly less volatile than real-time prices. As a consequence, suppliers and load-serving entities typically sign the vast majority of their long-term contracts to clear against these day-ahead prices rather than real-time prices. In this sense a multi-settlement mechanism facilitates the development of an active long-term forward market. A day-ahead market with multi-part bids also allows long-start fossil fuel units fired by coal and natural gas greater opportunities to compete to supply electricity against hydroelectric units. The ability of loads to make financially binding commitments in the day-ahead market and the ability of slow start units to have more advance notice to compete to supply energy, all have the potential to improve overall market efficiency and limit the opportunities for suppliers to exercise unilateral market power.

5.6. Transmission Pricing and Investment Decision-Making

A final area of potential market inefficiencies results from how transmission is priced and how investment decision-making is made in New Zealand. Both because of the geographic dispersion of customers and the fact that New Zealand is so dependent on hydroelectric energy, relatively more transmission capacity is needed in New Zealand than in other parts of the world with more geographically concentrated populations and fossil fuel-based generation sectors. In fossil-fuel based systems there is always the option to deliver the fossil fuel to the load center and burn it to produce electricity and avoid constructing transmission lines. In hydro-based systems, transmission capacity must be built from where the hydro resources are located to the load center.

A major challenge to all wholesale electricity markets is how to build, operate and price the transmission network to enhance the efficiency of the wholesale energy and ancillary services markets. Solving this problem is even more important to the efficiency of the New Zealand market. The recent controversy between Transpower and the Electricity Commission over the advisability of constructing a 400 kV line to serve the Auckland area, points to the importance of designing a transmission expansion and pricing methodology that enhances the efficiency of the wholesale market.

Different from the former vertically-integrated regime, the transmission network serves as a facilitator of competition in the wholesale market regime. In particular, unless there is transmission capacity into a specific geographic area, the local generation unit owner faces no competition for its output and can therefore exercise substantial unilateral market power. For this reason, a major source of benefits from a transmission network expansion in the wholesale market regime is the extent to which this expansion increases the number of independent generation unit owners that can compete to supply energy against at given location in the transmission network. The more independent suppliers able to compete to against a local generation unit owner the closer this generation unit owner will be forced to bid to its marginal cost of supplying energy, which will result in prices closer to the perfectly competitive ideal.

But these more efficient prices are only possible if this supplier faces sufficient competition, which only occurs if there is enough transmission capacity for there to be vigorous competition to provide energy at this location.

The optimal methodology for determining where and when to expand the transmission network in a wholesale market regime does not exist at this time. However, a number of countries have come up with creative ways to decide whether there is adequate transmission capacity to maximize the efficiency of the wholesale market.

6. Concluding Comments

This report has raised many more questions than it has answered. This is consistent with its goal of summarizing the history of the New Zealand electricity supply industry, the operation of the wholesale market, and discussing directions for future research. There are many lessons about from competition in wholesale and retail electricity markets from around the world applicable to New Zealand experience. Analysis of data on actual market outcomes and market participant behavior can determine which are applicable and how to apply best apply these lessons to understand the performance of the New Zealand market.

The discussion of Section 2 illuminates the unique route to electricity supply industry restructuring taken in New Zealand. Different from other countries, New Zealand began with retail competition and then introduced wholesale competition. It was also the first country in the world to implement nodal-pricing of energy in the short-term market. One goal of the initial restructuring process appears to be to limit the extent to which there is explicit government intervention in any segment of the industry. The wholesale market was initially designed to be largely self-regulating. However, the recent formation of the Electricity Commission and Reserve Generation Plant mechanism are clear departures from this policy.

The generation sector of the industry is more concentrated than other wholesale markets in industrialized countries, such as the United Kingdom, Australia, the Nordic countries, and all of the regional market in United States. However, the concentration of generation unit ownership is in line with smaller countries such as Spain and virtually all Latin American countries. The extent of vertical integration between generation and retailing in the New Zealand is also greater than what exists in a number of other industrialized countries such as the United Kingdom, Australia, and all of the regional markets in the United States. These markets have a sizeable "merchant generation" segment that primarily sells energy in long-term forward contracts or the short-term wholesale market.

The "light handed regulation" approach to distribution and transmission network pricing is another important difference between the New Zealand market and other markets around the world. The divestiture of distribution service provision from electricity retailing is another significant departure from the typical approach in restructured electricity markets, where many retailers continue have distribution network-owning affiliates and even generation unit-owning affiliates. Finally, the lack of short-term market for natural gas and coal, the two major input fuels is another dimension along which the New Zealand market differs from other industrialized countries, particularly those in Europe and United States where there are relatively liquid short-term markets for natural gas and coal.

There are several unique features of the wholesale market. The first is the use of a must-run generation auction to determine the generation units that are allowed to bid zero into the wholesale market. A second feature is the fact that demand bids into the market exert no explicit influence on the nodal prices that generation unit owners receive or retailers pay. These demand bids impact the prospective dispatch of the system but do not enter the process used to determine financially binding half-hourly ex post prices. A third unique feature is the tremendous flexibility generation unit owners are given in the bids they submit to the wholesale market. Different from markets in a number of other jurisdictions, suppliers can change both the price offers and quantity offers each half-hour of the day. Moreover, there are no explicit caps on the maximum price bids that suppliers can submit, or the maximum price that a generation unit owner can receive or a retailer can pay.

The preliminary analysis of data from the Centralized Data Set demonstrates a number of stylized facts about the performance of the industry. Specifically, this analysis provides strong evidence of a integrated national market for energy the vast majority of half-hours of the year. There also appear to be two distinct wholesale pricing regimes--one for a normal water year and the other for a low water year. However, the pattern of prices for 2005 presents a challenge to this paradigm because it appears to share features of both pricing regimes. The pattern of electricity demand throughout the day in New Zealand has less pronounced peaks than a number of other countries, particularly during the summer months. Although there has been continuous load growth over the past six years, the conservations efforts implements during the low water years of 2001 and 2003 have been surprisingly effective at reducing demand.

This analysis of the Centralized Data Set also revealed a number of shortcomings associated with versions of this data set starting in July 2005. In particular, there appears to be a substantial amount of missing or erroneous data. These issues are discussed in detail in Section 4.3. Unfortunately, it is currently impossible to determine precisely how much data is missing because the number of nodes in the New Zealand system changes over time. Future empirical analysis of the New Zealand electricity supply industry would greatly benefit from a complete, well-documented data set with minimal errors on all aspects of the electricity supply industry.

Finally, the report identified a number of features of the current market that may be degrading market efficiency and enhancing the ability of market participants to exercise unilateral market power. The infrequent incidence of extremely high nodal prices documented in Section 4 is one potential source of market inefficiencies. The level and pattern of wholesale prices in 2005 also presents a challenge for interpretation because they do not completely fit the pattern for normal water year or a low water year. For this reason, these prices may reflect the presence of significant market inefficiencies.

The extent of vertical integration generation and retailing may also present market performance problems. The unique regulatory oversight of the New Zealand market may also create opportunities for market participants to leverage market power in certain segments of the industry or geographic areas to other segments and larger geographic areas. The lack of a multi-settlement market and active demand-side participation in the wholesale market may be a source of concern. Finally, the mechanism used to price and determine transmission investments could limit the efficiency of the wholesale market.

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Tables

Table 1: New Zealand electricity generation summary

Year to 31 March 2005	South Island			North Island			New Zealand	
	GWh	% of island	% of NZ	GWh	% of island	% of NZ	GWh	% of total
Fuel type share								
Hydro	18,541	99.7%	70.1%	7,901	34.7%	29.9%	26,442	64.0%
Gas	-	-	-	5,128	22.5%	100%	5,128	12.4%
Coal and Oil	0	0.0%	0.0%	3,963	17.4%	100%	3,963	9.6%
Geothermal	-	-	-	2,632	11.6%	100%	2,632	6.4%
Wind	2	0.0%	0.4%	464	2.0%	99.6%	466	1.1%
Biogas	-	-	-	86	0.4%	100%	86	0.2%
Cogeneration	48	0.3%	1.8%	2,569	11.3%	98.2%	2,617	6.3%
Total	**18,591**	**100.0%**	**45.0%**	**22,742**	**100.0%**	**55.0%**	**41,335**	**100.0%**
Generator share								
Meridian Energy	13,088	70.4%	100%	-	-	-	13,088	31.7%
Contact Energy	4,172	22.4%	41.0%	5,997	26.4%	59.0%	10,169	24.6%
Genesis Energy	-	-	-	7,513	33.0%	100%	7,513	18.2%
Mighty River Power [1]	-	-	-	5,800	25.5%	100%	5,800	14.0%
TrustPower [1]	1,031	5.5%	49.8%	1,040	4.6%	50.2%	2,071	5.0%
Others	300	1.6%	11.2%	2,392	10.5%	88.8%	2,694	6.5%
Total	**18,591**	**100.0%**	**45.0%**	**22,742**	**100.0%**	**55.0%**	**41,335**	**100.0%**

1. Generation total for Mighty River Power, and the North Island/South Island split for TrustPower, are estimates only.

Sources: Energy Data File January 2006; Electricity Commission Centralized Data Set (for Meridian and Genesis generation); annual and mid-year reports for TrustPower and Contact Energy; TrustPower investor briefing May 2005.

Table 2: Generation Capacity, Ownership, and Capacity Shares in New Zealand					
Owners/Operators	Plant Name	Commissioned	Fuel type	Capacity (MW)	Capacity Share (Percent)
Alinta	Glenbrook	1998	Waste Heat (Cogen)	74	0.88
Bay of Plenty	Aniwhenua	1981	Hydro	25	0.41
Bay of Plenty	Edgecumbe	1996	Gas	10	
Contact Energy	Clyde	1992	Hydro	432	26.36
Contact Energy	New Plymouth	1976	Gas/Oil	300	
Contact Energy	Ohaaki	1989	Geothermal	1042	
Contact Energy	Otahuhu B	2000	Gas	380	
Contact Energy	Poihipi	1997	Geothermal	55	
Contact Energy	Roxburgh	1956	Hydro	320	
Contact Energy	Taranaki CC	1998	Gas	360	
Contact Energy	Te Rapa	2000	CoGen	44	
Contact Energy	Wairakei	1958	Geothermal	165	
Contact Energy	Wairakei Binary	2005	Geothermal	14	
Contact Energy (Govt)	Whirinaki	2004	Diesel	155	
Genesis Energy	Huntly	1987	Coal/Gas	960	17.78
Genesis Energy	Huntly-P40	2004	Gas	40	
Genesis Energy	Kaitawa	1947	Hydro	37	
Genesis Energy	Piripaua	1942	Hydro	44	
Genesis Energy	Tuai	1929	Hydro	60	
Genesis Energy	Rangipo	1983	Hydro	120	
Genesis Energy	Tokaanu	1973	Hydro	240	
Genesis/Carter Holt Harvey	Kinleith	1998	Gas/Wood/Coal	40	1.11
Genesis/Anchor Dairy	Te Awamutu	1995	Gas (Cogen)	54	
Mangahao Joint Venture	Mangahao	1925	Hydro	38	0.45
Meridian Energy	Aviemore	1968	Hydro	220	30.61
Meridian Energy	Benmore	1966	Hydro	540	
Meridian Energy	Manapouri	1971/2002	Hydro	755	
Meridian Energy	Ohau A	1979	Hydro	264	
Meridian Energy	Ohau B	1980	Hydro	212	
Meridian Energy	Ohau C	1985	Hydro	212	
Meridian Energy	Te Apiti	2004	Wind	91	
Meridian Energy	Tekapo A	1951	Hydro	25	
Meridian Energy	Tekapo B	1977	Hydro	160	
Meridian Energy	Waitaki	1936	Hydro	105	

Mighty River Power	Arapuni	1946	Hydro	188	14.77
Mighty River Power	Aratiatia	1964	Hydro	90	
Mighty River Power	Atiamuri	1962	Hydro	86	
Mighty River Power	Karapiro	1948	Hydro	96	
Mighty River Power	Maraetai	1954/1971	Hydro	360	
Mighty River Power	Ohakuri	1962	Hydro	112	
Mighty River Power	Rotokawa	1997	Geothermal	32	
Mighty River Power	Southdown	1997	Gas (Cogen)	125	
Mighty River Power	Waipapa	1961	Hydro	58	
Mighty River Power	Whakamaru	1956	Hydro	100	
NGC	Kapuni	1998	Gas (Cogen)	23	0.27
Pan Pac	Pan Pac Cogeneration	2005	Biomass/Steam	13	0.15
Tai Tokerau Trust	Ngawha	1998	Geothermal	11	0.13
TrustPower	Argyle x 2	1983	Hydro	11	5.35
TrustPower	Cobb	1956	Hydro	32	
TrustPower	Coleridge	1914	Hydro	45	
TrustPower	Highbank x 2	1945	Hydro	25	
TrustPower	Kaimai x 4	1972-1981	Hydro	42	
TrustPower	Matahina	1967	Hydro	76	
TrustPower	Paerau x 2	1984	Hydro	12	
TrustPower	Patea	1984	Hydro	31	
TrustPower	Tararua Wind Farm	1999/2004	Wind	68	
TrustPower	Waipori x 4	1903/1955	Hydro	84	
TrustPower	Wheao x 2	1984	Hydro	26	
Tuaropaki Power Company	Mokai	2000/2005	Geothermal	95	1.13
Whareroa Kiwi Dairy Plant	Kiwi Dairy	1997	Gas (Cogen)	50	0.59

Table 3A: Mean half-hourly prices at major nodes, 1997–2005

NZ$/MWh	South Island					North Island					
	BEN	INV	HWB	ISL	STK	HAY	WKM	SFD	HLY	OTA	TUI
1997	42.0	42.9	42.3	44.0	45.2	45.0	46.9	44.5	47.2	49.1	45.7
1998	29.9	29.8	29.6	31.3	32.0	35.1	39.2	35.3	40.7	42.0	39.3
1999	31.2	34.0	33.2	33.2	34.1	33.4	38.0	32.5	38.7	40.1	37.1
2000	29.5	31.1	30.6	31.1	31.9	32.5	39.5	32.8	40.0	41.5	52.1
2001	80.1	84.3	82.7	85.9	88.8	79.9	76.4	71.0	75.5	78.0	77.1
2002	35.8	36.5	36.1	37.8	38.9	40.2	41.5	39.4	42.0	43.3	42.6
2003	78.7	82.1	80.7	84.3	87.3	82.9	83.6	79.6	83.5	85.8	89.1
2004	29.9	29.8	29.7	32.3	33.2	37.2	37.2	36.2	38.0	39.2	38.0
2005	64.2	65.6	64.9	69.3	72.0	67.0	66.7	64.0	66.5	68.5	67.0

Table 3B: Standard deviation of half-hourly prices at major nodes, 1997–2005

NZ$/MWh	South Island					North Island					
	BEN	INV	HWB	ISL	STK	HAY	WKM	SFD	HLY	OTA	TUI
1997	12.6	13.6	13.2	13.6	14.1	14.2	14.3	13.5	14.6	15.4	13.9
1998	22.6	22.6	22.4	23.8	24.4	26.5	29.1	26.4	30.6	31.8	28.4
1999	21.8	27.1	26.3	23.6	24.3	24.8	30.0	24.4	30.7	31.9	28.8
2000	24.4	30.5	29.6	26.2	26.9	28.6	43.2	30.0	43.6	46.4	104.8
2001	85.1	90.3	88.2	98.6	102.9	84.2	75.1	68.5	73.3	76.8	78.0
2002	21.2	22.4	21.9	22.7	23.5	29.3	31.6	29.3	31.8	33.4	33.8
2003	73.7	82.7	79.7	86.5	90.9	76.8	76.3	73.1	76.0	78.4	98.2
2004	19.7	19.6	19.5	41.4	42.5	106.1	55.1	54.9	57.8	59.7	59.1
2005	18.9	19.9	19.5	21.9	23.5	22.9	23.9	22.6	24.8	25.7	22.2

Table 3C: Median of half-hourly prices at major nodes, 1997–2005

NZ$/MWh	South Island					North Island					
	BEN	**INV**	**HWB**	**ISL**	**STK**	**HAY**	**WKM**	**SFD**	**HLY**	**OTA**	**TUI**
1997	42.2	42.4	42.1	44.1	45.2	45.7	48.2	46.1	49.0	50.7	47.5
1998	33.1	32.6	32.5	34.2	35.1	39.0	43.3	39.4	44.0	45.6	44.2
1999	29.3	30.3	30.0	30.8	31.5	30.1	32.3	28.9	33.0	34.0	31.9
2000	26.9	28.1	27.4	28.0	28.8	28.7	32.1	28.3	33.1	34.3	32.4
2001	50.0	52.7	51.5	52.8	54.3	50.9	51.0	48.7	51.0	52.3	50.7
2002	32.1	32.0	31.9	33.7	34.7	34.1	34.6	33.4	35.1	36.3	34.5
2003	57.3	57.5	57.4	60.6	62.2	60.1	60.3	57.2	60.4	62.5	61.9
2004	30.8	30.4	30.3	32.5	33.5	35.0	36.0	35.2	36.6	37.5	35.8
2005	67.3	69.7	68.7	72.3	74.6	69.4	68.9	65.6	68.1	69.9	69.4

Table 3D: Maximum of half-hourly prices at major nodes, 1997–2005

NZ$/MWh	South Island					North Island					
	BEN	**INV**	**HWB**	**ISL**	**STK**	**HAY**	**WKM**	**SFD**	**HLY**	**OTA**	**TUI**
1997	149	161	157	158	162	615	642	615	670	697	628
1998	603	611	608	638	655	635	717	615	746	783	649
1999	309	519	512	334	361	683	646	620	671	689	581
2000	607	613	608	645	663	675	1223	669	1184	1276	1062
2001	983	1004	980	3840	3926	989	914	894	936	981	919
2002	521	503	503	564	582	846	893	881	932	957	813
2003	1237	1380	1337	3184	3273	1273	1237	1214	1287	1341	1210
2004	891	911	886	3196	3268	12019	2088	2116	2207	2258	2076
2005	292	285	282	392	415	939	1017	1016	1144	1148	915

Table 4A: Correlation coefficients for half-hourly prices at major nodes in 1997

	South Island					North Island					
	BEN	**INV**	**HWB**	**ISL**	**STK**	**HAY**	**WKM**	**SFD**	**HLY**	**OTA**	**TUI**
BEN	1.000										
INV	0.992	1.000									
HWB	0.996	0.999	1.000								
ISL	0.999	0.992	0.996	1.000							
STK	0.998	0.991	0.995	0.999	1.000						
HAY	**0.854**	**0.842**	**0.846**	**0.853**	**0.853**	1.000					
WKM	**0.787**	**0.767**	**0.772**	**0.784**	**0.784**	0.981	1.000				
SFD	**0.801**	**0.784**	**0.789**	**0.798**	**0.798**	0.990	0.996	1.000			
HLY	**0.754**	**0.732**	**0.738**	**0.751**	**0.751**	0.969	0.996	0.992	1.000		
OTA	**0.766**	**0.743**	**0.750**	**0.764**	**0.765**	0.972	0.996	0.993	0.999	1.000	
TUI	**0.741**	**0.717**	**0.723**	**0.735**	**0.735**	0.949	0.984	0.974	0.979	0.977	1.000

Note: Number of observations for each node = 17520. Correlation coefficients below 0.9 are shown in bold.

Table 4B: Correlation coefficients for half-hourly prices at major nodes in 1998

	South Island					North Island					
	BEN	**INV**	**HWB**	**ISL**	**STK**	**HAY**	**WKM**	**SFD**	**HLY**	**OTA**	**TUI**
BEN	1.000										
INV	0.994	1.000									
HWB	0.995	1.000	1.000								
ISL	1.000	0.995	0.995	1.000							
STK	0.999	0.994	0.995	1.000	1.000						
HAY	**0.877**	**0.868**	**0.870**	**0.877**	**0.877**	1.000					
WKM	**0.862**	**0.851**	**0.852**	**0.861**	**0.861**	0.991	1.000				
SFD	**0.868**	**0.858**	**0.859**	**0.867**	**0.867**	0.998	0.995	1.000			
HLY	**0.866**	**0.856**	**0.857**	**0.866**	**0.866**	0.992	0.999	0.995	1.000		
OTA	**0.866**	**0.855**	**0.857**	**0.866**	**0.866**	0.991	0.999	0.994	1.000	1.000	
TUI	**0.853**	**0.842**	**0.844**	**0.852**	**0.852**	0.984	0.993	0.990	0.991	0.991	1.000

Note: Number of observations for each node = 17520. Correlation coefficients below 0.9 are shown in bold.

Table 4C: Correlation coefficients for half-hourly prices at major nodes in 1999

	South Island					North Island					
	BEN	**INV**	**HWB**	**ISL**	**STK**	**HAY**	**WKM**	**SFD**	**HLY**	**OTA**	**TUI**
BEN	1.000										
INV	**0.885**	1.000									
HWB	**0.881**	0.997	1.000								
ISL	0.990	0.906	0.901	1.000							
STK	0.989	0.905	0.900	1.000	1.000						
HAY	0.933	**0.818**	**0.815**	0.924	0.924	1.000					
WKM	**0.891**	**0.779**	**0.776**	**0.882**	**0.882**	0.947	1.000				
SFD	0.913	**0.797**	**0.794**	0.903	0.904	0.982	0.950	1.000			
HLY	**0.894**	**0.783**	**0.779**	**0.885**	**0.885**	0.952	0.987	0.961	1.000		
OTA	**0.892**	**0.781**	**0.777**	**0.884**	**0.884**	0.951	0.993	0.959	0.999	1.000	
TUI	**0.870**	**0.751**	**0.748**	**0.855**	**0.855**	0.924	0.959	0.922	0.949	0.954	1.000

Note: Number of observations for each node = 17520. Correlation coefficients below 0.9 are shown in bold.

Table 4D: Correlation coefficients for half-hourly prices at major nodes in 2000

	South Island					North Island					
	BEN	**INV**	**HWB**	**ISL**	**STK**	**HAY**	**WKM**	**SFD**	**HLY**	**OTA**	**TUI**
BEN	1.000										
INV	**0.821**	1.000									
HWB	**0.833**	0.999	1.000								
ISL	0.990	**0.883**	**0.893**	1.000							
STK	0.990	**0.882**	**0.893**	1.000	1.000						
HAY	**0.895**	**0.727**	**0.740**	**0.887**	**0.888**	1.000					
WKM	**0.778**	**0.620**	**0.632**	**0.770**	**0.771**	**0.891**	1.000				
SFD	**0.869**	**0.700**	**0.713**	**0.861**	**0.862**	0.979	0.942	1.000			
HLY	**0.795**	**0.633**	**0.645**	**0.787**	**0.788**	0.908	0.998	0.956	1.000		
OTA	**0.789**	**0.627**	**0.640**	**0.781**	**0.782**	0.901	0.997	0.951	0.999	1.000	
TUI	**0.345**	**0.356**	**0.359**	**0.359**	**0.360**	**0.381**	**0.401**	**0.396**	**0.401**	**0.400**	1.000

Note: Number of observations for each node = 17568. Correlation coefficients below 0.9 are shown in bold.

Table 4E: Correlation coefficients for half-hourly prices at major nodes in 2001

	South Island					North Island					
	BEN	**INV**	**HWB**	**ISL**	**STK**	**HAY**	**WKM**	**SFD**	**HLY**	**OTA**	**TUI**
BEN	1.000										
INV	0.998	1.000									
HWB	0.998	1.000	1.000								
ISL	0.935	0.925	0.926	1.000							
STK	0.937	0.928	0.929	1.000	1.000						
HAY	0.978	0.974	0.975	0.915	0.918	1.000					
WKM	0.958	0.950	0.952	**0.896**	**0.899**	0.986	1.000				
SFD	0.935	0.924	0.926	**0.876**	**0.879**	0.966	0.982	1.000			
HLY	0.950	0.941	0.943	**0.889**	**0.893**	0.982	0.998	0.987	1.000		
OTA	0.950	0.942	0.944	**0.889**	**0.893**	0.982	0.998	0.985	1.000	1.000	
TUI	0.964	0.957	0.959	0.902	0.905	0.989	0.997	0.979	0.994	0.994	1.000

Note: Number of observations for each node = 17520. Correlation coefficients below 0.9 are shown in bold.

Table 4F: Correlation coefficients for half-hourly prices at major nodes in 2002

	South Island					North Island					
	BEN	**INV**	**HWB**	**ISL**	**STK**	**HAY**	**WKM**	**SFD**	**HLY**	**OTA**	**TUI**
BEN	1.000										
INV	0.993	1.000									
HWB	0.995	1.000	1.000								
ISL	1.000	0.993	0.995	1.000							
STK	0.999	0.992	0.994	0.999	1.000						
HAY	**0.714**	**0.704**	**0.706**	**0.713**	**0.712**	1.000					
WKM	**0.626**	**0.613**	**0.615**	**0.624**	**0.623**	0.948	1.000				
SFD	**0.669**	**0.658**	**0.659**	**0.667**	**0.666**	0.994	0.968	1.000			
HLY	**0.615**	**0.602**	**0.603**	**0.613**	**0.612**	0.953	0.995	0.975	1.000		
OTA	**0.614**	**0.600**	**0.602**	**0.613**	**0.613**	0.948	0.997	0.969	0.992	1.000	
TUI	**0.614**	**0.602**	**0.603**	**0.613**	**0.612**	**0.887**	0.920	0.901	0.916	0.918	1.000

Note: Number of observations for each node = 17520. Correlation coefficients below 0.9 are shown in bold.

Table 4G: Correlation coefficients for half-hourly prices at major nodes in 2003

	South Island					North Island					
	BEN	**INV**	**HWB**	**ISL**	**STK**	**HAY**	**WKM**	**SFD**	**HLY**	**OTA**	**TUI**
BEN	1.000										
INV	0.994	1.000									
HWB	0.993	0.998	1.000								
ISL	0.915	0.902	0.901	1.000							
STK	0.917	0.905	0.904	0.999	1.000						
HAY	0.984	0.977	0.976	0.901	0.903	1.000					
WKM	0.973	0.965	0.965	**0.891**	**0.894**	0.997	1.000				
SFD	0.976	0.968	0.967	**0.893**	**0.896**	0.998	0.998	1.000			
HLY	0.966	0.956	0.956	**0.885**	**0.887**	0.992	0.996	0.996	1.000		
OTA	0.965	0.955	0.955	**0.884**	**0.886**	0.992	0.995	0.996	1.000	1.000	
TUI	**0.761**	**0.751**	**0.751**	**0.696**	**0.698**	**0.777**	**0.780**	**0.779**	**0.777**	**0.777**	1.000

Note: Number of observations for each node = 17520. Correlation coefficients below 0.9 are shown in bold.

Table 4H: Correlation coefficients for half-hourly prices at major nodes in 2004

	South Island					North Island					
	BEN	**INV**	**HWB**	**ISL**	**STK**	**HAY**	**WKM**	**SFD**	**HLY**	**OTA**	**TUI**
BEN	1.000										
INV	0.994	1.000									
HWB	0.995	1.000	1.000								
ISL	**0.581**	**0.507**	**0.507**	1.000							
STK	**0.582**	**0.508**	**0.508**	0.999	1.000						
HAY	**0.169**	**0.171**	**0.170**	**0.100**	**0.100**	1.000					
WKM	**0.347**	**0.349**	**0.348**	**0.204**	**0.205**	**0.527**	1.000				
SFD	**0.333**	**0.335**	**0.334**	**0.197**	**0.197**	**0.525**	0.999	1.000			
HLY	**0.335**	**0.338**	**0.337**	**0.198**	**0.198**	**0.525**	0.999	0.999	1.000		
OTA	**0.337**	**0.339**	**0.338**	**0.199**	**0.199**	**0.525**	0.999	0.999	0.999	1.000	
TUI	**0.339**	**0.341**	**0.340**	**0.198**	**0.199**	**0.567**	0.907	0.906	0.906	0.905	1.000

Note: Number of observations for each node = 17568. Correlation coefficients below 0.9 are shown in bold.

Table 4I: Correlation coefficients for half-hourly prices at major nodes in 2005

	South Island					North Island					
	BEN	INV	HWB	ISL	STK	HAY	WKM	SFD	HLY	OTA	TUI
BEN	1.000										
INV	0.993	1.000									
HWB	0.996	0.999	1.000								
ISL	0.964	0.958	0.961	1.000							
STK	0.948	0.941	0.943	0.985	1.000						
HAY	**0.833**	**0.815**	**0.819**	**0.804**	**0.794**	1.000					
WKM	**0.748**	**0.719**	**0.725**	**0.722**	**0.713**	0.965	1.000				
SFD	**0.757**	**0.729**	**0.735**	**0.730**	**0.721**	0.979	0.986	1.000			
HLY	**0.714**	**0.684**	**0.690**	**0.690**	**0.682**	0.959	0.996	0.988	1.000		
OTA	**0.718**	**0.688**	**0.694**	**0.696**	**0.690**	0.959	0.996	0.986	0.999	1.000	
TUI	**0.783**	**0.757**	**0.764**	**0.755**	**0.744**	0.960	0.975	0.966	0.963	0.963	1.000

Note: Number of observations for each node = 14592. Correlation coefficients below 0.9 are shown in bold.

Table 5A

Nodes with missing quantity data

Node name	Number of half-hour periods with price but no load data									
	1997	1998	1999	2000	2001	2002	2003	2004	2005	Total
NI.Tarukenga.220KV	17,520	17,520	17,520	17,568	17,520	17,520	4,322	-	-	**109,490**
NI.Atiamuri	-	17,520	17,520	17,568	17,520	7,044	-	-	-	**77,172**
NI.Kaponga	-	12,618	17,465	13,154	-	-	-	-	-	**43,237**
NI.Gisborne.11KV	-	-	-	-	-	-	17,518	5,330	-	**22,848**
NI.Lichfield.T2	-	-	-	-	12,845	7,250	-	-	-	**20,095**
NI.Marsden	-	-	13,053	-	-	-	-	-	-	**13,053**
NI.Wairoa.50KV	-	-	-	4,414	5,264	-	-	-	-	**9,678**
SI.Motupipi.33KV	-	-	-	-	-	-	1,486	5,330	-	**6,816**
NI.TokomaruBay	-	-	-	-	-	2,688	-	-	-	**2,688**
SI.Arahura	-	-	-	-	-	2,540	-	-	-	**2,540**
SI.Westport.Robertson	-	-	-	-	-	-	-	1,895	-	**1,895**
SI.Hororata.66KV	-	-	-	-	528	-	-	-	-	**528**
SI.Westport.Orowaiti.1	-	-	-	-	-	-	-	336	-	**336**
SI.Westport.Orowaiti.2	-	-	-	-	-	-	-	336	-	**336**
SI.Dunedin.HWB.C332	-	-	-	-	-	-	-	97	-	**97**
SI.Cairnbrae	-	-	-	-	67	-	-	-	-	**67**
Total	**17,520**	**47,658**	**65,558**	**52,704**	**53,744**	**37,042**	**23,326**	**13,324**	**-**	**310,876**

Table 5B

Nodes with extreme price observations (price = $100,000)

Node name	Number of half-hour periods in which price = $100,000									
	1997	1998	1999	2000	2001	2002	2003	2004	2005	Total
NI.TokomaruBay	-	86	36	1	13,473	8,066	-	-	-	**21,662**
SI.Winton.11KV	-	-	-	-	9,529	1,776	-	-	-	**11,305**
SI.Winton.66KV	-	-	-	-	9,529	1,776	-	-	-	**11,305**
SI.Reefton	-	-	44	8,112	-	-	-	-	-	**8,156**
NI.Arohena	-	-	24	-	24	7,607	-	-	-	**7,655**
NI.Marsden	-	-	2,979	4,416	-	-	-	-	-	**7,395**
NI.Wairoa.50KV	-	-	-	-	6,354	-	-	-	-	**6,354**
SI.Cairnbrae	-	69	62	8	4,374	1,776	-	-	-	**6,289**
GEN.Hydro.Highbank	-	-	20	-	4,345	1,776	-	-	-	**6,141**
NI.Marotiri	-	-	22	-	1,567	3,408	-	-	-	**4,997**
NI.Maraetai	-	-	-	-	1,489	3,408	-	-	-	**4,897**
NI.Atiamuri	-	-	-	-	-	3,710	-	-	-	**3,710**
SI.Arahura	-	-	-	-	1	2,179	-	-	-	**2,180**
NI.Kaponga	-	1,974	55	-	4	-	-	-	-	**2,033**
SI.Ashburton.66KV	-	-	565	-	108	1,220	-	-	-	**1,893**
SI.Kaikoura	-	208	210	-	58	228	-	-	-	**704**
All other nodes	-	662	437	738	1,026	844	6	-	9	**3,722**
Total	**-**	**2,999**	**4,454**	**13,275**	**51,881**	**37,774**	**6**	**-**	**9**	**110,398**

Table 5C

Standard deviation of prices across all load nodes at each half-hour

	Year								
	1997	1998	1999	2000	2001	2002	2003	2004	2005
Number of observations	17,520	17,520	17,520	17,568	17,520	17,520	17,520	17,568	16,032
Summary statistics for standard deviation									
Minimum	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Mean	3.7	5.1	4.4	8.8	10.3	5.2	8.2	6.4	5.3
Median	3.2	4.0	2.1	2.8	3.6	3.1	4.1	3.2	4.4
75th percentile	4.5	6.5	5.0	5.2	8.1	5.1	7.3	4.7	5.9
90th percentile	6.0	9.9	9.9	12.8	19.6	8.9	12.3	7.5	8.0
99th percentile	11.2	24.2	34.4	170.3	115.8	44.8	108.3	43.9	25.0
Maximum	293.1	321.1	315.1	455.7	1,410.6	405.9	1,256.2	4,318.1	454.6
Number of half-hour periods									
50 < std dev < 100	10	8	29	199	367	114	111	49	21
100 < std dev < 200	-	6	14	326	156	23	139	27	19
200 < std dev < 500	2	7	2	29	95	21	37	53	2
500 < std dev < 1,000	-	-	-	-	2	-	8	6	-
1,000 < std dev	-	-	-	-	1	-	1	8	-
Total half-hours with std dev > 100	2	13	16	355	254	44	185	94	21
% of total observations in year	0.0%	0.1%	0.1%	2.0%	1.4%	0.3%	1.1%	0.5%	0.1%

Table 6A

Appendix: Generation data contained in the Centralized Data Set

Node name	Start of series	End of series	# days with data	# days with missing data
GEN.Hydro.Mangahao	1 Jan 2000	30 Nov 2005	2,161	-
GEN.Hydro.Wheao	1 Jan 2000	30 Nov 2005	2,161	-
GEN.Hydro.Cobb	1 Jan 2000	30 Nov 2005	1,887	274
GEN.Hydro.Coleridge	1 Jan 2000	30 Nov 2005	1,887	274
GEN.Geothermal.Kaikohe	1 Oct 2000	30 Nov 2005	1,857	30
GEN.Geothermal.Wairakei.33KV	1 Oct 2000	30 Nov 2005	1,857	30
GEN.Hydro.Albury	1 Oct 2000	30 Nov 2005	1,857	30
GEN.Hydro.Clyde.33KV	1 Oct 2000	30 Nov 2005	1,857	30
GEN.Hydro.Coleridge.B	1 Oct 2000	30 Nov 2005	1,857	30
GEN.Hydro.Dobson	1 Oct 2000	30 Nov 2005	1,857	30
GEN.Hydro.Hawera.110KV.1	1 Oct 2000	30 Nov 2005	1,857	30
GEN.Hydro.Hawera.33KV	1 Oct 2000	30 Nov 2005	1,857	30
GEN.Hydro.Kaimai	1 Oct 2000	30 Nov 2005	1,857	30
GEN.Hydro.Kumara.66KV	1 Oct 2000	30 Nov 2005	1,857	30
GEN.Hydro.Mangahao.B	1 Oct 2000	30 Nov 2005	1,857	30
GEN.Hydro.Matahina	1 Jan 2000	30 Nov 2005	1,857	304
GEN.Hydro.Matahina.B	1 Oct 2000	30 Nov 2005	1,857	30
GEN.Hydro.Monalto.33KV	1 Oct 2000	30 Nov 2005	1,857	30
GEN.Hydro.RoaringMeg.Cromwell	1 Oct 2000	30 Nov 2005	1,857	30
GEN.Hydro.Tokaanu.33KV	1 Oct 2000	30 Nov 2005	1,857	30
GEN.Hydro.Waipori	1 Jan 2000	30 Nov 2005	1,857	304
GEN.Hydro.Wairoa.B	1 Oct 2000	30 Nov 2005	1,857	30
GEN.Hydro.Wheao.B	1 Oct 2000	30 Nov 2005	1,857	30
GEN.Hydro.Wheao.C	1 Oct 2000	30 Nov 2005	1,857	30
GEN.Inertial.NZR.Bunnythorpe	1 Oct 2000	30 Nov 2005	1,857	30
GEN.Inertial.NZR.Hamilton	1 Oct 2000	30 Nov 2005	1,857	30
GEN.Inertial.NZR.Tangiwai	1 Oct 2000	30 Nov 2005	1,857	30
GEN.Inertial.NZR.Taumarunui	1 Oct 2000	30 Nov 2005	1,857	30
GEN.Ongarue	1 Oct 2000	30 Nov 2005	1,857	30
GEN.Thermal.Glenbrook.NZSteel	1 Oct 2000	30 Nov 2005	1,857	30
GEN.Thermal.Kaponga	1 Oct 2000	30 Nov 2005	1,857	30
GEN.Thermal.Kawerau.A	1 Oct 2000	30 Nov 2005	1,857	30
GEN.Thermal.Kinleith	1 Oct 2000	30 Nov 2005	1,857	30
GEN.Thermal.Twizel	1 Oct 2000	30 Nov 2005	1,857	30
GEN.Wind.HauNui	1 Oct 2000	30 Nov 2005	1,857	30
GEN.Wind.Tararua.Bunnythorpe	1 Oct 2000	30 Nov 2005	1,857	30
GEN.Wind.Tararua.Linton	1 Oct 2000	30 Nov 2005	1,857	30
GEN.Hydro.Waipori.C	1 Jan 2001	30 Nov 2005	1,765	30
GEN.Hydro.Hawera.110KV.2	1 Jan 2002	30 Nov 2005	1,400	30
GEN.Hydro.Monowai.33KV	1 Jan 2000	30 Nov 2005	1,400	761
GEN.Thermal.Huntly	1 Jan 2000	30 Nov 2005	1,310	851
GEN.Hydro.Highbank	1 Jan 2000	30 Nov 2005	1,035	1,126
GEN.Hydro.Hokitika	1 Jan 2003	30 Nov 2005	1,035	30
GEN.Geothermal.Ohaaki	1 Jan 2000	30 Nov 2005	945	1,216
GEN.Geothermal.Poihipi	1 May 2003	30 Nov 2005	945	-
GEN.Geothermal.Wairakei	1 Jan 2000	30 Nov 2005	945	1,216
GEN.Hydro.Arapuni	1 Jan 2000	30 Nov 2005	945	1,216
GEN.Hydro.Aratiatia	1 Jan 2000	30 Nov 2005	945	1,216
GEN.Hydro.Aviemore	1 Jan 2000	30 Nov 2005	945	1,216
GEN.Hydro.Benmore.162	1 May 2003	30 Nov 2005	945	-
GEN.Hydro.Benmore.163	1 May 2003	30 Nov 2005	945	-
GEN.Hydro.Clyde	1 Jan 2000	30 Nov 2005	945	1,216
GEN.Hydro.Karapiro	1 Jan 2000	30 Nov 2005	945	1,216
GEN.Hydro.Manapouri	1 Jan 2000	30 Nov 2005	945	1,216

Generation data contained in the Centralized Data Set (continued)

Node name	Start of series	End of series	# days with data	# days with missing data
GEN.Hydro.Ohakuri	1 Jan 2000	30 Nov 2005	945	1,216
GEN.Hydro.Ohau.A	1 Jan 2000	30 Nov 2005	945	1,216
GEN.Hydro.Ohau.B	1 Jan 2000	30 Nov 2005	945	1,216
GEN.Hydro.Ohau.C	1 Jan 2000	30 Nov 2005	945	1,216
GEN.Hydro.Rangipo	1 Jan 2000	30 Nov 2005	945	1,216
GEN.Hydro.Roxburgh.110KV	1 May 2003	30 Nov 2005	945	-
GEN.Hydro.Roxburgh.220KV	1 May 2003	30 Nov 2005	945	-
GEN.Hydro.Tekapo.A	1 Jan 2000	30 Nov 2005	945	1,216
GEN.Hydro.Tekapo.B	1 Jan 2000	30 Nov 2005	945	1,216
GEN.Hydro.Tokaanu	1 Jan 2000	30 Nov 2005	945	1,216
GEN.Hydro.Waikaremoana	1 May 2003	30 Nov 2005	945	-
GEN.Hydro.Waipapa	1 Jan 2000	30 Nov 2005	945	1,216
GEN.Hydro.Waitaki	1 Jan 2000	30 Nov 2005	945	1,216
GEN.Hydro.Whakamaru	1 Jan 2000	30 Nov 2005	945	1,216
GEN.Thermal.NewPlymouth.110KV	1 May 2003	30 Nov 2005	945	-
GEN.Thermal.NewPlymouth.220KV	1 May 2003	30 Nov 2005	945	-
GEN.Thermal.Otahuhu.A	1 May 2003	30 Nov 2005	945	-
GEN.Thermal.Otahuhu.B	1 May 2003	30 Nov 2005	945	-
GEN.Thermal.Southdown	1 May 2003	30 Nov 2005	945	-
GEN.Thermal.Stratford	1 Jan 2000	30 Nov 2005	945	1,216
GEN.Thermal.TeAwamutu	1 Jan 2000	30 Nov 2005	945	1,216
GEN.Hydro.Cobb.B	1 Jan 2004	30 Nov 2005	670	30
GEN.Wind.TeApiti	1 Jul 2004	30 Nov 2005	518	-
GEN.Thermal.Redvale	1 Jan 2004	31 Mar 2005	456	-
GEN.Geothermal.Ngawha	1 Nov 2004	30 Nov 2005	395	-
GEN.Hydro.Atiamuri	1 Jan 2000	30 Nov 2005	395	1,766
GEN.Hydro.Kourarau	1 Nov 2004	30 Nov 2005	395	-
GEN.Hydro.Mangatangi	1 Nov 2004	30 Nov 2005	395	-
GEN.Hydro.Wairoa	1 Nov 2004	30 Nov 2005	395	-
GEN.Hydro.Whakamaru.B	1 Nov 2004	30 Nov 2005	395	-
GEN.Thermal.Greenmount	1 Nov 2004	30 Nov 2005	395	-
GEN.Thermal.TeRapa	1 Nov 2004	30 Nov 2005	395	-
GEN.Wind.Greytown	1 Nov 2004	30 Nov 2005	395	-
GEN.Hydro.Waipori.A	1 Jan 2005	30 Nov 2005	304	30
GEN.Hydro.Waipori.B	1 Jan 2005	30 Nov 2005	304	30
GEN.Thermal.Glenbrook.NZSteelKiln	1 Jan 2005	30 Nov 2005	304	30
GEN.Thermal.Kawerau.B	1 Jan 2005	30 Nov 2005	304	30
GEN.TeKowhai	1 May 2005	30 Nov 2005	214	-
GEN.Hydro.Benmore.161	1 May 2003	30 Sep 2003	153	-
GEN.Addington	1 Oct 2005	30 Nov 2005	61	-
GEN.Auckland.Hospital	1 Oct 2005	30 Nov 2005	61	-
GEN.Christchurch.CrownePlaza	1 Oct 2005	30 Nov 2005	61	-
GEN.Christchurch.SimeonQuay	1 Oct 2005	30 Nov 2005	61	-
GEN.Christchurch.WasteWater	1 Oct 2005	30 Nov 2005	61	-
GEN.Edgecumbe	1 Oct 2005	30 Nov 2005	61	-
GEN.Fox.11KV	1 Oct 2005	30 Nov 2005	61	-
GEN.Geothermal.Rotokawa	1 Oct 2005	30 Nov 2005	61	-
GEN.Gisborne	1 Oct 2005	30 Nov 2005	61	-
GEN.Glenorchy	1 Oct 2005	30 Nov 2005	61	-
GEN.Hinemaia	1 Oct 2005	30 Nov 2005	61	-
GEN.Hydro.Aniwhenua	1 Oct 2005	30 Nov 2005	61	-
GEN.Hydro.Arnold	1 Jan 2000	30 Nov 2005	61	2,100
GEN.Hydro.Atiamuri.B	1 Oct 2005	30 Nov 2005	61	-
GEN.Hydro.Dillmans	1 Oct 2005	30 Nov 2005	61	-

Generation data contained in the Centralized Data Set (continued)

Node name	Start of series	End of series	# days with data	# days with missing data
GEN.Hydro.Ohakuri	1 Jan 2000	30 Nov 2005	945	1,216
GEN.Hydro.Ohau.A	1 Jan 2000	30 Nov 2005	945	1,216
GEN.Hydro.Ohau.B	1 Jan 2000	30 Nov 2005	945	1,216
GEN.Hydro.Ohau.C	1 Jan 2000	30 Nov 2005	945	1,216
GEN.Hydro.Rangipo	1 Jan 2000	30 Nov 2005	945	1,216
GEN.Hydro.Roxburgh.110KV	1 May 2003	30 Nov 2005	945	-
GEN.Hydro.Roxburgh.220KV	1 May 2003	30 Nov 2005	945	-
GEN.Hydro.Tekapo.A	1 Jan 2000	30 Nov 2005	945	1,216
GEN.Hydro.Tekapo.B	1 Jan 2000	30 Nov 2005	945	1,216
GEN.Hydro.Tokaanu	1 Jan 2000	30 Nov 2005	945	1,216
GEN.Hydro.Waikaremoana	1 May 2003	30 Nov 2005	945	-
GEN.Hydro.Waipapa	1 Jan 2000	30 Nov 2005	945	1,216
GEN.Hydro.Waitaki	1 Jan 2000	30 Nov 2005	945	1,216
GEN.Hydro.Whakamaru	1 Jan 2000	30 Nov 2005	945	1,216
GEN.Thermal.NewPlymouth.110KV	1 May 2003	30 Nov 2005	945	-
GEN.Thermal.NewPlymouth.220KV	1 May 2003	30 Nov 2005	945	-
GEN.Thermal.Otahuhu.A	1 May 2003	30 Nov 2005	945	-
GEN.Thermal.Otahuhu.B	1 May 2003	30 Nov 2005	945	-
GEN.Thermal.Southdown	1 May 2003	30 Nov 2005	945	-
GEN.Thermal.Stratford	1 Jan 2000	30 Nov 2005	945	1,216
GEN.Thermal.TeAwamutu	1 Jan 2000	30 Nov 2005	945	1,216
GEN.Hydro.Cobb.B	1 Jan 2004	30 Nov 2005	670	30
GEN.Wind.TeApiti	1 Jul 2004	30 Nov 2005	518	-
GEN.Thermal.Redvale	1 Jan 2004	31 Mar 2005	456	-
GEN.Geothermal.Ngawha	1 Nov 2004	30 Nov 2005	395	-
GEN.Hydro.Atiamuri	1 Jan 2000	30 Nov 2005	395	1,766
GEN.Hydro.Kourarau	1 Nov 2004	30 Nov 2005	395	-
GEN.Hydro.Mangatangi	1 Nov 2004	30 Nov 2005	395	-
GEN.Hydro.Wairoa	1 Nov 2004	30 Nov 2005	395	-
GEN.Hydro.Whakamaru.B	1 Nov 2004	30 Nov 2005	395	-
GEN.Thermal.Greenmount	1 Nov 2004	30 Nov 2005	395	-
GEN.Thermal.TeRapa	1 Nov 2004	30 Nov 2005	395	-
GEN.Wind.Greytown	1 Nov 2004	30 Nov 2005	395	-
GEN.Hydro.Waipori.A	1 Jan 2005	30 Nov 2005	304	30
GEN.Hydro.Waipori.B	1 Jan 2005	30 Nov 2005	304	30
GEN.Thermal.Glenbrook.NZSteelKiln	1 Jan 2005	30 Nov 2005	304	30
GEN.Thermal.Kawerau.B	1 Jan 2005	30 Nov 2005	304	30
GEN.TeKowhai	1 May 2005	30 Nov 2005	214	-
GEN.Hydro.Benmore.161	1 May 2003	30 Sep 2003	153	-
GEN.Addington	1 Oct 2005	30 Nov 2005	61	-
GEN.Auckland.Hospital	1 Oct 2005	30 Nov 2005	61	-
GEN.Christchurch.CrownePlaza	1 Oct 2005	30 Nov 2005	61	-
GEN.Christchurch.SimeonQuay	1 Oct 2005	30 Nov 2005	61	-
GEN.Christchurch.WasteWater	1 Oct 2005	30 Nov 2005	61	-
GEN.Edgecumbe	1 Oct 2005	30 Nov 2005	61	-
GEN.Fox.11KV	1 Oct 2005	30 Nov 2005	61	-
GEN.Geothermal.Rotokawa	1 Oct 2005	30 Nov 2005	61	-
GEN.Gisborne	1 Oct 2005	30 Nov 2005	61	-
GEN.Glenorchy	1 Oct 2005	30 Nov 2005	61	-
GEN.Hinemaia	1 Oct 2005	30 Nov 2005	61	-
GEN.Hydro.Aniwhenua	1 Oct 2005	30 Nov 2005	61	-
GEN.Hydro.Arnold	1 Jan 2000	30 Nov 2005	61	2,100
GEN.Hydro.Atiamuri.B	1 Oct 2005	30 Nov 2005	61	-
GEN.Hydro.Dillmans	1 Oct 2005	30 Nov 2005	61	-

Table 6B:

Comparison of generation totals from Energy Data File and Centralized Data Set

	Year to March 2004				Year to March 2005			
	Energy Data File		CDS [3]		Energy Data File		CDS [3]	
	GWh	% of total	GWh	% of EDF total	GWh	% of total	GWh	% of EDF tota
Generator share [1]								
Meridian Energy	12,560	31%	11,658	29%	13,200	32%	13,088	32%
Contact Energy	10,800	27%	9,690	24%	9,900	24%	10,114	24%
Genesis Power	6,320	16%	6,306	16%	7,400	18%	7,512	18%
Mighty River Power	4,960	12%	4,277	11%	5,800	14%	5,170	13%
TrustPower			1,119	3%	2,100	5%	1,481	4%
Others	5,360	13%	718	2%	2,935	7%	966	2%
Total	**40,006**	**100%**	**33,768**	**84%**	**41,335**	**100%**	**38,332**	**93%**
Fuel type share [2]								
Hydro	24,642	62%	22,005	55%	26,442	64%	25,604	62%
Gas	8,610	22%			6,645	16%		
Coal and Oil	2,846	7%			4,026	10%		
Thermal			8,912	22%			9,606	23%
Geothermal	2,504	6%	1,643	4%	2,654	6%	1,872	5%
Wind			0	0%	466	1%	208	1%
Other	1,403	4%	1,208	3%	1,101	3%	1,041	3%
Total	**40,006**	**100%**	**33,768**	**84%**	**41,335**	**100%**	**38,332**	**93%**

1. Generator production figures for the Energy Data File are estimated based on the total national generation and the reported shares.
2. Cogen production for the CDS figures is split between thermal and other. In the Energy Data File, cogen is included in gas, coal & oil, geothermal and other.
3. CDS percentages are reported based on actual generation from the Energy Data File, rather than the totals in the CDS.

Figures

Figure 1: Gentailer Net Positions for Various Hydro Scenarios (Source: NERA, 2004)

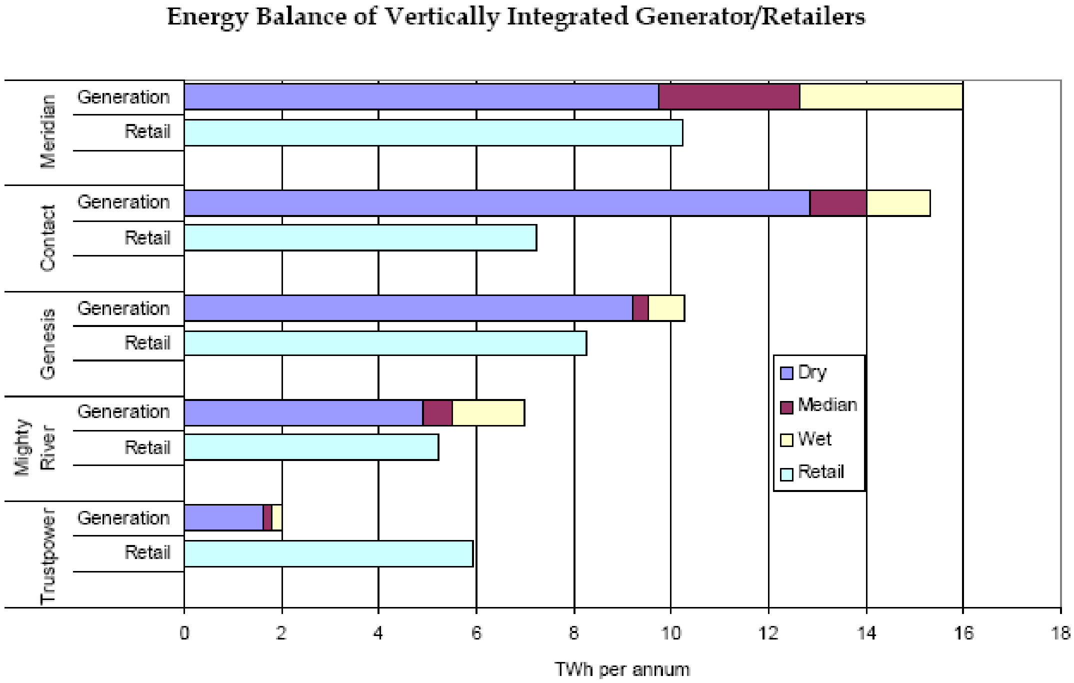

Figure 2: New Zealand Generation and Transmission Network

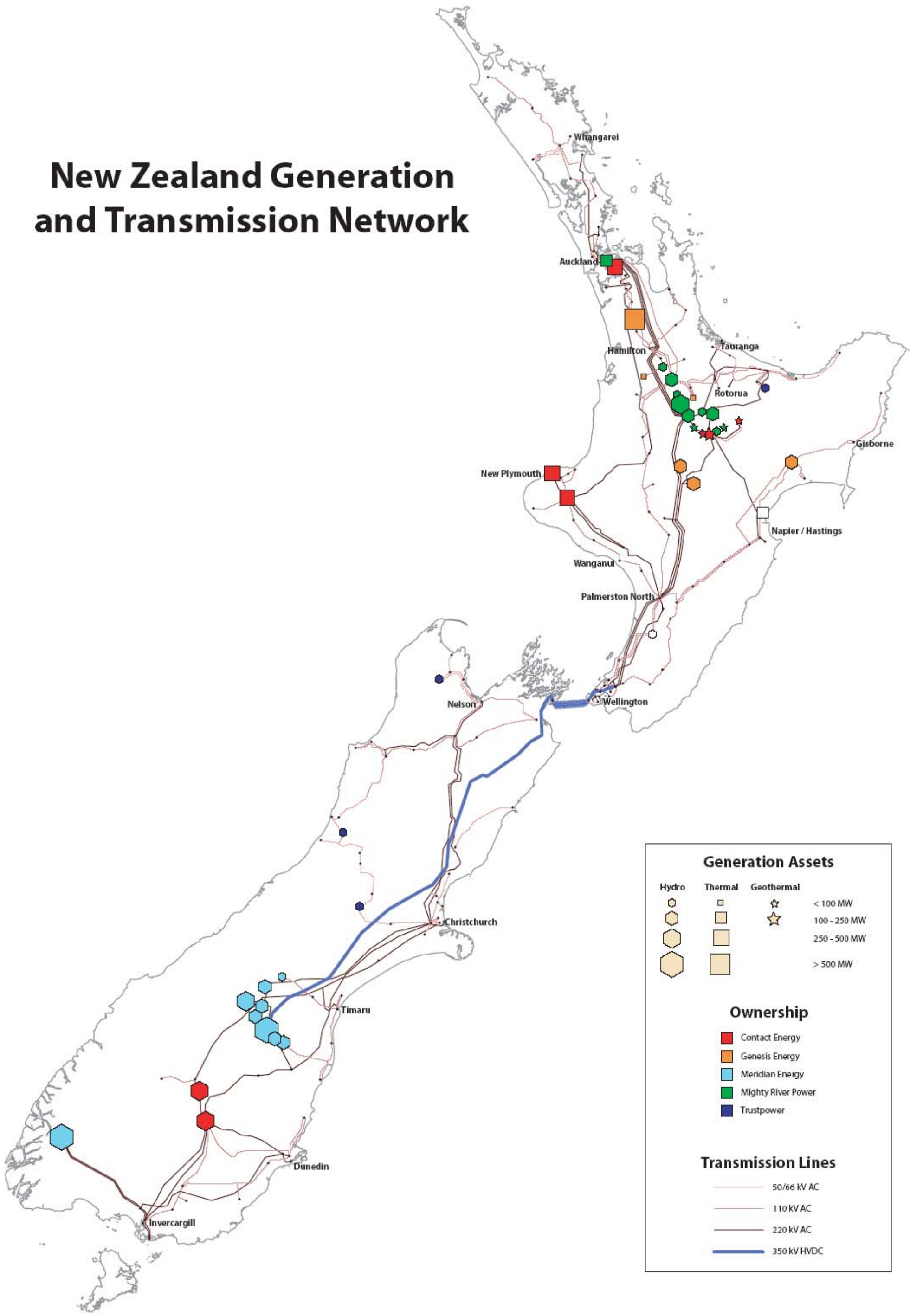

Figure 3: Nodes Used in Correlation Analysis

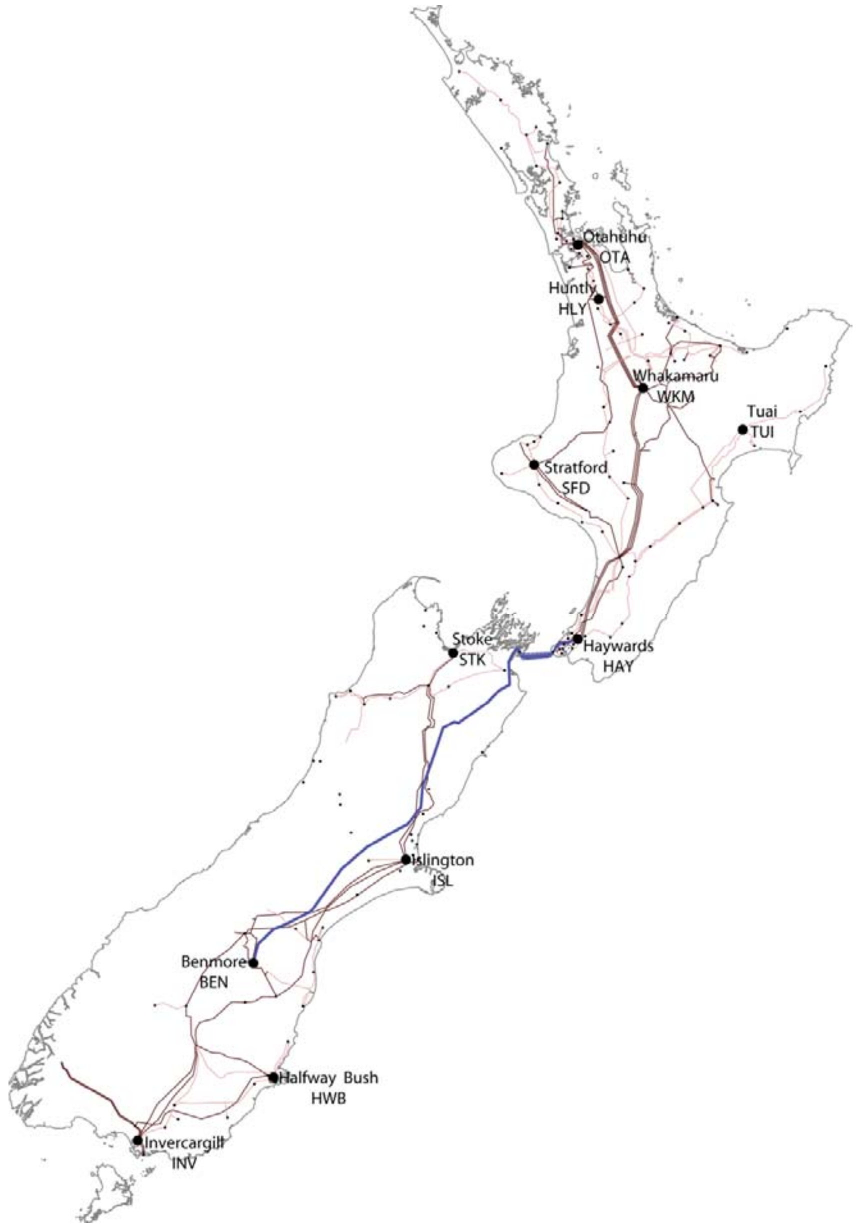

Figure 4A: WKM – HAY prices, 2004 ***(correlation = 0.527)***

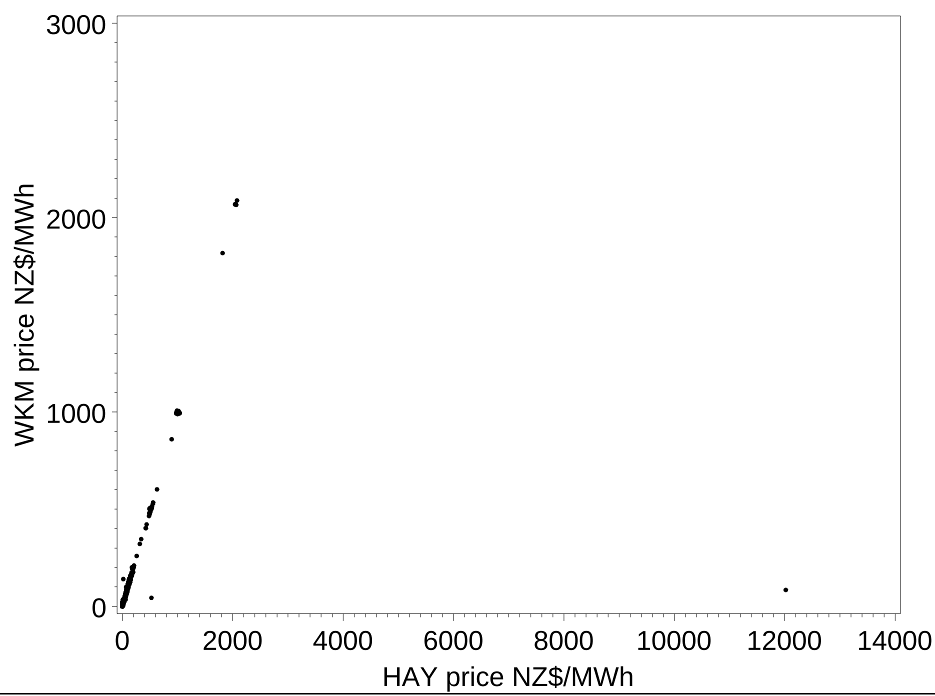

Figure 4B: STK – BEN prices, 2004 ***(correlation = 0.582)***

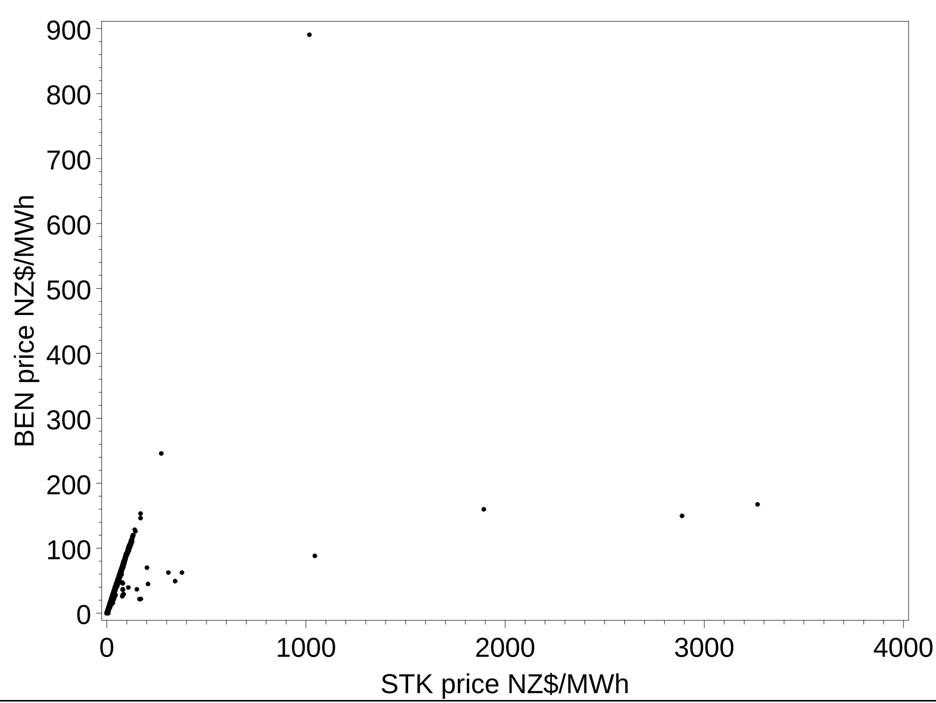

Figure 4C: TUI – WKM prices, 2000 ***(correlation = 0.401)***

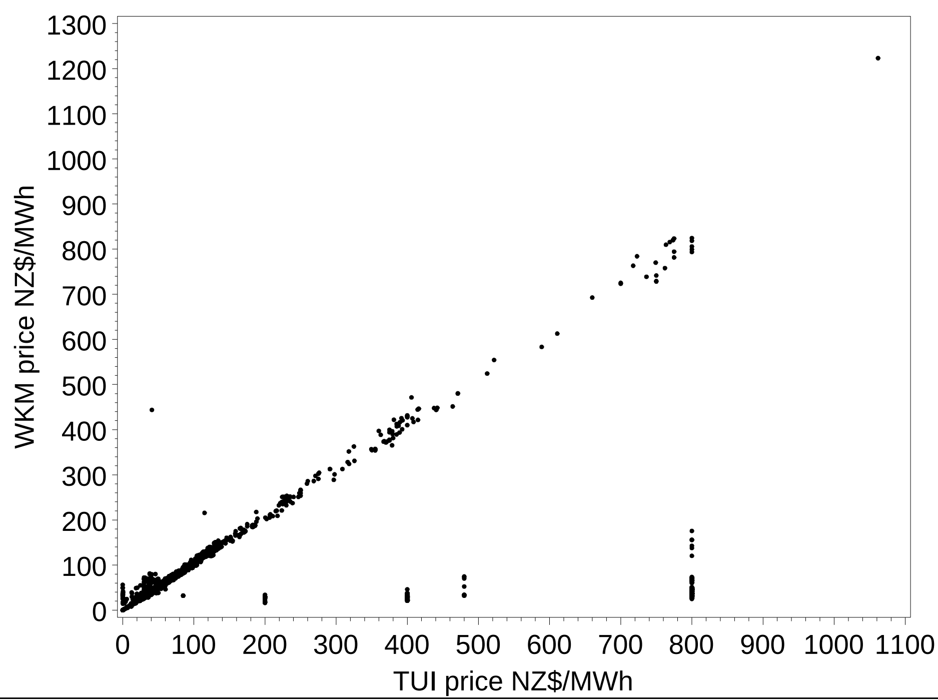

Figure 4D: BEN – HAY prices, 2002 ***(correlation = 0.714)***

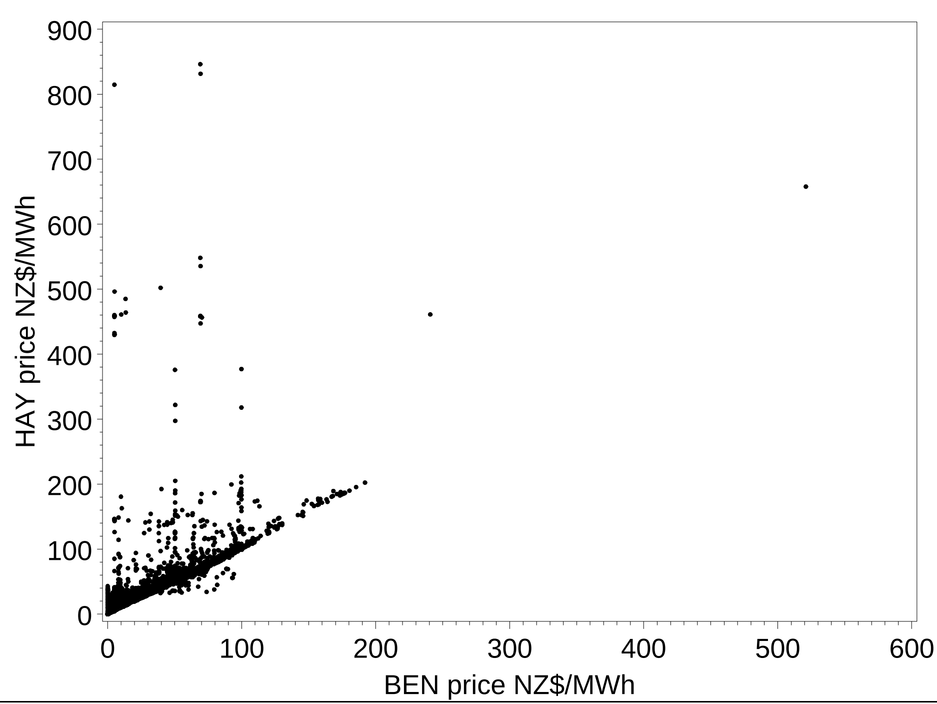

Figure 4E: BEN – HAY prices, 2001 ***(correlation = 0.978)***

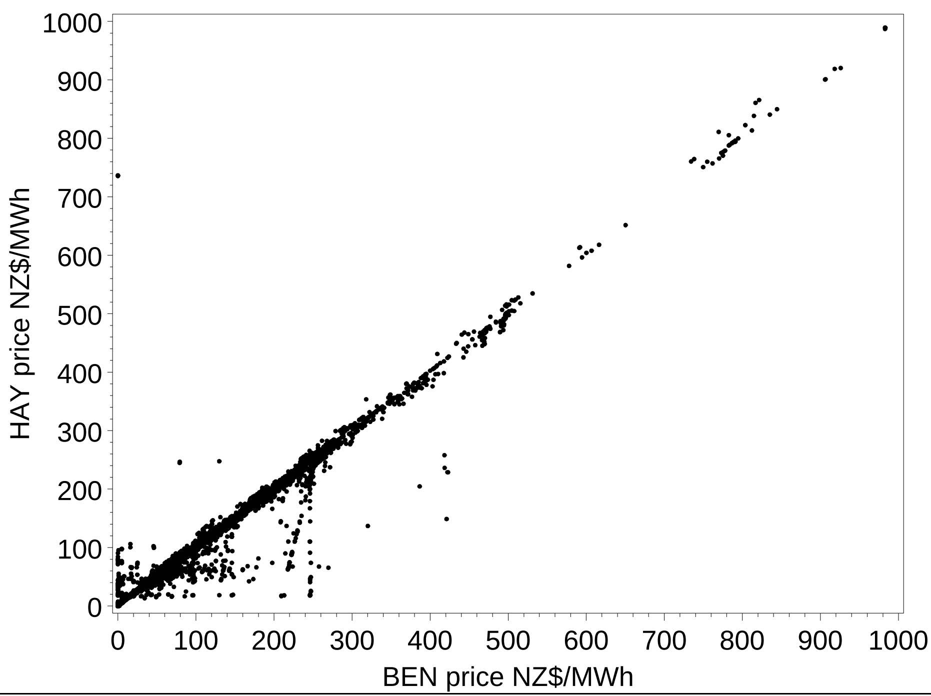

Figure 5A: BEN – HAY correlation coefficients and BEN prices, monthly 1997–2005

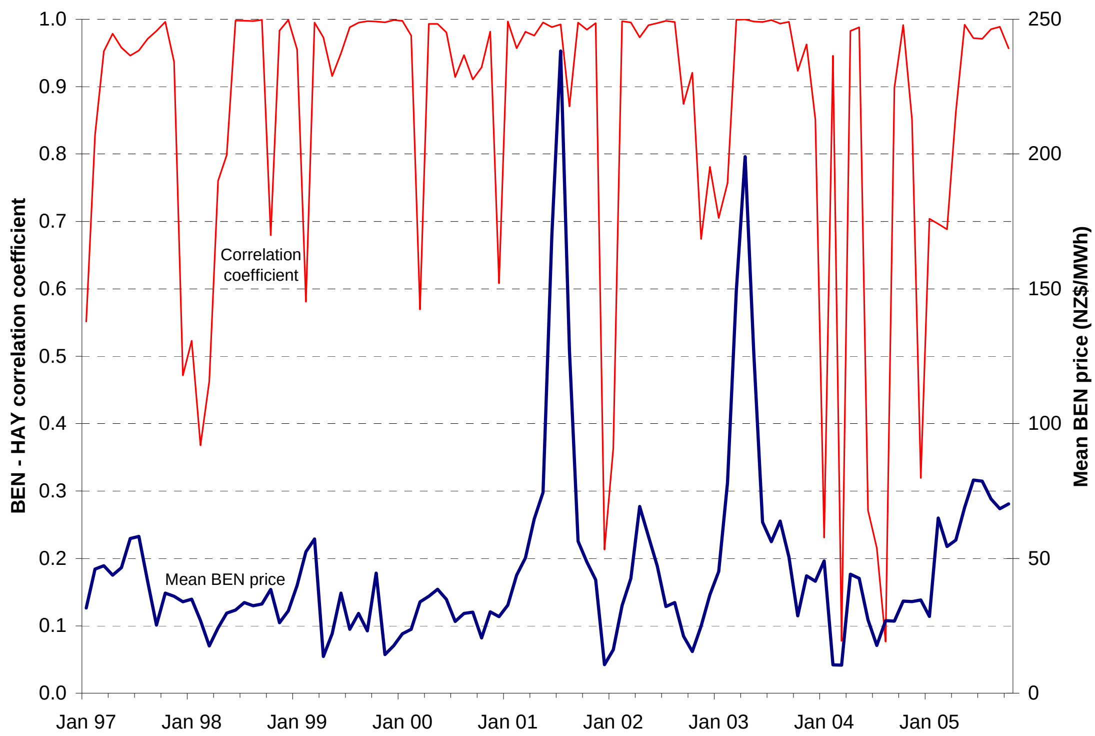

Figure 5B: BEN – HAY correlation coefficients and BEN prices, monthly 1997–2005

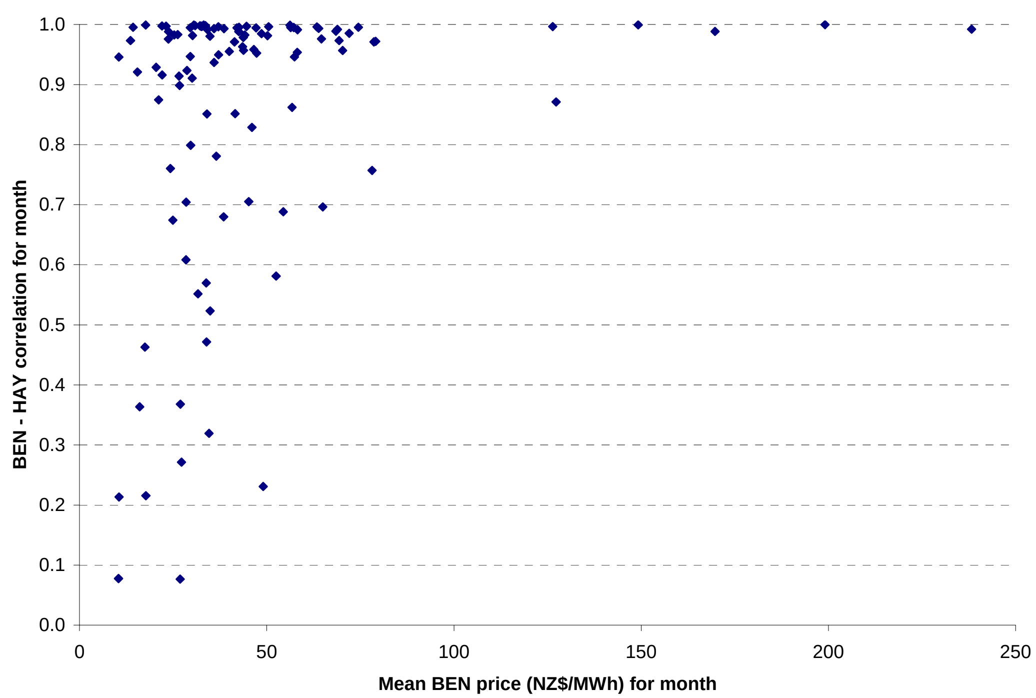

Figure 6A: Mean half-hourly prices for Benmore, 2000 – 2005

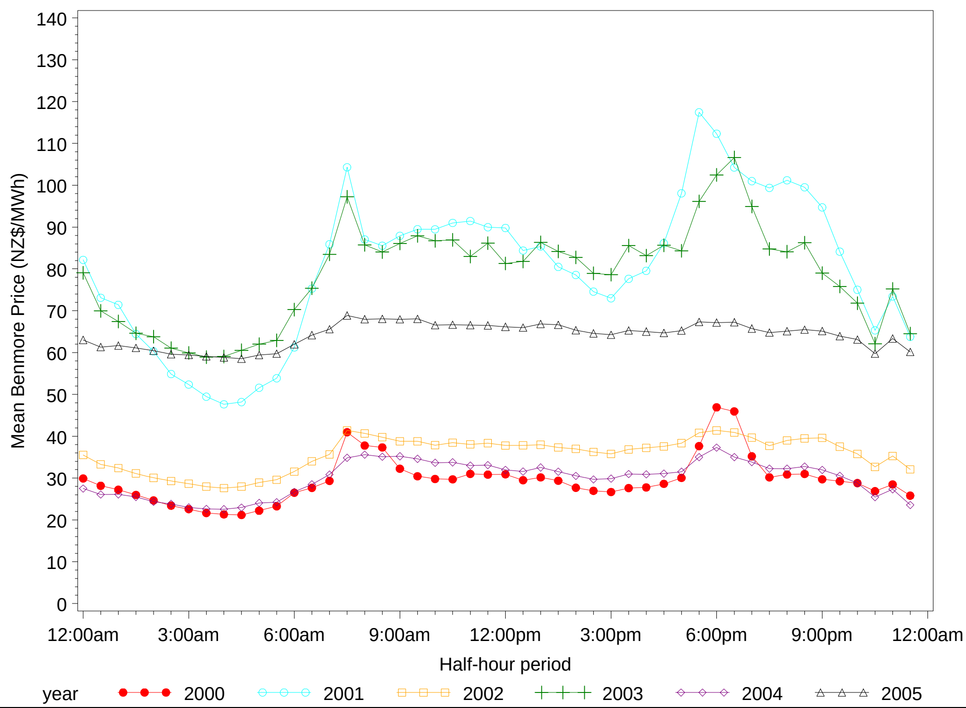

Figure 6B: Median half-hourly prices for Benmore, 2000 – 2005

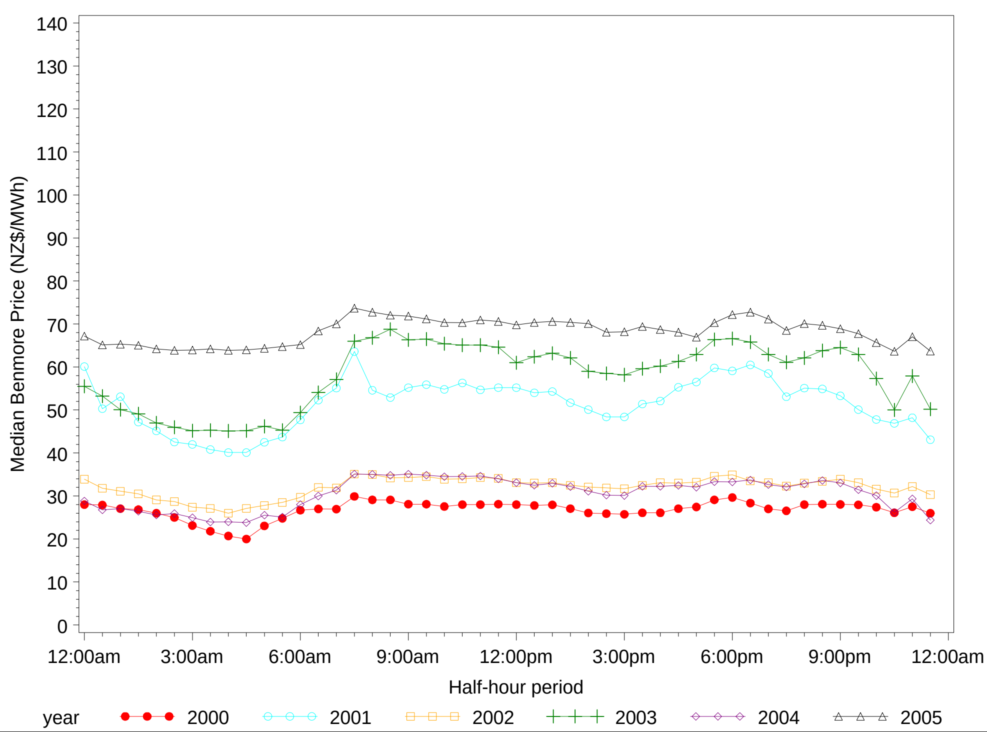

Figure 6C: Standard deviation of half-hourly prices for Benmore, 2000 – 2005

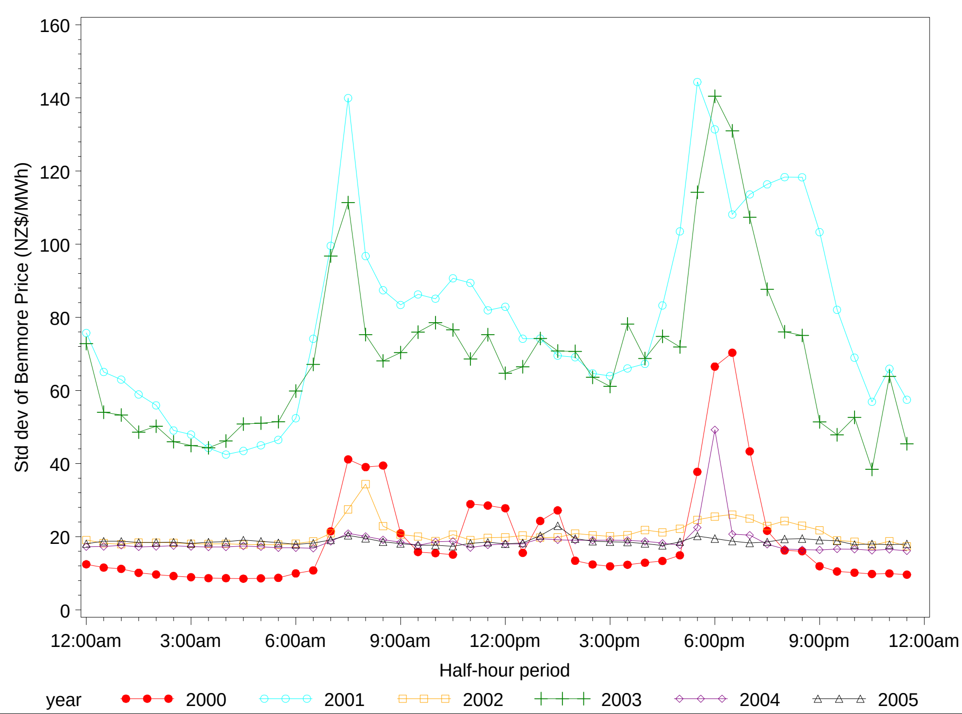

Figure 6D: Mean half-hourly prices for Benmore, Winter 2000 – 2005

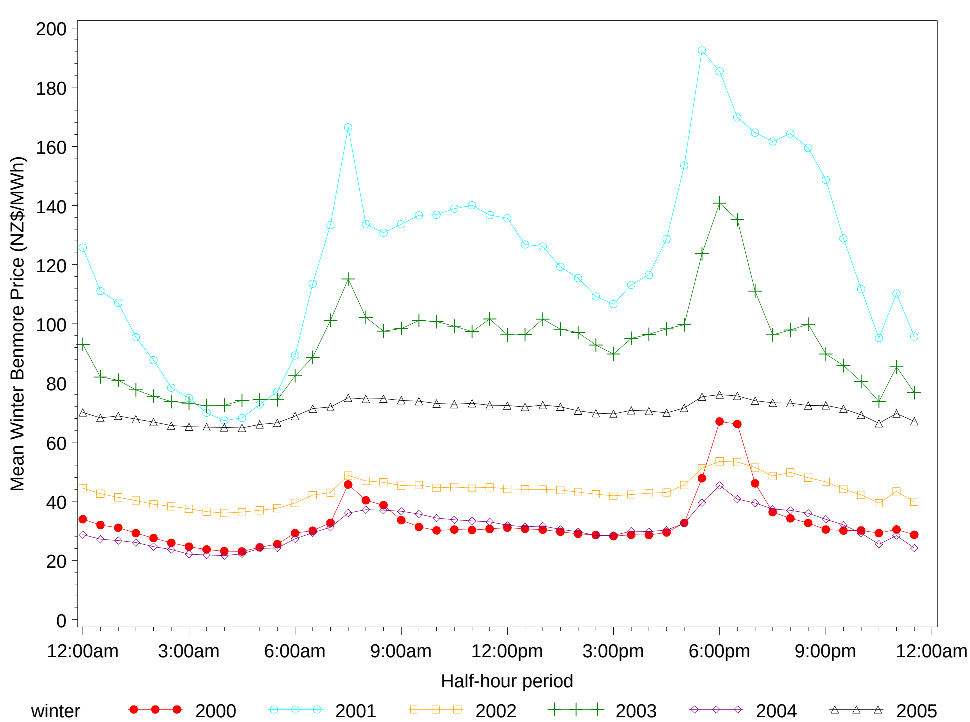

Figure 6E: Median half-hourly prices for Benmore, Winter 2000 – 2005

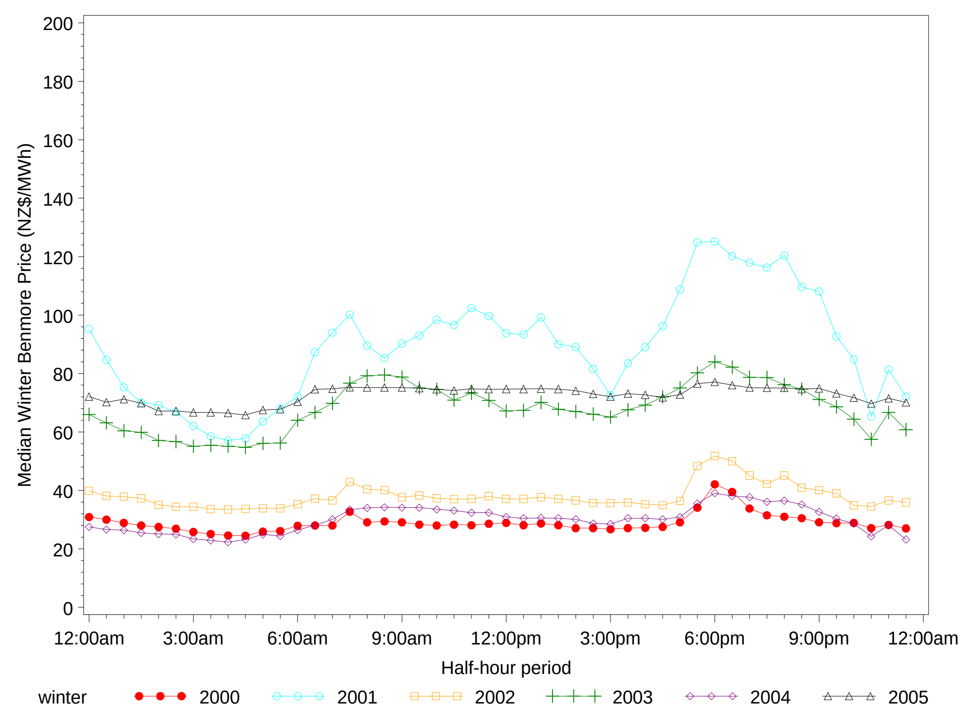

Figure 6F: Std deviation of half-hourly prices for Benmore, Winter 2000 – 2005

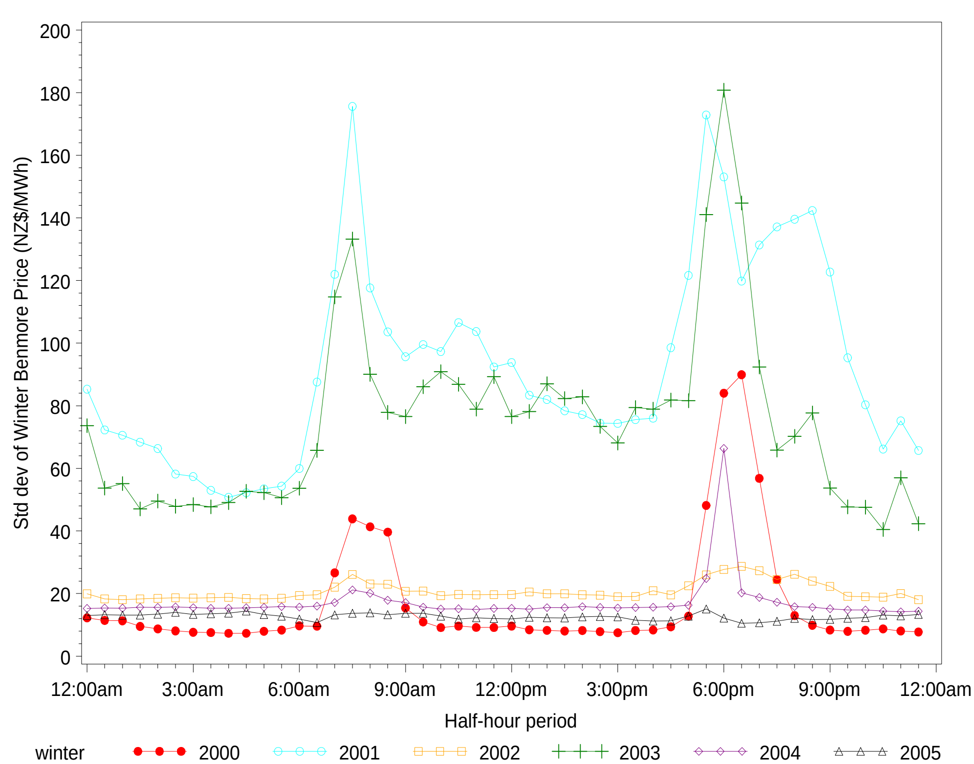

Figure 6G: Mean half-hourly prices for Benmore, Summer 2000 – 2005

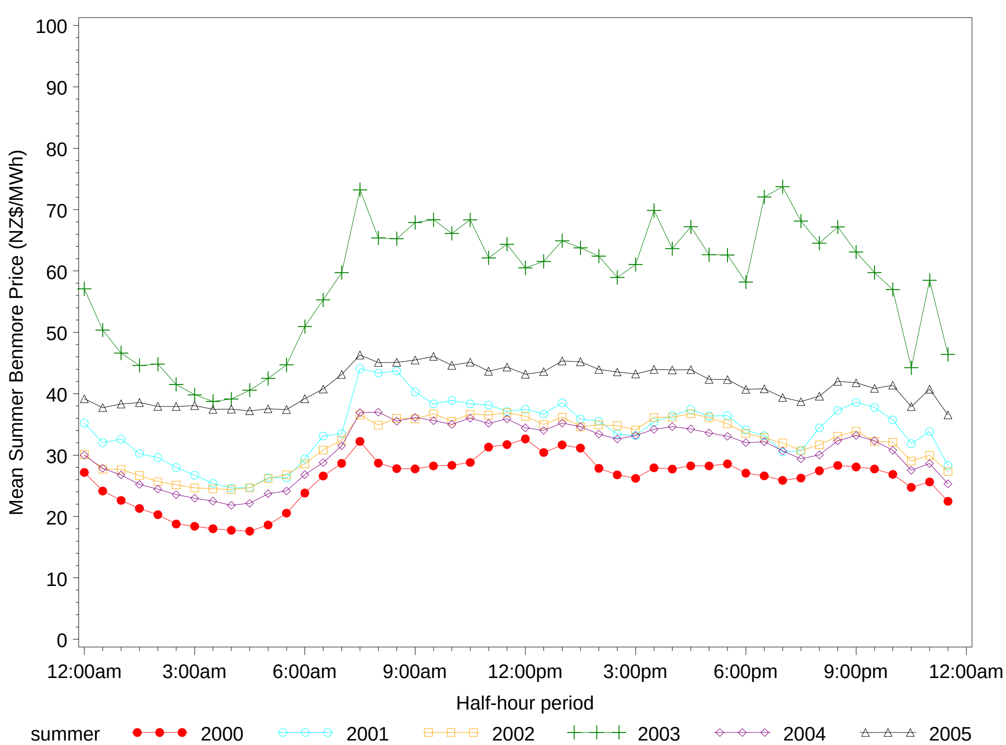

Figure 6H: Median half-hourly prices for Benmore, Summer 2000 – 2005

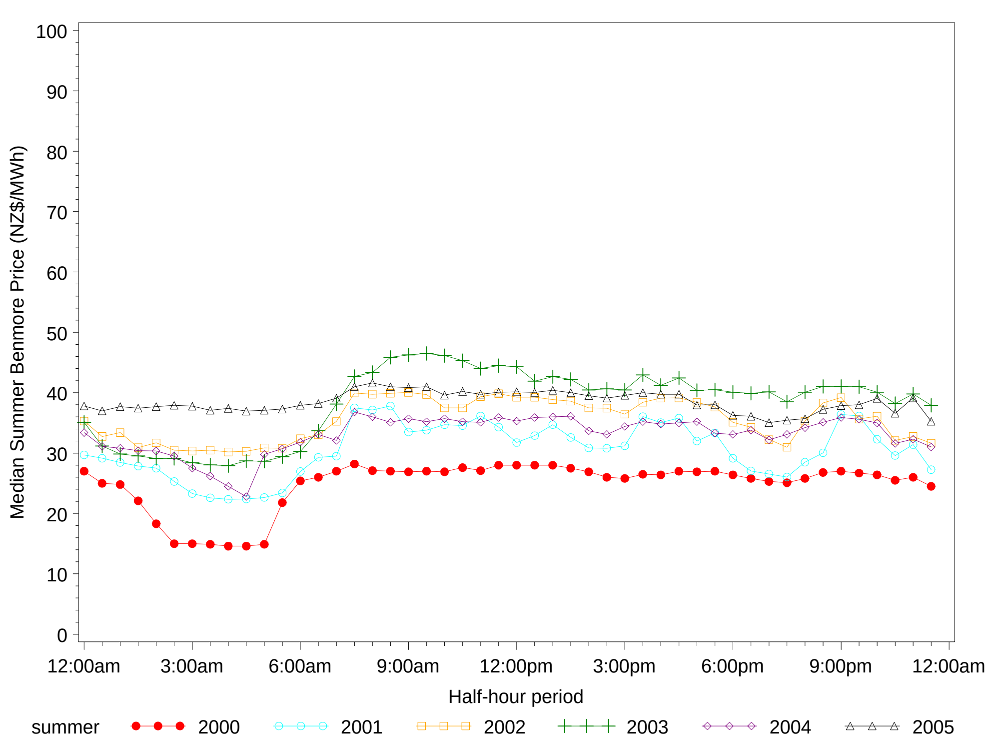

Figure 6I: Standard deviation of half-hourly prices for Benmore, Summer 2000 – 2005

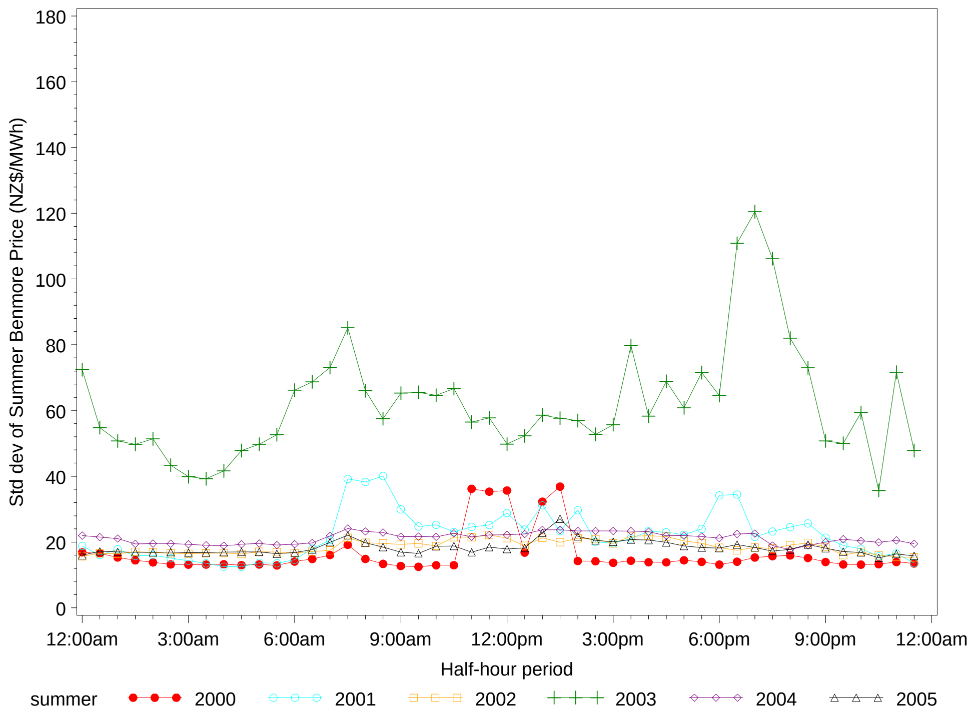

Figure 7A: Mean half-hourly prices for Haywards, 2000 – 2005

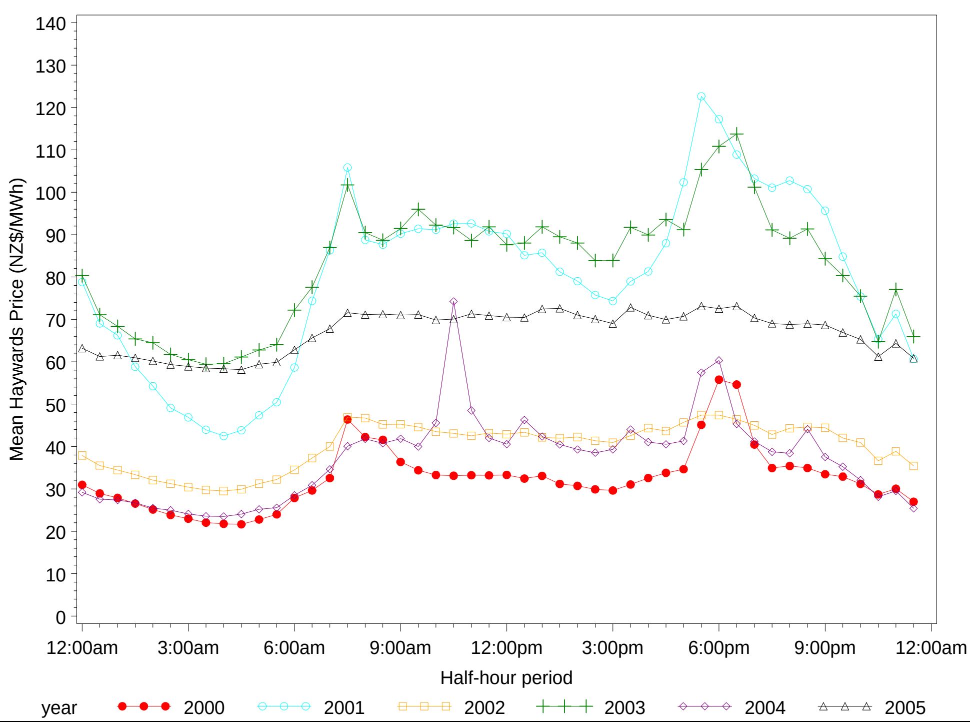

Figure 7B: Median half-hourly prices for Haywards, 2000 – 2005

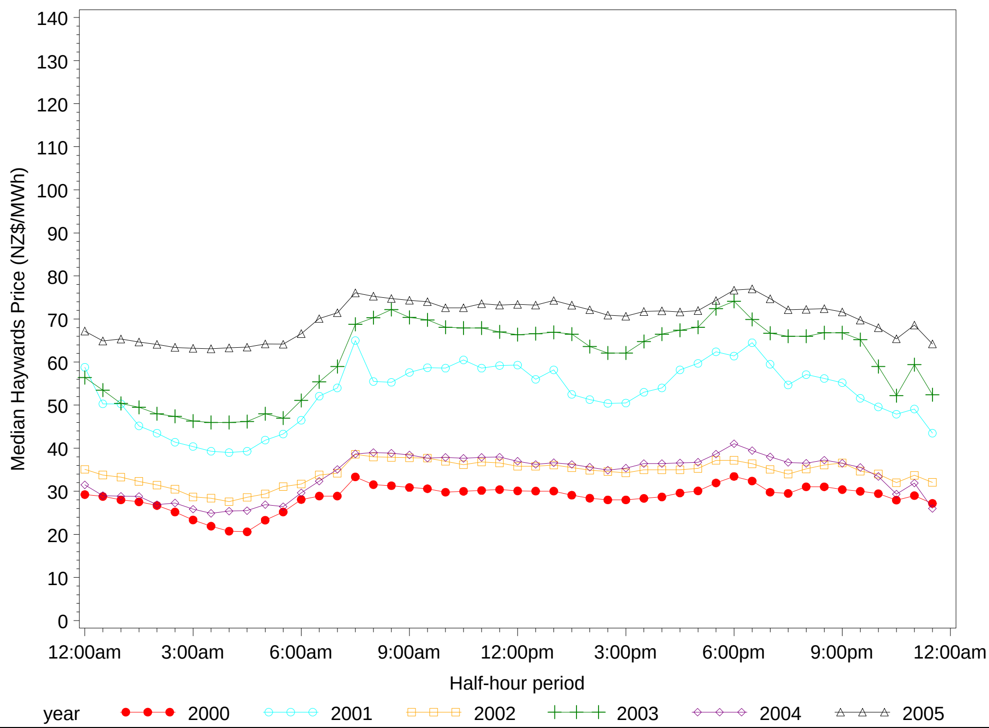

Figure 7C: Standard deviation of half-hourly prices for Haywards, 2000 – 2005

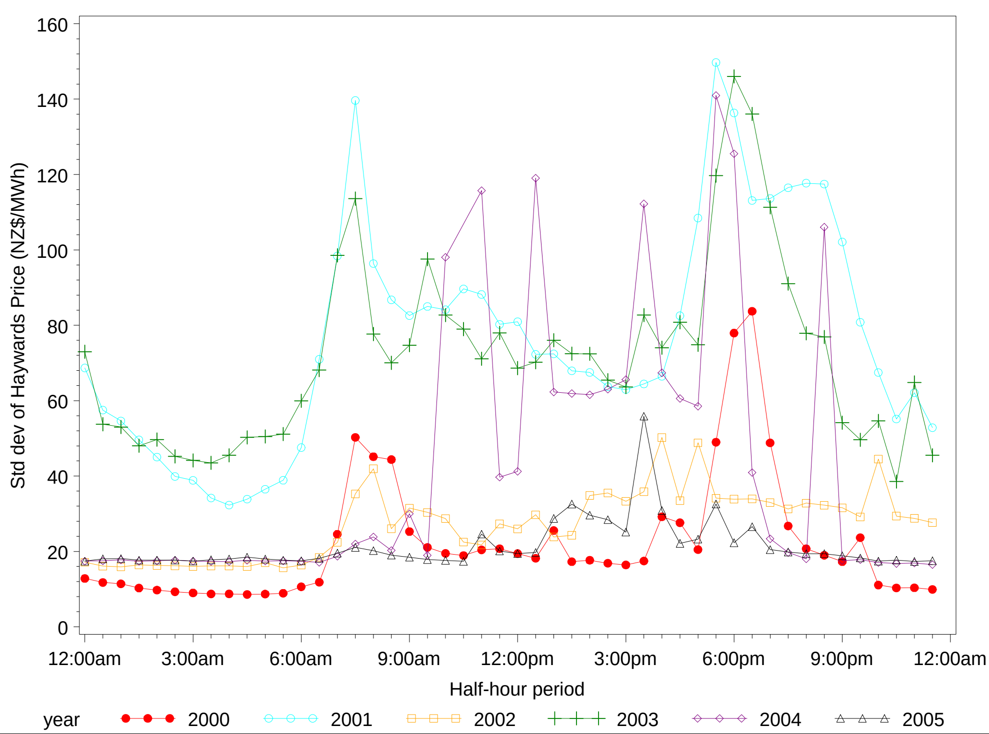

Figure 8A: Mean intra-day load for New Zealand, 2000 – 2005

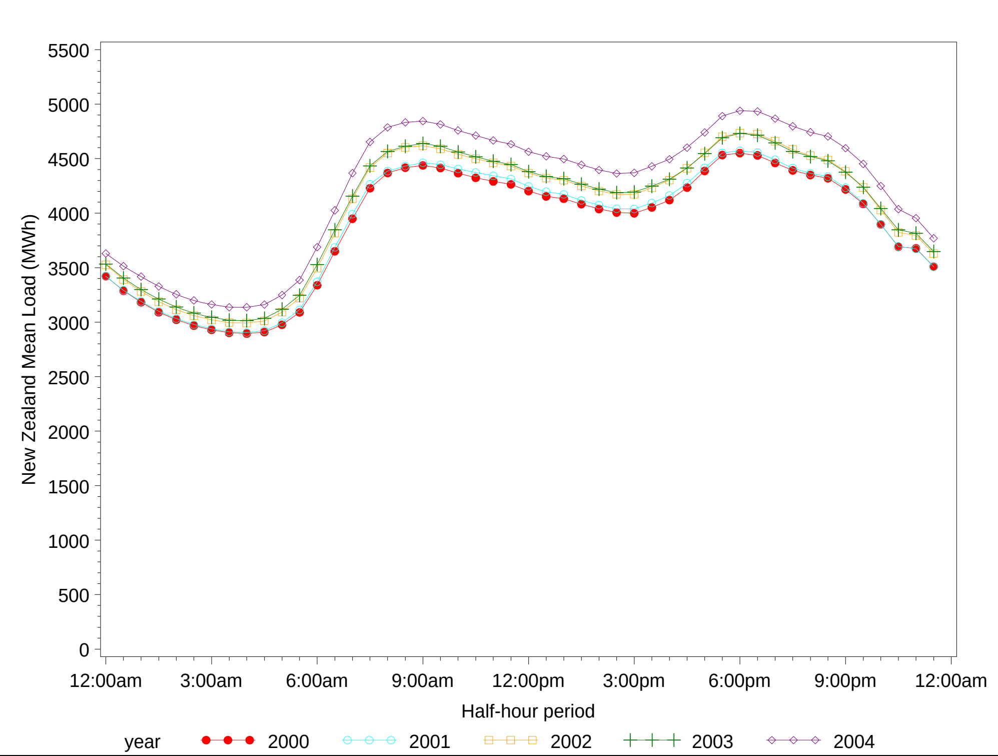

Figure 8B: Mean intra-day load for North Island, 2000 – 2005

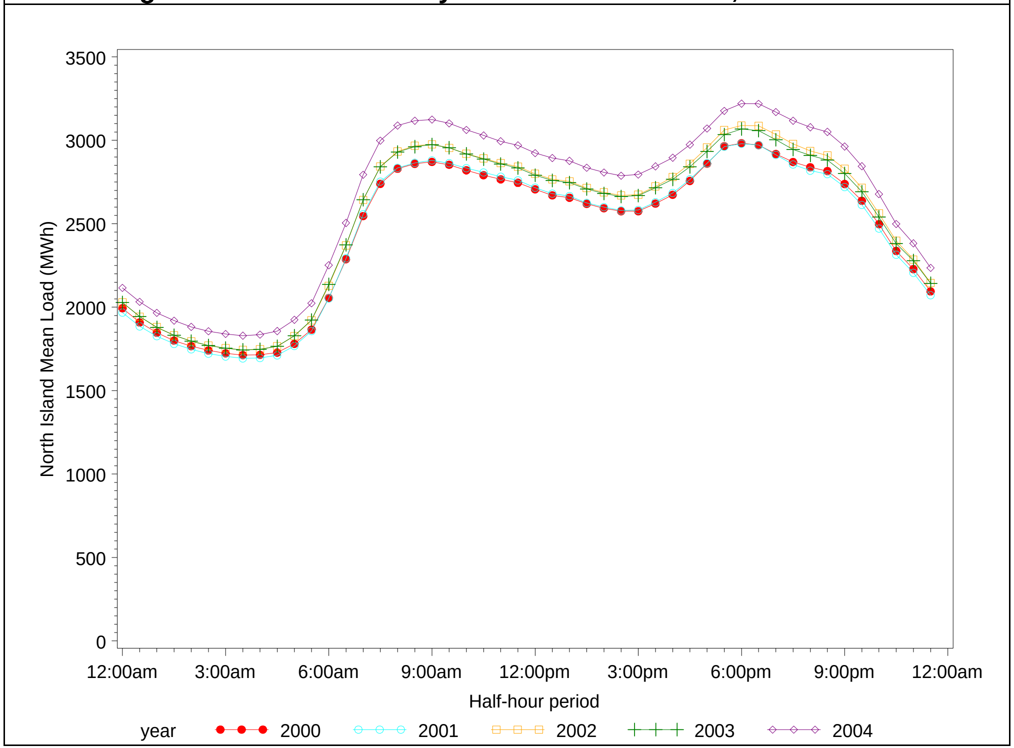

Figure 8C: Mean intra-day load for South Island (excluding Tiwai), 2000 – 2005

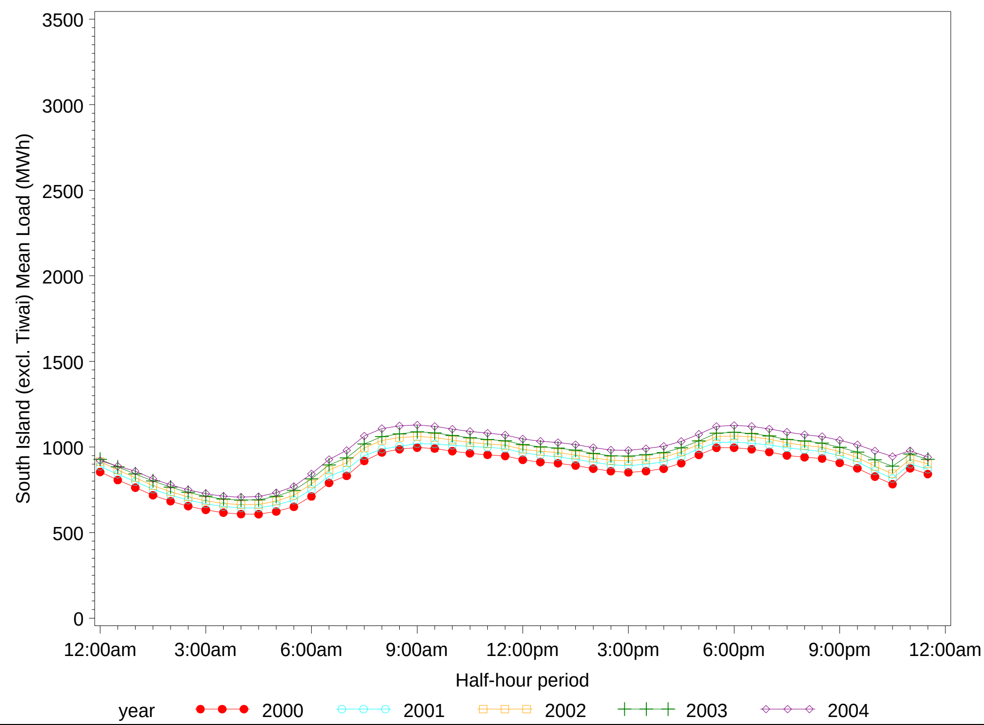

Figure 8D: Mean intra-day load for Tiwai Aluminum Smelter, 2000 – 2005

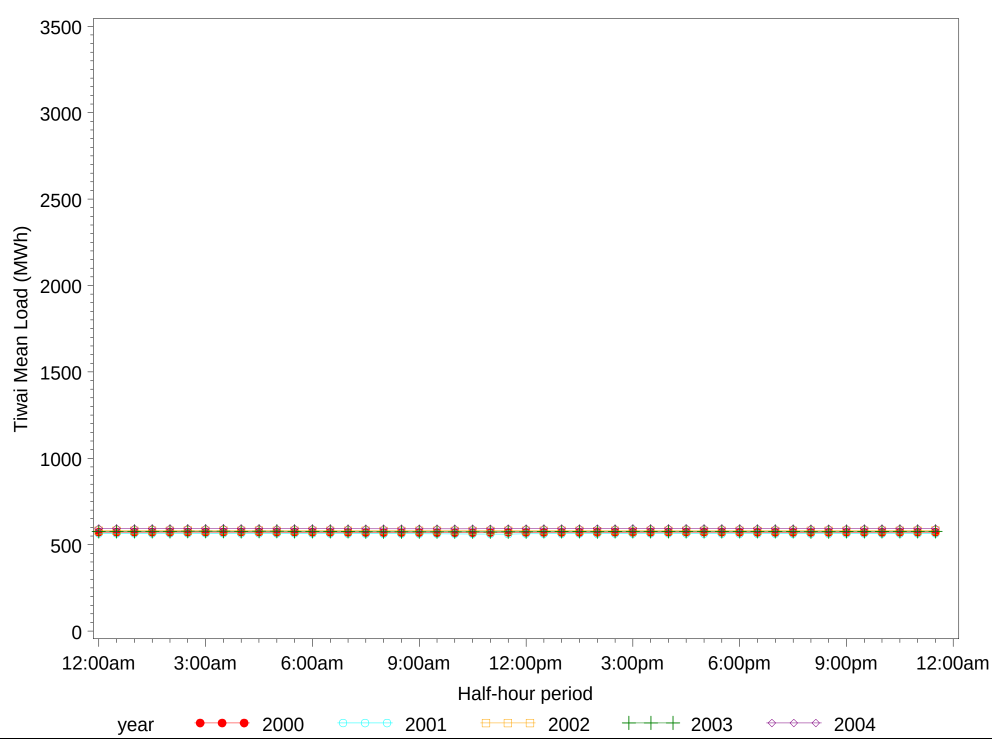

Figure 8E: Standard deviation of intra-day load for New Zealand, 2000 – 2005

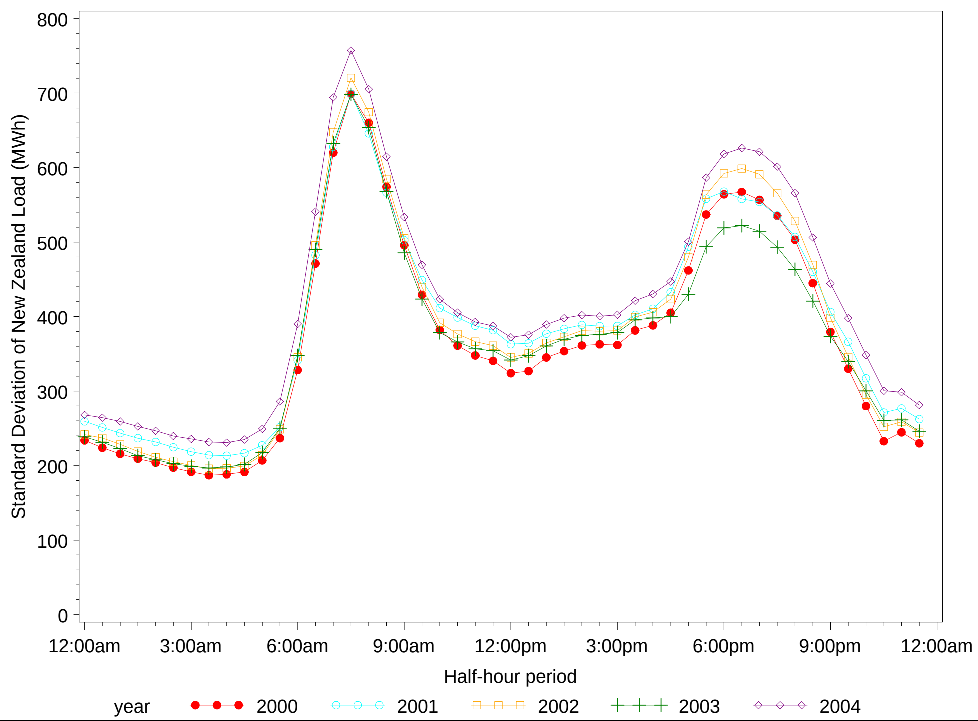

Figure 8F: Mean intra-day load for North Island in Summer, 2000 – 2005

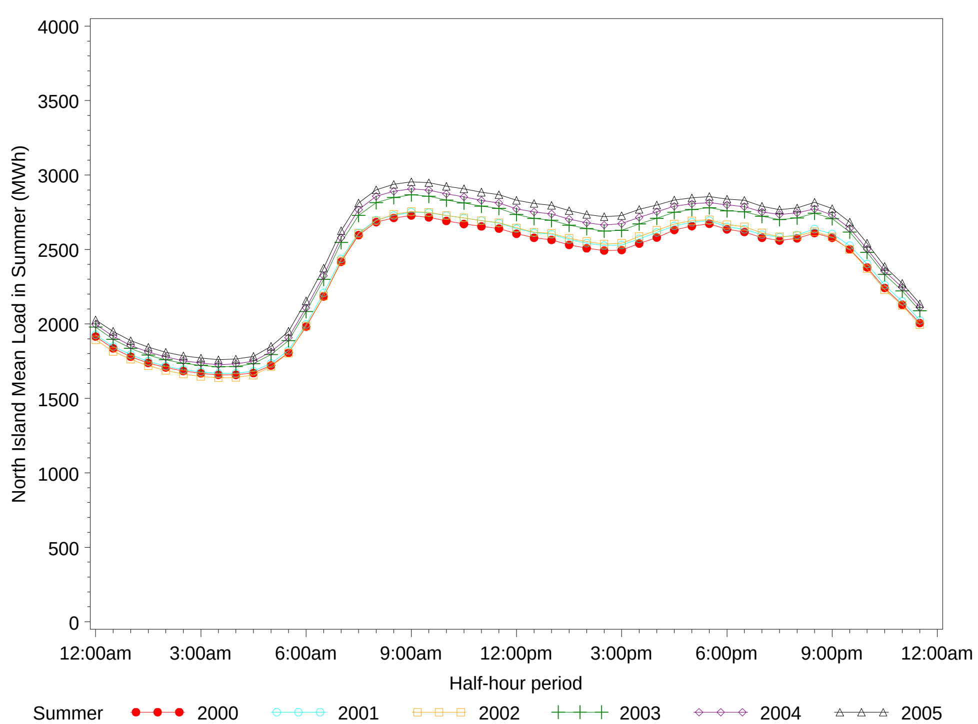

Figure 8G: Mean intra-day load for South Island in Summer, 2000 – 2005

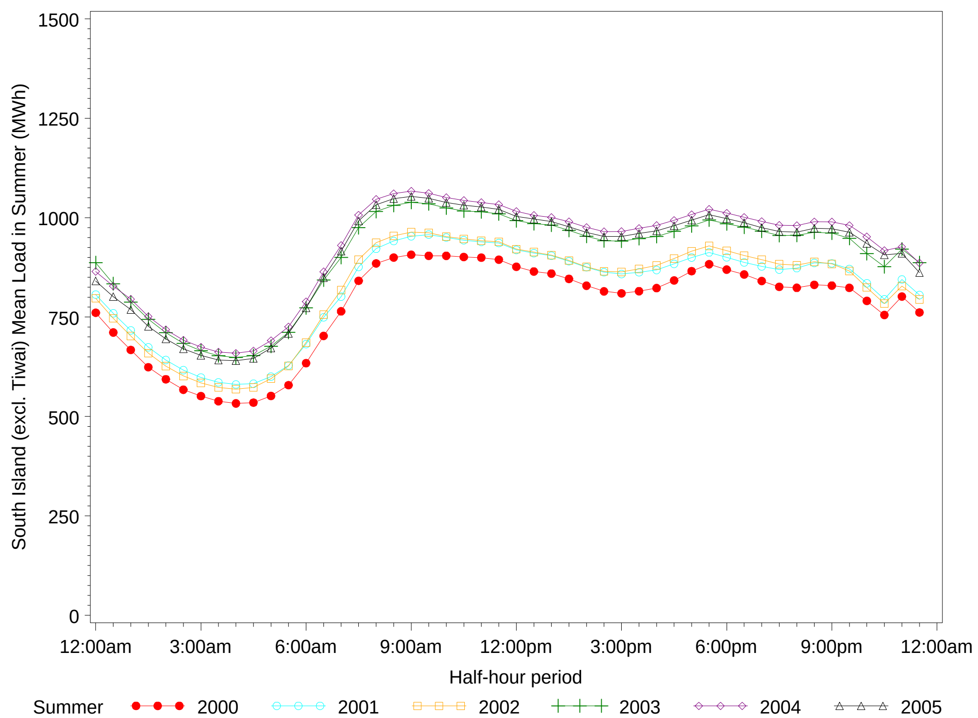

Figure 8H: Mean intra-day load for North Island in Winter, 2000 – 2005

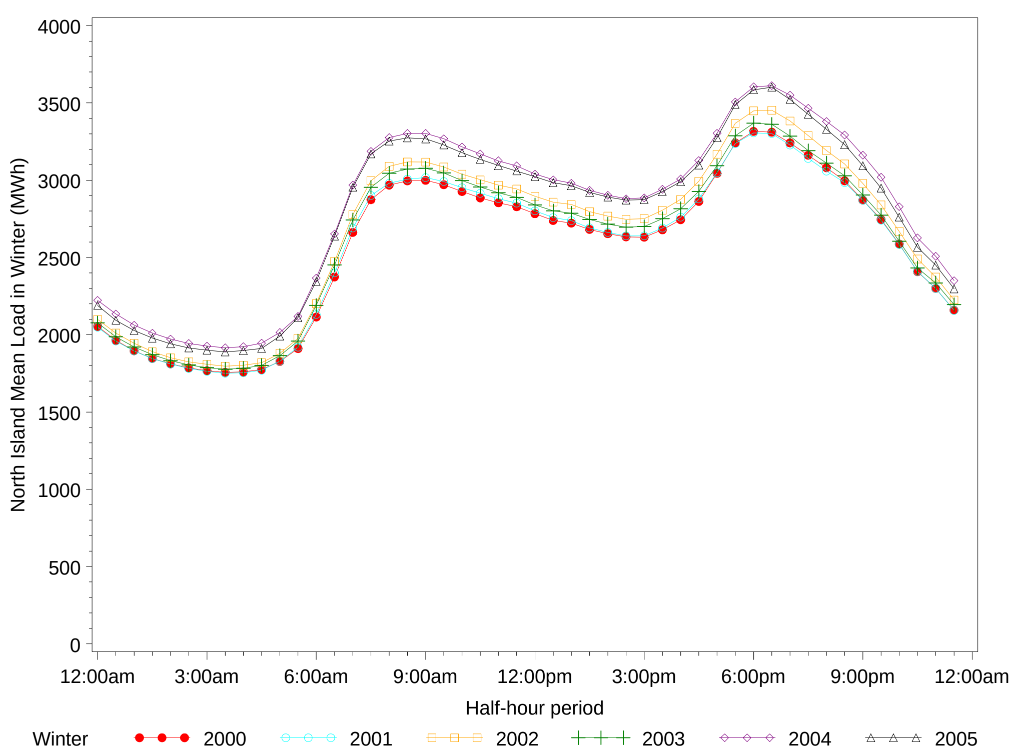

Figure 8I: Mean intra-day load for South Island in Winter, 2000 – 2005

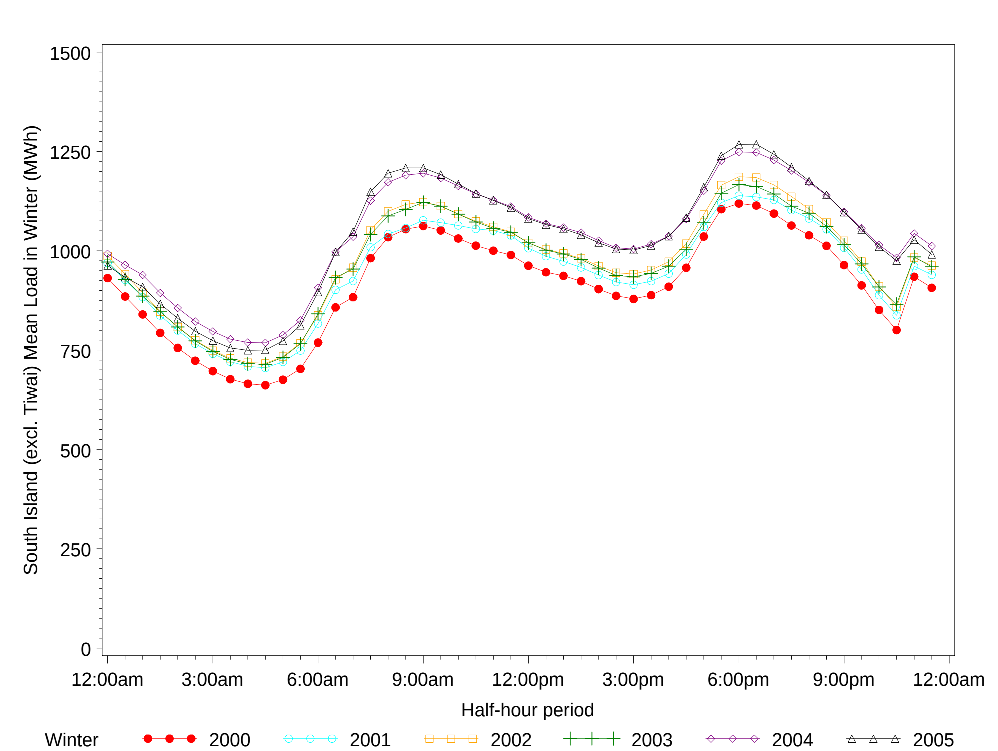

Figure 8J: Mean New Zealand load at 6:00pm, by month, 2000 – 2005

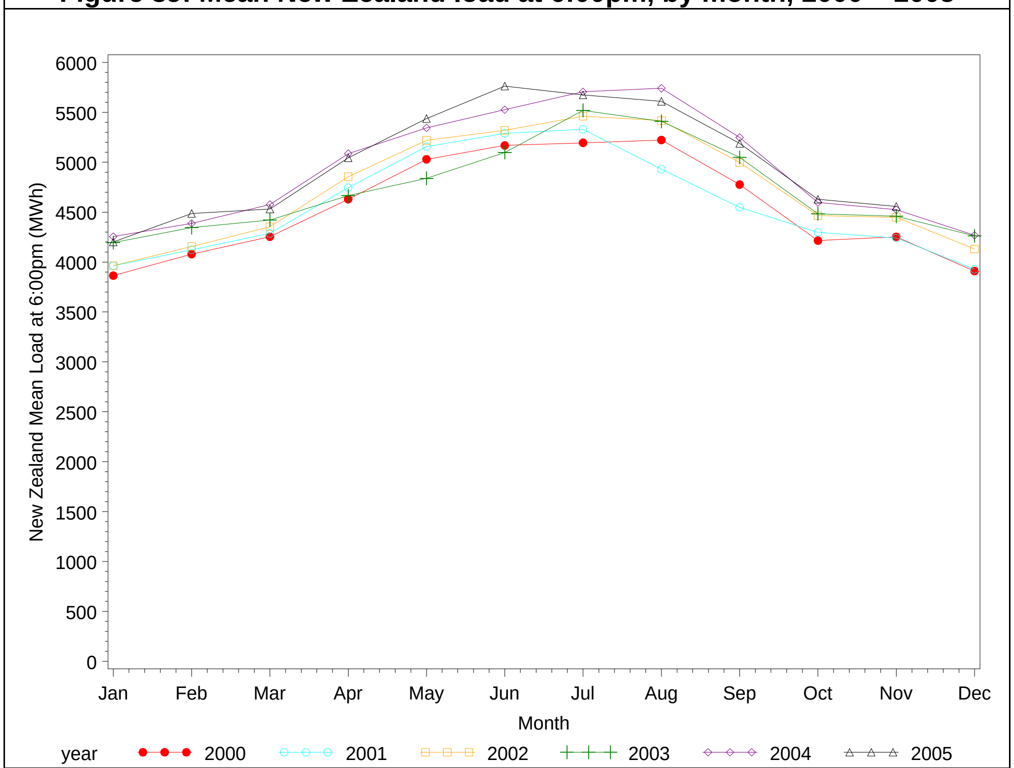

Figure 8K: Mean New Zealand intra-day loads, bi-monthly for 2004