Wholesale electricity prices: December 2010

28 January 2011

Executive summary

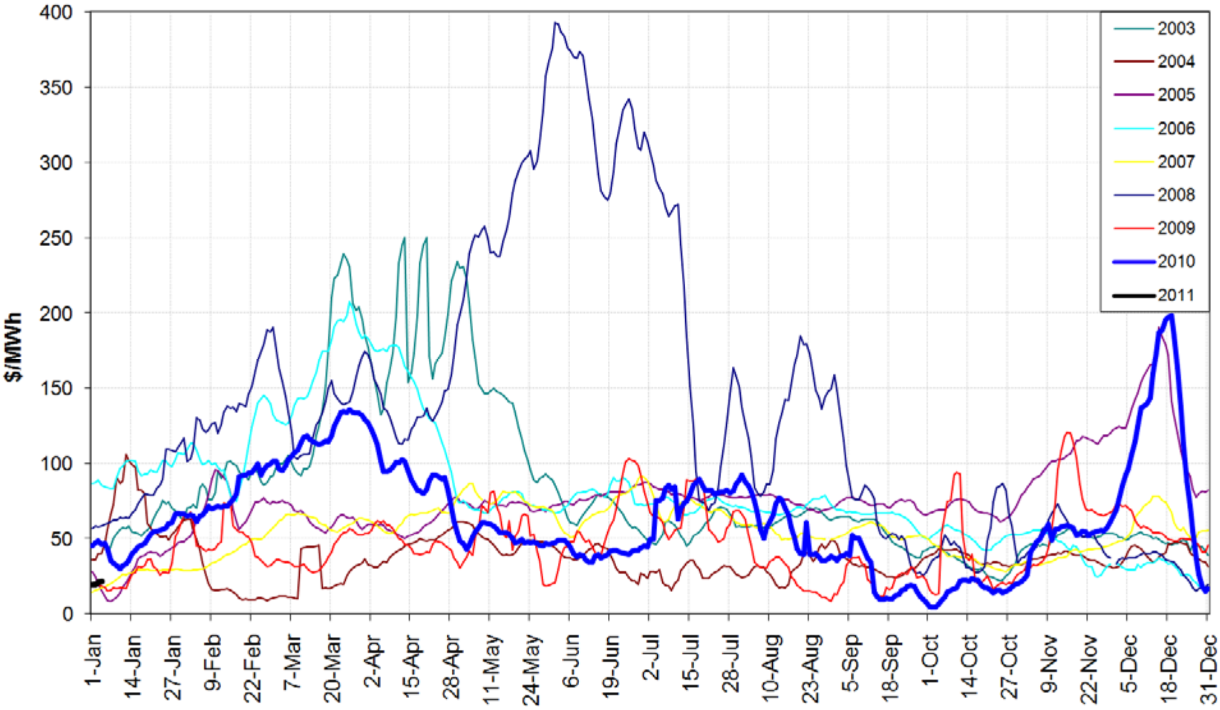
Towards the end of November 2010, wholesale spot prices began to increase and climbed quite rapidly throughout the first three weeks of December. Although prices were at very low levels relative to past experience throughout October and into November, the price levels attained in December were, by historical standards, high. The average price at the Haywards reference node for the first 22 days of December was $135.90/MWh, an increase of 144% over the November average and a 158% increase over the 1-22 December 2009 average.

Highlighting the volatility of spot prices during this period, prices had once again returned to historically very low levels by early January 2011.

The figure below shows average prices for the past eight years and the dark blue line is 2010. The December 2010 increase in prices is clearly evident, as is the historically low price period in September through to early November.

Throughout December 2010, the level and pattern of demand was typical and no transmission outages occurred.

The publicly available information at the end of November 2010 made it difficult to determine why the wholesale spot price increased so rapidly in December.



NZX New Zealand electricity price index, 2003-11

Note: 7-day demand-weighted rolling average.

The Authority has assessed the supply and demand conditions giving rise to the high prices in December 2010 and determined that several factors most likely contributed. These are:-

- Uncertainty regarding hydrology

  - Lake levels on a national basis in December 2010 were at average levels but trending downwards. Manapouri was well below average;
  - Inflows to the hydro reservoirs were well below average levels. Drought conditions in the Waikato caused inflows to Lake Taupo to be at less than 10% of average levels for December;
  - A strong La Niña weather pattern was emerging and by late November - early December was clearly evident to all participants. Such weather patterns are typically associated with significantly below normal inflows and early melting of the snow pack;
  - The early and rapid melting of snow pack was confirmed by measurement and modelling. By late November - early December, this information was understood by parties other than those engaged in monitoring snow pack. Early snow melt means that reliance on lake levels as a guide to storage conditions can potentially be misleading;
- Uncertainty regarding the planned Maui outage in February 2011; and
- Uncertainty regarding thermal plant availability.

An evolving situation with respect to hydrological conditions coupled with uncertainty and speculation regarding gas supplies and thermal plant availability came to a head in late November and early December. Although it is appropriate that a situation of fuel (including hydrology) scarcity should result in prices increasing, a key issue is the speed and magnitude of the run-up in prices.

Hydro generators were clearly signalling through their offer prices that they had some concern about hydro storage and expected inflows ahead of next winter. As the hydro generators increased their offer prices, thermal plant entered the market enabling water to be conserved. Prices increased rapidly once hydro offers were increased, as the remaining quantity of low price offers was quickly exhausted. A contributing factor to the price increase was the Otahuhu combined cycle plant outage.

The prospect of the proposed customer compensation scheme being adopted by the Authority in the first quarter of 2011 may have intensified the level of caution exhibited by generators when considering hydrological conditions in early December 2010. The proposed customer compensation scheme will require retailers to compensate their customers if they are called upon to voluntarily reduce demand in a dry winter.

The market responded to the high price signals; some consumers curtailed demand and all available thermal plant was made available. Also a thermal plant that was offline for maintenance was quickly brought back into service.

Offer behaviour has been analysed to see if spot prices could have been lower had generators selected lower priced offer strategies. Small reductions in offer prices, e.g. 5-10%, gave rise to trivial declines in spot prices. Dramatic reductions in offer prices, in the order of 40%, would have resulted in spot price declines of 19% or less had they been undertaken by a single participant, or up to 35% if all generators reduced offers simultaneously. Spot price declines of that magnitude would have still been well short of the price increases experienced in December. However, more importantly, they would have caused hydro storage to run down even further, which was precisely the risk generators were seeking to mitigate through increasing their offers in the first place.

Thermal plant had less ability to influence price than hydro plant, and there is no evidence the thermal generators attempted to do so, for example, by increasing thermal offer prices.

The analysis of price response to changes in offer price is also a measure of the market power of participants. It is clear that participants are able to influence the market price, and therefore they do possess some market power. One possible hypothesis is that hydro generators opportunistically raised offer prices under the guise of a concern about hydrology.

Rigorously testing that hypothesis would be a significant undertaking, requiring detailed information that would have to be obtained under the Authority's information gathering powers, (e.g. on production costs, fuel contracts, hedge contracts, and any other bilateral contracts held by the participant under investigation), and sophisticated economic modelling.

In this case, the Authority believes a formal investigation is not warranted as the potential benefits for Code development from a more formal investigation, over and above what has been achieved by the inquiry to date, do not outweigh the likely costs to it and other market participants of a more formal investigation. It appears to the Authority that hydro generators, acting in an environment of incomplete information and concern about hydrology, raised offers to the degree necessary to induce conservation of storage. A case for an in-depth investigation would have existed if thermal generators had increased their offer prices or if hydro generators had priced their offers well above the level needed to conserve storage.

A key lesson from this event is the importance of timely and reliable information for a well functioning market (for example snow-pack could be incorporated into hydro storage information). Certainty as to the performance of regulatory functions is also critical to informed decision-making by market participants.

More broadly, the strong public reaction from large spot market purchasers appears to have arisen from inadequate information available to them about supply risks in early December. The high prices in December should provide a timely reminder to all parties exposed to spot market prices to hedge their exposures if they are unable or unwilling to reduce demand when spot prices rise to the levels needed to bring all thermal generation into the market. The New Zealand electricity system relies on those price signals to efficiently manage its hydro resources, and spot prices will rise to those levels from time-to-time.

Next steps

The Electricity Industry Act 2010, which came into effect on 1 November 2010, made a number of changes to the regulatory arrangements under which the sector operates, including the introduction of a market monitoring role for the Authority. Its predecessor did not have this function.

From the Authority's perspective, the focus will be maintained on instituting its monitoring regime. This involves being positioned to detect, anticipate, and signal to the market the emergence of unsatisfactory aspects of the market. Where that is not possible due to events unfolding rapidly or are of very short duration, the intent is for the Market Performance group to be able to issue analysis and commentary in a timely manner; i.e. as situations unfold rather than after the event.

In particular, the Authority is in the process of developing tools and procedures for detecting the incentive and ability by participants to exercise market power. The Authority plans to release an information paper describing its industry and market monitoring plans as a priority.

Likewise, from 1 November 2010 the System Operator became responsible for the day-to-day management of security of supply matters. This has brought to light some ambiguity around the Emergency Management Policy and Security of Supply Forecasting and Information Policy documents. It has also become clear the System Operator didn't receive a timely flow of information to enable it to fully comply with those policies.

The Authority's predecessor, the Electricity Commission, undertook an initial scoping in early 2010 for a project requiring greater disclosure of management and security risks by electricity generators above a certain size.

Based on that initial scoping, and the matters that have come to light during this review, the Authority is currently giving consideration to establishing a project to review procedures, policies and oversight mechanisms concerning the disclosure of relevant information among participants. Areas to be considered include:

- The timeliness and reliability of plant availability information (including related infrastructure, e.g. gas supply facilities);
- Whether the Authority needs to better understand the hedge positions of participants;
- Whether dissemination of more timely and sophisticated fuel and hydro storage information is warranted, e.g. gas, coal, diesel and the breakdown of hydro storage information into its reservoir and snow pack components and;
- the flow of information to the System Operator required to enable it perform its security of supply functions.

Glossary of abbreviations and terms

Act	Electricity Industry Act 2010
Authority	Electricity Authority
Code	Electricity Industry Participation Code 2010
Contact	Contact Energy Limited
EMP	Emergency Management Policy
Genesis	Genesis Energy Limited
GWh	Gigawatt hour
GXP	Grid exit point
Meridian	Meridian Energy Limited
MEUG	Major Electricity Users' Group
MRP	Mighty River Power Limited
MW	Megawatt
MWh	Megawatt hour
NZAS	New Zealand Aluminium Smelters Limited
NZX	New Zealand stock exchange
POCP	Planned Outage Co-ordination Process
SCADA	Supervisory Control and Data Acquisition
SO	System Operator
STOS	Shell Todd Oil Services
TP	Trading period
TrustPower	TrustPower Limited
vSPD	Vectorised Scheduling, Pricing and Dispatch

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1. Introduction and purpose

1.1 Context

1.1.1 Wholesale electricity prices increased markedly in late November and early December 2010, despite hydro lake levels being at the national average for this time of year and the absence of any apparent fuel or capacity shortages.

1.1.2 From an average of $55.71/MWh in November 2010, the price at the Haywards node increased by $80.19/MWh to reach an average of $135.90/MWh for the period 1-22 December. The average Haywards price in November 2009 was $70.57/MWh, whereas for the period 1-22 December 2009 the average price was $52.66/MWh.[1]

1.1.3 The highest price observed during December 2010 was $555.43/MWh, in trading period 34 at the Kaitaia node on 15 December. Prices at the three key reference nodes in trading period 34 on 15 December were:

- $492.47/MWh at Otahuhu,
- $462.63/MWh at Haywards, and
- $447.92/MWh at Benmore.

1.1.4 Consistent with the Authority's function under the Electricity Industry Act 2010 (Act) to pro-actively monitor market performance, a Special Market Brief was issued on 9 December 2010 informing the market that the Authority was looking into these increases in wholesale electricity prices.

1.1.5 During the week before Christmas, substantial rain fell and wholesale prices began to recede. On Wednesday 22 December, the load-weighted average New Zealand price was $70.22/MWh while the average price at Haywards was $63.56/MWh. The maximum price in New Zealand on 22 December was $120.54/MWh, which occurred in TP 27 at Kaitaia. The price at Haywards during TP 27 on Wednesday was $96.88/MWh.

1.1.6 By January 2011, prices had receded even further and were lower than historical average levels for early January. By the second week of January, excess water was being spilled at Pukaki, Tekapo, Clyde and Roxburgh.

1.2 Purpose

1.2.1 This assessment addresses the basic question: Are there reasonable grounds for spot market prices to have increased as rapidly and to the level they did in December 2010?

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[1] On a load-weighted basis, the November average wholesale price across all of New Zealand was $73.32/MWh in 2009 and $57.35/MWh in 2010. Similarly, for the period 1-22 December, the load-weighted average price was $55.47/MWh in 2009 and $147.54/MWh in 2010.

1.2.2 With just five major generators in New Zealand, there is a common concern that one or more may be able to exploit a change in market conditions for their benefit, to the detriment of consumers.

1.2.3 Specific questions addressed in this document include:

- When did wholesale spot prices begin to increase and by how much?
- Was the increase in prices unusual given the time of year and relative to other years?
- What supply and demand conditions changed that may have led to the price increase? For example, energy demand; perceptions about future hydro inflows and storage; or generation, transmission, and other infrastructure outages.
- How did generators' offer behaviour change, if at all, prior to and during the high price period, and was it different for different types of generation?
- Was there any demand-side response to the high prices and did it have any impact?
- Was there any evidence of firms exercising undue market power?

1.2.4 Our assessment begins by summarising the basic facts of the situation as they relate to prices, hydrological conditions, generation plant availability and utilisation, other infrastructure outages, generator offers, and demand response. Attention is then given to analysing price outcomes under alternative hypothetical scenarios regarding perceptions about predicted hydrology and offer strategies. Finally, conclusions and the next steps are presented.

1.3 Background

1.3.1 The New Zealand electricity system is dominated by hydro generation, supported by relatively small storage reservoirs. Furthermore, inflows into reservoirs are variable and uncertain. Thermal plant is used to enable demand for electricity to be met when there is insufficient output available from hydro plant. Other plant types such as geothermal and wind contribute to meeting overall demand.

1.3.2 The wholesale electricity market is the mechanism used to ensure efficient utilisation of all available plant. Owners of both hydro and thermal generation plant must form a view as to the likely future availability of hydrological resources. In doing so, they are able to assess the value of offering their plant for use today relative to the value of offering it at some other time in the future.

1.3.3 When hydro resources are plentiful and plant owners expect that situation will persist, it is reasonable to assume hydro plant will be offered into the market at a relatively low price – certainly at a price that is lower than the fuel cost of thermal plant. Conversely, as hydro resources become scarce, hydro plant owners value their water more highly and ration their use of hydro resources to provide for future supply, but only to the extent that they have the ability to store water. In such situations, hydro plant may be offered to the market at a higher price than some thermal plant.

1.3.4 Future hydro inflows are not the only uncertainty that generators must consider. The level of demand, wind and thermal fuel availability, planned and unplanned generation outages, and potential transmission failures and constraints are all factors that need to be considered when determining how to offer and utilise plant.

1.3.5 Given the co-ordination and signalling role played by prices in the wholesale market, stakeholders and regulatory bodies pay particular attention to the efficacy of spot prices. In the short term, prices determine how resources are deployed, e.g. the scheduling and dispatch of generation plant and transmission equipment.

1.3.6 Expectations of future spot prices are an important factor in investment decisions, as investors need to be confident that future spot prices will provide an adequate return on their investments. Expectations of future spot prices also underpin prices bid for electricity hedge contracts. Concerns about market power in the spot market tend to undermine the development of an effective hedge market, which in turn makes it more costly for parties to hedge against spot market prices.

1.3.7 In both the short- and the long-term, a competitive pricing outcome is a prerequisite for efficient decision-making. Appropriate information disclosure is essential for effective competition in the spot market and for effective functioning of the hedge market, particularly futures contracts. Establishing an effective electricity futures market will in turn create incentives for greater information disclosure around key supply risks.

1.4 Industry and Market Monitoring

1.4.1 The Authority, which began operations on 1 November 2010, is currently in the process of designing and implementing its industry and market monitoring regime. A prescribed set of processes and accompanying nomenclature is yet to be finalised and shared with stakeholders.

1.4.2 It is important to note at the outset that the primary purpose of the Authority's industry and market monitoring activities is to inform Code (Electricity Industry Participation Code 2010) development and to support market-facilitation measures that promote competition in, reliable supply by, and the efficient operation of, the electricity industry for the long-term benefit of consumers. It is not to directly support the enforcement of Code compliance.

1.4.3 If evidence of a Code breach was uncovered, the matter would be referred to the Authority's Legal and Compliance team.

1.4.4 Routine screening and comparison with pre-determined thresholds will from time-to-time alert the Authority to delve more deeply into the underlying causes of unusual situations.

1.4.5 Over and above the reporting that emanates from routine screening activity, a two-tiered approach to more in-depth investigation is envisaged. Details will be set out in an information paper on industry and market monitoring which we hope to release to stakeholders in the second quarter of 2011.

1.4.6 The initial study arising from routine screening is essentially a fact-finding exercise that makes use of public domain data and models held by the Authority. This may be supplemented with data and knowledge requested of and supplied by participants on a voluntary basis. The purpose of the first stage is aimed at providing adequate explanations of unusual events by making use of minimal analytical resources.

1.4.7 The present assessment of prices in late November - December 2010 falls into this category.

1.4.8 Failure to adequately explain unusual events using the tools and data of the first stage would be a likely pre-condition to escalating the assessment to the second stage. At this point, the information gathering powers of the Authority would likely be invoked. If, after the first stage, the Authority does not believe it has a full explanation of events, it would exercise its discretion as to whether to proceed to the second stage of a more formal inquiry guided by its judgement of the potential benefits of doing so in terms of Code development relative to the likely costs to it, and other parties, of further investigation.

1.4.9 The focus of the review process is to identify potential Code changes and changes in procedures by the Authority for further consideration using the cost benefit framework adopted by the Authority.

2. Summary of external factors

2.1 Introduction

2.1.1 This section begins with a summary of the price situation, focusing particularly on the December high-price period. It then describes market conditions such as hydrology and gas availability.

2.2 Prices

2.2.1 Figure 1 shows prices at the Haywards node from 22 November to 22 December 2010. The run up in price and the increased volatility beginning in late November is clearly evident. Also shown on the plot is total New Zealand load. Load follows its usual pattern throughout the period, with demand at the weekends less than during the week. This would suggest that changes to the pattern of load do not explain the higher prices through to late December.

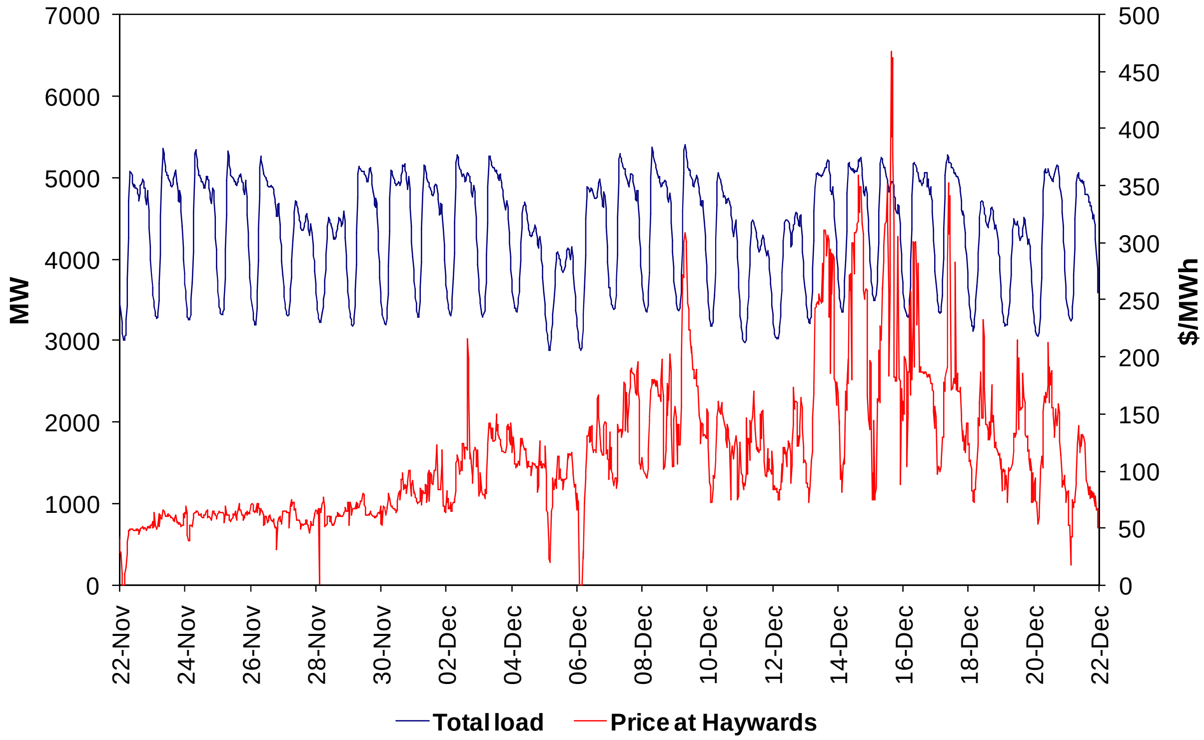

Figure 1 Haywards price and national load, 22 Nov – 21 Dec 2010

2.2.2 The same data is plotted over a three month and one year period, respectively in order to put these prices in greater context, (refer Appendix A). Once again, the run up in prices in December 2010 is clearly evident and notable. Although not shown on the plots, prices at other nodes followed similar trends and were at similar levels to those observed at Haywards.

2.2.3 An alternative context in which to view the December 2010 prices is to compare across several years. Figure 2 plots demand-weighted average prices since 2003. The heavy blue line denotes the price path throughout 2010. It is immediately apparent that prices throughout much of the September to November 2010 period were at, historically, quite low levels.

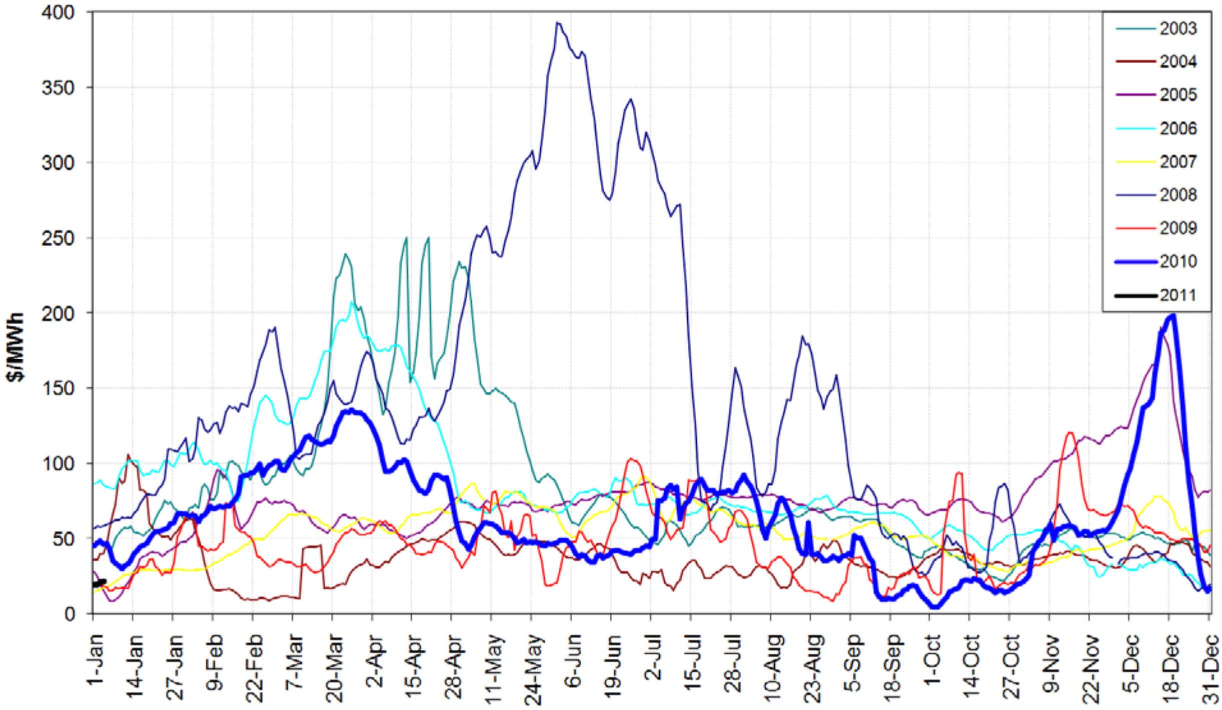

Figure 2 **NZX New Zealand electricity price index, 2003-11**

Note: 7-day demand-weighted rolling average.

2.2.4 Peak prices in December 2010, however, are higher than for any other month of December since 2003. December 2010 prices are substantially higher than all years except 2005,

2.2.5 Extremely high prices during the very dry winter of 2008 are clearly evident in Figure 2, yet the December prices preceding the 2008 winter (see the faint yellow line) are well below the December 2010 price levels. Expectations of low hydro inflows between now and the winter of 2011 might be part of the reason prices increased in December 2010.

2.3 Hydrological conditions

Hydro storage

2.3.1 On a national basis, hydro storage was at above average levels throughout much of December 2010, although it was trending downwards. With the pre-Christmas rainfall, however, it started trending back up.

2.3.2 Aggregate hydro storage in the New Zealand system is typically at its lowest levels at the end of winter. It then increases as the snow begins to melt and rain falls in the spring. Depending on how wet it is during the summer months, maximum aggregate hydro storage is typically attained at some point from December/January through to as late as March.

2.3.3 Figure 3 shows how nationwide hydro storage declined over the mid-November to mid-December period from 73% of full capacity to 70%. It also shows the change in storage levels at all major hydro reservoirs over this period.

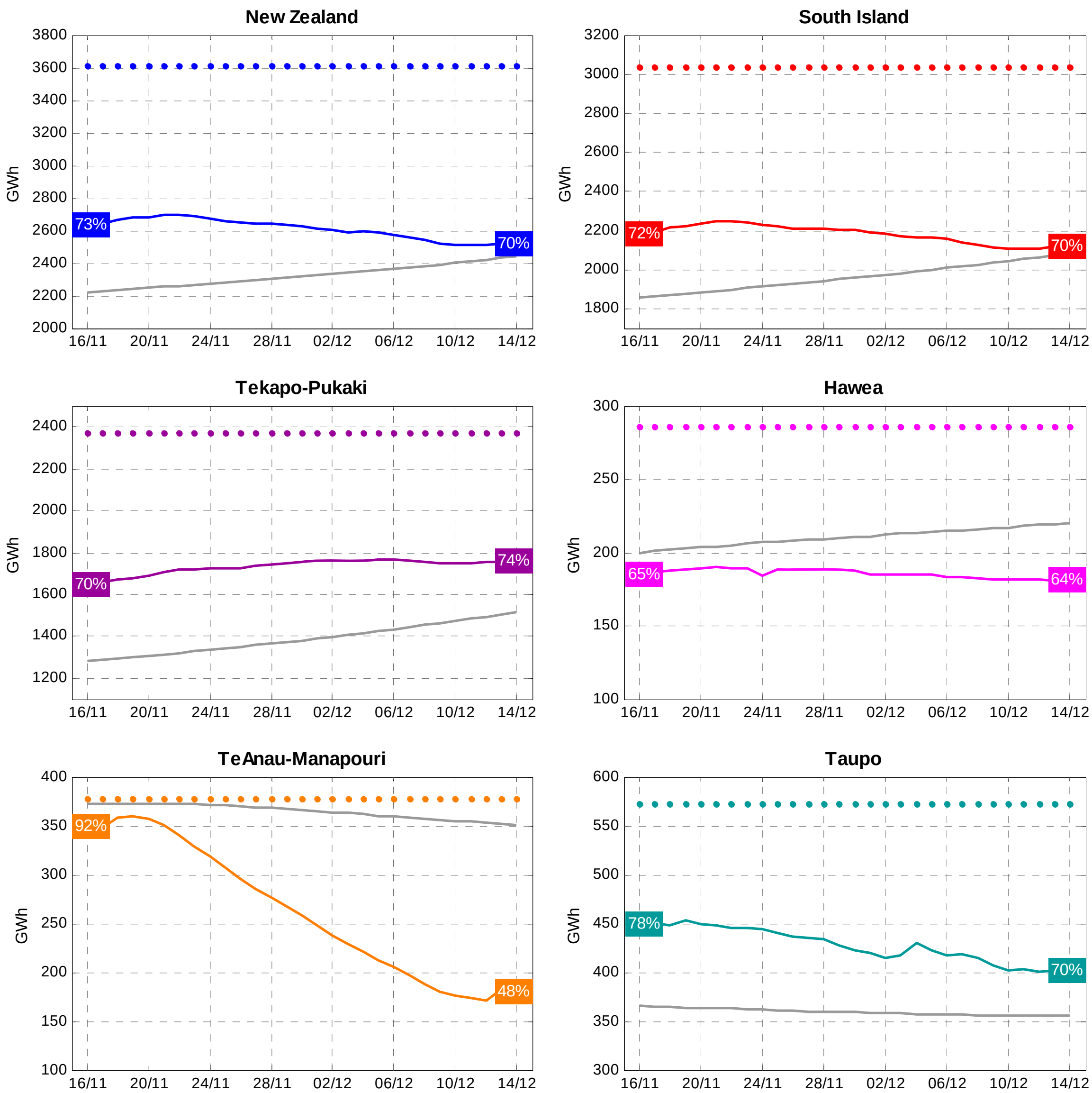

Figure 3 Hydro storage in the major lakes, mid-November through mid-December

Notes: Coloured solid lines denote actual levels.
Dotted lines denote nominal full levels.
Grey lines denote average storage levels.
Coloured boxes indicate percentage of the nominally full level.

2.3.4 Storage in the Tekapo-Pukaki system in the South Island, by far the largest hydro reservoir in New Zealand, increased over this period, from 70% to 74% of full capacity. Te Anau-Manapouri, the next largest system, was well below average levels and declined dramatically – from 92% full in mid-November to just 48% by mid-December.

2.3.5 Manapouri storage in mid-December 2010 was at about 150 GWh. In 2008, Manapouri storage went below 100 GWh and approached this level on several occasions. However, such low storage levels at Manapouri in 2008 did not occur until March, much later in the summer than is the case experienced n 2010. Low levels at Manapouri at such an early time may have raised concerns that fed through to prices in December 2010.

2.3.6 Meridian appeared to change how Manapouri was operated from about December 2007 so that storage was maintained at the 200 GWh level until about February 2008, when it was then allowed to run down to the 100 GWh level. Storage and generation at Manapouri for the period November 2007 through to June 2008 can be seen in Figure 4.

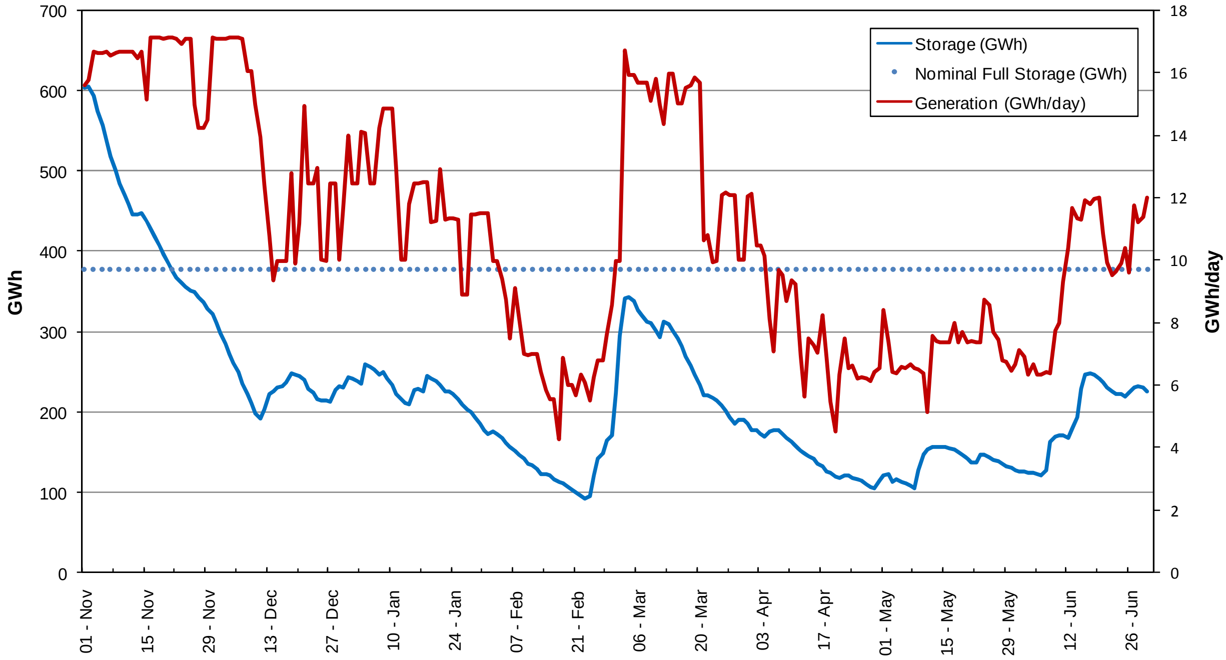

Figure 4 Manapouri storage and generation, November 2007 – June 2008

2.3.7 Meridian has contractual obligations to supply power to New Zealand Aluminium Smelters Ltd (NZAS). Although there is no requirement for Meridian to source that power from Manapouri, it is reasonable to assume that low hydro storage levels at Manapouri well before replenishing inflows can be expected would increase the commercial risks for Meridian in relation to its NZAS obligations.

Inflows

2.3.8 Figure 5 summarises inflows into the major hydro catchments between mid-November and mid-December. Inflows were generally well below average during this time, although South Island inflows tracked up towards average levels towards the end of the period.

2.3.9 Taupo inflows, on the other hand, dropped below the 10th percentile of mean inflows during November. This observation is consistent with the widely publicised drought conditions in the Waikato. The Waikato drought was officially declared on 15 December.

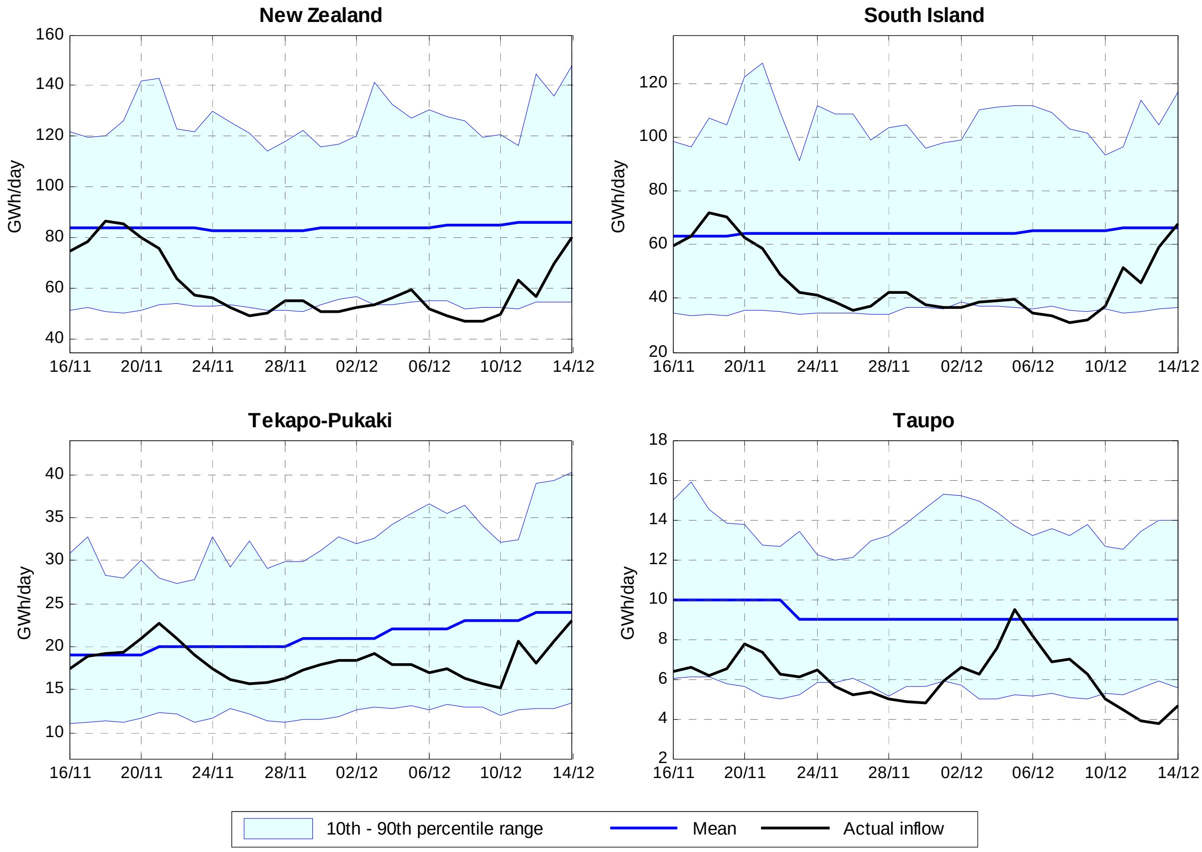

Figure 5 Inflows into major hydro catchments, mid-November – mid-December

Snow pack

2.3.10 A significant contributor to inflows in the South Island hydro catchments is snow melt. In a typical year, snow pack reaches its maximum around October after the snowfalls cease and as the temperatures begin to rise. The rate and degree of warm weather through the spring months and into summer influences the rate at which the snow melts and therefore the flows into the storage reservoirs.

2.3.11 It is our understanding that both Contact and Meridian independently monitor snow pack and model it using a tool known as Snowsim. Using information provided by Meridian, Figure 6 contrasts the 2010 snow pack (blue line) with mean snow pack levels (heavy pink line). The lightweight pink lines depict the first and third standard deviations around the mean.

2.3.12 The figure plainly demonstrates that snow pack reached a peak in 2010 at just below historical average levels. But the rate at which the snow pack has melted since about late October 2010 has been considerably faster than is the case on average.

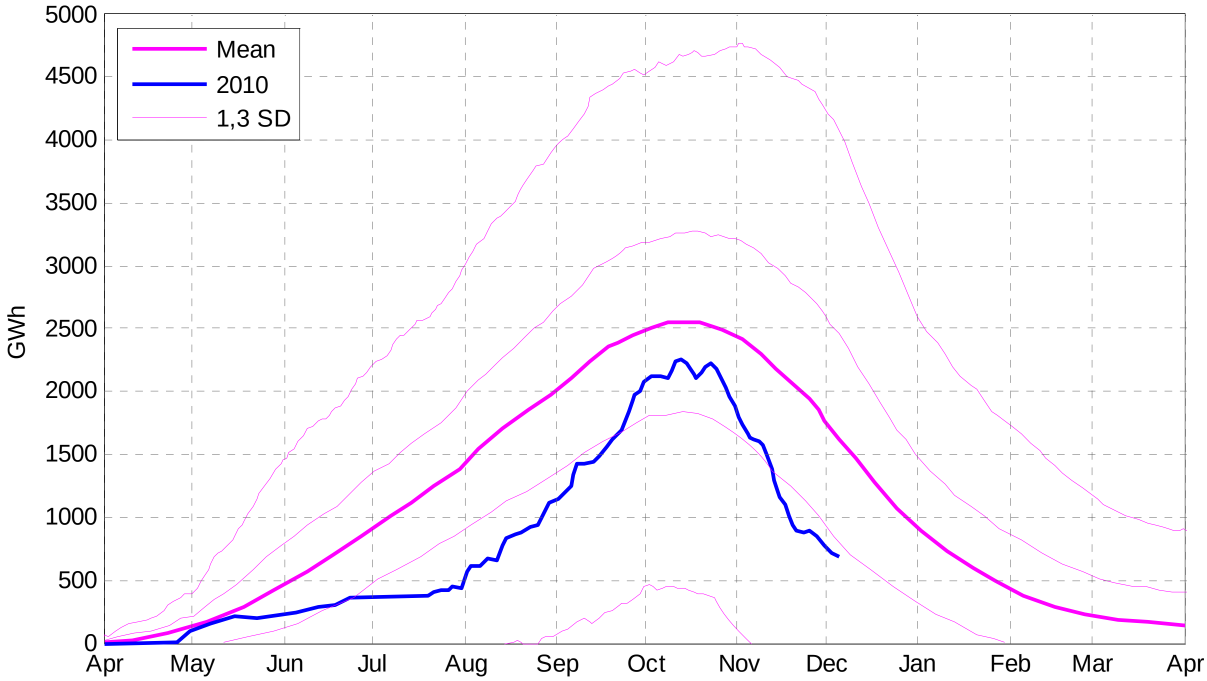

Figure 6 **South Island snow storage as at 4 December 2010**

Source: Meridian Energy Limited.

2.3.13 Consequently, the level of snow pack in early December 2010 was well below average levels. Meridian estimated the total South Island snow pack as at 4 December to be about 680 GWh ,(i.e. the amount of snow able to be converted into electrical energy), which is about 41% of average level for that time of year.

2.3.14 As a result of the snow melt occurring more quickly than usual while aggregate South Island hydro storage was only at average levels implies that inflows other than from snow melt were well below average since winter 2010. Stated differently, South Island lake levels in December appear to have been greater than they would have been in an average year because of the early occurrence of inflows from snow melt which is usually in January-March.

La Niña

2.3.15 The early and rapid melting of the snow pack is consistent with a La Niña weather pattern. The La Niña weather pattern is also associated with below normal inflows into hydro catchments generally.

2.3.16 Figure 7 shows the Southern Oscillation Index (SOI), which is a reliable predictor of El Niño and La Niña weather patterns. It is notable that the SOI for 2010 appears similar in magnitude to that experienced in 2008, a year categorised by very low inflows and storage in the months preceding the winter.

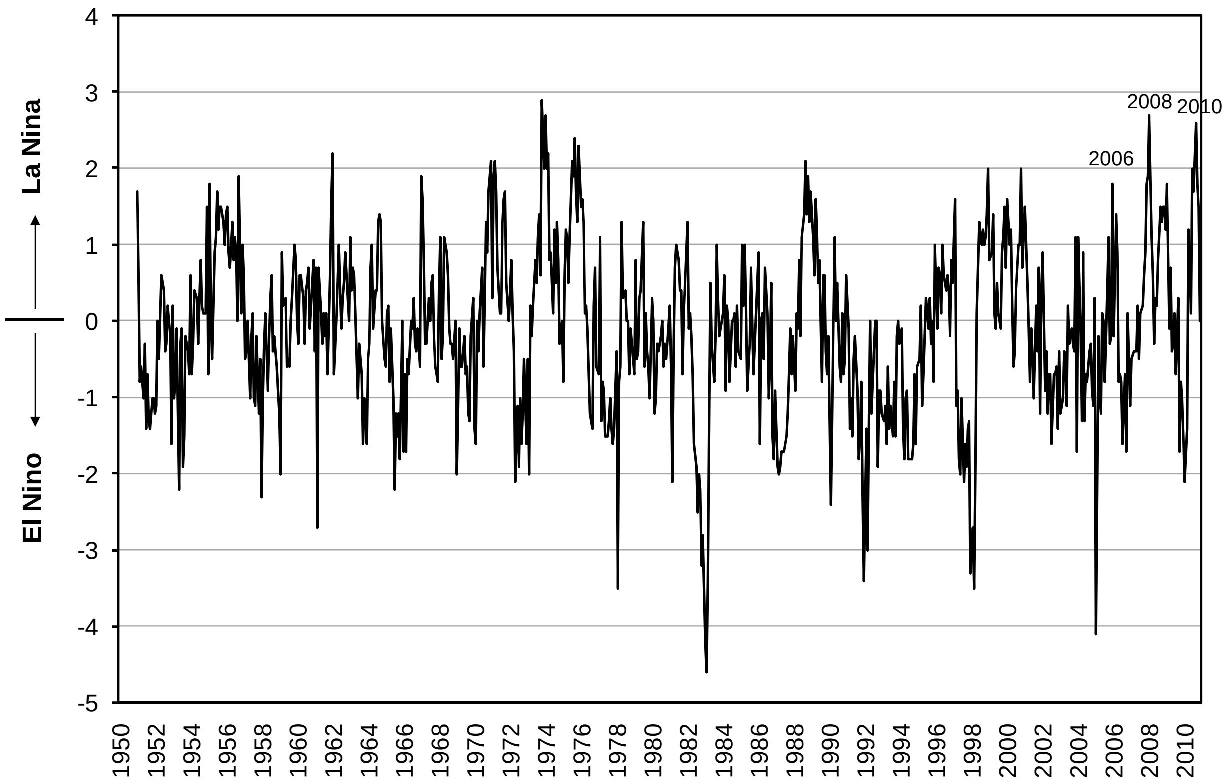

Figure 7 **Southern Oscillation Index, 1950 to 2010**

Source: NOAA National Weather Service, Climate Prediction Center. http://www.cpc.ncep.noaa.gov/data/indices/

Summary of hydrological conditions

2.3.17 A strong La Niña weather pattern has been observed developing over the past few months. History would suggest that under such conditions, hydro inflows between mid-late 2010 and the 2011 winter will likely be lower than normal. The snow pack from the 2010 winter has melted early and rapidly, masking the impact of low rainfall.

2.3.18 Figure 8 demonstrates this masking effect by showing where mid-December 2010 hydro storage, or lake levels, would have been had the snow melt between 1 November and 12 December 2010 occurred at the average rate. Water in the hydro reservoirs that comes from snow melt has been removed from the data and converted back into snow pack; it is then released into the reservoirs at the long-run mean rate of snow melt. Reservoir storage would have declined rapidly over the period 1 November to 12 December and this would have resulted in lake levels well below average levels by mid-December.

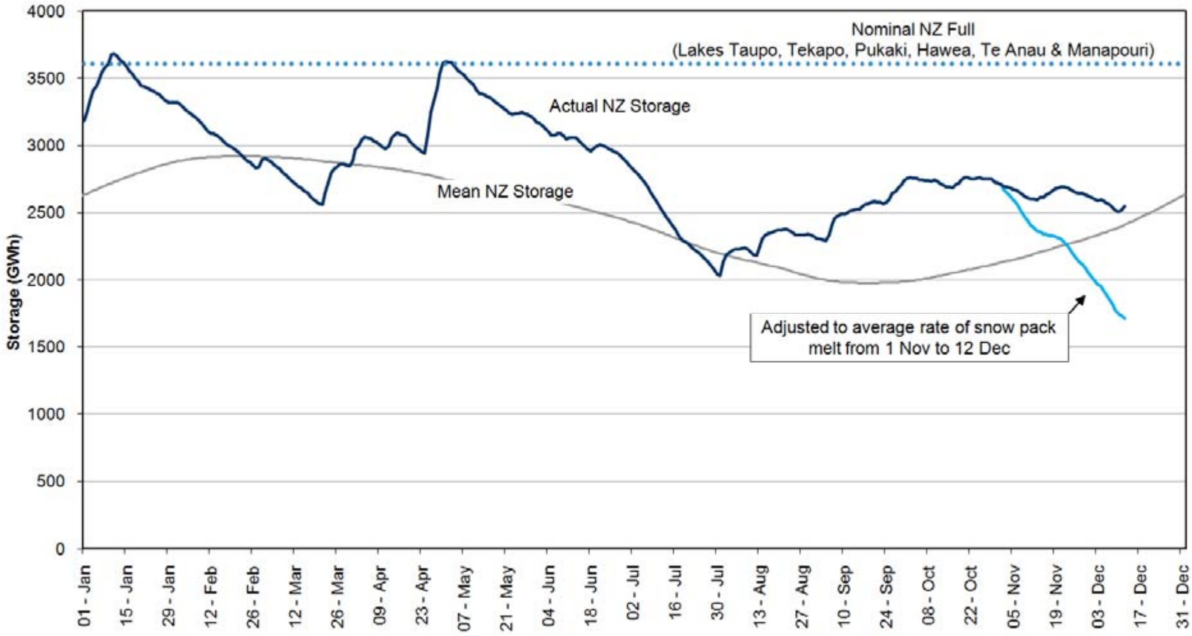

Figure 8 Hydro storage adjusted to average rate of snow melt, 2010

2.3.19 All of this suggests it would have been prudent for hydro operators to have been taking an increasingly cautious approach to the use of water during late November and early December.

2.3.20 It is important to be careful when reporting and interpreting 'storage' data. Storage can refer to both water in lakes (i.e. the lake level) and snow and ice (i.e. snow pack) that is yet to melt and make its way into the lakes. Snow pack essentially represents a guaranteed future inflow, although the timing of that inflow is decidedly temperature-dependent. Rainfall is a highly variable and uncertain source of inflows.[2]

2.3.21 The substantial rainfall immediately before and after Christmas 2010 has seen storage levels increase to the point where some spill of excess water has occurred. The events of recent weeks aptly demonstrate the challenges facing hydro operators. A seemingly prudent approach to water usage when expected inflows are low may appear unjustified when subsequent rainfall results in spill.

2 In a typical year, total South Island storage at mid-December would be approximately 36% snow pack and 64% water already in the lakes. With regard to inflows, an average December in the South Island would yield about 400 GWh from snow melt and about 900 GWh from contemporaneous rainfall.

The relatively low storage capacity of New Zealand hydro reservoirs exacerbates this challenge.

2.3.22 Unlike the case with inflow and lake-level data, information about snow pack is proprietary. It is therefore generally not made publicly available until such time as it has no further commercial value. Consequently, relevant information may remain unknown to parties trying to assess price movements.

2.4 Maui outage

2.4.1 Shell Todd Oil Services (STOS) plans to shut down the Maui gas field and onshore production facilities from 28 January through to 27 February, a period of 31 days. The outage is significant and is required for an extensive maintenance programme and is timed to coincide with a period of low demand in the gas market. In determining the outage timeframe, STOS make an allowance for adverse weather conditions that may cause delays. and therefore it is possible that the gas supply may return to service earlier than planned.

2.4.2 Information on the Maui outage became public on 20 December. Evidently, STOS customers were alerted as early as April 2010. It seems that other market participants ,(those with no exposure to the gas market) ,did not became aware of the planned shut down until more recently.

2.4.3 The impact of the Maui outage is complex because it is dependent on confidential contracts between gas suppliers and thermal generators. The market is not privy to details of swaps; contracts for replacement gas from other gas fields (e.g. Pohokura); the potential for spot purchases from these other fields; or the potential use of stored gas supplies.

2.4.4 This situation has created significant uncertainty as to the impact the Maui outage will have on electricity generation, despite the System Operator (SO) declaring that this outage in and of itself is not a major concern. The SO has for some time had more in-depth knowledge about the detail of the planned Maui outage than other participants.

3. Summary of participant responses

3.1.1 Plant availability, emergency management by the System Operator, generator offers and demand response are discussed in this section.

3.2 Plant availability and utilisation

3.2.1 As wholesale prices increased, against suggestions of concern about hydro storage and future inflows, the expectation would be that all *available* thermal plant would be offered and dispatched.[3]

3.2.2 Figure 9 shows the size (MW) of the planned outages relative to total demand throughout the latter half of November and into December. The Haywards price (red line) is overlaid on the plot.

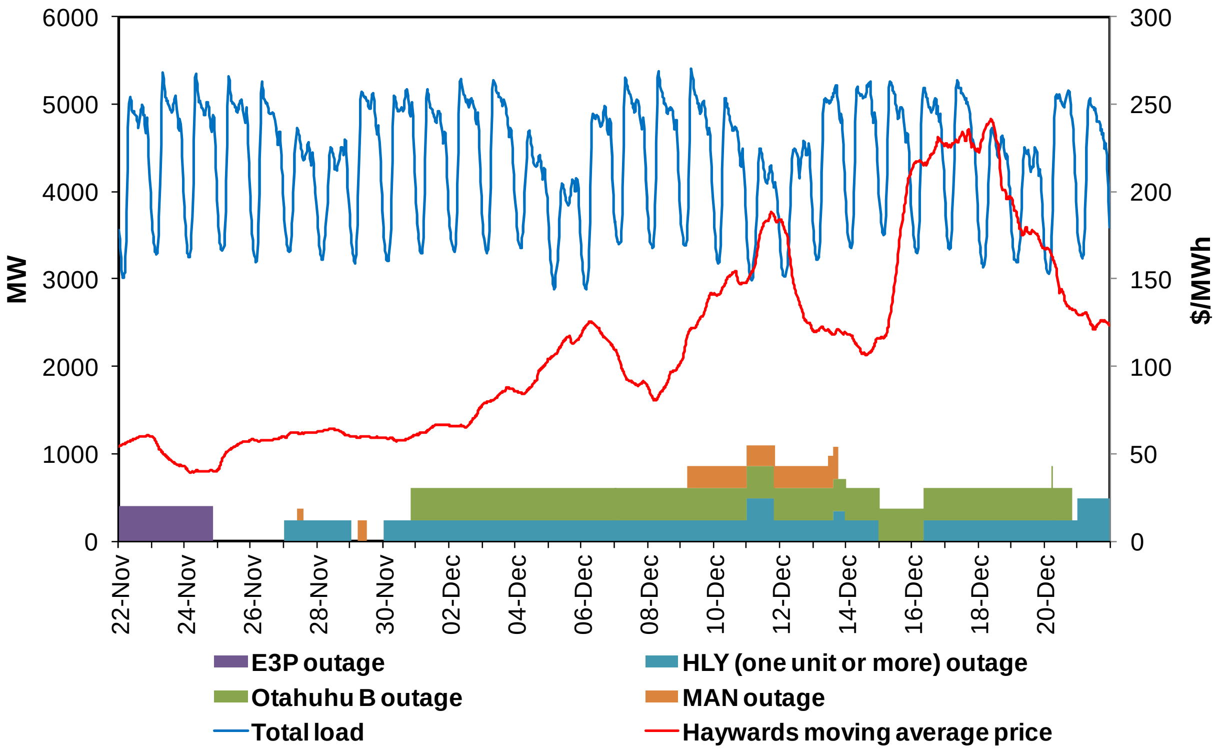

Figure 9 Major planned generation outages, demand and price

Notes: E3P is the gas-fired unit at Huntly, also known as HLY5.
MAN denotes Manapouri.

3.2.3 The industry has adopted a Planned Outage Co-ordination Process (POCP) and maintains the associated POCP database. Plant owners record their planned outages in the database whereupon the information becomes known to others. However, the POCP is voluntary. Comparison of information in the POCP

[3] Not all thermal plant is typically available during the low-demand months of December to March because the owners of such plant undertake planned maintenance during that period when demand for its output is typically low.

database with SCADA data suggests the POCP is not entirely reliable; some plant recorded as out for maintenance was in fact being offered and dispatched during December.

3.2.4 It appears generation plant can be brought back into service without a corresponding amendment to the outage status being recorded in the POCP database. This may involve minor maintenance that can quickly be ceased, or maintenance which hasn't started, or which has been deferred and not notified. Figure 9 shows plant outages as per the POCP database, but modifies that data if SCADA shows that the plant was in fact operational.

3.2.5 The database showed in the lead up to December that one and sometimes two Huntly units were scheduled to be out of service from December through to the end of March 2011. In fact as can be seen from Figure 9, all Huntly units were in service for one day at the end of November and again for one and a half days on 15 and 16 December when the price was quite high. In other words, where possible, owners of thermal plant responded to the high prices by returning plant to service.

3.2.6 The Maui outage was eventually added to the POCP database on 21 December 2010, but only the dates were supplied and no details of potential lost generation have been made publicly available. Recording the Maui outage in the POCP database was complicated because STOS is not an industry participant. Contact ultimately sought permission from STOS to record it.

3.2.7 Figure 10 demonstrates that throughout most of December, all available thermal plant was dispatched at or close to the energy offered. Generation from thermals was not quite at full capacity, because some thermal plant was providing reserve cover.

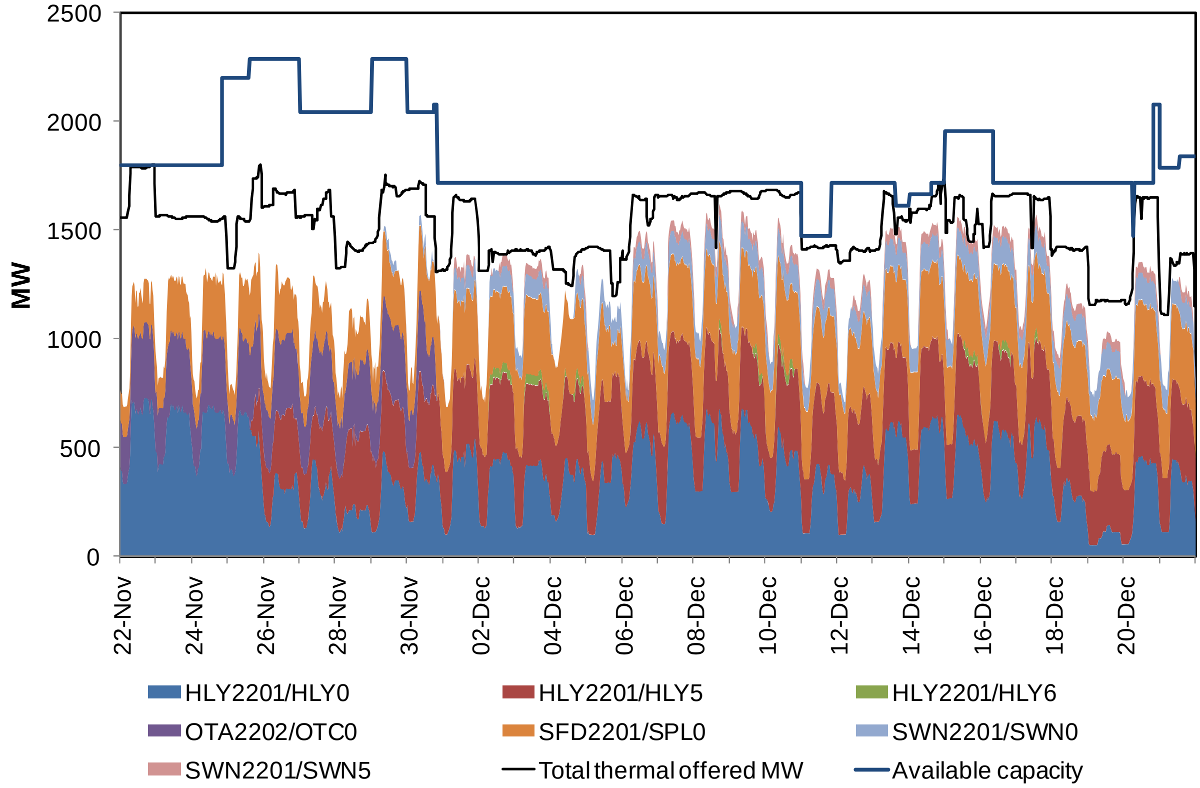

Figure 10 Thermal generation and total MW offered

Notes: The legend gives the name of the market node followed by the name of the plant. SFD denotes Stratford and SWN denotes Southdown.

3.2.8 Finally, Figure 11 overlays the Haywards price on the wind generation. While the relationship is not very stable, there is some degree of inverse correlation between wind generation and price. Given that wind is offered at a zero price and must be dispatched if offered, this suggests that wind was not always available during the high price period. While the absence of wind did not cause the high prices, if there had been more wind prices may have been slightly lower.

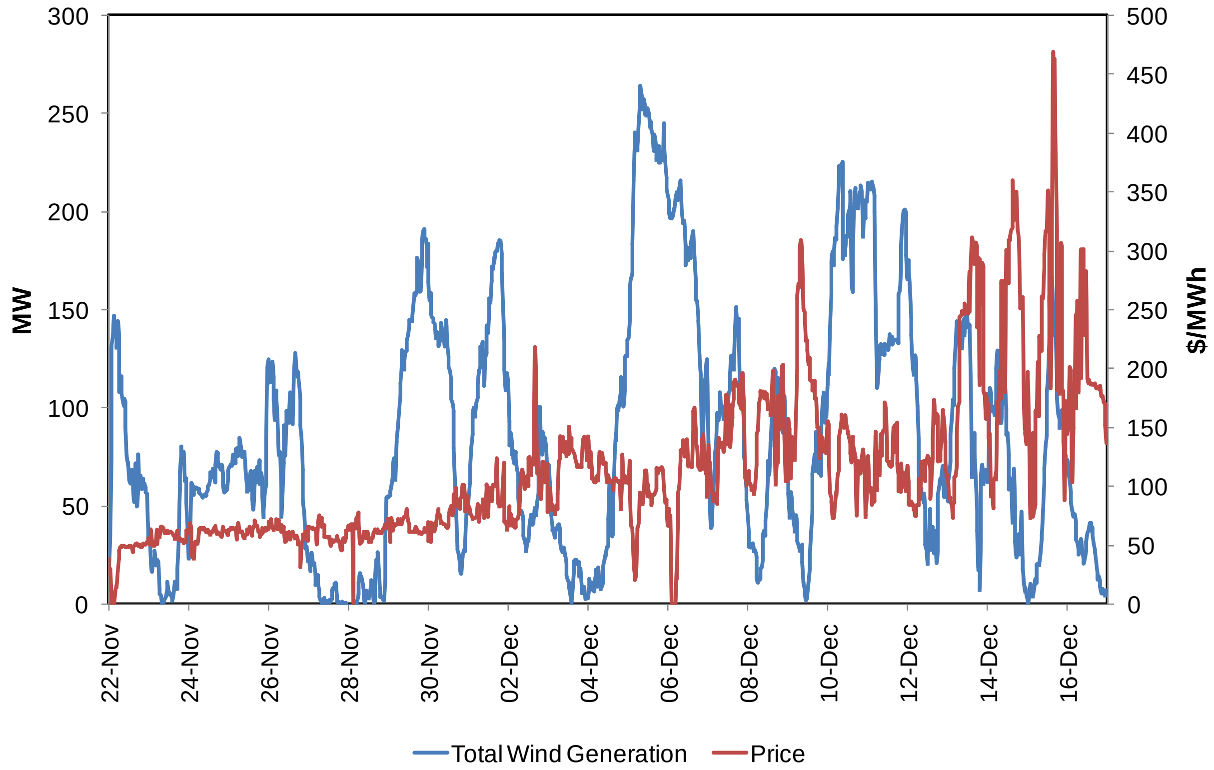

Figure 11 Total wind generation and price

3.3 Transmission

3.3.1 There were no significant outages of transmission assets that would have given rise to widespread high prices during the period from mid-November through to Christmas 2010.

3.4 Emergency Management Policy

3.4.1 Hydro generation makes up the major portion of generation capacity in the New Zealand system. But while hydro inflows are uncontrollable, uncertain and highly variable, they are by no means the only source of uncertainty for wholesale market participants. Factors such as the level of demand, thermal plant and fuel availability, optimally managing a portfolio of assets, transmission constraints, and net market position all play a role in shaping participants' behaviour and therefore in determining market prices.

3.4.2 Nevertheless, hydro storage levels provide a crude gauge as to the state of supply conditions and feature prominently in the System Operator's assessment of security of supply. The Emergency Management Policy (EMP), prepared and published under the Code clause 7.3(3)(a) describes the process by which the

SO is expected to monitor, assess and inform participants of its view regarding security of supply in forthcoming weeks and months.[4]

3.4.3 The Security of Supply Forecasting and Information Policy (SoSFIP), prepared and published under the Code clause 7.3(1) describes the types of information that will be provided by the System Operator to participants, to enable them to better manage supply risks.

3.4.4 The EMP requires the SO to publish a regular report that includes a comparison of storage in the hydro lakes with the hydro risk curves[5] in order to indicate the risk of possible future supply shortages. It is assumed that if actual storage gets down to the hydro risk curves, all available thermal plant will be offered and dispatched.

3.4.5 Both the EMP and SoSFIP require that the hydro risk curves be updated whenever there is a change in supply, demand, or transmission that is likely to yield a material change to the curves, e.g. a change in thermal plant or fuel, or HVDC transmission.[6] The degree of the security risk is communicated using the risk meter, a device containing four phases: Normal, Watch, Alert, and Emergency.[7]

3.4.6 The Authority is responsible for offering the Whirinaki reserve plant into the market.[8] In order to provide certainty for market participants, the Whirinaki offer strategy is strictly tied to the risk meter and the hydro risk curves underlying it. More specifically, the 'capacity offer', currently set at $5000/MWh, applies while the risk meter stands at Security Normal. The 'energy offer' or Reserve Energy Trigger Price (RETP) represents the short-run marginal fuel cost of Whirinaki and is currently set at $387/MWh. The RETP applies when the risk meter is at Security Watch, i.e. a 1-4% risk of an energy shortage.

3.4.7 Above a 4% risk of energy shortage, the risk meter is moved to Security Alert, whereupon the Authority exercises discretion over how Whirinaki is offered. Security Alert represents a serious shortage situation and the current policy allows the Authority to offer Whirinaki at a very low price to ensure it is dispatched and fully utilised to help alleviate the energy shortage.

3.4.8 Finally, the Security Emergency phase is designed to cope with short term and immediate situations that are unexpected and cannot be observed unfolding, e.g.

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4 The responsibility for implementing the EMP rested with the Electricity Commission prior to the SO taking over the security of supply function on 1 November 2010.

5 The hydro risk curves show for a given month of the year, the level of hydro storage associated with various levels of risk of supply shortfall. Only risk associated with hydro inflows is calculated, and thermal plant is assumed to be maximally utilised to conserve storage. The HRC's are a measure of the resilience of the physical plant making up the system to dry periods, as opposed to the market response.

6 Paragraph 5.1.2 of the EMP.

7 Section 5.3 of the EMP.

8 See http://www.ea.govt.nz/industry/security-of-supply/reserve-energy-scheme.

a sudden major outage, or an extremely serious hydro storage situation that sees actual storage breach the 10% risk curve.

3.4.9 Generators are mindful of changes in the Whirinaki offer in response to the SO effecting changes to the security status, or the risk meter. The SO advised its intention to move to Security Watch on 17 December when it issued a Customer Advice Notice (CAN), however this intention was reversed with a further CAN on 21 December.

3.4.10 The current hydro risk curves, the NZX electricity price index (demand-weighted, 7-day rolling average) and the state of storage throughout 2010 are illustrated in Figure 12. It is noticeable that when actual reservoir storage gets close to or passes below historical mean storage, prices tend to increase. Of particular interest is the December period in Figure 12, which shows prices at high levels while actual (reservoir) storage remains just above mean levels.

3.4.11 On two occasions in 2010, the actual storage can be seen to intersect mean storage yet on neither of those occasions did prices increase as much as they did in December. The timing of snow melt needs to be considered when forming a view as to the value of water; once the snow pack has melted there clearly is no more until after the following winter.

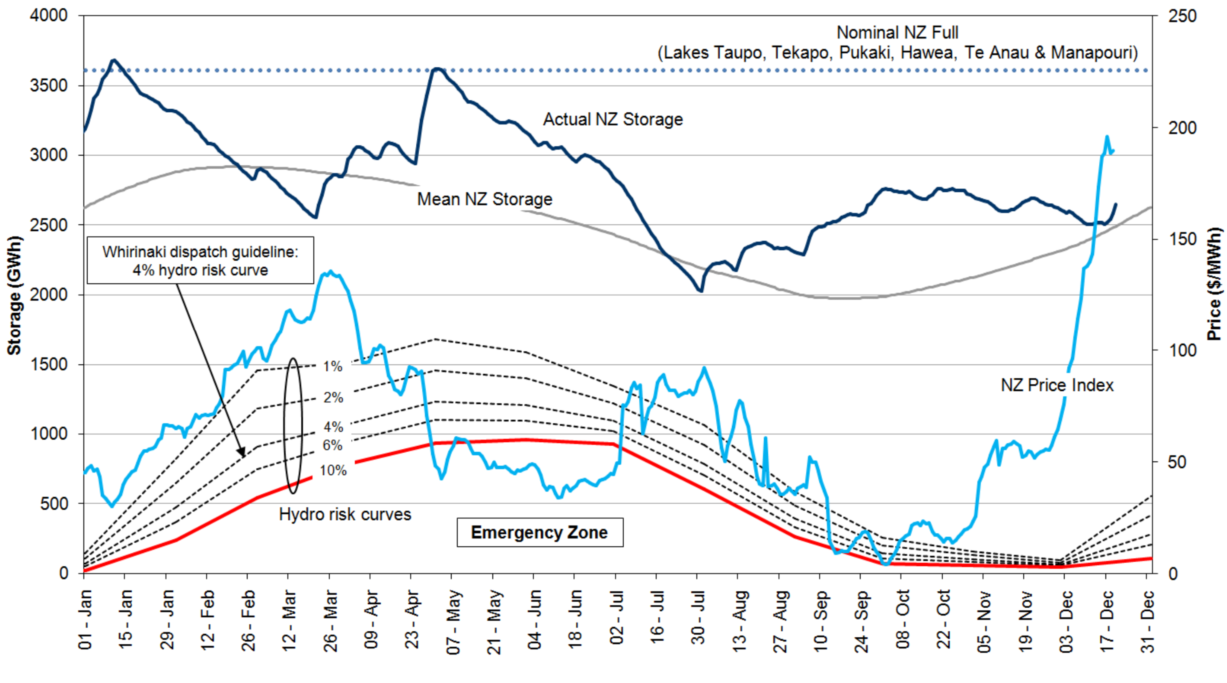

Figure 12 Prices and hydro risk curves, 2010

3.4.12 The strong La Niña weather pattern, well entrenched and widely understood by December 2010, married with growing awareness of the Maui outage during that month (section 2.4) appears to have had a significant influence on wholesale electricity prices in December 2010.

3.5 Offers

3.5.1 Offer behaviour by major participants throughout December 2010 is now described. A particular focus is on trading period 34 (4:30-5:00pm) because during the period analysed, it was TP 34 in which the highest final price was observed; $462.63/MWh at Haywards and $492.47 at Otahuhu on 15 December.

3.5.2 Figure 13 shows the national offer stacks for all offers in TP 34 of each day in the analysis period. Offers are represented as quantity tranches at various price bands indicated by the coloured bars, e.g. the grey bar spans all offers in the zero to $100/MWh band, the yellow bars show all offers in the $101-$200/MWh band, the maroon bars show all offers in the $201-$500/MWh band, and the light blue bars show all offers over $500/MWh band. The dollar value posted on the grey bars is the final Haywards price in TP 34 of each day, which can be seen to be increasing throughout December. Demand, or load, adjusted for approximate losses, is represented by the line connecting the pink squares.

3.5.3 The plot illustrates why prices increased in December; because the volume of energy offers at or below $100/MWh decreased significantly, leading to the market clearing in a higher offer band. For example, the left hand grey bar reveals that on 22 November, about 6000 MW was offered at less than $100/MWh. All offers above 6000 MW in TP 34 on 22 November were at prices exceeding $101/MWh. The final price was $51/MWh, indicating that the marginal generator’s offer was in the $0-$100/MWh tranche.

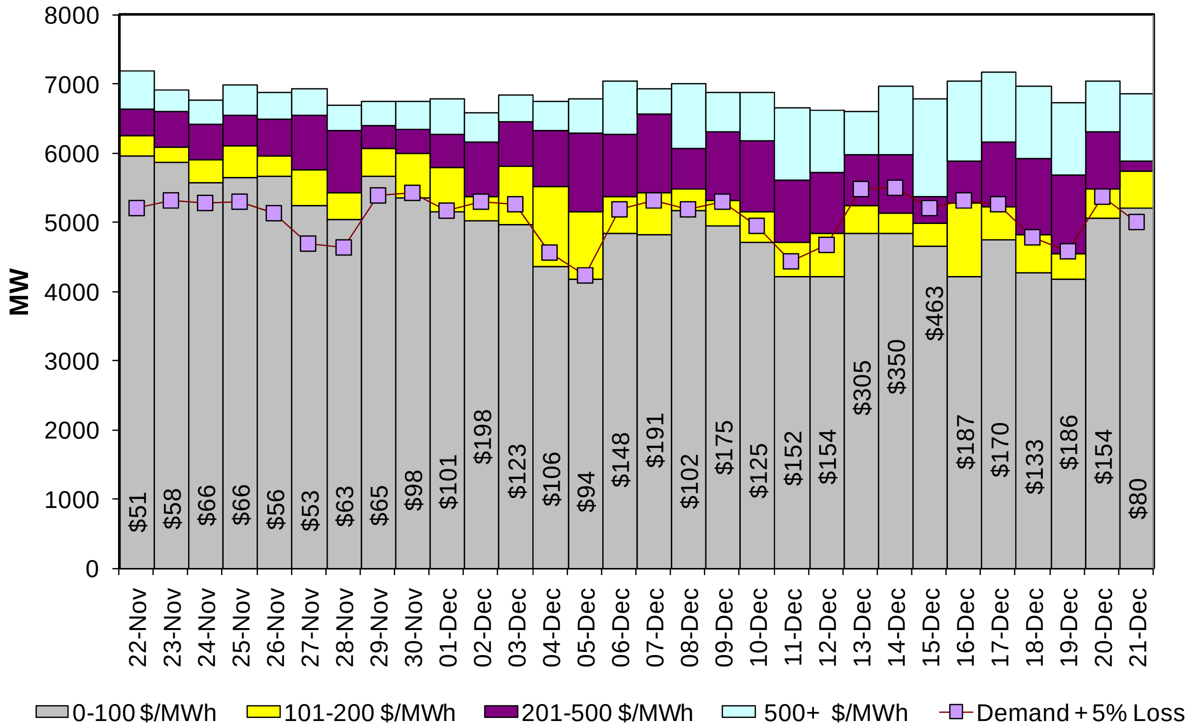

Figure 13 National offer stacks, load and final prices, TP 34

3.5.4 As we move to the right of the plot, it can be seen that the volume of offers at less than $100/MWh gets smaller while the higher price offer tranches become larger, e.g. observe the yellow, maroon and light blue bars ($100+/MWh) getting larger. In the last week of November, TP 34 cleared in the $51-$66/MWh range, although it increased to $98/MWh on 30 November. Once we move into December, there is only one day prior to 21 December, Sunday 5, where the cleared price is under $100/MWh.

3.5.5 Figure 14 shows an alternative view of the national offer stacks. It shows the volume (MW) of offers at or below $150/MWh for the five major generators for all offers over the analysis period rather than just TP 34. The pattern of fewer low priced offers is clearly evident, particularly for Contact and Meridian.

3.5.6 Figure 33 - Figure 42 in Appendix B illustrate all offers from Contact, Genesis, Meridian, Mighty River Power, and TrustPower, respectively. They show that the offer profile for all generators except Mighty River Power changed markedly during December. Contact's reduction of energy offers at or below $100/MWh is partly because of the Otahuhu B planned outage. In contrast, Genesis increased its energy offers at or below $100/MWh by making more units available. Figure 42 in Appendix B reveals that in the first week of December, TrustPower began to move a significant portion of its offers from the tranches at or below $100/MWh into higher priced tranches, particularly the $101-150/MWh tranche.

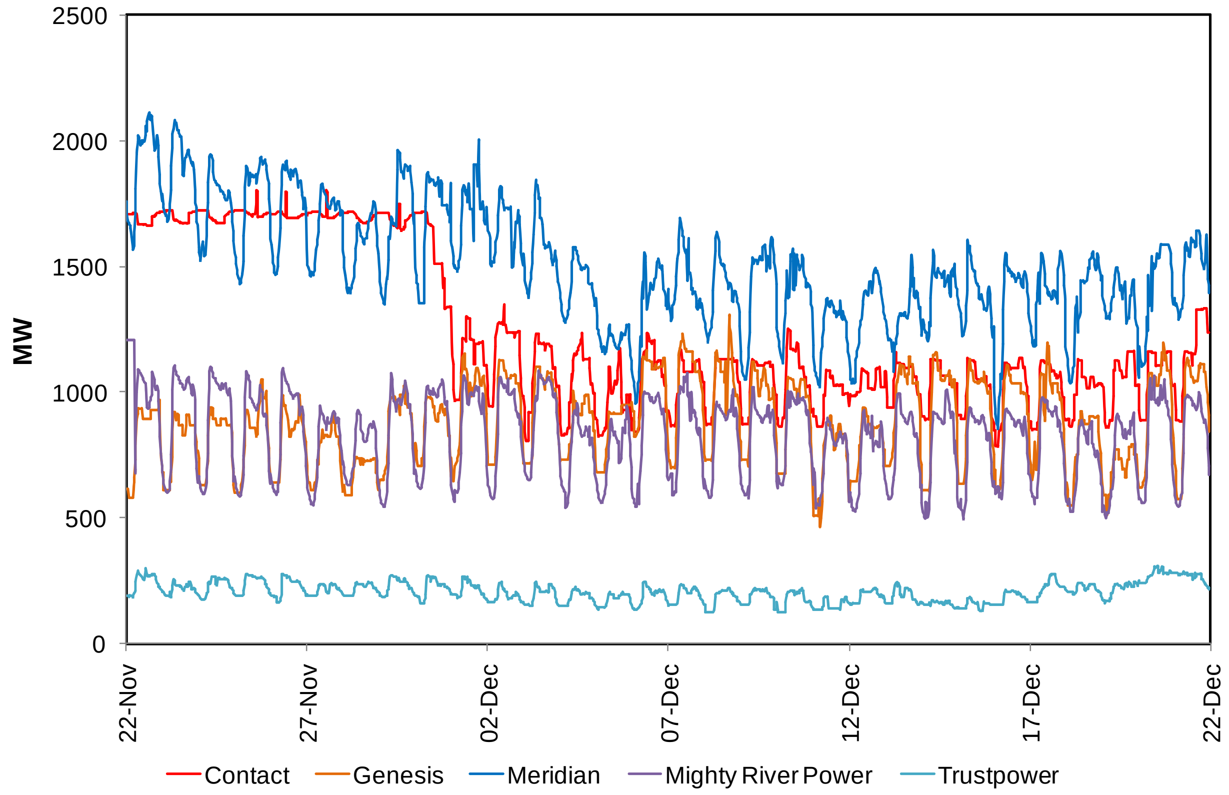

Figure 14 Total offers at or below $150/MWh

3.5.7 Further analysis of offer behaviour and implications for final prices is presented in section 4.

3.6 Demand response

3.6.1 Most consumers are on fixed price, variable volume contracts and don't notice or respond to high prices in the wholesale market, at least not in the short run. However, large users, especially those with electricity constituting a significant portion of their input costs, may well respond to high spot prices by curtailing production. During December 2010, some major users reported that they had reduced production in response to higher prices.

3.6.2 Large users may elect to make arrangements using forward markets or alternative generation sources such as co-generation facilities to avoid exposure to uncertain and volatile spot prices in the wholesale market.

3.6.3 On 16 December 2010, the Major Electricity Users' Group (MEUG) invited their members to confidentially report the details of any demand response action to the Authority – trading period, price responded to, quantity of demand reduction, etc. Two MEUG members took the opportunity to do so. In one case, there was no demand response as the company was not exposed to the high prices. In the other, a little less than 2 GWh of grid offtake was curtailed over the period 1-15 December.

3.6.4 A reduction of 5% in aluminium production by NZAS was widely reported in the media.

3.6.5 Grid exit point (GXP) data has been examined to see what, if any, load reduction was made by four large industrial users (New Zealand Steel, Norske Skog, Pan Pac, and NZAS) during the high price period in December. This data is illustrated in Figure 16 through Figure 18. In all four cases some response is noticeable.

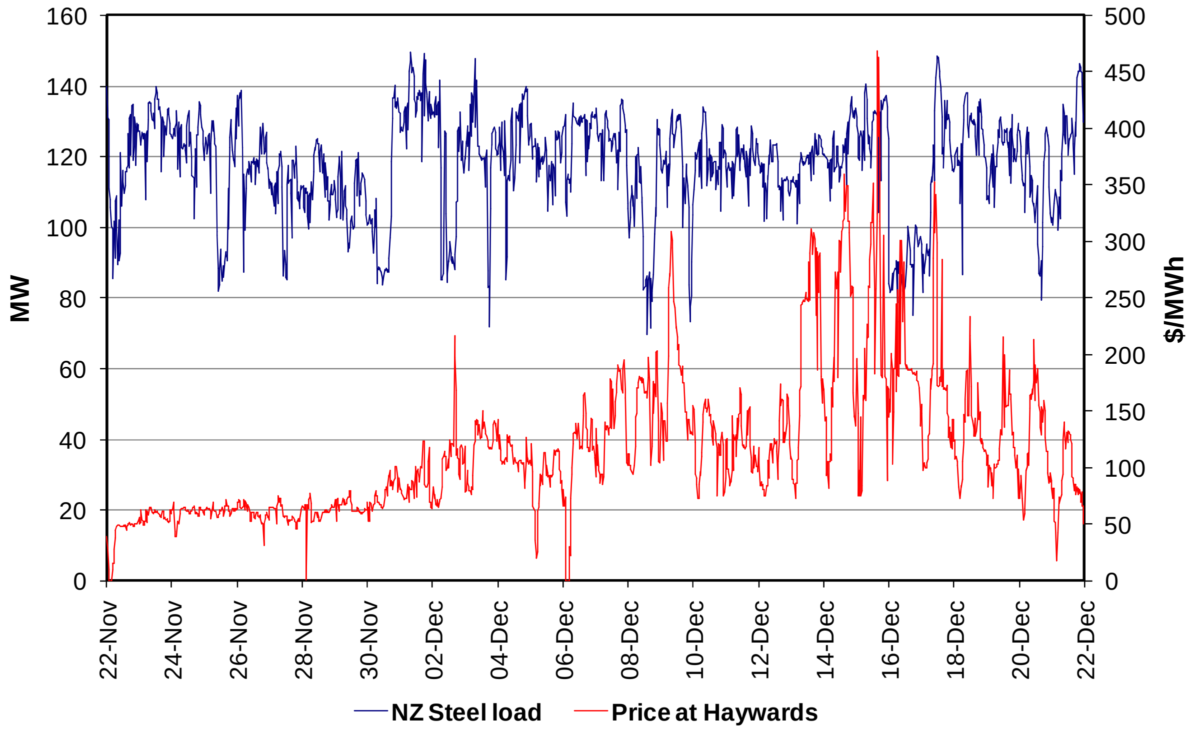

Figure 15 New Zealand Steel demand response

3.6.6 The overall level of demand response seems quite small. As is the case with almost any other good, it is to be expected that as the price increases, demand for it will decline. Firms will constantly reassess their willingness to pay a higher price for inputs, especially when they are in no position to pass that increase on in the form of higher final product prices.

3.6.7 The situation with NZAS is somewhat unique. NZAS is understood to have a long-term supply contract with Meridian and purchases some 90% (544 MW) of their annual electricity requirements at contracted prices. The contracted prices are indexed to the year-on-year change in a wholesale market price index, which is based on the volume weighted price in each trading period at grid injection points over the entire year, and can therefore change annually. As a result, wholesale spot market prices in any year influence the contracted prices in future years, and a short-term spike in wholesale spot prices can have longer term impacts for NZAS. December market pricing may, therefore, have a material impact on future prices for NZAS.

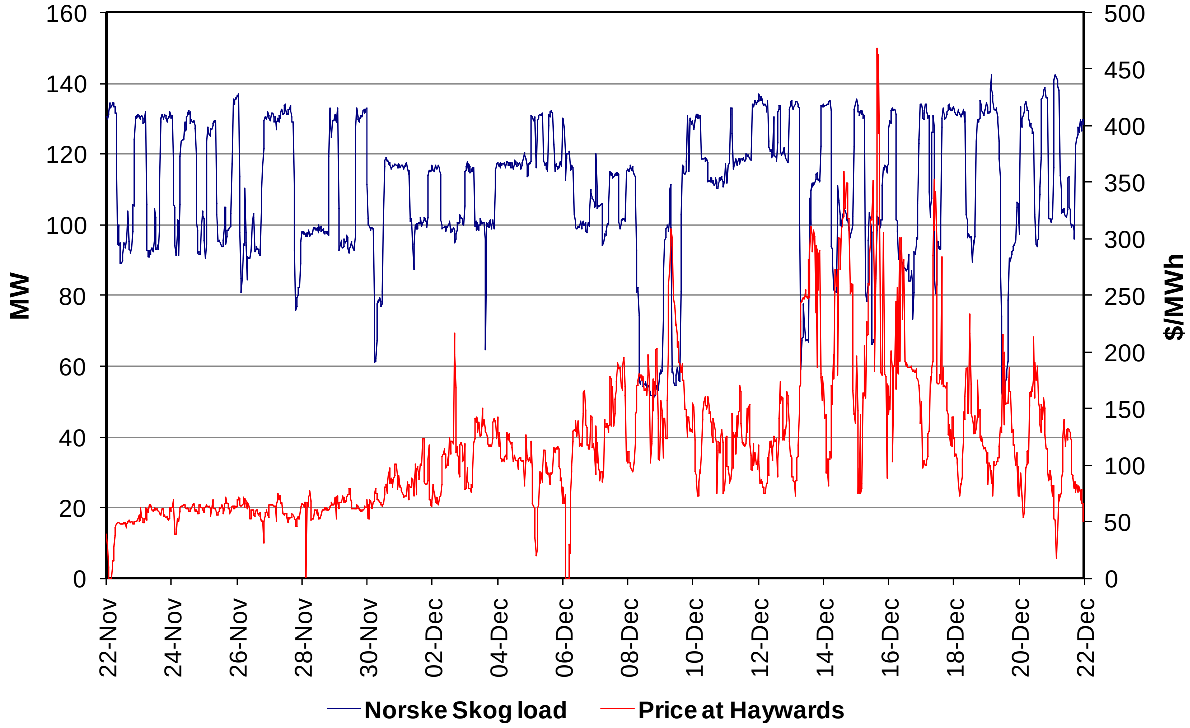

Figure 16 Norske Skog demand response

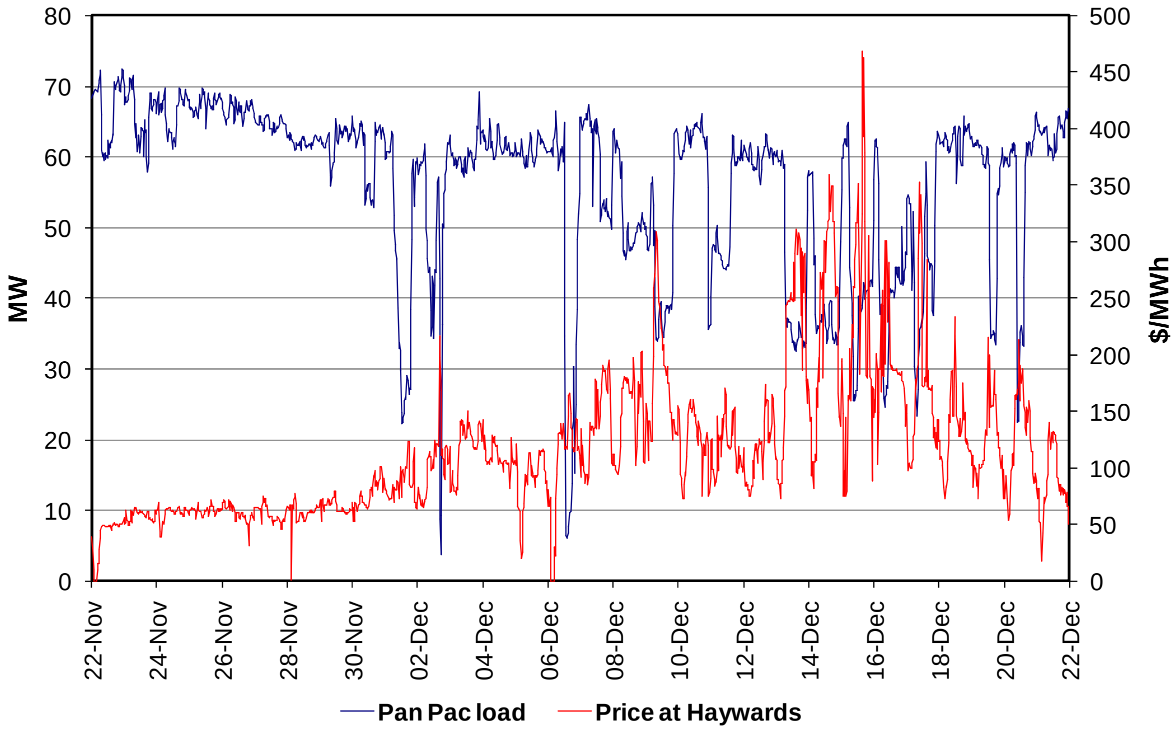

Figure 17 Pan Pac demand response

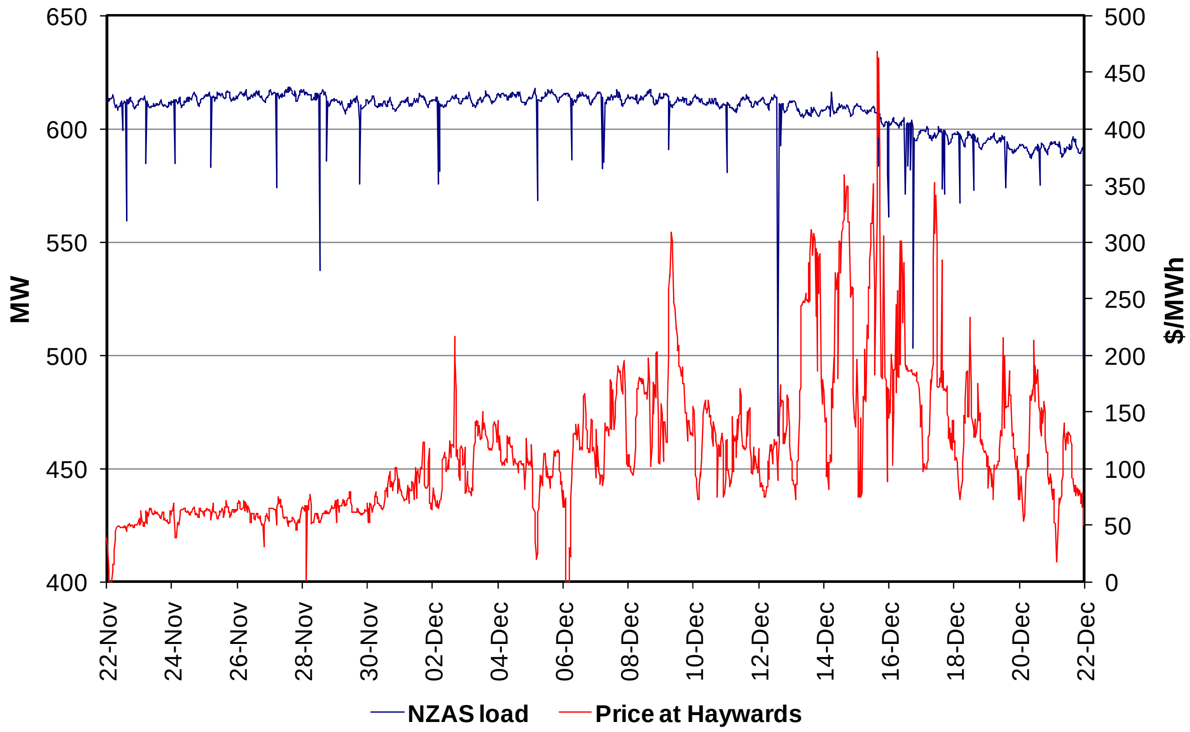

Figure 18 NZAS demand response

3.6.8 Looking forward, further action would be likely were it to be shown that the spot market was being gamed to impose higher future prices on any consumer, or there was other exploitation of a dominant position in the wholesale market to the long-term detriment of consumers. While it is not illegal under the Commerce Act to possess market power, it is illegal to abuse such a position.

3.6.9 By implementing a monitoring programme in the coming months , the capability of the Authority to monitor and test for strategic and opportunistic pricing behaviour will be strengthened in the coming months.,

3.6.10 Of greater concern to the Authority than the price level itself, is whether participants have access to mechanisms to mitigate exposure to high or volatile prices. The Authority would be interested to hear from participants that feel they have inadequate hedging or demand response options.

4. Assessment of market performance

4.1 Introduction

4.1.1 This section further examines the relationship between storage and prices, and then considers emergency management. Attention then turns to analysing offers in greater detail. In particular, an analysis of how market outcomes would have differed had participants chosen alternative offer strategies is presented.

4.1.2 Given that this analysis is undertaken with the benefit of hindsight, caution needs to be applied when interpreting these results, especially where such interpretation relates to ascribing motivation to industry participants.

4.2 Further analysis of storage and prices

4.2.1 On 15 December 2010, MEUG released a media statement arguing that December 2010 represented an *extreme outlier* relative to other years when price levels were contrasted with storage levels.[9] A diagram depicted the 2010 price well above a line fitted through the historical relationship between mid-December price and hydro storage. However, further analysis of the price-storage relationship tells a somewhat different story.

4.2.2 Figure 19 is a slightly more complex plot than the one presented by MEUG. The red squares denote mean December storage (horizontal axis) and price (vertical axis) co-ordinates for each year dating back to 2000. The MEUG plot went back to 2004. The key difference between the MEUG plot and Figure 19 lies in the definition of storage. MEUG depict only the lake-level storage whereas Figure 19 augments lake-level storage with snow pack – a guaranteed future inflow into the lakes. This difference manifests itself in the vertical line showing the mean historical storage for mid-December; which is about 2800 GWh on the MEUG plot and at about 3800 GWh in Figure 19.

4.2.3 The vertical lines passing through the red squares indicate the range of average daily prices at the Haywards node during December, except for 2010 which covers only the first 21 days of December.[10] The horizontal lines denote the range of storage in New Zealand during December. The storage indicators are decomposed into storage contained in the reservoirs (black horizontal lines) and total storage; including that still in the form of snow pack (the grey horizontal lines).

4.2.4 The intersection of the perpendicular lines, i.e. the red squares, indicates the mean level of prices and storage for the month of December. Note that a mean level nearer to one end of the range lines than the other indicates a skewed

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9 See http://www.meug.co.nz/includes/download.aspx?ID=113449.

10 Rather than December averages, the MEUG plot depicted prices selected from a single day; the 12th, the 13th or the 14th of December. This gives rise to some significant differences. For example, $211/MWh (MEUG) versus $142/MWh (Figure 19) in 2010 and $162/MWh (MEUG) versus $116/MWh (Figure 19) in 2005.

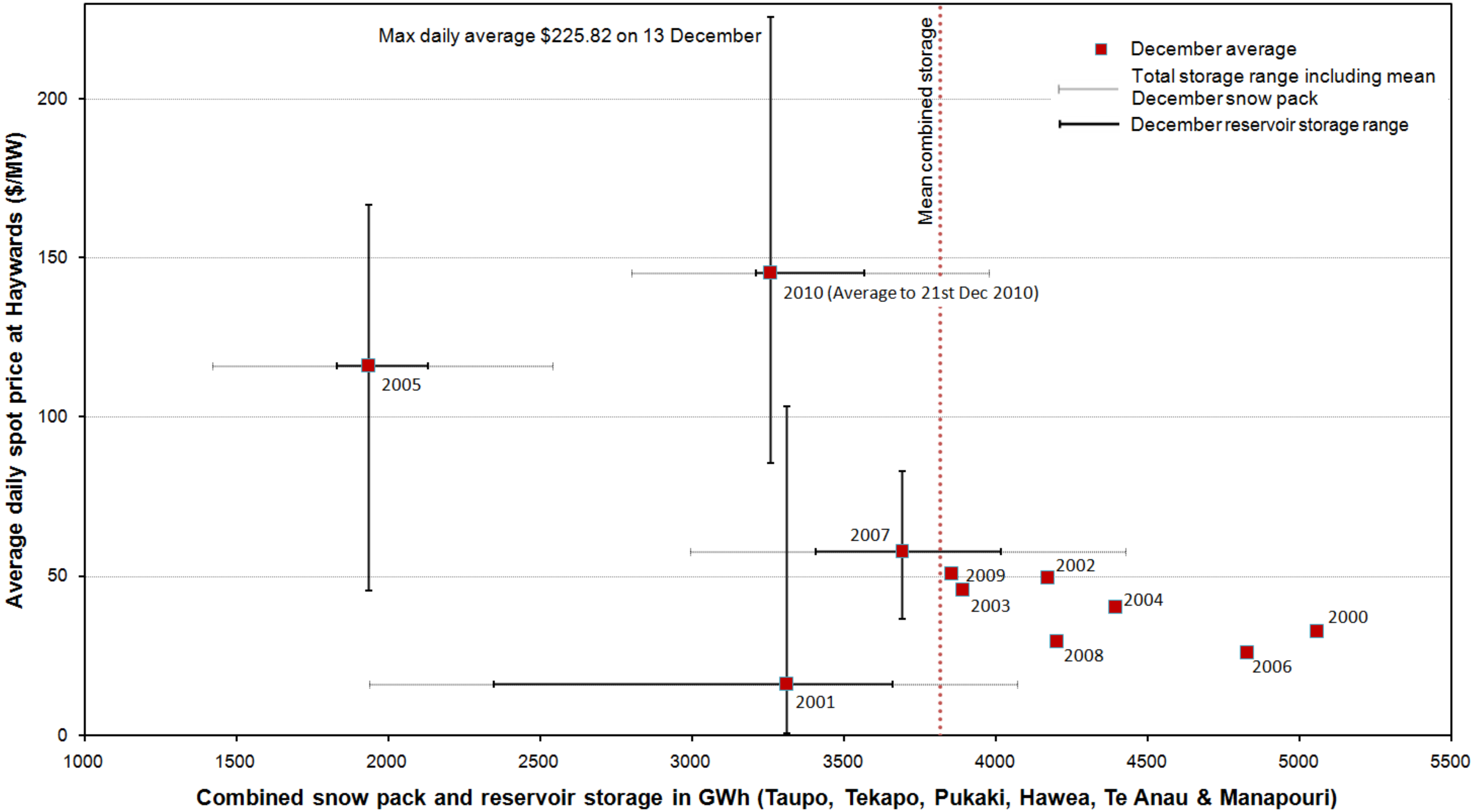

Figure 19 December prices versus storage (reservoirs and snow pack), 2000-10

distribution. For the sake of clarity, the range indicators are removed for all years with higher than mean storage, i.e. all points to the right of the vertical red dotted line.

4.2.5 While 2010 still appears to lie above a line that might be fitted through the red squares, the addition of the extra data points going back to 2000 renders the statistical reliability of such a fitted line highly dubious. In particular, the 2001 data point has slightly greater mean storage than 2010 but the mean December price is very low; lower than all other years depicted on the plot. All of the data points to the right of the mean combined storage line are more widely dispersed than is the case in the MEUG plot.

4.2.6 Including snow pack in the storage definition changes the order of the low storage years relative to the MEUG plot, i.e. December 2010 storage is now less than in 2007, and 2004 is now well above the mean level for December.

4.2.7 It is interesting to compare 2005 with 2010. Average prices in December were higher in 2005 than in all other years since 2000, except for 2010. Yet December 2005 had by far the lowest mean storage of any year since 2000. Storage and prices for the entire year of 2005 and 2010 are shown in Figure 20.

4.2.8 2005 was only a moderate La Niña year whereas 2010-11 has already revealed a strong La Niña pattern. The 2005 and 2010 years display very similar snow pack and snow melt curves. Both years reached approximately the average snow pack volume and both experienced very early snow melt. In December 2005, 69% of the storage was in the form of water in the lakes. It is expected that this information regarding reservoir levels was well understood by the market due to the more gradual and almost monotonic decline in actual storage beginning in early March 2005. Observed price increases were also more gradual in 2005 than was the case in late 2010; both of these trends are evident in Figure 20.

4.2.9 In December 2010, 78% of the storage is in the reservoirs; a slightly higher proportion than was the case in 2005. However, this may have caused little concern for those participants unaware of the snow pack conditions, or perhaps only became aware during December.

4.2.10 But unlike national storage, Manapouri storage ran down very quickly in 2010 relative to 2005. In 2010, Manapouri was just under the mean storage level at mid-November whereas in 2005 it was at least 120 GWh lower. By mid-December, both years had similar, low levels of storage. The quickly evolving nature of the 2010 storage situation at Manapouri may have been a driver of the rapid rate of price escalation in December relative to 2005.

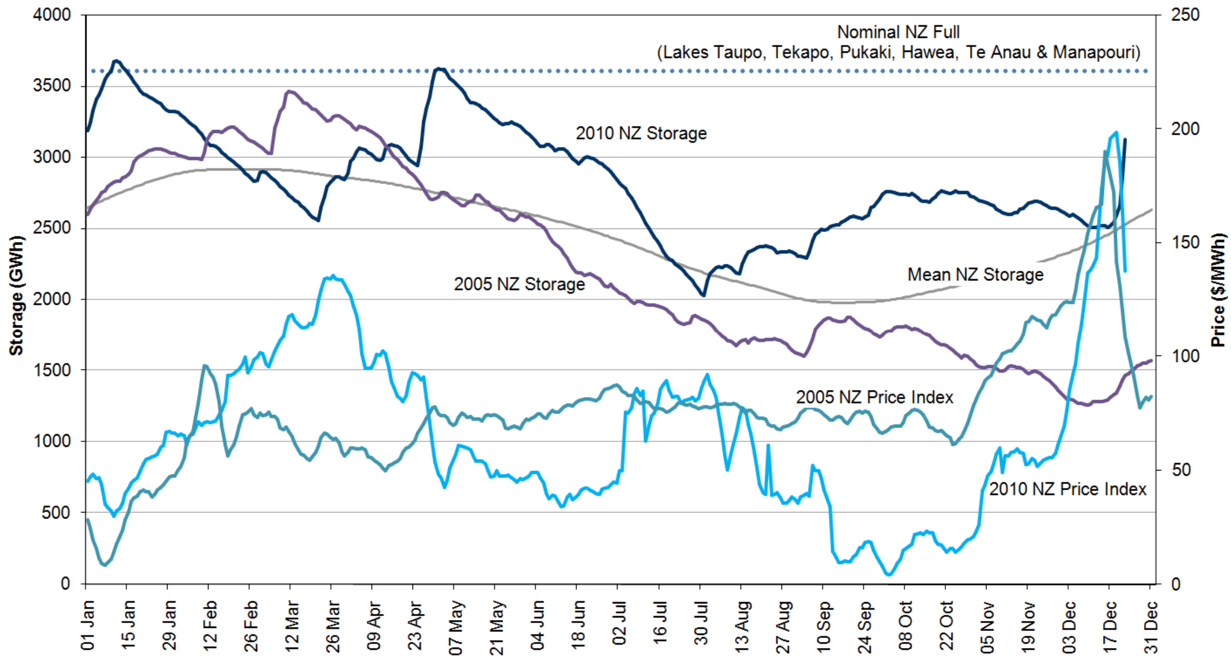

Figure 20 Reservoir storage (2005 and 2010) compared to price

Note: The light blue price lines shows the NZX Electricity Price Index

4.3 System Operator and the EMP and SoSFIP

4.3.1 The Emergency Management Policy and the Security of Supply Information and Forecasting Policy, (EMP and SoSFIP), and their associated devices such as hydro risk curves and the risk meter were previously introduced in section 3.4. Availability of timely information may have hindered the ability of the System Operator to fully implement the EMP and SoSFIP during November and December 2010, may have contributed to uncertainty in the market.

4.3.2 Figure 21 and Figure 22 illustrate storage, prices and the hydro risk curves for 2009 and 2008, respectively, and provides an interesting contrast to the 2010 situation depicted in Figure 12.

4.3.3 In December 2010, the price can be seen to peak at almost $200/MWh at a time when actual storage was just slightly above the mean level (Figure 12). In November 2009, the price spiked up to $121/MWh as actual storage approached the mean storage level (Figure 21). In the very dry year of 2008, actual storage is well below the mean level for much of the year, yet apart from the winter months when the min zone was breached, prices stayed well below $200/MWh (Figure 22).

4.3.4 The hydro risk curves are intended to embody all risks to supply that are known to the SO, not only the risks associated with hydrology. Nevertheless, the SO has informed the Authority that it was unable to incorporate several risks in the hydro risk curves and decided, as a reasonable and prudent operator, to signal an intention to move the risk meter to Security Watch. A move from Security Normal to Security Watch at a time when actual storage is well above the 1% hydro risk

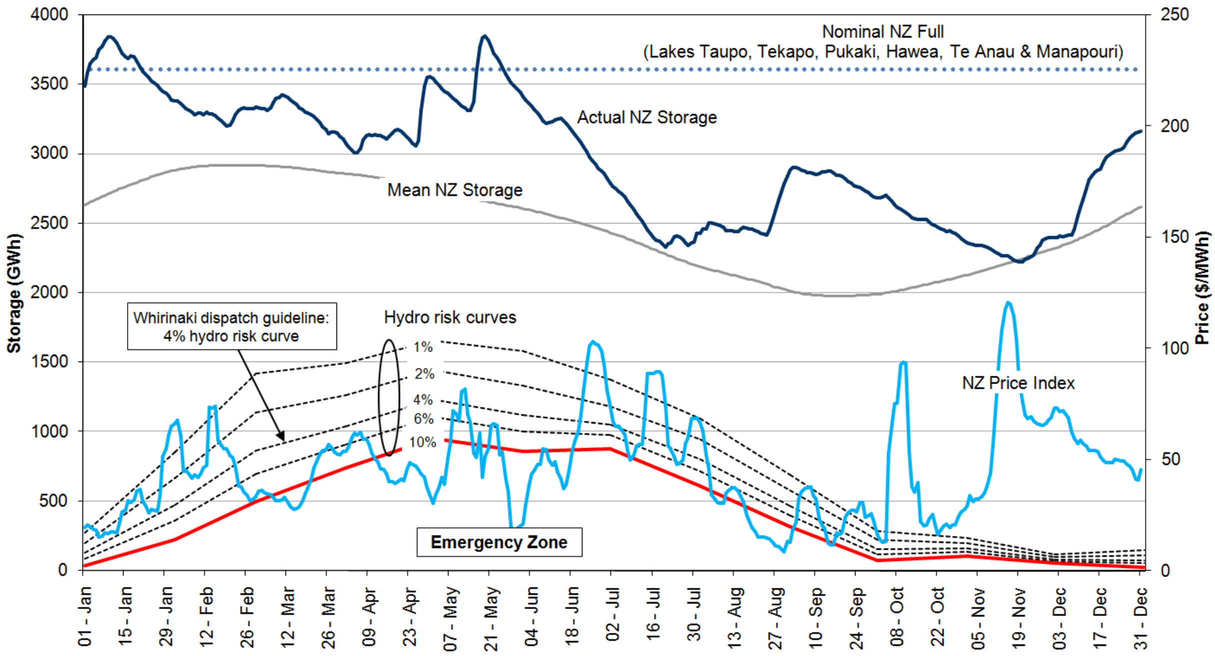

Figure 21 Prices and hydro risk curves, 2009

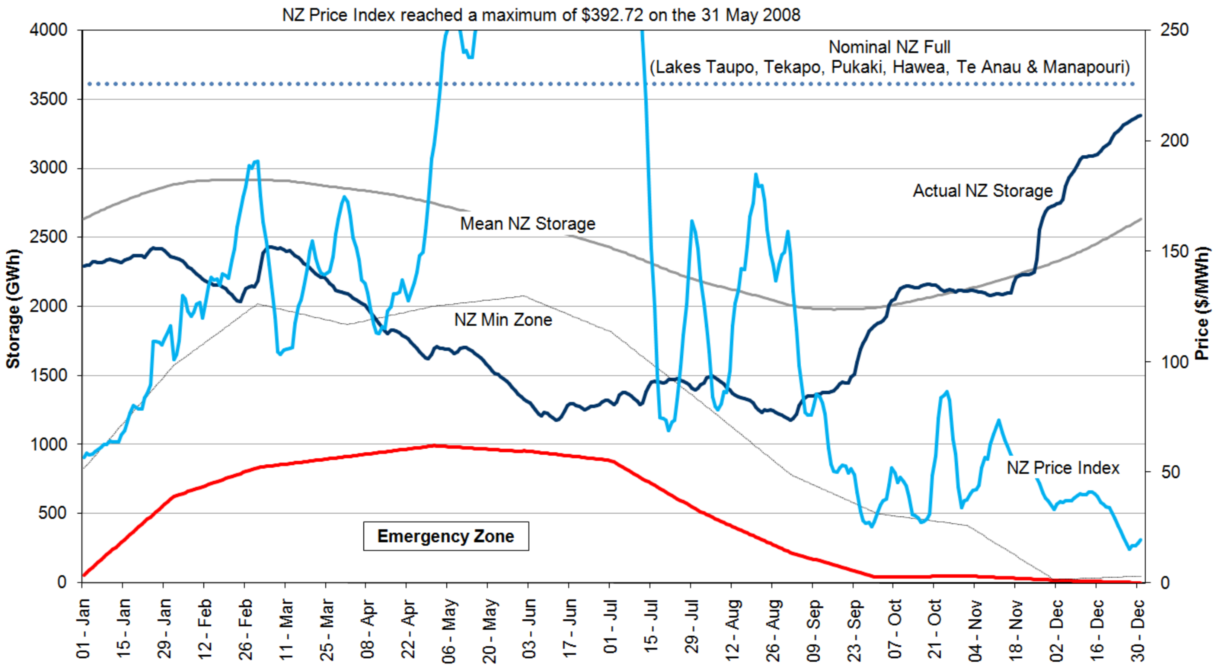

Figure 22 Prices and hydro risk curves, 2008

Note: Risk measurement and reporting used the Min Zone methodology in 2008.

curve signals to the market that the SO perceives or knows of other risks that pose a significant threat to security of supply.

4.3.5 Although the System Operator signalled its intention to move to Security Watch on 17th December via a Customer Advisory Notice (CAN), the System Operator had been aware of the Maui outage from 9 November.

4.3.6 The System Operator received additional information about the Otahuhu outage on 13 December.

4.3.7 It would have been desirable for the System Operator to update HRCs with this new information shortly after 9 November, and then again after 13 December, so all participants could be aware of the implications of the outages. This would be consistent with a requirement in the SoSFIP (1.6 (3)) and EMP (5.1.3) to update the HRCs if there has been a change in supply, demand, or transmission that is likely to yield a material change to the curves.

4.3.8 By releasing the CAN of 17th December, it is evident the System Operator thought the outages were material. Provision of updated HRCs shortly after 9 November, might have enabled a more informed response to supply risks by the market in late November and early December.

4.3.9 Unfortunately the System Operator was unable to quickly update HRCs immediately after 9 November, as it had to wait for significantly affected generators to quantify their generation strategies in light of the Maui outage. This took until mid-December. The System Operator was also hampered in its discussions with generators in mid-December by confidentiality issues.

4.3.10 Timely provision of information to the System Operator, and the ability to use that information to elicit further information from other parties, is essential for the System Operator to comply with the SoSFIP and EMP.

4.3.11 There is an open question whether the System Operator correctly assessed the risk of shortage when it released the 17 December CAN, and there is some ambiguity over whether it can alter the risk meter without operating under the prescriptions of the EMP. The System Operator is intending to provide a letter to the Authority on these matters, which the Authority will publish in due course.

4.3.12 Besides hydrology and the Maui outage, which have been discussed previously, other risks that may have been weighing on market participants during December 2010 include:

- uncertainty as to when Contact would resume commissioning one or both units of the Stratford peaking plant that caught fire on 5 December; and
- the preparedness, timing and capability of Contact's gas reservoir to supply gas during the Maui outage or at any other time of tight supply.

4.3.13 The Authority understands that the SO was also aware of commercially sensitive information relating to the ongoing capability of a certain thermal plant. This too may have been subject to conjecture in the market.

4.3.14 The uncertainty created by this combination of circumstances highlights the need for:

- better mechanisms for disseminating relevant information in a timely and accessible form;
- tightly prescribed implementation of security of supply policies; and
- close regulatory monitoring.

4.4 Market solution sensitivity analysis

4.4.1 Section 3.5 described how the profile of generator offers changed through the November-December 2010 period. The sensitivity of wholesale prices to changes in the offer prices made by generators for the period 1 December through to 19 December 2010 is now considered.

Impact of reduced hydro offer prices

4.4.2 The intent of this analysis is to determine if it would have been possible for hydro participants to offer in at a lower price, incur only a minimal change in generation with a commensurate minimal decline in storage, and have the market settle with significantly lower wholesale prices.

4.4.3 This analysis has the benefit of hindsight, which is not afforded to the market participants who face many uncertainties at the time of making their offer decisions. This ought to be considered when interpreting the results.

4.4.4 The vSPD model was used to re-run the final pricing cases for the first 19 days of December.[11] The prices of hydro offers of the major generator participants (Meridian, Contact, MRP, Genesis and TrustPower) were independently reduced by 5%, 10%, 20% and 40%, respectively, relative to the actual offer prices submitted during this period. The resulting percentage increases in scheduled energy and decreases in wholesale prices were recorded, and are illustrated in Figure 23 - Figure 27. The results for the 40% reduction in offer prices are also summarised in Table 1.

[11] The vSPD model is the Authority's replica of the SO's scheduling, pricing and dispatch (SPD) model.

Table 1: Changes in generation and prices due to a 40% reduction in offer prices

Generator	Change in energy dispatched		Change in average price	
	Percent	GWh	Benmore	Haywards
Meridian	5.1	31.5	-18.5%	-15.5%
MRP	17.2	29.2	-13.8%	-16.2%
Contact	9.8	16.9	-8.7%	-7.3%
Genesis	15.7	10.6	-4.1%	-4.2%
TrustPower	9.0	6.6	-3.4%	-2.9%

Source: Electricity Authority
Note: Offer prices reduced by 40% relative to actual offers during 1-19 December 2010.

4.4.5 The results show that for quite small reductions in offer prices from a hydro participant, there is a small increase in scheduled energy from that participant with a very small reduction in market prices. The price reduction is trivial when compared to the increase in average prices from November to December 2010.

4.4.6 For example, a 5% reduction in the offer prices from Meridian results in a 1.5% and 1.9% reduction in average market prices at the Haywards and Benmore reference nodes, respectively, with only a 0.6% increase in the scheduled energy from its hydro plant. This translates into an estimated 3.8 GWh of additional energy dispatched over the 19-day period analysed. Assuming an equivalent

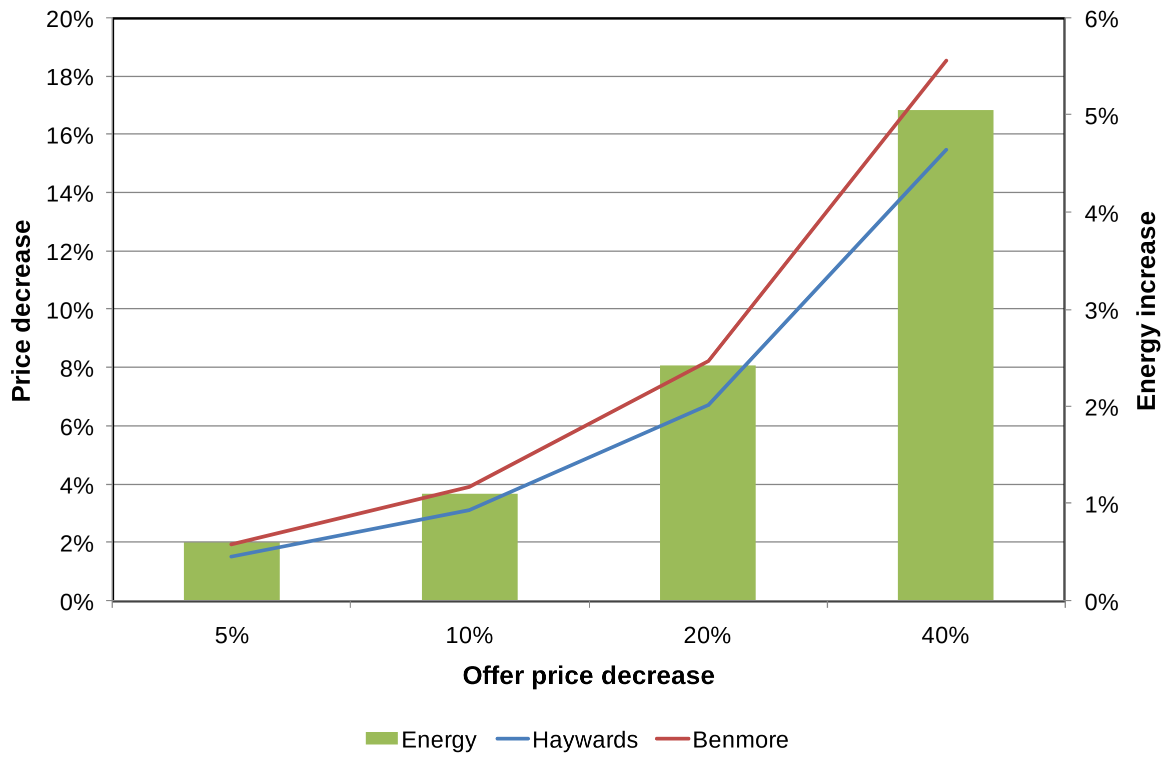

Figure 23 Meridian hydro offer sensitivity results

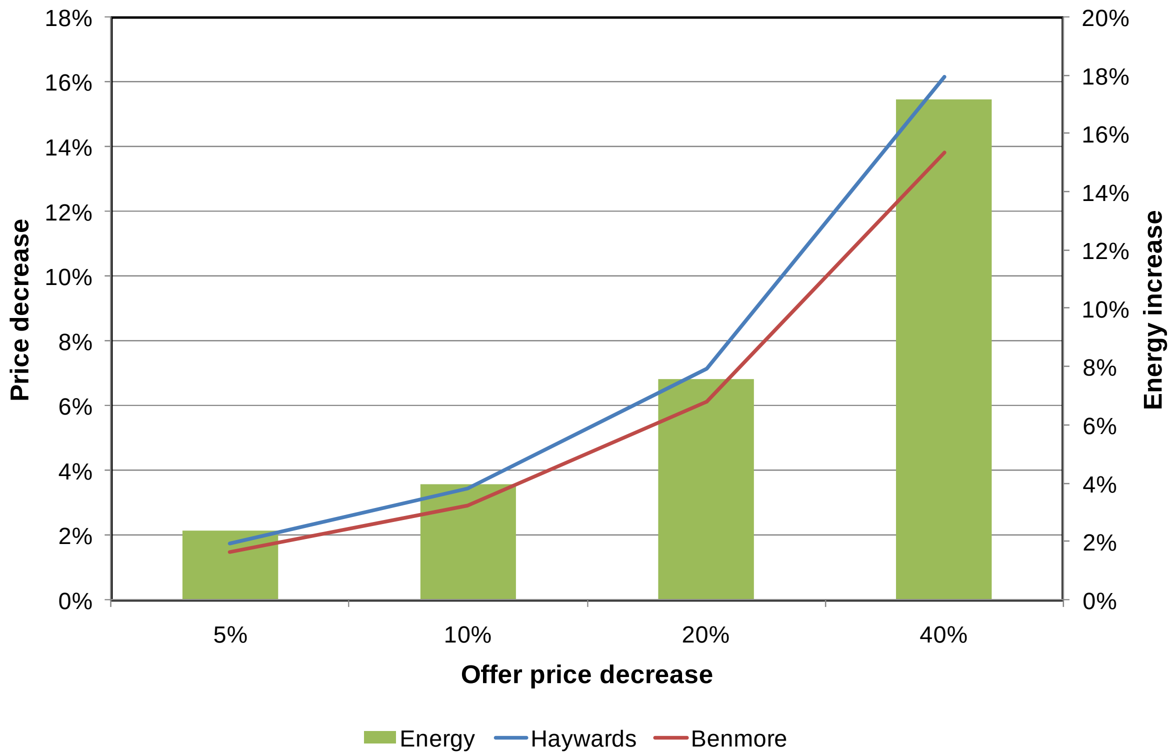

Figure 24 MRP hydro offer sensitivity results

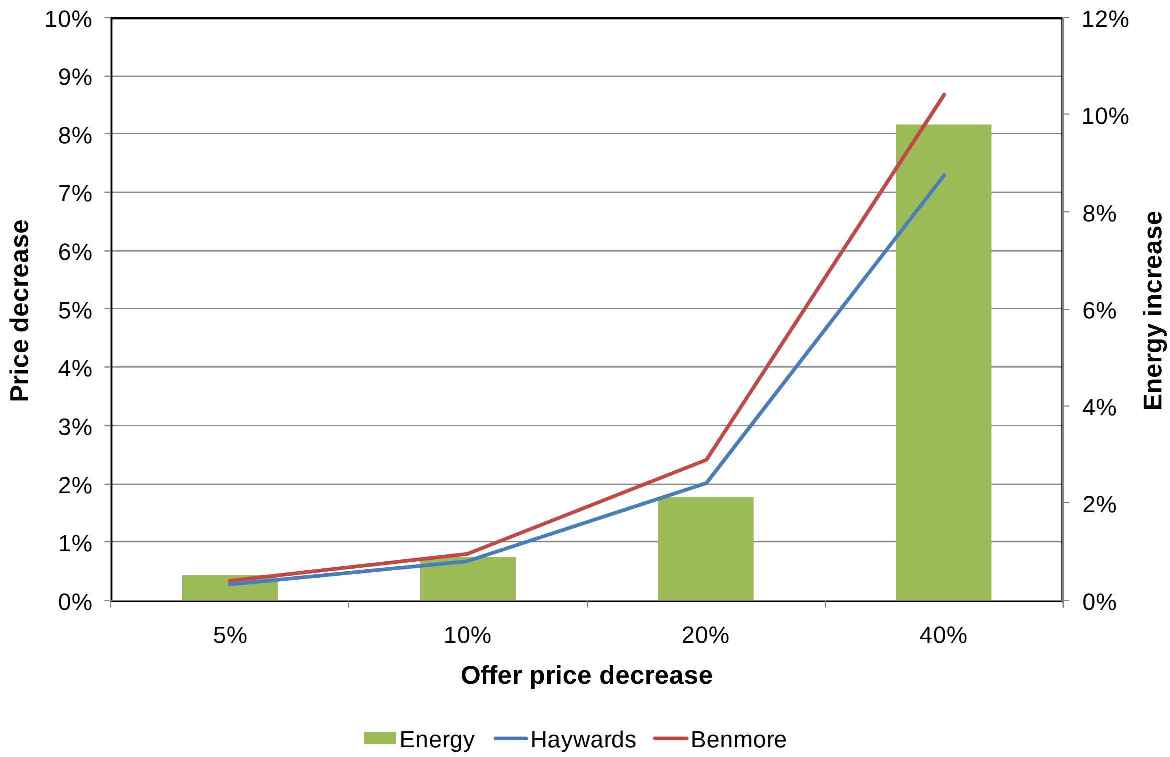

Figure 25 Contact hydro offer sensitivity results

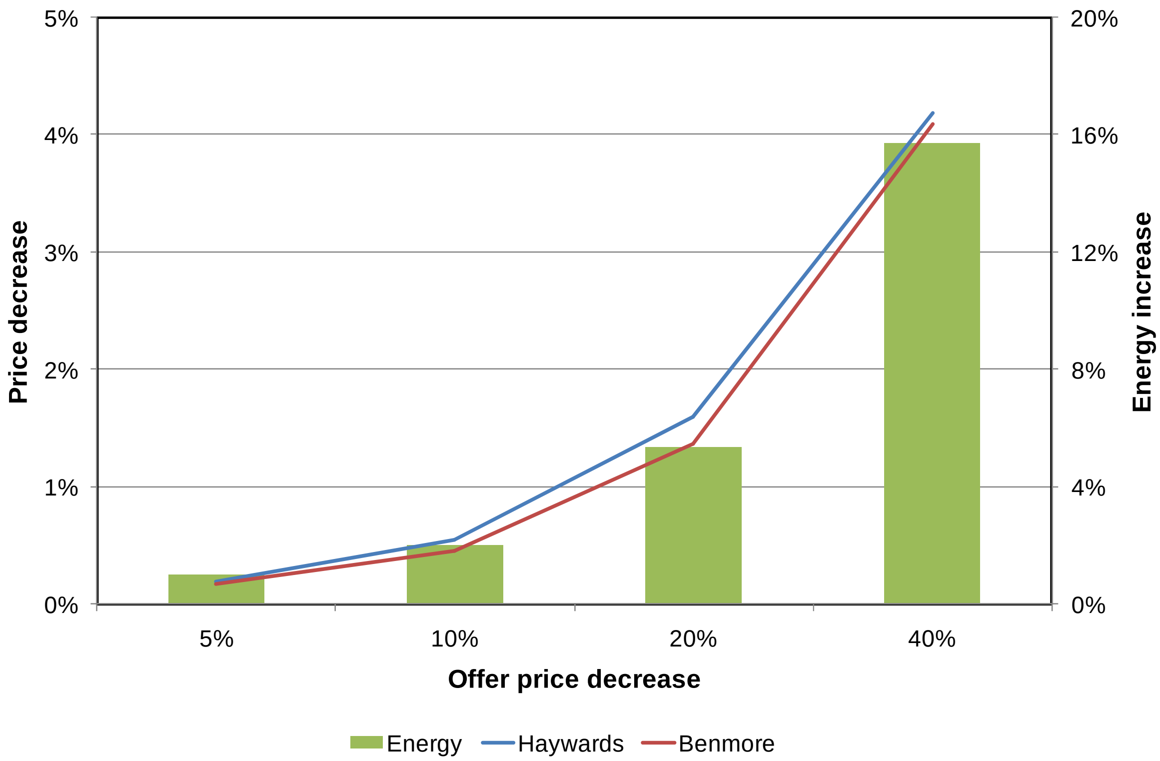

Figure 26 Genesis hydro offer sensitivity results

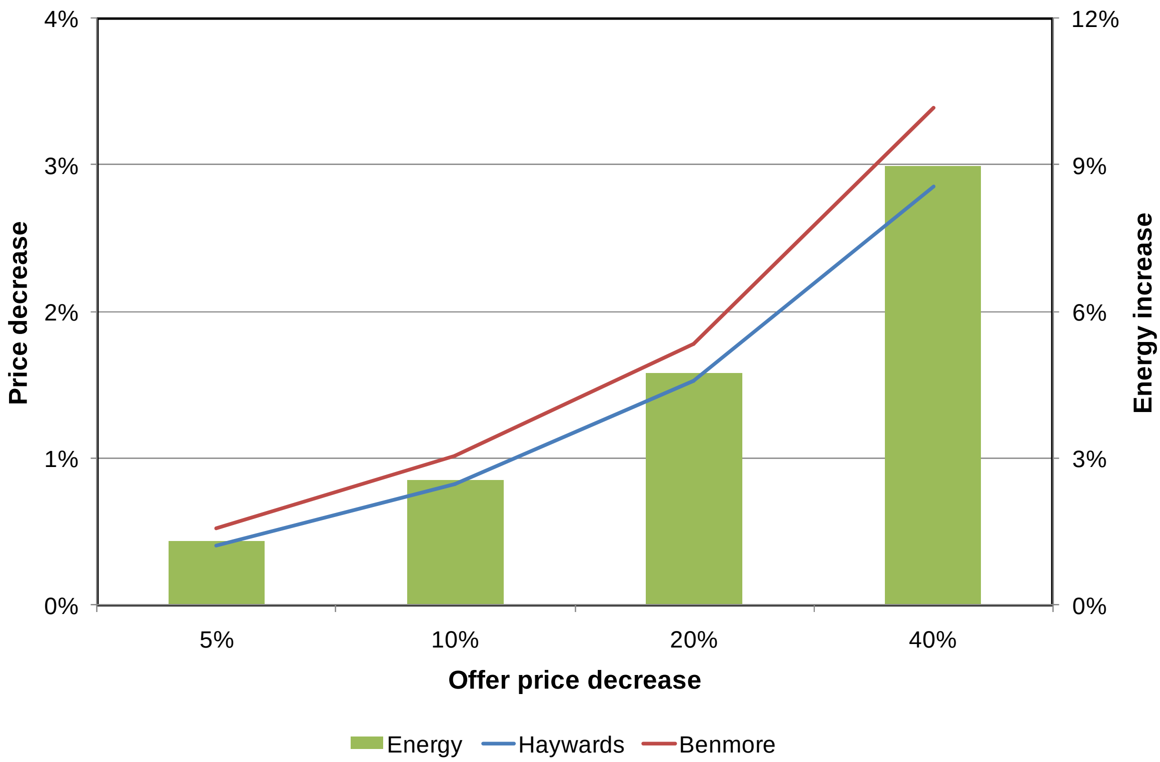

Figure 27 TrustPower hydro offer sensitivity results

translation into reservoir storage, this represents approximately a 0.2% reduction in the Waitaki storage levels as at 20 December 2010.[12]

4.4.7 To obtain a larger reduction in energy prices over this period, more aggressive reductions in offer prices are required. This, however, increases the scheduled energy from hydro sources. A 40% reduction in Meridian's offer prices would have increased its energy output over the 19-day period by 5.1% with average energy prices at the Haywards and Benmore nodes reducing to $121/MWh and $117/MWh, respectively. This represents a 15.5% and 18.5% reduction in these average prices but the 5.1% increase in scheduled energy equates to about 32 GWh of additional energy, primarily from the Waitaki system. Assuming the same translation into storage as above, this represents approximately a 1.8% reduction in the Waitaki storage levels as at 20 December 2010.

4.4.8 Similar results can be attained by returning Meridian's offer to their actual levels and reducing MRP's offer prices. As can be seen from Figure 24, a 5% reduction in offer prices yields just a 1.7% and 1.5% reduction in the Haywards and Benmore average nodal prices for the 19-day period in December 2010. This would have increased the scheduled energy from MRP by 2.4%, or about 4 GWh. Again, larger reductions in offer prices would have a greater impact on reducing

[12] Estimating the Waitaki storage level on 20 December 2010 to be 1800 GWh and calculating the percentage change as if it were 3.8 GWh lower yields a 0.2% decline, i.e. 100(1796.2-1800)/1800 = 0.21.

prices but with a commensurate increase in scheduled energy from the hydro generators.

4.4.9 A 40% reduction in MRP offers would have reduced the Haywards and Benmore average prices from $143/MWh to $120/MWh and $123/MWh, respectively (i.e. declines of 16.2% and 13.8%). An additional 17.2% of energy would have been dispatched from MRP's hydro stations, equating to about 29 GWh. Although the energy required from MRP to depress energy prices is just a little less than that required of Meridian for similar price declines, the relative size of the storage reservoirs would imply that this volume of energy has a greater influence on the MRP storage levels than is the case for Meridian.

4.4.10 Wholesale spot prices are less sensitive to deviations in the hydro offers from Contact, Genesis and TrustPower, with a maximum 8% price reduction attained following a 40% offer price reduction by Contact. Smaller price reductions were observed with similar offer price reductions applied to the Genesis and TrustPower.

4.4.11 This analysis suggests that for any given hydro participant to significantly reduce energy prices, they would have needed to offer at much lower prices than they did in practice. The consequence of this, however, is that there are larger reductions in reservoir levels and therefore an elevated risk of shortage in future months.

4.4.12 Although an individual hydro participant during this period has limited ability to unilaterally reduce the energy prices without an associated energy and storage impact, there is still the possibility that the market's perceptions of hydro shortages and water valuation could have been more moderate than what was the case.

Impact of simultaneous action

4.4.13 The analysis was repeated, but this time with the market offer prices for all the major hydro participants being reduced simultaneously (rather than one at a time). This simulated a scenario which converged on lower offer prices from hydro generators than those observed in December.

4.4.14 As with the individual sensitivity analysis, offer prices were decreased using a range of reductions; 5%, 10%, 20%, and 40%. The results of this analysis are illustrated in Figure 28.

4.4.15 Unsurprisingly, for any given offer price decrease applied simultaneously by all hydro participants, the wholesale energy price reduces by considerably more than when each participant acts separately. The larger price decline is also associated with a smaller increase in dispatched energy by all hydro plant. This is because the residual demand previously allocated to thermal generators is now spread across the various lower-priced hydro generators.

4.4.16 The results indicate that a 35% reduction in average energy prices at the two reference nodes is attainable with only an additional 21.6 GWh of energy from all hydro stations combined over the first 19 days of December. As highlighted previously, this analysis is conducted with the benefit of hindsight. Nevertheless, it does underscore the potential cost impacts of uncertainty and information asymmetries that exist in the market.

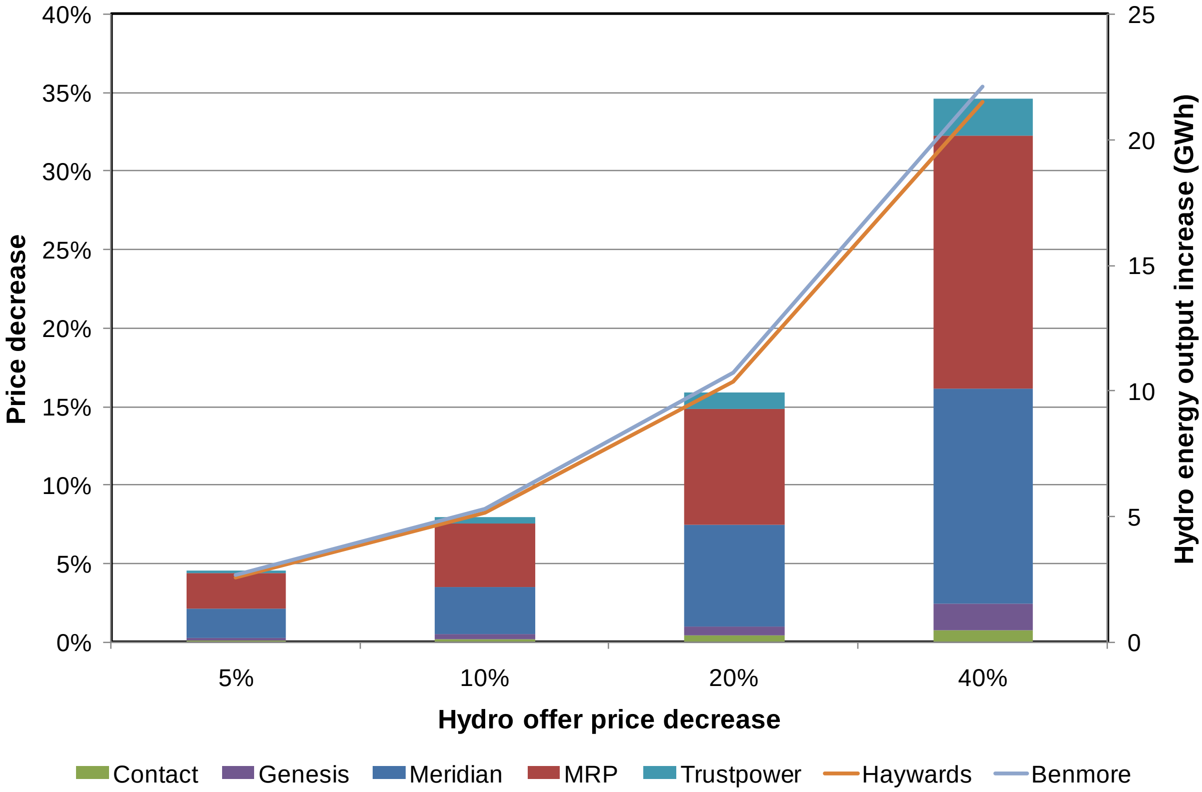

Figure 28 Aggregate hydro offer sensitivity results

Thermal offers

4.4.17 The potential impact of reductions in the offer prices by thermal plant is analysed in this section. Observing that the hydro generators increased their offer prices during late November and into December, it is natural to wonder if this then left thermal plant as the marginal resource. If so, what sort of impact would reductions in offer prices by thermals have had on wholesale prices?

4.4.18 Figure 29 illustrates the results of applying the same analysis as above to the thermal plant. The reduction in offer prices from all of the thermal generators reduces the average market price by about 8-10%, significantly less than was observed with some of the major hydro generators.

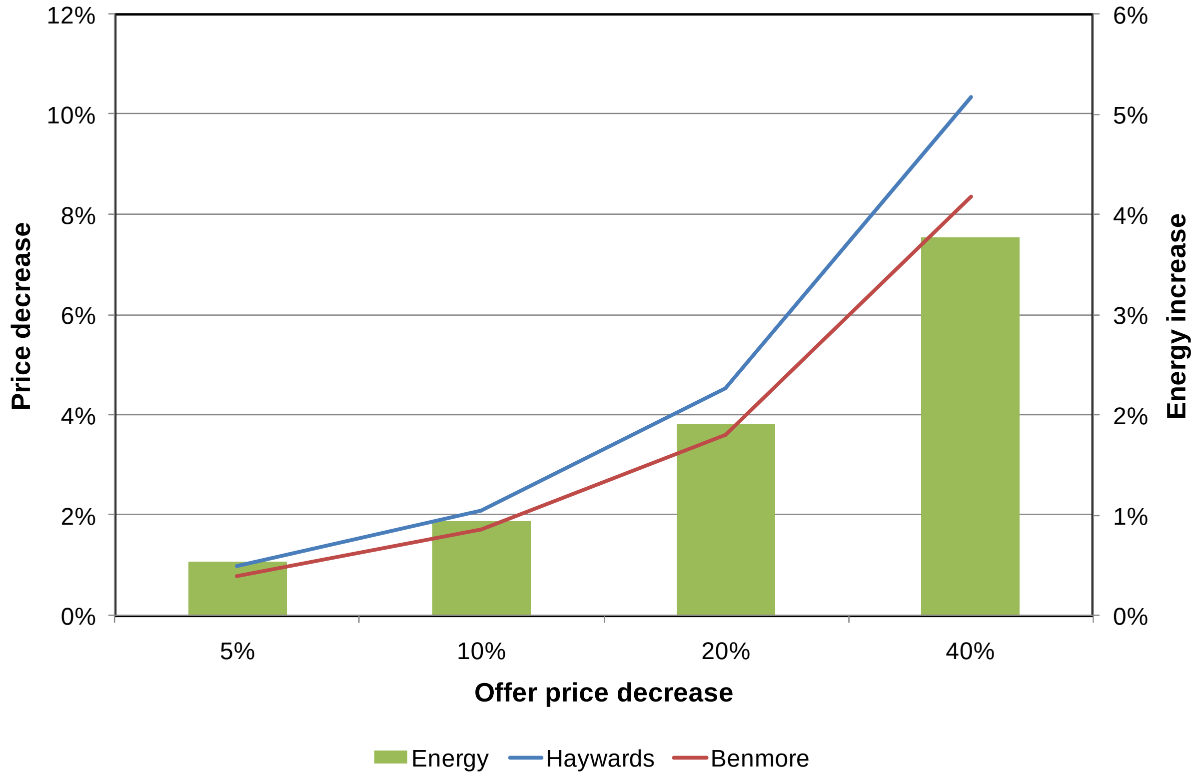

Figure 29 Thermal offer sensitivity results

4.4.19 To further consider the influence of thermal offers on the market price, the residual demand curve for thermal plant was analysed relative to the offers made by thermal generators. The residual demand curve facing thermal plant was determined by subtracting the demand served by non-thermal generators, including by wind and geothermal, from total demand.

4.4.20 TP 34 was observed for four different days; 24 November and 1, 8, and 15 December. The results are illustrated in Figure 30 where each of the four days is presented using a different colour. The stepped, upward-sloping curves denote the thermal offer curves while the corresponding residual demand curve (i.e. thermal generation) is represented by the dashed vertical line. The cross-markers on the demand curves indicate the relevant wholesale market price. For the sake of clarity, the residual thermal demand curves are truncated above the cross-markers denoting price.

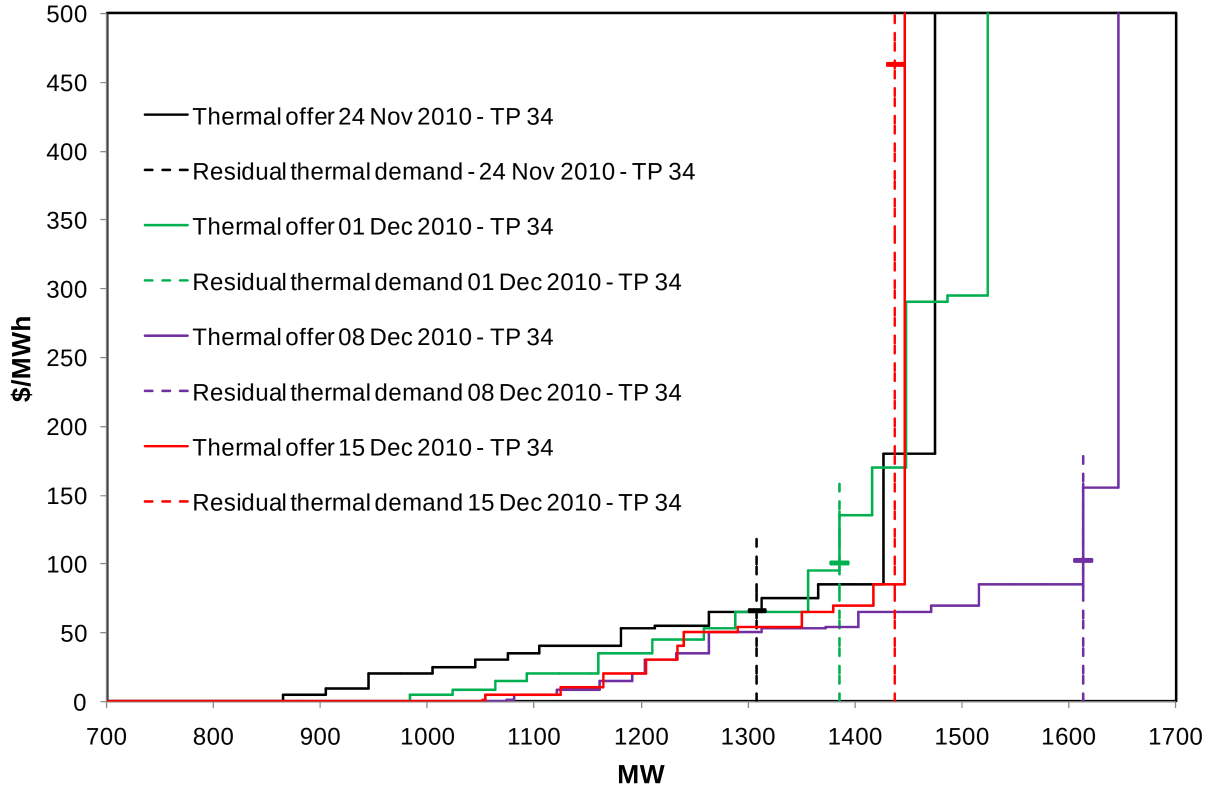

Figure 30 Thermal offer curves with residual thermal demand

Note: Residual thermal demand is defined as total demand less demand satisfied by non-thermal plant.

4.4.21 It can be observed that there is increased residual demand on thermal generators during the days in December that were analysed compared to 24 November. This increase in dispatched thermal plant during the period in December when the hydro generators increased their offer prices is also evident in Figure 10.

4.4.22 This increased residual demand placed on thermal generators was satisfied without significant upward adjustment of the offer prices by thermal operators. This is also evident from the offer stacks presented in Appendix B.

4.4.23 In the 4-day sample analysed, the thermal generators were marginal only once. On all other occasions, more expensive hydro offers were setting the market price. On 15 December, however, reduced capacity was offered by thermal plant. Coupled with the selection of a Huntly unit as the frequency keeper, and with that unit constrained down in order to provide frequency control, thermal plant availability was reduced even further. The wholesale market price therefore settled well above the offer price of the un-cleared thermal capacity.

5. Conclusions

5.1.1 The Authority's analysis of circumstances surrounding the run up in spot electricity prices in early-to-mid December has identified a number of contributory factors. These include:

- Uncertainty regarding lake levels, which were at average levels in December 2010, but trending downwards;
- Inflows to hydro reservoirs being well below average levels;
- A strong La Nina weather pattern emerging, typically associated with below normal inflows and early melting of the snow pack;
- Early and rapid melting of the snow pack, which meant that reliance on lake levels as a guide to storage conditions could be misleading;
- Uncertainty regarding the planned Maui outage in February 2011; and
- Uncertainty regarding thermal plant availability.

5.1.2 The Authority concludes that hydro generators, acting in response to these concerns and uncertainties, raised offers to the degree necessary to conserve storage.

5.1.3 The Authority's assessment is that the market responded appropriately to the higher prices. Some large-scale consumers reduced consumption and all available thermal plant was utilised, with some thermal generation offline for maintenance quickly being brought back into service. No transmission outages occurred.

5.1.4 Accordingly, the Authority does not consider that further investigation is warranted on this occasion.

5.1.5 However, there are lessons to be learnt from the event, particularly with regard to the adequacy of information to market participants regarding emerging supply risks. These matters will be addressed in conjunction with work initiated by the former Electricity Commission regarding greater generator disclosure of management and security–risk information.

5.1.6 The Authority considers the availability of timely and reliable information as a key feature of the market monitoring regime it is instituting in accordance with Electricity industry Act 2010, which came into effect in November.

5.1.7 A better informed industry will not only assist in improving market performance, but it will enable concerned consumers to better understand what generators are doing and why.

5.1.8 The work on information flows to the market will involve the Authority reviewing procedures, policies and oversight mechanisms concerning the disclosure of information within the sector.

Appendices

Appendix A Haywards price and national load

A.1 In this appendix, the price at the Haywards node ($/MWh) and the level of national load (MW) are plotted for the periods 1 October - 21 December 2010 and 1 January - 21 December 2010, respectively.

A.2 Load can be seen to have followed a distinct weekly pattern at a fairly constant level over the last three months of 2010, while for the past year the load profile can be seen to have followed the usual annual pattern of higher demand for electricity in the winter months. There is nothing remarkable about the load profile over the past year.

A.3 Prices over the past year, on the other hand, are more noteworthy. First, they appear to be unrelated to the level of load. And second, they are quite low for much of the May - November period.

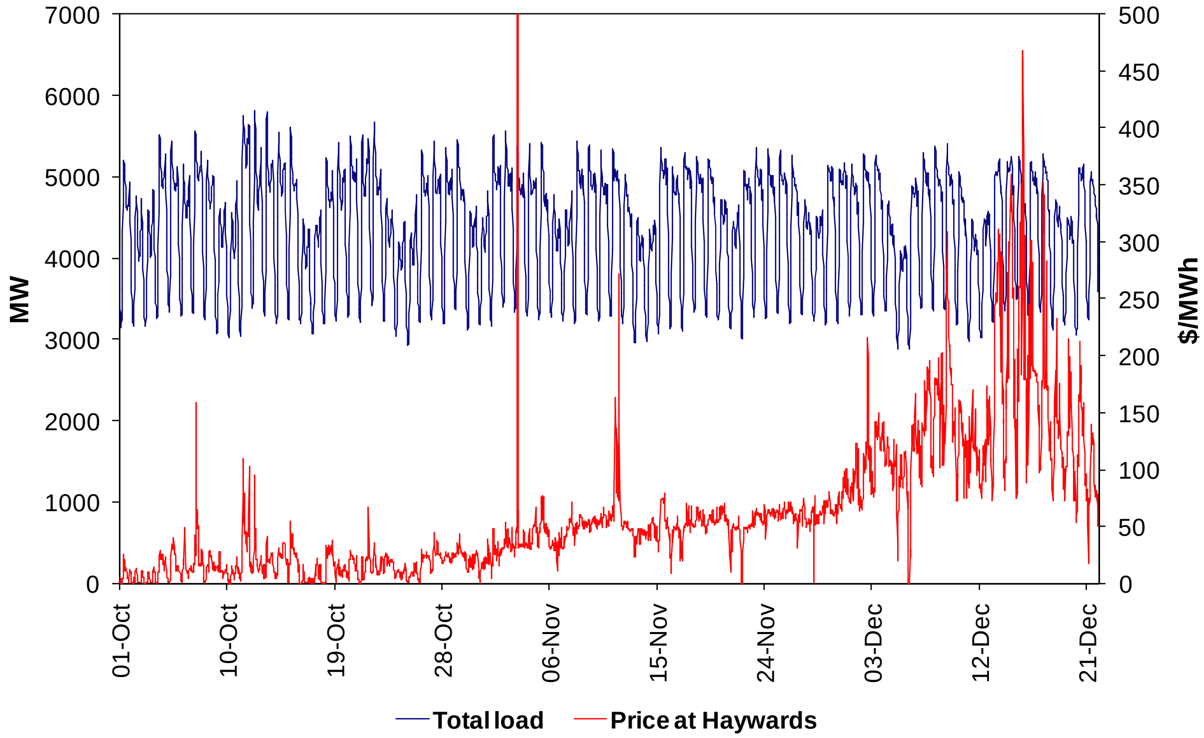

Figure 31 Haywards price and national load, 1 Oct – 21 Dec 2010

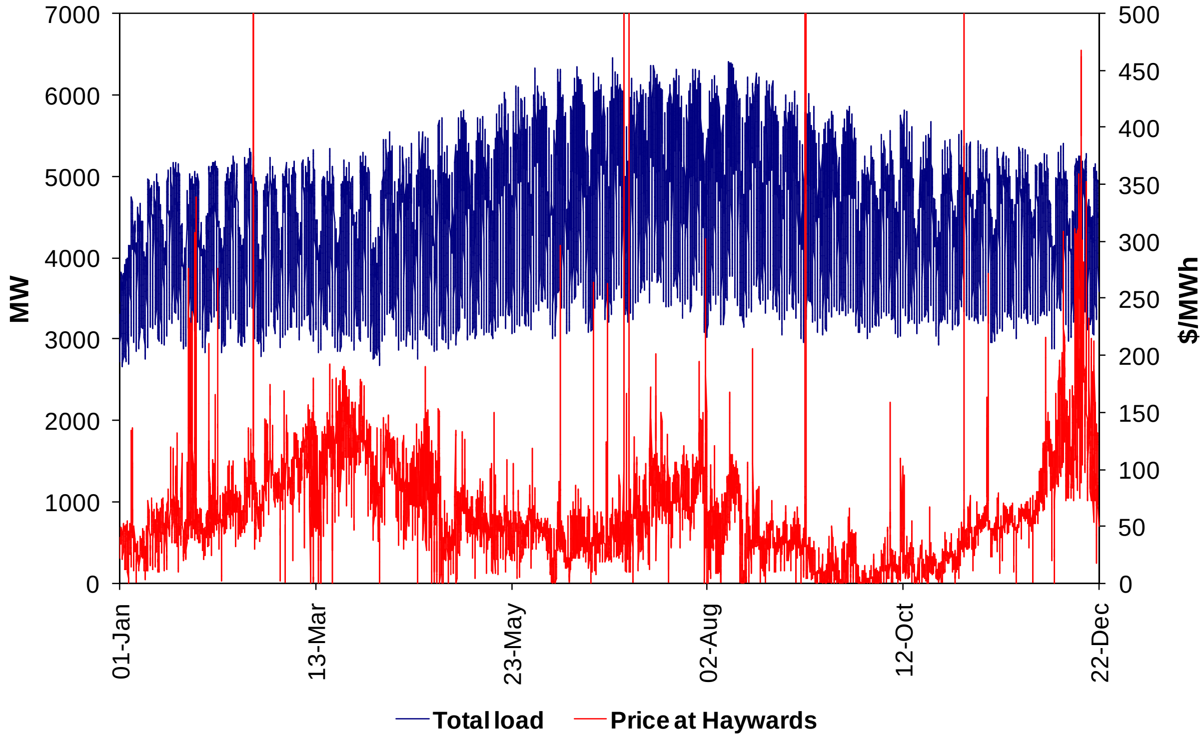

Figure 32 Haywards price and national load, 1 Jan – 21 Dec 2010

Appendix B Offers by major participants

B.1 The following 10 charts show stacked bar plots of all offers by the five major generators covering the period 22 November - 21 December 2010. Two plots for each generator are shown; one for TP 34 and the other for all trading periods in each day of the analysis period. These plots extend the descriptive analysis of offer behaviour presented in section 3.5.

Volume-weighted offer prices

B.2 Subtracting the cleared or dispatched generation capacity from the total amount offered provides a simple measure of residual capacity in the market.[13] Such a measure of residual capacity follows a periodic pattern with increased capacity unused on the weekend days and to a lesser degree on Monday and Tuesdays. Throughout December, residual capacity was at similar levels to those during November. This implies that the high prices were a result of generators pricing up their offers, rather than the consequence of a capacity supply-demand imbalance.

B.3 An alternative view of the trend of offer prices over time can be seen by plotting volume-weighted average offer prices. Figure 43 through Figure 47 show volume-weighted average offer prices for each of the five major generators for the period 1 October – 21 December 2010.

B.4 Figure 43 suggests that Contact reassessed their valuation of water at the end of November and again around 7 or 8 December. At about $160/MWh, the magnitude of these two increases was not as pronounced as Meridian's, although their hydro resources would have been experiencing broadly similar conditions, e.g. early and rapid snow melt and a strong La Niña weather pattern. Figure 45 indicates that Meridian revised upwards its valuation of water by more than $600/MWh during the first two weeks of December.

B.5 The large difference in water valuations might be due to differing market positions during this time. Contact has a large thermal, Otahuhu C offline for maintenance. It would be necessary to examine hedge contracts and net positions to understand the differences

B.6 Meridian begins to adjust upwards around 23 November. This may have been the start of some supply rationing to conserve storage levels based on current and expected future inflows. Prices increased quite rapidly after the first week of December, perhaps to ration output and align water resources with net position. By 10 December, Meridian's offer prices are up to about $1000/MWh – the same as the Huntly offers by Genesis.

B.7 TrustPower steadily increase their prices beginning in early November, with a dramatic increase up to the $120/MWh mark in the first week of December.

[13] The residual capacity can be inferred from Figure 13, i.e. use load as a proxy for dispatched generation.

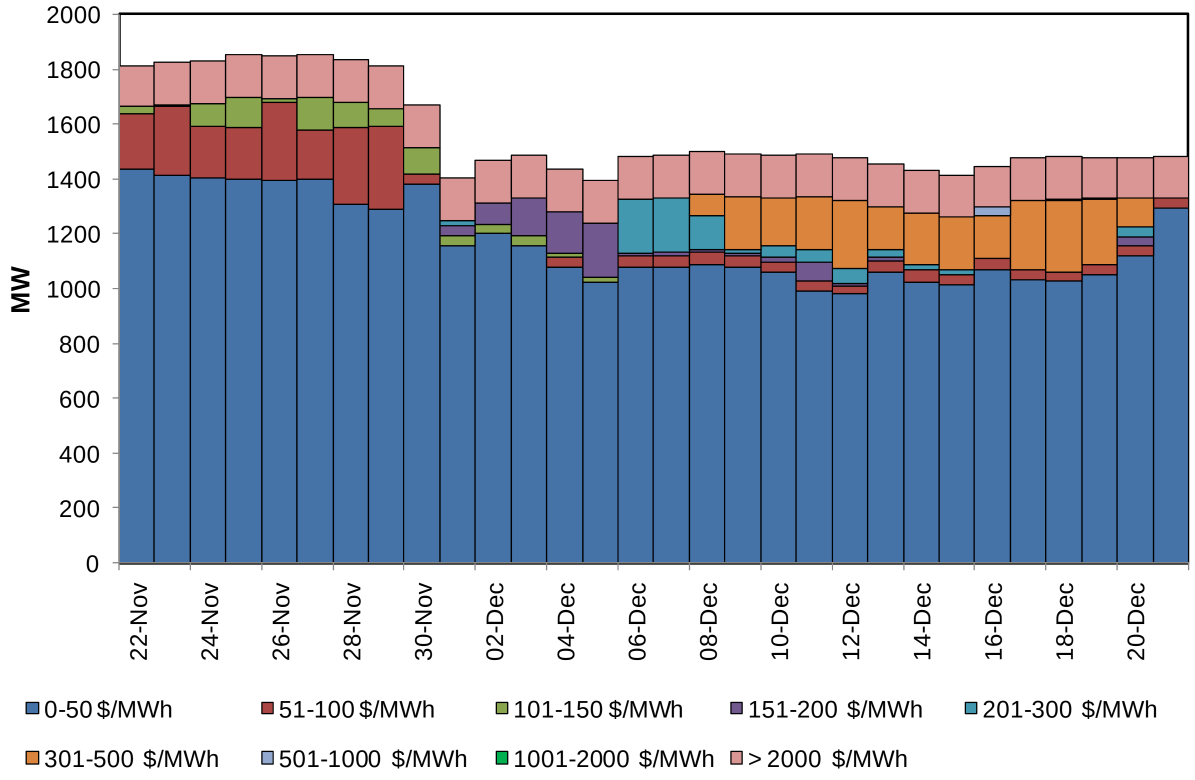

Figure 33 Contact's offer stacks, trading period 34

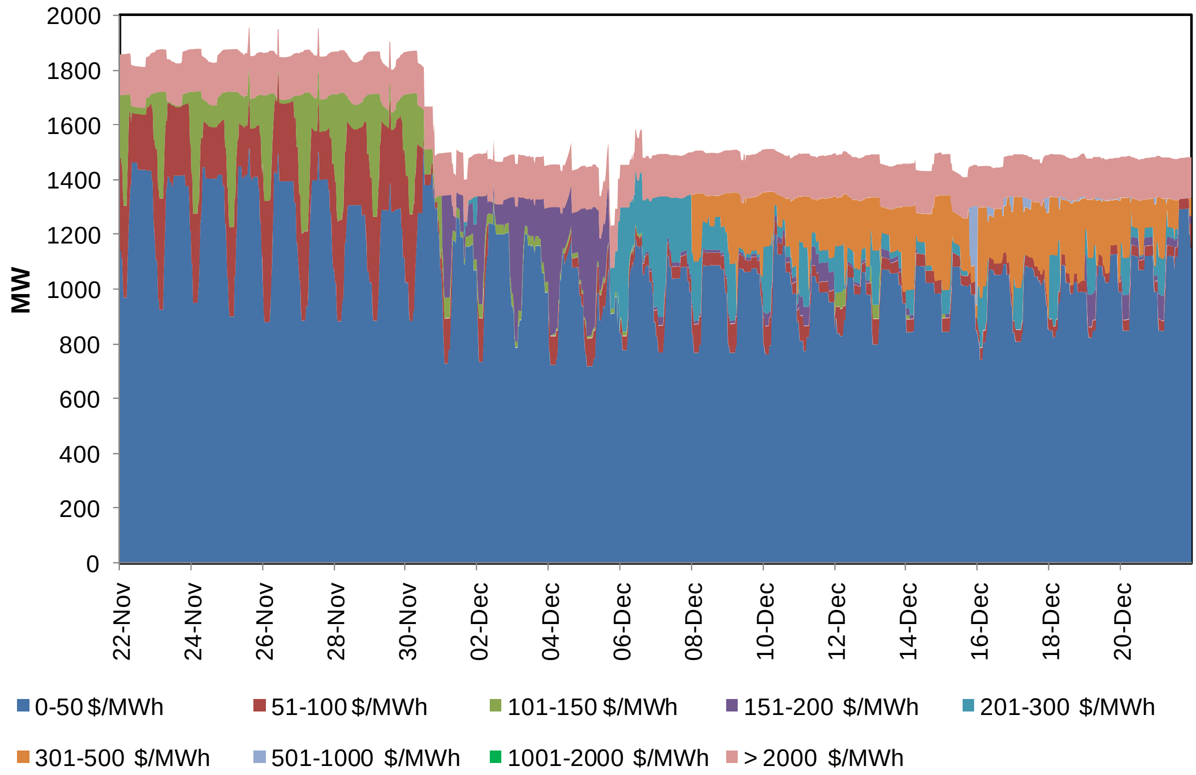

Figure 34 Contact's offer stacks, all trading periods

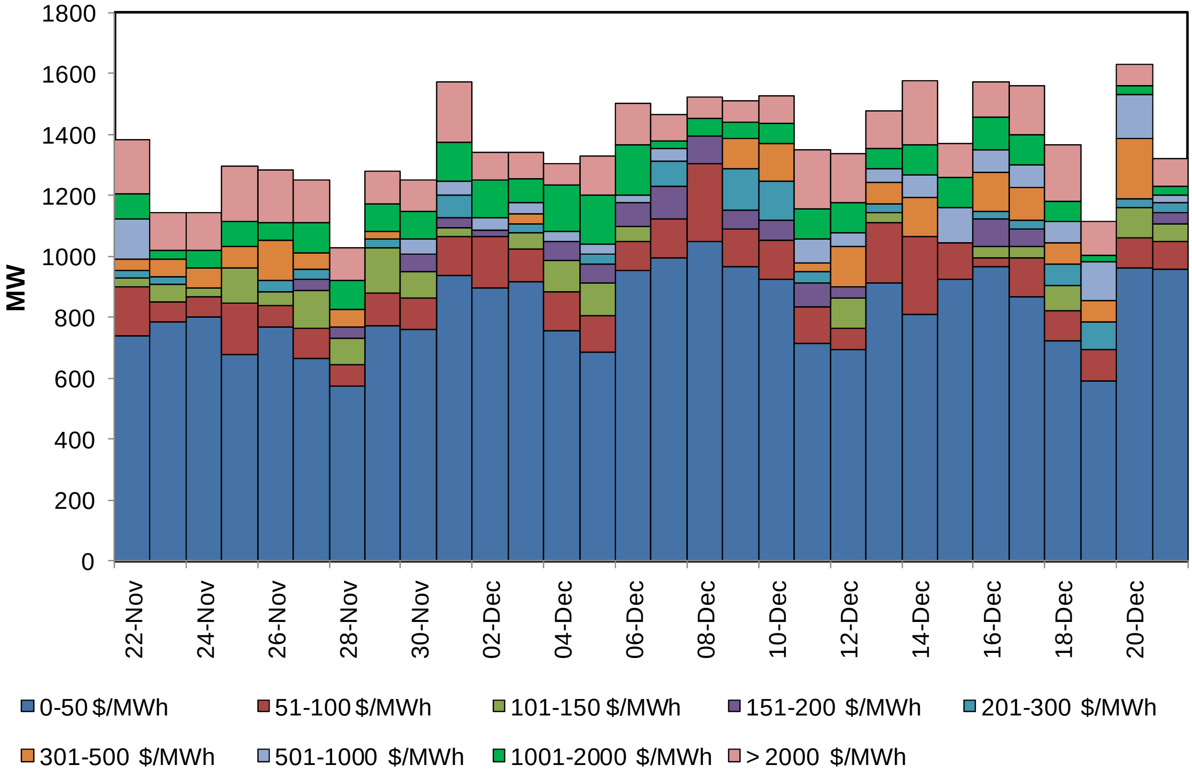

Figure 35 Genesis' offer stacks, trading period 34

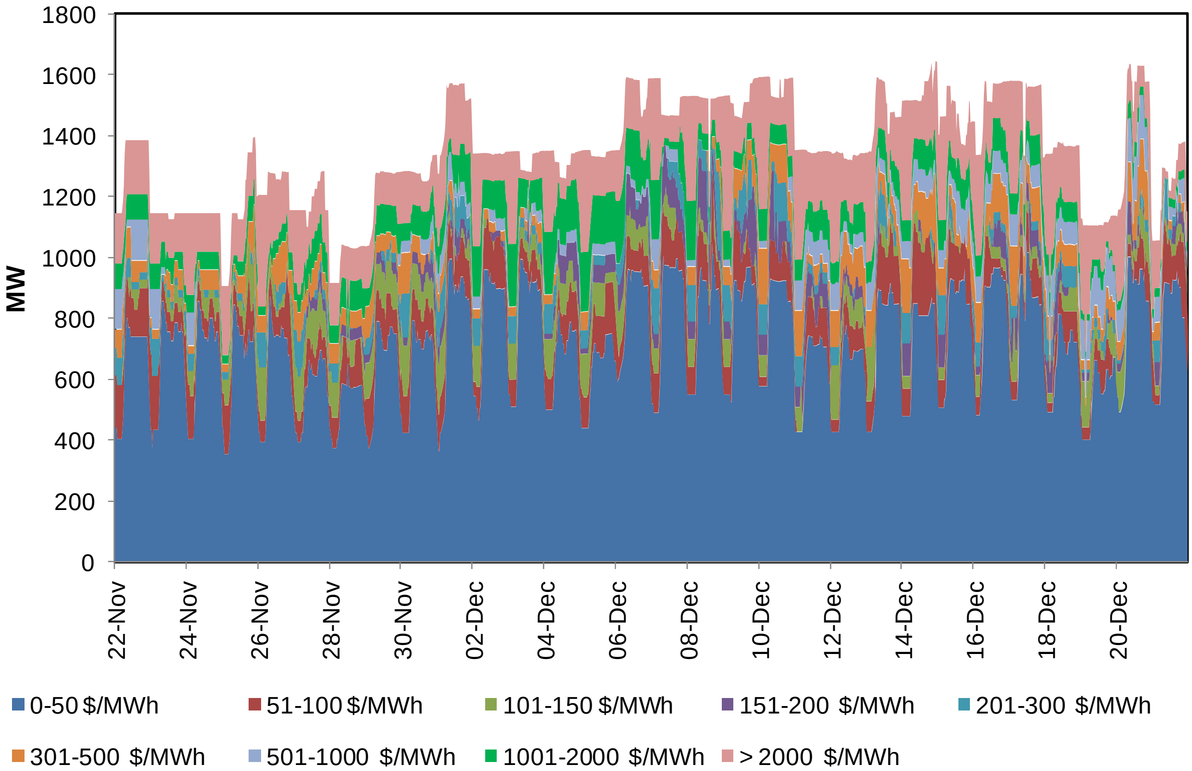

Figure 36 Genesis' offer stacks, all trading periods

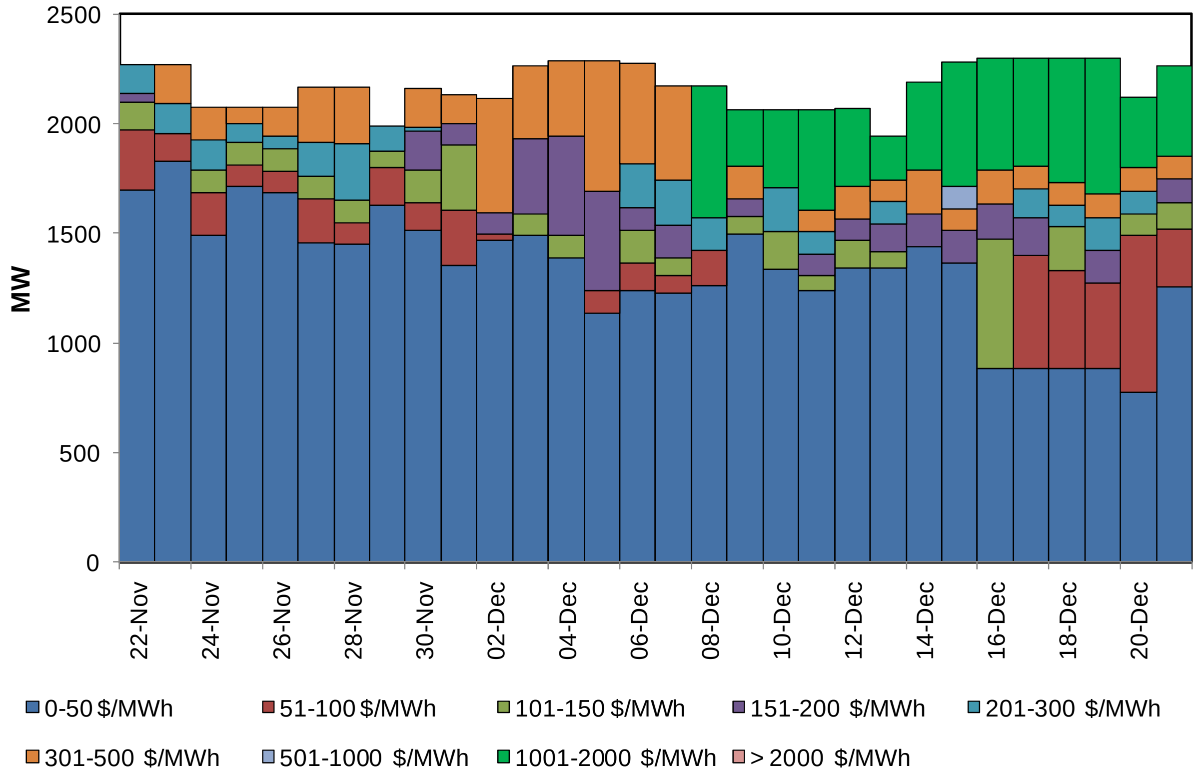

Figure 37 Meridian's offer stacks, trading period 34

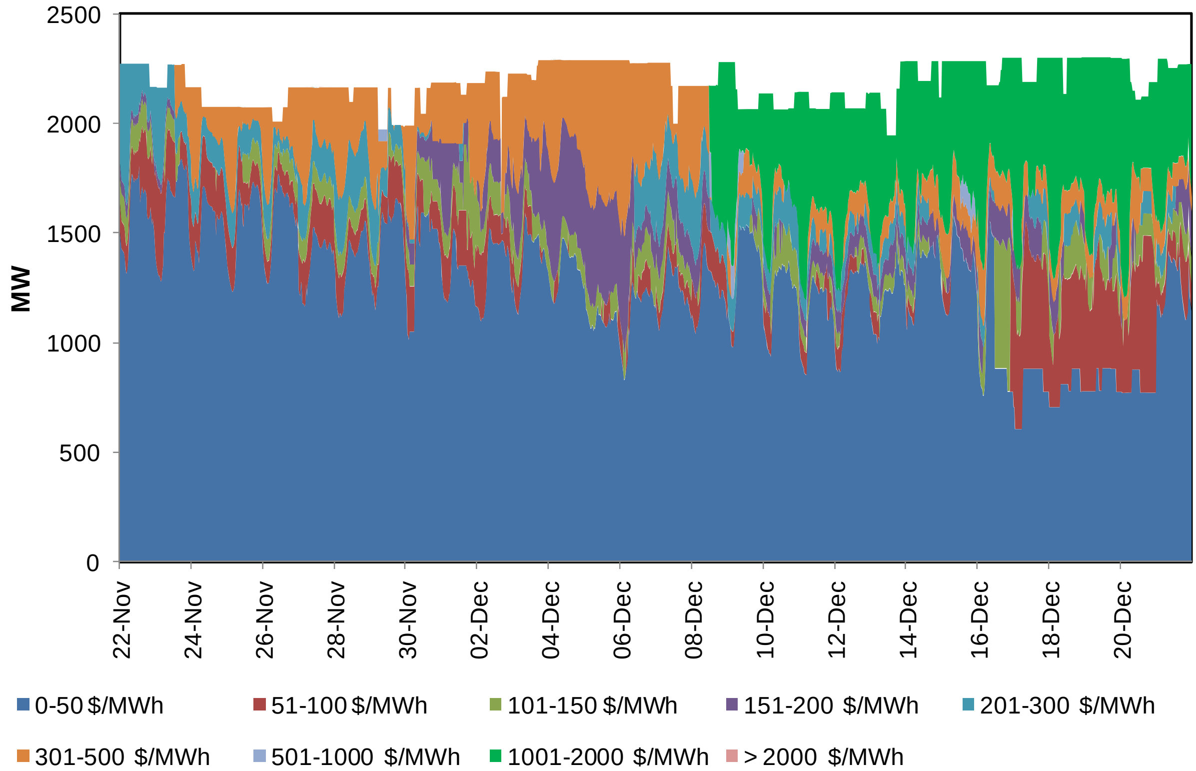

Figure 38 Meridian's offer stacks, all trading periods

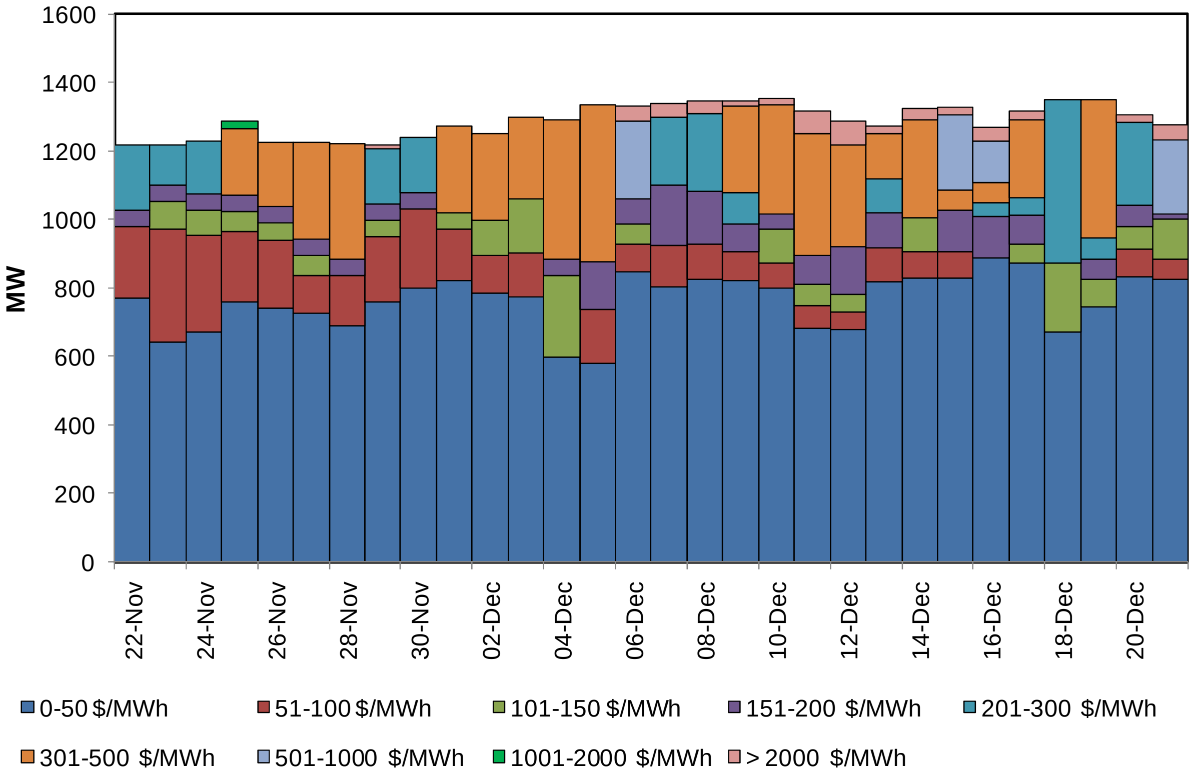

Figure 39 Mighty River Power's offer stacks, trading period 34

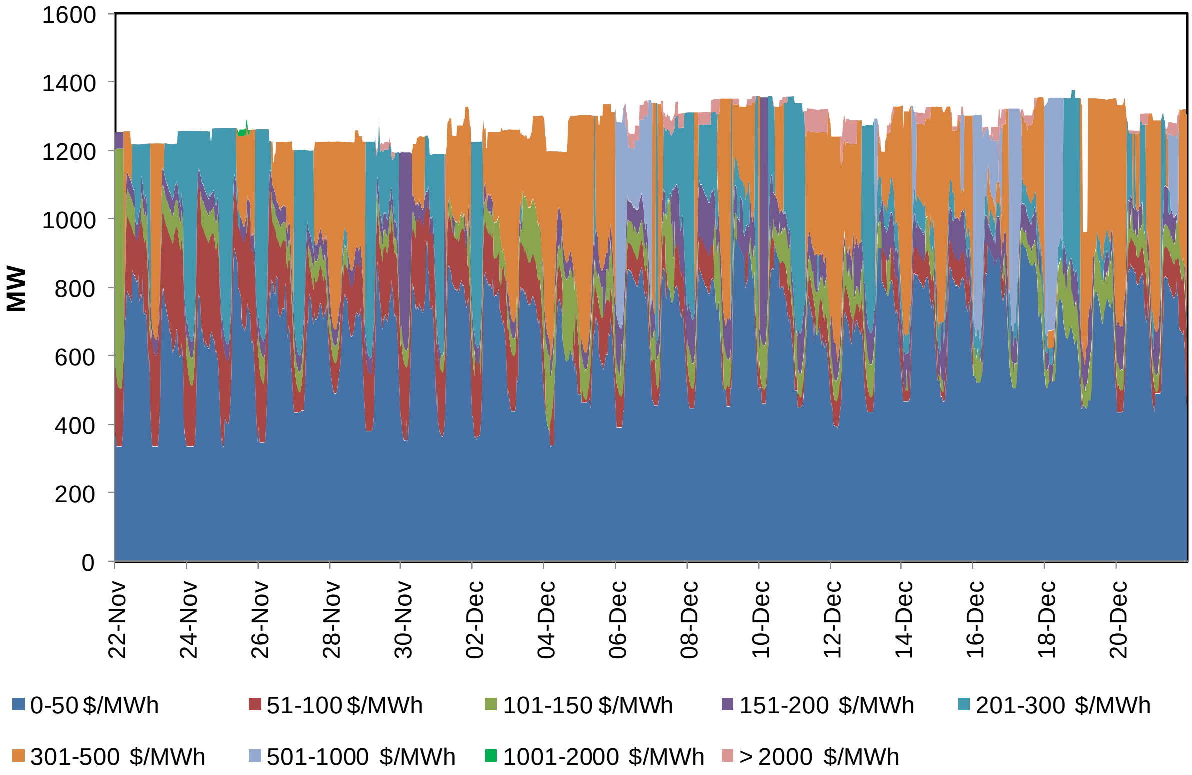

Figure 40 Mighty River Power's offer stacks, all trading periods

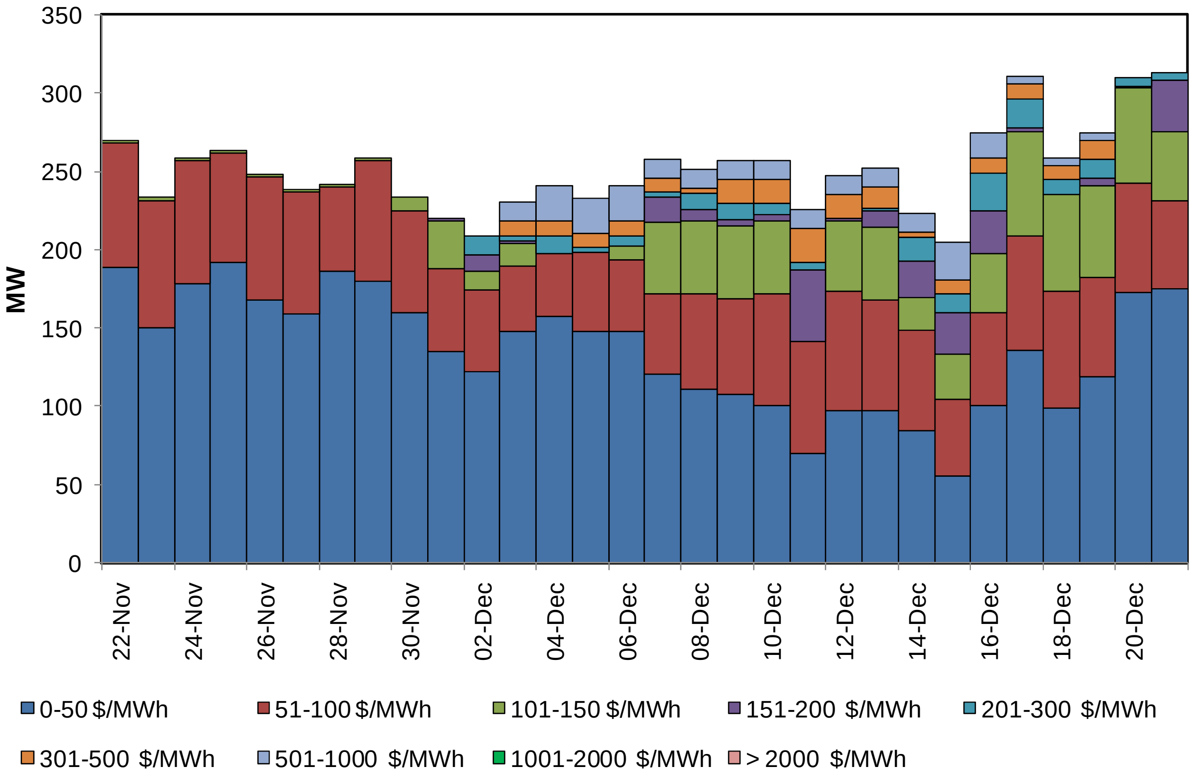

Figure 41 TrustPower's offer stacks, trading period 34

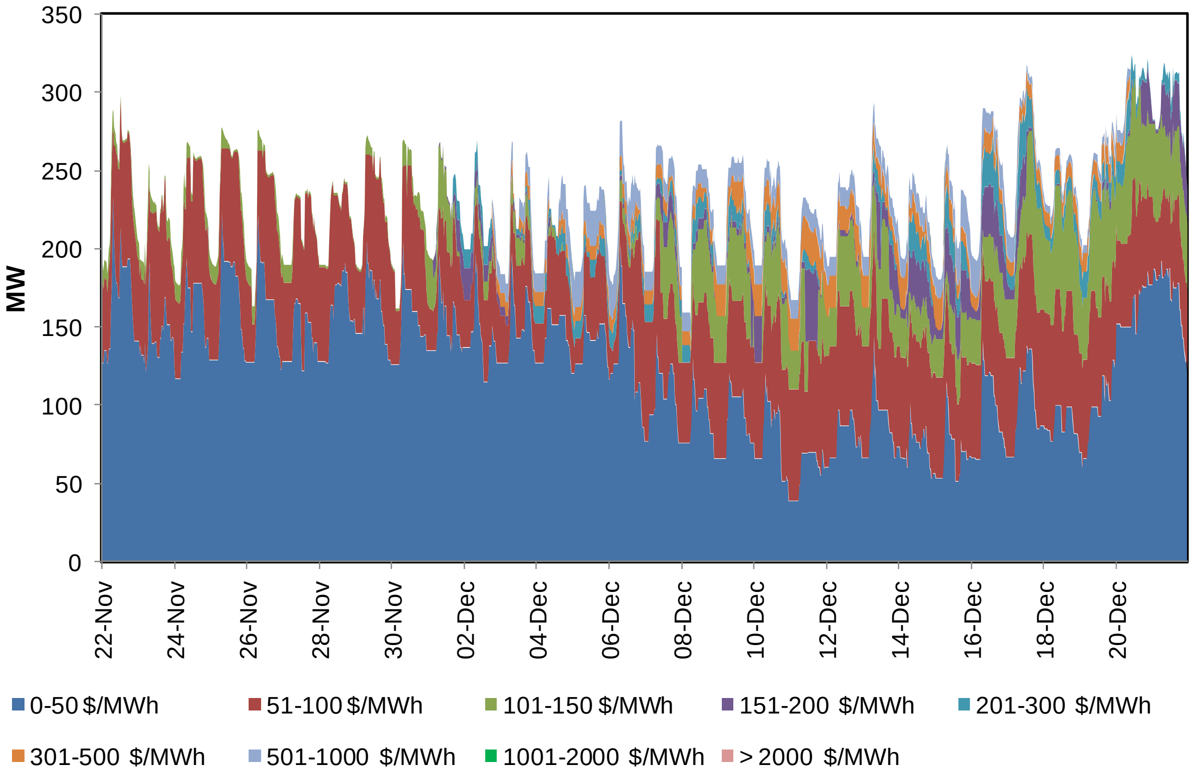

Figure 42 TrustPower's offer stacks, all trading periods

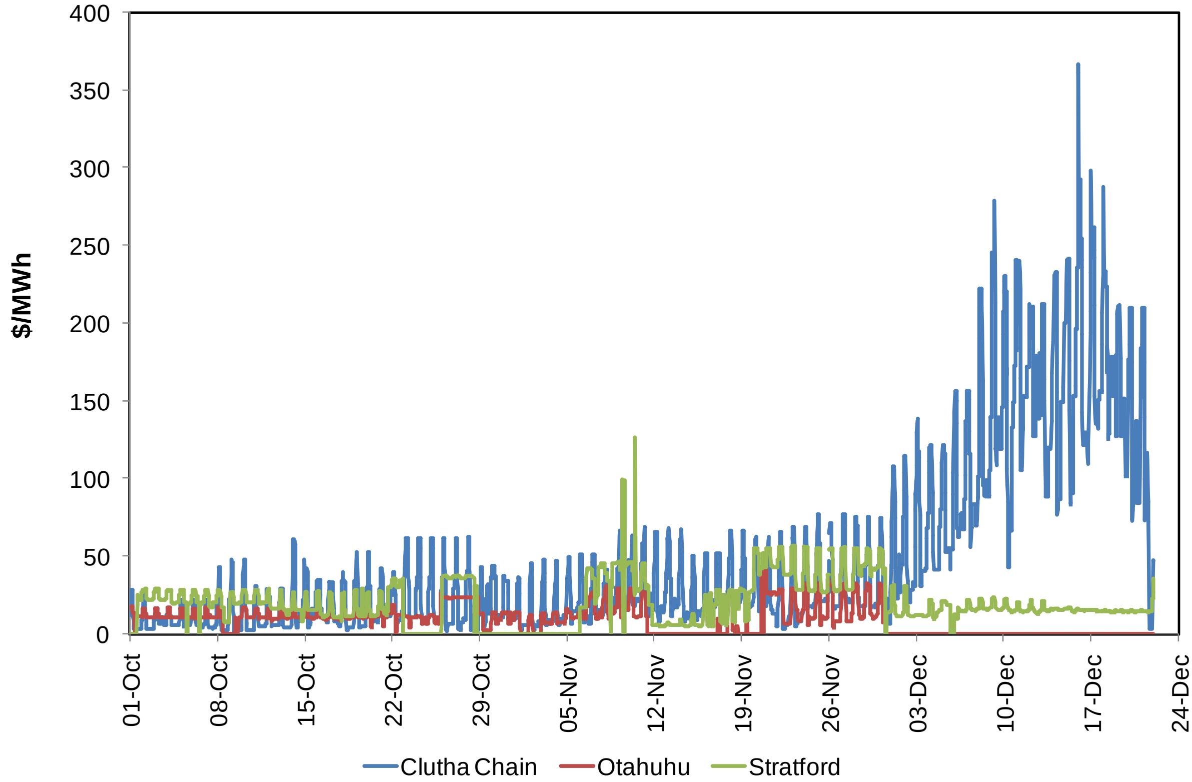

Figure 43 Contact's volume-weighted offer prices, 1 Oct – 21 Dec 2010

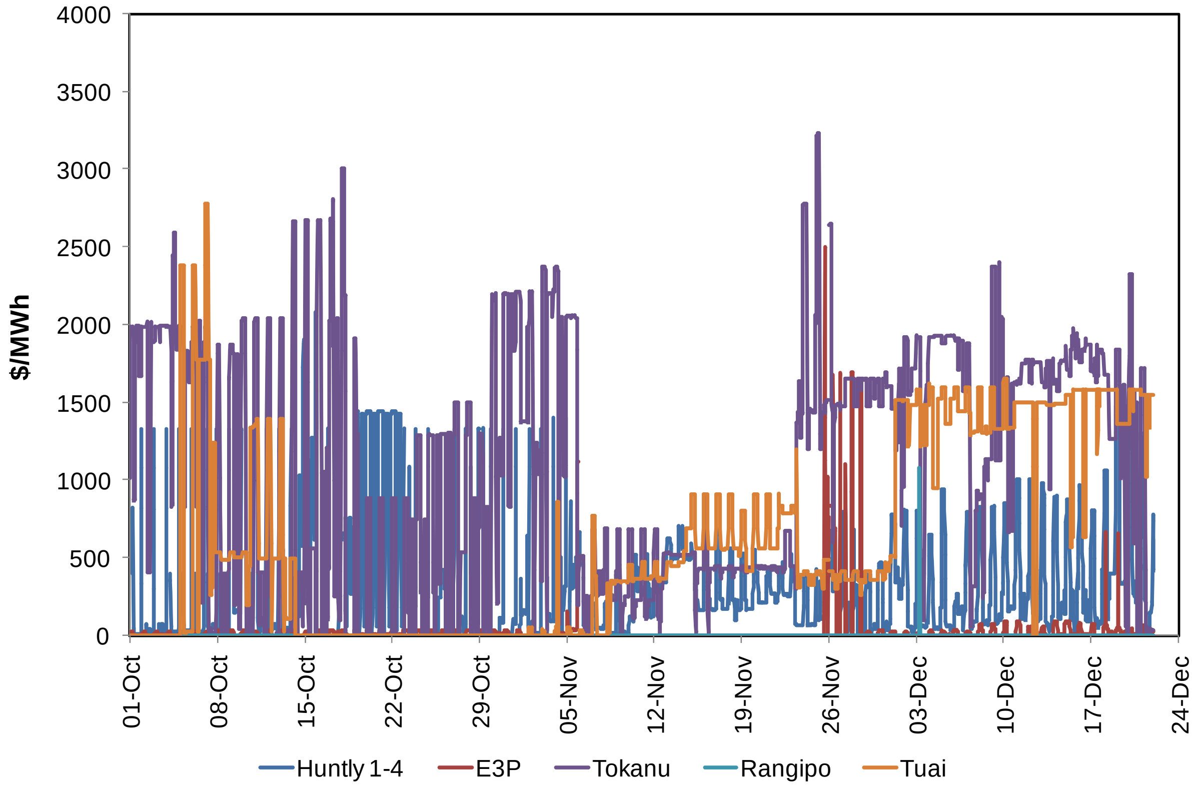

Figure 44 Genesis' volume-weighted offer prices, 1 Oct – 21 Dec 2010

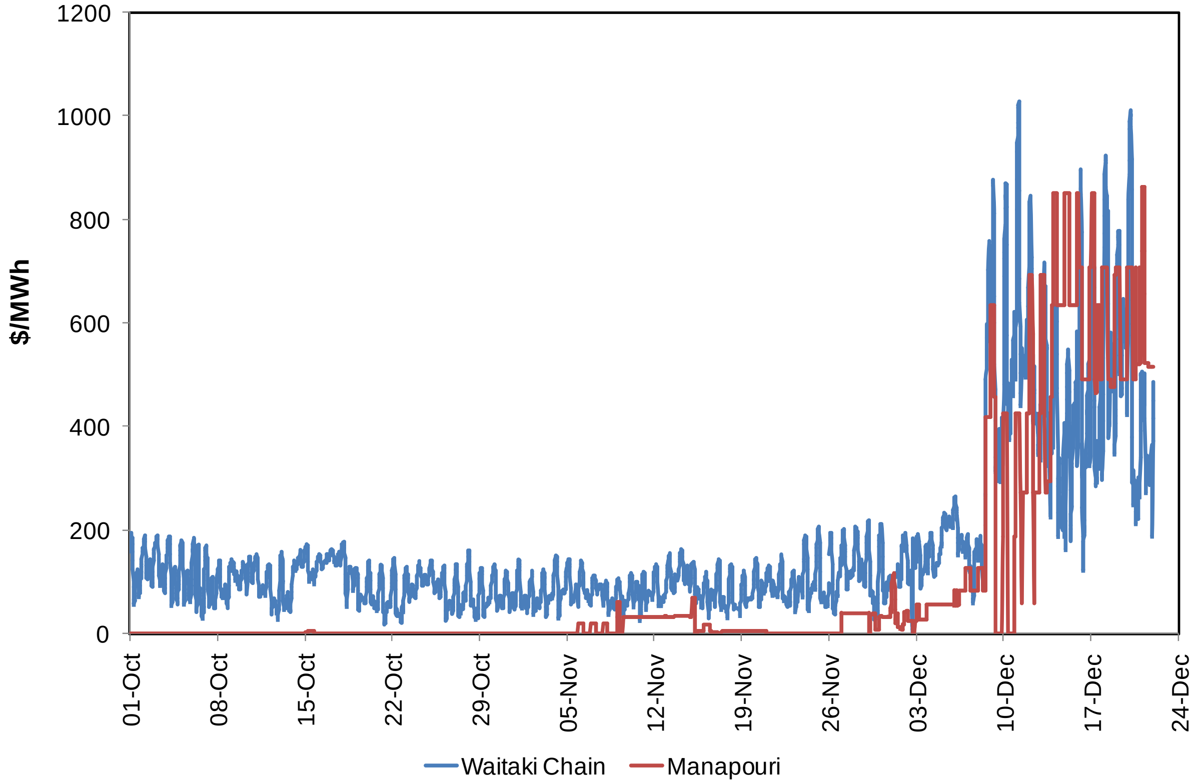

Figure 45 Meridian's volume-weighted offer prices, 1 Oct – 21 Dec 2010

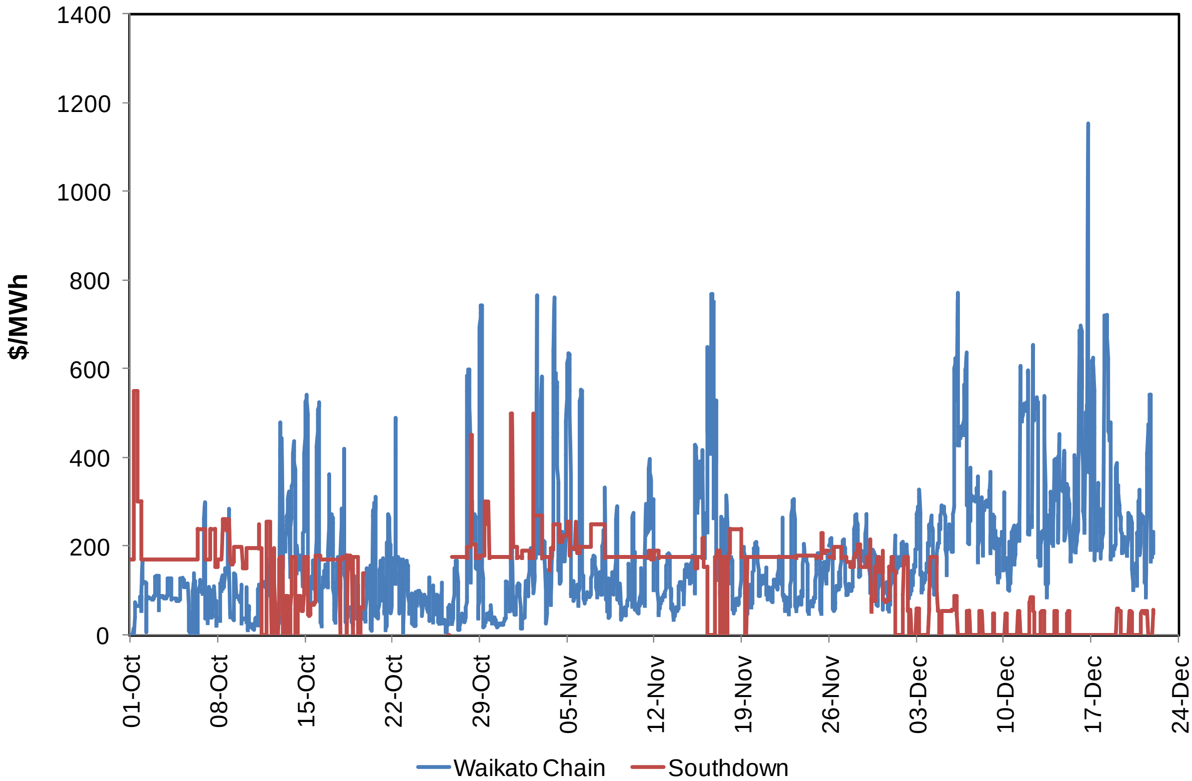

Figure 46 Mighty River Power's volume-weighted offer prices, 1 Oct – 21 Dec 2010

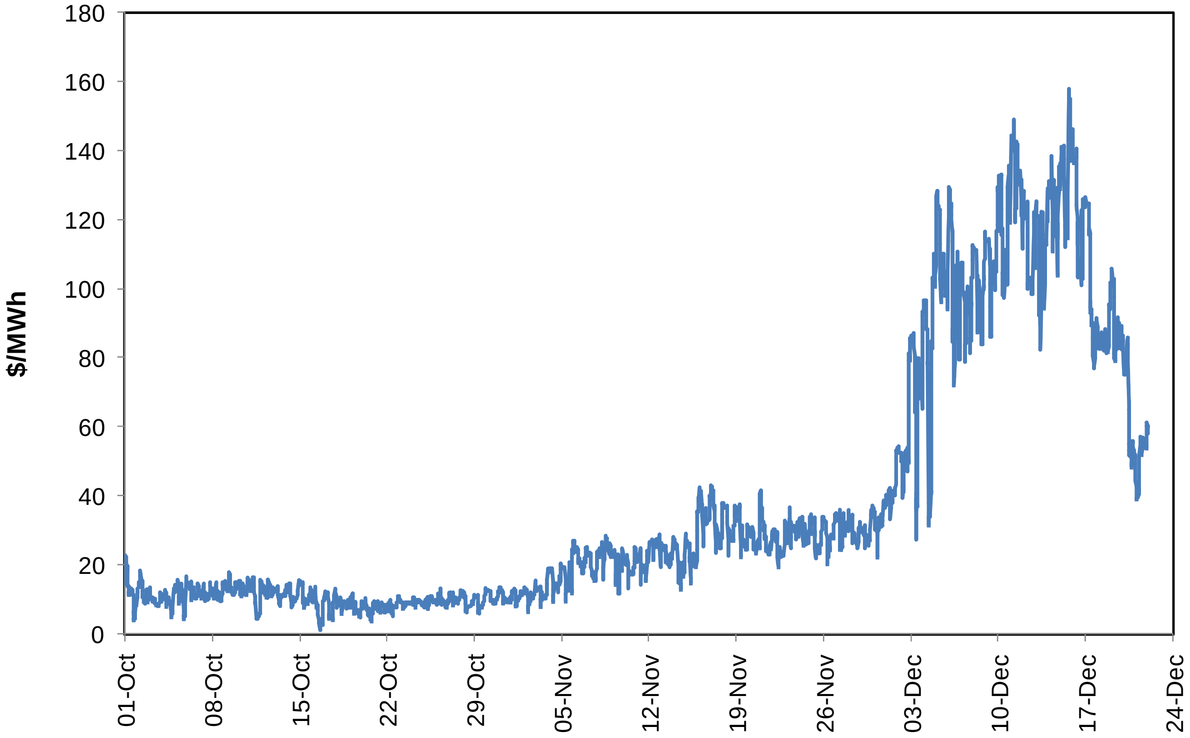

Figure 47 TrustPower's volume-weighted offer prices, 1 Oct – 21 Dec 2010