National Winter Group 2010 Initial Report

April 2010

Kevin Small on behalf of the National Winter Group

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SYSTEM OPERATOR

Keeping the energy flowing

TRANSPOWER

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1 Purpose

The purpose of this report is to advise both the Electricity Commission General Manager, GM System Operations Transpower and the New Zealand Electrictiy Industry of the initial outlook for winter 2010, as identified by the National Winter Group.

1.1 National Winter Group 2010

The first National Winter Group (NWG 2007) was established in August 2006. The NWG 2007 was an electricity industry working group co-ordinated by the System Operator. The task set for the group was to determine the ability of the power system cope with 2007 peak winter demand. The need for the 2006 group arose from apparent issues in meeting system peak demand in June 2006.

A NWG 2008 group was established in October 2007 at the request of the Electricity Commission (EC) and Ministry of Economic Development (MED) following the decision by Transpower to stand-down HVDC Pole 1. Contact Energy subsequently advised in late October that New Plymouth Power Station may not be available during winter 2008. As in 2006 the brief was to determine an industry view of the ability of the power system to meet winter peak demand using the same approach and methodologies as for the NWG 2007 work.

A NWG 2009 was established to consider changes since the 2008 report was issued. Given there has been only minor change in the generation stock since the 2008 report the NWG had sought further information regarding the intended use of the HVDC Pole 1, of New Plymouth (NPL) station and critically the expected demand for 2009. The demand value is of particular interest given the 2008 forecast was rendered unusable due to the power saving campaigns and reaction to high price during the low inflow period in winter 2008. In addition, the likely impact of the economic down turn on peak electrical demand needed careful consideration.

For NWG2010, one of the main concerns is the likely operating policy for HVDC Pole 1. A review was has been conducted of the methodology and assumptions applied to the analysis of the generation group data to ensure the relevance to the operating conditions likely to be prevalent in winter 2010. As a result of this review, a number of changes have been made around the HVDC transfer limits, the analysis of the variable generation and the available North Island Sustainable Instantaneous Reserve (SIR).

The individual members of the group have been drawn from electricity sector stakeholders and market participants. Details are in section 4.1.

1.2 Nature of this Report

As part of the NWG 2008 work it was identified that first establishing the demand and generation balance would provide a greater focus to any subsequent options work, this methodology has been carried over to the NWG 2010 report.

This report therefore is the view of the power system's ability to meet winter peak demand, in advance of the work to identify the options to address the possible outcomes in this report. As such it is the completion of the first stage of the NWG 2010 process and results may change when any options work is completed.

The views and recommendations expressed in this report and its attachments are drawn from the individual contributions and expertise of the various NWG members. They should not be read as in any way reflecting the views or positions of specific industry participants.

This report is a result of collaboration, consultation and co-ordination within the electricity industry. The analysis has been by necessity restricted as that required to pragmatically determine the ability of the power system to meet peak demand in winter 2010.

The purpose of this collaboration has been to collectively work to minimise risks in meeting the peak demand in winter 2010.

1.3 Summary of the Outcomes from NWG work

The NWG 2010 has established a view on the prudent estimate of the peak demand that is unlikely to be exceeded in winter 2009. This prudent demand is 5029 MW[1] for the North Island, up 8.6% on the actual peak winter demand in 2009 The prudent demand for the South Island is 2538 MW, up 15% on the equivalent peak demand in winter 2009. The South Island winter 2010 peak reflects the return to service of the potline at Tiwai towards the end of winter 2009. This accounts for an increase of approximately 180 MW over the 2009 peak (+8%) thus giving an actual growth of 7% for the South Island demand peak.

The generation group analysis has undergone a significant change from previous years. The review encompassed all aspects of the Generation analysis, including:

- The stations included in the statistical analysis of generation availability
- The assumptions around HVDC transfer limitations and an extension of the timeframes for considering generation outages and their effect on the available generation over demand peaks.

The review resulted in several additions and changes:

- Inclusion of Aniwhenua in the run of river generation analysis
- Addition of a SIR analysis for North Island Run of River hydro schemes
- Calculation of a statistical limit on HVDC north flow using total North Island SIR offers
- Inclusion of Pole 1 in the HVDC transfer as per the Grid Owner's offer of the 6th January 2010
- It was considered prudent not to include Contact Energy's Stratford peaking plant in the analysis as their planned commission date at the end of June would mean that they may not be available for the peak demand.

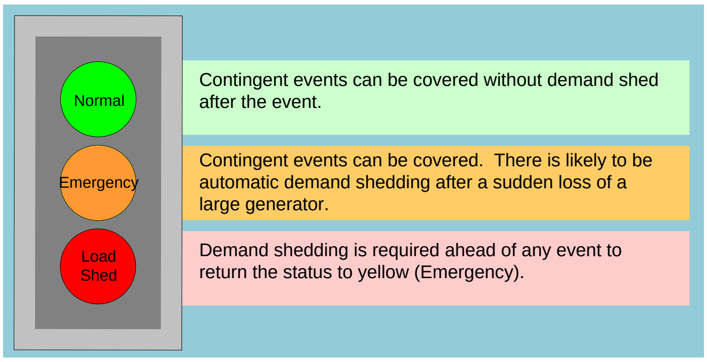
The results of the analysis of peak winter demand and generation availability for winter 2010 is summarised in the five key questions and answers below. The answers to the questions reflect the ability to continue to operate the power system in one of three states.

- <u>Normal secure state</u> – Power system status green. There will be no disconnection of consumers even if there is a sudden loss of a large generator or HVDC Pole during the critical winter evening peak demand periods.
- <u>Emergency secure state</u> – Power system status orange. There will be the automatic disconnection of a significant number of consumers,[2] ***only if*** there is a sudden loss of a large generator or the HVDC Pole at the time of winter peak evening demand.

[1] Demand group Prudent forecast plus losses and intra half hour variability allowance. The number used in graphs and generation report includes an additional 50MW for frequency keeping. The prudent demand is a projection from past years with a 5% probability of being exceeded (P95)

[2] This assumes that Automatic Under Frequency Load Shedding (AUFLS) operates. AUFLS is a critical safety mechanism to preserve the integrity of the power system by disconnecting one or two 16% blocks of consumer demand in this case across the North Island.

§ Load shedding required – Power system status red. Disconnection of consumers will be required for some critical winter peak periods to maintain the power system in an emergency secure state even without the loss of any generation or the HVDC.[3] There is still a risk that further demand will be shed automatically.



The answers assume all generation is available. In this context, "available" refers to generation being connected to the power system and ready to generate. The "commitment" issue for some slow starting generation is covered in the Background section that follows.

1.4 Key Questions

The answers are based in the assessment for Winter 2010. They do not reflect the impact of any initiatives from any options work that may be forthcoming.

Question 1: Can the forecast peak winter demand on the power system for winter 2010 be met?

Answer: There is a high confidence that should all the generation available be committed to run that the power system will be in its normal secure state (status green) at peak winter demand. Should there be a failure or inability to commit all available thermal units then the system may be operated in the Emergency Secure State (status Orange).

Question 2: Can the forecast peak winter demand on the power system be met if generation, equivalent to one of the large gas fired combined cycle generating units, is unavailable for a sustained period for some reason?

Answer: There is a medium level of confidence the power system will able to be operated in its normal secure state (status green) at peak winter demand if a large generating unit is unavailable and while all other generation with firm fuel supplies remain available.

Question 3: If there is already a sustained outage of a large combined cycle generating unit, can we still meet peak winter demand if a second such generating station stops running?

Answer: Even with all other generation in service it would be necessary to disconnect some consumers at peak times to maintain the power system in an emergency secure state. This question relates to a particularly onerous situation where the equivalent of two large combined cycle gas stations are not running.

Historically the NZ power system has never been able to meet this scenario at times of system peak.

If this situation arose the power system would be operated in an emergency secure state (status orange) for significant period at times of peak winter

[3] It is important that the power system is in a secure state at all times (even if demand must be shed to get back to the emergency secure state).

demand. The Power System would on a few occasions move into the load shedding required state (status red) when the disconnection of some consumers would be required at peak times to return the system to the emergency secure state.

Question 4: How does the capacity margin (n-1) for the NI between prudent peak demand forecast (5% probability of being exceeded) and prudent lower bound peak generation (20% probability of being less than) for winter 2010 compared to the forecast for 2009?

Answer: The capacity margin for 2010 has increased compared with the 2009 forecast. The forecast margin for winter 2009 was 82 MW, the forecast margin for 2010 is 134 MW.

Question 5: In the past how often has the power system been at, or near, to the maximum peak winter demand?

Answer: Historically the power system is within 1% (ie 70 MW) of the peak winter demand for about 2 to 3 hours in a typical winter. The power system is within 5% (325 MW or close to the output of a large generating unit) for about 60 to 80 hours over a typical winter.

1.5 Interim view on ability to meet Peak Demand for Winter 2010

In order to remain in the normal secure state (status green) we are reliant on the commitment or immediate availability of all thermal plant and the 100% reliability of this same plant, it is therefore the view of the National Winter Group 2010 in this Report that the ability of the power system to meet peak winter demand in 2010 in a normal secure state (status green) is "at risk" if all thermal plant is not available and committed.

If there was a sudden unexpected failure of a large generating unit the power system would be operated in the emergency secure state, however there is unlikely to be any impact on supply to consumers.

The System Operator advises that operating the power system in an emergency secure state is only contemplated for a short period following a major power system event. Due to the significant consequences to consumers, planning to operate the power system in the emergency secure state in the absence of any event is not considered prudent by the System Operator as safety mechanisms will automatically and instantaneously disconnect up to 32% of consumers following a sudden loss of a large generator or HVDC.

Based on this initial view of Winter 2010, there are no requirements for additional work streams to consider the management of peak security over and above existing work in which the EC and System Operator are already engaged.

2 Background

2.1 Peak Winter Demand

Peak winter demand can place the power system under some stress requiring all generating units on the power system and most grid assets to be able to deliver full consumer demand. The overall New Zealand wide peak on the power system usually occurs sometime between June and August at around 5:30 to 6:00 pm on a cold weekday evening. This can be associated with a fast moving southerly storm sweeping over the country within 24 hours.

The demand workstream of the NWG has developed a forecast of the prudent system peak for the North and South Islands for winter 2010. This forecast has a very high confidence and is unlikely to be exceeded by the actual winter peak in 2010.

2.2 Outlook for Winter 2010

The task set for the National Winter Group is to determine the ability of the power system to meet peak winter demand in 2010. The Electricity Commission has separate processes to manage “dry year” risk where there may be insufficient fuel to meet demand.

This report should not be read as expressing a view on overall power system adequacy. The NWG is only concerned with the ability of the power system to meet the peak winter demand. That is having sufficient generation capacity in the market at the time of peak winter demand to avert the need for a Grid Emergency being declared, and the consequential actions that can follow.

2.3 Enabling the Full Commitment of Generation at System peak

The current market arrangements focus on the delivery of generation to meet energy demand. Historically the underlying assumption has been that the New Zealand power system has sufficient fast starting generation capacity available to cover peak system demand along with any sudden credible changes in generation availability.

In this report, when the forecast peak winter demand is overlaid on the generation capability stack it requires all generation both “fast starting” and “slow starting” to be available to generate at times of peak winter demand.

2.4 Enabling the Timely Commitment of Slow Starting Generation

The generation capability stack includes uncommitted slow starting thermal generation, which can only contribute to meeting a peak winter demand if it has been warmed up or generating in advance. Start up times for this slow start thermal generation is from 3 to 12 hours. Therefore, if not already running, slow start generation is unlikely to be available immediately for an unexpected change in generation availability, such as the failure of a large gas fired generator during the day close to the time of peak winter demand.

Noting the slow starting nature of this generation, there is a risk that if the market signals showing that this generation is required, are not delivered in a timely and accurate manner , then the generation may not be offered and therefore available when needed.

3 Workstream Summaries

The summaries from the demand and generation workstreams follow. The detailed workstream reports are attached as appendices.

3.1 Demand Workstream

The **Demand Workstream** report details the analysis carried out in establishing a prudent, unlikely to be exceeded, peak forecast for winter 2009 for both the North and South Islands as well as New Zealand overall.

The system demand figures in the Demand workstream analysis refer to average half hour **offtake** from the power system at the Transpower grid/line company interface. Other references to overall system peak demand figures in the Generation workstream report are for average half hour **injection** into the power system – the energy transferred from power stations into the grid. The difference between offtake and injection are the losses in transmitting power through the grid.

The modelling of the prudent peak requires:

- A forecast of mean demand in 2010 (P50). As in previous years AVALON revenue metering data was used and applied to a number of top down forecasting methodologies.
- Calculation of an appropriate margin or confidence interval to allow for the likely variation around this mean resulting from changes in the peak demand growth rate, changes in ambient temperature, and changes in consumer behaviour. Consideration was given to how a number of factors would be dealt with including:
    - Impact of the 2008 demand saving campaign
        - Previous demand saving campaign in 2003 leaded to the year being removed from the data set, the 2008 year was treated in the same way.
    - Impact on peak demand of the economic down turn.
        - While the economic down turn will effect total energy consumption it is considered unlikely that it would materially impact peak demand.
- Calculation of an appropriate allowance for losses in each island and at a national level;

The load flow analysis conducted by the system operator suggests an allowance of 148MW for losses at system peak is appropriate for the North Island.

- Establishment of an appropriate allowance for the likely variation within the half hour.

The results of the various methodologies for modelling peak demand are set out in the following tables.

North Island		
Methodology	***Expected Peak (MW)***	***Prudent Peak (MW)***
Linear Regression (confidence interval)	4,473	4,634
Linear Regression (prediction interval)	4,473	4,536
Modified Linear Regression (Hi Growth)	4,507	4,668
Consensus		**4,645**
Losses		**148**
Half Hour Variability		**39**
Recommendation for Peak Demand		**4,832**

The South Island forecast has the Tiwai potline load added to the 2009 peak to allow for its return to service.

South Island		
Methodology	***Expected Peak (MW)***	***Prudent Peak (MW)***
Linear Regression (confidence interval)	2,249	2,311
Linear Regression (prediction interval)	2,202	2,281
Modified Linear Regression (Hi Growth)	2,254	2,316
Consensus		**2,321**
Losses		**110**
Half Hour Variability		**13**
Recommendation for Peak Demand		**2,444**

New Zealand		
Methodology	***Expected Peak (MW)***	***Prudent Peak (MW)***
Linear Regression (confidence interval)	6,694	6,884
Linear Regression (prediction interval)	6,596	6,820
Modified Linear Regression (Hi Growth)	6,721	6,911
Consensus		**6,931**
Losses		**241**
Half Hour Variability		**85**
Recommendation for Peak Demand		**7,257**

3.2 Generation Workstream

The **Generation workstream** report covers the analysis of generation available to cover system peaks. The report establishes a prudent view of generation availability at peak for both the North and South Islands. Given the demand forecast this report then sets out the result of the peak demand/generation balance. This result is summarised in the four questions and answers in the summary of this report.

The objective of this work was to define a generation capability stack to ascertain whether there is likely to be sufficient generation to cover the system and demand requirements (energy, reserve and frequency keeping) for the ***forecast*** 2009 peak winter ***demand***. The period considered for analysis purposes were the months of June to August.

The approach in developing the generation used was similar to that used in previous years.

Each of the generators provided their generation values and time series data for stations and blocks across New Zealand. For generation with a variable output due to fuel ***constraints***, the levels of generation have been taken at a 90% confidence level. That is, "the level of generation noted has, historically, been available 90% of the time using time of day and the last ten (10) years data where available."

Noting the varying types of generation within the New Zealand Power system, the generation group agreed on a "classification system" for generation type. The classification type is representative of the physical nature of the generation.

The generation capability stack therefore includes:

§ Thermal;
§ Geothermal;
§ Hydro – storage;
§ Hydro – run of river (variable);
§ Wind (variable);
§ Co-generation (variable);
§ Uncommitted – fast start (available within a couple of hours);
§ Uncommitted – slow start (requires a number of hours for a "cold start").

In addition the stack includes:

§ industrial interruptible load (classified as a "positive" generation figure);
§ Run of River Sustained Instantaneous Reserves (SIR - classified as a "positive" generation figure);
§ frequency keeping (classified as a "negative" generation figure);

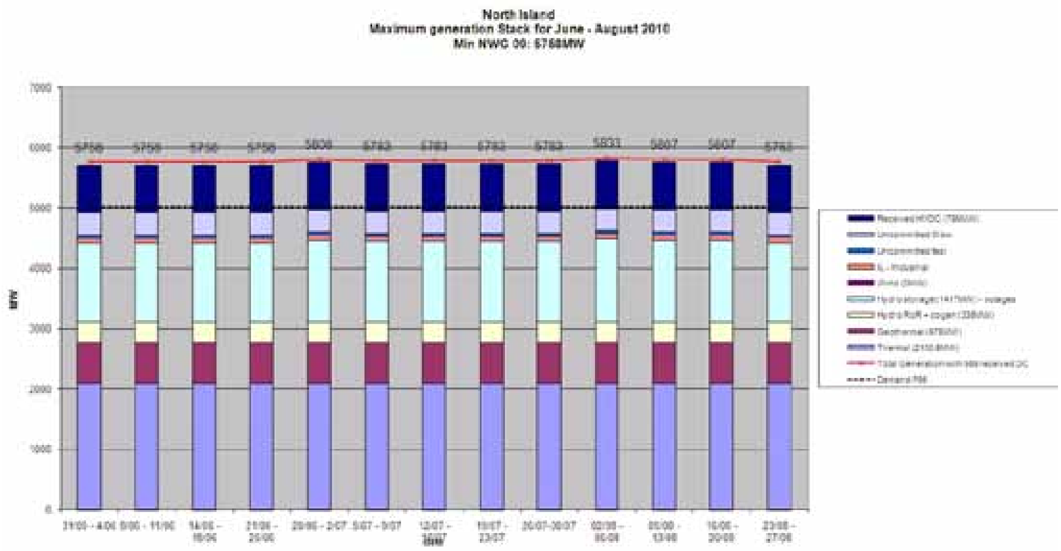
§ North or South Island ***contingent event*** risk with respect to reserve requirements (classified as a “negative” generation figure).

A further analysis of North Island SIR offers for 2009 was conducted to determine a prudent (P10), reserve constrained north flow transfer limit on the HVDC Pole 2.

Notified outages (from POCP) were considered and applied to generation output where appropriate for the relevant time periods.

Taking into consideration all of the above, the System Operator converted the data into two generation capability stacks one for each Island, with the “uncommitted” generation at the top. For simplicity, each stack has been presented in graphical form.

The North Island stack



The forecast peak demand figure for each Island (as advised by the demand group) was then overlaid on the respective generation capability graph. In the South Island this determined the surplus generation available for transfer to the North Island. In the North Island the generation stack and HVDC transfer was used to establish if there was sufficient capability to meet system peak demand.

The demand/generation balance for the South Island indicated that 495 MW was available for export to the North Island after South Island prudent demand, reserves and frequency keeping were deducted from the available generation. (683 MW in 2008)

Two scenarios have been considered for HVDC transfer. The first is that Pole 2 only is scheduled and run at 700 MW sent north flow (650 MW received). The second is that the bipole is running at 200 MW, as per the Grid Owner offer, and that Pole 2 is running at a level constrained by the available SIR in the North Island. A P10 value for the NI SIR allows up to 595 MW received over Pole 2. This would then set Pole 2 as the North Island risk and reserves are removed from the generation stack to allow for this.

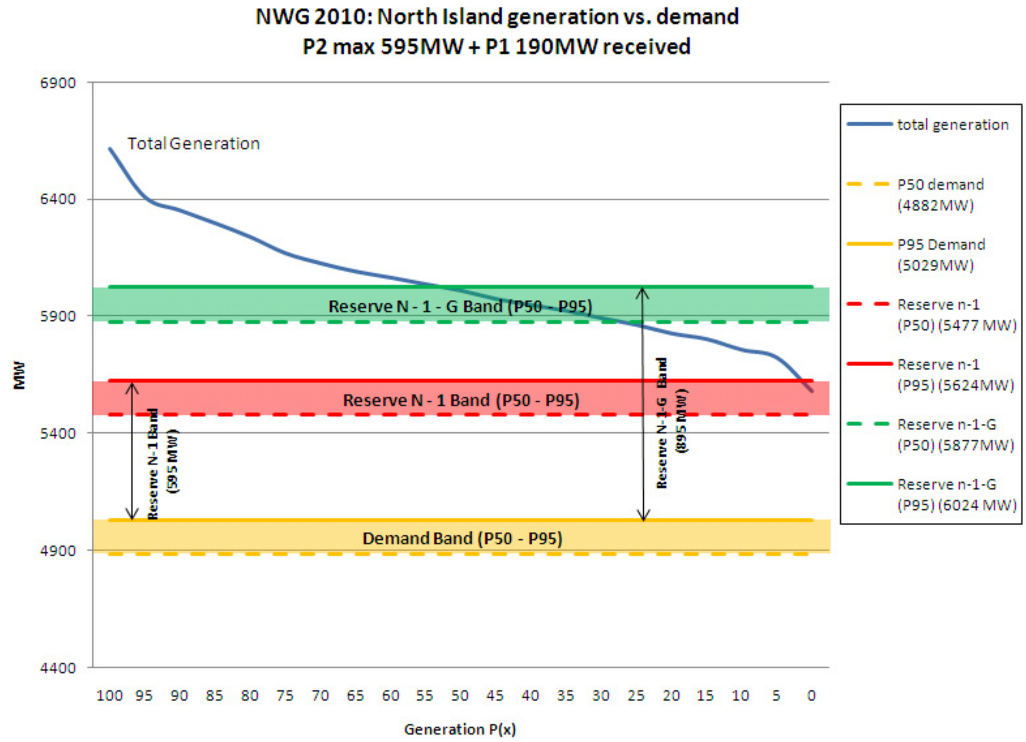
The graph above demonstrates that there is sufficient capability within the system to meet the forecast North Island peak demand of 4979 MW (which includes system losses) and a margin of 50 MW for frequency keeping.

The generation group then identified whether the system in the North Island would be secure in the normal secure state for the sudden loss of a large component (either the HVDC or a major CCGT). On occasions the power system would be operated in the emergency secure state.

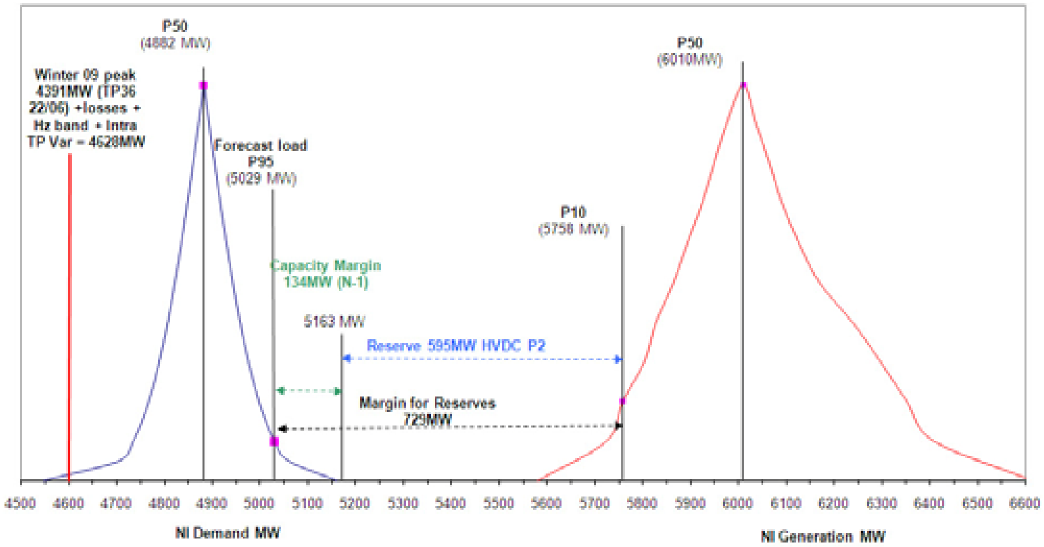
The group also considered the ability to have a secure power system ahead of the sudden loss of large component (either the HVDC or a major CCGT) if there was already a sustained outage of another major component. (e.g. an extended outage of a major CCGT).

The group concluded that there is a high level of confidence that the system can meet the projected peak in the normal secure state if all available generation is committed.

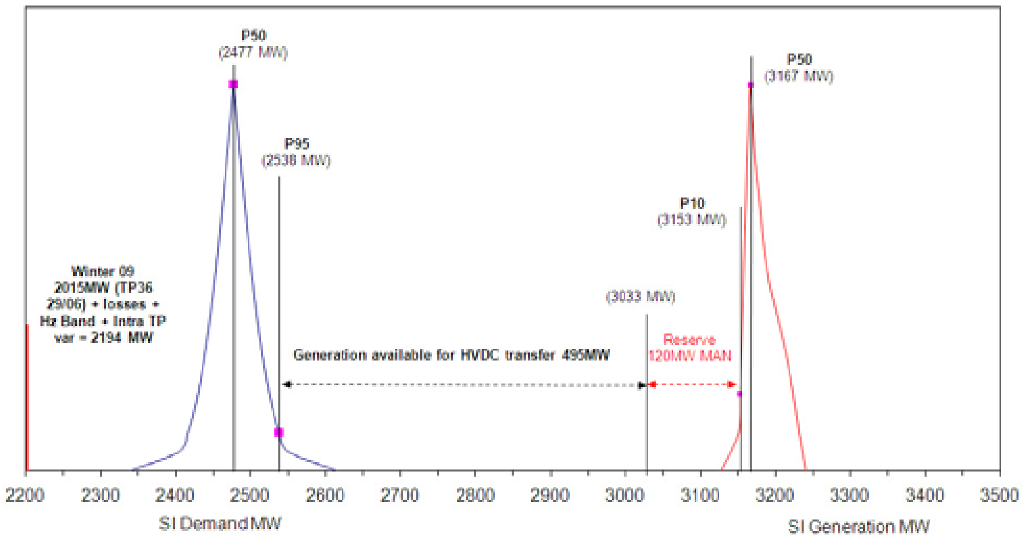
Extrapolating further the group agreed that there was a low confidence that the system would be operated in a secure state or meet peak demand with the sustained outage of two major components along with HVDC Pole 1 being unavailable. It was agreed however that historically, the system has not been able to meet this situation in the past during system peaks, nor has there been an expectation to do so.



North Island Demand and Generation Balance at Peak Winter 2010
15th Mar 2010 update. P1 at 190MW rec'd P2 at 595MW rec'd



South Island Demand and Generation Balance at Peak Winter 2010
15th Mar 2010 update.



Demand Curve – assumes demand peak values are normally distributed. P95 value is 5029 MW incl 39 MW for half hour variation, and 148 MW for transmission losses.

Generation Curve - Generation stack forecast for the weeks including 31 May to 25 June 2010, for which the P10 value was 5758 MW. The generation stack includes a fixed and variable generation components. Total generation for this week ranged from a minimum of 5581 MW (0 percentile from the 'variable generation component') to a maximum of 6613 MW (100% of the variable component). Note values were determined from the cumulative distribution curve (inverted after 50%).

The smallest N-1 margin between the P95 Demand and P10 Generation assessment over June/July is ~134 MW which is requires all generation including slow starting thermal generation.

4 Appendices

4.1 NWG Memberships

Name	Representing
Chris Sadler	Vector
Andy Anderson	Mighty River
Peter Yeung	Vector
Ashley Wall	Genesis Energy
Ting Si Kuok	Contact
Ralph Matthes	MEUG
Glenn Coates	Orion
James Collinson-Smith	Contact Energy
Richard Spearman	Trustpower
Peter Osborne	Genesis Energy
Greg Salmon	Meridian
Tristan Maunsell	Todd Energy
Brian Bull	Electricity Commission
Chris Otton	Transpower
Siobhan Procter	Transpower
Ray Basher	Transpower
Kevin Small	Transpower

4.2 Demand Forecast

4.2.1 Background

The Demand Group has been tasked with building on the work of the previous National Winter Groups in developing a prudent estimate of peak demand for winter 2010 for the North Island, the South Island and New Zealand.

4.2.2 Peak Demand Data Set

The demand working group used the Avalon data set, the same data set as used previously.

- Transmission losses are not included and therefore an appropriate allowance must be made when comparing the forecast demand with the generation stack;
- Distribution losses (or losses on the customer side of the GXP) are implicitly included in the data and therefore do not need to be separately provided for;
- This series records the net demand at the GXP therefore the volume of embedded generation dispatched “outside the market” is implicitly included. The decision was taken to add back embedded generation that have been included in the generation stack to the net demand figure;
- Embedded generation that is “market dispatched” is not netted against demand at the GXP and therefore need to be included in the generation stack.
- As with previous years the 2003 data point was affected by the “savings campaign” that year and therefore removed from the data set.
- Likewise the 2008 data point has been excluded from this data set on the same basis (the 2008 savings campaign likely affected the observed peak demand). In addition the 2008 data was not used to determine an

appropriate allowance for losses as the unusual generation pattern resulting from the lack of storage in the South Island damaged this data point.

- One Potline at Rio Tinto has been shut down from November 2008 to a partial return in July 2009. The potline was not drawing at full load until after the 2009 winter period. The demand figures for the South Island for 2009 have been adjusted to include the full potline load. This should allow the 2010 forecast to represent the true South island load with the potline running.

The modelling of the instantaneous prudent peak demand therefore requires:

- A forecast of mean demand in 2010 (P50);
- Calculation of an appropriate margin or confidence interval to allow for the likely variation around this mean resulting from changes in the peak demand growth rate, changes in ambient temperature, and changes in consumer behaviour. This margin will be expressed in probabilistic terms;
- Calculation of an appropriate allowance for losses in each island and at a national level; and
- Establishment of an appropriate allowance for the likely variation within the half hour (in order to generate the instantaneous peak demand forecast required for planning purposes).

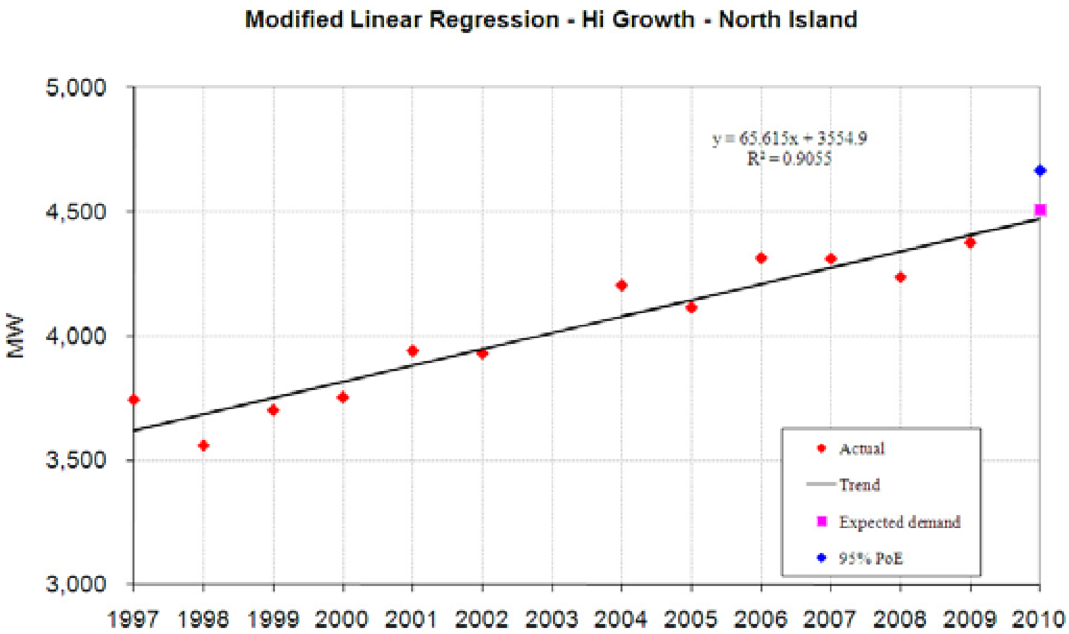
4.2.3 Linear Regression

The Demand Group applied a number of related statistical analysis techniques to the available data set. All of the techniques applied are founded on linear regression to some degree. The techniques can be characterised as top-down, rather than bottom-up, i.e. no attempt was made to estimate peak demand by building the likely demand up from discrete customer classes or activities. Therefore no allowance has been made for any reduction in peak demand resulting from the current global financial situation.

In the following sections the North Island data is used, the summary table sets out the equivalent results for the South Island and the New Zealand data sets.

Linear regression was applied to the annual highest peak data series to test whether the equation generated is a useful means to describe the series (and therefore useful in forecasting the 2010 peak). This technique fits a line to the data series producing what is often referred to as a ‘line of best fit” or trend line. A prudent peak demand forecast for 2010 is plotted (blue diamond); the calculation of this value is set out below.

The following chart displays the result of this analysis.



The R^2 factor of 0.9055 suggests that time (movement along the x-axis) explains 90.55% of the observed variance, which from a statistical analysis perspective is evidence that the linear regression technique applied is generating a useful model of the data set.

4.2.4 Variation Around the Trend Line

After fitting a trend line to the data series, the standard error of the variance between the data series and the trend line can be calculated. The standard error calculated using the Excel function is 86 MW. Variations around the trend line are assumed to be normally distributed with an equal likelihood of the 2010 demand peak being above or below the trend line.

Student's t Tables are used to estimate the range of this expected variation for a given confidence level. The Demand Group determined that an appropriate probability of exceedance (PoE) is in the order of 5% or one in twenty years.

4.2.5 Prudent Peak Forecast Using Linear regression

The application of linear regression, using excel to calculate the standard error of the data set, produces a prudent peak forecast as follows:

Prudent Peak NI $_{\text{Linear Regression}}$ = 2010 trend line + standard error x $t_{(.05,\ 8)}$

= 4,473 + 86 x 1.859548
= 4,473 + 160
= 4,634 MW

4.2.6 Limitations of Linear Regression

The available data set has just 12 data points (with 2003 excluded). This is a relatively small data set; therefore the linear model developed is relatively simple. The results of the linear regression analysis should therefore be viewed in this context.

4.2.7 Modified Linear Regression

This approach uses linear regression to fit a trend line to the observed peak demand data points since 1997. The linear regression model calculates mean demand in 2009 of 4,408 MW. This mean value is then grown by an assumed growth rate to generate the expected demand for the 2010 year.

As with linear regression approach, the variance around the mean peak demand is calculated using the standard excel approach to calculating the standard error implicit in the data series multiplied by the appropriate student t factor to give the desired level of confidence.

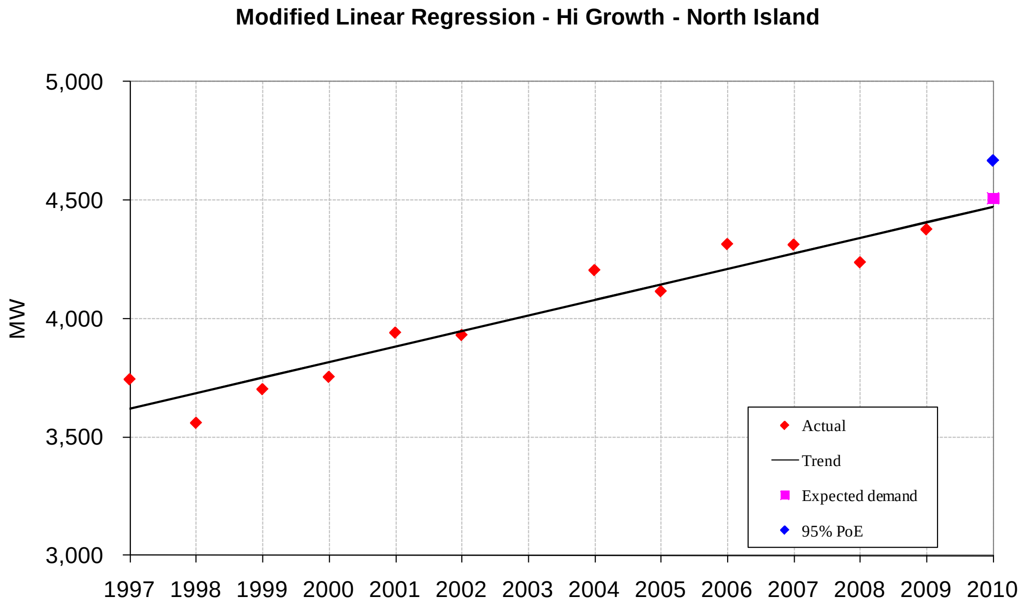
4.2.8 Modified Linear Regression (Hi Growth)

This 2009 expected peak is grown by 2.3% (per EC 2008 SoO) to give an expected forecast of 4,507 MW for 2010. The standard error calculated by excel was then applied to generate a prudent peak as follows:

Prudent Peak Mod $_{\text{Hi Growth}}$ = P50 forecast2008 + standard error x t (.05, 8)

= 4,507+ 86 x 1.859548
= 4,507 + 160
= 4,668 MW

The following chart illustrates this approach and the forecast generated:



4.2.9 Weaknesses of Modified Linear Regression Model

This methodology addresses the inability of a linear regression model to recognise emerging trends, by replacing the linear model with a growth rate to generate the 2010 expected forecast. The peak demand growth from the EC's 2008 Statement of Opportunities was used as the growth rate in the 2010 year.

4.2.10 Losses

The group has endeavoured to gain an understanding of transmission losses at system peak. The group recognises that losses vary significantly between normal and abnormal operations of the grid. The load flow analysis conducted by the system operator suggests an allowance of 148 MW for losses at system peak is appropriate for the North Island.

4.2.11 *Summary*

The results of the various methodologies for modelling peak demand are set out in the following tables.

North Island		
Methodology	Expected Peak (MW)	Prudent Peak (MW)
Linear Regression (confidence interval)	4,473	4,634
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Recommendation for Peak Demand		7,257

The demand group considered all approaches to have some merit and equally some weaknesses. In the interests of expediency, and with the requirement to produce a prudent forecast in mind, the Demand Group considers the recommendations made best meet the requirements of their brief.

4.3 Generation

4.3.1 Introduction

The purpose of the Generation group is to define the likely available generation during winter period 2010. This generation figure will be evaluated against the demand figure produced by the Demand Group.

Generation group examines three scenarios:

1. N – G (Loss of largest unit)
2. N – 1 (Loss of HVDC Pole 2)
3. N – G – 1 (Loss or outage of largest unit and loss of HVDC Pole 2)

Each scenario above looks at North Island and South Island separately.

An analysis of the winter 2009 North Island SIR offers has been made to determine a statistical basis for a reserve constraint on Pole 2 north flow. We consider two HVDC transfer scenarios, the first is a reserve limited Pole 2 North transfer of 595 MW received and the second is with an additional 190 MW received from the half pole.

The following section explains the provenance of data and methodology used to derive the generation figures for each generation type.

4.3.2 Provenance of Data and Methodology

Generators across New Zealand have provided their generation values and time series data. Generations values provided are typically for generators which are operated by fuel or non-varying profile i.e. thermal, geothermal and a number of the co-generation plants.

Time series data are for generators that have strong reliance on weather or varying profile i.e. hydro run of river, large hydro storage and wind turbines. Generation group utilised the time series data to obtain the 10 percentile value. The 10 percentile value indicates generation that is available 90% of the time.

Other than generation information, System Operator also evaluates Interruptible Load offers at 10 percentile.

Planned outage information is obtained from POCP and used to offset the total generation available for each generation type. This information is attached in the section 4.7.

Thermal

The table below provides detailed breakdown of thermal generation values provided by Contact, MRPL and Genesis. It excludes thermal generators that are categorised as uncommitted fast and uncommitted slow. Uncommitted generators figures are covered in Section 4.3.7.

Generators	MW	Comment
Stratford TCC	372	
Otahuhu OTC	392	
Southdown SWN	125	
Huntly 1-4 HLY	607.5	3 units, 1 or 2 are uncommitted slow (average 364.5 MW)
Huntly 5 HLY	400	
Huntly 6 HLY	48	
Whirinaki WHI	156	
Total Thermal	2100.5	

Geothermal

Contact and MRPL have provided generation values for geothermal plants as shown in table below.

Generators	MW	Comment
Poihipi	49	
Ohaaki	55	
Wairakei	171	
Mokai	113	MRP + TPC
Rotokawa	35	Embedded Generator
Tauhara	23	
Kawerau	102	
Nga Awa Purua	130	
Total Geothermal	678	

4.3.3 *Hydro Run-of-river and Co-generation*

North Island

The hydro run-of-river and some of the co-generations time series data have been aggregated to obtain the value at 10 percentile. The time series data only considers weekdays, trading period 34 to 38 (16:30 to 18:59), and covering the months of June to August from 1999 to 2009. Kinleith, Whareroa and TeRapa values were later added to obtain the collective value.

Hydro run-of-river generators in North Island are Kaimai, Patea, Matahina, Wheao, Mangahao, Aniwhenua and Rangipo. Co-generations in North Island that are aggregated together in the series are Glenbrook and Kapuni.

Kinleith (35 MW), Whareroa (60 MW) and TeRapa (45 MW) values are as given to System Operator.

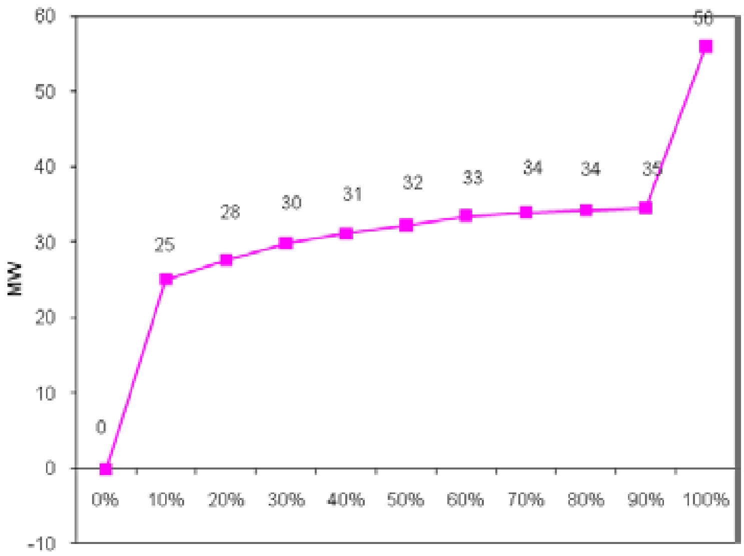
The table below shows the collective value of 338 MW at P10.

Percentile	Aggregated Hydro Run-of-river and Co-generation (MW)	Collective MW With Kin, WAA, TRC (+140 MW)
0%	121	261
10%	198	338
20%	222	362
30%	239	379
40%	255	395
50%	269	409
60%	284	424
70%	303	443
80%	325	465
90%	348	488
100%	424	564

South Island

Hydro run-of-river generators in South Island are Branch, Kumara, Highbank and Patearoa. The base data only considers weekdays, trading period 34 to 38, and covering the months of June to August from 1999 to 2009. The following table shows the generation cumulative distribution. The 10P value is 25 MW.

South Island Hydro Run of River



4.3.4 *Hydro Storage*

North Island

The table below summarises generation values from Genesis and MRPL. Total Hydro storage in North Island is 1417 MW.

Generators	MW	Comment
Waikato River WTO	1042	
Waikaremoana WKA	135	
Tokaanu	240	
Total Hydro Storage	1417	

South Island

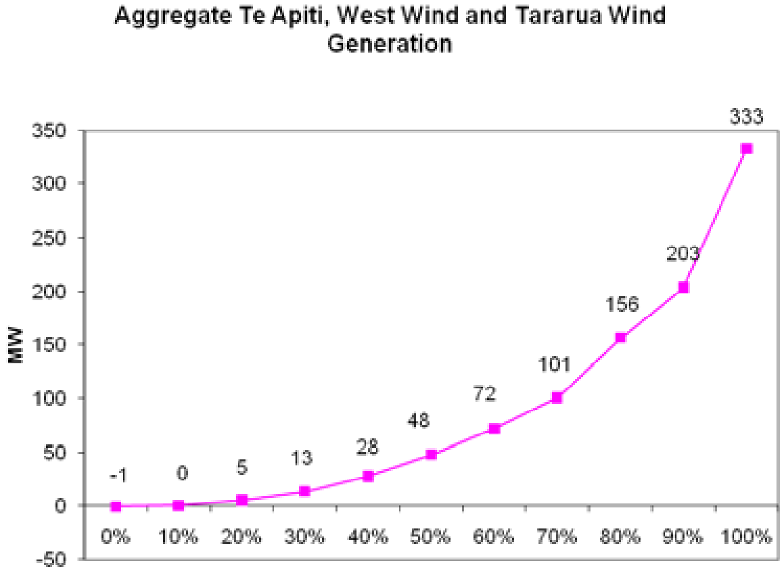
Total Hydro storage in South Island is 3219 MW.

Generators	MW	Comment
Roxburgh ROX	280	
Clyde CYD	400	
Waitaki River WTK	1665	
Manapouri MAN	729	
Cobb COB	32	
Coleridge COL	35	
Waipori WPI	78	
Total Hydro Storage	3219	

4.3.5 *Wind*

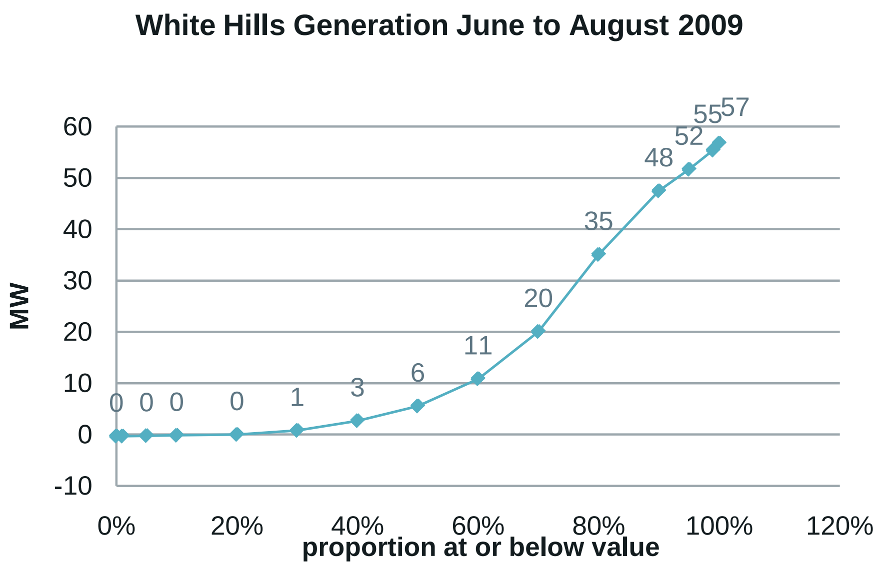
North Island

Te Apiti and Tararua wind farms data are aggregated from 2005 to 2009 for the months of June to August, covering trading period 34 - 38. The 2009 data also includes West Wind. The 10 percentile value is 0 MW as shown in the next chart.



South Island

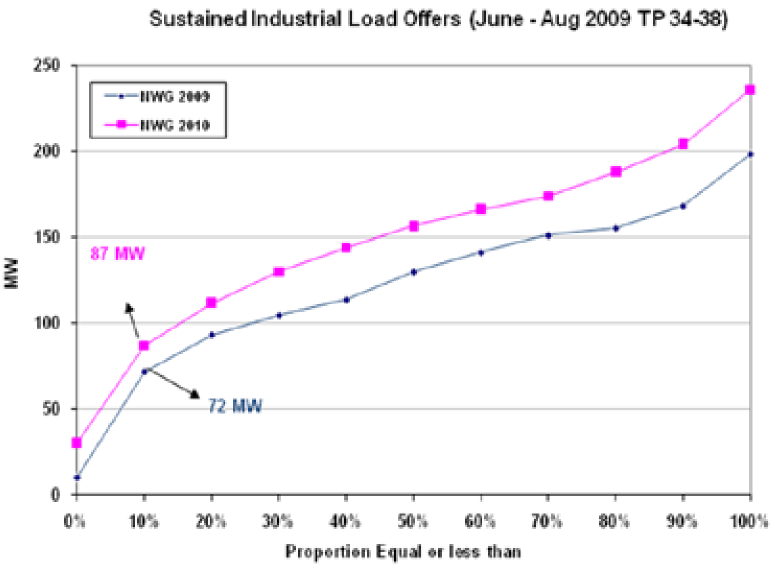
White Hills wind farms data has been analysed for the months of June to August 2007 to 2009. The 10 percentile value is 0 MW as shown in the chart below.



4.3.6 Sustained Instantaneous Reserves

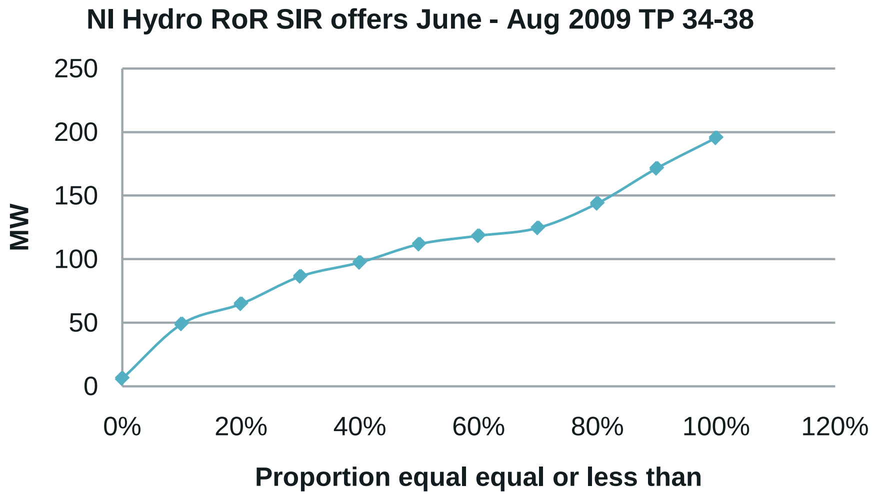
Interruptible Load

System Operator has analysed the sustained industrial load offers from NZST, PPAC and SKOG for June – August 2009, covering trading period 34 – 38. The chart below shows the resulted sustained load profile and profile produced by NWG 2010. The P10 value increased by 15 MW from last year's analysis. NWG 2009 only considered June to July offers but same trend is observed.



North Island Run of River SIR offers

System Operator has analysed the SIR offers from the North Island Run of River stations Matahina, Wheao and Rangipo. The offers for June to August 2009 were aggregated and the P10 value of 49 MW.



North Island generator SIR offers

The SIR offers for the North Island generators were extracted for June to August 2009 and aggregated by trading period for TPs 34 to 38. This data was then added to the IL and RoR SIR data to produce an approximate value for the North Island reserve capability. This value would be used to determine the maximum transfer level available for HVDC Pole 2 transfer. The 10th percentile value is 596 MW.

4.3.7 *Uncommitted Fast and Slow*

The table below summarises uncommitted plants figures as given to System Operator.

Generators	Fast	Slow	Comment
Huntly 1 / 2 units		364.5	
Southdown SWN – E105	50		
Roxburgh	40		
Clyde	64		
Total	154	364.5	

4.3.8 *Reserve and FK Requirements*

Reserve values are scenario-dependant as shown in the table below.

For N – 1, reserve scheduled is to cover received DC transfer. The losses for 700 MW of DC sent utilising only P2 is assumed to be 50 MW yielding 650 MW received in the North Island. The second scenario assumes maximum transfer of Pole 1 with 190 MW received and a reserve limited transfer of 595 MW received.

Maximum P2 transfer of 650 MW received

Scenario	Island	MW	Comment
N – G	NI	400	Assume HLY U5/OTB trips
N – 1	NI	650	Assume max DC received of 650 MW (P2)
N – G – 1	NI	1050	Assume HLY U5/OTB is under outage and DC trips

Maximum P2 transfer of 595 MW and Max Half Pole transfer of 190 MW received

Scenario	Island	MW	Comment
N – G	NI	400	Assume HLY U5/OTB trips
N – 1	NI	475	Assume max DC received of 595 MW (P2)
N – G – 1	NI	875	Assume HLY U5/OTB is under outage and DC trips

Reserve requirement is set to be 120 MW for South Island.

Frequency keeping is assumed to be 50 MW per island.

4.3.9 Generation Outage

We determined the planned MW loss over June – July 2009 from generation outages information in POCP. The table below summarises the planned outage that will contribute to the deduction of generation in the stack.

North Island

Outage Type	31/05 - 4/06	8 - 11/06	14 - 18/06	21 - 25/06	28/06 - 2/07	5 - 9/07	12 - 16/07	19 - 23/07	26 -30/07	02 - 06/08	09 - 13/08	16 - 20/08	23 - 27/08
Hydro Storage	110.2	110.2	110.2	110.2	60.2	85.2	85.2	85.2	85.2	35.2	61.2	61.2	105.2

South Island

Outage Type	31/05 - 4/06	8 - 11/06	14 - 18/06	21 - 25/06	28/06 - 2/07	5 - 09/07	12 - 16/07	19 - 23/07	26-30/07	2/06/2008	09 - 13/08	16 - 20/08	23 - 27/08
Hydro Storage	90	195	105	365	365	90	196	209	155	235	145	305.2	200

The followings are the assumptions made (similar to NWG 2009):

- ARI_7 is excluded as 2 MW of long term outage is probably already accounted for
- Outages ending by 17:00 hours are not included for that day
- Manapouri unit is excluded if only 1 unit is out

4.3.10 *Summary of Variable MW*

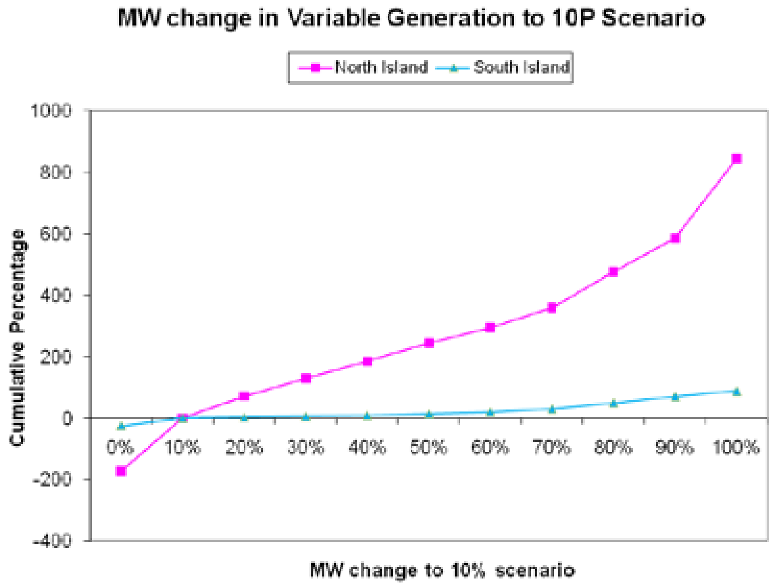
The following table gives an indication of the change in MW available as affected by variable MW components. From the North Island table it can be seen that 50P scenario gives 244 MW extra as compared to the 10P scenario. Likewise, an additional of 15 MW is observed for South Island.

North Island

Percentile	Hydro Run of River + Co-gen (Co-gen: GLN & KPI)	Wind	IL (Offers)	RoR SIR offers	Total Variable MW	MW change from 10% basecase
0%	261	-1	46	6	312	-173
10%	338	0	98	49	485	0
20%	362	5	124	65	556	71
30%	379	13	136	86	614	129
40%	395	28	149	97	669	184
50%	409	48	160	112	729	244
60%	424	72	166	118	780	295
70%	443	101	175	125	844	359
80%	465	156	196	144	961	476
90%	488	203	207	172	1070	585
100%	564	333	236	196	1329	844

South Island

Percentile	Hydro Run of River	Wind	Total Variable MW	MW change from 10% basecase
0%	0	0	0	25
10%	25	0	25	0
20%	28	0	28	3
30%	30	1	31	6
40%	31	3	34	9
50%	33	6	39	14
60%	34	11	45	20
70%	35	20	55	30
80%	40	35	75	50
90%	49	48	96	71
100%	56	57	113	88

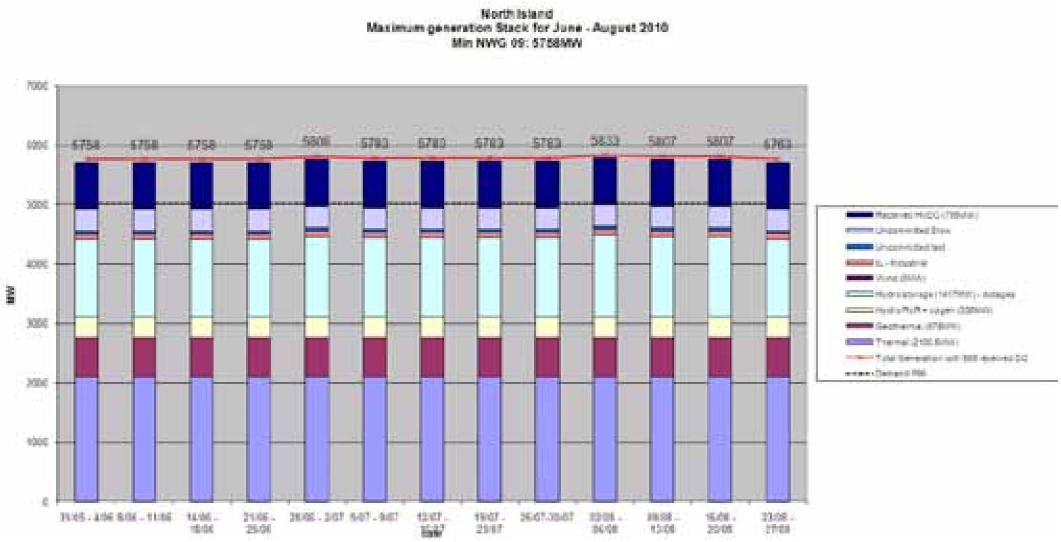

MW change in Variable Generation to 10P Scenario
North Island
South Island
Cumulative Percentage
1000
800
600
400
200
0
-200
-400
0%
10%
20%
30%
40%
50%
60%
70%
80%
90%
100%
MW change to 10% scenario

4.4 Generation Stack

The chart below consolidates all available generation based on analyses in Section 4.3.2. The generation profile is presented in a work week basis.

For each week of the generation stack, planned generation outages have been removed from the generation type. The HVDC is assumed to be running with both Pole 2 and the half pole

Generation Type	31/05 - 4/06	8/06 - 11/06	14/06 - 18/06	21/06 - 25/06	28/06 - 2/07	5/07 - 9/07	12/07 - 16/07	19/07 - 23/07	26/07- 30/07	02/08 - 06/08	09/08 - 13/08	16/08 - 20/08	23/08 - 27/08
Thermal (2100.5 MW)	2100.5	2100.5	2100.5	2100.5	2100.5	2100.5	2100.5	2100.5	2100.5	2100.5	2100.5	2100.5	2100.5
Geothermal (678 MW)	678	678	678	678	678	678	678	678	678	678	678	678	678
Hydro RoR + cogen (338 MW)	338	338	338	338	338	338	338	338	338	338	338	338	338
Hydro storage (1417 MW) - outages	1306.8	1306.8	1306.8	1306.8	1356.8	1331.8	1331.8	1331.8	1331.8	1381.8	1355.8	1355.8	1311.8
Wind (0 MW)	0	0	0	0	0	0	0	0	0	0	0	0	0
IL - Industrial	87	87	87	87	87	87	87	87	87	87	87	87	87
SIR - Hydro RoR	49	49	49	49	49	49	49	49	49	49	49	49	49
Uncommitted fast	50	50	50	50	50	50	50	50	50	50	50	50	50
Uncommitted Slow	364.5	364.5	364.5	364.5	364.5	364.5	364.5	364.5	364.5	364.5	364.5	364.5	364.5
Received HVDC (785 MW)	785	785	785	785	785	785	785	785	785	785	785	785	785
Total Generation with 785 received DC	5758	5758	5758	5758	5808	5783	5783	5783	5783	5833	5807	5807	5763
Demand P95	5029	5029	5029	5029	5029	5029	5029	5029	5029	5029	5029	5029	5029
Fixed total	4499.8	4499.8	4499.8	4499.8	4549.8	4524.8	4524.8	4524.8	4524.8	4574.8	4548.8	4548.8	4504.8



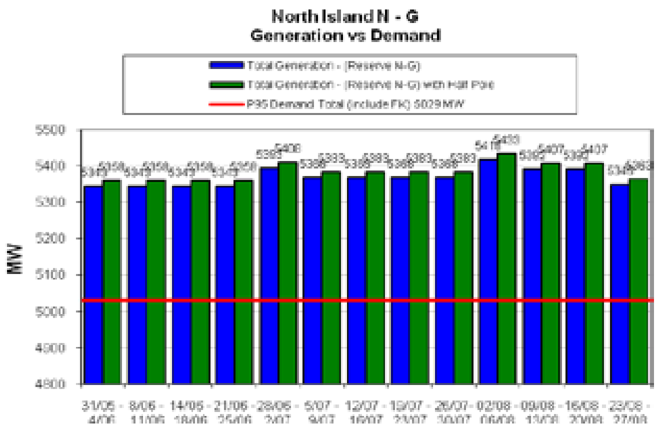
4.5 North Island Results

N-G

Reserve and Frequency Keeping requirement is set as 400 MW and 50 MW. P95 demand total refers to the summation of P95 demand (4792 MW), losses (148 MW), intra half hour variability (39 MW) and frequency keeping (50 MW).

N-G (P2 595MW and Half Pole 190 MW)	31/05 - 4/06	8/06 - 11/06	14/06 - 18/06	21/06 - 25/06	28/06 - 2/07	5/07 - 9/07	12/07 - 16/07	19/07 - 23/07	26/07-30/07	02/08 - 06/08	09/08 - 13/08	16/08 - 20/08	23/08 - 27/08
Total Generation with Received DC 785 MW	5758	5758	5758	5758	5808	5783	5783	5783	5783	5833	5807	5807	5763
Reserve N-G	-400	-400	-400	-400	-400	-400	-400	-400	-400	-400	-400	-400	-400
Total Generation - (Reserve N-G) with Half Pole	5358	5358	5358	5358	5408	5383	5383	5383	5383	5433	5407	5407	5363
P95 Demand Total (include FK) 5029 MW	5029	5029	5029	5029	5029	5029	5029	5029	5029	5029	5029	5029	5029
Surplus/Deficit	329	329	329	329	379	354	354	354	354	404	378	378	334

N-G (P2 700MW)	31/05 - 4/06	8/06 - 11/06	14/06 - 18/06	21/06 - 25/06	28/06 - 2/07	5/07 - 9/07	12/07 - 16/07	19/07 - 23/07	26/07-30/07	02/08 - 06/08	09/08 - 13/08	16/08 - 20/08	23/08 - 27/08
Total Generation with Received DC 650 MW	5743	5743	5743	5743	5793	5768	5768	5768	5768	5818	5792	5792	5748
Reserve N-G	-400	-400	-400	-400	-400	-400	-400	-400	-400	-400	-400	-400	-400
Total Generation - (Reserve N-G)	5343	5343	5343	5343	5393	5368	5368	5368	5368	5418	5392	5392	5348
P95 Demand Total (include FK)	5029	5029	5029	5029	5029	5029	5029	5029	5029	5029	5029	5029	5029
Surplus/Deficit	314	314	314	314	364	339	339	339	339	389	363	363	319

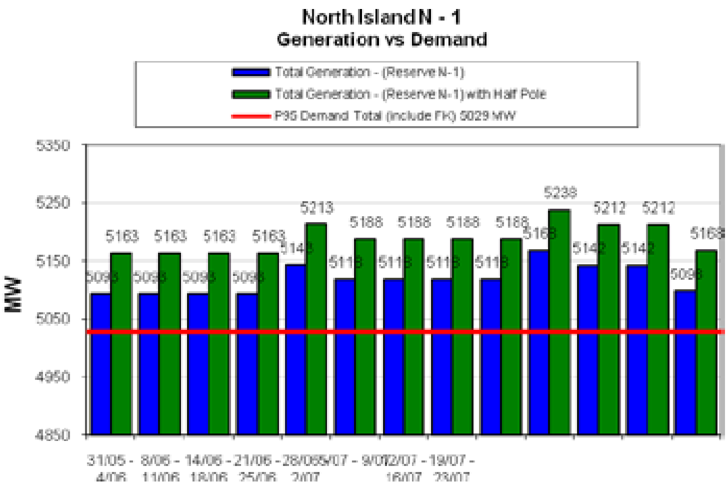


N-1

Reserve requirement is set as 650 MW and 595 MW.

N-1 (P2 595MW and Half Pole 190MW)	31/05 - 4/06	8/06 - 11/06	14/06 - 18/06	21/06 - 25/06	28/06 - 2/07	5/07 - 9/07	12/07 - 16/07	19/07 - 23/07	26/07-30/07	02/08 - 06/08	09/08 - 13/08	16/08 - 20/08	23/08 - 27/08
Total Generation with Received DC 785 MW	5758	5758	5758	5758	5808	5783	5783	5783	5783	5833	5807	5807	5763
Reserve N-1	-595	-595	-595	-595	-595	-595	-595	-595	-595	-595	-595	-595	-595
Total Generation - (Reserve N-1) with Half Pole	5163	5163	5163	5163	5213	5188	5188	5188	5188	5238	5212	5212	5168
P95 Demand Total (include FK)	5029	5029	5029	5029	5029	5029	5029	5029	5029	5029	5029	5029	5029
Surplus/Deficit	134	134	134	134	184	159	159	159	159	209	183	183	139

N-1 (P2 700MW)	31/05 - 4/06	8/06 - 11/06	14/06 - 18/06	21/06 - 25/06	28/06 - 2/07	5/07 - 9/07	12/07 - 16/07	19/07 - 23/07	26/07-30/07	02/08 - 06/08	09/08 - 13/08	16/08 - 20/08	23/08 - 27/08
Total Generation with Received DC 650 MW	5743	5743	5743	5743	5793	5768	5768	5768	5768	5818	5792	5792	5748
Reserve N-1	-650	-650	-650	-650	-650	-650	-650	-650	-650	-650	-650	-650	-650
Total Generation - (Reserve N-1)	5093	5093	5093	5093	5143	5118	5118	5118	5118	5168	5142	5142	5098
P95 Demand Total (include FK)	5029	5029	5029	5029	5029	5029	5029	5029	5029	5029	5029	5029	5029
Surplus/Deficit	64	64	64	64	114	89	89	89	89	139	113	113	69

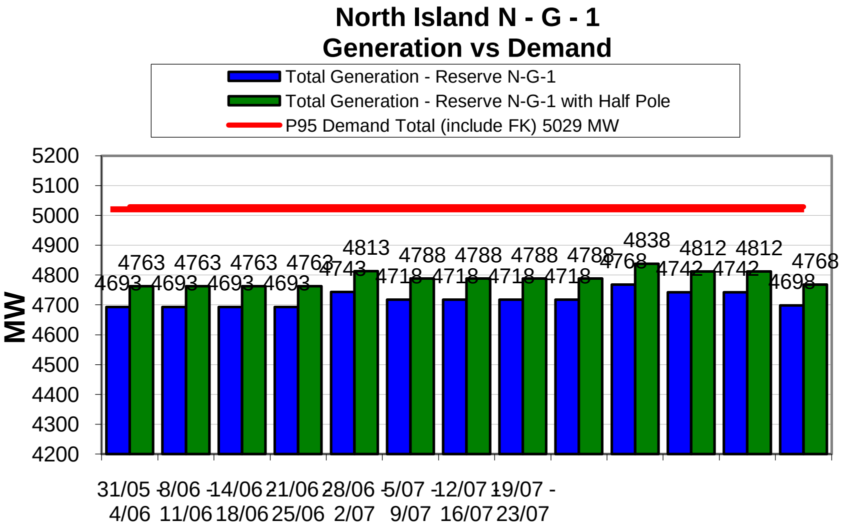


N-G-1

Reserve is now set as 1050 MW and 995 MW to represent the outage of largest unit.

N-G-1 (P2 595 MW and Half Pole 190 MW)	31/05 - 4/06	8/06 - 11/06	14/06 - 18/06	21/06 - 25/06	28/06 - 2/07	5/07 - 9/07	12/07 - 16/07	19/07 - 23/07	26/07-30/07	02/08 - 06/08	09/08 - 13/08	16/08 - 20/08	23/08 - 27/08
Total Generation with Received DC 785 MW	5758	5758	5758	5758	5808	5783	5783	5783	5783	5833	5807	5807	5763
Reserve N-G-1	-995	-995	-995	-995	-995	-995	-995	-995	-995	-995	-995	-995	-995
Total Generation - Reserve N-G-1 with Half Pole	4763	4763	4763	4763	4813	4788	4788	4788	4788	4838	4812	4812	4768
P95 Demand Total (include FK)	5029	5029	5029	5029	5029	5029	5029	5029	5029	5029	5029	5029	5029
Surplus/Deficit	-266	-266	-266	-266	-216	-241	-241	-241	-241	-191	-217	-217	-261

N-G-1 (P2 700 MW)	31/05 - 4/06	8/06 - 11/06	14/06 - 18/06	21/06 - 25/06	28/06 - 2/07	5/07 - 9/07	12/07 - 16/07	19/07 - 23/07	26/07-30/07	02/08 - 06/08	09/08 - 13/08	16/08 - 20/08	23/08 - 27/08
Total Generation with Received DC 650 MW	5743	5743	5743	5743	5793	5768	5768	5768	5768	5818	5792	5792	5748
Reserve N-G-1	-1050	-1050	-1050	-1050	-1050	-1050	-1050	-1050	-1050	-1050	-1050	-1050	-1050
Total Generation - Reserve N-G-1	4693	4693	4693	4693	4743	4718	4718	4718	4718	4768	4742	4742	4698
P95 Demand Total (include FK)	5029	5029	5029	5029	5029	5029	5029	5029	5029	5029	5029	5029	5029
Surplus/Deficit	-336	-336	-336	-336	-286	-311	-311	-311	-311	-261	-287	-287	-331

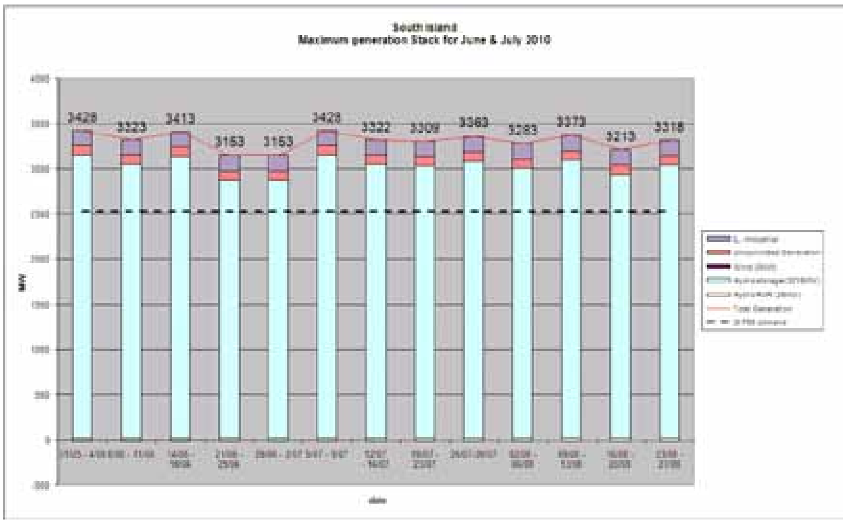


4.6 South Island Results

Total generation in South Island after taking into consideration allowance for reserve (120 MW) is 3033 MW. With South Island P95 demand of 2538 MW, there will be 495 MW of extra generation available for north transfer.

P95 Demand total refers to the summation of total P95 demand (2359 MW), losses (110 MW), frequency keeping (50MW) and intra half hour variability (19 MW).

Generation Type	31/05 - 4/06	8/06 - 11/06	14/06 - 18/06	21/06 - 25/06	28/06 - 2/07	5/07 - 9/07	12/07 - 16/07	19/07 - 23/07	26/07-30/07	02/08 - 06/08	09/08 - 13/08	16/08 - 20/08	23/08 - 27/08
Hydro RoR (25 MW)	25	25	25	25	25	25	25	25	25	25	25	25	25
Hydro storage (3219 MW)	3129	3024	3114	2854	2854	3129	3023	3010	3064	2984	3074	2913.8	3019
Wind (0 MW)	0	0	0	0	0	0	0	0	0	0	0	0	0
Uncommitted Generation	104	104	104	104	104	104	104	104	104	104	104	104	104
IL - Industrial	170	170	170	170	170	170	170	170	170	170	170	170	170
Total Generation	3428	3323	3413	3153	3153	3428	3322	3309	3363	3283	3373	3213	3318
SI P95 demand	2538	2538	2538	2538	2538	2538	2538	2538	2538	2538	2538	2538	2538
Total Fixed	3403	3298	3388	3128	3128	3403	3297	3284	3338	3258	3348	3188	3293



4.7 POCP Outage Information (Data extracted on 12 March 2010)

Island	Outage Block	GIP/GXPs	Start	End	Category	Type	Owner	Assessment	Last Modified	Planning Status	MW Loss
NI	ARI_7	ARI	14/12/2005 13:59	1/07/2016 00:00	Generation	continuous	Mighty River	Assessed	7/10/2009 15:55	Confirmed	2
NI	MTI_5	MTI	31/08/2009 07:00	30/12/2010 19:00	Generation	continuous	Mighty River	Assessed	12/10/2009 12:05	Confirmed	35.2
NI	WKM_1	WKM	11/01/2010 07:00	30/06/2010 19:00	Generation	continuous	Mighty River	Assessed	19/02/2010 14:26	Confirmed	25
SI	BEN1	BEN	3/05/2010 06:00	29/08/2010 06:00	Generation	continuous	Meridian	New	9/03/2010 02:05	Confirmed	90
NI	KTW7	TUI,KTW	17/05/2010 00:01	27/06/2010 23:59	Generation	continuous	Genesis	New	7/12/2009 19:05	Confirmed	18
	CYD_2	CYD2201	28/05/2010 07:00	15/06/2010 17:00	Generation	continuous	Contact Energy	New	27/01/2010 11:39	Tentative	108
	OHK_4	OHK	1/06/2010 08:00	1/06/2010 16:00	Generation	continuous	Mighty River	New	4/12/2009 08:09	Tentative	26.5
	SWN_2	SWN	5/06/2010 00:00	5/06/2010 18:00	Generation	continuous	Mighty River	New	4/12/2009 08:09	Tentative	45
	SWN_3	SWN	5/06/2010 00:00	5/06/2010 18:00	Generation	continuous	Mighty River	New	4/12/2009 08:09	Tentative	20
	SWN_5	SWN	5/06/2010 00:00	5/06/2010 18:00	Generation	continuous	Mighty River	New	4/12/2009 08:09	Tentative	50
	ROT_STN	ROT	5/06/2010 23:30	6/06/2010 01:30	Generation	continuous	Trustpower	New	13/08/2009 05:12	Tentative	11
SI	WTK2	WTK	7/06/2010 07:30	18/06/2010 18:00	Generation	continuous	Meridian	New	22/10/2009 02:03	Confirmed	15
SI	TKA1	TKA	8/06/2010 06:30	8/06/2010 18:00	Generation	continuous	Meridian	New	9/06/2009 02:03	Confirmed	25.2
	WTK4	WTK	8/06/2010 07:30	8/06/2010 14:00	Generation	continuous	Meridian	New	22/10/2009 02:03	Confirmed	15
	MTI_6	MTI	9/06/2010 09:00	9/06/2010 17:00	Generation	continuous	Mighty River	New	24/12/2009 11:47	Tentative	35.2
SI	BEN2	BEN	10/06/2010 07:00	12/06/2010 18:00	Generation	continuous	Meridian	New	20/10/2009 02:03	Confirmed	90
	WPA_3	WPA	10/06/2010 22:00	11/06/2010 04:00	Generation	continuous	Mighty River	New	4/12/2009 08:09	Tentative	18
	ROT_STN	ROT	12/06/2010 23:30	13/06/2010 01:30	Generation	continuous	Trustpower	New	13/08/2009 05:12	Tentative	11
	MAN6	MAN	14/06/2010 06:00	15/06/2010 20:00	Generation	continuous	Meridian	New	15/06/2009 02:04	Confirmed	121.5
	ATI_1	ATI	15/06/2010 09:00	15/06/2010 17:00	Generation	continuous	Mighty River	New	4/12/2009 08:09	Tentative	18.5
	CYD_4	CYD2201	16/06/2010 07:00	30/06/2010 17:00	Generation	continuous	Contact Energy	New	27/01/2010 11:39	Tentative	108
	MAN7	MAN	17/06/2010 06:00	18/06/2010 20:00	Generation	continuous	Meridian	New	18/06/2009 02:04	Confirmed	121.5
	MTI_4	MTI	19/06/2010 08:00	19/06/2010 16:00	Generation	continuous	Mighty River	New	4/12/2009 08:09	Tentative	35.2
	MAN5	MAN	20/06/2010 06:00	21/06/2010 20:00	Generation	continuous	Meridian	New	21/06/2009 02:04	Confirmed	121.5
SI	TKB3	TKB	21/06/2010 06:30	2/07/2010 18:00	Generation	continuous	Meridian	New	22/10/2009 02:03	Confirmed	80

Island	Outage Block	GIP/GXPs	Start	End	Category	Type	Owner	Assessment	Last Modified	Planning Status	MW Loss
SI	WTK5	WTK	21/06/2010 07:30	2/07/2010 16:00	Generation	continuous	Meridian	New	10/02/2010 02:03	Confirmed	15
	ARI_7	ARI	21/06/2010 14:30	21/06/2010 15:30	Generation	continuous	Mighty River	New	4/12/2009 08:09	Tentative	24
SI	BEN6	BEN	23/06/2010 07:30	30/06/2010 18:00	Generation	continuous	Meridian	New	9/03/2010 02:05	Confirmed	90
SI	BEN2	BEN	23/06/2010 08:00	24/06/2010 20:00	Generation	continuous	Meridian	New	24/06/2009 02:04	Confirmed	90
	ARI_2	ARI	24/06/2010 11:00	24/06/2010 16:00	Generation	continuous	Mighty River	New	4/12/2009 08:09	Tentative	22
	ARI_1	ARI	25/06/2010 11:00	25/06/2010 12:00	Generation	continuous	Mighty River	New	4/12/2009 08:09	Tentative	22
	ARI_3	ARI	25/06/2010 12:30	25/06/2010 13:30	Generation	continuous	Mighty River	New	4/12/2009 08:09	Tentative	22
	ARI_5	ARI	1/07/2010 08:00	1/07/2010 10:00	Generation	continuous	Mighty River	New	4/12/2009 08:09	Tentative	26
	ARI_6	ARI	1/07/2010 10:00	1/07/2010 12:00	Generation	continuous	Mighty River	New	4/12/2009 08:09	Tentative	26
	ARI_7	ARI	1/07/2010 12:00	1/07/2010 14:00	Generation	continuous	Mighty River	New	4/12/2009 08:09	Tentative	24
	ARI_8	ARI	1/07/2010 14:00	1/07/2010 16:00	Generation	continuous	Mighty River	New	4/12/2009 08:09	Tentative	26
	SWN_1	SWN	3/07/2010 00:00	3/07/2010 18:00	Generation	continuous	Mighty River	New	4/12/2009 08:09	Tentative	45
	SWN_3	SWN	3/07/2010 00:00	3/07/2010 18:00	Generation	continuous	Mighty River	New	4/12/2009 08:09	Tentative	20
	WKM_3	WKM	3/07/2010 08:00	3/07/2010 15:00	Generation	continuous	Mighty River	New	22/02/2010 12:07	Tentative	25
NI	KTW6	TUI,KTW	5/07/2010 00:01	1/08/2010 23:59	Generation	continuous	Genesis	New	7/12/2009 19:05	Confirmed	18
	MTI_2	MTI	5/07/2010 09:00	5/07/2010 13:00	Generation	continuous	Mighty River	New	10/12/2009 16:30	Tentative	35.2
	ARI_6	ARI	6/07/2010 10:00	6/07/2010 15:00	Generation	continuous	Mighty River	New	25/01/2010 14:04	Tentative	26
	MTI_3	MTI	7/07/2010 10:00	7/07/2010 14:00	Generation	continuous	Mighty River	New	10/12/2009 16:30	Tentative	35.2
	ATI_4	ATI	9/07/2010 11:00	9/07/2010 12:00	Generation	continuous	Mighty River	New	3/03/2010 09:24	Tentative	18.5
	OHA	OHA	10/07/2010 13:30	10/07/2010 16:00	Generation	continuous	Meridian	New	9/02/2010 02:03	Confirmed	132
SI	OHB8	OHB	12/07/2010 06:00	12/07/2010 18:00	Generation	continuous	Meridian	New	13/07/2009 02:06	Confirmed	53
SI	OHC14	OHC	12/07/2010 06:00	12/07/2010 18:00	Generation	continuous	Meridian	New	17/11/2009 02:06	Confirmed	53
	WTK6	WTK	12/07/2010 07:30	12/07/2010 14:00	Generation	continuous	Meridian	New	23/10/2009 02:04	Confirmed	15
	ARA_3	ARA	12/07/2010 13:00	12/07/2010 15:00	Generation	continuous	Mighty River	New	4/12/2009 08:09	Tentative	26
SI	OHC13	OHC	13/07/2010 06:00	14/07/2010 18:00	Generation	continuous	Meridian	New	17/11/2009 02:06	Confirmed	53
	WTK7	WTK	13/07/2010 07:30	13/07/2010 14:00	Generation	continuous	Meridian	New	23/10/2009 02:04	Confirmed	15
	OHK_2	OHK	13/07/2010 13:00	13/07/2010 15:00	Generation	continuous	Mighty River	New	25/01/2010 14:04	Tentative	26.5
	ARI_5	ARI	14/07/2010 11:00	14/07/2010 16:00	Generation	continuous	Mighty River	New	4/12/2009 08:09	Tentative	26

Island	Outage Block	GIP/GXPs	Start	End	Category	Type	Owner	Assessment	Last Modified	Planning Status	MW Loss
SI	OHC15	OHC	15/07/2010 06:00	15/07/2010 18:00	Generation	continuous	Meridian	New	16/07/2009 02:06	Confirmed	53
SI	OHB11	OHB	15/07/2010 06:30	15/07/2010 17:30	Generation	continuous	Meridian	New	16/07/2009 02:06	Confirmed	53
	ARI_8	ARI	15/07/2010 10:00	15/07/2010 15:00	Generation	continuous	Mighty River	New	4/12/2009 08:09	Tentative	26
	OHA5	OHA	17/07/2010 06:30	17/07/2010 17:30	Generation	continuous	Meridian	New	18/07/2009 02:06	Confirmed	66
SI	OHB9	OHB	19/07/2010 06:00	22/07/2010 18:00	Generation	continuous	Meridian	New	9/02/2010 02:03	Confirmed	53
SI	MAN2	MAN	19/07/2010 06:00	29/07/2010 18:00	Generation	continuous	Meridian	New	17/11/2009 02:06	Confirmed	121.5
SI	OHA7	OHA	19/07/2010 06:30	21/07/2010 17:30	Generation	continuous	Meridian	New	22/10/2009 02:03	Confirmed	66
	MTI_4	MTI	20/07/2010 11:00	20/07/2010 15:00	Generation	continuous	Mighty River	New	25/01/2010 14:04	Tentative	35.2
	ARI_1	ARI	21/07/2010 11:00	21/07/2010 16:00	Generation	continuous	Mighty River	New	20/01/2010 16:30	Tentative	22
SI	OHA4	OHA	22/07/2010 06:30	22/07/2010 17:30	Generation	continuous	Meridian	New	17/11/2009 02:06	Confirmed	66
	ARA_1	ARA	22/07/2010 09:00	22/07/2010 17:00	Generation	continuous	Mighty River	New	25/01/2010 14:04	Tentative	26
	ARA_2	ARA	23/07/2010 13:00	23/07/2010 15:00	Generation	continuous	Mighty River	New	25/01/2010 14:04	Tentative	26
	SWN_2	SWN	24/07/2010 00:00	24/07/2010 18:00	Generation	continuous	Mighty River	New	13/01/2010 10:07	Tentative	45
	SWN_3	SWN	24/07/2010 00:00	24/07/2010 18:00	Generation	continuous	Mighty River	New	13/01/2010 10:07	Tentative	20
	SWN_5	SWN	24/07/2010 00:00	24/07/2010 18:00	Generation	continuous	Mighty River	New	13/01/2010 10:07	Tentative	50
SI	OHA6	OHA	26/07/2010 06:30	29/07/2010 17:30	Generation	continuous	Meridian	New	17/11/2009 02:06	Confirmed	66
	ARI_4	ARI	26/07/2010 11:00	26/07/2010 12:00	Generation	continuous	Mighty River	New	25/01/2010 14:04	Tentative	22
	BEN2	BEN	27/07/2010 08:00	27/07/2010 17:00	Generation	continuous	Meridian	New	17/11/2009 02:06	Confirmed	90
	BEN5	BEN	28/07/2010 08:00	28/07/2010 17:00	Generation	continuous	Meridian	New	17/11/2009 02:06	Confirmed	90
	KPO_2	KPO	29/07/2010 10:00	29/07/2010 16:00	Generation	continuous	Mighty River	New	4/12/2009 08:09	Tentative	32
	BEN3	BEN	30/07/2010 08:00	30/07/2010 17:00	Generation	continuous	Meridian	New	17/11/2009 02:06	Confirmed	90
SI	AVI1	AVI	2/08/2010 07:30	13/08/2010 18:00	Generation	continuous	Meridian	New	14/11/2009 02:05	Confirmed	55
SI	BEN4	BEN	2/08/2010 08:00	3/08/2010 17:00	Generation	continuous	Meridian	New	9/02/2010 02:03	Confirmed	90
	MTI_7	MTI	3/08/2010 08:00	3/08/2010 16:00	Generation	continuous	Mighty River	New	25/01/2010 14:04	Tentative	35.2
SI	AVI1	AVI	5/08/2010 07:00	6/08/2010 17:00	Generation	continuous	Meridian	New	14/11/2009 02:05	Confirmed	55
	KPO_1	KPO	5/08/2010 10:00	5/08/2010 16:00	Generation	continuous	Mighty River	New	4/12/2009 08:09	Tentative	32
SI	MAN1	MAN	9/08/2010 06:00	12/08/2010 20:00	Generation	continuous	Meridian	New	9/02/2010 02:03	Confirmed	121.5
	WTK1	WTK	9/08/2010 06:45	9/08/2010 16:00	Generation	continuous	Meridian	New	22/10/2009 02:03	Confirmed	15

Island	Outage Block	GIP/GXPs	Start	End	Category	Type	Owner	Assessment	Last Modified	Planning Status	MW Loss
NI	ARI_6	ARI	9/08/2010 07:00	24/08/2010 19:00	Generation	continuous	Mighty River	New	8/03/2010 12:24	Tentative	26
	MTI_8	MTI	9/08/2010 08:00	9/08/2010 16:00	Generation	continuous	Mighty River	New	4/12/2009 08:09	Tentative	35.2
	WPA_2	WPA	10/08/2010 10:00	10/08/2010 16:00	Generation	continuous	Mighty River	New	4/12/2009 08:09	Tentative	18
	OHA	OHA	14/08/2010 13:30	14/08/2010 16:00	Generation	continuous	Meridian	New	9/02/2010 02:03	Confirmed	132
SI	TKB2	TKB	16/08/2010 06:30	17/08/2010 18:00	Generation	continuous	Meridian	New	18/11/2009 02:06	Confirmed	80
SI	TKA1	TKA	16/08/2010 06:30	17/08/2010 18:00	Generation	continuous	Meridian	New	18/11/2009 02:06	Confirmed	25.2
SI	AVI2	AVI	16/08/2010 07:00	28/08/2010 20:00	Generation	continuous	Meridian	New	14/11/2009 02:05	Confirmed	55
	MTI_1	MTI	16/08/2010 09:00	16/08/2010 17:00	Generation	continuous	Mighty River	New	9/12/2009 14:44	Tentative	35.2
SI	MAN7	MAN	17/08/2010 06:00	18/08/2010 20:00	Generation	continuous	Meridian	New	17/11/2009 02:06	Confirmed	121.5
SI	AVI2	AVI	17/08/2010 07:30	26/08/2010 18:00	Generation	continuous	Meridian	New	31/10/2009 02:04	Confirmed	55
	WPA_1	WPA	17/08/2010 10:00	17/08/2010 16:00	Generation	continuous	Mighty River	New	20/01/2010 16:30	Tentative	18
	ATI_2	ATI	18/08/2010 11:00	18/08/2010 12:00	Generation	continuous	Mighty River	New	4/12/2009 08:09	Tentative	18.5
	BEN6	BEN	19/08/2010 08:00	19/08/2010 17:00	Generation	continuous	Meridian	New	17/11/2009 02:06	Confirmed	90
	WKM_4	WKM	19/08/2010 10:00	19/08/2010 17:00	Generation	continuous	Mighty River	New	4/12/2009 08:09	Tentative	25
	MTI_10	MTI	20/08/2010 09:00	20/08/2010 17:00	Generation	continuous	Mighty River	New	24/12/2009 11:47	Tentative	35.2
	PRI_STN	PRI,TUI	22/08/2010 09:00	22/08/2010 15:00	Generation	continuous	Genesis	New	21/12/2009 16:26	Confirmed	0
NI	PRI_STN	TUI,PRI	23/08/2010 00:01	24/08/2010 23:59	Generation	continuous	Genesis	New	10/07/2009 11:12	Confirmed	44
NI	PRI4	TUI,PRI	23/08/2010 00:01	3/10/2010 23:59	Generation	continuous	Genesis	New	7/07/2009 15:49	Confirmed	22
	MTI_1	MTI	23/08/2010 11:00	23/08/2010 15:00	Generation	continuous	Mighty River	New	4/12/2009 08:09	Tentative	35.2
	MTI_9	MTI	24/08/2010 08:00	24/08/2010 16:00	Generation	continuous	Mighty River	New	4/12/2009 08:09	Tentative	35.2
	ARI_4	ARI	25/08/2010 11:00	25/08/2010 15:00	Generation	continuous	Mighty River	New	20/01/2010 16:30	Tentative	22
	WKM_2	WKM	26/08/2010 10:00	26/08/2010 17:00	Generation	continuous	Mighty River	New	4/12/2009 08:09	Tentative	25
	OHK_3	OHK	26/08/2010 13:00	26/08/2010 15:00	Generation	continuous	Mighty River	New	4/12/2009 08:09	Tentative	26.5
	ARI_2	ARI	27/08/2010 10:00	27/08/2010 11:00	Generation	continuous	Mighty River	New	25/01/2010 14:04	Tentative	22
	ARI_7	ARI	27/08/2010 11:00	27/08/2010 15:00	Generation	continuous	Mighty River	New	25/01/2010 14:04	Tentative	24
	SWN_1	SWN	28/08/2010 00:00	28/08/2010 18:00	Generation	continuous	Mighty River	New	4/12/2009 08:09	Tentative	45
	SWN_3	SWN	28/08/2010 00:00	28/08/2010 18:00	Generation	continuous	Mighty River	New	4/12/2009 08:09	Tentative	20