Under Frequency Management

Work Stream 1:

Reserve Review Phase 1

System Operator

5/08/2011

SYSTEM OPERATOR

TRANSPOWER

Keeping the energy flowing

	Position	Date
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Reviewed By:		

This report and the appendices are available to download from the System Operator website at www.systemoperator.co.nz

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1 Executive Summary

In 2010, the System Operator conducted a technical review of the existing Automatic Under-Frequency Load Shedding (AUFLS) scheme to evaluate the scheme’s ability to cover identified large risks given the changing nature of New Zealand’s power system. The technical review highlighted that while the current AUFLS system is sufficient for known risk, it is likely to be ineffective at recovering the system from a number of high impact low probability events. The review also identified the need to improve the way reserves are currently procured and utilised, and to research options for other products.

The System Operator and the Electricity Authority, in line with the industry Common Quality Development Plan, agreed to review the Under-Frequency Management arrangements. The purpose of the Under-frequency review was to propose strategies and measures that offer the most reliable, secure, and cost effective under-frequency management system to provide greater certainty on system integrity during major under-frequency events, and to operate an efficient market

The project included three work streams: a review of instantaneous reserves; stage II of the AUFLS review; and a review of asset owner performance obligations. This paper sets out the results of the reserve review work stream undertaken by the System Operator as part of the Under Frequency Management review.

The review included the various assumptions used in the System Operator’s Reserve Management Tool (RMT) to calculate reserve procurement quantities. The System Operator recommends the following improvements to the modelling within RMT:

- Changing the current 60 second simulation in RMT to 10 second
- Modelling the actual delivery times and quantities for Interruptible Load
- Using the actual HVDC transfer limit of 250 MW rather than the modelled 25 MW

The above changes will have an impact on participants with respect to data resolution and the likely occurrence of more severe under-frequency events. As such, industry endorsement of the changes is critical, and software, code, and procurement contract changes are likely to be necessary before the changes can be implemented.

The System Operator has also concluded that a mix of reserves is essential and beneficial for managing system disturbances. Therefore, to retain an appropriate mix of products and ensure provision of one type of reserve is not inadvertently incentivised over another, a transparent approach for all reserve providers for testing and monitoring is desirable.

Further, as the New Zealand power system changes and evolves, more changes in its generation mix are expected. It is expected that with higher HVDC transfer, the frequency will reach its minimum in less than the mandated 6 seconds. The System Operator therefore recommends further investigation of faster reserve products such as faster operating IL, df/dt operated reserves, faster spinning reserve, and system inertia.

2 Introduction

Robust under frequency management plays a significant role in operating a secure and cost efficient power system. Poor management can lead to high procurement costs of frequency management products, inefficient demand interruption, or, in the worst case, cascade failure of the system. The current under frequency standards are achieved mainly through a combination of mandated generator and HVDC owner obligations, procurement of instantaneous reserves (IR) and mandated automatic under frequency load shedding (AUFLS) obligations.

The System Operator has recently completed and presented a technical review of the current AUFLS arrangements. The review identified that the current AUFLS scheme would require enhancement for optimal operation in the event of significant system disturbance. The review also demonstrated the need to re-evaluate the present reserve market and to seek faster operating reserve products that also interact well with AUFLS.

Investment in grid infrastructure, in particular HVDC Pole 3 and the new technologies considered in proposed generation investments, further underline the need for a review of the current reserve arrangements and the opportunities to create a national reserve market. In addition, the increasing number of generators with little or no inertial contribution also necessitates a review of the existing operating standards and practices to ensure they are appropriate.

All of these complexities have led to questions over whether the current arrangements for managing under-frequency events are appropriate and optimal. The arrangements in question include the following:

- the suitability of current instantaneous reserve products
- the amount of instantaneous reserves procured
- current AUFLS availability and arrangement
- asset owner's and HVDC owner's obligations
- under frequency standards set out in the Reserve Management Objective (Schedule 8.4 of the Code)

The disestablished Common Quality Advisory Group carried out a study on potential under frequency development work using an evaluation framework which included a quantitative analysis. The assessments projected that an under frequency management project is estimated to have an indicative net benefits value ranging between $17m to $73m, lower and upper bound respectively.

Consequently, in November 2010, the System Operator and Electricity Authority agreed that the System Operator would undertake a detailed review of the current under-frequency arrangements. The System Operator has completed the engineering studies and is seeking input from the Electricity Authority and industry participants on the results outlined in this report.

2.1.1 *Providing comments to the System Operator*

The System Operator request comments on this report's findings by Friday 16 September 2011 so that it can continue the next phase of work. We will also take account of any feedback received at our upcoming workshops on the 8, 10, or 12th of August 2011. Appendix 9 contains a feedback questionnaire that we would appreciate being completed and returned to the System Operator.

The System Operator's preference is to receive submissions in electronic form. The electronic version should be emailed with the phrase "Submissions on UFM:

Reserve Review" in the subject header to Ina.Ilieva@transpower.co.nz . Hard copies can be posted to the following address:

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Transpower New Zealand Limited
Level 7, Transpower House
96 The Terrace
PO Box 1021
Wellington
New Zealand

The System Operator will acknowledge receipt of all submissions electronically.

The System Operator values openness and transparency and therefore comments will be published on the System Operator's website. Those providing comments should discuss with the System Operator any intended provision of confidential information, prior to sending the information.

3 Objective and Scope

The purpose of this review was to determine strategies and measures that offer the most reliable, secure and cost effective under frequency management model to provide greater certainty on system integrity during major under frequency events, and to operate an efficient market.

The first phase of the project was to:

- Evaluate the existing components and mechanisms of the current reserve market
- Investigate alternative technologies to improve the way reserves are procured and utilised
- Further the work from the AUFLS technical review to seek technically and economically viable arrangements that will ensure that frequency management products better meet the requirements of the power system
- Review under-frequency performance objectives
- Review asset owners' obligations.

The reserve cost allocation methodology was not reviewed. Any implementation of the recommendations in this report is beyond the scope of this project. Any implementation will be delivered separately.

The work is divided into three work streams:

- Work Stream 1: Instantaneous Reserve
- Work Stream 2: AUFLS Stage II
- Work Stream 3: Asset Owner Performance Obligations (AOPOs) and Principle Performance Obligations (PPOs)

This report describes the analysis and results for:

- Work Stream 1: Instantaneous Reserve.
- Work Stream 2: AUFLS Stage II is also completed in draft and will be published as a separate report concurrently with this report.
- Work Stream 3: AOPO and PPO review is currently underway and is due to be completed over the next few months and results will be published.

An Executive Summary for the Collective Review for the entire review will then be published together with the final reports for each Work Stream.

Work Stream 1: Instantaneous Reserves

4 Purpose and Scope

This work stream examined the current reserve modelling and potential alternative reserve products and arrangements better suited to manage New Zealand's reserve needs.

The report provides an initial review of the findings by the System Operator for the reserve review conducted. The System Operator seeks to inform and enable industry conversation and feedback that will allow a clear set of recommendations to be endorsed by the industry in the final report.

This review of the instantaneous reserves included:

- Studying historical contingent events to identity the reasons why the actual frequency response is often considerably different than the modelled outcome
- Reviewing and modifying (when deemed appropriate) the modelling philosophy and assumptions employed in the existing reserve management tool (RMT) to make the modelling better reflect reality. In particular, HVDC reserve sharing, IL modelling, FIR simulation time, time-based load modelling, North Island net free reserve (NFR) hydro assumptions
- Researching opportunities and possibilities for other classes of reserve products that are technically feasible and investigate ways to accommodate these in the reserve market including:
  - Very fast reserve products
  - Machine inertia (as a potential instantaneous reserve product)
  - Df/dt related reserve products
- Summarizing the findings, their plausibility, and the possible implications for electricity industry participants

5 RMT Performance Analysis

5.1 Background and Introduction

RMT is the System Operator's software used to estimate and schedule the reserves needed in the system to keep the system frequency within the levels prescribed by the Reserve Management Objective. RMT provides an automated process for reserves management and contains a detailed model of the New Zealand power system.

RMT models the frequency response of the power system, in advance of real time, by tripping a critical amount of generation supply and schedules reserves accordingly. The amount of generation RMT will trip equates to the largest amount of supply (generation or HVDC) that is likely to be lost in a single event.

A loss of generation is called an "event". The types of events are defined as Contingent Events (CE) for a loss of a single generating unit or a single HVDC Pole and as Extended Contingent Events (ECE) for loss of a bipole, a bus bar, or an interconnected transformer.

The frequency for a CE must not go below 48 Hz. CEs are covered by reserves. For an ECE, the frequency must not drop lower than 47 Hz in the North Island and 45 Hz in the South Island; these events are covered by reserves and AUFLS. A definition of CE and ECE, as set in the Code, and a list of CEs and ECEs events are given in Appendix 1, The Glossary.

The RMT contains governor models of generators in the power system that have provided an asset capability statement to the System Operator. These are modelled calibrated to the test data supplied by asset owners. Models of interruptible load, uncontrolled load, AUFLS blocks and a simplified model of HVDC are also included.

The instantaneous reserve (IR) products currently available are divided into two types: Fast Instantaneous Reserve (FIR); and Sustained Instantaneous Reserve (SIR). More information about the definitions of FIR and SIR can be found in the Appendix 1. FIR response is required 6 seconds after an event and must be sustained for 60 seconds; it is intended to stop the frequency from falling below 48 Hz. The FIR MW values are modelled in RMT. SIR is used to restore the frequency to 50 Hz. It is calculated on the average output over the first 60 seconds following an event and is sustained for 15 minutes. At present, SIR values are not calculated; they are replaced on a one to one basis with MW lost. The IR is offered as interruptible load (IL) and spinning reserve. IL FIR is required to trip within 1 second of the frequency reaching 49.2 Hz. A detailed description of how RMT works, with relevant examples, is given in Appendix 2.

There have been a number of concerns raised about the amount of reserve procured in relation to the quantity required. These concerns are based on the fact that the frequency in an under frequency event rarely reaches the target frequency for the event. To address these issues, and to initiate wide industry consultation, the Electricity Authority selected twelve under frequency events in the North Island and six in the South Island for the System Operator to analyse. The events were selected as representative of typical frequency excursions. In all events the frequency reached was in the range of 49.24 Hz to 48.6 Hz.

The analysis undertaken sought to investigate the validity of the assumptions RMT makes when calculating the reserves, and to the extent to which a change in any of these assumptions impacts on the calculated reserves quantities. Once quantified and assessed, the assumptions were then further investigated for changes. Recommended changes have been summarised for wider industry discussion

5.2 Methodology for Assessing the Assumptions in RMT

RMT calculates procurement quantities using a number of assumptions. For the purposes of the current work, the following assumptions have been examined:

- A calculated risk in MW (the ‘risk setter’) that may be different from the actual MW lost from the power system during the actual event
- A scheduled quantity that may be different from the actual dispatch quantities for the trading period (due to the iterative nature of the RMT calculation)
- A dispatched quantity of IL that is almost certain to be different from the actual quantity that trips during an event
- A modelled HVDC response

There is also an ‘unknown component’ which covers any, or a combination, of any other discrepancy between the actual and the modelled (calculated) frequency. It could not easily be associated with any particular causer or specific difference.

Each of the eighteen selected events caused the frequency to drop below 49.2 Hz in the respective island. The analysis used the original RMT case as a base case on which the assessment of the different assumptions is built.

Because all assumptions are used by the model simultaneously and form the end result as a package rather than individually, it was considered appropriate to change one assumption at a time and assess the impact of changing that assumption on the overall solution. Whilst the first assumption change would be assessed against the change in the base case solution, each subsequent assumption would then be tested based on the *incremental* effect of the change on the solution (rather than each against the base case). The cumulative manner in which the evaluation was done across a variety of cases ensures that the impact of the assumptions was not solely taken on a specific case but spread over the selected cases.

The full study report can be found in Appendix 3.

5.3 Results

A) Calculated risk versus actual event

The RMT takes the generator with the largest scheduled energy and reserve output as a risk setter to calculate how much reserve is necessary to be purchased for the AC CE event. For DC CE events, it takes the loss of an HVDC pole. In reality, an under frequency event may be caused by generation loss other than the calculated risk, thus changing the MW value of the actual initiating event. The first step in analysing the RMT performance is to evaluate the impact of this difference.

In the studies performed, the actual MW tripped replaced the calculated risk MW in the original RMT market case. The difference between the calculated RMT frequency and the target frequency (for a CE event it is 48.0 Hz) is taken as the absolute percentage deviation for this case and is caused solely by replacing the calculated risk MW with the actual MW lost. The value of the deviation (or error[1]) caused by the difference in the machines was then calculated as a percentage of the real time frequency error: the actual minimum frequency reached for the event and the target frequency 48.0 Hz. The deviation can be both negative and positive and the validity of the assumptions is thus assessed as an absolute rather than positive or negative value.

The differences between the calculated and actual risk were significant. For the North Island, the average deviation is 39%. For the South Island, it is 59%. This result confirms that the difference between the calculated maximum risk to the system versus the actual size of the initiating event translates into a substantial difference between procurement quantities and actual requirements.

B) Generator actual output versus scheduled output ('actual system')

Following the analysis in A), the real MW output of each machine at the time of the event was loaded into the cases, replacing the scheduled quantity. The data was extracted from PI[2] for the particular time. To keep the system inertia consistent with the original RMT case, the number of machines at each station was adjusted according to the actual data at the time. The adjustment had a two-fold effect:

- the RMT system load matched the actual load at the time of the event; and
- the available reserve is maximised.

During an RMT run, the RMT calculates the number of machines for each station based on the energy and reserves offered. In doing so, RMT assumes there is available capacity for reserves. In reality, the number of machines at each station may be different from that assumed because of station and block dispatch. The frequency deviation calculated is a result of the different inertia on

[1] The term "error" is the mathematical expression of the deviation

[2] PI is a software tool which archives SCADA information for easy retrieval at a later date. It is used by Transpower for accessing historical data and analysing and trends from a wide variety of inputs

the system and the difference in the available reserves. The same approach was applied to the TWD units.

The difference between the calculated and actual solutions was again significant, making a significant contribution to the procurement quantities - for the North Island, this deviation is 26% and in the South Island it is 21%.

C) Tripped IL versus dispatched IL

Following the analysis in B), the actual tripped load (IL) for the event was replaced for the events in the North Island and the frequency response error was again calculated compared to the previous case. The IL is offered conservatively and this often leads to more IL tripping than that offered. In practice, the effect of more delivered IL is higher than expected frequency.

The percentage of deviation attributed to the difference between dispatched and tripped IL is approximately 14%.

There is no IL in the South Island. Therefore, no changes were made to the South Island cases.

D) HVDC Response

The North Island and South Island models are connected by the HVDC Bipole model. The HVDC Bipole model contains “Frequency Stabiliser” and “Spinning Reserve Sharing”. However, each island’s frequency response is calculated independently of the other island. The HVDC controls (also modelled in RMT) then modify the Bipole power transfer to counteract frequency fluctuations in either island.

The HVDC model is limited by maximum and minimum transfer limits provided by the HVDC owner. It is clamped to a maximum of +/- 50 MW in winter and +/- 25 MW in summer to give a modest reduction in the FIR required for generator risks.

In reality, the HVDC is able to respond to +/-250 MW. Replacing the clamped response with the actual capability was analysed - the actual HVDC response was introduced and the deviation in the frequency was calculated using the same methodology previously used in A), B) and C). The average percentage deviation for the HVDC response is 15.12%.

E) The unknown component

The unknown component consists of all other factors which affect the RMT calculation. These include but are not limited to the load-frequency response, the impact of the voltage, the effect of the system inertia, the speed of the governor responses, the IR SIR, etc. The contribution to the error of the unknown component is considered to be the balance of the difference between calculated and actual frequency for the solution.

5.4 Conclusions

The investigation of the RMT performance in the selected events showed that there is a margin between calculated (RMT) and actual frequency. A graph representing the studied cases is given in Figure 5-1. The margin between calculated and actual frequency has been identified as the impact of the different assumptions on this deviation. Figure 5-2 gives the results of what RMT could calculate if all assumptions were able to be modelled as they manifested in real time. The overall impact of the studied assumptions is summarised in Figure 5-3 below.

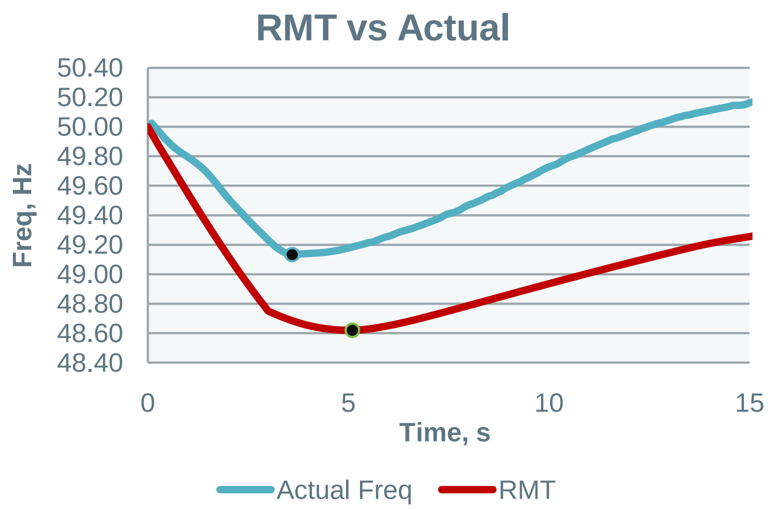


Figure 5-1 An example of the deviation between calculated and actual frequency

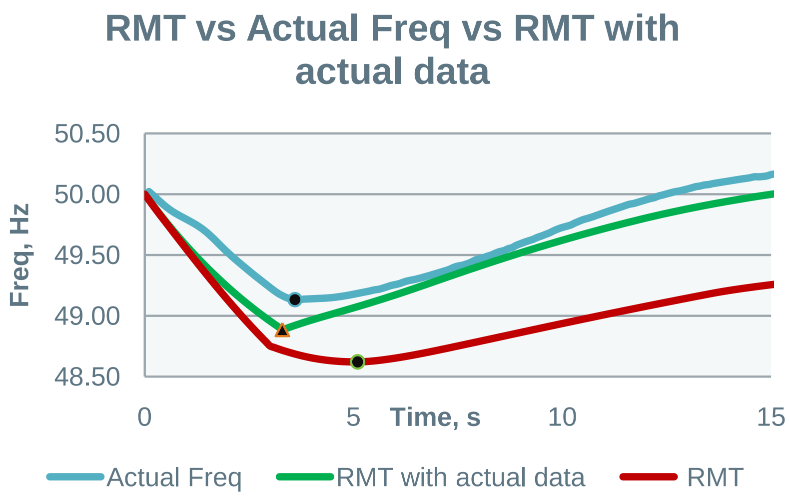
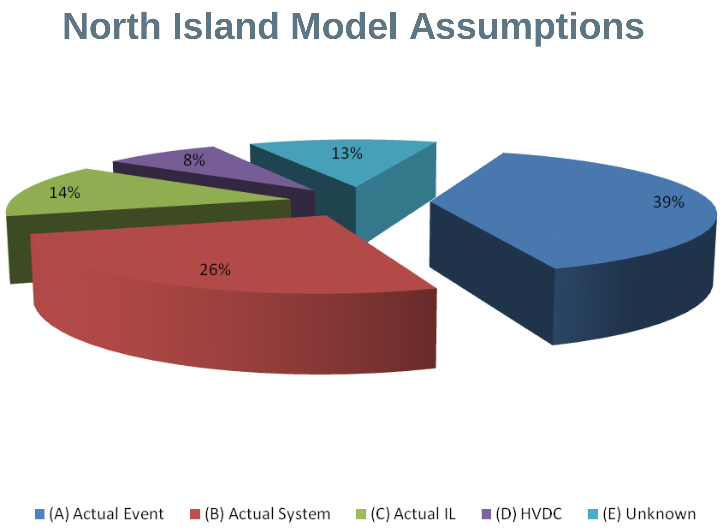


Figure 5-2 An example of the RMT result with actual data (as opposed to assumed) as in A), B), C) and D) above



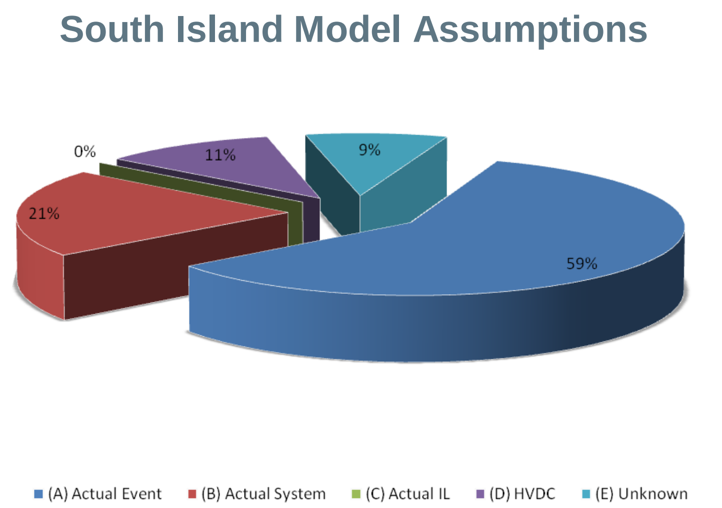


Figure 5-3 Evaluation of the impact of the different assumptions by RMT

The graph indicates that the most significant deviation between calculated and actual frequency is caused by the initiating events being different from the calculated risk (A). For the North Island, the average deviation is 39%. For the South Island, it is 59%.

The second largest contribution is caused by the actual dispatched quantities differing from the schedule. The deviation is a result of what RMT assumes is available and what is actually generating. For the North Island, this deviation is 26% and in the South Island it is 21%.

The impact of actual versus dispatched quantities for IL result in a deviation of 14% in the North Island. There is no IL for South Island.

The impact of the HVDC clamped response accounts for 8% of the deviation in the North Island and 11% - in the South Island.

The analysis showed that overall, the mismatch between schedule dispatch and actual dispatch, combined with the difference between calculated risk and the actual event, makes the largest overall contribution to the mismatch: approximately 65% for the North Island; and 80% for the South Island. RMT tends to be conservative. The assumptions are inherent in the calculation and are as a result of how the software iterates with SPD. As such, there is little that can be done to reduce the impact of such assumptions without making substantial changes to the software and potentially the market.

A difference between calculated and actual frequency in under frequency events may, at times, result in more reserves being procured than is required for an actual event on the power system (noting it could also result in less reserves being procured than required). The investigation has demonstrated that some of the modelling assumptions can be changed to positive market effect.

However, there is a reasonably high risk that making such changes, in some circumstances, is likely to reduce the reserve margin that exists as a direct result of the difference between calculated and actual reserve requirements. This margin essentially acts as a 'buffer' from the effects of sudden generation loss from the power system. Therefore, removing the margin is likely to lead to more significant[3] frequency excursions and possible AUFLS tripping. A wider industry discussion is recommended that includes consideration of the existing System Operator PPOs.

[3] Higher magnitude and/or of longer duration

6 Changes to Reserve Modelling

Whilst there is little that can be done to the existing software to reflect the actual initiating event (as opposed to a calculated risk) or the actual dispatch quantities, the investigation highlighted some areas where improvement in the RMT modelling (with respect to the assumptions analysed) would allow more cost-effective procurement of FIR. The full study report is presented in Appendix 3.

6.1 Using the Actual DC frequency limit

The RMT currently models the ‘other’ island response to a frequency event (via the HVDC) by assuming that the ‘sending’ island has no reserves. The System Operator has investigated the effect of the actual HVDC response of +/-250 MW. The expected performance is presented in Figure 6-1. Modelling the actual response will also require the System Operator to model the inertial and damping response of the non-event island

The graph in Figure 6-1 below shows a typical gain in response from raising the HVDC transfer limit.

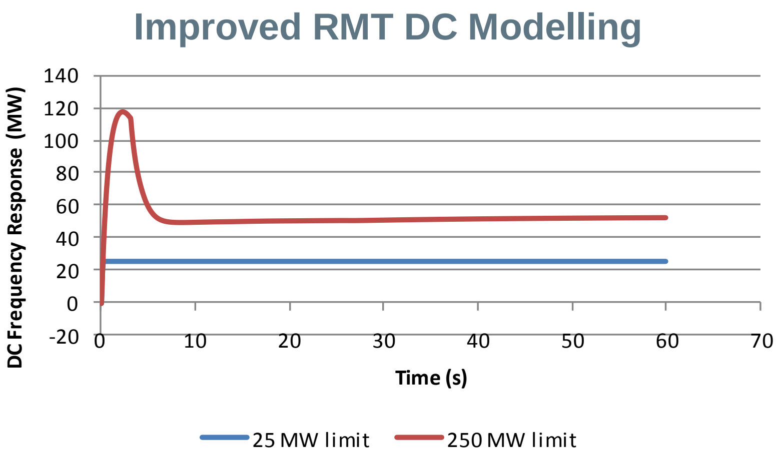


Figure 6-1 Improved RMT with actual DC modelling

6.2 Modelling IL reduction curve

FIR IL reserve is required to trip 1s after the system frequency has reached 49.2 Hz. SIR IL is the average drop in load over 60 seconds. In reality, quite a high proportion of this load (both FIR and SIR) trips after about 400 milliseconds. The amount of IL tripped is often higher than dispatched as a result of the IL provider compliance obligation in the code to meet the dispatched quantities. The higher-than-dispatched IL quantities and the faster trip time than modelled are estimated to result in a higher frequency than is modelled by RMT.

To better calculate the FIR requirements, the actual time at which the load trips ought to be modelled by the System Operator. This will require IL providers to test and continuously monitor IL at a data sampling rate of 100 milliseconds (see paragraph 6.4 on data resolution).

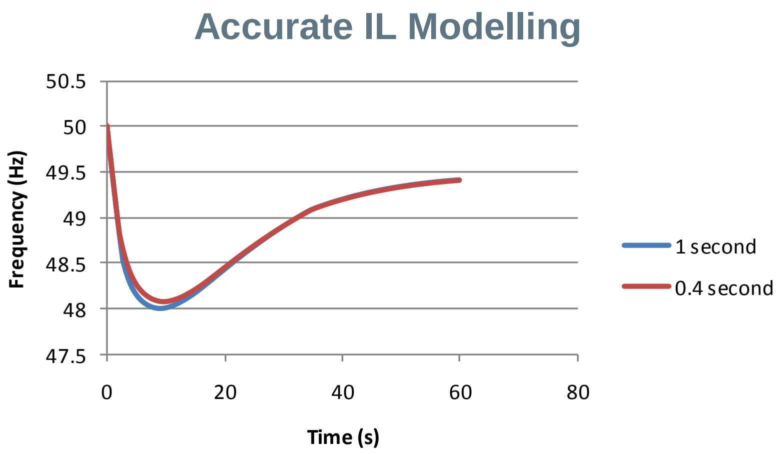


Figure 6-2 Effect of accurate IL modelling

The graph in Figure 6-2 above shows an expected average decrease in reserve procurement quantity of 8% depending on the system conditions.

6.3 Reducing RMT time simulation from 60 seconds to 10 seconds

RMT iterates to calculate the amount of reserves (FIR) required to stop the system frequency falling below 48 Hz in 60 seconds but uses a reserve product that is 'clamped' at its 6 seconds value. RMT does not model SIR response. This means that RMT assumes a reserve response over 60 seconds that is equal to the response over the first 6 seconds, when, in fact, governor and IL SIR responses will actually restore the frequency back to its normal operating range well within the 60 seconds period.

A representative graph of how FIR and SIR are delivered is given in Figure 6-3. The graph is for illustration only and is not associated with any particular generator or output values.

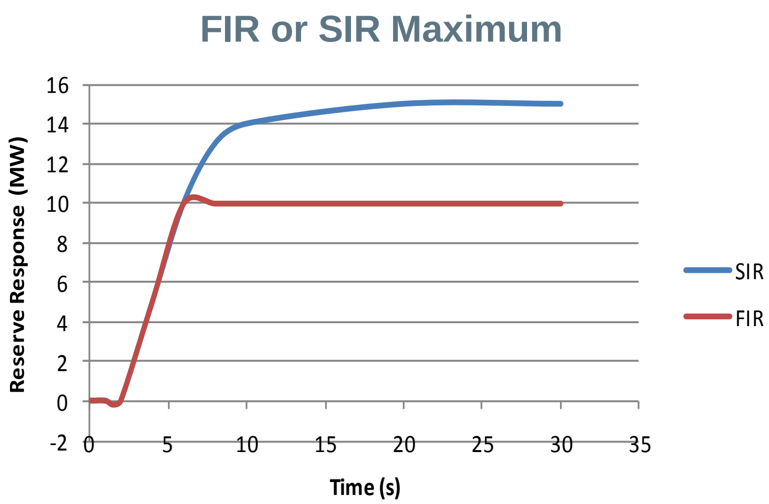


Figure 6-3 FIR and SIR Response

The red line shows the governor response limited to its FIR value and the blue line shows its actual value, which is assumed to be the SIR dispatch without the limitations at the 6 second FIR values. If the 6-second clamp on the machine was removed, the generators would be modelled as responding to their maximum outputs (inclusive of SIR response).

A representation of the difference between the existing under-frequency curve and the RMT simulations is presented in Figure 6-4 In reality, the blue curve reaches a minimum of 48.45 Hz within a short time before reserve response (FIR and SIR) return the frequency to the normal band, meaning less FIR is required than procured for the event.

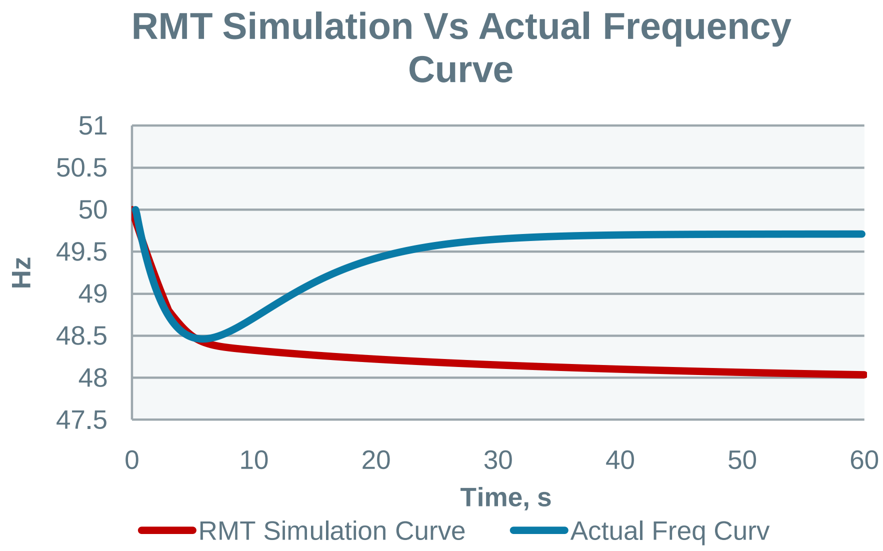


Figure 6-4 An example of the existing RMT curve and the actual 60s response

The System Operator suggests modelling a 10 second response instead of a 60 second response. Modelling a 10 second response for a 6 second product is likely to be more accurate in most cases than modelling a 60 seconds response for a 6 second product. In other words, the System Operator recommends the industry considers procuring reserves calculated on a 10 second basis rather than a 60 second basis. An example is given in Figure 6-5 below.

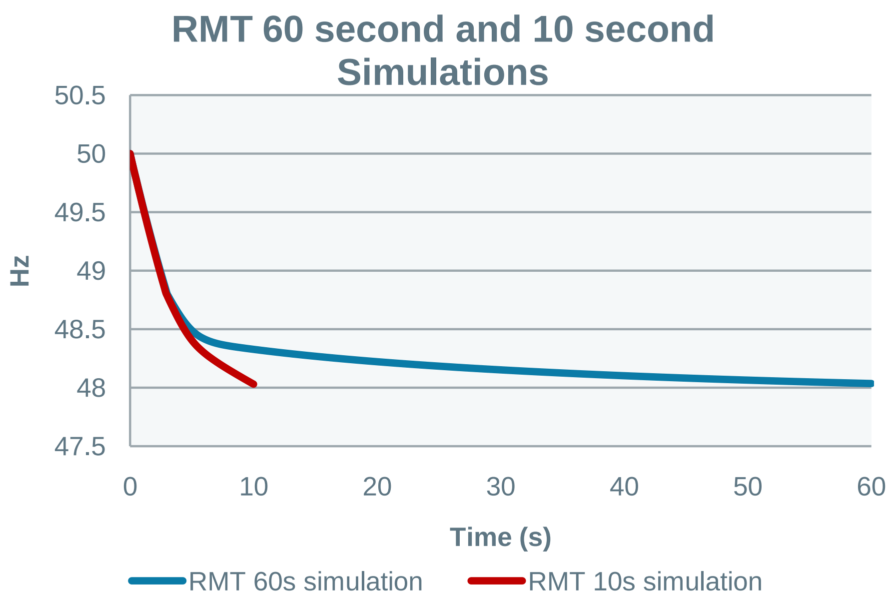


Figure 6-5 An example of an RMT simulation at 60 second and 10 second

For a 10 second simulation to deliver the required gains without affecting system security, the System Operator needs to rely on the majority of dispatched SIR being delivered within 10 seconds. This currently occurs in practice for some reserve providers but is not mandated by the codes or monitored by the System Operator. If the System Operator can rely on dispatched SIR being produced by 10 seconds this would provide a simple means to ensure system security is not unduly affected by late delivery of the majority of dispatched reserves.

A more detailed investigation into SIR response over 10 seconds (and any resultant modelling requirements in RMT) is required before the System Operator recommends changing the simulation time from 60 to 10 seconds.

Ideally, in the longer term, the System Operator believes it needs to be able to model SIR as well as FIR. This is not currently possible with the existing software. Modelling SIR causes solution instabilities and oscillations between RMT and SPD. More information can be found in Appendix 4. However, a detailed investigation into ways of modelling both FIR and SIR should be part of any project to replace the existing software (RMT).

6.4 Data Resolution

The current provisions for monitoring do not allow the System Operator to be confident when modelling the asset response by reserve providers. The post-event data received is often filtered, inaccurately time stamped and with low data resolution (1 second, 6 second and 10 seconds). The filtering is due to data storage compression techniques. Data is assumed to be changing at a constant rate which allows less total storage.

The filtered signal lacks the full magnitude of the actual signal and is time delayed. Depending on the filtering these factors can be sufficient to make the data too inaccurate to assess. The graph on Figure 6-6 below provides an example of the discrepancy between actual and filtered data. The graph is a representation only and cannot be associated with any particular machine or station.

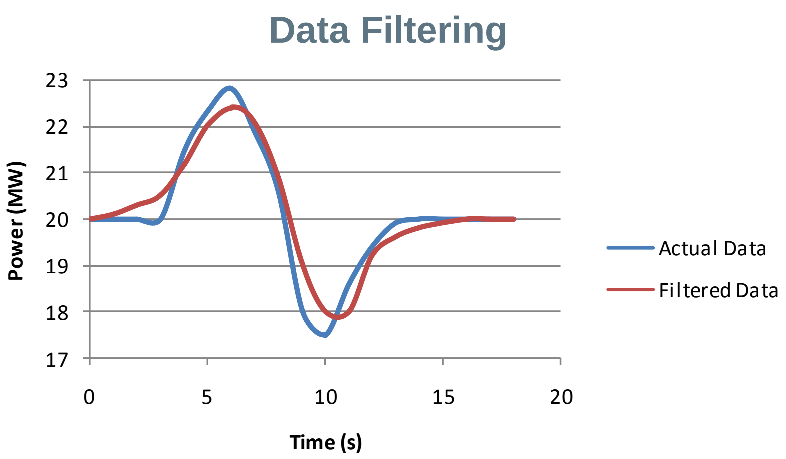


Figure 6-6 Difference between Actual and Filtered Data

The standard method of assessing governor response is to use a time step of 100 milliseconds. Given the event frequency may be at its low point by 3 to 4 seconds, this time-step allows 30 to 40 points to assess the response. Using 1 second data, as often occurs now, can hide time delays, may skew actual versus assessed performance and does not demonstrate whether the response occurs with the same rate of change of output as it should.

To align multiple recorded data points with events, the time stamp of data has to be to a common clock. One way of doing this is using a GPS clock. The data must be time tagged at or as close as possible to the monitoring device not time tagged at the point of storage.

6.5 Time based load models

Load is sensitive to frequency providing both an inertial and damped response which helps alleviate the effect of events on the system. RMT currently uses one load model for each island. The type of load on the grid changes during the course of a day, week, and month as the proportion of industrial and domestic load changes. Currently, the extent of the changes is unknown and the model used is considered conservative.

By using the data that is currently being collected by the power quality meter project, a more accurate time based load model of the system will be achieved. This model is not yet available but will be considered for use in any future work.

6.6 North Island NFR Assumptions

RMT assumes that 80% of the non dispatched hydro reserve is available for frequency regulation and includes this in its model in the form of Net Free Reserve, or NFR. The System Operator has tested the validity of this assumption.

The North Island FIR Margin duration curve as of 2002 is given in Figure 6-7 below. It shows that the RMT- assumed FIR margin (the yellow graph) is equal to or below the actual FIR margin (the red graph). In other words, the assumptions and the reality are valid for 90% of the time and for 5% of the time only (the last 5% of the graph below) there is a strongly negative connection between assumptions and reality. More information on the NFR can be found in Appendix 2, Introduction to RMT.

North Island FIR Margin Duration Curve August 2002

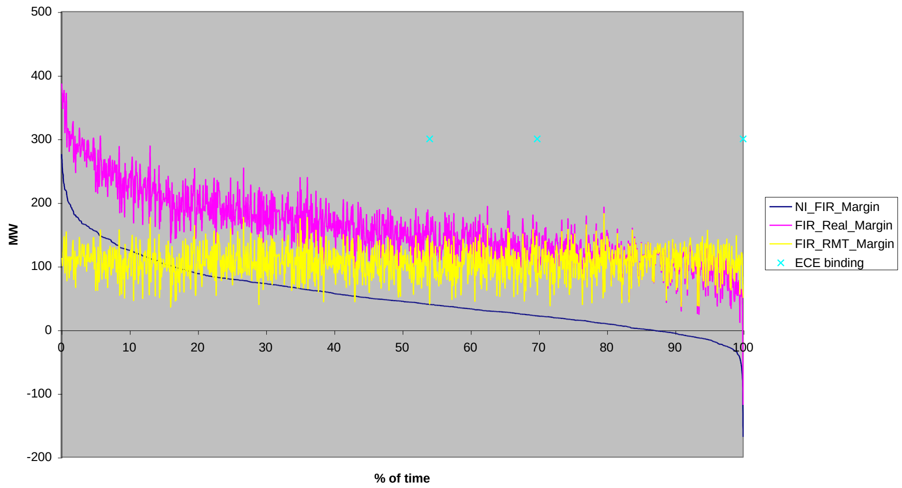


Figure 6-7 North Island FIR Margin Duration Curve

Therefore, The System Operator does not propose to make changes to this assumption at this stage. The System Operator continues to check the validity of this assumption with the hydro generators.

6.7 Economic analysis

The System Operator has carried out a high-level analysis of the economic impact of the 10 second simulation and the HVDC changes. A set of thirty North Island RMT cases was used as inputs for a market dispatch model. This model estimated the total reserve market costs. The cases were designed to represent the worst cases of under-frequency excursions under the conditions of light, medium, and heavy system load.

The results showed that a 10 second simulation time results in a cost decrease per trading period. A decrease in costs is also observed for an increase in HVDC ramp up from 25 MW to 50 MW, but not beyond 50MW. It appears that market behaviour is such that small changes in reserve quantity can result in large increases in costs. This makes the average effect on cost of changing the assumptions difficult to estimate with any degree of accuracy. However, broadly speaking, the result is approximately $5 million per annum for the 10 second simulation and $ 3 million per annum for the increase in ramp from 25 MW to 50 MW. The two effects are cumulative.

The impact of any participant behaviour change in this estimation has not been assessed.

The report of the economic analysis is given in Appendix 5. This appendix details the economic work done for the UFM options. The analysis is similar to that done for the AUFLS II report, Appendix B

6.8 Conclusions

The System Operator investigated ways of improving the current arrangements by looking at possible mechanisms of achieving more accurate procurement of FIR (when compared with actual post event frequency). However, each of the improvements, if made, will have some industry impact. These are outlined below:

- With respect to using the actual HVDC limits:
  - Using the actual HVDC limits and control actions requires the input from Transpower Grid Owner. The Grid Owner would have to agree to revise its standing data for use in the reserve model.
  - Both island calculations are done independently of each other. Using an actual HVDC model will require modifications to the RMT software.

- With respect to using actual IL modelling:
  - RMT model changes will be required
  - Rule changes will be required to mandate testing and verification of IL performance in a similar manner to generation reserves. Not all IL trips at or within 1 second and there is IL that can, and does trip faster. The quantities of IL tripped often exceed that which is procured and, within reasonable limits, the ‘over-tripping’ of IL can provide an added buffer to help the System Operator achieve its PPOs.

- With respect to data resolution:
  - Data resolution requirements in the code are 6 second and 10 second data for generators as reserve providers and 1 second data for IL providers. This data resolution is not likely to be adequate if the System Operator is to model or monitor actual FIR response. The data requirements in the rules do not match the technology available to-date.
  - Higher resolution data for reserve providers will enable ongoing and thorough performance monitoring to acceptable standards.
  - The costs incurred could be offset by relaxing the requirement for a standard frequency injection curve on a five yearly basis

- With respect to changing simulation time:
  - RMT model changes are required to change the simulation time from 60 second to 10 second; this should be considered as an option for better modelling reserves (noting it addresses only the FIR calculation)

  - The majority of SIR response will have to be provided within the first 10 seconds; this will require further studies, model changes, and some changes to the rules and/or the contract

- Further studies are required to determine how SIR response can, and should be modelled. This is unlikely to be possible with the existing software but should be considered for a future RMT replacement project.

- Time-based load modelling will be a valuable input into the RMT calculation. At present, an extensive load modelling project is under way. The outcome of the project will provide another significant input into the RMT load response. Currently, RMT uses a conservative load response while in reality the effect of the load may be quite different. It is expected that load modelling in RMT will require considerable changes to the RMT software.

- With respect to the overall effect of the other changes:
  - The existing safety margin or ‘buffer’ created from the somewhat conservative RMT approach will be reduced or lost noting that it protects the system against delayed governor response, less system inertia, or less load response and has, in the past, prevented an AUFLs activation
  - Reducing or losing the safety margin means that frequency will fall closer to 48 Hz whereas currently it seldom drops below 49 Hz. With the expected large HVDC transfers, the lost ‘buffer’ could mean more AUFLs events than are currently mandated in the PPOs
  - There is likely to be more severe frequency excursions as a result of reducing FIR procurement. The industry and the regulator will need to make, and approve rule changes that will likely have that effect.

7 Other classes of reserve products

One of the objectives of the current project is to look into the possibility of other reserve products. The necessity of more and different types of reserves arises from the expected large HVDC transfers after the completion of Pole 3. Large amounts of transfers to the North will require more reserves and better reserve management for the North Island and over-frequency management of the South Island, and vice versa.

The System Operator has recently noticed that the frequency tends to reach its minimum before the mandated 6 seconds.

The investigation of large magnitude under-frequency events has established that the frequency reaches a minimum in less than the expected 6 seconds (on which the requirement for FIR is based). This, together with the already observed trend for the frequency to reach its minimum values in less than 6 seconds in recent events, has prompted a review of the existing reserve products and their adequacy and cost-effectiveness for the changing system conditions.

The investigation considered whether the current reserve mix is optimal and whether other classes of reserves could improve the system performance. The question highlights the need to procure the ideal mix of reserve products to address both under and over frequency issues and the various factors that affect reserve performance. The question of procuring sufficient under-frequency reserves to arrest the frequency from falling and over-procuring of reserves resulting in over-frequency has been addressed in the AUFLS report.

The System Operator considered it appropriate to investigate the average time it would take to reach the minimum system frequency for large system events under various load scenarios. The objective was to research reserve products which correspond to this frequency curve (noting that FIR is procured at 6 second when the standard frequency curve is assumed to reach its minimum value).

7.1 Assessing the frequency curve

Case studies were developed for large events and for different HVDC flows. The objective was to assess, for each of the cases, the time taken to reach the minimum frequency. The optimum time for calculating the reserve within 6 seconds was then re-assessed, and the results are given on Figure 7-1. The full study report is with the results are given in Appendix 6.

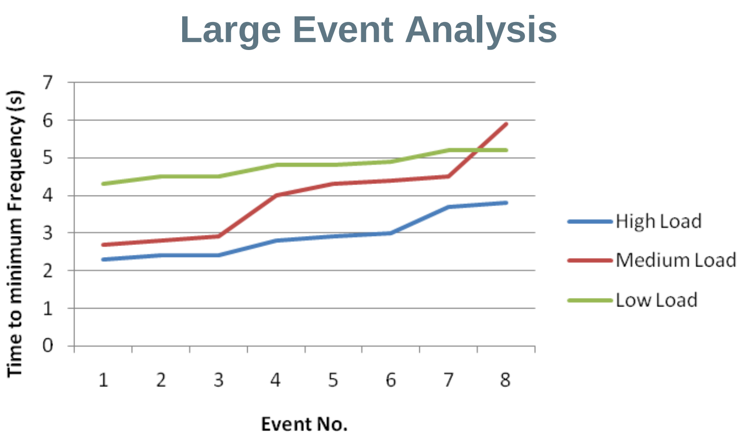


Figure 7-1 Time to reach minimum frequency

In the majority of cases, the minimum frequency occurs before the regulated 6 seconds. When the times are averaged over the cases, it suggests that, for large events, a new reserve product is required based on the 4 second output of the reserve provider.

For large events at higher system loads, the frequency falls faster than when the system is lightly loaded. During large events and higher loads, the absolute amount of AUFLs available usually exceeds the amount of the risk. Load shedding is therefore sufficient to cover the risk without using reserves. For light load cases and the same risks, the available amounts of AUFLS is less than the risk and therefore governor response and IL are necessary.

To summarise, under the current methodology for calculating reserves, at high load conditions, the amount of AUFLS available is higher than the risk, so the frequency drop is managed by shedding load alone; for medium and light load conditions, a large event is managed by relying on generator response and IL, as well as AUFLS.

7.2 Effect of faster IL

The System Operator is aware that a high proportion of Interruptible load can trip faster than the required 1 second after the frequency reaches 49.2 Hz. Therefore, the System Operator used this knowledge to explore the effect of any new, very fast reserve. Two different IL settings under medium and light load conditions in the North Island were used for the studies, and a comparison was made between them. The two different IL settings considered were:

- Tripping IL within 1 second when the frequency reaches 49.2 Hz (current arrangement)
- Tripping IL within 0.4 seconds when the frequency reaches 49.2 Hz (previous and still used arrangement)

The full study and the results are given in Appendix 7.

For the South Island, IL is offered during a dry year only. There is no IL offered under normal conditions.

The results showed that for the North Island, there is not much discrimination between the AUFLS settings of 47.8 Hz and the frequency at which IL trips after 1 second. However, if IL providers set IL to trip faster (for example at 0.4 seconds), then the discrimination between IL and AUFLS is greater, on average, by 0.9 Hz. The median value for minimum frequency with IL at 1 second delay is 48.01 seconds and at 0.4 second delay is 48.74 seconds.

Changing the discrimination between the IL and the AUFLS settings has been discussed in the Work Stream 2 – AUFLS II report. Increasing the discrimination prevents the AUFLS from tripping for ECE events when the frequency is falling faster than anticipated.

The following outcomes were observed by changing the IL trip setting from 1 second to 0.4 seconds:

- A higher (therefore better) discrimination between the AUFLS relay settings and the IL
- A higher minimum frequency which means less FIR is necessary

The overall effect of changing the IL trip setting on the minimum frequency is presented in Figure 7-2 for the North Island and Figure 7-3 for the South Island.

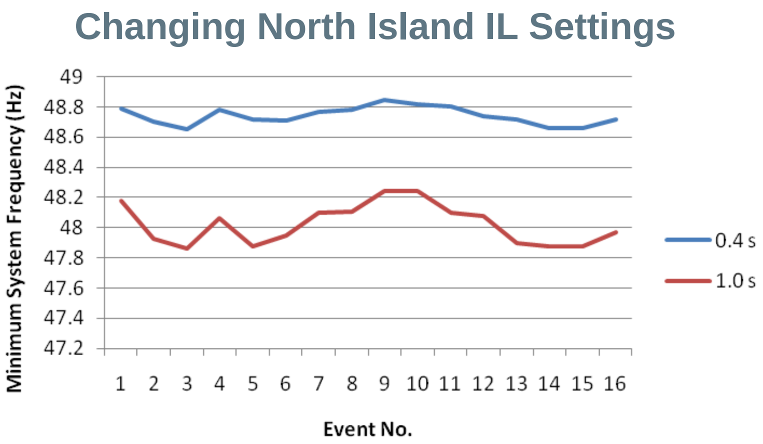


Figure 7-2 The effect of changed IL trip settings for the North Island on the minimum frequency for the North Island

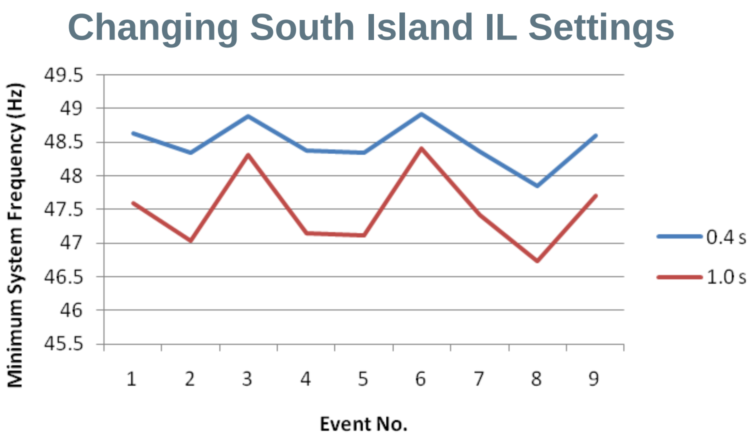


Figure 7-3 The effect of changed IL trip settings for the South Island on the minimum frequency for the SI

The setting of 0.4 seconds was chosen because it was the previous setting in New Zealand. Implementation cost, for most parties, should be relatively low. The System Operator believes that faster operation of IL is technically achievable.

7.3 The Effect of the Machine Inertia

The system inertia is the inherent ability of the power system to oppose changes in frequency. The inertia is the kinetic energy stored in the rotating mass connected to the system. If system inertia is high, then frequency will fall slowly during a system loss of supply. If system inertia is low, then frequency will fall faster for the same event. Inertia does influence the time it takes for a contingent event to cause frequency to fall. Therefore higher system inertia is preferable and more beneficial than lower system inertia because it will provide more time for governors to respond to the drop in frequency.

The effect of inertia was investigated by injecting the standard under frequency curve in two scenarios and recording the governor responses for selected hydro machines. The machines' governor response in RMT was analysed for governor and inertia contributions at different modes of machine operation: PLSR and TWD. Three representative machines were studied for each island. Machine 1, 2 and 3 were selected to have different mass.

The contribution of inertia was studied using two methods:

- the governor response from RMT at 4 seconds and calculating the inertia contribution as a percentage of the total output
- the Area-under-a-Curve method with and without considering the inertia

The full study with the detailed results is given in Appendix 8.

The results for the North Island are given on Figure 7-4 and for the South Island– in Figure 7-5.

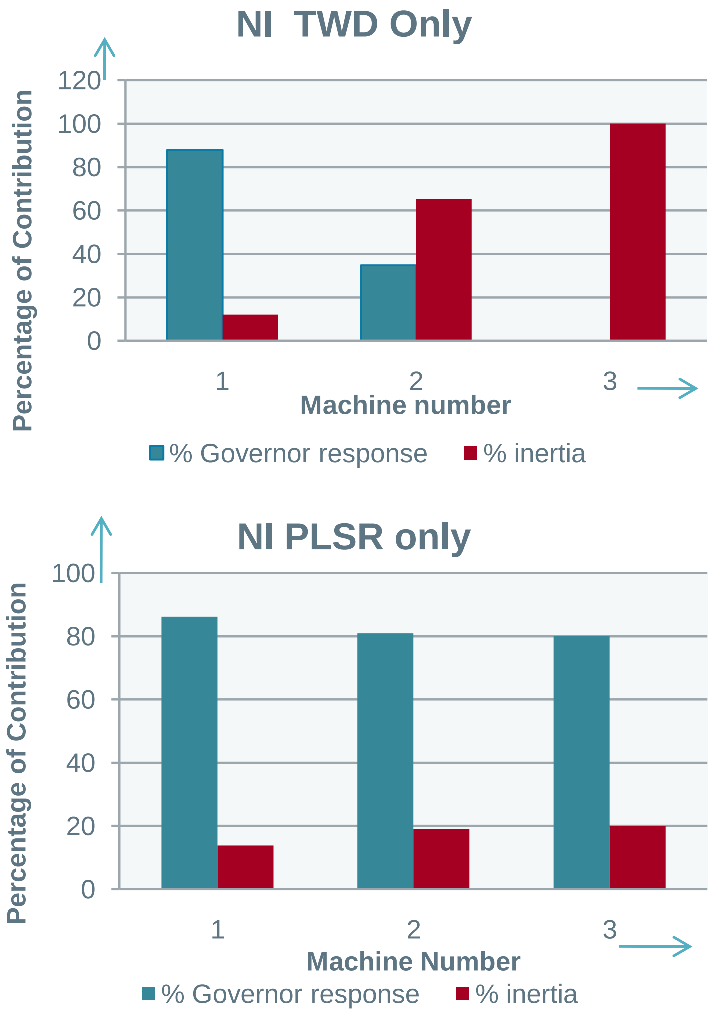
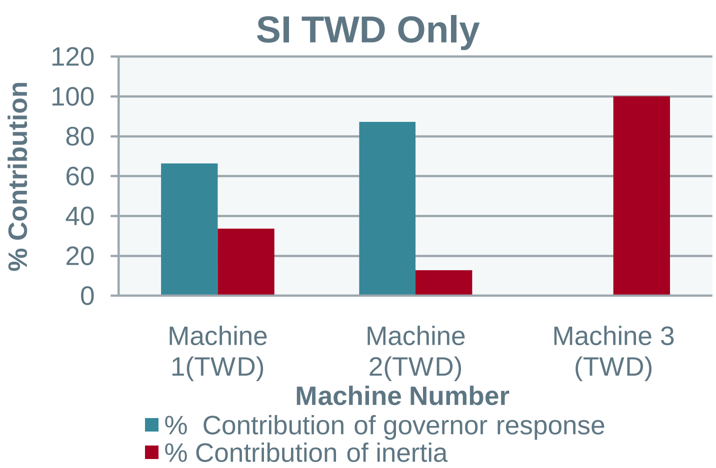


Figure 7-4 North Island, TWD and PLSR governor response breakdown at 4 seconds



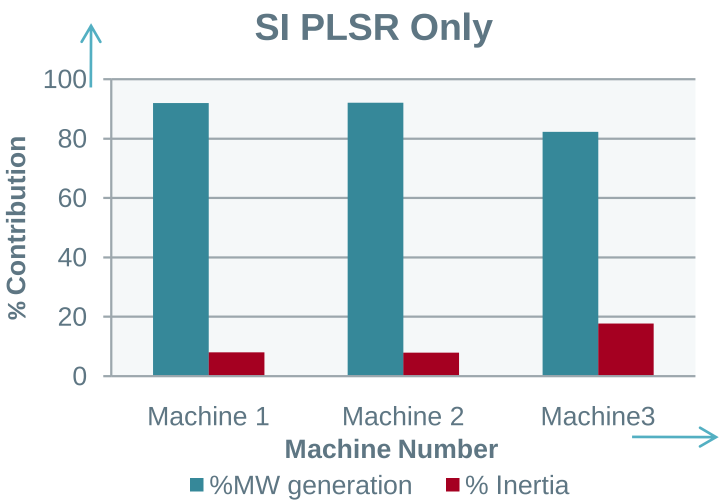


Figure 7-5 South Island, TWD and PLSR governor response breakdown at 4 second

The System Operator analysed the machines' inertia contribution for the different modes. The analysis showed that at 4 seconds, the TWD inertia contribution is predominant compared with the PLSR mode. However, in PLSR mode, the governor response has a higher percentage of the total response by a faster operation.

The System Operator has concluded that if the system was deprived of the TWD contribution, it would also lose inertia, resulting in a faster frequency fall, requiring more reserves to be procured. Therefore, inertia has a significant role in arresting the frequency fall and should be incentivised.

On the other hand, PLSR speed of response is faster compared to the speed of the TWD response. It is thus critical for the system to have both types of reserves, otherwise reserve procurement quantities are higher.

The System Operator recommends the industry discusses and considers ways of recognising and incentivising generator inertia as a new fast reserve product .

7.4 Df/dt related products

The work undertaken highlights the importance of adapting the existing technical products to the changing needs of the New Zealand power system. The frequency fall does not always match the standard under frequency curve used by the generators to tune their governor responses.

The System Operator has identified a trend of accelerated frequency fall under certain conditions. Such a trend is of concern with HVDC Pole 3 completion. Losing a pole or a bipole will have a considerable impact on the frequency fall. Using the existing reserve products may not prove sufficient in terms of both quantity and speed of operation.

The current micro-processing protection technology has the ability to accurately detect the rates of frequency change. The df/dt relays concept has the advantage of detecting and anticipating rapid frequency changes and sending signals for other protective decision-making schemes. More information on the df/dt relays can be found in the AUFLS II report.

The df/dt relays have many advantages, one of which is the speed of operation. Such relays are actively used in some countries (noting that the correct settings for the NZ environment will require a separate technical study). Further investigation into implementation and use of such relays is recommended.

A variety of Df/dt relays are also available and known as frequency-sensitive RO relays. Previous work has been done with a view to accommodating such a reserve product in the market by taking a limit-test approach to compliance assessment rather than a predictive one. The proposed compliance methodology did not provide the System Operator with a high level of confidence with respect to operation time and quantity and, if adopted, could potentially incentivise more of these relays on the system than is desirable from a security perspective (noting that indications are a balance of products is required). As such, the System Operator has reservations about adopting the technology. With the newly identified issues and concerns arising from this reserve study, further study based on tests and performance monitoring is strongly advised.

8 Conclusions and Recommendations

The objective of the current review was to evaluate the existing components and mechanisms of the current reserve market and to investigate ways of making reserve procurement more efficient and effective.

The relevant factors affecting procurement are the tools and mechanisms used to procure reserves and the suite of available reserve products. As such, the System Operator reviewed the RMT modelling assumptions and investigated ways of improving its accuracy in relation to actual system events. The System Operator also analysed the system behaviour during under-frequency events after the completion of HVDC Pole 3 . New reserve products matching the changing reality of the New Zealand power system have been identified a part of the reserve review initiative.

The reserve review identified the following possible improvements to reserve procurement:

- Optimise the current 60 second simulation in RMT to 10 second subject to further studies and rule changes relating to SIR delivery within the 10 second simulation time.
- Change the RMT model and the codes to facilitate more accurate modelling of IL with respect to delivered quantities and response times
- Change the codes to require higher data resolution and GPS time-stamping for all reserve providers and then remove the current requirement for five-yearly frequency injection testing (as long as controls are not modified)
- Use the actual HVDC transfer limit of 250 MW rather than the existing 25 MW modelled in RMT (subject to Grid Owner agreement)
- The System Operator PPOs are relaxed to recognise that in making the above changes, a certain safety buffer will be removed and potentially result in more severe under-frequency events
- Ensure ways of modelling SIR and FIR are considered for replacement in the reserve management software

The results highlighted the complexity of the existing reserve arrangements and showed that a single and straightforward fix, without affecting the overall system performance, is not possible. The above changes are likely to reduce reserve quantities but in doing so, are likely to result in some consequences for participants. Increase accuracy in the modelling is likely to reduce the system's somewhat conservative margin which serves as a 'buffer' in unexpected circumstances. If the margin is removed, the system is likely to experience more events closer to 48 Hz and possibly triggering AUFLS blocks for events larger than the modelled contingent events. As such, the System Operator cannot implement the changes without some acknowledgement in the Codes of such consequences and the co-operation and active participation of the industry and the regulator.

a) A reserve mix is essential and beneficial for managing system disturbances
b) A transparent approach must be applied for all reserve providers for testing and monitoring to ensure the mix is retained and provision of one type of reserve is not inappropriately incentivised over another.
c) The New Zealand power system has changed and evolved and more changes in its generation mix are expected. The system is becoming lighter and consequently disturbances are likely to increase. It is expected that with higher HVDC transfer, the frequency will reach its minimum in less than the mandated 6 seconds. The following faster reserve products are recommended for further consideration:

- faster operating IL
- df/dt operated reserves
- faster (4s) spinning reserve
- (system) machine inertia .

The extent of the work highlighted the complexity of the issues associated with and arising from an overhaul of the existing reserve management process. Although attempts were made to single out various components and assumptions, a unified approach to the matter is strongly recommended. Modelling and compliance questions cannot be addressed without looking at the whole picture of the NZ power system, its evolvement and in separation from the advances in the technologies