

Electricity market performance

A review of 2012





The Electricity Authority's objective is to ensure New Zealand consumers benefit over the long term from a competitive, reliable and efficient electricity market. Measuring and reporting on how we are meeting this objective is important. This review outlines our progress in 2012.

The Authority uses a workably competitive benchmark to assess competition. This means that competitive pressure from entrants and potential entrants to electricity markets should lead to more efficient outcomes over time. Therefore, measuring the direction of travel is as important as measuring the state of play.

Consumers receive benefits from lower energy prices over the long term due to more efficient production and from avoiding inefficient costs of non-supply. The Authority's focus on these benefits over the long term puts the spotlight on incentives to innovate and invest in reducing costs and increasing reliability.

The first thing we look at in this review is what consumers are demanding, what patterns they follow and the location of their demand.

After looking at consumer demand, we look at the retail electricity market. Competition in the retail market should mean that consumers can choose the supplier that gives them the level of service they require at the lowest price. A workably competitive retail market should also see innovation and entry, particularly in the early stages of competition. This year, we have seen an increasingly competitive retail sector as measured by the structure of retail markets, the level of consumer switching and the ensuing changes in market share.

A competitive hedge market is also very important given the structure of the New Zealand electricity industry. We

are seeing the hedge market evolving rapidly and becoming the preferred platform for retailers and generators to manage spot price risk. A competitive hedge market lowers the risk of operating a stand-alone retail business and therefore facilitates entry. It also provides generators price certainty.

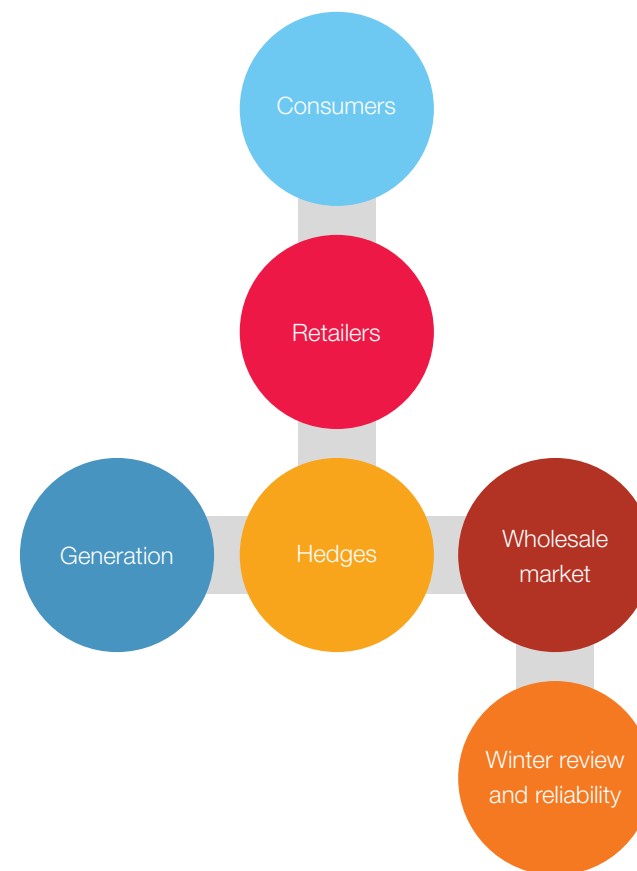
We then turn our attention to generation as this responds to meet demand. We'll look at how fuel diversity is evolving and take a closer look at wind generation. Although wind is intermittent and has an impact on the rest of the system, it's hard to ignore how efficient it is in New Zealand.

Generators use the wholesale electricity market to cover hedge contracts and their retail positions if they are vertically integrated – that is, they are generators as well as retailers. Retailers use the wholesale market to balance demand above what they generate from their own plant and/or hedge contracts they have entered into.

This year saw the introduction of new schedules in the wholesale market aimed at creating signals about the value of reducing load. We'll look at examples of how changes to demand-side bidding and forecasting have affected final prices in the electricity market.

A competitive wholesale market also deals with situations where supply or demand is unexpectedly perturbed. This year, low hydro inflows meant a hydro fuel shortage in the South Island, and this report looks at how the wholesale market and various ancillary markets dealt with this situation. We'll see that, despite very difficult conditions, the markets worked to ensure reliable supply.

Finally, we'll look at reliability of the transmission network, using and analysing data from Transpower's annual *Quality Performance Report*.



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The Authority has released two information papers outlining how it measures the performance of the electricity sector,¹ including metrics for assessing competition, reliability and efficiency. The papers set out a structure, conduct and performance framework for analysing the sector.

This 2012 review is the first time we have used this monitoring framework. We acknowledge that the review doesn't capture all the measures from the information papers, and we will continue to work to implement the framework set out in them.

In reviewing competition, we have implemented many of the structural measures from the information papers. We have been less successful to date at implementing conduct measures where we have focused on changes in market shares in the retail market, the amount of switching and

the quality of forward price signals from ASX futures. For performance measures of competition, we have looked closely at the retail market and charted how price movement relates to market structure and how regions are moving relative to the mean available offer. We set out how costs have changed in the frequency-keeping market and present evidence of innovation in the instantaneous reserves market.

When reviewing reliability and efficiency, we have again focused on structure. We have looked closely at the increase in wind generation and what effect this might have on the market, and we continue to monitor changes in generation fuel type, and hydro capacity and risk. We have reviewed how the forward and spot markets reflected the physical reality of hydro storage in the South Island, as this was an important measure of efficiency of the electricity market

this year. In the conduct dimension, we have looked at how changes to demand-side bidding and forecasting have been working, as well as the activity of an aggregator into the instantaneous reserves market. Our review of the winter addresses how water was managed, and we have analysed transmission reliability.

In future reviews, we will look at a greater variety of measures of market structure and price trend analysis to monitor market performance in the spot market.

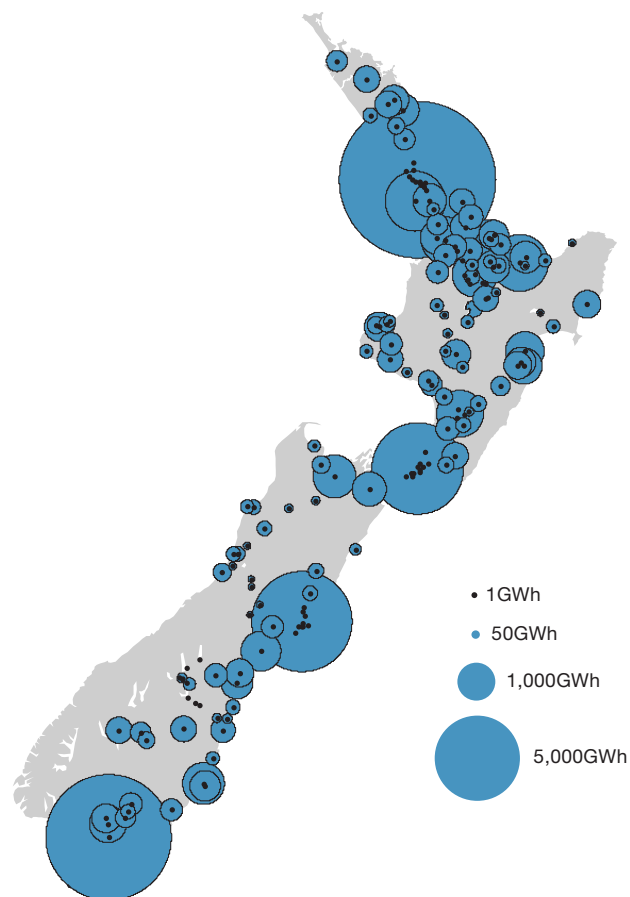
We will also do more work on benchmarking overheads and investment as measures of conduct, the use of smart meters to enable innovative tariff offers and more analysis of outage data.

¹ See www.ea.govt.nz/industry/monitoring/reports-publications.

Demand is concentrated in the cities

Figure 1 shows the location of electricity demand. Electricity demand in New Zealand is concentrated in the main cities and a few large grid-connected customers like the Tiwai aluminium smelter near Bluff and the Glenbrook steel mill, south of Auckland. The Eastern Bay of Plenty also shows the energy-intensive forest-processing industry.

Figure 1: Electricity demand by location

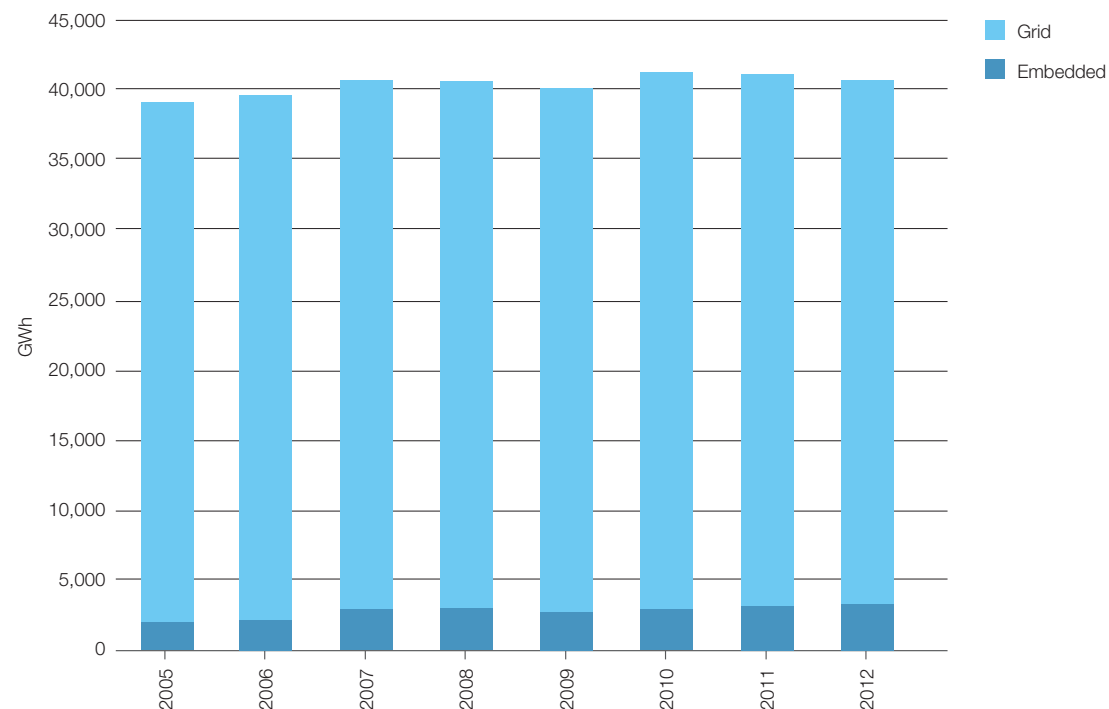


Total energy use in New Zealand has been flat over the past five years after fairly consistent growth. Figure 2 shows total supplied energy since 2005, comprising embedded generation and grid-supplied energy, and shows the flat supply since 2007.

Increased embedded generation is associated mainly with the Whitehill wind farm in Southland and the upgrade at the Ngawha geothermal plant in Northland. Some of the large embedded plant is effectively supplying the grid due to low local demand relative to the size of the generator.

There were a number of underlying factors at play in these aggregate numbers. The number of households and GDP have all continued to grow since 2007, and we would generally expect this to increase demand for energy. The 2008 dry year and a subsequent transformer failure reduced production at the Tiwai aluminium smelter in 2008–09. This reduced demand significantly in those years because the smelter is about 13% of national demand. The Christchurch earthquakes and the global recession also reduced demand. The net effect of these influences was the flat demand that we have observed over the last five years.

Figure 2: Total supplied energy, 2005–2012



Daily, weekly and seasonal patterns

Electricity demand has a number of patterns. There is a daily pattern with morning and evening peaks driven by households waking up and heating the house in the morning and cooking the evening meal. Overlaid on this is a weekly pattern of higher use during the week driven by commercial and manufacturing activity, and on top of this is the seasonal

pattern of higher use in the winter as people and businesses heat buildings. This causes the winter daily peak to be consistently in the evening, whereas the summer peak can be either the morning or the evening.

These patterns are shown in the following figures. Figure 3 shows how the year's demand is distributed over each half-hour trading period. The dotted line through the middle

of each rectangle shows the median consumption in each trading period for the year. The rectangles run from the lower to the upper quartile. The pattern of daily demand with morning and evening peaks is very clear.

Figure 4 shows how the year's demand is distributed over each day of the week. Demand is lower on weekends when many businesses are using less energy.

Figure 3: National demand by trading period, 2012

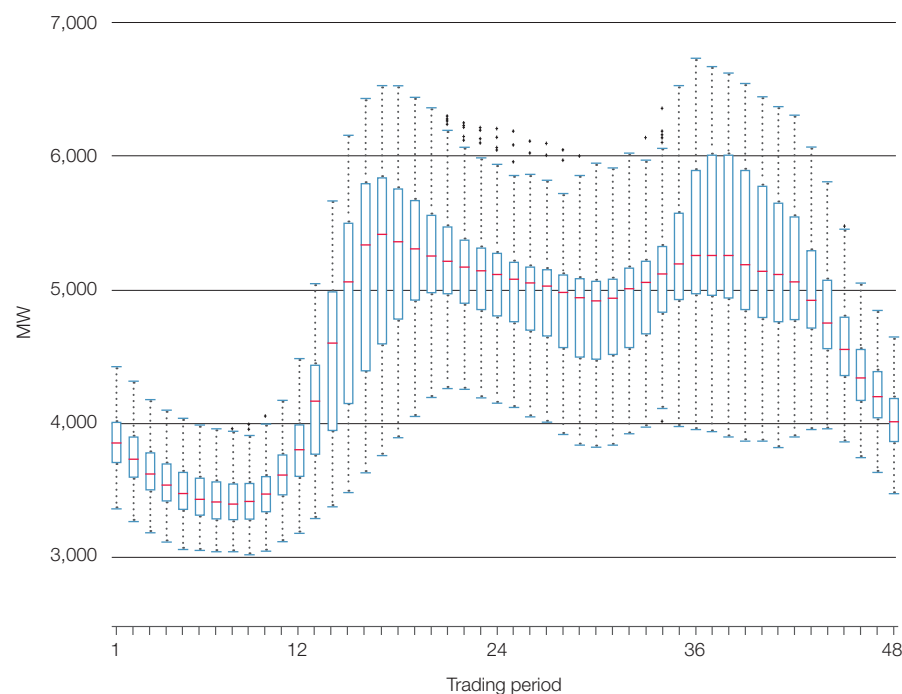
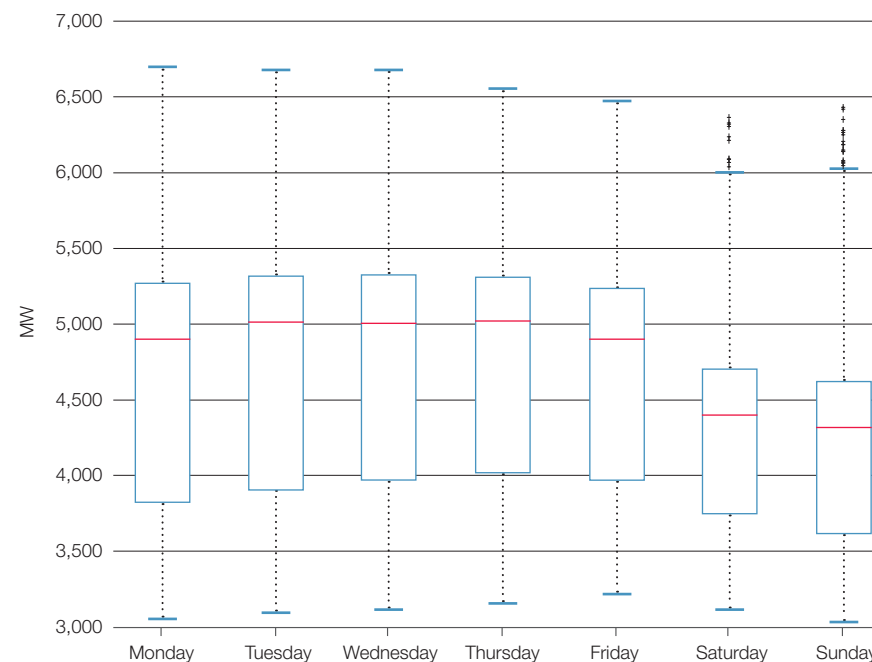


Figure 4: National daily demand, 2012



In the box and whisker plots, rectangles run from the lower to upper quartile. The upper horizontal line is the lesser of either the maximum value in the data or 1.5 times the interquartile range above the upper quartile. This is about 2.7 standard deviations. Conversely, the lower horizontal line is the greater of either the minimum in the data or 1.5 times the interquartile range below the lower quartile. Any outliers beyond the horizontal lines are shown as individual points.

Figure 5 shows the distribution of the year's demand for each month and the seasonal peak during the winter.

These patterns are not universal, and it is useful to look at counter-examples.

Figure 6 shows demand at the Ashburton grid exit point (GXP), which shows a 2.5-fold increase from 2003 to 2012 and a summer peak. The demand growth over 2008–2012 and the summer peak are unusual and caused by the increase in irrigation in this region.

Figure 7 shows monthly demand in the eastern South Island for 2012. The summer irrigation peak is clear, with a profile that is the opposite of the national profile shown in Figure 5.

Figure 5: National monthly demand, 2012

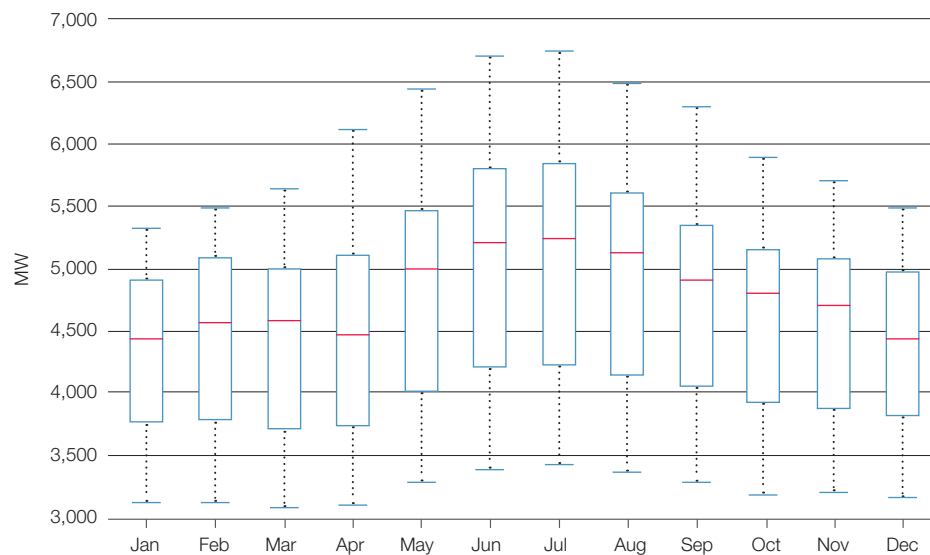


Figure 6: Demand at Ashburton GXP since 2002

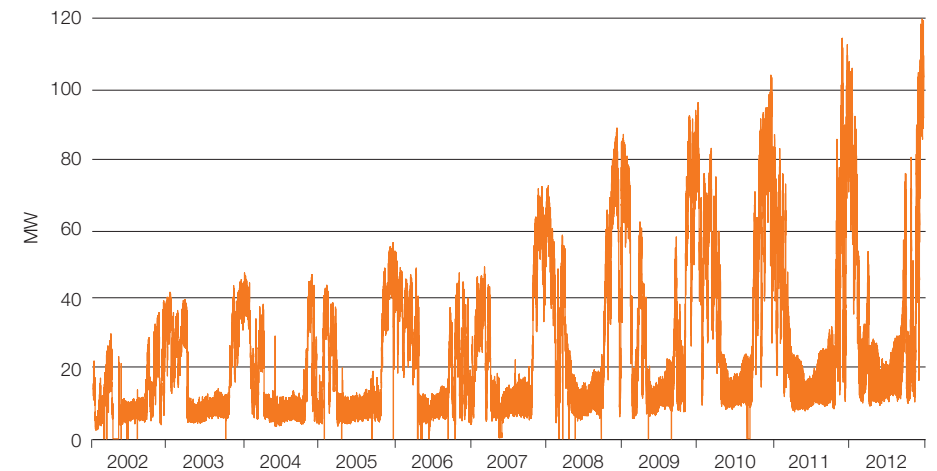
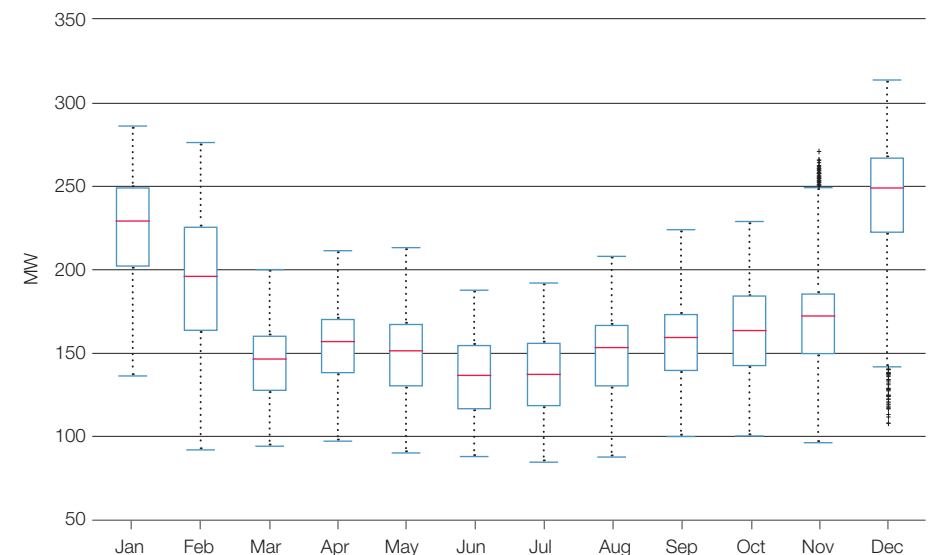


Figure 7: Monthly demand eastern South Island, 2012



Unpacking daily demand on the east coast of the South Island shows sharp drops in demand in the summer that correspond to rainy weather when irrigation is not needed. Figure 8 shows demand from Electricity Ashburton, Alpine Energy and Network Waitaki from November 2010 to March 2011. The figure shows a dramatic fall on 28 December 2010 when there was heavy rain in the area and a reduced need for irrigation.

Another counter-example is the demand from the Tiwai aluminium smelter. Figures 9 and 10 show the daily and monthly demand from Tiwai, reflecting almost constant demand through the day and small drops in January and April.

Figure 8: Eastern South Island rain event

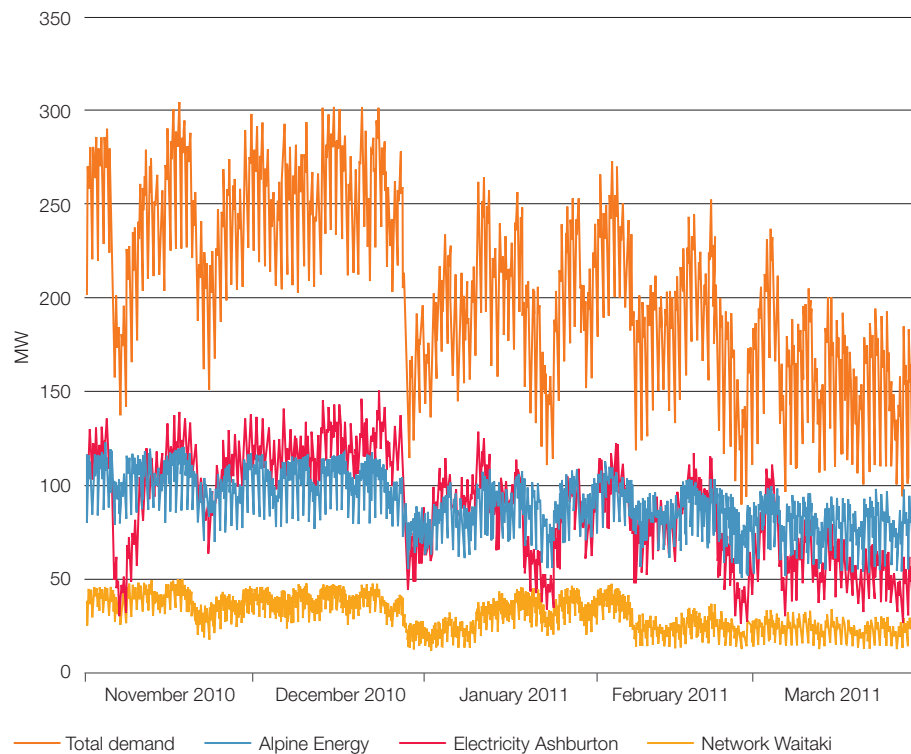


Figure 9: Demand at Tiwai aluminium smelter by trading period, 2012

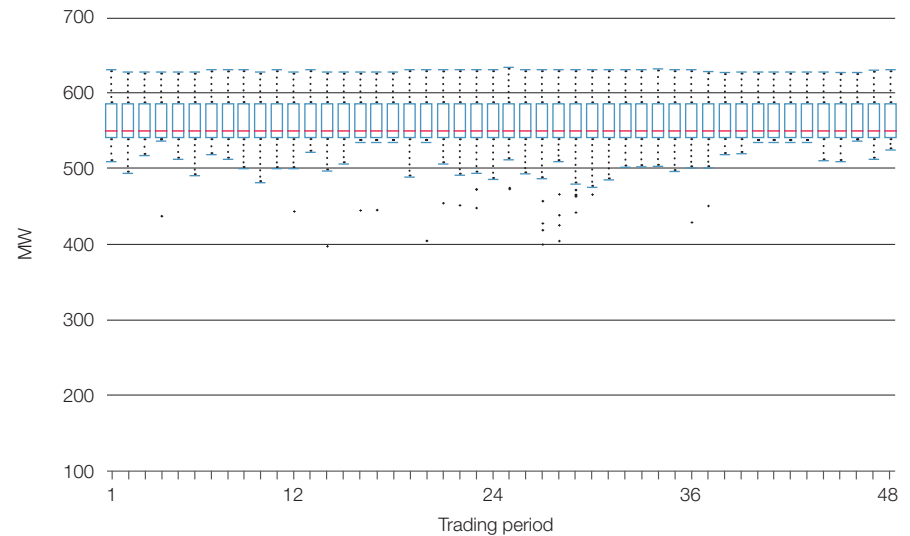
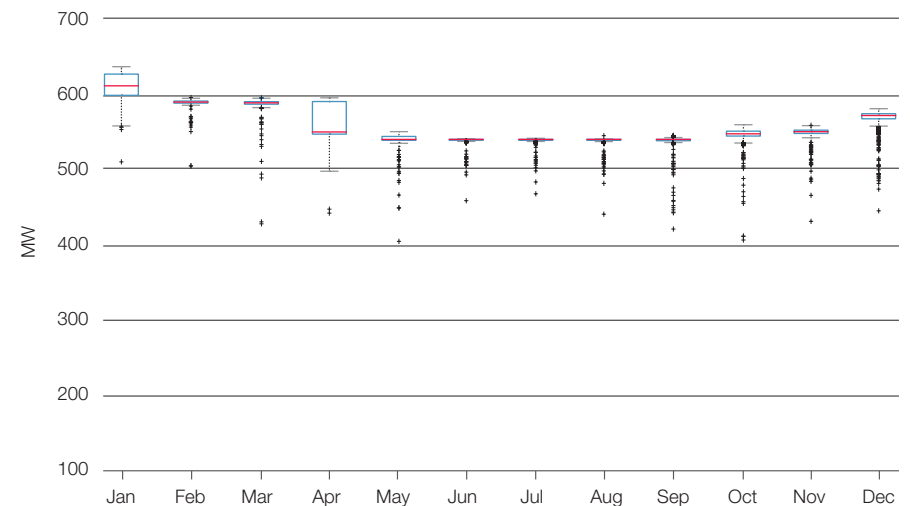


Figure 10: Monthly demand at Tiwai aluminium smelter, 2012



It's interesting to compare demand from Wellington city with Tiwai, as the Wellington peak is about the same as the Tiwai baseload.

Figure 11 shows Wellington demand for the year over a day split into half-hourly trading periods. The ratio of high demand to low demand is far greater than occurs nationally. This is because Wellington's demand comes from a very large proportion of residential customers, and it's these customers that cause the dramatic peaks and troughs in demand throughout the day.

Central Canterbury follows the national trend, with strong growth until the global financial crisis in 2008 where demand flattens. Figure 12 shows that demand fell sharply on the Orion network – about 10% – as a result of the February 2011 earthquake. It partially recovered in 2012. The September 2010 earthquake didn't have a discernible effect on demand.

Diversity of demand requires flexibility

The diversity of consumers' consumption patterns and growth patterns demonstrates the need for adaptive market arrangements. Consumers of electricity during periods where supply costs are reduced ought to access lower prices. A key point to note from the diversity of consumption patterns is the likely benefit from greater demand-side participation in our markets. A useful measure to consider in the future is the volume of consumption on contracts that use a fixed-price/variable-demand mechanism and the likely efficient costs of serving different demand profiles.

The diverse demand patterns help to explain the differences in energy prices for residential, commercial and heavy industrial consumers.

Figure 11: Wellington demand by trading period, 2012

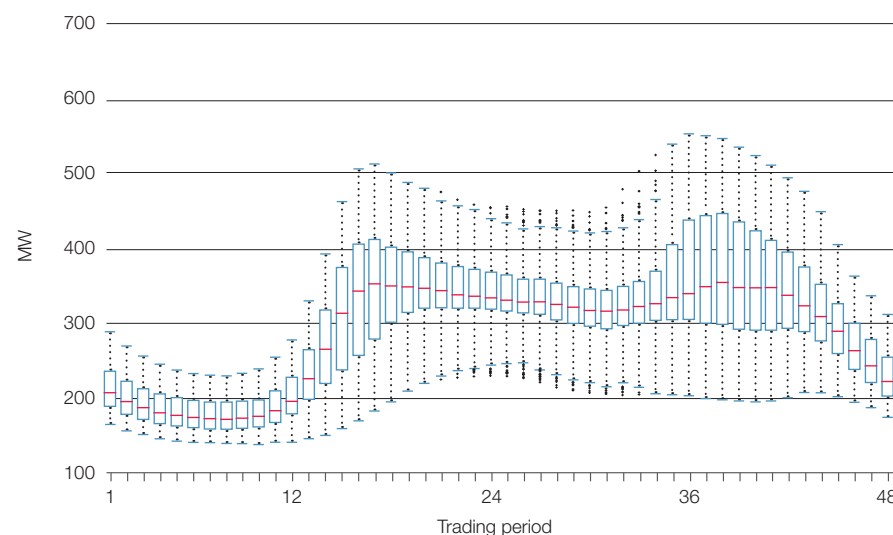
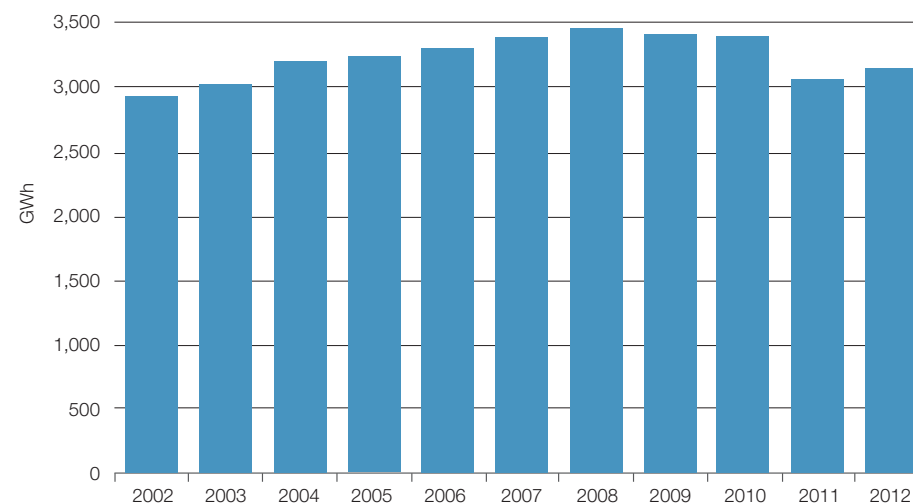


Figure 12: Total demand on the Orion network



An increasingly competitive retail market

The retail market in 2012 was characterised by sustained high levels of switching, reducing retailers' concentration in various regional markets and retailers aggressively chasing customers.

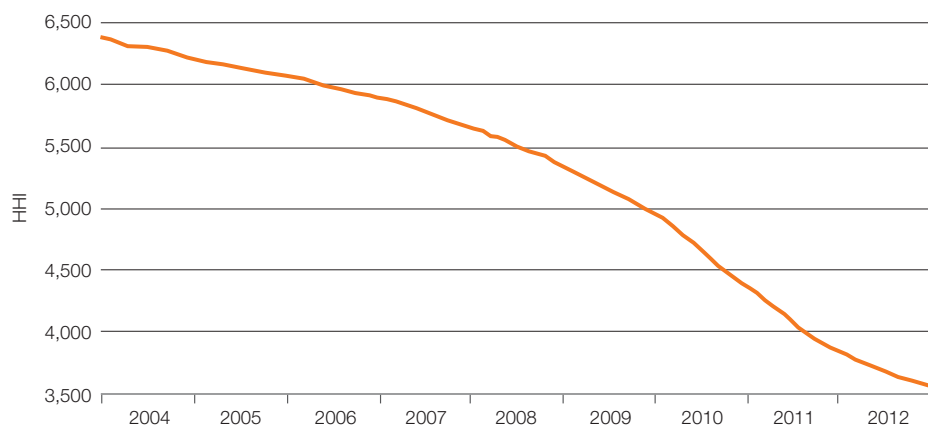
The retail electricity market varied greatly from region to region with retailers seemingly taking different approaches depending on their strategy in the region. It is difficult to analyse conduct in the retail market as it is so varied. We focused instead on structure and performance.

The retail end of the electricity market has evolved considerably through time. The market now has approximately 2 million active connections called installation control points (ICPs), an increase of about 200,000 since 2004. There has been significant change in the structure of this market throughout this time as retailers have competed to supply these ICPs. Figures 13 and 14 illustrate this change using the Herfindahl-Hirschman Index (HHI).

The HHI is the sum of the squares of the percentages of market shares. It is a measure of market concentration, and the relationship with competition occurs because less concentrated markets are likely to be more competitive. It has a maximum value of 10,000 for a monopoly, so the lower the number, the more indicative of a competitive market structure. Two things reduce the HHI: more participants and market shares becoming more even. These indicate a more competitive market; hence, we use HHI as a measure of market structure. By way of comparison, for merger and acquisition analysis, the US Department of Justice considers an HHI of 2,500 or above to be highly concentrated and an HHI of 1,500–2,500 to be moderately concentrated.

Figure 13 shows how the national average HHI has declined between 2004 and 2012, and Figure 14 shows how this decline was distributed nationally.

Figure 13: National average retail market HHI



National average HHI is the connection (ICP) weighted average of the regional HHI by retail parent companies.

Focusing on 2012, the right-hand map in Figure 14, where green corresponds to lower HHI, shows less concentrated and likely more competitive markets. The map shows concentration is lowest in Auckland, parts of Northland, parts of the Waikato and Otago and highest (reddest) in the Bay of Plenty, King Country, the West Coast of the South Island and Waitaki Valley.

Figure 14: Change in retail market HHI between 2004 and 2012

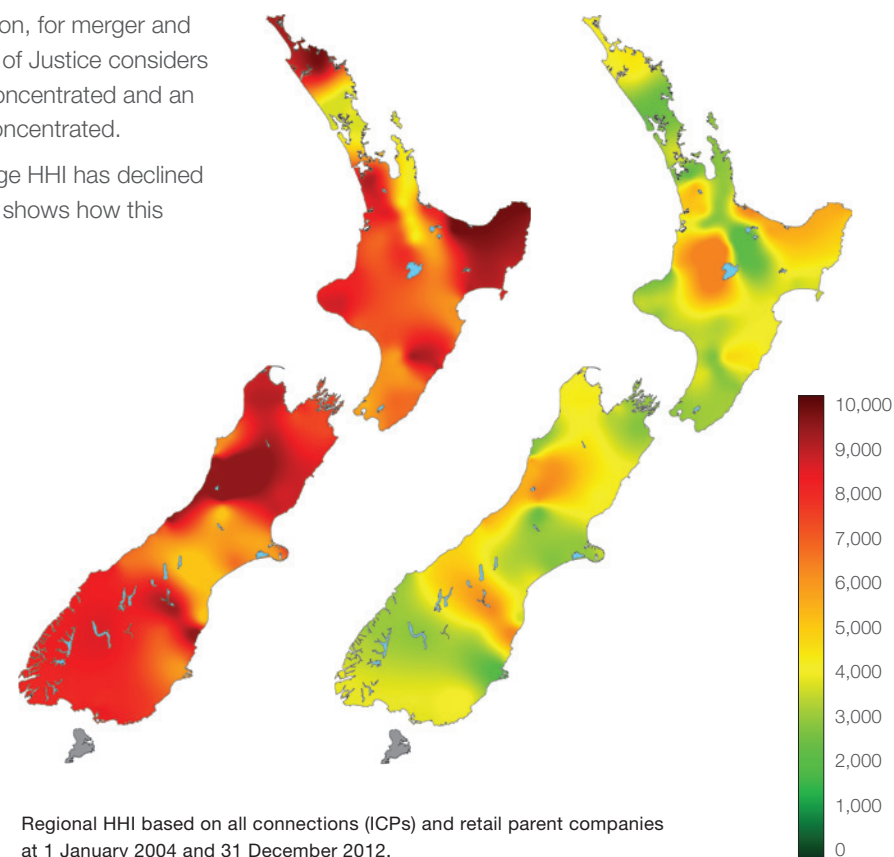
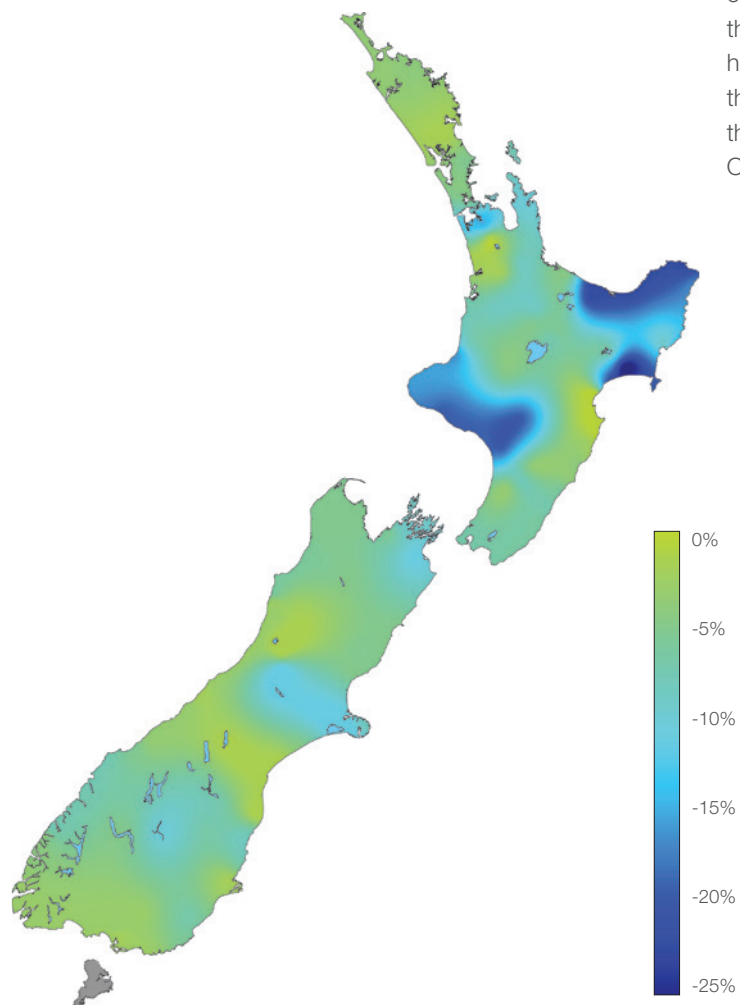


Figure 15: Percentage change in retail market HHI in 2012

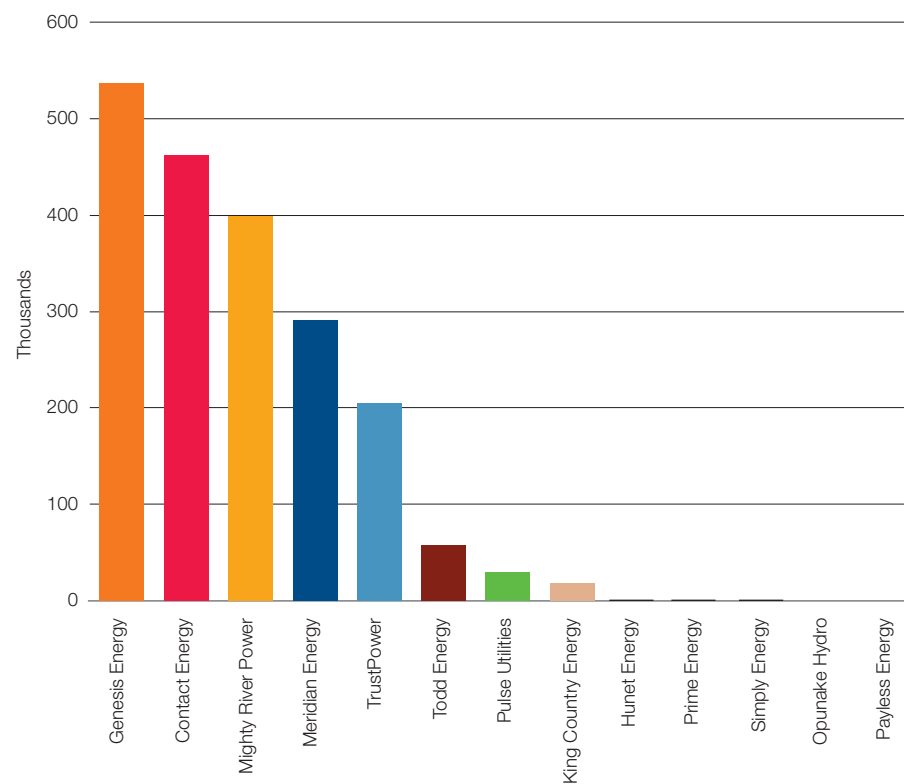


HHI based on all connections (ICPs) and retail parent companies.
Percentage change is the change during the year as a percentage of the HHI at 1 January 2012.

Figure 15 shows that the HHI decreased in the retail market over the whole country in 2012. The Bay of Plenty, where the right-hand side of Figure 14 shows the HHI is high, has had a 25% drop in HHI. This is encouraging as it indicates that retailers are viewing the relatively high concentration in the Bay of Plenty as an opportunity to enter and compete. Other areas that improved were Taranaki and Canterbury.

Figure 16 shows the number of connections by retail parent company in New Zealand. The market is split into large and established retailers and smaller entrants. Part of the reason the HHI shown in Figures 14 and 15 has been decreasing is the number of entrants. Again, this is an encouraging sign that the market is moving to a more competitive structure.

Figure 16: Number of connections by retail parent company



Based on active connections (ICPs) at 31 December 2012.

Some contrast to the whole retail market can be gained by looking at a smaller segment of the market. Small and medium-sized enterprise² (SME) connections totalled approximately 270,000 in 2012. Figure 17 shows the level of HHI for retailers competing for SME customers in 2012, and Figure 18 shows how this HHI has changed over the year. The most concentrated areas for this market segment are the King Country, the East Coast/Eastern Bay of Plenty and the Waitaki Valley. The HHI fell the fastest in Central Canterbury and the Eastern Bay of Plenty – a good sign that this area where HHI is highest (competition is likely to be weakest) is also the area where HHI fell fastest.

² Small and medium-sized enterprise (SME) connections are ICPs with ANZSIC codes (as at 30 November 2012) that are supplied through category 1 or 2 meters as defined in the Code. ICPs relating to central and local government services along with other utility services have been excluded.

Figure 17: HHI for the SME segment of the retail market, 2012

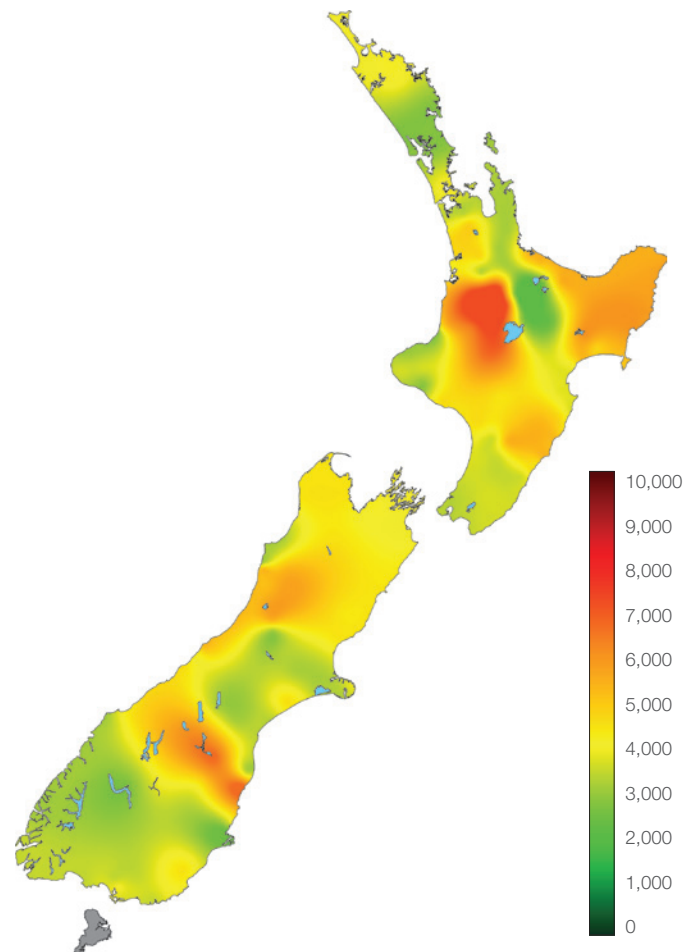
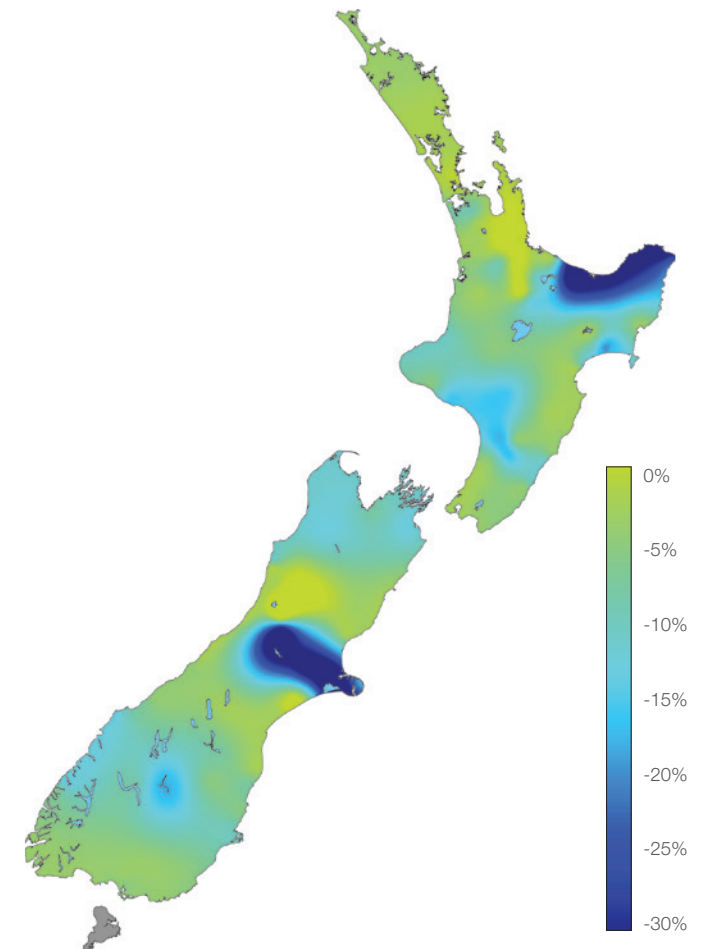


Figure 18: Percentage change in HHI for the SME segment of the retail market, 2012



HHI based on active SME connections (ICPs) and retail parent companies at 31 December 2012.
Percentage change is the change during the year as a percentage of the HHI at 1 January 2012.

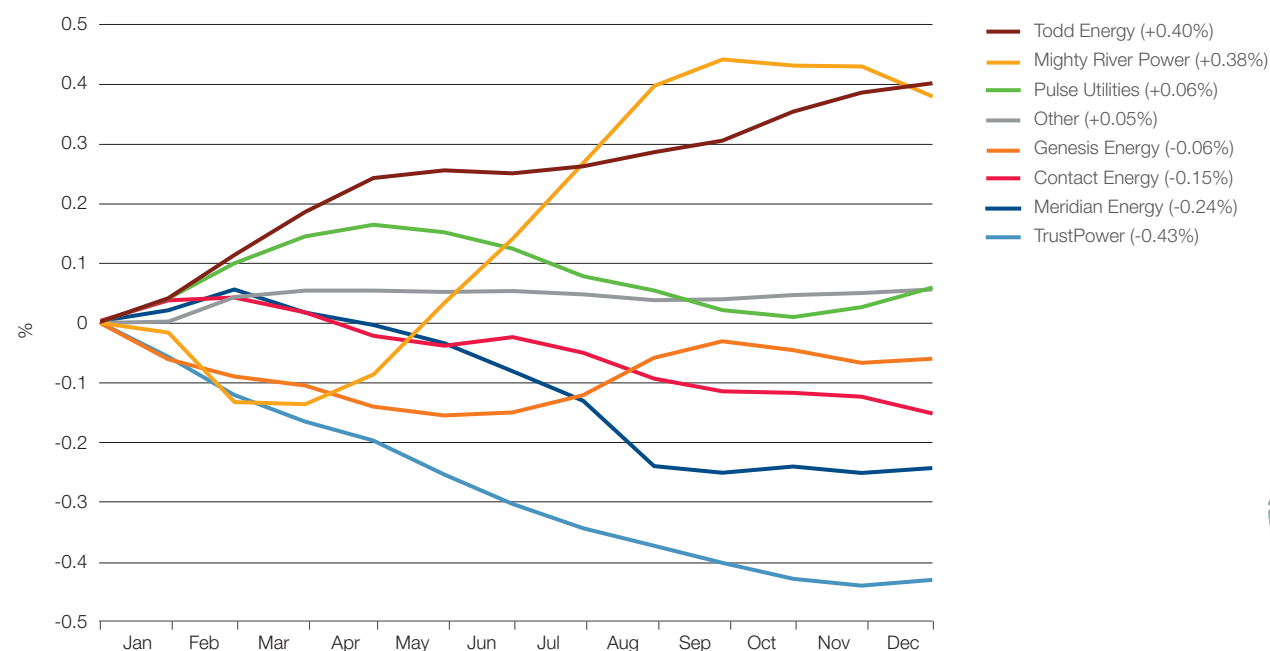
Figure 19 shows the percentage change in national market share for each large retail parent company during 2012. Mighty River Power and Todd Energy made the most significant gains. TrustPower and Meridian Energy lost the greatest percentage of national market share in 2012.

Customers changing suppliers is one way they can exert pressure for lower prices. In the retail market, this is reflected in levels of customer switching. Nationally, switching levels stayed strong but dropped back from record levels of 19.5% in 2011 to 18% in 2012.

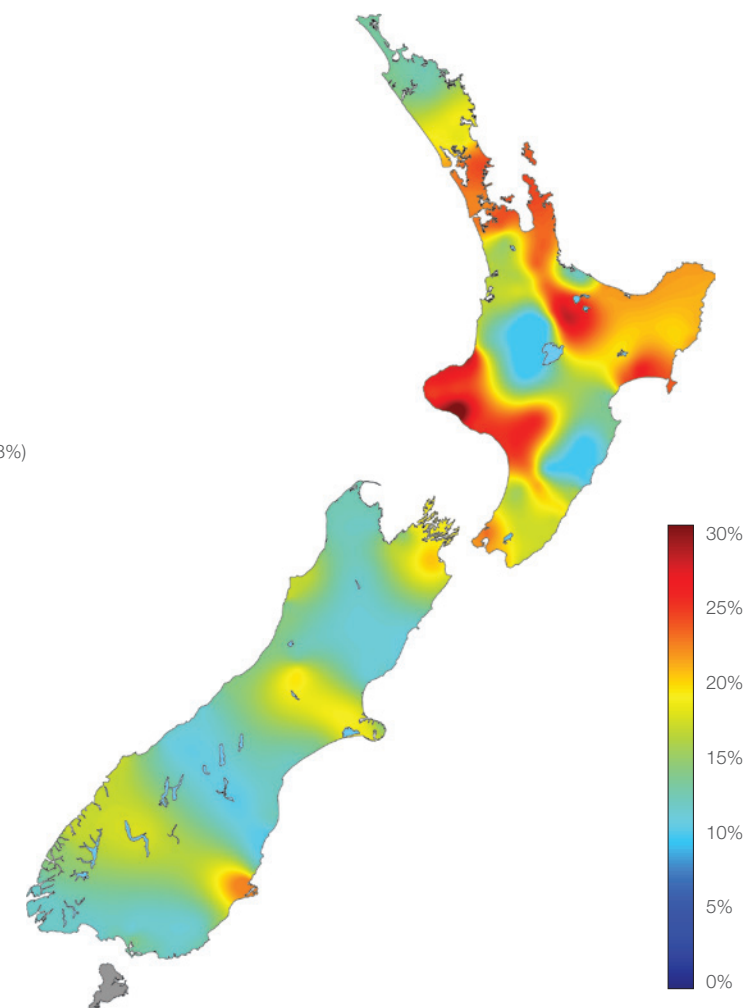
Figure 20 shows 2012 switching regionally as a percentage of the market size. Taranaki, East Coast, the eastern Waikato and Auckland were hot spots in the North Island, while Dunedin had the highest switching rates in the South Island. These areas are mostly the same as the areas in Figure 15 where the HHI changed fastest.

Figure 20: Relative switching rates in 2012

Figure 19: Percentage change in national market share for main retail parent companies in 2012



Market share is of active connections (ICPs). 'Other' combines results for companies that did not exceed 1% national market share during the year. The values in parentheses denote the change over 2012.



Relative switching rates are based on switches during 2012 as a percentage of mean active connections (ICPs) during the year within each region. Switches exclude bulk transfers of ICPs between retailers.

Splitting the national market share into the North Island and South Island and also separating traders³ from their parent companies is revealing. Figure 21 shows the North Island changes in customer numbers by energy trader, and Figure 22 shows the South Island.

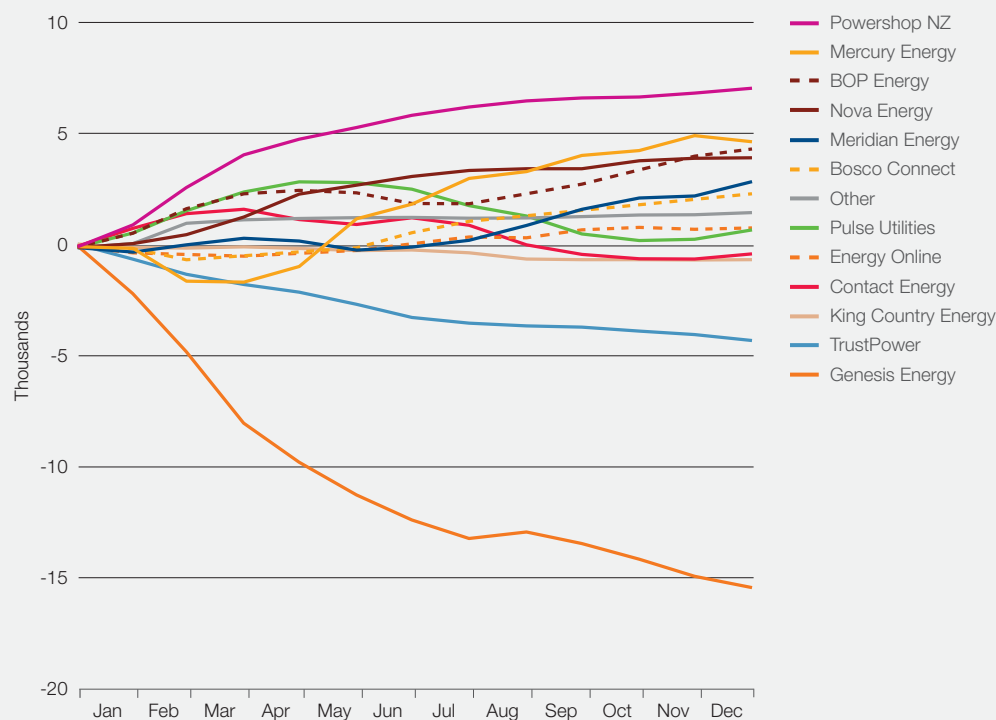
³ Traders manage retailer ICP data in the registry and consumption details for the reconciliation process.

They show Meridian Energy lost customers in the South Island and its subsidiary Powershop NZ held steady – possibly due to the dry conditions in the South Island and the impact this had on Meridian Energy's generation. In contrast, Powershop NZ gained rapidly in the North Island while Meridian Energy's customer numbers remained steady.

Genesis Energy's relatively neutral national position masks large losses in the North Island and corresponding gains in the South Island. Its subsidiary, Energy Online, remained steady in the North Island and does not retail in the South Island.

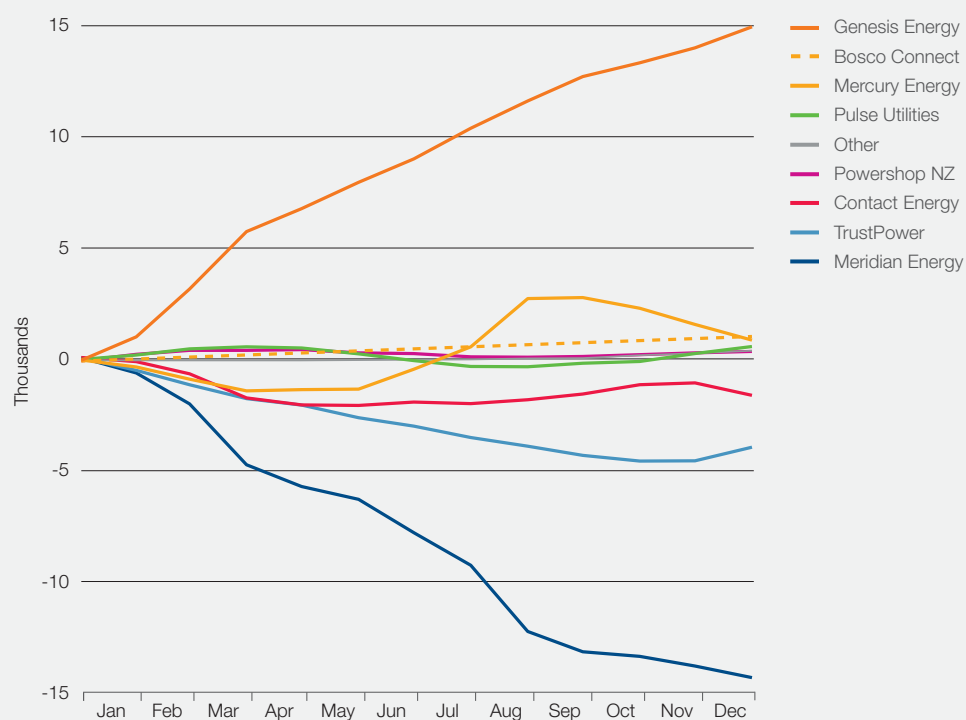
Mercury Energy and Bosco Connect gained in both islands, but more strongly in the North Island. Both are owned by Mighty River Power.

Figure 21: North Island changes in trader ICP numbers, 2012



'Other' combines results for traders that did not exceed 0.5% market share of each respective island during the year.

Figure 22: South Island changes in trader ICP numbers, 2012



More detail can be seen in the sequences of maps in Figures 23 and 24. Figure 23 shows the monthly change in Genesis Energy's regional market share over the year. The consistent gains in the South Island and losses in the North Island reflect the new geographic locations of Genesis Energy's generation portfolio that resulted from the asset swaps of January 2011. The fact that generators aligned retail and generation geographically hints at the locality risk of trading in New Zealand and the importance of the hedge market and financial transmission rights. These areas are both a major focus for the Authority and will contribute to a market environment with fewer distortions caused by location.

In contrast to Genesis Energy's strategy, Mighty River Power appeared to have taken a region by region approach to gaining market share. Figure 24 suggests different areas have been the subject of intense acquisition by Mighty River Power over the year.

It's revealing to contrast the fortunes of two large retailers in regions where the HHI has been high and competition is likely to have been weak. In Marlborough, TrustPower had almost 80% market share in 2008. By 2012, this fell below 50% (Figure 25). In contrast, Figure 26 shows that King Country Energy had over 80% market share in 2008, and while this has fallen slightly to 75%, it remains one of the network regions with the highest HHI in the North Island.

This is a case where the structure of the market doesn't tell the full story. The King Country is where we can speculate that the threat of entry is disciplining an incumbent retailer. In contrast, in the Marlborough region, we observe the entry of several new retailers and a decline the incumbent retailer market share.

Stepping back to the national picture, it is useful to use another measure of market structure to compare with the HHI. The concentration ratio (CR) measures the sum of the market shares for the largest retailers – the higher the number, the more concentrated the market is. We chose CR4, the sum of the market shares for the top four parent retail companies, because the market started with four large

Figure 23: Monthly change in market share for Genesis Energy

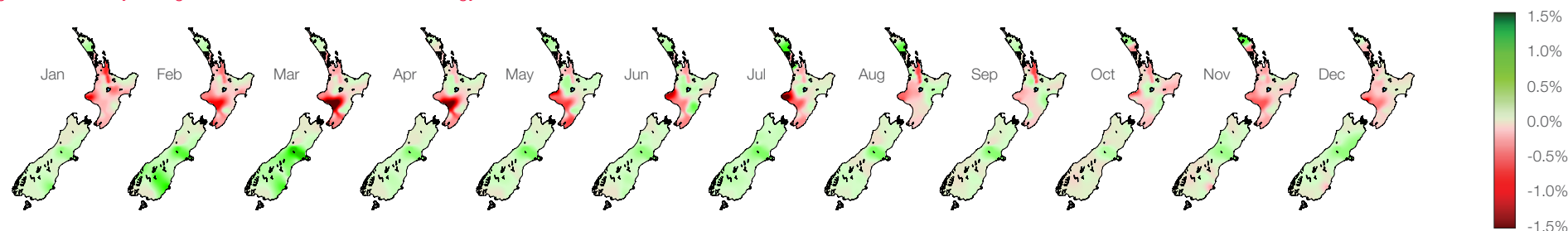
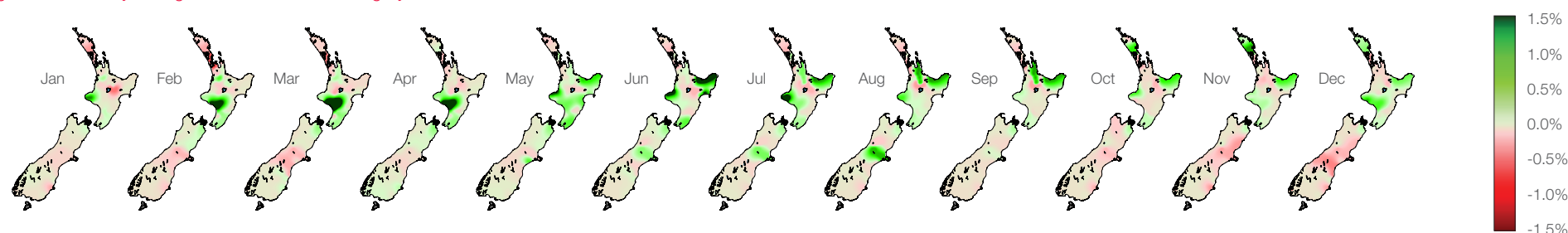


Figure 24: Monthly change in market share for Mighty River Power



generation-retail companies (gentailers), and CR4 will help identify how the structure has changed. It should be noted that these four gentailers are not the dominant players in every region.

The national average CR4⁴ at the beginning of 2011 was 97%. This is high in an absolute sense, showing the majority of market share is held within the four largest companies

⁴ National average CR4 is the connection (ICP) weighted average of the regional CR4 by retail parent companies.

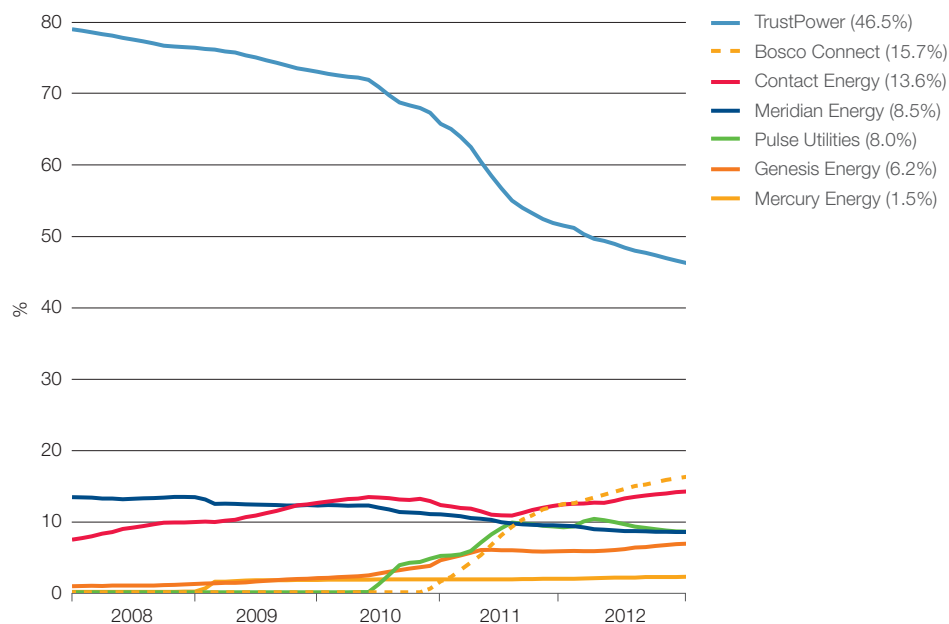
in most regional markets. The national average HHI at the beginning of 2011 was 4,385. At the end of 2012, the CR4 decreased to 95% and the HHI dropped to 3,580.

When interpreting these numbers, it helps to use a benchmark. If the four largest retailers split the market evenly and there were no other participants in the retail market, the CR4 would be 100% and the HHI would be 2,500. Comparing these benchmarks with the actual numbers shows that the HHI is getting close to its

benchmark. The CR4 is decreasing, although is still relatively close to the level we would see if four large players split the market.

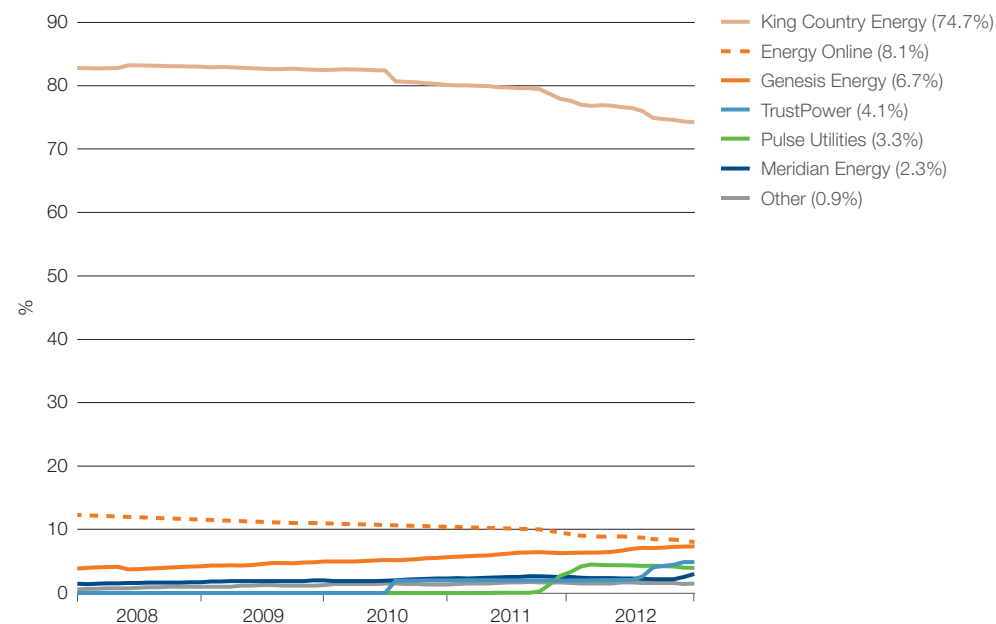
Given this situation, the overall level of competition in the retail market is one of reducing regional market concentration with some new independent retailer entry and growth slowly having an effect on the dominance of the main retailers. Generally, the retail market continues to head towards a more competitive market structure.

Figure 25: Trader market share trends in the Marlborough (Marlborough Lines) network region, 2008–2012



The values in parentheses denote the market share at 31 December 2012.

Figure 26: Trader market share trends in King Country (The Lines Company) network region, 2008–2012



The residential segment of the retail market consists of 1.7 million or 84% of active connections. Over time, a competitive retail market structure should drive competitive outcomes and benefits for consumers. In Figures 27 and 28, we show the relationship between market structure and price⁵ for the residential segment of each regional retail market. These figures connect market structure and market performance as measured by price under the structure, conduct and performance framework.

The plots show the change in relative market concentration and relative price during the year. The horizontal axis is regional HHI relative to national average HHI. A positive value indicates a more concentrated and less competitive market structure than average. Conversely, a negative value is a more competitive and less concentrated market structure than average.

The vertical axis is the average price paid by residential consumers relative to the average price offered by retailers in the region. Essentially, a positive value means that, on average, consumers are paying above the mean tariff available, and a negative value means consumers are taking advantage of the lower-priced offers and are paying less than the mean offer.

More generally, the lower left quadrant has low concentration and relative price – so there is a competitive market structure and consumers benefiting from the competitive prices. In contrast, the upper right quadrant has high concentration, with most consumers not benefiting from the competitive offers.

The change during 2012 is illustrated by looking at each region at two points in time. The open circle denotes the situation at 1 January and is connected by a line to a closed circle showing the situation at 31 December. This illustrates how the regional markets have moved and takes into account both changes in relative pricing by retailers and switching of consumers.

Looking at the regional markets, movement downwards to more competitive prices occurs more often than movement up in both islands, with 28 of 39 regions moving in this direction. Note that the average regional price increased over the year, so while more consumers are getting relatively better deals, absolute prices are rising (see Figure 29). For market concentration, 15 of the 39 regions shifted to the left, illustrating a decrease in relative market concentration during the year.

Although there were only two regions ending the year with an average price less than the mean offer in the South Island, there was about the same proportion of residential ICPs or customers in these regions, with 43% in the South Island compared with 46% in the North Island. If we consider the proportion below the 2% relative price line, we see a greater difference, with 95% of ICPs in the North Island below the line and only 81% in the South Island.

Switching was about the same on the more competitive side of the vertical axis in both islands but significantly higher in the North Island on the less competitive side. This indicates consumers and/or retailers acquiring market share are more active in these North Island regions.

Generally, there are more regions with consumers paying above the mean offer price in the South Island and at a higher margin above competitive offers than in the North Island. This comparison indicates the North Island regional markets are more competitive than the South Island, although we are encouraged to see things improved during 2012 and moved in the right direction.

This analysis is supported by Figures 15 and 20, which show that, for the whole of the retail market, switching is higher and HHI falling faster in the North Island. North Island consumers had more choice and exercised it more often.

As previously identified, HHI was high in the King Country (region 9) and Marlborough (region 26) and that the incumbent was losing market share in Marlborough but not in the King Country (Figures 25 and 26). Clearly, the relative price is high in Marlborough and low in the King Country, suggesting the threat of entry may have been controlling prices in the King Country but not in Marlborough.

⁵ Analysis of residential retail prices is based on a bottom-up approach. It takes into account: all residential consumers; the average monthly residential consumption within each region; each consumer's electricity supplier, including any changes; pricing plans for standard metering configurations for each retailer in each region and any price changes that occur. Plan tariffs are sourced from the Powerswitch database, and selection depends on annual consumption in the region. Some weightings are applied where there are multiple standard plans available, for example, we assume 36% of Contact's customers are on the Online OnTime plan in 2012 (*Energy News* 15 August 2012).

Figure 27: Change in relative price and concentration during 2012 in the residential retail market, North Island

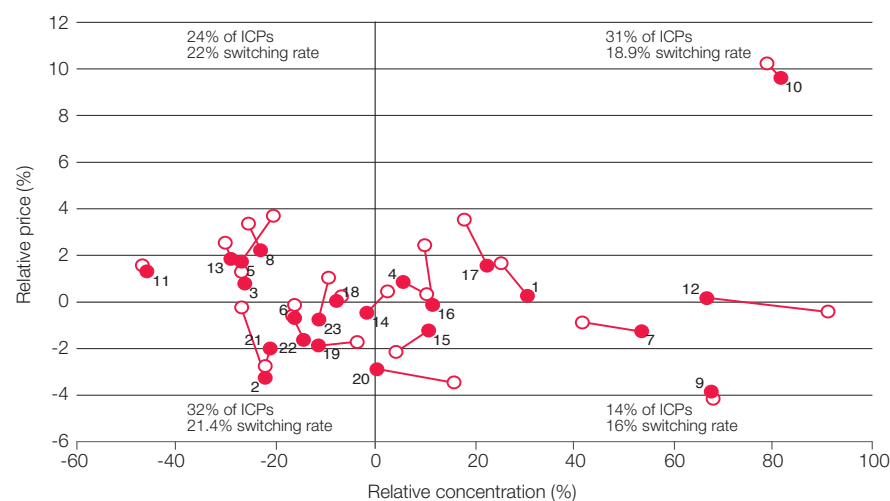
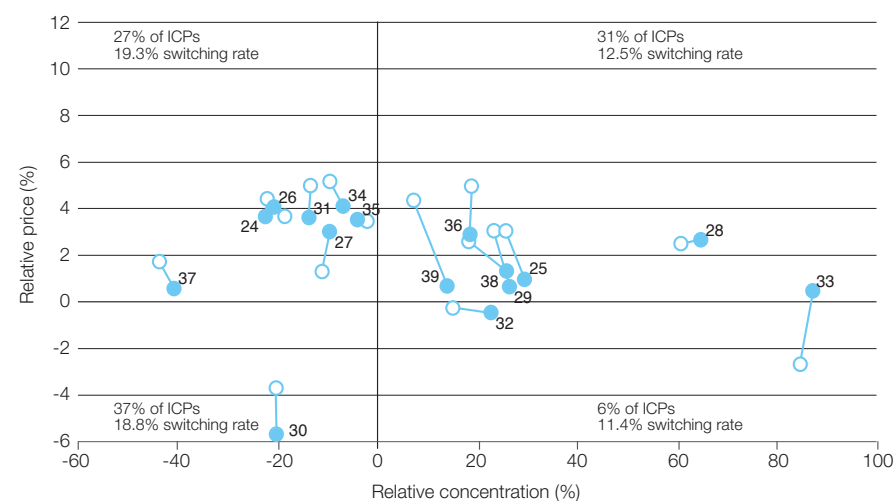


Figure 28: Change in relative price and concentration during 2012 in the residential retail market, South Island



See Table 1 for network region identifiers. Open circles are at 1 January, and closed circles are at 31 December 2012. Proportions of switching and ICPs are based on residential switches during the year and residential ICPs at 31 December 2012. HHI used to calculate relative concentration is based on traders responsible for residential ICPs in this analysis.

Table 1: Network regions

1	Bay of Islands (Top Energy)	11	Rotorua (Unison Networks)	21	Manawatu (Powerco)	31	Ashburton (Electricity Ashburton)
2	Whangarei and Kaipara (Northpower)	12	Eastern Bay of Plenty (Horizon Energy)	22	Kapiti and Horowhenua (Electra)	32	South Canterbury (Alpine Energy)
3	Waitemata (Vector)	13	Taupo (Unison Networks)	23	Wellington (Wellington Electricity)	33	Waitaki (Network Waitaki)
4	Auckland (Vector)	14	Eastland (Eastland Network)	24	Nelson (Nelson Electricity)	34	Queenstown (Aurora Energy)
5	Counties (Counties Power)	15	Hawke's Bay (Unison Networks)	25	Tasman (Network Tasman)	35	Central Otago (Aurora Energy)
6	Thames Valley (Powerco)	16	Central Hawke's Bay (Centralines)	26	Marlborough (Marlborough Lines)	36	Otago (OtagoNet JV)
7	Waikato (WEL Networks)	17	Southern Hawke's Bay (Scanpower)	27	Buller (Buller Electricity)	37	Dunedin (Aurora Energy)
8	Waipa (Waipa Networks)	18	Wairarapa (Powerco)	28	West Coast (Westpower)	38	Southland (The Power Company)
9	King Country (The Lines Company)	19	Taranaki (Powerco)	29	North Canterbury (MainPower NZ)	39	Invercargill (Electricity Invercargill)
10	Tauranga (Powerco)	20	Wanganui (Powerco)	30	Central Canterbury (Orion New Zealand)		

Figure 29 shows the change in average price (including GST) paid by residential consumers per kilowatt hour (kWh). This is a measure of absolute price and includes transmission and distribution charges as well as energy charges.

Figure 29 shows that the total average cost of electricity increased over the last three years by about 5% per year. The GST increase from 12.5% to 15% in October 2010 impacted price. However, inflation over this period had been about 2.14%. Retailers tend to increase their charges at

the time when distribution and transmission charges are increased, which is shown in the Q3 jumps in prices. There was no discernible jump in 2011, perhaps because of the very high level of switching that was occurring at that time.

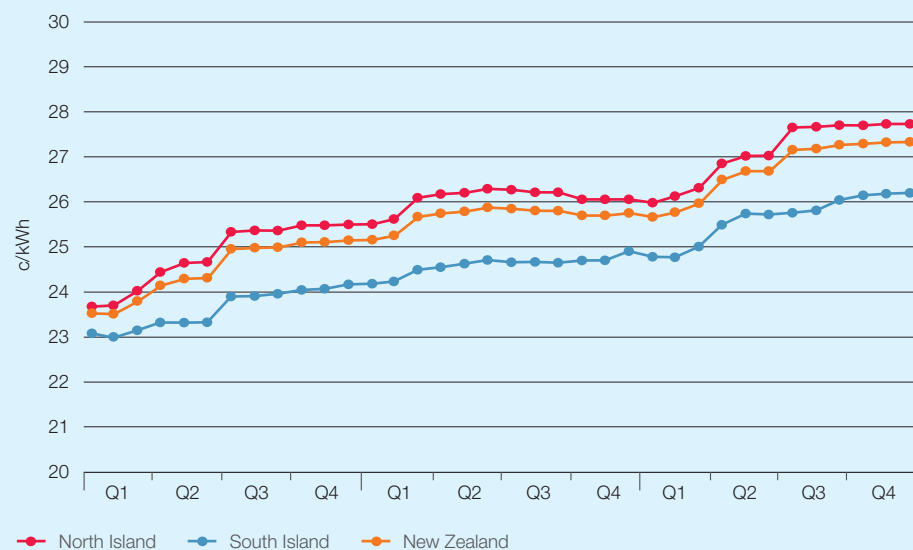
Rapid growth in smart metering

At the end of 2012, there were 820,000 ICPs with installed smart meters or advanced metering infrastructure (AMI). Figure 30 shows AMI growth over time from 2008 to 2012.

Figure 31 shows retail parent company market share of residential, connections and indicates what proportion of customers have AMI installed.

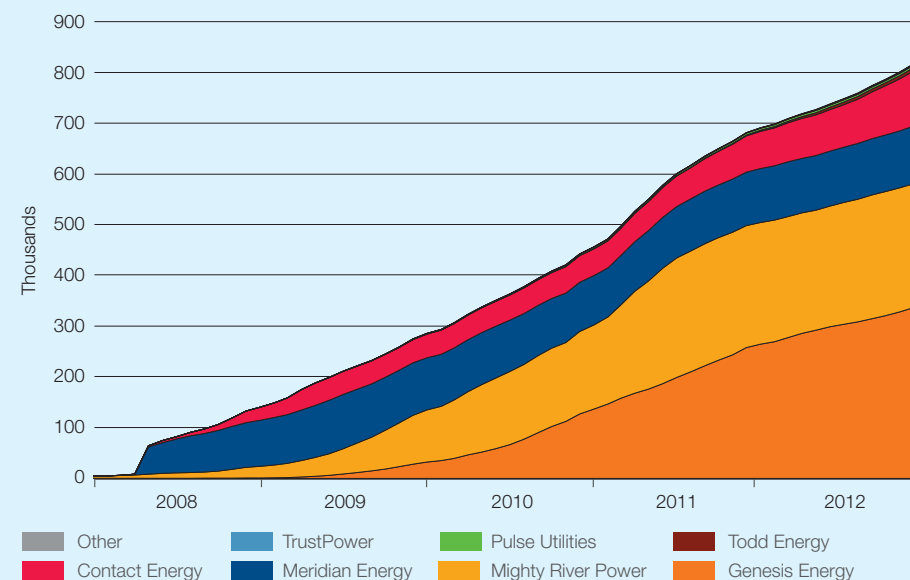
The shift to AMI is significant, with the technology driving improvements in reconciliation accuracy, reducing cost to serve, supporting better information provision to consumers and enabling the potential for different tariff structures. This is particularly relevant for residential consumers, where their consumption drives the daily peaks in demand and, in turn,

Figure 29: Average residential price per kWh in nominal terms, 2010–2012



North Island and New Zealand prices excludes the impact of the King Country (The Lines Company) network region where consumers are billed independently for network charges.

Figure 30: Growth in installed AMI by retail parent company



This data is based on the trader recorded in the registry for an ICP at any point in time. It does not necessarily reflect who installed the AMI, as ICPs may switch suppliers.

these peaks drive a lot of cost in the electricity sector in transmission and peaking plant. Effectively, this means that energy is more expensive at peak times, as reflected in the wholesale price. Generally, the nature of the retail market is that consumers pay a fixed price and therefore face the average cost of energy.

AMI can enable time-of-use tariffs necessary for consumers to face the cost of their consumption in real time, providing incentives to reduce demand at peak times and therefore costs.

Retail innovation

Part of the innovation in the retail market is branding. There are some parallels to what has happened in the airline industry over the last 10 or 15 years where budget carriers owned by established carriers have segmented the market by offering a differentiated service mostly based around low cost. In the retail electricity market, the rebranding doesn't necessarily mean lower tariffs but segmentation more generally. Powershop NZ, for example, has a greater online presence than other retailers and aims for more technology-

savvy customers. In contrast, Tiny Mighty, a subsidiary of Bosco Connect, has a greater presence in rural areas and focuses more on face-to-face interactions.

In a competitive retail market, consumers should benefit from innovation as companies respond to pressure and seek ways to reduce costs and provide enhanced services. We asked retailers about innovation in their retail offerings during 2012. There were some clear themes that came back in the replies.

The use of smart metering information appears to be driving much of the innovation we see. Along with reducing the costs to serve customers, 2012 saw several retailers undertake and expand pilot programmes, introducing time-of-use styled tariffs and energy management tools that help customers manage their consumption.

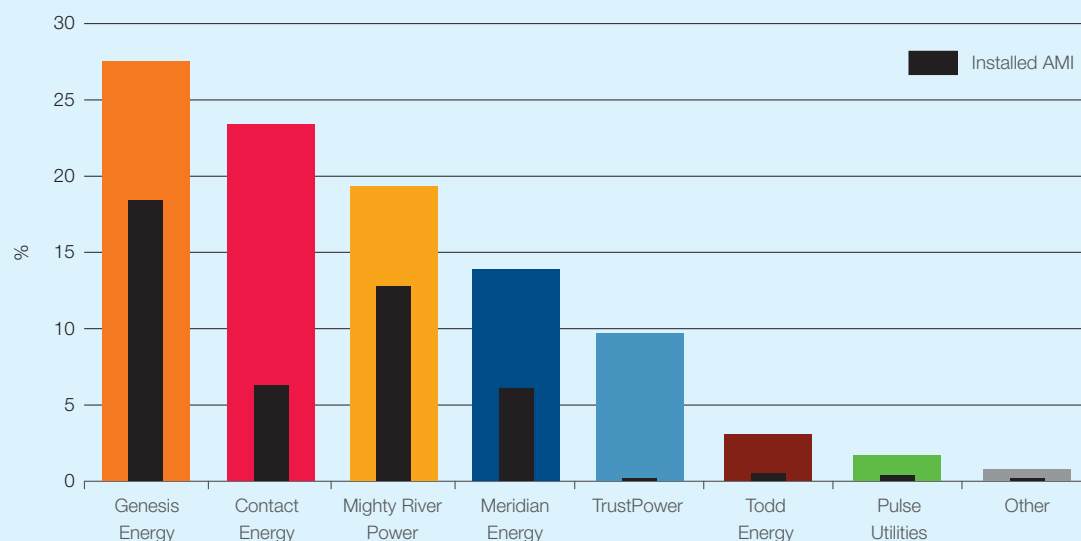
More generally, we see smart meters facilitating improved customer interfaces and increasing the accuracy and timeliness of information available to consumers. This is driven through websites and smartphone applications and continues to channel customer interaction to these media.

2012 has seen options where electricity can be bundled with other services continuing to be offered by several retailers. Additionally, we see many partnered product promotions occurring in this space.

Another development was Meridian Energy splitting out the distribution and transmission costs from the energy costs in its billing information. This improves the transparency of information that customers get and helps explain what is driving price changes. This is important for retailers who pass transmission and distribution charges – that they do not control – on to consumers.

The Authority will continue to monitor and report on innovation as it is an important part of conduct in a competitive market.

Figure 31: Retail parent company market share of residential ICPs and installed AMI at 31 December 2012



'Other' combines results retail for parent companies that did not exceed 1% market share of the residential market during the year.

A very good year for the hedge market

The hedge market is integral to the operation of the electricity system because it enables generators and retailers to lock in prices, providing certainty about wholesale market costs. A transparent and robust hedge market is therefore beneficial for competition as it allows generators and retailers that are not physically hedged (i.e. those who do not generate and retail in the same region) to manage their spot price risk.

2012 was a very good year for the hedge market. It saw increased activity driven by new market-making agreements for ASX hedges, narrowing bid-ask spreads on the ASX, a challenge from record low hydro inflows early in the winter and significant innovation.

The Authority's biennial survey of hedge market participants showed that, for the first time, participants were positive about its competitiveness. However, there is some way to go, with distinctly polarised views between those using the over-the-counter (OTC) market and those using the ASX market. Those purchasing on the OTC market were far less supportive of the notion that competition had improved than those using the ASX.

ASX activity increases

There was a big increase in activity on the ASX, driven in part by market-making agreements introduced in November 2011, which have resulted in greater liquidity and more

dynamic trading. Figure 32 shows the increase in trading volumes that coincided with the new market-making agreements at the beginning of 2012.

February 2012 saw record trading volumes on the ASX, and March saw record trading of Otahuhu futures on the ASX. This may be due to the winter storage situation becoming clear and energy purchasers moving to cover their positions using ASX hedges.

It suggests that participants are using the ASX futures to help manage their spot price risk and that the ASX has sufficient depth to enable this. The Authority continues to work with market makers to promote favourable developments.

Figure 32: Increased trading volumes for ASX hedges

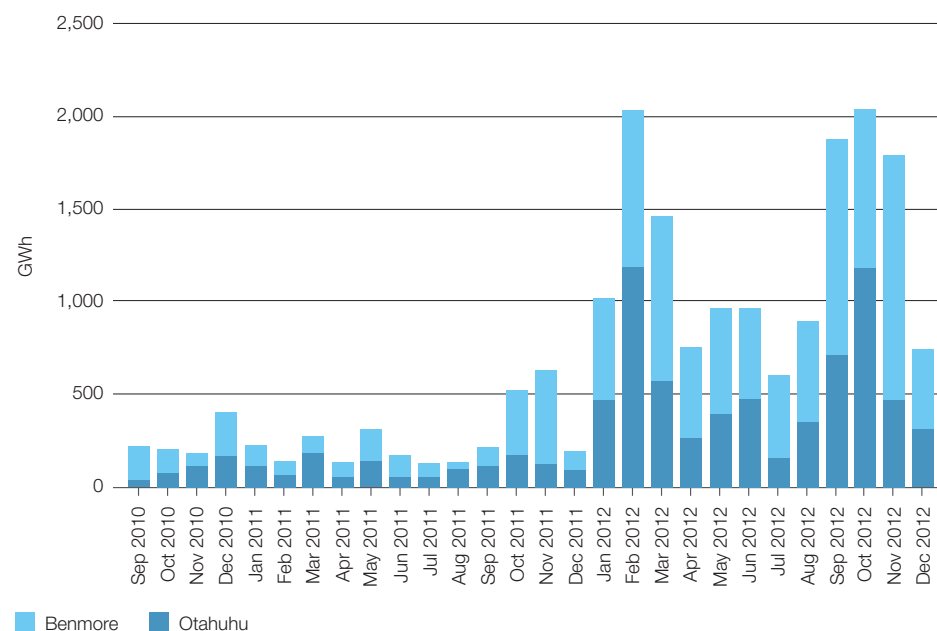
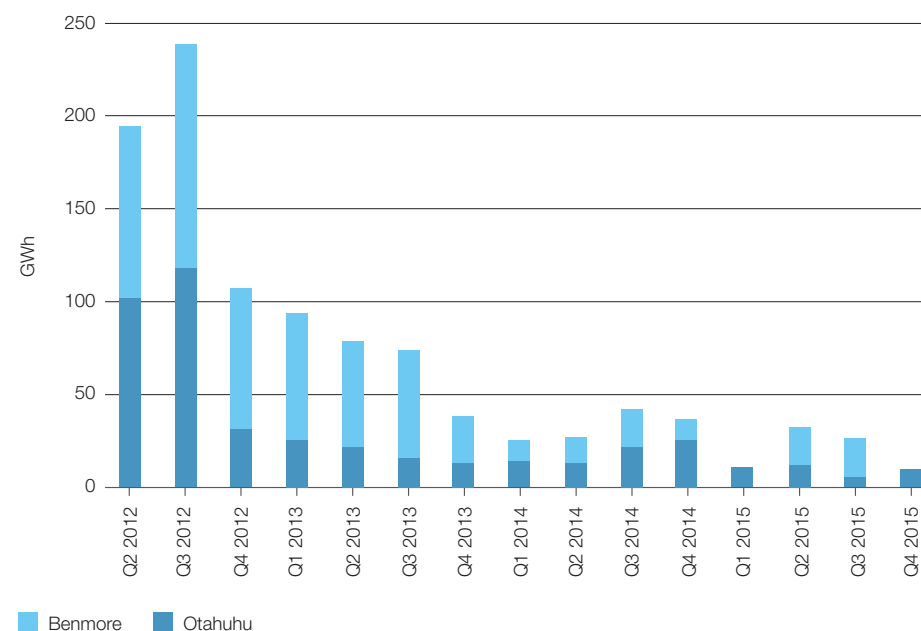


Figure 33: Uncovered open interest by quarter as at the end of June 2012



There was high uncovered open interest (UOI) for the June and September 2012 quarters, probably due to low South Island hydro inflows and the consequent need for retailers to cover their positions. Figure 33 shows the quarterly UOI for ASX instruments as at the end of June 2012. The high volumes for the June and September quarters are clear.

Spring 2012 saw prices for future winter quarter forward contracts start to fall dramatically. The June 2013 quarter forward contracts at Benmore were trading at \$117 in mid-August and, by mid-November, had fallen as far as \$81.50 before recovering to near \$90 by late November. June quarters in 2014 and 2015 for Benmore had similar falls, although there were few trades in June 2015 forward contracts during this period.

There was record UOI on 20 September 2012 of 2,574 gigawatt hours (GWh). September saw a new record for the volume of Benmore futures traded, and in October, there was record trading for combined Otahuhu and Benmore futures.

Numerous factors could have contributed to the price changes and high volumes:

- There was speculation about the future of the Tiwai smelter.
- The winter had seen record low South Island inflows that were managed more conservatively by hydro generators.
- Meridian Energy gained access to about 550GWh of storage in Lake Pukaki on 29 September 2012 for dry-year emergencies.

Each of these factors separately point to lower winter hydro risk and together may explain the hedge market activity between September and November.

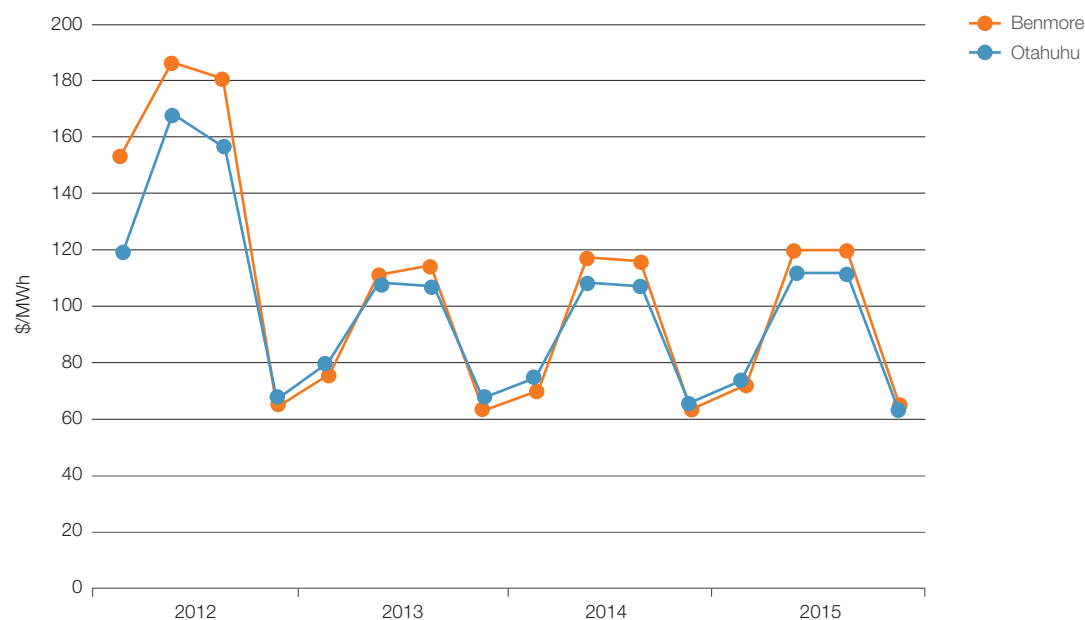
The Authority's objective in the hedge market is for a robust and transparently determined forward price curve. The forward price curve should reflect the best available information about future prices at any point in time. Higher-quality information embodied in hedge prices should mean more efficient consumption and investment decisions.

This is demonstrated later in Figure 62 (page 35), which shows June and September forward prices at Benmore against relative South Island hydro storage. Forward prices reflect hydrological information and therefore provide good information about expected future spot prices and the cost of hedging these prices – the current market price for the instruments.

This pattern of forward prices reflecting physical circumstances is encouraging and suggests prices are being determined robustly and represent participants' views of future spot prices.

Figure 34 shows the forward price curve as at February 2012. The high prices for the June and September quarterly hedges are clear. Winter seasonality is apparent in the June and September quarterly hedges in out years. Also it is interesting that the years are independent, as the 2012 high prices are not affecting 2013–2015.

Figure 34: Forward price curves, February 2012



As well as growing the overall hedge market, ASX futures displaced over-the-counter contracts for difference and over-the-counter options during 2012 (Figure 35). While the Authority doesn't have a preference for how companies manage their spot price risk, we see this as a positive development because of the increased transparency that exchange-based hedge prices provide, especially with the increased depth and liquidity that has been apparent this year.

Figure 36 shows that bid/ask spreads dropped to a fairly constant 4% since tighter market-making agreements were introduced in November 2011. The Authority continues to observe how increased competition will affect these spreads,

which, as expected, are already below those committed to in market-making agreements.

The average time to maturity is a measure of how far forward the hedge market is looking. Figure 37 shows how the average time to maturity evolved throughout the year. The long average time to maturity at the start of the year was probably due to high demand for winter hedges. As the winter played out, these hedges would have expired and were not replaced by hedges for the summer months when demand for hedges is low, causing the average time to maturity to increase. The vertical jumps in the data occur on the expiry dates of the hedges when a quarter's hedges cease to be included in the data.

There has been significant innovation in the hedge market in the last year. OMF, an Auckland-based brokerage firm, established a platform to trade quarterly over-the-counter options. At the time of writing, there was little activity on the platform, but the Authority expects this to change in 2013.

Although slower than ideal, the ASX is working on quarterly options over its futures contracts to complement the existing annual options, which are over four quarter strip futures. There is support from generators for quarterly options. The ASX has indicated these could become available in 2013. Several parties have shown interest in market making of these options.

Figure 35: Change in mix of instruments used

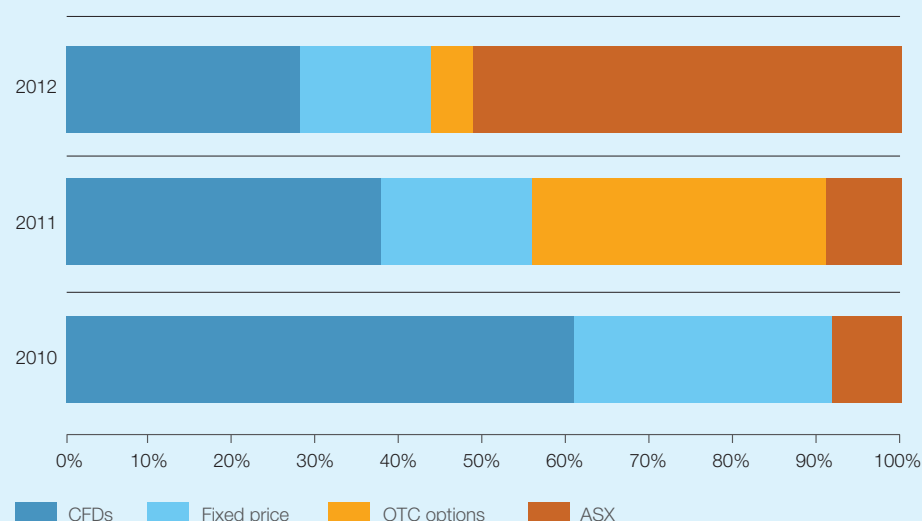
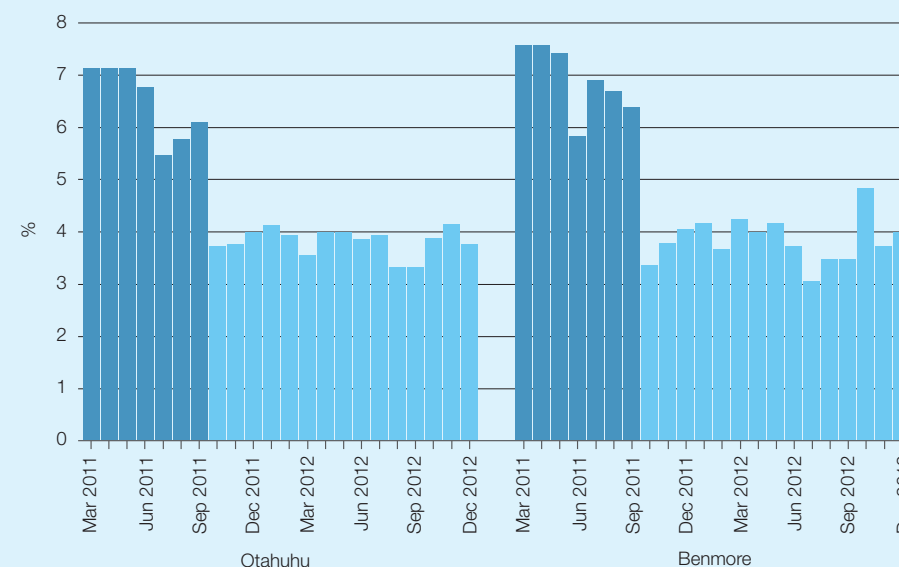


Figure 36: Bid/ask spreads



What the survey tells us

The Authority has engaged research company UMR to conduct a survey of the New Zealand electricity hedge market every two years since 2005. The 2012 survey showed views were polarised as to the competitiveness of the market between purchasers of bilateral hedges and generator-retailers that were directly involved in the ASX. The dominant view of purchasers of bilateral hedges was that the bilateral market was much thinner than desirable.

Spot price risk disclosure – stress testing

The first two spot price risk disclosure statements for the July–September and October–December quarters were provided to the stress test registrar in 2012. Stress testing is a disclosure regime that ensures the Authority will be able to assure policy makers and others that parties exposed to high spot prices are doing so knowing the risks. The Electricity Industry Participation Code requires that the results be discussed with the boards of the companies that participate.

The stress test is one of a suite of measures the Authority has adopted to deal with issues that have previously affected managing dry years and other supply shortages. The stress test complements the customer compensation scheme, which requires retailers to pay consumers during official conservation campaigns, and scarcity pricing for temporary island-wide capacity shortages.

Stress tests generated good transparency about the range of risk positions that exist in the industry. Our reporting emphasises that we do not have a view on participants' risk positions, as long as these are being adopted knowingly. Our view is that the spot price risk disclosure statements did a good job of making these choices transparent.

Consumer guide and other developments

The Authority is exploring how retailers that are sufficiently hedged can access a reduction in their prudential requirements. This proposal is at an early stage and will be consulted on in 2013.

The Authority produced a publication, *Managing electricity price risk: a guide for consumers*, to provide information on the benefits and risks of buying electricity on the spot market. It is available on the Authority's website at www.ea.govt.nz/consumer/guides or in hard copy by contacting info@ea.govt.nz.

Figure 37: Average time to maturity for ASX hedges



Generation shift to renewables

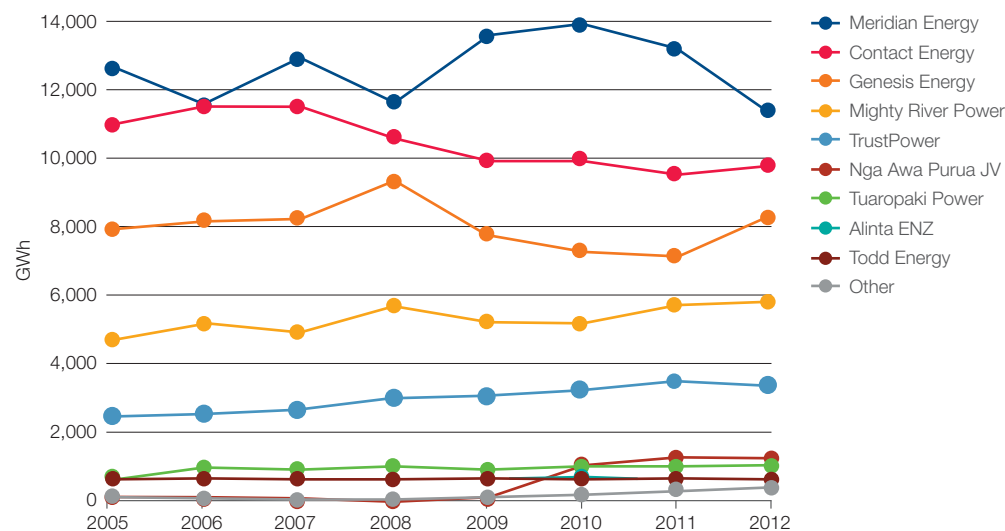
Market share of generation from 2005 to 2012 shows the same flat pattern as demand (Figure 38). In 2008 and in 2012, there were upward spikes in energy generated by Genesis Energy and downward spikes in energy generated by Meridian Energy. This reflects what happens in dry years, with thermal generation increasing to compensate for a shortage of water available for hydro generation in the South Island.

Figure 39 also shows competition in generation increased as measured by HHI. The reduction in HHI in generation is due to smaller generators increasing their share of generation.

New Zealand has about 75 generators in total of various sizes. Figure 40 shows the size of generating entities from smallest to largest and how the market facilitates the entry of generators of different sizes.

The mean size of generating entities is 1,055GWh and the median is 12.5GWh. This difference is due to the asymmetry of the distribution of generation. It indicates that, although there are large generating entities, economic entry on a smaller scale is possible.

Figure 38: Market share of generation



'Other' combines participants that did not exceed 200GWh annual generation in any year.

Figure 39: Herfindahl-Hirschman Index (HHI) for generation

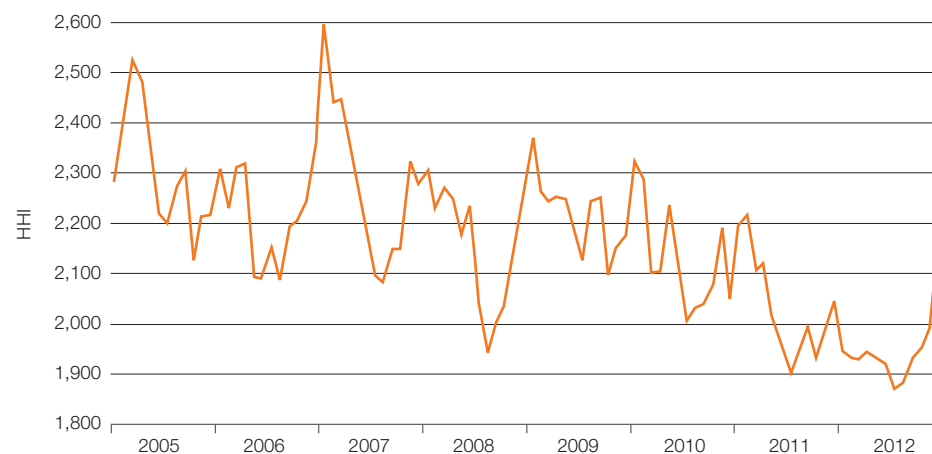


Figure 40: Scale of generating entities

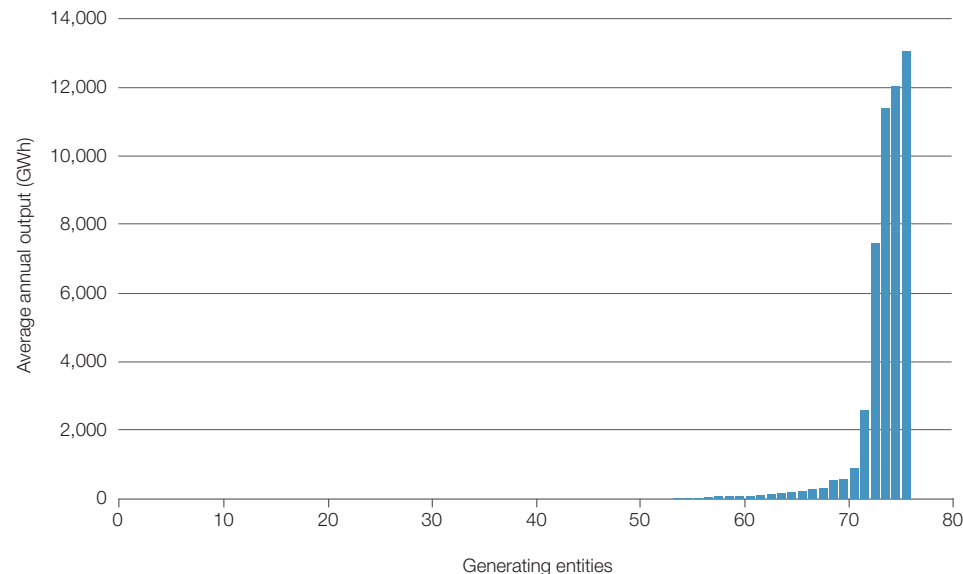


Figure 41 splits up the same data to show the size of individual generating plant. Each point on the horizontal axis is a generating entity. Above each of these points is a dot representing the size of each separate generating plant owned by the entity. This shows the different scales of generating plant – a measure of technological diversity.

The mean generator size in Figure 41 is about 54MW. The median is 4.8MW. As in Figure 40, this difference results from the asymmetric distribution of generation. In turn, this asymmetry shows that entry is technologically possible at a small scale.

Generation by fuel type continued to shift towards renewable energy. Figure 42 shows the split of fuel type from 2000 to

2012. Much of the increase in total generation was due to the increase in geothermal and wind generation. Geothermal generation has grown significantly since 2000, with the expansion of the existing Rotokawa, Wairakei, Mokai and Ngawha plants and the new Kawerau, KA24, Nga Awa Purua JV and Te Huka plants adding a total of about 360MW on the existing base of 470MW.

Figure 41: Scale of generating plant by entity

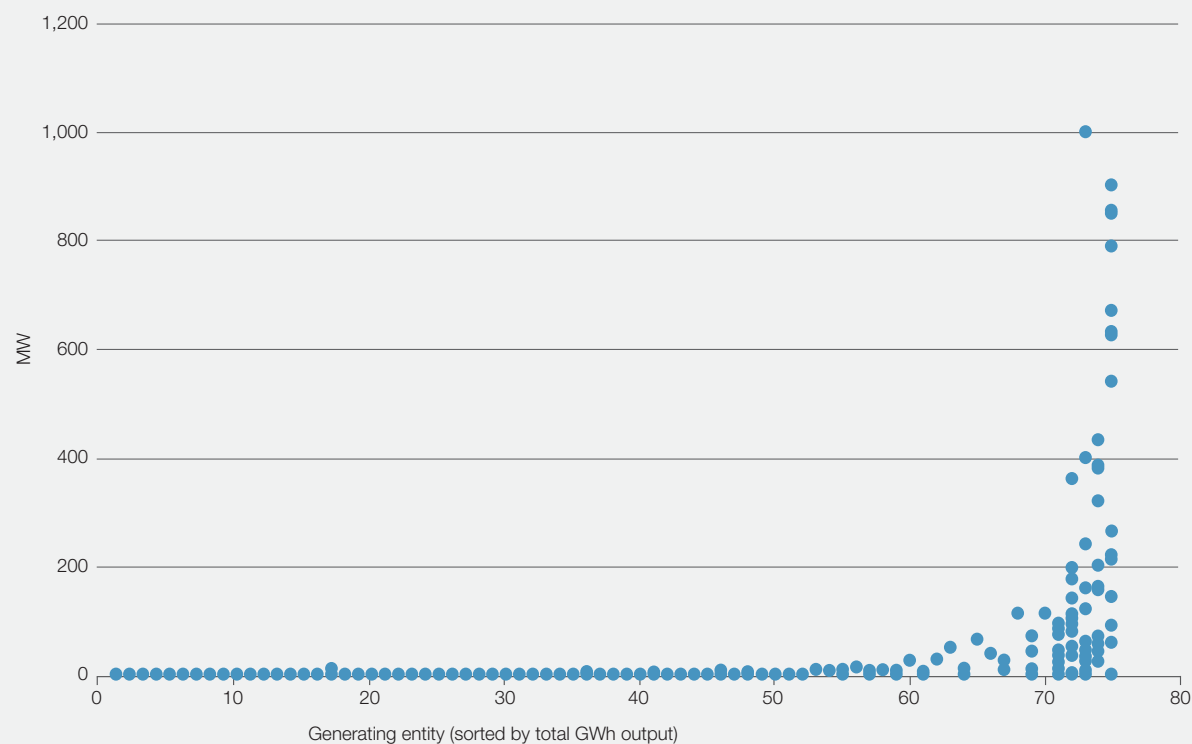


Figure 42: Generation by fuel type

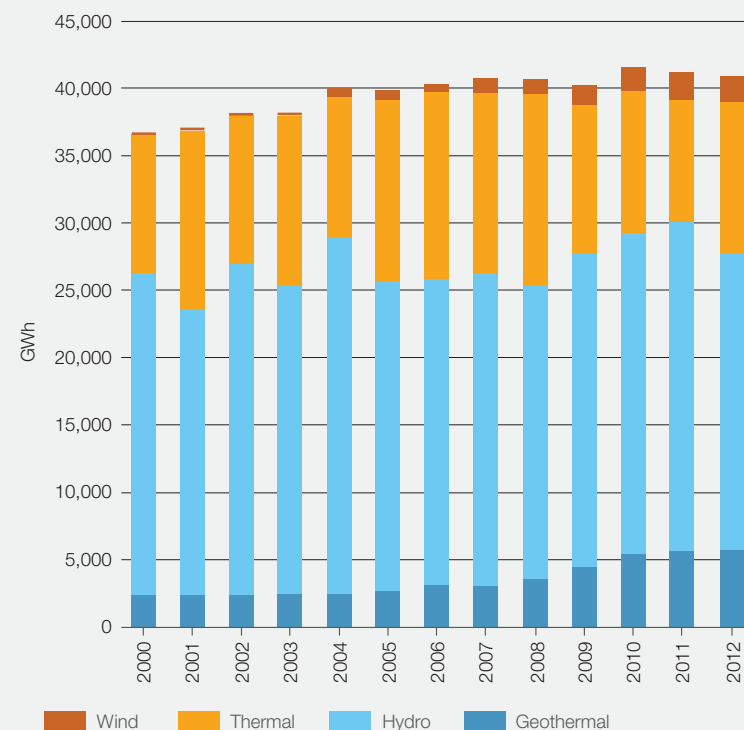


Figure 43: Wind farm locations



In wind generation, 580MW of new plant has been built since 2000, of which 450MW has been built since 2005. Before 2000, the only installed large wind generators were the Brooklyn turbine in Wellington (0.225MW built in 1993), the initial stage of the Hau Nui wind farm (3.8MW built in 1996) and Stage 1 of the Tararua Wind Farm (31.7MW built in 1999). The locations of New Zealand's large wind farms are shown in Figure 43.

Wind generation growing

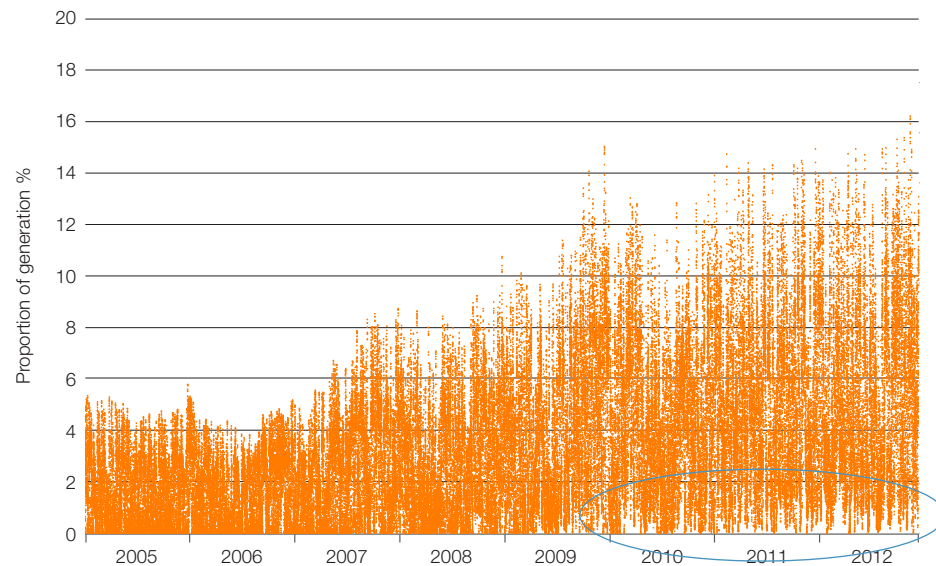
While wind and geothermal are both renewable, they are different in nature, with geothermal being constant baseload and wind being intermittent. Figure 44 shows wind generation as a percentage of total generation for half-hour intervals from 2005. It shows the volatility that has an impact

on the rest of the system. At times, wind generation was supplying as much as 12% or 13% of total demand, but this tended to be early in the morning when demand was low.

The white space (circled) in Figure 44 suggests that, in recent years, there were fewer periods when wind generation contributed nothing to total generation. This is likely due to the increased geographic diversity of wind generation, making it more likely that wind turbines are generating somewhere.

In earlier years, the data shows that it was common for wind generation to contribute nothing to total generation, hence more orange near the horizontal axis. As time has passed, increased white space near the horizontal axis indicates wind plant is generating most of the time.

Figure 44: Wind generation as a percentage of total generation



The volatility of wind generation has increased in absolute terms. Figure 45 shows the change in wind generation output between half hours in MW from 2005. The increase in installed wind generation was associated with an increase in how much generation from wind can change in absolute terms over a half hour.

Repeating the same analysis but using the change in half-hourly wind generation as a proportion of installed wind generation shows that the proportional change reduced with the increase in wind generation (shown in Figure 46). Together, these charts suggest that, although more wind generation creates more volatility in absolute terms, it does so at a decreasing rate as more wind generation is built. This is likely caused by increased geographic diversity of wind farms.

The variation in wind generation output across periods is not independent of current wind generation output. Wind generation currently at zero output has no chance of experiencing a sudden drop. Similarly, wind generation at maximum or close to maximum total output has little or no chance of experiencing a rapid increase but does have an increased chance of experiencing a large drop as a result of turbines shutting down should wind speed exceed the operational limits of the turbine.

Figure 45: Absolute half-hourly change in wind generation

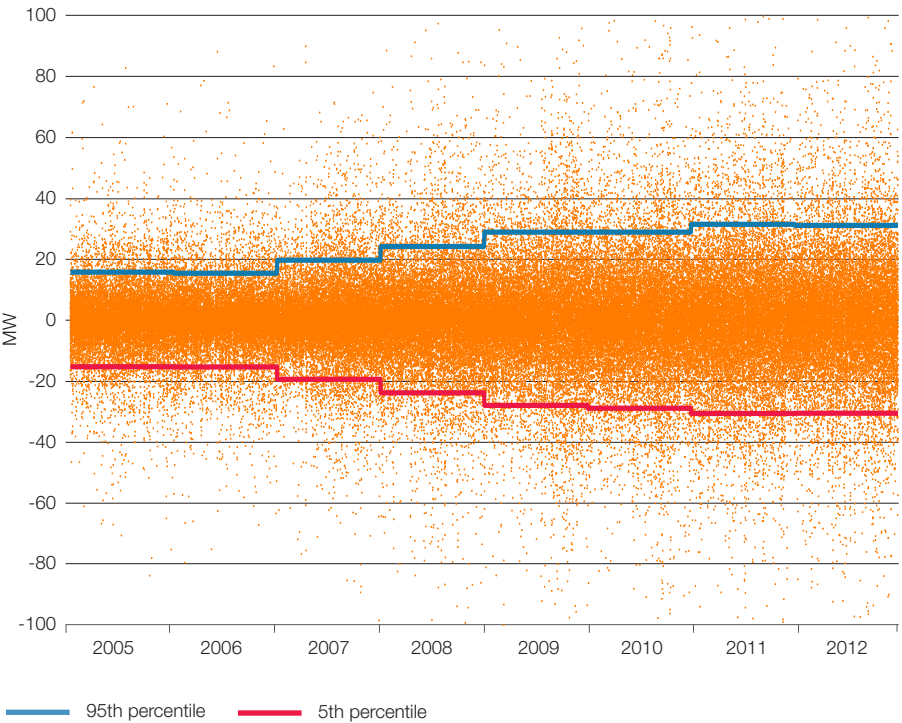


Figure 46: Half-hourly change in wind generation relative to installed wind generation capacity



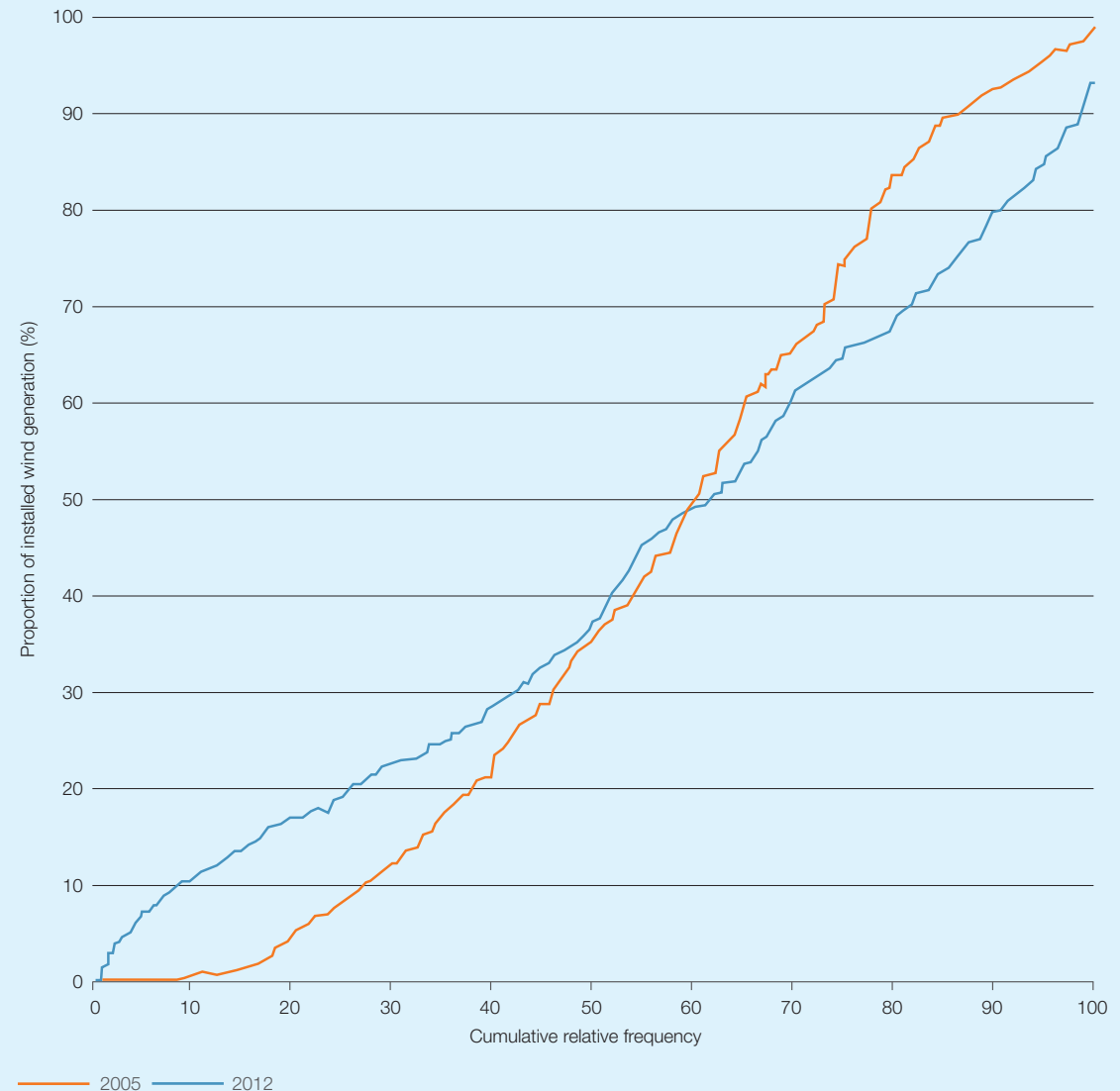
Over time, the probability of at least some wind output contributing to peak supply has gradually increased.

Figure 47 shows the cumulative likelihood of wind generation contributing at the time of each daily peak in 2005 and 2012. The y-axis shows wind output as a percentage of total installed wind generation capacity. The x-axis shows the cumulative relative frequency of wind generation at peak.

For example, in 2005, wind generation output at the time of the daily peak was less than 20% of total wind capacity 37% of the time (to see this, read the x-axis at the point where the horizontal 20% line cuts the 2005 line). By 2012, this changed to wind being at less than 20% capacity at peak times only 27% of the time, so this means that it has become less likely that wind makes a small (less than 20%) contribution to supplying energy at peak demand.

The probability that all wind generation will be generating at any one time falls with geographic diversity. This can be seen in the top right of the figure, where the probability of wind generating at less than 80% of installed capacity at peak time was 78% in 2005 but increased to 90% in 2012. In other words, wind generation output at daily peak exceeded 80% of installed capacity 22% of the time in 2005 but only 10% of the time in 2012. It has become less likely that wind makes a greater than 80% contribution to supplying energy at peak demand.

Figure 47: Cumulative likelihood of wind generation contributing to peak demand



Accurate price signals a priority in spot market

The spot market is where generators and purchasers trade energy that is not covered by physical or financial hedges. Although all energy is traded in the spot market, it can be viewed as a balancing market where energy not pre-committed and demand not covered by physical or financial hedges is reconciled.

The spot market is essential for competition as it provides a balancing mechanism and also signals scarcity in real time. These signals are essential for providing incentives for peaking and other last resort resources.

Figure 48 shows the major buyers of electricity on the spot market from 2005 to 2012. It shows Mighty River Power and Contact Energy increased the amount they purchased over

this period, while Genesis Energy and, to a lesser extent, TrustPower reduced their purchase.

Residual supply analysis suggests a competitive spot market

The Authority has analysed residual supply on the spot market for the period from January 2010 to October 2012. The idea is to alter actual offers to get an idea of how much ability generators have to reduce supply and raise price. We then measure whether this would be profitable or not.

The methodology involved two scheduling pricing and dispatch (SPD) solves, a base case and a counterfactual where 50MW is taken from the lowest price band for each

trader and placed in the highest price band. We did this analysis for the five largest generating companies and assumed no alternating current transmission constraints.

For each pair of SPD solves, we calculated the change in weighted average price divided by the change in quantity supplied. This was each trader's **ability** to influence price by changing the structure of their offers to the spot market.

We also calculated the change in profit for each scenario as a measure of the **incentive** to raise prices by changing the structure of offers.

We looked at the correlation between the ability to influence prices and the quantity weighted average offer. We found weak correlation between these two series (Figure 49).

Figure 48: Wholesale energy purchases

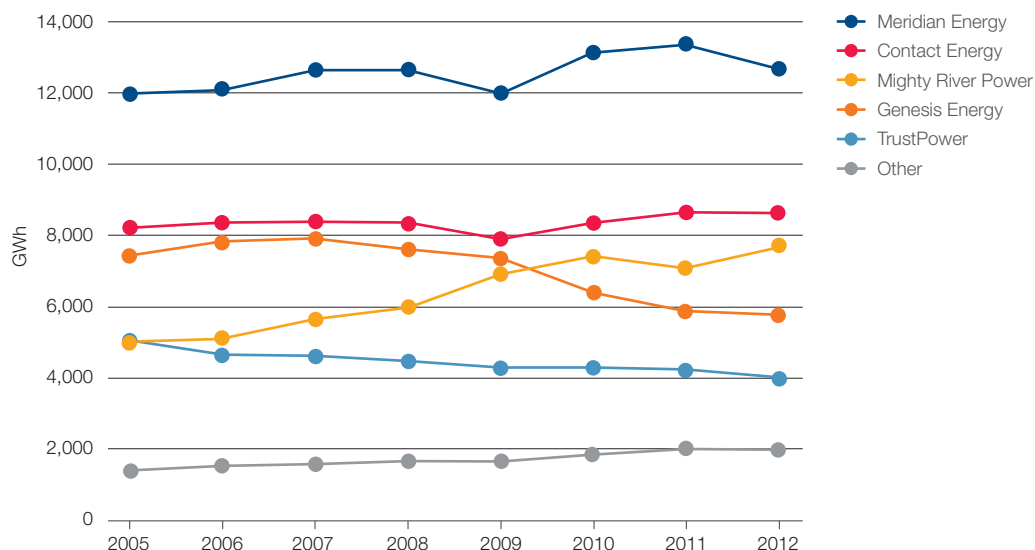
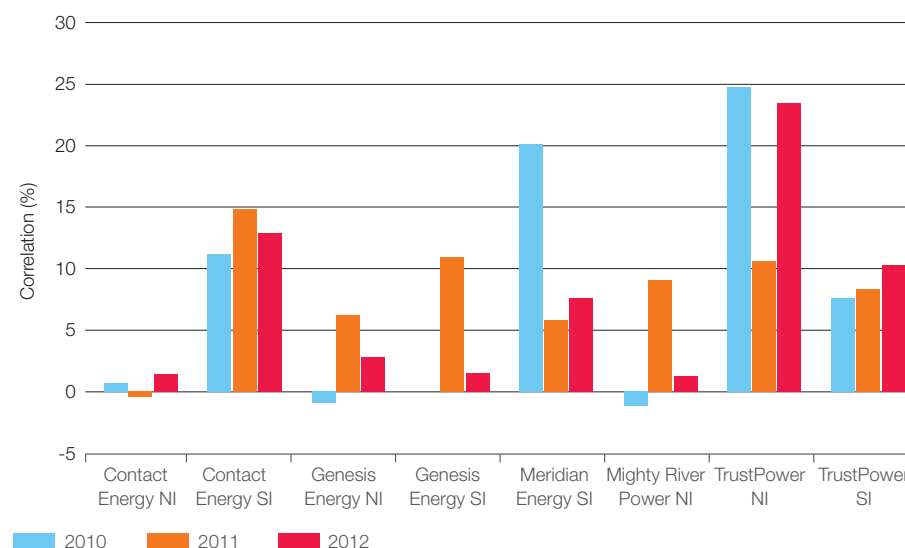


Figure 49: Correlation between the ability to influence price and the quantity weighted average offer for the five large generators



We also looked at the correlation between the incentive to increase prices and the quantity weighted average price. We found negative correlation between the incentive to increase prices and the quantity weighted average price for each generator. This indicated that the reduction in volume of energy dispatched more than outweighs any increase in price that might be derived from changing the structure of offers.

Taken together, these results suggest that generators were structuring offers to optimise profits, and although they could increase price from time to time, they tended not to do so because it is harmful to their profits.

This is the first time that the Authority has implemented this methodology, and we have taken it directly from Wolak,⁶ but instead of using a simple offer stack, we have used SPD. We intend to continue to monitor this relationship and develop a time series.

Demand-side bidding and forecasting changes

Demand-side bidding and forecasting (DSBF) was introduced on 28 June 2012 – an initiative designed to reduce transaction costs on wholesale purchasers and to facilitate demand response to spot prices. Conforming nodes are nodes at which the system operator relies on central forecasts of demand to make scheduling and dispatch decisions, whereas non-conforming nodes are nodes at which the system operator relies on demand bids from large consumers to make scheduling and dispatch decisions. The introduction of DSBF made no change at non-conforming nodes but reduced transaction costs at conforming nodes as purchasers are no longer required to bid. However, purchasers at conforming nodes retain

the option to provide difference bids to signal how they might respond to different prices.

The system operator published two new schedules based on the central forecasts and optional bids at conforming grid exit points (GXPs) and the nominated bids at non-conforming GXPs. These are the non-responsive schedule (NRS) and the price-responsive schedule (PRS).

The NRS is a forward-looking estimate of the final price over each trading period without considering any demand response. This provides a forecast for the next 72 trading periods. The next eight trading periods are refreshed every 30 minutes, and the remaining trading periods are updated every two hours.

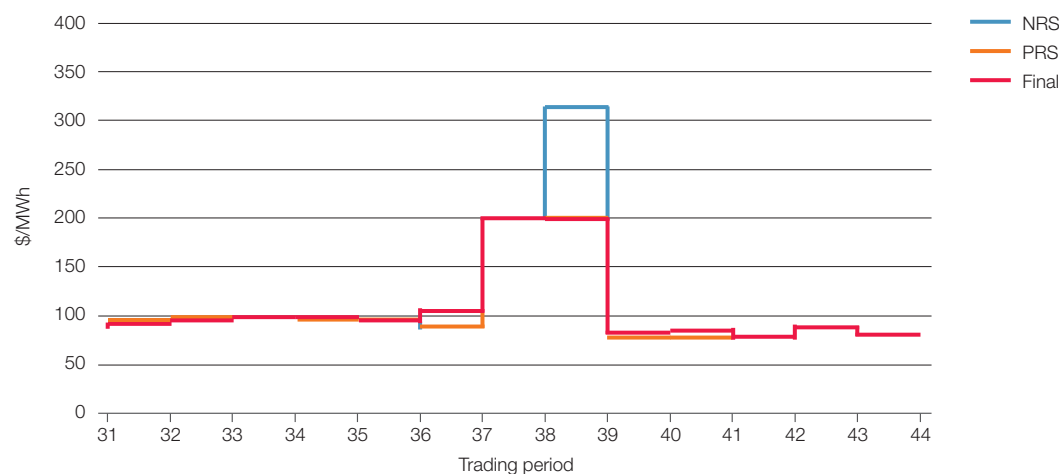
The PRS is forecast the same way but estimates the price assuming that demand responds according to the bids.

The difference between the NRS and the PRS is the price change that would occur if load shedding is consistent with the bids submitted, so this makes explicit the effect of potential load shedding on the price.

The idea is to make the effect of shedding load transparent to participants so they can make informed decisions about load scheduling.

We found three examples in August 2012 that showed significant differences between the NRS and PRS prices. In one case, the new schedules worked well and the final price was equal to the PRS. In another case, more load was shed than was anticipated by the difference bids and the price fell to below the PRS. In a third case, less demand was shed than anticipated and the price stayed at the NRS.

Figure 50: NRS, PRS and final pricing from 8 August 2012



⁶ See www.comcom.govt.nz/investigation-reports.

Figure 50, from 8 August 2012, shows in trading period 38 (6.30pm) the final NRS (blue line) signalled a price of over \$300 compared with the PRS (orange line) of about \$200. The demand response was as predicted based on the difference bids, and the final price (red line) was equal to the PRS price.

Figure 51 shows that, on 15 August 2012, the final NRS signalled a price of nearly \$2,500 compared with the PRS price of just over \$1,000. Schedules in the final few trading periods leading up to the period concerned showed even larger price differences caused by a genuine shortage of generation in the North Island. In the event, more demand was shed than anticipated by the bids submitted, and the final price ended up close to \$100.

Figure 52, from 5 August 2012, shows an NRS price of about \$500 in one trading period followed by one of about \$400. These were very close to the final prices even though the PRS was around \$200 for the two trading periods. This lack of response was likely due to the fact that prices in the previous iterations of both schedules for the trading periods concerned were completely normal and the sudden change in circumstances was unexpected.

These new schedules enable increased competition and efficiency. The competition comes from demand shedding competing with generation when energy is scarce. Efficiency should increase as users make explicit decisions about whether to continue to pay for energy or to shed load.

Figure 51: NRS, PRS and final pricing from 15 August 2012

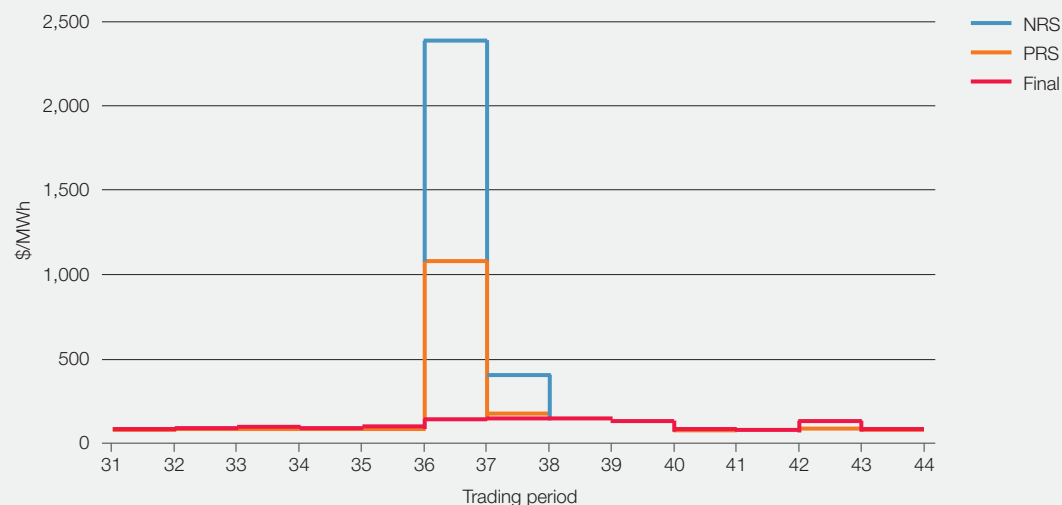
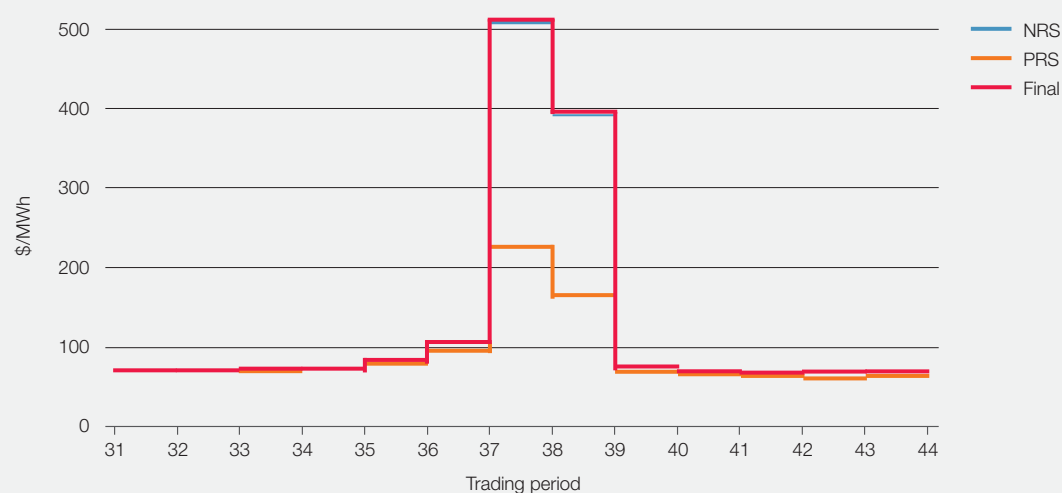


Figure 52: NRS, PRS and final pricing from 5 August 2012



Instantaneous reserves

Changes in competition in the reserves market are illustrated in Figure 53. It shows the HHI for cleared reserves for both North and South Islands. North Island HHI values are much lower than the South Island and also much less volatile.

South Island reserves saw an increase in the HHI during the first quarter of 2012. Initially, this was due to Meridian Energy anticipating the need for increased South Island reserves to support southward flow on the HVDC and upgrading its control systems to enable its plant to offer more reserves.

Meridian Energy then acquired the rights to offer the Tiwai smelter as interruptible load, again to support southwards transfer on the HVDC. Both these changes led to increased concentration in the South Island reserve market.

This increase in volume of reserve being offered in a more concentrated market didn't have an effect on prices until May, when Meridian Energy changed its offer strategy. This change is discussed below in the section on the high South Island reserve prices.

Late in the second quarter, the HHI fell again before rising briefly in the third quarter.

Currently, all aggregated demand response offered directly into the reserve market by an aggregating company is offered in the North Island. The size of the amount offered relative to total reserve offers is shown in the two graphs (fast instantaneous reserve (FIR) in Figure 54 and sustained instantaneous reserve (SIR) in Figure 55). The amount of both types of reserve being offered by an aggregating company increased steadily, with interruptible load from aggregated demand representing 6.4% of total FIR offers and 5.2% of total SIR offers.

Figure 53: Herfindahl-Hirschman Index (HHI) for reserves, 2010–2012

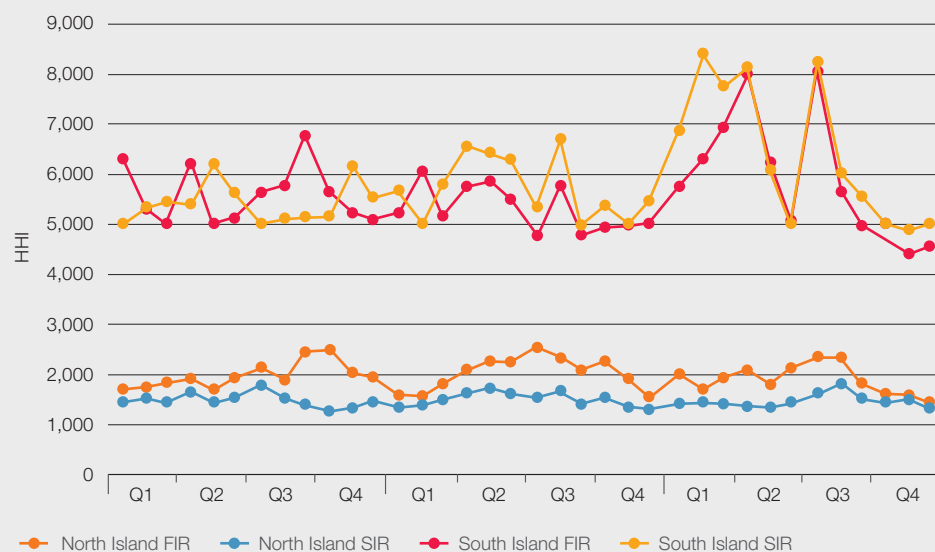
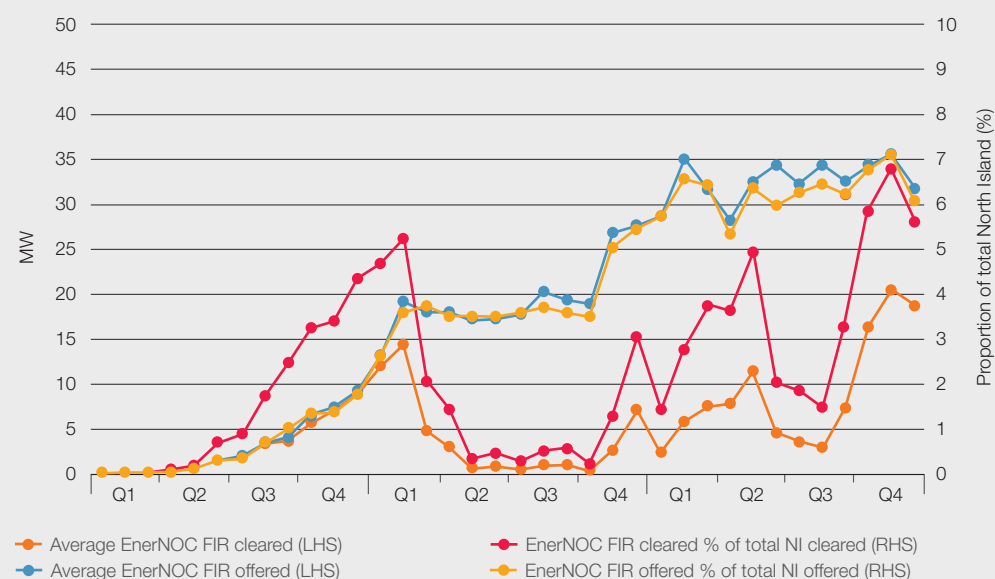


Figure 54: North Island fast instantaneous reserves, 2010–2012



The amount of reserve being cleared by an aggregator has changed significantly. During 2010, nearly all offered aggregated reserve was cleared. The proportion of offered reserve that was cleared dropped markedly in 2011.

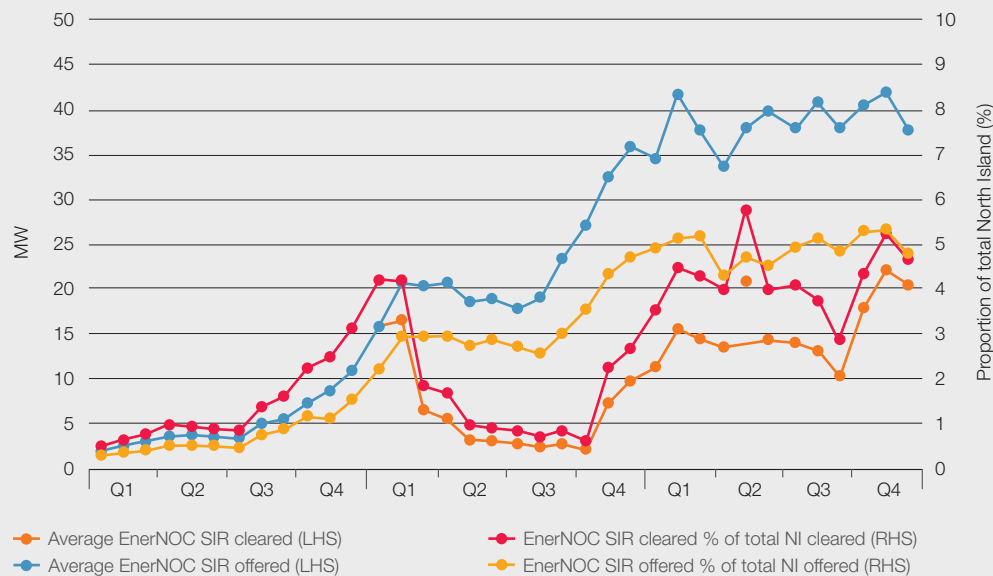
Frequency-keeping

Frequency-keepers continually adjust their output to maintain the power system frequency within the normal band of 49.8 and 50.2Hz. The selected frequency-keeper in each trading period is compensated for its capacity offer and is provided

with constrained on or off payments related to any movement in its generation to maintain the frequency.

In providing the service, frequency-keepers have to reserve some generation capacity to allow for an increase or decrease in output. This capacity cannot be dispatched within the market. In providing this service, frequency-keepers experience an opportunity cost related to potential forgone revenue in the spot energy market. Therefore, one would reasonably expect some correlation between the frequency-keeper costs and the spot energy price.

Figure 55: North Island sustained instantaneous reserves, 2010–2012



Figures 56 and 57 illustrate the North Island and South Island frequency-keeping costs from January 2011 to December 2012, as well as the average energy price at the reference node within the respective island.

In 2011, the majority of the frequency-keeping costs in the North Island was attributed to constrained-on payments to the frequency-keeper. The Authority's review, following the increased frequency-keeping costs in August 2011, highlighted a shortcoming in the previous frequency-keeper selection methodology, which exposed the market to potentially large constrained-on costs. This prompted a change in methodology from November 2011, resulting in reduced frequency-keeping costs with the primary proportion of the cost attributed to the offer for providing the service.

The increased frequency-keeper costs in the South Island during the first half of 2012 was primarily driven by the increased risk of hydro shortage in the South Island during this time. It reflected the increased value of water in the South Island and the corresponding increased opportunity cost of providing frequency-keeping services. The risk of hydro shortage in the South Island has reduced since July 2012. This has decreased the South Island energy price and the South Island frequency-keeping cost.

Figure 56: North Island frequency-keeping costs

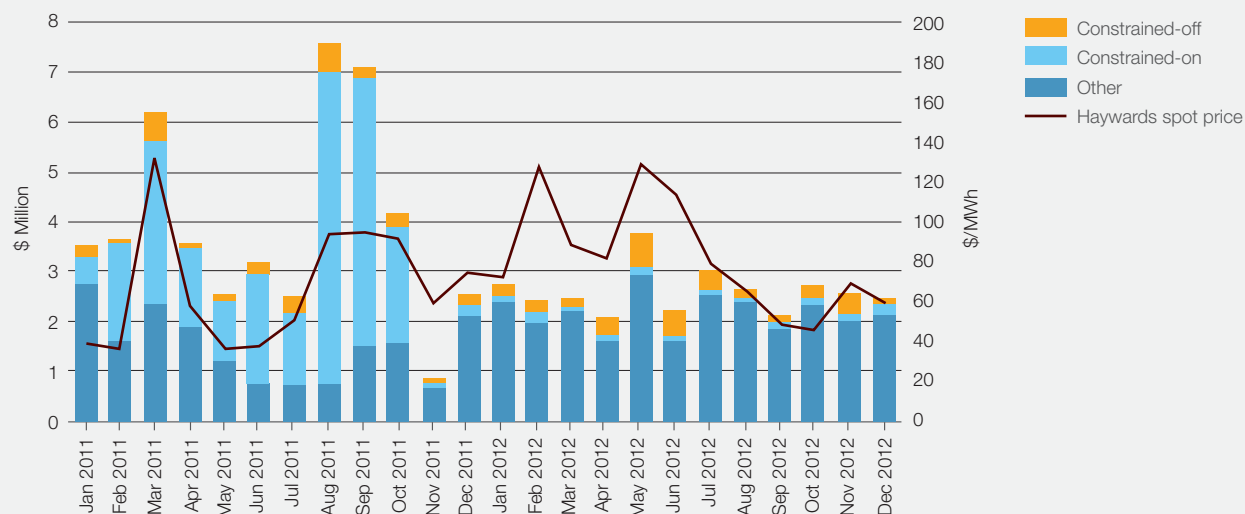
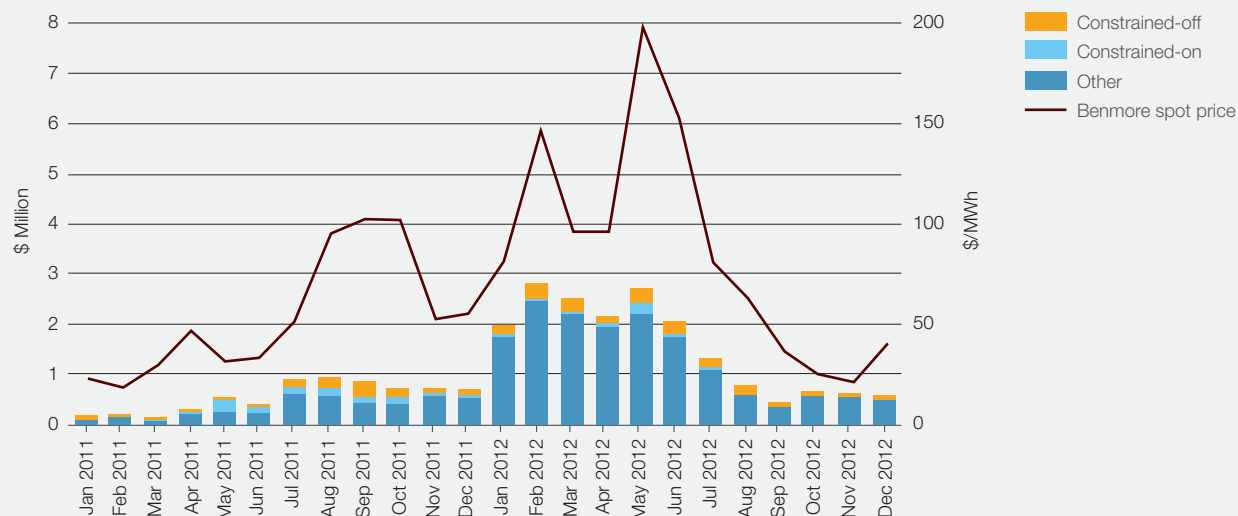


Figure 57: South Island frequency-keeping costs



Winter review shows driest half year since records began

A characteristic of New Zealand's electricity system is high reliance on hydro generation that has comparatively small amounts of storage, making the country vulnerable to dry years. It is important, that when this happens, institutional arrangements can deal with it. Markets signal scarcity with high prices. In the context of the electricity market, this means that, in dry years, wholesale prices should rise and thermal plant should become economic and start to operate.

The defining feature of the winter of 2012 was record low inflows in the South Island. Inflows for the first six months of the year were 75% of average and the lowest since records began. The market responded in a variety of ways to the shortage of water available for hydro generation in the South Island and avoided the need for extraordinary measures.

Figure 58 shows inflows for the first six months of the year for each year since 1932 ranked from highest to lowest. 2012 had the lowest inflows. Other recent dry years are also highlighted.

Figure 58: South Island inflows for first six months of the year, from highest to lowest

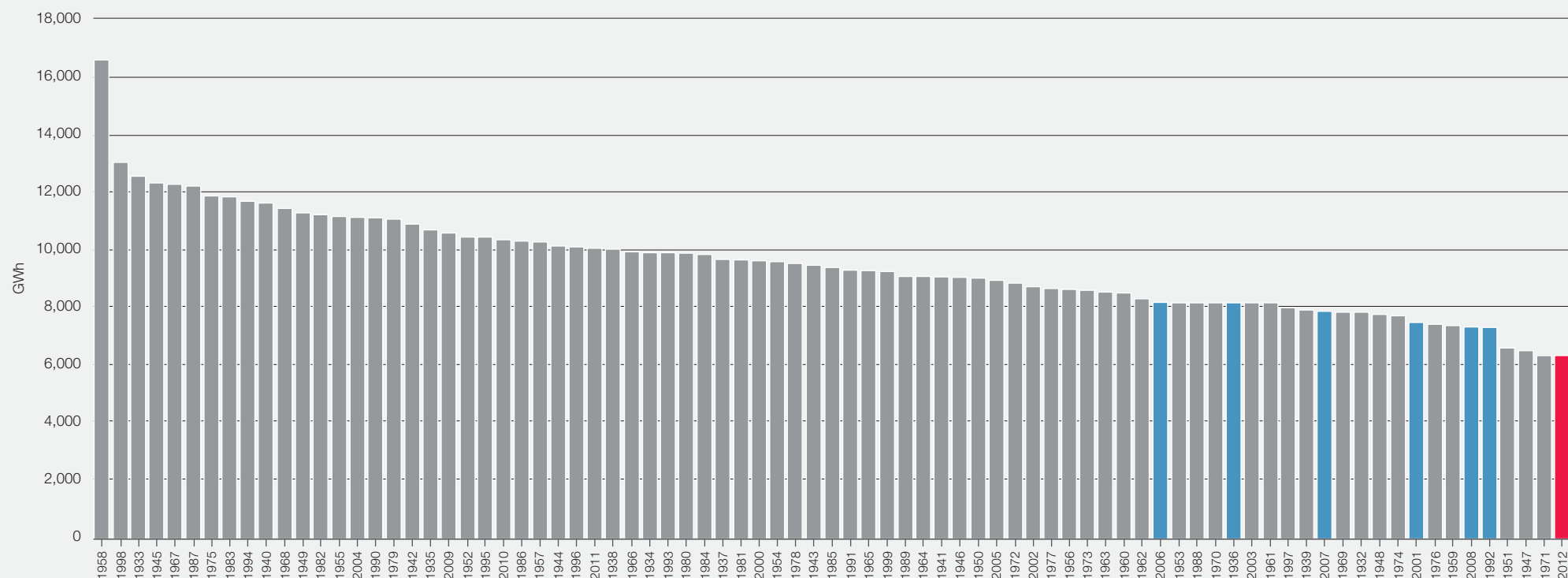


Figure 59 shows cumulative daily inflows for 2011 and 2012 compared to a historical distribution. It reflects Figure 58, with cumulative inflows for 2012 far lower than the average line. The line for 2011 shows inflows were below average from October 2011.

Correspondingly, the hydro storage situation reflects inflows with storage far below average for the most of the winter. South Island storage fell to very low levels by October 2011 (Figure 60) and then recovered before dipping low again in February 2012. It recovered again before falling to another low in May 2012. At this point, storage met the 1% hydro risk curve – a measure of the probability of forced electricity cuts. From May 2012, storage was much closer to mean storage eventually hitting mean storage for the first time in mid-September and remaining above this level for the rest of the year.

It is interesting to compare South Island hydro storage in 2012 to 2008, the next most recent dry year. Generally, storage remained more stable through the winter despite lower inflows and starting from a similar level early in the year. This suggests generators had a more conservative approach to managing storage (Figure 61).

Figure 59: South Island cumulative daily inflows, 2011–2012

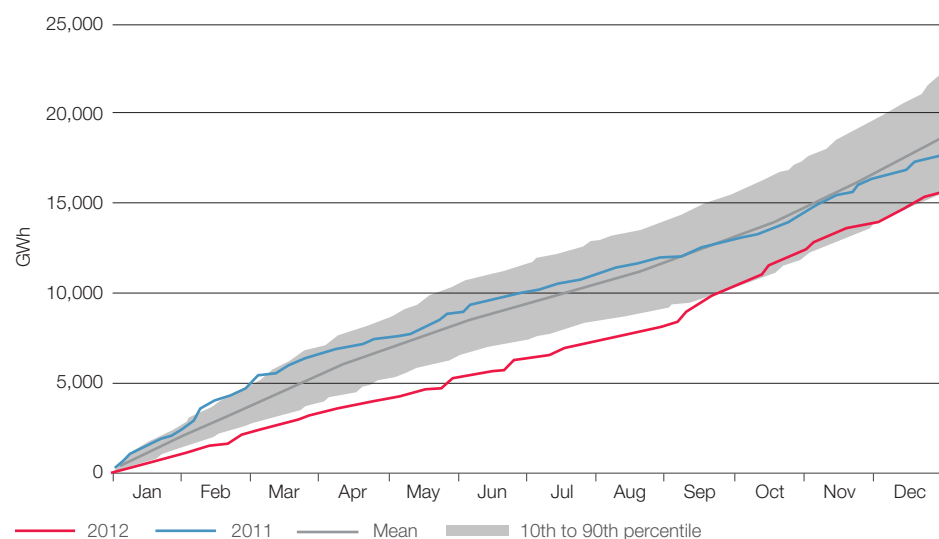
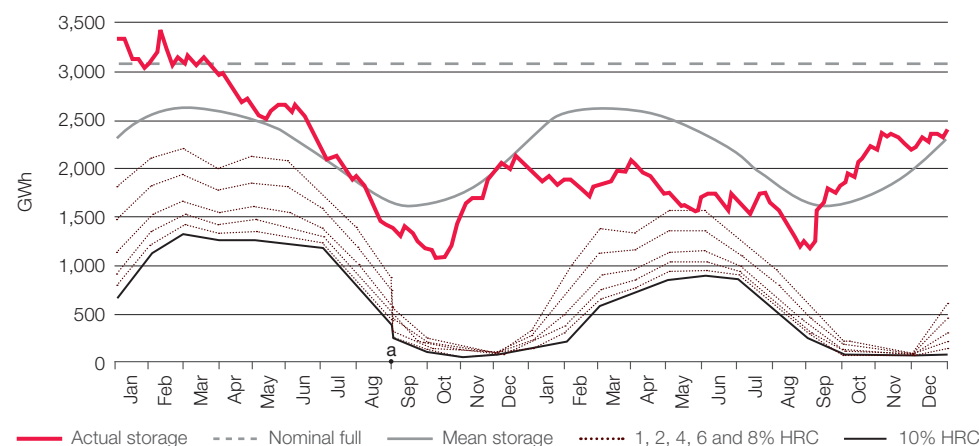
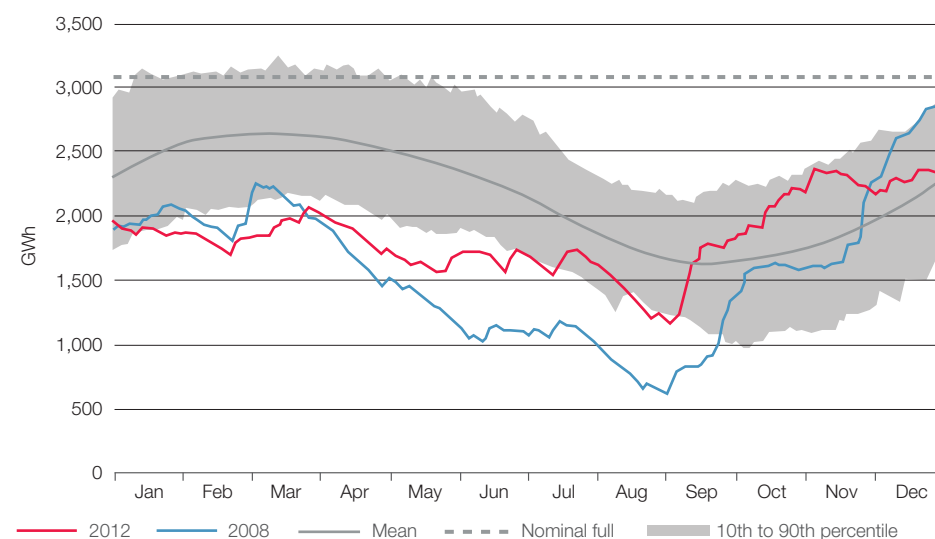


Figure 60: South Island controlled storage and hydro risk curves for 2011 and 2012



The 'a' denotes new hydro risk curves were calculated by the system operator and applied from 1 September 2011. South Island controlled storage includes Lakes Tekapo, Pukaki, Hawea, Te Anau and Manapouri.

Figure 61: South Island controlled storage, 2012 compared with 2008



There have been changes since 2008 that may point to why the 2012 shortage seems to have been better managed. The customer compensation scheme provisions introduced in April 2011 require that each retailer has a scheme and describes how it will compensate its customers during public conservation periods. This creates strong incentives for retailers to continue to supply their customers. Retailers with generation therefore have incentives to continue to generate and supply rather than calling for conservation measures. Generators that enter into hedges also have incentives to continue to generate to cover their hedge positions, although they would not be directly affected by the customer compensation obligations of the energy purchasers holding these hedges.

A more robust and transparent hedge market means that the hedge price is more likely to reflect the market's best estimate of future prices. This should help purchasers moderate their demand early and generators to conserve fuel in anticipation of generating when the price is high.

The virtual and physical asset swaps completed in January 2011 may also have influenced the outcome.

Another difference between 2008 and 2012 likely reflects the fact that 2008 was a dry year in the North Island as well as the South Island but 2012 was only dry in the South Island. There was also more geothermal generation available in 2012, which is likely to have been dispatched before thermal generation.

The 2012 wholesale and hedge market prices reflected the underlying hydrology. This is exactly what market prices are supposed to do – transmit information about scarcity so that buyers and sellers can make efficient consumption and investment decisions. The fact that hydrological information and spot prices are correlated is an encouraging indicator of market performance.

Figure 62 shows South Island hydro storage as a percentage of mean storage and the Benmore forward price for the September 2012 quarter. Clearly, the hedge price reflected industry expectations that spot prices would rise when storage ran low. The hedge price embodied relevant market information and provided the market with its own collective best estimate of likely future spot prices.

Figure 63 shows that spot prices at Benmore in 2011 and 2012 followed a similar pattern and reflected the underlying hydrology. Leading into summer 2011–2012,

Figure 62: Benmore forward prices and South Island storage, January–September 2012

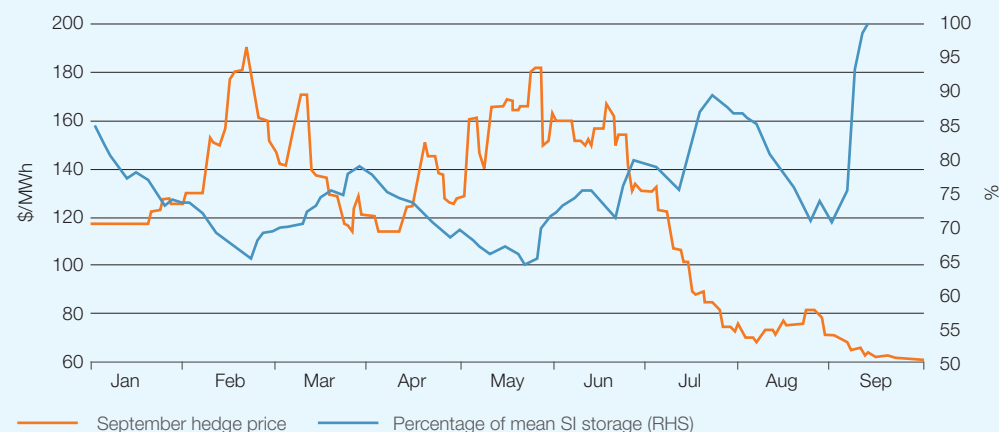
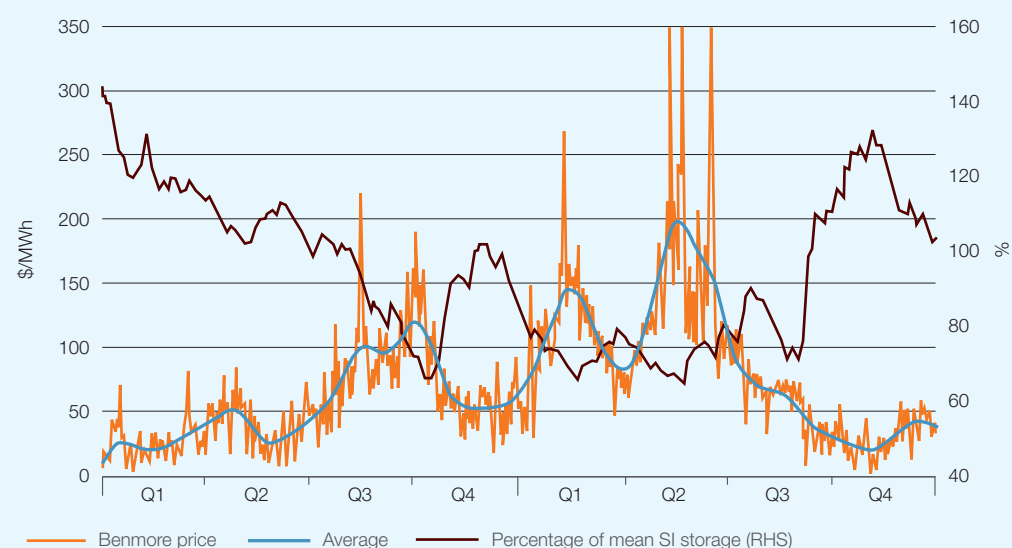


Figure 63: Spot prices and South Island relative storage, 2011 and 2012



storage fell and prices reached a peak as early as October 2011. Prices peaked again in February and May 2012 as storage fell to low points at these times, then prices fell away as storage rapidly improved during the third quarter.

In looking at the relationship between South Island price and hydro storage using data since 1996, the level of storage relative to mean storage has had a significant effect on prices. This is more pronounced in dry years where storage relative to mean storage has between two to five times the impact on price than the average impact for other years. In wet years, above-average storage reduces prices but the effect is far weaker than the impact on prices in dry years.

Figure 64 shows thermal generation for two dry years – 2008 and 2012 – as well as an archetypal wet year – 2011. The high spot prices in 2008 and 2012 caused thermal generation in the North Island to be profitable and generate more and earlier in 2008 and 2012.

Increased prices led to higher thermal generation and resulted in export of energy to the South Island. This can be seen in Figure 65, which shows that there was more and earlier southwards flow over the HVDC in 2012 compared with 2008.

The patterns for 2008 and 2012 are similar, with peak thermal output occurring at the same time in both years, but 2008 saw higher levels. This in turn led to sustained southwards flow of energy across the HVDC. The contrast with 2011 is clear. Both 2008 and 2012 had far more southwards flow and thermal generation than 2011, demonstrating the difference between dry and wet years.

The difference between 2008 and 2012 seems to reflect more conservative management of water available for hydro generation in the South Island and the changes in the South Island reserve market discussed above. The end result was that water was managed much better in 2012.

Figure 64: Thermal generation, 2012, 2011, 2008

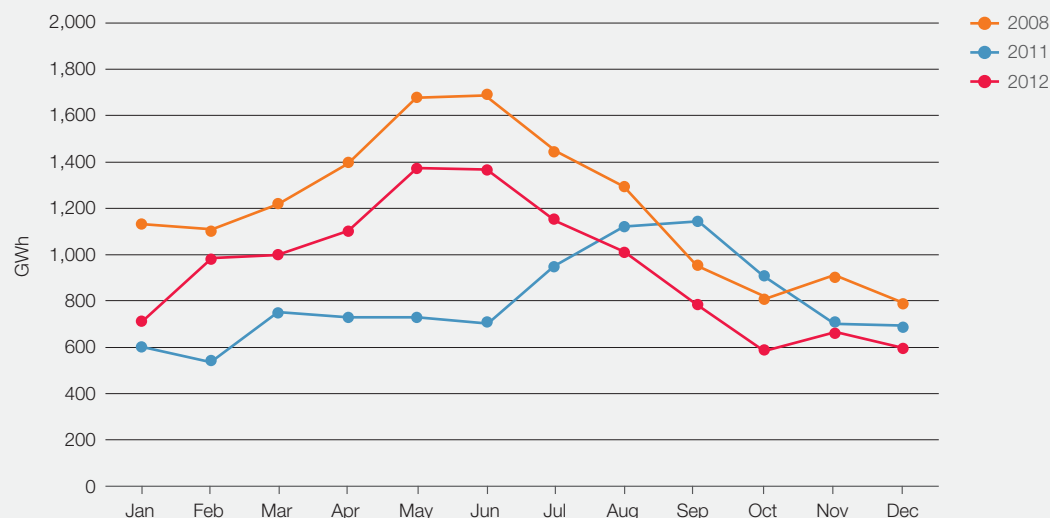
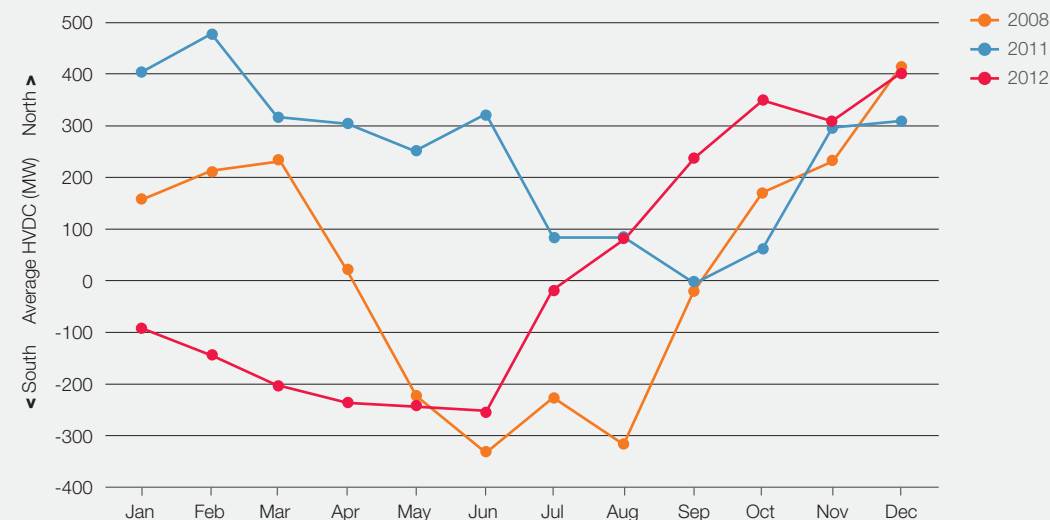


Figure 65: HVDC flows, 2012, 2011, 2008



High South Island reserve prices

Early in 2012, with storage levels well below average, market participants coordinated an increase in the amount of instantaneous reserve offered in the South Island. This supported southwards transfer over the HVDC by covering the possibility of an HVDC contingent event. It resulted in South Island FIR offers increasing from 300MW to 700MW

and South Island SIR offers increasing from 550MW to over 1,000MW between January and May 2012. These increases are shown in Figure 66.

A big part of this increase was due to Meridian Energy acquiring the offer rights for 165MW of interruptible load from the Tiwai smelter in March 2012. This created a block of reserve equivalent to 70% of the market volume.

Figure 67 shows that, starting on 9 May 2012, the price for 70% of South Island FIR increased from less than \$1 per MW to over \$150 per MW due to a change in Meridian Energy's offer strategy.

This increased the cost of covering an HVDC contingent event and led to a price separation of the North and South Island spot prices and the ASX hedge prices for the winter quarters.

Figure 66: South Island reserve offers, June 2011 to May 2012

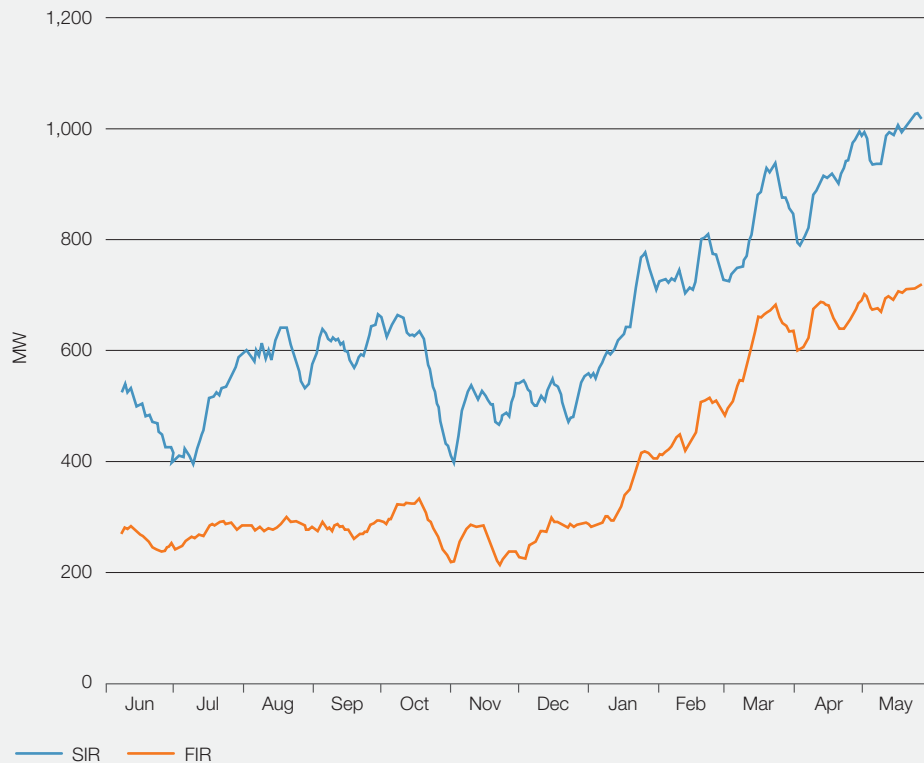
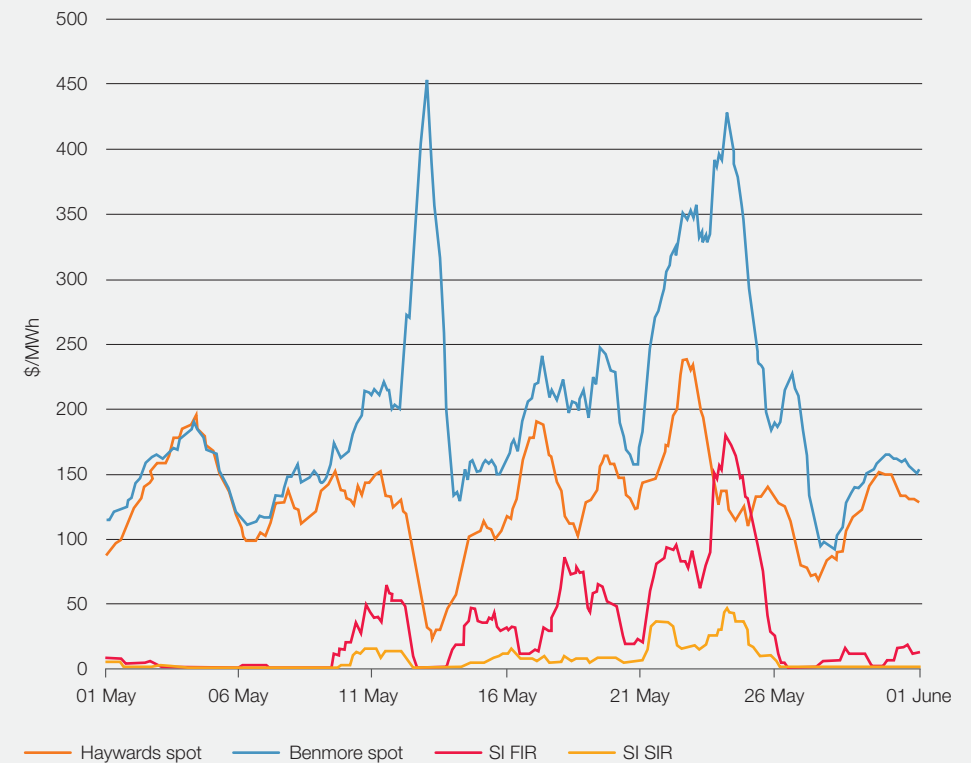


Figure 67: South Island reserve prices and spot prices at Haywards and Benmore, May 2012



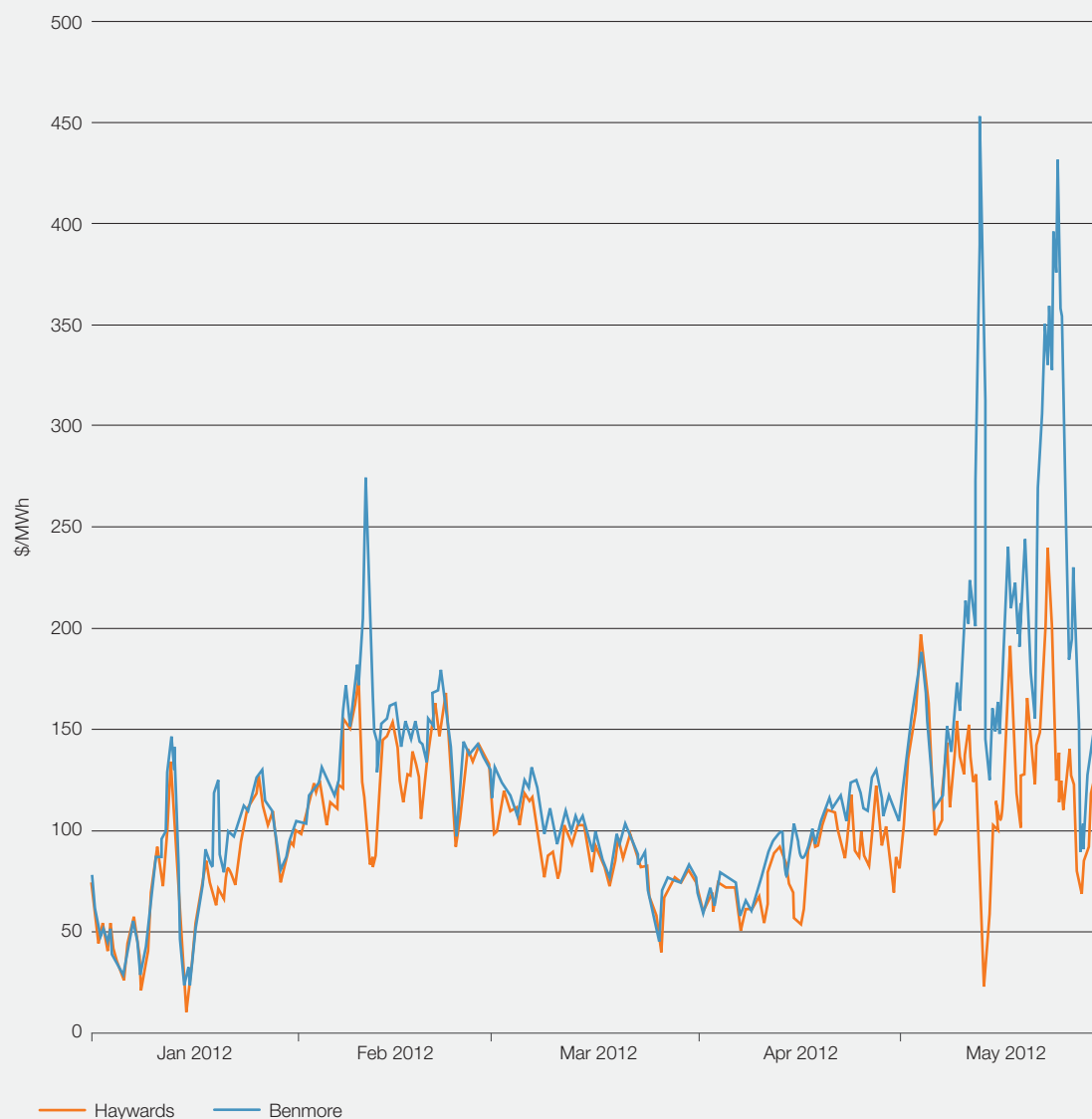
There was also an increase in volatility of spot prices at Benmore. The standard deviation of spot prices in May was \$77 compared with \$36 for the four months prior to May. Figure 68 shows spot prices between January and May 2012. The high volatility in May is obvious from this graph.

The Authority's Market Performance team investigated high South Island reserve prices in 2012.⁷ It concluded that the high South Island reserve prices caused higher energy prices in the South Island (13%) and lower energy prices in the North Island (14%) relative to a counterfactual where South Island reserve prices didn't spike.

The investigation also found that the spike in South Island reserve prices caused a separation in ASX hedge prices. The net cost of this was relatively low at \$1.3 million. However, this ignores the effect of price volatility on purchasers, the cost of which is difficult to measure. In theory, the increased volatility would make decision making more difficult and hedges more valuable. This probably contributed to the north-south separation in the hedge prices in May.

The review recommended that the Authority consider Code amendments to restrict the transfer of offer rights between participants as these can reduce competition. Any provisions would need to consider the potential reduction in transaction costs that intermediaries can bring to a market. The review also recommended that reserve hedges be disclosed.

Figure 68: Increased spot price volatility in May 2012



⁷ See www.ea.govt.nz/industry/monitoring/enquiries-reviews-investigations/2012.

Reliable supply of electricity is a key part of the Authority's statutory objective: to promote competition in, reliable supply by, and the efficient operation of the electricity industry for the long-term benefit of consumers.

Reliable supply includes security and reliability – the number and duration of outages as well as resilience to adverse events. The long-term benefit to consumers comes from avoiding the costs of outages. Efficiency occurs if reliability and security is achieved at least cost.

One caveat of our analysis is that the benefits are avoided costs, and measuring cost/benefit where the benefit is something that isn't going to occur is always going to require an estimate.

A lot of disclosure of reliability already occurs in the industry, with the Commerce Commission requiring Transpower and distribution companies to disclose reliability measures. The Commission also does plenty of comparative analysis of distribution companies.

Given this context, the Authority focused on transmission and was interested in two strands of reliability and security:

- Dynamic – ensuring that incentives for innovation and investment are working well.
- Static – ensuring that existing assets are being managed well.

Dynamic

The heart of the electricity system is the spot market for electricity and the wholesale prices and coordination that this market provides. As such, accurate price signals are necessary to ensure that investors are able to make fully informed decisions about where to build generation, load and transmission. The Authority will continue its focus on

any activity that distorts price signals. This includes:

- scrutinising when constrained-on is used by the system operator to ensure that it is the best option to achieve real time coordination of dispatch
- scrutinising instances where the demand for reserve generation is suppressed
- monitoring the relationship between final pricing and dispatch to ensure that, when participants make decisions on five minute prices, these are mirrored in final pricing
- monitoring investment in peaking/last resort/firming plant and how this complements the overall generation mix
- checking incentives in relation to outages and under-frequency events to ensure that those creating costs in the market are also paying for them.

Static

The static strand of reliability and security revolves around finding ways of ensuring that existing assets are being managed to ensure reliability and security.

Examining industrial accidents like Piper Alpha, Three Mile Island and Deepwater Horizon shows that these accidents were caused by small faults that are assumed to be independent but in fact are coupled together, with the result being a failure that is greater than the sum of the individual faults. Studies of these sorts of accidents show that, before an accident, there are clues such as faulty design and practices that are assumed to be safe but are not. These clues are not joined, as the system's complexity makes it difficult to foresee the consequences of existing settings. These faults are called latent failures and are factors in the system that may have been dormant for a long time (days, weeks or months) until they finally contribute to an accident.

Part of what happened at Huntly on 13 December 2011 was due to protection settings that were not designed for the circumstances that emerged – a latent failure. Similarly, the rusty shackle that caused the blackout at Otahuhu in June 2006 was difficult to identify as it passed inspection. The inspection practice was a latent fault that then caused the shackle to become a latent fault.

The Authority has taken a preliminary look at this aspect of the 13 December event, and although our review concentrated on the effect on the market, future reviews are likely to include a focus on latent failures and the engineering behind failures to determine if there are any systemic problems.

A question that arises is how to minimise these latent failures in a way that is cost effective. Cost effectiveness is important, as total reliability is neither realistic nor desirable in the sense that the cost of avoiding disruption eventually must outweigh the benefit.

As signalled in the Authority's information paper on reliability and efficiency,⁸ the Authority will be using a reliability-centred monitoring regime to guide investigations into incidents. Our expectation is that this approach will help identify instances where latent or hidden failures have caused outages and, through reporting of these, encourage the industry to proactively audit aspects of the system.

We will adopt this approach in future enquiries, reviews and investigations that relate to reliability.

The Authority intends to implement the reliability-centred regime by looking at data from Transpower and our own reviews to see if there are patterns in the underlying causes of faults.

⁸ See www.ea.govt.nz/industry/monitoring/reports-publications.

We have collated information from Transpower's annual Quality Performance Reports to show trends in the causes of system outages (Table 2). This information is very high level, and to implement the new regime properly will require more detail. For example, we cannot tell from this information the contribution that wrongly set protection made to faults overall even though we know it was partly the cause of the 13 December event. We are particularly interested in:

- cross asset-boundary coordination
- management of hidden failures, particularly complexity of secondary asset systems
- longer-term trends in failure types down to specific details like protection or design.

The fault data in Figure 69 comes from the system minute fault data published by Transpower in its annual Quality Performance Report. It starts by taking the system minutes of outages and dividing this by peak energy for that year which gives unserved energy. Then this unserved energy is divided by total delivered energy for the year. This is then indexed to 100 for the 1990–91 year.

Ideally, unserved energy should be scaled by a variable that is driving the faults. A quick look at the list of causes of significant events reveals that the causes were seemingly random – from earthquakes to rats to faulty protection settings. What is certain is that these faults were not driven by peak load, which is why peak system minutes have not been used. We have chosen to scale unserved energy by total load for the year because this is a measure of scale or activity that we think is a better denominator than peak

energy. We interpret these numbers as a measure of unserved energy in proportion to the total energy used in a year.

Transpower's 2010–11 performance target is also calculated as 2010–11 system minutes then indexed the same way as the fault data.

Figure 69 shows an overall increase in unserved energy driven by an increase in significant events from 2005/06 onwards as well as a similar increase in the early 1990s. It should be noted that this increase is not an artefact of how we have chosen to present this data – the raw data from Transpower shows this same deterioration in performance.

Looking at the causes of the significant events as outlined in Transpower's reports from 2005 onwards, we have separated equipment failure, poor maintenance, human action and 'acts of god', finding that 75% of the unserved energy is caused by either equipment failing or inadequate maintenance, 9% by lightning or earthquakes and 15% by human error.

Even with 20 years of data, it is difficult to distinguish between the transmission network becoming more vulnerable to significant events and a run of bad luck. It's even more difficult to determine whether it is cost effective to invest in network resilience or improved maintenance procedures. However, it is important to be transparent with the information and continue to monitor what is happening.

Figure 69: Normalised volume of unserved energy

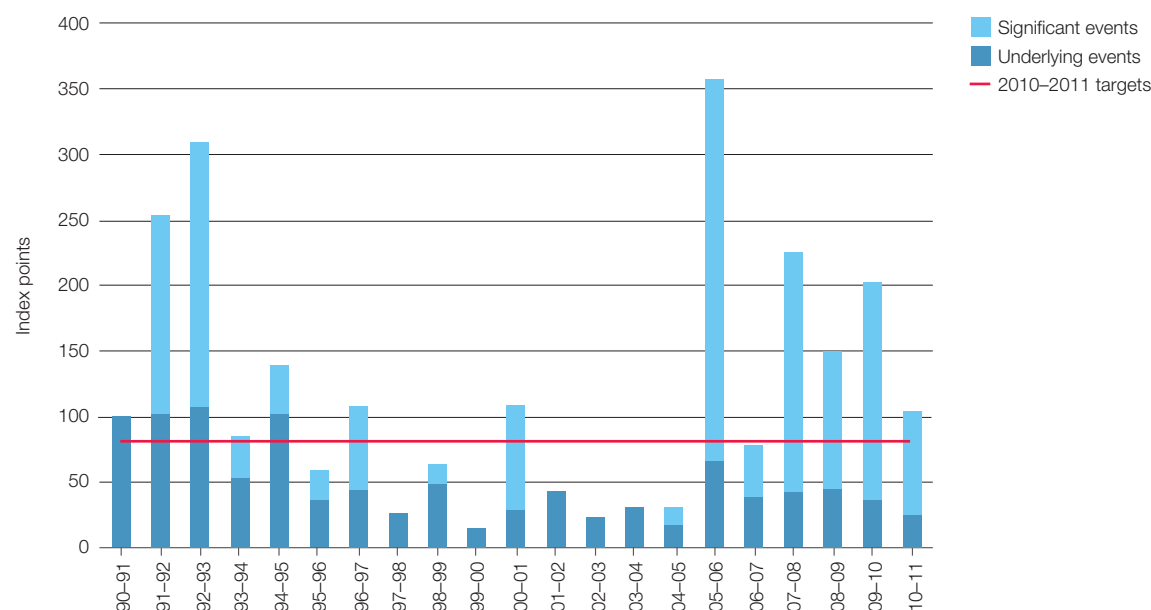


Table 2: Significant faults reported by Transpower, in descending order of system minutes, since 2005

System minutes lost	Date	Event	Category
29.8	12/06/06	Earthwire failed at Otahuhu causing 110kV bus fault and widespread loss of load in Auckland area.	Equipment
14.1	12/10/07	At Kawerau, two 11kV buses were removed from service to investigate a bus noise, eventually found to be caused by a faulty current transformer .	Equipment
8.2	30/10/09	The Henderson-Otahuhu circuit tripped when a container hoist operating in a storage facility made contact with the blue phase conductor of one of two circuits on the Henderson-Otahuhu 220kV transmission line that supplies north Auckland and Northland. The other circuit on the line was out of service for planned work, and the remaining in-service circuit tripped, causing widespread supply interruptions.	Human error
6.4	25/01/10	Trees underneath the Otahuhu-Whakamaru C transmission line near Hamilton caused a flashover, and one of the two circuits on the line tripped out. Approximately 30 minutes later, before Transpower could identify the cause of the first fault, a tree fire started by the flashover caused the other circuit to trip. Prior to this incident, another circuit in the area had been taken out of service for planned work, but neither of the trippings caused interruptions to this point. Shortly thereafter, another circuit supplying Auckland tripped coincidentally because of a lightning strike , and other circuits in the region began tripping on overload. Load management became necessary to maintain the power system integrity, and there were operator-initiated rolling power cuts throughout Auckland and Northland over the next 5 to 6 hours.	Maintenance
5.4	04/09/10 and 22/02/11	Two significant events were caused by the Canterbury earthquakes in September 2010 and February 2011. During the earthquakes, the transmission system responded extremely well, and damage was relatively minor. There was no interruption to supply from the Transpower network to the local networks following any of the other earthquakes or aftershocks.	Earthquake
4.9	01/09/08	At Whirinaki, an 11kV cable fault caused a partial interruption at one of two in-service sections of the 11kV bus, and resulted in a total plant shutdown of the customer's plant. This occurred during a planned outage to upgrade another section of the 11kV switchgear.	Equipment
4.1	03/02/09	At Penrose, a 220/33kV supply transformer developed a fault and tripped, causing an interruption to supply and subsequent load shedding to control load. Although this was one of three transformers normally in service at Penrose, one of the other two was already out of service for refurbishment work, and the remaining unit was unable to meet the load.	Equipment
3.9	07/10/07	Part of Westport 11kV bus exploded following a close-in lightning strike .	Lightning

System minutes lost	Date	Event	Category
3.4	02/12/10	A flashover on a 33kV bus insulator in the outdoor switchyard supplying the Glenbrook steel mill. This substation is a high-maintenance site mainly because of atmospheric pollution. This particular event was caused by bird droppings on an insulator . At the time of the fault in December 2010, Transpower was already progressing plans to convert this to an indoor substation, and this was scheduled for completion by late 2012.	Maintenance
2.3	11/03/10	At Kawerau substation, a rat found its way into an enclosed 11kV bus bar, causing a bus fault and consequent supply interruption to the Norske Skog plant.	Maintenance
1.9	24/09/07	Protection relay at Kinleith failed to operate for line fault, resulting in interruptions at five points of service.	Equipment
1.8	14/09/06	Earth sticks left on Islington 220kV bus in error caused 220kV bus fault and supply interruptions to the north of the South Island.	Human error
1.3	25/08/06	Glenbrook 33kV bus tripped when a bus insulator failed .	Equipment
1.3	22/04/10	At Wilton substation, maintenance workers were working on the 'top' 110kV bus and accidentally dropped a test lead onto the live 'bottom' bus underneath. Switching was being organised to safely remove the test lead when a gust of wind caught the test lead, causing a bus fault. This resulted in supply interruptions at Central Park and Kaiwharawhara.	Human error
1.1	28/08/06	At Kawerau, a switching error combined with misleading indication resulted in supply being disconnected.	Human error
1.1	15/10/06	Kaikohe-Kaitaia line removed from service to repair conductor damage caused by quarry operations .	Human error
1.1	07/03/09	A fault on the Kaitimako-Mount Maunganui-Tauranga circuit caused supply interruptions throughout the Bay of Plenty area. The initial fault was not cleared correctly because of incorrect protection settings at the new Kaitimako substation, causing other circuits to trip.	Equipment
1	11/05/06	Protection relay maloperation at Tarukenga resulted in a grid emergency and forced disconnection of load in the Bay of Plenty.	Equipment
1	17/03/09	A switching error at Timaru resulted in a 110kV bus fault, which caused interruptions at four sites in South Canterbury.	Human error



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