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<th>Version</th>
<th>Date</th>
<th>Author</th>
<th>Change</th>
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<tr>
<td>1.0</td>
<td>17 February 2004</td>
<td>Richard Donaldson</td>
<td>Original</td>
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<tr>
<td>1.1</td>
<td>11 June 2008</td>
<td>Roger Miller</td>
<td>Update Section 5.6 HVDC Bipole Model</td>
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<td>2.0</td>
<td>24 November 2011</td>
<td>Ina Ilieva</td>
<td>Major Update associated with pole3 system operator tool changes</td>
</tr>
<tr>
<td>2.1</td>
<td>14 August 2012</td>
<td>Heidi Heath</td>
<td>Updated to include changes to frequency keeper calculations</td>
</tr>
<tr>
<td>3.0</td>
<td>30 September 2014</td>
<td>Heidi Heath</td>
<td>Major update resulting from the change of the RMT software application from Simulink to RMTSAT</td>
</tr>
<tr>
<td>4.0</td>
<td>29 September 2016</td>
<td>Andrew Paver</td>
<td>Introduction of NMIR</td>
</tr>
<tr>
<td>5.0</td>
<td>17 December 2017</td>
<td>Richard Sherry</td>
<td>Revisions to section 3.2 for new NI AUFLS scheme</td>
</tr>
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IMPORTANT

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1 INTRODUCTION

This document is the functional specification for the System Operator’s Reserve Management Tool (RMT). RMT is implemented by RMTSAT application software. This application software is used by the System Operator to calculate the instantaneous reserves required to meet the Reserve Management Objective.

RMT provides an automated process for reserves management within the New Zealand power system, able to represent it in considerable detail.

This document provides a background to the characteristics of the New Zealand power system modelled by RMT. A description of the use of RMT to manage reserves follows.

Section 3 provides a functional specification for the RMT Solver and associated external calculations, as set out in section 1.1 and depicted diagrammatically in Figure 2. Section 4 provides the validation requirements. Section 5 provides a summary of the assumptions inherent in RMT.

1.1 SCOPE OF RMT CERTIFICATION

RMT certification covers the following described components as depicted in Figure 2:

- RMT Solver
- HVDC Model calculations within the RMT User Interface program
- Database calculations relating to variable reserve requirements
- Key Input Parameters:
  - Load inertia
  - Load damping
  - Frequency standards
  - Safety margins
  - AUFLS settings
  - AC loss model assumptions
  - Free Reserve modelling limits
  - HVDC settings

1.2 FUNCTIONALITY NOT INCLUDED IN RMT

The functionality of RMT does not cover the following features:

- Enhanced modelling of Sustained Instantaneous Reserve
- Modelling of uncleared reserve
- Modelling of AC transmission constraints
- Enhanced economic dispatch (Five minute reserve modelling)
- Generator compliance monitoring and associated cost allocation
2 RESERVES MANAGEMENT IN NEW ZEALAND

2.1 THE NEW ZEALAND ELECTRICITY SYSTEM

The management of generation reserves in the New Zealand electricity system poses significantly different problems to the management of reserves in larger ‘continental’ systems, consisting of large synchronous interconnected areas. On a large continental system each large generating unit typically represents a small portion of the total generation and consequently the tripping of a large unit generally results in a minor frequency fluctuation. In contrast the largest generating units or the HVDC Bipole in the New Zealand system represent a relatively large portion of the total generation and a generator or Bipole trip can result in a relatively large frequency fluctuation.

For the purpose of analysing the management of reserves, the New Zealand electricity system is represented by Figure 1.

![Figure 1. New Zealand Electricity System](image)

In RMT the North Island and South Island networks are each represented by a 2 bus system with generation and the HVDC Bipole connected to one bus and load connected to the other bus. The AC transmission loss in each island is represented by a resistive loss between the buses.
The AC networks within each island are not represented as it is assumed that the network topology is irrelevant to reserves management.¹

The North and South Islands are linked by a two pole (often described as Bipole) HVDC Link. The HVDC link is, at the time of publication, rated to transfer 1200 MW from South to North or 850 MW from North to South. AC transmission constraints prevent the HVDC Link from operating at its rated maximum in some circumstances.

The tripping of an HVDC pole or the tripping of the largest generating unit in the North Island represents a significant power loss. Both Islands have a load shedding scheme to compensate for the potential loss. The load shedding schemes include ‘Interruptible Load’ and ‘Automatic Under-Frequency Load Shedding’.

To model AUFLS and Interruptible Load, RMT includes separate independent blocks of load (in each Island) that trip at predefined frequencies.

2.2 **Electricity Industry Participation Code 2010**

The steady state operation of the New Zealand power system is based on the Scheduling, Pricing, and Dispatch (SPD) model. The SPD application takes generation offers and load bids as inputs into a linear programming algorithm which determines a clearing price for electricity at each of approximately 550 nodes in the power system. Constraints are included within the SPD model to represent contingent and dynamic power system operating limits.

As part of the scheduling and dispatch process, reserve offers are co-optimised with the energy offers from generators. The requirement for reserves is defined by Part 7 and Schedule 8.4 of the Electricity Industry Participation Code 2010 (Code). These rules require that for a Contingent Event (CE) the frequency fall to no less than 48 Hz and recover to no less than 49.25 Hz within 60 seconds (in both islands). The Code also requires that for an Extended Contingent Event (ECE) the frequency fall to no less than 47/45 Hz (North Island/South Island) and recover to no less than 49.25 Hz within 60 seconds. In the North Island it is also required that the frequency does not stay below 47.3 Hz for longer than 20 seconds or below 47.1 Hz for longer than 5 seconds.

On the New Zealand power system the tripping of a large generating unit or HVDC pole will generally result in a large frequency fluctuation whose magnitude is dependent on the size of the tripped unit or pole and the response characteristics of the remaining units. The frequency-oriented requirements of the Code are intended to prevent excessive load shedding and the cascade tripping of other generators due to low frequency operation.

2.3 **The Role of RMT in the SPD Process**

Figure 2 shows how RMT interacts with the SPD application. The SPD application is used in 3 different modes:

- Scheduling Mode
- Dispatch Mode
- Pricing Mode

¹ Assuming that the AC network topology is irrelevant to the calculation of reserve requirements is not valid under circumstances where the generation reserves cannot be supplied to the load without overloading transmission circuits. However, these circumstances occur rarely and are not included in the design of RMT.
2.3.1 SPD Scheduling Mode

The Scheduling Mode of SPD is used to forecast a schedule for generation for 13 to 35 hours ahead of time. Market Participants (Generators and Loads) make offers and bids for each half-hour trading period to inject or take off power at each node in the system. Reserves are also offered by generators and contracted interruptible load providers.

The SPD application takes the offers and bids (or load forecast) for each trading period and employs a linear programming solution to match generation to load at minimum cost, subject to constraints in the network. Forecast information on cleared generation and load (those that have had successful offers and bids) as well as nodal prices is then fed back to the market participants. The participants may then choose to alter their offers and bids and resubmit these for a subsequent scheduling solution. By the time that each actual trading period comes to pass the participants will have had the opportunity to resubmit offers and bids up from 6 to 17 times, which is generally a sufficient number of iterations to result in a satisfactory solution to all participants.

2.3.2 SPD Dispatch Mode

The Dispatch Mode of SPD is used to determine dispatch instructions in near real time. The valid offers from the forecast schedule are finally used by the SPD application to provide a dispatch schedule for the current demand conditions. The SPD application runs every 5 minutes to keep pace with the changing load.
Figure 2. Role of RMT in the SPD Process. (See key on next page)
### Key to Figure 2.

<table>
<thead>
<tr>
<th>Term</th>
<th>Explanation</th>
</tr>
</thead>
<tbody>
<tr>
<td>FIR</td>
<td>Fast Instantaneous Reserve, refer Glossary.</td>
</tr>
<tr>
<td>SIR</td>
<td>Sustained Instantaneous Reserve, refer Glossary.</td>
</tr>
<tr>
<td>Interruptible Load Reserve</td>
<td>Refer Interruptible Load, the Code, Part 1. Defined Terms.</td>
</tr>
<tr>
<td>Partly Loaded Reserve</td>
<td>Refer Partly Loaded Spinning Reserve, the Code, Part 1. Defined Terms.</td>
</tr>
<tr>
<td>Tailwater Depressed Reserve</td>
<td>Refer Tail Water Depressed Reserve, the Code, Part 1. Defined Terms.</td>
</tr>
<tr>
<td>Load Forecast</td>
<td>The estimated load forecast given for each trading period.</td>
</tr>
<tr>
<td>Manual_ACCE Risk</td>
<td>The Island manually entered min ACCE risk MW. If both the ACCE FIR and ACCE SIR primary risk plant are known risk units then this value is set to zero. A fixed risk that cannot be optimised by the SPD solver; it applies to ACCE events</td>
</tr>
<tr>
<td>Manual_ACECE_Risk</td>
<td>This is the island manual AC ECE risk MW. If both the AC ECE FIR and AC ECE SIR primary risk plant are known risk units then this value is set to zero. Otherwise it is set to the maximum of AC ECE FIR MW and AC ECE SIR MW that are not known risk units; the manually entered risk cannot be optimized by SPD solver; it applies to ACECE events</td>
</tr>
<tr>
<td>FIR_MW</td>
<td>The required FIR. Applies to ACCE, DCCE, ACECE, and DCECE</td>
</tr>
<tr>
<td>SIR_MW</td>
<td>The required SIR. Applies to ACCE, DCCE, ACECE, and DCECE</td>
</tr>
<tr>
<td>NFR</td>
<td>Net Free Reserve. The offset from the risk.</td>
</tr>
<tr>
<td>ACCE</td>
<td>AC Contingent Event, refer Glossary.</td>
</tr>
<tr>
<td>ACECE</td>
<td>AC Extended Contingent Event, refer Glossary.</td>
</tr>
<tr>
<td>DCCE</td>
<td>DC Contingent Event, refer Glossary.</td>
</tr>
<tr>
<td>DCECE</td>
<td>DC Extended Contingent Event, refer Glossary.</td>
</tr>
<tr>
<td>Cleared Load</td>
<td>Load that will be connected at a cleared price.</td>
</tr>
<tr>
<td>Cleared Reserve</td>
<td>Reserves that will be connected at a cleared price.</td>
</tr>
<tr>
<td>Cleared Generation</td>
<td>Generation that will be connected at a cleared price.</td>
</tr>
<tr>
<td>HVDC Bipole Transfer</td>
<td>The MW transfer of the HVDC link.</td>
</tr>
<tr>
<td>Commissioning Risk</td>
<td>Flag added to generators it indicate that it may be a secondary commissioning risk for ECE and CE risk events. If defined as a risk then it is tripped for the requested risk events.</td>
</tr>
<tr>
<td>Secondary DCCE_MW</td>
<td>DC secondary risk MW to be applied as an additional risk on ACCE and ACECE risk events for receiving island</td>
</tr>
<tr>
<td>Secondary DCECE_MW</td>
<td>DC secondary risk MW to be applied as an additional risk on ACECE risk events for receiving island</td>
</tr>
<tr>
<td>Frequency Keeper Band</td>
<td>MW band in which the frequency keeper could be generating, relative to its set point.</td>
</tr>
</tbody>
</table>
2.3.3 SPD Pricing Mode

The Pricing Mode of SPD is an ex-post solution used to determine nodal prices after the event. These prices may differ from ex-ante dispatch prices because the load bids do not exactly match the load off-take.

RMT is not actively used in the SPD Pricing Mode although the historical RMT inputs to the SPD solution are retained for the pricing solution.

Fast and Sustained Instantaneous Reserve

The reserve offers are categorised as Fast Instantaneous Reserves (FIR) and Sustained Instantaneous Reserves (SIR). These terms are defined by the Code for the convenience of classifying the variety of reserve responses from different plant on the system.

For spinning reserve, FIR refers to the fast initial response to a frequency fall and is defined as the additional reserve capacity in MW provided at 6 seconds in relation to a standard frequency excursion where the frequency drops to 48 Hz at 6 seconds and then recovers to 49.25 Hz at 60 seconds. This standard frequency excursion is described in section 7.

For interruptible load, FIR refers to the fast initial response to a frequency fall and is defined as the drop in MW that occurs within one second of the grid system frequency falling to or below the trip frequency (49.2 Hz) and which is sustained for a period of at least 60 seconds.

For spinning reserve, SIR refers to the relatively slow but sustainable response to a frequency fall and is defined as the average additional capacity in MW provided between 0 and 60 seconds in relation to the standard frequency excursion where the frequency drops to 48 Hz at 6 seconds and then recovers to 49.25 Hz at 60 seconds and where the total output provided at 60 seconds is to be sustained until 15 minutes after the event.

For interruptible load, SIR refers to the sustainable response to a frequency fall and is defined as the average drop in MW that occurs between 0 and 60 seconds of the frequency of the grid system falling to or below the trip frequency (49.2 Hz) and which is sustained until advised by the system operator. Note that a generator (or other reserve provider) that offers an amount of FIR will also generally offer the same amount or a greater amount of SIR as the fast initial response at 6 seconds will typically be sustained or increased over 60 seconds.

The FIR and SIR offers are also sub-categorised as Interruptible Load Reserve Offers (ILRO), Partly Loaded Reserve Offers (PLRO), and Tailwater Depressed Reserve Offers (TWRO).

- ILRO refers to load that is contracted to be tripped when the frequency falls below an agreed value – currently 49.2 Hz.
- PLRO refers to the reserve that is offered by partly loaded generators which are not running at their maximum output limits.
- TWRO refers to the reserve offered by hydro generators that are running as synchronous compensators with pressurised air excluding water from the turbine. In New Zealand this mode of operation is termed ‘Tailwater Depressed’ due to the depressed tailwater level caused by the pressurised air.

In all there are 6 different types of reserve offer that can be made, each type representing a significantly different type of response:

1. FIR ILRO
2. FIR PLRO
3. FIR TWRO
4. SIR ILRO
5. SIR PLRO
6. SIR TWRO

2.3.4 Risk Adjustment

In addition to offers and bids the SPD application also requires Net Free Reserve (NFR's) which define the amount of reserve that should be carried in order to cope with the under frequency effects of a CE (AC or DC) or ECE (AC or DC). The NFR's are provided by RMT.

The NFR's are calculated according to the risk in each island. This risk is the largest power loss that may result from an ACCE, DCCE or ACECE or DCECE. NFR's represent the reserve requirement offset from the risk.

There are eight different types of NFR for each island:

- NFR for FIR ACCE.
- NFR for FIR DCCE.
- NFR for FIR ACECE.
- NFR for FIR DCCE.
- NFR for SIR ACCE
- NFR for SIR DCCE.
- NFR for SIR ACECE.
- NFR for SIR DCECE

As an example, if the current CE risk in the North Island is the Otahuhu B generator running at 350 MW and carrying 20 MW FIR then an NFR of 50 MW would indicate that a FIR of:

\[ 1 \times (350+20-50) = 320 \text{ MW} \]

should be carried to cover that risk.

Note that NFR's can be negative as well and that not all stations carry reserve.

2.3.5 Calculation of NFR’s by RMT

RMT calculates a set of NFR's that will ensure that the Code under frequency requirements are fulfilled.

Specifically, RMT calculates NFR’s that will ensure that the frequency minimum is 48 Hz for a CE and 47/45 Hz for an ECE (North Island/South Island). There is an additional Code requirement that the frequency return to at least 49.25 Hz after 60 seconds. The specified ECE frequency envelope consists of up to 6 rectangular segments that the frequency must stay above. The North Island envelope is currently specified as follows - the frequency must not go below:

- 47.3 Hz for more than 20 seconds.
- 47.1 Hz for more than 5 seconds.

There is no envelope currently specified for the South Island.

To calculate the NFR's, RMT uses the following data from the SPD solution:

- Cleared Generation
- Cleared HVDC transfer
- Cleared FIR and SIR Interruptible Load Reserve
- Cleared FIR and SIR Partly Loaded Reserve
- Cleared FIR and SIR Tailwater Depressed Reserve

Note that the nodal prices and cleared load are not required to be used by RMT.
(Note that the SPD application creates this solution data partially based on the NFR’s provided by RMT on the previous iteration.)

To calculate the NFR, RMT uses the following data calculated by MDB based on SPD solution data:

- DC configuration
- DC capacity
- DC subtractor max
- DC secondary commissioning risk setting
- Additional frequency keeper MW band, if the risk setter is also a frequency keeper

Ideally, after the NFR’s are calculated by RMT, the SPD application should be re-run and the NFR’s recalculated until the cleared generation, reserves, and load for a trading period are sufficient to meet the under frequency requirements. However, to avoid time-consuming SPD and RMT iterations, the NFR’s calculated by RMT are used directly in the next SPD solution. This is justified by the experience that the NFR’s generally change only slowly from trading period to trading period.

If a major tripping does occur then the current SPD solution will be invalid and the NFR’s from RMT will also be invalid (although RMT will have already performed its function of determining the reserves necessary to cover the tripping). In this situation the Dispatcher uses discretionary action to recover the system by which time the SPD solution and RMT NFR’s are generally valid again. During this recovery period, a scaling factor between 0% and 100% is applied to the reserve requirement to allow SPD to meet the energy demand while partially or totally ignoring reserves. The system operates with reduced security until recovery is complete.

---

3 The NFR’s calculated by RMT are used for display purposes only and not written back to the database to be used by the SPD solver. Instead RMT writes back the raw reserve requirements in MW corresponding to each of the 12 NFR’s. This allows the scaling factor to be applied to the reserve requirements to generate a set of modified NFR’s – it is these NFR’s that are written to the database to be used by the SPD solver.
3 RMT FUNCTIONAL SPECIFICATION

3.1 INTRODUCTION

The foregoing sections described the context within which RMT functions as a part of the whole application software. This section specifies the functional requirements of the RMT Solver and the other important functional components, as explicitly defined in Section 1.1 “Scope of RMT Certification”. All references to RMT within this section specifically refer to this group of functional components.

The types of plant that are modelled by RMT are as set out in Table 1.

Table 1.

<table>
<thead>
<tr>
<th>Generic Model Type</th>
</tr>
</thead>
<tbody>
<tr>
<td>1. HVDC Bipole</td>
</tr>
<tr>
<td>2. Partly Loaded Hydro</td>
</tr>
<tr>
<td>(Hydro plant that may offer FIR when partly loaded)</td>
</tr>
<tr>
<td>3. Tail Water Depressed Hydro&lt;sup&gt;4&lt;/sup&gt;</td>
</tr>
<tr>
<td>(Hydro plant that may offer FIR when operated in TWD mode)</td>
</tr>
<tr>
<td>4. Steam Turbine&lt;sup&gt;5&lt;/sup&gt;</td>
</tr>
<tr>
<td>5. Geothermal&lt;sup&gt;6&lt;/sup&gt;</td>
</tr>
<tr>
<td>6. Gas Turbine</td>
</tr>
<tr>
<td>7. Combined Cycle Mitsubishi</td>
</tr>
<tr>
<td>8. Combined Cycle ABB</td>
</tr>
<tr>
<td>9. Ungoverned Generator</td>
</tr>
<tr>
<td>10. Sheddable Load</td>
</tr>
<tr>
<td>11. Uncontrolled Load</td>
</tr>
</tbody>
</table>

3.2 TRANSLATION BETWEEN SPD DATA AND SIMULATION DATA

The SPD process and the RMT simulation process represent generation and reserves in quite different ways. A translation is required to transfer information between the two processes.

The SPD application handles generation in terms of MW and reserves in terms of FIR and SIR MW for interruptible load, partly loaded units, and tail water depressed units. Generation and reserves may be handled at either a station level or unit level. Large thermal plant is typically offered and cleared as individual units whilst smaller thermal plant and hydros are offered and cleared as a station block. RMT is capable of receiving offers in either form.

<sup>4</sup> Includes stations that do not require TWD to be able to motor as their tailwater level is already below the turbine runner.

<sup>5</sup> Used for large steam turbine machines handled on a unit basis by SPD.

<sup>6</sup> Also used for smaller steam turbine machines handled on a station basis by SPD.
The RMT time domain solution is required to represent generators by their governor/turbine block diagrams. The translation process converts the SPD generation and reserves associated with each station into the appropriate operating conditions for the simulation model. The different types of model have been listed in Table 1.

### 3.2.1 Translation for Loads (Existing AUFLS scheme)

Figure 3 and Figure 6 show how the North and South Island loads are presently allocated to the different load models.

In the North Island the total load is taken to be the sum of the cleared generation and HVDC Bipole injection (referred to as the North Island Power Supply or NIPS) minus the fixed and variable transmission losses. The transmission losses are calculated from the SPD solution data and are not dynamically altered during the simulation.

The total load is then allocated between models for AUFLS, the scheduled Interruptible Load and Uncontrolled Load. Note that only the cleared Interruptible load will be tripped in a study, but the scheduled value is used to determine the size of the Uncontrolled Load.

Certain connected parties (eg North Island distributors) provide a specified percentage of their load as AUFLS. The model allows a quantity of load to be exempt from this requirement. Such loads may still offer interruptible load but are otherwise unaffected by load shedding schemes. Exempt loads not offered as Interruptible Loads are added to the Uncontrolled Load. A specified percentage of the total non-exempt load (including scheduled IL load) is allocated to each of AUFLS Zone 1 and Zone 2.

Three of the AUFLS blocks are required for tripping embedded load at non-compliant generators when the generator trips.

The Interruptible Load model is allocated the Interruptible Loads that have been cleared as FIR.

The South Island model is similar to the North Island, but no AUFLS blocks are currently required for tripping embedded load at non-compliant generators.

Provision is made for the operator to specify that non-compliant generators (generators that trip on under frequency) must trip along with some embedded load. The embedded load must equal the embedded generation up to the specified maximum.

### 3.2.2 Revisions for proposed North Island AUFLS scheme

To enable the proposed 4-block AUFLS scheme for the North Island, the model has been expanded to allow for 9 blocks in the transition period as shown in Figure 4, with the existing blocks 1 and 2 becoming blocks 8 and 9.

Under the revised scheme the MW_excluded (exempt) load will be zero for the 4 new blocks. The model allows for the existing MW_excluded value to be included in blocks 8 and 9 during the transition period. Note that the % values applied to blocks 1 to 4 are therefore % of a different total load than for blocks 8 and 9.

During the transition period, load relays will be modified and load will therefore move from the old blocks into the new blocks. The % of load in each block will be updated periodically. Ultimately no load will remain in blocks 8 and 9 which will then be disabled as shown in Figure 5.

Under the new scheme the Zone 4 AUFLS load will also trip if the rate of change of frequency exceeds -1.2 Hz/s for 100ms and the frequency is below 48.5 Hz.
Figure 3. Existing Allocation of Load to Models for the North Island.
North Island Load

- **Cleared Generation + HVDC Bipole Injection (= NIPS)**
  - Load Used for AUFLS
    - 1 - 4 % calcs
  - Load Used for AUFLS
    - 8 / 9 % calcs

- **Scheduled Interruptible Load (IL)**
  - To be set as %, MW or embedded load
  - 52 MW + 0.0000092 x (NIPS)^2

- **Automatic Under Frequency Load Shedding Zone 1:** < 47.9 Hz for 0.16s + 0.14s delay
- **Automatic Under Frequency Load Shedding Zone 2:** < 47.7 Hz for 0.16s + 0.14s delay or < 47.8 Hz for 14s + 0.1s delay
- **Automatic Under Frequency Load Shedding Zone 3:** < 47.5 Hz for 0.16s + 0.14s delay or < 47.7 Hz for 14s + 0.1s delay
- **Automatic Under Frequency Load Shedding Zone 4:** < 47.3 Hz for 0.16s + 0.14s delay or < 47.5 Hz for 14s + 0.1s delay
- **Under Frequency Load Shedding Zone 5:** Load associated with Generation trip
- **Under Frequency Load Shedding Zone 6:** Load associated with Generation trip
- **Under Frequency Load Shedding Zone 7:** Load associated with Generation trip
- **Automatic Under Frequency Load Shedding Zone 8:** < 47.8 Hz for 0.2s + 0.1s delay or < 47.9 Hz for 15s + 0.1s delay
- **Automatic Under Frequency Load Shedding Zone 9:** < 47.5 Hz for 0.2s + 0.1s delay or < 47.8 Hz for 15s + 0.1s delay

- **Interruptible Load:** < 49.2 Hz for 0.2s + 0.8s delay
- **Uncontrolled Load**
  - Including Load Exempt from (existing) AUFLS
  - Fixed and Variable Transmission Losses

- **Embedded load in Zone 5**
- **Embedded load in Zone 6**
- **Embedded load in Zone 7**
- **To be set as %, MW or embedded load**

**The Rest of this Load**

{ i.e. NIPS – (any assigned blocks) }

---

**Figure 4. Allocation of Load to Models for the North Island during Transition to 4 block scheme**
Figure 5. Allocation of Load to Models for the North Island with final 4 block scheme
South Island Load

- **Automatic Under Frequency Load Shedding Zone 1**: 
  - < 47.5 Hz for 0.15s + 0.2s delay
- **Automatic Under Frequency Load Shedding Zone 2**: 
  - < 46 Hz for 0.15s + 0.2s delay or < 47.5 Hz for 15s + 0.1s delay
- **Automatic Under Frequency Load Shedding Zone 3**: 
  - Initially disabled
- **Automatic Under Frequency Load Shedding Zone 4**: 
  - Initially disabled
- **Automatic Under Frequency Load Shedding Zone 5**: 
  - Initially disabled
- **Automatic Under Frequency Load Shedding Zone 6**: 
  - Initially disabled
- **Under Frequency Load Shedding Zone 7**: 
  - < 46 Hz for 0.2s + 0.2s delay
  - Used for TIWAI AUFLS trip

- **Interruptible Load** 
  - < 49.2 Hz for 0.2s + 0.8s delay

- **Uncontrolled Load** 
  - Including Load Exempt from AUFLS

- **Scheduled Interruptible Load**
- **To be set as %, MW or embedded load**
- **MW load tripped in Zone 7**

- **The Rest of this Load**
  - (i.e. SIPS – (any assigned blocks))

- **MW_Excluded Value**
  - 28.5 MW + 0.000018 x (SIPS)^2

**Figure 6. Allocation of Load to Models for the South Island.**
As an example, Figure 7 shows typical percentage quantities of load allocated to different load models for the following hypothetical scenario:

- Island Generation 2400 MW
- HVDC Injection 600 MW
- Fast Interruptible Load 200 MW

### 3.2.3 Translation for Hydro, Gas Turbine, and Geothermal Stations

For Hydro, Gas Turbine, and Geothermal (and smaller steam turbine) stations, the SPD process handles generation and reserves on a station basis rather than as individual units. Consequently, the cleared generation and reserves information from the SPD solution is generally insufficient to determine exactly how many units will be on-line or what their individual loading will be.

The RMT simulation model assumes that the station will run the minimum number of units necessary to provide the cleared generation and FIR, and that all on-line units will have identical loadings. These assumptions allow the on-line units at a station to be represented by a single lumped model. (The exception to this is for stations which are cleared for tailwater depressed FIR. These stations are represented by two lumped models, one lumped model for the partly loaded units and another lumped model for the tailwater depressed units).

The RMT simulation model allows turbine gate or valve limits to be applied to limit the amount of FIR that the generators can deliver. Gas Turbine and Geothermal models allow the available FIR to be restricted to the cleared quantity. The partly-loaded hydro model provides a configuration setting that specifies the percentage of free FIR to be modelled. A setting of 0% permits the model to only deliver...

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7 The assumption that the minimum number of units will be run is based on the principle that generators are usually most efficient at high loading. The assumption that all on-line units will have identical loadings will not be valid if units are physically different or if some units have been derated due to mechanical problems.
the amount of FIR cleared by the SPD solution. Conversely, a setting of 100% permits all the free FIR available from the online units to be delivered.

3.2.4 Translation for Tailwater Depressed Hydro Plant
Some hydro stations are capable of offering both partly loaded reserve and tailwater depressed reserve. In these cases the partly loaded reserve is represented in the same manner as described in Section 3.1.2 which determines the number of units necessary to deliver the cleared generation and cleared partly loaded reserve. It is assumed that the:

- remaining units are available for tailwater depressed operation
- available FIR is the power output at 6 seconds
- number of units running to provide tailwater depressed reserve will be the minimum number necessary to provide the cleared FIR
- turbine gate limits will be set to restrict the available FIR to the amount of cleared FIR.

3.2.5 Translation for Ungoverned Generation
Generators that do not employ a governor speed control (such as some co-generation plants), are represented in RMT by the Ungoverned Generator Model. Generators not modelled in SPD but which will have an impact on frequency are also represented in RMT by the Ungoverned Generator model, with the quantity of generation being assumed. The SPD process handles ungoverned generators on a station basis rather than as individual units. The RMT simulation model assumes that the station will run the minimum number of units necessary to provide the cleared generation, and represents the online units at each station by a single lumped model. The Ungoverned Generator model contributes only inertia and turbine damping. No reserve is offered, cleared or modelled.

3.2.6 Translation for Steam Turbine Plant
The large steam turbine units are offered and cleared in SPD for generation and reserve on a unit basis. Consequently there is no requirement for RMT to estimate the number of units that are online at these stations. However, the FIR available from the steam turbines is dependent on their generated power and the boiler pressure.

RMT models the initial boiler pressure required to produce the cleared generation and FIR according to the simulation model.

If the steam turbine is a frequency keeper, it generates higher and lower than its dispatch setpoint to maintain frequency. If the turbine is the risk setter in addition to being a frequency keeper, an additional set of equations is required to add the frequency keeping band to the risk. The frequency keeping band is provided by MDB.

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8 The assumption that generator operators will apply turbine gate or valve limits to restrict available reserve to the cleared reserve is recognised to be very unlikely. The usual practice is to set these limits to slightly above the generator rating unless there are specific mechanical limitations. This assumption is made in RMT in an attempt to be consistent with an electricity market principle that only cleared generation, load, and reserves should be connected to the system. Uncleared reserve that remains connected is ‘free’ and not paid for.

9 There is a risk associated with the modelling of free reserve. The Code allows generators to meet their total energy and reserve dispatch across the whole block (e.g. river chain), so the actual number of machines connected, and hence the free reserve capability, can vary from what was assumed in the model. Choosing a factor between 0% and 100% allows a more realistic assumption, providing a safety margin to help mitigate this risk.
3.2.7 Translation for Combined Cycle Plant

The large combined cycle generators are also offered and cleared in SPD on a unit basis so there is no requirement to estimate the number of units that are online at these stations. If these stations are not cleared to provide FIR then the speed governor control is disabled in the models. However, the rest of the model continues to model the effect of frequency on the combined cycle operation. If the stations are cleared to provide FIR then the speed governors are enabled, and simulated valve limits are imposed to restrict the available FIR to the cleared value.

If the combined cycle plant is a frequency keeper, it generates higher and lower than its dispatch setpoint to maintain frequency. If the plant is the risk setter in addition to being a frequency keeper, an additional set of equations is required to add the frequency keeping band to the risk. The frequency keeping band is provided by MDB.

3.2.8 Translation of Generator Commissioning Risk

AC plant set as a commissioning risk is added to all the CE and ECE Event solutions. The commissioning risk type and level of the AC plants is passed on from the MDB.

3.2.9 Translation for HVDC Bipole

The HVDC Bipole data that RMT receives from SPD includes the pole power transfers and losses. RMT takes the expected HVDC plant configuration, frequency control mode, and the capability of each pole from MDB.

3.2.10 Translation of DC Secondary Commissioning Risk

MDB provides the following two factors for RMT to calculate secondary DC risk to be applied to ACCE and ACECE event solution of the receiving island.

**HVDCAsACSecondaryRisk:**
- 0 – No Secondary Risk
- 1 – Bipole as secondary risk
- 2 – Pole 2 as secondary risk
- 3 – Pole 3 as secondary risk

**HVDCCommissioningLevel:**
This is the MW level that the commissioning plant identified by the previous factor has been commissioned to be as a CE Risk

The DC secondary risk for the receiving island is added to the primary AC risk for the associated event solution. When calculating the NFR value for these event solutions this DC secondary risk is removed from the primary risk.

If there is either a DC secondary CE or ECE risk defined then the DC model will be turned off as the RMT wrapper will set the DC reserve sharing limits to zero. This does result in a conservative approach when DC plant is only defined as a secondary ECE risk.

3.3 Estimate of Required SIR

RMT is not required to take account of cleared SIR in the simulations. However, it still estimates the required SIR so that SIR NFR’s can be fed back to the SPD application along with the FIR NFR’s derived from the simulations. This SIR estimate is required to cover the net power lost but not to ensure that the frequency will recover to 49.25 Hz within 60 seconds as required by the Code.

A CE is expected to result in the frequency remaining above 48 Hz so cascade generator tripping should have only a minor impact (only one generator has a trip frequency higher than 48 Hz). Consequently the SIR required to cover a CE is assumed to be equal to:

- the CE risk
plus any cleared SIR carried on the risk unit
plus any generation or SIR lost in the simulation due to cascade tripping.

A ECE may result in the frequency falling as far as 47 Hz in the North Island or 45 Hz in the South Island with consequent cascade generator tripping and under frequency load shedding from the AUFLS scheme. The SIR required to cover the ECE is assumed to be equal to:

- the ECE risk
- plus any SIR cleared on the risk unit
- minus any AUFLS load shed in the simulation
- plus any generation or SIR lost in the simulation due to cascade tripping
4 **OUTLINE OF VALIDATION OF SYSTEM MODELS**

The time domain simulation model in RMT is both complex and critical to the management of reserves in the New Zealand power system. In order to ensure an acceptable accuracy a number of validation tests are required to be performed on the model.

The generator models are largely based on data provided by the generating companies as part of their compliance testing required under the Code. Data from regular required compliance tests is used to validate generator governor models. Validation tests are summarised as follows:

4.1 **SIMULATION OF INJECTED FREQUENCY TESTS**

Generators are required to perform regular governor tests and submit the test data to the system operator along with associated governor models. The first step in the validation process requires the standard under-frequency curve to be injected at several levels of generator output with the test results recorded. The simulated model response is matched with the actual response from the test data.

4.2 **SIMULATION OF HVDC BIPOLE TRIP AND SEVERAL GENERATOR TRIPS**

After each generator model has been tested the remaining modelling uncertainty lies with the characteristics of the load – specifically the load frequency damping coefficient and the load inertia (H) constant.

Unlike the generators, which mostly have test data for each unit, there is no test data available for the system loads. However, RMT calibration is verified every time a significant under-frequency event happens on the system. Using actual generation and load data just prior to the event, RMT is run and results are compared with actual system data recorded during the event.

These comparisons include:

- Generator behaviour
- IL behaviour
- Rate of change of frequency
- Magnitude of drop in frequency
- Load behaviour.
5 SUMMARY OF ASSUMPTIONS INHERENT IN RMT

The present version of RMT incorporates a number of assumptions that have been described at various points in this specification. These assumptions are also summarised in this section.

5.1 NETWORK MODEL

The North Island and South Island networks are each represented by a 2 bus system with generation and the HVDC Bipole connected to one bus and load connected to the other bus. The AC transmission loss in each island is represented by a resistive loss between the buses. This loss is calculated from the cleared generation and Bipole power and remains fixed throughout the simulation.

The AC networks within each island are not represented as it is assumed that the network topology is irrelevant to reserves management. This assumption is not valid under circumstances where the generation reserves cannot be supplied to the load without overloading transmission circuits. However, these circumstances occur rarely and have not been considered in the design of the present version of RMT.

5.2 MINIMUM FREQUENCY TARGETS

RMT determines the FIR required to meet the Code requirements, Schedule 8.4, that the frequency minimum is 48 Hz for a CE and 47/45 Hz for an ECE (North Island/South Island). The additional Code requirement that the frequency return to at least 49.25 Hz after 60 seconds is not specifically handled by the present version of RMT but is expected to normally be met in any case. RMT ensures that the North Island ECE frequency will not go below:

- 47.3 Hz for more than 20 seconds
- 47.1 Hz for more than 5 seconds.

5.3 SUSTAINED INSTANTANEOUS RESERVE

RMT ignores the SIR cleared by the SPD solution in the dynamic simulations used to calculate the FIR requirements. However, RMT still provides SIR NFR’s back to SPD which are intended to cover the net power loss.

The required SIR to cover the ACCE risk is estimated to be the CE risk plus any cleared SIR carried on the risk unit plus any generation or SIR lost in the simulation due to cascade tripping.

The required SIR to cover the DCCE risk is estimated to be the CE risk plus any generation or SIR lost in the simulation due to cascade tripping.

The required SIR to cover the ACECE risk is estimated to be the ACECE risk, minus any AUFLS load shed in the simulation, plus any SIR cleared on the risk unit, plus any generation or SIR lost in the simulation due to cascade tripping.

The required SIR to cover the DCECE risk is estimated to be the DCECE risk, minus any AUFLS load shed in the simulation, plus any generation or SIR lost in the simulation due to cascade tripping.

5.4 ITERATIVE RELATIONSHIP BETWEEN SPD AND RMT

There is an iterative relationship between the SPD application and RMT. Ideally, after the NFR’s are calculated by RMT, the SPD application should be re-run and the NFR’s recalculated until the cleared generation, reserves, and load for a trading period are sufficient to meet the under frequency requirements. However to avoid time consuming SPD and RMT iterations the NFR’s calculated by RMT are used directly in the next SPD solution. This is justified by the experience that the NFR’s generally change only slowly from trading period to trading period.
If a major tripping does occur then the current SPD solution will be invalid and the NFR's from RMT will also be invalid (although RMT will have already performed its function of determining the reserves necessary to cover the tripping). In this situation the Dispatcher uses discretionary action to recover the system by which time the SPD solution and RMT NFR's are generally valid again. During this recovery period, the NFR's may be increased to allow SPD to meet the energy demand while partially or totally ignoring reserves. The system operates with reduced security until recovery is complete.

5.5 **TRANSLATION FROM SPD TO RMT SIMULATION**

The translation from the SPD process to the RMT process is required because the two processes represent generation and reserves in different ways. The SPD application handles generation in MW and reserves in terms of FIR and SIR. On the other hand RMT represents both generation and reserves by detailed simulation models.

The translation between SPD and RMT involves a number of assumptions, the most significant of which are summarised here.

RMT assumes a relationship between generation, FIR, and the number of units connected at a station. This relationship is based on the characteristics of the plant models used in RMT and the expectation that the generator operators will load units based on cleared generation, maximum efficiency, and maximum availability. However there is no explicit agreement with the generating companies that the RMT assumptions are correct (although the model data is derived from information provided by the generating companies).

The translation assumptions may also be invalidated if the generating company chooses to ‘block dispatch’ a chain of hydro stations on a river so that the total block generation matches the total cleared block generation. The generation at individual stations may not match the cleared generation at those stations.

For some types of generator, only cleared reserve is represented in the simulation. Gate or valve limits are imposed so that generators cannot provide more reserve than they have been cleared for. For partly loaded hydro generators, the percentage of free reserve to be modelled is configurable.

The assumption that generator operators will apply turbine gate or valve limits to restrict available reserve to the cleared reserve is recognised to be very unlikely. The usual operating practice is to set these limits to slightly above the generator rating unless there are specific mechanical problems. This assumption is made in RMT in an attempt to be consistent with an electricity market principle that only cleared generation, load, and reserves should be connected to the system. Uncleared reserve that remains connected is ‘free’ and not paid for.

5.6 **HVDC Bipole Model**

The HVDC Bipole model is presently capable of representing the effects of tripping either a single Pole or the Bipole. The model represents the various HVDC frequency keeping configuration modes such as ‘Frequency Stabiliser,’ ‘Spinning Reserve Sharing,’ and ‘Frequency Keeping Control.’ SPD calculates the DCCE risk using the HVDC risk subtractor and passes this value to RMT.

The HVDC modulation is limited by the minimum and maximum transfer limits.

The HVDC model enables reserve sharing modelled as part of the National Market for Instantaneous Reserves (NMIR). NMIR is designed to allow reserves to be procured in one island to cover generation risk in the other. As a result the quantity of reserves procured can be reduced.

NMIR RMT looks at the frequency in both Islands for AC risks, modelling a two-island HVDC response. Reserves are shared across the HVDC link. A portion of NFR (approximately 1% of the sending island’s load) is also shared.
5.7 **LOAD MODELS**

The loads are represented as lumped models for uncontrolled load, interruptible load, and AUFLS.

This lumped representation is necessary because little is known about the individual characteristics of each load.

5.8 **VALIDATION TESTS**

The generator models are largely based on data provided by the generating companies. This data includes manufacturer tests and governor test data. Tests are performed whenever generators make a change to governor settings or plant hardware which may affect under-frequency performance.

Routine performance tests are also compulsory for all generators above 30 MW. Drop load test results and frequency injection test results are used to check the response of each model.

The overall system response is verified and calibrated if necessary after each under-frequency event where the system frequency in either island falls below 49.2 Hz.
## 6 GLOSSARY

<table>
<thead>
<tr>
<th>Acronym</th>
<th>Definition</th>
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<tbody>
<tr>
<td>ACCE</td>
<td>AC Contingent Event, caused by the loss of (usually) one generator unit</td>
</tr>
<tr>
<td>AUFLS</td>
<td>Automatic Under Frequency Load Shedding</td>
</tr>
<tr>
<td>ACECE</td>
<td>Loss of an interconnected transformer or a bus bar fault Contingent Event. This is an event for which, in the reasonable opinion of the system operator, resources are able to be economically provided to maintain the security of the grid system and power quality without the disconnecting of demand. (In practice this means that without resorting to the AUFLS the system will tolerate the loss of either a single AC circuit (ACCE), or a single generating set (ACCE), or a single pole of the HVDC (DCCE).)</td>
</tr>
<tr>
<td>Code</td>
<td>Electricity Industry Participation Code</td>
</tr>
<tr>
<td>DCCE</td>
<td>DC Contingent Event, loss of one HVDC Pole</td>
</tr>
<tr>
<td>DCECE</td>
<td>Loss of the HVDC bipole</td>
</tr>
<tr>
<td>ECE</td>
<td>Extended Contingent Event. This is an event for which, in the reasonable opinion of the system operator, resources are able to be economically provided to maintain the security of the grid system and power quality with the disconnecting of demand. (In practice this means that by using the Automatic Under Frequency Load Shedding the system will tolerate the relatively unlikely loss of the HVDC Bipole).</td>
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<tr>
<td>FIR</td>
<td>Fast Instantaneous Reserve. Spinning reserve: The additional output in MW provided at 6 seconds in relation to a standard frequency excursion where the frequency drops to 48 Hz at 6 seconds and then recovers to 49.25 Hz at 60 seconds. Interruptible load: The drop in MW that occurs within one second of the grid system frequency falling to or below the trip frequency (49.2 Hz) and which is sustained for a period of at least 60 seconds.</td>
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<tr>
<td>ILRO</td>
<td>Interruptible Load Reserve Offer</td>
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<tr>
<td>MDE</td>
<td>Market Data Entry application</td>
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<tr>
<td>NFR</td>
<td>Net Free Reserve. Calculated by RMT to represent the net outcome of helpful and detrimental effects on the reserve required to cover a particular risk. Helpful effects include such things as uncleared or unoffered reserve capability from partly-loaded hydro machines (FIR only), AUFLS (ECE only), load damping associated with motors slowing down as frequency falls (FIR only), a limited allowance for HVDC reserve sharing (ACCE FIR only). Detrimental effects include cascade tripping of non-compliant generators (generators that do not remain connected to the grid or do not maintain output at frequencies down to the CODE limits.) NFR's are calculated for two risk classes (CE and ECE) and two reserve products (FIR and SIR) in each island. In SPD, the NFR is deducted from the risk MW associated with each event. The result of this calculation is the FIR or SIR that SPD must clear to cover the event.</td>
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<tr>
<td>NMIR</td>
<td>National Market for Instantaneous Reserve</td>
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<tr>
<td>Acronym</td>
<td>Description</td>
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<tr>
<td>PLRO</td>
<td>Partly Loaded Reserve Offer</td>
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<td>Reserve Management Objective:</td>
<td>Refer to the Code, Schedule 8.4.</td>
</tr>
<tr>
<td>RMT</td>
<td>Reserve Management Tool, being the reserve management function which incorporates the whole software application including the RMT Solver, RMT user interfaces and system interfaces to SPD.</td>
</tr>
<tr>
<td>RMT Solver</td>
<td>That part of the RMT application software that provides the model simulations and predicts reserve requirements.</td>
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<tr>
<td>RMTSAT</td>
<td>A TSAT software application that allows complex control systems to be represented.</td>
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<tr>
<td>SIR</td>
<td>Sustained Instantaneous Reserve&lt;br&gt;&lt;br&gt;<strong>Spinning reserve</strong>: The average additional output in MW provided between 0 and 60 seconds in relation to a standard frequency excursion where the frequency drops to 48 Hz at 6 seconds and then recovers to 49.25 Hz at 60 seconds and where the total output provided at 60 seconds is to be sustained until 15 minutes after the event.&lt;br&gt;&lt;br&gt;<strong>Interruptible load</strong>: The average drop in MW that occurs between 0 and 60 seconds of the frequency of the grid system falling to or below the trip frequency (49.2 Hz) and which is sustained until advised by the system operator.</td>
</tr>
<tr>
<td>SPD</td>
<td>Scheduling, Pricing, and Dispatch Software</td>
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<tr>
<td>TWRO</td>
<td>Tailwater Depressed Reserve Offer</td>
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7 STANDARD FREQUENCY EXCURSION CURVE

The standard frequency excursion curve represents the typical worst case under frequency that may occur in response to a contingent event. The curve has been chosen as the critically damped second order response that reaches a minimum of 48 Hz at 6 seconds and recovers to 49.25 Hz at 60 seconds:

\[ \text{Freq (t)} = 49.25 + (0.75 - 0.8055t)e^{-0.1973t} \text{ Hz} \]

Figure 8 - Standard Frequency Excursion Curve