2011: a year in review

EEA Conference 2012
SKYCITY Convention Centre, Auckland, New Zealand, 20–22 June 2012

David Hume, Bruce Smith, Ramu Naidoo, Roger Miller and Tuong Nguyen
Electricity Authority, Level 7, 2 Hunter Street, Wellington
Email: humed@ea.govt.nz

***Abstract*—**
2011 was an interesting year for the New Zealand power system. Although average in terms of hydrology, a number of events were witnessed leading to a year of higher than normal volatility; both in terms of the market, and the physical supply of electricity.
In January, temporary transmission outages led to the dispatch of significant amounts of unscheduled generation resulting in high costs for market purchasers. In February, Christchurch was hit by a significant earthquake, and on the 26 March an unprecedented price spike was witnessed in the North Island. In July and August severe storms stressed the power system resulting in a record peak demand. Finally, on 13 December, a major outage at the Huntly generating station resulted in an under frequency event causing the tripping of the Automatic Under Frequency Load Shedding (AUFLS) relays in the North Island.
In addition to this, throughout the year the handling of transmission outages and constraint limits by the system operator led to a number of high spring washer events where market prices rose substantially above those offered by generators.
This paper, with the aid of analysis performed by the Market Performance team at the Electricity Authority, provides a technical commentary on events that occurred throughout 2011. It attempts to aid understanding to some of the causes, failures, and possible solutions in terms of the market and the reliability of the physical power system.

I. Introduction

Earthquakes, extreme weather, changes to market systems, transmission outages and hidden hardware failures, resulted in the year 2011 being one of higher than normal volatility. This paper provides both a technical and illustrative overview to some of these events.

The paper starts and ends with events involving the Huntly Power station in January and December respectively. Near the end of January the System Operator was required to constrain on high priced generation at Huntly for several days. The cause, in addition to the high prices offered at Huntly, was identified as a missing transmission constraint in the market dispatch software, SPD. This is described in more detail in Section II.

Fast forward eleven months and again Huntly features in a near unprecedented event with significant loss of generation triggering a North Island wide under frequency event. This event resulted in some (but not all) of the North Island Automatic Under Frequency Load Shedding (AUFLS) relays being deployed.

The result was a scattering of localised blackouts throughout the North Island followed by the observation of a number of issues relating to the spot market. This event is a wake up call in terms of both system reliability and robustness of the spot market. From a technical point of view, the observed power system behaviour in the seconds following the event is extremely interesting. Both the power system and market issues related to 13 December are described in sections VI and VII.

Between these two events; the New Zealand power system experienced a number of other interesting events. A price spike of unprecedented magnitude occurred on 26 March. This resulted in the declaring of an Undesirable Trading Situation (UTS). Several days later, the System Operator's Simultaneous Feasibility Test (SFT), which calculates transmission constraints "on the fly", was enabled. On 15 August, record snow falls across the country resulted in an all time peak demand of ≈6600MW.

The time-line depicted in figure 1, and list below, set out the year with various events that are further described in this paper.

- 23-27 January Huntly constrained on;
- 22 February, Chch earthquake;
- 26 March, price spike;
- 15 August peak demand;
- 14 August and 26 September - price separation during HVDC reversal
- 13 December Huntly outage

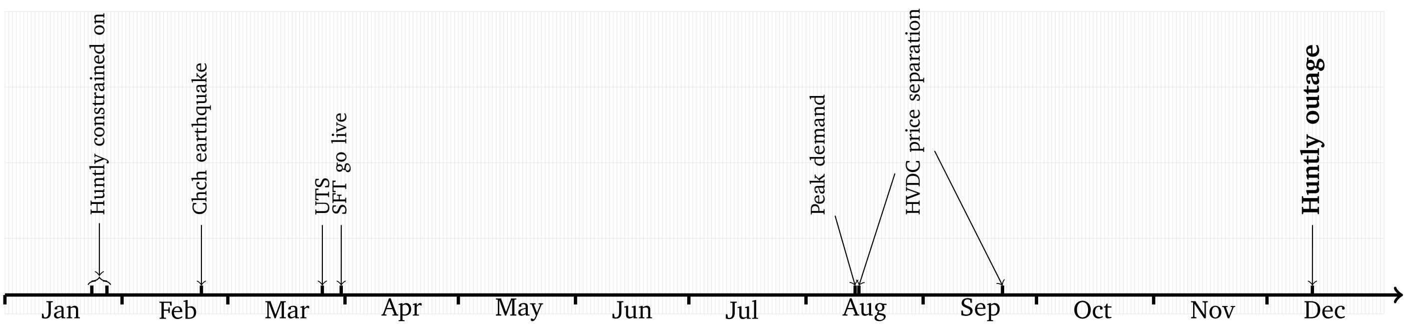

Fig. 1. Time line of events in 2011

II. 23-27 January, Huntly constrained on

Between the 23 and 27 of January, the System Operator dispatched Huntly, outside of the market model, to meet security requirements into Auckland. This unscheduled, or constrained-on, generation was therefore not dispatched as part of the market pool, yet was able to obtain its offer price. On this occasion Genesis used this to their advantage to increase offers at Huntly. Constrained-on generation is paid for by spot market purchasers each month, pro-rated among participants by the half-hourly demand during constrained on events. In January, spot market purchasers paid over $7 million for constrained-on generation compared to $1 million - $2 million in a typical month[1].

A. Alignment of market model to physical system

Constrained-on generation is typically required during transient system events that are not easily predicted in advance. Ideally, the events between the 23 to 27 of January should have been identified beforehand, during routine steady state systems analysis of the power system, and a constraint developed in the lead-up to real-time dispatch.

In this case, an unidentified combination of system topology (circuit outages for maintenance at the time) and unpredicted power system conditions appeared to contribute to the event. This, coupled with the significant time it took to develop a constraint, led to a significant amount of unscheduled generation to be dispatched.

Constraints in the market model are used to align the SPD model with the limits of the physical system. In this instance there was a significant constraint missing. On 31 March the System Operator introduced a process for automatic constraint building. The process is termed the Simultaneous Feasibility Test (SFT) and had this been in operation during the 23–27 January would have likely developed the system constraint required. Section V provides further details of this new tool and some of the teething issues that have occurred through out 2011.

III. 22 February, Canterbury earthquake and demand forecasting

The earthquake that hit Christchurch near noon on the 22 February caused a significant loss of demand. Figure 3 illustrates the effect of power demand in Christchurch following the earthquake. The green line illustrates the actual demand, while the blue line illustrates the demand that was forecast several hours earlier. The difference (residuals) between the two is also illustrated. Lagged residuals, i.e., the short term historical error in prediction, are used in the demand forecast model in the lead-up to real time operation. A large error occurs after the event, but is then corrected by these lagged residuals after a few hours.

Another interesting example, illustrated in Figure 4, occurred in Wellington in April 2010. An unplanned outage at the Wilton substation tripped around 125MW from the system. The green line illustrates actual demand, while the blue line illustrates the forecast. Of interest is the effect the lagged residuals have on the demand forecast several hours later and continuing over the following several days.

Forecasts can never be 100% accurate, however they can effect both market (dispatch) efficiency and system reliability. The current forecasts used by the System Operator are on a regional basis. Ten regions are forecast throughout New Zealand with these forecasts used to predict demand at GXP level. This is achieved by pro-rating the individual GXPs that make up the region with their demand one week earlier[2]. As many of the individual GXPs load profiles differ from their combined region, this leads to forecast errors at the GXP level.

The System Operator is currently running a tender process for possible replacements to the current forecasting system. It is therefore likely that an improvement will be seen in short term demand forecasts throughout New Zealand in the near term. This should improve both reliability, and price consistency leading up to real-time and through to final prices.

IV. 26 March, Undesirable Trading Situation

On Saturday 26 March, 2011, interim prices in the wholesale market for electricity exceeded $19,000/MWh over several hours for Hamilton and regions north of Hamilton, and reached several thousands of dollars in other regions of the North Island over the same time period.

Figure 2 shows the distribution of interim prices across the North Island for trading period 23 (11:00am – 11:30am) on 26 March 2011.

The Electricity Authority received 35 Undesirable Trading Situation (UTS) claims relating to the offer behaviour of Genesis Energy during planned transmission outages and the consequential high interim prices in the wholesale market for electricity across many parts of the North Island, especially Hamilton and regions north of Hamilton.

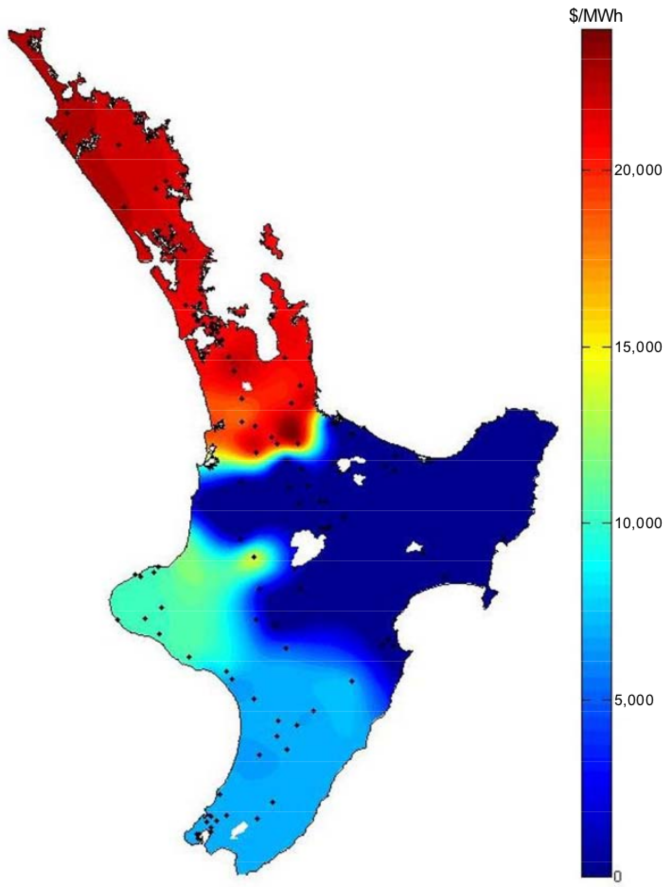

Fig. 2. North Island price distribution for Trading Period 23.

The planned transmission outages involved the temporary removal from service of two 220kV circuits between Whakamaru and Otahuhu and three 110kV circuits between Arapuni and Otahuhu. Transpower first notified industry

[1] A review of this event is available at http://www.ea.govt.nz/industry/monitoring/enquiries-reviews-investigations/2011/

[2] This is termed the Bus Load Participation Factor (BLPF) by the System Operator.

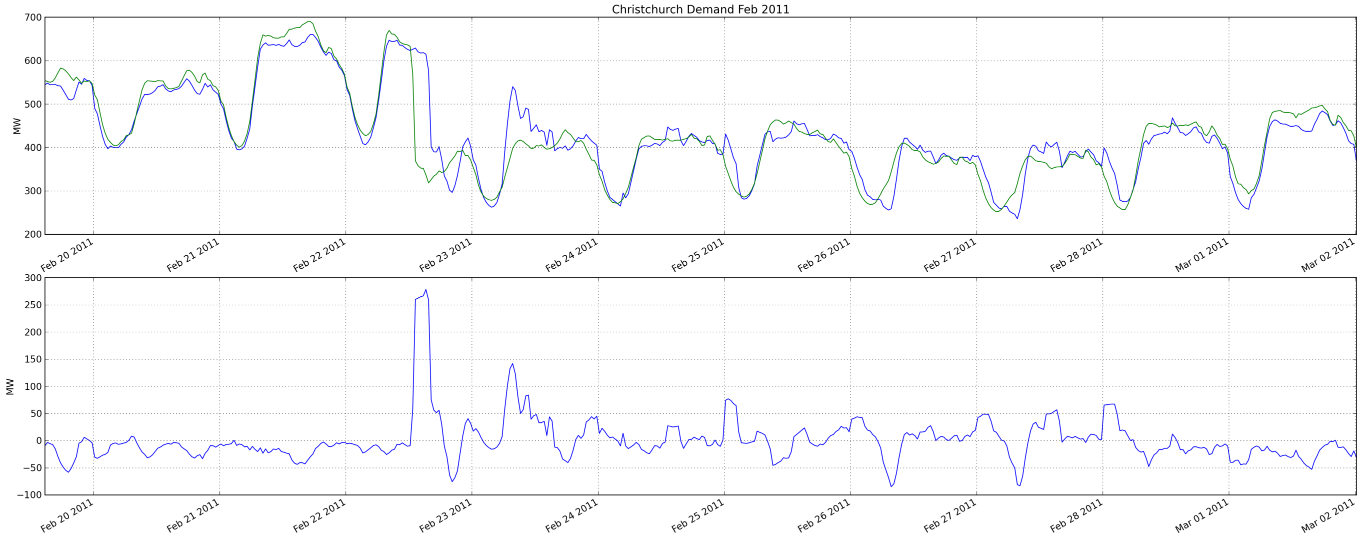

Fig. 3. Christchurch actual power demand (green) and forecast demand (blue) around the 22nd February earthquake.

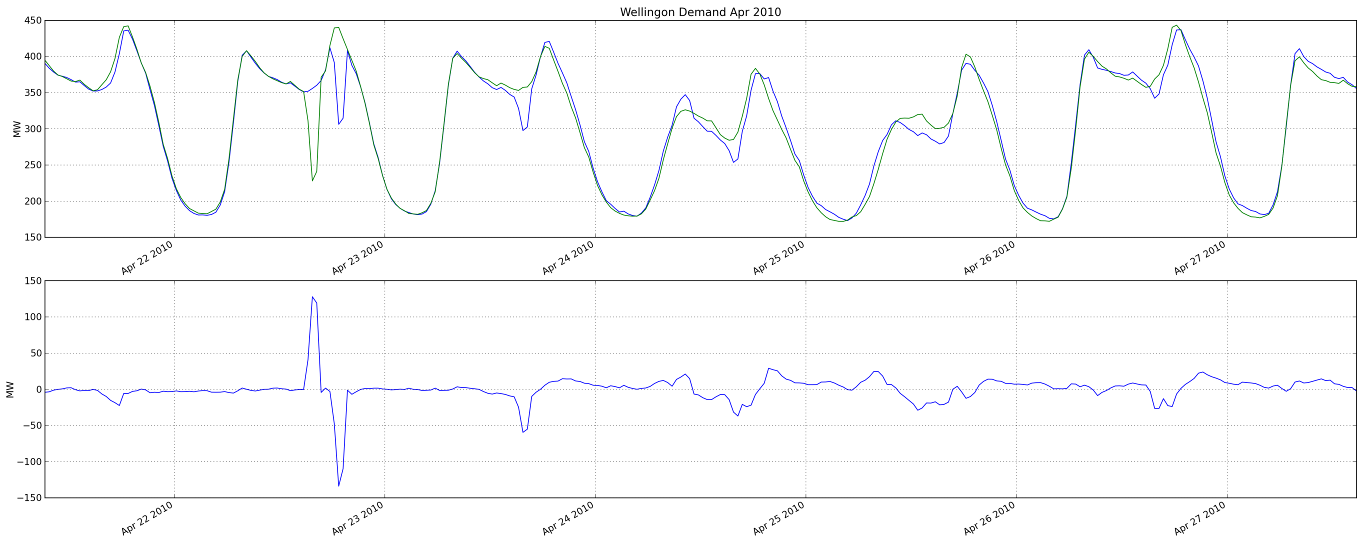

Fig. 4. Wellington actual power demand (green) and forecast demand (blue) on April 22nd, 2010, following an unplanned outage at the Wilton substation.

participants of the 220kV line outages on 15 December 2010 under the planned outage co-ordination process (POCP). The outages were confirmed on 16 February 2011. The split on the 110kV transmission system was first notified and confirmed to industry participants under the POCP on 9 March 2011. On 22 March 2011 the transmission outages were entered into the wholesale information and trading system (WITS), where SPD schedules may be viewed.

The outages meant generation from the Huntly power station was required to support electricity demand for Hamilton and regions north of Hamilton.

Interim prices at Huntly were around $19,750/MWh for all trading periods between 10:30 (the start of trading period 22) and 17:30 (the end of trading period 35). These interim prices were determined by the offers for the Huntly power station's generating units 2, 5 and 6.

On the 15 June the UTS Committee determined that trading periods 22 to 35 constituted a UTS, this was upheld in late February 2012 after appeals from several of the larger generators. Futher information is available on the Authority's website.

V. 31 March, SFT go live

SFT (Simultaneous Feasibility Test) is an automatic transmission constraint builder used by the System Operator as part of the market security and dispatch process. It is able to automatically, "on the fly", generate N–1 transmission constraint equations used in SPD. SFT went live on the 31 March, 2011.

The automatic generation of constraints means that the system can be run within its limits, as defined by the power system operating condition with constraints developed if N–1 flows on circuits come within a certain threshold.

The advantages of this tool are many, mainly arising from better alignment of physical power system limits with those in the market model (SPD). However, there have been some teething problems, some of which have resulted in issues and processes around the resolution of high spring washer prices. One such issue is around SFTs development of multiple constraints on parallel transmission circuits.

This is an issue where there exist two near identical transmission constraints. On Sunday 14 August 2011, such a situation occurred on the two parallel lines between Bunnythorpe and Woodville. At the time the code allowed for only one constraint to be relaxed meaning the other constraint bound with no change in high spring washer prices. This was remedied with an urgent code change[a].

[a] The reports on this issue is available at: http://www.ea.govt.nz/industry/monitoring/enquiries-reviews-investigations/2011/.

VI. HUNTLY - 13 DECEMBER

Disclaimer: This section attempts a technical description of the effects of the loss of the Huntly generating station on the North Island power system. Rather than provide results from a detailed dynamic model (such as from PSS/E or DigSilient), the section uses fundamental power system principles to help enable a better understanding of what occurred.

Rather than concentrating on the lead-up and cause/causer of the event, this section describes the aftermath, on a system wide basis, both in terms of the unusual and interesting technical system wide effects witnessed (in the following seconds); and on the effects seen by the market (in the following 24 hours). The author acknowledges that the technical complexity of this event, combined with an absence of any technical report (market issues aside), mean that the work presented here is more to provide a fundamental understanding of what may have occurred, using first principles, and with scarce information that has been made available.

A. The event

At the time of writing no formal report had been written regarding the events at Huntly on 13 December, 2011. The exact details therefore remain unclear. However, enough information has been presented by Transpower (in the form of presentation handouts), that some understanding and timing of the different events leading to, and following the loss of generation at Huntly, can be gained.

The resulting event was a rare, high impact event with very interesting results. In under 30 seconds 25% (844MW) of the North Island generation was tripped. The system responded automatically to equalize this loss of input energy with a combination of; shedding Interruptible Load (≈ 344MW of which ≈ 115MW was hot water), tripping some AUFLS feeders on distribution networks (≈ 216MW) and increasing northward transfer on the HVDC link by over 200MW.

Much insight can be gained from such an event, especially with regard to future possible design changes to the AUFLS scheme, and how such events are managed in the market. A basic chronological list of events follows:

- 12:10 normal operation, G3, G4 and G6 out for maintenance with G1,G2 and G5 generating ≈844MW. Total NI demand of ≈3400MW, with HVDC transfer ≈365MW (northwards);
- 12:11 unexpected opening of two circuit breakers (CB422) and (CB242);
- 12:30 unexpected opening of circuit breaker (CB362);
- 12:31 attempts to close (CB422) and (CB242) fail;
- 12:33 G5 trips (≈ 380MW), followed 2.7s later by G2;
- 12:34 G1 trips, ≈ 844MW total lost generation.
- 12:35 560MW of load shed over 30 seconds, consisting of;
  - 344MW of interruptible load (IL),
  - 216MW of Automatic Under Frequency Load Shedding, (AUFLS) and,
  - ≈200MW increased northwards transfer on the HVDC link.
- 1pm→market related events described in Section VII.

The Huntly substation uses a 'breaker and a half' layout, as illustrated in figure 5[3]. The initial circuit breakers that opened unexpectedly (CB422, CB242, and several minutes later CB362) were breakers connecting the line side 220kV bus, with the generating side 220kV bus. Three of these relays appear to have shared a common power source. In Transpower's presentation, the cause was a common mode failure (multiple earth faults on the 220V DC system) that powers all three circuit breakers. The result of the earth faults was an over-voltage, double the design voltage, which caused the relays to subsequently fail.

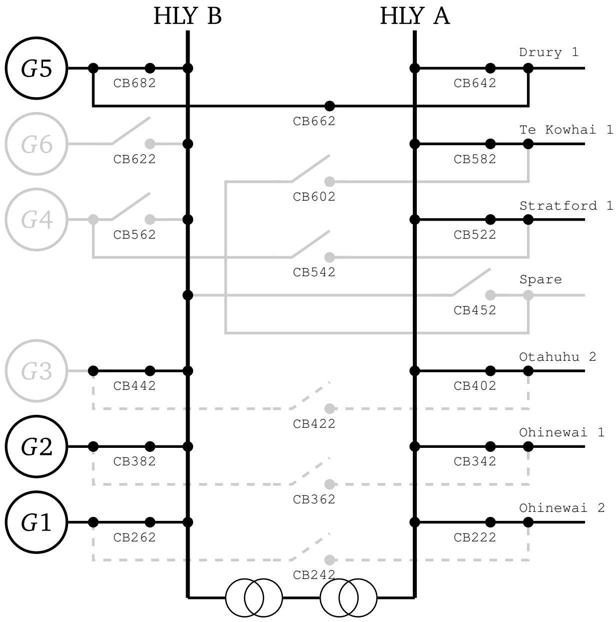

Fig. 5. Huntly substation immediately prior to generation tripping

The failure meant all generation on the generation side 220kV bus (844MW) at 12:30pm was connected to the system side bus by CB662 and CB642), and two 220/33kV distribution supply transformers (also in series) for several minutes[4].

It appears that at this time, although all equipment was within operating limits, the protection settings were not designed for this unusual operating state (with all power from all three units flowing through a series combination of CB682 and CB662). At 12:33pm, the protection settings for G5 caused the unit CB (CB52) to trip 380MW off the system on thermal overload. A consequence was the tripping, 0.15 seconds later, of CB662 and CB682[5] disconnecting all electrical connection, apart from two 60MVA 220/33kV distribution supply transformers providing a series connection between each 220kV bus.

At this time, G1 and G2 remained generating with an input mechanical power of ≈ 464MW, but limited in their electrical output power by the now high impedance of the 220/33kV distribution supply transformers. This situation lasted 2.7 seconds with both generators speeding up and losing synchronism with the remainder of the North Island power system. At this point G2 tripped, lowering the mechanical input power of the Huntly system but leaving G1 still connected.

In the 10 seconds between 12:33:45pm and 12:33:55pm, the 220kV generation side bus at Huntly[6] became asynchronously attached through a high impedance, to the rest of the North Island system. At around 12:33:55pm, G1 either resynchronised with the NI system or its electrical output reduced to near zero until it too tripped 13 seconds later at 12:34:08pm.

[3]This essentially means every circuit into or out of the substation is protected by ≈1.5 circuit breakers. This is a very common breaker arrangement and is used throughout the world.

[4]A further CB, (CB542) could have also connected the two bus sections, however this CB was open due to maintenance being conducted on generating unit G4. Another two CBs (CB602 and CB452) are normally open and were so at the time of the fault.

[5]Exact details remain unclear to the authors.

[6]With G2 initially connected and G1 connected for the entire 10 second period.

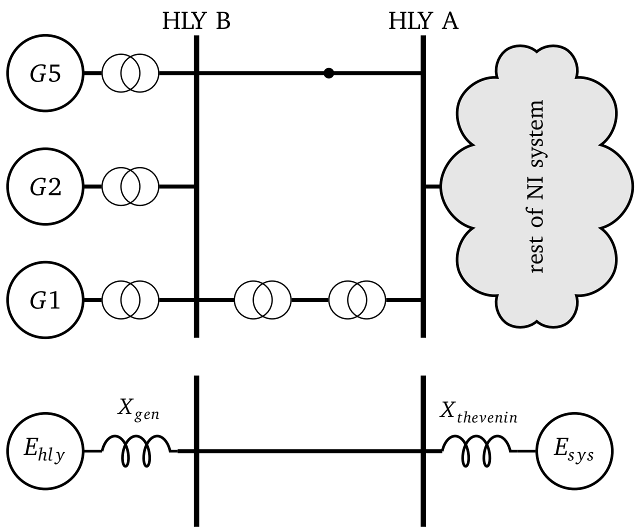

Fig. 6. Equivalent circuit prior to generation tripping.

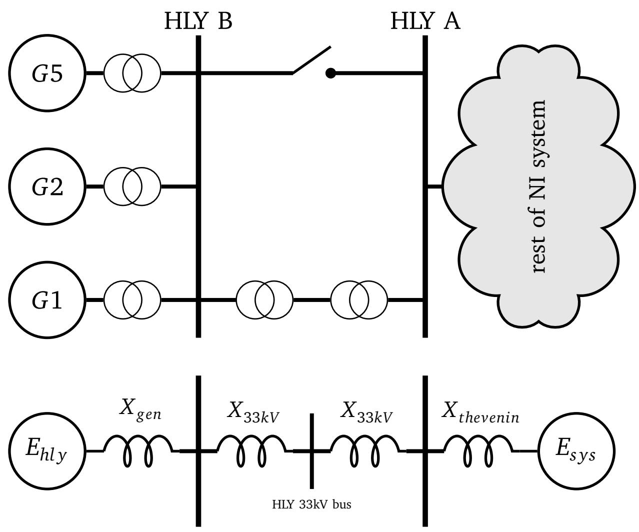

Fig. 7. Equivalent circuit after tripping of G5 and G2.

B. First principles model

In any complex event, it is best to start with the most basic model possible. This helps enable an understanding of what may have occurred and why. It also provides insight into what may be expected when using more complicated dynamic time-domain models and provides better understanding on how to prevent such things occurring in the future.

Figure 6 illustrates the situation at the Huntly substation immediately prior to G5 tripping. There are two electrical connections of the three generators to the system side (HLY A), one through `CB682`, `CB662` and `CB642`, and the other through two high impedance 220kV/33kV distribution transformers feeding into WELL Networks network.

An equivalent two bus system is also illustrated. Here, X_{gen} is the parallel combination of all unit transformers combined in series with each generators transient reactance. $X_{thevenin}$ is the thevenin equivalent system impedance.

Figure 7 illustrates the situation 2.7 seconds later following the tripping of G5, `CB682`,`CB662` and G2. Here, G1 is electrically connected through two 220/33kV high impedance[7] transformers.

In both figures, E_{hly} and E_{sys} indicate the approximate *EMF* behind the transient reactance of the Huntly machines and the rest of the NI system machines respectively.

Using the standard power flow equation (equation 1) we can get a rough idea of the pre and post states on the power angle diagram and, importantly, the effect of the increased impedance which appears to increase by approximately an order of magnitude[8].

$$P_e = \frac{E_{hly}E_{sys}}{X} sin\delta \tag{1}$$

An approximate power-angle diagram is illustrated in figure 8. Point A represents the operating point immediately prior to the loss of G5.

Following the trip of G5, the operating point slides down the sine curve to point B halving the power angle[9]. Several cycles later, `CB662` and `CB682` trip. G1 and G2 remain connected to the NI system through two series 33kV transformers. The operating point falls to point C. At this point, the maximum power transferable from the Huntly generators to the NI system is determined by the series impedance of the two 220/33kV distribution supply transformers. Without knowing exact numbers, a reactance of around 0.25pu for each distribution supply transformer has been used (on a 100MVA base). Including the estimated reactance of the system and machines would allow for a maximum transferable power of perhaps $\approx 150 - 170$MW. As the mechanical input power exceeds this, at 464MW, the power angle between the 220kV line side bus and the generating bus starts increasing as the machines start to speed up. Beyond 90^o, G1 and G2 lose synchronism, but remain electrically connected to the remainder of the NI system.

Figure 9 shows a measured frequency trace provided by Transpower, but plotted on time-stamped graph paper, at the Henderson substation in Auckland. The red lines indicate times when generation is tripped. The blue braces sum the wobble seen in the measured frequency for each of the following seconds.

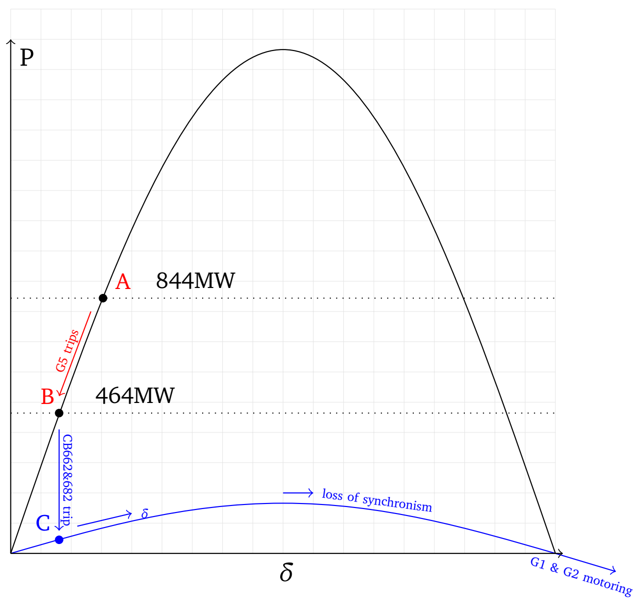

Fig. 8. Power–angle (P–δ) diagram

[7]Relative to the Huntly generators.

[8]Not knowing the exact numbers, we roughly assume: $E_{hly} \approx E_{sys} \approx 1pu$, $X_{pre} \approx X_{gen} + X_{thevenin} \approx j0.04 + j0.02 \approx j0.06pu$ and $X_{post} \approx X_{gen} + X_{33kV} + X_{thevenin} \approx j0.1 + j0.5 + j0.02 \approx j0.6pu$, all on a 100MVA base.

[9]This is a simplification as the power angle diagram will change due to the slightly higher impedance caused by the loss of G5.

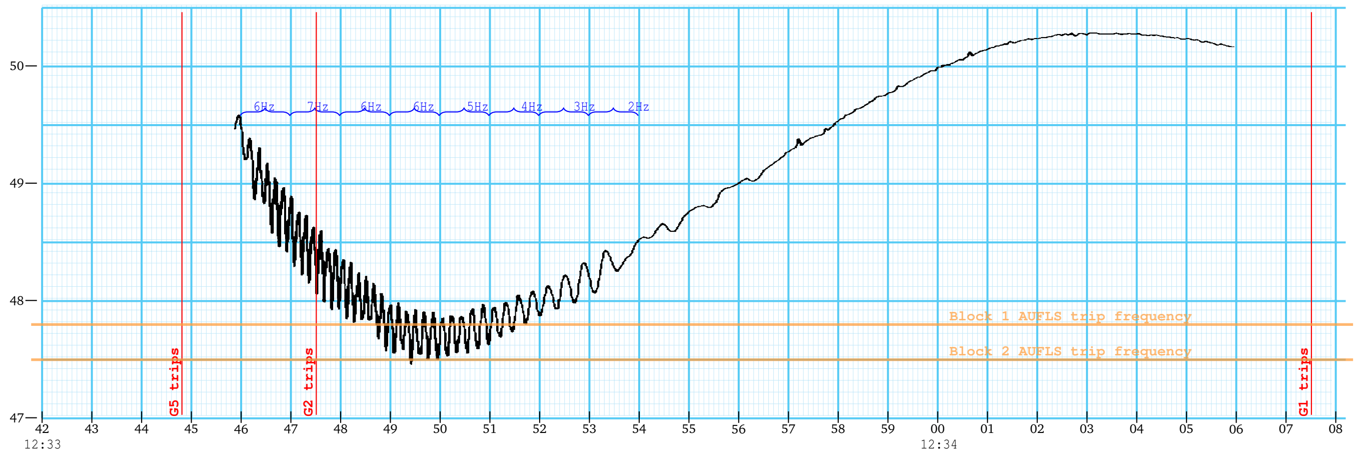

Fig. 9. Frequency trace at Henderson plotted on graph paper.

The loss of synchronism causes the power angle δ between the two connected systems to increase indefinitely[10]. This results in a large signal, ≈150MW, sinusoidal power perturbation at a frequency equal to the difference between the two system frequencies. For half the δ-angle cycle, the Huntly units are generating, for the other half they are motoring.

For G2 this lasts for several seconds, while for G1 this lasts around 9 to 10 seconds before it appears to either resynchronize with the NI system, or reduce its output power to near zero. In either case, at this point the mechanical input power to G1 is likely below the Pmax limit set by the series impedance to the two 220/33kV distribution transformers (i.e., <150MW).

The 10 seconds where the two systems were out of synchronism provides an ideal, real-life test of the NI power system and its response to a large signal perturbation. It is clear that a lot could be learnt about the characteristics of the North Island power system from this event.

C. Phasor model

Phasor diagrams are a great way to illustrate the basic relationships on the power system in the steady state. However, in this instance, with out-of-sync generators and a moving power angle, phase angle diagrams require a third dimension, time.

A simple model has been developed by Authority staff and will be presented during the EEA presentation. Figure 10 illustrates the modelled voltages and powers at Huntly at approximately 12:33:49 for around 333ms.

The blue and red voltage traces indicate the internal EMF of the system and Huntly G1 generator (E_{sys} and E_{hly}) respectively while the green trace indicates the modelled mid-point voltage on the 33kV bus.

The lower plot illustrates the modelled real (blue) and reactive (red) power transfer through the high impedance distribution transformers. As shown, G1 was generating and then motoring with an amplitude of ≈ 150MW.

D. Protection systems and impedance diagrams

With reference to figures 7 and 10 it is clear that, assuming equal magnitude internal EMFs, there will be times when the voltages are equal and opposite causing a zero voltage condition at the midpoint of the total series impedance.

[10]Assuming no change in mechanical input power.

This is illustrated on the 33kV bus (green line) in figure 10 where the voltage collapses to near zero. This has a similar appearance to a short circuit fault and can be detected using 'apparent' impedance type relaying[11].

Kundur [1] explains how impedance diagrams are used for protection in such circumstances[12]. The key is in understanding how the apparent impedance moves in a Locus (termed the swing Locus) on the R–X plane. This is related to the voltage (and resulting current) phasors that are continuously shifting in phase.

To protect against such 'swinging' conditions Kundur explains the use of mho element type relays with the use of 'blinders' or 'ohm' units used to help determine the trip region on the impedance diagram.

E. df/dt – the best way forward?

Frequency measurement devices measure the zero crossings of the sinusoidal voltage waveform[13]. On 13 December, there was an alternating power transfer, dependent on the frequency difference between Huntly and the NI system, into and out of the North Island power system. The transfer could have been as high as ±170MW (around ±5% of the NI demand at the time) and ranged in frequency from 7Hz falling to 2Hz.

[11]At zero current (assuming the two system voltages are equal), the impedance appears infinite.

[12]Kundur [1], page 914 onwards, describes how power system protection is set up under similar conditions to those that occurred at Huntly on 13 December.

[13]Or sometimes by more sophisticated methods such as FFT.

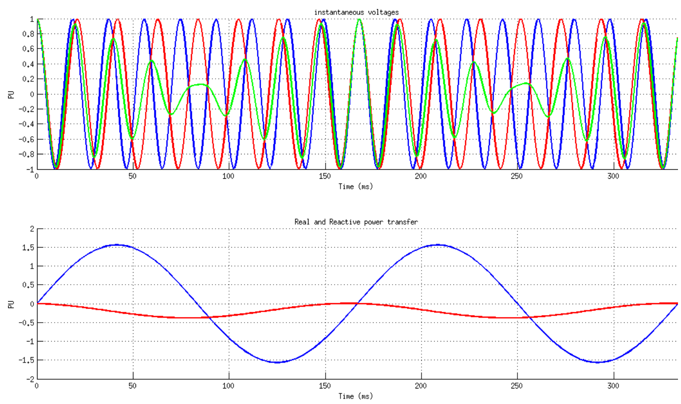

Fig. 10. Modelled voltages and power transfer at Huntly.

The result was a power-angle (δ) perturbation throughout the North Island that directly effected the voltage angles, reducing in magnitude the further away from Huntly (i.e., the source of the alternating power injection). In this instance, the effects were seen in frequency traces as far away as Haywards.

Such oscillations appear as localised frequency deviations wobbling around the average system frequency. A quick calculation shows that such a frequency perturbation is clearly not the average system frequency. The simplified general equation of inertia is: [2]

$$\Delta P \approx M \frac{df}{dt} \tag{2}$$

where df/dt is the frequency change in Hz/s, ΔP is the power change (pu on a 100MVA base), and M is the inertial constant in seconds. Using figure 9 (ignoring the frequency wobble), $df/dt \approx 0.75Hz/s$ (0.015pu/s) and $\Delta P = 3.8pu$. This gives an inertial constant, M, of around 250 seconds. Substituting this back into the equation and solving for the steeper slope caused by the power-angle perturbation, (up to $\approx 5Hz/s$) seen in the frequency trace would require a power perturbation of over 25pu, or 2500MW! It is therefore clear that the measured frequency is not average system frequency, but rather the result of power-angle wobbles affecting the voltage zero crossings.

As frequency is measured using zero crossings of the voltage phasors, any phase angle wobble directly affects frequency measurement and can interfere with the operation of the AUFLS relays.

All AUFLS relays will have some sort of guard band or averaging employed. During the event, the average system frequency fell below 47.8Hz.

Where the wobbles were greatest in magnitude (anywhere electrically close to Huntly) it appears that the AUFLS relays have reset, as the larger wobble has lifted the frequency above the guard band for a short period of time, and hence not tripped the relay. This can be seen in figure 9 at Henderson where the frequency trace falls below the AUFLS block 1 trigger frequency and then wobbles back above the limit (first orange line).

Where the wobbles in frequency are smaller, the AUFLS relays have not reset and have tripped. This is likely why some, not all, of the AULFS relays tripped. It should be noted that the AUFLS relays likely worked *exactly as they were designed*. The result was that many of the AUFLS relays some electrical distance away from the event location, Huntly, did trip. Many tripped in the lower half of the North Island and contributed to creating transmission constraints throughout the Lower North Island. This, among other factors, had impact on the spot price market following the event and is further discussed in section VII.

The System Operator is currently investigating a change in the way AUFLS operates. One current suggestion is to use rate-of-change-of-frequency (RoCoF) relays. These relays, also known as df/dt relays are able to sense the rate of change of frequency and trip demand sooner. The System Operator is currently testing these relays for use in the New Zealand power system. In the authors' view, it is unclear, after the events on 13 December, whether df/dt relays are an appropriate solution for New Zealand's small island networks since df/dt (RoCoF) would be even more sensitive to such power-angle perturbation effects. Many questions still remain and any change from the current simple system will require a great deal of care and appropriate testing.

VII. Market effects

The Authority has completed a market performance review investigating the operation of the spot electricity market following the sudden unplanned disconnection of generation at Huntly[14].

The Authority's review identified several shortcomings in the spot electricity market following this major disturbance event. Although this could be thought of a one-off event, several of these issues are reoccurring and related to other events throughout the year. The 13 December event therefore provides a template for the discussion of these reoccurring issues.

A. Price uncertainty

Under the current electricity market rules, indicative spot electricity prices are provided to market participants before and during the trading day, however, the final prices used for payment in the spot electricity market are not known during this time. The final prices are only calculated after the relevant trading day.

On 13 December, the final spot electricity prices differed, sometimes significantly, from the indicative prices following the disconnection of Huntly generation. Figure 11 illustrates the calculated final prices for trading period 27 (1pm) on the 13 December. In contrast, the maximum real-time price observed during this time was under \$1000/MWh.

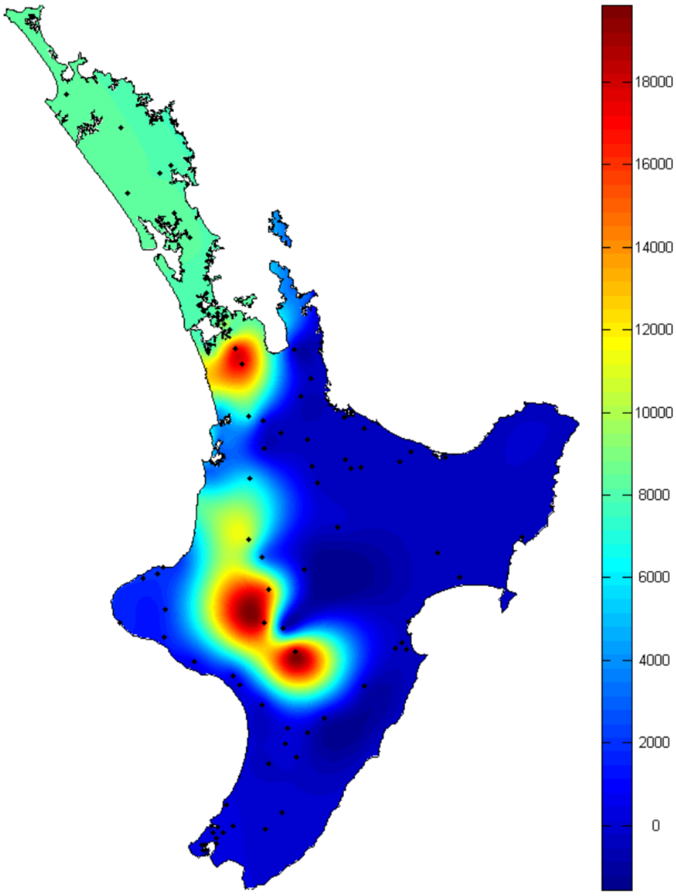

Fig. 11. Final prices for Trading Period 27, 1pm, on 13 December.

The divergence between the indicative and final spot electricity prices increases the uncertainty faced by market participants exposed to spot electricity prices and reduces their ability to make efficient consumption and production decisions based on observed indicative prices.

The Authority's review proposes a migration to a final pricing process more aligned with the actual system conditions.

[14]Available at http://tinyurl.com/dec13review.

The review also recommends providing indicative forecast prices to participants, based on a range of demand forecasts, to indicate forecast price variability.

B. Price suppression

The system operator reduced the North Island reserve requirements to zero for approximately two hours following the disconnection of Huntly generation due to the automatic reduction in the availability of offered reserve capability. This automatic decrease was due to the automatic response of reserve providers following the sudden disconnection of Huntly generation. As reserve providers who responded would have difficulty in complying with dispatch instructions for reserves immediately following the event, the system operator reduces the reserve requirements to zero, thus not dispatching reserves.

The spot electricity market prices in the North Island were suppressed when the North Island reserve requirements were reduced to zero, as observed in Figure 12. Reducing the prices during this time is the incorrect economic signal when there was a requirement for an increase in the supply of energy and reserves, implying a high energy and reserve price. The suppressed spot electricity prices also reduce revenue to last resort plant, thus reducing incentives for the efficient provision of last resort resources.

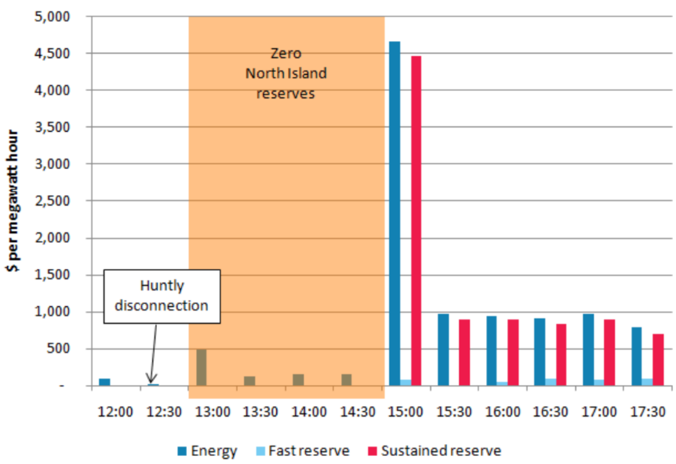

Fig. 12. Haywards energy and North Island reserve prices between 12:00 and 17:30 on 13 December 2011

The Authority's review recommends reducing the supply of offered reserves rather than the demand for reserves, as an alternate solution to the information asymmetry between offered and available reserves in the market. The benefits of the Authority's alternate treatment are that reserve dispatch is maintained and the spot energy and reserve prices increase to reflect the increased value of energy and reserve supply during this time.

C. Multiple potential prices

The scheduling, pricing and dispatch (SPD) model is used to efficiently dispatch resources and calculate prices within the New Zealand spot electricity market. When SPD cannot satisfy all the model requirements, the solution is termed infeasible and produces infeasible prices.

When infeasibilities are produced during the calculation of final prices, an infeasibility resolution process is invoked. This process involves adjusting inputs into the final pricing calculation to remove the infeasibilities and infeasible prices. Such a process was invoked for seven trading periods on 13 December 2011.

The Authority's review has determined that the current infeasibility resolution process, for one of these trading periods could have produced multiple pricing outcomes. This reduces the robustness and repeatability of the current pricing process.

The review proposes a model-based approach that resolves the infeasibilities with minimum adjustment to the model inputs. Such an approach would be more objective, reduce the potential for multiple potential prices and increase the authoritativeness of the pricing process.

D. Market impact of Huntly station risk

The system operator treated the entire Huntly power station as a single risk to the power system when it was reconnected to the grid on 13 December 2011 with additional reserves procured in the spot electricity market to cater for this increased risk. The system operator removed this requirement at 18:00 on 14 December 2011.

The increased risk requirement could only be represented as a manual risk within the current market system. The implication was a loss of co-optimisation between the energy and reserve markets.

The market impact of this increased risk and loss of co-optimisation resulted in an increase in the North Island reserve price and a reduction in the North Island energy price relative to a co-optimised approach. The co-optimised approach would have enabled a more efficient trade-off of resources between the energy and reserve markets.

Maintaining a co-optimised energy and reserve market whilst enabling multiple risks could also have benefits during other scenarios, such as accurately representing the market trade-offs during commissioning of new generation assets. These expected benefits need to be considered relative to the costs of such a development to the market system.

VIII. Summary

This paper has provided a review of various issues related to events that occurred in the New Zealand power system during 2011. Huntly features prominently, starting with constrained on payments in January, a price spike in March and finally the events of 13 December.

The 13 December event has, from both a technical and market perspective, provided valuable lessons for the New Zealand power system.

In terms of the technical aspects, the 10 seconds of asynchronous connection of the Huntly generators provided an unusual and certainly interesting real-life test of the resilience of the power system. Aside from the multiple failures that resulted in the event, the AUFLS relays functioned as they were designed. Following this event it is unclear whether the benefits in future use of df/dt, or, RoCoF relays for tripping AUFLS will be appropriate for New Zealand's small power system.

In terms of market issues, better alignment of the market model with the physical power system would appear to solve a number of issues that have appeared throughout the year. In addition, the market review into the 13 December event highlights a potential systemic issue within the current market structure where several pricing functions are split across the pricing manager and the system operator. The review proposes an investigation into the current functional allocation between the pricing manager and the system operator to determine if this mix best delivers an efficient pricing process for the New Zealand spot electricity market. These issues would need to be prioritised within the Authority for further development together with industry consultation.

References

[1] *Power System Stability and Control*, Kundur, McGraw-Hill, Inc, 1994.
[2] *Estimation of WECC System Inertia Using Observed Frequency Transients*, D. P. Chassin,Z. Huang,M. K. Donnelly,C. Hassler,E. Ramirez,C. Ray.