

Review of events of 13 and 14 December 2011

Market performance review

13 January 2012

Investigation stages

An in-depth investigation will typically be the final step of a sequence of escalating investigation stages. The investigations are targeted at gathering sufficient information to decide whether a Code amendment or market facilitation measure should be considered.

Market Performance Enquiry (Stage I): At the first stage, routine monitoring results in the identification of circumstances that require follow-up. This stage may entail the design of low-cost ad hoc analysis, using existing data and resources, to better characterise and understand what has been observed. The Authority would not usually announce it is carrying out this work.

This stage may result in no further action being taken if the enquiry is unlikely to have any implications for the competitive, reliable and efficient operation of the electricity industry. In this case, the Authority publishes its enquiry only if the matter is likely to be of interest to industry participants.

Market Performance Review (Stage II): A second stage of investigation occurs if there is insufficient information available to understand the issue and it could be significant for the competitive, reliable or efficient operation of the electricity industry. Relatively informal requests for information are made to relevant service providers and industry participants. There is typically a period of iterative information-gathering and analysis. The Authority would usually publish the results of these reviews but would not announce it is undertaking this work unless a high level of stakeholder or media interest was evident.

Market Performance Formal Investigation (Stage III): The Authority may exercise statutory information-gathering powers under section 46 of the Act to acquire the information it needs to fully investigate an issue. The Authority would generally announce early in the process that it is undertaking the investigation and indicate when it expects to complete the work. Draft reports will go to the Board of the Authority for publication approval.

The outcome of any of the three stages of investigation can be either a recommendation for a Code amendment, provision of information to a Code amendment process already underway, a brief report provided to industry as a market facilitation measure, or no further action.

From the point of view of participants, repeated information requests are generally concerned with Stage II; trying to understand the issue to such an extent that a decision can be made about materiality.

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Executive summary

At 12:33 on 13 December 2011, the tripping of generation at the Huntly power station resulted in an under-frequency event and the operation of the first block of automatic under-frequency load shedding (AUFLS) in the North Island (NI). During this time, NI load was approximately 3,300MW. The system operator (SO) has indicated that approximately 560MW of load was shed, which included between 344MW to 366MW of interruptible load (IL). Load restoration commenced at 13:00 and was complete at 15:30. Following the reconnection of Huntly to the grid, the SO informed the market that the Huntly station would be treated as a single risk. This remained the case for most of 14 December 2011.

This review analyses the operation of the spot electricity market during this event. A number of issues have been observed.

The first issue is the significant deviation between the indicative real-time and dispatch prices following the event and the ex-post final prices used for clearing and settlement. This highlighted the discrepancies that exist between the indicative and ex-post final prices in the spot electricity market. A number of potential enhancements are discussed in this review to reduce the divergence between these processes, one of these being a move towards a 5-minute final pricing process. Greater alignment would improve price certainty in the spot electricity market and the ability of market participants to balance their production and consumption decisions relative to the state of the power system, as indicated by the market prices. Three pricing error claims were raised with regards to the prices calculated for trading period 27 on 13 December 2011 and for prices calculated for 14 December 2011. None of these claims were upheld as the calculated prices were consistent with the requirements in the Electricity Industry Participation Code 2010 (Code).

Another issue that has surfaced in this review is the lack of robustness¹ in the final pricing process with the current Code provisions for the resolution of infeasibility situations. The Code requires the SO to use reasonable endeavours to resolve infeasibility situations^{2,3}. The pricing calculation for trading period 27 of 13 December 2011 illustrated the potential path-dependency of the current infeasibility resolution process which reduces the repeatability of the process and introduces the possibility of multiple potential feasible prices in the calculation of final prices. The review considers a model-based approach to the resolution of infeasibilities with potential amendments to the Code around infeasibility resolutions to support such an approach. These Code amendments, without being too prescriptive, could specify an overarching requirement to improve the repeatability of the process. An example would be to resolve infeasibility situations with minimum adjustment to the model inputs.

The review also investigates the indicative real-time energy and instantaneous reserve (IR) prices which were relatively low for energy, and zero in the case of IR, for several trading periods following the tripping of Huntly. This was, in part, due to the removal of the NI IR requirements by the SO. This is done by the SO due to the mismatch between the offered IR in the market and the availability of these resources following a contingent event (CE) or extended contingent event (ECE), as was the case on 13 December 2011. To prevent the dispatching of IR, which might be unavailable, the SO sets the IR requirements to zero, thus not dispatching any IR during these periods. The price impact of this is that energy and IR prices are reduced and not indicative of the

¹ Robustness, in this context refers to the repeatability of the process.

² Clause 13.157 of the Code.

³ The SO publishes their process for resolving infeasibilities. See <http://www.systemoperator.co.nz/n2766,254.html>

state of the system being operated at reduced security. The Authority has raised with the SO an alternative treatment of the IR resources following a CE or ECE event which could improve the price signals during these instances. This would involve maintaining the IR requirements but applying discretionary constraints to IR resources following a CE or ECE to indicate their unavailability with re-offering required to remove the constraint.

Following the reconnection of Huntly generation on 13 December 2011, the SO informed market participants that the Huntly station would be treated as a single risk which could only be represented as a manual risk within the scheduling, pricing and dispatch (SPD) market application. This representation removed the ability of SPD to co-optimize the energy and IR markets which was managed in real-time through the use of discretionary constraints. The Authority's analysis indicates that as a result this increased the NI IR costs due to increased IR prices and increased IR requirement with a reduction in NI energy prices, relative to a co-optimised energy-reserve solution. While enhancements to SPD to enable co-optimisation of energy and reserves under these conditions are possible, the costs of such a development need to be considered against the associated benefits, considering the frequency that such a capability would be used. Similar functionality could be used during the commissioning of plant where there is an increased risk of tripping of the plant being commissioned.

The Authority's experience was that the Wholesale Information Trading System (WITS) was extremely slow during 13 December 2011. This reduced the timely availability of market information. The Authority is investigating these issues with the WITS service provider, NZX.

The Authority considers the development of an efficient pricing process a vital component of the New Zealand electricity market with the events of 13 and 14 December 2011 providing a valuable learning experience in revealing shortcomings in the current process. Some of these shortcomings, such as the robustness in the infeasibility resolution process, and the recent issues affecting the efficiency of prices in the market, which have prompted several market performance reviews⁴, illustrate a potential recurring issue within the current market structure. The current market structure has several market-related functions split between the pricing manager and the system operator, such as the resolution of infeasibility situations and high spring washer price situations. To better facilitate the objectives of developing an efficient pricing process, it is recommended the Authority consider altering the allocation of these functions between the two parties.

⁴ These include the Review of high spring washer resolution issue with SFT, Review of price separation during HVDC reversal and Review of 26 September 2011 infeasibility situation.

1 Introduction

- 1.1 This report outlines the events that occurred on 13 and 14 December 2011 and the market-related impacts.
- 1.2 The areas of assessment in this review include:
- (a) the final price formation process and in particular its alignment with real-time prices and dispatch prices;
 - (b) the infeasibility resolution process and the impact on final prices;
 - (c) the impact of reducing the NI IR requirements on market prices;
 - (d) the impact of treating the Huntly power station as a single manual risk on 14 December 2011;
 - (e) the pricing errors claimed for 13 and 14 December 2011; and
 - (f) the availability of information during real-time from WITS.
- 1.3 Several issues have been observed and, where applicable, potential solutions have been proposed for further analysis and cost-benefit evaluation.

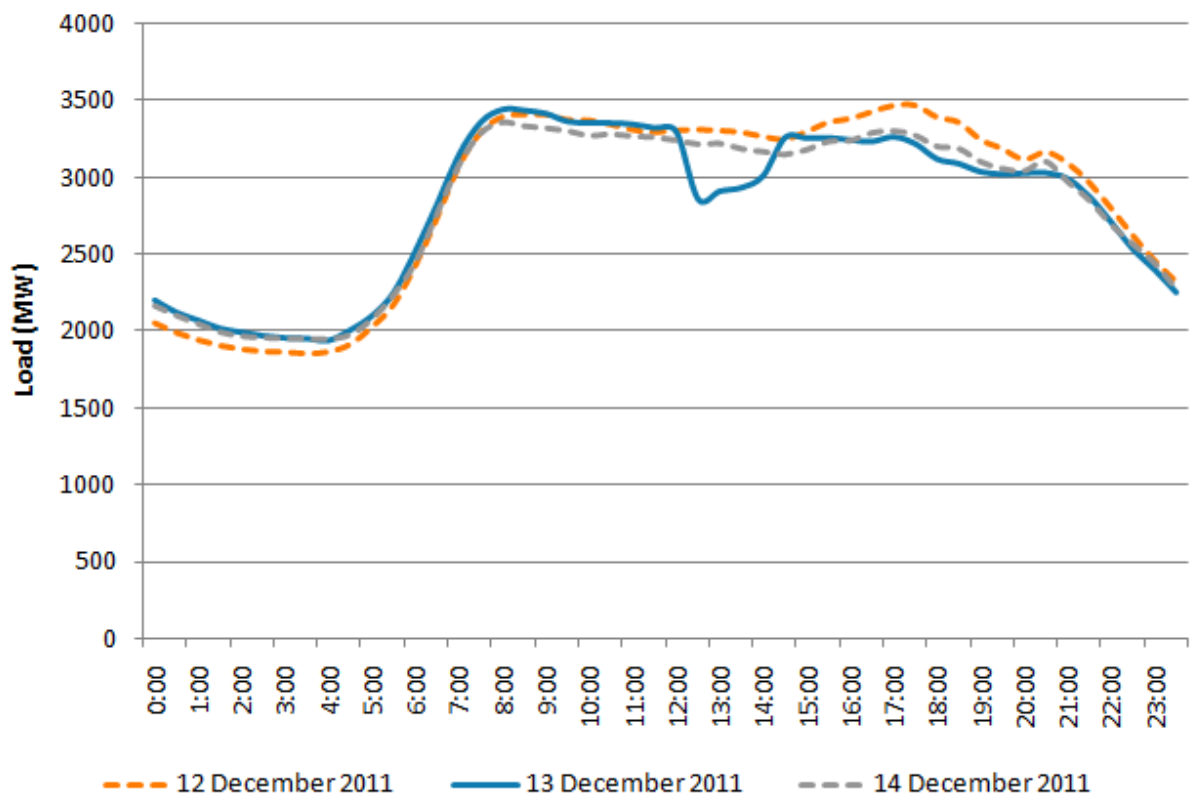
2 Summary of events

- 2.1 The following timeline provides an overview of the primary events on 13 and 14 December 2011.
- 2.2 A 12:33, on 13 December 2011, the tripping of Huntly generation resulted in the NI frequency dropping to 47.63Hz⁵. This under-frequency event triggered the operation of AUFLS and IL in the NI. In response, approximately 560MW of load was shed⁶.
- 2.3 A comparison of the NI load on 12, 13 and 14 December 2011 is shown in Figure 1 which illustrates the sudden reduction in NI load following the tripping of generation at Huntly.

⁵ A copy of the Excursion Notice is provided in Appendix A.

⁶ This also includes interruptible loads (IL).

Figure 1 Comparison of NI load on 12, 13 and 14 December 2011



Source: Em6

Notes: 1. Values indicate average SCADA levels.

- 2.4 At 12:35 the SO reduced the NI risk adjustment factor (RAF) to zero, reducing the NI IR⁷ requirement to zero.
- 2.5 At 12:36 and 12:41, the SO applied discretionary⁸ constraints to the outputs of Huntly units 1 to 5 and Huntly unit 6 respectively. These constraints restricted the output of these units to zero in the real-time dispatch (RTD) and real-time pricing (RTP) schedules, thus representing the unavailability of generation from Huntly in the real-time dispatch process, until an offer change was received from Genesis Energy (Genesis).
- 2.6 Genesis reduced the quantity offered for Huntly units 1 to 5 to zero at 12:47⁹. The quantity offered for Huntly unit 6 was reduced to zero at 13:44¹⁰.
- 2.7 Restoration of IL and AUFLS load commenced at 13:00.

⁷ Instantaneous reserves are additional generation or interruptible load which can be activated at short notice to cater for CE or ECE risk.

⁸ Clause 13.70 of the Code makes provides that the SO may depart from the dispatch schedule if it is necessary to meet the dispatch objectives or in the restoration of the power system. Discretionary constraints on market nodes are applied to the RTD and RTP schedules only.

⁹ This was after the start of trading period 26 (12:30).

¹⁰ Genesis has indicated that the reason for the delay was because Huntly unit 6 remained connected to the grid, and during this time they had determined that it was best to remove the Huntly 6 offers, as they were unsure if it was able to generate if required, or could potentially have caused other issues.

- 2.8 At 13:02, the SO issued a grid emergency notice informing participants of the tripping at Huntly, resulting in the loss of generation and the operation of AUFLS. Participants were requested to increase transmission, energy and IR offers. The system operator provided grid emergency notice revisions at 17:48 and 19:00 which provided revised expected end times to the grid emergency notice period¹¹.
- 2.9 At 13:05, at the request of the SO, Bombay circuit breaker 222 was opened. This network reconfiguration separated the parallel connection of the 110kV and 220kV transmission system into Otahuhu¹².
- 2.10 The system operator reset the NI RAFs to 1 at 14:50. This restored the reserve requirements in the NI.
- 2.11 The real-time prices indicated deficit generation infeasibilities in the upper NI from 14:35 to 17:25. There were also several binding transmission security constraints during this time as load was being restored.
- 2.12 The Authority's experience was that access to real-time prices via WITS was extremely slow from approximately 13:00 to 17:00 on 13 December 2011¹³.
- 2.13 All load was restored at 15:30.
- 2.14 At 17:46, the SO issued a customer advice notice informing participants that the Huntly power station would be treated as a single risk. To manage this, the SO applied a NI manual risk to the market system which resulted in the NI energy and reserve markets not being fully co-optimised¹⁴.
- 2.15 On 14 December 2011, the pricing manager raised a metering situation and infeasibility situation notice while calculating final prices for 13 December 2011. Following the resolution of the metering situation, the SO resolved the infeasibilities in the affected trading periods¹⁵.
- 2.16 Following the infeasibility resolution, a high spring washer (HSW) price situation was triggered for trading period 27. The maximum price in the NI was at the Mataroa 33kV market node (MTR0331). The application of the HSW relaxation factor reduced the maximum price from \$26,587 per MWh to \$18,734 per MWh. The maximum real-time indicator price for trading period 27, at the Mataroa 33kV market node was \$216 per MWh.
- 2.17 A HSW price situation was also triggered for trading period 28 with the Mataroa 33kV market node again being the highest priced node in the NI. Application of the HSW relaxation factor reduced the price at Mataroa from \$1,836 per MWh to \$1,177 per MWh.
- 2.18 At 17:23 on 14 December 2011, the SO issued a customer advice notice informing participants that a reconfiguration at the Huntly power station resulted in Huntly unit 5 being excluded from the station risk.
- 2.19 On 15 December 2011, the interim prices for 14 December 2011 yielded high IR prices with the fast instantaneous reserve (FIR) price reaching \$899 per MW/h in trading period 16.
- 2.20 On 16 December 2011, Genesis lodged a pricing error claim with regards to the energy and IR prices for all trading periods of 14 December 2011.

¹¹ These Grid Emergency Notices are included in Appendix A.

¹² This is discussed further in Section 3.

¹³ The reasons for this are being investigated.

¹⁴ This is discussed further in Section 6.

¹⁵ Trading periods 27 and 30 to 35 were affected.

- 2.21 The Authority and King Country Energy (KCE) raised pricing errors for trading period 27 on 13 December 2011.
- 2.22 On 28 December 2011, the Authority notified its decisions regarding the pricing error claims for the trading dates of 13 and 14 December 2011. The Authority accepted the pricing managers' recommendations following its investigations of the claimed pricing errors and determined that pricing errors had not occurred and that the claims should not be upheld.

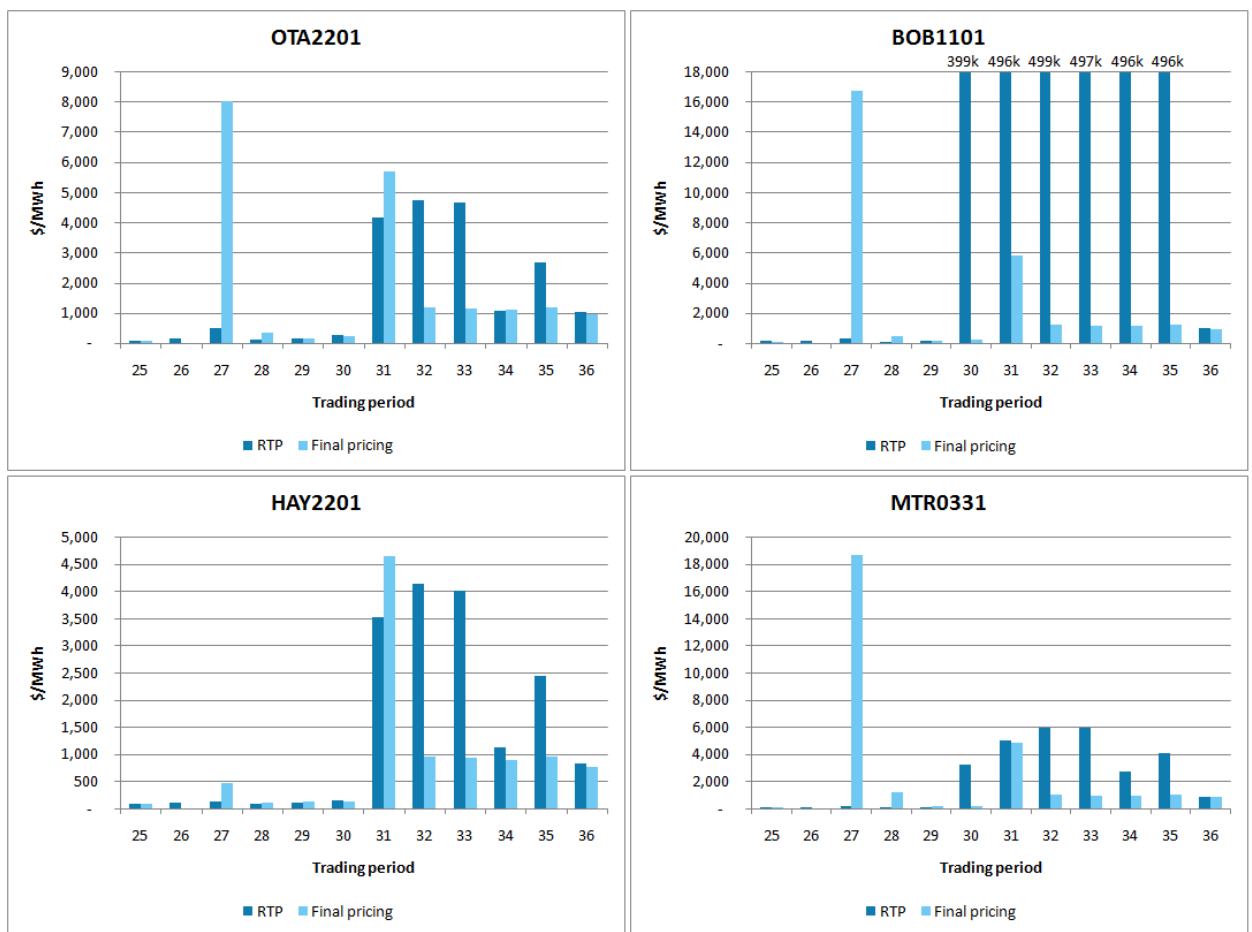
3 Comparison of real-time, dispatch and final prices on 13 December 2011

- 3.1 On 13 December 2011, the calculated final prices differed significantly from the real-time prices in trading periods 26, 27 and trading periods 30 to 35. Figure 2 and Figure 3 illustrate the average real-time prices and final prices calculated at various nodes in the NI and SI respectively. Figure 4 illustrates the comparative IR prices produced in real-time versus the final IR prices.
- 3.2 The calculation of the final prices used for the clearing and settlement process in the New Zealand electricity market is initiated the day after the relevant trading day. Indicative prices are provided to market participants via the different market schedules¹⁶ prior to and during real-time.
- 3.3 While only indicative, the real-time prices provide the only real-time indication of the relative value of energy and IR in the market given the system conditions at that time. Participants therefore rely on these price indicators to manage their own real-time consumption and production decisions. This, in addition to the prices from the Schedule of Dispatch, Pricing and Quantities (SDPQ¹⁷), has become an important aid to participants in the spot electricity market. The prices from the SDPQ schedule are also referred to as dispatch prices in the WITS.
- 3.4 Inefficient consumption and production decisions can occur when these indicative prices deviate significantly from the final prices. That is, if the real-time indicator prices were high and turn out to be low in final pricing, consumers responding to the real-time price signal would reduce demand but only to regret this decision after the calculation of final prices. Conversely, real-time prices could be low thus providing the signal to increase consumption. However later, the final prices are calculated much higher and potentially at a level at which consumers would have preferred to not consume.
- 3.5 The Authority is aware of several industrial consumers with exposure to spot price who responded rationally to real time prices on 13 December 2011. However, when final prices were published it was apparent that the demand response was incorrect relative to the final price. In some cases the financial impact of the incorrect demand response to real time price was significant, and of the order of several hundreds of thousands of dollars.

¹⁶ These schedules include the pre-dispatch schedule (PDS), security dispatch schedule (SDS), special winter schedule (SWS), schedule of dispatch, prices and quantities (SDPQ) and real-time pricing (RTP).

¹⁷ The SDPQ schedule is a forward looking schedule solving for the current and next 7 trading periods using a combination of load forecast and load bid information.

Figure 2 Comparison of real-time and final NI nodal prices for 13 December 2011

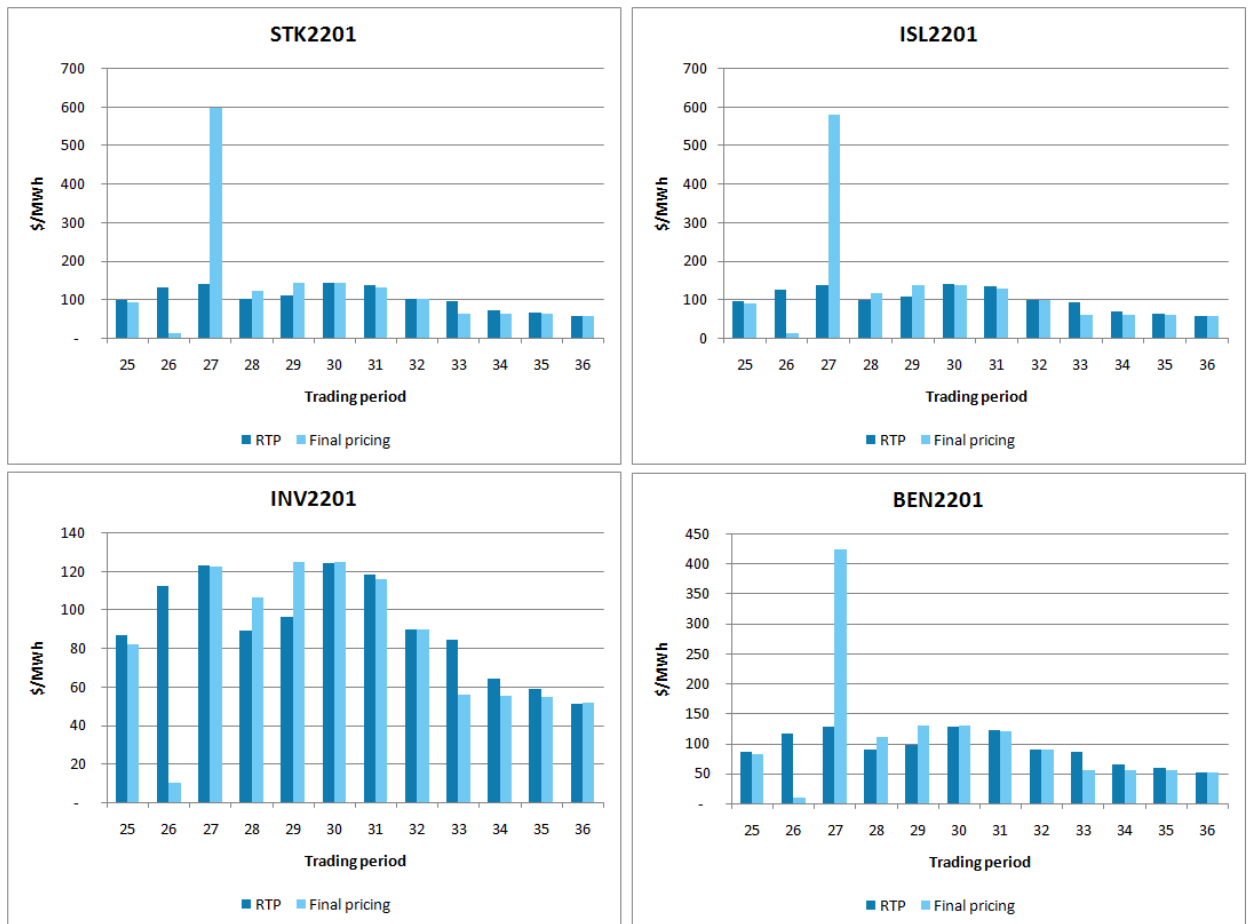


Source: WITS

- Notes:
1. The following nodes are illustrated Otahuhu 220kV (OTA2201), Bombay 110kV (BOB1101), Haywards 220kV (HAY2201) and Mataroa 33kV (MTR0331).
 2. These nodes represent a sample of nodes in the NI.
 3. The RTP represents the average real-time prices during that trading period.
 4. The real-time prices at BOB1101 in trading periods 30-35 were close to the deficit generation constraint violation penalty (CVP) indicating the presence of some deficit generation infeasibilities in the vicinity of BOB1101 in the RTP schedules.
 5. No real-time prices were produced for the following real-time pricing intervals 13:00, 13:30, 14:55, 15:55, 16:00 and 16:10.

- 3.6 The divergence between the final prices and observed real-time prices in the NI is illustrated in Figure 2. In trading period 27 the final price at the OTA2201, BOB1101 and MTR0331 nodes are much greater than the average real-time prices over the trading period. In trading periods 30 to 35, the real-time prices at the BOB1101 node is much greater than the calculated final prices.
- 3.7 The price divergence in the SI is most pronounced in trading periods 26 and 27, as indicated in Figure 3.

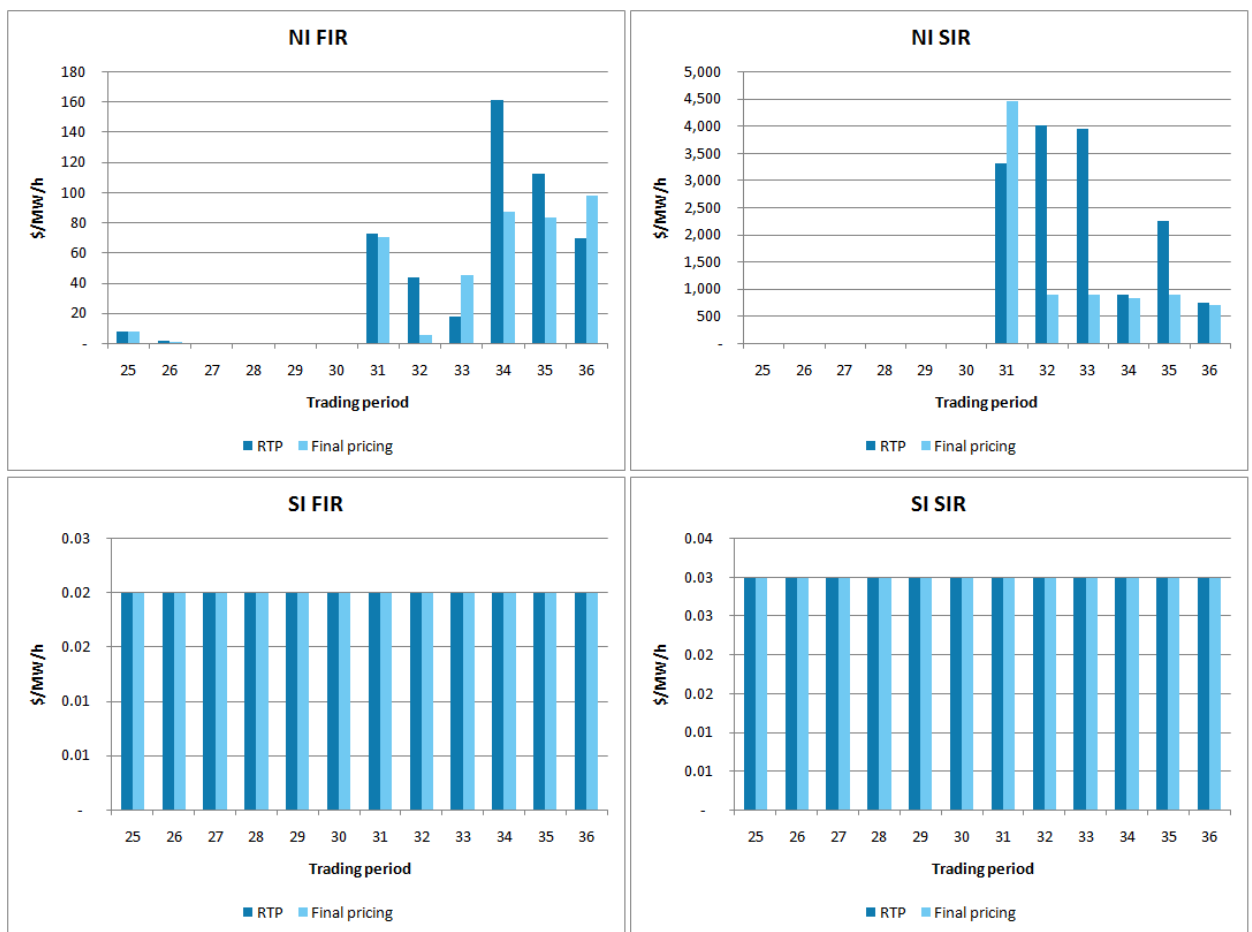
Figure 3 Comparison of real-time and final SI nodal prices for 13 December 2011



Source: WITS

- Notes:
1. The following nodes are illustrated Stoke 220kV (STK2201), Islington 220kV (ISL2201), Invercargill 220kV (INV2201) and Benmore 220kV (BEN2201).
 2. These nodes represent a sample of nodes in the SI.

Figure 4 Comparison of real-time and final IR prices for 13 December 2011



Source: WITS

Notes: 1. FIR and SIR represent fast instantaneous reserve and sustained instantaneous reserve respectively.

- 3.8 While both real-time and final prices are calculated using the market clearing engine (SPD), the inputs into each of these pricing schedules can differ, therefore resulting in final prices being different from the indicative real-time prices.
- 3.9 The final pricing schedule calculates prices for each trading period using the half-hour metered load as well as network configuration, network capacity and reserve requirements (RAFTs and net free reserves (NFRs)) as they were at the start of the trading period. In contrast, the RTP schedule is initiated every 5 minutes and calculates indicative prices using the 5-minute average of actual load from SCADA, and network and reserve requirements in place at the start of each 5-minute real-time pricing period. Therefore, when the conditions during a trading period change from the conditions at the start of the trading period, there can be divergence between the calculated final price and observed real-time price during that trading period. The nature of these and other impacts influencing the divergence in prices during each of the affected trading periods are discussed further in this section.
- 3.10 A noticeable observation from Figure 2 and Figure 4 is the relatively low energy and IR prices in the NI in the four trading periods immediately following the tripping of Huntly generation (trading periods 27 to 30). This is observed in both the real-time and final prices. The reason for this is the

relaxation of the NI IR requirements when the NI RAFs were set to zero. This is discussed further in Section 5.

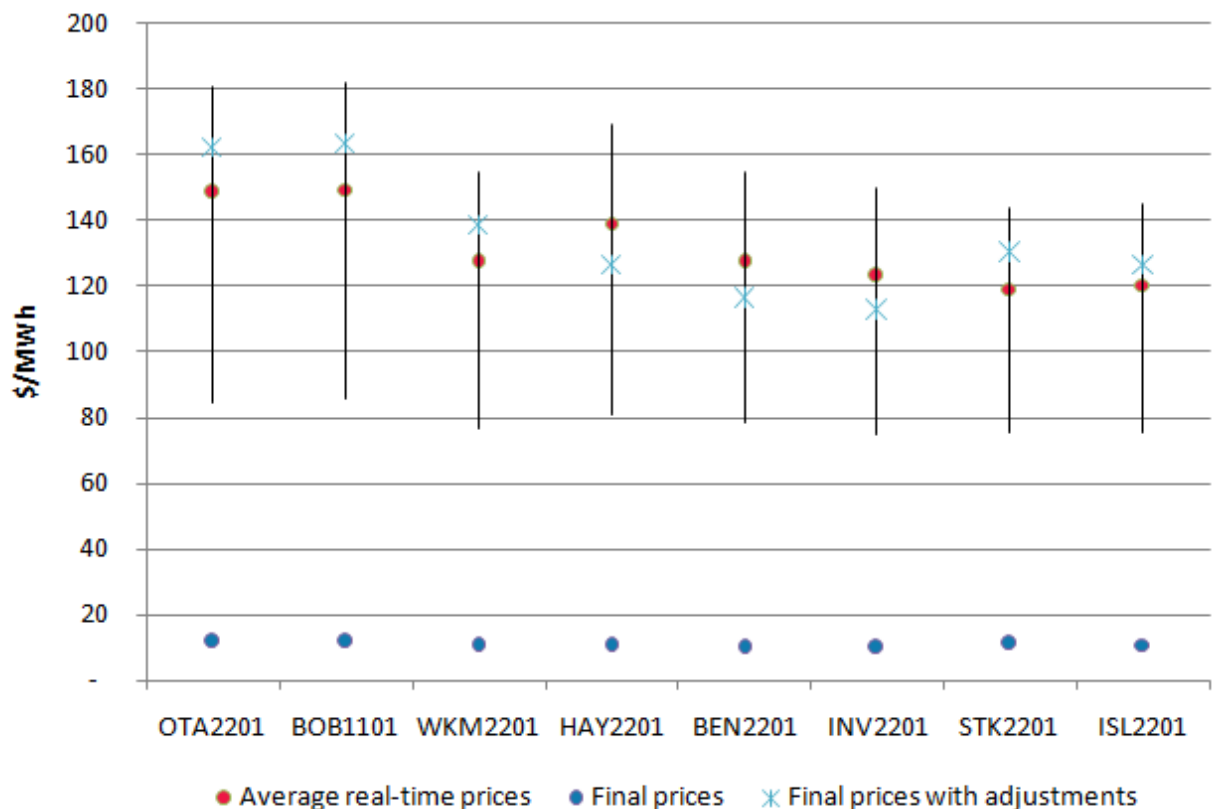
Trading period 26

- 3.11 The SI price differences in trading period 26, observable in Figure 3, are mainly attributed to the differences in the treatment of the generation at Huntly in the RTP and final pricing schedule. There are also some differences between the NI IR requirements used in the RTP and final pricing schedules.
- 3.12 The generation at Huntly was connected to the grid at the start of trading period 26 (12:30), tripping at 12:33. This resulted in Huntly generation being included in the calculation of final prices for trading period 26¹⁸.
- 3.13 The RTP schedule in contrast is executed every 5 minutes. The unavailability of Huntly generation during trading period 26 was represented in RTP, and RTD, through the application of discretionary constraints by the SO which constrained the output of Huntly to zero. This reduction of Huntly generation capability in the RTP schedule resulted in increased SI generation and HVDC north transfer, thus resulting in the observed NI and SI real-time prices greater than those produced by final pricing.
- 3.14 A further difference between the RTP and final pricing schedule in trading period 26 is the NI RAF, which affects the calculated IR requirements in the island. The island RAF is a scaling factor used within SPD to adjust the amount the IR dispatched relative to the IR required within the island. A RAF of 1 indicates that SPD would attempt to satisfy the full IR requirements, whereas a RAF of zero would imply that none of the required IR needs to be satisfied.
- 3.15 At the start of trading period 26, the NI RAF was 1, which was used in the calculation of final prices. However, following the Huntly trip, the SO reduced the NI RAF to 0 (at 12:35). This reduced RAF was used by the subsequent RTP schedules for the remainder of trading period 26. This implies that no IR was scheduled for the NI in the RTP schedules from 12:35, whereas the full complement of IR was scheduled in the calculation of final prices.
- 3.16 As a comparison, the final pricing schedule for trading period 26 was executed in the Authority's vSPD model, with Huntly generation constrained to zero and the NI RAF set to zero, as they were for the majority of trading period 26. The comparative results between the published final prices, average real-time prices and prices calculated using the above-stated adjustments to the final pricing calculation¹⁹ are shown in Figure 5.
- 3.17 The adjustments applied to the final pricing calculation produce prices which more closely align with the average real-time prices, as compared to the published final prices. There are still differences noted. These are due to the fact that the applied adjustments, while representing the majority of the trading period conditions, do not represent the conditions of the entire trading period. This is one of the issues in calculating prices based on a 30-minute trading period representation when conditions and therefore indicative real-time prices can change in a shorter timescale.

¹⁸ Huntly generation was scheduled at 650MW during trading period 26 of the final pricing schedule. The average output from Huntly during this trading period was 103MW (based on SCADA data).

¹⁹ This is also referred to as final prices with adjustments in this document.

Figure 5 Comparison final prices, real-time prices and adjusted final prices for TP 26



Source: Electricity Authority

Notes: 1. The spread between the minimum and maximum real-time price during each of the trading periods is illustrated by the vertical line.

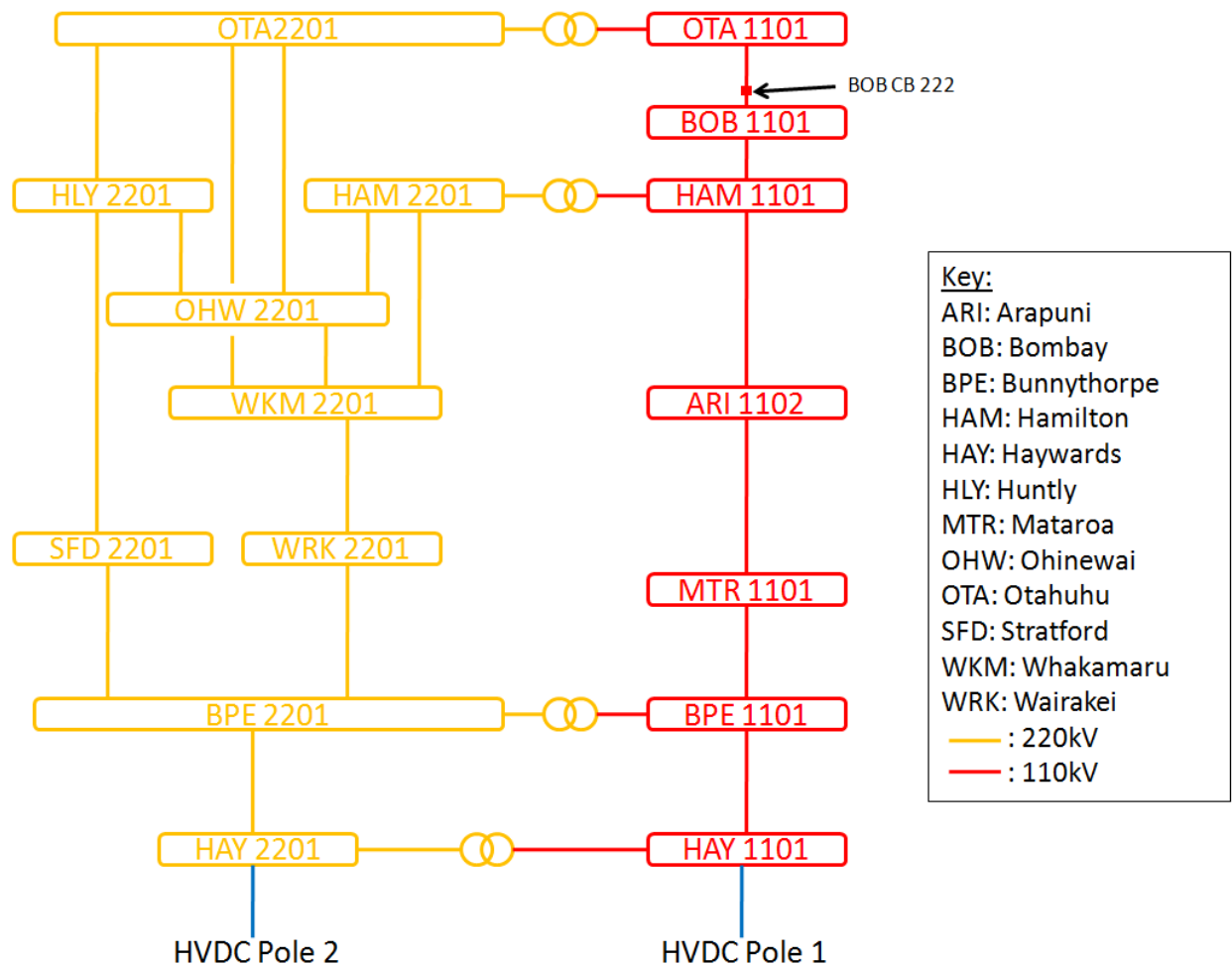
Trading period 27

- 3.18 Differences in network configuration and generator discretionary constraints applied in real-time are the major reasons for the divergence in final and real-time prices for trading period 27.
- 3.19 At the start of trading period 27 (13:00), the 220kV transmission system between Bunnythorpe (BPE) and Otahuhu (OTA) was in parallel to the Bunnythorpe-Mataroa-Otahuhu 110kV transmission circuit. A simplified schematic of this configuration is illustrated in Figure 6. This network configuration, in conjunction with the low upper North Island generation resulted in a large number of transmission security constraints²⁰ being generated to protect the lower capacity 110kV circuit for the contingent loss of a 220kV parallel circuit.
- 3.20 This network configuration and the associated transmission security constraints accompanying this configuration, was used in the calculation of final prices for trading period 27. This resulted in several infeasibilities occurring in the calculation of the final prices for this trading period, which the system operator subsequently resolved. The details of the infeasibility resolution process are discussed further in Section 4.

²⁰ These were n-1 transmission security constraints produced by the system operator's Simultaneous Feasibility Test (SFT) automatic constraint builder application.

- 3.21 At 13:05, at the request of the SO, circuit breaker 222 at Bombay substation (BOB_222) was opened²¹. This reconfiguration removed the parallel operation of the 220kV and the 110kV transmission system at Bombay and the associated transmission security constraints discussed in 3.19.

Figure 6 Simplified schematic of NI 110kV and 220kV parallel network configuration



Source: Electricity Authority

Notes: 1. The simplified representation omits a large number of intermediate nodes and is intended to illustrate parallel operation of the 220kV and 110kV transmission system between the lower North Island (Bunnythorpe and Haywards) and the upper North Island at Otahuhu.

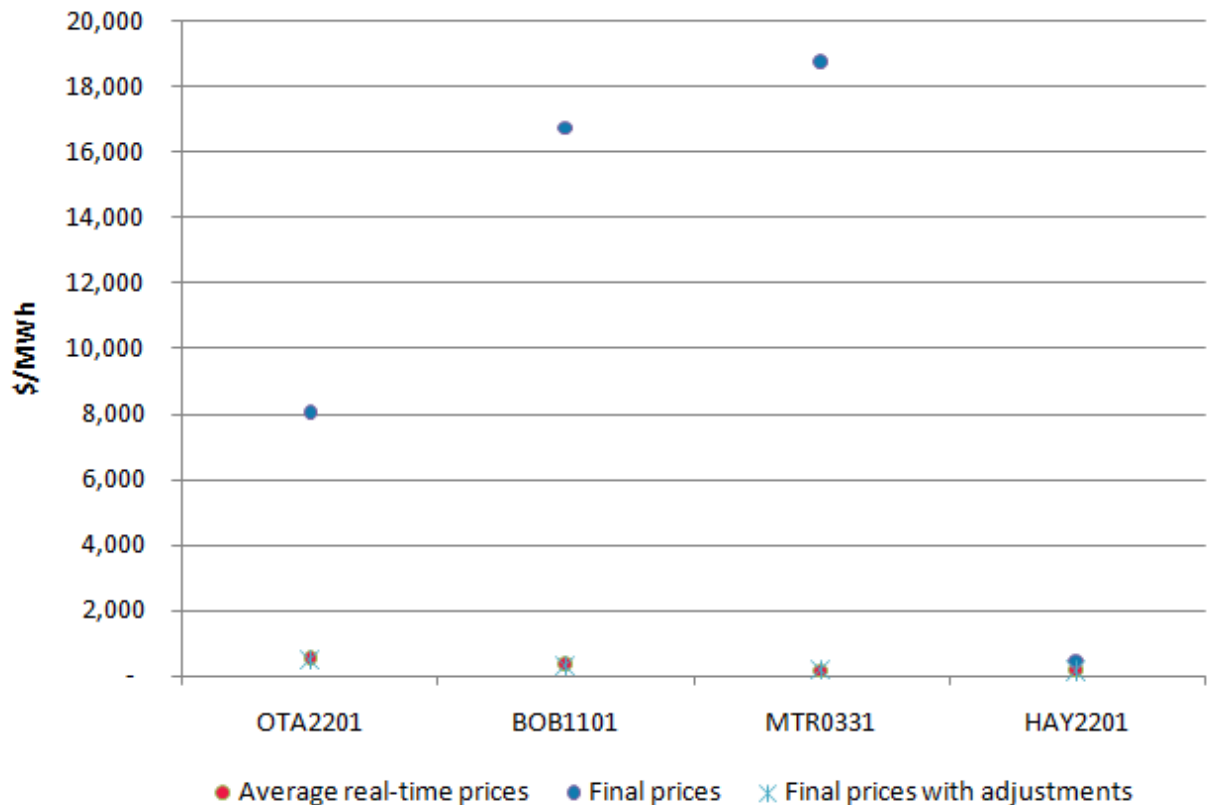
- 3.22 The published RTP schedules during trading period 27²² utilised the updated network configuration and the reduced set of transmission security constraints.
- 3.23 In addition to the network configuration difference, the final pricing schedule still included the energy offers for Huntly unit 6, which were only revised by Genesis after the start of trading period 28 (at 13:44). In the RTD and RTP schedules, the total output from Huntly unit 6 was constrained to zero by the SO using discretionary constraints.

²¹ Outage data obtained of WITS.

²² There were no real-time prices published for 13:00.

- 3.24 To simulate the impact of these input differences between the RTP and final pricing schedule on the calculation of final prices, the Authority adjusted the inputs into the calculation of prices for trading period 27 using the network configuration in place just after the start of the trading period²³ with the associated transmission security constraints, and with the output of Huntly unit 6 constrained to zero, as used in RTP.
- 3.25 A comparison of the final prices, average real-time prices and final prices with the adjusted inputs are shown in Figure 7 and Figure 8 for the NI and SI respectively.

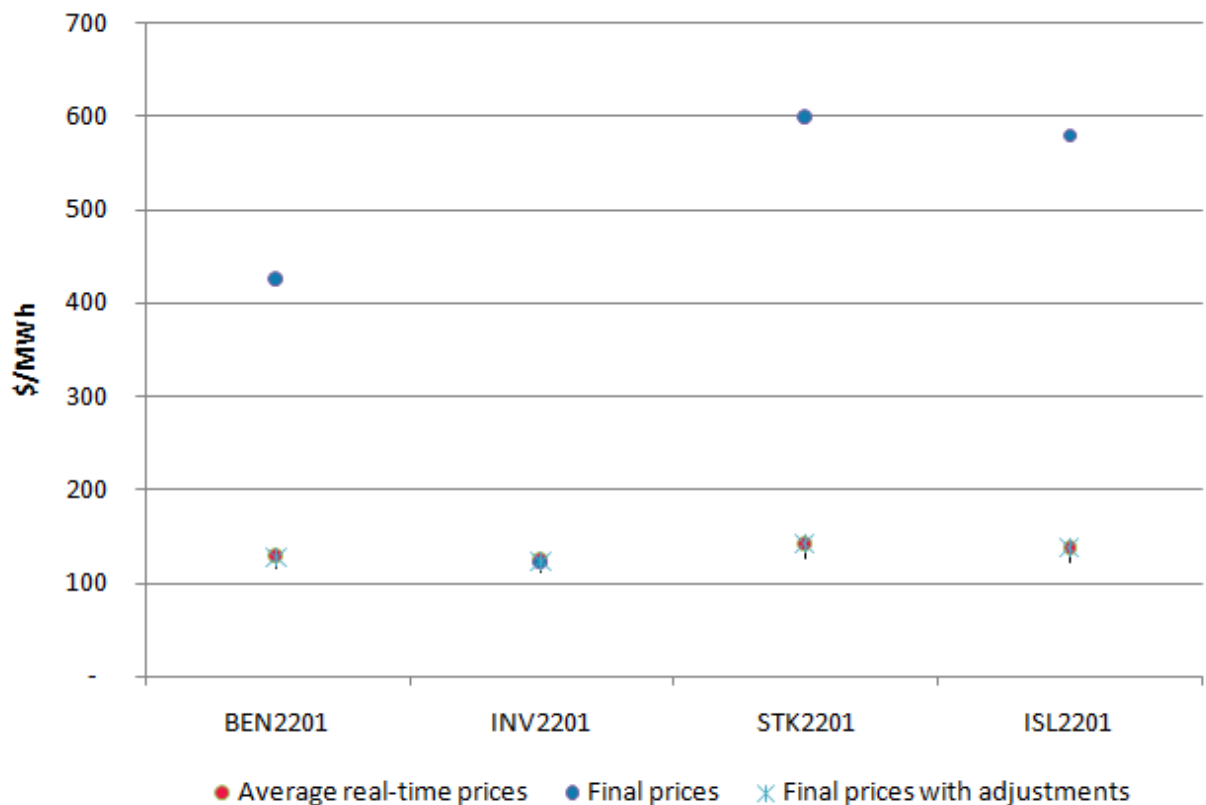
Figure 7 Comparison NI final prices, real-time prices and adjusted final prices for TP 27



Source: Electricity Authority

²³ With the BOB_222 circuit breaker opened.

Figure 8 Comparison SI final prices, real-time prices and adjusted final prices for TP 27

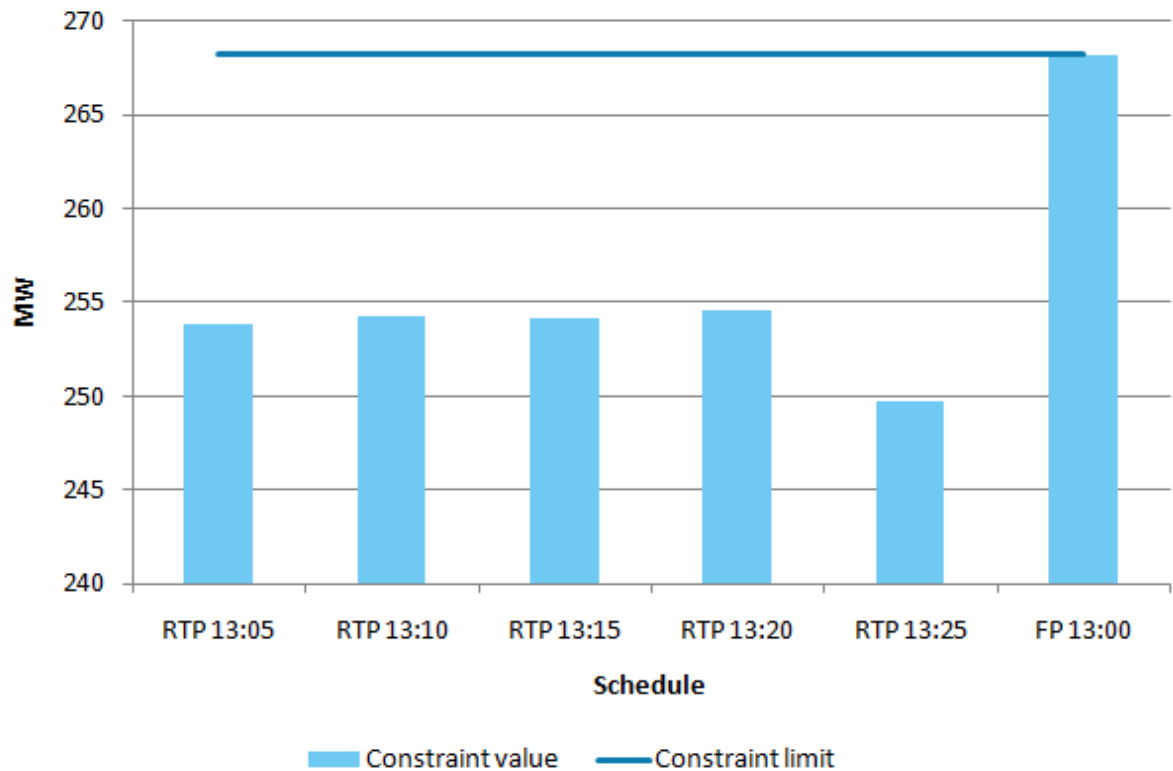


Source: Electricity Authority

- 3.26 The applied adjustments to align the inputs of final pricing with those in real-time, results in a better alignment of final prices with the average real-time prices. Conversely, the differences in the inputs used in the calculation of final prices versus those used for the calculation of real-time prices resulted in significant deviations between the indicative real-time prices and the ex-post final prices.
- 3.27 Furthermore, this alignment of input conditions eliminated the infeasibilities encountered in the calculation of the actual final prices for trading period 27.
- 3.28 Under the Code, the SO is required to resolve the infeasibility situation. In this instance the resolution involved relaxing several branch security constraint limits as indicated in Table 2.
- 3.29 Following this resolution the feasible final pricing solution yielded extreme final prices at Mataroa and Bombay due to several binding transmission security constraints. This triggered a HSW price situation. Application of the HSW price relaxation factor reduced the prices at these nodes. The reduced final prices are shown in Figure 7 which are still well above the prices observed in real-time.
- 3.30 A further observation from trading period 27 is the deviation between the real-time and final prices in the central and upper South Island (SI), as illustrated in Figure 8.
- 3.31 This difference arose due to the relaxation of branch security limits in the infeasibility resolution process. In increasing branch security limits to resolve the multiple infeasibilities during this trading period, a greater amount of northward HVDC flow, and consequently SI generation, was scheduled in the “feasible” final pricing solution.

- 3.32 The increase in SI generation resulted in a near-binding transmission security constraint in the SI²⁴ becoming binding, thus causing price separation between the lower SI and the central and upper SI, in final prices. This constraint was not binding in the RTP schedules and therefore not evident in the real-time prices.
- 3.33 A comparison of the differences in the associated constraint value in the RTP and final pricing schedule for 13:00 (TP 27) is shown in Figure 9.

Figure 9 Comparative values for the binding SI constraint in final pricing



Source: Electricity Authority

Notes: 1. The affected constraint is the NSY_ROX.1__CYD_TWZ1.1__CYD_TWZ1__ROX__LN
2. FP represents the final pricing schedule

- 3.34 In this instance, the additional adjustment of inputs to resolve infeasibilities in final pricing further increased the divergence between the real-time and final prices in the SI. The issues surrounding the infeasibility resolution process are discussed further in Section 4.

Trading periods 30 to 35

- 3.35 There are significant differences between the real-time prices and final prices, at Bombay (BOB1101) in particular, from trading periods 30 to 35, as indicated in Figure 2. This is due to the presence of deficit generation infeasibilities²⁵ in the RTP schedules during this time as load was being restored. These infeasibilities are not removed from the published real-time prices and their

²⁴ This constraint was NSY_ROX.1__CYD_TWZ1.1__CYD_TWZ1__ROX__LN.

²⁵ Section 4 contains a more detailed description on the existence of infeasibility variables within SPD and their purpose.

impact results in the real-time prices at the affected nodes²⁶ rising up to the specified deficit generation constraint violation penalty (CVP).

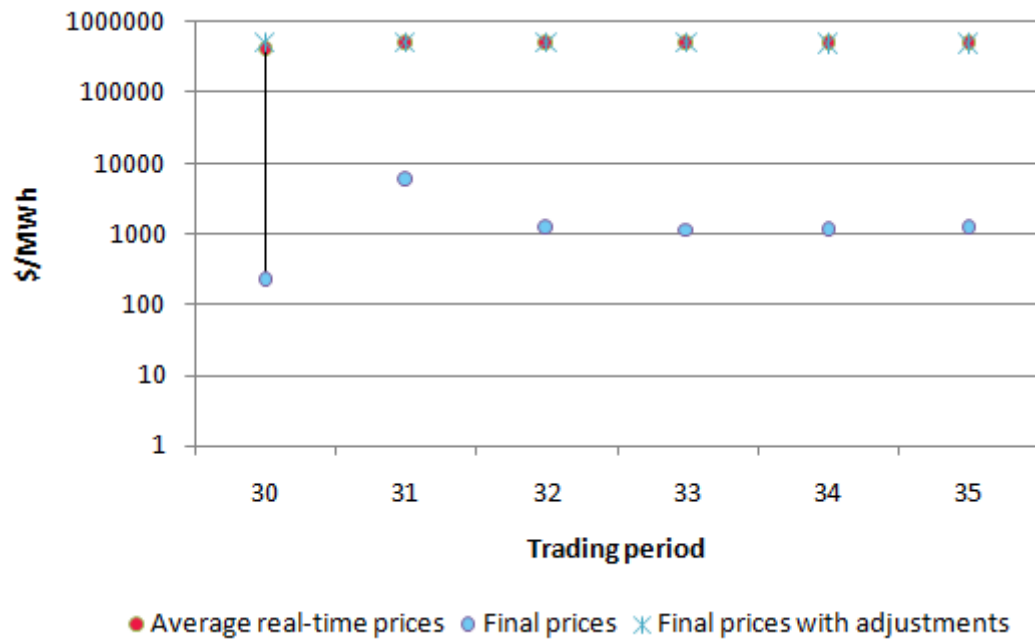
- 3.36 These deficit generation infeasibilities also occurred in the final pricing calculation process for trading periods 30 to 35 with the pricing manager declaring an infeasibility situation. These infeasibilities were removed by adjusting constraint limits in the final pricing calculation, as indicated in Table 2.
- 3.37 Adjusting the branch security constraint limits enables additional physical resources to supply the node with the deficit generation infeasibility. With the limit increased sufficiently, the deficit generation infeasibility is removed, with the price at the node reducing from the CVP to the marginal cost of supplying the consumption at that node. The marginal costs using physical resources are much lower than the specified deficit generation CVP²⁷, thus in the case of Bombay, the final prices are much lower than the real-time prices due to the application of the infeasibility resolution process in the calculation of final prices.
- 3.38 In addition to the infeasibility resolution process, there are also some other contributing reasons for the price divergences observed at other nodes on the network. These are determined to be primarily the difference in the load used in the RTP and final pricing schedules at some nodes (e.g. Glenbrook (GLN0331 and GLN0332) and Kaikohe (KOE0331)) and the application of discretionary constraints used in the RTP and RTD schedules only. The SO has indicated that there was a loss of reliable SCADA data at these locations. When this occurs estimated values are used in the RTP schedules and this would account for these differences in load.
- 3.39 To understand the impact of these differences, the above-mentioned adjustments were applied to the inputs of the final pricing calculation. This involved “undoing” the infeasibility resolution process to re-introduce the infeasibility into final pricing²⁸, using the average loads from the RTP schedules as well as applying those discretionary constraints used for the entire trading period in the RTP schedules. A comparison of real-time prices, published final prices and final prices with the above-mentioned adjustments applied to the inputs are shown in Figure 10 to 15.

²⁶ The affected node could be a node within close electrical proximity to the node experiencing the infeasibility.

²⁷ The CVPs are intentionally set at values much larger than offered energy and IR resources in the market. This is to avoid their interaction with the physical market resources. As an example, the deficit generation CVP is \$500,000 per MWh.

²⁸ Since this was the case in the RTP schedule.

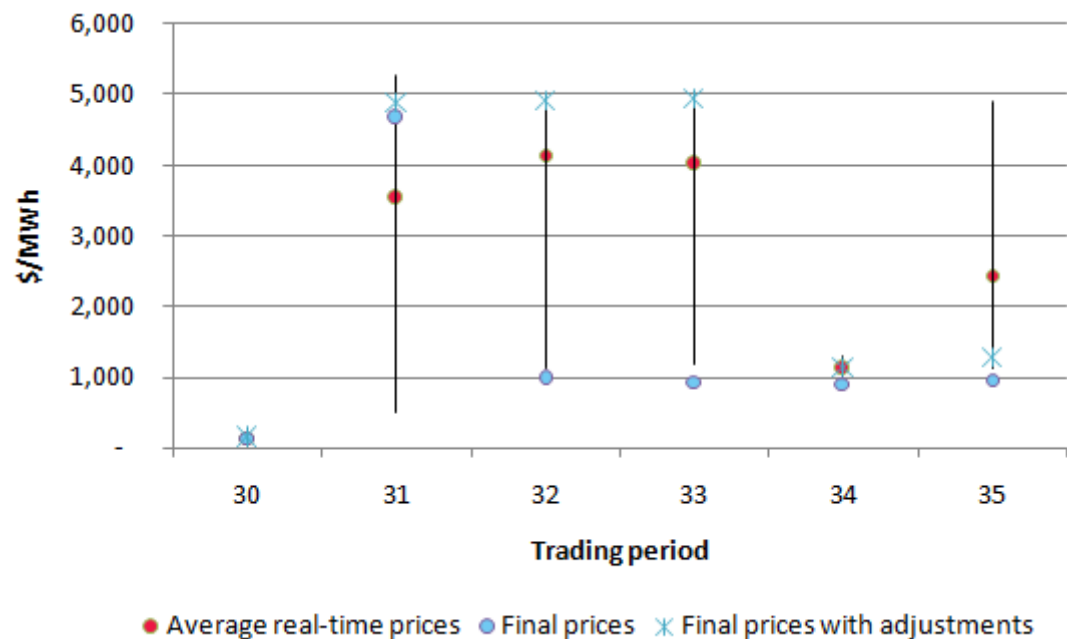
Figure 10 Bombay (BOB1101) price comparison with adjusted final prices



Source: Electricity Authority

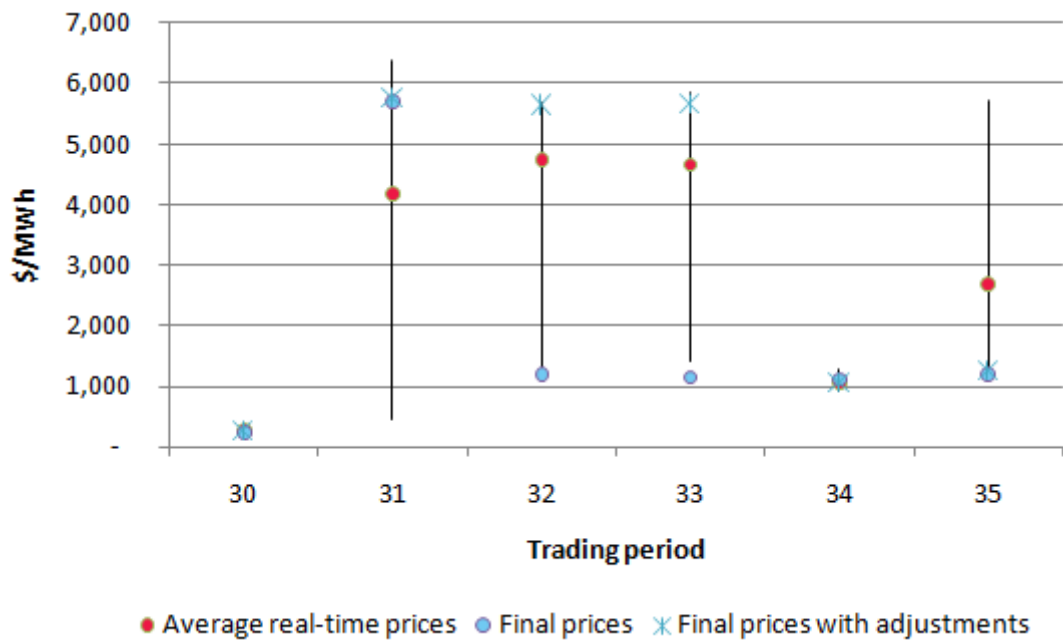
Notes: 1. Adjustment to final pricing calculation include the usage of average real-time loads, application of discretionary constraints applied during the entire trading period in the RTP schedules with the unadjusted constraint limits (i.e. including the infeasibility)

Figure 11 Haywards (HAY2201) price comparison with adjusted final prices



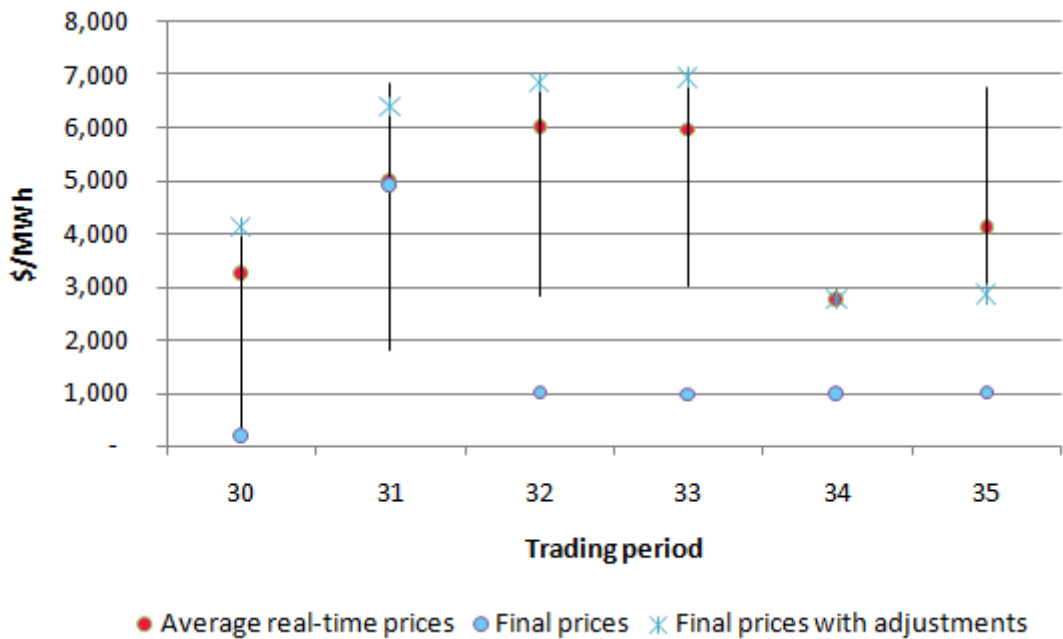
Source: Electricity Authority

Figure 12 Otahuhu (OTA2201) price comparison with adjusted final prices



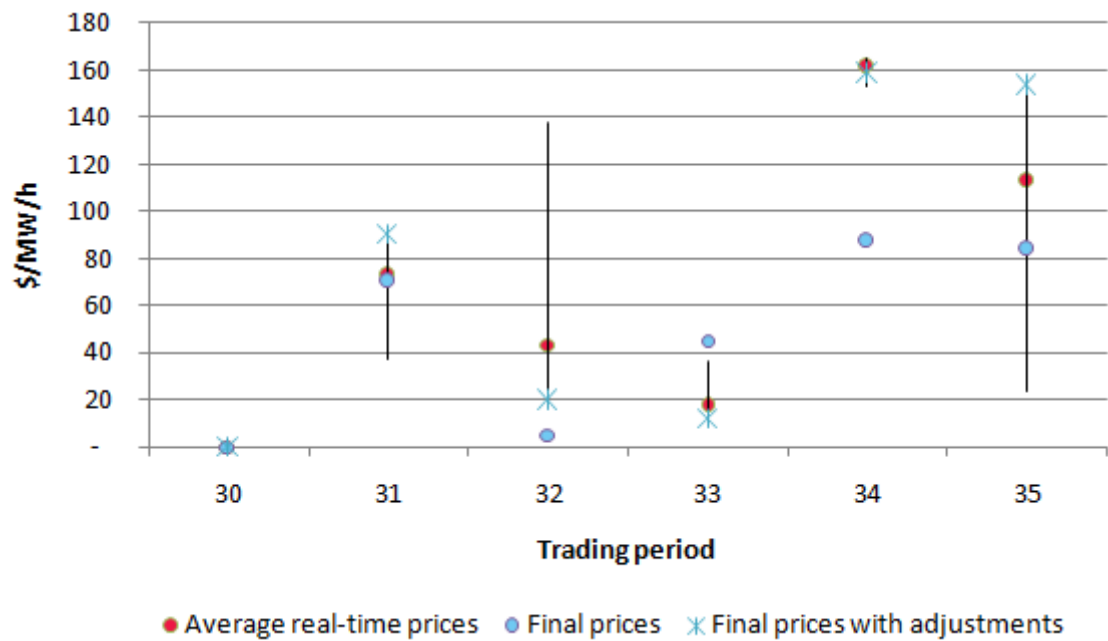
Source: Electricity Authority

Figure 13 Mataroa (MTR0331) price comparison with adjusted final prices



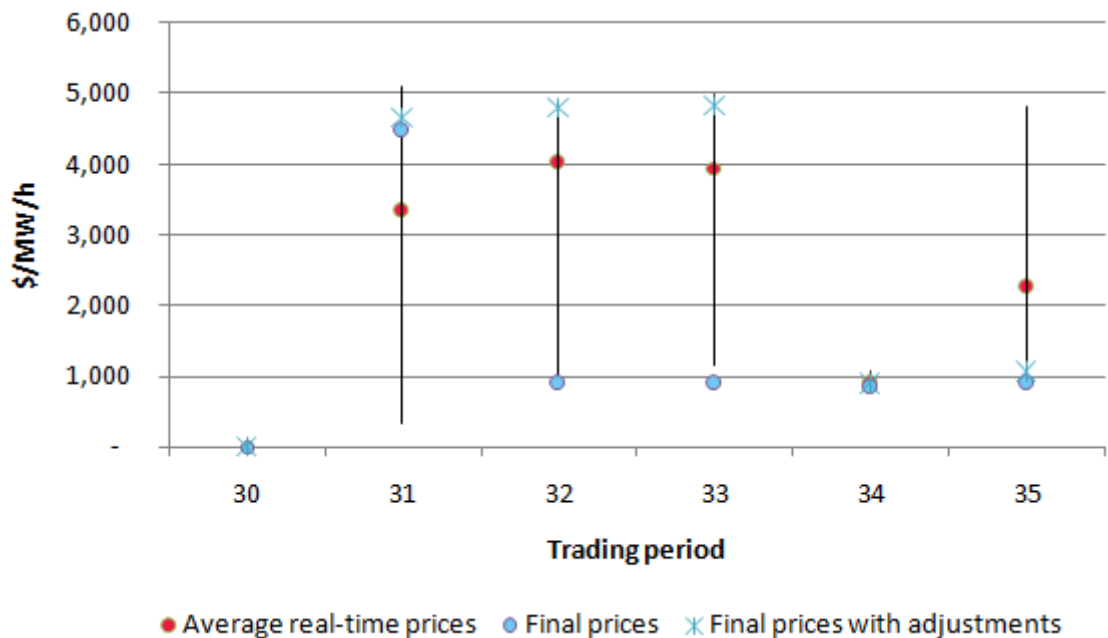
Source: Electricity Authority

Figure 14 NI FIR price comparison with adjusted final prices



Source: Electricity Authority

Figure 15 NI SIR price comparison with adjusted final prices



Source: Electricity Authority

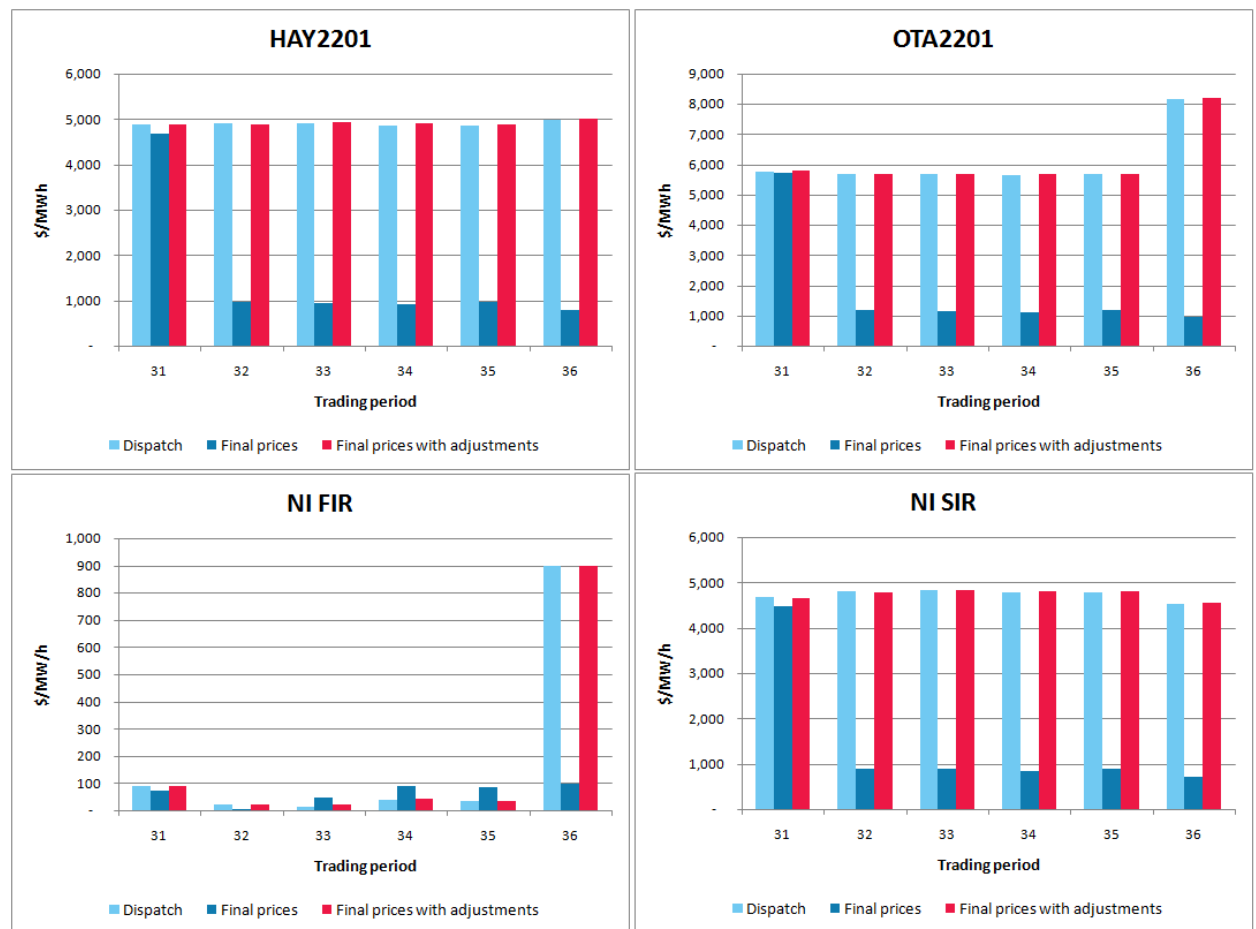
- 3.40 The increase in the real-time energy²⁹ and IR prices from trading period 31 to 35 is due to the restoration of the NI IR requirements at 14:50.
- 3.41 The large deviation between the minimum and maximum real-time prices within trading periods 31, 32, 33 and 35, as illustrated in Figure 12 to Figure 15 is indicative of the volatility of the real-time prices during this time and their sensitivity to changes in the RTP schedule inputs. The adjustments applied to the final pricing calculation to cater for the input differences results in the adjusted prices being within the range of observed real-time prices during the respective trading periods.
- 3.42 However, given the large price deviations during real-time, the 30-minute trading period representation in final pricing can still be too coarse a representation to capture within trading period real-time price fluctuations, and result in calculated final prices still deviating from the average real-time price.

Comparison of dispatch and final prices

- 3.43 Deviations between the dispatch and final prices were also observed during trading periods 31 to 36.
- 3.44 The primary reason for the differences between the dispatch and final prices during trading periods 31 to 35 is due to higher NI demand used in the SDPQ schedule relative to the metered load used in the final pricing schedule, as well as the infeasibilities encountered in the dispatch schedule which are resolved in the final pricing process.
- 3.45 There was also a deviation between the dispatch and final prices observed for trading period 36. In addition to the load differences noted above, additional branch security constraints were calculated by the system operator during trading period 36 and used in the calculation of the dispatch prices for this trading period. One of the added security constraints bound in the dispatch schedule resulting in an increase in prices in the NI and in particular upper NI. This constraint was not included in the calculation of final prices, due to it being determined after the start of the trading period.
- 3.46 Figure 16 illustrates a comparison of prices produced from the dispatch, final pricing and an adjusted final pricing schedule which utilised the dispatch schedule's load and affected branch security constraints.
- 3.47 Compensating for the adjustments in the pricing provides a closer match to the published dispatch prices. As with the comparison of final prices to the real-time prices, the primary reasons for the deviations are due to differing inputs into the different processes.

²⁹ These are with reference to those nodes not affected by the CVPs.

Figure 16 Comparison of dispatch, final and adjusted final prices within the NI



Source: Electricity Authority and WITS

Notes:

1. HAY2201 and OTA2201 represent the Haywards and Otahuhu 220kV market nodes respectively.
2. NI FIR and NI SIR represent the North Island fast instantaneous reserve and North Island sustained instantaneous reserve respectively.

Recommendations to improve price efficiency

- 3.48 The primary reasons for the observed misalignment between real-time and final prices during 13 December 2011 can be grouped into the following categories:
- (a) Due to trading period misalignment;
 - (b) Due to real-time discretion; and
 - (c) Due to infeasibilities.
- 3.49 A pricing process with a shorter timescale would address some of the issues listed in paragraph 3.48(a). This would involve calculating 5-minute final prices, and thus reducing the occurrence of input discontinuities between indicative real-time and 5-minute final prices and therefore the potential for large price deviations.
- 3.50 To reduce potential implementation costs, the final pricing process could be maintained as an ex-post process. Further reductions in implementation costs could be achieved if the 30-minute

metering infrastructure is still used, but shaped with 5-minute average load information from the RTP schedules.

- 3.51 The Authority is planning to undertake work as part of its 2012/13 work plan to investigate the use of 5-minute prices in the final pricing process.
- 3.52 Real-time discretionary action is sometimes required to manage the real-time nature of the system with changing conditions. Including these constraints within the pricing process would result in the pricing signals persisting in the calculation of final prices. If these constraints are omitted, as done currently, the resulting final prices could be somewhat different from the indicative real-time. This affects the predictability of prices and furthermore increases the amount of constrained-on payments.
- 3.53 If the current treatment of infeasible variables continues, that is, all resources are exhausted prior to using the infeasible variables, then an infeasibility resolution process would still be needed within the pricing process, however a model-based infeasibility resolution process could improve the robustness in this process³⁰. This approach could be facilitated with changes to the Code around the resolution of infeasibilities, as discussed in Section 4.
- 3.54 An alternative treatment of the infeasibility variables would be to represent them with their economic cost, thus allowing prices to settle at the economic CVP. This would enable a consistent treatment of infeasibilities in the scheduling, real-time and final pricing processes, thus improving price certainty in the market. If these economic CVPs are not transferred into the real-time dispatch process then the trade-off is loss of some accuracy, where prices might reduce below the marginal cost of production and transportation, for increased certainty.
- 3.55 The Authority is considering investigating the viability of economic softening of constraints as part of its 2012/13 work plan.
- 3.56 The dispatch prices are produced using a combination of the SO forecasts of load and load bid information with market participants using these dispatch prices to guide operational decisions. A potential development could be to introduce sensitivity forecasts for dispatch prices using a range of load forecasts for conforming loads with different levels of confidence, such as a 90th and 10th percentile forecast. These developments would need to be consistent with the upcoming changes to these forward looking schedules made by the demand-side bidding and forecasting (DSBF) and dispatchable demand (DD) Code amendments. These developments would need to be agreed with industry participation as part of the improved provision of information to market participants. This issue is being considered by the Authority's Market Design team.
- 3.57 Market participants should have confidence in the efficient pricing process within the market, where price accuracy, certainty and robustness are all desirable attributes³¹.
- 3.58 The above analysis has indicated several shortcomings in the current pricing process. The large deviations observed between the real-time and dispatch indicative prices and the eventual final prices, calculated ex-post, are examples where all of the above desirable attributes are challenged.

4 Issues with the infeasibility resolution process

- 4.1 The market clearing engine (SPD) utilises a number of model variables to represent deficit or surplus quantities (infeasibilities) within the solution. The intention of these infeasibility variables

³⁰ This is discussed further in Section 4.

³¹ See Issues and Indicative Options for the Spot Market Pricing Process and UTS Provisions available from <http://www.ea.govt.nz/our-work/consultations/wholesale/spot-market-pricing-process-and-uts-provisions/>

is to enable a solution even when the problem being attempted by SPD is infeasible. Infeasibilities can arise due to inconsistencies in the inputs of the model, or due to an inability to supply the energy and reserve requirements with the available supply resources, whilst respecting all of the system constraints.

- 4.2 In both instances, the SO is able to utilise this infeasibility information to address the reasons for the infeasibility.
- 4.3 The costs associated with these infeasibility variables have no economic basis and are set well above the physical supply. This serves the purpose of ensuring that all available supply resources are exhausted before the violation variables are invoked.
- 4.4 Under the Code, the pricing manager is required to give notice of an infeasibility situation³². Furthermore, the Code requires the SO to resolve these infeasibility situations using reasonable endeavours³³.
- 4.5 The SO process to investigate and resolve infeasibilities is published on its website³⁴ and allows for the resolution of infeasibilities by relaxing branch security limits.
- 4.6 Several infeasibilities were encountered during the calculation of final prices for 13 December 2011, with the pricing manager raising an infeasibility situation notice for trading period 27 and trading periods 30 to 35. A list of these infeasibilities is provided in Table 1.
- 4.7 The infeasibilities encountered during trading period 27 were particularly severe and interrelated, as they affected numerous nodes and branch constraints in the NI, as indicated in Table 1. This interdependence results in the infeasibility resolution process being path-dependent, that is, the order in which inputs are adjusted to resolve the underlying infeasibilities, affects the resulting final prices. The issue of path dependence and the resolution of multiple simultaneous infeasibilities is not outlined in the SO's infeasibility resolution process.

Table 1 Infeasibilities in calculation of final prices for 13 December 2011

Trading period	Infeasibility	Node/constraint affected	Cause
27	1	MTR0331	Deficit generation
27	2	NPK0331	Deficit generation
27	3	OKN0111	Deficit generation
27	4	OKN1101	Deficit generation
27	5	BOB_HAM2.1__HAM_OHW1.1__\$HAMO HW1__HAM__LN	Deficit branch group constraint
27	6	BPE_MTR1.1__HAM_WKM.1__\$HAMWK M1__BPE__LN	Deficit branch group constraint
30	1	MER0331	Deficit generation
30	2	BOB0331	Deficit generation
31	1	MER0331	Deficit generation
32	1	MER0331	Deficit generation
32	2	BOB0331	Deficit generation

³² See Clause 13.144

³³ See Clause 13.146

³⁴ See <http://www.systemoperator.co.nz/n2766,254.html>

Trading period	Infeasibility	Node/constraint affected	Cause
33	1	MER0331	Deficit generation
33	2	BOB0331	Deficit generation
34	1	MER0331	Deficit generation
35	1	MER0331	Deficit generation

Source: Pricing Manager

Table 2 Branch security constraint limit adjustment by SO to resolve infeasibilities

Trading period	Constraint name	Original limit (MW)	Revised limit (MW)	Change (MW)
27	BOB_HAM2.1__HAM_OHW1.1__\$HAMOHW1__HAM__LN	53.67	70.67	17
27	BPE_MTR1.1__HAM_WKM.1__\$HAMWKM1__BPE__LN	61.65	74.65	13
27	BPE_MTR1.1__HLY_SFD.1__\$HLYSFD1__BPE__LN	61.65	66.65	5
27	BPE_MTR1.1__OHW_WKM1.1__\$OHWWKM1__BPE__LN	61.65	63.65	2
27	BPE_MTR1.1__SFD_TMN1.1__\$SFDTMN1__BPE__LN	61.65	67.65	6
27	BPE_MTR1.1__TMN_TWH1.1__\$TMNTWH1__BPE__LN	61.65	66.65	5
27	MTR_OKN1.1__HAM_WKM.1__\$HAMWKM1__MTR__LN	61.24	67.24	6
27	OKN_ONG1.1__HAM_WKM.1__\$HAMWKM1__OKN__LN	61.03	63.03	2
27	Total change (MW)			56
30	ARI_BOB1.1__BOB_HAM2.1__BOB_HAM2__BOB__LN	52.08	65.08	13
30	BOB_HAM2.1__ARI_BOB1.1__\$ARIBOB1__HAM__LN	51.81	60.81	9
30	Total change (MW)			22
31	ARI_BOB1.1__BOB_HAM2.1__BOB_HAM2__BOB__LN	50.9	57.9	7
31	BOB_HAM2.1__ARI_BOB1.1__\$ARIBOB1__HAM__LN	51.19	54.19	3
31	Total change (MW)			10
32	ARI_BOB1.1__BOB_HAM2.1__BOB_HAM2__BOB__LN	48.82	58.82	10
32	BOB_HAM2.1__ARI_BOB1.1__\$ARIBOB1__HAM__LN	50.38	54.38	4
32	Total change (MW)			14
33	ARI_BOB1.1__BOB_HAM2.1__BOB_HAM2__BOB__LN	48.89	57.89	9
33	BOB_HAM2.1__ARI_BOB1.1__\$ARIBOB1__HAM__LN	50.98	52.98	2
33	Total change (MW)			11
34	ARI_BOB1.1__BOB_HAM2.1__BOB_HAM2__BOB__LN	49.36	57.36	8
34	BOB_HAM2.1__ARI_BOB1.1__\$ARIBOB1__HAM__LN	51.13	53.13	2
34	Total change (MW)			10
35	ARI_BOB1.1__BOB_HAM2.1__BOB_HAM2__BOB__LN	49.61	57.61	8
35	BOB_HAM2.1__ARI_BOB1.1__\$ARIBOB1__HAM__LN	51.15	53.15	2
35	Total change (MW)			10

Source: Pricing Manager

- 4.8 The SO resolved the infeasibilities in trading period 27 by adjusting various branch security constraint limits, as indicated in Table 2. A total of 56MW of additional capacity was added to the transmission security constraints to resolve all of the underlying infeasibilities during this trading period.
- 4.9 The Authority's analysis of these infeasibilities indicate that for trading period 27, another resolution was possible, requiring less adjustment in the model inputs, and resulting in an alternative pricing solution.
- 4.10 This potential path dependence in the infeasibility resolution process and its impact on the resulting final prices in the market reduces the repeatability and therefore the robustness of the pricing process.
- 4.11 One potential solution to improve the repeatability and minimise the adjustments of the pricing inputs when resolving infeasibilities is to utilise a model-based approach. The Authority has simulated this approach for the infeasibility situations of 13 December 2011.
- 4.12 The Authority's vSPD model was configured to minimise the adjustments made to branch security constraint limits to resolve the observed infeasibilities. These model-based adjustments for trading period 27 are listed in Table 3.
- 4.13 The model-based approach was able to resolve the infeasibilities by increasing the limits by 22MW less than the actual adjustments applied.
- 4.14 Furthermore, the calculated prices are different as indicated in Figure 17 and Figure 18. While both these calculated feasible prices differ significantly from the real-time prices, for the reasons discussed in Section 3, the resolution using the model-based approach does not induce the price separation in the SI final prices. More importantly though is the fact that the model-based approach is less prone to multiple solutions due to path-dependency.

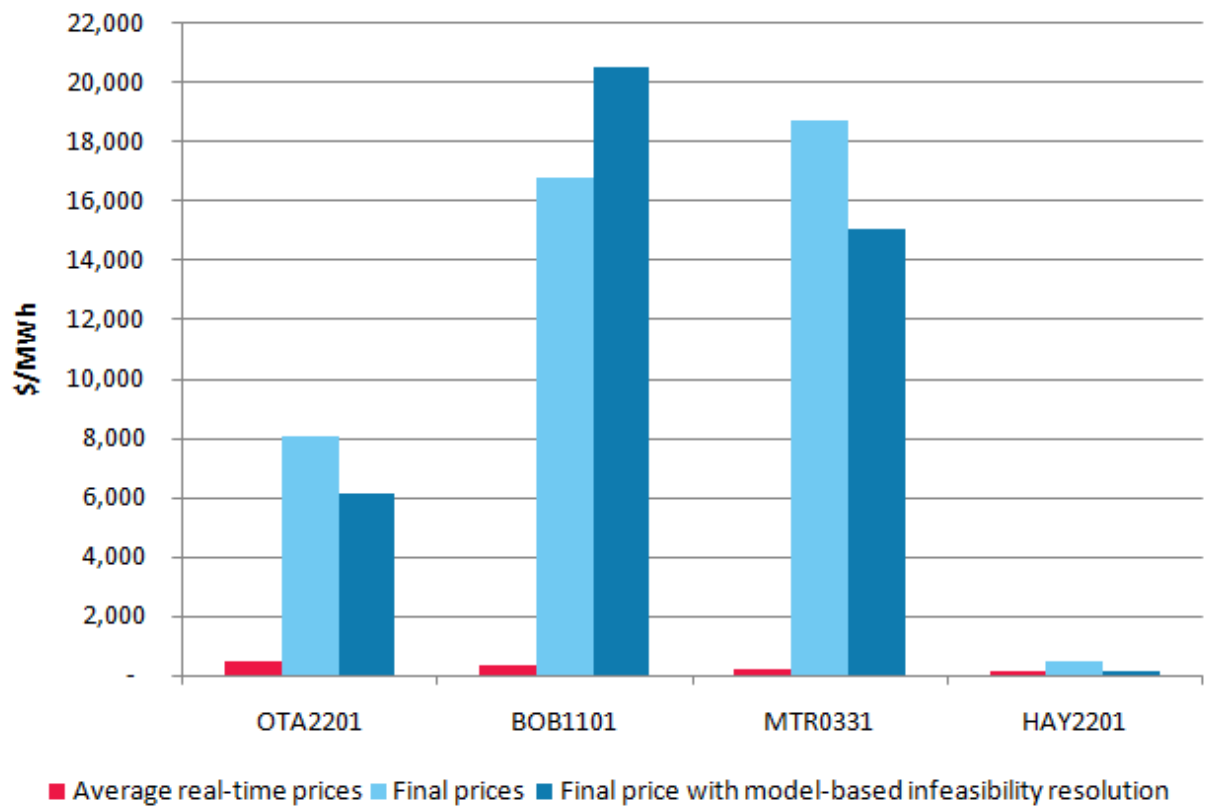
Table 3 Model-based branch security limit adjustment to resolve infeasibilities

Trading period	Constraint name	Original limit (MW)	Revised limit (MW)	Change (MW)
27	BOB_HAM2.1__HAM_OHW1.1__\$HAMOHW1__HAM__LN	53.67	74.67	21
27	BPE_MTR1.1__HAM_WKM.1__\$HAMWKM1__BPE__LN	61.65	69.65	8
27	BOB_HAM2.1__HAM_OHW1.1__:S__\$HAMOHW1__HAM__LN	68.4	72.4	4
27	ARI_BOB1.1__HAM_OHW1.1__\$HAMOHW1__BOB__LN	53.33	54.33	1
27	Total change (MW)			34

Source: Electricity Authority

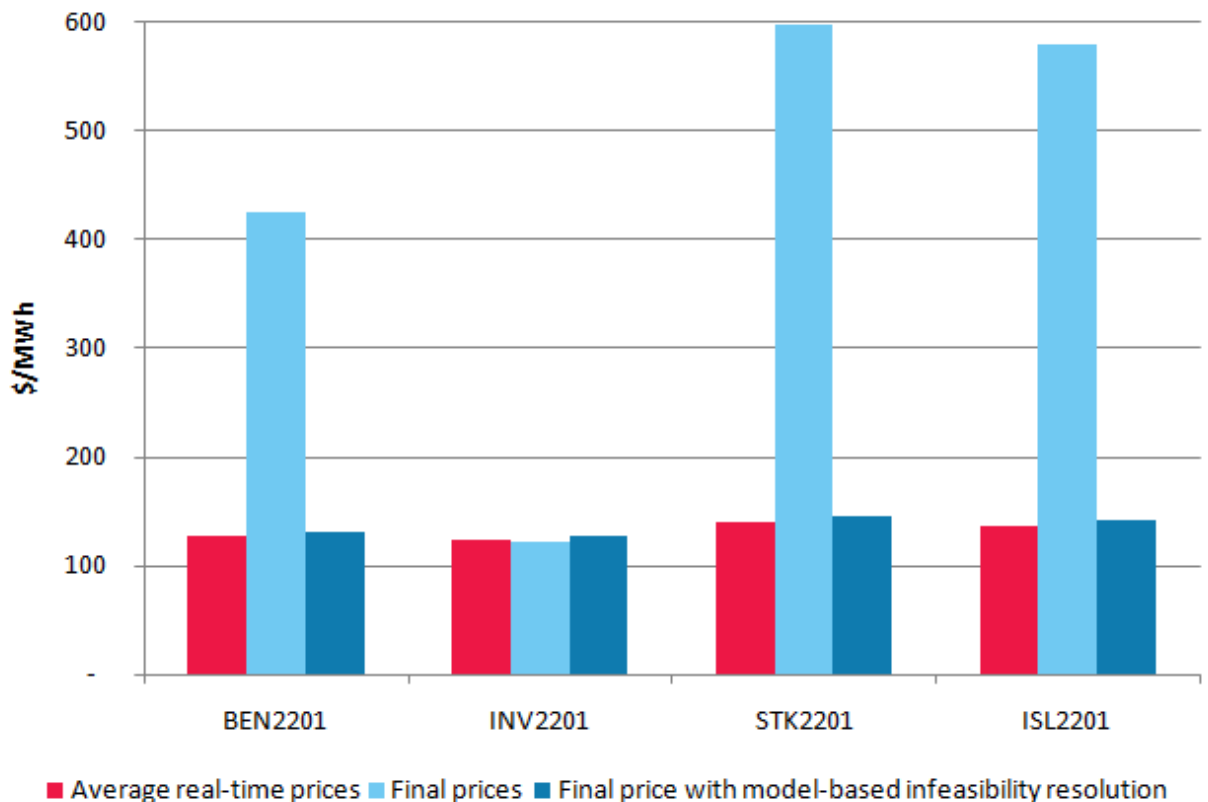
- 4.15 The adjustments applied using the model-based approach are identical to those applied by the SO for trading periods 30 to 35.

Figure 17 Comparison of NI prices for TP 27 with the different infeasibility resolutions



Source: Electricity Authority

Figure 18 Comparison of SI prices for TP 27 with the different infeasibility resolutions



Source: Electricity Authority

Recommendations for improvement to infeasibility resolution

- 4.16 The resolution of the infeasibilities for trading period 27 on 13 December 2011 were consistent with the requirements of the Code, however several issues with these requirements have been observed and discussed above.
- 4.17 Under the current provisions, the SO is required to use reasonable endeavours. This avoids the Code being too prescriptive, thus preventing undesirable outcomes when dealing with potentially complex scenarios.
- 4.18 One of the potential areas of improvement would be to expand the requirements in the Code when resolving infeasibilities³⁵. An overarching requirement in the infeasibility resolution process (such as to minimise the total adjustment), could be considered to maintain its flexibility. This requirement would pave the way for adopting a model-based resolution of infeasibilities which would improve the robustness of the infeasibility resolution process.

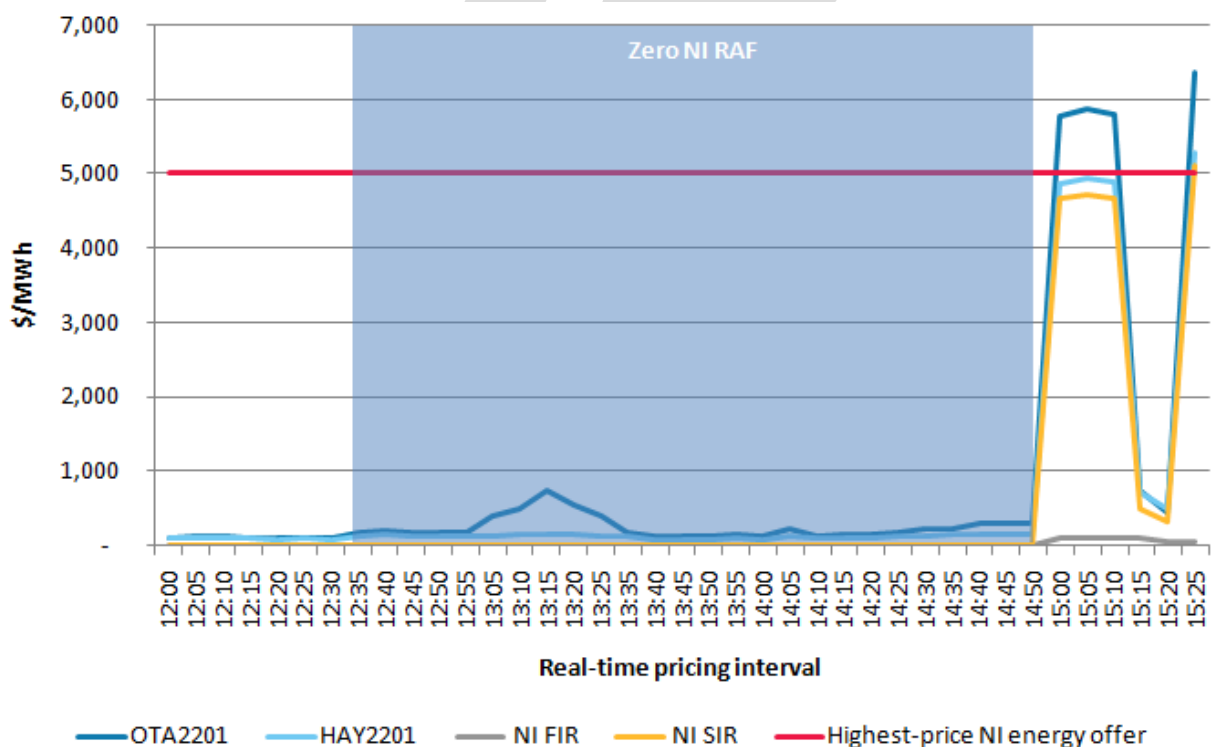
5 Impact of reducing the NI IR requirements on 13 December 2011

- 5.1 Following the tripping of AUFLS, the SO reduced the NI IR requirements to zero at 12:35, by setting the NI RAFs to zero in SPD.

³⁵ Clause 13.146 of the Code outlines the requirements placed on the system operator when resolving infeasibilities.

- 5.2 The SO's reason for reducing RAFs following a CE or ECE event is because the availability of reserve is automatically reduced as a result of the event, so providers would have difficulty in complying with any dispatch instructions sent for reserve immediately following the event. Following a CE, the aim is to have RAFs restored within 15 minutes, which is coincident with the restoration of tripped IL. For an ECE, AUFLS and RAFs are restored as soon as practicable. This timeline would be dependent upon system security conditions at the time.
- 5.3 On 13 December 2011, the NI RAFs were restored to 1 at 14:50. This was 2 hours and 15 minutes after the RAFs were reduced to zero. At this time, the NI reserve requirements were restored.
- 5.4 The reduced NI RAFs were in effect at the start of trading periods 27 to 30 (13:00 to 14:30) and consequently also applied to the calculation of final prices for these trading periods.
- 5.5 Setting the RAFs to zero has a suppressing effect on the calculated market prices. This effect is visible when comparing the real-time and final prices (energy and IR) in the NI when the NI RAFs were at zero (trading periods 27 to 30) to those trading periods when the RAFs were restored (trading period 31), as shown in Figure 2 and Figure 4.
- 5.6 An illustration of the real-time prices at the Otahuhu and Haywards 220kV market nodes as well as the NI FIR, SIR and highest priced energy offer in the NI from trading period 26 to 31 is provided in Figure 19.

Figure 19 Real-time prices during periods of reduced NI RAF on 13 December 2011



Source: Electricity Authority

- Notes:
1. OTA2201 and HAY2201 represent the 220kV market nodes at Otahuhu and Haywards respectively.
 2. Whirinaki had the highest price energy offer in the NI during this time.

- 5.7 This price suppression effect is due to reduced requirements being specified to SPD when the RAFs are zeroed. SPD co-optimises the energy and IR resources in the system to satisfy the energy and IR requirements. The market prices produced by SPD reflect the calculated prices to support this optimal dispatch of energy and IR resources.
- 5.8 The reduction of the RAFs, in effect, sets the IR requirement to zero thus reducing the resource allocation problem presented to SPD as an energy-only problem. While some IR resources cannot be utilised by SPD to supply energy requirements, such as IL, generator energy output can be increased if there is no IR requirement.
- 5.9 This reduced requirement implied that SPD, with the same pool of resources had only the energy requirements and, on 13 December, the SI IR requirements to satisfy. This enabled SPD to use lower-priced generator offers in the NI, since some of the capacity which would have been needed for NI IR could now be utilised for energy. SPD was also able to call upon lower-priced generator offers in the SI, since the risk of importing this energy across the HVDC was not considered by SPD³⁶. This access to lower-priced resources, caused by the reduction of the NI RAFs resulted in the reduction of both real-time and final prices during this time.
- 5.10 The reduced real-time prices would have provided the signal to those participants with higher-value uses to start consumption. The Authority understands that this was the case for some major electricity users in the NI.
- 5.11 During the period of reduced RAF, the SO issued a grid emergency notice at 13:02 which informed participants about the tripping at Huntly, and the operation of AUFLS. Participants were also requested to increase energy, transmission and IR offers³⁷.
- 5.12 WITS indicated non-zero MW levels for both FIR and SIR in the NI for several five-minute intervals during the zero-RAF period. These are highlighted in Table 4. This indicated that some NI IR was being dispatched in the RTP schedules, which appears counter-intuitive considering the zero IR requirement in the NI.

Table 4 Five-minute intervals during zero-RAF period with non-zero NI IR MW

Trading period	Interval	NI FIR MW	NI FIR Price	NI SIR MW	NI SIR Price
28	13:40	32	0	32	0
29	14:05	30.6	0	37	0
30	14:30	30.6	0	37	0
30	14:35	30.6	0	37	0
30	14:40	30.6	0	37	0

Source: Wholesale Information Trading System (WITS)

- 5.13 The non-zero IR quantities in the 13:40 interval of trading period 28 was a result of two discretionary constraints added to the real-time schedules (RTD and RTP) during this time. These constraints specified the minimum energy and IR output from one of the Stratford peaking units (SFD2201 SFD21).

³⁶ This is because with the RAF set to zero, the calculated risks (generator trip or HVDC trip) are scaled to zero.

³⁷ See Appendix A.

- 5.14 Due to the form of the constraint (i.e with energy and IR), SPD was able to find a lower cost solution and still satisfy the constraint by reducing the energy output from SFD2201 and SFD21 and increasing the IR from this unit. This resulted in the non-zero IR quantities being specified in the RTP schedule.
- 5.15 In the other real-time pricing intervals, the non-zero IR MW displayed in WITS is due to IR offers at a price of \$0 per MW/h. With no IR requirement, SPD is indifferent to including these zero-priced IR offers into the solution since they have no impact on the system costs. In these instances, these zero-priced IR offers from the NI were included into the solution and resulted in the non-zero IR MW displayed in WITS.
- 5.16 It therefore appears that the IR MW displayed on WITS is the IR dispatched within the RTP schedules and not the IR requirements. These are usually similar, however as indicated in the above instances can differ if there is a constraint or zero cost in providing the IR requirement. These can also differ if there is insufficient available IR to satisfy the requirements.
- 5.17 The displaying of these non-zero IR MW in the NI during periods of zero IR requirement in the NI would have provided contradictory information and a source of additional uncertainty for market participants.
- 5.18 To reduce this uncertainty, the IR MW information displayed on WITS for the RTP schedules could indicate the required IR MW as well as the dispatched IR MW.

Recommendations around treatment of IR following CE and ECE

- 5.19 The SOs inability to accurately dispatch IR following a CE or ECE is due to the difference between the offered IR quantities in the market and the availability of this IR. In these instances the SO reduced the RAFs.
- 5.20 The SO manages similar discrepancies in the offered capability and available capability of energy offers via the use of discretionary constraints, as was done when Huntly tripped on 13 December 2011. A consistent approach to the IR unavailability could be to use discretionary constraints to reduce the offered IR following a CE or ECE rather than reduce the RAFs, with participant re-offering required to remove the discretionary constraints.
- 5.21 This would invariably result in IR shortages in the real-time dispatch, where the real-time price of energy and IR would rise to reflect shortages, currently these would be prices in the range of the deficit IR price³⁸. A feasible energy dispatch solution would still be maintained, based on the variable reserve changes implemented by the SO in July 2010.
- 5.22 The price impact of this implementation is that a consistent pricing signal is provided during real-time, which indicates the high economic value of additional IR offered into the market to cover the system risk. This would incentivise participants with available IR to offer into the market and furthermore be consistent with the requests for additional IR provided by the SO in its grid emergency notice.
- 5.23 The Authority has queried the practicalities of such an approach with the SO.

6 Impact of setting Huntly as a single risk

- 6.1 Generation from Huntly was reconnected to the transmission system during trading period 36 (17:30) on 13 December 2011. At 17:46 on 13 December 2011, the SO issued a customer advice

³⁸ This could change if the move to economic constraint violations is made.

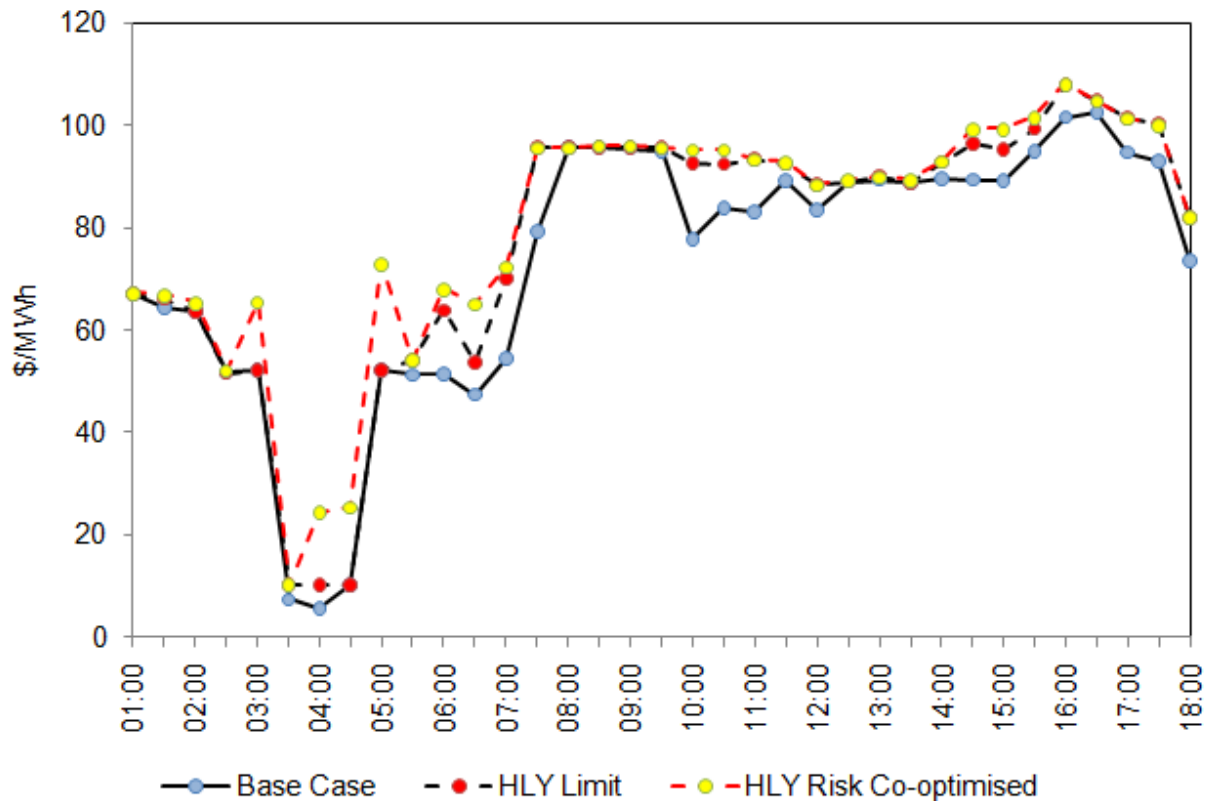
notice³⁹ indicating that in order to meet their principle performance obligations (PPO), the Huntly power station would be treated as a single risk. This implied that the combined output of all Huntly units was treated as a single CE risk.

- 6.2 In order to manage this, the SO applied a NI manual risk to the market system. However there is no ability for SPD, in the energy-reserve co-optimisation, to reduce the manual risk. This could result in an excess of IR being dispatched to cover the largest risk and/or the risk setter being dispatched above the manual risk level (i.e. not enough IR is dispatched).
- 6.3 To manage this loss of energy-IR co-optimisation, the SO also applied discretionary constraints to manage the combined energy and IR dispatch from Huntly, to ensure that it was not higher than the NI risk, which was set by the NI manual risk.
- 6.4 The SO was also investigating the use of market node constraints to replace the use of discretion in real-time. This constraint would not resolve the inability of the market system to fully co-optimize, but would enable the forward looking schedules (SDPQ, SWS and PDS) to incorporate the constraint thus improving the forward looking signals to the market. Analysis of the final pricing case indicates that no market node constraint was applied to Huntly during 14 December 2011.
- 6.5 At 17:23 on 14 December 2011, the SO issued a customer advice notice informing market participants that a bus reconfiguration at Huntly was planned for 18:00, and that Huntly unit 5 would no longer be part of the Huntly station risk. All other units at Huntly would remain as a single risk.
- 6.6 To understand the impact of this application of the manual risk and the use of discretionary constraints applied to Huntly in real-time, the Authority has carried out two simulations and compared these to the actual base case. The first simulation involves introducing a set of market node constraints⁴⁰ into vSPD to constrain the total of cleared energy and IR by the NI manual risk. This is similar to the way the SO managed the Huntly risk in real-time dispatch. This is referred to as the "HLY Limit" scenario.
- 6.7 The second simulation assumed the NI manual risk was not used but that the energy and reserves were fully co-optimised while treating Huntly station as a single risk. This was done by introducing a set of additional constraints into vSPD. This is referred to as the "HLY risk co-optimised" scenario.
- 6.8 These two scenarios were compared to the results from the base case final pricing solution, for trading periods 3-37 on 14 December 2011. Trading periods 1-2 and 38-48 are not considered because the NI manual risks for these trading periods were set to zero in the final pricing case, and therefore fully co-optimised in the final pricing solution. This comparison is shown in Figure 20.

³⁹ See Appendix A.

⁴⁰ A separate constraint was added for each IR class (FIR and SIR).

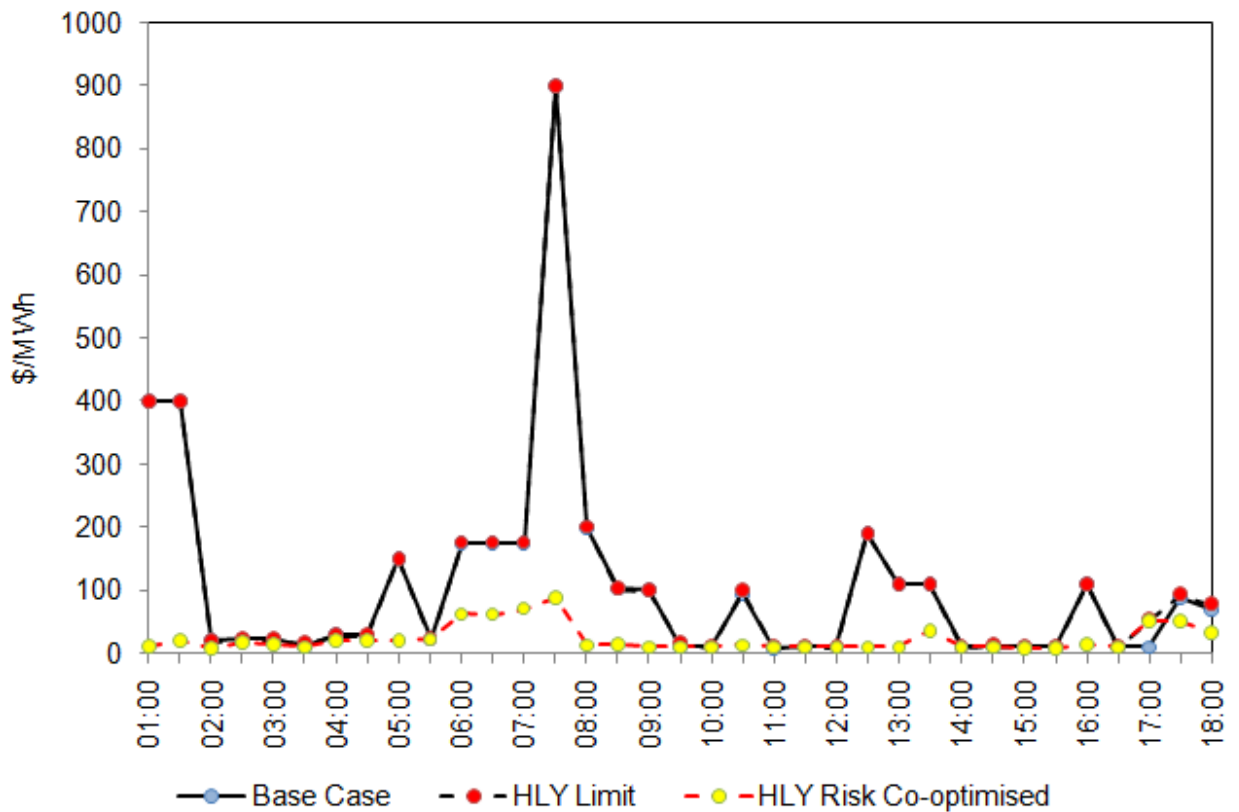
Figure 20 Haywards price – 14 December 2011



Source: Electricity Authority

- 6.9 Figure 20 illustrates that the base case final energy prices are always lower than the energy prices of both of the simulated scenarios. This is because the constraint on energy is the most relaxed for the base case final pricing solution.
- 6.10 In the “HLY Limit” scenario, there are additional market node constraints on the cleared energy and IR from Huntly. Therefore prices in the “HLY Limit” scenario are greater than in the base case.
- 6.11 In the “HLY risk co-optimised” scenario, the cleared energy and reserves from Huntly are economically constrained by the NI risk. Therefore the energy prices in the “HLY risk co-optimised” scenario are likely to be greater than the base case unless the NI manual risk, as used in the base case, is set very high.
- 6.12 Figure 21 compares the NI FIR prices of the base case, “HLY Limit” and the “HLY risk co-optimised” scenarios for 14 December 2011. When the energy-reserve market system is fully co-optimised, the FIR price reduced significantly in most of the studied trading periods.
- 6.13 The base case and “HLY Limit” scenarios both have the same NI risk requirement as set by manual risk, however, the “HLY Limit” scenario has market node constraints applied. All else being equal, this should result in the FIR price for the “HLY Limit” scenario being at least as much as the FIR price in the base case. Figure 21 illustrates that the FIR price for both the base case and HLY Limit scenario are identical for most of the time except for trading period 35 (17:00).

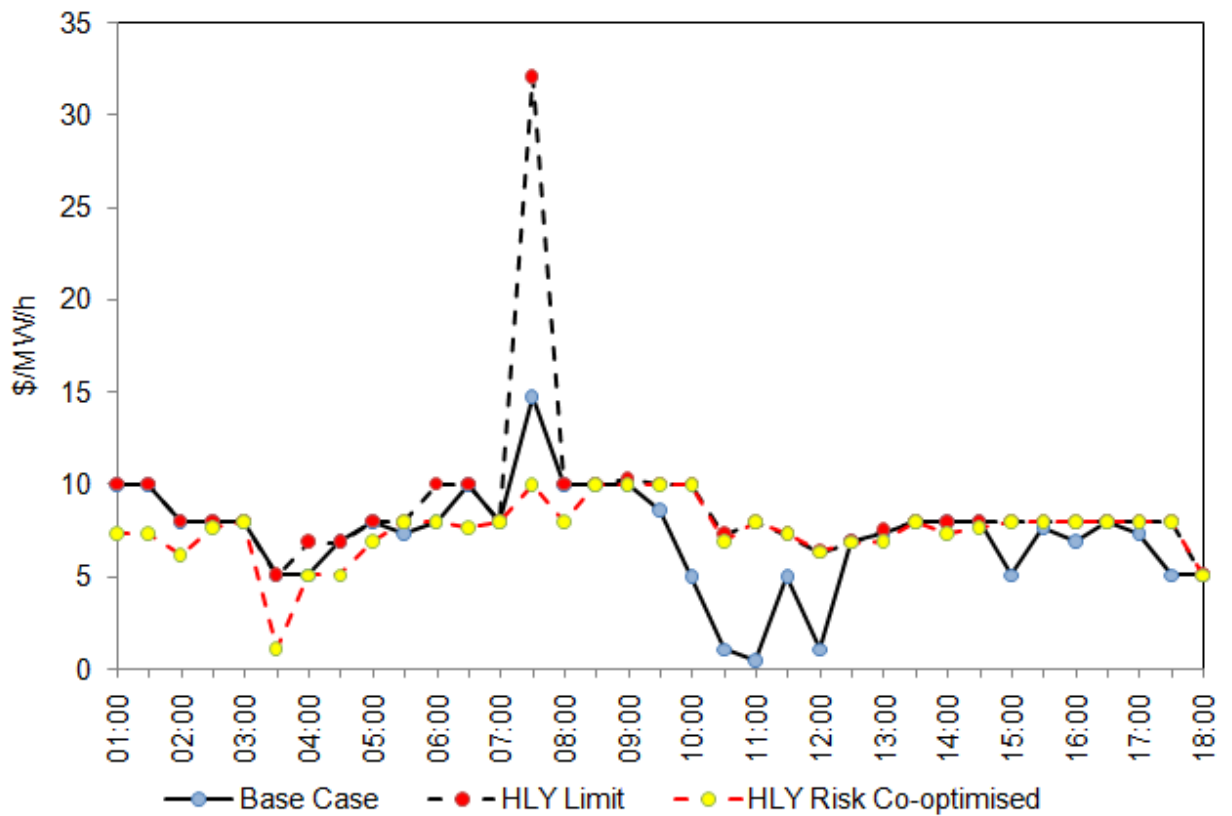
Figure 21 NI FIR prices – 14 December 2011



Source: Electricity Authority

- 6.14 Figure 22 compares the NI SIR prices of the base case, “HLY Limit” and the “HLY risk co-optimised” scenarios for 14 December 2011. The SIR prices of the “HLY Limit” scenario are always at least as high as the SIR prices of the other two scenarios.
- 6.15 Compared to the “HLY risk co-optimised” case, the cleared energy and reserve from Huntly in the final pricing base case is lower in some trading periods and higher in others.

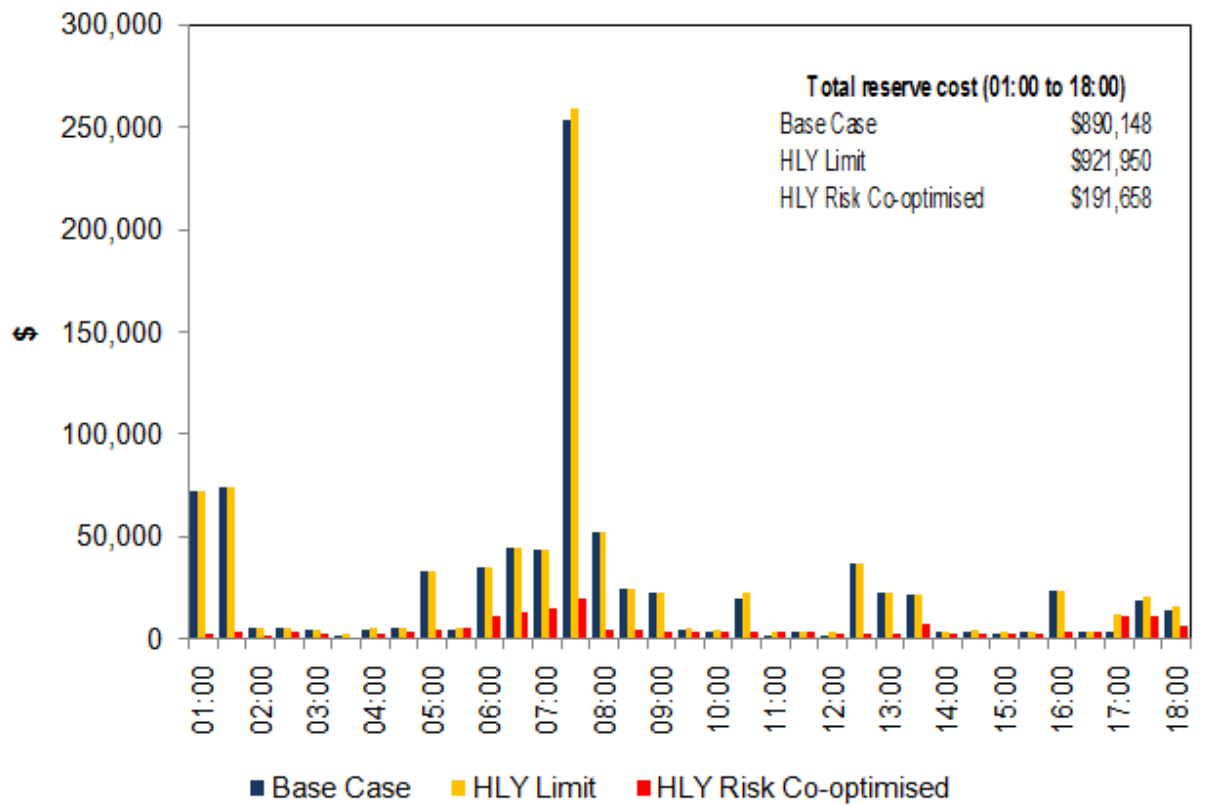
Figure 22 NI SIR prices – 14 December 2011



Source: Electricity Authority

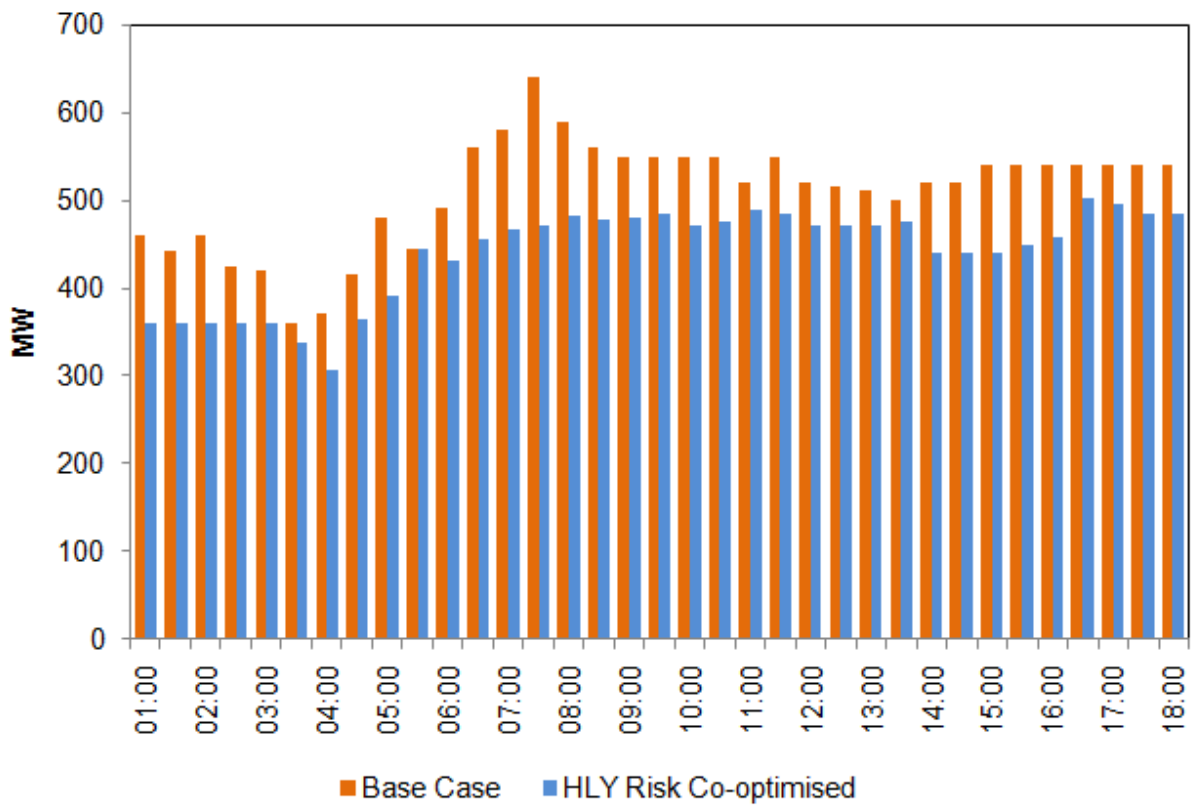
- 6.16 Figure 23 compares the estimated NI IR cost for the final pricing base case, “HLY Limit” and “HLY risk co-optimised” scenarios for 14 December 2011. The NI IR cost in the “HLY risk co-optimised” scenario is significantly lower than that in the other two scenarios, primarily due to the reduced IR prices under co-optimisation, as illustrated in Figure 21 and Figure 22. In addition, the “HLY co-optimised” scenario schedules a lower NI risk when compared to the manual risk setting, as illustrated in Figure 24

Figure 23 NI IR cost – 14 December 2011



Source: Electricity Authority

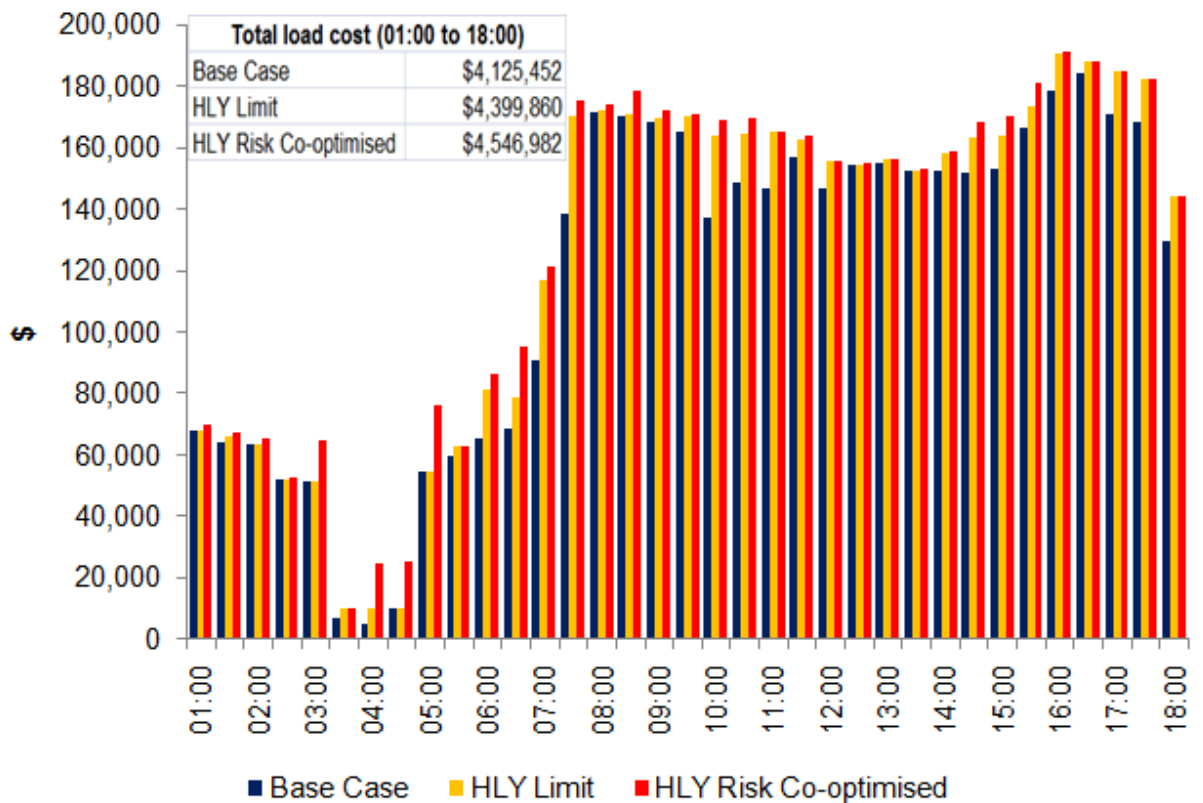
Figure 24 NI risk



Source: Electricity Authority

- 6.17 Figure 25 compares the estimated cost to NI load calculated for each of the scenarios. The total cost to NI load is highest under the "HLY risk co-optimised" scenario and lowest under the base case final pricing scenario. This is consistent with the relative magnitudes of the Haywards energy price under the "HLY risk co-optimised" and base case scenarios, as illustrated in Figure 20.

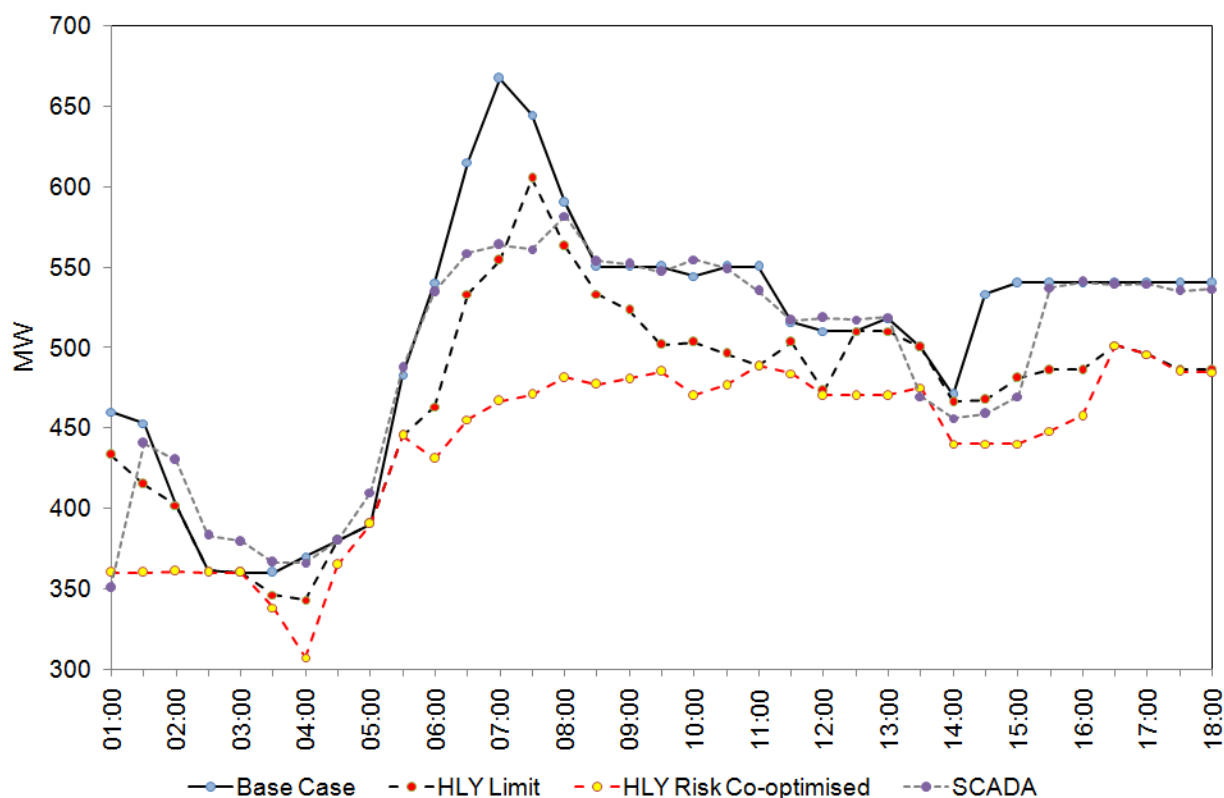
Figure 25 NI load cost – 14 December 2011



Source: Electricity Authority

- 6.18 Genesis had, in its pricing error claim, indicated that an unspecified amount of energy was not dispatched at prices that would have been beneficial to Genesis and the market.
- 6.19 The Authority has compared the actual output of Huntly from SCADA against the scheduled outputs of Huntly from the base case, "HLY Limit" and "HLY risk co-optimised" scenarios. This is illustrated in Figure 26.

Figure 26 Huntly generation comparison under difference scenarios



Source: Electricity Authority

- 6.20 Figure 26 illustrates that had the increased risk of Huntly been co-optimised, the resulting generation from Huntly would be lower than was actually dispatched. The discretionary constraints applied by the SO to Huntly during real-time were needed to manage the Huntly station manual risk in the absence of this co-optimisation.

Summary and recommendations following events of 14 December 2011

- 6.21 The application of the NI manual risk for most of the trading periods on 14 December 2011 resulted in the NI energy and reserve markets not being fully co-optimised.
- 6.22 The Authority's analysis indicates that as a result this increased the NI IR costs due to increased IR prices and increased IR requirement relative to a co-optimised energy-reserve solution.
- 6.23 In contrast, the application of the manual risk and removal of discretionary constraints from the calculation of final prices resulted in a reduction in NI energy price relative to the co-optimised solution.
- 6.24 The current market clearing engine (SPD) is not capable of co-optimising energy and reserves when multiple risk setters need to be treated as a single risk. In order to achieve this, some modifications are needed to the market system including SPD.
- 6.25 While this can be potentially time-consuming and costly, cost savings and more efficient allocation of energy and reserve resources could be achieved when this functionality is needed to co-optimize energy and reserve market. While these events are typically infrequent, a cost-benefit analysis should be considered to understand the trade-offs. Similar functionality could be used

during the commissioning of plant where there is an increased risk that the plant being commissioned will trip.

- 6.26 Another option which could be explored is using vSPD for the calculation of final prices. vSPD is relatively simple and quick to modify to include additional constraints, such as those used to co-optimize the energy and reserves market. Discretionary constraints and/or manual risks can still be used within real time, with a co-optimized energy-reserve formulation in vSPD used for pricing. This option would reduce the cost of modifying SPD but would require vSPD to be fully audited to ensure its unmodified model is exactly the same as SPD and any modifications operate as intended. However, this option would introduce further discrepancies between the real-time dispatch and final pricing process, which reduces price predictability.

7 Pricing error claims on 13 and 14 December 2011

- 7.1 Pricing error⁴¹ claims were raised by the Authority and King Country Energy (KCE) for trading period 27 on 13 December 2011. A further pricing error claim was raised by Genesis for all trading periods on 14 December 2011.
- 7.2 The pricing error raised by the Authority for trading period 27 was based on an understanding that all Huntly generation was disconnected from the grid following the trip at Huntly power station at 12:33. However the calculation of interim prices for trading period 27 (13:00) still included generation from Huntly unit 6 (HLY2201 HLY6). Concerns were also raised by the Authority about the resolution of the infeasibilities for trading period 27.
- 7.3 In response to the claim, the SO indicated that Huntly unit 6 had remained connected to the grid and was connected at the start of trading period 27 and therefore it had been correct to include it within the calculation of interim prices.
- 7.4 Since the correct input was used, as defined by the Code, the pricing error claim was not upheld.
- 7.5 The pricing error claim raised by KCE was in relation to unique prices being produced in the spot electricity market due to the grid not being configured efficiently and the system operator's actions being primarily based on stabilising the system rather than operating the system efficiently.
- 7.6 This pricing error claim was not upheld since no specific error in either inputs or process was identified.
- 7.7 The pricing error claim by Genesis for 14 December 2011 indicated that reserve and energy prices were higher than they should have been due to the SO applying incorrect security constraints to the Huntly station following the tripping on 13 December 2011, and due to additional constraints applied by the system operator in real-time.
- 7.8 This pricing error claim was not upheld since no evidence of an error in the inputs or calculation of interim prices was found.

8 Issues with WITS

- 8.1 The Authority's experience was that WITS was extremely slow during 13 December 2011. This reduced the timely availability of market information.
- 8.2 The Authority is investigating these issues with the WITS service provider, NZX.

⁴¹ A pricing error as defined in the Code, includes an interim price that is incorrect, or is likely to be incorrect, as the result of an incorrect input, or incorrect process, being used in calculating the interim prices.

- 8.3 Specified and monitored performance standards for the timely availability of real-time information should be included as part of the agreement with the WITS service provider. Furthermore, the performance standard should be based on a maximum loading requirement of the WITS as this would better represent an expected response during high usage periods.

9 Conclusions and recommendations

- 9.1 A timely, robust and accurate pricing process is essential for providing efficient price signals to generators and consumers.
- 9.2 The events on 13 and 14 December 2011 provide valuable lessons for understanding the shortcomings within, and developing improvements for, the wholesale spot electricity market pricing process.
- 9.3 The above review has considered the issues observed with the current pricing process during the events of 13 and 14 December 2011 and has proposed recommendations for the Authority to investigate further with industry participants.
- 9.4 These recommendations include:
- (a) Consideration of a move to use 5-minute prices in the final pricing process, to improve price certainty and accuracy and address some of the issues experienced with the current ex-post 30-minute trading period pricing process.
 - (b) In regard to infeasibilities, two potential alternatives need to be evaluated:
 - (i) An economic representation of constraint violations would allow greater alignment of prices in the scheduling (before real-time), real-time and final prices. These economic costs of constraint violations would also be used for settlement, reducing the need for an infeasibility resolution process and improving price certainty. There is a trade-off with price accuracy if these economic constraint violations are not used within the real-time dispatch process, due to security concerns.
 - (ii) Potential amendment of the Code around the resolution of infeasibility situations to require minimum adjustments to the inputs when resolving such situations. This could facilitate a model-based approach to resolve infeasibilities and improve the robustness of this process.
 - (c) Consideration of sensitivity demand forecasts when developing prices for forward looking schedules. This would provide an indication to market participants about the potential volatility in price with changes in demand.
 - (d) Consideration of an alternative treatment of IR resources following CE and ECE. This would involve applying discretionary constraints to IR resources to reflect their unavailability following such an event. This would enable the dispatching of re-offered available IR and prices to better reflect the operation of the system at reduced security.
 - (e) Consideration of a co-optimised energy-reserve SPD model with flexible definition of system risks. The benefits of such a development are the improved allocation of energy and reserve resources during these conditions. These benefits would need to be considered against the costs of such a development.
 - (f) Reconsider the requirements on providers of wholesale market information to improve the timely availability of real-time information.
- 9.5 The current market structure has several pricing functions split across the pricing manager and the system operator, such as the resolution of infeasibility situations and HSW price situations. To

facilitate the objectives of developing an efficient pricing process, consideration could be given to altering the allocation of these functions across the two parties.

Draft

Appendix A Notices relating to 13 and 14 December 2011



Excursion Notice

To: Excursion NZ Participants
Sent: 13-dec-2011 12:53
Ref: 702730480

From: The System Operator
Telephone: 0800 488 500
Facsimile: 07 843 7176

Revision of:

Excursion:	Frequency
Time:	13-dec-2011 12:33
Location:	National
Level:	47.63
Comments:	NI Frequency 47.63 Hz SI Frequency 48.38 Hz Loss of Huntly 220kV bus connection resulting in the disconnection of all Huntly generation

Frequency Excursion notices are only issued if the deviation is out side 49.5 and 50.5 Hz.

A revision of this notice will be issued if there is any change to the situation above.

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Grid Emergency Notice



To: GEN NZ Participants
Sent: 13-dec-2011 13:02
Ref: 702736887

From: The System Operator
Telephone: 0800 488 500
Facsimile: 07 843 7176

Revision of:



Cause: Unplanned outage North Island
Region or GXP affected: North Island
Starting: 13-dec-2011 12:45
Ending: 13-dec-2011 18:00
Tripping at Huntly resulting in the loss of generation, and the operation of Automatic Under frequency Load Shedding (AUFLS)

Participants are Requested to:	At:
Increase Transmission offers	North Island
Increase Energy Offers	North Island
Increase Instantaneous Reserve Offers	North Island

Consequences if insufficient responses by participants:

Where participant response is insufficient, the System Operator will manage demand to alleviate the Grid Emergency.

This notice is issued in accordance with Technical Code B - Emergencies, Schedule 8.3, Part 8

A revision of this notice will be issued if there is any change to the situation above.

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Grid Emergency Notice Revision

To: GEN NZ Participants
Sent: 13-dec-2011 17:48
Ref: 702894690

From: The System Operator
Telephone: 0800 488 500
Facsimile: 07 843 7176

Revision of: GEN, 702736887, 13-dec-2011 13:02, Unplanned outage

Cause:	Unplanned outage North Island	
Region or GXP affected:	North Island	
Starting:	13-dec-2011 12:45	13-dec-2011 12:45
Ending:	13-dec-2011 18:00	13-dec-2011 19:00

Tripping at Huntly resulting in the loss of generation, and the operation of Automatic Under frequency Load Shedding (AUFLS)

Participants are Requested to:	At:
Increase Transmission offers	North Island
Increase Energy Offers	North Island
Increase Instantaneous Reserve Offers	North Island

Consequences if insufficient responses by participants:

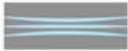
Where participant response is insufficient, the System Operator will manage demand to alleviate the Grid Emergency.

This notice is issued in accordance with Technical Code B - Emergencies, Schedule 8.3, Part 8

A revision of this notice will be issued if there is any change to the situation above.

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Grid Emergency Notice Revision

To: GEN NZ Participants
Sent: 13-dec-2011 19:00
Ref: 702934958

From: The System Operator
Telephone: 0800 488 500
Facsimile: 07 843 7176

Revision of: GEN, 702894690, 13-dec-2011 17:48, Unplanned outage

Cause:	Unplanned outage North Island	
Region or GXP affected:	North Island	
Starting:	13-dec-2011 12:45	13-dec-2011 12:45
Ending:	13-dec-2011 18:00	13-dec-2011 23:00
Tripping at Huntly resulting in the loss of generation, and the operation of Automatic Under frequency Load Shedding (AUFLS)		

Participants are Requested to:	At:
Increase Transmission offers	North Island
Increase Energy Offers	North Island
Increase Instantaneous Reserve Offers	North Island

Consequences if insufficient responses by participants:

Where participant response is insufficient, the System Operator will manage demand to alleviate the Grid Emergency.

This notice is issued in accordance with Technical Code B - Emergencies, Schedule 8.3, Part 8

A revision of this notice will be issued if there is any change to the situation above.

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Customer Advice Notice

To: CAN Energy Traders
Sent: 13-dec-2011 17:46
Ref: 702890520

From: The System Operator
Telephone: 0800 488 500
Facsimile: 07 843 7176

Revision of:

System Reserve Requirements Regarding Huntly

The System Operator advises participants that in order to meet their PPO's Huntly power station will be treated as a single risk.

This situation will remain until further notice.

A revision of this notice will be issued if there is any change to the situation above.

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Customer Advice Notice

To: CAN Energy Traders
Sent: 14-dec-2011 12:20
Ref: 703602213

From: The System Operator
Telephone: 0800 488 500
Facsimile: 07 843 7176

Revision of:

System Reserve Requirements - further information

The following is explanatory information on the market effect of the ongoing treatment of the Huntly power station as a single risk in the market system. As previously advised in the CAN 13-Dec-2011 17:46, this treatment is required to meet the System Operators PPO's and will remain in force until further notice.

Under normal operations the market system co-optimisation of energy and reserve allows for the identification of the risk setting generator in the North Island for the set of all generators with a capacity larger than 60MW. The market co-optimisation can reduce the cleared generation at the risk generator if the cost to the market of that forgone generation is less than the benefit to the market of the reduced risk and the consequential reduced requirement to purchase reserves.

Where multiple generating units are identified as a single credible event the combined output of these units is treated as a single risk. This is currently the case for the Huntly station. The combined output of many generating units as a single risk can only be modelled in the market system as a 'manual risk'. During co-optimisation there is no ability for the system to reduce a manual risk. The market system will always try and procure enough reserves to cover the full manual risk. This can lead to infeasible solutions which are managed in real time via the use of discretion. It can also lead to price separation in the market.

The System Operator is investigating the use of a market node constraint to replace the current use of discretion in RTD. This will give a better forward indication to the market of the management of this situation but will not resolve the inability of the market system to fully co-optimise.

We are continuing to explore further options.

Please contact Market Services if you have any further questions.

Market.Services@transpower.co.nz

04 494 7470

...

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Customer Advice Notice Revision

To: CAN Energy Traders
Sent: 14-dec-2011 17:23
Ref: 703754519

From: The System Operator
Telephone: 0800 488 500
Facsimile: 07 843 7176

Revision of: CAN, 702890520, 13-dec-2011 17:46, System Reserve Requirements Regarding Huntly

System Reserve Requirements Regarding Huntly

The System Operator advises that the Huntly bus will be reconfigured at 18:00 today. Huntly Unit 5 will no longer be part of Huntly station single risk.

All the other Huntly units remain a single risk.

This situation will remain until further notice.

A revision of this notice will be issued if there is any change to the situation above.

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Glossary of abbreviations and terms

Act	Electricity Industry Act 2010
Authority	Electricity Authority
CE	Contingent event
Code	Electricity Industry Participation Code 2010
Contact	Contact Energy Limited
CVP	Constraint violation penalty
ECE	Extended contingent event
Genesis	Genesis Power Limited (trading as Genesis Energy)
GWh	Gigawatt hour
GXP	Grid exit point
IMM	Industry and Market Monitoring
Meridian	Meridian Energy Limited
MEUG	Major Electricity Users' Group
MRP	Mighty River Power Limited
MW	Megawatt
MWh	Megawatt hour
NFR	Net free reserve
RAF	Risk adjustment factor
SCADA	Supervisory Control and Data Acquisition
SO	System Operator
SPD	Scheduling, Pricing and Dispatch
TP	Trading period
TrustPower	TrustPower Limited
vSPD	Vectorised Scheduling, Pricing and Dispatch
WITS	Wholesale information trading system